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MASTER'S THESIS

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Summary

The petroleum industry constantly works to optimize operational aspects within drilling. The cost to drill a well is a parameter all companies want to minimize. To do this new technology and new methods are used to optimize the drilling process. Drilling the shoetrack is a process where components in the bottom of the casing are drilled out. The components include different equipment used when cementing the casing. Drilling the shoetrack can be a time consuming process, generating large cost and problems for the operators. The drilling of the shoetrack includes many factors, making it a complex situation. A study of the drilling parameters will help to optimize this process. Studies of the drilling parameters are expected to reduce the operational cost and time when drilling the shoetrack.

Drilling data from 143 runs were given in order to get a better overview over the problems occurring, and to show were most of the time is used. Special cementing plugs are used to displace the cement slurry and give surface pressure indications during the cementing operation. After the casing is cemented into place, all the equipment in the shoetrack needs to be drilled out in order to reach the next open hole section. The inclination of the wells plotted against the total time to drill the shoetrack, shows that the more deviated a well is, the more time consuming the shoetrack drill out process is. The study further shows that the component in the shoetrack taking the most time to drill is the landing collar, this applies for 6 of 7 casing sizes studied. The landing collar is a component used in the shoetrack when the cementing operation takes place. The cement plugs that displace the cement when pumping will land and seal inside and on top of the landing collar, this will give surface pressure indications, indicating that the cementing job is complete. The use of different bit did not give any big difference when studying all the drilling runs, so for drilling the shoetrack, it is the drilling parameters that account for most of the effect.

The shoetrack drillout of the 10 ¾" liners has shown to take too much time. The focus was therefore directed towards this casing size. A total of 15 wells in this casing size were selected, where Halliburton was the provider of the shoetrack equipment. Further, feet-by-feet data were examined, containing drilling parameters as weight on bit, rotation speed, torque and flowrate. The study included both single stage cemented liners and two stage cemented liners. The study clearly shows that drilling the cementing plug and lading collar, is the process taking most of the time. Since the landing collar took most of the time of the shoetrack drillout, a deeper studied was performed. For the single stage cemented liners a trend was seen when studying the flow rate up against the total time to drill the shoetrack. An increased flow gave better drillout times. For the WOB, no trend was seen. No trends were seen when studying the total drilling time up against WOB and flowrate for the two stage cemented liners. The materials studied for the shoetrack of 10 ¾" liners was relatively soft materials, consisting of aluminium, rubber, plastic and cement.

Connecting the time to drill the landing collar up against the average values of WOB, Torque, flowrate and revolution speed gave some interesting results. The more weight and torque applied the more time the drilling of the landing collar took. The flowrate and rotation speed did not show a large effect in the drill out times.

The best performance to drill the cement plug and the landing collar was with a roller cone bit, using only 0,33 hrs. But the data shows that this varies a lot for other wells. All bit type had more or less a good and bad performance when drilling the landing collar. Therefore the drilling parameters need to be optimized when drilling the 10 ¾” liner shoetrack. A recommended drilling procedure was made for drilling the landing collar, including a low WOB which will prevent the cementing plugs from starting to rotate, and a high flowrate to remove debris from the bit.

Table of Contents

Figures

Tables

Chapter 1

Acknowledgement

This thesis represents the conclusion of my MSc degree in industrial economics at the University of Stavanger, Norway. My 3 year BSc degree in Petroleum Technology was also taken at the same University.

Without the help from my supervisors at Halliburton and the University of Stavanger this would not have been possible. I would like to thank my supervisor at Halliburton, Alexander Jacobsen, for the continuous support and guidance throughout the semester. I would also thank Sofiane Abdellaoui for the good support and feedback. In addition I would also like to thank Halliburton Drill bits and Services, Casing Equipment and Cementing department for taking time to give good answers on my questions.

Finally I would like to thank my internal supervisor at the University, Dan Sui, for giving good feedback and her academic opinions.

All the help from the supervisors have contributed greatly to the end product of my master thesis.

Chapter 2

Intro

The drilling of a well and running the casing, requires the casing to be cemented due to governmental regulations. This will prevent oil and gas from migrating up the wellbore if an eventual kick is taken. The cementing operation will also meet other requirements and satisfy the technical aspects within the drilling process.

The cementing operation is an operation where cement is pumped down inside the casing string, exits the bottom of the casing and flows upwards in to the annulus. The operation can be performed in different techniques with different equipment. In the bottom of the casing string, special components are installed to make the cementing operation possible. When running the casing in hole, a casing shoe is attached to the bottom. This has a rounded shape, and will make it easier to run the casing through large doglegs, sidewall cavings etc.

After the casing has been run in hole, the cement is pumped down inside the casing string with displacement fluid and cementing plugs. The displacement fluid is the fluid used in front of or behind the cement slurry, this to avoid mud contamination of the cement. The cementing plugs are used to separate the cement and displacing fluid, prevent over displacement when pumping and to pressure test the casing.

The cement plugs will force the cement down the casing and push the cement out to annulus. The pumping will continue until the cement plug lands in a special collar. Now the pumping pressure will increase, because the plug gives perfect seal when landing in the collar. An increased pumping pressure at surface will indicate that the job is finished.

It is now mud inside the casing and cement in annulus. To prevent the cement from reentering the casing, due to the higher hydrostatic pressure in annulus, special one-way valves are found in the bottom of the casing.

After the cement is set, this section of different components and some cement needs to be drilled out. The interval is referred to as the shoetrack. The shoetrack is the interval of all the special components that needs to be drilled out to the bit is out of the shoe. This is called drilling the shoetrack. When drilling the shoetrack it has shown that it can be a time consuming process, generating large cost for the operator.

The thesis will give an introduction of the shoetrack and the equipment used in chapter 3. Well cementing and operation will be described in chapter 4.

The study shows that the shoetrack of the 10 ¾” liners has too high drill out time. The study will focus on these wells and try to find optimized drilling parameters from drilling logs. All the wells studied will contain shoetrack equipment supplied by Halliburton. The Halliburton cementing operation of the 10 ¾”liners will be described in chapter 5.

Chapter 6 will give an introduction to different drill bits, and bit geometry. The bit is the main tool that drill the shoetrack, and needs more attention.

The study part of this thesis will be represented in chapter 7. This chapter will first give a broad view over shoetrack drill out to show how time consuming the operation is and where the problems occur. The chapter will include factors affecting the drill out and associated problems when drilling the shoetrack. Further, the 10 ¾" liners will be studied in detail, with drilling parameters obtained from feet-by-feet drilling logs. 15 selected wells will be studied drilled by one of the major operator in Norway. The discussion of the results will be posted in chapter 8, with some factors that might tend to affect the results. Conclusion and recommendations will be presented in chapter 9.

[13,15,18]

Chapter 3

Introduction to shoetrack and cementing plugs

3.1 The Shoetrack

The *shoetrack* is an interval inside a cemented casing that needs to be drilled out in order to reach the target for the next open hole section. The shoetrack includes different equipment/components in order to perform a cementing job. These components need to be drilled out by the drill bit in order to drill the next open hole section which will make room for a smaller casing size.

Components in the shoetrack can vary depending on the casing size, casing type and cement job. A liner will have different components in the shoetrack than a surface casing. The term shoetrack will refer to all the equipment/components found from the top cementing plugs down to the bottom of the shoe.

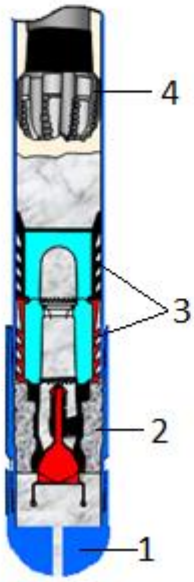


Figure 3.1: Showing the shoetrack that needs to be drilled out after a single-stage cement job is performed. 1: Shoe, 2: Float collar, 3: Cementing plugs and 4: Drill bit. [20]

On the next page there are listed some general components/equipment found in the shoetrack that are used in the drilling industry.

3.1.1 Floating equipment

Floating equipment is used in the lower sections of a casing string. It is used to reduce the strain on the derrick when running the casing in hole. Floating equipment consist of a backpressure valve (often ball or spring-loaded valves). This will make the casing lighter when running it in hole, and it will also prevent the cement from re-entering the casing when the cement have been displaced to annulus. After a cement job is complete, there will be cement in annulus and displacing fluid inside the casing. To prevent the U-tube effect (cement reentering the inside of the casing due to difference in hydrostatic pressure), the backpressure valve is therefore installed. Differential-fill-up and automatic-fill-up valves can also be installed in the shoe or float collar, having drilling fluids entering the casing in a controlled manner. [15]

3.1.2 Casing Shoe

A shoe (also known as guide shoe or float shoe) is placed at the end joint of the casing string. The component is of rounded shape. This makes it easier to guide the casing past irregularities in the open hole section when running the casing. The irregularities can be sidewall cavings, deviated sections of the well etc. A shoe can also contain floating equipment, consisting of anti-backflow devices. [15,16]

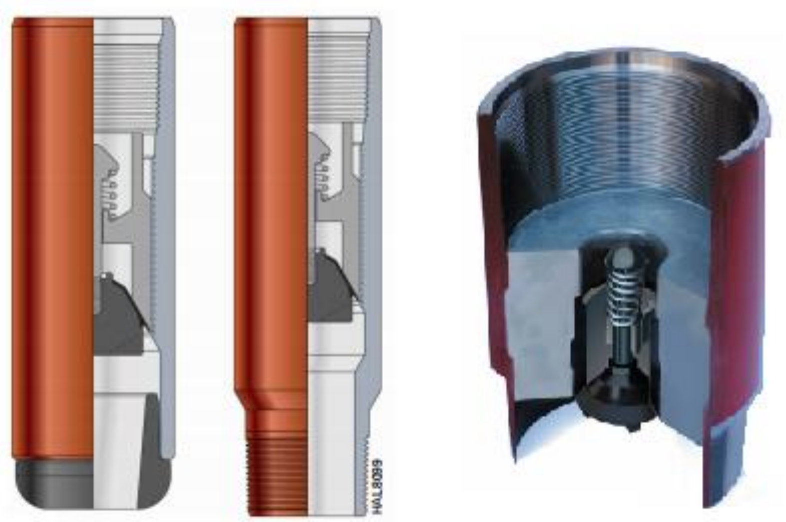


Figure 3.2: From left; Guide shoe, float collar and the inside of a float collar. All the floating equipment shown here is spring loaded. [19,34]

3.1.3 Float collar

A float collar is a short component with the same OD as the casing string. Inside the float collar there is a backpressure valve. The function of a float collar is to serve as a seat for the cementing plug(s) and prevent backflow after a cementing operation. [15]

3.1.4 Landing collar

Landing collar is located usually one or two casing joints above the float collar. The landing collar is normally used in liners, and is not installed in a regular casing string during a cementing operation.

The landing collar catch the cementing plugs used in the cementing operation. The landing collar acts as a seat-and-latch-assembly for the cementing plugs. The dart and plug cementing equipment must be compatible with the landing collar in order to use a plug setup in combination with a landing collar. The landing collar can also contain a one-way valve. [17]

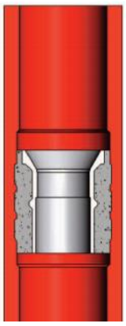


Figure 3.3: VersaFlex liner hanger landing collar. [22]

3.1.5 Cementing plugs

Cementing plugs are used during the cementing operation. Usually two plugs will be found in the shoetrack, but that will depend on the setup of the cementing operation. The function of a cementing plug is to separate the fluids during pumping (spacer, mud and cement) and reduce the risk for contamination. The plugs will also act as a pump pressure indicator on the surface when they land either in the float collar or landing collar, this will indicate that the job is finished. The top cement plug will be the first plug that will be drilled out during drilling of the shoe track. The top plug requires a tougher material to withstand higher pressures; this allows the operator the pressure test the casing string after the cementing operation is complete. [15,16]

Figure 3.4: Cementing plugs in different sizes. [21]

3.1.6 Stage equipment

These components consist of stage collars. They are placed within the casing string and provide passage through ports from the inside of the casing to annulus. The ports are opened and closed by sliding sleeves. The ports can be opened hydraulically or mechanically. This equipment is used in multistage cementing, where the cementing is performed by pumping cement into the well in two or more separate stages. The cementing operation with stage equipment are often performed in weak formations, where fracturing of the formation can occur due to high hydrostatic pressure of the cement. [16-18]

Figure 3.5: Type P ES Stage collar [19]

3.1.7 Section with no components (filled with cement after the cementing operation)

The shoetrack will contain some intervals with only cement inside the casing. This space is used to trap contaminated cement or mud that may accumulate from the displacement with the cement plugs. This will tend to keep the contaminated cement away from the shoe, where the best bond is required. The shoetrack intervals with only cement inside will be the interval below the float collar, and the interval between the landing collar and the float collar. [15]

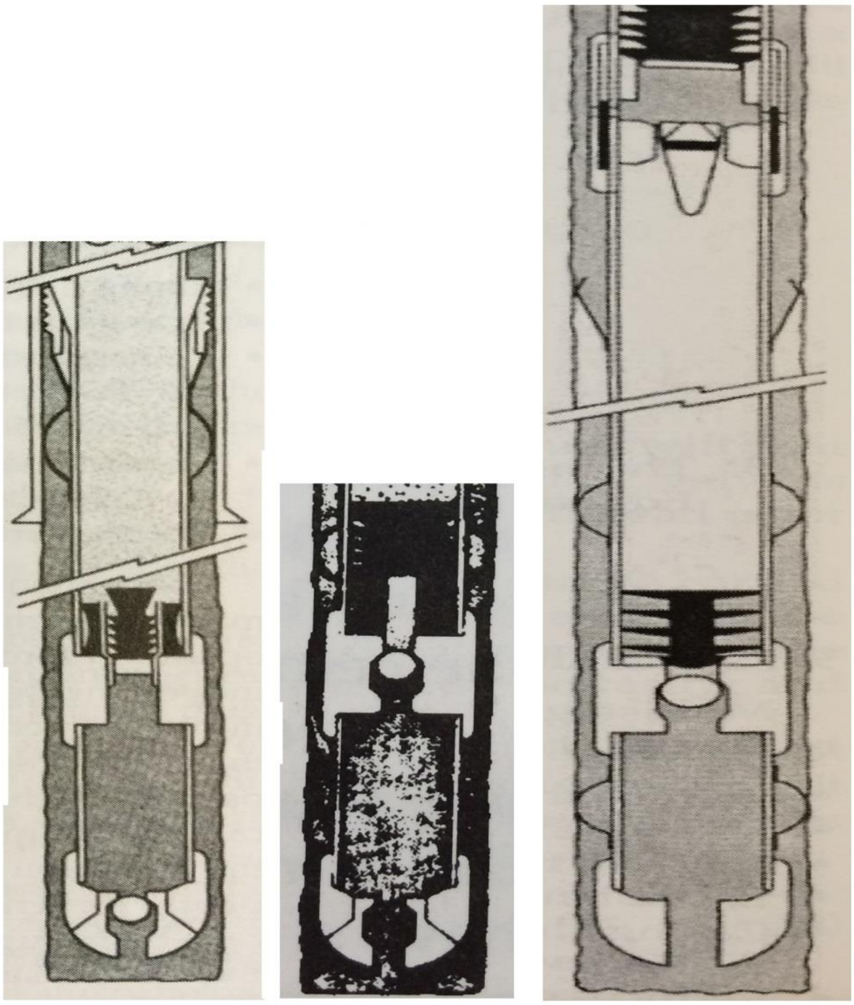


Figure 3.6: Different cementing equipment that needs to be drilled out in the shoetrack. From left: Liner cementing job, regular single-stage cementing job and two-stage cementing job. The equipment drilled out will depend on cementing operation type and the contractor providing equipment for the cement job. [24]

3.1.8 Materials used for the shoetrack equipment

Many vendors offer cementing equipment in different sizes and materials. A short study was performed on the large vendors in Norway (Halliburton, Schlumberger, Weatherford and Baker Hughes), to see what kind of materials that are commonly used for the cementing equipment in the drilling industry.

For the plugs and darts it is common to use rubber or foam as wiper material. These are flexible materials that provide a good wiping effect inside the drill string or casing. The table below shows the material of the parts being drilled out for each shoetrack component. This will only be the material on the inside of the equipment which comes in contact with the drill bit. The body of the floating equipment and stage equipment usually consist of standard casing graded steel. [35-38]

Equipment	**Material**
Regular single-stage cementing plugs	Core material: Aluminum, plastic or hard rubber.
Subsea/Subsurface cementing plugs	Core material: Plastic, composite or aluminum.
Releasing plugs/darts	Core material: Aluminum, composite or plastic
Floating equipment (Float collar and shoe)	Composite, plastic, aluminum
Landing collars	Available in all materials
Stage equipment (including dropped opening components)	Aluminum and composite.

Table 3.1: Shows the material used for different components found in the shoetrack. [35-38]

As the study shows, the cementing equipment contains very similar material types. These are material that are not so hard compared to steel, but contain more soft materials, and can easily be drilled out with most of the drill bits used today.
The cementing plugs contain often a harder and stronger material in order to withstand the high pressures and temperatures they are exposed to when drilling deep wells. [35-38]

3.2 Cementing plugs

Figure 3.7: Halliburton Wiper Plug Technology [24]

Cementing plugs are used when cementing operations are performed in the drilling industry. They are also referred to as wiper plugs. The plugs perform many important aspects in the cementing operation. The reasons for using the cementing plugs are [21]:

- Remove mud sheet
- Separate cement and mud
- Prevent over displacement when pumping
- Surface indication (Pressure indications)
- Pressure test casing

As the cement is being pumped down the casing string, the plug(s) are pushed down from the force of the cement pumps. The plug(s) wipe the inner diameter of the casing string, and separate the cement from contamination with mud or displacing fluid. It also prevents over displacement when pumping. When the cement job is finished, a robust plug lands in a special collar (floating or landing collar). This top plug gives perfect seal and prevents further flow; this will give a pressure indication on the surface that the cement has been displaced, it also seals the casing which allows the operator to pressure test the casing to its design pressure. [21,24]

Different plugs are used when cementing the different casing strings of a well. A single-stage cement job will usually contain a bottom and a top plug, but cementing a liner will usually contain one plug. The plugs can either be released and pumped down from the surface when installed in a cementing head, or released from “stab-in” equipment by smaller plugs/darts. This will be discussed more in detail later. [24]

The plugs need to be compatible with the other cementing equipment that is used in the well. Many different plugs exist in the drilling industry from many vendors, for example conventional wiper plugs, latch-down or tear-drop plugs, non-rotating wiper plugs, subsea plugs and plastic-insert plugs. [26]

3.2.1 Conventional top and bottom wiper plug used in single-stage cementing

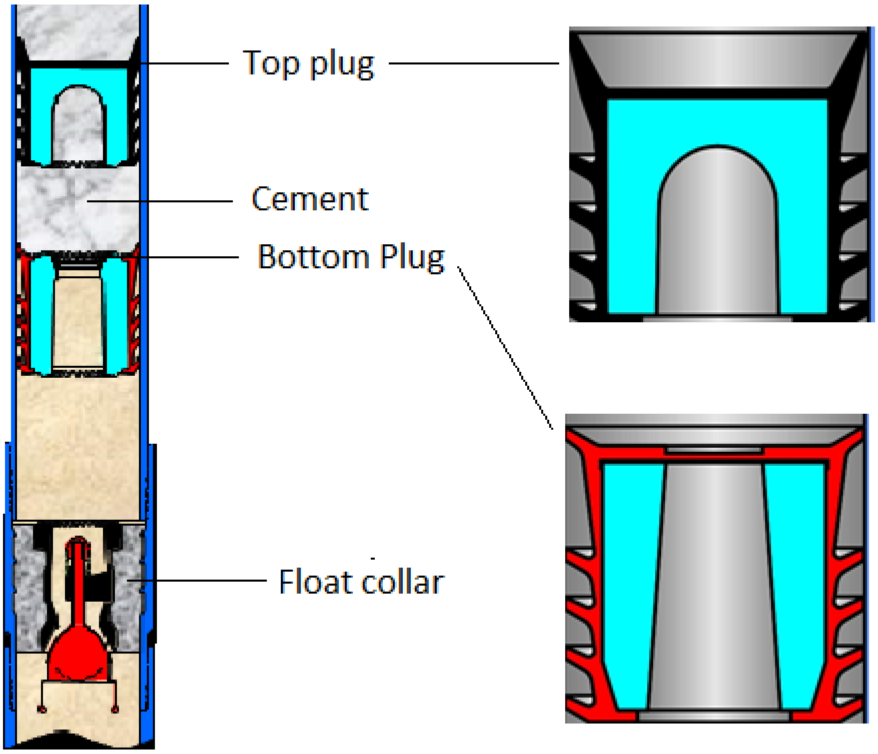


Figure 3.8: Conventional wiper plugs used in a regular single-stage cementing operation. [21]

For a regular single-stage cementing job, a top and bottom wiper plug is used. The plugs separate the fluids in the well as the cement is being pumped down. The bottom plug is hollower than the top plug and has a diaphragm of rubber or plastic that ruptures when the plug seats in the float collar. The diaphragm usually ruptures at 200 to 400 psi. This will give a good surface indication that the first plug has reached the float collar. A float collar is a one-way valve that prevents the cement from back flowing when the cement is fully displaced to the annular room between the casing and the formation. The cement is pumped further until the top plug lands on top of the bottom plug. The pump pressure will again increase and indicate that the cement job is complete. The top plug is more robust and can handle higher pressures; this will allow the operator to test the casing string to its design pressure. [15]

The plugs have molded wipers and the inserts are often manufactured of plastic or aluminum. An insert of aluminum increases the strength and temperature ratings of the cement plugs. The aluminum inserts should be used when the BHCT (Bottom hole circulating temperature) exceeds 300°F, and drilled out with a tricone drill bit. The plugs with plastic inserts should be used at BHCT lower than 300°F, and drilled out with PDC or tricone bit. [15]

3.2.2 Non-rotation five-wiper cementing plugs

Figure 3.9: Halliburton non-rotation five wiper cement plugs and float collar. [21]

These plugs are manufactured with locking teeth, and must be used with a similar float collar with locking teeth. These locking teeth prevents the plugs from spinning when the next open hole section will be drilled. This will reduce the drill out times and associated rig cost. The NR (non-rotating) plugs use plastic or aluminum inserts that are both PDC and tricone bit drillable. These plugs can be used in vertical and horizontal wells with temperatures up to 350°F. The plugs are available in 4 ½” to 20” and is compatible with the most fluid systems. The NR-plugs can also be used in combination with other cementing applications than the single-stage cementing operation. [15,27]

3.2.3 Releasing plugs used for liner and subsurface cementing

Releasing plugs are used to release the cementing plugs which are used in liner cementing or subsurface cementing (when the wellhead is located at the seabed). Common for these operations is that the cement needs to be pumped through the drill string. In order to get a large enough plug to wipe the inside of the casing and separate the fluids, releasing plugs are therefore used. The releasing plugs connect to the cementing plugs (located in a special installation tool in the end of the drill string attached to the casing string). The releasing plugs seats in the cementing plugs in the installation tool when displacing takes place. The releasing plug is now inside the middle of the cementing plug, and an efficient wiping and separating action is now fulfilled in the casing string. Releasing plugs are often darts consisting of foam or rubber combined with alumina. Balls are also used to release the cementing plugs in this kind of cementing operations. The releasing plugs will also provide a good wiping effect inside the drill string before it reaches the cementing plug(s). [42]

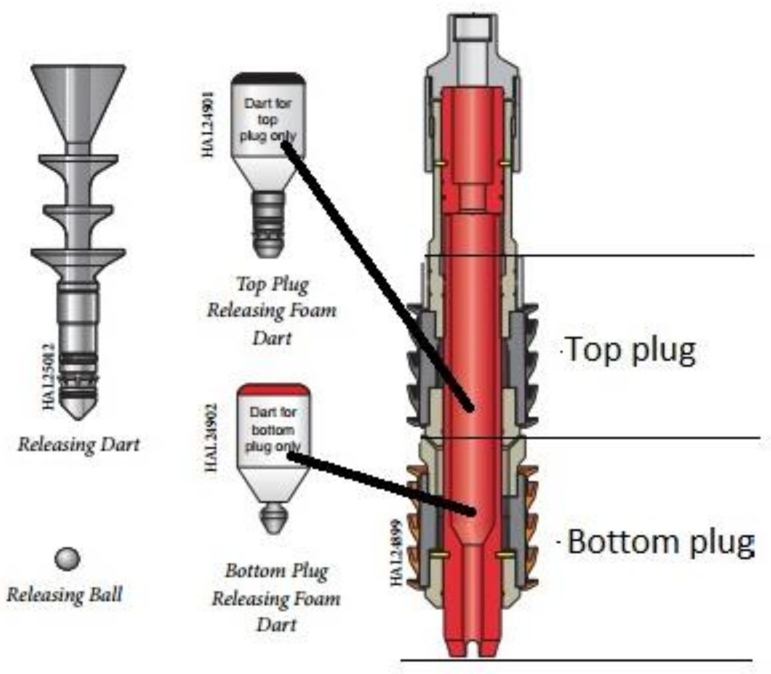


Figure 3.10: Showing different releasing plugs and a cementing equipment (SSR-II from Halliburton). The lines indicate where the foam darts will be seated when pumping takes place. The bottom plug releasing dart will be attached to the bottom cementing plug, and the bottom cementing plug will then disconnect from the top plug as pump pressure increases. [42]

Chapter 4

Well cementing and operation

Oil well cementing is the operation where water and slurry of cement is mixed and pumped down the well to create a barrier in the annulus, open hole or below the casing. Cementing is essential to drilling oil and gas wells, and it has many different applications in this industry. If the cement operation is performed in a correct way, then the economic, safety, government regulations, and other requirements imposed during drilling will be met.
Cementing operations can be divided into two main categories: Primary cementing and remedial cementing. Remedial cementing is the operation where cement is usually used to correct problems with the primary cementing operation. Cementing the casing to the formation immediately after the casing has been run in hole, is referred to as *primary cementing*. The main objective with primary cementing is to:

- Isolate the annulus between the casing and the formation to prevent migration of gas and oil along the wellbore
- Support and give mechanical strength to the casing
- Support and strengthen the formation against the wellbore

In addition to zonal isolation cement also aids in:
- Protecting the casing from erosion
- Preventing blowouts by quickly forming a seal
- Protecting the casing from shock loads
- Sealing off zones of lost circulation or thief zones.

[13,15,18]

4.1 Cement

Cement is a powder consisting of silica, lime, alumina and other substances that hardens when mixed with water. Cement is made of calcareous and argillaceous rock, which is usually obtained from quarries. To obtain the cement powder, the rock is crushed and subjected to high temperatures. Cement is widely used in the drilling industry to bond casing to the walls of the wellbore, and for other applications. [18,24]
Cement used in oil wells is classified according to API (American Petroleum Institute) standards. Each class accommodates different downhole conditions. Class G and H cements are most often used, because they have characteristics that allow them to be used at different depths. [18]

4.2 Additives

Additives are important when designing the cement for a specific cementing operation. When the cement (powder) is mixed with water and additives the resulting mixture is *slurry*.
An additive changes the properties of the slurry, and can be both solid material and chemicals. One additive can change many properties with the slurry itself. Properties as density, water requirement, viscosity, thickening time, setting time, strength, durability and water loss are important factors to make the cementing operation successful.
It is important to be sure that the additives are compatible with the cement and other additives in the slurry. When the cement is mixed with water the cement hydration will begin, and the cement will gradually start to set to a solid as the hydration continues.
The cement slurry needs to be carefully designed for each job. Temperature and pressure are parameters that vary a lot in a well, and this will affect the properties of the slurry. The slurry needs satisfying rheological properties in able to be pumped and not interact with the formation, in addition the slurry needs to be set in a specific time. This will normally be decided by the pumping time for the slurry plus a safety factor. Laboratory testing and design will be performed for each cement job by service companies, to secure the right properties and quality for the cement slurry. Below there are listed some general additives used in the cement slurry in order to change the properties. [17,18]

4.2.1 Retarders

If a cement job is performed in a deep well it will have high temperatures and pressures. This is factors that will affect the cement hydration and setting time. Higher pressures and temperatures will shorten the setting time. It is important that the cement do not set before it has been pumped to its final destination of the cementing operation. In order to increase the setting time, additives as retarders are used. A retarder prolongs the setting time, so the cement can be pumped into place without setting prematurely. Retarders includes chemical that are similar to mud thinners, such as lingnosulfonates. [18]

4.2.2 Fluid loss additives

When the cement slurry is subjected to pressure it will tend to loose water to the formation during slurry placement. This will change the properties of the slurry and make it thicker. If the fluid loss is too high the cement slurry can be too viscous to be pumped. Fluid loss additives prevent or minimize the water loss into the formation. Water lost to the formation can also interact with clay, which can cause swelling and blocking in annulus. Fluid loss additives used are dispersants and organic cellulose; these additives will trap the filtrate in the slurry. [18]

4.2.3 Dispersants

Dispersants are used if the viscosity of the cement slurry is too high. When a large volume of cement is being pumped it requires the slurry to be sufficient thin, in order to reduce the frictional pressure while pumping and not damaging weak zones. [18]

4.2.4 Accelerators

If a cementing operation is performed in a shallow depth the temperature might be very low. The temperature has great influence on the thickening time of the slurry, and will decrease with lower temperatures. The thickening time is the length of time the slurry will remain in a fluid state under downhole conditions. To make the thickening time decrease accelerators are added. Accelerators acts as a catalyst, making the hydration process to speed up which will decrease the setting time of the cement. Calcium chloride and sodium chloride are frequently used accelerators. Another way to reduce the setting time is to reduce the amount of water in the mixture. But this will tend to increase the viscosity, so more additives might have to be presented in the slurry in order to make it acceptable for pumping. [18,23]

4.2.4 Extenders

The yield of the cement is referred to the volume of slurry that is possible to mix with one sack of dry cement. Additives that generate a greater yield are called extenders. The extenders will increase the amount of water required to mix the dry cement. This additive can be used to for example lighten the cement slurry. Since cement is more expensive than water, it will also make the cement slurry cheaper as it will consist of more water than the mixture without the additive represented. [18]

4.2.5 Heavyweight additives

When cementing in high pressure zones the cement has to have sufficient specific density in order to create a higher hydrostatic pressure. The heavy weight additives are weighing agents that are added to the cement in order to make the cement mixture denser. Cement needs to be heavier than the drilling mud in order to not start to migrate up the well section (floating). Additives such as barite, sand and hematite are used to increase the density. These are common additives also used in drilling mud. [18]

4.2.6 Lightweight additives

These additives reduce the slurry density in order to be able to drill in low-pressure zones and weak formations. One way to reduce the density is to add water, since water is lighter than cement. But adding too much water will reduce the strength of the cement, and create channels and pockets in the set cement. The lightweight additives will prevent the water from settling out. Bentonite is being used for this application, it reacts chemically to hold water and keep it from settling out. Bentonite will increase the volume and produce lighter and more versatile slurry. Other lightweight additives are pozzolans, silicates, hollow spheres and foam. [18]

4.2.7 Bridging material additives

These materials are flaky, fibrous and granular. They are added to the cement slurry to prevent loss of cement into zones of lost circulation. The most used additives are Kolite, Gilsonite and Cliton flake. [18]

4.2.8 Effects of some additives on the physical properties of cement

		Bentonite	Perlite	Diatimaceous Earth	Pozzolan	SilicaFlow	Barite	Hematite	Calcium Chloride	Sodium Chloride*	Lignosulfonates	CMHEC+	Diesel Oil	Low Water Loss Material	Lost circulation Materials	Activated Charcoal
Density	Decreased	2	2	2	1	1										
	Increased						2	2	1	1	1					
Water Required	Decreased										2					
	Increased	2	1	2	1	1	1	1							1	1
Viscosity	Decreased									1	2					
	Increased	1	1	1	1	1	1	1	1						1	1
Thickening Time	Decreased						1		2	2						
	Increased			1						2	2	2	1	1		
Setting Time	Decreased						1		2	2						
	Increased	1	1	1	1					2	2	2		1		
Early Strength	Decreased	1	1	1	1		1	1		2	2	2		1	1	1
	Increased								2	2						
Final Strength	Decreased	1	1	2	1		1					2		1	1	1
	Increased					2					1					
Durability	Decreased	1	1	1									1		1	
	Increased				2	2										1
Water loss	Decreased	2										2	1	2	1	
	Increased		1	1					1	1	1					

Table 4.1: 1 denotes minor effect, 2 denoted major effect and/or principal purpose for which used. * Small percentages of sodium chloride accelerate thickening time. Large percentages may retard API class A cement. +: Carboxymethyl hydroxethyl cellulose. [18]

4.3 Displacement fluid

When the casing is run into a well the open hole is usually filled with drilling mud from the previous drilled section. When the cement is pumped it is normal to pump a displacing fluid before and after the cement slurry. The displacement fluids are used to reduce the risk of contamination of the cement with drilling mud. These fluids are known as flush or spacers. Spacers are thick fluids that displace the drilling mud which is ahead of the cement. The displacement takes place in a slug or piston-like manner. The flush fluids are thinner and work in a combination of turbulent and surfactant action to separate the drilling mud from the cement being pumped. The displacing fluids also remove and clean the annulus to ensure a better bond between the casing and the formation. Between the cement and displacing fluid there is wiper plugs which wipe of the mud/cement inside the casing and helps to keep the different fluids separated. The displacement fluids need to have a specific rheology compared to the cement. If the yield strength of the displacement fluid is larger than the cement, the displacement fluid might tend to be “pushed” into the cement. [18]

4.4 Strength-Testing technique of cement

After the cement is pumped the hydration of the cement takes place. The cement will build compressive strength with time as the cement hardens. The cement requires very little early strength to support a string of casing. The compressive strength of set cement is tested by measuring the force needed to crush a 2 inch cube under an unconfined compressive load. This method has been used for more than 40 years in order to decide the WOC (wait on cement) time. The compressive strength is usually given in psi or bar. [23]

The never method uses ultrasonic waves and traveling time to calculate the compressive strength. This is called a UCA (Ultrasonic cement analyzer), and it continuously monitor the strength development of any given cement composition. Slurry is placed inside a cell and set under pressures and temperatures which correspond to the downhole conditions. The UCA will send ultrasonic waves through the cement and give the compressive strength from start of the test until the test has been terminated. The strength development can be plotted against time, and gives complete result and precise history of when the cement is starting to build strength. [23]

Figure 4.1: Ultrasonic cement analyzer. [23]

4.5 Handling and mixing of cement offshore

4.5.1 Mixing

Dry cement is stored in large bulk tanks offshore. The dry cement is transported to a mixing system. The mixing system proportions and blends the dry cement with water and additives. The recirculating mixer is designed for mixing more-uniform and homogeneous cement slurries. It is a large tub with high capacity combined with a pressurized jet mixer. The recirculation pumps provide a lot of shear forces, when the slurry is recirculated; this gives good mixing properties of the system.
Batch mixing is used to blend cement slurry at the surface before it is pumped down the well. The mixing tank in the batch mixer is filled with enough water for a specified amount of cement. A mixing turbine circulates the water, as cement is added to get the final volume and properties of the slurry. A batch mixer is used when a specified volume of cement is required. A prehydrator is usually used to wet the dry cement, this to prevent problems with all the dust usually generated. The disadvantages with a batch mixer are the volume limitations and the need to use additional equipment. When a volume limitation is the constraint, units with multiple mixing tanks may be used. This will give precise consistency of the slurry and volume. [15]

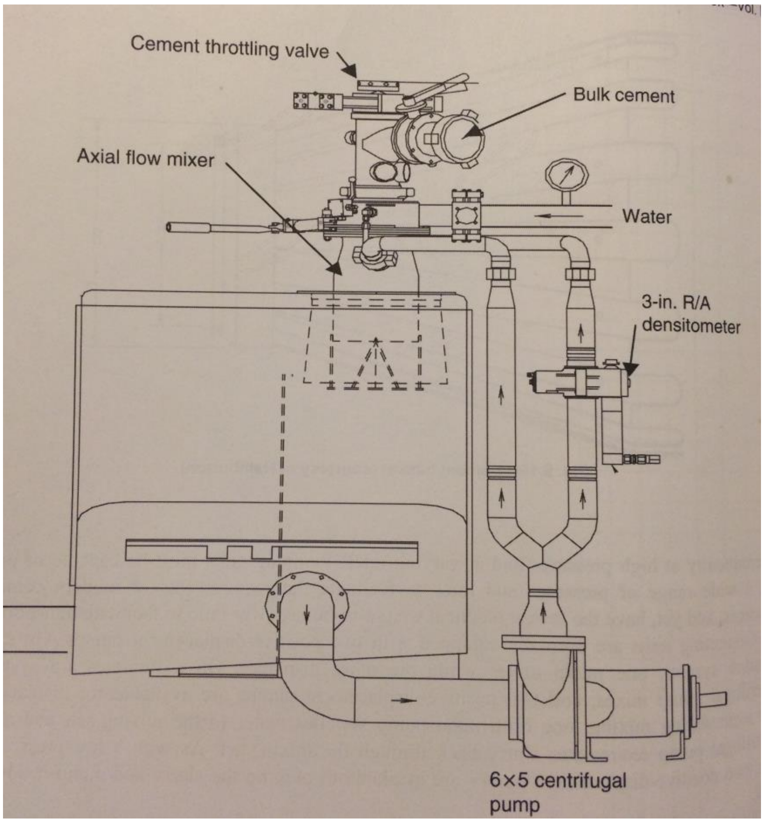


Figure 4.2: Reciprocating mixer (courtesy of Halliburton). [15]

4.5.2 Pumping

When performing a cement job, high turbulent flow around the well is most effective; this gives the best displacing. When a turbulent flow is not appropriate for the well condition, then the highest allowable pump rate should be used. The cement pumps are operated at high pressures and varying rates. The pumps must be capable of providing a wide range of rates and pressure to meet the requirements for the modern cementing operations. [15]

Cementing units are normally equipped with positive displacement pumps. Duplex double acting piston pumps or single-acting triplex plunger pumps is mostly used. The triplex pumps discharge more smoothly, and can normally handle a higher pressure than the duplex pumps.
Cementing operations uses maximum pressures of less than 5000 psi, but pressures as high as 20 000 psi are not unusual. [15]

Figure 4.3: Halliburton cementing unit, the unit provides mixing, pumping and environmental performance. [32]

4.5.3 Cementing heads

Cementing heads contains valves and cementing plugs or releasing darts. This allow for cementing plugs to be released ahead or behind the cement slurry when pumping. The plugs or darts are usually held in the cementing head and can be released by the operator of the cementing equipment. A cementing head can be attached to a casing string or on the top of a drill pipe. The plugs or darts can be pre-installed in the cementing head before the pumping and displacing of the slurry takes place. The plugs can easily be released from the cementing head without interrupting the pumping. The cementing head needs to be strong enough to handle high pumping pressures. [15]

Figure 4.4: Halliburton high-pressure cementing head. 3 valves are available on this head. A bottom (red) and top plug (black) is pre-installed. [30]

4.5.4 Casing centralizers

Centralizers are used to guide the pipe in the middle of the hole. Hole deviations will tend to connect the casing and the formation by gravitation, especially in high deviating wells (up to 90° inclination). When cementing, a good bound between the formation and the casing is needed. The centralizers centralize the casing in the middle of the open hole, and a cement job can now be performed. This will create a more effective seal and bound between the casing and wellbore. [15]

Figure 4.5: Halliburton Isolizer™ Centralizer. [33]

4.6 General setup of a well

Casing and tubing string are the main parts of the well construction. Casing is used to secure stability, prevent contamination of water sands, isolate water from producing formation, and control well pressures during drilling, production and work over operations. After a casing has been cemented into place, a new open hole is drilled with a smaller drill bit. [15]

Casing also allow for installation of important well equipment such as blow out preventers, wellhead, packers and tubing. The length of the casing has to be designed from the wellbore stresses i.e. pore pressure, mud weight, collapse design, burst design etc. [15]

Casing can be found in various sizes and material grades. The cost of the casing is a major part of the drilling operation, so the selection of casing grade, connectors and setting depth is primary engineering and economic considerations. The sizes are today usually used in standard sizes by the operator. Casing strings consist of six basic types; some regular used sizes in the drilling industry are given to the right of each string type (this will be different from operator and formation properties): [15]

4.6.1 Conductor casing (30")

This is the first string set. The casing isolates unconsolidated formations, water sands and protect against shallow gas zones. This is usually the string where the wellhead and blow out preventer is installed. This casing is usually cemented from bottom to top to give good anchoring to the seabed. [15]

4.6.2 Surface casing (20")

The casing function is to provide blowout protection, isolate water sands and prevent lost circulation. The casing also provides strength to drill in high pressure zones. The casing needs to handle a kick taken from the next open hole section. This string is often cemented from the bottom to the top. [15]

4.6.3 Intermediate casing (13 ⅜")

This casing primary tasks is to isolate unstable hole sections, lost-circulation zones, low-pressure zones and production zones. The casing is often set in the transition zone from normal to abnormal pressure. The cement needs to cover and isolate any hydrocarbon zones. Some wells require more than one intermediate casing. [15]

4.6.4 Production casing (9 ⅝”)

Used to isolate production zones. The casing also needs to be strong enough to handle leaking tubing. This casing must also be strong enough to handle large injection pressures when having gas lift, fracture jobs, gas lift or injection of chemicals. This casing requires a good primary cementing job. The length of the cemented interval will depend of the collapse pressure of the casing, and the formation characteristics. [15]

4.6.5 Liner (7”)

Liners differ from a regular casing as it is not hung from the wellhead. It is a smaller section that is hung of in the previous casing string. Liners are used to reduce cost, improve hydraulic performance in deeper drilling, and allow for larger tubing over the liner top. Liners can be either an intermediate or a production string. [15]

4.6.6 Tieback string (7”)

A tieback string is a string that provides additional pressure integrity from the liner top up to the wellhead. A tieback string is used to isolate a casing string that cannot withstand possible pressure loads if drilling is continued. The tieback string will isolates an intermediate string from production loads. These kinds of strings can be uncemented or partially cemented. [15]

4.6.7 Tubing (4 ½”)

Tubing is the string which the produced oil and gas flow trough. The tubing must be strong in order to handle high pressures and work over operations. The tubing can have different sizes and must be optimized to the flow properties of the hydrocarbons to ensure the best economic performance of the well. [15]

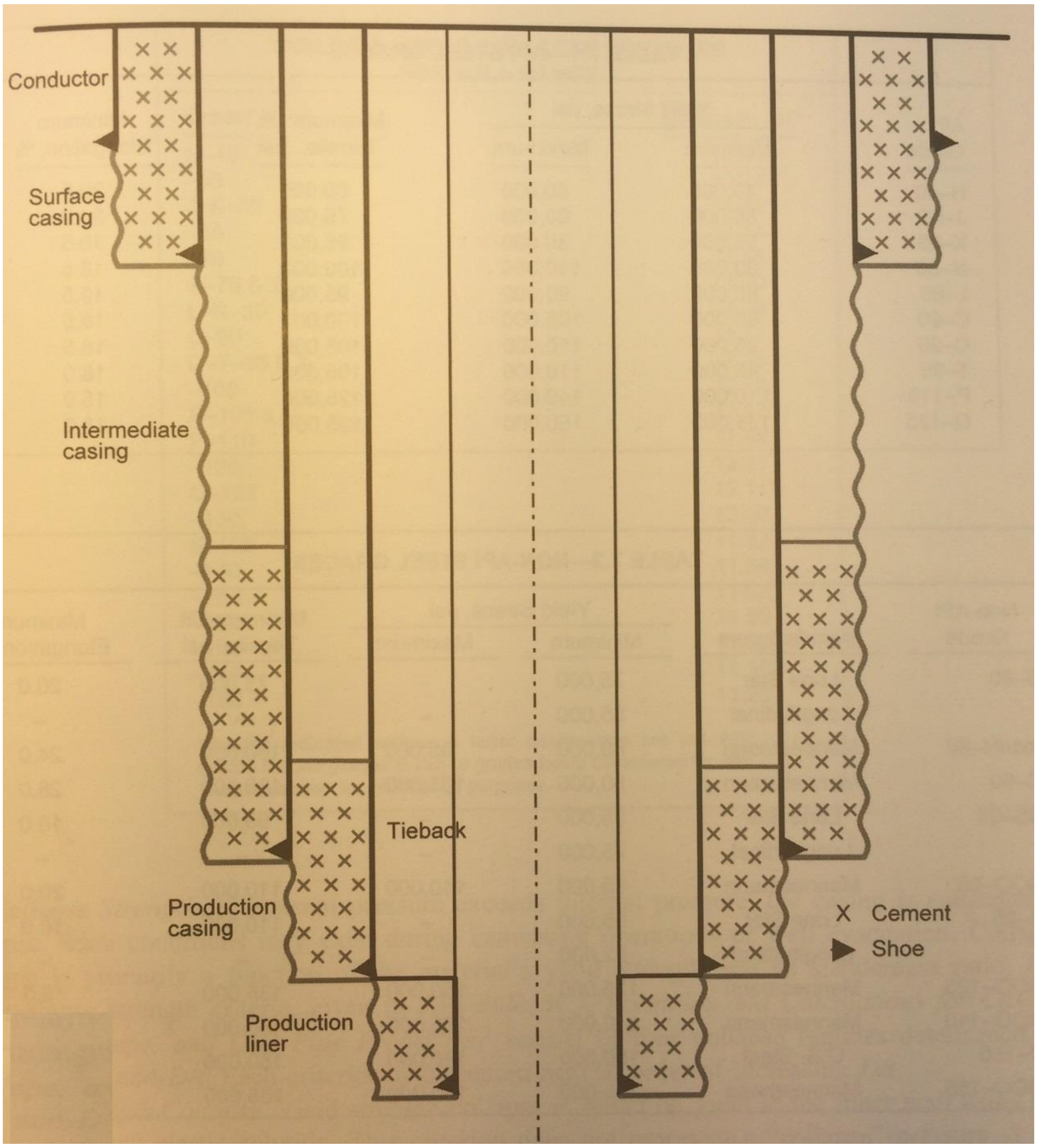


Figure 4.6: Shows a typical casing program for a well, the cement and casing shoes are indicated on the figure. [15]

4.7 Different primary cementing techniques

Cementing the liners and casing to the formation refers to the primary cementing operations. Cementing operations are carried out with surface equipment which is specially designed for the cementing operation. Different setup exists from many different vendors, but the technique is very similar. Some different general cementing techniques will be discussed here to give the reader a better understanding of the operation, and to show the different equipment that needs to be drilled out which is left in the shoetrack. Single stage cementing is the most used method for regular casings, but two stage cementing and liner cementing will also be discussed. [24]

4.7.1 Normal single-stage casing cementing

The casing is run in hole with the shoetrack equipment installed (guide shoe, float collar and centralizers). The float collar is usually installed one to four casing joint above the shoe. Centralizers are installed usually in a density of 2 centralizers per casing joint to 1 every four joints. The centralizer density will vary depending on the hole size, well profile and fluid rheology.
The casing is lowered into the open hole by using the rig draw works and elevator.
A cementing head is installed on top of the casing. Cementing can also be performed through the drill string, where the drill string is stabbed into the upper part of the casing, where a special plug set is installed. The figure below shows the schematic series of a typical single stage cementing operation [24]:

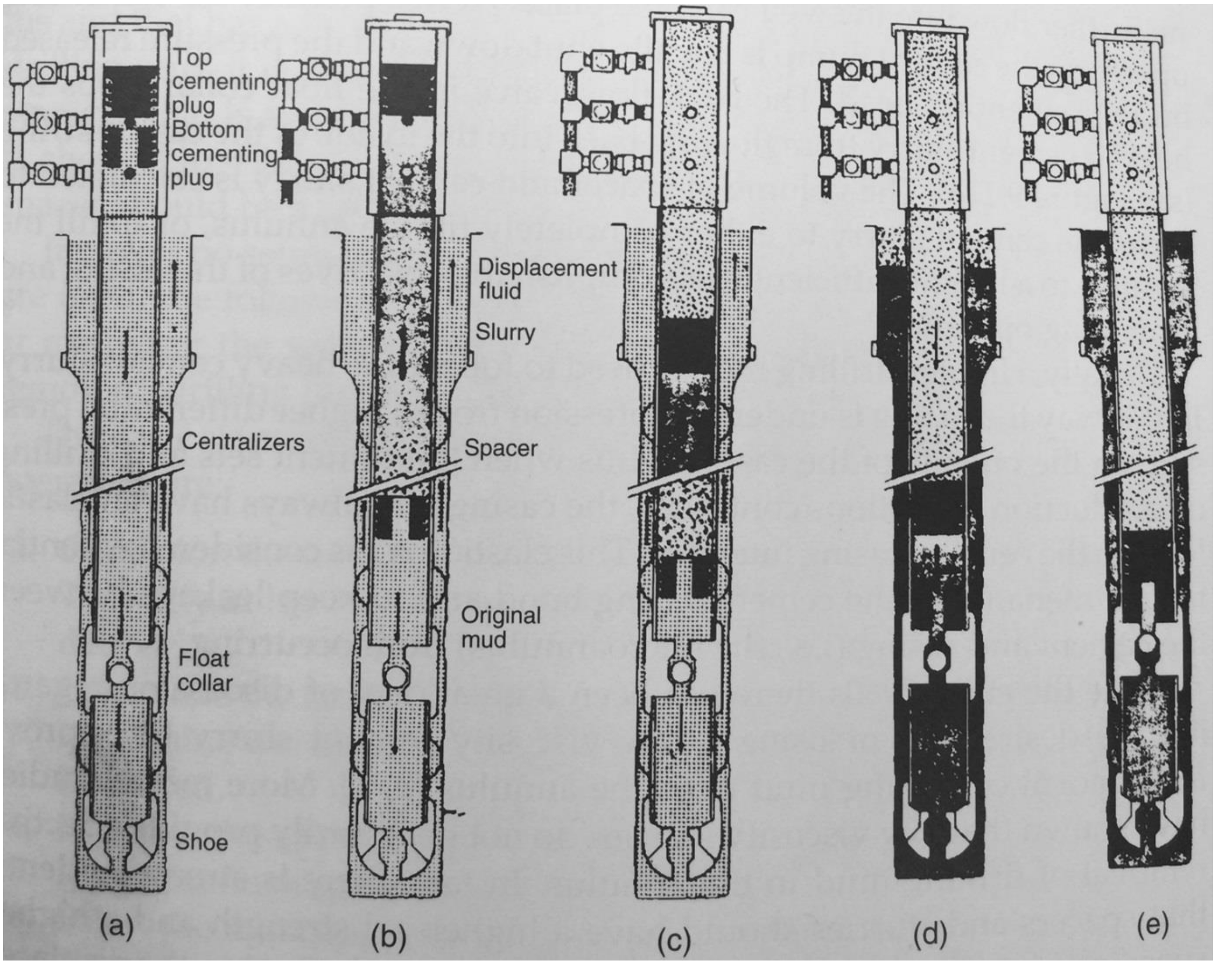


Figure 4.7: Single-stage cementing: (a) Circulation of mud; (b) pumping displacement fluid; (c&d) displacing; (e) job complete. [24]

The figure above shows the single stage cementing step by step. The cementing head contains two cementing plugs in this case. The bottom plug is released from the cementing head, and some displacement fluid is pumped (spacer). The pumping action forces the fluids and plugs down the casing. After a volume of displacing fluid is pumped the cement slurry is pumped behind. When all the cement volume has been pumped, the upper plug is released from the cementing head. The bottom plug reaches the float collar, and the pumping pressure will increase. The diaphragm in the bottom plug will rupture (usually at 200 to 400 psi), and cement will then be displaced through the bottom plug, float collar and guide shoe out to annulus. When the top plug lands on the bottom plug the pumping pressure will increase, which will indicate that the cement job is complete. [24]

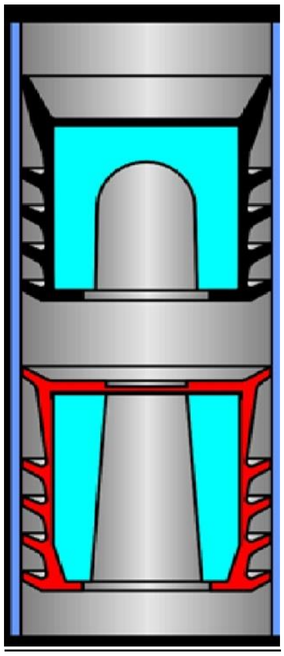


Figure 4.8: Shows a top cementing plug (black), and bottom cement plug (red). The bottom plug has a diaphragm that ruptures when the plug is landed and the pumping pressure increases. The top plug provides a seal, and is more robust than the bottom plug. [21]

4.7.2 Large-diameter casing cementing (inner-string cementing)

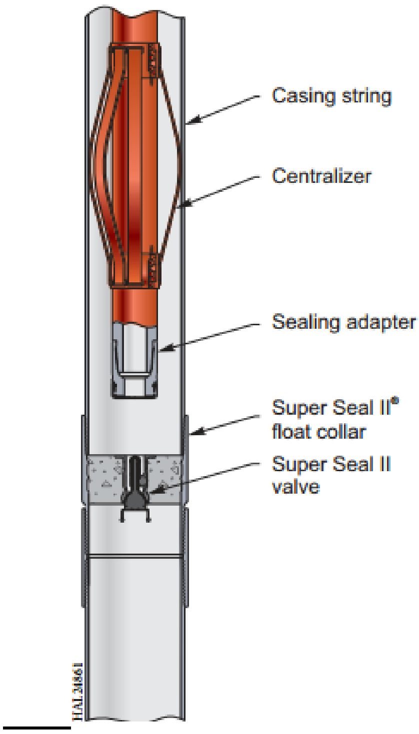


Figure 4.9: Shows the setup of an inner-string cementing operation. [39]

Often when large diameter casing strings are cemented, an alternative method is used. The large casing will contain "stab-in" float collar or shoe, where the drill string can be attached and sealed in. This makes the cementing operation possible without having oversized cementing heads.
This method requires the drill string to be centralized inside the casing and attached to the "stab-in" equipment. Once the stab-in unit of the drill string is in place and locked, a special circulating head is made up on the surface. A flexible latch-in plug is used to displace the cement. After the cement job is complete, the drill pipe can be unlocked from the floating equipment and withdrawn from the casing. The advantages of using an inner drill pipe string when cementing large diameter casing are:

- Avoids excessive mud contaminations of the cement slurry with drilling mud prior to reaching the annulus
- Allows cement slurry to be added if wash out zones are excessive

Figure 4.10: Shows a sealing sleeve adapter with Stab-In Float collar. [39]

4.7.3 Regular two-stage cementing

Multistage casing cementing is used to cement long casing strings. The two-stage cementing job can be performed in regular casings, and liners. When running a two-stage cementing job in a liner, a special running tool is attached to the end of the drill pipe to connect to the liner. The reason why the cement job is performed in more than two steps is:

- Reduce the pumping pressure of the cement pumping equipment
- Reduce the hydrostatic pressure on weak formations to prevent fracture
- Selected formations can be cemented
- Entire length of a casing string may be cemented
- Casing shoe of the previous casing string may be effectively cemented to the new casing string
- Reduces cement contamination

In addition to the regular two-stage cementing there exists other types of multistage cementing: continuous two-stage cementing and regular three stage cementing. Different setups exist from different vendors. The regular two-stage cementing requires special equipment in addition to regular cementing. It requires the use of stage cementing collar and plugs. The stage collar is located in the casing string in a position where the upper cementing of the casing will take place. The stage collar is a special collar with ports to the annulus that can be opened and closed by pressure operated sleeves. The figure below shows a schematic of a regular two-stage casing cementing operation. [24]

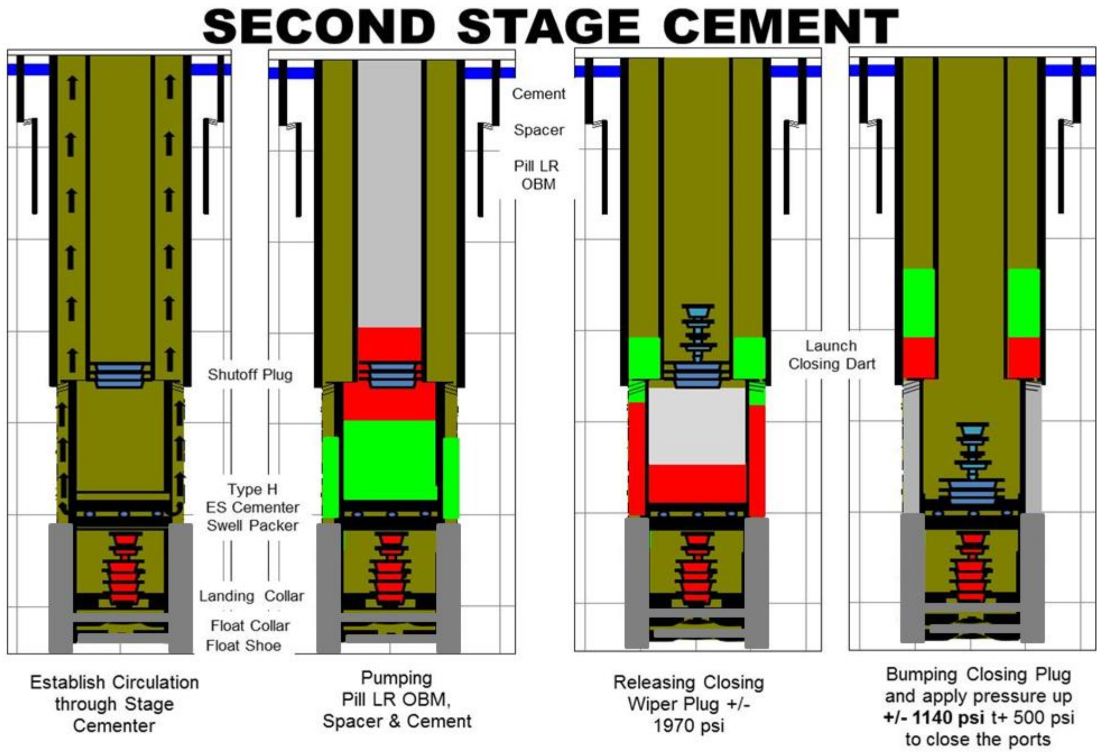


Figure 4.111: Shows the schematics of a two-stage cementing job performed on a liner, after the first-stage cementing job has been completed. First, the stage tool is opened by hydraulic force (pumping pressure), then the second stage cement (light grey color) is mixed and pumped with spacer (red). In this case a mud pill is used in addition in front of the spacer (green color). The closing releasing dart is dropped after the cement, this land in the upper closing cement plug. The plug will be released from the running tool when pressure is added. The cement is displaced inside the liner out to annulus through the ports in the stage collar. The cement plug will land in the stage collar. Then additional pressure is added to close the stage collar. [42]

4.7.4 The two-stage cementing operation:

The first stage (lower section of the casing) of the cementing operation is carried out the same way as a regular one-stage cementing job. The exception is that a wiper plug is usually not used prior the cement. During the first stage cementing the ports in the stage collar is closed. The first stage plug is designed to pass through the stage collar without actuating it. When the first stage plug lands on the float collar or a special designed landing collar, it gives perfect seal and a pressure increase at the surface will indicate that the first stage cementing is complete, and the second stage cementing can now begin. [24,42]

The second stage cementing can begin immediately, or at some later time when the lower section of the well have had time to set. The second stage cementing can be started by dropping an opening bomb that lands in the stage collar or pressure up without dropping any objects to open the stage collar hydraulically.
When the stage collar has been opened the second-stage cement is pumped with displacing fluid in front. When the total volume of the cement has been pumped, a releasing closing dart is launched from the cementing head. The releasing dart will wipe away any cement at the inside of the drill pipe. When the dart reaches the plug which is connected to the running tool, it will latch inn and break some pins. The pins hold the cementing plug connected to the running tool. The plug will be released from the running tool when additional pressure is added (The pins will break). The closing cementing plug is now displacing the cement until it lands in the stage collar. To close the stage collar, pressure is added. [24,42]

Continuous two-stage cementing is an operation where the cement is mixed and displaced without stopping to wait for an opening bomb to actuate the stage cementing collar.
A liner cementing job with stage-equipment will be discussed more in detail under “ Halliburton cementing operation (10 ¾”-Liners) (page 46). [24,42]

4.7.5 Liner cementing

The liner hangs from the previous casing with a set of slips, and does not hang from the wellhead as regular casing strings. This requires the cementing operation to be performed through the drill string. The placing and cementing of liners are some of the most difficult operation in the drilling and completion operation. When cementing a liner some special equipment is used in addition to the regular cementing operation. A liner running tool is used to connect the drill string to the liner. This tool is installed on top of the liner string. The top of the liner hanger makes up to the drill pipe on which the entire liner assembly is lowered into the well. Liner hangers can either be mechanically or hydraulically actuated. The liner hanger is the key element when running the liner in hole and performing the cement operation. After a liner is cemented in to place the upper part of the liner hanger is retrievable (the running tool). This allow for the residual cement to be cleaned out of the annulus between the drill pipe and the previous casing. This is done by reverse circulation when the liner is left in the well. [24]

Regular floating equipment is installed in the bottom of the liner. Sometimes a guide shoe is used with a back-pressure valve, but a float collar can also be used in addition. In addition to the floating equipment, a landing collar is installed in the casing, which gives perfect seal when the cementing plug lands in it. [24]

The plug(s) are pre-installed at the end of the running tool, and darts/plugs are pumped down from the surface cementing head to release them. The dart will land in the cementing plug, and some pins will be sheared as the pumping pressure will increase. The dart will stay inside the cement plug as it displaces the cement. A liner cementing job is very similar to a single stage cementing job, but there is usually only one plug installed in the liner running tool. A liner can also be in combination with stage collar, but then a special plug set needs to be installed in the liner hanger. [24]

After a liner is set, the drill pipe disconnects and re-connect to check the setting tool mechanism of the running tool before the cement job is performed. After the testing of the liner hanger is finished and the upper part of the liner hanger is sealed in place with the running tool, the liner cementing head is installed on the surface. It is also possible to first pump the cement, and then connect the liner to the previous casing. [24]

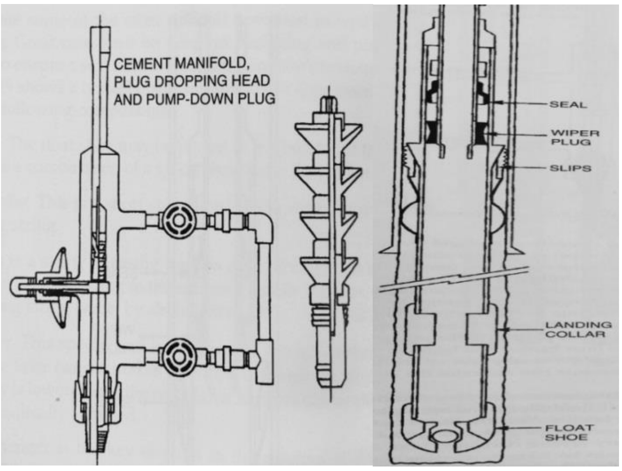


Figure 4.12: Shows the cement head where the releasing dart/plug is installed (left) and a liner which is connected to the previous casing (right). [24]

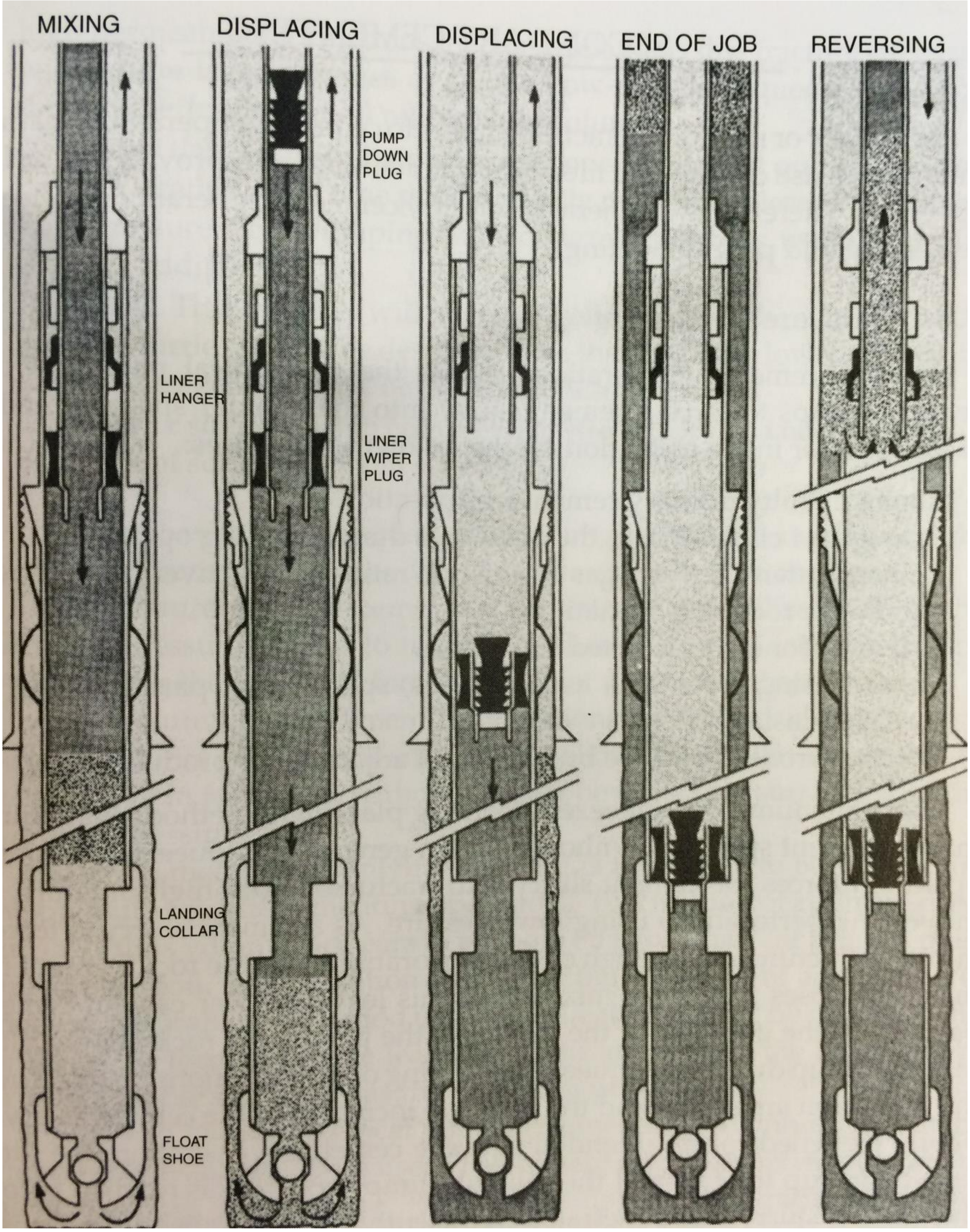


Figure 4.13: Shows the schematics of a liner cement job. From left: circulating, displacing the cement and dropping the dart, the dart lands in the cement plug and is disconnected from the liner hanger, the cement plug lands in the float collar, the running tool retrieves when having reverse circulating as the cement job is complete. [24]

4.7.6 Cementing of wells with subsea wellhead

Cementing of wells which have the wellhead located on the seabed requires a special cementing operation. This cement operation is usually referred to as subsurface cementing or subsea cementing operation. The operation is very similar to the cementing technique used for cementing liners. The operation requires cement to be pumped inside the drill string. An installation tool connects the drill string to the casing, which contains a special plug set. The installation tool contains up to three plugs for multistage cementing, but in this case a two-plug tool will be discussed. [28,29]

On the drill floor there is a cementing head installed on top of the drill string. The cementing head contains dart(s) which will release the plugs(s) in the installation tool when pumped. Foam wipers and weighted balls may also be used to release the plugs. Example on a one-stage cementing job, where subsurface equipment is used [28,29]:

The ball is dropped ahead of the displacement fluid, which is followed by the cement. When the ball lands in the first plug (bottom plug), the force of the pump pressure releases the plug. When all the cement is pumped, the dart is released from the plug container in the cementing head. The dart will wipe the inside of the drill string and separate the cement from the displacing fluid used behind the cement. The dart will fall into the bottom plug and seal and thereafter release it when the pump pressure increases. When the bottom plug reaches the float collar, the ball allows for a bypass mechanism to pump cement through the bottom plug. The displacing continues until the final pressure increase is indicated on the surface, i.e. the top plug with the dart has landed on the float collar and the cement job is complete. [28,29]

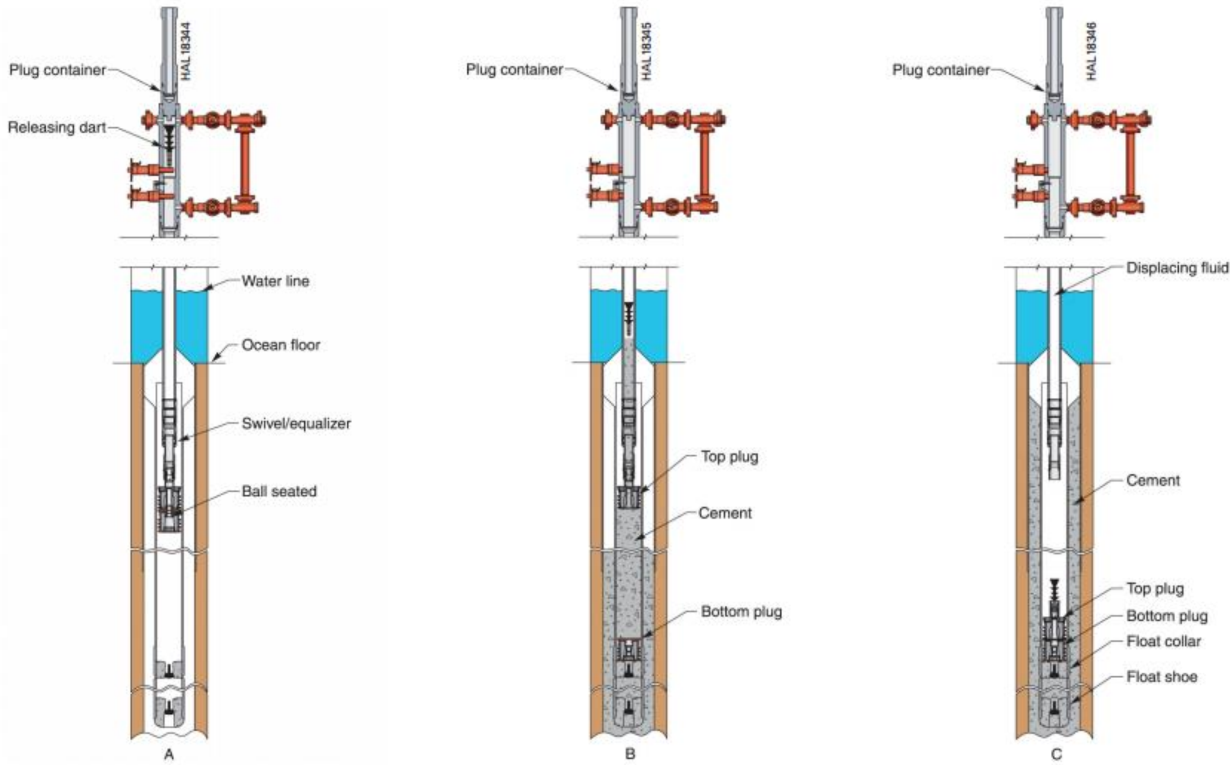


Figure 4.14: Shows the schematics of a subsurface cement job. A; The ball is dropped and seated in the bottom plug, B; Displacing and dropping dart, C; Dart released the bottom plug and is pumped and landed on the float collar. [26]

4.8 Introduction to stage collar

Stage collars are used in multiple-stage cementing. This will allow for different intervals around the casing to be cemented. The multistage cementing jobs can be performed at different times, or in intervals (continuous cementing). The most common multiple-stage cementing technique is two-stage cementing, but three-stages cementing operations also exist.
The stage collars provide a flow path from the inside of the casing out to annulus. This is done by ports that can be opened and closed by sliding sleeves. Different stage equipment exists, and the ports can both be mechanically or hydraulically opened. However, the mechanically operated stage collar will need hydraulic forced to open/close. The mechanically operated stage collars uses opening plugs that are dropped and seats in the stage collar. [16-18,40]

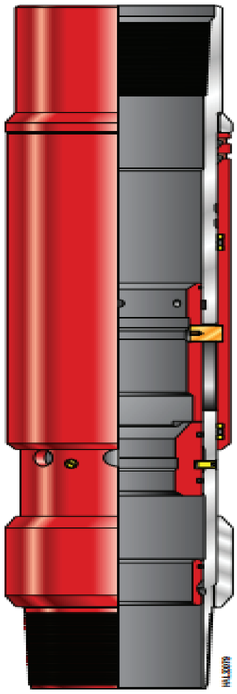


Figure 4.15: Halliburton Type P ES II Stage collar. [41]

When performing a cementing job, the hydrostatic head of the cement slurry will increase as the cement is displaced in annulus. If the formation is very weak, the length of the cemented interval cannot exceed a critical value. The formation will fracture and the length of the cemented area will not be sufficient. Light cement can be used to increase the length of the cemented interval, but for some situations a multiple-stage cement job is required. A more detailed cementing operation with stage collar will be described on the next pages.
Multiple-stage cementing is recommended for the following circumstances [16-18,40]:

- The hydrostatic head of the cement is greater than the fracture pressure in some intervals, but not in other intervals
- In deep wells, where the time to pump a sufficient quality and quantity of the cement is limited.
- In wells where only particular zones requires zonal isolation
- In horizontal wells, where the build section requires cementing
- In wells where the conditions requires different slurries to be pumped and make zonal isolation for each interval.

Chapter 5

Halliburton cementing operation (10 ¾”-Liners)

This thesis will focus on the shoetrack drill out of 10 ¾ “liners drilled by one of the major operator in Norway. The equipment found in the liners will be common for each drill out. The cementing operation description will therefore focus on this specific operation, to give the reader a better overview of the equipment used and job sequence. A short summary for running the liner, cementing the liner and setting the liner hanger will also be described. The running and setting of the liner will be common for the two described operations. The liner hanger used in these operations is a VersaFlex liner hanger. [42]

Two main cementing operations will be discussed here:

- Single stage cementing of 10 ¾ “ liners
- Two-stage cementing of 10 ¾ “liners with use of stage equipment.

5.1 Running the liner

The liner assembly is lifted up to the drill floor with the rig crane. It is thereafter connected to the liner. The VersaFlex plug set is preinstalled in the running tool, which is connected to the drill pipe. The liner and liner hanger is pumped through to ensure circulation. Drill pipes are connected when the liner and liner hanger is being tripped down the well. Caution should be taken when running the liner through the BOP and wellhead. Every 5-10 stand with drill pipe is being filled with drill mud. The load taken in the derrick (hook load), should be compared to the calculated values from simulations, this to ensure that there is not any extra unexpected forces acting on the system.
When the liner has reached bottom, some test are performed, which including torque and weight testing. The cement head is installed on the drill pipe and the dart(s) is already preinstalled. Contingency plans and recommendations are also available when running the liner. [42]

5.2 Single stage cementing (10 ¾" liner)

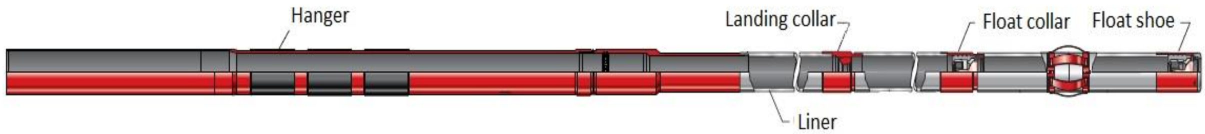


Figure 5.1: 10 3/4" VersaFlex liner hanger. [42]

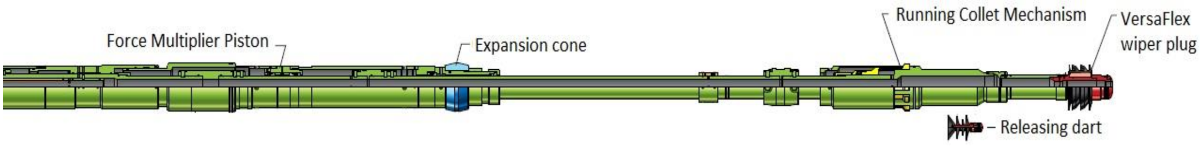


Figure 5.2: Running tool for VersaFlex liner hanger. The running tool has a crossover (not shown here), from the running tool to the drill pipe. The running tool contains the VersaFlex plug set in the end of the running tool. [42]

This operation will be common for all the single stage 10 ¾" liner cementing jobs studied. These wells will later be studied for shoetrack drill out. The equipment showed here will is the same for every well studied.

5.2.1 Cementing the liner

The cementing of the liner starts after running the liner is completed. Before the cementing operation starts a toolbox meeting is held. The cementing procedure is reviewed and all the responsible personnel are involved. The cementing head lines are rigged up and pressure tested. Pressure data systems are also rigged up, these systems can record pressures with 1 second intervals, during the liner hanger expansion and pumping operation. Circulation of the well starts, the circulation takes place until the shakers are cleared and any gas has stabilized. A circulation of one bottom up is required. When pumping through the VersaFlex plug set, the rate should not exceed a critical value of xx bpm/min and gpm for x hours.
The liner should be at least 1 meter off the bottom before the cementing operation takes place. The cement and additives are now being mixed. [42]

The cement is pumped through the cement head with displacing fluid. When all the cement volume has been pumped the dart is released from the cementing head. The dart is displaced with mud. It is important to verify that the dart has left the cementing head. When displacing, a fixed pump rate is used. The pumping continues until the dart engages the wiper plug. The wiper plug will shear with 1350 psi/93 bar with (+- 10%) differential pressure. The wiper plug shears some pins, which attached the plug to the running tool. The dart is now seated in the wiper plug, and the displacement continues down the liner. After the plug shear, it is not recommended to pump no more than ½ the shoetrack volume over calculated displacement. The pump rate is decreased prior landing the plug in the landing collar. When the plug is landed, an additional pressure of 500 psi/35 bars is added to the pumping pressure. The pressure is held for 5 minutes to ensure that the plug is holding. The pressure is released and the floating equipment is checked. The eventual total backflow is measured and reported. The next step will be to set the liner. [42]

5.3 Two stage cementing (10 ¾" liner with stage equipment)

In addition to the single stage cementing, the two stage cementing operation uses some additional equipment. The running tool and liner will have the same setup, but the plug set in the end of the running tool will contain 2 wiper plugs. During the cementing operation there will therefore be need for two releasing darts. The two stage cementing operation will also need a stage collar. [42]

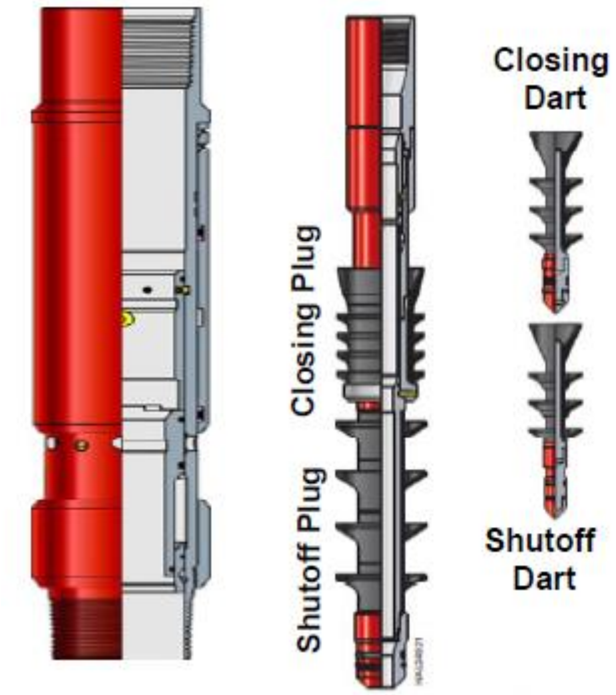


Figure 5.3: The plug setup (Type II SR Plug Set) and stage collar (Type H ES II) used for two stage cementing. [42]

Technical information about the stage equipment:

<u>10-3/4" 65,7# Stage Cementer Tool Type H ES II</u>

- Type H is hydraulically operated.
- Length: 42 inches.
- Drill out ID: 9.524 inches
- Maximum OD: 12.25 inches.
- Burst and collapse pressure: 8887 psi.
- Tensile Strength: 2045340
- Torque: 50000 ft-lbs
- Opening Pressure: 2000 psi, 5 shear pins.
- Closing Pressure: 1140 psi, 6 shear pins.
- Maximum External Force to apply: 65000 lbs.
- Guide Pins Shear Pressure: 1800 psi.
- Internal Seat Retainer Shear Pressure: 2800 psi
- Maximum pump rate: 12 bpm
- Nozzle size: 1 inch
- Quantity of circulation holes: 6
- Total flow area: 4.71 sq.in
- PDC drillable.

5.3.1 Cementing the liner:

5.3.2 First-stage cementing

The first stage cementing will be common for the single-stage cementing operation. The critical aspect with the first- stage cementing, is not to use high pumping pressure, 1000 psi should not be exceeded during pumping, this to avoid prematurely activation of the stage equipment which is hydraulically operated. [42]

After the first- stage cementing is completed; the well will look like this:

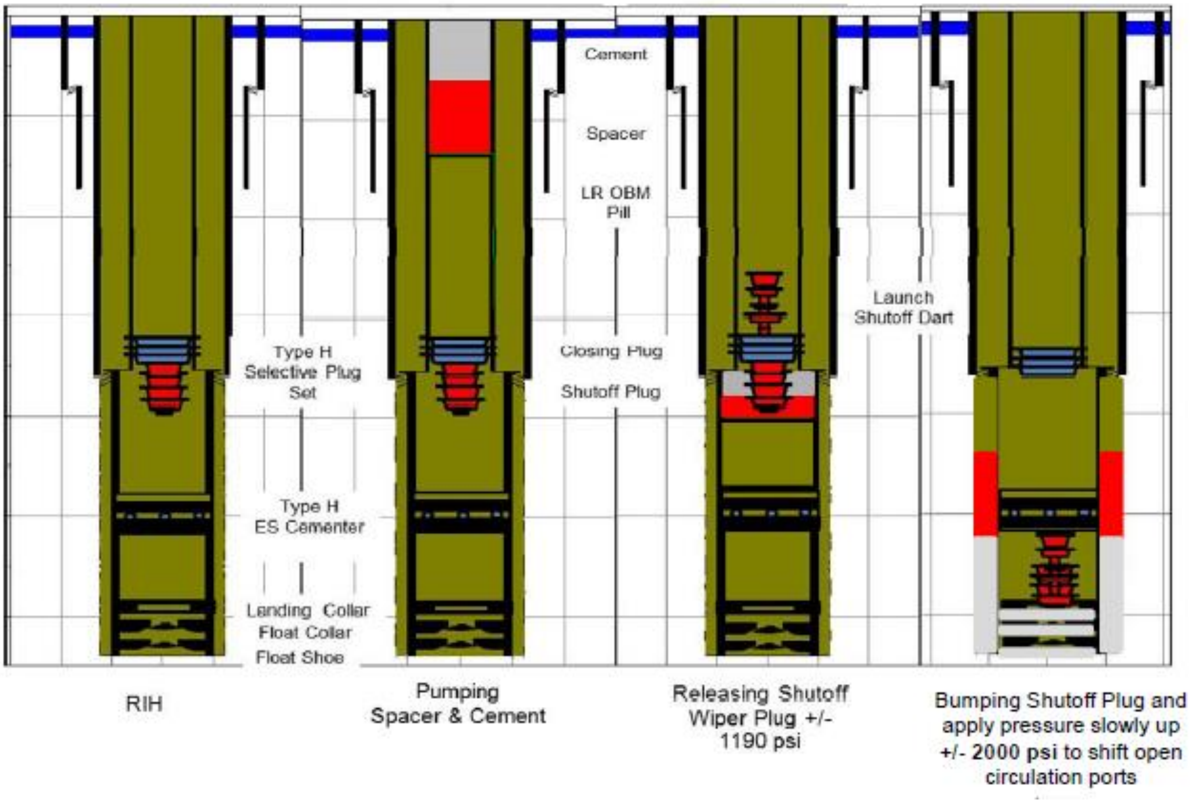


Figure 5.4: The placement of fluids and equipment after a completed first stage cementing operation. The first plug is seated in the landing collar and one plug remains in the running tool. The grey color indicates cement, red is spacer (displacing fluid) and brown color indicates drilling mud. [42]

When the first stage cementing is completed the floating equipment is checked. The next step is to open the stage collar. The cement unit is set to 1 bpm, and the pressure is slowly increased to 2000 psi (+- 10%), this will shear the 5 pins in the stage collar, and the sleeves will move and circulation through the ports is achieved. The circulation is kept low to reduce the equivalent circulating density (ECD) on top of the first cement column. High circulation will increase the ECD and might tend to fracture the formation under the cement column. The circulation continues until the first-stage cement has reached sufficient compressive strength. A UCA (ultrasonic cement analyzer) cell is put on when the first-stage cement job starts. The crew can now see when the second-stage cementing operation can start, in order to not destroy the formation with the casing shoe. A compressive strength of 50 psi is needed until the next cement can be pumped. This is sufficient to avoid disturbing the formation where the first-stage cement job took place. [42]

5.3.3 Second-stage cementing:

Mud and spacer is pumped in front of the cement. The cement is displaced through the ports in the stage collar and continues up in the open hole between the liner and formation. When all the cement volume is pumped the closing releasing dart is launched from the cementing head. The pump rate is decreased before expected landing in the "closing" wiper plug. The dart seats and the pump pressure is increased to around 1970 psi in order to shear the pins and release the closing wiper plug. The cement is displaced and the closing wiper plug will land in the stage collar. The final circulation pressure is noted, and an additional pressure of 1140 psi is added. After this, an additional 500 psi is added and held for 2 minutes. The pressure will shear the 6 pins inside the stage collar, and a sleeve will cover and close the circulation ports in the stage collar. After the plug is landed and the stage collar closed the pressure is released and the system is controlled for u-tube effects. [42]

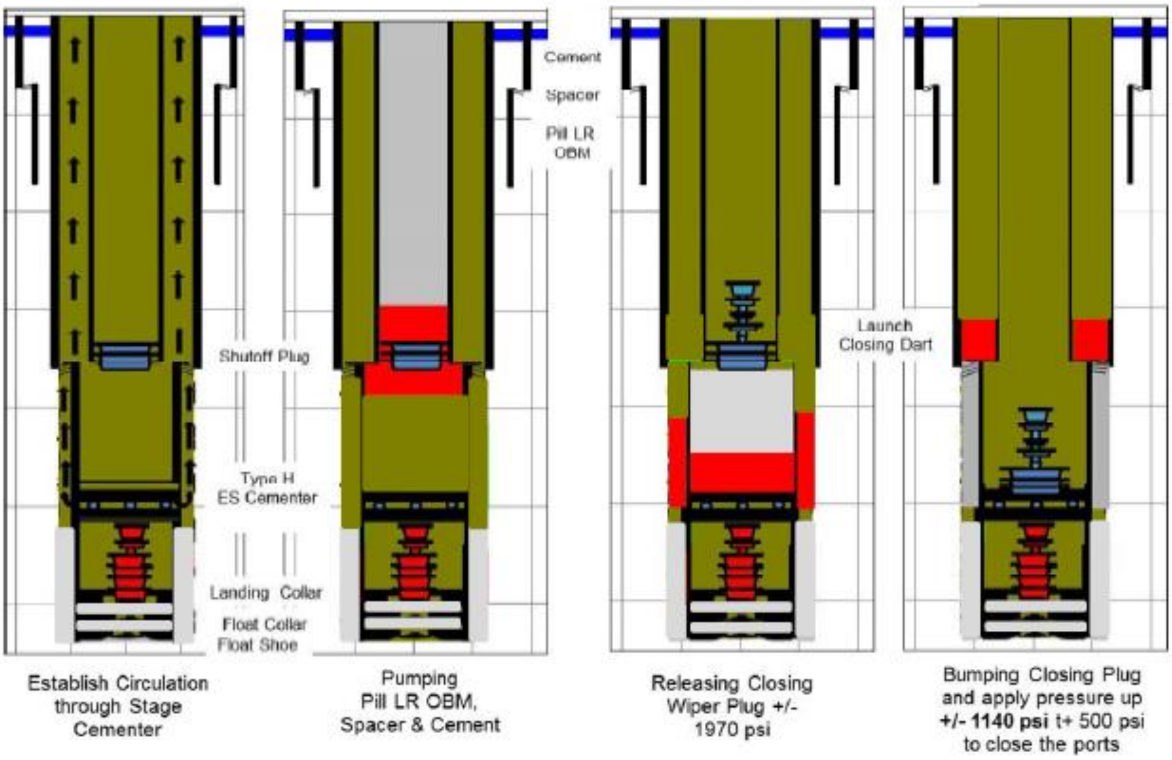


Figure 5.5: Shows the schematics of the second stage cementing. Fluid color description: Spacer (red), cement (grey) and mud (brown). [42]

5.4 Stage collar: Opening and closing pressure plots

5.4.1 Opening of the stage collar

This plot shows the displacing of the first-stage cement and opening of the stage collar. The first-stage cement is displaced into annulus (almost constant pressure). When the plug lands in the landing collar, the pressure will increase, because the liner is now a closed volume. After this the well is checked for backflow (check of floating equipment). Further, the pressure is increased to open the ports in the stage collar. A slower circulation rate is used (as the green line indicates: "Total flow"). The circulation is continued (waiting on cement), until the compressive strength is sufficient to pump the second-stage cement. [42]

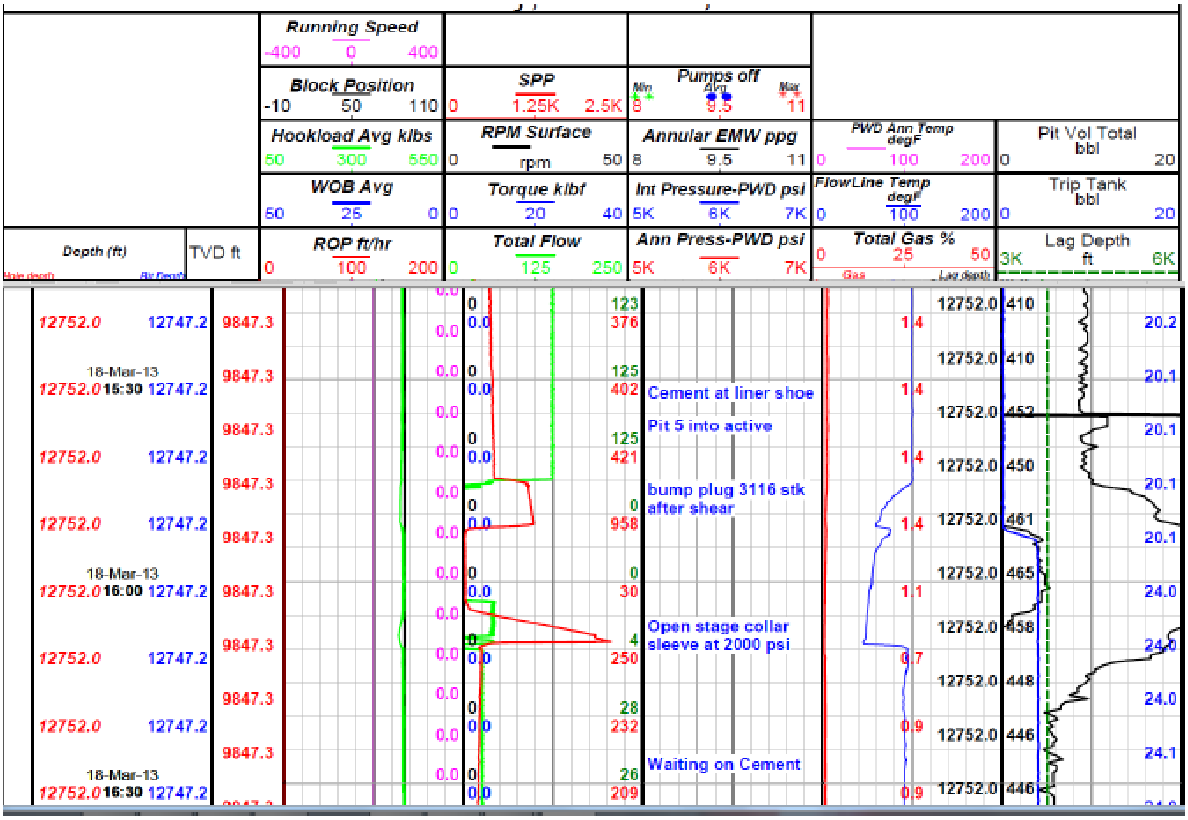


Figure 5.6: Shows the operational parameters for the well. SPP: Stand pipe pressure, which is the pressure added from the drill floor. The plot shows the displacing and landing ("bumping") of the first plug, and the opening of the stage collar. The graph has the newest plots at the bottom, and the oldest starting at top. The time is given in the left column of the plot. [42]

5.4.2 Closing the stage collar

The plot below shows the displacing of the second-stage cement and closing of the stage collar. The pumping continues until the closing plug lands in the stage collar. The pressure will increase when the plug lands, and some additional pressure is added. The pressure is bled off, and the stand-pipe-pressure (SPP) and total flow goes down to zero. This will indicate that the stage collar is closed. [42]

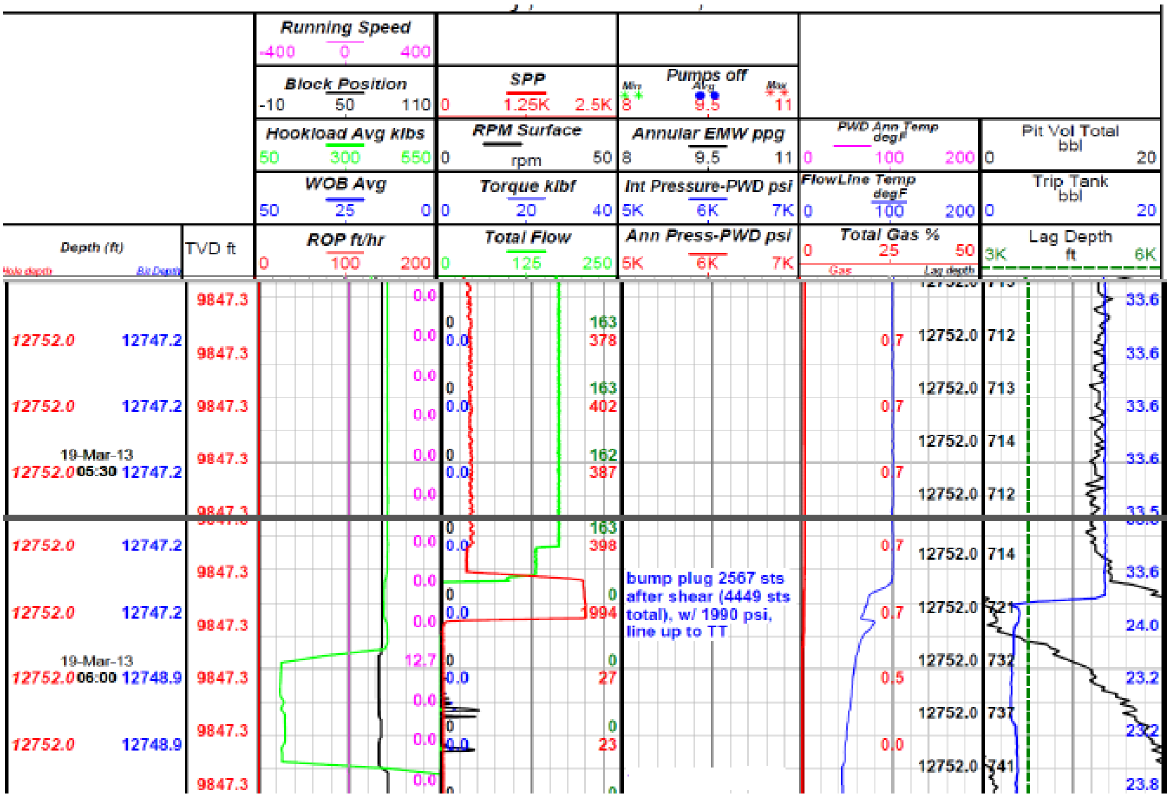


Figure 5.7: Shows the schematics of landing the closing plug and closing the stage collar. [42]

5.4.3 Setting the liner

This operation is common for the two cementing jobs discussed. First the crew needs to be sure that the running tool is in tension before expanding the liner. When pressure is added a flapper will close inside the running tool (see figure below). The pressure is then bled off.
After this more pressure is added, some sleeves will slide inside the running tool, and the hydraulic force will be transmitted through channels, which will engage the piston. The pump pressure will be the hydraulic force, which will push the cone downwards. The cone will slide on the outside of the running tool. The red arrow on the figure below shows the hydraulic chamber which creates the hydraulic forces pushing the piston. The expansion cone will slide down the hanger and push out the hangers. The hangers will expand as the cone slides downwards. The hangers will attach to the outside casing, which is already set. When the piston has expanded all the hangers, it will reach its final position. When the piston reaches its final position, some channels will be opened. The flow will now be directed to annulus, through the expansion bypass. This will give pressure indication at the surface that the liner hangers are fully expanded.
The liner is tested with overpull, to ensure that the liner is set. To release the running tool, slack off weight is used (releasing the tension). The running tool disconnects from the liner and can be retrieved to the surface. [42]

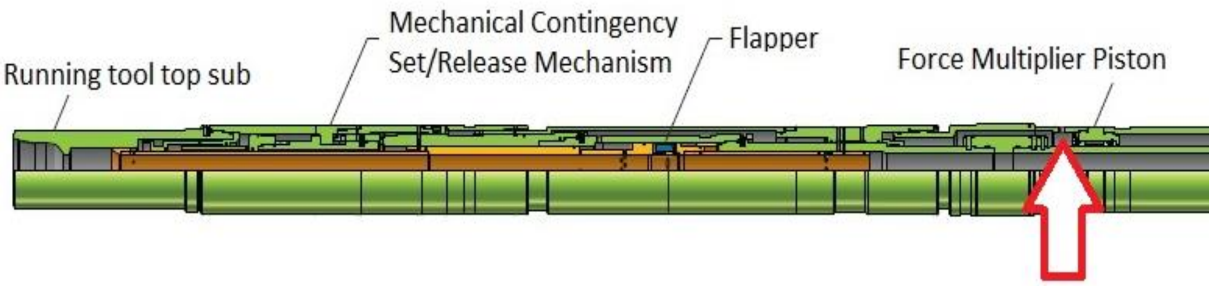


Figure 5.8: Shows the upper part of the VersaFlex liner hanger running tool. The red arrow indicates where the mud will flow after the flapper has been closed. The pumping action will force the piston downwards, extending the expansion cone. The expansion cone will expand the liner hangers.[42]

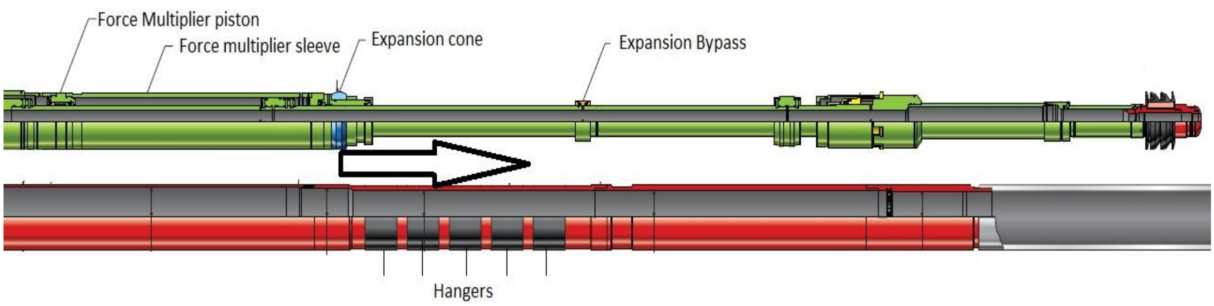


Figure 5.9: Shows where the lower part of the running tool is located inside the liner hanger. The expansion cone will be pushed by hydraulic forces, expand the hangers, and attach it to the casing which is located on the outside. The plug on the running tool will not be attached to the running tool when the liner is set, it is just included to give a better overview of the setup. [42]

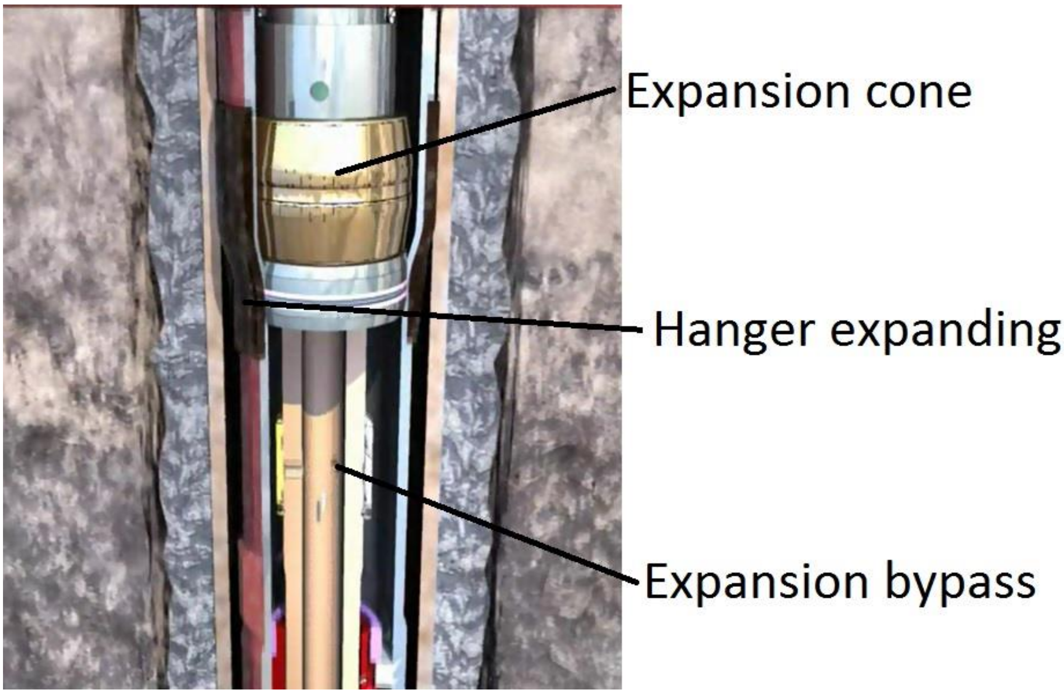


Figure 5.10: Showing the expansion cone being pushed downwards and expanding the hangers. The hangers will expand and attach to the previous casing. [43]

Chapter 6

Drill bits

The drill bit is the major tool that performs the cutting action at the bottom of the drill string. The drilling is driven by scraping, chipping, gouging or grinding the rock as the bit rotates. Drilling fluids are circulated through the nozzles in the bit to remove cuttings generated when removing drilled formation. [5]

Many bits exist for different applications; selection of the bit depends on the type of formation being drilled and the operating drilling conditions. Factors determining the performance of the bits are several, this includes factors as: weight on bit (WOB), drill sting rotations per minute (RPM), hydraulics and properties of the drilling mud. [5]

Halliburton Drill Bits & Services offers a wide variety of both PDC (Polycrystalline Diamond Compact) bits and roller cone bits. Each bit type has its own drilling application. The bits are optimized using the DatCL process. [3]

6.1 Halliburton's bit design process: Design at the Customer Interface (DatCI^{SM}) Process

With different applications around the world, there is no one-size-fits-all solution. Every well is unique. The (DatCI^{SM}) process takes that into account. Halliburton Drill bits & Services (HDBS) has highly trained Application Design Evaluation (ADE^{SM}) service specialists in locations around the globe. This gives Halliburton the advantage to work directly with the customers to design application-specific solutions. [1]

In combination with local knowledge and some of the industry`s most powerful software, the specialists can design drill bits and tools which correspond to the customer's needs.
When the designs are complete they are sent directly to manufacturing, where drill bits are rapidly produced within industry-best cycle times. Halliburton's DatCI process has made Halliburton the market leader in drill bits in North America. [1]

The DatCI^{SM} process is a continuous improved loop driven by Halliburton's ADE^{SM} service specialist to define drill bits which have specific applications for a specific well; this is done via well planning. This proprietary drill bit optimization process uses the industry`s most powerful software tools, and enables the specialist to predict the optimal bit performance and design for different objectives. The specialist analyzes formation properties to precisely define the application, and then optimize the bit design for that application. [1]

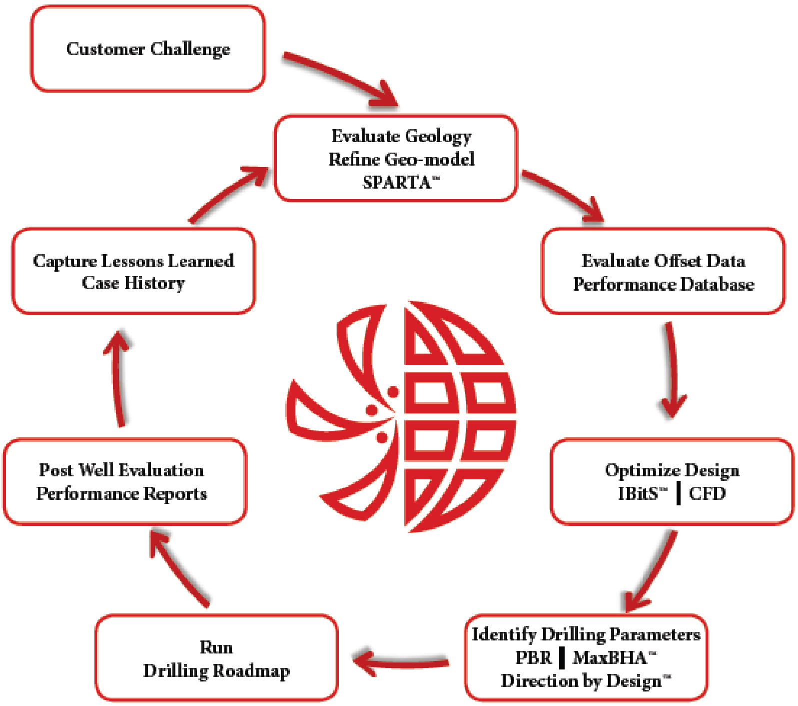


Figure 6.1: The improvement loop of DatCI process. [1]

6.1.1 SPARTA^{SM} Software

Scientific Planning and Real Time Applications

The SPARTA software is a tool which delivers advance rock strength analysis and modeling. This information helps the team to optimize drill bit selections and drilling parameters. The software helps to generate an anticipated map of the geology. This map can gives good assistance when plotted against offset wells. It can also be utilized for post-run evaluation to identify future bit selection and operation parameters. When running a multi-well-drilling program the SPARTA process enhances the DATCI process, which leads to reduced overall drilling cost. [1]

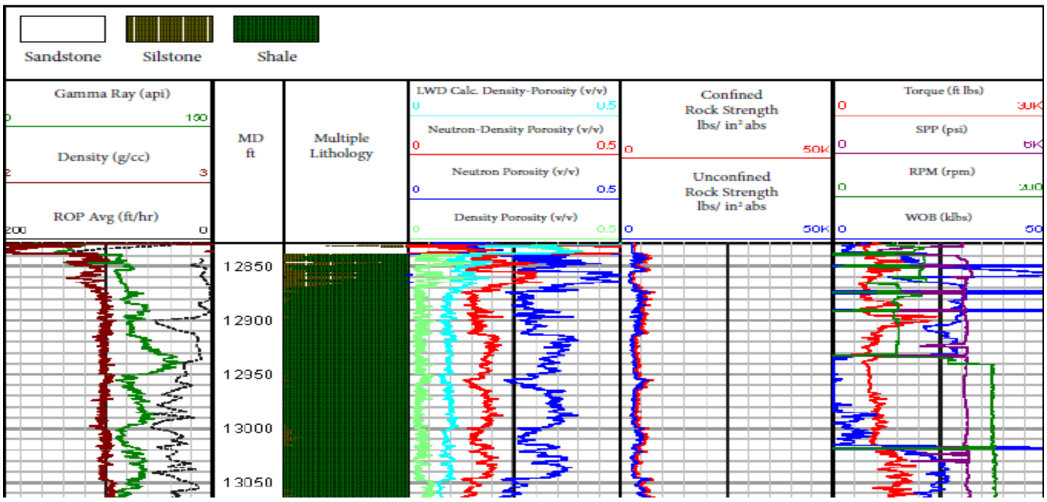


Figure 6.2: Shows different well logs and the optimized drilling parameters for each section. [1]

6.1.2 *Direction by Design™ Software*

This software provides Halliburton the advantage of optimizing the bit design in directional drilling. Evaluating the bit behavior depends on the understating of how the bit interacts with the bit design and the formation properties. The ADE℠ specialists use a wide variety of inputs such as BHA configurations, operating parameters, hole geometry and formation characteristics to make a specific bit design for the customer. Halliburton also takes the connection between the bit design and how the impact affects the directional deliverables. This gives the ideal combination of steerability, stability and aggressiveness for the application. Different parameters are evaluated in the software to create the best optimization for the given drilling condition, this include bit geometry, steerability, bit torque, and walk rate. To combine the bit to the directional application gives an optimized drilling. The results are fast and responsive directional drilling. [1]

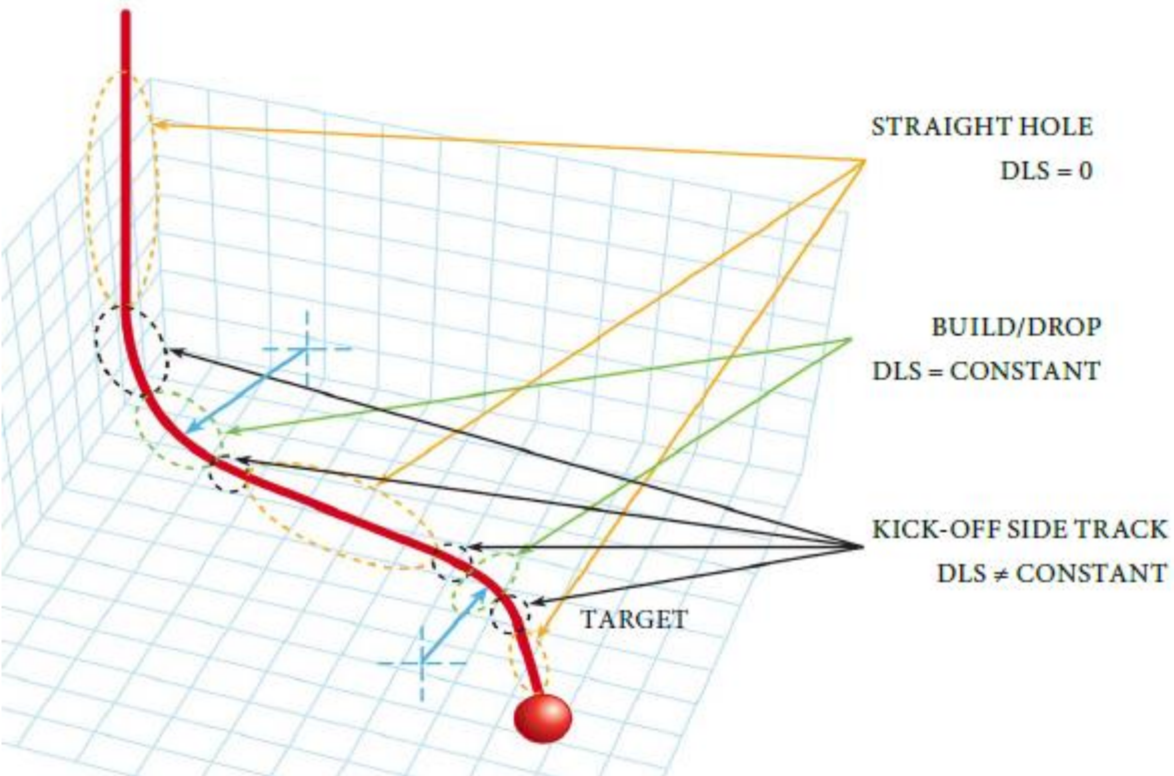


Figure 6.3: Figures showing the directional trajectory of a well. The specialist can isolate different zones to focus on directional performance that are important for each zone. [1]

6.1.3 IBitS^{TM} Software

Interactive Bit Solutions

This software is used by the Applications Design Evaluation (ADE) service specialists to optimize the bit selection or design for a new bit for a specific application. Given the drilling parameters HDBS can design the optimized bits with the highest performance by simulating the forces which will act on the bit under specific drilling parameters. The software takes parameters as torsional, axial and lateral forces on each cutting structure into account. This is simulated on different cutting structures, geometry and space position on the bit face. The sum of these forces is displayed as an output to indicate how the bit will perform in the given application. [1]

6.1.4 MaxBHA^{TM} Design Software

This is an integrated BHA modeling and drilling optimization software for a wide range of applications, such as directional drilling, vibration reduction, survey improvement and tool design optimization. This software can also be used for well planning, real-time optimization and post-run analysis. [1]

The ADE service specialists run the software with drill bit and reamer design to gain insight on bending forces and to determine the critical rotary speeds for the BHA. The software extends bit and reamer life by finding the optimal run parameters that will reduce vibration and increase the tool reliability. [1]

6.1.5 Performance Database

This is a global software system used to capture and analyze the bit performance data. The system is constantly updated with new bit runs. This allow HDBS to quickly and efficiently analyze the bit performance and give the customers detailed reports. This database gives HDBS the ability to understand the challenges and see trends of good products. This gives the development team good feedback in order to constantly evolving and improving products. [1]

6.1.6 Energy and force balancing technology

Halliburton has done a lot of research work on how to balance energy and forces action on the bit. A drilling simulator is used to determine the interactions between the bit and the formation. This allows for force and energy calculations. That way, more of the weight on bit goes down on the formation instead of being translated back to the drill string. [3,4,7]

Force and energy balancing technology offers more stability when drilling. The technology reduces vibrations and extends the bit life. When reducing vibration it also protects other sensitive tools in the drill string, such as MWD (Measurement while drilling) components. More stability will lead to less risk for unplanned trips and it also reduces non-productive time, which is a big benefit for Halliburton`s customers. [3,4,7]

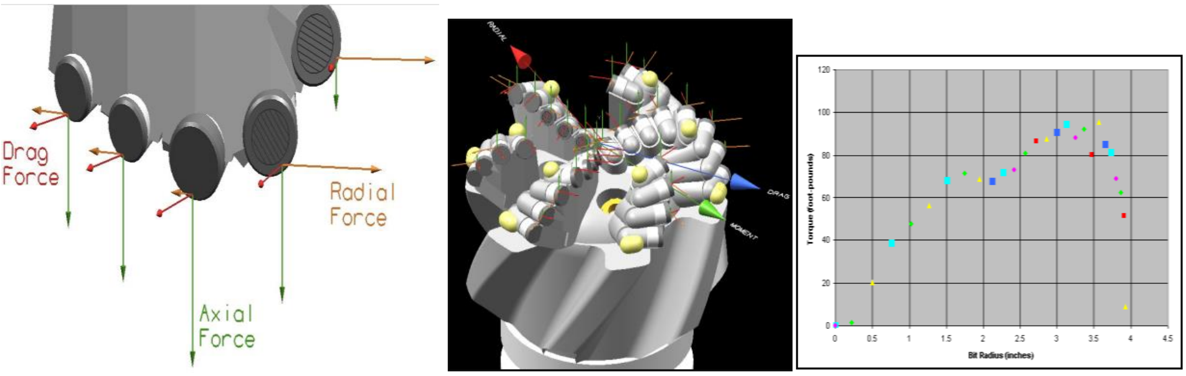


Figure 6.4: Shows the forces acting on the PDC bit (left) and the torque acting on each cutter (right). [7]

For PDC bits the force balancing is carried out until the radial and drag force are zero. The forces should be maximized axially (downwards). By doing this, it reduces the risk of lateral movements and vibrations. By looking at each cutter, one by one, the torque can be determined. The bit design is designed until the torque is smooth over the entire radius of the bit. The figure above shows that the PDC bit does not have a smooth graph and the energy will be transmitted differently over the bit radius. [3,4,7]

In the balancing technology of roller cone bits it is important to get equal force distribution over the cones. By doing this it will extend the bearing/seal life, increase ROP, reduce vibrations and give a better directional responsiveness. The balance technology wants to achieve balance between: weight acting on each cone, moment, and bearing load. This will equalize the rock formation volume for each cone. [3,4,7]

Figure 6.5: At left the roller cone is imbalance, and the cones bear more load than others. By using the balance technology, balance is achieved among all the cones. [7]

6.1.7 Anti-tacking

Halliburton energy balanced bits makes use of a feature called “anti-tracking”. Tracking is the phenomena when the cutting elements will continue to hit the existing craters as the bit rotates. This will lead to an inefficient cutting action, and it will have a decreased penetration rate. The anti-tracking system will make the cutters orientated in a way so the cutting elements will constantly drill new formation instead of hitting the existing craters. [12]

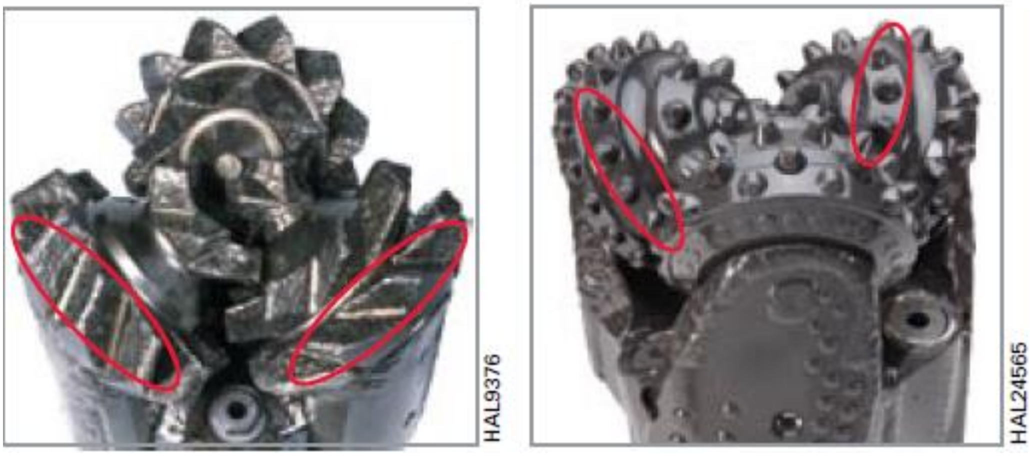
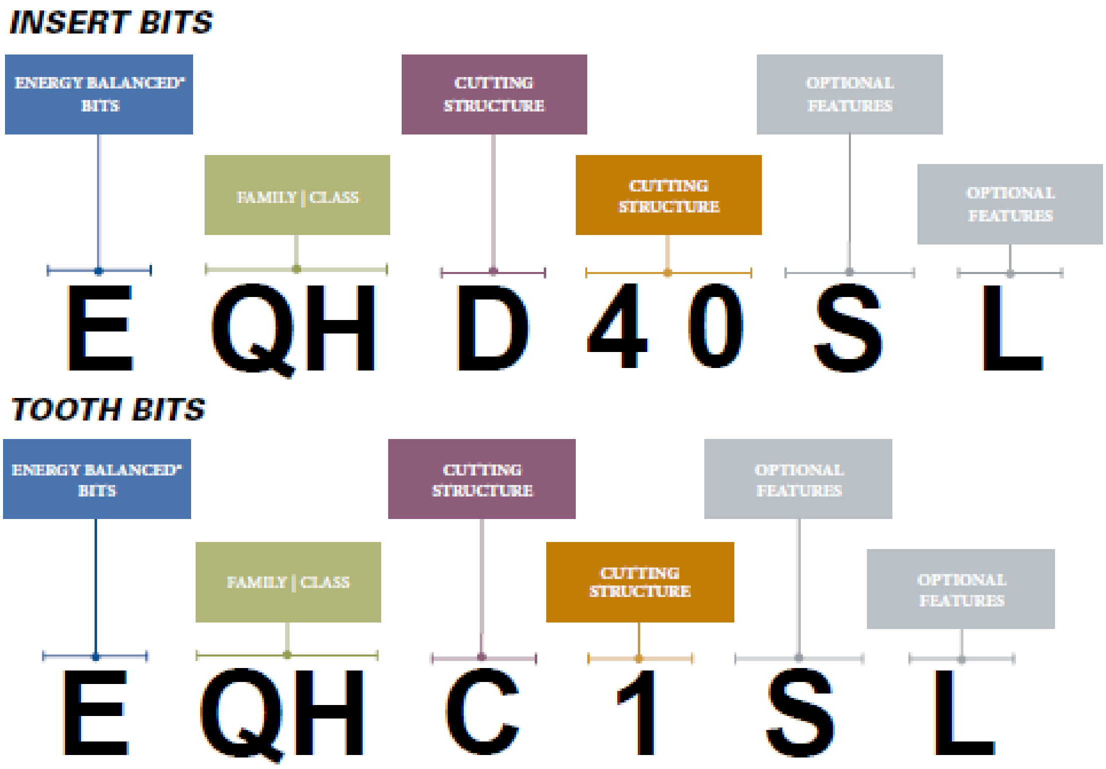


Figure 6.6: All of Halliburton steel tooth bits make use of this feature in the gauge row. The orientation angle on the gauge row is different on at least one cone (left). For insert bits (right) the adjacent inserts on the same inner rows are offset from another. These changes will prevent the cutters from hitting the same craters when rotating, but instead penetration new formation. [12]

6.1.8 Nomenclature of Halliburton drill bits



ENERGY BALANCED* BITS

E = Energy Balanced* Bits

FAMILY | CLASS

QH = QuadPack* Plus Engineered Hydraulics Bits (4-1/2" through 13-1/2")

CUTTING STRUCTURE (PREFIX)

C = After Class Alpha for Claw Tooth on Steel Tooth Model
D = For Gauge/Face Diamond Insert on Insert Model

CUTTING STRUCTURE

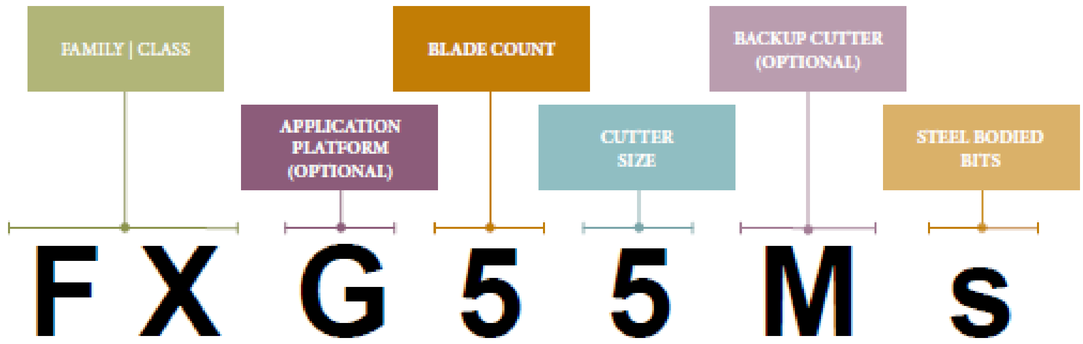
For Tooth Bits Single Numeric Variant From 1 to 7
For Insert Bits Dual Numeric Variant From 00 to 99

OPTIONAL FEATURES

For more information, please contact your local Halliburton Drill Bits representative.

A = Air Application
C = Center Jet
D = Diamond Surf Row (33%)
D2 = Diamond Surf Row (50%)
D3 = Diamond Surf Row (100%)
G = Non-Standard Gauge Row
L = Lug Pads
LD = Diamond Insert Lug Pads
P = Protective Carbide Coating
R = Raised Enhanced Shirttail / Arm Protection
S = Enhanced Shirttail Protection
SD = Shirttail Diamond – Enhanced Protection
RD = Shirttail Diamond – Raised Protection

Figure 6.7: The Halliburton nomenclature for roller cone bits. [1]



FAMILY | CLASS

FX Series™ Drill Bits

APPLICATION PLATFORM (OPTIONAL)

D = Directional (all other directional systems)
G = Geo-Pilot® Rotary Steerable
E = Geo-Pilot® EDL Rotary Steerable
T = Turbine High Rotational Speed

BLADE COUNT

The blade count describes the number of blades on the bit.

3 = Three Blades
4 = Four Blades
5 = Five Blades
6 = Six Blades
7 = Seven Blades
8 = Eight Blades
9 = Nine Blades
0 = Ten Blades
1 = Eleven Blades
2 = Twelve or More Blades

CUTTER SIZE

The cutter size digit describes the size of the PDC cutters on the bit. On bits with multiple cutter sizes, the predominant size is described.

2 = 8 mm | 3/8"
3 = 10.5 mm | 13/32"
4 = 13 mm | 1/2"
5 = 16 mm | 5/8"
6 = 19 mm | 3/4"
8 = 25 mm | 1"

BACKUP CUTTER (OPTIONAL)

D = Dual Row Backup
M = Modified Diamond Round
R = R1™ Backup Cutters
I = Impreg Backup Discs

STEEL BODIED BITS

s = Steel Bodied

OPTIONAL FEATURES

Not listed in nomenclature but found on marketing spec sheet. For more information, please contact your local Halliburton Drill Bits representative.

b = Back Reaming
c = Carbide Reinforcement
e = SE - Highly Spiraled
f = Full PDC Gauge Trimmers
k = Kerfing - Scribe Cutters
p = PDC Gauge Reinforcement
u = Updrill

Figure 6.8: The Halliburton nomenclature for fixed cutter bits. [1]

6.2 Roller cone bits

A roller cone bit is a tool designed to crush rock efficiently while incurring a minimal amount of wear on the cutting surfaces. The roller cone bits consist of one or more conical cutters or cones that have spiked teeth around them. When the drill string rotates, the bit cones roll along the bottom of the hole in a circular motion. The cones are rotated around their own axis with the help of bearings. As the cones roll, a new tooth comes in contact with the bottom, crushing the rock around the bit tooth. The bits drill by a chipping/crushing and/or gouging/scraping the rock. There are two main types of roller-cone bits, steel milled-tooth bits and tungsten carbide insert bits.
[2,3,5]

Figure 6.9: Shows the components of a roller cone bit. [4]

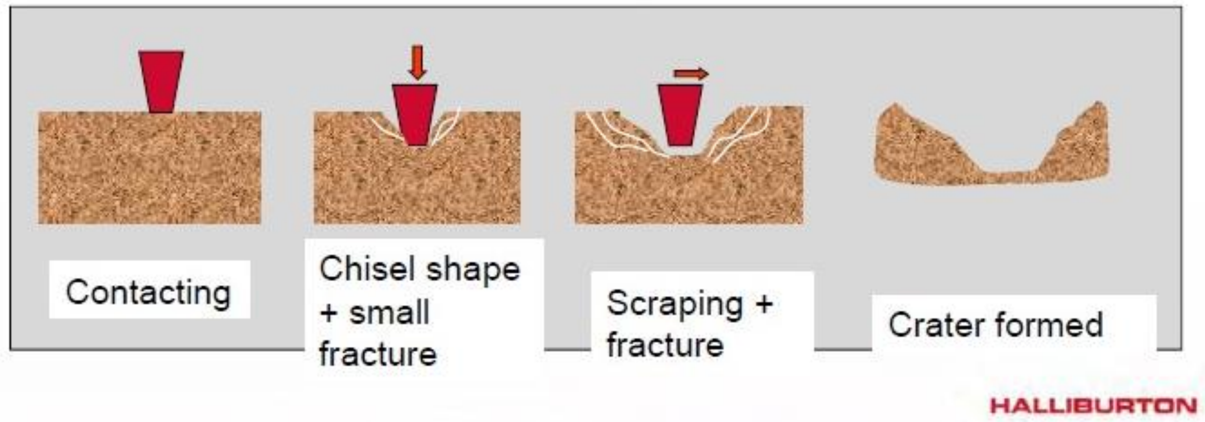


Figure 6.10: The tooth from the roller cone comes in contact with the rock. The vertical arrow indicates the crushing action. The horizontal arrow shows the scraping action. The end product of these forces acting is a crater. [4]

6.2.1 Tungsten carbide insert bits

These bits have tungsten carbide inserts that are pressed into the steel cone and kept in place by the interference fit and the resulting hoop stress keeping it in place. The holes drilled in the cones are very precise both in diameter and location. The bit teeth are individually fabricated from various grades of tungsten carbide before pressed into the cone. The shape and size of the insert will vary after the application of the bit. Long chisel shaped teeth are designed for drilling in soft formations, and short and rounded inserts are better when drilling hard rock formations. [3,4]

Figure 6.11: Showing the production of a tungsten carbide insert bit. From left: The holes are drilled in the cone, thereafter the inserts are pressed into the holes. The bit is then mounted to a final product. [4]

6.2.2 Milled tooth bits

Milled tooth bits are made of steel, where the cones and teeth are fabricated as one piece.
The bit is covered with a wear resistant hard facing material. The construction of the milled tooth bits allows for a very aggressive cutting structure, and they are typically used for drilling in soft formations. [3,4]

Figure 6.12: Milled tooth bit. [6]

6.2.3 Lubrication of the bearings

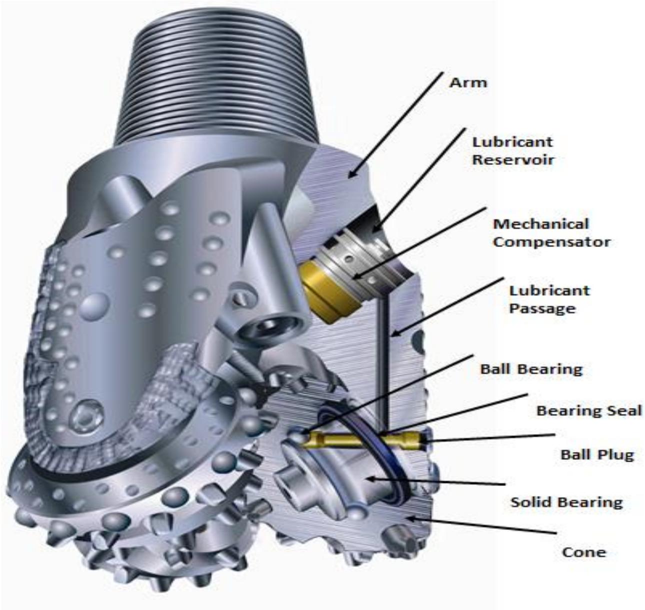


Figure 6.13: Shows the lubrication system of a Roller Cone bit. [4]

The roller cone consists of bearings which makes it easier for the cones to rotate. The bearings are connected to a lubricant reservoir trough a lubricant passage. The reservoir diaphragm will acts as a pressure compensator; the outside pressure will push grease from the reservoir and grease the bearings while equalizing the pressure over the seal. If the pressure is not equalized it can result in damage to the bearing system [4]

6.2.4 Bearings

Many different bearings exist with different applications and sizes. Some bits are more subjected to energy (ROP & WOB) than others. Drilling engineers are pushed to drill the well faster than before, this increases the stresses acting on the bit and have therefore led to designs of the bearings. Models have been made to predict bearing failure, as we will go more into later. [3,4]

6.2.5 Premium double sealed roller bearing

This bearing is available in 8½”-28”. The bearing uses two primary seals with a dual compensation system (patented) for increased bearing life. The compensation system allows the equalization of pressure between the each seal. The life of the bearing is extended by keeping intrusion of cuttings into the inner primary seal. [4]

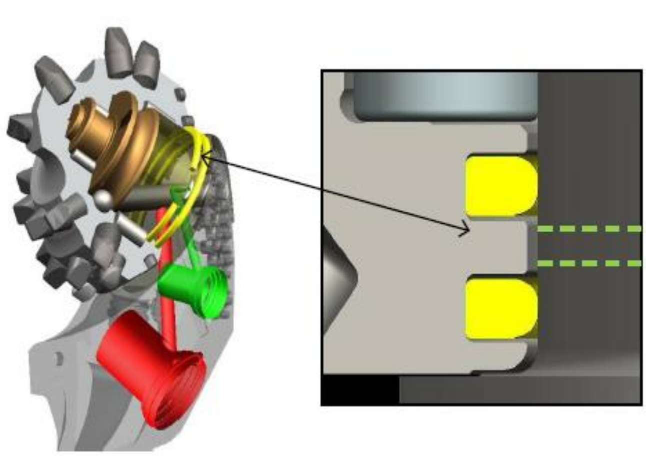


Figure 6.14: Halliburton Premium double sealed bearing. [1]

6.3 Roller cone bit geometry

6.3.1 Offset

When offsetting the centerlines away from the center of the bit rotation, it will produce more action on the bottom which will result in higher penetration rates. The offset is a measure of how much the cones are moved so that their axes do not intersect at a common point on the centerline of the hole. The offsetting causes the cone to periodically stop as the bit is rotated and scrapes the bottom of the hole. This behavior increases the rate of penetration (ROP) in the most formation types, but it also leads to a faster tooth wear. For soft formation the offset is usually between 0,5 and 0,375 inches, and for hard formations it is between 0 and 0,0325 inches.
[4,5].

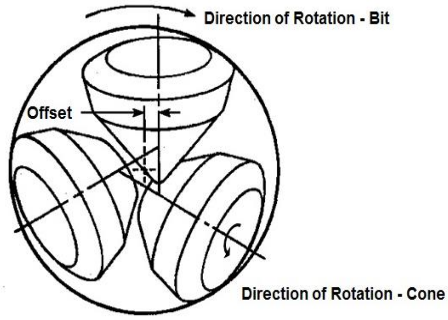


Figure 6.15: Shows the offset in a tricone bit. [4]

The figure above illustrates a positive offset, because the cones are offset in the direction of the rotation. This positive offset will result in an out-thrust load, which is taken on the thrust flange of the bearing. [4]

Figure 6.16: The left bit has a higher offset, which is more adapted for drilling in soft formation. The bit to the right has little or no offset, making it more adapted for drilling in hard formations. [4]

When drilling in soft formation the bits are designed with larger offset to increase the gouging and scraping actions. The action on the formation rock increases the penetration rates on soft and medium formation bits. The medium formation bits have less offset than the soft formation bits. They combine twisting and tearing with crushing and chipping. An increased offset in abrasive formation will decrease the tooth life. A hard formation bit uses little or no offset, breaking the rock primarily by crushing. [4]

6.3.2 Journal (or Pin) Angle

The journal angle is a basic element in the roller cone determining the roller cone contour, cone size and the aggressiveness of the bottom hole profile. The angle is formed between a line perpendicular to the axis of the bit (horizontal) and the axis of the journal. For soft formations the journal angle is ~33°, this allows a more aggressive cone contour and larger cones. For harder formations the angle is ~36° which better supports the flatter cone profiles and improves the arm strength. [4]

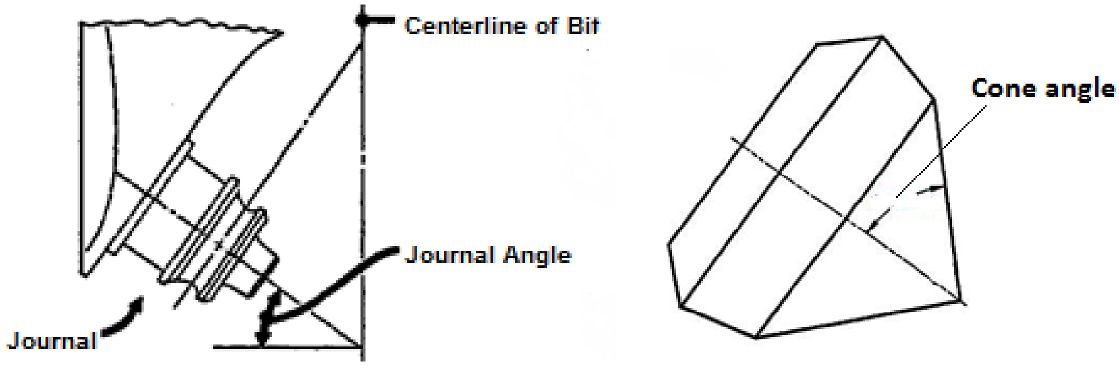


Figure 6.172: Overview of the journal angle (left) and the cone angle (right). [4]

6.3.3 Cone angle

Cones designed for drilling in medium and soft formation have a larger cone angle. This creates an irregular rolling motion that increases the action on the bottom. Cones which are designed to drill hard formations generally have a small angle and they produce a flatter overall bottom hole profile more adapted for a true rolling action. Hard rock formations are best penetrated when using a crushing action; this is obtained with a true rolling action. [4]

6.3.4 Oversize angle

The oversize angle determines the diameter of the cone at the gauge of the roller cone bit. Increasing the oversize angle, will increase the action on the bottom, this making the bit more adapted to soft formations. When increasing the oversize angle combined with a high offset value it will result in a larger degree of reaming by the gauge of the cone. Reducing the angle will reduce the action on the gauge, the cone diameter and the reaming making it more customized for drilling hard formations. [4]

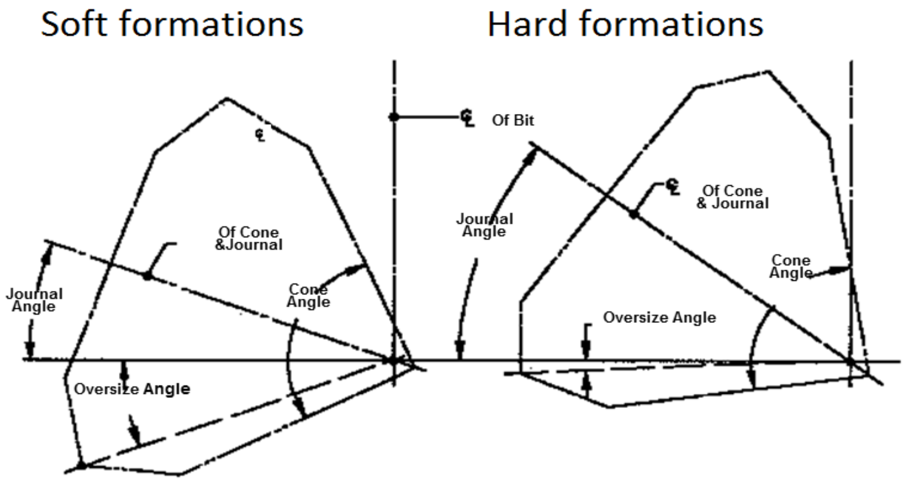


Figure 6.18: Showing the oversize angle for soft formations rocks (left) and hard formations rocks (right). [4]

6.3.5 Projection, Pitch and Intermesh

Projection is the height of the tooth in the roller cone, relative to the cone surface. Pith is defined as the spacing between the tip of the teeth or inserts. The *pitch* allows comparison of cutting element spacing regardless of the positioning on the cone and relative diameters of the rows.
The intermesh is the distance that the peaks of the teeth of a cone extend in the grooves of the adjacent cone. This distance prevent packing of formation between the rows of teeth and allows for maximum tooth length. It also allows for better cutting structure, extended tooth/insert length and a larger bearing size. [4]

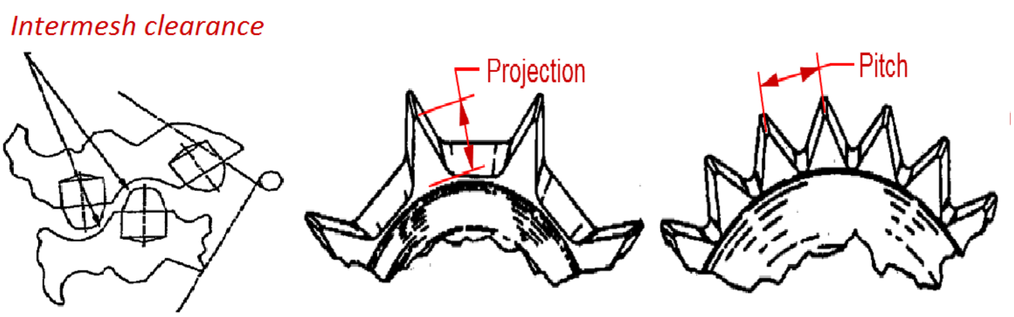


Figure 6.19: From left: Intermesh clearance, Projection and Pitch. [4]

6.4 Roller Cone General Design Characteristic

Given the general information about roller cone geometry, a table is presented below, showing the relation between basic geometry, cutting structure and cutting action relative to formation strength.

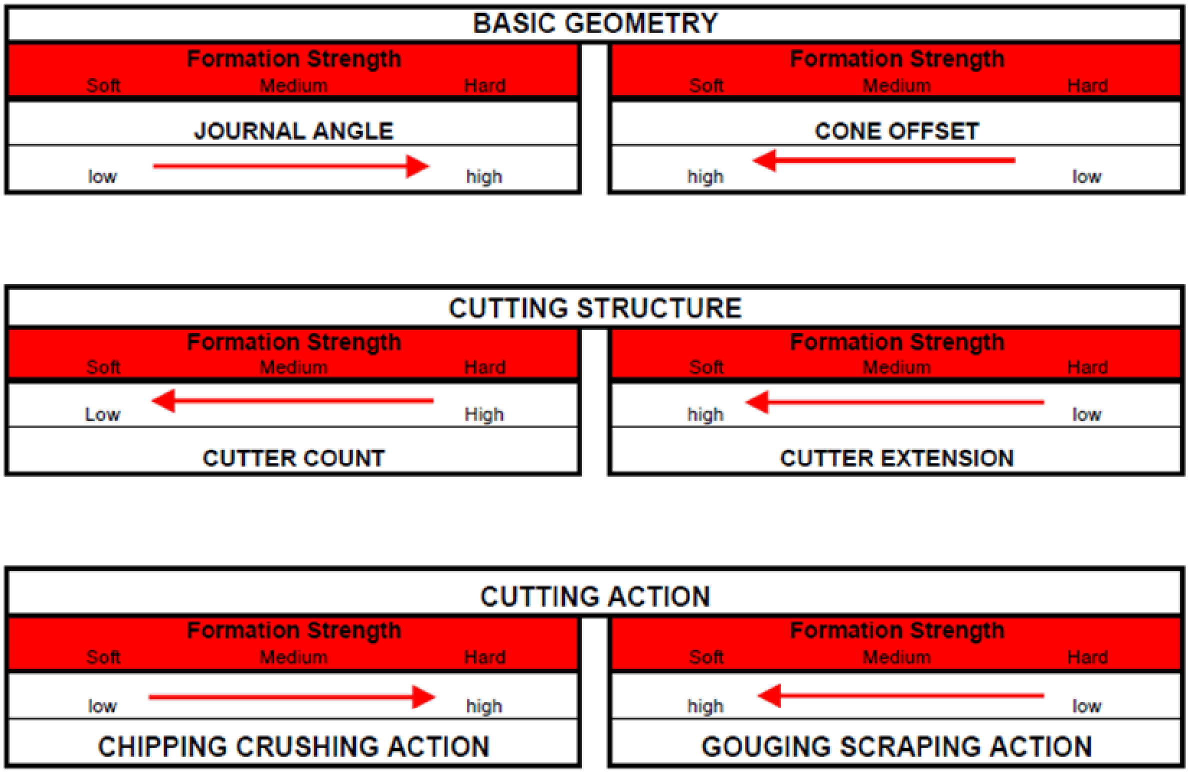


Figure 6.20: Table showing the roller cone general design and application characteristics. [4]

6.5 Bearing wear model for roller cone bits: Total energy

Failure of the bearings in a roller cone may lead to time consuming fishing jobs and increases in drilling costs. The bearing failure generally comes from wear of surfaces between the journal and the bearing of the cone. The total energy parameter is an important factor for Halliburton, which can both describe bit performance predict bit failures.
The formula of total energy takes weight on bit (WOB), revolutions per minute (RPM), diameter of the bit and hours drilled into account. [14]

$$Total\ energy(TE) = \frac{WOB[ton] \cdot 2{,}2046 \cdot \frac{Total\ bit\ revelutions}{1000}}{Bit\ diameter[inches]} = \frac{WOB[klb] \cdot Krevs}{inches} \qquad \text{(Eq. 6.1)}$$

The formula calculates the energy for every meter drilled, and then every step is summarized to get the total energy. [3, 14]

The two general reported bit wear is wear on the cutting structure and on the bearings. It is the bearing failure which needs close attention, because it can lead to catastrophic events for the well progress and the operational costs. [14]

The factors affecting the seal/bearing are numerous and complex. The bearing failure will occur after a critical volume (V) of material has been removed (Doiron, H.H., 1987), which gives a wear equation for the general wear in a journal bearing [14]:

$$V = \frac{cLx}{p} \qquad \text{(Eq. 6.2)}$$

c: wear coefficient, L: load on the sliding surface, x: distance traveled, p: hardness of material

After modification, the formula is changed to:

$$V = K \cdot WOB \cdot RPM \cdot Hours \qquad \text{(Eq. 6.3)}$$

K: coefficient, WOB: weight on bit, RPM: rounds per minute, Hours: bit hours

The wear on the bearings is proportional to the frictional work, this indicates the contact pressure between the cone and journal and the distance traveled. The distance traveled and contact pressure is related to the weight on bit and rotary speed. [14]

From the given equation it can appear as the wear model only is a function of weight on bit and rotary speed. In reality the bearing fails due to many complex factors: formation, bit profile, tooth size, BHA configuration etc. Therefore, the two independent parameters WOB and RPM are selected to model the bearing wear. This assumption provides for a bit wear function consisting of four different parameters which includes diameter of the bit, bit hours, RPM and WOB. [14]

$$Bit\ wear = K \cdot (D_b) \cdot (T^b) \cdot (WOB^c) \cdot (RPM) \qquad \text{(Eq. 6.4)}$$

K: coefficient, D_b: diameter of bit, T^b: bit hours WOB: weight on bit, RPM: rounds per minute

Each parameter is assigned a power, to make the model more flexible. To determine the coefficients, models have been developed, using regression and data from certain bit runs. (See table 6.1) [14]

Below a table is presented to illustrate how much the coefficients can vary when using different input data. The bit wear formula will be a number between 0-8, and a number above 4 is graded as bearing failure. [3]

	K	a	b	c	d	R^2
Assign b (Author's Model)	0.00073151	-0.20000	1.00000	0.15000	1.1158	0.76309
Assign a, b, c and d (Kelly model)	0.00017894	0.00000	1.00000	0.50000	1.00000	0.57886
Assign a, b, c and d (Doiron model)	4.91411E-5	0.00000	1.00000	1.00000	1.00000	0.18570

Table 6.1: Three different models are made to determine the coefficients. The column to the right shows the correlation coefficient (R^2). From this we can see that (Author`s model) is the best correlation for the data used in the study. [3]

The limitation with the bearing failure model is that it is correlated against the bearing wear grading, which can be hard to decide. Different people will have different opinions when it comes to the grading system. [3]

When having the coefficients: a=-1, b=1, c=1 and d=1 the bit wear model transform to the Halliburton Total energy formula (Equation 6.1). This formula does not follow a 0-8 grading system as the bit wear equation does, but gives increasing values as the bit is being used. The Total Energy formula can give good indications when to pull the bit out from the hole. The upper limit of total energy for a roller cone bit varies between 1000-1200, where each roller cone bit has its own TE value. This parameter is evaluated in real-time together with bit hours. [3]

In general, a big bit will be able to withstand higher values of weigh applied and rotary speeds. In the total energy formula, the product of RPM and WOB are divided by the bit diameter, this is to neutralize this effect and make it possible to compare different bit sizes with the same TE values. [3]

Some bit companies also uses the total revolutions of a bit, to decide when to pull out the bit from the hole. This method doesn't give any information about how much weight is applied. A bit spinning for 100 revolutions in air will not suffer the same damage as a bit spinning the same amount revolutions with a 20 ton WOB. This is the reason why Halliburton uses the total energy analysis. It monitors how the bit life is and how well different bit has performed. This is also very useful to decide when to pull the bit, which can save the operators for cost and extra rig time. [3]

The total energy formula does not provide exact science, but is more a guideline/indicator. A bearing is being exposed to many parameters, which affects the failure time. A bit with an upper TE value of 1200, has no guarantee for failure at TE=300, but under "perfect" conditions it will not. [3]

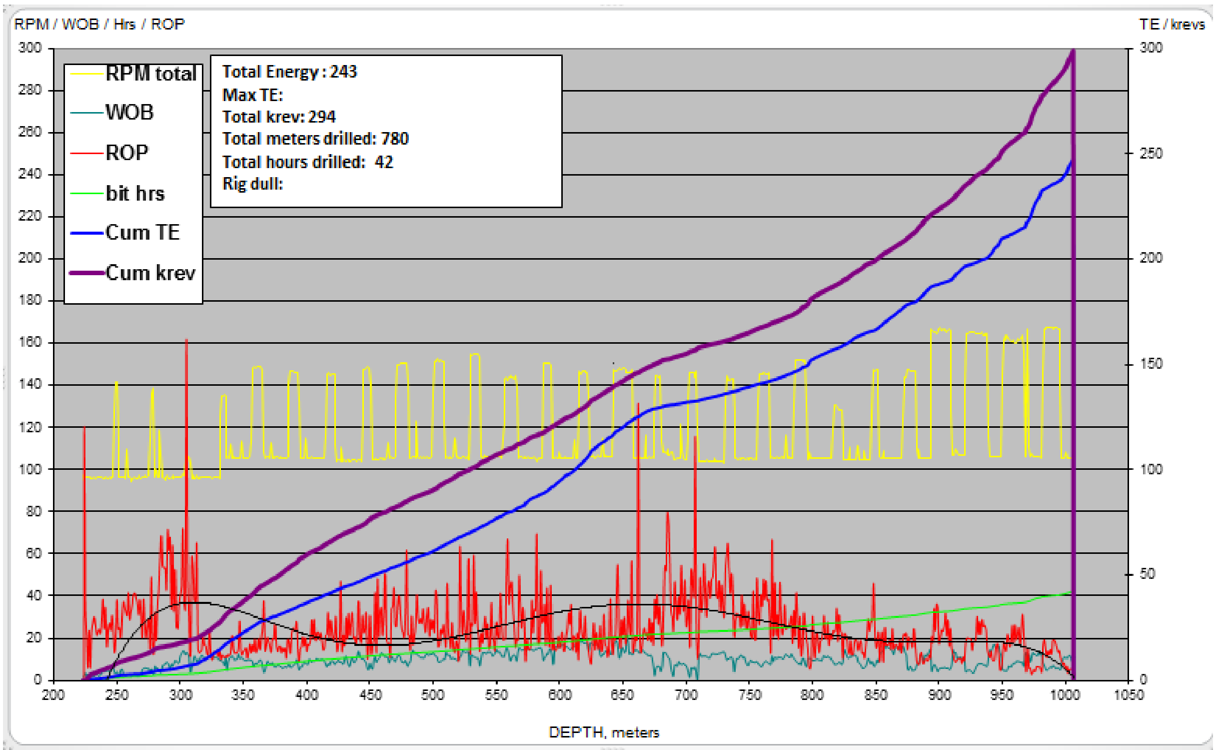


Figure 6.21: A general Total energy (TE) plot for a drilled well. The total energy is indicated as a blue line. When drilling deeper and deeper, the bit will be subjected to a lot of weight and revolutions, which are the parameters found in the TE formula. We can clearly see how the Total Energy is increasing as deeper the well is. [48]

6.6 Polycrystalline diamond compact (PDC) bits

PDC bits do not have any moving parts, and they therefore differ from the roller cone bits. This is an advantage because there will not be any needs for bearings and the durability will increase. The PDC bits use a scraping/dragging action on the formation rock, and therefore high RPM and low WOB are applied. Rocks typically fails more easily when subjected to shear forces, this is why a lower WOB is required (less energy). The cutters consist of a tungsten carbide substrate and a layer of synthetic diamond. The diamond grit in combination with tungsten carbide is subjected to high pressure and temperatures to make the PDC cutters (1 000 000 psi and 2800 °F). To make the tungsten carbide bound better to the diamond an alloy is present under the heat and pressure treatment consisting of cobalt. [3,5,7]

Small disk of synthetic diamond provides the scraping/dragging action, and the discs are available in different sizes. The synthetic diamond discs are not sensitive to failures along the cleavage planes as in natural diamond; this makes the cutting elements extremely strong.
The body of the bit is made in steel or wolfram carbide to increase the wear resistance. When drilling holes larger than 17 ½" it is not normal to use a PDC bit. [3,5,7]

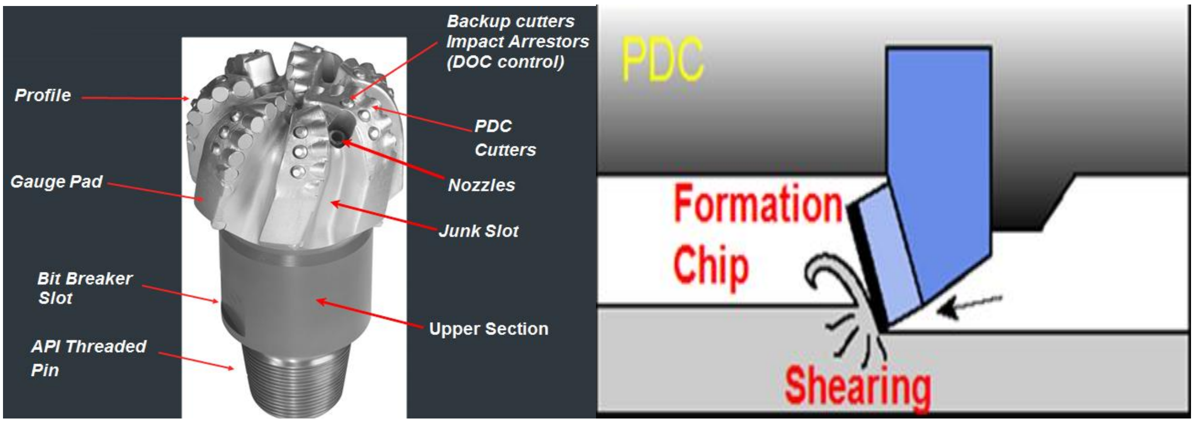


Figure 6.22: The main components of a PDC bit (left) and the cutting action of a PDC bit (right). [7]

6.7 PDC bit geometry

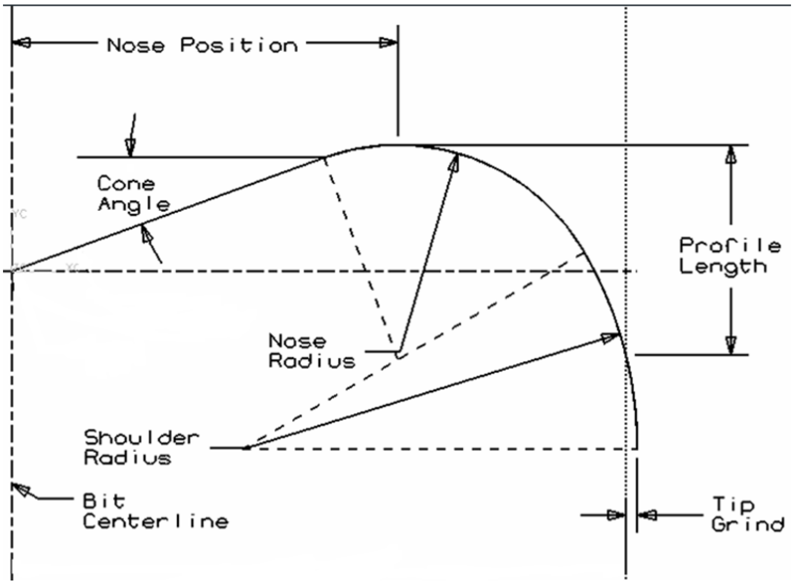


Figure 6.23: Shows the PDC bit profile [7]

To obtain an aggressive profile a short profile length, shallow cone angel and small nose radius is appropriate. For special milling operation, when drilling through casing and hard materials, special junk mills bits exist. These have a very similar cutting structure as for a PDC bits, with a very aggressive cutting structure. When having a non-aggressive profile a longer profile length, deeper cone and larger nose radius is appropriate. The profile length is calculated by the following formula: [7,50]

$$Profile\ length = \frac{Bit\ diameter}{Profile\ height} \qquad \text{(Eq. 6.5)}$$

When having a shallower cone (more flat) the bit will be more aggressive, but it will also be less stable when drilling. The bit will tend to track when having a shallower cone, it is therefore better to have some coning to get a more stability. [7,50,51]

6.7.1 Effect of cutter size and blade count

Cutters are available in different shapes and sizes. Big cutters will give a more aggressive profile. There will be a lower cutter count and the durability will be decreased. When having smaller cutter size the bit will have a less aggressive profile, higher cutter counts and increased durability.
A lower blade count will make the bit profile more aggressive with a less total cutter count, but the bit will be less stable. High blade count will have a higher total cutter count; this will make the bit profile less aggressive and give more stability when drilling. [7]

Sizes	Shapes
– 8mm	– Cylindrical*
– 10.5 mm	– Bullet
– 13 mm*	– Round
– 16 mm*	– Scribe*
– 19 mm*	

Figure 6.24: Illustration of the most common sizes and shapes of PDC cutter used in Norway. [7]

6.8 Drilling with different bit types

6.8.1 Drilling with roller cone bits

If a bit has a high offset it will cause the cone to stop periodically rotating and create a scraping action. This feature will tend to increase the drilling action in most formation types, but it will also increase the tooth wear.
The shape of the bit also has a large effect on the drilling action. Long widely spaced steel teeth are used for drilling soft formations. When the formation becomes harder, the offset and the tooth size must be smaller in order to prevent breakage of teeth. A bit with less offset will create a more crushing action. This combined with smaller tooth size also gives more room for stronger bearings.
For a fixed WOB, wide spacing between the teeth results in an improved penetration rate and higher lateral loading on the teeth. But when having close spacing between the teeth, it will reduce the loading at the teeth and the penetration rate will be reduced.
To obtain a desirable penetration rate, the bit must be designed for the formation. A soft formation requires a gouging/scraping action, but harder formation requires a crushing action. This behavior is achieved from how the bit rolls or skids. A bit that will tend to skid more than it rolls will require a combination of small journal angle, large offset and variation in the cone profile to make the cones skid more than they roll. The hard formations are best drilled when having a combination of large journal angles, no offset and minimum variation in the cone profile. The bit will be designed to have a "true roll" instead of skidding. [5]

6.8.2 Drilling with fixed cutter bits

The advantage of the fixed cutter bits is that it does not have any rotating parts, and bearing failure is therefore not a problem. This will also make the fixed cutter bits more appropriate for drilling small holes, when the roller cone bits cannot fit with proper teeth structure and bearings. The fixed cutter bits uses a scraping action on the formation, therefore it is applied low WOB and high ROP, often in combination with positive-displacement motors. The high ROP will create high temperatures, and it is therefore very important with effective fluid circulation. Effective fluid circulation is also important to prevent bit balling (cuttings agglomerating on the bit). [5]

6.9 Removing of cuttings

6.9.1 Nozzles

The nozzles are installed in the drill bit, and different design exists. The main objective for the nozzles is to obtain proper hole cleaning and remove cuttings from the bit. Proper hole cleaning is essential to maintain high penetration rates. For a roller cone bit it is possible to have four nozzles, one center jet and 3 nozzles between the cones. For the PDC bits the nozzles are installed in the face of the bit. Different nozzle configurations exist, and some have their own applications (For example special nozzle setup to prevent washout of unconsolidated formation). The drilling mud flows through the nozzles at high velocities, typically 70-150 m/s. To obtain these velocities, a high pressure drop over the nozzles is needed (30-130 bar with a mud weight of 1050 kg/m^3 (Equation 6.7). The flow of mud must also be sufficiently high in order to transport the cuttings up annulus. [13]

6.9.2 Nozzle calculations

For nozzle velocity,Vn, the only parameters affecting the speed is the flow rate (Q), and the total flow area (TFA). Equation (med Cn) contains a factor Cn, this called the nozzle factor and depends on the shape of the nozzle. In practical the factor is from 0,95 to 0,98. The reaction force from the nozzles will be acting in the opposite direction of the mud flow. It can be compared to the forces felt when holding a high pressure washer.

6.9.3 Nozzle velocity:

$$Vn = \frac{Q}{TFA} \qquad \text{(Eq. 6.6)}$$

$$\mathrm{Vn} = \mathrm{Cn}\sqrt{\frac{2\Delta Pd}{\rho m}} \qquad \text{(Eq. 6.7)}$$

6.9.4 Hydraulic horsepower per square inch of bit diameter (HSI):

$$\mathrm{HSI} = \frac{\Delta \mathrm{Pd} * \mathrm{Q}}{\frac{\pi}{4}\mathrm{Dbit}^2} \qquad \text{(Eq. 6.8)}$$

6.9.5 Reaction force from the nozzles:

Rf= mass flow * velocity = ρm*Q*Vn (Eq. 6.9)

Other parameters included in the equations are pressure drop over the nozzles, ΔPd, mud density ρm and diameter of the bit , Dbit. [13]

6.9. Nozzle types

Many different kinds of shapes and sizes are available for nozzles. The nozzles needs to be hydraulically optimized for the drilling application, in order to have the best bit and hole cleaning properties. The nozzle optimization will include the pressure calculations given in the previous section, and pressure losses in annulus. Below there will be listed two different nozzle types that are provided by Halliburton [46]:

6.9.1 Sideport nozzles

Side port nozzles have a cross flow action, which cleans a larger area of a roller cone bit and helps to prevent bit balling. Bit balling is when the formation being drilled through is sticking to the bit. The sideport nozzles provide cleaning of larger parts of the bit compared with conventional drill bit nozzles. Increased cleaning will also lead to a higher rate of penetration. [46]

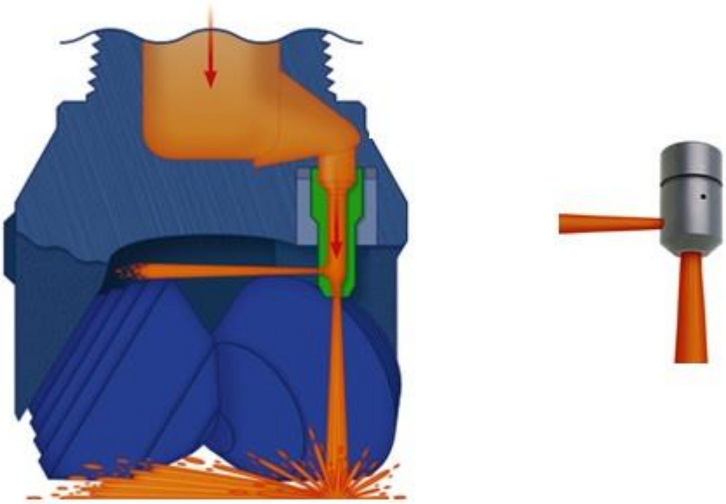


Figure 6.25: Sideport nozzles. [46]

6.9.2 Vortexx nozzles

Compared to conventional nozzles, the Vortexx nozzles create a negative impingement pressure at the formation interface. The shape of the nozzles also increases the turbulence under the bit which increases the bit cleaning.

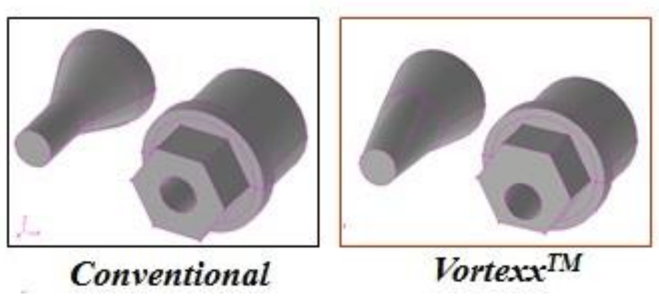


Figure 6.26: Shoes the different look of a conventional nozzle and a Vortexx nozzle. [46]

6.9.3 PDC hydraulics

When drilling with a PDC bit compared to a roller cone bit, the cuttings will not be crushed in the cones when rotating, removing of the cuttings through the channels at the bit face is therefore important to maintain good hole cleaning and sufficient rate of penetration. The junk slot area is the volume of channels where the cuttings will flow. To get a larger junk slot area the number of blades can be reduced, increase the blade height or reduce the blade thickness by using a steel body bit. A PDC with shallow channels is more adapted for drilling hard formations (referred to as matrix body), and a PDC bit with deeper channels (referred to as steel body bit) is more adapted for drilling soft formations. In soft formations the ROP is often higher; in order to remove the cuttings in an effective manner a larger junk slot area is needed. Larger junk slot area will also improve the flow and reduce the risk for cuttings agglomerating on the bit. [46]

Figure 6.27: From left: The junk slot area of a PCD bit, a PDC bit with shallow channels used for drilling hard formations and a PDC bit with deep channels (large junk slot area) used to drill soft formations. [46]

6.10 IADC system for drill bits

The IADC (International Association of Drilling Contractors) code makes it easier for the drillers to describe what kind of bit they are looking for to the supplier. The system uses codes which describe properties of the formation being drilled, and letters which describes additional features of the bit. A similar system exists for PDC bits. [3,9]

- **First digit:** 1, 2 and 3 indicates steel tooth bits. 1 is used for soft formations, 2 for medium formations and 3 for hard formations. 4,5,6,7 and 8 indicates tungsten carbide insert bits. The formation hardness ranges between 4-8, with 4 being the softest and 8 the hardest.
- **Second digit:** Further breakdown of the formation hardness. The scale goes from 1-4, where 1 is softest and 4 being the hardest.
- **Third digit:** This digit classifies the bit according to the bearing/seal type and gauge wear protection.
- **Fourth digit/letter:** This indicated additional features.

An example can be a bit with IADC classification 115W. The first digit (1) indicates that this is a steel tooth bit used for soft formations; second digit (1) is a further breakdown of the formation which in this case is a soft formation. The third digit (5) shows from the IADC system that the bearing type is a sealed roller bearing with gauge protection. The fourth digit/letter (W) is an additional feature which is enhanced cutting structure. [3,9]

6.10.1 The IADC dull grading system

Bits are classified after the IADC dull grading system. The system gives an overview over the bit condition and why the bit is pulled out of the hole. The information gives an indication of how well the bit has performed in a run. Problems with the bit can be of great information for the technical development and for further improvements. The system is used both for roller cone (RC) bits and fixed cutter (FC) bits (ex: PDC) [3,10,11]

Cutting Structure							
Inner Rows	Outer Rows	Dull Char.	Location	Bearings/Seals	Gauge	Other Dull Char.	Reason Pulled
1	2	3	4	5	6	7	8

Table 6.2: IADC dull grading system. [10]

The IADC system consists of 8 rows, each row describing their own characteristic of the bit.

1. Inner cutter structure: The grading scale is 0-8. 0 indicates an "as new" condition, and 8 is total loss of tooth height (see figure 6.28).
   RC bits: Indicates the cutting structure of all the inner rows.
   FC bits: Indicates condition of the inner ⅔ radius of the cutting structure
2. Outer cutter structure: Same grading scale as the inner cutter structure
   RC bits: Reports the cutting structure of the gauge row.
   FC bits: Condition of the cutting structure which is located on the outer ⅓ of the radius
3. Dull characteristic:
   A two letter description of the major dull characteristics of the cutting structure.
   Example: code BT: Indicates broken cutters on a fixed cutter bit.
4. Location:
   Gives an area description of where the dull characteristics occur on the cutting structure.
   Example: N: Indicates wear on the nose of a fixed cutter.
5. Bearing/Seals:
   Gives the condition of seals and bearings, the condition is described by letter and number codes. Fixed cutters are graded "X" since they do not have bearing or seals.
6. Gauge:
   Gives an indication to show if the bit is in gauge. This is measures by using a gauge ring. If the bit is not in gauge, it is reported in fractions of an inch.
7. Other dull characteristics:
   The bit is graded in addition to the cutting structure itself. The same codes from column 3 are used to describe the dulling characteristics.
8. Reason pulled:
   Gives the reason why the bit is pulled from the hole. The reason is described using letter codes.
   Example: BHA: Change Bottom Hole Assembly

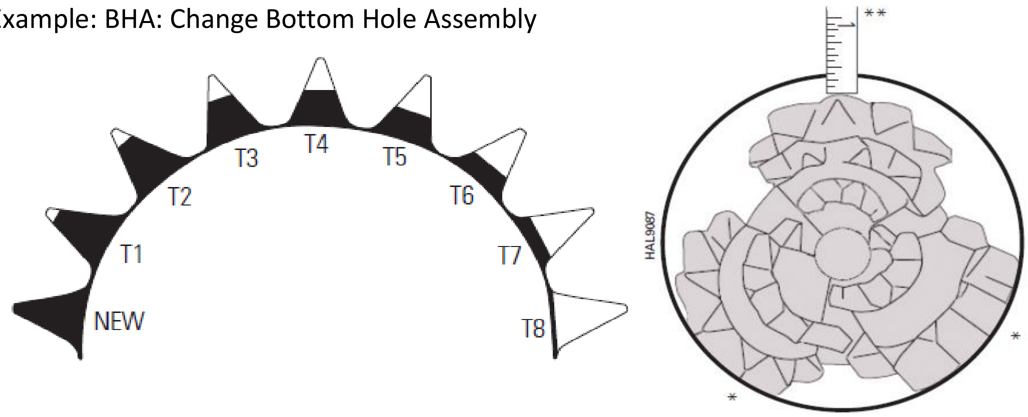


Figure 6.28: Showing the wear classification on the cutting structure of a roller cone bit (left) and the gauge ring used in column 6 (right) [10]

Chapter 7

Drilling Shoetrack optimization study

7.1 Problem definition

This thesis was carried out to study the drilling process of the shoetrack. The main problem around this subject is:

- The shoetrack drill out can be a time consuming process. In the drilling industry, additional time used is a large cost for the operator. For that reason a better overview over the shoetrack drill out must be made, and try to find optimized drilling parameters to reduce the drill out time.

The thesis will focus on 10 ¾" liners for the following reasons:

- The drill out times are high for these sections
- A lot of information available
- The landing collar is the component taking the most of the time
- Halliburton was the supplier for the shoetrack equipment in many wells (lot of information available, reducing the uncertainty)

The thesis will study many parameters for these liners, and try to see some concluding trends that will help to reduce the drill out times. First the study will give a broad study of different casing sizes to show the time consuming process when drilling the shoetrack. Thereafter the study will go more in detail on the 10 ¾" liners.

7.2 Problems occurring when drilling the shoetrack

The problems occurring when drilling out the shoetrack are many. Different problems can occur, but they will all affect the economic perspective of the drilling process in a negative manner. When drilling a section, the bit is optimized for the formation rock, and it will therefore not be as effective for drilling the shoetrack components. Due to large cost, the companies would like to drill out the shoetrack and reach the target depth in one run. For that reason, the same bit must be used to drill out the shoetrack and the next open hole section. Adapted bits could be used when drilling the shoetrack, but then the drill string must be pulled out after the shoetrack drillout is complete to change the bit. This will lead to many hours of tripping pipe and large costs. A bit optimized for shoetrack drill out and to drilling junk (junk mill), will not have stability when drilling formation rock. Below there will be listed some of the problems occurring when drilling the shoetrack [55]:

7.2.1 High drill out times → Large rig costs

Floaters and fixed platform has a very high rig rate today (up to 500 000 $ +). When using additional time for drilling out the shoetrack, this will lead to large cost. In the oil and gas industry, time is money. Some hours saved in an operation can lead to large savings for the operators. [44]

7.2.2 Cementing plugs starting to rotate when drilling

When applying both high weight on bit and rotational speed, there will be a lot of torsional forces acting on the cementing plugs. This can force the cementing plug to be ripped off the cement and start to rotate. Now the cementing plug will prevent the bit from biting, and reduce the penetration rate heavily. [55]

7.2.3 Cuttings agglomerating on the bit

During drilling of the shoetrack, large debris from the shoetrack equipment can stick to the bit and interfere with the mud flow. This will lead to reduced hole cleaning. The bit hydraulics will not be optimized any more, and this will affect the penetration rate in a negative manner. [55]

7.2.4 Worn bit

If the drilling process of the shoetrack takes a lot of time, this will lead to reduced cutting action of the bit. The blades of a PDC might be destroyed, or a bearing in a roller cone bit might tend to reach it upper value of Total Energy (TE). If the bit gets worn, the operator might have to change the bit in order to reach the next target of the open hole section. The drill bit also might be worn and thereby reduce the rate of penetration when hitting the formation rock. This will lead to additional time, followed by the high rig rates. [55]

Figure 7.1: A worn PDC bit after drilling through shoetrack equipment. The picture shows broken cutters and large wear in the middle of the PDC bit. This bit drilled through some shoetrack equipment, then hitting the formation. The bit was then pulled out of the hole due to very low rate of penetration. [49]

7.3 Factors affecting the shoetrack drill out time

Drilling through the shoetrack involves many parameters. The operation is complex due to many factors interacting with each other. Parameters that will affect the drill out performance includes [47]:

- Rate of penetration (ROP)
- Weight on bit (WOB)
- Rotation speed (RPM)
- Components and design
- Cutting removal
- Mud properties (Density, gel strength, yield, viscosity etc.)
- Flow rate
- Nozzle force
- Material
- Bit type (Roller cone, PDC etc.)
- Bit configuration (Offset, cutter size, bit profile)
- Well profile (Inclination, doglegs)
- Bottom hole assembly
- Casing shoe size

In this thesis, bits and drilling parameters will be the main factors studied, which are important for drilling the shoetrack.

7.4 Data available for the study

For this study, data from 143 drilling runs were given from HDBS, ranging from 17,5” to 6,5” bit size. All the wells were drilled by one of the major operator in Norway. The data available takes the starting points and the ending points of a drilled section. The data given is presented in the table below. In this study the problems occurring when drilling out will be discussed, and some wells will be studied more in detail.

Platform*
Well-ID*
Bit size
Last shoe size
Depth range
Bit type
Bit supplier
Bit model
Assembly
Mud weight
Inclination range
Time to drill stage collar
Time to drill/clean out from stage collar to landing collar (hrs)
Time to drill Landing collar (hrs)
Time to drill cement between landing collar and float collar (hrs)
Time to drill Float collar (hrs)
Time to drill cement below float collar (hrs)
Time to drill shoe (hrs)
Total time drilling from wiper plugs to out of shoe (hrs)
Shoe Track Length (ft)
Hanger Supplier
Wiper Plug Supplier
Landing Collar Supplier
Cement Compressive Strength (psi)
Average shoetrack ROP

Table 7.1: Showing available data from the 143 wells. *: Will in this thesis not be given due to confidentiality. [58]

The data given for each section gives a lot of information about the shoetrack drill out.
First a broad view of all the data collected will be represented to show where the problems occur, and to show that the shoetrack drill out can be a time consuming process.
For the following graphs that will be posted, uncertainty is not taken into account. It is only used to give the reader a broad view of the drill out problem, and to show where the problems occur.

7.5. Broad study of all the runs

7.5.1 The effect of casing shoe size and drilling time

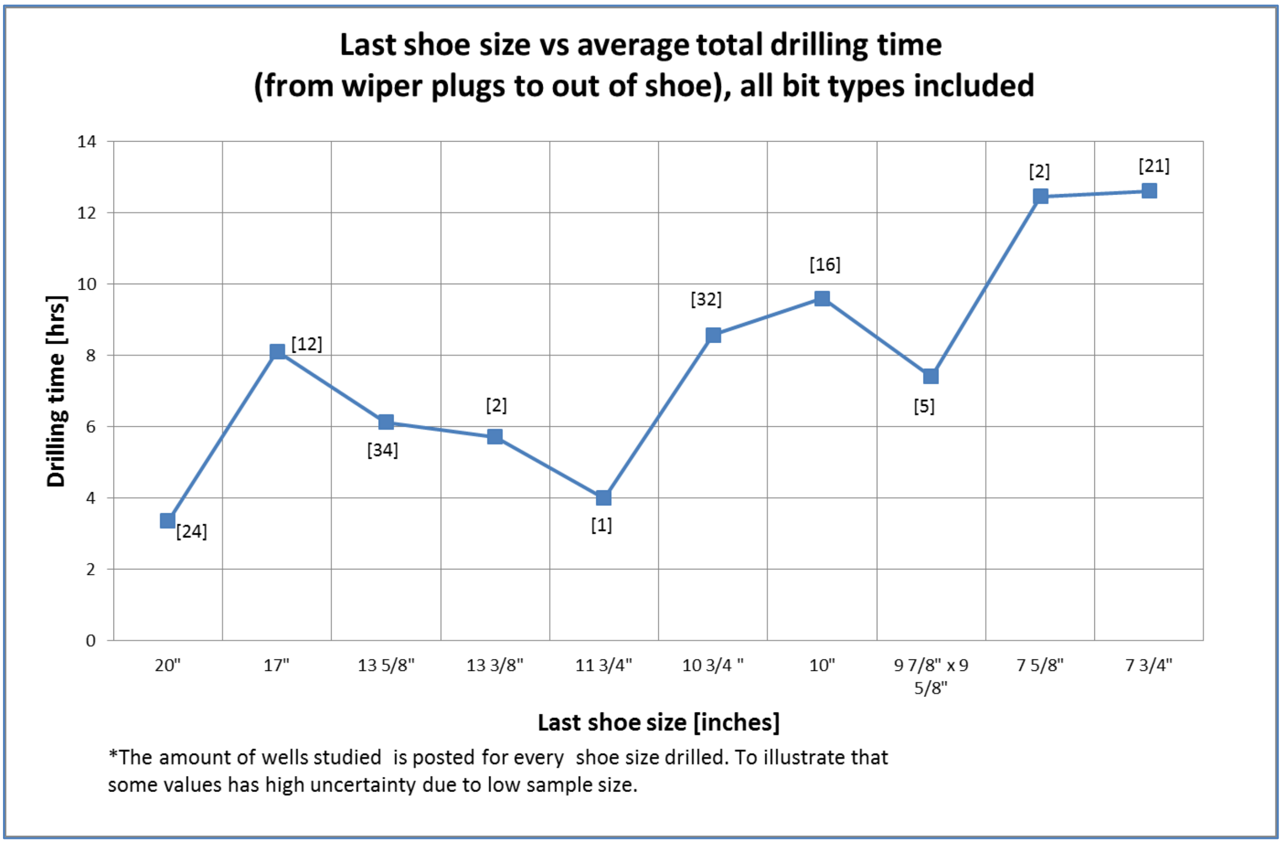


Figure 7.2: Last shoe size vs average total drilling time.

From this figure we can clearly see that the deeper and smaller the sections are, the more time consuming the average time of drilling out the shoetrack is. The total drilling time, will in this thesis refer to the time the bit takes to drill out from the first plug until it is out of the shoe.

7.5.2 The use of different bits

All the different runs usually used different bits. The figures below contain information of all the drillouts with different bit types. Some sections were not drilled with Roller cone or PDC from the available data, as the figures below represent. There were some sections that were drilled with hybrid bits; they are not given in these graphs as the amounts of wells were too low to give representative analytical information.

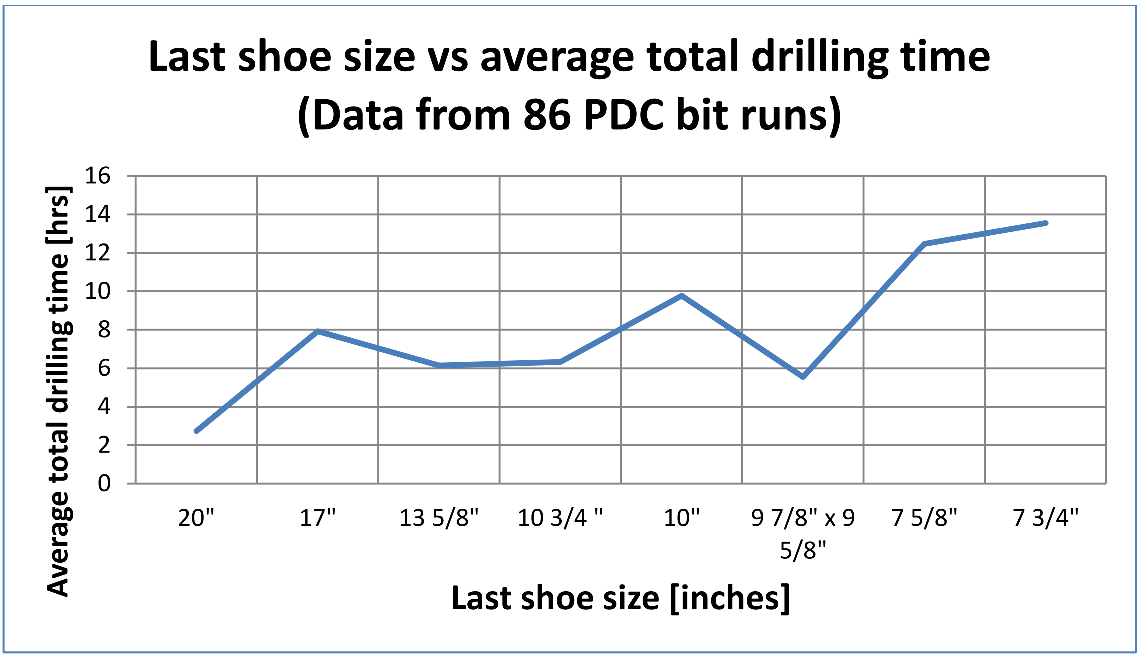


Figure 7.3: Last shoe size vs average total drilling time with PDC bit.

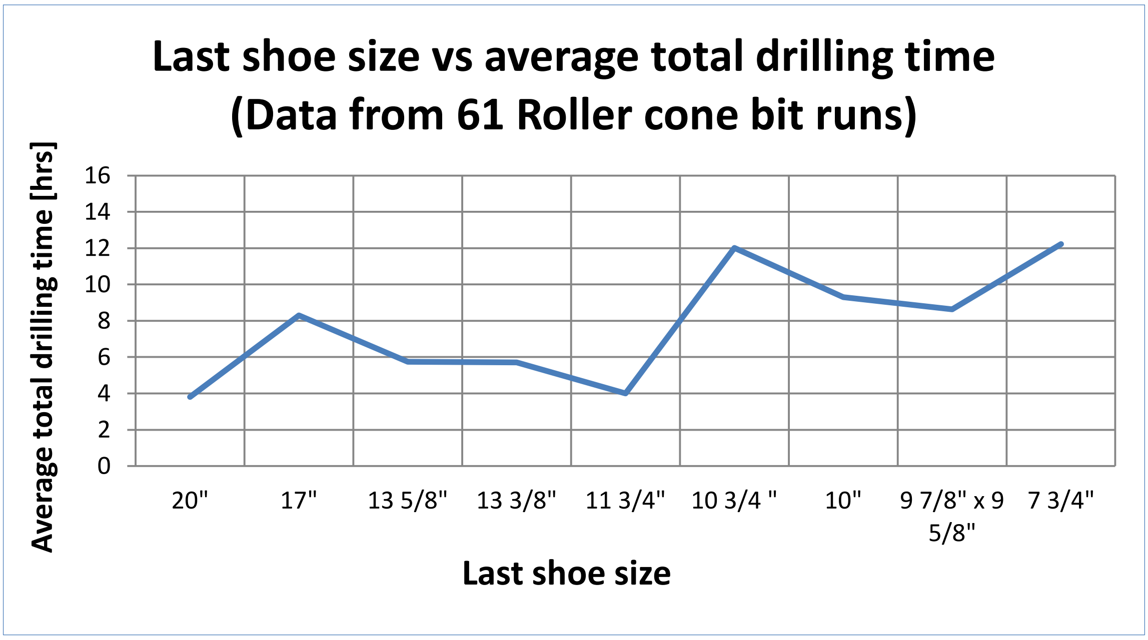


Figure 7.4: Last shoe size vs total drilling time with roller cone bit

7.5.3 The time to drill different components of the shoetrack

It will here be represented all the different sections given in the available data. The data is only represented to give the reader a big view of the shoetrack drill out. Standard deviations are not taken into account for these data represented, as it is only given to see the trends and what components taking the most time. The amount of each section studied will be posted on each graph. The data where the sample size is below 5 are nod included, due to large uncertainties. The component in the drill out that takes the most time will be indicated with a red color on the graphs.

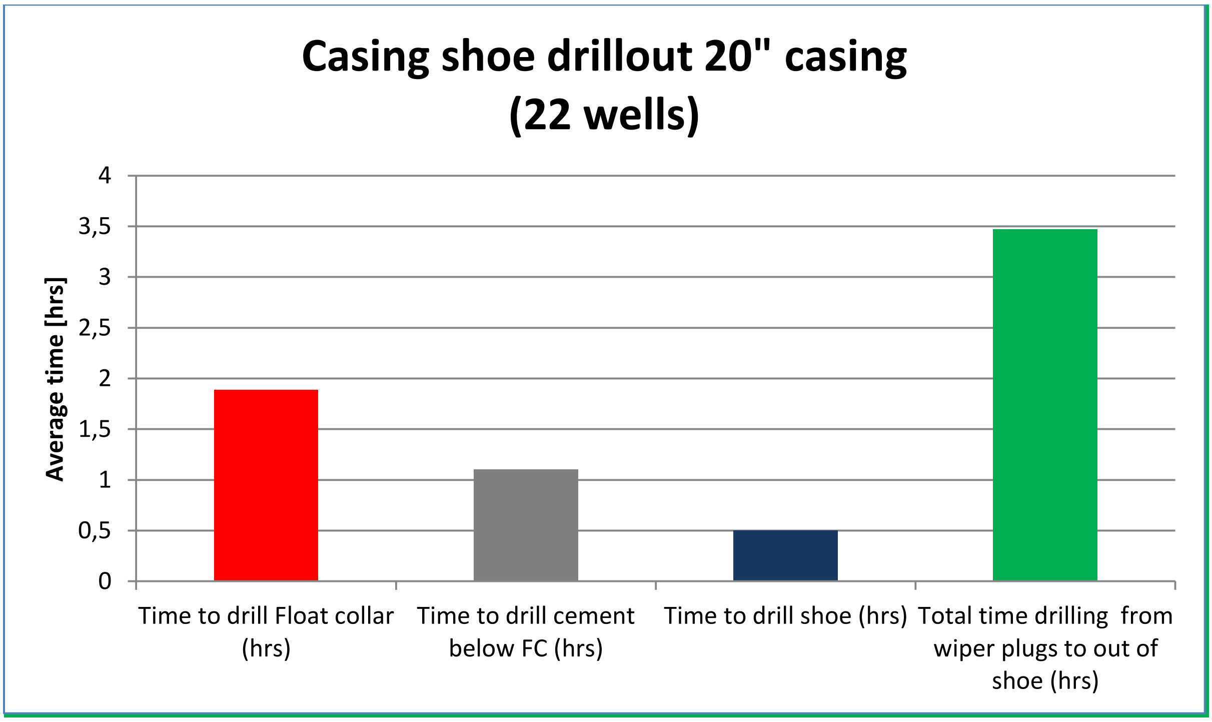


Figure 7.5: Shoetrack drill out times of 20" casing shoe

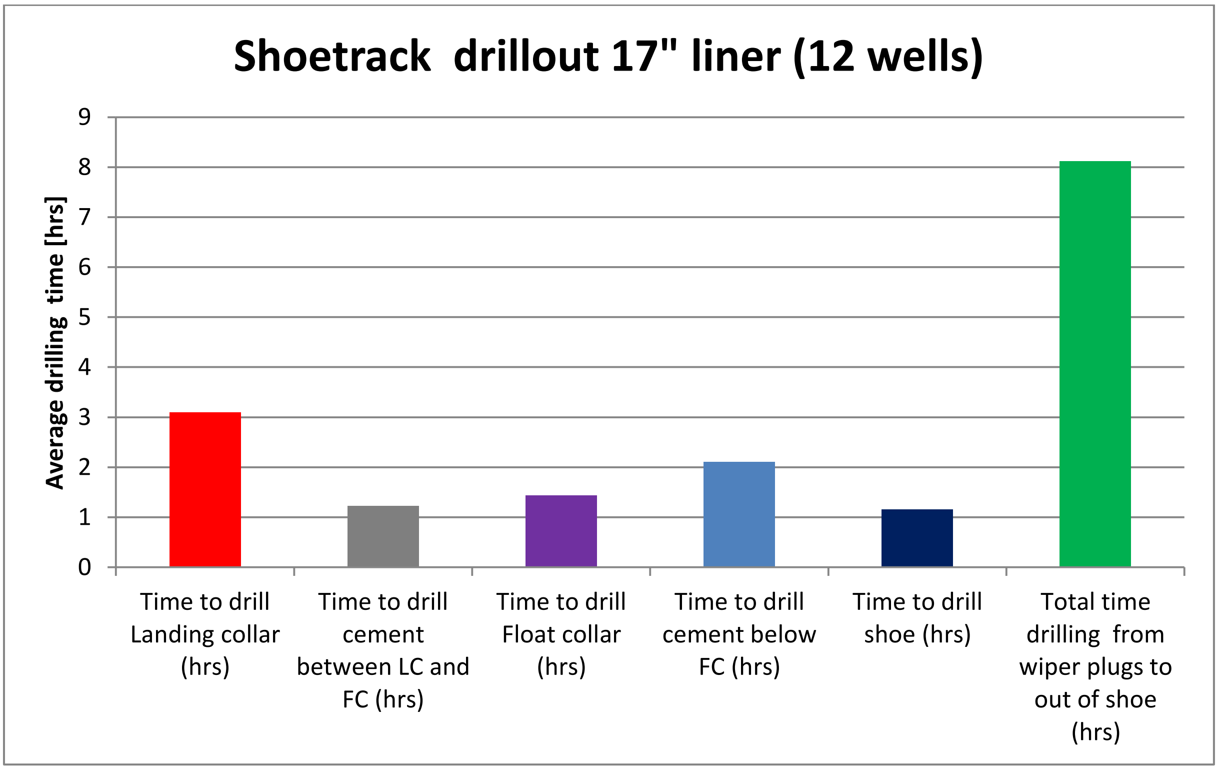


Figure 7.6: Shoetrack drill out times of 17" casing shoe

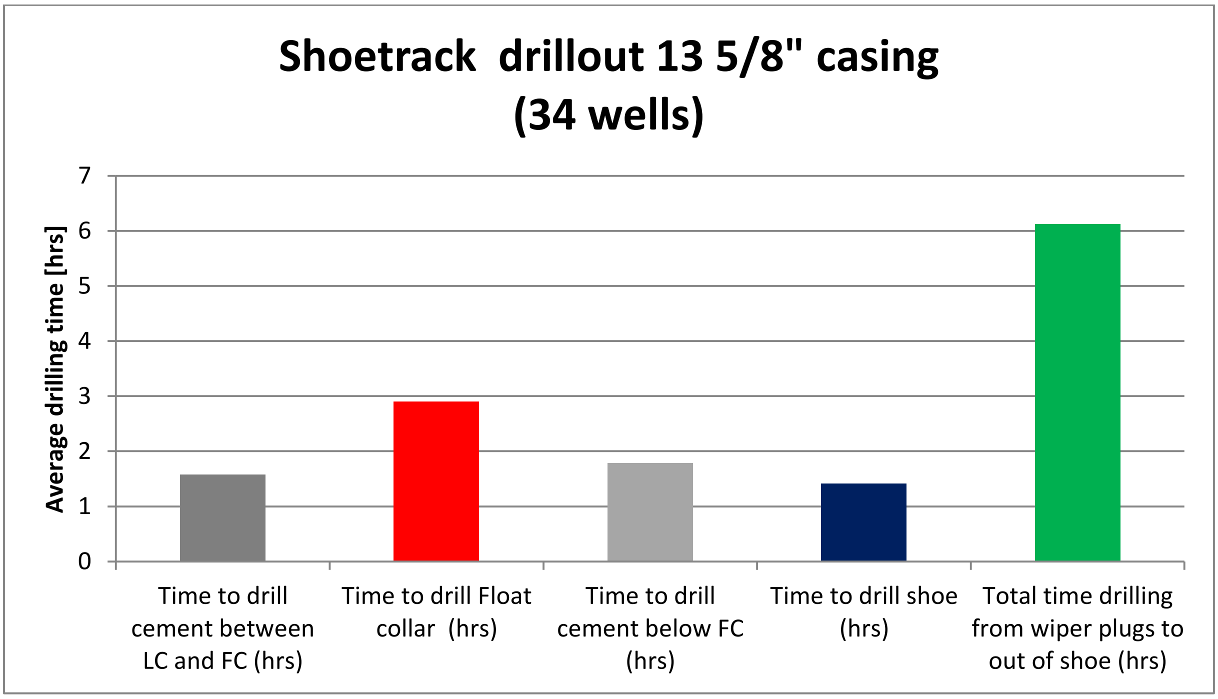


Figure 7.7: Shoetrack drill out times of 13 5/8" casing shoe

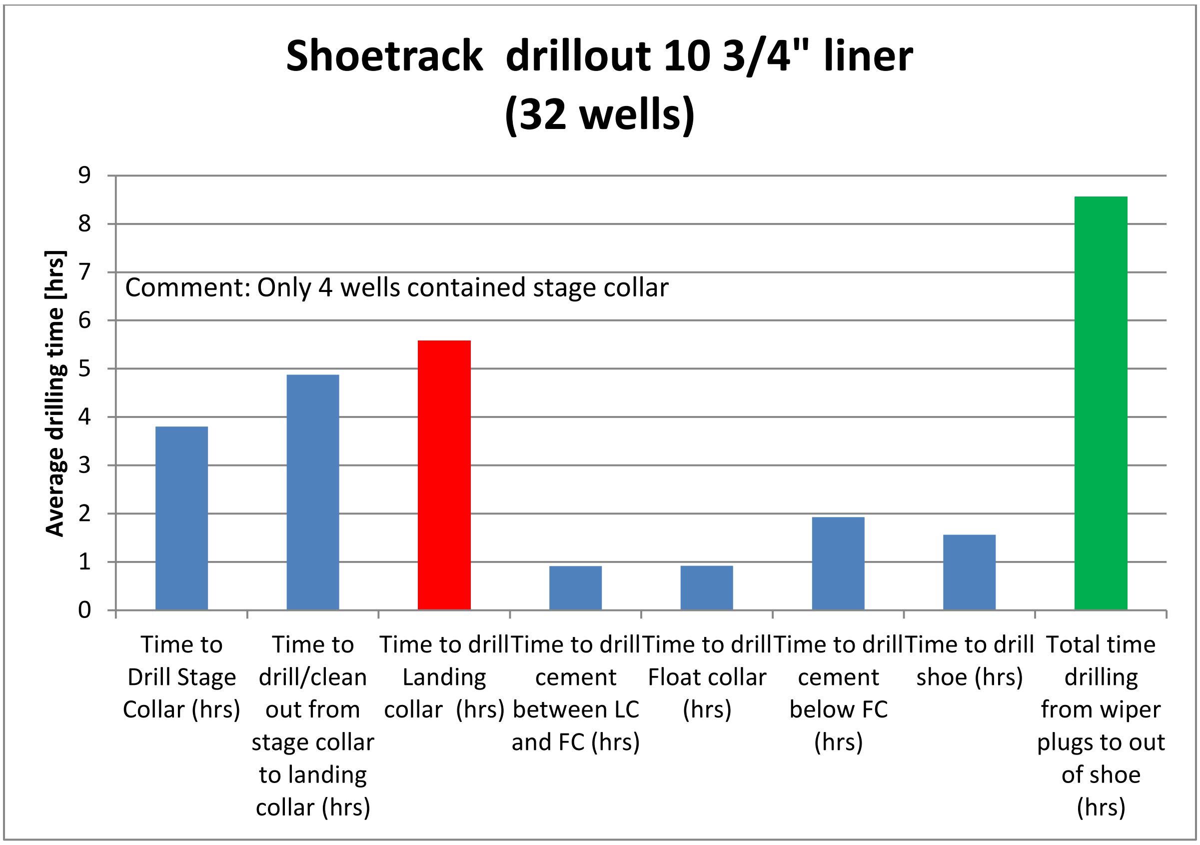


Figure 7.8: Shoetrack drill out times of 10 3/4" casing shoe

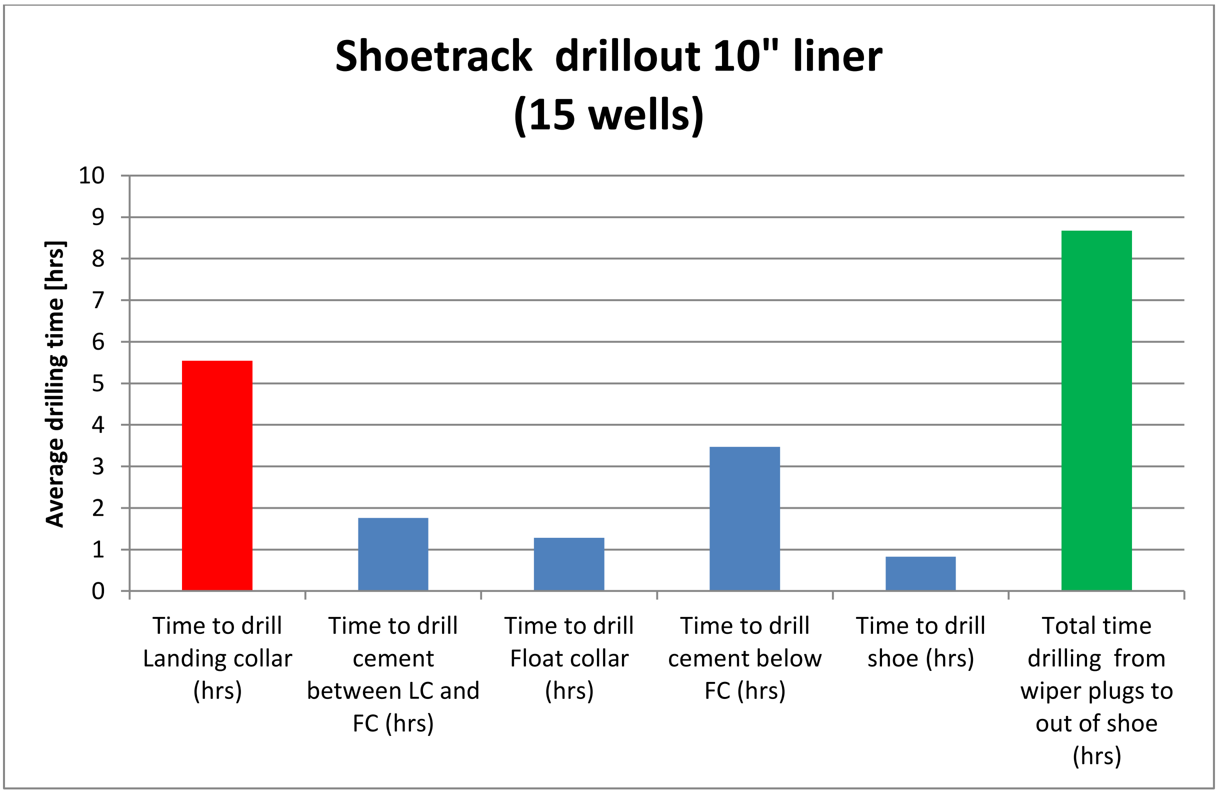


Figure 7.9: Shoetrack drill out times of 10" casing shoe

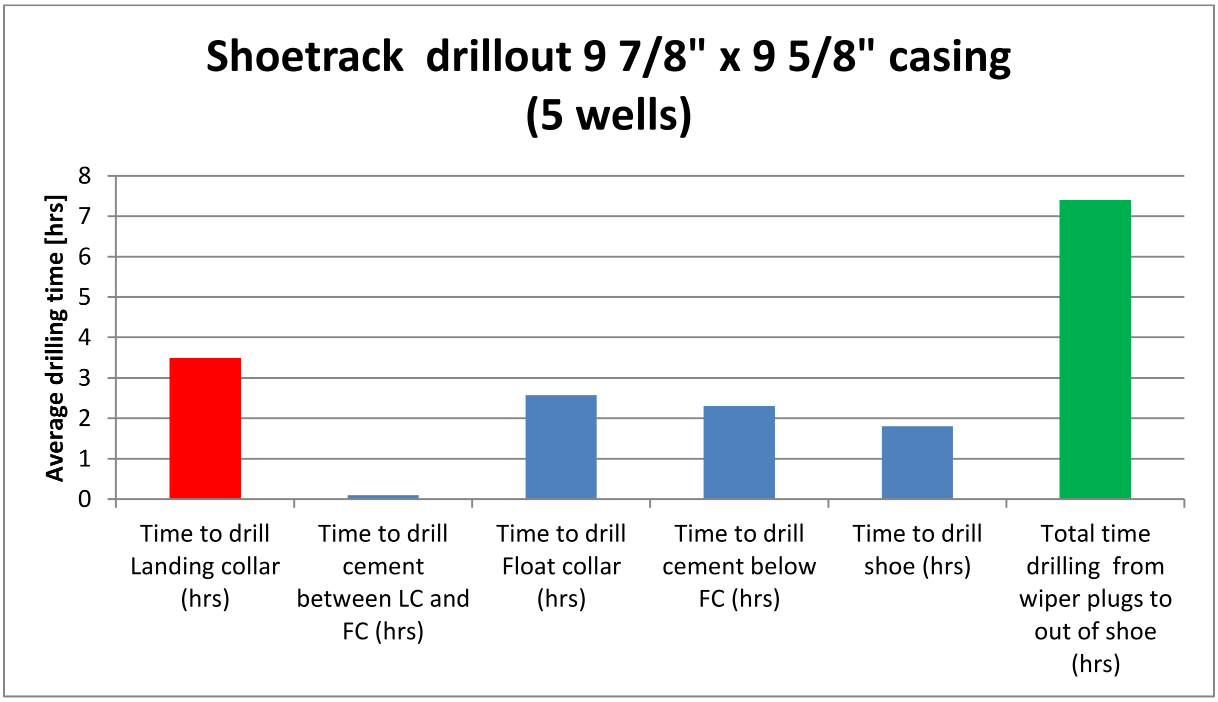


Figure 7.10: Shoetrack drill out times of 9 7/8 x 9 5/8" casing shoe

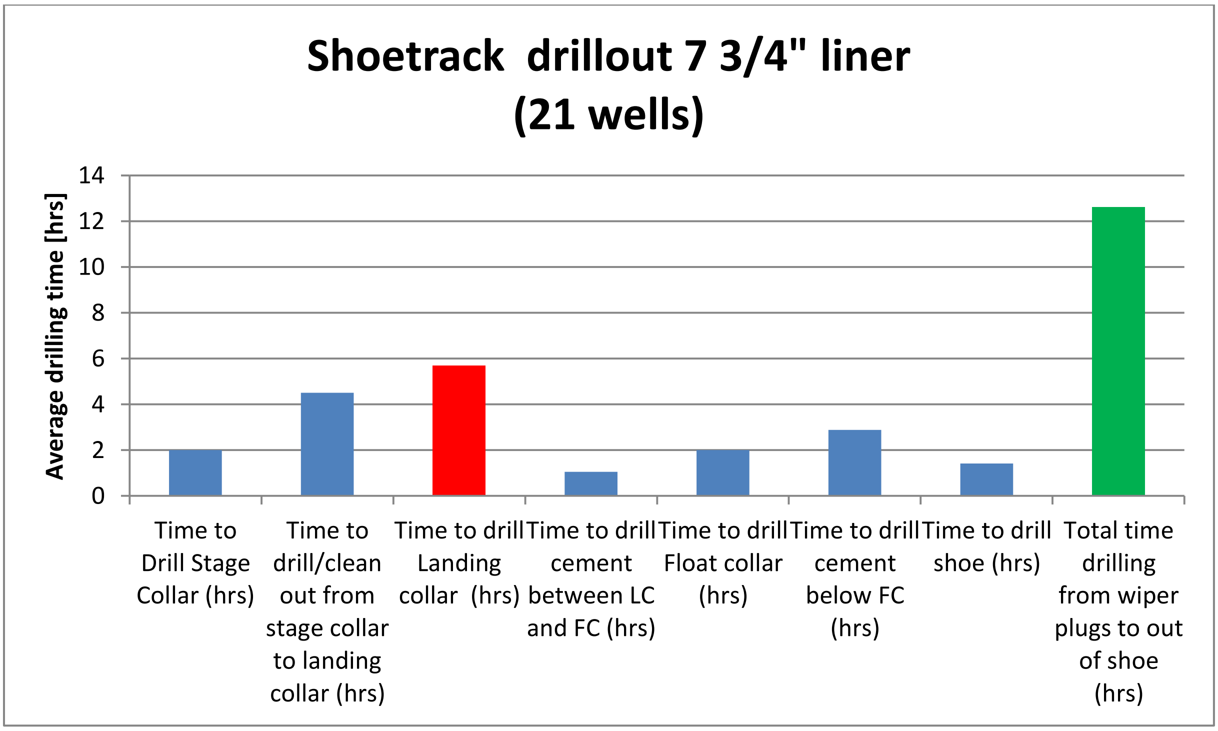


Figure 7.11: Shoetrack drill out times of 73/4" casing shoe

7.5.4 Effect of the inclination of the well

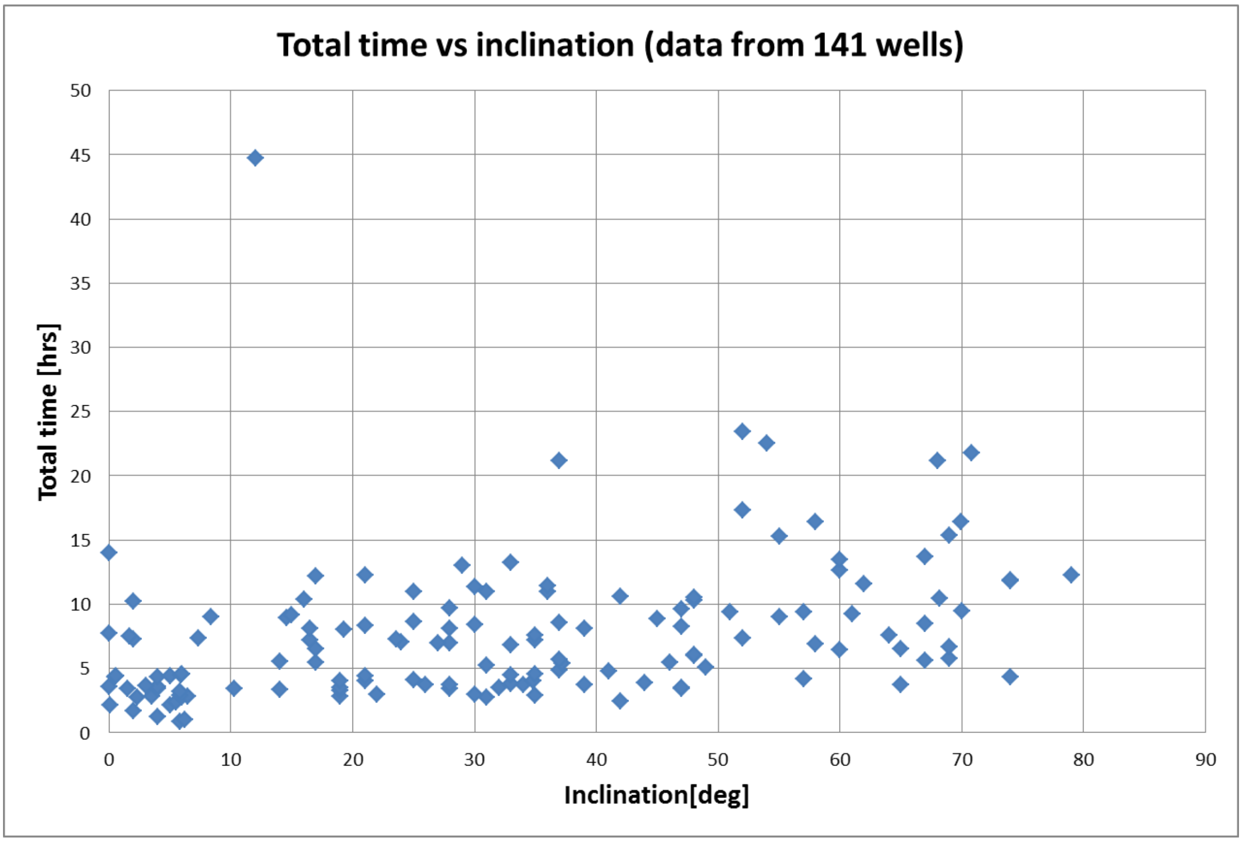


Figure 7.12: Shows the shoetrack drill out times of 141 wells with given inclination, all section sizes are included.

This graph shows us that there is a trend when plotting the inclination up against the total drilling time. The more inclination a well has, the more time it will take to drill out the shoetrack.

7.6 Study of the 10 ¾“ liner shoetrack drill out

A deeper study was performed on the 10 ¾ “liners. This casing string was selected for the following reasons:

- The drill out times were high
- The cementing plugs, landing collar and liner hanger was provided by Halliburton (Lot of information available and more adapted to comparison between the results)
- The landing collar took the most of the time when drilling out
- A lot of wells available (To reduce the uncertainties in the study)

In this study a total of 15 wells were selected, all being 10 ¾” liners. The wells are all drilled by one of the major operator in Norway. The well identification is confidentially, and will therefore be represented as well 1,2,3….15. The table below shows the 15 selected wells. Four of the wells contained stage collar (from two stage cementing job). The first column shows the well, bit type and bit supplier. The other columns show the drill out times of the different components in the shoetrack, with the following uncertainties posted below. The time to drill the landing collar, will also include the time to drill the cementing plug and dart, as it seats in the landing collar after the cementing operation. This will also apply for the time to drill stage collar. A dart and cementing plug will be found in the stage collar, and will be included in the “time to drill stage collar”. As seen, there are three different bit providers for the different wells: BHC (Baker Hughes), Lyng and HDBS (Halliburton Drill Bit Services).

Well	**Time to Drill Stage Collar (hrs)**	**Time to drill/clean out from stage collar to landing collar (hrs)**	**Time to drill Landing collar (hrs)**	**Time to drill cement between LC and FC (hrs)**	**Time to drill Float collar (hrs)**	**Time to drill cement below FC (hrs)**	**Time to drill shoe (hrs)**	**Total time drilling from wiper plugs to out of shoe (hrs)**
Well 1 - Hybrid - BHC			2,83	0,50	0,13	0,20	0,67	**4,33**
Well 2 - RC/Smith			0,33	0,75	0,25	3,00	0,75	**5,08**
Well 3 - PDC - Lyng			3,33	0,25	0,63	2,1	0,16	**6,47**
Well 4 - PDC - HDBS			2,18	1,38	0,28	2,71	1	**7,55**
Well 5 - PDC - HDBS			3,00	0,33	1,42	0,25	3,50	**8,50**
Well 6 - PDC - HDBS			4,00	0,42	0,83	1,00	3,00	**9,25**
Well 7 - PDC - Lyng			6,91	0,33	0,63	1,42	0,16	**9,45**
Well 8 - Hybrid - BHC			8,30	0,58	0,75	1,50	0,67	**11,80**
Well 9 - RC - HDBS			6,25	0,2	1,46	0,43	3,2	**11,9**
Well 10 - RC - HDBS			5,95	1,48	1,12	5,8	1	**15,35**
Well 11 - RC - HDBS			6,17	1,00	1,25	2,25	5,75	**16,42**
Well 12 - RC - HDBS	0,4	0,5	11,7	0,35	0,2	1,9	1,4	**16,45**
Well 13 - RC - BHC	1,8	9	2,25	1,2	0,2	2	0,9	**17,35**
Well 14 - PDC - HDBS	5	7	4,50	2,00	0,50	0,80	0,50	**21,80**
Well 15 - RC - HDBS	8	3	8,00	0,25	0,25	2,00	1,00	**22,50**
Average	3,80	4,88	5,05	0,73	0,66	1,82	1,58	12,28
Variance	8,66	11,05	8,15	0,28	0,20	1,82	2,32	31,18
Standard deviation	2,94	3,32	2,85	0,53	0,45	1,35	1,52	5,58
Confidence interval	2,88	1,68	1,44	0,27	0,23	0,68	0,77	2,83
Significans level	95 %	0,05						

Table 7.2: Shows the drill out times of different parts of the shoe track in 15 different 10 3/4" liners. The uncertainties of the statistics are posted below

7.6.1 Drill out times of different components in the 10 ¾ "liners

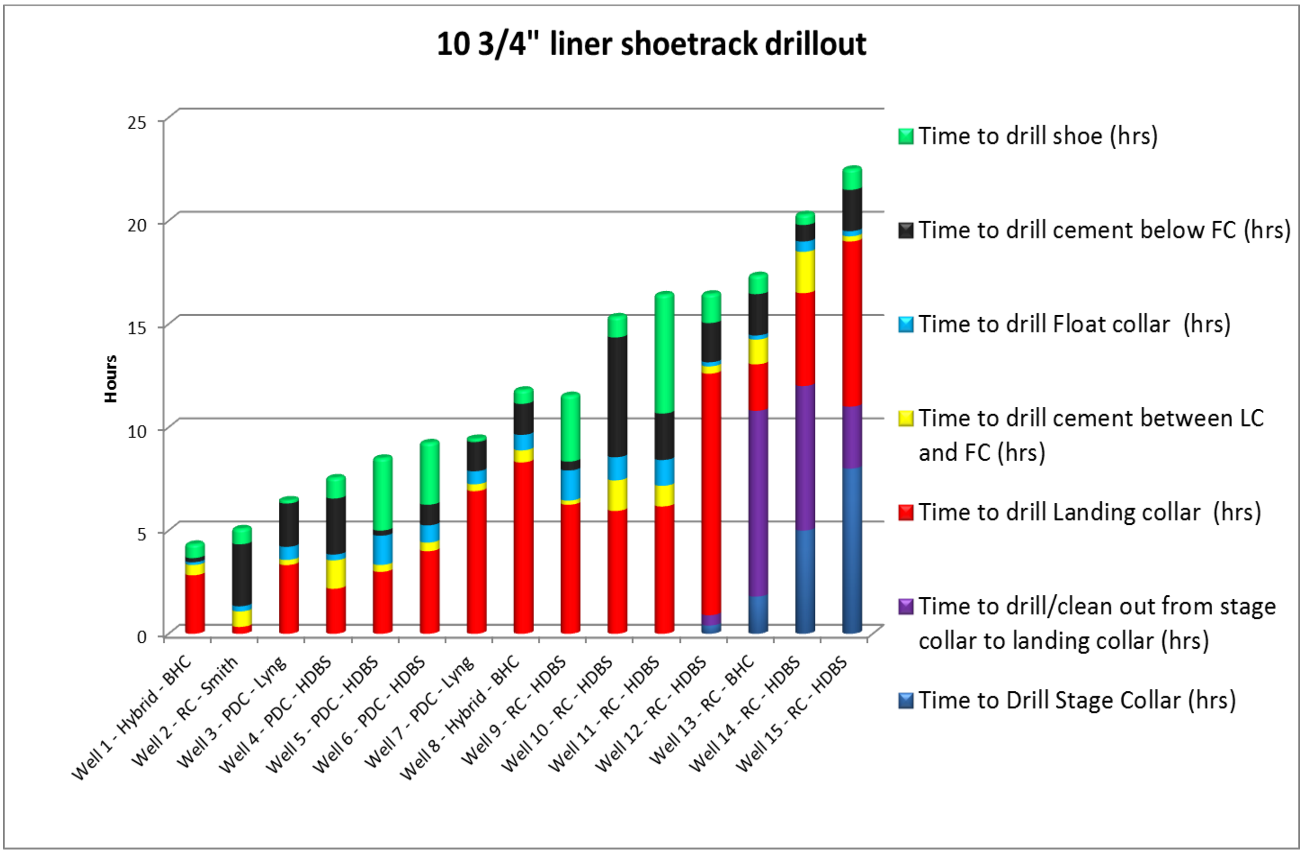


Figure 7.13: Graph showing the drilling time for each component in the shoetrack for 15 different wells. The colour code of each component is given to the right in the figure, with the drilling time in hours on the y-axis.

The graph above is a summary of all the statistics for the 15 selected wells on the previous page. The figure above clearly shows that the component taking the most time of the drill out is the landing collar (indicated with a red colour). We can also see that wells containing stage equipment is taking long time to drill (Well 12-15). For that reason, the focus will be directed towards the shoe track equipment which has the longest drill out times. The cementing plugs will also be included in the time to drill landing collar and stage collar, as there lands a cementing plug and dart after the cementing job is complete. On the next page, the landing collar, cementing plugs, opening/closing darts and stage collar will be discussed. The float collar, cement, and shoe are having in general low drill out times compared to the stage collar, and will not further be discussed in detail.

7.6. Study of the material types in the shoetrack for the 10 ¾” liners

Below a material study was performed on the 15 selected wells. The study was performed to see if the shoetrack equipment contained very hard or “undrillable” materials. The graph on the previous page shows that the cement, float collar and shoe has low drill out times. They will therefore not be discussed further in detail.

7.6.1 The single stage cementing

For the one stage cementing of the 10 ¾” liners, the shoetrack equipment will be the same for all studied wells. In the shoetrack, the material study was performed on the landing collar, cementing plug and the closing dart.

7.6.1.1 Cementing plug

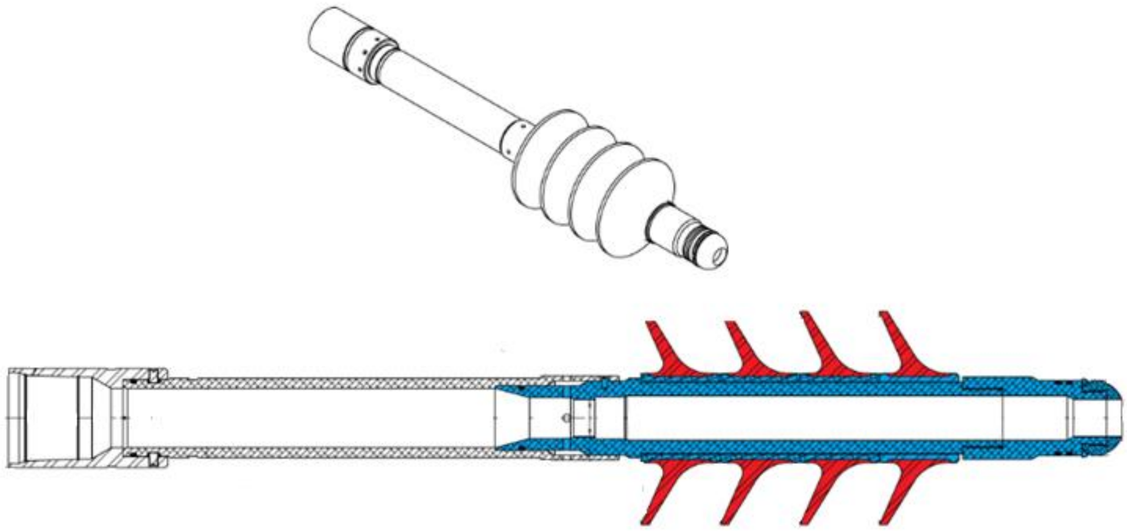


Figure 7.14: Cementing plug used for single stage cementing of the 10 3/4"liners. The red colour indicates rubber, the blue colour is aluminium. The part which is not colored is the running tool for the cement job; this will be retrieved to surface after the cementing job is complete. [56]

7.6.1.2 Closing dart

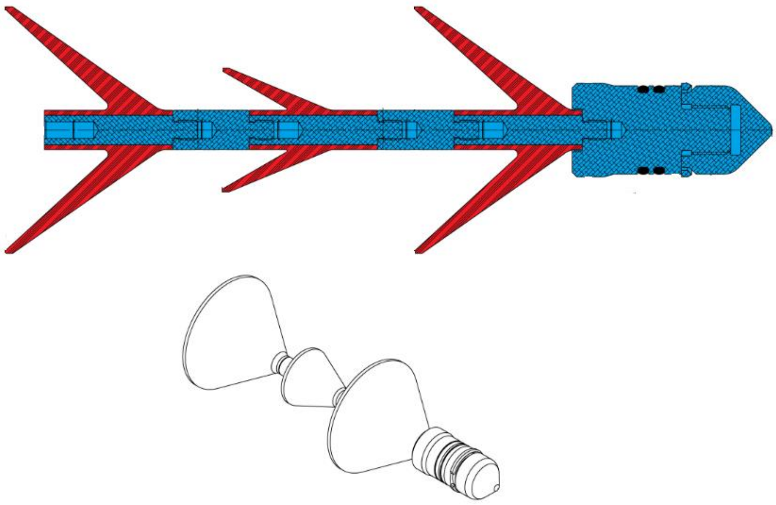


Figure 7.15: Closing dart which land inside the cementing plug for the single stage cementing job of 10 3/4 " liners. The red colour indicates rubber, and the blue colour indicated aluminium. [56]

7.6.1.3 Landing collar

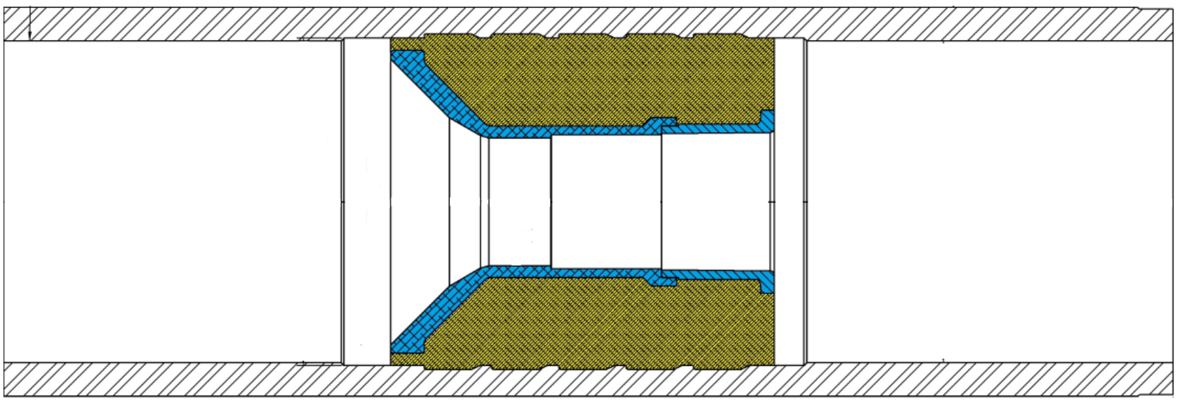


Figure 7.16: Landing collar used for 10 3/4 " liner cementing jobs. The yellow collar indicates cement, and the blue colour indicates aluminium. The left side of this component will be facing upwards when installed in the liner. This is the component where the cementing plug will be seated in after the first stage cementing operation is complete. [56]

7.6.2 Two stage cementing

For the two-stage cementing job a material study was performed on the cementing plugs, landing collar and stage collar. The closing dart and landing collar will be identical to the equipment used for one stage cementing of the liners (shown on the previous page)

7.6.2.1 Cementing plugs

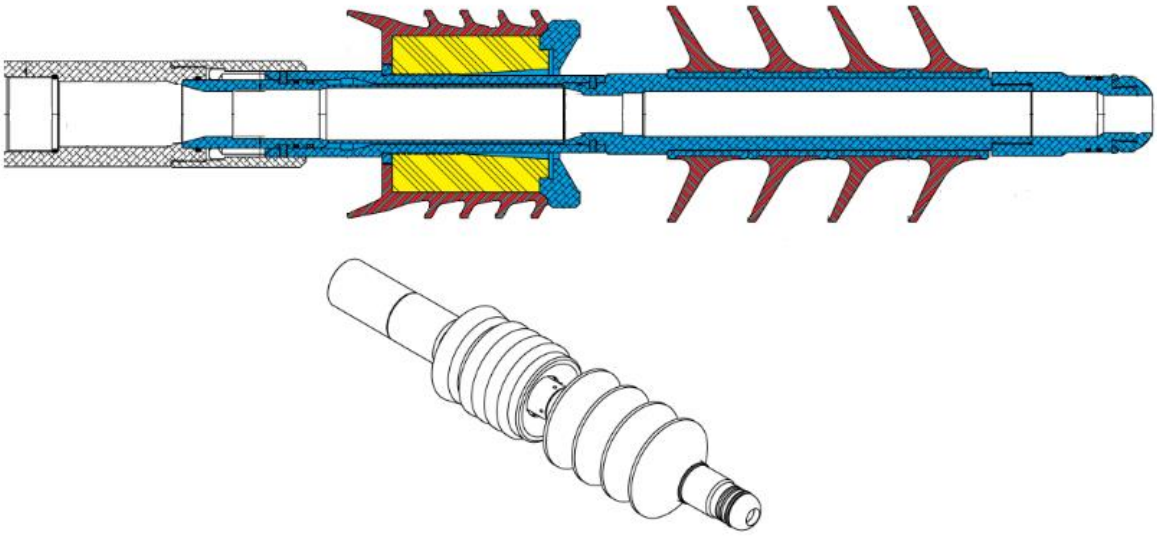


Figure 7.17: Cementing plugs used for two-stage cementing of 10 3/4" liners. Colour indications: Red (Rubber), Yellow (Hard plastic) and blue (aluminium). The uncoloured part is the running tool, which will be retrieved to surface after the cement job is complete. [56]

7.6.2.2 Stage collar

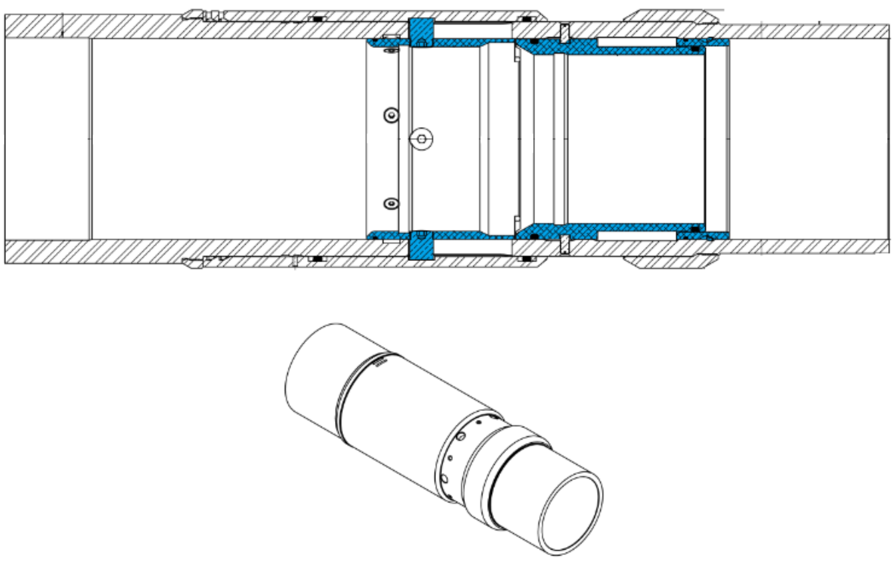


Figure 7.18: The stage collar used for two stage cementing 10 3/4" liners. The blue colour indicates material type of aluminium. The colored area is the parts that will be drilled out when drilling the shoetrack. [56]

7.6.2.3 Opening dart

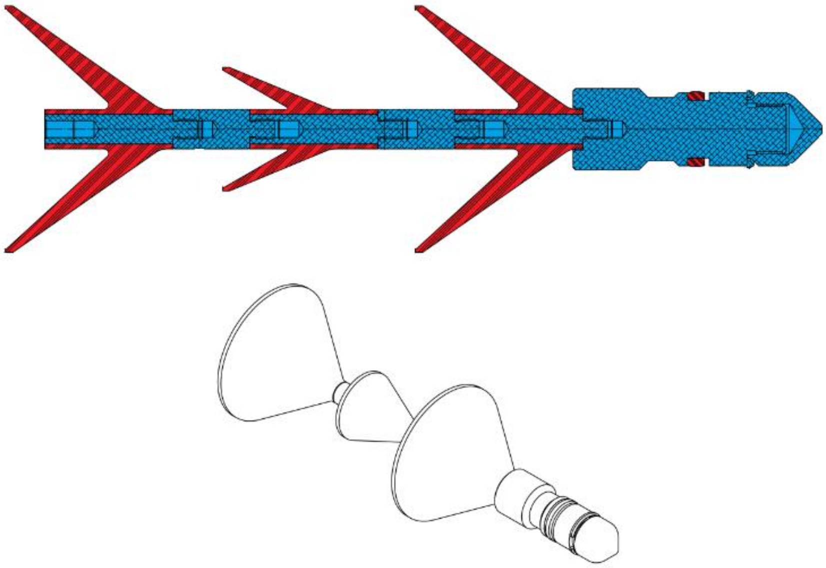


Figure 7.19: The opening dart used for releasing the lower cementing plug in 10 3/4" liners. Colour indications: Blue (aluminium) and red (rubber). [56]

7.6.3 Summary of material types

As shown, the materials found in the shoetrack equipment studied are: Hard plastic, rubber, aluminium and cement. These are relatively soft materials, and should not be a problem when drilling with conventional bits.

7.7 Feet-by-feet drilling parameter study of the 10 ¾”liners

For the 15 selected wells, feet-by-feet data logs were collected. The data was collected from drilling logs. The data was sorted out to study the parameters when drilling out the shoetrack. In this detailed study, the main objective was to see what drilling parameters is the most effective when drilling the shoetrack, with main weight on the landing collar. The study will try to conclude and find the optimized drilling parameters for the landing collar, since this component takes most of the time to drill. The study will look at weight on bit, flow rate, revolution speed and torque. The results will further be discussed under “Discussion of the results” (Chapter 8).

7.7.1 About the field data:

The feet-by-feet data is collected from feet-by-feet logs. From the logs, one parameter will be represented as the average for each foot drilled. These averages are further used to calculate the total average, maximum value and cumulative values.
The torque and weight on bit is measured from the surface, and does not represent the actual WOB and torque at the bit, this is discussed further in section 8.3.

7.7.2 About the equipment used:

As discussed under “Halliburton cementing operation (10 ¾”-Liners) (page 51), the same equipment will be found in all the wells studied. The single page description of each well, will indicated what kind of cementing job that was performed. Halliburton is the provider for the cementing plug equipment and landing collar. For more detailed pictures about the shoetrack equipment, this can be found under the material study (Section 7.6).

On the next following pages, a 1 page spec sheet about the shoetrack drill out will be posted for each well. The speech sheet will include drilling parameters used (max, average and cumulative values) and information about the shoetrack (Assembly, inclination, length etc.). For hybrid bits and roller cone bits, the total energy (TE) is also calculated, to show how much the shoetrack is affecting the bearing life of the cones. The bit used will also be posted as a picture for wells with available figures. Bit spec sheet is available as appendix for the bits used in Well (4-6 & 9-15).

7.7.3 Well 1

Shoetrack composition:	Single stage cementing job
Assembly:	Geopilot
Shoe track length: (ft)	181
Inclination: (Start inclination of shoetrack)	74°
Bit supplier/Bit type	Baker Hughes/Hybrid
Total Energy (TE) used through shoetrack	16,01

Time to drill different components in the shoetrack:	**Drilling time [hrs]**
Time to drill Landing collar	2,83
Time to drill cement between LC and FC	0,50
Time to drill Float collar	0,13
Time to drill cement below FC	0,20
Time to drill shoe	0,67
Total time drilling from wiper plugs to out of shoe	4,33

Parameters	**Max**	**Average**	**Cummulative**
WOB[klb]	40,76	13,35	2428,99
Flow rate[gpm]	638,09	553,66	143841,51
Torque[f-kp]	16,88	14,72	2678,89
RPM	80,29	72,69	18885,81
ROP [ft/hr]		41,80	

**Cummulative flow rate= Average flow rate*time to drill shoetrack [hrs]*60min/hr*

***Cummulative RPM=Average RPM*time to drill shoetrack[hrs]*60min/hr*

Figure 7.20: The Kymera HP623F hybrid bit. [58]

7.7.4 Well 2

Shoetrack composition:	Single stage cementing job
Assembly:	Geopilot
Shoe track length: (ft)	186
Inclination: (Start inclination of shoetrack)	73,7°
Bit supplier/Bit type	Smith/Roller Cone
Total Energy (TE) used through shoetrack	20,08

Time to drill different components in the shoetrack	**Drilling time [hrs]**
Time to drill Landing collar	0,33
Time to drill cement between LC and FC	0,75
Time to drill Float collar	0,25
Time to drill cement below FC	3,00
Time to drill shoe	0,75
Total time drilling from wiper plugs to out of shoe	5,08

Parameters	**Max**	**Average**	**Cummulative**
WOB[klb]	25,62	4,73	875,50
Flow rate[gpm]	699,30	543,81	165752,84
Torque[f-kp]	18,92	12,59	2505,27
RPM	90,17	76,65	23364,43
ROP [ft/hr]		36,61	

**Cummulative flow rate= Average flow rate*time to drill shoetrack [hrs]*60min/hr*

***Cummulative RPM=Average RPM*time to drill shoetrack[hrs]*60min/hr*

Figure 7.21: GF30OD Roller Cone bit. [58]

7.7.5 Well 3

Shoetrack composition:	Single stage cementing job
Assembly:	Xceed 675
Shoe track length: (ft)	180
Inclination: (Start inclination of shoetrack)	60°
Bit supplier/Bit type	Lyng/PDC

Time to drill different components in the shoetrack	**Drilling time [hrs]**
Time to drill Landing collar	3,33
Time to drill cement between LC and FC	0,25
Time to drill Float collar	0,63
Time to drill cement below FC	2,1
Time to drill shoe	0,16
Total time drilling from wiper plugs to out of shoe	6,47

*No feet-by-feet data available for this drill out

Bit model	LMX6342D1

7.7.6 Well 4

Shoetrack composition:	Single stage cementing job
Assembly:	Geopilot
Shoe track length: (ft)	169,4
Inclination: (Start inclination of shoetrack)	64°
Bit supplier/Bit type	Halliburton/PDC

Time to drill different components in the shoetrack	**Drilling time [hrs]**
Time to drill Landing collar	2,18
Time to drill cement between LC and FC	1,38
Time to drill Float collar	0,28
Time to drill cement below FC	2,71
Time to drill shoe	1
Total time drilling from wiper plugs to out of shoe	7,55

Parameters	**Max**	**Average**	**Cummulative**
WOB[klb]	18,82	3,53	599,91
Flow rate[gpm]	510,05	509,24	230684,44
Torque[f-kp]	15,45	12,69	2157,63
RPM	59,46	49,10	22240,09
ROP [ft/hr]		22,44	
**Cummulative flow rate= Average flow rate*time to drill shoetrack [hrs]*60min/hr*			
***Cummulative RPM=Average RPM*time to drill shoetrack[hrs]*60min/hr*			

Comments: No cement was found between LC and FC, this is why the average WOB is so low.

Figure 7.21: MMG64D PDC bit. [57]

7.7.7 Well 5

Shoetrack composition:	Single stage cementing job
Assembly:	Geopilot
Shoe track length: (ft)	105
Inclination: (Start inclination of shoetrack)	67°
Bit supplier/Bit type	Halliburton/PDC

Time to drill different components in the shoetrack:	**Drilling time [hrs]**
Time to drill Landing collar	3,00
Time to drill cement between LC and FC	0,33
Time to drill Float collar	1,42
Time to drill cement below FC	0,25
Time to drill shoe	3,50
Total time drilling from wiper plugs to out of shoe	8,50

Parameters	**Max**	**Average**	**Cummulative**
WOB[klb]	31,52	8,66	918,46
Flow rate[gpm]	526,98	506,01	258064,71
Torque[f-kp]	9,92	7,18	761,09
RPM	97,85	70,65	36029,39
ROP [ft/hr]		12,35	

**Cummulative flow rate= Average flow rate*time to drill shoetrack [hrs]*60min/hr*

***Cummulative RPM=Average RPM*time to drill shoetrack[hrs]*60min/hr*

Figure 7.22: SFG65RH PDC Bit. [57]

7.7.8 Well 6

Shoetrack composition:	Single stage cementing job
Assembly:	Geopilot
Shoe track length: (ft)	188
Inclination: (Start inclination of shoetrack)	61°
Bit supplier/Bit type	Halliburton/PDC

Time to drill different components in the shoetrack	**Drilling time [hrs]**
Time to drill Landing collar	4,00
Time to drill cement between LC and FC	0,42
Time to drill Float collar	0,83
Time to drill cement below FC	1,00
Time to drill shoe	3,00
Total time drilling from wiper plugs to out of shoe	9,25

Parameters	Max	Average	Cummulative
WOB[klb]	22,21	14,42	2710,29
Flow rate[gpm]	562,54	516,74	286792,56
Torque[f-kp]	19,17	17,44	3279,15
RPM	85,13	73,57	40829,30
ROP [ft/hr]		20,32	
**Cummulative flow rate= Average flow rate*time to drill shoetrack [hrs]*60min/hr*			
***Cummulative RPM=Average RPM*time to drill shoetrack[hrs]*60min/hr*			

Figure 7.23: MMG64H PDC Bit. [57]

7.7.9 Well 7

Shoetrack composition:	Single stage cementing job
Assembly:	Xceed 675
Shoe track length: (ft)	125,67
Inclination: (Start inclination of shoetrack)	70°
Bit supplier/Bit type	Lyng/PDC

Time to drill different components in the shoetrack	**Drilling time [hrs]**
Time to drill Landing collar	6,91
Time to drill cement between LC and FC	0,33
Time to drill Float collar	0,63
Time to drill cement below FC	1,42
Time to drill shoe	0,16
Total time drilling from wiper plugs to out of shoe	9,45

Parameters	**Max**	**Average**	**Cummulative**
WOB[klb]	27,05	7,60	958,12
Flow rate[gpm]	535,47	503,13	285272,70
Torque[f-kp]	22,84	18,18	2290,48
RPM	60,08	53,53	30352,74
ROP [ft/hr]		13,30	

**Cummulative flow rate= Average flow rate*time to drill shoetrack [hrs]*60min/hr*

***Cummulative RPM=Average RPM*time to drill shoetrack[hrs]*60min/hr*

Bit model	LM7332M1

7.7.10 Well 8

Shoetrack composition:	Single stage cementing job
Assembly:	Geopilot
Shoe track length: (ft)	151,4
Inclination: (Start inclination of shoetrack)	74°
Bit supplier/Bit type	Baker Hughes/Hybrid
Total Energy (TE) used through shoetrack	59,12

Time to drill different components in the shoetrack	**Drilling time [hrs]**
Time to drill Landing collar	8,30
Time to drill cement between LC and FC	0,58
Time to drill Float collar	0,75
Time to drill cement below FC	1,50
Time to drill shoe	0,67
Total time drilling from wiper plugs to out of shoe	11,80

Parameters	**Max**	**Average**	**Cummulative**
WOB[klb]	66,51	13,76	2091,57
Flow rate[gpm]	638,32	553,95	392193,22
Torque[f-kp]	19,06	15,40	2340,21
RPM	90,07	81,00	57349,87
ROP [ft/hr]		12,83	

**Cummulative flow rate= Average flow rate*time to drill shoetrack [hrs]*60min/hr*

***Cummulative RPM=Average RPM*time to drill shoetrack[hrs]*60min/hr*

Figure 7.24: The Kymera HP623 hybrid bit. [58]

7.7.11 Well 9

Shoetrack composition:	Single stage cementing job
Assembly:	Geopilot
Shoe track length: (ft)	182
Inclination: (Start inclination of shoetrack)	74°
Bit supplier/Bit type	Halliburton/Roller Cone
Total Energy (TE) used through shoetrack	55,28

Time to drill different components in the shoetrack	**Drilling time [hrs]**
Time to drill Landing collar	6,25
Time to drill cement between LC and FC	0,20
Time to drill Float collar	1,46
Time to drill cement below FC	0,43
Time to drill shoe	3,20
Total time drilling from wiper plugs to out of shoe	11,9

Parameters	**Max**	**Average**	**Cummulative**
WOB[klb]	29,88	4,94	884,07
Flow rate[gpm]	468,09	457,40	326580,93
Torque[f-kp]	15,76	15,04	2692,65
RPM	60,00	49,74	35515,87
ROP [ft/hr]		15,29	

**Cummulative flow rate= Average flow rate*time to drill shoetrack [hrs]*60min/hr*

***Cummulative RPM=Average RPM*time to drill shoetrack[hrs]*60min/hr*

Figure 7.25: EQH30D2RC Roller Cone bit. [57]

7.7.12 Well 10

Shoetrack composition:	Single stage cementing job
Assembly:	Geopilot
Shoe track length: (ft)	271
Inclination: (Start inclination of shoetrack)	69°
Bit supplier/Bit type	Halliburton/PDC
Total Energy (TE) used through shoetrack	79,26

Time to drill different components in the shoetrack	**Drilling time [hrs]**
Time to drill Landing collar	5,95
Time to drill cement between LC and FC	1,48
Time to drill Float collar	1,12
Time to drill cement below FC	5,80
Time to drill shoe	1,00
Total time drilling from wiper plugs to out of shoe	15,35

Parameters	**Max**	**Average**	**Cummulative**
WOB[klb]	23,54	9,45	2569,92
Flow rate[gpm]	460,54	423,42	389969,97
Torque[f-kp]	19,63	18,39	5000,98
RPM	85,00	72,87	67109,27
ROP [ft/hr]		17,65	
**Cummulative flow rate= Average flow rate*time to drill shoetrack [hrs]*60min/hr*			
***Cummulative RPM=Average RPM*time to drill shoetrack[hrs]*60min/hr*			

Figure 7.26: EQH12DS Roller Cone Bit. [57]

7.7.13 Well 11

Shoetrack composition:	Single stage cementing job
Assembly:	Geopilot
Shoe track length: (ft)	232
Inclination: (Start inclination of shoetrack)	69,9°
Bit supplier/Bit type	Halliburton/Roller Cone
Total Energy (TE) used through shoetrack	26,65

Time to drill different components in the shoetrack	**Drilling time [hrs]**
Time to drill Landing collar	6,17
Time to drill cement between LC and FC	1,00
Time to drill Float collar	1,25
Time to drill cement below FC	2,25
Time to drill shoe	5,75
Total time drilling from wiper plugs to out of shoe	16,42

Parameters	**Max**	**Average**	**Cummulative**
WOB[klb]	30,96	3,53	823,14
Flow rate[gpm]	654,71	433,48	427065,98
Torque[f-kp]	14,22	12,77	2974,44
RPM	62,00	43,28	42635,85
ROP [ft/hr]		14,13	

***Cummulative flow rate= Average flow rate*time to drill shoetrack [hrs]*60min/h*

***Cummulative RPM=Average RPM*time to drill shoetrack[hrs]*60min/hr*

Figure 7.27: EQH20D2R Roller Cone Bit. [57]

7.7.14 Well 12

Shoetrack composition:	Two stage cementing job
Assembly:	Geopilot
Shoe track length: (ft)	272
Inclination: (Start inclination of shoetrack)	58°
Bit supplier/Bit type	Halliburton/Roller Cone
Total Energy (TE) used through shoetrack	58,43

Time to drill different components in the shoetrack	**Drilling time [hrs]**
Time to drill Stage Collar	0,40
Time to drill/clean out from stage collar to landing collar	0,50
Time to drill Landing collar	11,7
Time to drill cement between LC and FC	0,35
Time to drill Float collar	0,20
Time to drill cement below FC	1,90
Time to drill shoe (hrs)	1,40
Total time drilling from wiper plugs to out of shoe	16,45

Note:
Drilled thru' stage collar (15mins). Suggested the sleeve collar below the stage collar was knocked off (maybe during Pressure Test) and fell onto landing collar. This could have contributed to spinning and prevent the bit from biting.

Parameters	**Max**	**Average**	**Cummulative**
WOB[klb]	44,25	15,95	4354,30
Flow rate[gpm]	662,06	602,75	594913,77
Torque[f-kp]	22,60	17,74	4841,74
RPM	100,25	94,87	93632,13
ROP [ft/hr]		16,53	

**Cummulative flow rate= Average flow rate*time to drill shoetrack [hrs]*60min/hr*

***Cummulative RPM=Average RPM*time to drill shoetrack[hrs]*60min/hr*

Figure 7.28: EQH12DS Roller Cone Bit. [57]

7.7.15 Well 13

Shoetrack composition:	Two stage cementing job
Assembly:	Geopilot
Shoe track length: (ft)	1270
Inclination: (Start inclination of shoetrack)	52°
Bit supplier/Bit type	Baker Hughes/Roller Cone
Total Energy (TE) used through shoetrack	339,73

Time to drill different components in the shoetrack	**Drilling time [hrs]**
Time to drill Stage Collar	1,80
Time to drill/clean out from stage collar to landing collar	9,00
Time to drill Landing collar	2,25
Time to drill cement between LC and FC	1,20
Time to drill Float collar	0,20
Time to drill cement below FC	2,00
Time to drill shoe	0,90
Total time drilling from wiper plugs to out of shoe	17,35

Parameters	**Max**	**Average**	**Cummulative**
WOB[klb]	47,56	14,66	18746,95
Flow rate[gpm]	786,32	580,40	604195,76
Torque[f-kp]	18,38	15,52	19848,91
RPM	154,80	130,03	135357,40
ROP [ft/hr]		73,20	

**Cummulative flow rate= Average flow rate*time to drill shoetrack [hrs]*60min/hr*

***Cummulative RPM=Average RPM*time to drill shoetrack[hrs]*60min/hr*

Comment from drilling log:

Indication of pushing objects when tripping in below stage collar.

Figure 7.29: VMD-20DVHX Roller Cone bit. [57]

7.7.16 Well 14

Shoetrack composition:	Two stage cementing job
Assembly:	Geopilot
Shoe track length: (ft)	40,50
Inclination: (Start inclination of shoetrack)	70,77°
Bit supplier/Bit type	Halliburton/Roller Cone
Total Energy (TE) used through shoetrack	5,63

Time to drill different components in the shoetrack	**Drilling time [hrs]**
Time to drill Stage Collar	5,00
Time to drill/clean out from stage collar to landing collar	7,00
Time to drill Landing collar	4,50
Time to drill cement between LC and FC	2,00
Time to drill Float collar	0,50
Time to drill cement below FC	0,80
Time to drill shoe	0,50
Total time drilling from wiper plugs to out of shoe	21,80

Parameters	**Max**	**Average**	**Cummulative**
WOB[klb]	22,69	12,53	513,81
Flow rate[gpm]	417,89	385,66	504446,57
Torque[f-kp]	17,34	14,75	604,91
RPM	62,89	57,42	75105,87
ROP [ft/hr]		1,86	

**Cummulative flow rate= Average flow rate*time to drill shoetrack [hrs]*60min/hr*

***Cummulative RPM=Average RPM*time to drill shoetrack[hrs]*60min/hr*

Figure 7.30: EQHC1RC Roller Cone Bit. [57]

7.7.17 Well 15

Shoetrack composition:	Two stage cementing job
Assembly:	Geopilot
Shoe track length: (ft)	886
Inclination: (Start inclination of shoetrack)	54°
Bit supplier/Bit type	Halliburton/Roller Cone
Total Energy (TE) used through shoetrack	381,74

Time to drill different components in the shoetrack	**Drilling time [hrs]**
Time to Drill Stage Collar	8,00
Time to drill/clean out from stage collar to landing collar	3,00
Time to drill Landing collar	8,00
Time to drill cement between LC and FC	0,25
Time to drill Float collar	0,25
Time to drill cement below FC	2,00
Time to drill shoe	1,00
Total time drilling from wiper plugs to out of shoe	22,50

Parameters	**Max**	**Average**	**Cummulative**
WOB[klb]	46,67	24,37	21619,75
Flow rate[gpm]	610,27	560,23	756313,80
Torque[f-kp]	16,43	14,20	12598,84
RPM	140,01	110,64	149370,44
ROP [ft/hr]		39,38	
**Cummulative flow rate= Average flow rate*time to drill shoetrack [hrs]*60min/hr*			
***Cummulative RPM=Average RPM*time to drill shoetrack[hrs]*60min/hr*			

Figure 7.31: EQH20D2R Roller Cone bit. [57]

7.8 Comparisons of the 10 ¾" liner drillouts

It will here be posted some graphs containing information about the drilling parameters used for the 10 ¾" liner shoetrack drill out (Well 3 will not be included, because no drilling data was available). The graphs are posted to try to identify any possible trends in the drilling parameters, and to make a better overview of the results. Some comments about the analytical grade are also posted for some graphs that have high uncertainty due to low sample size. The results will be discussed more in detail under "Discussion of the results" (page130).

7.8.1 Single stage cementing

7.8.1.1 Average flowrate vs total drilling time

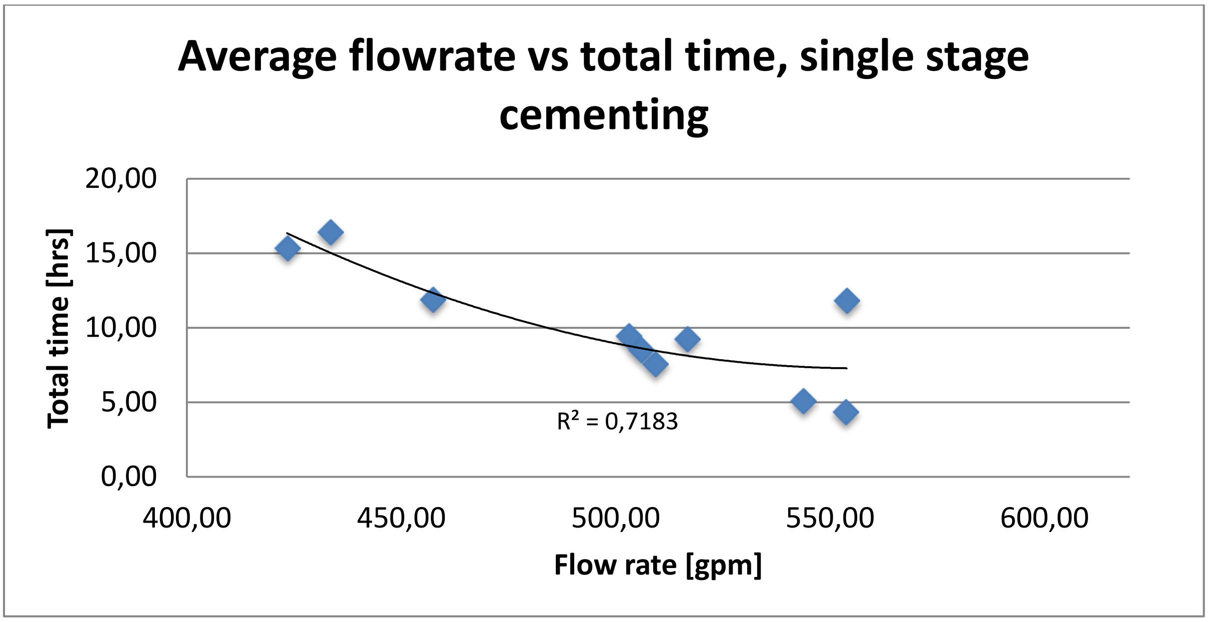


Figure 7.32: The relationship between the average flowrate and total drilling time of the shoetrack for the liners containing single stage cementing equipment

The graph above shows that there might be a relation between the flow rate and the total drilling time for the single stage cemented liners. A linear regression (2nd order polynomial) shows that the correlation coefficient is 0,7183. The reason for this might be that, the higher the flow rate, the better hole cleaning. As discussed earlier in general when drilling formation, hole cleaning is essential for the rate of penetration, but when drilling shoetrack equipment a lot of factors affect each other.

7.8.1.2 Average WOB vs total drilling time

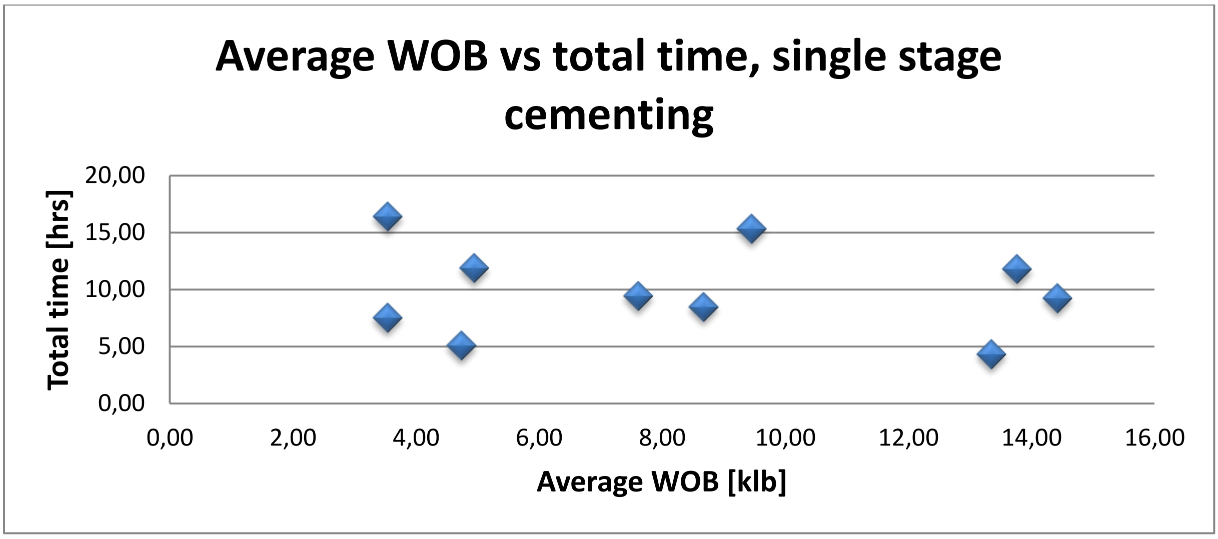


Figure 7.33: Showing the average weight on bit used for the liners containing single stage cementing equipment plotted against the total drilling time.

From the graph above we can see that it is hard to connect the average WOB and the total drilling time.

7.8.2 Two stage cementing

7.8.2.1 Average flowrate vs total drilling time

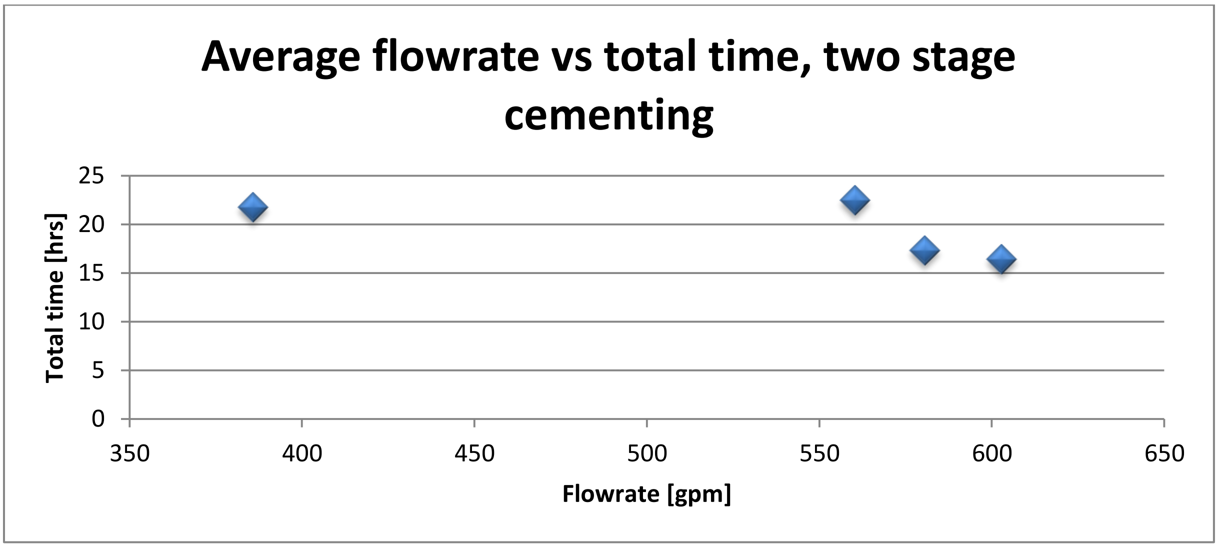


Figure 7.34: Average flowrate used for drilling two stage cemented liners plotted against total time

From this graph we can see that it is hard to conclude on anything when plotting the average flow rate against the total drilling time. It should also be noticed that when drilling through two stage cemented liners, the flow rate will also include some cleaning and reaming. This will affect the flow rate a lot, and does not represent the real flow when only drilling shoetrack equipment.

7.8.2.2 Average WOB vs total time

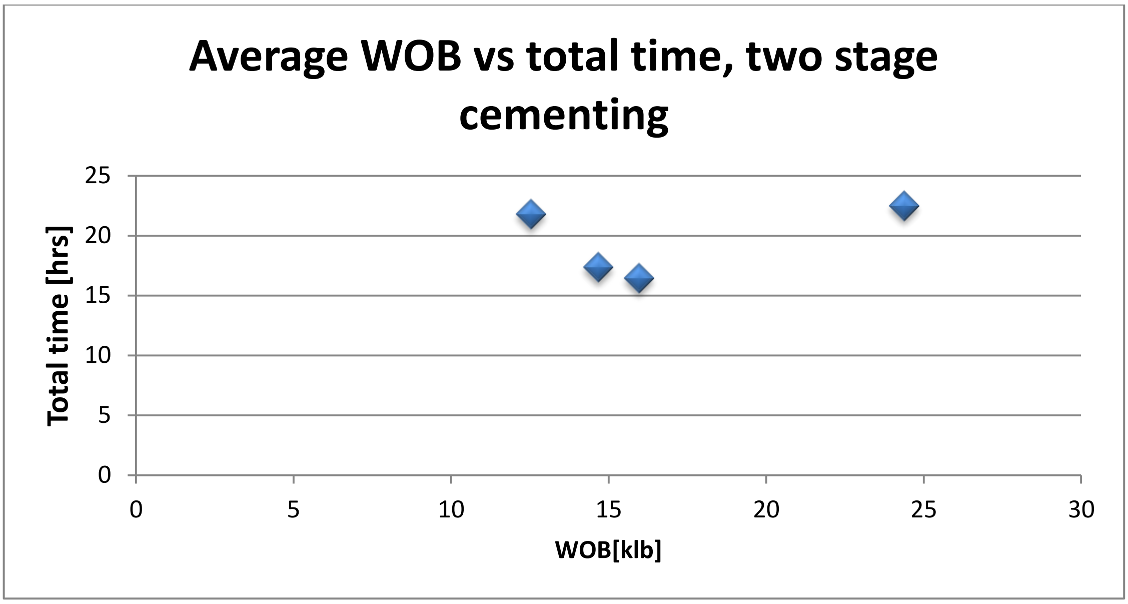


Figure 7.35: Average weight on bit plotted against total time to drilling time for two stage cemented liners

For the two stage cemented liners, the WOB will be affected greatly of the washing and reaming operations. This will affect the results, and does not represent the average WOB when only drilling shoetrack equipment.

7.9 Landing collar study

7.9.1 Time to drill landing collar vs average flowrate

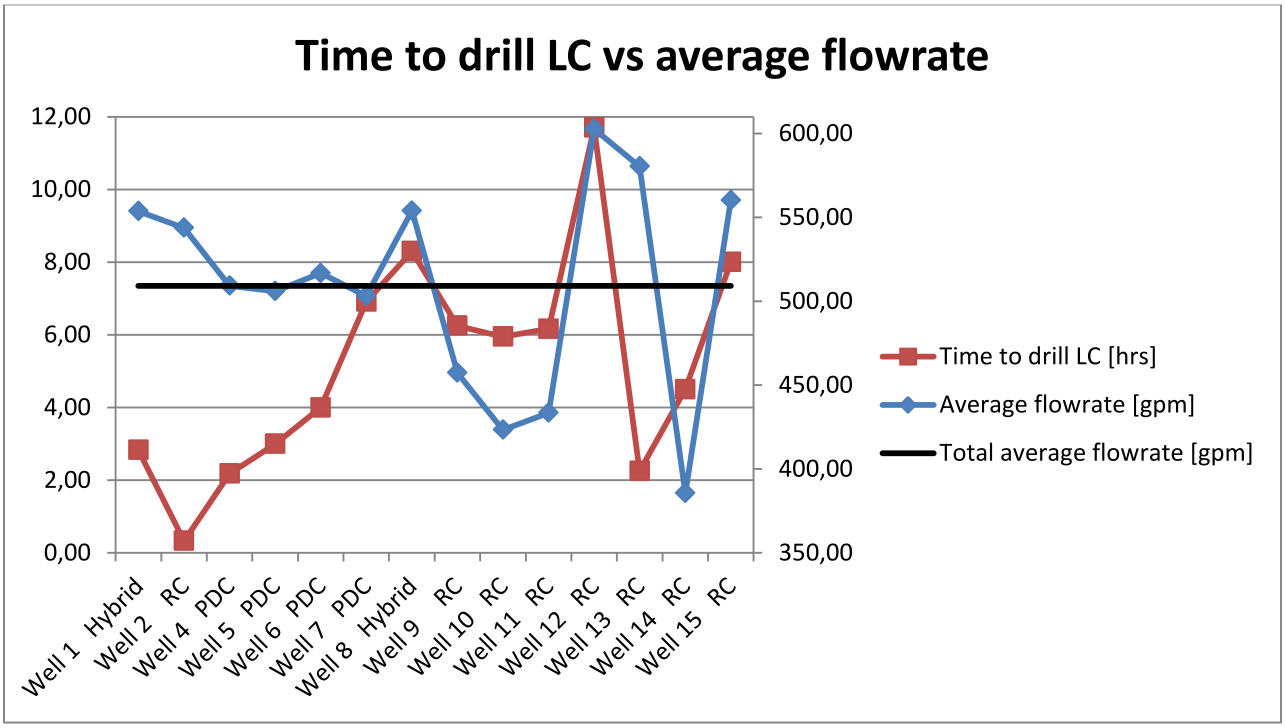


Figure 7.36: Time to drill landing collar plotted against average flowrate. The total average flowrate (trend) for all the selected wells is also plotted (black line)

Parameter: Flowrate		Average time to drill LC
Wells with flowrate over total average	7	5,35
Wells with flowrate under total average	7	4,99

Table 7.3: Showing the associated time to drill the landing collar, for the wells with an average flowrate over or under the trend

7.9.2 Time to drill landing collar vs average weight on bit

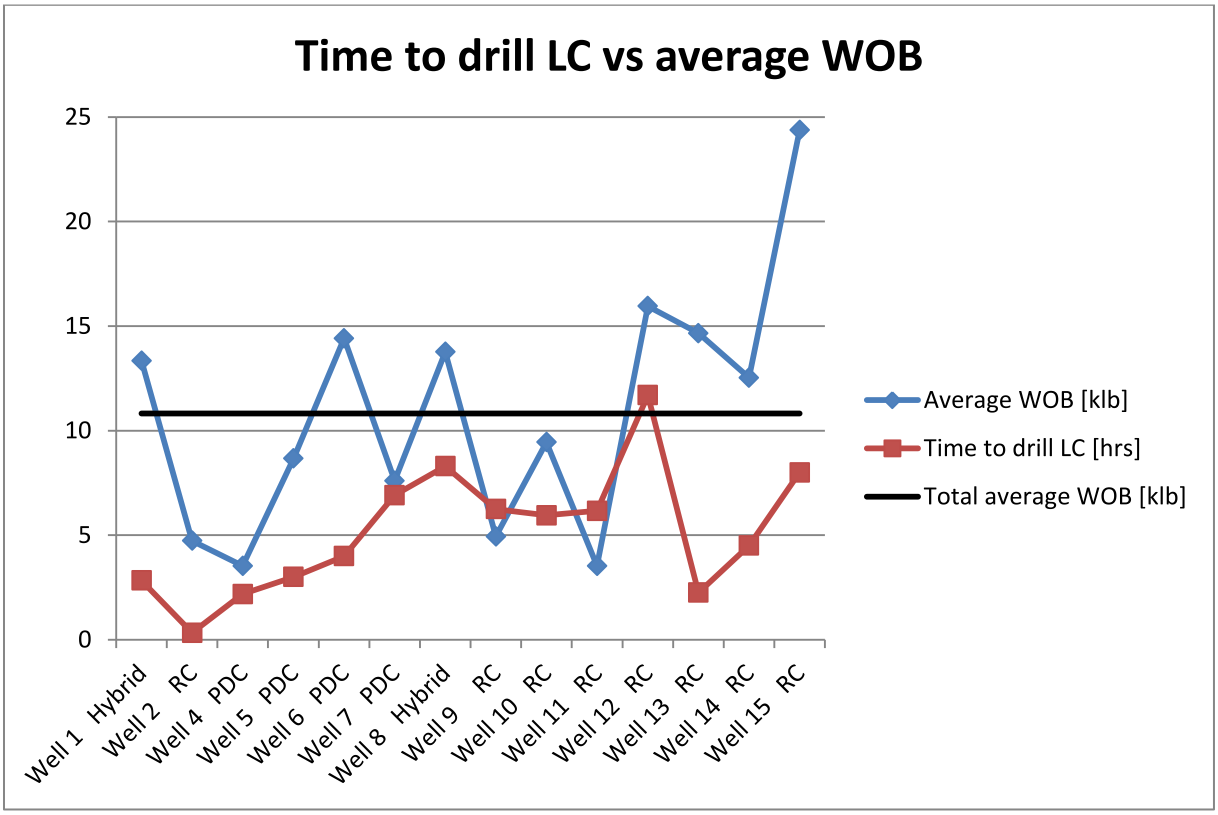


Figure 7.37: Time to drill landing collar plotted against the average weight on bit (WOB) used. The total average WOB (trend) for all the selected wells is also plotted (black line)

Parameter: Weight on bit (WOB)		Average time to drill LC
Wells with WOB over total average	7	14,78
Wells with WOB under total average	7	10,61

Table 7.4: Showing the associated time to drill the landing collar, for the wells with an average WOB value over or under the trend

7.9.3 Time to drill landing collar vs torque

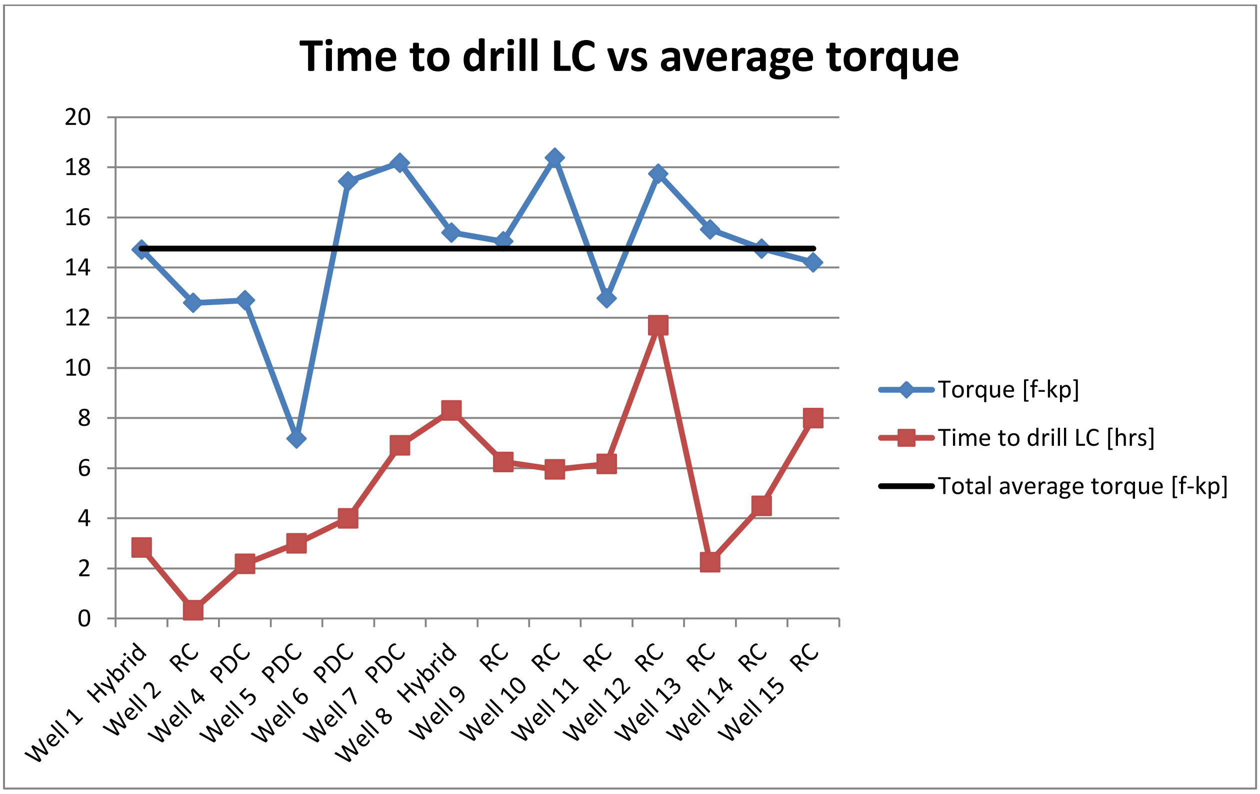


Figure 7.38: Time to drill the landing collar plotted against the average torque. The total average torque (trend) for all the selected wells is also plotted (black line).

Parameter: Torque		**Average time to drill LC**
Wells with torque over total average	7	6,48
Wells with torque under total average	7	3,86

Table 7.5: Showing the associated time to drill the landing collar, for the wells with an average torque over or under the trend

We can see that if the torque is increasing, the time to drill landing collar decreases in general. This might indicate that if the torque is too high, the cementing plugs will start to rotate, and the bit would not bite. For the two-stage cemented shoetracks, the trend does not follow as good as for the single stage cemented shoetrack. This might be due to the long intervals drilled, and the torque will not be so representative for the landing collar. The single stage cemented shoetracks are shorter and have a more common length.

7.9.4 Time to drill landing collar vs bit rotation speed

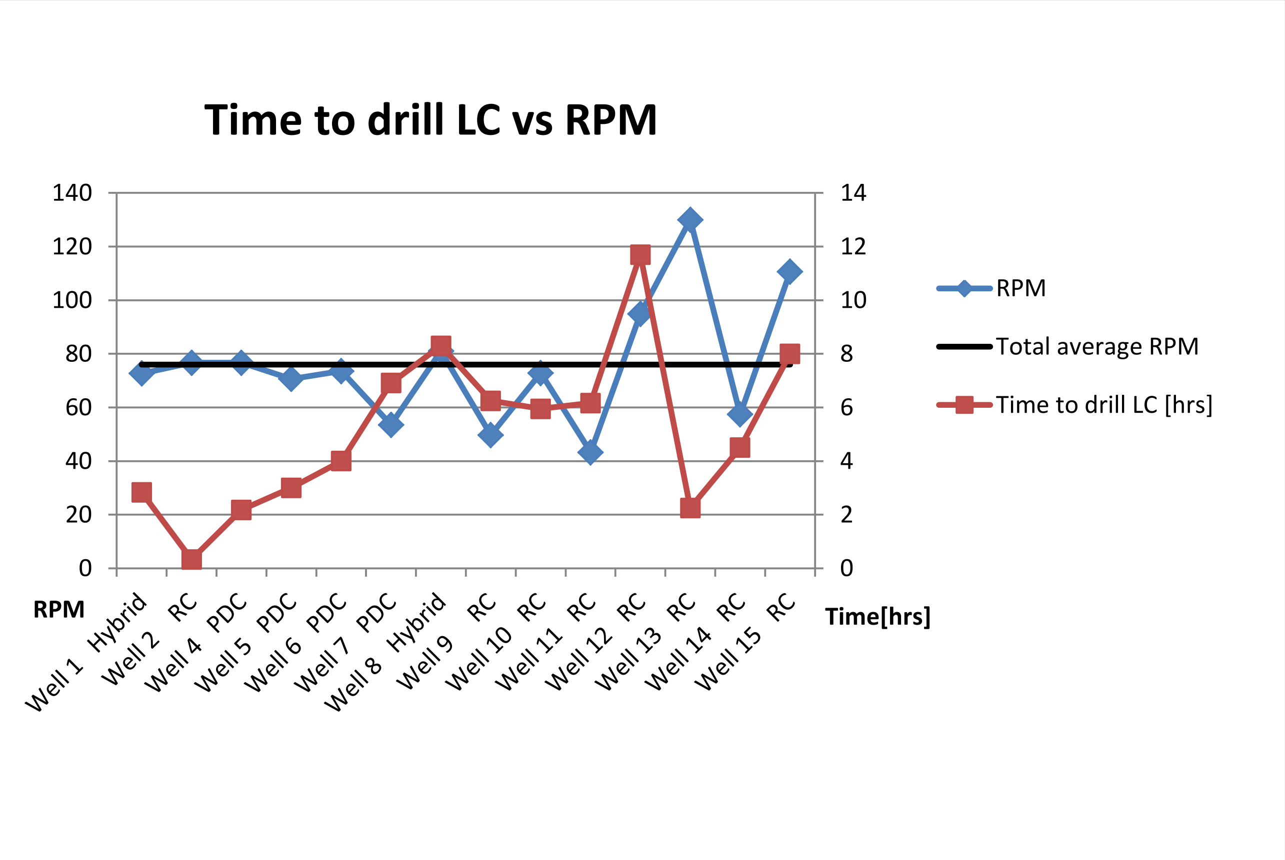


Figure 7.39: Time to drill the landing collar plotted against the average bit rotation speed. The total average revolution speed (trend) for all the selected wells is also plotted (black line).

Parameter: Rotation speed of bit (RPM)		Average time to drill LC
Wells with RPM over total average	6	5,5
Wells with RPM under total average	8	4,6

Table 7.6: Showing the associated time to drill the landing collar, for the wells with an average RPM over or under the trend

7.9.5 Time to drill landing collar with different drill bits

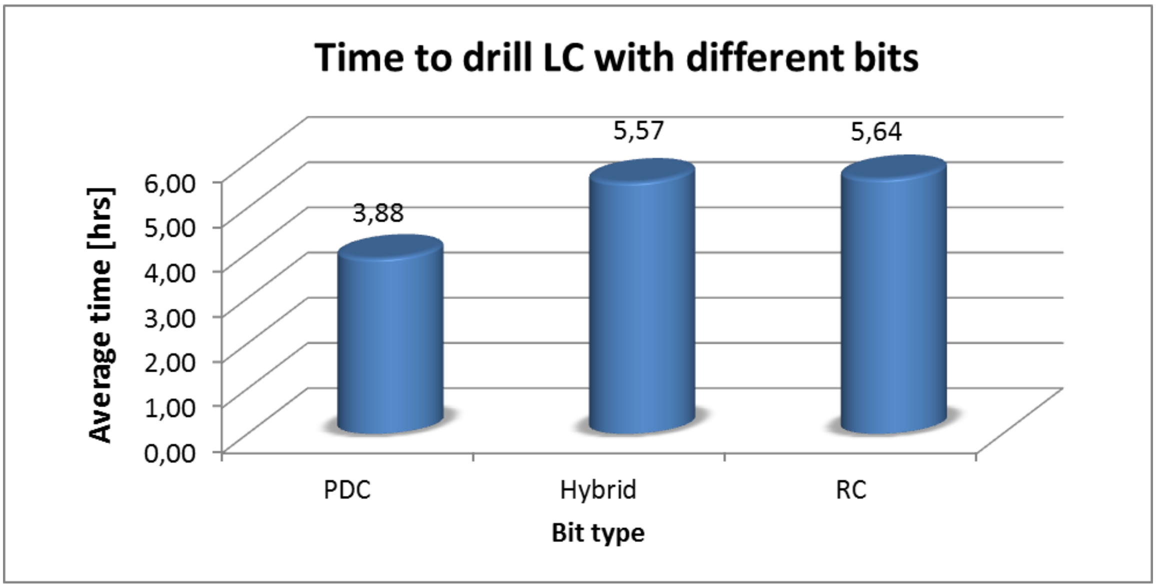


Figure 7.40: Shows the average time to drill the landing collar for different bit types for the 15 selected wells

This graph shows the drilling time of the landing collar in general, both for a single- and two stage cemented liner. The downside of this graph is that is has low analytic value. Only 2 wells were drilled with hybrid bit, 5 wells were drilled with PDC bit and 8 wells with roller cone. This will give misleading results, due to a low sample value.

7.9.6 Cost to drill the landing collar and potential savings

As shown the landing collar is a large problem for the 10 ¾" liners. Below there are posted a table showing the average of total time it takes to drill the LC (Landing collar) with different bits. An example is shown to illustrate the cost of drilling the landing collar, based on the average with all bits for the 15 selected wells. The drilling is assumed to be from a semi-sub rig (4000+ WD), with an average day rate of 432 000 $ [42].

The cost to drill the landing collar is 90 844 $, based on average data for the 15 wells. By just reducing the drill out time by 10%, a saving of 9 084 $ is achieved. This example shows that large savings is possible when reducing the drill out times of the landing collar.

Percentage of total time to drill Landing collar with different bits		
Roller Cone	**PDC**	**Hybrid**
34 %	46 %	68 %

Total average time to drill shoetrack (all wells) [hrs]	**Average time to drill LC [hrs]**	**Percentage of time to drill LC of total time**
12,28	5,05	41,1 %

Daily rig rate	$ 432 000
Hourly rig rate	$ 18 000
Cost to drill LC	$ 90 844

Reduction in time to drill LC	**10 %**	**20 %**	**30 %**	**40 %**	**50 %**	**60 %**	**70 %**	**80 %**
Cost to drill LC	$ 81 759	$ 72 675	$ 63 591	$ 54 506	$ 45 422	$ 36 337	$ 27 253	$ 18 169
Money saved	$ 9 084	$ 18 169	$ 27 253	$ 36 337	$ 45 422	$ 54 506	$ 63 591	$ 72 675

*Data based on averages values for the 15 selected wells

*LC=Landing collar

Table 7.7: Showing the expected percentage time to drill the landing collar for different bits, for the 15 selected wells. For example: If you choose to drill the landing collar with a PDC bit, you can expect to used 46% of the time to drill the landing collar of the total time to drill the whole shoetrack interval. These values are based on averages for the data from the 15 wells. The average time to drill the LC is based on the percentage time for all bits. The costs and savings possible when reducing the drill out time are also illustrated. It is assumed to drill from a floating rig with a daily rate of $ 432 000.

Chapter 8

Discussion of the results

As shown in the broad study, the deeper and smaller the bit size will be, the more time consuming the shoetrack drill out process will be (Figure 7.2). The deeper wells are often more horizontal, in order to get a better recovery rate from the reservoir. Factors as drag, hydraulic packoff and torque will discuss further in section 8.3. The inclination plotted against the total time for drillout also shows this trend (Figure 7.12). The first casings will also have a smaller shoetrack interval, with different plugs than the deeper wells.

The formations drilled in the first sections are softer than the deeper sections, as the confining pressure will increase [53]. Bit designed to drill soft formations will be used when drilling the shoetrack for the first casing sections, and bits more adapted for harder formations will be used when drilling the deeper wells. The materials found in the shoetrack has shown to be relatively soft materials, this trend might show that the soft material in the shoetrack equipment are better drilled with bit optimised for drilling soft formations.

Below there is posted a general discussion about the parameters used when drilling out the shoetrack for the 15 selected wells. Well 3 is not included, as there was no data available for this well. It should be noticed that when referring to landing collar and stage collar in the discussion below, this will include the cementing plug with the dart on top plus the stage- or landing collar. A table is present below to make it easier for the reader to see how the parameters varied for the different wells.

	Average Wob [klb]	Average Flow rate [gpm]	Average ROP [ft/hr]	Average RPM	Average Torque [f-kp]	Cummulative WOB [klb]	Cummulative Flow rate [gpm]	Time to drill LC [hrs]	Total time [hrs]
Well 1 Hybrid	13,35	553,66	41,80	72,69	14,72	2428,99	143841,51	2,83	4,33
Well 2 RC	4,73	543,81	36,61	76,65	12,59	875,50	165752,84	0,33	5,08
Well 3 PDC	-	-	-	-	-	-	-	3,33	6,47
Well 4 PDC	3,53	509,24	22,44	76,65	12,69	599,91	230684,44	2,18	7,55
Well 5 PDC	8,66	506,01	12,35	70,65	7,18	918,46	258064,71	3,00	8,50
Well 6 PDC	14,42	516,74	20,32	73,57	17,44	2710,29	286792,56	4,00	9,25
Well 7 PDC	7,60	503,13	13,30	53,53	18,18	958,12	285272,70	6,91	9,45
Well 8 Hybrid	13,76	553,95	12,83	81,00	15,40	2091,57	392193,22	8,30	11,80
Well 9 RC	4,94	457,40	15,29	49,74	15,04	884,07	326580,93	6,25	11,90
Well 10 RC	9,45	423,42	17,65	72,87	18,39	2569,92	389969,97	5,95	15,35
Well 11 RC	3,53	433,48	14,13	43,28	12,77	823,14	427065,98	6,17	16,42
Well 12 RC	15,95	602,75	16,53	94,87	17,74	4354,30	594913,77	11,70	16,45
Well 13 RC	14,66	580,40	73,20	130,03	15,52	18746,95	604195,76	2,25	17,35
Well 14 RC	12,53	385,66	1,86	57,42	14,75	513,81	504446,57	4,50	21,80
Well 15 RC	24,37	560,23	39,38	110,64	14,20	21619,75	756313,80	8,00	22,50
Min	3,53	385,66	1,86	43,28	7,18	513,81	143841,51		
Max	24,37	602,75	73,20	130,03	18,39	21619,75	756313,80		
Average	10,82	509,28	24,12	75,97	14,76	4292,49	383292,05	5,05	12,28

Table 8.1: Summary of all the shoetrack drill out studied from feet-by-feet logs. Below there is min, max and average values of all the drillouts. The blue colour indicates the wells containing single stage cementing equipment, and the yellow are wells containing two stage cementing equipment. No feet-by-feet data were available for well 3, this is the reason no parameters are given. The time to drill landing collar (LC) is also included in this drill out summary.

8.1 Discussion of single stage cemented 10 ¾" liners (Well 1-11)

8.1.1 Well 1

This well had the shortest drill out time of 4,33 hrs. The bit was a hybrid bit provided by Baker Hughes. This bit was also used in Well 8, which has the same shoetrack composition. But this well took 11,8 hrs to drill. When comparing the results we can see that the difference in shoetrack length for these two wells is 29,8 ft. The other equipment except the landing collar took similar time to drill out. So the reason why well 8 took longer time to drill, is the landing collar. The drilling parameters are very similar as seen from the feet-by-feet data. The averages of WOB,RPM, Flow rate and torque is almost identical. The inclination for this well is also the same (74°). It is therefore hard to conclude what the optimized drilling parameters for this bit will be. Other factors will tend to affect the result as seen under section 7.3.4.

8.1.2 Well 2

This well had the shortest drill out time of the landing collar (0,33 hrs), which was drilled out with a roller cone bit supplied by Smith. The total drilling time was 5,08 hrs. A low WOB was used (4,73 klb in average) in combination with a high flow rate (543,18 gpm in average). This will might give smaller cuttings as there is not so much weigh applied, and good hole cleaning when combining it with the high flow rate. Low WOB will also minimize the probability for the cementing plug starting to rotate. As seen from the bit nomenclature from smith bits, we can see that the bit GF30OD is used on soft to medium hard formations, with low compressive strength [52]. As discussed in the theory part about roller cones, a roller cone bit adapted to more soft formations will usually have low journal angle, high offset, low cutter count and high cutter extension. A roller cone will also have the possibility to grind up the debris to smaller parts; this will reduce the possibility of large cuttings agglomerating on the bit.

8.1.3 Well 3

No feet by feet data available for this drill out. The total drilling time was 6,47 hrs, with the landing collar taking the longest time to drill (3,33 hrs). The shoetrack was drilled with a PDC bit, supplied by Lyng.
From the bit nomenclature of Lyng (Appendix 1), we can see that the bit used (LMX6342D1)has the following setup:

- Rib count: 6
- Cutter size = 13mm
- Profile height: 5 (From a scale ranging from 0-9, the scale goes from 0->9, a scale of 9 is when (height >=Bit radius)
- Cone depth: 2 (The scale goes from 0-9, where 0 indicates a flat bit, and 9 indicates cone depth >= 1/6 of the bit radius.

As discussed under the “PDC bit geometry” (page 79) a bit with a flat profile, will be aggressive, and easily drill through different “junk”.

8.1.4 Well 4

The shoetrack was drilled out in 7,55 hrs with a PDC bit from Halliburton, with the cement taking the longest time (2,71 hrs), although there was no cement found. The landing collar was drilled through in 2,18 hrs. Also for this well, a very low WOB was applied. 3,53 klb in average. The reason is that there was no cement found between the landing collar and the float collar. This will give a low WOB (also negative values) when the bit is not in contact with material, and give misleading drill out parameters. When studying the first 3 feet from the feet-by-feet data, an average WOB of 13,33 klb was used over the landing collar. The bit used is very similar to the bit used in well 6, but this bit has double rows of cutters.

8.1.5 Well 5

The total drill out time was 8,5 hrs, with a PDC bit from Halliburton. The component taking the longest time to drill was the shoe(3,5 hrs), followed by the landing collar (3,0 hrs). An average WOB of 8,66 klb was used, which is not so high compared with the other wells. This drill out also had the lowest average torque (7,18 f-kp). This might indicate that the weight applied was too low. The fastest drillouts had an average torque between [12-14]f-kp. This might also be the reason why the shoe took so long time to drill.

8.1.6 Well 6

Total time to drill shoetrack was 9,25 hrs with a Halliburton PDC bit. This bit is very similar to the PDC bit used for well 4, but this bit has single row cutters instead of double rows. The component taking the most time was the landing collar (4,0 hrs), followed by the shoe (3,0 hrs). The other parts of the shoetrack were drilled in an acceptable time. The average WOB was higher on this well (14,42 klb) compared with Well 5, which was also drilled with a PDC bit. This is also represented in the average torque of 17,44 f-kp. This is logical; more weigh applied will generate more friction and thereafter more torque required. The flow rate and rotation speed was very equal to well 5.

8.1.7 Well 7

This shoetrack was also drilled with a PDC bit, but from Lyng. The total drilling time was 9,45 hrs, with the landing collar taking the most time (6,91 hrs). All the other parts of the shoetrack did not take noticeable time to drill. The average WOB and RPM for this drill out was low, 7,6 kbl and 53,53 RPM. The flow rate used is very close to the average flowrate used for all the drillouts (503,13 gpm). We can for this well see that with the PDC bit, the other parts except the landing collar, is being fast drilled with low WOB and low RPM in combination with a flowrate of 500 gpm.

From the bit nomenclature of Lyng (Appendix 1) we can see that the bit (LM7332M1) has the following setup:

- Rib count: 7
- Cutter size = 13mm
- Profile height: 3 (From a scale ranging from 0-9, the scale goes from 0->9, a scale of 9 is when (height >= Bit radius)
- Cone depth: 2 (The scale goes from 0-9, where 0 indicates a flat bit, and 9 indicates cone depth >= 1/6 of the bit radius.

If we compare this to the bit used for well 3, we can see that the bits are very similar, but the difference is the rib count, and profile height. The bit used in Well 3 has a profile height of 5, and this bit (LM7332M1) has a profile height of 3. A higher profile height will create a larger junk slot area, and contribute to better cuttings removal and better hydraulic performance. A large junk slot area will contribute to less cutting agglomerating on the bit.

It is not so easy to compare well 7 and 3, as the drilling parameters are not available for well 3. But if we compare the component taking the longest time (Landing collar), it will for this well be over twice as high than for well 3. It is hard to say if it is the difference in bit, when the drilling parameters are not available.

8.1.8 Well 8

The shoetrack was drilled out in a total time of 11,80 hrs, with the landing collar taking 8,30 hrs. The other components of the shoetrack had acceptable drill out times. This well is very similar to Well 1, where the same bit is used (Hybrid bit from Baker Hughes). A comparison between well 8 and 1 was performed under “Well 1”. The average parameters used are very similar. The average WOB is only 0,41 klb higher for this well, this might be the extra force needed to make the plugs stating to rotate. But it can also be other factors that come into play.

8.1.9 Well 9

The total time to drill the shoetrack took 11,9 hrs, with the landing collar taking the most time (6,25 hrs), followed by the shoe (3,2 hrs). The shoetrack was drilled with a Halliburton roller cone bit. A very low average WOB (4,94 klb) was used, in combination with a low average RPM (49,74). The flow rate was also not the highest, in average 457,40 gpm. The problem for this well, might have been insufficient hole cleaning, due to the low flow rate.

8.1.10 Well 10

This shoetrack was drilled out in 15,35 hrs, with a PDC bit from Halliburton. The landing collar took the longest time to drill (5,95 hrs), followed by the cement below the float collar (5,8 hrs). The time to drill the cement below the float collar is the highest for all the studied wells, and is almost the double for all the wells. This might indicate that some debris from the shoetrack equipment have been plugging/interacting with the bit, and thereafter reducing the hydraulic and penetration characteristics of the bit.

8.1.11 Well 11

Total drilling time of shoetrack was 16,42 hrs, with a roller cone bit supplied by Halliburton. The component taking the longest time was the landing collar (6,17 hrs), followed by the shoe (5,75 hrs). The other components of the shoetrack were drilled out relatively fast. A low average WOB (3,53 klb) was used in combination with a low average revolution speed (43,28 RPM) and not so high flow rate (433,48 gpm in average). For this well, it looks like the weight and revolution speed was too low.

8.2 Discussion of two stage cemented 10 ¾” liners (Well 12-15)

8.2.1 Well 12

The shoetrack was drilled out in 16,45 hrs, with a roller cone bit from Halliburton. All the components was drilled relatively quickly, but the landing collar took 11,7 hrs, which is very high. On the data available, there is posted a comment. The comment suggest that the sleeve on the stage collar was knocked off during pressure testing after the cement job, and thereafter fell onto the landing collar. This will lead to parts starting to spin and prevents the bit from biting. After the landing collar was drilled, the other parts of the shoetrack were drilled through in acceptable times. This with high flow rate (average of 602,75 gpm), high rotation (average of 94,75 RPM) and relatively high WOB (average of 15,95 klb) compared to the other wells.

8.2.2 Well 13

The shoetrack was drilled in 17,35 hrs. The most time-consuming part of the drill out was to drill/clean out from stage collar to landing collar, which took 9 hrs. This shoetrack was also drilled with a roller cone, but from Baker Hughes. From the bit catalogue from Baker Hughes, this bit is a tungsten carbide tooth bit, designed to drill soft-medium formations. [54].
From the drilling logs there was also an indication of pushing objects below the stage collar. This could be the same problem as for Well 12. The stage collar is not sufficient strong enough to handle the forces when pressure testing the liner. The landing collar took 2,25 hrs to drill, which is a lot less then Well 12 (11,7 hrs). The drill/cleaning action might have removed most of the parts that could interfere with the bit. It is therefore hard to conclude what roller cone bit from Well 12 and 13 which have the best performance when drilling the landing collar. As seen from the results we can see that a much higher average rotation speed was used for this well (130,03 RPM), and for Well 12 (94,87 RPM), this might be a good parameter when drilling the landing collar with a roller cone bit. The average WOB for this well is 12,53 klb, which is very close to the value for well 12 (15,95). Therefore , a higher RPM might tend to create smaller debris and hole cleaning. But too high rotation speed is dangerous; it will increase the rotational forces acting on the shoetrack equipment and make them spin. The ROP is very high for this well, but for a two stage cementing job, there is not cement between the stage collar and landing collar, it is only mud. This will increase the ROP as it is only to trip pipe in this interval without any drilling.
A high flow rate is also used for this drill out (580,40 gpm in average), but this includes a lot of washing where the flow rate might have been increased to remove any residual debris in the well.

8.2.3 Well 14

This shoetrack took 21,8 hrs to drill, with a roller cone bit supplied by Halliburton. The stage collar took 5 hrs, drill/clean between stag- and landing collar (7 hrs) and landing collar (4,5 hrs). This gives this well the lowest ROP of only 1,86 ft/hr in average. The WOB was in average 12,53 klb for this well, in combination with an average flow rate of 385,66 gpm. This flow rate is the lowest of all the wells studied. It might be too low and insufficient to give sufficient hole cleaning, which is might match the low ROP. The average rotation speed was also low of 57,42 RPM.

8.2.4 Well 15

The shoetrack for this well took the most time to drill of all the studied wells. A total time of 22,50 hrs, The stage collar and landing collar both took 8 hrs to drill, and the cleaning between the stage collar and landing collar took 3 hrs. The rest of the shoetrack was drilled relatively quickly. For this shoetrack a roller cone bit from Halliburton was used. This well has the highest average WOB of 24,37 klb. The average RPM and flow rate is also high (110,64 RPM and 560,23 gpm). For this well it might have been used too much forces and energy on the shoetrack equipment, and the cementing plugs in the stage collar and landing collar might have started to rotate, preventing the bit from biting.

8.3 Factors influencing the parameters for the feet-by-feet data

Below there will be represented some factors that will influence the parameters used in the study part. The factors posted below will show that the parameters in the result part are not the “actual” forces acting on the bit. So the results must be interpreted with caution, as these factors are not taken into account due to high complexity.

8.3.1 WOB vs actual weight applied

During drilling out of the shoetrack, the weight on bit is not the actual weight applied on the bit. The WOB measured from surface is calculated from a load cell, and the weight of everything that is hanging in traveling block. Due to deviation in the wellbore, a lot of weight will be lost to the sidewalls. This force will be referred to as the drag. The drag will be the friction between the drill string and the casing. This force will be very significant in wells with high inclination, build sections or dogleg severity (Many wells with high inclination in this thesis). [47]

8.3.2 Hydraulic packoff effect

When having large bottom hole assembly compared to the inner diameter of the casing (Especially rotary steerable assemblies), this will create a piston like effect. If this is the scenario, an increased flow rate will tend to push the bit off the bottom. When the shoetrack equipment comes in contact with the bit, large debris might be torn off. The aggressiveness of the bits, are designed to maximize the penetration in the formation. When hitting soft materials found in the shoetrack, large debris can be generated. The debris will be larger than the cuttings generated when drilling formation. This debris can also make the packoff effect even worse. If the debris agglomerate on the junk slot area of the bit, or around the stabilizers on the bottom hole assembly. [47]

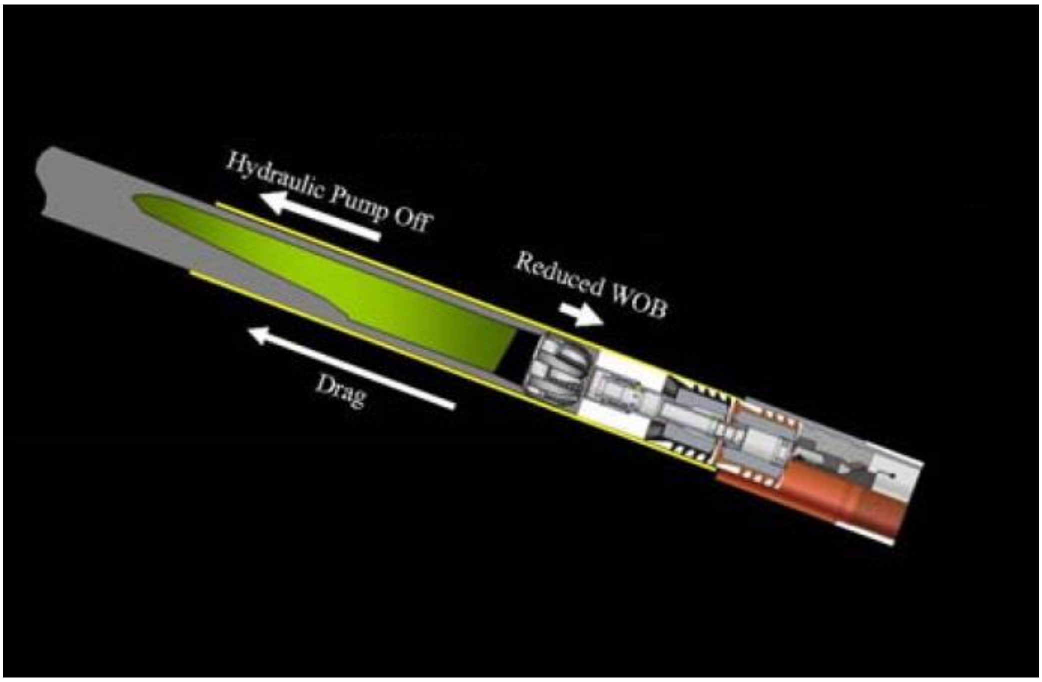


Figure 8.1: Picture showing the drag and hydraulic packoff effect that will result in a reduced weight on bit. [47]

8.3.3 Surface torque vs torque at the bit

The same principal applies for the torque. The torque is also measured on surface for this study. The torque will also be influenced by different factors. For a highly deviated well, a lot of the weight will be pushed towards the casing wall. This will increase the amount of torque needed to twist the drill string (higher friction). The more horizontal a well is the more torque is needed to rotate the drill string. The torque measured on surface, will therefore not be the same torque acting on the bit. [47]

8.3.4 Tagging the cementing plugs

If the driller lowers the pipe more quickly, the dart and cementing plug will might be forced down inside the landing collar. This will create more friction, and prevent the bit from spinning. It will also tend the bit to bite more quickly. The cutting structure is though in danger of being destroyed if the bit hits the shoetrack equipment with too high speed.
[55]

8.3.5 The averages are influenced by the washing/reaming process for the two stage cemented liners

As seen on the results it is hard to conclude and make some decisions about the drilling parameters. It should also be noticed that for the two stage cementing operations, the washing and reaming (drilling parameters) are included in the average results. This will apply for the two stage cemented wells (Well 12-15). As seen from figure 7.13 (page 99), the reaming/washing operation can be a time consuming process. This will therefore have great influence on the statistics, and it should therefore be analysed with caution.

8.3.6 The feet-by feet data are averages

For the drill out of the different components in the shoetrack, it will be hard to conclude what kind of drilling parameters that is the optimized. The shoetrack equipment is not so long, and takes a lot of time to drill. When looking at the averages values of WOB, RPM, Flow rate etc.; this can be misleading. The parameters can have varied a lot when drilling a specific footage over a long period of time. Example: The driller might have used a WOB of 30 klb for a period and then reduced it to 15 klb. The average will be a number between these numbers. It might have been the high WOB that is the optimized parameter for a shoetrack component, but when representing average values this can be misleading when concluding. This thesis therefore represents a broad view of the drillouts, and show a more general optimization. Due to high uncertainty in the drilling parameters used over the landing collar, some data had to be excluded (some samples missing). The average drilling parameters used over the shoetrack interval is therefore used when studying the landing collar. An example is posted below to show how the average data used when drilling a specific footage can be misleading:

Drilling paramter	**x**	**y**	**z**
Average of 1 ft drilled	18,75	525	72,5

Drilling parameter used when drilling the length (1 ft)	**Time**	**x**	**y**	**z**
Constant (no progress)	1 hrs	30	600	90
Constant (no progress)	1 hrs	20	500	80
Constant (no progress)	1 hrs	15	500	70
Constang (Fast progress)	0,5 hrs	10	500	50
Average of 1 ft drilled		18,75	525	72,5

Table 8.1: Showing the average values of some drilling parameters (x,y,x) for a specific footage drilled, and the actual parameters used. The green row represent the drilling parameters which gave fast progress (x=10, y=500 and z=50). This does not correspond to the average parameter for the footage drilled.

Chapter 9

Conclusion

After getting all the data (ft/ft) from the drilling out all the plugs (especially 10 ¾" liners), we understand that most of the operators are suffering from drilling out the shoetrack that might take several hours and cause some damage to the BHA, that's why the aim of this study is to try understanding the mechanism of drilling out the shoetrack and getting an optimised solution to reduce time and risk. An overall study for different casing sizes shows that the drilling of the shoetrack can be in general a time consuming (Figure7.2).

When comparing all the different casing sizes, from 20" surface casing down to 7 ¾" liner (Figure 7.5-7.11), it shows that it is the landing collar that is the main problem to drill out as it takes 41.1% (Table 7.7) of the time to drill and most likely all the bit are damaged there .

When studying different bits used to drill the shoetrack, it shows that it is possible to drill the shoetrack with different bits in about the same time; no concluding trends were seen when using different bits (Figure 7.3 & 7.4).

One of the major factors saw in this study is inclination at the bit, wells where drill out happened with high inclination had tendency to spend more time to drill out the shoe track. (Figure 7.12)

The reason for this factor is the weight applied from surface as we already mention it above (8.3.1 WOB vs actual weight applied), the weight applied is reduced trough the bit when drilling out at high inclination and that can be done due to BHA hanging and also the cutters are not digging into the shoe track like if you apply vertical force.

A detailed study of drilling the shoetrack of 10 ¾" liners was performed since it is one of the major issues for our case:

The study was done due to the high drillout times, and the landing collar being the component taking most of it, a total of 15 wells selected were studied with focus on the landing collar, where all the wells contained the same shoetrack equipment supplied by Halliburton.

The landing collar took 5,05 hrs to drill in average for the 10 ¾ " liner, which is 41.1 % of the total average time to drill the shoetrack. The 15 selected wells had an average total drillout time of 12,28 hrs. (Table 8.1)

The materials of the shoetrack equipment (landing collar, cementing plugs and darts), shows that the equipment drilled is relatively soft, and should not be a problem to drill with today`s conventional bits. (Section 7.6)

The results show (Table 8.1) that the shoetrack can be drilled both quick and slow with the same bit type.

The optimization needs therefore to take place in the drilling parameters, those are essential for how the bit behaves when drilling the shoetrack.

The drilling parameters collected from feet by feet drilling data, showed the following results for the 15 selected wells (Data was not available for well nr 3):

<u>Drilling through single stage cemented 10 ¾” liners (Well 1-11)</u>

- No trend found when studying the average weight on bit up against the total drilling time of the shoetrack (Figure 7.33)

- The flowrate showed a noticeable trend (Figure 7.32), when increasing the flowrate, the total drillout time of the shoe track was reduced and that mean flow help by evacuating junk out from the BHA, clean and add cooling to the bit.

- The fact that flowrate reduces the drillout time, can be connected to the rate of penetration when drilling. In general: Better flow rate will increase the cuttings removal, which is essential for the penetration rate for drilling formation and can see that is also applicable for drilling out the shoetrack.

<u>Drilling through two stage cemented 10 ¾” liners (Well 12-15)</u>

- The WOB plotted against total time did not show any relations in total drilling time (Figure 7.35), that because of the complexity of the shoe track when using 2 stage collar cementing job.

- The flow rate plotted against the total drilling time of the shoetrack did not show any concluding trend for this kind of shoe track (Figure 7.34).

<u>Drilling the landing collar (All 15 wells included)</u>

By plotting all the wells, and taking the averages of the parameters used when drilling the shoetrack, flowrate, weight on bit (WOB), torque and RPM plotted against the time to drill the landing collar. It shows that the average time to drill the landing collar will vary in a realistic manner.

Weight on bit (WOB) (Figure 7.37)

The average weight on bit during drilling the shoetrack was 10,82 klb.

All the wells that are above the trend had an average of 14,78 hrs.
The wells that are under the trend had an average of 10.61 hrs. (Table 7.3)

When adding high weight on bit, this will create a lot of forces acting on the cementing plug which is seated in the landing collar, the force might be so high that it tends to make the cementing plug to rotate, this will prevent the bit from biting, and increase the drilling time.

If the WOB is low during the drillout, this will increase the bit action on the plug while preventing the bit from rotating the cementing plug.

Increased WOB will also generate large cuttings; the bit is often designed to drill hard formation under the 10 ¾" liners, when hitting the shoetrack large debris can be generated.

The debris can plug parts of the bit and interfere with the bit hydraulics which leads to reduced hole cleaning, reduced hole cleaning is a factor which is important for maintaining satisfying rate of penetration, when the hole cleaning is not sufficient, the rate of penetration will decrease.

Flowrate (Figure 7.36)

All the wells above the trend had an average drill out time of 5,55 hrs. The wells that are under the trend had an average of 4,99 hrs. (Table 7.3)

*It should here be noticed that when including the two stage cemented liners, the average flowrate will increase due to the long period of washing/reaming operation. Looking at the drillouts of the single stage cemented liners, this will give more representative perspective over the flowrate used, because there is no washing or reaming operation in these sections.

Torque (Figure 7.38)
All the wells above the trend had an average drill out time of 6,48 hrs. The wells that are under the trend had an average of 3,86 hrs. (Table 7.5)

When adding more torque, more rotational forces will act on the cementing plugs. More torque will tend to rotate the cementing plugs, and making them spin. The scenario will be the same as for too much weight applied. The cementing plugs will start to rotate and prevent the bit from biting.

Bit rotation speed (RPM) (Figure 7.39)

All the wells above the trend had an average drill out time of 5,5 hrs. The wells that are under the trend had an average of 4,6 hrs. (Table 7.6)

A high RPM will tend to create more rotational forces acting on the cementing plug. Too high RPM can rip the cementing plug apart or off the landing collar. This will create the "plug-spinning problem" and more time will be used. High rotational speed will also increase the likelihood of BHA damage.

Different bit used to drill the landing collar (Figure 7.40)

By just looking at the bit as a factor, the best performance was achieved in well nr.2, with a roller cone bit. The bit drilled the landing collar in only 0,33 hrs (Table 8.1). From the drilling parameters the average WOB was 4,73 klb (Table 8.1). By involving the points above, a low WOB will reduce the possibility for the cementing plugs starting to rotate, and give faster drillouts of the landing collar. By comparing this to the highest average WOB used, we find one of the worst landing collar dril lout performances of 8 hrs (Table 8.1). The worst landing collar performance was seen in well 12, where it took 11,7 hrs to drill the landing collar (Section 7.7.14). A high WOB was used, and the drilling logs indicated pushing objects between the stage collar and landing collar. The conclusion for the weight applied is that less is more. Less WOB will reduce the possibilities of the cementing plugs starting to rotate, and create better drilling performance over the landing collar.

The different bit used when drilling the landing collar, shows that PDC has the best performance in average, drilling the landing collar in 3,88 hrs (Figure 7.40). From the results the performance is best when combining the different bit with low WOB over the landing collar (Figure 7.37)

From the study we can clearly see that the shoetrack is affecting the bearing life from the total energy achieved for the bits containing cones (Hybrid and Roller cone). The largest total energy value was produced in well 15, with a total drilling time of 22,5 hrs and a TE value of 381,74.
(Section 7.7.17)

Recommendations

The fact that the drilling parameters are based on average values for every footage drilled makes it hard to conclude on specific parameters to concentrate our optimization.

The trend shows above that all parameters except the inclination at the bit and flow rate used (for single stage cemented liners) are not going in one direction and are giving 2 different understanding to conclude.

Drilling out the shoe track can have different recommendation from all this study:

- Since the landing collar and cementing plugs are not long intervals (a few feet), it will be misleading to come up with optimized drilling parameters for drilling the shoetrack of the 10 ¾" liners, then a visualisation model or simulator need to be used to have a visual when the bit is drilling the different part of the landing collar.
- By having a live simulator, the drilling team can prevent damage to the bit by applying optimized parameters when digging into the different parts (rubber, aluminium... etc.).
- The simulator to visualise the different part of the landing collar need to have data forward it instantly to the drilling team and optimization team 24hrs a day and try to select the best parameters to use.
- The inclination is not a fact that we can change, but since we have the parameters that we can change, we don't see any other factors to change here.
- The landing collar with the cement plug seated is made with rubber and aluminium to support pressure and hold cement below, we recommend that companies providing those landing collar to look into a fibre glass or composite (graphite, titanium …etc.) to reduce the impact damage on the bit and improve time to drill the landing collar as now many other industry are using these new composite material for the other reason but for the same result which is optimization it could weight, material resistance to temperature and in our case harness to drill through it with reduce time.
- It is recommended to perform a deeper study with time based data for the 10 ¾" liners (looking at every sample from the drilling logs, and not averages values), the data that was available are not showing a good output with time based, then our recommendation for mud logger to set up a unit and get data for every second.

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Recommended drill out procedure for landing collar (10 ¾” liners)

The recommendations below is a summary of the optimized drilling parameters from the study in section 7.9:

1- Carefully tag the landing collar [47]
   This with reduce the possibility of destroying the cutters on the bit
2- Apply rotation speed of 50-70 RPM
3- Apply flowrate of 500 gpm
4- Note the torque
5- Lower the bit slowly by closely monitoring the torque and WOB
6- The WOB should not exceed 11 klb
7- Pay closely attention to the drilling parameters. If the penetration rate decreases, change the drilling parameters.
8- If the SPP (Stand pipe pressure is increased) when starting to drill the landing collar (Usually 150 psi [58], this might indicate hydraulic packoff effect. If this happens, rise bit 3m off bottom and increase circulation and rotation speed for some minutes. This will remove debris around the BHA. [47]

Chapter 10

Abbreviations

BHCT: Bottom Hole Circulating Temperature

PDC: Polycrystalline Diamond Compact

RC: Roller Cone

NR-Plug: Non rotating Plug

WOC: Wait on Cement

UCA: Ultrasonic Cement Analyser

Gpm: Gallons per minute

ECD: Equivalent Circulating Density

RPM: Revolutions per minute

WOB: Weight on Bit

HDBS: Halliburton Drill Bits & Services

DatCI: Design at the Customer Interface

ADE: Application Design Evaluation

SPARTA: Scientific Planning and Real Time Applications

BHA: Bottom Hole Assembly

MWD: Measurement While Drilling

ROP: Rate of Penetration

HSI: (Hydraulic) Horsepower per Square Inch

TE: Total Energy

LC: Landing collar

OD: Outer Diameter

ID: Inner Diamter

Psi: (Pressure force) Pounds per Square Inch

SPP: Stand Pipe Pressure

IBitS: Interactive Bit Solutions

Krevs: 10^3 revolutions

Chapter 11

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[53] http://dea-global.org/?p=549
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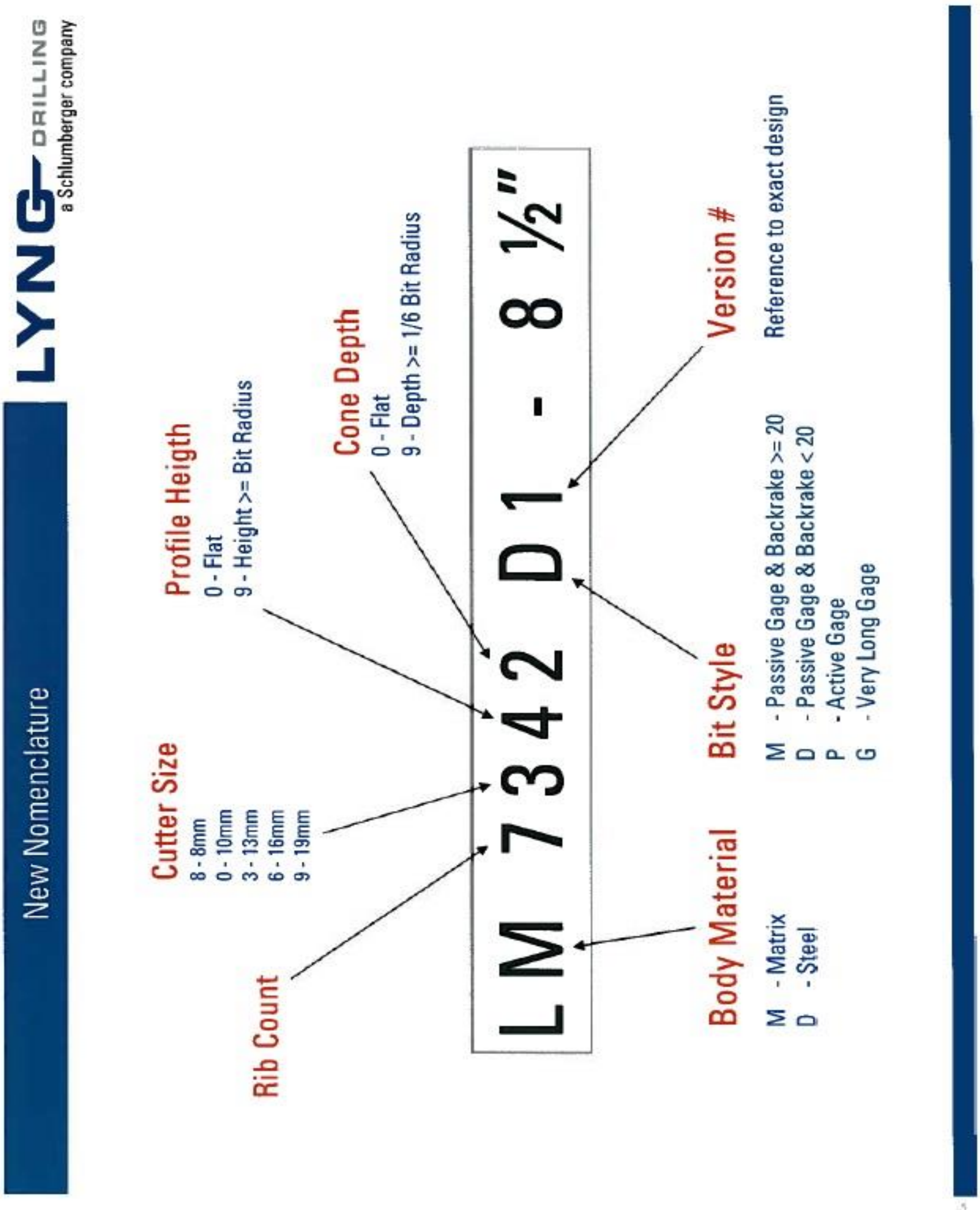
[56] Halliburton, *internal documents*, Casing Equipment.

[57] HDBS, *internal documents* (bit database)

[58] Abdellaoi, Sofiane., Account Representative BD, HDBS, personal communication, February-June 2014.

Appendix 1: LYNG PDC Bit Nomenclature



Appendix 2: MMG64D PDC Bit

HALLIBURTON | Drill Bits & Services

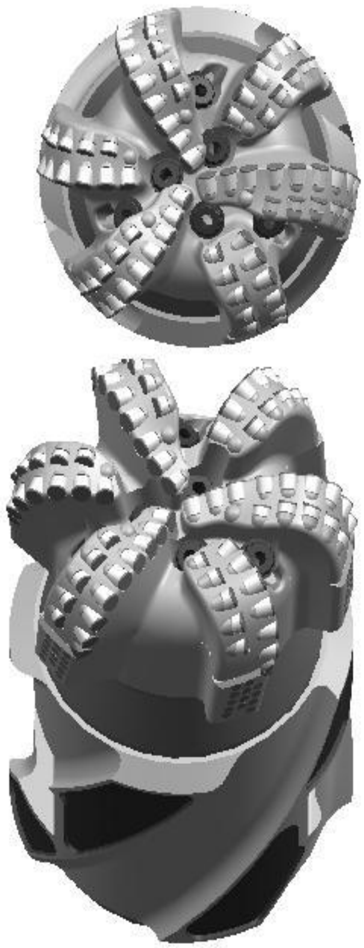
9-1/2" (241mm) MMG64D

PRODUCT SPECIFICATIONS

Cutter Type		SelectCutter
IADC Code		M432
Body Type		MATRIX
Total Cutter Count		80
Cutter Distribution		13mm
	Face	65
	Gauge	15
Number of Large Nozzles		6
Number of Medium Nozzles		0
Number of Small Nozzles		0
Number of Micro Nozzles		0
Number of Ports (Size)		0
Number of Replaceable Ports (Size)		0
Junk Slot Area (sq in)		21.22
Normalized Face Volume		57.96%
API Connection		4-1/2 I.F. BOX
Recommended Make-Up Torque*		40,920 Ft*lbs.
Nominal Dimensions**		
Make-Up Face to Nose		18.04 in - 458 mm
Gauge Length		2 in - 51 mm
Sleeve Length		8 in - 203 mm
Shank Diameter		7.625 in - 194 mm
Break Out Plate (Mat.#/Legacy#)		181976/44751
Approximate Shipping Weight		325Lbs. - 147Kg.

SPECIAL FEATURES

Secondary Cutting Element - "R" Feature, 1/32" Relieved Gage, (MEG) Modified Extended Gage Sleeve - 4 Blade, 1/32" Undergage Sleeve, 3 Side Port Nozzles, Optimized Dual Row - "D" Feature



Material #773950

*Bit specific recommended make-up torque is a function of the bit I.D. and actual bit sub O.D. utilized as specified in API RP7G Section A.8.2.

**Design dimensions are nominal and may vary slightly on manufactured product. Halliburton Drill Bits and Services models are continuously reviewed and refined. Product specifications may change without notice.

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Appendix 3: SFG65R PDC Bit

HALLIBURTON | Drill Bits & Services

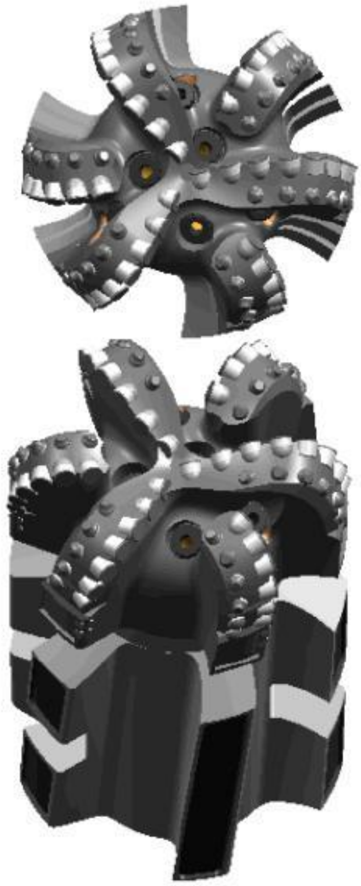
9-1/2" (241mm) SFG65R

PRODUCT SPECIFICATIONS

Cutter Type			SelectCutter
IADC Code			S423
Body Type			STEEL
Total Cutter Count			53
Cutter Distribution		13mm	16mm
	Face	0	32
	Gauge	21	0
Number of Large Nozzles			6
Number of Medium Nozzles			0
Number of Small Nozzles			0
Number of Micro Nozzles			0
Number of Ports (Size)			0
Number of Replaceable Ports (Size)			0
Junk Slot Area (sq in)			26.85
Normalized Face Volume			61.25%
API Connection			4-1/2 I.F. BOX
Recommended Make-Up Torque*			25,000 Ft*lbs.
Nominal Dimensions**			
Make-Up Face to Nose			21.05 in - 535 mm
Gauge Length			2 in - 51 mm
Sleeve Length			10 in - 254 mm
Shank Diameter			6.25 in - 159 mm
Break Out Plate (Mat.#/Legacy#)			640618/44_24344
Approximate Shipping Weight			400Lbs. - 181Kg.

SPECIAL FEATURES

Secondary Cutting Element - "R" Feature, Anti-Balling Coating, Relieved Gage, Cylinder Cutters, 1/32" Undergage Sleeve



Material #789486

*Bit specific recommended make-up torque is a function of the bit I.D. and actual bit sub O.D. utilized as specified in API RP7G Section A.8.2.

**Design dimensions are nominal and may vary slightly on manufactured product. Halliburton Drill Bits and Services models are continuously reviewed and refined. Product specifications may change without notice.

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Appendix 4: MMG64H PDC Bit

HALLIBURTON | Drill Bits & Services

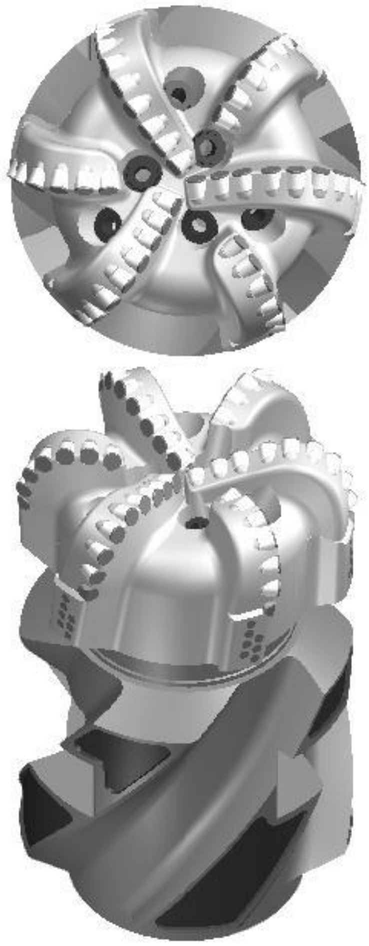
9-1/2" (241mm) MMG64H

PRODUCT SPECIFICATIONS

Cutter Type		SelectCutter
IADC Code		M332
Body Type		MATRIX
Total Cutter Count		50
Cutter Distribution		13mm
	Face	38
	Gauge	12
Number of Large Nozzles		6
Number of Medium Nozzles		0
Number of Small Nozzles		0
Number of Micro Nozzles		0
Number of Ports (Size)		0
Number of Replaceable Ports (Size)		0
Junk Slot Area (sq in)		19.78
Normalized Face Volume		55.62%
API Connection		4-1/2 I.F. BOX
Recommended Make-Up Torque*		25,000 Ft*lbs.
Nominal Dimensions**		
Make-Up Face to Nose		16.38 in - 416 mm
Gauge Length		2 in - 51 mm
Sleeve Length		7.33 in - 186 mm
Shank Diameter		6.25 in - 159 mm
Break Out Plate (Mat.#/Legacy#)		786462/44_35919
Approximate Shipping Weight		335Lbs. - 152Kg.

SPECIAL FEATURES

1/32" Relieved Gage, (MEG) Modified Extended Gage Sleeve - 4 Blade, 1/16" Undergage Sleeve, Multi Level Force Balancing



Material #789295

*Bit specific recommended make-up torque is a function of the bit I.D. and actual bit sub O.D. utilized as specified in API RP7G Section A.8.2.

**Design dimensions are nominal and may vary slightly on manufactured product. Halliburton Drill Bits and Services models are continuously reviewed and refined. Product specifications may change without notice.

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Appendix 5: EQH30D2RC RC Bit

HALLIBURTON | Drill Bits & Services

9-1/2" (241mm) EQH30D2RC

PRODUCT SPECIFICATIONS

IADC Code	537W
Total Insert Count	153
Gage Row Insert Count	49
Journal Angle	33°
Offset (1/16")	6
Jet Nozzle Types	
Standard	83244
Extended	302447
Center Jet	(If Center Jetted) 501813
T.J. Connection	6-5/8" (API Reg.)
Recommended Make-Up Torque*	28000/32000 Ft*lbs.
Bit Weight (Boxed)	200 Lbs. (91 Kg.)
Bit Breaker (Mat.#/Legacy#)	515352/506464

PRODUCT FEATURES

- Aggressive cutting structure with tooth shaped inserts.
- Diamond 'Full Face' surf inserts minimize gage wear.
- Shaped gage inserts for improved gage performance and increased rate of penetration.
- Energy Balanced® cutting structure for increased rate of penetration and increased bit life.
- Proprietary 'Security Plus' inserts to enhance gage protection.
- High-speed bearing designed for high rpm and high-energy applications.
- Innovative mechanical pressure compensating system provides reliable pressure equalization and relief for maximum bearing and seal life.
- Raised tungsten carbide inserts and proprietary hardfacing provides maximum arm protection in abrasive and directional applications while minimizing drill string torque.
- QuadPack® Plus Series incorporates its successful "longevity" features and patented engineered hydraulics system for optimal cleaning efficiency.
- Center jet feature to prevent bit balling problems

Material #714019

*Calculations based on recommendations from API and tool-joint manufacturers.

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Appendix 6: EQH12DS RC Bit

HALLIBURTON | Drill Bits & Services

9-1/2" (241mm) EQH12DS

PRODUCT SPECIFICATIONS

IADC Code	437W
Total Insert Count	90
Gage Row Insert Count	38
Journal Angle	33°
Offset (1/16")	4
Jet Nozzle Types	
Standard	83244
Extended	302447
Center Jet	(If Center Jetted) 310749
T.J. Connection	6-5/8" (API Reg.)
Recommended Make-Up Torque*	28000/32000 Ft*lbs.
Bit Weight (Boxed)	200 Lbs. (91 Kg.)
Bit Breaker (Mat.#/Legacy#)	515352/506464

PRODUCT FEATURES

- Aggressive cutting structure with tooth shaped inserts.
- Shaped gage inserts for improved gage performance and increased rate of penetration.
- Energy Balanced® cutting structure for increased rate of penetration and increased bit life.
- Diamond 'Full Face' surf inserts minimize gage wear.
- Proprietary 'Security Plus' inserts to enhance gage protection.
- High-speed bearing designed for high rpm and high-energy applications.
- Innovative mechanical pressure compensating system provides reliable pressure equalization and relief for maximum bearing and seal life.
- Shirttails protected with proprietary hardfacing and tungsten carbide inserts for maximum abrasion resistance.
- QuadPack® Plus Series incorporates its successful "longevity" features and patented engineered hydraulics system for optimal cleaning efficiency.
- Shale burn inserts provide additional protection for seals and bearings.

Material #673761

*Calculations based on recommendations from API and tool-joint manufacturers.

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Appendix 7: EQH20D2R RC Bit

HALLIBURTON | Drill Bits & Services

9-1/2" (241mm) EQH20D2R

PRODUCT SPECIFICATIONS

IADC Code	517W
Total Insert Count	117
Gage Row Insert Count	43
Journal Angle	33°
Offset (1/16")	4
Jet Nozzle Types	
Standard	83244
Extended	302447
Center Jet	(If Center Jetted) 501813
T.J. Connection	6-5/8" (API Reg.)
Recommended Make-Up Torque*	28000/32000 Ft*lbs.
Bit Weight (Boxed)	200 Lbs. (91 Kg.)
Bit Breaker (Mat.#/Legacy#)	515352/506464

PRODUCT FEATURES

- Aggressive cutting structure with tooth shaped inserts.
- Diamond 'Full Face' surf inserts minimize gage wear.
- Shaped gage inserts for improved gage performance and increased rate of penetration.
- Energy Balanced® cutting structure for increased rate of penetration and increased bit life.
- Proprietary 'Security Plus' inserts to enhance gage protection.
- Raised tungsten carbide inserts and proprietary hardfacing provides maximum arm protection in abrasive and directional applications while minimizing drill string torque.
- QuadPack® Plus Series incorporates its successful "longevity" features and patented engineered hydraulics system for optimal cleaning efficiency.
- Dual seal/dual compensation bearing system containing dual seals, dual independent pressure compensators, and a dual grease formulation.
- The latest OCP seal technology designed with the highest contact pressures on the outside edges of the seal where it is needed most, helps keep contaminants out extending bearing life.

Material #789436

*Calculations based on recommendations from API and tool-joint manufacturers.

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Appendix 8: EQH12DS RC Bit

HALLIBURTON | Drill Bits & Services

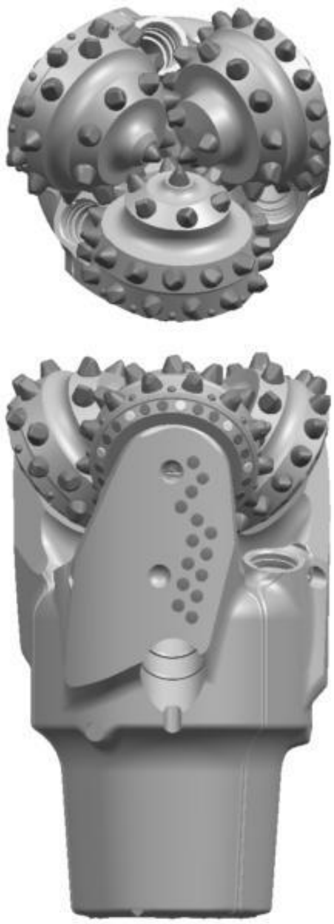
9-1/2" (241mm) EQH12DS

PRODUCT SPECIFICATIONS

IADC Code	437W
Total Insert Count	90
Gage Row Insert Count	38
Journal Angle	33°
Offset (1/16")	4
Jet Nozzle Types	
Standard	83244
Extended	302447
Center Jet	(If Center Jetted) 310749
T.J. Connection	6-5/8" (API Reg.)
Recommended Make-Up Torque*	28000/32000 Ft*lbs.
Bit Weight (Boxed)	200 Lbs. (91 Kg.)
Bit Breaker (Mat.#/Legacy#)	515352/506464

PRODUCT FEATURES

- Aggressive cutting structure with tooth shaped inserts.
- Shaped gage inserts for improved gage performance and increased rate of penetration.
- Energy Balanced® cutting structure for increased rate of penetration and increased bit life.
- Diamond 'Full Face' surf inserts minimize gage wear.
- Proprietary 'Security Plus' inserts to enhance gage protection.
- High-speed bearing designed for high rpm and high-energy applications.
- Innovative mechanical pressure compensating system provides reliable pressure equalization and relief for maximum bearing and seal life.
- Shirttails protected with proprietary hardfacing and tungsten carbide inserts for maximum abrasion resistance.
- QuadPack® Plus Series incorporates its successful "longevity" features and patented engineered hydraulics system for optimal cleaning efficiency.
- Shale burn inserts provide additional protection for seals and bearings.



Material #673761

*Calculations based on recommendations from API and tool-joint manufacturers.

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Appendix 9: EQHC1RC RC Bit

HALLIBURTON | Drill Bits & Services

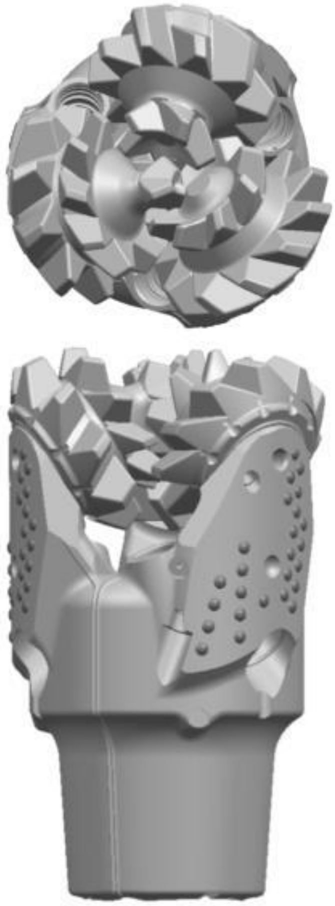
9-1/2" (241mm) EQHC1RC

PRODUCT SPECIFICATIONS

IADC Code	117W
Total Tooth Count	55
Gage Row Tooth Count	30
Journal Angle	33°
Offset (1/16")	6
Jet Nozzle Types	
Standard	83244
Extended	302447
Center Jet	(If Center Jetted) 501813
T.J. Connection	6-5/8" (API Reg.)
Recommended Make-Up Torque*	28000/32000 Ft*lbs.
Bit Weight (Boxed)	130 Lbs. (59 Kg.)
Bit Breaker (Mat.#/Legacy#)	515352/506464

PRODUCT FEATURES

- New patented Diamond™ Claw® tooth bit design.
- Optimal tooth extension and offset to provide aggressive cutting action and increased ROP.
- Energy Balanced® cutting structure for increased rate of penetration and increased bit life.
- Newly formulated, proprietary hardfacing on cutting structure and gage maximizes carbide and diamond volume for ultimate wear resistance.
- Raised tungsten carbide inserts and proprietary hardfacing provides maximum arm protection in abrasive and directional applications while minimizing drill string torque.
- QuadPack® Plus Series incorporates its successful "longevity" features and patented engineered hydraulics system for optimal cleaning efficiency.
- Center jet feature to prevent bit balling problems
- Dual seal/dual compensation bearing system containing dual seals, dual independent pressure compensators, and a dual grease formulation.
- The latest OCP seal technology designed with the highest contact pressures on the outside edges of the seal where it is needed most, helps keep contaminants out extending bearing life.



Material #800398

*Calculations based on recommendations from API and tool-joint manufacturers.

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