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Petroleum and Mining Engineering

Master thesis in Petroleum Engineering

Managed Pressure Drilling (MPD)

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Abstract

The MPD or the managed pressure drilling technique became a point of interest recently as a result of the many problems that faced the drilling process recently in deep wells. The MPD technique is known to provide solutions such as minimizing the NPT, minimizing the number of kicks, limiting the lost circulation, solving the problem of differential sticking, increasing the ROP. This technique is deployable on both onshore and offshore drilling sites. It also allows the possibility of drilling wells that have narrow window of drilling where there is a high variance between the pore pressure and the fracture pressure while minimizing the risk.

This research was made in order to investigate where the managed pressure drilling technique was newly used and what formations was it used in among with the benefits gained from using this technique and some of the tools used in it to make this process even more successful.

Being faced with harsh conditions limit the use of conventional drilling to accomplish a safe and minimum risk drilling process and to mitigate the hazards that result from these harsh conditions. It was noticed that although the cost of managed pressure drilling is considerably high, the trends of the market showed an interesting increase in using the managed pressure drilling technique due to the benefits it provides and the amount of money it is capable of saving to the companies. Besides saving money and time, some special requirements must be considered while dealing with managed pressure drilling such as: the rig must be modified to perform such job, special equipment must be available to conduct the process successfully, personnel using this technique must be highly trained to deal with such an advanced technique,….etc.

Adding to that, discussing some tools used in managed pressure drilling technique such as the RCDs and the active systems as the rotating annular preventors, the chokes and there different types and uses of each, the (NRV) non return valves and there importance in Managed pressure drilling, the downhole annular valves and there advantages, the Coriolis flowmeter and its uses in the managed pressure drilling and finally the disc pump or the friction pump.

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Chapter 1 Introduction

The rapid growth of the petroleum industry has gone beyond imagination as the demand increased a lot. By which the drilling was forced to continue as drilling new wells or drilling in further depths in old wells of extreme environments, so they resorted to different techniques in order to make the drilling operation successful and as economic as possible. One of these techniques is the (MPD) Managed pressure drilling.it is a new technology of drilling control which is responsible of treating the borehole annulus and the drill string as a form of a large pressure vessel. One of its aims is drilling with a pressure close to the pore pressure by the continuous adjustment of the pressures of the downhole by the help of a special control system known as the automated choke.

This system is responsible for providing a practical solution in the narrow margin areas which is found between both the pore pressure and the fracture pressure. An example of these areas such as deep offshore or ultra-deep applications done offshore and the previously depleted zones that exists in mature fields.

MPD was defined as it is considered an adapting process of drilling which is used to accurately control the profile of the annular pressure all over the wellbore. One of its main objectives is to find out the limits of the environment of the downhole pressure and according to that it is responsible for managing the hydraulic pressure of the annular profile. Also, it is intended to use the managed pressure drilling to evade the formation fluids continuous influx towards the surface such that any secondary influx happens during the operation can be controlled in a safe way by the use of suitable process. The managed pressure drilling process mainly consists of a combination between some procedures and tools to help in reducing the cost and minimizing the risk the accompanies the narrow environmental limit wells drilling by the proactive management of the hydraulic pressure profile of the anulus.

The managed pressure drilling is known to have control upon the back pressure, density of the fluid, the rheology of the fluid, the annulare level of the fluid, geometry of the hole, the friction of the circulation and the theory of combination. It is also responsible for allowing the fast correct action when dealing with the pressure vibrations observed. It is responsible also for making the dynamic control of the pressures of the annulus be able to make the drilling easy considering the economic wise of achievable expectations.

Moving on to the hydraulics of the managed pressure drilling where it is essential to accurately determine the pressures of the downhole all the way from the planning phase to the deployment of the managed pressure drilling phase in order to achieve a successful execution of the application of the managed pressure drilling. Adding to that, minimizing the losses and the influxes can be achieved by the managed pressure drilling systems that gives important information considering the formation characteristics in which the drilling is to happen.

Chapter 2 Literature review

2.1 Mitigating Drilling Hazards in a High Differential Pressure Well Using Managed Pressure Drilling and Cementing Techniques(Egbe.P,2020).

It is well known that the reservoir heterogeneity considering the formation pressure is significantly challenging at the condition of high overbalance in the low pore pressure zone which results in total losses of the drilling fluid and may cause a stuck pipe which in turn increase the NPT (non productive time) and also increases the cost of the well. A case of high differential pressure is presented below where the drilling operation took place in a direction of up dip which made the operation more complex(Egbe.P,2020)

It was planned to drill the whole section of the reservoir in $6\frac{1}{8}in$ section but in order to overcome the challenges that was mentioned before in the operation a 7in liner depth has been adjusted in order to obtain full coverage on the reservoir’s highly pressured section and therefore isolate the weak zones of the reservoir at the TD (total depth) of the well. The MPD (managed pressure drilling) technique was installed to be able to drill the two sections in order to minimize the condition of overall balance and to add another method for determining the pore pressure value. Adding to that, the 7in liner was deployed in the managed pressure drilling mode to decrease the differential sticking chances and it was cemented by using the MPC (managed pressure cementing) technique to reduce the losses downhole while running the cementing operation which helps in achieving an efficient isolation of the zones and increases the well integrity on the long term which leads to a possible (SCP) sustained casing pressure(Egbe.P,2020).

The MPD (managed pressure drilling) is known as a drilling technique considered to be adaptive which is used to provide precise assessment of the pressure of the formation and helps in managing the pressure of the bottomhole consequently. It also allows using lighter mud density in the drilling fluid in order to minimize the overbalancing condition and a constant pressure of the bottomhole can be achieved by influencing the pressure of the annular surface. The managed pressure drilling was applied to succeed in the formation pressure determination and defining the optimum mud weight that must be used in the drilling operation while running the liner and cementing it which minimizes the risk of losses and differentially sticking pipes(Egbe.P,2020).

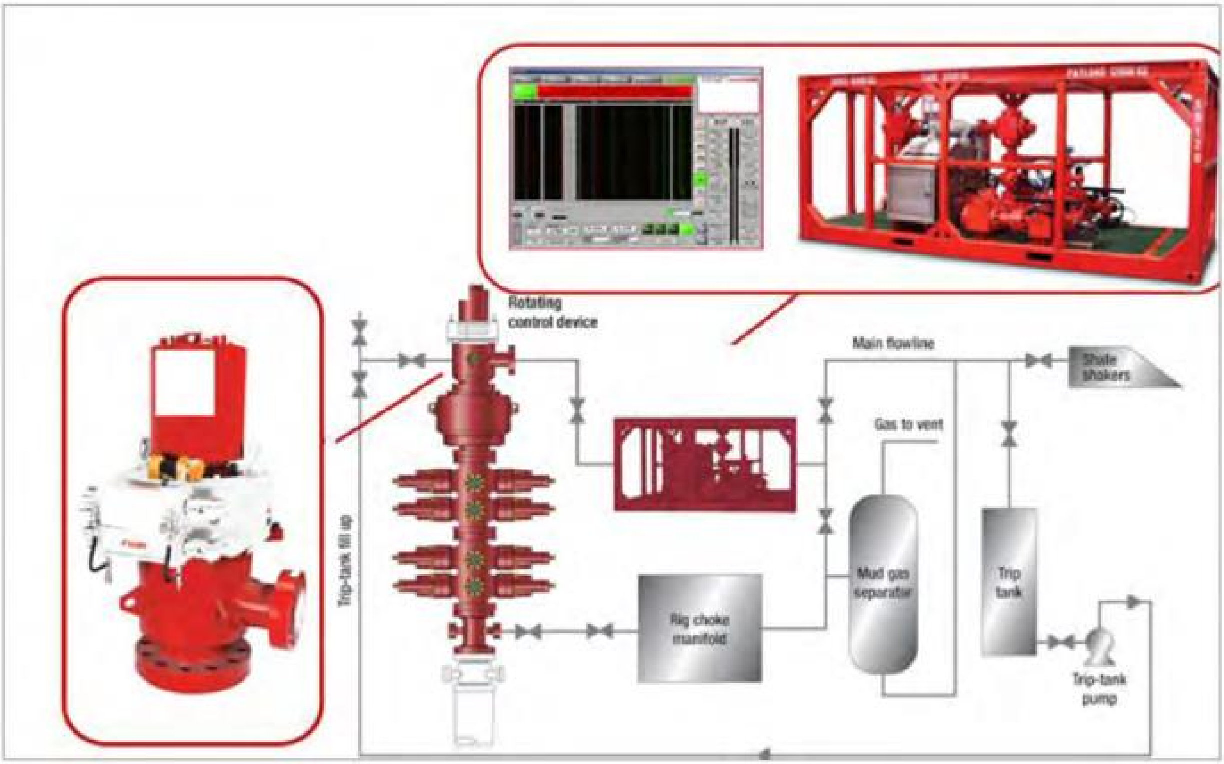


Figure 1: The system components of the managed pressure drilling(Egbe.P,2020).

In fig1, the managed pressure drilling system is represented where each component has gone through the design, maintenance, tested under the standards of API and ISO(Egbe.P,2020).

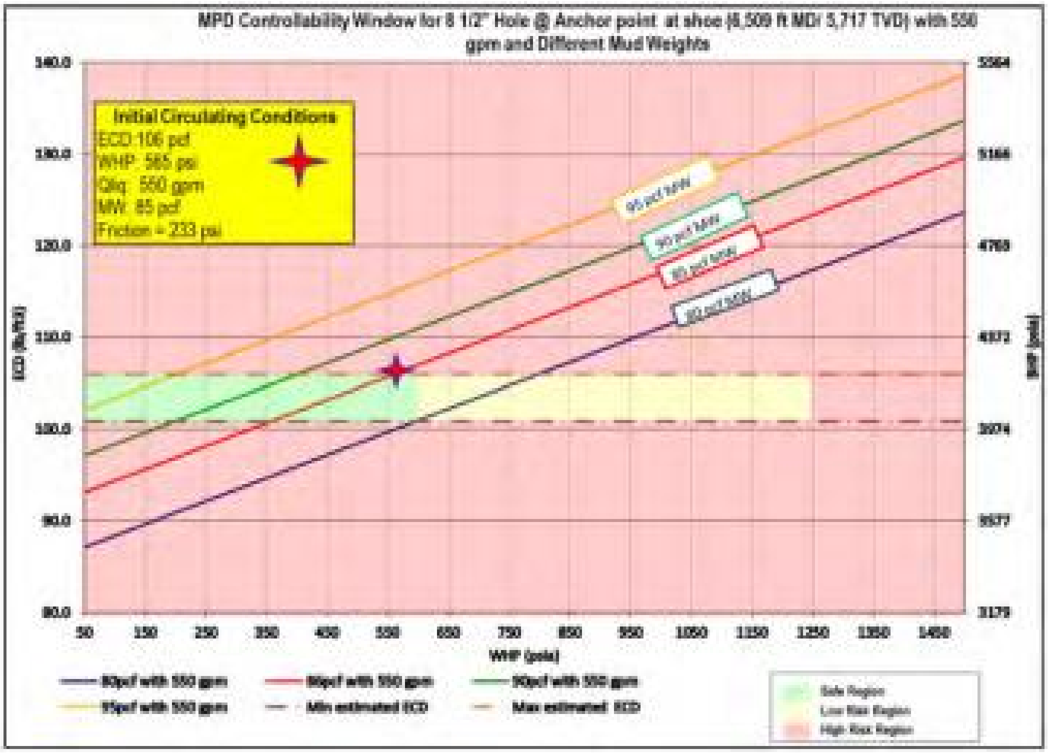


Figure 2: The controllability window of the managed pressure drilling for the $8\frac{1}{2}$ in section in dynamic conditions (Egbe.P,2020).

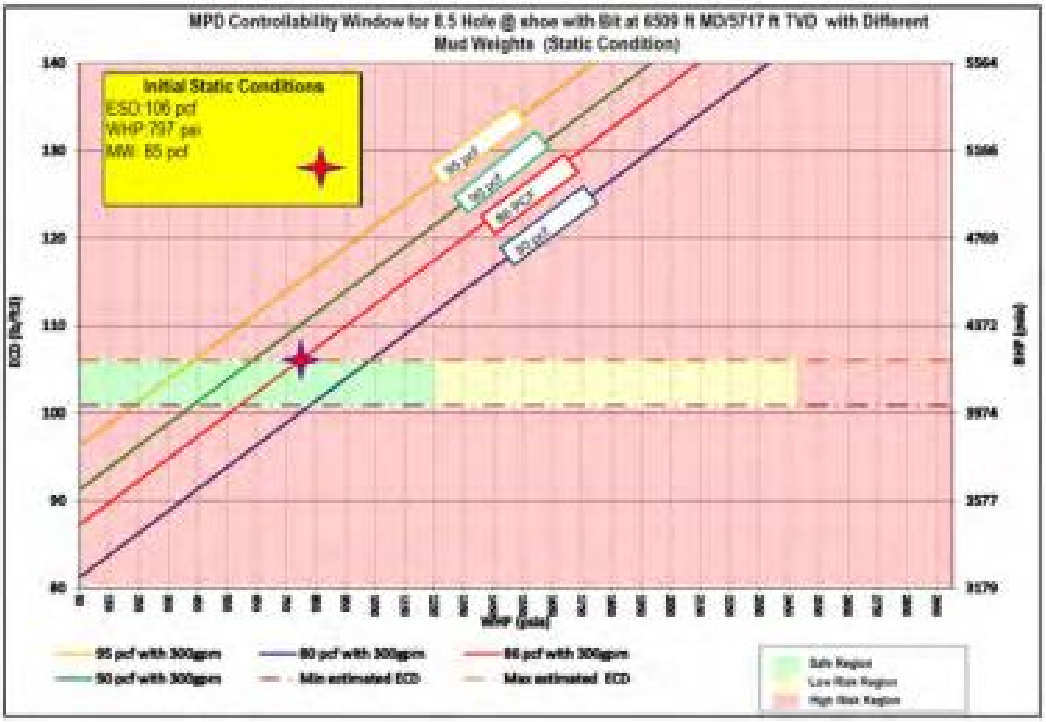


Figure 3: The controllability window of the managed pressure drilling for the $8\frac{1}{2}$ in section in static conditions (Egbe.P,2020).

In fig 2 and fig 3 the control window of the managed pressure drilling for the $8\frac{1}{2}$ in section, it is clearly shown that for generating the target equivalent circulating density (ECD)of 106 pcfthe density of mud was selected to be 85 pcf along with a 550 gal/min pump rate and a 565 psi (SBP) surface back pressure(Egbe.P,2020).

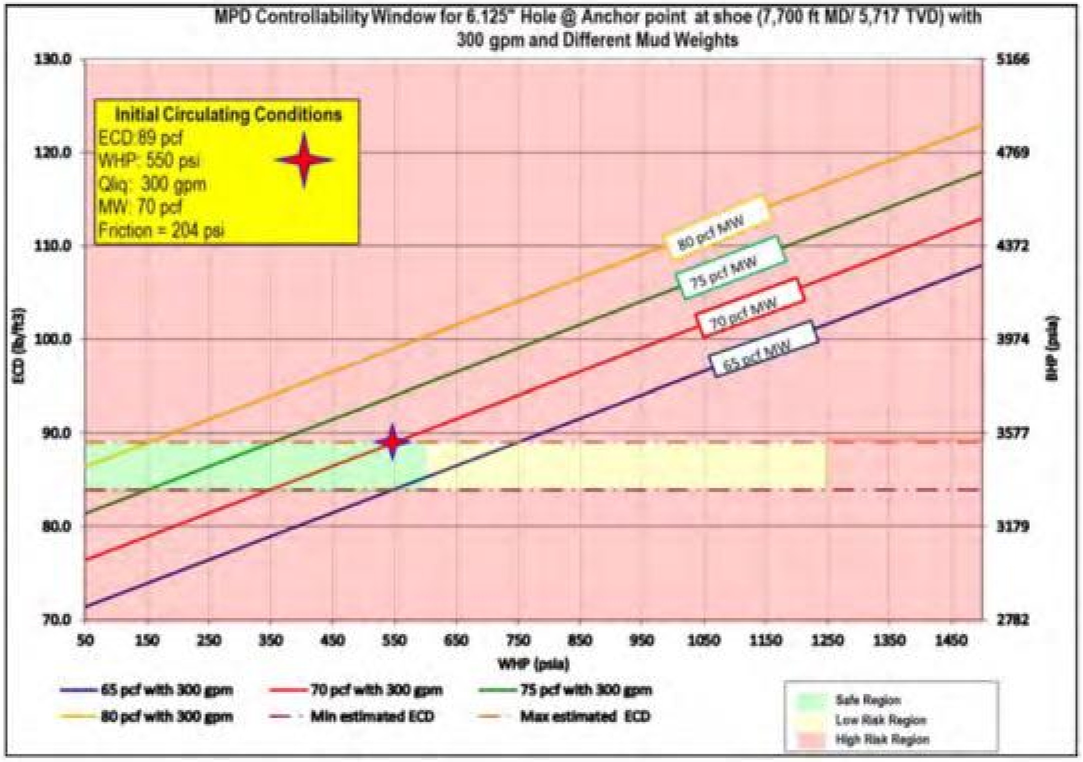


Figure 4: The controllability window of the managed pressure drilling for the $8\frac{1}{2}$ in section in dynamic conditions (Egbe.P,2020).

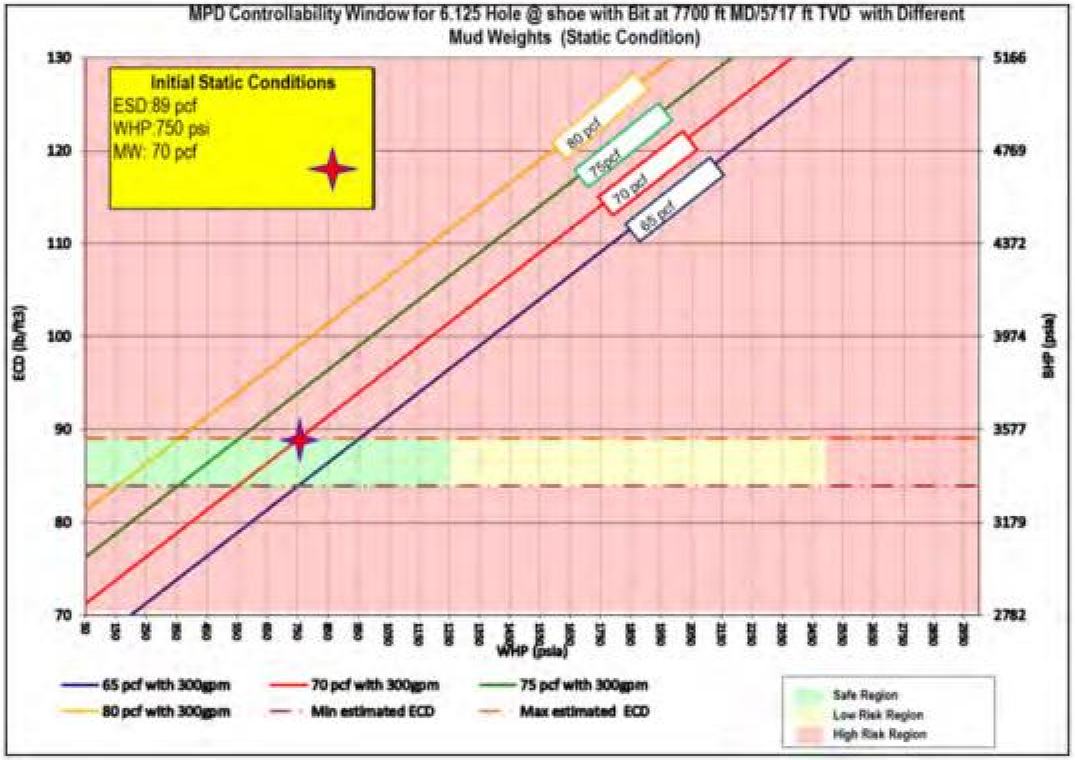


Figure 5: The controllability window of the managed pressure drilling for the $8\frac{1}{2}$ in section in static conditions (Egbe.P,2020).

In fig 4&5 the control window of the managed pressure drilling in the static conditions and dynamic conditions of the $8\frac{1}{2}$ in section. Based on the 7' liner shoe depth expected pore pressure the target equivalent circulating density is 89 pcf. And in order to achieve this density it was suggested to use mud density of 70 pcf along with a pump rate of 300 gal/min and surface back pressure of 550 psi. combining these three conditions is responsible for allowing a good adjustment range in case a pore pressure lower than anticipated occurred(Egbe.P,2020).

MPD Well Control Matrix				
Surface Back Pressure				
Normal Operations No Influx (100-500 psi)		Influx Detected Drill Pipe Rotation Greater Than 5 RPM SBP less than 1,500 psi	Influx Detected Drill Pipe Rotation Less Than 5 RPM SBP > 1,500 psi & < 2,500 psi	Influx Detected SBP Greater Than 2500psi
Pit Gain / Influx Indicator	Influx Less Than 5 bbls	•Increase SBP, Pump Rate or a combination of both •Pick up off Bottom •Maintain Rotation •Circulate out influx •Adjust Fluid Density as Required	•Increase SBP, Pump Rate or a combination of both •Pick up off Bottom •Maintain Rotation 5 RPM or Less •Circulate out influx •Adjust Fluid Density as Required	•Space Out Drill Pipe •Shut down mud pumps •Shut in on BOP •Inform Aramco Foreman •Proceed With Conventional Well Control Through Rig Choke Manifold
	Influx Greater Than 5 bbls	•Shut down mud pumps •Shut in on MPD Choke •Isolate MPD Choke from well •Maintain Rotation •Space Out Drill Pipe •Inform Aramco Foreman •Proceed With Conventional Well Control Through Rig Choke Manifold keeping pipe movement	•Shut down mud pumps •Shut in on MPD Choke •Isolate MPD Choke from well •Maintain Rotation •Space Out Drill Pipe •Inform Aramco Foreman •Proceed With Conventional Well Control Through Rig Choke Manifold keeping pipe movement	

Figure 6: Managed pressure drilling control matriz(Egbe.P,2020).

The operations of the managed pressure drilling face complex scenarios such as demonstrated in this case which is the drilling fluid used in underbalanced drilling technique where it was found to be lower than the required in the conventional one. The existence of uncertainties related to the pore pressure might assist in the undesired fluids from the reservoir coming in the wellbore. Managed pressure drilling is designed to deal with this type of problems. The managed pressure drilling control matrix, which is demonstrated in fig6, is an indication for the orders that must be given when an influx is discovered where limits and boundaries are defined where the well control is handled by the well operator(Egbe.P,2020).

2.2 Enhancing Performance and Operational Safety of Argentinean Vaca Muerta Shale Wells by Drilling High Pressure Formations Using Managed Pressure Drilling. (Pozo.M, 2017)

A drilling project took place in the in the onshore field where an unconventional shale gas drilling operation was performed and developed for the purpose of reaching a formation called Vaca Muerta. This type of formation is characterized to be overlaid by another formation called Quintuco which is more shallow and full of troubles. This formation consists of 2 layers known to be over pressurized and the exist in two positions in the formation the middle and the bottom. The lower formation of Quintuco is considered to contain hydrocarbons, fractured naturally, drilling hazards may occur during the operation and it is known to be trapped in a regime characterized to be over pressurized. The prediction of pore pressure is considered highly uncertain which makes the selection of proper mud weight very challenging. The conventional offset wells drilled have experienced a remarkable NPT(non productive time) as a result of the events of the well control where the specified weight of the kill mud has been a hard task as a result of natural fractures existence(Pozo.M, 2017).

The drilling campaign 's aim was defining an effective and a dependable drilling technique to overcome the uncertainty of the pore pressure as economically and safe as possible. These can be achieved through implementing the MPD (managed pressure drilling) to achieve full control on the zones that are characterized as over pressured zones and choosing the optimal mud weight to achieve full control on the well. The vertical wells that were conventionally drilled previously having the two types of formations (Quintuco and Vaca Muerta) were isolated by using two various casing strings to separate them(Pozo.M, 2017).

Redefining the strategy of the drilling technique was obligatory and was represented as 3 horizontal wells merging the two formations in 1 hole section. It was intended to drill the new wells while minimizing the mud density as low as possible and increasing the ROP(rate of penetration) as a result. These conditions are achievable by remaining the bottom hole pressure at constant conditions while there are different depths of anchor points along the hole when the formation of Quintuco is being drilled. An underbalanced condition which is set under control is created before starting to drill the horizontal part in the Vaca Muerta formation type at the deepest depth of the anchor point which is as near as they could get to the transitional zone between the two formations(Pozo.M, 2017).

The drilling performance is improved by that brilliant technique and what enforces the idea of being successful is that the drilling time was reduced from 123.4 days to 51.7 days by almost 40% per well and the non productive time (NPT) was reduced to 7.5% from 30% by the management of events concerning the well control and the elimination of 1 casing string and the improvement of the efficiency of drilling to achieve maximum rate of penetration (ROP). And by the previous achievements the well cost faced a reduction of 5.5 MM USD/well when in comparison to the final well of the campaign without causing any HSE (health safety and environment) problems(Pozo.M, 2017).

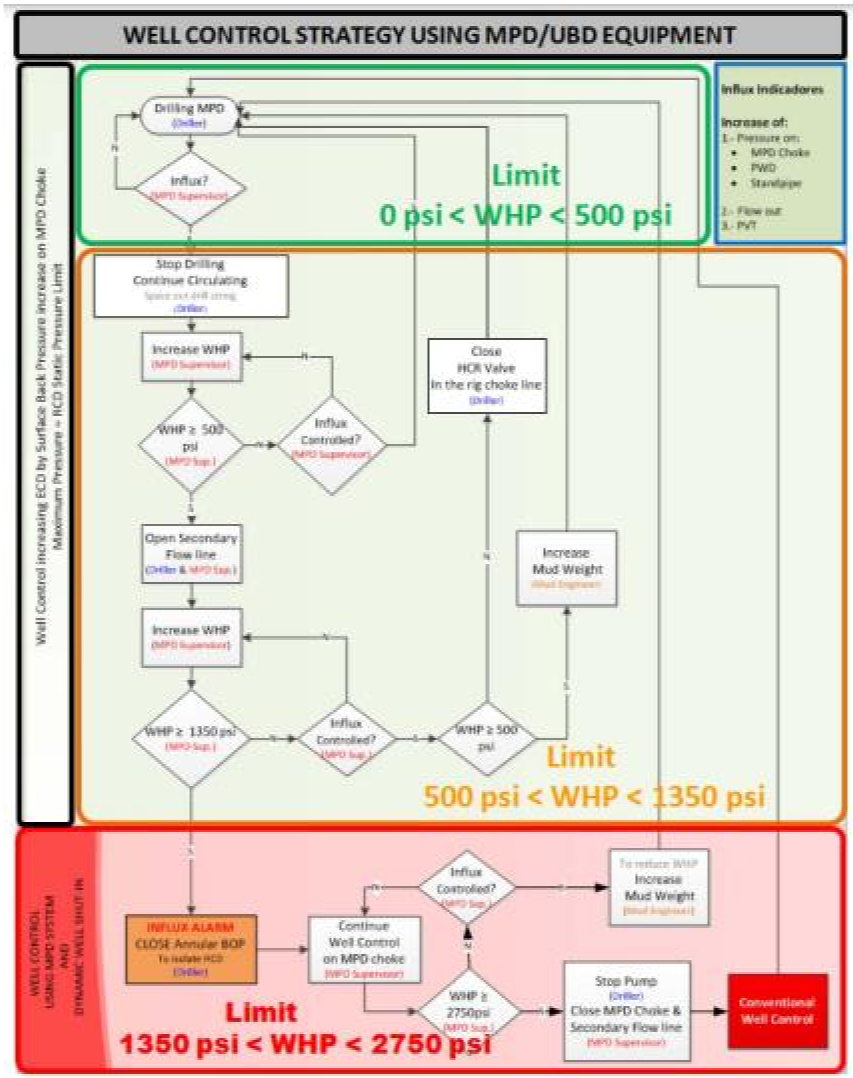


Figure 7: The strategy of well control while using managed pressure drilling operations (Pozo.M, 2017).

In fig7 the strategy of well control diagram where the steps are identified in a certain order to bring the conditions under control back in case any influx has been indicated but at the same time it maintains the pressure along with the flow control with the managed pressure drilling system. These steps are a merge of well control conventional procedures from the identifying of an influx to the shutting in of the well and the recommendations and assignments for every certain action per step(Pozo.M, 2017).

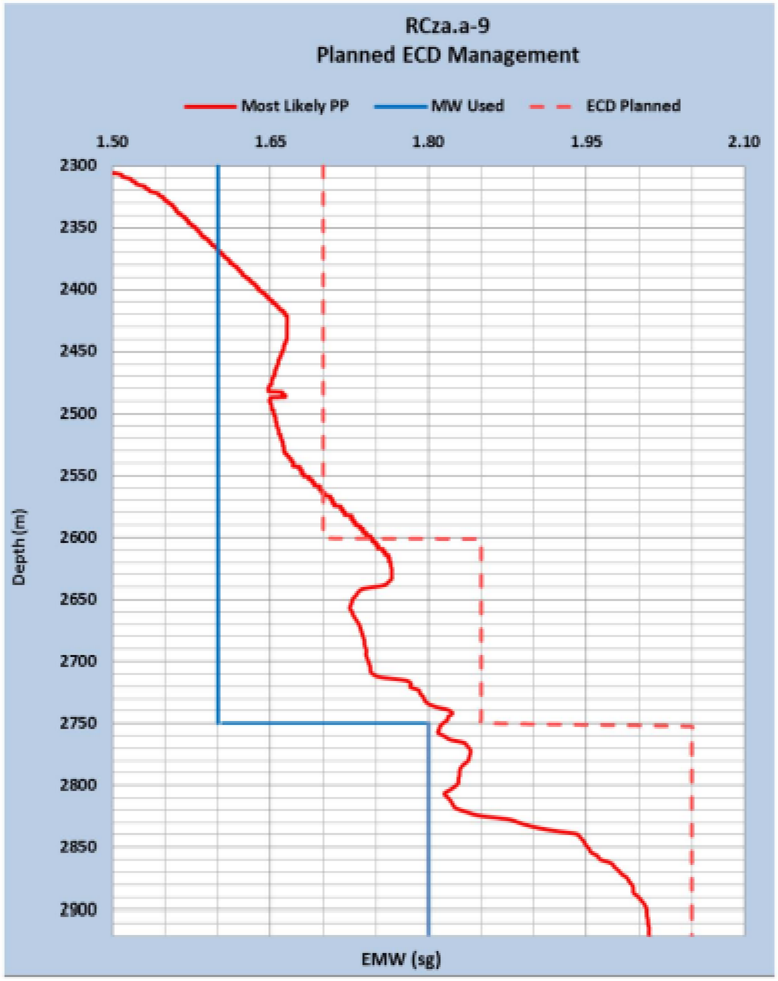


Figure 8: Equivalent circulation density(ECD) management plan for RCza.a9-v(Pozo.M, 2017).

In fig8 the equivalent circulation density management plan of the RCza.a9-v is demonstrated clearly as approaching the pore pressure control during the drilling operation of the $9\frac{1}{2}$ in the RCza.a9-v section was done depending on the 3 critical depths selection where the equivalent circulation density is kept constant during the drilling process and during connections such as the period of pumps off in order to achieve balanced conditions(Pozo.M, 2017).

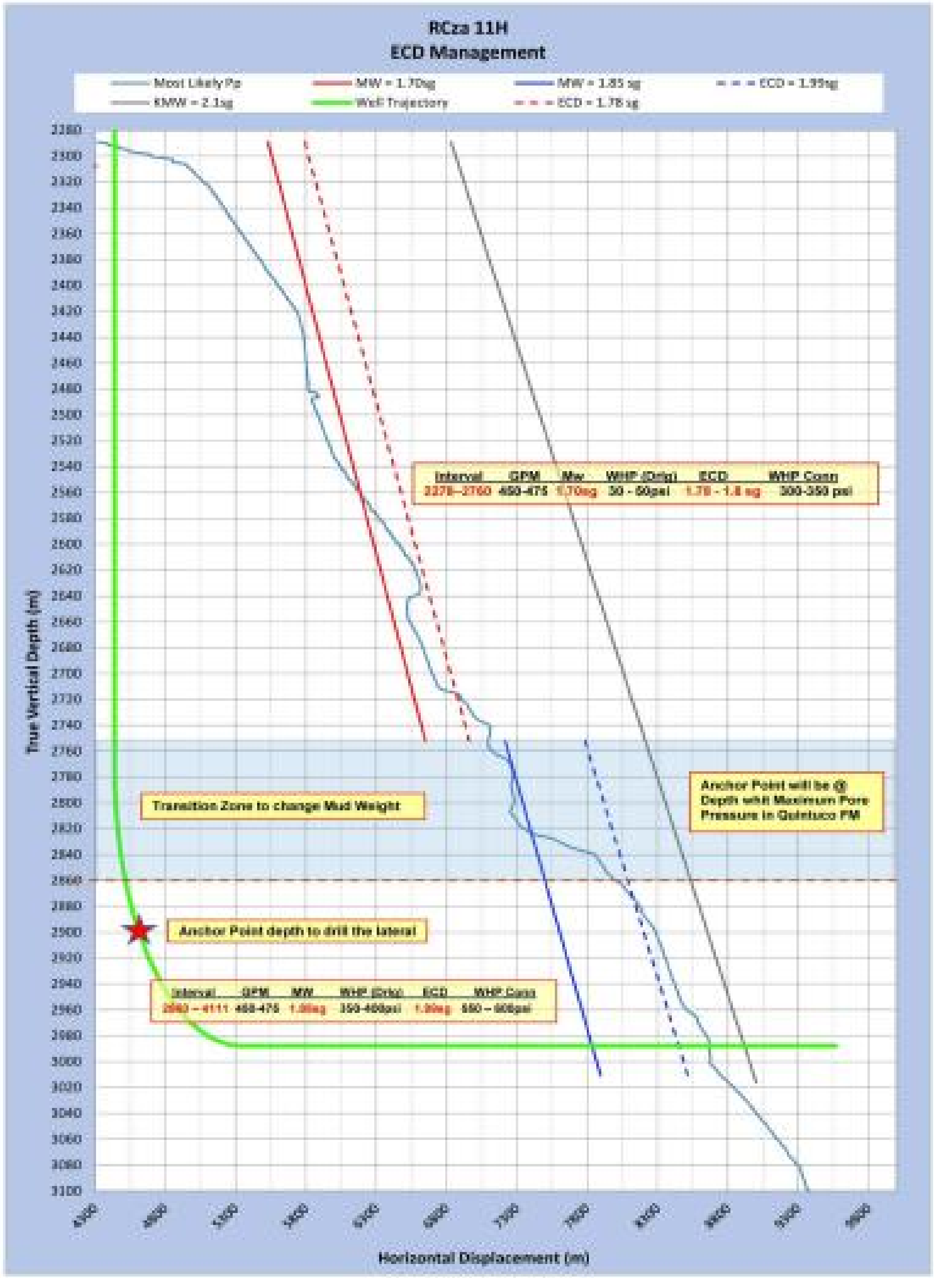


Figure 9: Equivalent circulation density(ECD) management plan for RCza-11h(Pozo.M, 2017).

In fig9 the equivalent circulation density management plan of the RCza-11h v is demonstrated clearly as a hole section of $8\frac{1}{2}$ in was drilled while containing both types of formations, in the vertical drain the Quintuco formation type and in the horizontal drain the Vaca Muerta. It was planned to use managed pressure drilling in the drilling of this section in order to control the equivalent circulation density along the Quintuco formation in the vertical section to minimize the changing of mud weight as much as possible(Pozo.M, 2017).

2.3 Successful Implementation of Managed Pressure Drilling and Managed Pressure Cementing Techniques in Fractured Carbonate Formation Prone to Total Lost Circulation in Far North Region(Kazakbayeva.Z,2021)

In the region of the far north a drilling process took place in a reservoir which has many challenges such as an increasing risk of mud losses which was a result of serious lost circulation issue. A huge number of various of trials to fix theses losses with the customary techniques butall have failed. In order to overcome these challenges, they tried applying MPD(managed pressure drilling) and MPC(managed pressure cementing) to drill a hole section of $6\frac{1}{8}''$ and running and cementing a$5''$ liner in order to manage the pressure of the bottomhole and to get control over the challenges of the wellbore construction(Kazakbayeva.Z,2021).

The implementation of the managed pressure drilling allowed them to drill a hole section of $6\frac{1}{8}''$ along with an underbalanced static mud which holds a constant pressure at the bottomhole in static conditions and dynamic conditions. The uncertainty of the drilling window has made the planning of the exact mud density to successfully drill this section very difficult. The mud weight and the design of the managed pressure drilling were carefully chosen post risk assessment and they were also chosen as the drilling operator decides. A device called Coriolis flowmeter which has proved its importance in solving the problem of minor losses and known for its fast response and improvising to the shifting conditions. When the targeted depth is reached, a heavier mud weight is displaced in the managed pressure drilling mode before the operation of open hole logging and managed pressure cementing(Kazakbayeva.Z,2021).

The managed pressure drilling methods give the client the freedom to continue the drilling operation through fractured formations without being compromised to mud losses or gains in a period less than the normal drilling type which takes months while in the MPD it takes days to control the problems of the wellbore for example: sticking as in differential sticking, well kicks, total losses, and other problems. The managed pressure drilling job aided in reducing the drilling time and minimizing the costs of well construction and at the same time increasing the performance of the drilling process(Kazakbayeva.Z,2021).

Due to the losses risk that was mentioned before, a normal cementing job was not suitable in the previous wells. Here comes the rule of the managed pressure cementing technique (MPC) where the BHP(bottomhole pressure) is kept lower than the loss expected zones which was responsible for providing the cement height required and provided an excellent barrier to finish the well and starting the production phase. They succeeded in isolating the zones perfectly by using the managed pressure cementing technique and it was confirmed by the (CBL) cement bond log and the test of casing integrity. During the period of the project, real measurements were transmitted at the time they were taken in to both the client and the support team which consists of engineers who are responsible for monitoring and optimizing the process's real time responding to the changes done in the wellbore(Kazakbayeva.Z,2021).

The managed pressure drilling method aided greatly in reducing the time of well drilling while using minimum mud density and therefore minimizing the requirements of mud. It also helped in delivering appropriate data considering the reservoir like the pore and fracture pressure gradients in conditions that are known to be uncertainly geological.

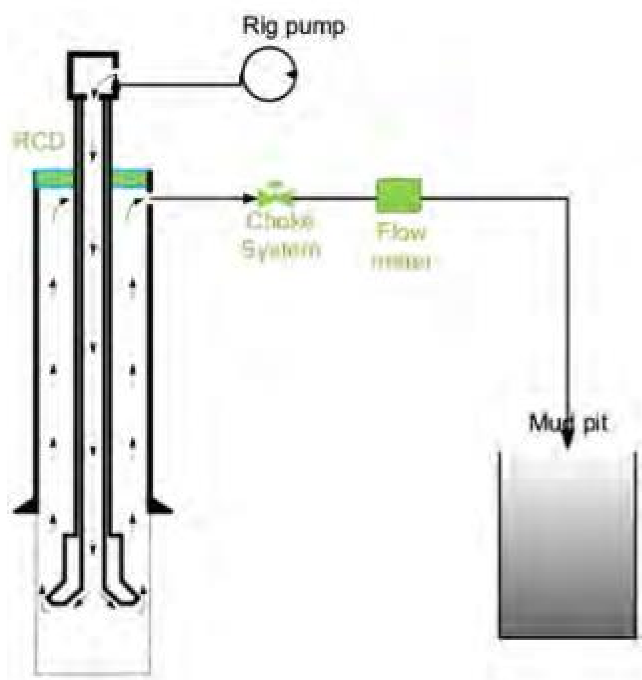


Figure 10: Schematics of managed pressure drilling(Kazakbayeva.Z,2021).

In fig10 the MPD system schematics of its main components such as the(RCD) rotating control device, the rig pump, the choke system and the flow meter(Kazakbayeva.Z,2021).

Figure 11: The managed pressure drilling dual choke in addition to the Coriolis flow meter integrated(Kazakbayeva.Z,2021).

Fig 11 demonstrates the managed pressure drilling choke manifold which is used when operating in extreme low temperaures such as $-50^{\circ}C$ so that every operation is done in a safe natural environment and heat insulated. Adding to that the Coriolis flow meature which is responsible for density measurements and the high accuracy measurement of the volumetric flow (±0.01%) in the applications of drilling and also it minimizes the diffuclty of mounting and facilitate the handling(Kazakbayeva.Z,2021).

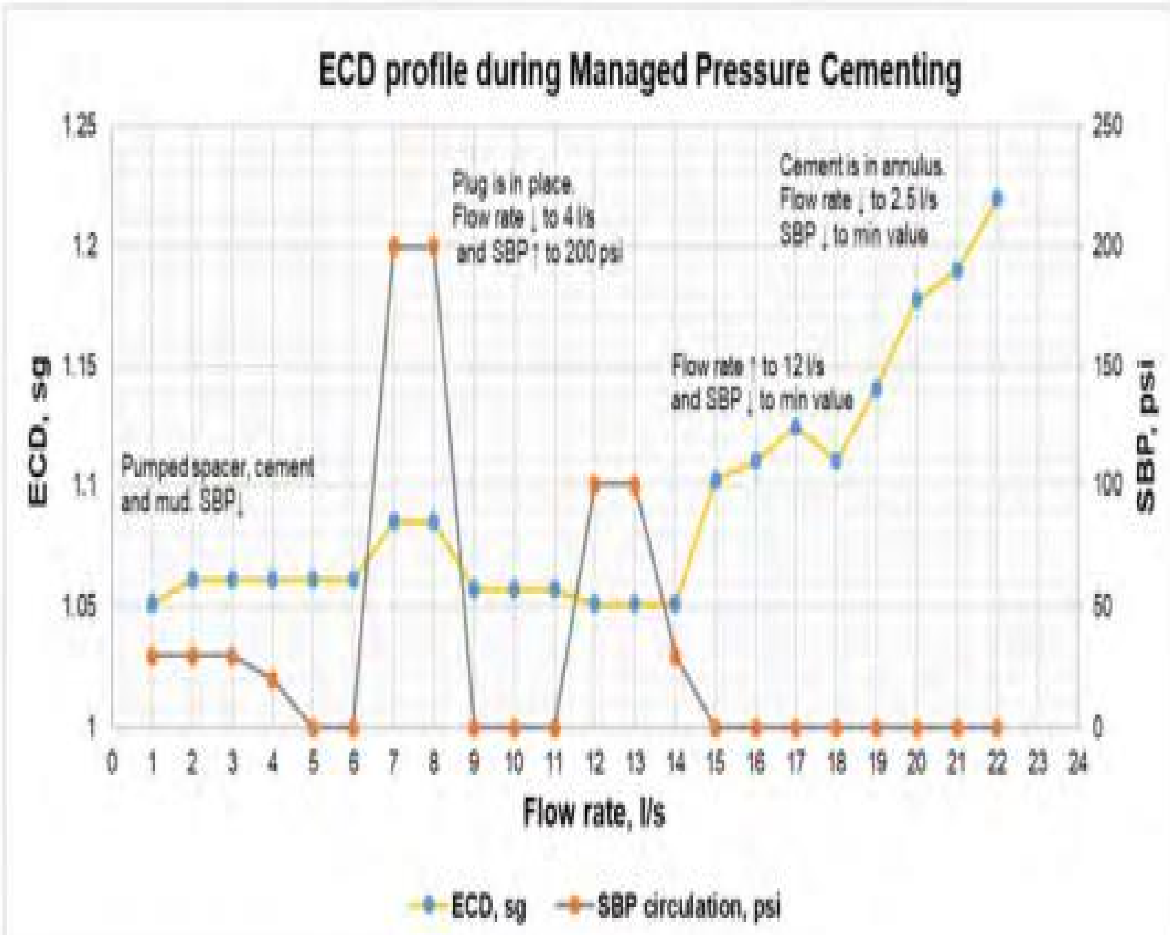


Figure 12: Effective circulation density profile during the MPC operation(Kazakbayeva.Z,2021).

In fig 12 the effective circulation density profile was consistant with the drilling window which is considered to be very narrow and there were no losses obsereved as the cementing job took place which points out the quality of the cement job and was confirmed by the (CBL) cement bond log after the well was finished and the values calculated in fig 11 was highly matching with the real data which implies the planning process importance(Kazakbayeva.Z,2021).

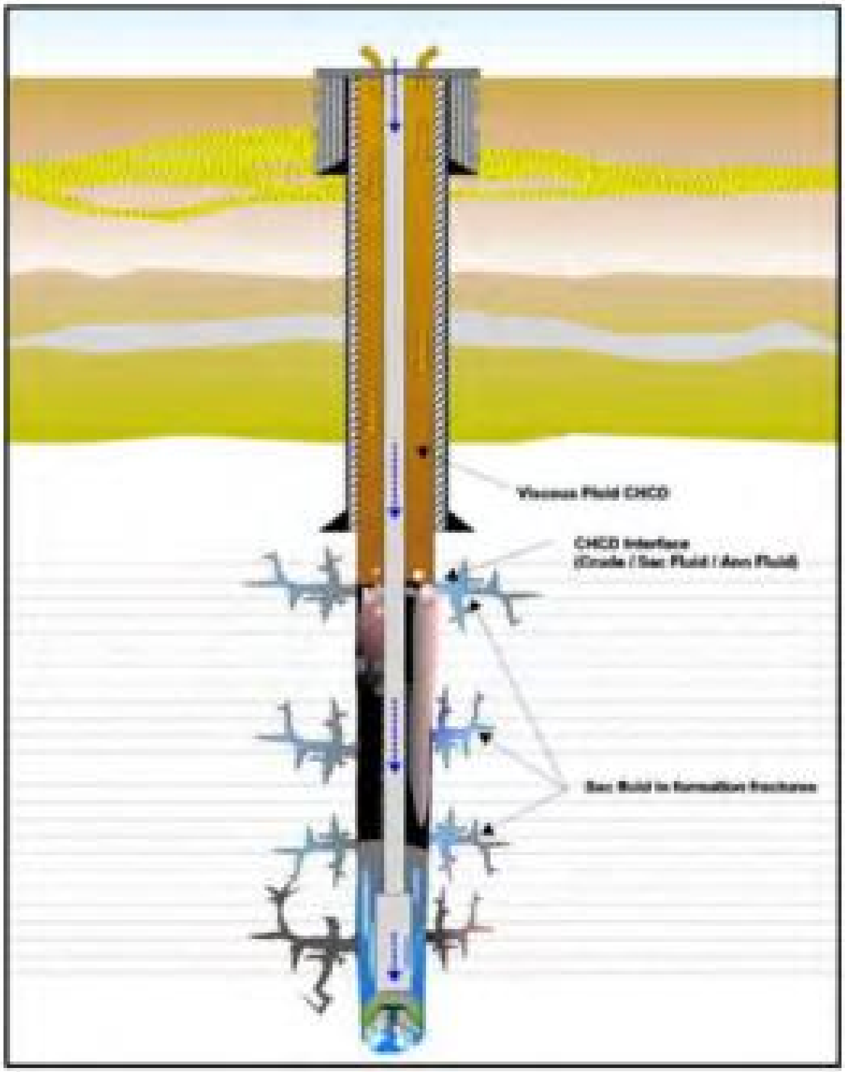


Figure 13: Pressurized mud cap drilling schematics(Kazakbayeva.Z,2021).

Upon knwoing that lost circulation has begun, there is a backup plan which is known as the PMCD(pressurized mud cap drilling) which is a form of the managed pressure drilling technique and it is used when encountring big fracture zones and reservoirs that are suspected to cause total lost circulation. The PMCD is a form of drilling which is known to be blind drilling which have no returns where the formation takes all of the mud displaced along with the cuttings. The sacrificaial mud used is pumped through the drill string while the LAM(lighter annular mud) is displaced through the annulus in order to control the hydrostatic pressure and prevent the gas to migrate(Kazakbayeva.Z,2021).

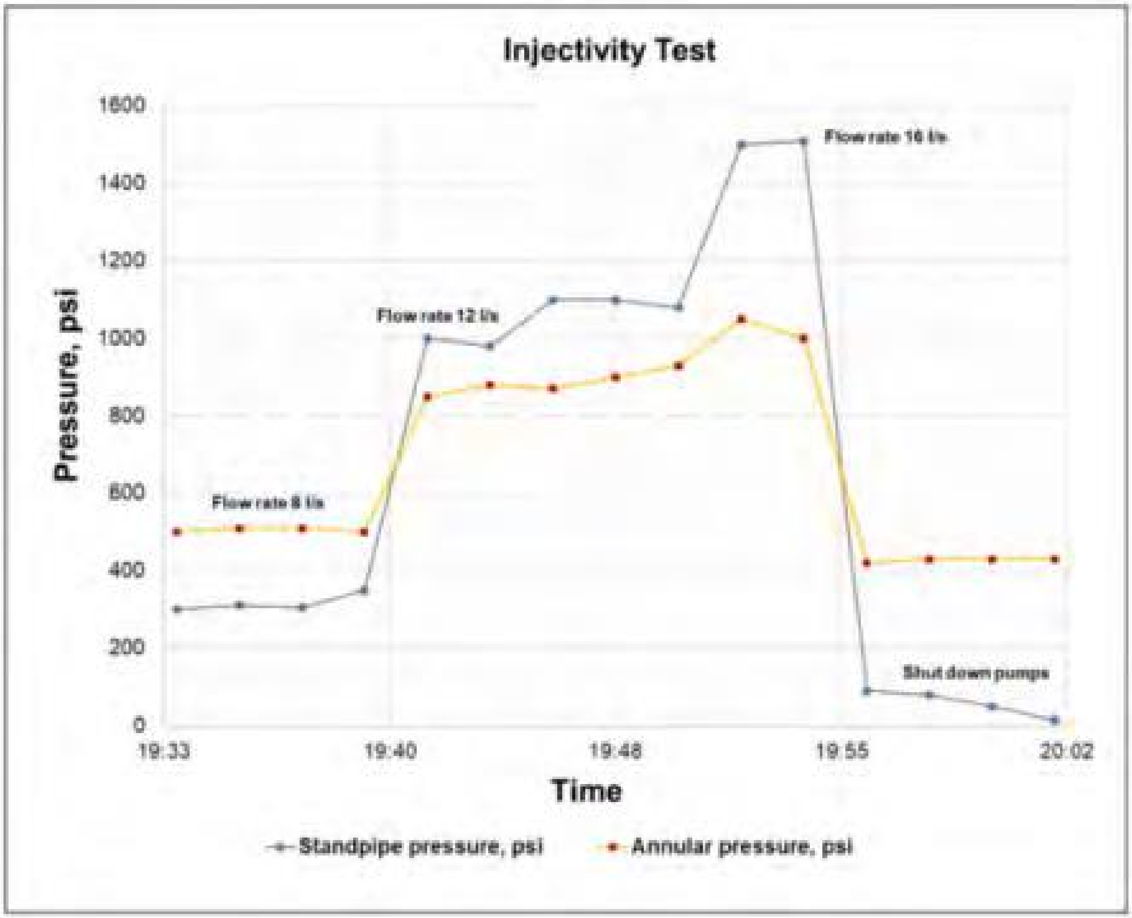


Figure 14: Injectivity test results(Kazakbayeva.Z,2021).

One of the main parameters that must be taken into consideration while deploying the pressurized mud cap drilling is determining the sustainability of the annular pressure to the operations of the pressurized mud cap drilling through an injectivity test which is demonstrated clearly in fig14. As the test is conducted, the casing and standpipe pressure values are overlooked at various flow rates where the PMCD is deployed if the pressure of the casing, at maximum flow rate, is found to be lower than the RCD's working pressure(Kazakbayeva.Z,2021).

Casing Pressure	Drillpipe Pressure	Probable Cause	Action
Decreases	Decreases	Increased loss rate into the formation due to the formation cleaning up or a lower bottom hole pressure formation being encountered	Continue drilling ahead if other factors are not a problem.
Increases	Stays the Same	Gas bubble migrating in the annulus	Pump cap fluid down the annulus until previous annular pressure has been restored.
Increases	Increases	Formation plugging can also be caused by encountering a new, prolific, higher-pressured formation.	Switch to conventional circulation if the well regains sufficient integrity to hold kill mud
Stays the Same	Decreases	Drillstring washout	Displace DP with cap fluid POOH and find washout
Stays the Same	Increases	Drillstring plugging	Continue drilling as long as DP pressure does not exceed acceptable limits.

Figure 15: Typical trends of PMCD(Kazakbayeva.Z,2021).

Post the success of the injectivity test, oil based mud was replaced by water based mud and the pressurized mud cap drilling mode was carried on with the water based mud being pumped in the drill string and annulus while monitoring the pressure continuously inside the annulus to reduce the non productive time that is linked to dealing with kicks that are likely to occur. Typical pressure trends that are demonstrated in fig15 were the base upon which these decisions were made(Kazakbayeva.Z,2021).

2.4 Successfully implementing automated MPD and MPC Techniques in the troublesome intermediate and reservoir sections of a remote well in the Peruvian Jungle which aided in eliminating wellbore instability, severe fluid losses and differential sticking(Soto.B,2017)

A reservoir section was drilled in Peru in a field called Sagari had so many challenges for example: the collapsing of the wellbore in a formation type known as Shinai which is known for its mechanical unstablitity, the differential sticking of pipes in sandstone reservoirs where there is low pressure and high permability characterisitics and total losses occured as a result of the formation being naturally fractured. It is decribed here how they had succeeded in implementing the automated MPD(managed pressure drilling) and the MPC(managed pressure cementing) to help them in controlling these problems which exited in a far location where the mobility of equipement and logistsics is considered also a challenge(Soto.B,2017).

As it is known that the automated managed pressure drilling consumes less energy, it can be transported by the aid of a helicopter near the drilling site. As planned, the managed pressure drilling technique was applied and it succeeded in the prevention of the instability of the wellbore and reducing the differential sticking helping the wellbore to be in a good condition. At 2700 ft of openhole the production liner was smoothly run down in a time which is considered relatively short (less than 6 hours) and the mechanical skin factor was reveled by the well testing techinques in the section of the reservoir which turns out to be zero(Soto.B,2017).

When the final feet of sidetrack was drilled with equivalent density equals to 10.5 lbm/gal, they faced a natural fracture which was detected instantly by the managed pressure drilling coriolis flow meter which helped for quicly responding to this issue and fixing the losses in a fast way which was responsible for reducing the size of the operating window. The managed pressure cementing aided in the usage of the static underbalanced drilling mud and at the same time it protected the integrity of the well and prevented the collapse of the wellbore during the cement job. The calculated equivalent denisty at the bottom was observed in the real time and the prevention of lossesc succeeded. The wiper plug's coupling which was placed on the landing collar was monitored as palnned and isolating the zones was a successful job and that was confirmed later on by the CBL(cement bond logging) and the CIT(casing integrity test) (Soto.B,2017).

Adding to the MPD(managed pressure drilling)strategy applications is the production. The managed pressure cementing of the $9\frac{5}{8}$in intermediate casing was a back up measure such that the area of the annular flow that took place between both casing strings and the narrow window of the pore and fracture pressure wasn't able to allow the conventional cementing of the casing(Soto.B,2017).

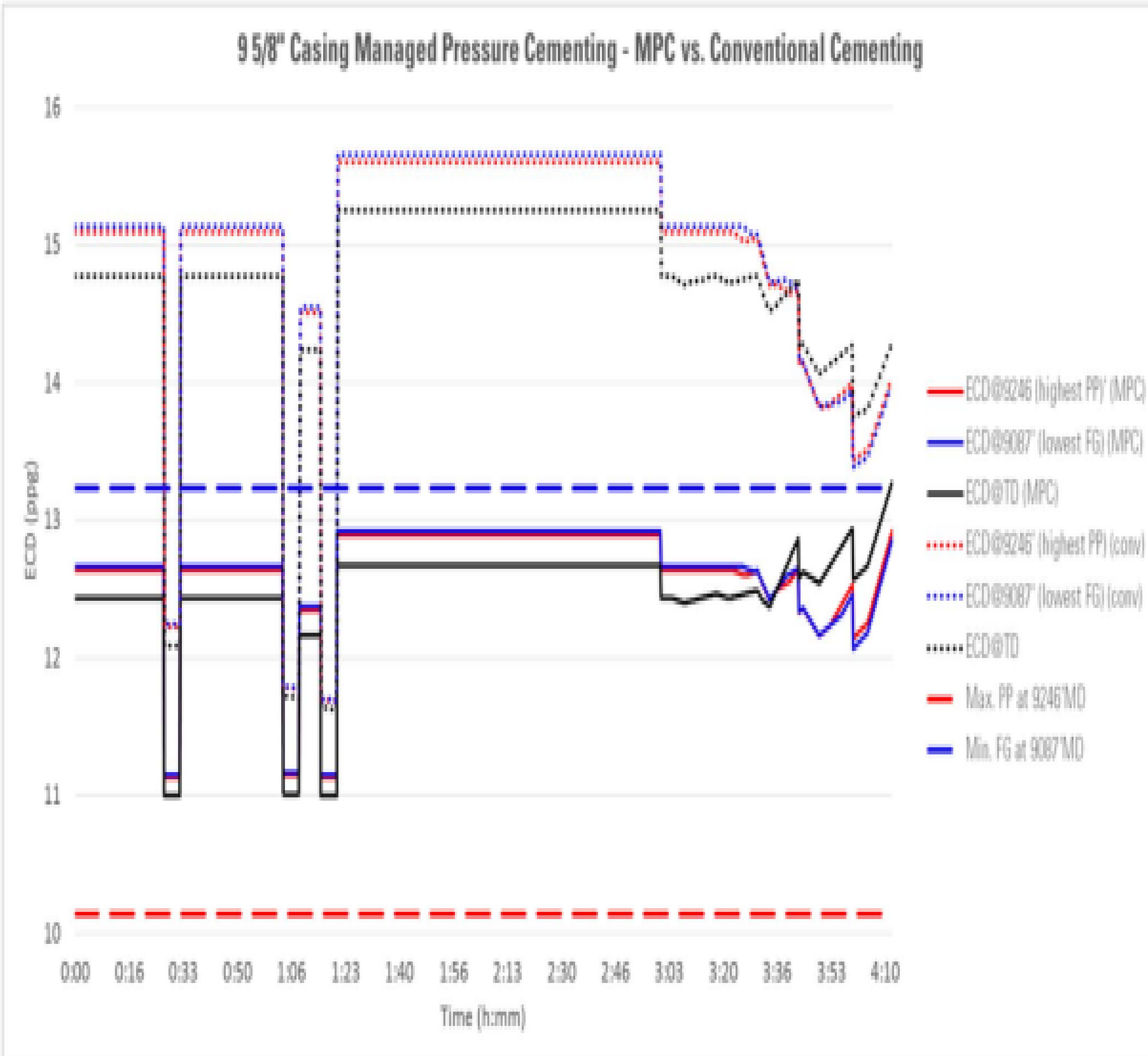


Figure 16: A comparison of cementing hydraulics between conventional and managed pressure cementing of the $9\frac{5}{8}$in casing (Soto.B,2017).

In fig 16 the simulations of the cementing hydraulics performed were clearly demonstrated such that it puts the ECD (equivalent circulating density) of a cementing job done conventionally in comparison with MPC(managed pressure cementing) job such that at the conventional one a 10.6 lbm/gal mud was used in order to perform the drilling operatipon which is demonstrated as dotted lines. While at the MPC one a 9.5 lbm/gal mud was used which is much lighter and considered a thin fluid which is demonstrated as solid lines. Also the dashed blue line demonstrates the fracture gradient which was over by 1.9 lbm/gal at the initiation of the pumping when the conventional cement job was performed(Soto.B,2017).

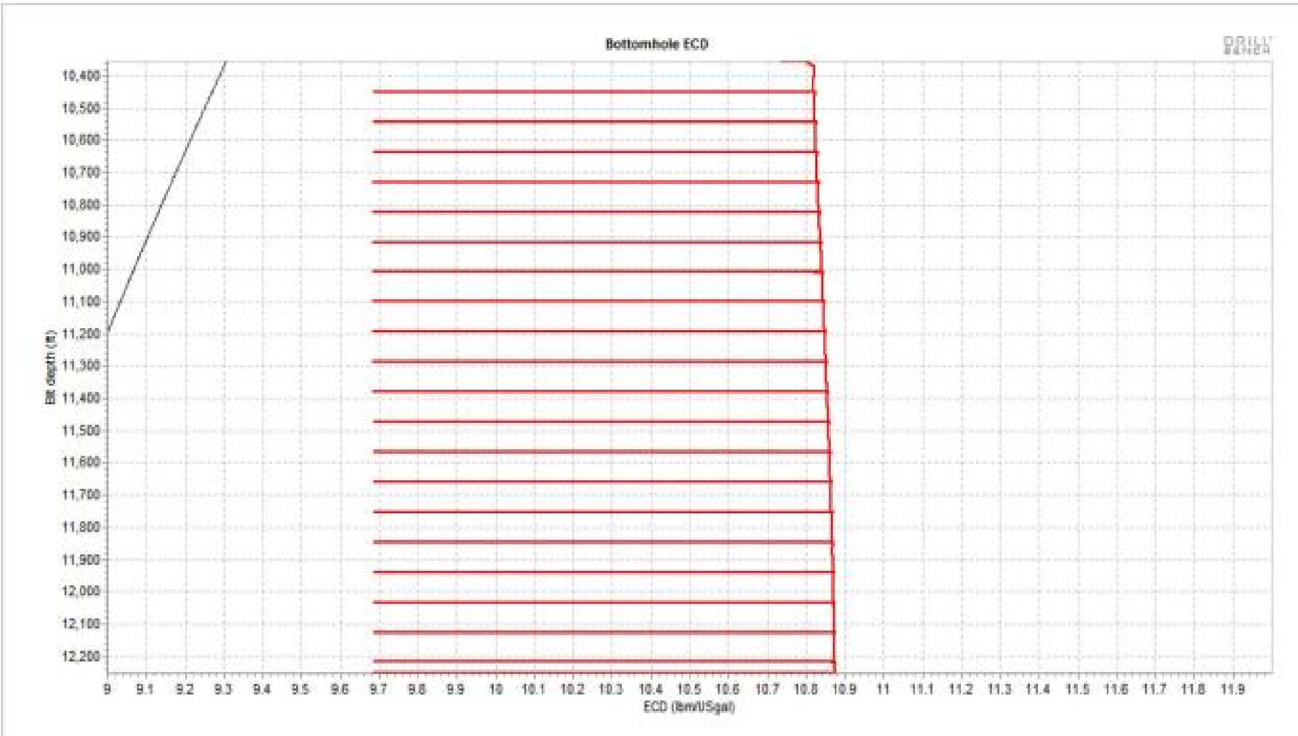


Figure 17: A simulation of transient hydraulics showing the variations of the equivalent circulating density in the bottom hole while drilling conventionally the $8\frac{1}{2}in$ production section(Soto.B,2017).

Fig17 demonstrates an analysis done on the transient hydraulics which shows the ECD (equivalent circulating density) when the production section was drilled conventionally from the casing shoe to the final depth using a 9.7 lbm/gal mud. The red spikes are a demonstration of the ESD(equivalent static density) when they turn of the mud pumps during connections(Soto.B,2017).

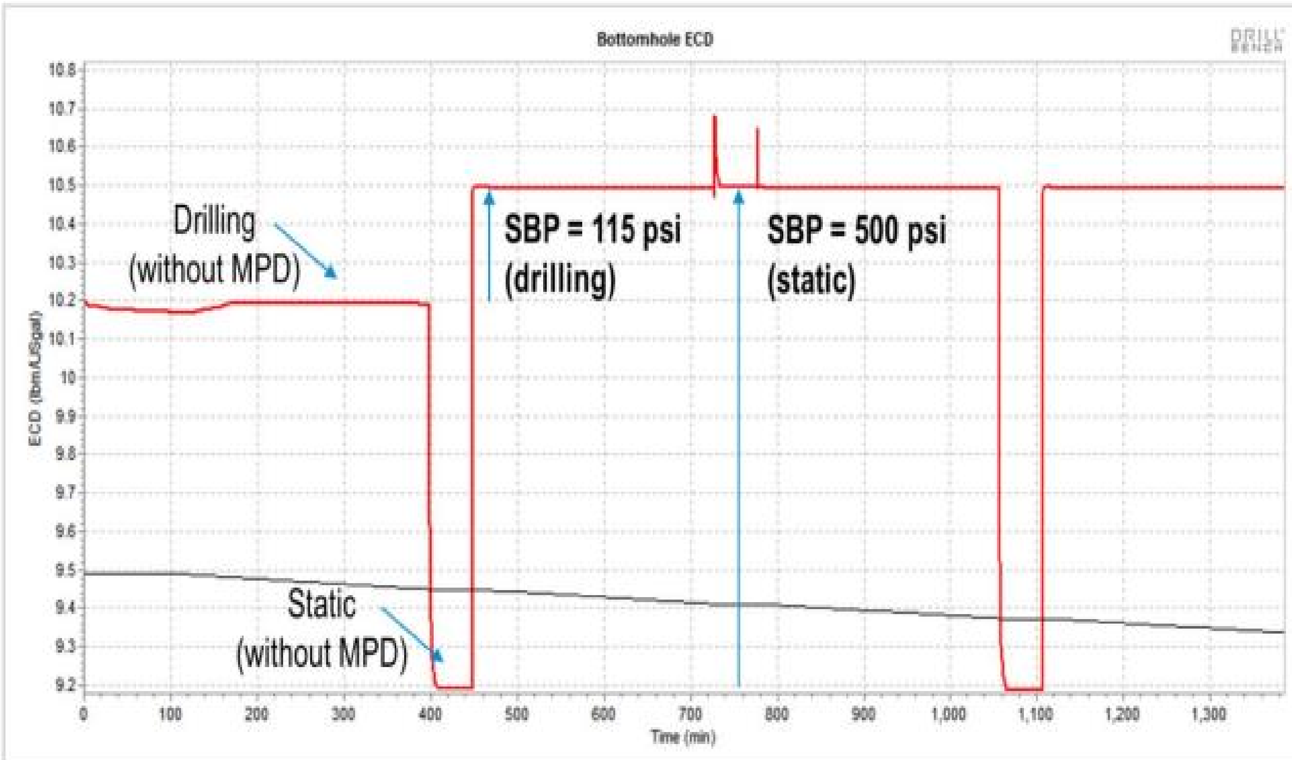


Figure 18: A simulation of transient hydraulics showing the dynamic and static conditions with and without applying back pressure (Soto.B,2017).

Fig 18 demonstrates how the managed pressure drilling eliminates the variations of pressures between the static conditions and the dynamic conditions through the appliance of the exact SBP(surface back pressure) amount in order to help in the compensation of the friction losses in the wellbore equipment along with the surface equipment(Soto.B,2017).

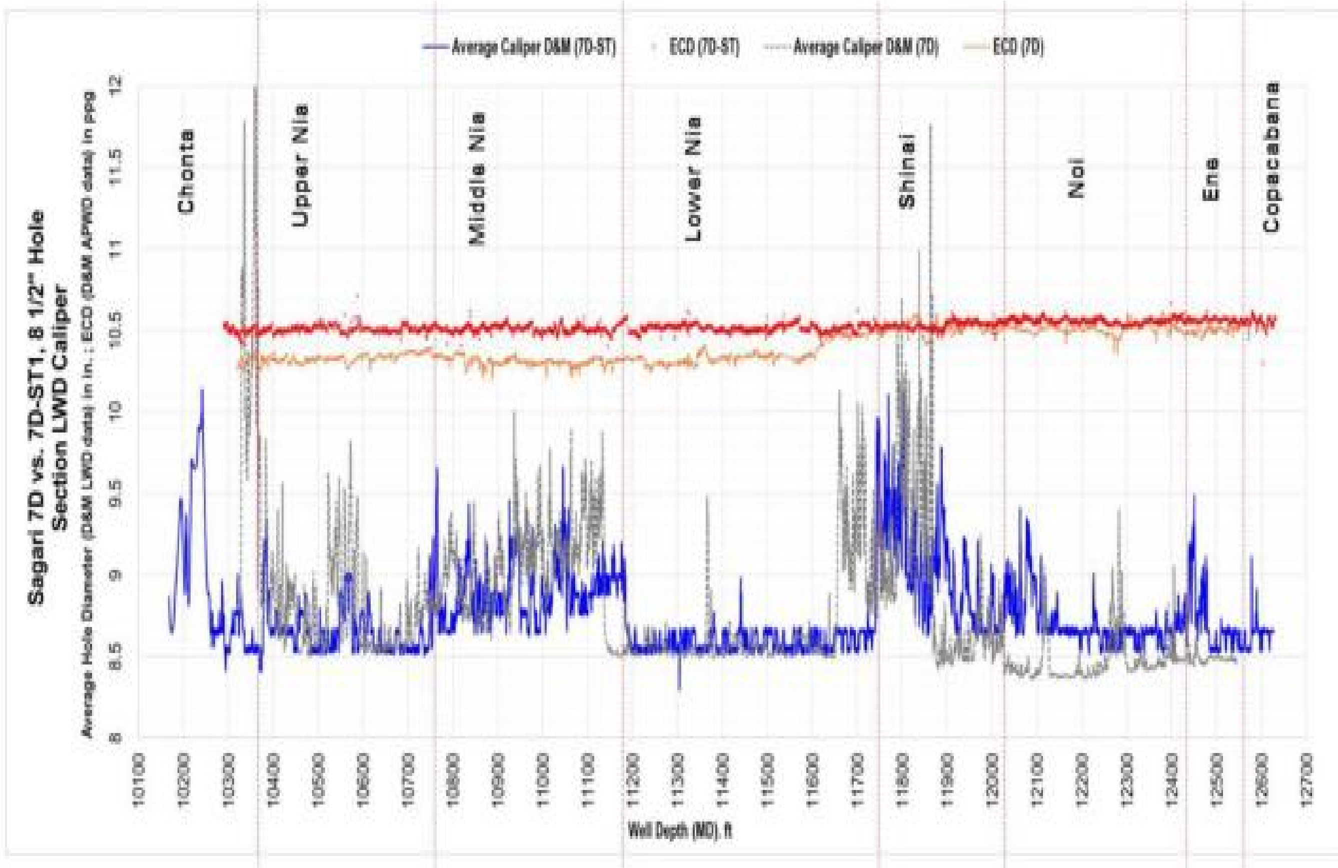


Figure 19: MWD(measurement while drilling) caliper with ECD vs depth in Sagari 7D & Sagari 7D-ST1, $8\frac{1}{2}in$ hole section(Soto.B,2017).

Fig 19 demonstrates the caliper of the wellbore as it was measured by the measurement while drilling tool and also shows the equivalent circulating density which is measured by the APWD(annular pressure while drilling) tool in the drilling process of the main hole which is presented int grey and orange lines and in the process of drilling the side track which is presented in the blue and red lines (Soto.B,2017).

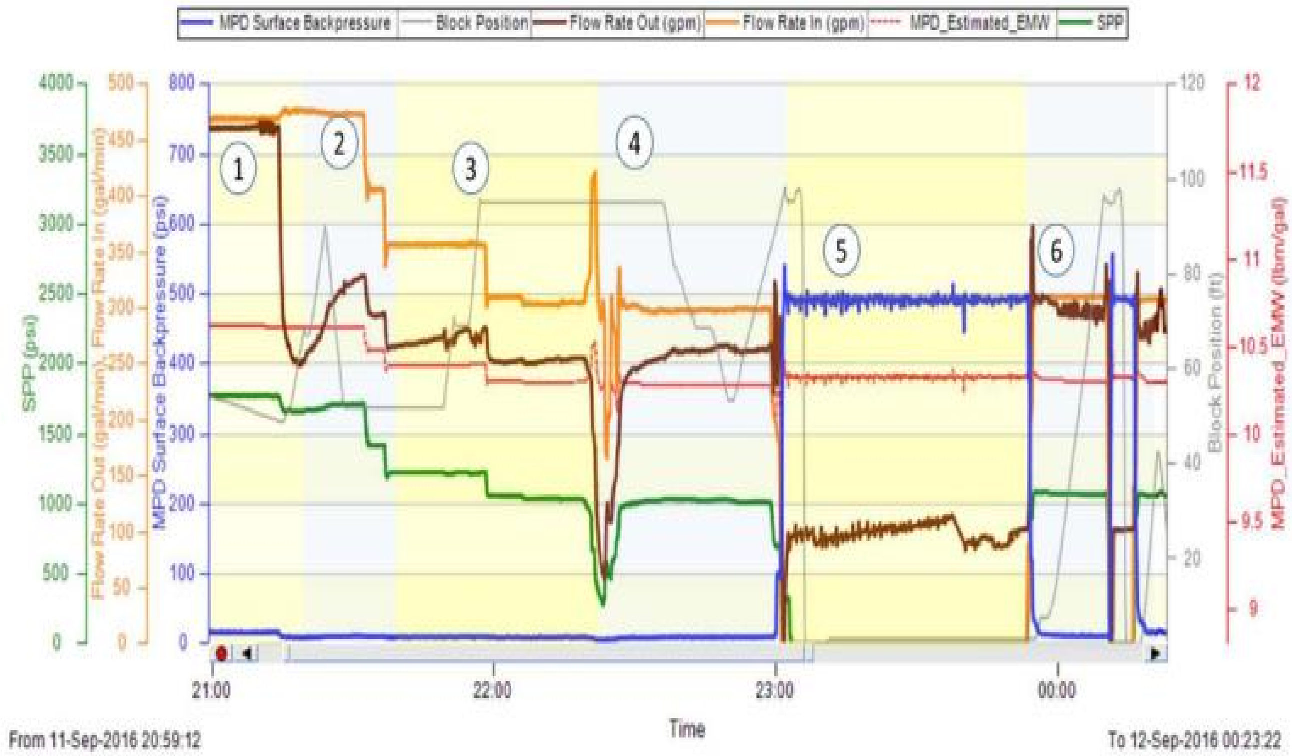


Figure 20: A severe event of lost circulation at 12700 ft MD (Copacabana)(Sagari 7D-ST1) (Soto.B,2017).

Fig 20 demonstrates an unexpected natural fractural encountered 70 ft from the final depth when the sider track was being drilled. the sequence of the events demonstrates how the Coriolis flow meter was able to detect the loss immediately where the flow out is demonstrated as the brown lines and how the well integrity was regained(Soto.B,2017).

2.5 Managed Pressure Drilling Tackles Pore Pressure Uncertainty While Drilling, Running Liner, and Cementing Across Multiple and Heterogonic Layered Reservoirs for the First Time in the United Arab Emirates(Al shehhi.M,2019)

A new technique is used considering the drilling process, running liner process, and cementing process which took place in a development well. This well is characterized to be passing through a number of high pore pressure reservoirs which are also known for their heterogeneity which was responsible for some drilling related problems such as differential sticking, losses (both partial and total), problems with well control and the rate of penetration getting slower. There are some conditions and terms that must be followed upon the existence of a depleted and high pressured types of reservoirs in exact hole section. These terms are that the density of the drilling fluid must be greater than the reservoir which has high pressure and that is responsible for putting a differential pressure high enough to cause differential sticking and mud losses in the depleted reservoir(Al shehhi.M,2019).

Another problem that faces this reservoir is the uncertain determination of the pore pressure such that the density of the drilling fluid must be greater than the pore pressure that is expected to exist. Facing these challenges was easy upon using the MPD (managed pressure drilling) which gave access to the pore pressure determination while performing the drilling process and controlling the ECD(equivalent circulation density) to be slightly matching the minimum overbalance(Al shehhi.M,2019).

This section was drilled by the aid of the managed pressure drilling using a mud weight of 12ppg while the conventional method required using 15.7ppg and that helped in reducing the differential pressure that exists between the formation that is said to be depleted and other formations remarkably and therefore the ROP(rate of penetration) was enhanced while the well was balanced. This also helped in proving that the condition of the well concerning the pressure must be verifies in order to avoid disastrous hazards(Al shehhi.M,2019).

The managed pressure drilling has a mode called the CBHP(constant bottom hole pressure) which is used in maintaining the equivalent circulation density during the drilling and connection process to evade the well influx by the compensation of the friction pressure loss that is done in the annulus by the effect of the surface back pressure while pumps are off. The managed pressure drilling was used in the running process of the 7″ liner in order to be completely sure that the density of the mud wasn't low enough to be responsible for stabilizing the well(Al shehhi.M,2019).

The operation was successfully completed with no safety problems of quality problems and the performance of the managed pressure drilling system was outstanding looking to the NPT(non productive time) which came out to be equal to zero. Adding to that, the drilling of the hole section was shoe to shoe without needing to change the RCD(rotating control device). Applying this method was preventing the differential sticking more than reacting to it. This was used in one of ADNOC's onshore fields and it is considered the first time they are using the managed pressure drilling technique and first ever to be used in the UAE which used an adaptive program to control the mud weight to deal with the drilling catastrophes (Al shehhi.M,2019).

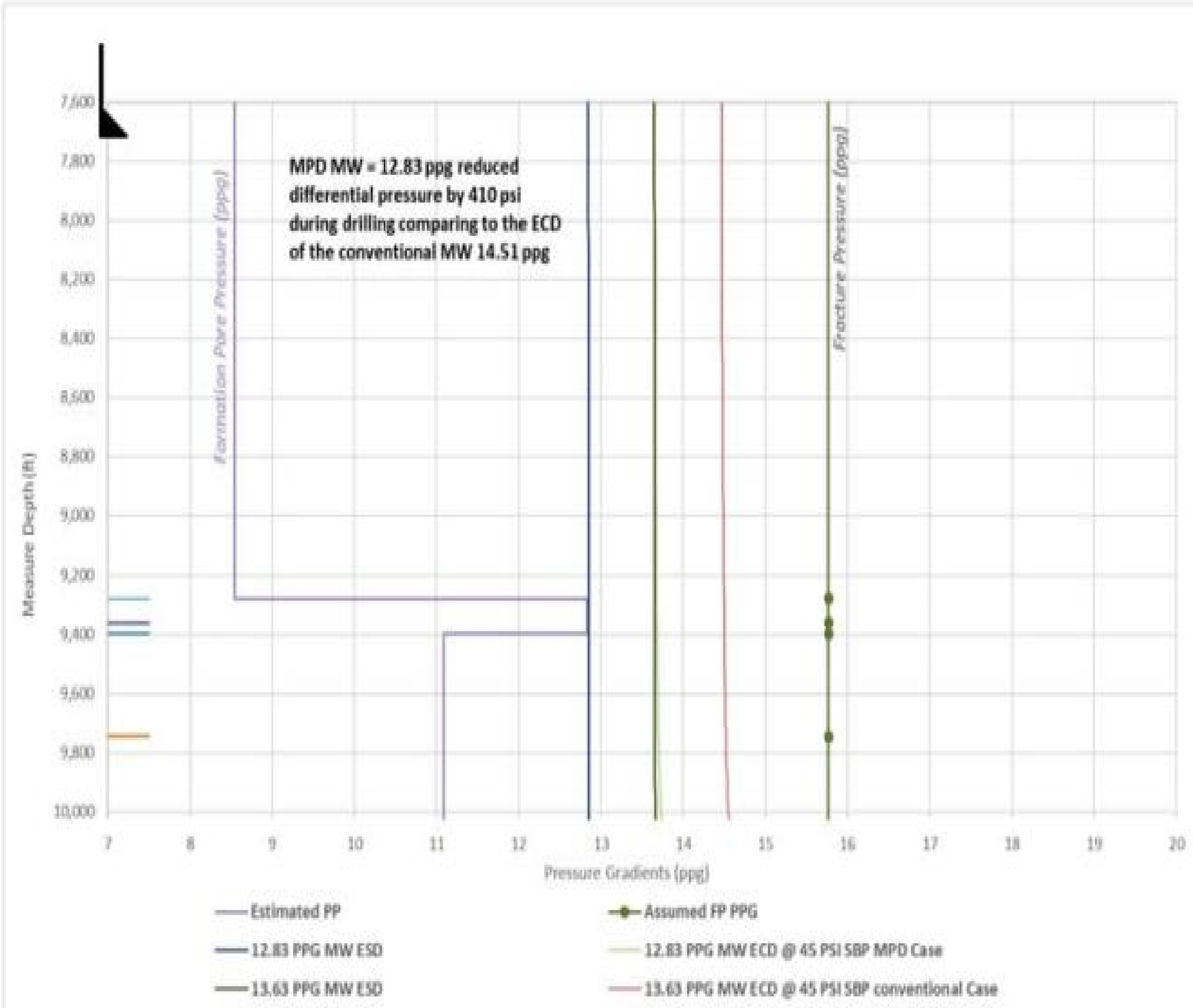


Figure 21: Managed pressure drilling hydraulic modeling done on well A to compare the conventional mud weight with the managed pressure drilling one (Al shehhi.M,2019).

In fig 21 a noticeable high overbalance was found to be causing differential sticking previously and the only reasonable way to minimize this overbalance was to commence with lower mud density and therefore creating less ECD. So, a decision was made to begin drilling the formation 9 with a mud density of 12.8 ppg while the conventional drilling process required a 13.6 ppg mud weight and this was responsible for reducing the overbalance by 21%(Al shehhi.M,2019).

		Surface Back Pressure (RCD 1,500 psi)			
		Planned Limit SBP during drilling (0 psi)	Planned Limit SBP during Connection (1,000 psi)	>Planned Limit SBP during < Back Pressure Limit (1,000 – 1250 psi)	> Back Pressure Limit (1,250 psi)
Influx volume	No Influx	Continue Operation	Continue Operation	Increase pump rate, mud weight or both AND reduce pressure to planned or contingency levels	Pick up, shut in BOP, evaluate next action.
	Operating Limit (<= 5 Bbl)	Increase back pressure, pump rate, mud weight or a combination of all	Increase back pressure, pump rate, mud weight or a combination of all	Increase pump rate, mud weight or both AND reduce pressure to planned or contingency levels	Pick up, shut in BOP, evaluate next action.
	Planned Limit (> 5 Bbl)	Pick up, shut in BOP, evaluate next action.	Pick up, shut in BOP, evaluate next action.	Pick up, shut in BOP, evaluate next action.	Pick up, shut in BOP, evaluate next action.

Figure 22: Managed pressure drilling well control matrix of well-A (Al shehhi.M,2019).

In fig22 the well control matrix is demonstrated by which applying the managed pressure drilling technique can be conducted properly which demand a maintained surface pressure in the range of the safe ratings of the working pressure. The well control equipment of the rig must be deployed if the managed pressure drilling equipment failed to handle the return fluids of the well and dynamic annular pressure control conditions must be engaged(Al shehhi.M,2019).

Chapter 3 Methodology

In this chapter different techniques of managed pressure drilling are defined along with some specific equipment that are used in this specific operation where the equipment's operational effect, operation methods and some details on this equipment which are: RCDs, drilling chokes, NT valves of the drill pipe, isolation valves, effective circulation density downhole pump, Coriolis flow meter, disc pump

3.1 RCD(rotating control device) and annular preventers

The Rotating control device (RCD) is a popular device in the managed pressure drilling techniques as a result of annular requirements of being packed off from the surface during the drilling process or during making connections or/and while tripping. It is a job that can be done on temporary basis by the annular preventer or by the pipe ram but in order to minimize the rotational wear in the drilling process, depending on the rotating annular preventer or RCD(rotating control device) is a must. They even came up with specific types of RCD which can be used in multiple drilling operations such as: geothermal, air also used in stripping casing and riser diverters and the sealing around the drill pipe.(Reham.B,2009)

In the beginning of the 20th century, the RCD was considered having a long history when related to commercially rented tools. There is a huge difference between the shaffer's catalog rotating head and the modern RCDs such that nowadays the rotating control device is made mainly to act as a pressure hold, and not as a diverter used in gaseated and air mud process that was used as a main function back in the days, in managed pressure drilling. (Reham.B,2009)

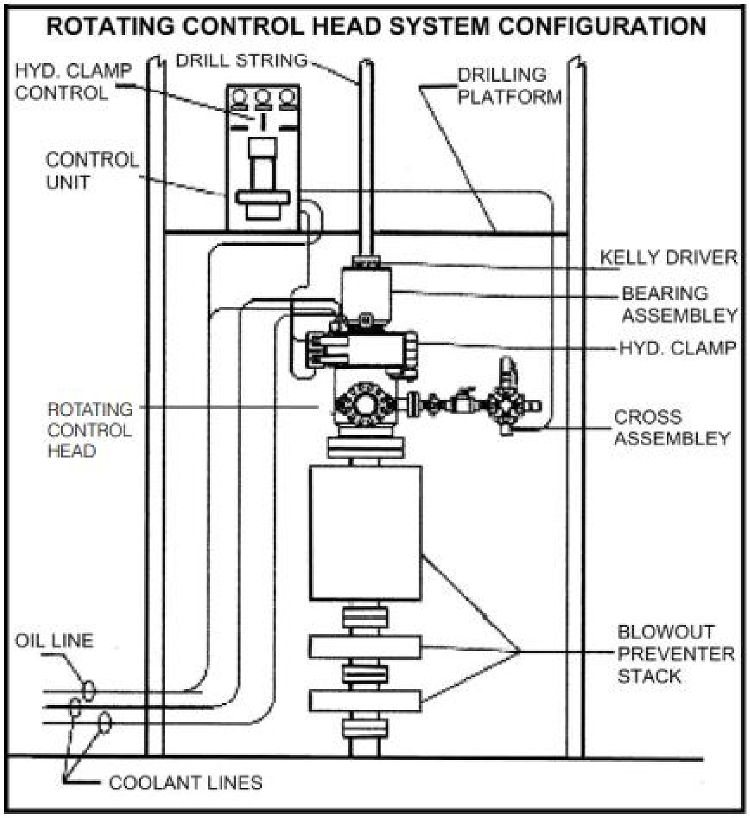


Figure 23: A configuration of the RCD system(Reham.B,2009)

As represented in fig23, the new RCDs along with the rotating annular preventers are known to operate usually at pressures that can reach to 5000psi in static conditions and 2500psi in rotating conditions where the power rating of the equipment is normally reduced to nearly half of the static specs to minimize the generated heat that exists in the bearing packs as a result of the rotation speed which is considerably high and maximum load is applied. Rotating systems that go under high pressure conditions normally apply oil system circulation in order to apply lubrication on the bearing also aids in the heat transfer of which is generated by the pressure rotation(Reham.B,2009).

The systems are separated into two sections active system and passive system. The active system is the rotating annular preventer, and the passive is the RCD. While a great number of RCD dealers supply pressure rotating devices of low pressure for air drilling and gas drilling which centers on the tools provided by a small number of rotating devices manufacturers that are used in managed pressure drilling techniques(Reham.B,2009).

3.1.1 Passive system RCD:

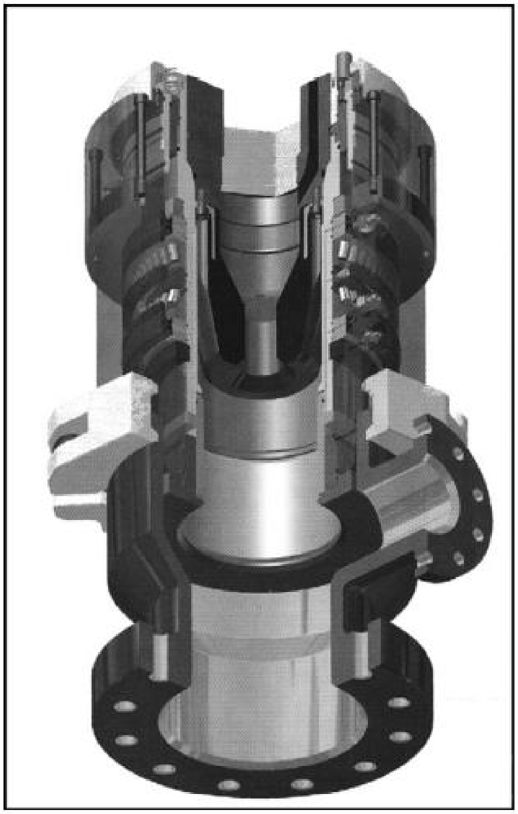


Figure 24: Rotating control device(RCD) (Reham.B,2009)

As demonstrated in fig 24 the rotating control device(RCD) is considered as a rotating packer which uses a $\frac{1}{2}in$ to $\frac{7}{8}in$ annular seal element (nearly 12.7 to 22.2 mm)or commonly known as a stripper rubber in order to minimize the drill pipe size and to be forcibly fitted in it which is responsible for forming a 0 pressure conditions seal. When it faces the pressure of the well bore and the annular pressure force causes more sealing. The annular pressure buildup against it puts more sealing pressure /unit area on the annular seal element which is known as a passive activation system(Reham.B,2009) (Møgster et al., 2013)

This element is fitted forcibly in the drill pipe joint with the aid of a specially pointed sub in order to decrease the hardness of the force fitting. The element is then connected to the carrier set by being bolted to it into which a bowl that contains the bearing system and a quick connect collar is used to lock it in place. As the element rotates along with the pipe and the bearing assembly to which it is locked and sealed exposed to a circulating hydraulic oil system which lubricates and cools the bearing pack(Mujir,k.2006)

The driller doesn't need to take actions weather on drilling operations or stripping processes as the rubber seal is known to respond to the annular pressure. As soon as the stripping operations are not required anymore, the rotating seal assembly must be separated from the bearing pack and the stand of the drill pipe which holds the assembly is put away. When stripping operations are needed in the hole, a bowl full of lubricating liquid (water or oil) is put over the rotating element to keep it lubricated(Mujir,k.2006) (Managed Pressure Drilling, 2012)

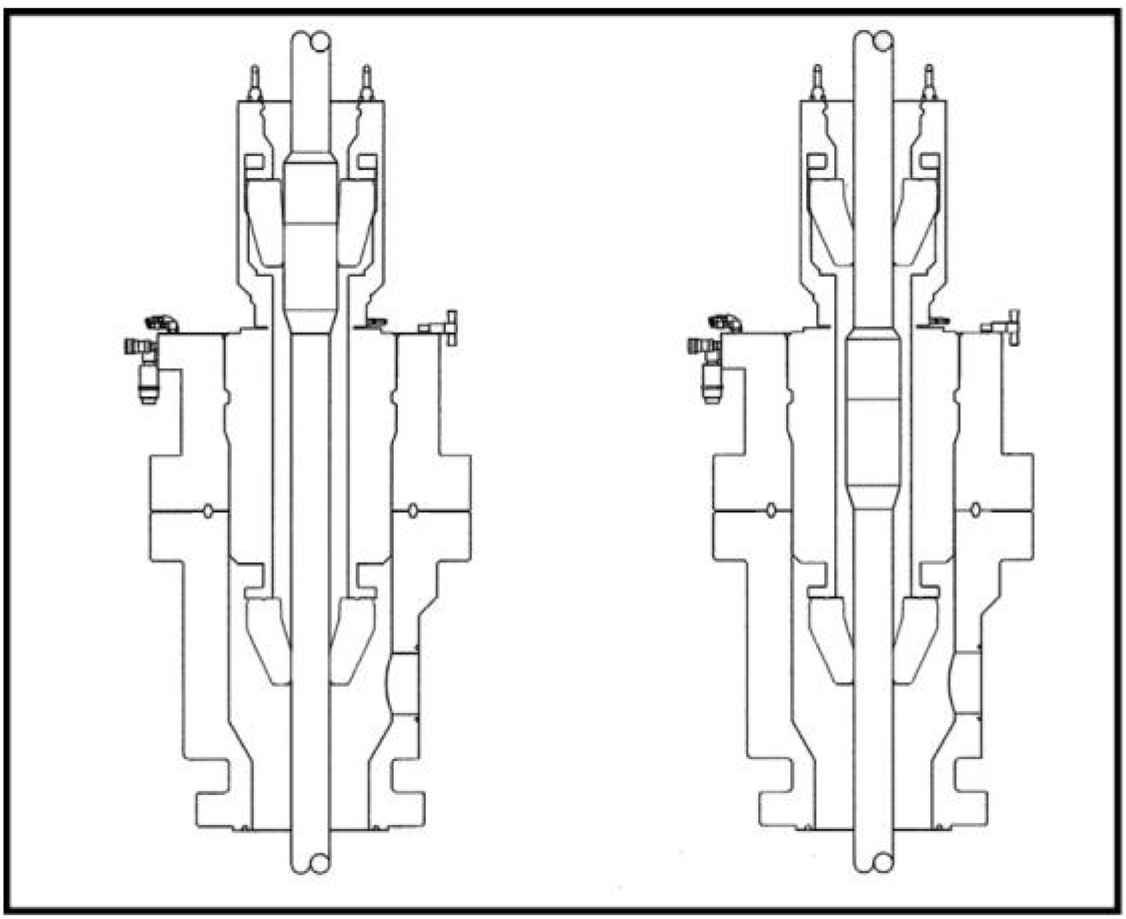


Figure 25: High pressure rotating control device dual stripper units(Reham.B,2009).

As demonstrated in fig25 Weatherford high pressure rotating control device that uses dual elements where the upper one acts as a backup plan if the lower one had a wear and caused seal leak. The lower one usually responsible for doing most of the sealing, taking the differential pressure and has 60% of wearing. As the dual stripper rubbers are set far from each other, on passing the tool joint, one of the two rubbers is sealed all the time to the drill pipe in order to prevent gas leakage events that comes from the wellbore(Reham.B,2009) (Islam and Hossain, 2021)

The rotating control devices failure mode in the majority of the cases is that the seal surrounding the pipe or the drill collars is leaking at low pressures. On the existence of wear in the packer or the strippers, a point is reached at which sealing is not tight at the low pressures. While leakage may occur on a pressure test, it is quite normal to be seen on the floor while doing a trip or connection process done under pressure(Reham.B,2009).

3.1.2 Active systems (rotating annular preventers)

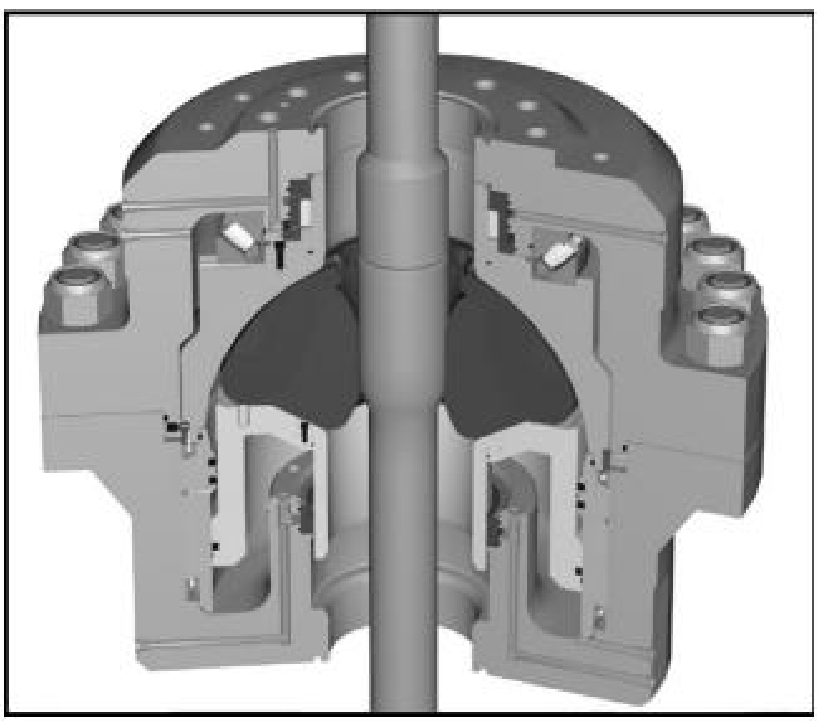


Figure 26: Varco Shaffer PCWD(Reham.B,2009).

The rotating annular preventer is known to be an annular packer that is activated hydraulically and the most common example is the rotating annular preventer called Varco Shaffer PCWD(pressure control while drilling) as represented in fig 26. Although it didn't meet all the legal specifications as an annular BOP, it is known as a spherical annular preventer which is to be installed on the bearing pack that was mentioned earlier. It is not activated by the pressure of the well but it is activated by a ram that operates hydraulically and forces up the element to a spherical head where the pipe is packed off against(Reham.B,2009). (Ilin et al., 2020)

A system of dual hydraulics is used where the first one is responsible for opening and closing the preventer while the second one is responsible for cooling and lubricating the pack. The pressure control while drilling(PCWD) is greater in size than the Shaffer spherical annular preventer equivalent size and it suits the big sized rings much better and providing a good and sufficient clearance between the wellhead and rotary table. This system is known to be automated highly and the driller takes no action but to either close the packer or open the packer. Adding to that, the pressure of the packer can be controlled by hand from the control panel or can be under fully automated control(Reham.B,2009). (Ilin et al., 2020)

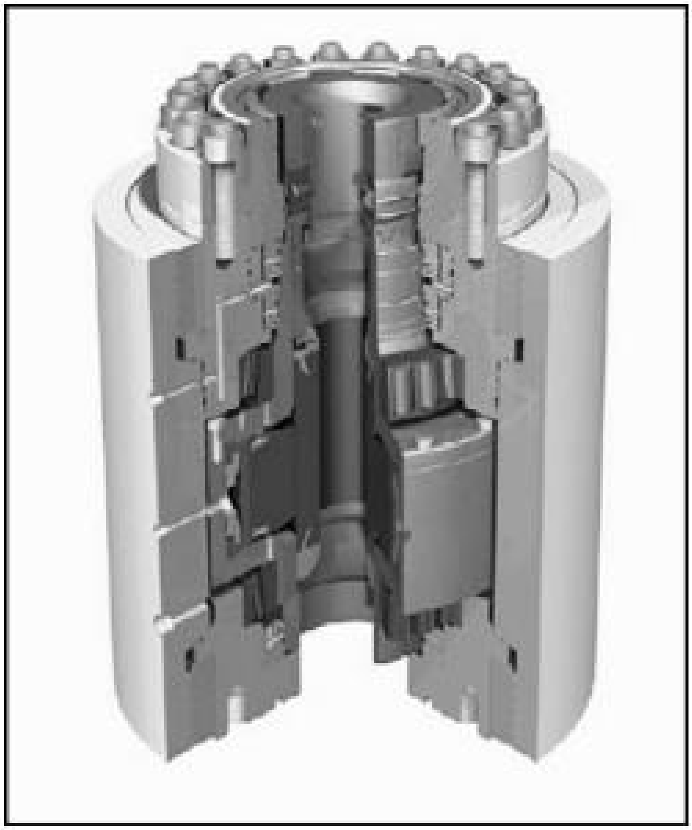


Figure 27: A section of the RBOP(Reham.B,2009).

Fig 27 represents a rotating blowout preventer(RBOP) which is included in other active rotating systems. It uses a diaphragm under pressure to push the element against the pipe and it is known that the it is smaller in size when compared to the pressure control while drilling but it is greater in size when compared to the equivalent passive systems(Reham.B,2009)(Breyholtz et al., 2010)

3.2 Chokes

The chokes that are deployed when using the managed pressure drilling method are isolated from the ones of the well control. As the managed pressure drilling system is continuously used, it is considered wise to isolate the system of the well control although it consists of the same equipment. The closing choke element that is deployed is classified into three types:

- Choke gates
- Sliding plates
- Shuttles

The chokes that are rented are characterized to have an operating panel along with pressure gauges and drill pipe gauges, operating controls of the choke and a choke operation power source. The chokes that are deployed are usually rated to H2S with managed pressure drilling equipment that set to withstand a maximum operating pressure of 10000 psi. There are a lot of companies who design drilling chokes that are operated remotely which will be discussed below (Reham.B,2009)(Breyholtz et al., 2010)

3.2.1 Power choke

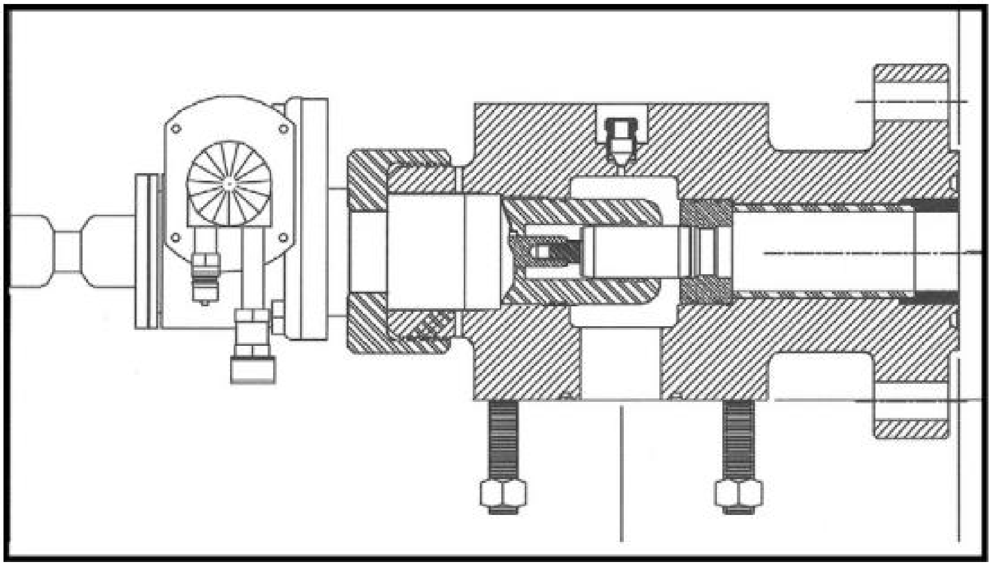


Figure 28: Power choke section(Reham.B,2009).

The Sc models of power choke has a gate shaped like a cylindrical choke which has a forward movement in order to obtain accurate sealing as demonstrated in fig 28. In order to achieve smooth process, balancing the pressure by the trim is a must. On closing, a tight leak seal is done through the choke gate being pushed towards the seat. The air hydraulic pump system which is responsible for operating the choke. Normally, the hydraulic motor that is used in the operation is responsible for also operating a worm gear, despite the existence of an electric one. The hydraulic motor is to be rated for a range between 1200-3000 starts and stops /hour to ensure that the choke operation is precise. The worm gear drives carry the manual override(Reham.B,2009) (Abir, 2016)

The control panel consists of many elements such as:

- Counters of pump strokes
- Hydraulic pump
- Annular pressure gauge
- Drill pipe pressure gauge
- Control handle
- Choke position indicator
- Controller of pump speed

The controller of the pump speed is responsible for controlling the speed of both opening and closing. The operating pressure of chokes models are 5000, 10000, 15000 and 20000 psi. When used in managed pressure drilling, the chokes are 2 and 3 in available sizes. The operator is responsible for controlling the movement of the choke weather to open it or close it as the choke doesn't move when put in a certain position. In the managed pressure drilling process the choke is kept opened until the operator changes it and the open and close operations are done through the operator of the choke(Reham.B,2009).

When a choke fails it means that it is not capable of sealing tight during the pressure test. Damage during the operation can be caused as a result of failure in the hydraulic or air system. As a result of the existence of the operating worm drive system, the failure mode of the choke is kept at the final position that it was fixed on. In managed pressure drilling process, using the power choke is high. In order to achieve full control while deploying managed pressure drilling technique, a computerized control system is mandatory of which it can maintain a suitable back pressure automatically which is relevant to the software system feedback(Reham.B,2009).

3.2.2 Swaco auto super choke

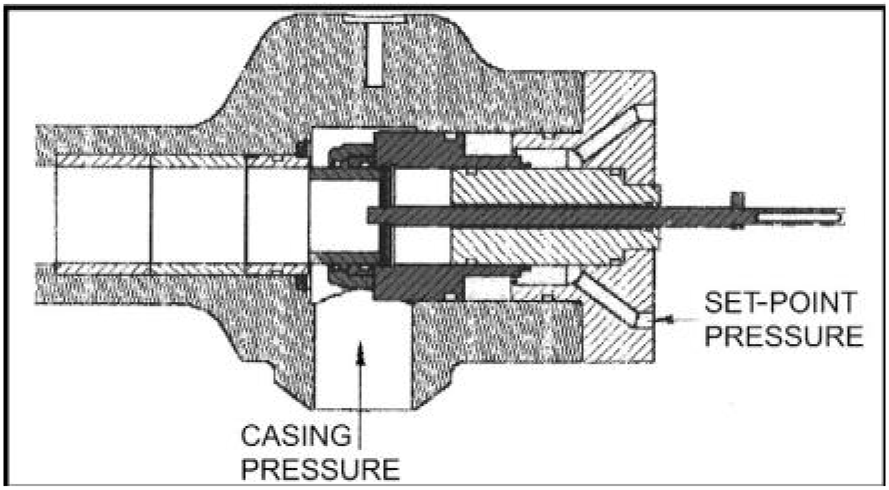


Figure 29: Auto super choke(Reham.B,2009).

It is suitable in managed pressure drilling to use the auto choke system as it aids in keeping the annular pressure stable as the metal to Teflon seal is tightened by closing the shuttle bubble tight as demonstrated in fig29 Apart from the various types of the super choke, the auto choke is a unique one as its sliding shuttle is made of tungsten carbide which slides directly into a sleeve which is hydraulic pressure operated. The working area is worked against by means of the pressure that is set on the console. The well pressure is responsible for balancing this pressure. A device called the casing pressure transmitter which is mainly a piston shuttle that is responsible for providing the pressure directly to the sensor of the control panel. A rapid response considering the choke to the changing of pressure(Cavander,T.2004).

The movement of the choke is under direct control by means of the hydraulic balance between the pressure of the wellbore and the hydraulic setting pressure where the normal operations are usually done by using an operated air hydraulic pump otherwise the manual hydraulic pump is used as an alternative. The control panel consists of :

- Set point indicator
- Set point control
- Hydraulic pump
- Pump stroke counter

- Annular pressure gauges
- Drill pipe pressure gauges

This choke type comes in an operating pressure of 10000 psi and its rate is 3in choke(Cavander,T.2004).

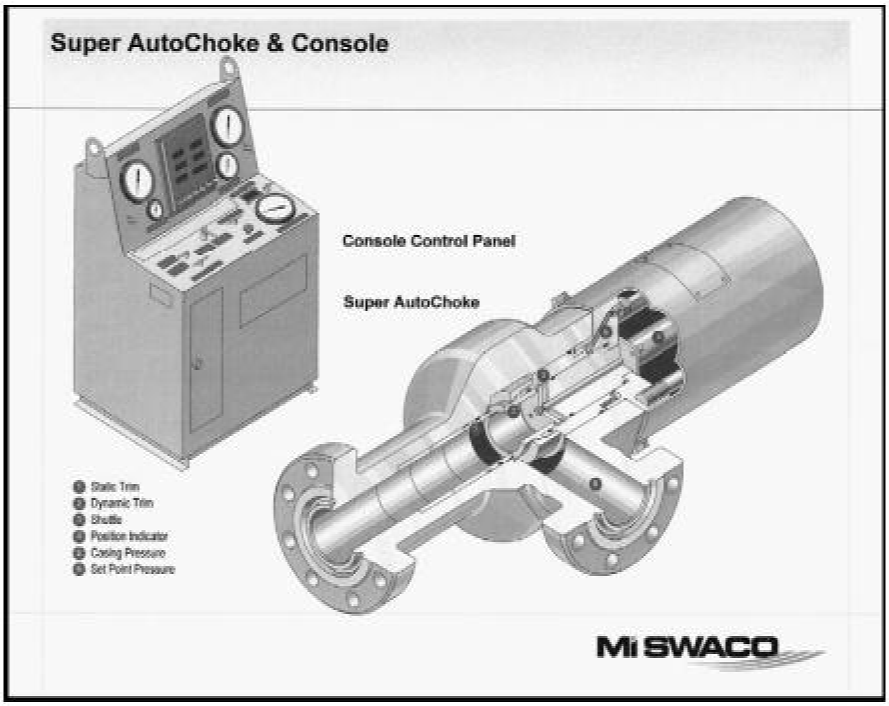


Figure 30: Super auto choke & console (Reham.B,2009).

It is accustomed that the auto choke is to be set on the automatic mode and that helps in maintaining the pressure of the casing at value that was set before. The operator has no further rule as far as the pressure of the casing that was preset didn't change. Another way of operating the auto choke is through the manual mode where the operator controls the pressure of the casing manually from the panel as demonstrated in fig30 above. The failure of the auto choke is so hard to reach as the pressure test reveals nearly all of the problems that are related to the seal tightness. On the condition of the air pressure being low, the operator can manually operate the hydraulic pump and the choke is kept open if the hydraulic control lines were cut(Cavander,T.2004).

3.3 Non return valves of the drill pipe

The drill pipe NRV(non-return valve) is very important in the managed pressure drilling process as it often requires a back pressure from the annulus. Considering the principle of the U tube, it is clear that upon the existence of +ve unbalance in the forces of the annulus the drill pipe is backed up by the drilling fluid. The cuttings that may cause plugging to the managed pressure drilling or the motor are carried by the drilling fluid or worse, the could cause a drill pipe blow out. The NRV(non return valve) or commonly known as the one way valve present in the drill pipe previously called a float which is still used in previous catalogs of equipment descriptions. It is replaced by the NRV term as a description of the one way valve of the drillpipe(Cavander,T.2004).

3.3.1 Basic piston type float

The first defensive line in front of the problems of the backflow was the (Type G) baker float which is known also as a piston float. The non-return valve piston consists of a spring closing drive piston which looks similar to an engine valve stem. The valve is opened by the pressure force of the drilling fluid in the circulation process against the spring and on turning off the pump, the spring and the pressure of the wellbore closes the valve. The basic piston float(Type G baker float) proved to be very dependable and durable and its failing is a rare occasion which results on the condition of no maintenance at all or being compromised to a high volume pumping of a fluid that causes wear. A special sub that exists over the bit is where the valve is set and it is common for the critical wells to utilize the dual non return valves(Reham.B,2009).

The type G float faces two main issues which are:

1- It causes blockage of the drill pipe for wire line
2- It may cause blockage to the back pressure or the shut in pressure of the drill pipe caused by a well kick

As far as the non return valve is positioned above the bit, the wire line passing is a bit limited and the issue of the pressure of shut is solved by slow increase in the pressure of the pump till leveling out is achieved and considering the open valve and the pressure is equalized to the pressure of shut in(Reham.B,2009).

3.3.2 Hydrostatic control valve

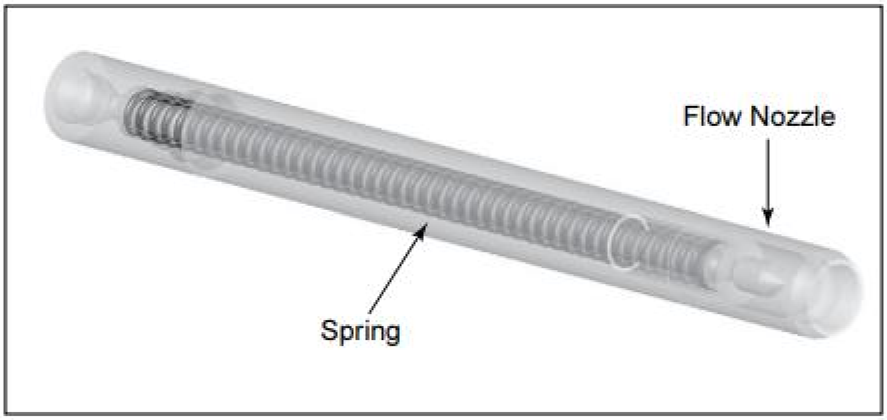


Figure 31: Hydrostatic control valve(Reham.B,2009).

The HCV or the hydrostatic control valve is known to be a subsea type of the bit float valve which is commonly used in the drilling process characterized as dual gradient is clearly demonstrated in fig31. Its main use is to hold the drilling mud column to dodge the u tube effect in the drill pipe upon shutting the pump off which in this case would be equal to full mud column pressure - the seawater column pressure no matter how deep the hole is. The hydrostatic control valve doesn't limit using the non return valve above the bit preventing the plugging and the backflow. It is considered a long tool when compared to the type G float to achieve a successful accommodation of the calibrated spring to keep the piston closed in front of the full column equivalent pressure of mud in the riser (Technical papers, 2013)

3.3.3 Pump down check valve (inside BOP)

The inside blow out preventer is a previously used tool from the piston float's generation and it is made as pump down device which is set in a sub just over the bottom hole assembly and it is known to act as check valve opposite to the upward flow. Originally, it was used when there were second thoughts about using non return valves at the bit as there was a chance the lost circulation rate being increased. While nowadays it is used in backing up the bit float(Reham.B,2009).

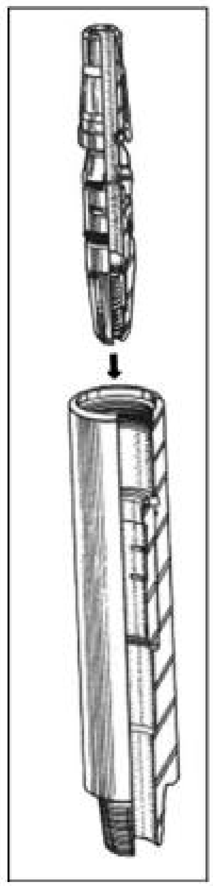


Figure 32: Inside BOP non return valve(Reham.B,2009).

The requirement of the inside BOP is that there must be a sub inside the drill string and the inside must be cleared to run. Usually, the sub is run on top of the bottom hole assembly or the collars. It cannot be retrieved once deployed and the drill string is blocked above the collars as demonstrated in fig29(Reham.B,2009).

3.3.4 Retrievable NRV or check valve

Figure 33: Retrievable non return valve(Reham.B,2009).

The retrievable non return valves are considered an update to the old version of inside blow out preventers as it can be retrieved without tripping out and there are 2 types where the first type is the retrievable wire line dart valve which is considered a very dependable system that is set inside a sub and prevent access beneath it as demonstrated in fig33, the second type is the retrievable check valve which known as a flapper type of non return valves and it allows passage for wire line or balls through(Reham.B,2009).

3.4 Coriolis Flowmeter

One of the significant flow measurements in the managed pressure drilling process is the flowmeter. A novel method introduced the drilling process which is the Coriolis flowmeter where the background of the surface equipment is described as: it relies on the concept of flowing mass that deflects a tube. As demonstrated in fig34 below, the Coriolis meter is known for its great accuracy in the measuring methods of the drilling mud as it contains the cuttings resulted from drilling which affect other meters measurements. The Coriolis flow meter is responsible for measuring and calculating four parameters which are: the mass flow, the volumetric flow, the density and temperature(Reham.B,2009) (Nandan et al., 2014)

Figure 34: Coriolis meter basis as parallel twin tubes(Reham.B,2009).

A description of the how the system works in a simple way:

i. Twin parallel flow tubes or commonly known as u tubes are oscillated by a magnetic coil at the natural frequency of them opposite to each other
ii. The assemblies of magnet and coil are installed in and out the flow tubes sides as the magnet is installed on one tube and the coil on the other tube.
iii. The vibrating motion of the tubes(fig31) causes the coil to act as a sin wave which represents the relative motion of one tube to another

iv. At the no flow scenario, the sin wave of the coils are harmonized

v. The effect of the Coriolis as a result of the mass flow inside the tubes hold out against the vibrations while outside the tubes strengthen the vibrations.

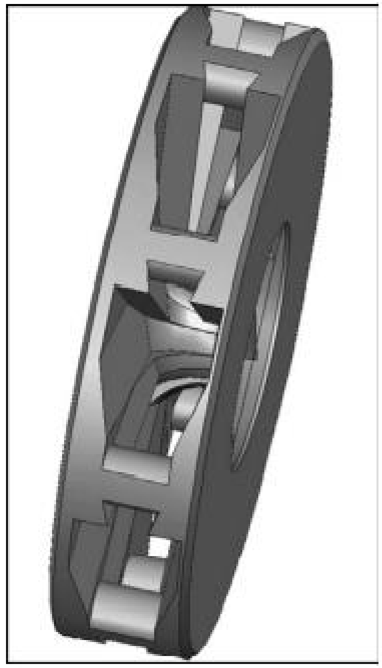
vi. The mass flow is calculated from the phase difference between the input and output side signals

vii. As the frequency vary from the natural one, it is an indication of a change in density. And as the mass is increased the frequency is decreased.

viii. $\text{volume flow} = \frac{\text{mass flow}}{\text{density}}$

ix. In order to correct the changes of temperature, the measurement of direct temperature is used(Reham.B,2009).

3.5 Disc pump or friction pump



X`Figure 35: Disc pump(Reham.B,2009).

The disc pump is demonstrated in fig 35 or as commonly known the friction pump or a subsea pump. It has several parallel plates as it was designed originally some can reach a $\frac{1}{1000}$ in apart. As the pump spines, the fluid moving through the plates causing a friction force which results in the pumping action taking place. As the plates becomes near, the pumping action to fluids of low viscosity is limited. It was discovered that on a 500mm apart plates, the pump is still effective and ever more effective than the centrifugal one specially with fluids of high viscosity(Reham.B,2009).

By enhancing the experimental work, a high head disc pump was developed which is capable of handling fluids that contain solids and gas. This developed pump is the basic form of the subsea pump. It is known for its ability to pump mud, cuttings and also mud with gas cut. It also responsible for holding a fluid column at a constant height. A frequency controlled motor is used in running the AGR system in order to be able to give any required torque at any speed preferred(Reham.B,2009).

Chapter 4 Conclusion

This research was made in order to investigate where the managed pressure drilling technique was newly used and what formations was it used in among with the benefits gained from using this technique and some of the tools used in it to make this process even more successful. It was noticed that although the cost of managed pressure drilling is considerably high, the trends of the market showed an interesting increase in using the managed pressure drilling technique due to the benefits it provides and the amount of money it is capable of saving to the companies. After finishing this research, it was found that:

1- Deploying MPD in different regions and different well conditions all over the world
2- The outcome of using the MPD technique was outstanding in each cased we discussed
3- Reduction of non productive time in all the cases
4- Increased ROP by the application of managed pressure drilling
5- Managed pressure drilling saved a lot of time while reducing also the risks countered
6- The drilling operation's safety was maintained due to the early detection of kicks and losses
7- The tools used in managed pressure drilling
8- Each purpose of every tool and when to deploy it

discussing some tools used in managed pressure drilling technique such as the RCDs and the active systems as the rotating annular preventors, the chokes and there different types and uses of each, the (NRV) non return valves and there importance in Managed pressure drilling, the downhole annular valves and there advantages, the Coriolis flowmeter and its uses in the managed pressure drilling and finally the disc pump or the friction pump.

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