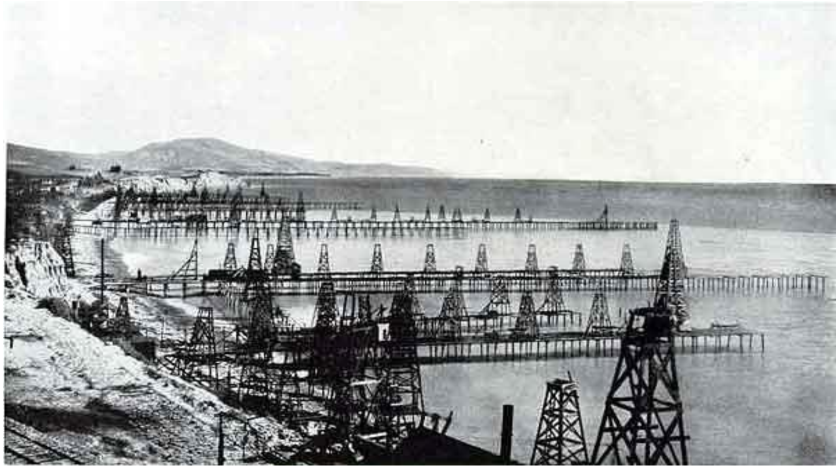

Managed Pressure Cementing

Control System Design & Simulation

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Thesis to obtain the Master of Science Degree in

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ABSTRACT

Oil and gas extraction have always been a dangerous process, starting with the hole drilling. When it starts, to avoid walls collapse, casings are inserted and cemented. Not only does this process guarantee a solid well structure but it also avoids losses of any fluid to the formation, where cement works as isolator, preventing environmental problems.

Managed Pressure Cementing (MPC) is a method developed essentially to cement deep offshore wells in a safer, more controlled and more efficient way. It is a relatively new process therefore companies are very conservative with releasing information to the outside world. Oil platforms normally belong to companies that hire subcontractors, i.e. smaller companies, to perform different specialized works, but the rig owner always assigns his own staff to supervise the different operations. Statoil commissioned this project thesis with the objective of providing a complement to the training given to supervisors who will follow future cementing processes.

A model for predicting fluids behaviour inside the well was implemented using MATLAB software. The objective of such approach is to develop simulations in a controlled computational environment and draw relevant conclusions e.g. to characterize the pressure profiles inside the well. In order to fulfil the main objective of managing the Bottom Hole Pressure (BHP), a Proportional and Integral (PI) controller is integrated on the model. It actuates on an automatic choke at the rig that regulates the flow out of the well, opening/closing it and consequently changing Surface Back Pressure (SBP). The pressure reference at the bottom is $898\ Bar$, which has an error window of $\pm 6{,}9\ Bar$.

The results obtained from computational simulations validate proposed control objectives, since the BHP evolved inside defined boundaries, except during one critical moment.

Key words: Managed Pressure Cementing; Bottom Hole Pressure; Modelling Well Structure & Fluid Flow; Proportional and Integral Controller; Automatic Choke.

RESUMO

A extração de petróleo e gás natural sempre foi um processo perigoso, começando pela perfuração do poço. Quando esta começa, para evitar o colapso das paredes do poço, são inseridas e cimentadas tubagens. Este processo garante tanto uma estrutura sólida para o poço como uma melhor isolação relativamente ao meio ambiente, evitando o escoamento de qualquer fluido para a camada terrestre e consequentes problemas ambientais.

Cimentação por Pressão Controlada (MPC) é um método desenvolvido essencialmente para cimentar poços no mar, de uma forma mais segura, controlada e eficiente. É um processo relativamente novo e como tal as empresas estão ainda relutantes em divulgar o seu trabalho desenvolvido. As plataformas petrolíferas normalmente pertencem a uma companhia que subcontrata companhias mais pequenas, para desempenhar trabalhos especializados, sendo que a empresa que está a explorar a plataforma atribui o trabalho de supervisão a um dos seus funcionários. A Statoil confiou esta tese precisamente com o objetivo de providenciar um complemento ao treino dado a esses mesmos supervisores que seguirão o processo de cimentação.

Através da utilização do *software* MATLAB, foi implementado um modelo que prediz o comportamento dos fluidos dentro de um poço. O objetivo deste é simular esse comportamento num ambiente computacionalmente controlado, retirando as conclusões relevantes, tais como os perfis das pressões. Para que o principal objetivo – controlar a pressão no fundo do poço – fosse alcançado, um controlador Proporcional e Integral (PI) foi integrado no modelo, atuando numa válvula automática à saída do poço, regulando assim o seu caudal, abrindo e fechando-a. Consequentemente, a pressão sobre esta varia, alterando a pressão no fundo do poço. O valor de referência para a pressão neste último local é de $898\ Bar$, cuja janela de erro é de $\pm 6{,}9\ Bar$.

Os resultados obtidos através das simulações computacionais estão conforme os objetivos propostos uma vez que a pressão no fundo do poço evolui no tempo sempre dentro dos limites definidos, excetuando num momento crítico da simulação.

Palavras-chave: Cimentação por Pressão Controlada; Pressão no Fundo do Poço; Modelação da Estrutura de um Poço & de Fluxo de Fluidos; Controlador Proporcional e Integral; Válvula Automática.

CONTENTS

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List of Acronyms

BHA – Bottom Hole Assembly
BHP – Bottom Hole Pressure
BOP – Blowout Preventer
ECD – Equivalent Circulating Density
MPC – Managed Pressure Cementing
MPD – Managed Pressure Drilling
MRC – Multi-Reservoir Contact
MWW – Mud Weight Window
NTNU – Norwegian University of Science and Technology
OD – Overbalanced Drilling
ODE – Ordinary Differential Equation
PI – Proportional and Integral
RMR – Riserless Mud Recovery
ROP – Rate Of Penetration
SBP – Surface Back Pressure
SI – International System
UD – Underbalanced Drilling
USR – Ultra Short Radius

Nomenclature

Latin symbols

A – Cross sectional area

a – Acceleration

D – Diameter

E – Energy

e – Energy per unit mass

e_r – Bottom hole pressure deviation

F – Force

f – Darcy friction factor

g – Acceleration of gravity

h_f – Friction coefficient

k_c – Choke constant

k_d – Controller derivative gain

k_i – Controller integral gain

k_p – Controller proportional gain

l – Length

m – Mass

P – Pressure

p – Linear momentum

Q – Heat

q – Fluid flow rate

Re – Reynolds number

r – Radius

T_i – Integral time

T_d – Derivative time

t – Time

u – Choke opening

V – Volume

v – Velocity

W – Work

x – Position

y – Position

z – Position

Greek symbols

β – Isothermal Bulk Modulus

θ – Angle

ρ – Fluid density

μ – Viscosity

CHAPTER 1
INTRODUCTION

The oil and gas industry is one of the most costly but also most profitable industries in the world. Leaving oil or gas inside a wellbore due to its depth or to its short workable pressure window is something companies do not desire. So investing on profitable and safe ways to drill in such conditions became a necessity. The risks of well collapse or fracture increase with depth and so the risks of losing fluids to the formation. Even the risk of resulting blowouts, therefore causing environmental problems, is too high. All these risks need to be managed and mitigation actions are required to avoid them: pressure inside the well has to be kept steady during all the processes, starting on drilling procedure, going through casing, cementing, resources production and finishing with the shutdown of well facilities.

1.1. Motivation

This project thesis was developed in cooperation with Statoil, which is appointed as one of the world’s biggest oil companies in 2015 [1]. Statoil owns a large number of offshore rigs, therefore it is a normal procedure to hire specialized contractors, which are smaller companies with competencies and capacities to execute specific operations. As petroleum industry is a business sector that involves large quantities of financial resources, a company can be specialized only in drilling wells, or cementing them, while other is responsible for extracting resources, still making a huge profit of it. However, it is necessary for Statoil to have its own staff supervising all field operations individually.

Managed Pressure Cementing (MPC) is a technique already being implemented by small companies, but as it is a new method they are normally conservative about sharing specific information and details regarding the process. This project aims at becoming the beginning of a guide to complement the supervisor’s training on the cementation process.

In terms of technological progress, MPC technique mainly brings more safety by improving zonal isolation without inducing losses to the formation and avoiding formation fluids flowing to the annulus during cementing process [2].

1.2. Objectives

The thesis consists on building a model on MATLAB software environment to simulate the cementing process, since cement slurry starts until it reaches the desired final state (all inside the annulus). The program has to be able to control the Bottom Hole Pressure (BHP) by using a Proportional and Integral (PI) controller on the valve opening, which actuates through Surface Back Pressure (SBP).

The main MPC goal is to keep the annular BHP between the pore pressure and fracture pressure which define the pressure window, but as the project implements a PI controller, the expected BHP is compared to a reference value to minimize the difference between them (middle value between the two pressures enunciated before). For a pioneer project such as this, the value at the bottom of the well is not of major importance as long as it is realistic. It is of utmost significance the controller works properly and BHP stays inside the desired Mud Weight Window (MWW).

This model is built up based on techniques like Managed Pressure Drilling (MPD), Underbalanced Drilling (UD) and/or Riserless Mud Recovery (RMR) techniques, which are used to drill wellbore sections and were already adapted and tried out on the cementing and drilling process successfully.

1.3. Thesis Structure

This dissertation is divided into five chapters including the present one, which enunciates its scope, the objectives proposed and the methods used to reach them. The next chapter refers to the background of the project, including historical references not only to extraction industry but also to Statoil Company. A description on existing methods that influence MPC model projected and real cases where cementing process was automatically controlled through a choke at the top are also described in this chapter.

Theoretical foundations used for this model compose the third chapter. It starts with the main physical laws applied and with some relevant fluid properties, differentiating cement and mud. The variables used in MATLAB code to accomplish a realistic representation of what happens during the cementing process and the conventional well structure complete this chapter, finishing it with a detailed description of the designed PI controller.

The fourth chapter illustrates the simulation of the model projected in the previous chapter, justifying some particular choices in order to have better results. As the output from MATLAB is a simulation in time and as this chapter is divided according to some important transitions during the entire simulation time, the results are discussed after each transition is exposed.

The last chapter presents the final conclusions over the project and possible future work and improvements to this thesis.

CHAPTER 2
BACKGROUND

2.1. Framework

In 1896 Henry L. Williams claimed to be the first to drill an offshore well in California. The results obtained while drilling onshore on that same beach during the two years before were so good that it led them to explore oil at sea [3]. Despite being offshore it required a connection to shore (Figure 1). This connection was dropped in 1911 when first independent platforms were built in Caddo Lake in Texas, Louisiana (Figure 2).

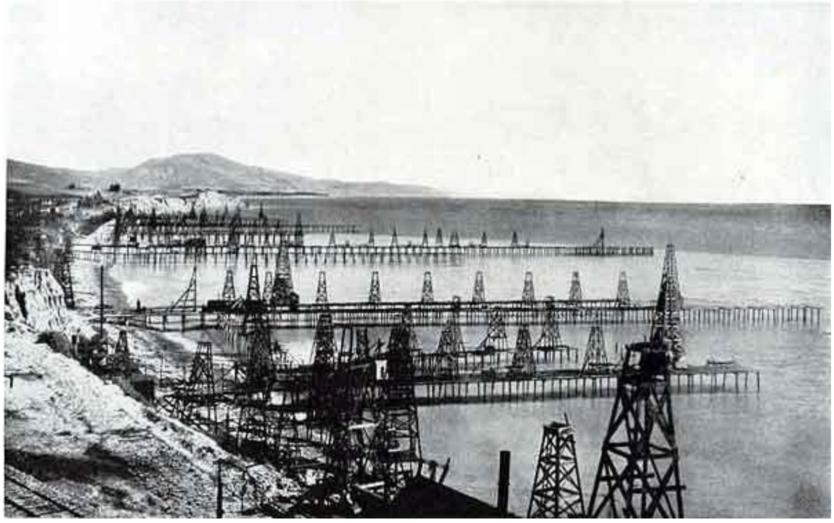


Figure 1: Oil piers on a beach at Summerland, California (Pacific Ocean), [3].

Figure 2: Caddo Lake in Louisiana, circa 1911 [3].

However, the first offshore sketch goes back to 1869, a platform designed by Thomas Fitch Rowland but never built (Figure 3). The first underwater drilled wells documented are from 1891 in Ohio. Joyce Alig and other Ohio historians proved “hundreds of 1890s oil wells pumping far out in the waters of Grand Lake St. Marys (near Celina) in Mercer and Auglaize counties” [3, 4] (Figure 4).

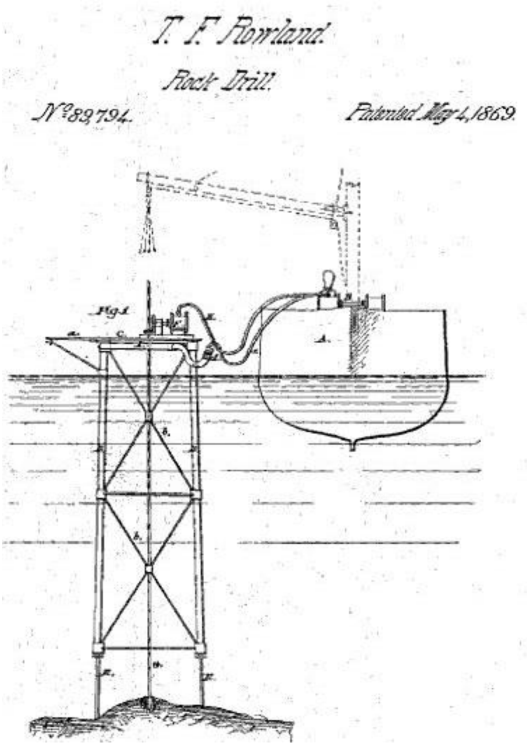


Figure 3: First offshore platform design by Thomas Rowland [3].

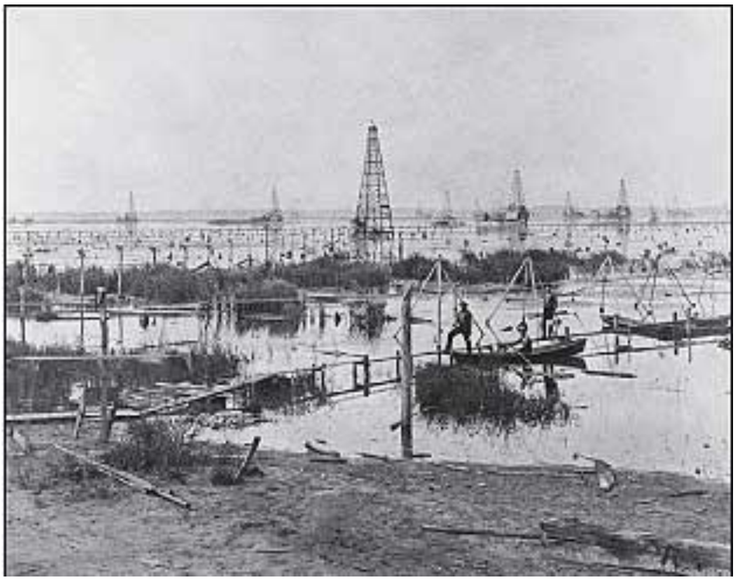


Figure 4: Grand Lake St. Marys in Ohio, 1890s [3].

Soon (1938) offshore techniques reached Gulf of Mexico and in 1947 the Kerr-McGee drilling platform, known as Kerr-McGee's Mighty Kermac No. 16 (Figure 5), was out of sight of land. It was the first offshore rig being in such condition, producing 40 barrels[1] per hour.

Figure 5: Kermac Rig No.16, the first being out of sight of land [3].

Since 1990s petroleum industry suffered a tremendous evolution with new processes being discovered and advanced technology. In 1996, the Troll A natural gas platform, operated by Statoil, "set the Guinness World Record for largest offshore gas platform" [3], standing over 1000 feet[2] of water and being 1500 feet high (Figure 6). It is not only one of "the largest and most complex engineering projects in history" but also one of "the largest objects ever to be moved by man across the surface of the Earth" [3].

Figure 6: Troll A offshore platform, built in land and moved across the water, in North Sea [3].

[1] 1 American barrel of petroleum is equal to 159 litres.
[2] 1 foot is equal to 0,305 metre.

2.2. Statoil Company

Petroleum industry is one of the largest industries in Norway for the past years. In 2013, state revenues from this industry were NOK[3] 401 billion meaning 29% of state revenues of that year. The company that most contributed and still contributes to this value is Norwegian State Oil Company, Statoil, which is one of the most well succeeded oil and gas companies all over the world. It was firstly founded in 1972, in Norway, and after seven years it started the extraction of resources. Nine years ago, Statoil merged with Norsk Hydro's oil and gas department. This joint made the company stronger which allowed its internationalization. Since then Statoil has been playing a huge roll on Norwegian economy by entering on Norway's stock exchange [5, 6].

As an international company Statoil has operations in 37 different countries around the world. They explore gas and oil mainly but their worries regarding environment and their interested in joining clean energy market made them start capturing and storing carbon during fossil fuels extraction processes. Oil and gas stations offshore are also being improved in order to produce clean energy from renewable resources like wind power stations. Statoil's biggest activities are in Norway on its continental shelf as it has plentiful oil and gas resources. It is divided in 3 ocean areas, the North Sea, the Norwegian Sea and the Barents Sea, covering an area greater than two million square kilometres with almost 80 production fields, where the North Sea plays the major part (60 fields). Statoil is currently the leading operator on the continental shelf being presented in 52 fields [5, 6].

To such a big company as Statoil, innovation and development must be presented all the time and this project is a proof of it. MPC is an improvement to the way wells are cemented after drilled. According to the Society of Petroleum Engineers it was already successfully implemented in fields where specific conditions were verified though the final objective is to use this method in every well regardless its conditions [2].

2.3. Background

Different techniques are normally used to drill and cement depending on different conditions found and also different types of wells. With the evolution of technology methods were optimized as in the past it was frequent to have severe environmental incidents and even operators' death. Nowadays these situations are atypical [7].

Before a well starts producing hydrocarbons it must be completed, meaning it has to be drilled until the reservoir is reached and its walls must be cemented to prevent flow leakage to the formation or loss of circulation. However, it cannot be drilled and then cemented. Wells are bored in sections and after each, a sequence of casings is introduced to be cemented so that the risk of walls fracture/collapse is mitigated. According to Gomes and Alves [7], sections can have different lengths due to different reasons: the smaller is the bit the faster is to drill so it gets less costly; abrupt pressure variation or a different type of rock detected implies to cement to avoid well collapse or fracture; the use of drill strings and casings with a smaller diameter reduces the time and costs of drilling.

[3] 1 Norwegian Crown (NOK) is equal to 0,105€.

2.3.1. Conventional Techniques

Conventional techniques are the ones used in vertical wells (Figure 7) with less than $2000\,m$ depth. A drill bit at the end of the drill pipe rotates with it in order to dig the hole. A special (drilling) mud is pumped inside the well in order to contain the pressure of the reservoir. Its circulation also helps to the rotation of the drill pipe, brings the removed sediments (cuttings) up to the rig and cools down the drill bit. After each drilled section the casings are inserted and cemented to the walls to prevent not only flow leaks and losses of circulation but also fracture or collapse of the well. Mud density is controlled in order to practice a higher hydrostatic pressure than reservoir pressure. This technique, called Overbalanced Drilling (OD), also prevents leaks to the formation [7].

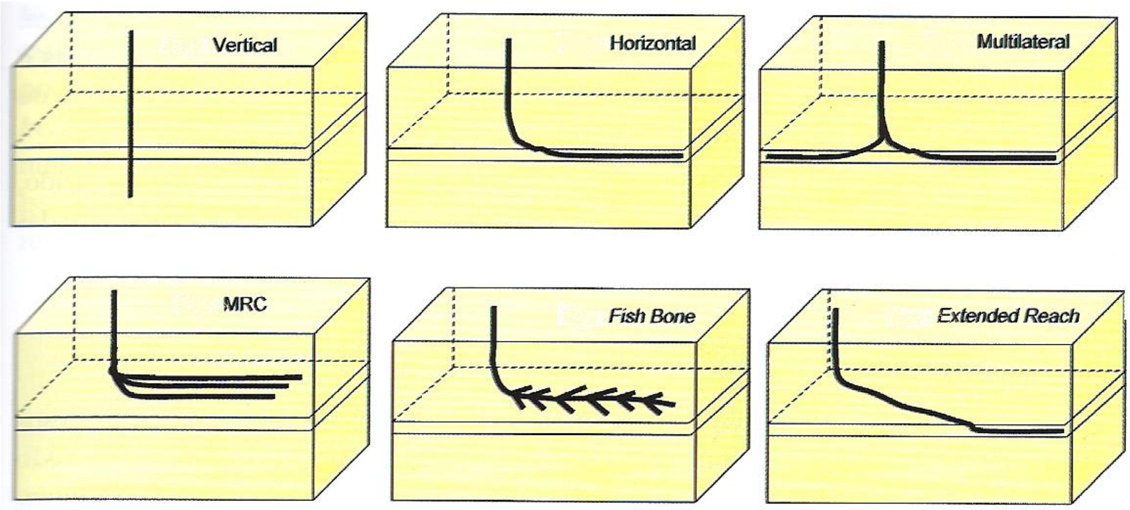


Figure 7: Most common well's configurations (MRC – Multi-Reservoir Contact) [7].

2.3.2. Advanced Techniques

Advanced techniques are the ones used on vertical wells deeper than $2000\,m$ and horizontal wells, more specifically on wells with an angle higher than $80°$. With the progress on technology multilateral wells appeared, allowing to reach different points of the same reservoir (or even different reservoirs) from the same well (Figure 7). Other techniques also appeared and severely depleted wells closed a few years ago were reopened to test the new techniques.

2.3.2.1. Horizontal Wells

Despite being more expensive than vertical wells, horizontal wells produce two to four times more hydrocarbons in the same period of time, therefore they are more profitable. At first they were made to connect natural fractures from fractured reservoirs and to avoid water coning and gas expansion but nowadays oil companies started to use them in a regular basis as they are more lucrative and allow the development of thinner and/or depleted reservoirs [7].

Horizontal wells are classified in Ultra Short Radius (USR), short radius, medium radius and long radius where the first two reach horizontality close to surface. USR classification can differ from surface between 10 to 30 metres while the others are normally $140\,m$, $250\,m$ and $300\,m$ in depth, respectively [7]. Extended reach wells (Figure 7) are a kind of horizontal wells used to go far from the vertical well positioning and to cross the reservoir.

2.3.2.2. Multilateral Wells

Multilateral wells are characterized by two or more lateral wells connected to the mother borehole through a junction point (Figure 8). This may be a huge disadvantage as it is only used one main well. If there is a mechanical breakdown all lateral wells have to stop instead of one. On the other hand the advantages this technique brings to the production surpass this problem. The rate of recuperation increases, just like the rate of production, and the costs decrease just as the number of injectors and producers. Geological risks also diminish since the lateral wells become shorter occupying more space around the main well and reaching numerous points of the same reservoir. Figure 7 shows two different types of multilateral wells: multi-reservoir contact (MRC) wells, which allow reaching different points of the reservoir by extending the lateral ramifications if the access through surface is difficult, and the fish bone configuration.

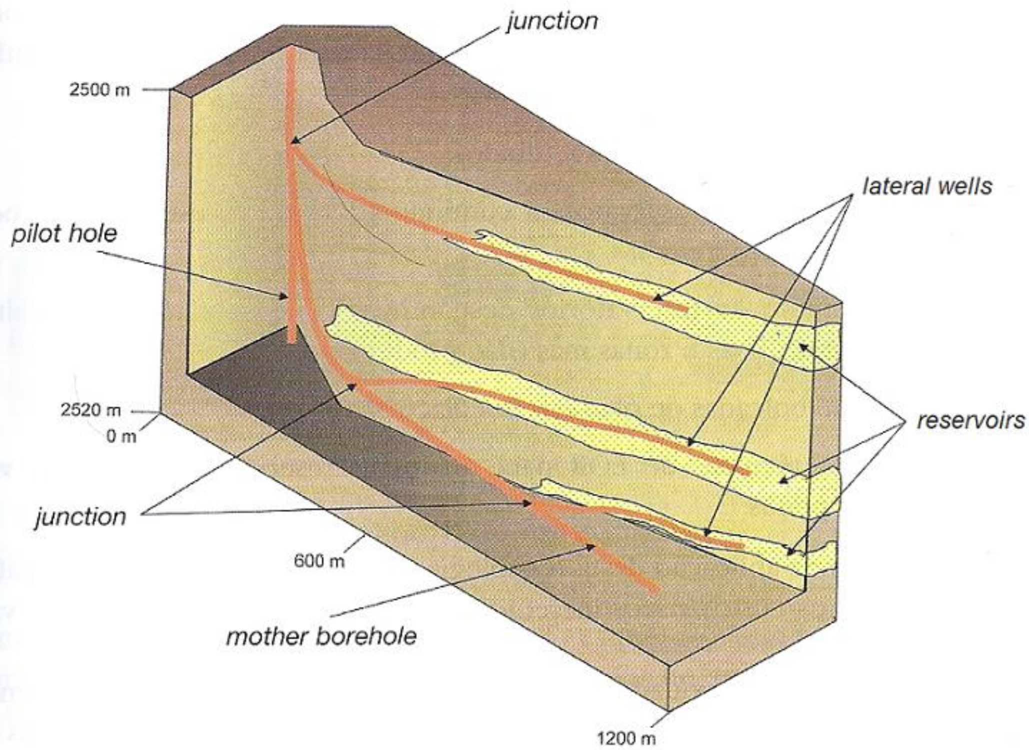


Figure 8: Multilateral well [7].

2.3.2.3. Riserless Mud Recovery Technique

Drilling offshore top holes is always a challenge because pore pressure limit (when risk of well collapse is higher) is close to the hydrostatic pressure of the sea water column and also due to the marine sediments. According to Stave *et al*. [8] drilling a top hole is normally done with seawater as drilling fluid (especially if there is a shallow gas risk) and marine sediments are discharged to seabed. Also if there is a blowout risk the hole has to be thinner in order to be easier to avoid it.

RMR technique incorporates a dual gradient technology which allows returning the marine sediments with the flow to the rig with the help of a subsea pump connected to a suction module. As the drilling fluid returns to the rig it is possible to reuse it, so one of the advantages is that there are no worries it may run out. The fact of having a closed loop enables to control the volume of the fluid and consequently its flow, allowing the monitoring of pressure variations, compensating them earlier. “This process enables the use of weighted and engineered mud since there are no discharge of mud and cuttings to the marine environment” [8], ensuring improved hole conditions and wellbore quality. With the decreasing of shallow gas kicks and flow loss risks, in addition to the increasing of the mud weight window (explained ahead), it also extends the casing set point depth.

Volume control ends up being important during cement process. By monitoring the amount of mud volume going out of the well it is possible to predict where the cement is and consequently stop the process when cement volume is all inside the annulus.

2.3.2.4. Underbalanced Drilling

Unlike OD, underbalanced drilling technique is used to have a natural flow of fluids from the reservoir to the rig meaning the hydrostatic pressure is not high enough to make the flow going down. This carries various advantages: reduces the degradation effects (skin effects) on the well; diminishes circulation losses due to fractures or depleted wells; increases the Rate of Penetration (ROP). The most frequent method to drop hydrostatic pressure is to reduce drilling fluid density by injecting an inert gas, predominantly on impermeable formations in order to raise the ROP, as on permeable ones the risk of well collapse is higher [7].

The biggest con is the fact that it is easier to lose control over the hydrocarbons production which can lead to a blowout. At the beginning this was a common and involuntary situation resulting on severe environmental incidents and workers death. With the new technology it is no longer usual to have blowouts as it is now possible to predict the expected pressure at the reservoir and the use of Blowout Preventers (BOP) is mandatory. Other disadvantage of having a low hydrostatic pressure is the increasing of well’s collapsing risk. Its costs are higher but, once again, it ends up being more profitable to do it in this way if risks are minimal [7]. Due to this risk, the technique is confined to wells with a wider MWW (deep wells are excluded).

According to Yuhuan Bu *et al*. [9], UD applied to cementing process has the same risks as during drilling operations but with higher chances to occur; the “cementing fluid is more easily to invade the formation”. Regarding the process itself, the technique is “still inadequate either from operation, performance, or from the cementing quality guarantee and economic view”, which is enough to restrain it from deep well. By 2010 there was no research on the real-time control of annulus pressure during cementing.

2.3.2.5. Managed Pressure Drilling Technique

Managed pressure drilling is a technique to “drill wells where there is a tight MWW, [...] to more accurately control the annular bottom hole pressure (BHP)” [10]. This tight interval normally appears not only in offshore drilling due to soft marine sediments, but also in land drilling for shallow holes or deep wells [2]. The method described by Mashaal *et al*. [10] states that the basic principle “of MPD is to apply annular SBP to control the BHP and compensate for annular pressure fluctuations that result from switching mud pumps on and off” while “the flow of mud from the well is controlled by a choke manifold to apply a desired SBP.”

The MWW referred previously allows understanding the necessary mud density to use while drilling. During well completion (or any other process inside the well like hydrocarbons production) it is crucial to keep the pressure between the collapse and fracture values (Figure 9). If the pressure at a certain point is too low the walls of the well may collapse while if it is too high fractures along the walls may appear and fluids start to flow into the formation.

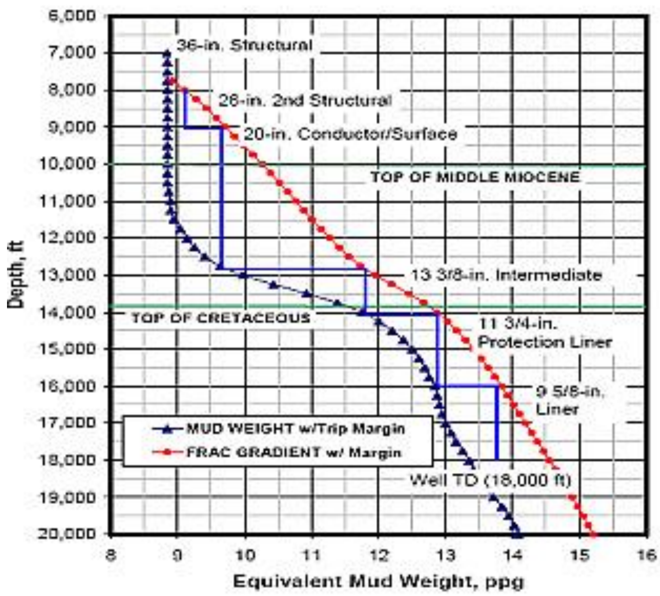


Figure 9: Mud weight window [11].

MPD main characteristic is the use of an automated choke which mechanically reacts to any pressure oscillation by applying SBP through its opening/closing, in order to keep the BHP steady, around its estimated value for the set-point to the feedback loop. This value is estimated based on input values like wellbore geometry, fluid properties and flow rate (and others detailed ahead) and then is used to estimate the necessary SBP to adjust the choke position, taking hydrostatic and frictional pressures into account as well. All these estimates generate their own error leading to inaccuracies. Other sources of error are the transient regimes which provide transient values, like fluid acceleration or flow in changing, and unexpected events like equipment failures, or gas chambers which originate depressions [10].

Drilling cost reduction and safety increasing are the main advantages of using MPD [2]. The first one is achieved mainly by reducing the drilling time while the second one is by keeping the BHP away from the pore and fracture limits (avoiding fluids flowing to the formation). In Figure 9 it is possible to see the different sections drilled with conventional drilling. As the pressure applied at the top is constant, instead of being adjusted, the continuous blue line increases constantly with depth. Each time it reaches one of the limits the section has to be cemented and a new one has to be drilled. With MPD, that same curve would become more irregular but it would touch (if it would happen) fewer times the limits. It would mean fewer sections to drill and cement, which would be translated into less time spent in removing drill bits and less changes of mud.

2.3.2.6. Balanced Pressure Cementing by Air Injection in Annuli

Air injection is a method based on UD, used to reduce drilling fluid's density. A new study was introduced by Bu *et al*. [9] consisting on both UD and MPD techniques, taking advantage of the air injection and wellbore control pressure from both, respectively. *Balanced Pressure Cementing Technology by Air Injection in Annuli* "could effectively control the annulus pressure of wellbore, assure the cementing quality and protect the hydrocarbon reservoir, thus reduces the exploration and development cost" [9].

Considering air injection occurs in annuli, wellbore annular pressure drops until it is lower than reservoir's. The pressure difference will make the fluid flow from the bottom to the top through the annulus. SBP is then used to keep annular pressure inside MWW [9].

Besides reducing fluid column pressure, this technique manages it preventing leakage and fully protecting reservoir. Reducing drilling fluid density allows using the desired density cement slurry guaranteeing its strength during cementing process. The fact that the injected gas is air reduces the risk of environmental problems [9].

2.3.2.7. Managed Pressure Cementing Technique

Managed pressure cementing process came up right after good and regular results with techniques like RMR or MPD. It exploits dual gradient method as in the first technique and applies SBP like in the second. Similar to what is chased while drilling, the main objective of this method is to smooth pressure oscillations at the bottom as much as possible. To avoid loss of circulation, and consequently fluid flow to the formation, and to achieve a better cementation, allowing its verification and analysis when curing state is over, are the main benefits of keeping BHP steady [8].

Dual gradient is used in MPC as in RMR, but instead of having the return line (which still exists) as return path, it starts at the bottom of the annulus. Before pumping the cement, the casings are inserted after the drilled well section. Cement is then pumped over the mud pushing it downwards. As soon as it reaches the bottom it starts going upwards through the annular cavity. When cement is almost all inside the annulus the flow rate decreases gradually until it stops. The subsea pump used in RMR, according to Stave *et al*. [8], would control the flow rate and the pressure at the top "while placing the cement against problematic formations in terms of tight drilling pressure windows and presence of high-pressure fluids".

Instead of the subsea pump, MPC explored in this project uses a choke at the wellhead to control the fluid flow out of the annulus. When the BHP is close to fracture pressure limit it means that it has to decrease, leading to a top pressure diminishing by opening the choke gradually (increasing the flow through it). In the other hand, if BHP is close to pore pressure limit, the choke is closed (not totally) in order to have a bottom hole pressure increasing.

Nowadays, automation is already a reality in almost all biggest industries. Petroleum industry is finally accepting automatic control as a developed and advanced technology, which can improve processes like drilling and cementing, reducing costs at the same time. In this two referred cases, success is still associated to human interpretation, as "human can better process the data and make better decisions" [12]. If it is considered reduced pressure margins (as in depleted or deep wells) the limitations are huge in terms of error. Harsh environments, "employee's workload, stress and fatigue affect performance, creating a greater chance of human error", while "an automated system is faster, more reliable, and more consistent" [12].

Safety also increases radically, not only to workers but also to the environment and to the well. This last situation is corroborated by efficiency and accuracy increasing, avoiding pressure limits and consequently fluid losses to the formation or well damaging.

Applying MPD technique to the cementing process upgraded it a lot. The usage of an automated system has originated a faster reaction to pressure oscillations, by setting a target BHP value to maintain during the entire process. This is the main advantage as it improves the safety of the well and its "zonal isolation by cementing the annulus without inducing losses to the formation or result in formation fluids flowing to the annulus in a narrow down hole pressure margins." [2]. Protect the open hole and "provide sufficient shoe integrity to drill ahead" is also documented by Elmarsafawi and Beggah [2].

One of the biggest challenges is to keep the pressure bellow fracture limit. As cement is denser than mud there is a natural increasing of fluid's Equivalent Circulating Density (ECD[4]), meaning the annular pressure also increases. With the purpose of avoiding well kicks and gas flow to the formation, the slurry is also increased, which will rise the pressure even more. By using the subsea pump to apply SBP at the top of the annular cavity, it is possible to counter the increasing of pressure at the bottom, stabilizing it [4]. Managed pressure cementing method not only appears to reduce cementing costs and to increase safety but also to provide "a stronger foundation for well integrity over the lifetime of the well." [8].

[4]ECD is an equivalent density because pressures are applied at the top of the well that will change pressure inside the entire well and consequently mud density will change [8].

2.4. Case Histories

The next case histories show how MPC started to emerge by necessity. The influence of some of the referred techniques on MPC development is also visible. All the cases represent specific well conditions which engineers came across with and where conventional methods did not work out.

2.4.1. PNE2a – North Sea

The first case history is exposed by Mashaal *et al.* [10] and is about utilizing MPD technique not only to drill but also to case and cement the Harding PNE2a well in the North Sea. This well is an extended reach well in order to access the remaining oil, but a "combination of reservoir depletion and weak interbedded sands and shales has result in a further reduction of the already narrow MWW" [10]. The fact of the reservoir being distant from the platform also generated an ECD which exceeds the MWW in 50%, disallowing its perforation through conventional methods.

At first two wells (PNE2 and PNE4) were drilled conventionally in order to use MPD as soon as the reservoir would be reached but they had to be abandoned because both suffered fluid losses to the formation due to severe lost of circulation. The reattempt of drilling PNE2 (PNE2a) was done with MPD since the beginning in order to maintain the BHP while "drilling, tripping, circulating BHA[5] change out and cementing, running screens and liner." [10].

Starting with the drilling process, it was firstly used a viscous pill between two different mud densities in order to avoid fluid mixing, keeping BHP constant. It ended up being useless as both fluids mixed up and the MPD system failed, but the process went on as wellbore pressure was maintained. The drilling continued smoothly until the auxiliary pump started to reveal continuing problems like cavitation (steam bubbles produced due to under pressure points) and pressure failures which triggered the "switch to the cement unit" [10].

After drilling, the hole had to be cleaned and for that SBP had to be regulated manually due to MPD software system limitations. Running the liner also had its cons, mainly because there was a joint between sections that was hard to surpass.

At first the cementing process was supposed to occur without MPD technique, but as the liner was run with a mud with lower density than planned, MPD had to be used, otherwise the walls would collapse due to lower pressures. SBP was managed to counterbalance variations of fluid density and friction pressure. Despite the immediate failure of the auxiliary pump after start pumping cement, the rig's pump and choke manifold took care of SBP control and "the cement job successfully placed a $1900ft$ column of slurry" [10].

To conclude, despite some equipment failure that contributed with 10 days of non production time, MPD system worked while drilling but only because there were back up and contingency plans. While cementing, MPD allowed more pressure stability, by adapting SBP, and no circulation losses were verified. The extended reach well achieved the reservoir showing that it was possible "to perform further infill drilling to far reservoir targets within tight MWW and increasing distances from the field centre." [10].

[5] Bottom Hole Assembly

2.4.2. Kvitebjørn Field – North Sea

The next case history is exposed by Bjørkevoll *et al.* [13] and is also about utilizing MPD technique to cement an offshore depleted reservoir (Kvitebjørn Field) in the North Sea. This was, "to the author's knowledge, the first time running and cementing a liner has been done with an automatic choke system controlled in real time by an online dynamic flow model" [13]. During drilling operations on the first wells, while the reservoir was full, the conventional method worked, but when the pressure started to increase "depletion caused severe losses". An MPD method had to be developed and tried out. The main concerning while planning it was to maintain the down hole pressure constant and focus on the pressure on the entire well.

In order to develop a model some major guidelines were assumed: conservation of mass of each fluid component and conservation of the total momentum were the governing equations for the system; all variables depended on only one spatial dimension (along the flow), including temperature and a real time control of the choke pressure. These guidelines were used on running and cementing the liner as well.

The drilling process ran its course with no problems. Running the liner afterwards was done with no problems as well, but slower than expected. The cementing process "was done very carefully to reduce the chance of fracturing to a minimum" [13] as the MWW was very narrow and the natural course of pressure was to increase. The cement flow rate was gradually increased up to $800\ l/min$ and when it was all almost inside the annulus the flow was reduced. During this operation pressure was being monitored and the choke was actuating to balance the pressure at the bottom, especially at the end, when it was necessary to achieve a certain SBP that would be "equal to the necessary pressure in *static* well conditions" [13].

Just to assure the success of the well assembly, a contingency plan was outlined by doing detailed offline simulations with the dynamic model, in case the automatic system should fail the operators could switch to manual choke control. However there was no need to change as the processes went all well taking only a little of more time than what was expected.

2.4.3. Top Hole – Caspian Sea

According to Rajabi *et al.* [14], Caspian Sea witnessed in 2010 the first time MPC method was used successfully under sea. The technique consisted in RMR using a "closed loop circulation system […] facilitating an excellent level of control over the wellbore pressure".

Managed pressure cementing was implemented in a top-hole, so the MWW was tight and the cementing job was difficult due to "loss of cement slurry and shallow water and gas flow" [14]. According to their predictions, if they would have used the conventional cementation method, the wellbore pressure would have surpassed the fracture pressure limit (Figure 10). MPC was implemented with an RMR equipment which had been doing well in other top-holes drilling jobs.

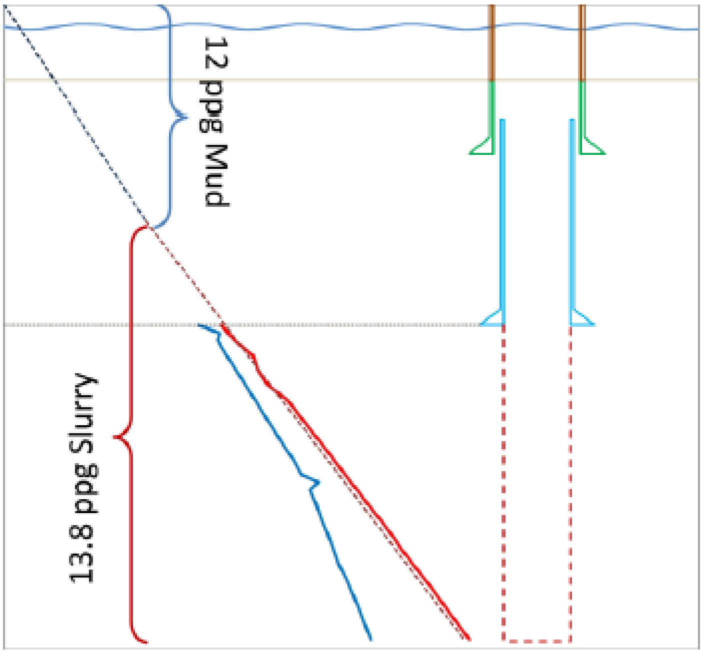


Figure 10: Wellbore pressure would have exceeded fracture pressure limit with conventional cement placement [14].

A subsea pump will manipulate the wellhead pressure, maintaining it inside the desired MWW, essentially assuring safety. Any change in flow rate (indicating fluid loss to the formation) would mean a change in pressure which would make the pump react automatically. The set point pressure would be restored with the opening/closing of choke's pump.

Top-holes "are more sensitive to gas migration than deep holes" because they are larger, so the losses happen faster [14]. In order to avoid it, the closed loop is done with the annulus closed. That way the fluids will naturally go through the subsea pump, which makes easier to control the flow and consequently the pressure.

After pumping the cement inside the wellbore, it reaches the last casing shoe, which is the critical zone. The change of the cement to the annular cavity will change the annular pressure as the equivalent fluid density inside is varying. Before reaching this stage, the goal is to keep "constant inlet pressure", while as soon as the critical zone is achieved, this pressure should alter automatically in order to have a constant pressure at the exit of the subsea pump [14].

After placing the cement it was recorded some losses to the formation. Even after a few hours it was possible to notice with the acquired data that pressure would change from zone to zone. Some fluid was still being lost to the formation, but not enough to go beyond the limits of formation and fracture pressures. Also "no gas invasion or leakage" had been detected until the paper publishing [14].

CHAPTER 3
THEORETICAL FOUNDATIONS

This chapter introduces the basis to the design of the well structure and fluid flow model. The three physical laws that will allow calculating most of the variables to reproduce the simulation will be detailed and assumptions related to the involved fluids (cement and mud) will be explained while comparing them to reality. The model governing equations will also be presented, such as the ones used on MATLAB (R2011a version) to compute the state variables of the controller. It ends with a general well structure description and a closer look to the controller.

3.1. Physical Laws

According to Welty *et al.* [15] there are three main physical laws (disregarding "relativistic and nuclear phenomena") which rule fluid dynamics regardless their nature: the law of conservation of mass (continuity equation), Newton's second law of motion (momentum theorem) and the first law of thermodynamics (energy equation). They will be presented for a general control volume in the integral form and simplified for a better understanding.

3.1.1. Law of Conservation of Mass

The Law of Conservation of Mass states that the difference of mass efflux from and flow into control volume, plus the accumulation of mass within that same control volume during a certain period of time, has to be null (1) [16], that is,

$$\left\{\begin{matrix} rate\ of\ mass \\ efflux\ from \\ control \\ volume \end{matrix}\right\} - \left\{\begin{matrix} rate\ of\ mass \\ flow\ into \\ control \\ volume \end{matrix}\right\} + \left\{\begin{matrix} rate\ of \\ accumulation \\ of\ mass\ within \\ control\ volume \end{matrix}\right\} = 0 \tag{1}$$

The equation which represents this law is called the continuity equation, as in a system "mass may be neither created nor destroyed" [16] meaning in this case mass cannot appear or disappear in control volume, only stay in the system or flow in or out of it.

Considering a small volume dV, cylindrical, which has the structure shape of a drill string section (Figure 11), mass enters at the top and flows out at the bottom, meaning the lateral area is irrelevant as a control surface. The rate of mass crossing a small area dA [16] is given by

$$\rho\ dA\ |\boldsymbol{v}|\ |\boldsymbol{n}| \cos\theta \tag{2}$$

The vector $\boldsymbol{n}$ represents the normal to the small area dA while $\boldsymbol{v}$ is the velocity across it. The angle θ between both vectors in this case defines if the small amount of mass calculated is going in or out of dV as they are always parallel to each other. To the entire surface, an integral can be defined (3) and if its result is positive there is a net efflux of mass while if it is negative there is a net influx of mass. Naturally if it is zero the mass inside the control volume is constant.

$$\iint_A \rho(\boldsymbol{v} \cdot \boldsymbol{n}) dA \tag{3}$$

Finally the rate of accumulation within dV is defined by the second term of the next equation.

$$\iint_A \rho(\boldsymbol{v} \cdot \boldsymbol{n}) dA + \frac{\partial}{\partial t} \iiint_V \rho dV = 0 \tag{4}$$

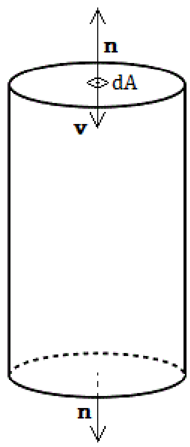


Figure 11: Cylindrical section, dV, identical to a drill string or a casing.

3.1.2. Newton's Second Law of Motion

Newton's Second Law of Motion also known as the conservation law of momentum states the "time rate of change of momentum of a system is equal to the net force acting on the system and takes place in the direction of the net force" [17]. The well known Newton's Second Law equation (5) captures this sentence, where $\boldsymbol{F}$ represents the sum of all forces acting on the system and $\boldsymbol{p}$ is the total linear momentum of the system.

$$\sum \boldsymbol{F} = \frac{d}{dt}(m\boldsymbol{v}) = \frac{d}{dt}\boldsymbol{p} \tag{5}$$

This law does not differ much from the previous one in such way that the rate of mass flowing through a system is still present but this time with its velocity associated (momentum). It can be physically explained in equation (6) [17].

$$\left\{\begin{matrix} sum\ of \\ forces \\ acting \\ on\ control \\ volume \end{matrix}\right\} = \left\{\begin{matrix} rate\ of \\ momentum \\ out\ of \\ control \\ volume \end{matrix}\right\} - \left\{\begin{matrix} rate\ of \\ momentum \\ into \\ control \\ volume \end{matrix}\right\} + \left\{\begin{matrix} rate\ of \\ accumulation \\ of\ momentum \\ within\ control \\ volume \end{matrix}\right\} \tag{6}$$

Looking at equation (2) that gives the rate of mass for a small area dA, if the velocity term is added to the equation the momentum can be retrieved (7). Following a similar procedure as before for the same volume dV (Figure 11), the total rate of momentum through the entire control surface assumes the integral form given by equation (8).

$$\boldsymbol{v}m = \boldsymbol{v}(\rho\ dA)[|\boldsymbol{v}|\ |\boldsymbol{n}| \cos\theta] \tag{7}$$

$$\iint_A \boldsymbol{v}\rho(\boldsymbol{v} \cdot \boldsymbol{n})\ dA \tag{8}$$

In the same way, the rate of accumulation of momentum is the last term of Newton's equation [17],

$$\sum \boldsymbol{F} = \iint_A \boldsymbol{v}\rho(\boldsymbol{v} \cdot \boldsymbol{n})\ dA + \frac{d}{dt}\iiint_V \boldsymbol{v}\rho\ dV \tag{9}$$

3.1.3. First Law of Thermodynamics

The last law considered for fluid flow physics is the First Law of Thermodynamics which approaches the conservation of energy by asserting the total variation of energy is due to the exchange of heat between the system and its surroundings and the work done by the system (10) [18].

$$\partial Q - \partial W = \partial E \tag{10}$$

Applying the previous equation to a time interval and assuming ∂Q positive when heat is transferred to the system and ∂W positive when work is done by the system, equation (10) becomes [18]

$$\begin{gathered} \left\{\begin{matrix} rate\ of\ addition \\ of\ heat\ to\ control \\ volume\ from\ its \\ surroundings \end{matrix}\right\} - \left\{\begin{matrix} rate\ of\ work \\ done\ by\ control \\ volume\ on\ its \\ surroundings \end{matrix}\right\} = \\ = \left\{\begin{matrix} rate\ of\ energy \\ out\ of\ control \\ volume\ due\ to \\ fluid\ flow \end{matrix}\right\} - \left\{\begin{matrix} rate\ of\ energy\ into \\ control\ volume \\ due\ to\ fluid\ flow \end{matrix}\right\} + \left\{\begin{matrix} rate\ of\ accumulation \\ of\ energy\ within \\ control\ volume \end{matrix}\right\} \end{gathered} \tag{11}$$

Going back to the control volume from Figure 11, and once again picking the rate of mass efflux from equation (2) and adding the specific energy term (or energy per unit mass), e[6], to it, equation (12) shows the rate of energy efflux through the area dA of the control volume. Integrating that equation over the control surface, the difference between the rates of energy out and into control volume becomes the net efflux of energy referring to the system (13) [18].

$$e \cdot m = e \cdot (\rho \, dA)[|\boldsymbol{v}| \, |\boldsymbol{n}| \cos\theta] \tag{12}$$

$$\iint_A e\rho(\boldsymbol{v} \cdot \boldsymbol{n}) \, dA \tag{13}$$

The rate of accumulation of energy is no more than the extra energy that stayed inside the control volume and is represented by the last term of equation (14).

$$\frac{\partial Q}{dt} - \frac{\partial W}{dt} = \iint_A e\rho(\boldsymbol{v} \cdot \boldsymbol{n}) \, dA + \frac{d}{dt}\iiint_V e\rho \, dV \tag{14}$$

3.2. Fluid Properties

With fluid physical laws already approached fluid properties come next in line as they define how fluids behave and consequently how the simulation will run afterwards.

There will be two different fluids inside the well at the same time during the simulation: mud, which is used to help drilling and to bring sediments to surface; and cement, which is used to cement the casing to the well wall after drilling a section.

Most properties values are functions of time and space but for simplicity, intrinsic ones like density or compressibility will be assumed not to change in time or space. Others like velocity, will change in time and space, but instead of having a three dimensional space variation (height, radius and azimuth) they will be considered only as function of one space dimension (height), as the well depth is much bigger (thousands of metres) than the radial dimension (few centimetres).

3.2.1. Mud

As a drilling fluid, mud is in general considered a non-Newtonian fluid and its flow path contains both laminar and turbulent regimes and transitions between them [19]. A Newtonian fluid is defined by a linear relation between the shear stress incurred by the fluid on the solid surface (pipe wall) and the rate of shearing strain (rate of change of fluid deformation).The stress is the force applied by the fluid on the solid surface and the strain is the result from that stress which is visible in viscosity variations. The fluid can become thicker or more liquid than before the stress is applied. For this project it was decided to consider mud (and cement as well) a Newtonian fluid, in order to simplify the model.

[6] The specific energy contains potential, kinetic and internal energy terms.

Still related to viscosity, Reynolds Number (Re) is a dimensionless value that relates several fluid properties. Considering a pipe flow, the important variables to calculate this value are pipe diameter, D, and fluid density, viscosity and velocity, ρ, μ and v, respectively (15). Through Reynolds's experiment it is possible to understand that with the increase of velocity flow molecules take an unpredictable path.

$$\mathrm{Re} = \frac{\mathrm{D\rho v}}{\mu} \tag{15}$$

Reynolds's experiment consists on water flowing through a pipe with a certain velocity with dye flowing with the water inside the same pipe (both with the same specific gravity). A single string line (Figure 12 – a) was observed while the flow rate was low but it became irregular as soon as the flow rate was set too high (Figure 12 – b). For a circular pipe (case study of this project) the value that marks the transition point between regimes is $Re = 2300$ [20] but sometimes laminar flow can be verified with a larger Re or vice-versa. Moody's diagram (Figure 13) shows those values. Between 2000 and 4000 is represented uncertainty.

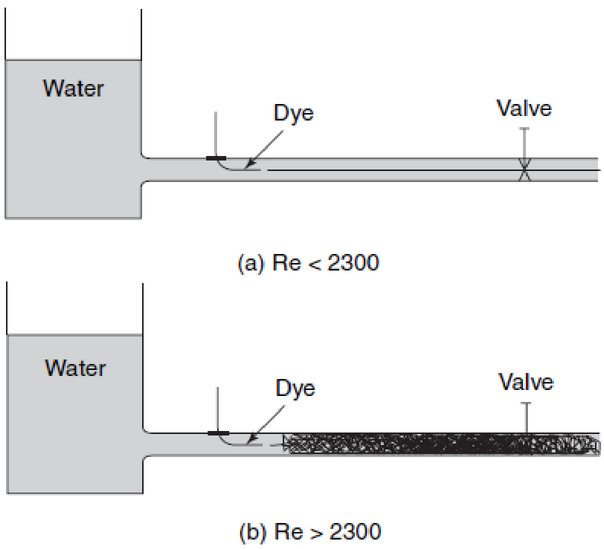


Figure 12: Reynolds's experiment [20].

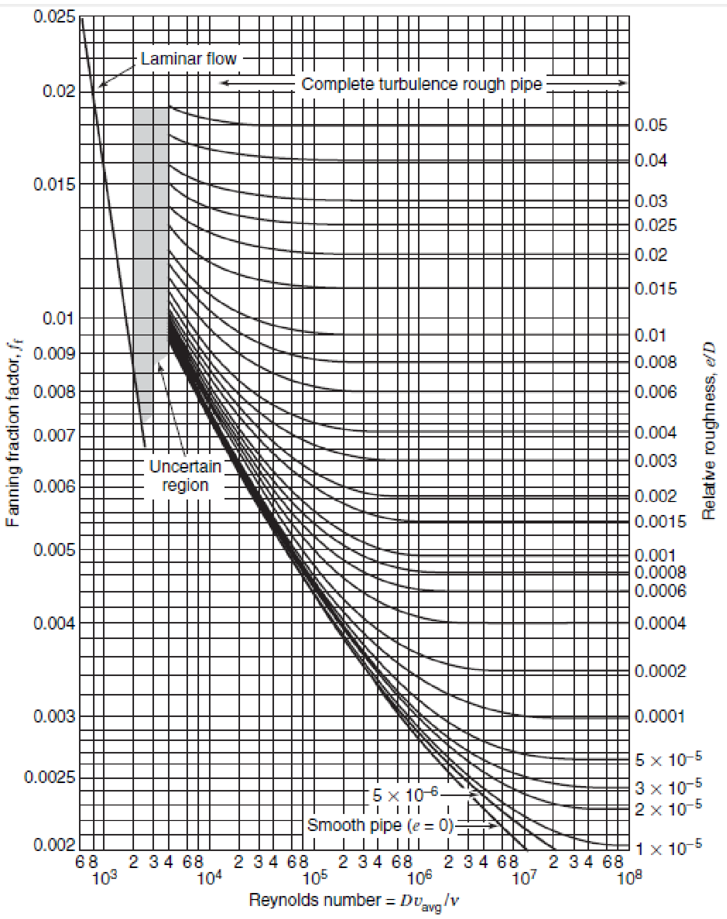


Figure 13: Moody's Diagram [21].

The formula to calculate friction losses is different depending on the type of flow. Velocity changes through the entire simulation, so does the type of flow. Also due to joints between strings/casings inside the well and other kind of irregularities the flow might be laminar at some point in depth but turbulent after a few metres so it is not that linear to formulate (including MATLAB code) a correct model for it. Simplifying, it will be assumed mud is at a laminar regime during the entire simulation (cement as well) [19]. Darcy friction factor for laminar flow becomes

$$f = \frac{64}{Re} \tag{16}$$

As referred before, viscosity is a property of any fluid so all fluids follow the no-slip condition which states that "the layer of fluid adjacent to the boundary has zero velocity relative to the boundary." [22] This effect implies a parabolic velocity profile inside the pipe, reaching its maximum at the centre of the pipe (Figure 14). Since depth is the only space variable considered, during this project the velocity that will be referred from here on is the average one (detailed later). Besides depth, temperature also plays a major role at viscosity level. With pressure and depth variations, temperature (intern energy) changes and consequently the viscosity as well [22]. As it is desired to keep viscosity constant temperature will be disregarded through the entire project otherwise there would be a different value for it at every height of the well.

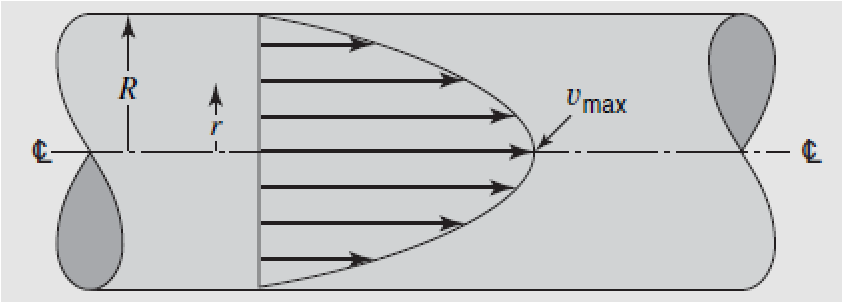


Figure 14: Parabolic velocity profile in a circular flow passage [16].

Finally we have compressibility and fluid density. They are related to each other as when a fluid is compressed its density increases. In this case mud will suffer compressions and decompressions and consequently its ECD will change. However, there are two values that will not change, which are the density of the fluid when it is pumped in and its isothermal bulk modulus. The bulk modulus indicates the necessary force per unit area (pressure) to reduce the volume under pressure in one unit. As mud can change from operation to operation and from well to well it was decided to adopt the fluid referred by Stamnes *et al.* [19] at first, ending up using $1450\,kg/m^3$ for density and $1{,}5\,GPa$ for its bulk modulus. During the process of modelling on MATLAB, it was concluded that mud density value had to be raised as hydrostatic pressure was not enough, making possible do decrease top pressures.

3.2.2. Cement

Cement will be treated differently from mud. Most properties are equal and some of the assumptions done to mud will be assumed to the cement as well. It is admitted that cement is a Newtonian fluid with a laminar regime. Cement velocity will have the profile of a rigid body (equal at every point) and its temperature and viscosity will not change.

The main difference to mud will be concerning compressibility. The cement often used in petroleum engineering is the Portland cement, which is the one normally used in construction [23]. Cement paste foremost properties are associated to its hydration, mainly cement shrinkage with the two most important hydration products being calcium silicate hydrate ($C\text{–}S\text{–}H$) and calcium hydroxide (CH) (together constitute 72% of cement paste) [24]. They are mostly the ones which will define cement compressibility. According to Lin [10], the bulk modulus for each fluid is the one in Table 1. As it is possible to verify, mud is at least ten times more compressible than cement so when they are compressed against each other mud will be much more compressed compared to cement. It is considered that cement paste is incompressible as during the entire simulation cement is being compressed against the mud.

Table 2 summarizes the assumptions made in comparison with what happens in reality for both fluids.

Table 1 – Values of fluids properties relevant to simulation [19, 24].

	Cement[7]	Mud
Density $(\mathbf{Kg/m^3})$	$2000 - 2240$	1450
Bulk Modulus $(\mathbf{GPa})$	$15{,}2 - 40{,}0$	$1{,}5$
Viscosity $(\mathbf{N.s/m^2})$	–	4×10^{-3}

Table 2 – Fluids properties assumed compared to reality.

	Cement		Mud	
Properties	**Reality**	**Assumed**	**Reality**	**Assumed**
Regime	Non-Newtonian	Newtonian	Non-Newtonian	Newtonian
Flow	Uncertain	Laminar	Uncertain	Laminar
Velocity Profile	Parabolic	Constant	Parabolic	Constant
Compressibility	Compressible	Incompressible	Compressible	Compressible
Temperature	Uncertain	Disregarded	Uncertain	Disregarded

3.3. Model

In order to have a better understanding of the next chapters about the model of this project, the relevant variables will be detailed in terms of meaning, how they are calculated and why they are important.

Several characteristics of the considered model such as BHP, fluids velocity or the volume of each fluid inside the well must have a continuous behaviour meaning they cannot abruptly change from one instant to another. This aspect is very important as it defines the problem as a dynamic one where the continuous variables become state variables (they will depend on the remainder ones) which will be governed upon Euler method for Ordinary Differential Equations (ODE).

Model's goal is to displace cement over mud along a well, helping pushing it down by pumping mud in afterwards, while a PI controller adjusts SBP at the exit of the well to maintain the BHP steady, until cement is placed all inside the annulus.

[7] Values considered for cement are within an interval due to the presence of both $C - S - H$ and CH which have different values for the same property.

3.3.1. Euler Integration

A dynamic system is normally continuous in time; however, when it is desired to represent such system computationally an "equivalent discrete-time model must be used. The smaller the time step between iterations is, the smaller is the error and consequently the results will become more accurate.

The state system can be represented through the following ODE, where γ represents the state variable and $f(.)$ is the function which governs it according to other independent variables w.

$$\dot{\gamma} = f(\gamma, w) \tag{17}$$

Physically, the considered characteristics for state variables are continuous, but in order to be able to represent them in programming language, a discrete algorithm had to be used. By definition, the derivative is approximated by

$$\dot{\gamma} = \frac{\gamma(k + \Delta t) - \gamma(k)}{\Delta t} \tag{18}$$

where k represents the current iteration and Δt the time step. Manipulating the previous two equations, the Euler equation (19) is obtained, which allows calculating the sequence of iterations, knowing the initial values (γ_0, w_0) in advance.

$$\gamma_{k+1} = \gamma_k + \Delta t \cdot f(\gamma_k, w_k) \tag{19}$$

The state variables considered in the simulation are the position (x) of the head of the cement inside the well (Figure 15) and its average velocity (v_{av}). Other two are the pressures at the top near the pump (input), P_p, and choke (output), P_c. Cement and mud volumes (V_{cem} and V_{mud}, respectively) are the last state variables despite that most of the time they only depend on constants.

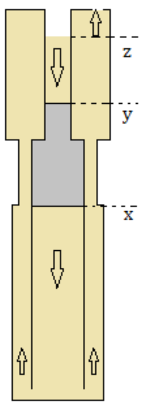


Figure 15: Middle state with cement between muds. x – cement head; y – cement tail; z – mud tail.

3.3.2. Kinematics

With the introduction of the state variables done, if we examine each $f(.)$ function (19) for each state variable, it is explained how the incremental term is obtained. Starting with the next position at the front of the cement, x (20), it depends on the current velocity at the current x value (21). Through mass balance equation (4), if it is considered a steady state, what goes inside a system is equal to what comes out of it, which means the flow, q, must be the same at any point of the system. This yields to

$$x_{k+1} = x_k + \Delta t \cdot v_x \tag{20}$$

$$q_x = q_{av} \Leftrightarrow v_x\, A_x = v_{av}\, A_{av} \Leftrightarrow v_x = \frac{A_{av}}{A_x}\, v_{av} \tag{21}$$

It is important to referrer that the concept of average area A_{av} is no more than the current cement volume inside the well divided by the length of its column. A new position inside the well, y (cement tail), is also introduced as the cement column length is the difference between x and the previous position y (Figure 15). In the same way, mud tail, z, allows to understand if, due to gravitational force, a gap is created at the top (explained ahead).

Cement average velocity (22) is the other state variable relative to cement movement inside the well. At first, the chosen variable was the cement head velocity, but when transitions from one casing to another, with a different diameter occurred, the velocity of the fluid would change abruptly and the system did not have enough time to counteract the situation, so the cement would move backwards.

$${v_{av}}_{k+1} = {v_{av}}_k + \Delta t \cdot a \tag{22}$$

As cement is considered incompressible, its acceleration is the same at each point, which will contribute to the increment of velocity state variable. From Newton's Second Law of Motion (5), it is possible to sum up all the forces applied at the cement and retrieve its acceleration (23). The considered forces[8] are the ones made by the fluids under ($\boldsymbol{F_x}$) and over ($\boldsymbol{F_y}$) the cement and the ones due to gravity ($\boldsymbol{F_g}$) and friction ($\boldsymbol{F_f}$).

$$\sum \boldsymbol{F} = \boldsymbol{F_x} + \boldsymbol{F_y} + \boldsymbol{F_g} + \boldsymbol{F_f} \tag{23}$$

[8] When not working with vectors in equations, the positive referential of all forces, pressures, acceleration, velocity or positions is pointing downwards inside the drill string and upwards inside the annulus (following the flow from Figure 15).

With pressure being the main characteristic to analyze throughout this project, it will naturally interfere with acceleration. While the force done by the mud under the cement pushes it upwards, mud over the cement pushes it on the opposite direction. Both can be written as the pressure, P, done on the surface area (cement head and tail, respectively). As it is considered an average area for the theoretical pipe where cement is, we have equation (24)

$$\boldsymbol{F_x} + \boldsymbol{F_y} = (P_y - P_x) \cdot A_{av} \tag{24}$$

$$\boldsymbol{F_g} = m_{cem} \cdot \boldsymbol{g} \tag{25}$$

In what concerns gravitational and frictional forces, the first one is given by cement mass inside the well times the gravitational constant, $g = 9{,}8\ m/s^2$ (25), while the second one is due to friction losses through cement movement along the well/pipes walls (explained ahead). Combining equation (5) with the last three the equation for acceleration is obtained (26). As cement density does not change in time it only matters the derivative of velocity – acceleration.

$$\begin{gathered} \frac{d}{dt}(m_{cem} v_{av}) = \left(P_y - P_x\right) \cdot A_{av} + m_{cem} \cdot g + F_f \Leftrightarrow \\ \Leftrightarrow a = \frac{\left(P_y - P_x\right) \cdot A_{av} + m_{cem} \cdot g + F_f}{m_{cem}} \end{gathered} \tag{26}$$

The pressure term due to friction is calculated based on Darcy's friction factor f (consequently on Reynolds' Number) and it depends on fluid velocity v, length l and radius r of the casing and acceleration of gravity g, originating Darcy's Equation (27) [21], that represents the extra length that the fluid would have to travel if only hydrostatic pressure would be considered. Equation (28) translates gravitational and frictional pressure terms, where h is the length between the two pressure points.

$$h_f = \frac{f l v^2}{4 g r} \tag{27}$$

$$F_g + F_f = \rho_{cem} \cdot g \cdot (h + h_f) \tag{28}$$

3.3.3. Volumes

Cement and mud volumes increments are given by the flow rate at the entrance of the well ((29) and (30), respectively). Cement flow rate, q_{cem}, is constant and is defined by the engineer, while mud flow in, q_{mud}, besides being also set by the engineer, from a certain stage on (specified in later chapter) is controlled by the PI controller through the average velocity and area of the casing, as flow units are m^3/s (31).

$$V_{cem_{k+1}} = V_{cem_k} + \Delta t \cdot q_{cem_k} \tag{29}$$

$$V_{mud_{k+1}} = V_{mud_k} + \Delta t \cdot q_{mud_k} \tag{30}$$

$$q_{mud} = v_{av} \cdot A_{av} \tag{31}$$

3.3.4. Top & Bottom Pressures

Finally from equation (4) (mass balance), both pressures at the top (pump and choke pressures – p_p and p_c respectively) can be retrieved. While de first term refers to the flow in and/or out of the system, the accumulation of momentum term concerns to compressibility (32) [19].

$$(q_{out} - q_{in}) + \frac{V}{\beta}\dot{P} = 0 \tag{32}$$

Starting with the variation of pressure at the entrance of the well, $\dot{P}_p$, the flow in is the flow of the fluid going inside the well, or pump flow, q_p, set by the engineer, while the flow out is the variation in volume of the fluid being pumped in from the previous iteration to the current one, $\dot{V}$. The variation of pressure at the exit, $\dot{P}_c$, is controlled by a choke at the exit of the annular cavity at the top. The flow in is the changing in volume of the fluid going out while the flow out, q_c, is regulated by the PI controller and it is calculated through a choke equation (detailed ahead). Equation (33) and (34) represent both pressure variations, respectively, where the two last constants are the total volume of mud or cement (depending on which one is being under analysis), where β is the isothermal bulk modulus of that same fluid.

$$\dot{P}_p = \left(q_p - \dot{V}\right)\frac{\beta}{V} \tag{33}$$

$$\dot{P}_c = \left(-q_c + \dot{V}\right)\frac{\beta}{V} \tag{34}$$

Both previous expressions concerning pressure variations are used in next equation as top pressures are state variables.

$$P_{k+1} = P_k + \Delta t \cdot \dot{P} \tag{35}$$

Finally, the most important one to track that will allow understanding if the model is viable or not is the BHP (P_{BH}). In order to calculate it three parameters are considered: P_c, the hydrostatic pressure P_h, due to the fluids inside the annulus, and the pressure due to friction P_f, also inside the annular cavity (36) [19].

$$P_{BH} = P_c + P_h + P_f \tag{36}$$

3.3.5. Choke Flow Equation

According to Engineered Software, Inc.'s PIPE-FLO® [25], for processes involving high temperatures it is more likely to observe the phenomenon of cavitation. It consists on the formation of vapour bubbles on the liquid flow which when implode originate pressure variations that may damage the valve. As the actual flow rate starts to deviate from the predicted value due to the volume occupied by the bubbles, the valve's behaviour also starts to deviate from the linear relationship between flow coefficient, flow rate and square root of the pressure drop (37).

$$q_c = k_c u \sqrt{P_c - P_{atm}} \tag{37}$$

Since it is desired to keep this model simple and as temperature is being disregarded, it will be assumed that the linear relationship is maintained, where k_c is the choke coefficient related to physical characteristics given by the manufacturer, u is the valve opening and the pressure difference is related to pressures before and after the choke (choke and atmospheric pressures, respectively). A quick note for the inside of the square root, where atmospheric pressure is ignored during the entire simulation, considering it zero as it becomes irrelevant through time.

$$q_c = k_c u \sqrt{P_c} \tag{38}$$

3.4. Common Well Structure & Fluid Flow

The content of this section is based on information given during the meetings attended at Statoil Company with the presence of Prof. Dr. Lars Imsland, from Norwegian University of Science and Technology (NTNU) and Prof. Dr. John-Morten Godhavn and Senior Researcher Espen Hauge, from Statoil Company.

Before start drilling a well, its structure must be planned. To do it, a first tight vertical perforation near the well must be done to understand the different layers of sands and rocks that will be encountered along the production well.

A wellbore is never equal to another but its main structure can be. It has different dimensions along the process (sections lengths are different from one another and diameter decreases with depth for example) but the structures used are similar on most of the wells (considering onshore and offshore wells separately). At the top, a riser (in offshore cases) is used to connect the rig to the sea floor. The drilling starts at this level and several casings are cemented after each other, one section at a time. The next casings section must be narrower than the previous one, as it has to be moved through the ones already cemented. The drill pipe moves inside the riser and casings and the drill bit (end of the drill pipe) moves downwards inside the open hole that it drills, which will be cemented next. Before cementing a section, normally a malleable liner is attached to the end of the previous casing before inserting the next casing in order to save steel and therefore reduce costs.

The fluid circulation during cementing starts at the top by pumping the fluid inside the casings. After reaching the open hole (with the casing to be cemented already inside it), the fluid starts moving up through the annular cavity created by the casing to be cemented and the drilled section, ending expelled through a choke placed at the rig level. The process stops when all the cement slurry left the inside pipe and is inside the annulus at the bottom part.

The model for this project presents the structure referred before with some exceptions for simplicity. Firstly the fact that it is an offshore well will be ignored so the pilot hole will be the riser. The liner and the casing to be cemented at the first drilled section (after the pilot hole) are already in place. Finally the drill pipe is at the pilot hole level through which the cement flows downwards.

3.5. PI Controller Model

The controller is a crucial piece in this project. An automatic controller compares the real value from its output with the desired value, determining its deviation and producing a control signal which reduces the error to zero (or close to zero) [26]. It is common practice in the industry to start by exploiting simple controllers with three types of action: proportional, integral and derivative. This is the approach undertaken in this project, where a simple proportional and integral controller is used.

3.5.1. Control Actions

A proportional controller is essentially an amplifier of the deviation $e_r(t)$ enunciated before. The relation between the output signal, $m(t)$, and the actuator error, $e_r(t)$, is

$$m_p(t) = K_p e_r(t) \tag{39}$$

An integral action is defined by a change at the output through a proportional variation of the error, taking into account its accumulation from the start (40). The integral gain, K_i, can be defined by the proportional gain divided by the reset time (41), T_i, which represents the time the controller needs to double the proportional gain, K_p, (Figure 16).

$$m_i(t) = K_i \int_0^t e_r(t)\,dt \tag{40}$$

where,

$$K_i = \frac{K_p}{T_i} \tag{41}$$

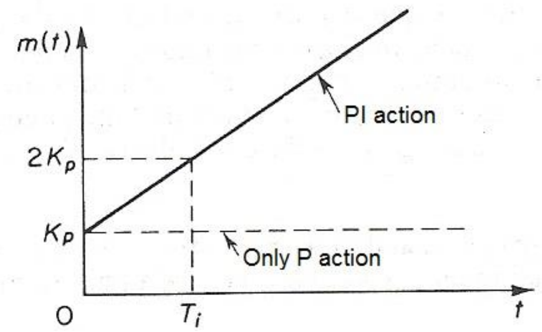


Figure 16: Controller's output only with proportional action and with both proportional and integral actions, as step response. Relation between integral time and proportional gain (adapted from [27]).

The term from the derivative action is directly proportional to the variation of the error signal (42), where T_d (43) is the time interval the proportional action is forwarded.

$$m_d(t) = K_d \frac{d\, e_r(t)}{dt} \tag{42}$$

$$K_d = K_p T_d \tag{43}$$

Since the derivative term easily amplifies the noise, saturating the actuator [26], it was defined that the controller to be applied on this model would only include PI terms. Equation (44) represents the final equation used in this controller with transfer function from Figure 17.

$$m(t) = K_p e_r(t) + \frac{K_p}{T_i} \int_0^t e_r(t)\, dt \tag{44}$$

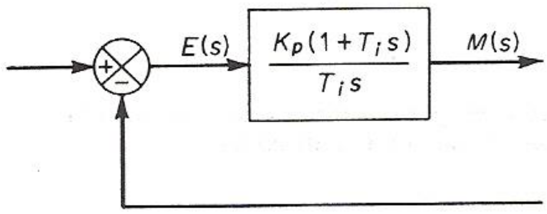


Figure 17: Controller transfer function between the output and the error [27].

3.5.2. Feedback Loop

As a crucial part to the success of the model, the controller provides the closed loop to maintain the BHP steady, by adjusting the SBP. The pressure at the bottom will be the reference value of the system, while the pressure at the exit of the annulus at the top will be the output of the loop. Basically, the SBP variation will compensate the hydrostatic and frictional pressure oscillations in order to keep BHP steady.

The controller will allow constraining the annular bottom hole pressure to the desired MWW through an automatic choke at the top, which will work as actuator. However, this is not exactly how a control system works. Instead of defining boundary values, the purpose of having a controller is to set a reference value, which in this case is the annular BHP, and keep the real value around it. At this stage of the project, the reference value is irrelevant as long as the system is able to respond to the oscillations.

The difference between the reference pressure value and the real one gives the pressure error, e_r, which when combined with PI terms results in the new choke opening value, u. A new choke flow value is calculated and consequently the choke pressure. It is necessary to take into account a possible integral windup, as if the choke reaches one of the limits, the error will keep accumulating due to the integral. For this reason, if it happens, the integral term is kept equal to the previous iteration (Figure 18).

```
if u > 1
    u = 1;
    u_integral = previous_u_integral;
elseif u < 0
    u = 0;
    u_integral = previous_u_integral;
end
```

Figure 18: Windup and saturation elimination.

3.5.3. Gains

The two gains were obtained by trial and error, as the feedback loop is non-linear (38) due to the square root, to calculate the flow through the choke. The addition of the hydrostatic pressure to BHP also brings non-linearity.

Proportional gain was the first to be tried out, considering the integral gain zero. Bearing in mind that the BHP highest deviation is of the order of the units of Bars and that all the estimates on MATLAB are done according to the International System of units (SI), the order of the error (PI controller input) is $10^6\ Pa$. For that reason, as the goal on the exit of the controller is to have a value between 0 and 1 (choke opening), the desired gain should be inversely proportional to the error, meaning less than $10^{-6}\ Pa^{-1}$. Considering small changes down to the thousandth per iteration, the proportional gain has to go down to 10^{-9} order. The chosen value for K_p ended up being $8 \times 10^{-9}\ Pa^{-1}$ (absolute value). If this value was decreased, the BHP deviation would become greater as the response would be slower. If it was increased, the response would be faster and consequently the error would be lesser. On the other side, as the pressure variation would be greater at the bottom, it would also be greater at the top, meaning more oscillations on the position of the fluid on a way that it could move backwards.

Another issue that must be taken into account is that the proportional term can be either positive or negative. If the real BHP is lower than the reference one it means that the pressure error is positive and, with K_p positive, the increment on the choke opening would also be positive, opening even more the valve. Its pressure would decrease and so would the BHP, increasing the error. To invert this situation K_p must be negative (45).

$$K_p = -8 \times 10^{-9}\ Pa^{-1} \tag{45}$$

The integral term is calculated based on the proportional one ((40) and (41)), where T_i represents the period of time that the controller needs to double the proportional contribution, which in this case is 6 seconds. Both final gain values were adjusted at the same time in order to get the best possible results.

Next figure resumes the model in terms of its main equations. Indexes h and f refer to hydrostatic and frictional terms.

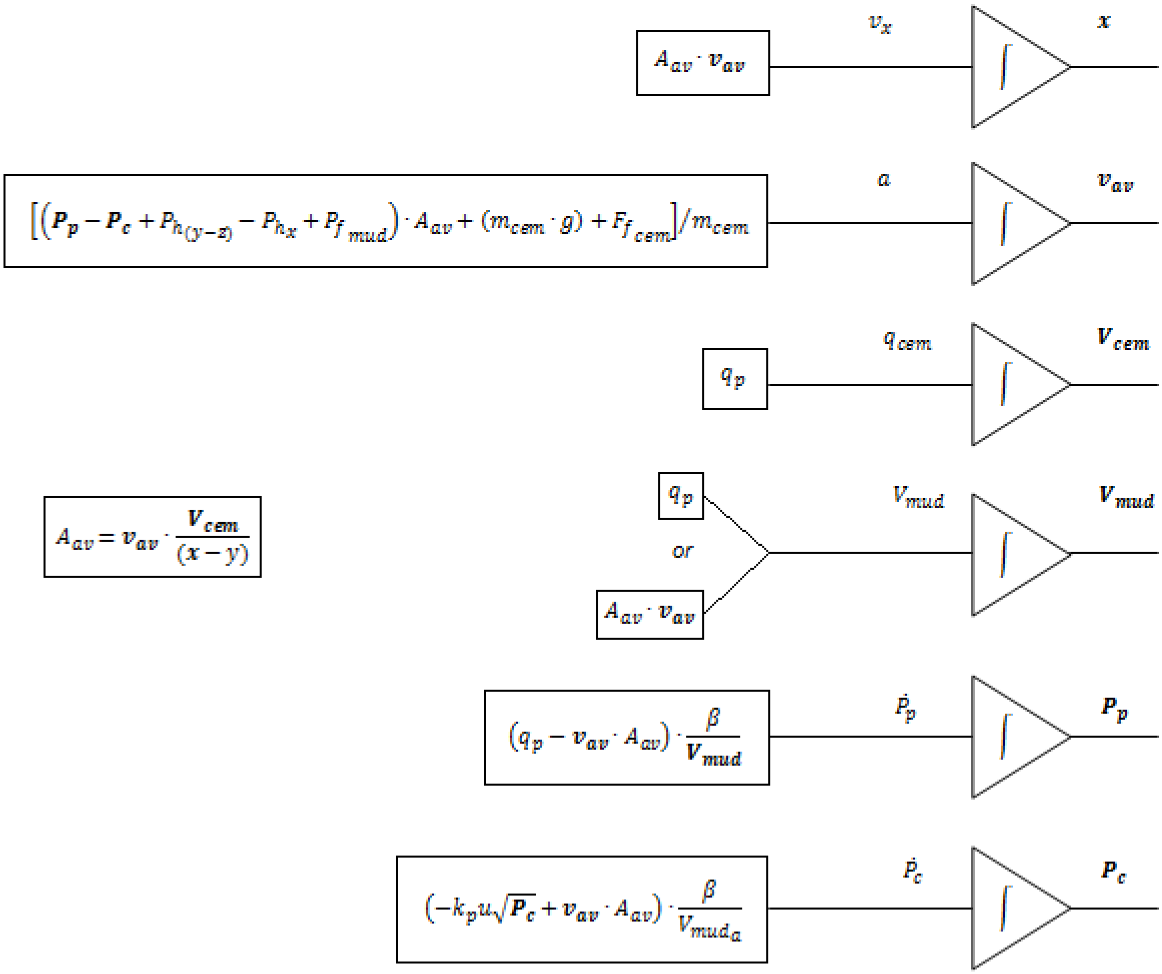


Figure 19: Summary of model equations.

CHAPTER 4
SIMULATION & RESULTS DISCUSSION

After explaining the whole generalized model with its equations in chapter 3, it is important to take into account that models are not that simple. There are always some special cases or situations where equations suffer some changes or another equation must be used, especially during transition moments. This model is no exception. The chapter presents the simulation in detail, taking into account the transitions, which define the different stages cement goes through. The results concerning each stage are specified and discussed right after each simulation stage is introduced.

4.1. Well Dimensioning

Before approaching the simulation itself the well dimensioning has to be clarified. In order to have a more realistic case, Statoil engineers provided the well physical dimensions, like casings sections length and diameters along the well. Some of the initial conditions were also provided by them while others were assumed.

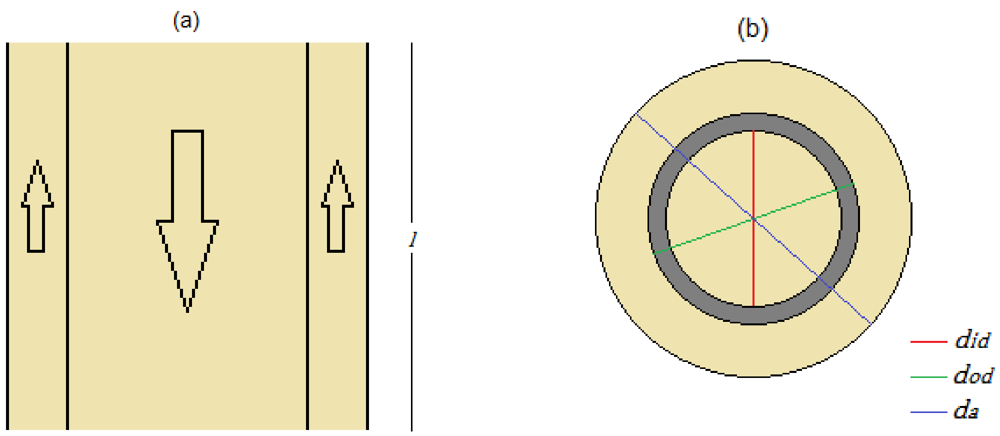


Figure 20: Longitudinal (a) and cross sectional (b) views of a well section.

Figure 20 shows the variables needed for the model: in image (a) we can see a casing's length (l); in (b) are included the different diameters considered for a cross section. The variable l stands for a uniform casing section length, while d_{id} and d_{od} correspond to the inner and outer diameters of a casing section, respectively. d_a refers to the annular diameter of the matching section well (open hole wall) segment. For the different sections along the well presented in Figure 21 we have the sizes from Table 3.

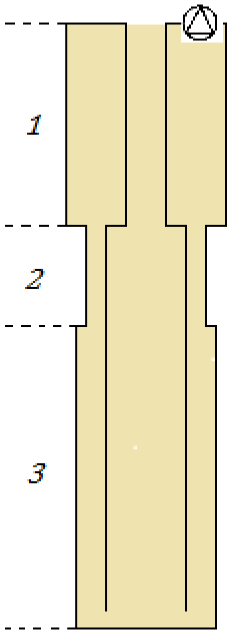


Figure 21: Longitudinal cut of the well that shows the different sections of the well structure.

Table 3 – Lengths and diameters of different well's sections given by Statoil. Numbers between parentheses are making reference to the different sections on Figure 21.

Section	Depth (m)	Inner Diameter $(Inch^9)$	Outer Diameter $(Inch)$
Drill Pipe (1)	$0 - 2000$	$5{,}000$	$6{,}625$
Casing (2 & 3)	$2000 - 6000$	$12{,}409$	$14{,}000$
Open Hole (3)	$3000 - 6000$	$19{,}000$	$-$
Liner (2)	$2000 - 3000$	$16{,}750$	$18{,}000$
Riser (1)	$0 - 2000$	$19{,}000$	$21{,}000$

4.2. Cement Displacement

With the general model and equations defined, the focus is now on the methodology applied and the necessary simplifications due to obstacles that appeared after implement it. As the well of the case study has different dimensions in depth it was necessary to define different stages for different physical dimensions, which led to transition situations that required special attention.

Along the exhibition of the stages, the results obtained on the BHP oscillations and on pressure and flow out at the exit of the well are analysed, as different transition moments may have different impacts on their outcome.

[9] Diameters are in Inch instead of Meter (SI unit) to avoid the usage of small numbers and because it is the common unit inside petroleum engineering community ($1\ Inch = 0{,}0254\ m$).

4.2.1. Initial State

4.2.1.1. Simulation

Looking now into the initial conditions that will trigger the beginning of the simulation, it is important to understand that, despite of the non simulation of fluid circulation inside the well before pumping the cement, it is taken into account that when the simulation starts, the fluid inside the well is supposed to be in equilibrium. Consequently, the flow out should be equal to the flow in and pressures applied at the top should not change abruptly.

The process begins by pumping the cement at a constant rate, equals to $500\ l/min$ (60 thousand litres during 2 hours). In order to try to keep the steady state it is assumed that the initial flow out, q_{c_i}, is the same as the initial flow in (Figure 22), which is equal to the cement flow rate stated before. Despite this consideration, after the first iteration, it is possible to see in Figure 22 flow out decreasing in few minutes. The starting value should be calculated according to equation (38), but as the choke pressure is the state variable on that equation, it was decided to manipulate it, obtaining equation (46), just for the initial condition, setting the desired flow out, where u_i is the initial valve opening (equals to $0{,}11$), adjusted in order to get the less oscillations possible.

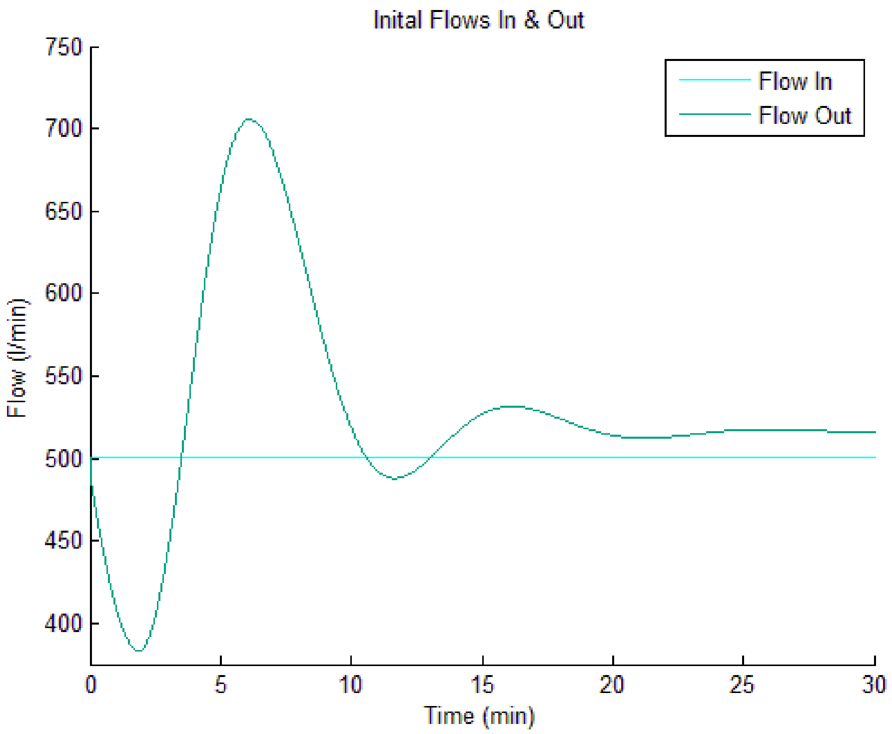


Figure 22: Initial flows in and out (30 minutes of simulation).

$$P_{c_i} = \left(\frac{q_{c_i}}{u_i k_c}\right)^2 = \left(\frac{0{,}5/60}{0{,}11 k_c}\right)^2 = 42{,}69\ Bar^{10} \tag{46}$$

[10] For pressure values the adopted unit is Bar instead of Pascal (SI unit) to avoid large numbers and because it is the common unit inside petroleum engineering community ($1\ Bar = 1 \times 10^5\ Pa$).

$$k_c = \frac{q_{mud}}{u_h \sqrt{P_{c\_ref}}} = 3{,}6667 \times 10^{-5} \tag{47}$$

There is also a constant, k_c, considered to be inherent to the choke physical characteristics (47), where q_{mud} is the most used value for mud flow ($1100\ l/min$) during the simulation. u_h is the value for the choke half opened and $P_{c\_ref} = 10\ Bar$ is an acceptable value for choke pressure reference. These values were the chosen ones because they are references during the simulation, so they represent the most common/desired values.

With an initial pressure at the exit already defined, the pressure at the entrance should not only balance it but also push the cement downwards. The fluid can move up but not too much so it will not hit the top, therefore it must be higher than P_{c_i}. The achieved value which does not allow the fluid to go up and beyond pump position is $65\ Bar$ (Figure 23).

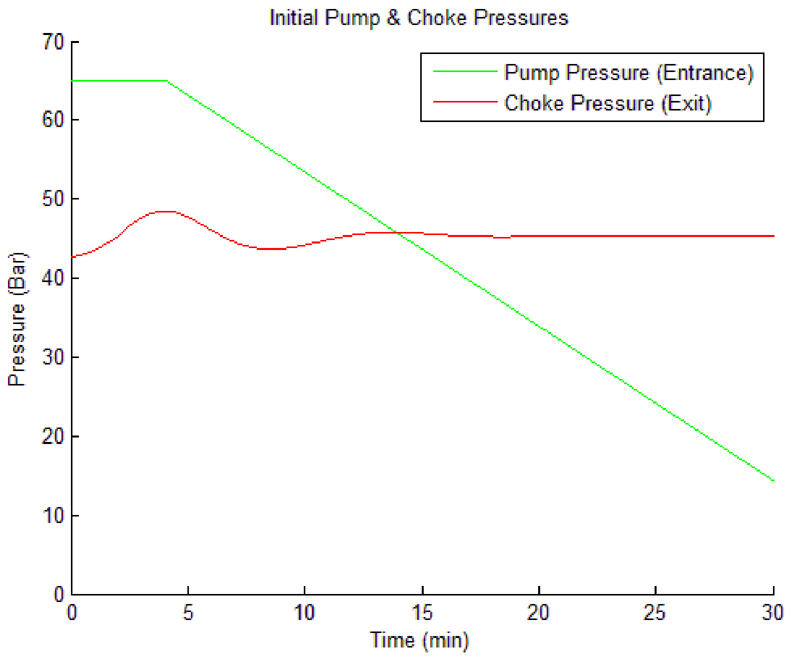


Figure 23: Initial top pressures during the first half hour. The choke is at the entrance while the pump is at the exit.

Finally, as the pressure reference (P_{ref}) at the bottom of the well is $898\ Bar$, it was expected to get a starting value not too far from it. Using initial conditions on equation (36), initial real BHP is $895{,}3\ Bar$ (Figure 24).

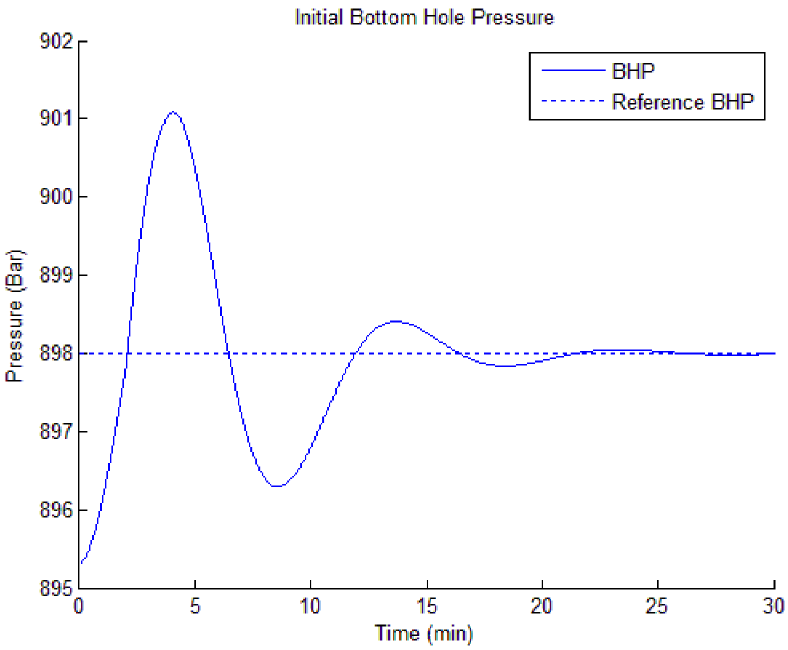


Figure 24: Initial bottom hole pressure and respective desired one (30 minutes of simulation).

4.2.1.2. Discussion

According to Mashaal *et al.* [10], the planning stage for the well in study "required BHP to be controlled within $\pm 100\, psi$ of the set-point", which led to a designed MPD system "based around a goal of maintaining $\pm 50\, psi$ from the set-point, allowing further margin for other sources of error." Assuming $1\, psi \cong 0{,}069 Bar$, [10] planned a MWW within $\pm 6{,}90\, Bar$, halving it just for BHP fluctuations.

It is easily seen that if it is considered a MWW of $\pm 6{,}90\, Bar$ for this model, the initial BHP is inside the interval of $[891{,}10\, ;\, 904{,}90]\, Bar$, just like the oscillations that come after it (Figure 24).

Considering the oscillations of first half hour of simulation (last three figures), they occur because BHP has to be adjusted. As choke pressure has to increase, to increase BHP, the choke starts closing (Figure 25), reducing flow rate through it. When BHP surpasses the reference pressure, the controller adjusts the choke, opening it and increasing flow out. In the mean time, as soon as it is safe to reduce pump pressure, fluid acceleration decreases, and consequently its velocity too, decreasing choke pressure according to equation (34), opening the valve even more and leading to an amplitude oscillation (first maximum of Figure 24) greater than the deviation started with. After it, the other oscillations are due to the controller feedback loop.

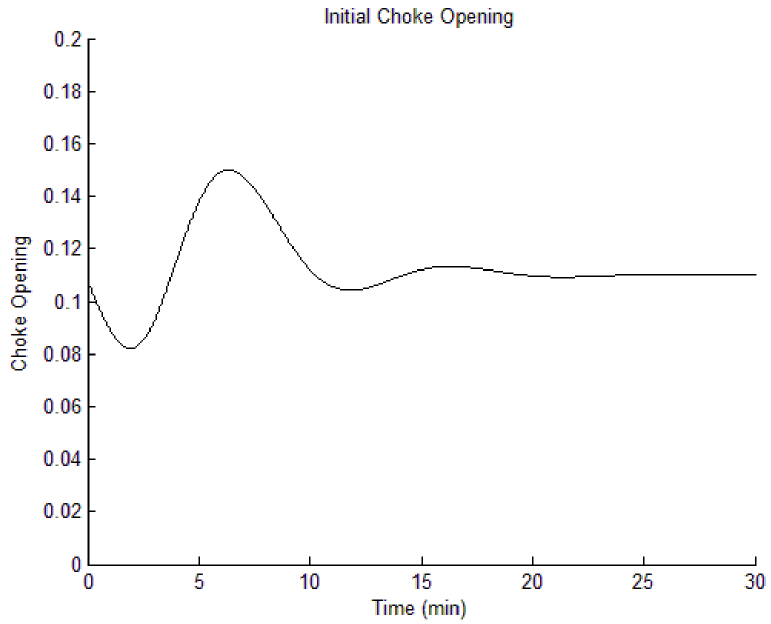


Figure 25: Choke opening during first 30 minutes of simulation.

One last note at this stage: although BHP reaching the reference pressure, it is possible to see on Figure 22 that flow out is not trending towards flow in value. At this stage it is normal as a gap at the entrance starts to appear forcing flow out to be greater than flow in (next stages will approach this situation).

4.2.2. Pumping Cement

4.2.2.1. Simulation

The simulation starts with the casing already inside the well ready to be cemented (Figure 26 – a) and with the cement being pumped in. As its density is higher than the mud already inside the well, cement weight will play a major role pushing the mud downwards, creating a gap at the top (Figure 26 – b) due to gravity force. During the first cubic meter of cement pumped, it is assumed that its acceleration is zero so it has a constant velocity. This situation occurs because if we try to calculate the acceleration with equation (26) it would be too big because cement mass would be too small.

The pump pressure also suffers changes while pumping the cement. Instead of considering it as a state variable, when the height of the gap created at the top is higher than 10 meters, the pump pressure decreases at a rate of $0.18\ Bar/min$ until it reaches zero[11], whereas if it is smaller, the value increases at the same rate, to a maximum of $65\ Bar$ (Figure 27). As soon as pump pressure achieves zero Bars it remains with that value until the gap at the top disappears (cement needed is all inside the well by that time).

[11] In reality the pressure drops to atmospheric pressure but as in all calculations made this value was much smaller than other pressure values at stake the value for it is $0\ Bar$ instead of $1\ Bar$.

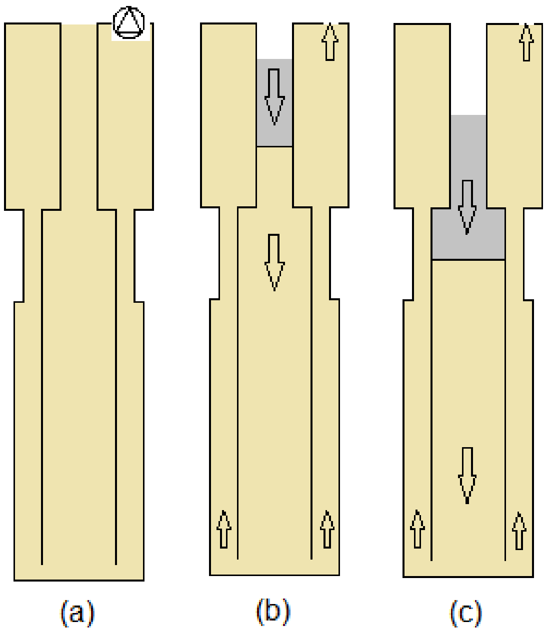


Figure 26: Cement displacement while pumping it. (a) Initial state with no cement; (b) Cement inside drill pipe section; (c) Cement inside both drill pipe and casing sections.

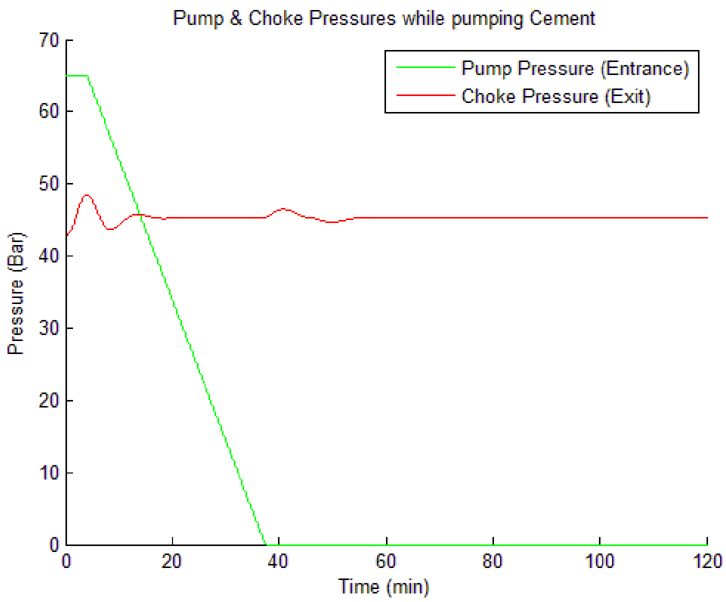


Figure 27: Top pressures during the stage of cement pumping.

When cement reaches the casing (Figure 26 – c) the changing in cross sectional area makes the difference. Physically, in order to keep the flow constant, if the cross sectional area increases, the velocity across it should decrease proportionally. As in reality this area change is abrupt, the velocity also changes suddenly, which leads to abrupt oscillations on cement position. It was decided to use the average value for cross sectional area casing section, considering on MATLAB code the Figure 28 instead of Figure 26 – c. With this simplification, the average area increases smoothly and consequently the average velocity decreases the same way, avoiding sudden oscillations on the cement position.

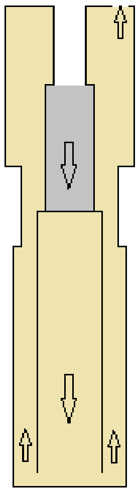


Figure 28: Casing section considered in theory when, in this case, cement is in both drill string and casing sections, to simplify calculations and decrease oscillations.

4.2.2.2. Discussion

After the pump pressure gets down to zero Bar, the valve pressure starts increasing because the first one stops decreasing. The controller reacts by opening the choke to release pressure over it. When BHP is re-established the choke opening is maintained but not for long as pressure goes below its reference, so the valve starts closing to raise its pressure and consequently BHP. Next figure explains this behaviour, bearing in mind that the first vertical dashed line is the instant when pump pressure is null, while the second marks the instant when choke starts closing again as BHP becomes lower than its reference. The flow out has the same behaviour as the choke opening: when it opens flow increases and when it closes decreases (Figure 29).

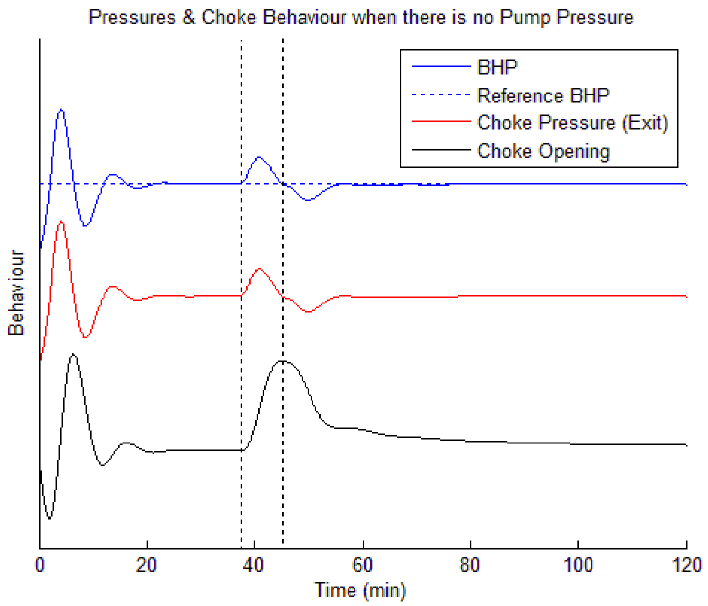


Figure 29: Influence of pump pressure when it gets down to zero Bar. BHP has the same behaviour as choke pressure and choke reacts when BHP oscillates above or below its reference.

4.2.3. Pumping Mud until Cement hits the Bottom

4.2.3.1. Simulation

After pumping the $60\ m^3$ of cement (after 2 hours) it is time to keep pushing it down, with the goal of filling the gap at the top. Mud rate is increased up to $2200\ l/min$ (Figure 30) and the controller tries to equalize the flow out with the flow in, however the second one is always higher than the first, which makes the space to disappear after a few minutes (Figure 31).

With flow rate rising, fluid inside the well circulates faster, which makes the mud to reach the casing at $2000\ m$ depth also faster (gradient of light grey curve, on graphic from Figure 31, between the vertical dashed lines, is greater than previously). After this moment, as cement is all inside the same casing, grey lines from Figure 31 go along with each other.

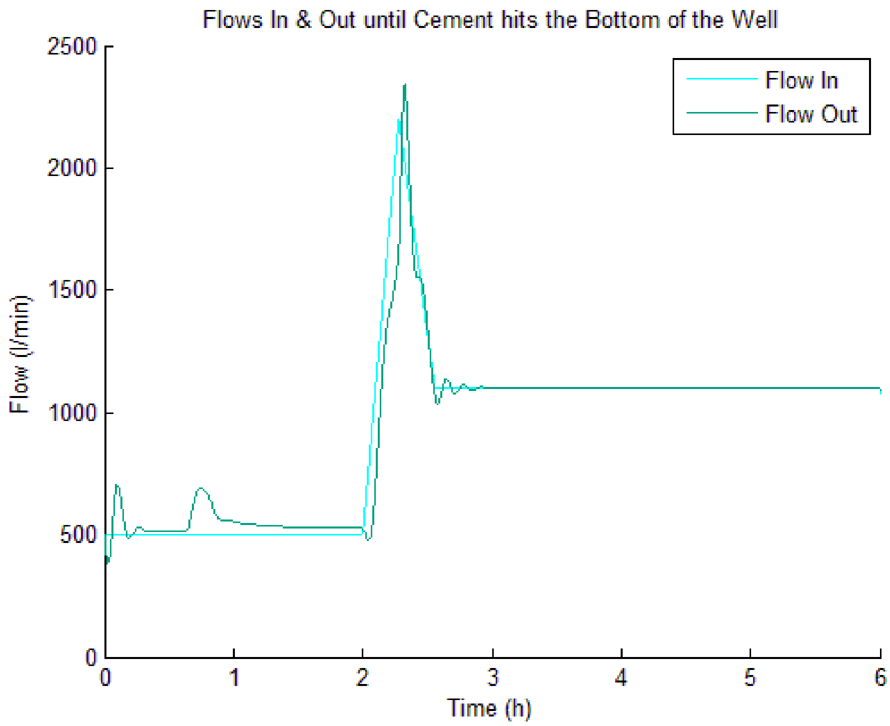


Figure 30: Flows in and out until cement hits the bottom of the well. After 2 hours mud is pumped in and the flow increases until the gap vanishes, starting to decrease to $1100\ l/min$.

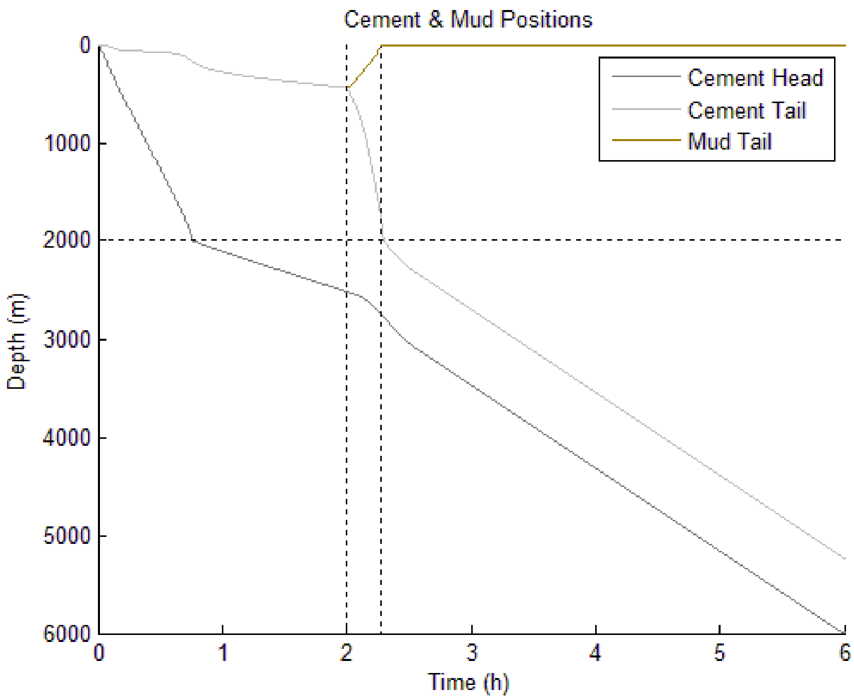


Figure 31: Cement and mud positions until the first hits the bottom. First vertical dashed line marks the beginning of mud pumping while the second indicates the instant when the gap comes to an end. Horizontal dashed line separates the drill string from the casing in depth.

According to Statoil engineers, the flow in is decreased by the time the gap at the top fades, as the well is again under pressure at the entrance. That way the pressure at the top does not increase too much and consequently neither at the bottom. This is the instant when pump pressure becomes a state variable, depending on controller adjustments (Figure 32).

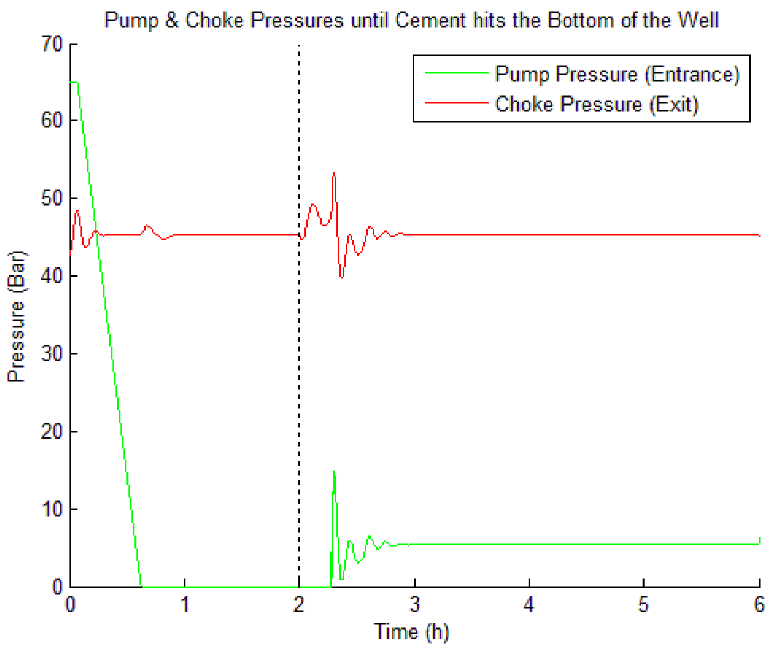


Figure 32: Top pressures until cement hits the bottom. Vertical dashed line marks the instant flow is changed, varying choke pressure. Pump pressure increases as soon as mud hits the top.

4.2.3.2. Discussion

With flow change it is possible to see that the velocity at the head of the cement remains almost unchanged. This is due to the fact there is still space at the top to fill. Naturally, this makes the valve at the exit to open, supposedly decreasing its pressure. As flow keeps increasing, pressure at the choke also augments with oscillations from the controller feedback, decreasing later when pump pressure also diminishes (Figure 33).

With the well filled, flow out must be equal to flow in and pressures at the top must behave according to each other. In this case, as both are measured at the same depth, they should be equal if the fluid inside the well were homogeneous. As there are two fluids with different densities, and as the denser is still only inside the drill string and casing, the hydrostatic pressure of the inside column is higher than the annular one. Then, pump pressure has to be lower than choke pressure so that BHP gives the same result both ways, by adding the corresponding hydrostatic pressure. Despite pressures at the top being different from each other, they still must behave in the same way: if, in this situation, pump pressure rises, choke pressure also increases.

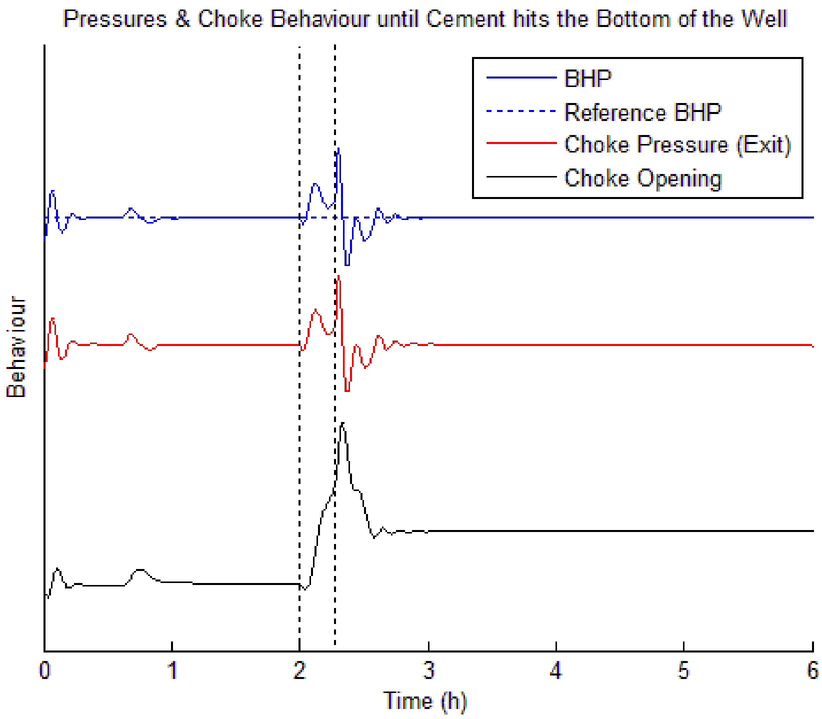


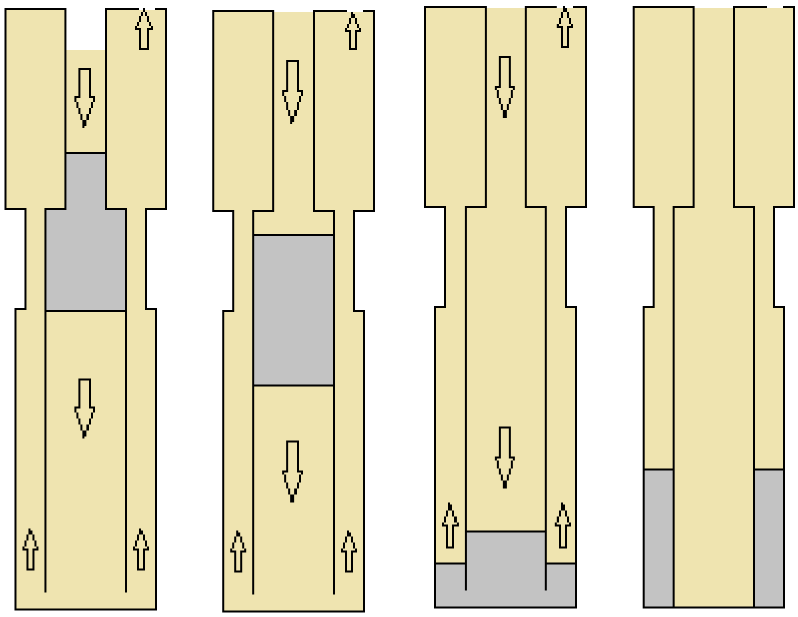
Figure 33: Pressures and choke behaviour during 6 hours of simulation. First vertical dashed line indicates the instant when mud starts being pumped in, while the second is when the mud hits the top and the pump is under pressure again.

Finally, when flow in is decreased, pump pressure has an almost instantaneous change due to the mud impact at the top, reducing afterwards, as it has to follow choke pressure that also has to be lessened thanks to BHP. Choke is then closed, not only because of flow reduction but also of BHP being bellow the reference target. The remain oscillations are due to the controller feedback loop.

4.2.4. Cementing the Annulus

4.2.4.1. Simulation

After 6 hours of simulation pushing cement downwards (Figure 34 – a and b), it finally hits the bottom and goes into the annular cavity (Figure 34 – c). This is the most critical moment during the entire process. Hydrostatic pressure inside the annulus changes while cement moves upwards it.



(a) (b) (c) (d)

Figure 34: Ciment displacement while pumping mud. (a) Cement still inside drill pipe and casing sections; (b) Cement only inside casing section; (c) Cement reaches the bottom and goes to the annulus; (d) Final state with cement inside of the bottom part of the annulus.

To help balancing the BHP, the flow in is decreased once again until a third of $2200 l/min$ is reached. During the last 50 meters casing with cement inside it, the pump flow rate decreases even more, according to the code from Figure 35, until approximately $23 l/min$, as it is possible to see on Figure 36 (with this pump rate there is no problem in closing the choke, finishing the process, in order to stop the flow as soon as the cement is all inside the annulus – Figure 34 – d).

```
if (well_length - cement_tail) < 50
    if i < 20000
        flow = previous_flow * (1 - 1/(i/5));
        i = i+1;
    else
        flow = previous_flow;
    end
end
```

Figure 35: Code that defines the flow rate during the last 50 meters casing with cement inside (variable $i = 10000$ at first iteration).

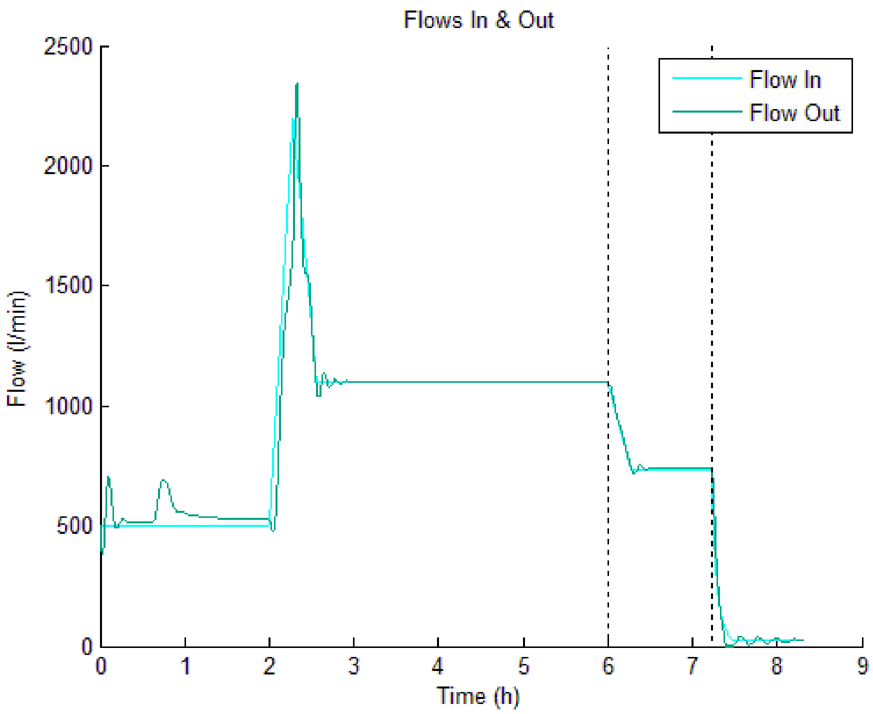


Figure 36: Flows in and out during the entire simulation. First vertical dashed line marks the moment cement reaches the bottom well while the second indicates that there are missing 50 meters casing with cement inside.

Next figure shows the positions of the cement and the mud along the well during the simulation. The pinpointed points on the graph represent those transition moments, which are detailed in Table 4. As soon as the cement hits the bottom, velocity decreases again so that the controller is able to keep up with the BHP growth.

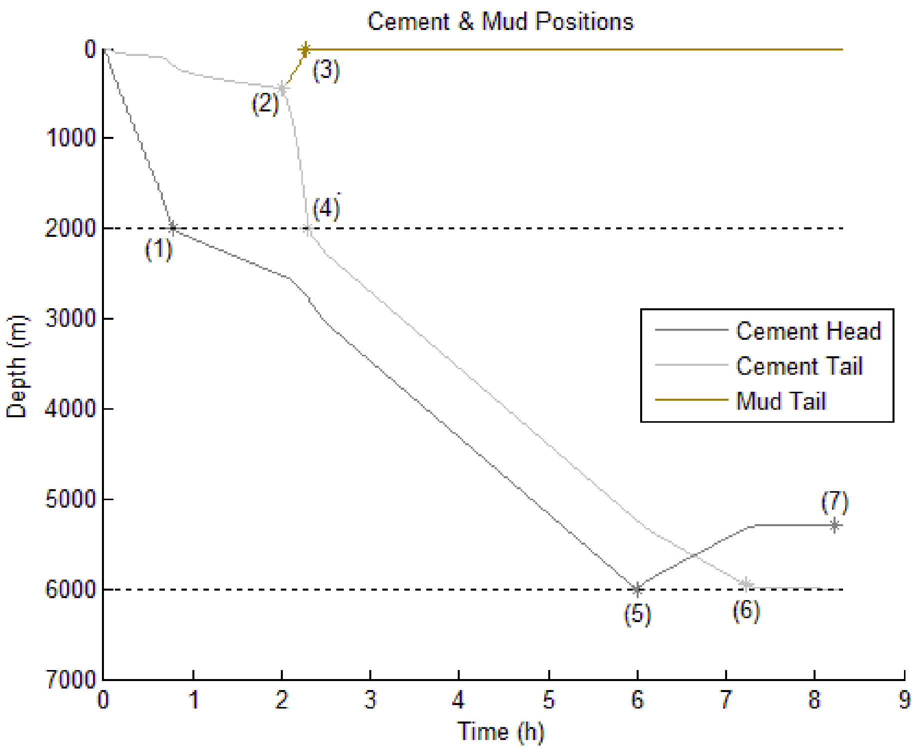


Figure 37: Simulation of the behaviour of the fluids inside the well. After 8,23 hours cement is all in place. Numbered coordinates are on Table 4.

Table 4 – Coordinates of the sequence of transition moments pinpointed in Figure 37.

Point	Time (h)	Cement Head Depth (m)	Cement Tail Depth (m)	Mud Tail Depth (m)	Description
(0)	0,00	0,0	0,0	-	Beginning of simulation by pumping cement
(1)	0,77	2000,0	178,1	-	Cement head reaches the casing
(2)	2,00	2516,0	438,7	438,7	Mud started to be pumped
(3)	2,28	2736,0	1798,0	0,0	Gap at the top of the well disappears
(4)	2,30	2769,0	2000,0	0,0	Mud head reaches the casing
(5)	6,00	6000,0	5231,0	0,0	Cement head hits the bottom of the well
(6)	7,23	5326.0	5950,0	0,0	Last 50 meters casing of cement
(7)	8,23	5283,0	6000,0	0,0	End of simulation

4.2.4.2. Discussion

As said before, the pump pressure is mainly estimated based on the hydrostatic pressure due to the column of fluid inside the annulus. If a new and heavier fluid (cement) is going inside it while at the same time the less dense (mud) is expelled, the hydrostatic pressure of the total quantity of fluid increases. In order to keep BHP as steady as possible, the controller starts by closing the choke when cement hits the bottom, to accompany the flow in decrease. When it stabilizes again the choke has to start opening, as annular hydrostatic pressure continues to increase, obliging the choke pressure to decrease. At the end, as the flow is becoming really low, the controller closes again (not totally) the choke so that its pressure do not decreases too much (Figure 38).

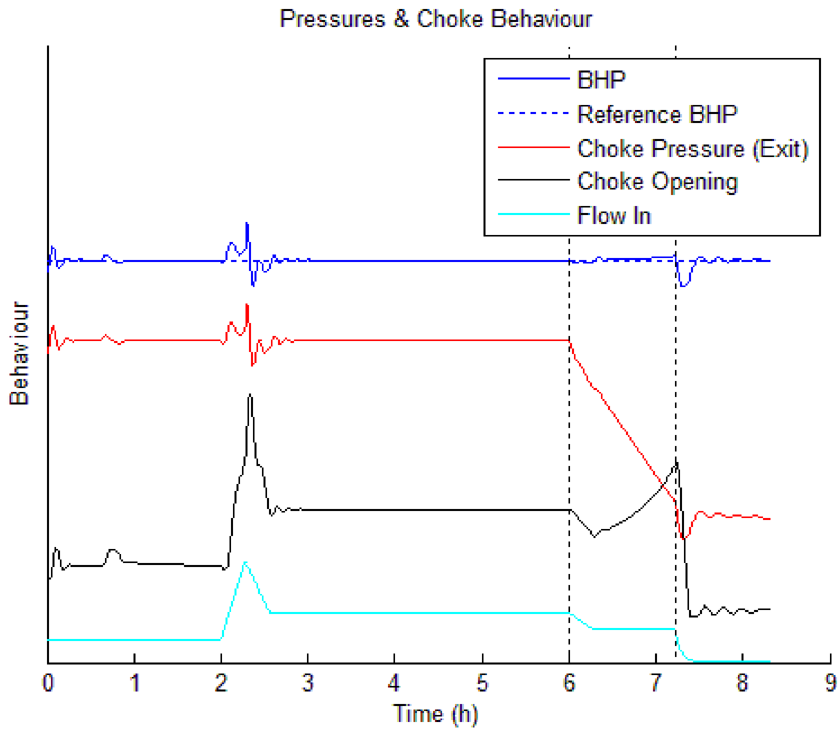


Figure 38: Controller reaction, through choke opening/closing, to the flow in changing and the annular hydrostatic pressure increasing.

The pump pressure changes in the opposite direction. While hydrostatic pressure inside the annulus is increasing, inside the drill string and casing it is decreasing (entering mud and expelling cement to annular cavity at the same time). The pressure at the entrance has to increase to balance BHP (Figure 39).

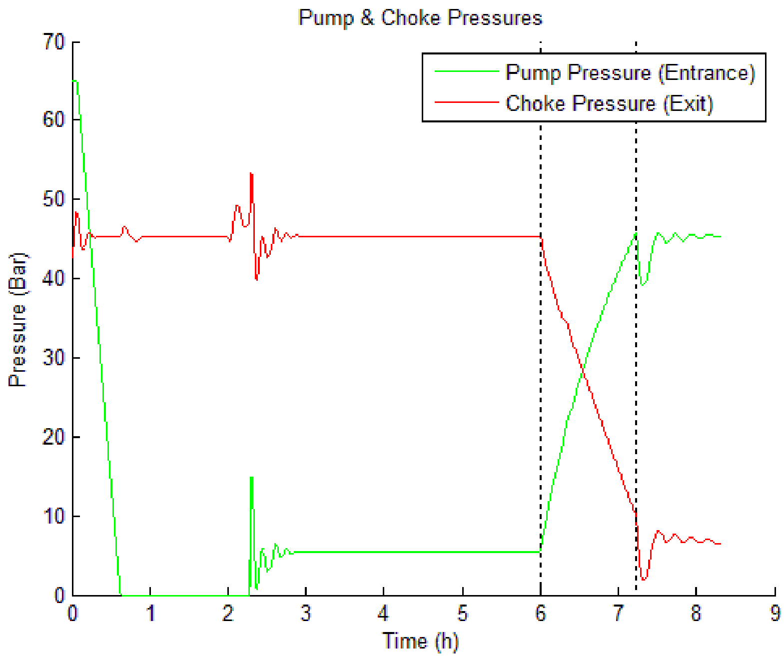


Figure 39: Top pressures during the entire simulation. First vertical dashed line marks the moment cement reaches the bottom well while the second indicates that there are missing 50 meters casing with cement inside.

Making again reference to the main goal of the simulation, in Figure 40 is represented the BHP along the simulation, where the dashed lines represent the limits imposed on the projected model by Mohamed A. Mashaal *et al*. [10], ($\pm 6{,}90$ Bar from reference pressure). It is possible to see that during the $8{,}23$ hours of simulation the boundaries are exceeded only once. Comparing with BHP curve from Figure 33, this small time interval corresponds to the moments after the gap at the top disappears. From all perturbations during the model this is possibly the most abrupt situation the model has to react to. When flow in changes, it does it smoothly. Even when cement moves into the annulus it goes gradually.

Figure 41 shows one of the best obtained results. Despite not being able to maintain the pressure inside the boundaries for a few moments, the choke does not have abrupt variations and never go from one extreme to another. It never reaches them either, except at the end when the simulation is almost finished and the flow out is really low, implying choke's closure.

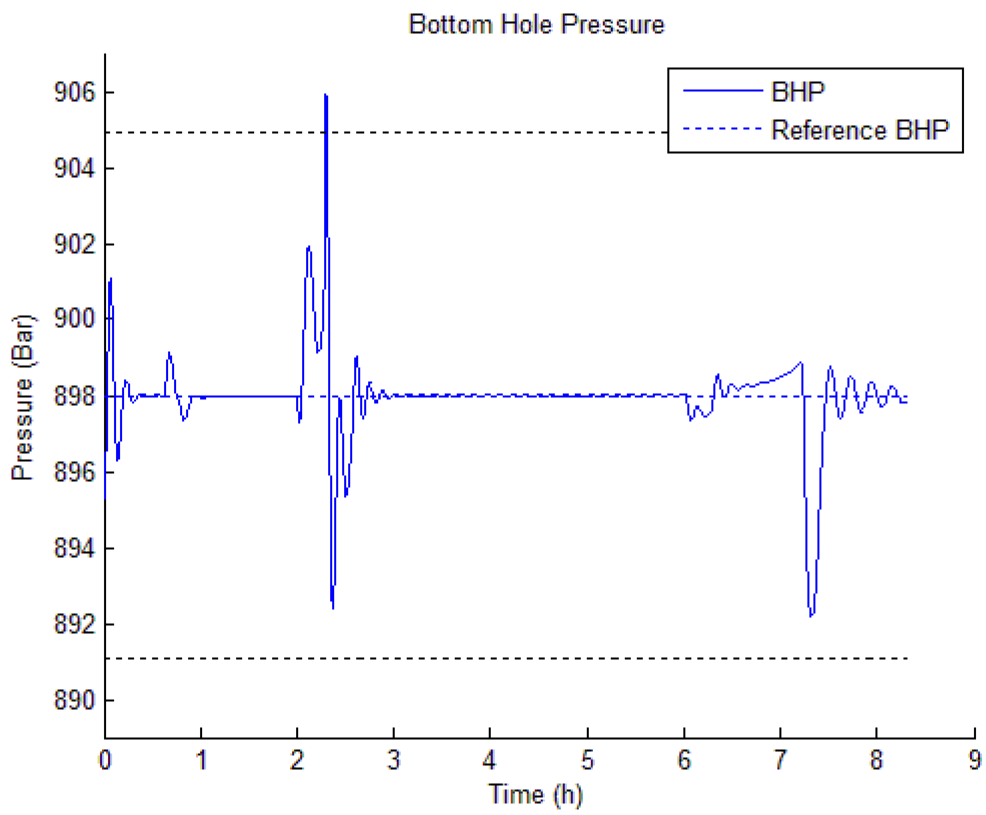


Figure 40: Bottom hole pressure during the entire simulation. Horizontal dashed lines represent the boundaries that should not be exceeded ($\pm 6{,}90\ Bar$).

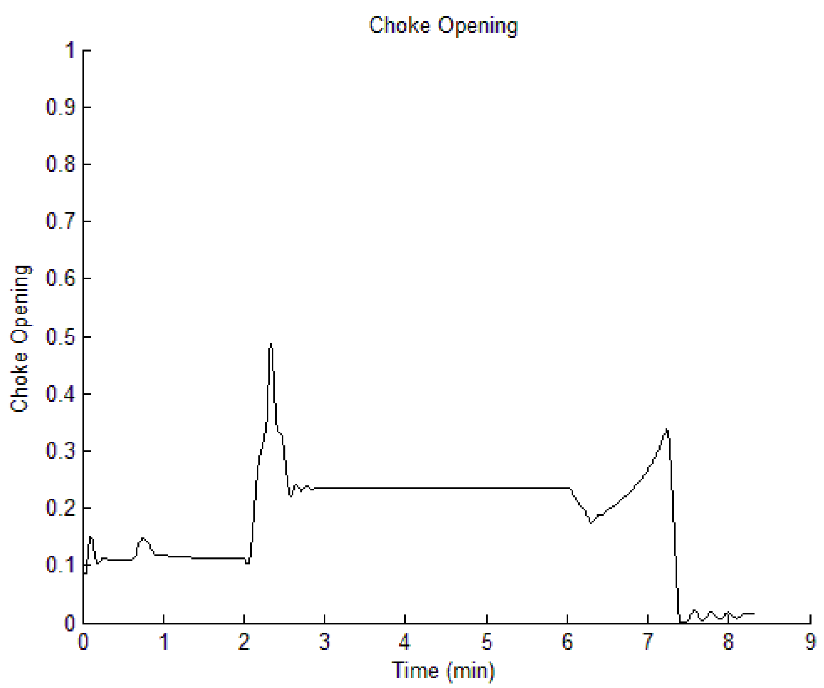


Figure 41: Choke opening for the entire simulation time. It is possible to see that it never reaches the extremes.

CHAPTER 5
CONCLUSIONS & FUTURE WORK

5.1. Conclusions

The work developed in this project provides an early stage contribution towards understanding the use of systems control theory and practice to enhance the managed pressure cementing process. Several assumptions and simplifications were considered in this project, as there were no support and previous work on the model, at least to the best of the author's knowledge. There were some obstacles, such as the type of fluids considered in this work (e.g. mud and cement) with complex structures and exhibit different behaviours in similar situations, therefore experimental work and testing is needed in the future.

Regarding the simulation results, they are within prescribed expectations as the pressure at the bottom of the well, and along it, was inside the interval imposed during the entire simulation, except for a few moments when the gap at the top disappeared.

The model that was developed in this thesis for predicting fluids behaviour does not completely capture the reality of phenomena of fluid interactions inside the well, but it showed to be valuable to provide early understanding of the processes. The fact that the velocity considered inside the well to make the calculations was an average value it is probably one of the biggest differences to reality, as it changes when it is compressed (for example the head of the cement does not have necessarily the same velocity as the other points along the cement column, especially if they are in different diameter sections at the same instant time) and it also varies from a central position to a position near a wall due to friction losses.

Given the scope of the thesis and the time limitations imposed by the project, it was decided from the outset to resort, it all possible, to a simple linear fixed controller structure. In accordance, a simple proportional plus integral controller structure was exploited, whereby the gains were essentially tuned using a combination of first physical principles and trial and error methods. The final results obtained proved satisfactory for an initial study of this challenging area of research.

Concerning the moment when BHP surpassed its limits, it could have been avoided by stating to decrease the flow rate when the gap at the top approaches small values. It is likely that it would have smoothed the pump pressure variation, avoiding BHP variation and containing it in between limits.

To conclude, the pressure at the top revealed to be one of the most difficult variables to adjust. In real time there is always pressure at the pump as long as there is no gap at the top right after it, but programming that became really difficult as there is no such thing as an infinitesimal value to define as a gap size. If the value was too small pressure would end up not being high enough and the fluids would flow in the opposite direction and if it was too large at a certain point it would not make sense to apply pressure at the pump if there was a space right next to it.

5.2. Future Work

There are some aspects in this work that can be improved with further work and experimentation. Starting with the model itself, fluids properties applied on the model could be more realistic. This project was not approached through the point of view of fluid mechanics, which would be interesting, not only in terms of flow regime and flow type but also in its compressibility, changing its density in time. This change is also influenced by temperature, as it may vary with e.g. depth and friction.

An analysis to the influence of each pressure term that contributes to BHP would also complement this project. That way it would be possible to understand which flow rate at the entrance of the well would be ideal to each stage.

Taking a look at the controller, the non-linearity of the choke equation brought difficulties to the project, where a linear controller may not be the best choice. An alternative to this adversity could be, instead of having one controller, to apply gain scheduled linear controllers to each state enunciated on the previous chapter, computing a number of gains for a selected number of frozen-time operating points and interpolating them afterwards to obtain a controller that changes naturally with time. The possible use of more advanced nonlinear control laws is also worth exploring.

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