University of Stavanger

Faculty of Science and Technology

MASTER'S THESIS

Study program/ Specialization: Petroleum Technology / Drilling	Spring semester, 2014 Open
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Thesis title: **Centralization of Casings in Wells**	
Credits (ECTS): 30	
Key words: Casing, Cementing, Centralizers, OptiCem, Standoff, Well	Pages: 80 + Enclosure: 4 Stavanger, 30th of May 2014

Abstract

Centralization of casings is very important in order to ensure a high quality well. Poor centralization of casing is often the main reason for bad cement jobs, which forces the operators to perform remedial cementing. This increases the costs and delays the completion of wells. By ensuring proper spacing between centralizers, a good primary cement job can be achieved. The “do it right the first time” principle cannot be stressed enough.

This thesis focus on the use of the OptiCem™ module included in the WELLPLAN™ software. The module have been used to do simulations on proper distribution of centralizers along the casing in order to achieve good standoff values. Several well profiles have been investigated, as well as the DLS’, radius’ and casing-weight’s effect on centralizer density.

Results of the simulations shows that distribution rates from 1,5-3 centralizers per 100 ft. of casing is sufficient in order to meet the industrial standoff requirement of 70%. This coincides well with today’s current practice.

Table of Contents

1. Introduction

The drilling and completion of wells have been highly improved over the years. This has mainly been driven by the desire for optimizing production rates and recovery factor and to increase the safety in the industry.

While drilling to reach TD, it is necessary to seal off the surrounding formation to prevent it from collapsing into the wellbore, causing the operator huge economic losses. While drilling, a drilling mud with special properties is used to ensure stability in the well, mainly by having an optimal density or weight. It does not only prevent the well from collapsing, but also acts to prevent unwanted inflow from the formation, which in turn can cause a kick.

At a point the mud weight alone is no longer enough to ensure stability in the well. Further drilling may either cause fracturing of the formations, or more likely a kick from a high pore pressure in the formation. At this point, we have to set casings in order to stabilize the well before drilling further with a new mud, with a more suitable density.

Casings are high OD tubulars, which comes in different material grades and sizes. These pipes are run into the hole and cemented in place. This operation is called “running pipe”. The biggest challenge when running casing is that we do not have much control of the placement of the pipe in reference to the wellbore walls. If the pipe is not well centralized, the following cementing operation is just a waste of time and money.

Correct placement and spacing of centralizers along the casing string can assist in getting a successful cement job, and complete isolation around the casing string. This thesis will discuss the events prior to running casing, and simulate optimal distribution of centralizers for different well profiles and cases.

2. The Drilling and Completion of Wells

2.1 Initial Drilling

After a reservoir has been discovered, or whenever an operator decides to extend the production of a field, a well needs to be drilled. The well then acts as a direct connection between the reservoir and the surface. In order to drill a well, a drilling rig is needed, along with a series of different equipment.

2.1.1 Drilling Rigs

There exist many different drilling rigs with different properties, but they can be categorized into two main groups. Stationary and mobile rigs.

Stationary rigs

Stationary rigs are rigs that are installed at site, often on top on a steel jacket, or on concrete legs. Stationary rigs can include a living quarters along with drilling and productions facilities. These platforms are often referred to as PDQ-platforms (Production Drilling & Quarters). It is also normal to separate the living quarters from the production and drilling facilities due to safety of accommodation.

The X platform in the Ekofisk-Field is a good example of a stationary rig without quarters.

Figure 2.1: The 2/4-X located in the Ekofisk-field [3].

Mobile rigs

Mobile rigs are the most common for drilling wells offshore. These can be either jack-up rigs, semisubmersible, or drilling ships. These rigs can move around and do work on several oilfields. These rigs are usually leased by operators on long term contracts.

Statoil has their own classification system for rigs used for both drilling and intervention.

Cat A: Vessel for light well intervention. Used for light wireline operations in subsea wells. Can also be used to plug wells.

Cat B: Fit for purpose rig for well intervention and sidetrack drilling through production tubing (so-called ”through tubing drilling and completion”). For use in wireline operations, coiled tubing, plugging of wells and sidetrack drilling. The well services will be done through existing subsea x-mas trees.

Cat C: Ordinary drilling rig that can be used for all types of operations.

Cat D: Custom-built rig adapted to medium water depths on the Norwegian Shelf. For use in drilling, completion and well work overs, but can also be used for similar operations as Cat A and Cat B, but is not optimized for this. Statoil has four rigs of this type on order.

Cat J: Jack-up drilling rig with longer legs for deeper waters than customary for this type of rig. For use in drilling, completion and well work overs, but can also be used for similar operations as Cat A and Cat B, but is not optimized for this [4].

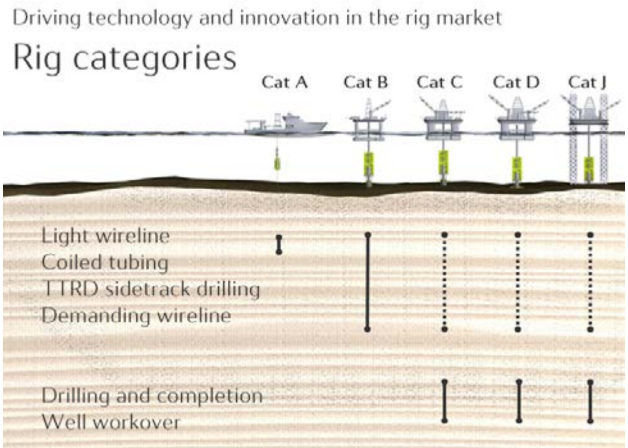

Figure 2.2: Rig categories [4].

2.1.2 Drilling Equipment

The drilling of a well is a long and costly process. Rig rates are high & equipment is expensive. When rig rates extends as high as 600 000$ per day, it is crucial that drilling is optimized with regards to time consumption [5].

When reserves has been proven, the operator need to develop a PDO which is delivered to the NPD for approval [6]. This is required on the NCS, while other rules and regulations apply in other countries.

The drilling is carried out with a drill string, which now will be described briefly.

Drill Bit

The drill bit finalizes the drill string, and serves to crush or scrape away the formation in order to reach TD. It is made of high endurance materials such as tungsten carbide, natural diamonds and artificial diamonds. Almost all other equipment on the drilling rig and in the drill string serves to assist the drill bit in achieving the highest ROP possible.

Drill bits can be categorized in two main types; the roller-cone bit and the PDC bit. The roller-cone bit has moving parts, which serves to crush the formation. The PDC bit has no moving parts, but has imbedded cutters, which serves to shear the formation. The bits are selected with respect to the formation to be drilled.

Recently the oilfield service company Baker Hughes Inc. has developed a new type of bit, which combines the properties of the PDC-bit, and the roller cone bit. They have decided to call it Kymera Hybrid Drill Bit [7]. By using this type of bit it is not necessary to change bit when hitting new types of formations. This reduces tripping time, which again saves the operator money.

Figure 2.3: PDC-bit, roller cone bit & the Kymera Hybrid bit below [7].

Bottom Hole Assembly

The BHA is located above the bit and includes several tools and parts. Along with the bit the BHA consists of components which assist in making the drilling process as effective as possible.

In order for the bit to crush the formation, it is necessary to provide weight on the bit. This is provided by heavy weight drill collars. These thick walled pipes also keeps the drill string in tension, preventing it from buckling.

During drilling operations it is beneficial for the operator to know as much as possible about the down-hole environment, as well as the strings location. By including MWD and LWD equipment in the BHA it is possible for the operator to gain such knowledge. These tools are usually high technology equipment, and can provide a lot of information. However, the data transmission needed are putting limitations on this. Today the most common transmission method is mud pulse telemetry. This technology sends signals by creating encoded pressure fluctuations in the drilling mud, and signals are then decoded when reaching surface. This is a very primitive method, which only provides a rate of 8 – 12 bits/s [8]. The operators are therefore forced to only prioritize the most critical data, whereas the rest needs to be stored in the equipment, or goes to waste. Lately there has been a lot of improvements on this field, and high speed telemetry and wired drill pipe are methods that have the potential to revolutionize exploration and development drilling. With field proven transmission rates of 57 000 bits/s, it clearly sets a new standard for real-time data during drilling [8].

At some point during drilling the drill-pipe may get stuck due to collapsing somewhere in the well, or due to differential sticking. In order to get the drill-string loose the BHA have a jar.
The jar is a mechanical device which serves to deliver impact loads in order to loosen the string [9]. If successful the drilling may proceed. If the driller is not able to free a stuck pipe, the stuck part of the pipe must be cut off and left in the hole. The hole containing the stuck part must then be cemented and before the well can be sidetracked and drilled down to TD.

The BHA can with benefit also include a down-hole motor. The motor is powered by the mud flowing through the drill pipe. By adding a down-hole motor, the driller is able to get a higher RPM on his bit, increasing the penetration. Especially when drilling horizontal wells, the rotation provided by the top drive is not always sufficient, and the down-hole motor is then necessary to include in the BHA.

Often when drilling horizontal wells, it is done in very thin formations. The driller therefore wants to achieve as precise steering as possible, in order to stay within the pay zone. If successful, it can maximize the contact area to the reservoir, which again results in increased production. To achieve this the BHA must have a rotary steerable system. The RSS uses logging data continuously so that the navigation of the drill bit is optimized [10].

Apart from the components mentioned in the sections above, the BHA can include several other components, which acts to increase the ROP. Components such as under reamers, hole openers and stabilizers are common in the BHA.

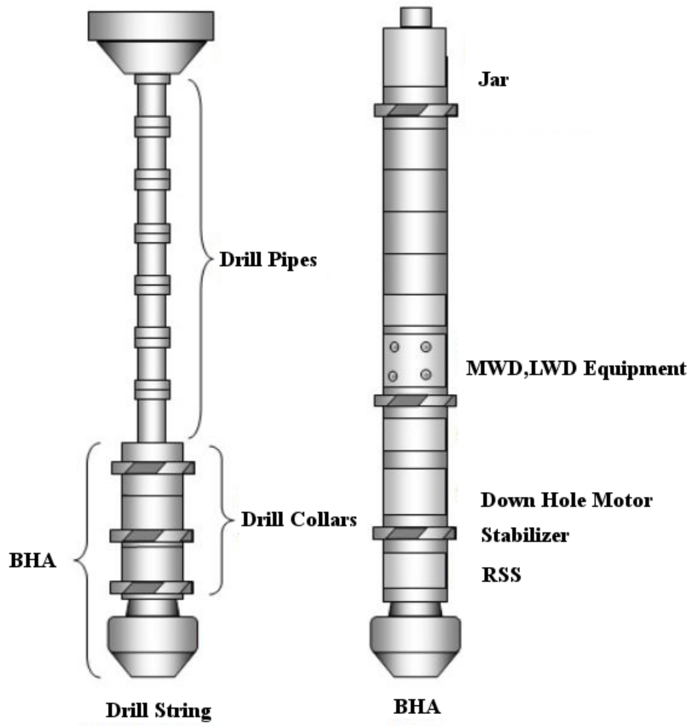

Figure 2.4: The BHA (Based on Skaugen [11]).

Drill Pipes

Above the BHA we find the largest portion of the drill string. This section is made up by several drill pipes which each measures around 30ft or 9m. Every pipe have a male and a female thread used for connecting the drill pipes together.

The drill pipes are hollow inside making it possible to pump drilling mud through the drill string and the bit. The mud then flows up through the annulus, carrying cuttings from down hole.

When drilling deep and extended wells, the pipes will experience a series of combined forces. The top section must be able to carry the entire weight of the string, while also enduring forces exerted by rotating the bit. The selection of drill pipes is therefore an important factor in order to optimize and ensure safe drilling operations.

Drill pipes come in several different dimensions and grades. The grades show the yield strength of the pipe and in which environment it is suitable. The system is developed by API.

Example: A pipe with grading L80, has a yield strength of 80 000 psi and is suitable in sour environments [12].

Nominal Size (in)	Nominal Weight (lb/ft)	Grade	Tool Joint	
			OD (in)	ID (in)
2 3/8 2 3/8 2 3/8	6.65 6.65 6.65	E75 X95 G105	3 3/8 3 3/8 3 3/8	1 3/4 1 3/4 1 3/4
4 1/2 4 1/2	13.75 13.75	E75 E75	6 3/8 6 5/8	3 3/4 3 7/8
6 5/8 6 5/8 6 5/8 6 5/8	27.70 27.70 27.70 27.70	E75 X95 G105 S135	8 8 1/4 8 1/4 8 1/2	5 4 3/4 4 3/4 4 1/2

Table 2.1: Drill pipes, dimensions and grades. Based on DDH [13].

2.1.3 Wellbore Stability

Drilling Mud

When drilling a well the bit crushes and grinds the formation, producing cuttings, which must be transported to surface. In order to transport the cuttings to surface a high viscous fluid is used. This fluid is commonly known as a drilling mud.

The mud's most important task is, however, not to transport cuttings, but to ensure wellbore stability. The mud's weight is designed in such a way that drilling can be conducted without risking the well collapsing or fracturing. In order to achieve this both the static and the equivalent mud weigh must be located between the pore pressure and the fracture pressure equivalents. The equivalent mud weight is the density of a mud that gives a bottom hole pressure that is equal to the static mud pressure plus the friction pressure drop of the mud flow up the annulus [14].

When the driller has reached a depth where the current mud weight will conflict with both the pore pressure and fracture pressure a casing must be set. After setting the casing, the mud weight can be increased or decreased and drilling can commence.

The loss of wellbore stability can be hazardous, causing loss of equipment or in worst case; a blowout due to a kick.

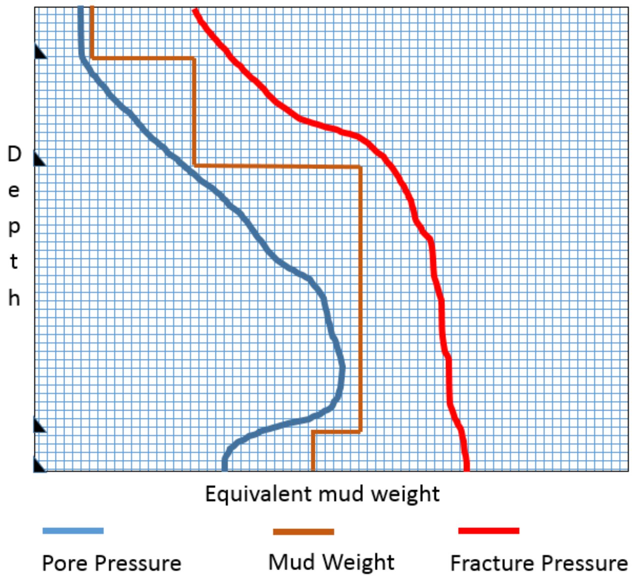

Figure 2.5: The design of mud weight.

Casings

Casings are steel tubulars which are lowered into the well bore when drilling no longer can be continued with the current mud weight, or when the driller have reached TD. The casing acts to support the well bore, preventing surrounding formation from caving in or fracture.

When the casing shoe has reached desired depth, cement is pumped through the casing and into the annular space between the well bore and the outer casing wall. The cement acts to isolate the annulus and keep the casing rigid.

Correct setting of casing is crucial in order to achieve good well integrity. The use of centralizers and the placement of these are essential. Centralizers are tools that keep the casing from touching the wellbore. If a casing is off-centered when pumping down cement, we'll risk getting poor isolation around the casing. This results in degraded integrity of the well, and will cause problems. This subject will be discussed more thorough later.
Casings come in different sizes and grades, all relative to the application. The most common sizes and types will now be presented.

Conductor pipe

The conductor is the first and largest pipe, which is set into the ground. Its primary objective is to support the surface formations, which often consist of unconsolidated material such as sand and mud. The conductor pipe is normally set 100-200m into the seafloor in offshore wells. The size of this pipe is usually 30" OD. The pipe often gets driven into the ground before drilling commences. Alternatively, a 36" hole is drilled before landing and cementing the conductor in place.

Surface casing

After the conductor is set drilling continues. In these shallow formations the pore pressure gradient is often the same as the seawater's. Because of this seawater is often used instead of drilling mud. The use of seawater instead of drilling mud is something that require serious consideration. The seawater is cheap but does not provide the same amount of well control as a heavier mud. This combined with fact that this section is drilled without a BOP installed, demands for even more caution.

The surface casing, which usually has an OD of 20”, acts as a fundament for the well head if this is on the sea bottom. It has to support the remaining casings, which will be installed, as well as the BOP and the X-mas tree when the well is completed.

Intermediate casing

The intermediate casing is a casing, which is set after the surface casing but prior to the production casing. Its purpose is to seal off the formation to assist in deepening the well. The size of this casing varies, but traditionally has an OD of 13 3/8”.

Production casing

After drilling through the reservoir the production casing is run into the well. This is the final casing, and the reservoir is now connected to the surface, making production of hydrocarbons possible. After drilling through the cap-rock, hydrocarbons will try to migrate upwards towards surface. It is therefore extremely important to have good isolation around the production casing [15]. According to NORSOK-D010 there is a minimum requirement of 200m of good isolation above the source of inflow [1]. The production casing has commonly an OD of 9-5/8”, but can also come in other dimensions. The size of the production casing dictates the size of the production tubing, and should be taken into consideration early in the planning process.

Liners

Liners are casing strings, which do not extend all the way up to the wellhead. The liner is hung off inside the last run casing string [15]. The use of liners have several advantages. The most common application of a liner is to use it as a reservoir liner. In this way the operator have a proper sealing of the reservoir, but at the same time have more accommodation for the tubing.

If the operator ever get problems with a leak in the production casing, a solution can be to run a scab-liner, which isolates over the damaged section.

The use of liners instead of casing is also something that reduces the cost by reducing the total length of pipes in the well.

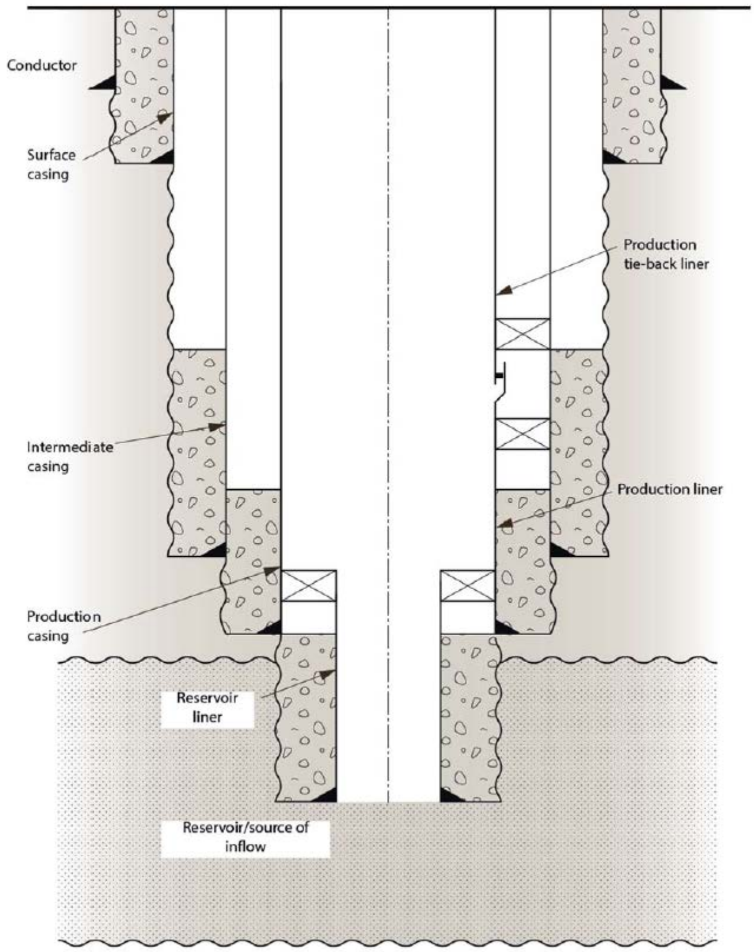

Figure 2.6: Casing design with liners [1].

2.2 Completion

The completion of wells is the process in which a very expensive hole in the ground is transformed into a reservoir depletion tool [16].

2.2.1 Production Tubing

After the well is drilled to TD, and hydrocarbons have been proven, the process of completing the well begins. At this stage the well may be filled with drilling mud. This fluid need to be replaced with a solids-free completion fluid, in order to ensure a successful completion and to avoid damage on the equipment.

After displacing the well with completion fluid the production tubing can be run into the well. The tubing is hanged off inside the wellhead, and the production packer ensures isolation of the annulus, forcing the fluids to flow through the tubing. Between the tubing hanger and the production packer there exist several tools, which contribute to the safety of the well and to optimize production.

Down Hole Safety Valve

The DHSV can be considered as the most important component in the production tubing. This valve isolates the well pressure in case of an emergency, and where well control at surface is lost. The valve is fail-safe meaning that it will close automatically in case of malfunction. The valve is kept open by hydraulic pressure provided by control lines leading to surface. If pressure is lost, the valve automatically closes, preventing fluids from reaching the surface.

Annular Safety Valve

The ASV is a common component in wells, which is produced with gas lift. The ASV reduces the risk of pressurized gas in the annulus from reaching surface in case of failure or malfunction. The ASV is located close to surface, limiting the amount of gas between the ASV and the wellhead.

Side Pocket Mandrels

The tubing string can include several side pocket mandrels. These acts as housing for gas lift valves or similar components.

Gas Lift Valves

Throughout the life of a field the reservoir pressure will be depleted. At some point the pressure is not enough to push the oil through the production tubing and up to surface. A way to counteract this is to use gas lift. By installing a GLV inside one of the side pocket mandrels, gas can be injecting into the tubing. The fluids inside the tubing will then mix with the gas, and the density of the combined fluid will be lowered. The pressure needed to push the fluids through the tubing is then reduced and production can be commenced.

Chemical Injection Valves

When producing oil and gas the operator may experience development of scale, corrosion of tubulars, and wax. By installing a CIV it is possible to inject chemicals into the tubulars. These chemicals can help remove wax and scale, and act to prevent corrosion.

2.2.2 X-mas Tree

After installing the production tubing the well is made ready for production by installing a X-mas Tree. The tree is a set of chokes and valves, which acts to control the production. The tree is also the final barrier preventing unwanted flow from reaching surface [17].

There are typically 5 main valves a x-mas tree:

The MMV is a manual operated valve, which is able to close the flow from the well. The HMV has the same properties but is hydraulically operated. The uppermost valve is the Swab Valve and provides vertical access to the well.

The PWV is the valve where the produced fluids flow through. The last valve is the kill valve, which can be used to pump fluids into the well for different purposes.

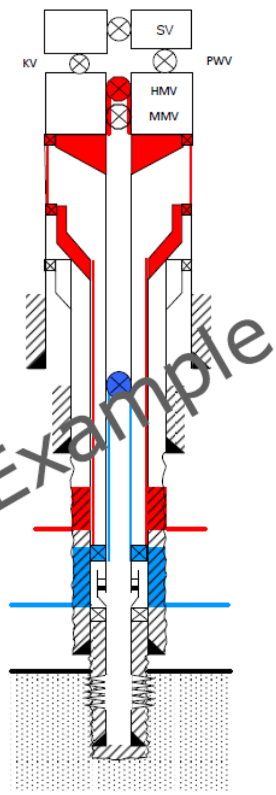

Figure 2.7: Completed platform well [1]

For full WBS see Appendix A.

3. Cementing

Production optimization begins with a good completion, and good completion depends on the integrity of the primary cement job [18]. Every year poor cement jobs causes tremendous cost to the oil and gas industry. Poor cement jobs demands for additional cementing operations such as squeeze jobs. These operations are time consuming and rig demanding, which in turn leads to economic loss. If a poor cement job is left unattended, the result can be catastrophic.

3.1 Cement jobs

Complete zonal isolation is the main goal of a cement job. To ensure the longevity of the well, a high quality cement job must be conducted. A good cement job exhibits an extremely low matrix permeability, providing an excellent seal [18].

During the life of a well, the cement is subject to numerous conditions, which combined, can reduce the longevity of the well. Temperature and pressure fluctuations can cause the cement to expand and contract. This stress can eventually crack the cement, which will reduce its integrity. Another problem is de-bonding. This means that the bond between the rock and cement, or cement and casing fails, creating a migration route for gas and liquids. Shear failure is the third problem and is the most severe & hardest to prevent. This is often caused by stress in the formation due to subsidence and movement as the reservoir is produced. The result can be complete failure of the cement sheet [18].

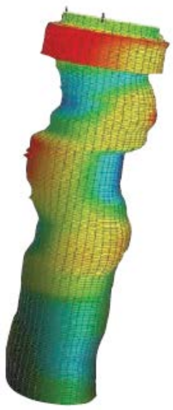

Figure 3.1: Casing deformation caused by movement of the formation [18].

3.1.1 Primary Cementing

After driller has reached desired depth, the drill string is tripped out of the hole. The casing is run into the hole, which as this point is filled with drilling mud. This mud must be removed before cementing. This is done by pumping a spacer fluid down the well, followed by the cement. The spacer displaces the mud and prevents it from contaminating the cement.
On its way down the casing, the cement flows through the float collar. This tool is located near the bottom of the well and acts to prevent backflow of fluids and gas through the casing [19].

After passing the float collar and casing shoe the cement flows upwards through the annulus. The pressure is monitored at the surface, and indicates when the cement plug has reached the desired depth. The well is then shut in to allow the cement to harden before completion or further drilling commences.

Primary cementing is considered to be one of the most critical stages during drilling and completion of wells. You only have one chance to complete a successful job, so careful planning cannot be stressed enough [18].

According to NORSOK D-010 the length of the primary cement job must be minimum 200m above the casing shoe. If the casing is installed across a productive formation, the cement must extend 200m above the top of the productive formation [1].

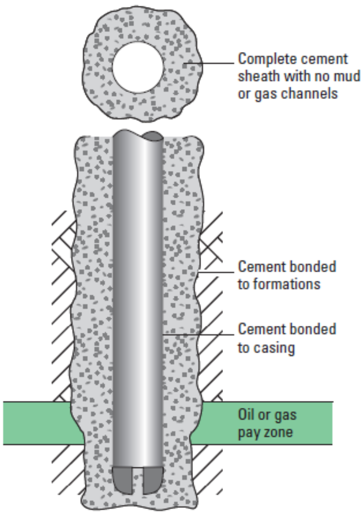

Figure 3.2: A successful primary cement job [18].

3.1.2 Remedial Cementing

Remedial cementing is the term describing cement jobs, which is done to cure a well problem. This may be due to a failed primary cement job, leaking tubulars or to seal of a productive zone in order to alter the production characteristics [18].

Remedial cementing is usually divided into two categories. Squeeze cementing and plug cementing.

Squeeze cementing

Squeeze cementing is the operation where cement is forced through holes in tubulars, cracks in the formation or into existing cement [20].

If the primary cement job is confirmed to be inadequate, a squeeze operation is necessary. Perforating guns need to be run and fire shots in the area where squeezing is planned. Then cement is squeezed through the perforations and into the annulus. This is of course a time demanding operation, and should be avoided if possible.

If there is a leak in the casing cement can be squeezed through the leak in order to seal it. In this case it is important to choose correct cement material. The leak may be due to a very narrow passage, and the particle sizing in the cement must be selected thereafter.

During the life of a reservoir the oil water contact, normally rise towards surface. A zone, which initially produced oil, can later on produce water due to this fact. By squeezing cement through the original perforations, water production can be postponed. New perforations can be shot at a shallower depth, and production can be resumed.

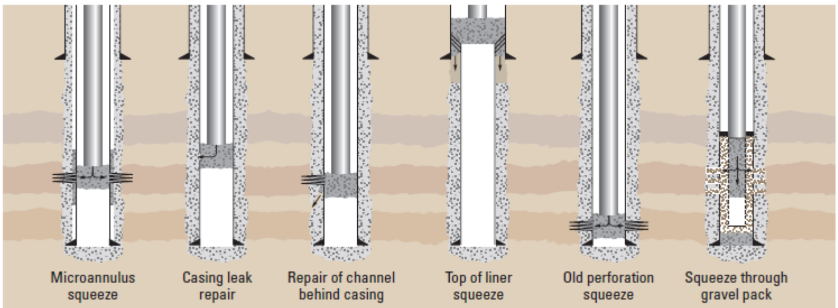

Figure 3.3: Different squeeze jobs [18].

Plug cementing

Plug cementing is the method where cement slurry is placed in a cased off, or open-hole section the well. The slurry is then allowed to set in order to form a barrier, which may be permanent or temporary.

Plug cementing is the main tool used for permanent plugging of wells in the event of abandonment. However, plug cementing has several other applications.

- Sealing off a depleted zone
- Used to initiate directional drilling – kick off plug
- Isolate weaker formation during well testing
- Seal off when sidetracking around a fish
- Provide an anchor for open-hole tests such as LOTs and FITs.

The setting of plugs can be done by several methods, but the most common is the balanced plug method, followed by the dump bailer method [18].

The balanced plug method is performed by running a drill pipe or tubing into the well. When the pipe has reached the desired depth the pumping of cement commences. To avoid contamination of the cement, spacer is pumped both ahead and behind the cement. The volumes are designed in such a way that the heights corresponds in the pipe and in the annulus when pumping is finished. The pipe is then pulled out slowly and the plug is allowed to set [18].

The dump bailer method is performed by running a cement retainer into the well by using either slickline or wireline. Actuation of the cement retainer can be done by predefining a pressure before running in hole. When the retainer achieves the predefined pressure, the cement retainer opens and the cement inside is dumped into the well. The cement can be dumped on a preset plug, which then acts as a foundation for the cement plug [18].

3.2 Plug and Abandonment

The number of aging fields on the Norwegian continental shelf is increasing. When production cannot be maintained due to a drained reservoir or integrity issues, the well must be plugged & abandoned. In order to abandon a well, several barriers must be set to ensure proper sealing of the wellbore.

Since the first discovery on the NCS in 1966, over 3600 offshore development wells have been drilled. Eventually these wells must be plugged and abandoned. Today the cost of an abandonment operation can be just as expensive as the drilling operation. It is therefore important that the industry develops methods that increase the efficiency of plugging operations [21].

3.2.1 Reasons for Abandonment

There exist several situations where the abandonment of a wellbore is necessary. Some of them are mentioned below.

Stuck pipe

When drilling a well, the driller may experience that the drill string get stuck. If attempts on freeing the pipe prove unsuccessful, the driller is forced to cut the string above the stuck point. The following procedure is then to place a cement plug above the fish, before continuing the drilling. If the wellbore has no potential source of inflow, one barrier is sufficient [1].

Production

When production rate decreases, the well will reach a point where it’s no longer sustainable. To maintain the production within the field it may be necessary to perform a slot recovery, and re-drill to a higher productive area of the reservoir. Slot recovery operations includes permanently plugging of the old well, before creating a window in the casing and sidetracking to an area with higher oil saturation and/or higher mobility.

Reduced integrity

If the well cannot be produced in a safe manner, it must be shut-in. If well integrity cannot be re-established, the well must be plugged and abandoned. Reduced integrity can be caused by leaking tubulars, poor cement, collapsing, and/or failed equipment.

Decommissioning

When an operator considers a field to be fully recovered, they will start a decommissioning campaign. This includes the removal of all platform installations and the plugging of their corresponding wells.

3.2.2 Requirements

The Petroleum Safety Authority of Norway (PSA) governs all plugging operations on the NCS. In addition to the regulations provided by the PSA, the industry has a guideline. This guideline is the NORSOK D-010, and is meant to provide minimum requirements for all well operations on the NCS.

"Permanently abandoned wells shall be plugged with an eternal perspective taking into account the effects of any foreseeable chemical and geological processes. The eternal perspective with regards to re-charge of formation pressure shall be verified and documented[1]".

To satisfy the acceptance criteria provided by NORSOK, several barriers must be set into the well.

Primary well barrier

The primary well barrier acts to isolate the source of inflow. The barrier must be impermeable and placed at a depth so that the formation integrity is higher than the potential pressure from below [1].

Secondary well barrier

The secondary barrier acts as a back-up for the primary barrier. The same requirements applies to both of them [1].

Cross-flow well barrier

The cross-flow barrier must be placed in a well if it extends across multiple reservoirs with different pressure profiles. If the reservoirs have the same pressure profile, a cross flow barrier is not necessary. See Figure 3.4 for example. This barrier can also act as a primary barrier for the deepest reservoir. The same requirements with regards to depth applies [1].

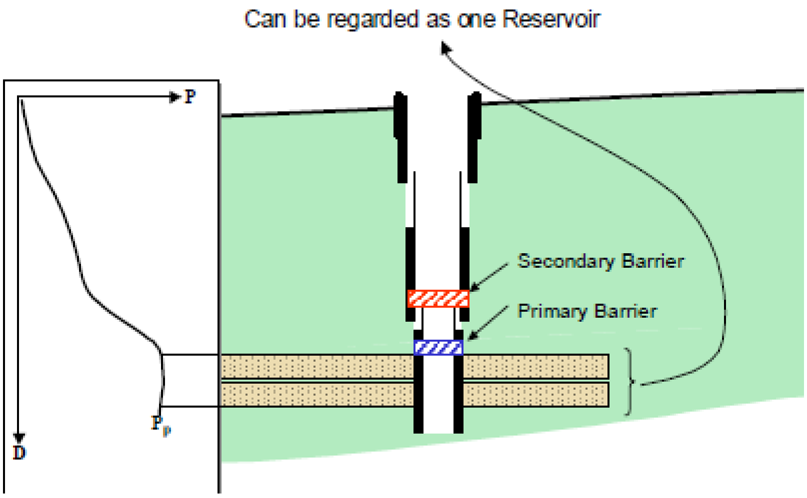

Figure 3.4: Multiple reservoirs with no cross-flow [1].

Open hole to surface well barrier

The last cement barrier to be set acts to isolate all possible flow paths between surface and the well. The plug is set after retrieving the production casing. The plug has no depth requirement with respect to formation integrity [1]. After this plug is set the surface casing and conductor is retrieved some meters below the seabed. This is to ensure no exposure of the casing above the sea bottom in the future – minimizing the footprint.

Plug requirements

A permanent well barrier must extend across the full cross section of the well. This includes the wellbore and all the belonging annuli. The cement behind the casing must be verified by logging and shall be a minimum of 30m with acceptable bonding [1]. The primary cement jobs quality is therefore crucial in order to execute an effective P&A operation.

The cement plug itself shall have a length of minimum 100m MD with minimum 50m MD above any source of inflow/leakage point. If the cement is set above a mechanical plug, the minimum length of the plug is 50m [1].

According to NORSOK D-010 a permanent well barrier shall have the following characteristics [1]:

- Provide long term integrity (eternal perspective)
- Impermeable
- Non-shrinking
- Able to withstand mechanical loads/impact
- Resistant to chemicals/substances (H_2S, CO_2 and hydrocarbons)
- Ensure bonding to steel
- Not harmful to the steel tubulars integrity

Prior to setting a permanent plug the casing cement must verified to have a good bond. If not, the casing must be milled, so that a full cross-sectional rock-to-rock barrier can be established. A milling operation is a time consuming one, and should be avoided if possible.

The production tubing may be left in hole if proper sealing can be provided. Control lines must, however, be removed prior to the placement of plugs, as they can induce leak paths in the barrier [1].

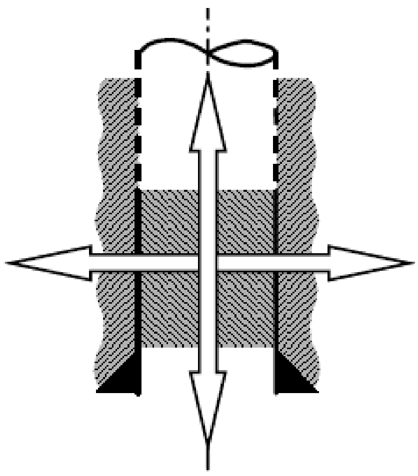

Figure 3.5: The barrier shall seal both vertically and horizontally [1].

After setting a plug, its location must be verified by tagging. In addition, its sealing ability must be verified by pressure testing the barrier.

As previously mentioned the P&A operations deeply depends on the wells status. Today abandonment is often postponed, which is unfortunate as wells tend to deteriorate over time. The quality of the primary cement jobs is essential in performing an effective P&A. It reduces the amount of equipment needed along with the type of rigs. In the future, dedicated P&A vessels can be important in rationalizing the P&A operations, and making the drilling rigs available for their intended use [22].

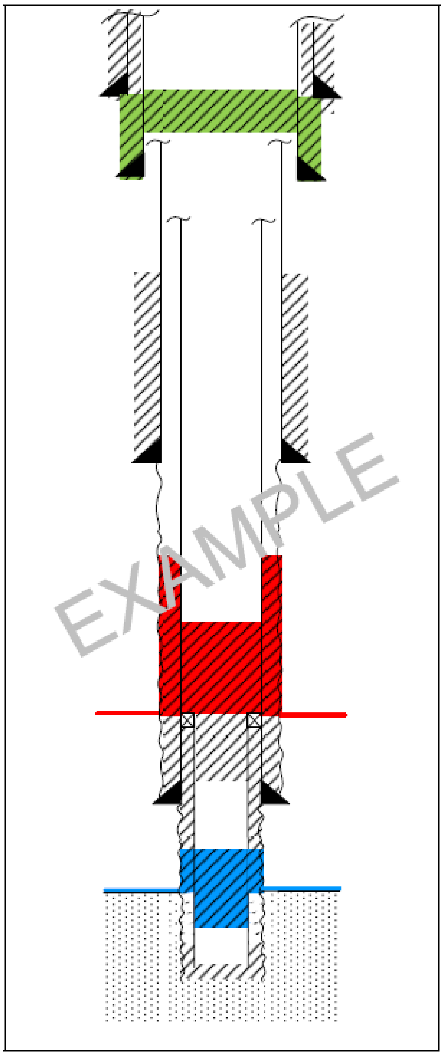

Figure 3.6: An abandoned well with the tubing removed [1]. For full WBS see Appendix B.

3.2.3 Perforate, Wash & Cement

A newly developed method in P&A called Perforate Wash & Cement can contribute in making the operation more effective. By accessing the annulus through perforations, the system can set a full cross-sectional barrier.

This method is effective for placing plugs in both poor and non-cemented sections of the casing.

Unlike traditional methods where cutting, milling, and pulling of casings is necessary, the PWC-methods provide rock-to-rock seals in one run. A full milling and cementing operation can take as much as 10-11 days, while a successful 1 trip PWC operation can take 2.55 days [23]. The time and cost saved by this method is unquestionable, and if we take into account all the wells that need to be P&A, the money saved is quite immense.

The PWC method also eliminates the production of swarf, associated with milling. This contributes to better safety, and the need for handling equipment is not necessary. High viscous fluids for swarf transporting is not needed. However, there is need for high-density fluids to maintain the stability of exposed formations.

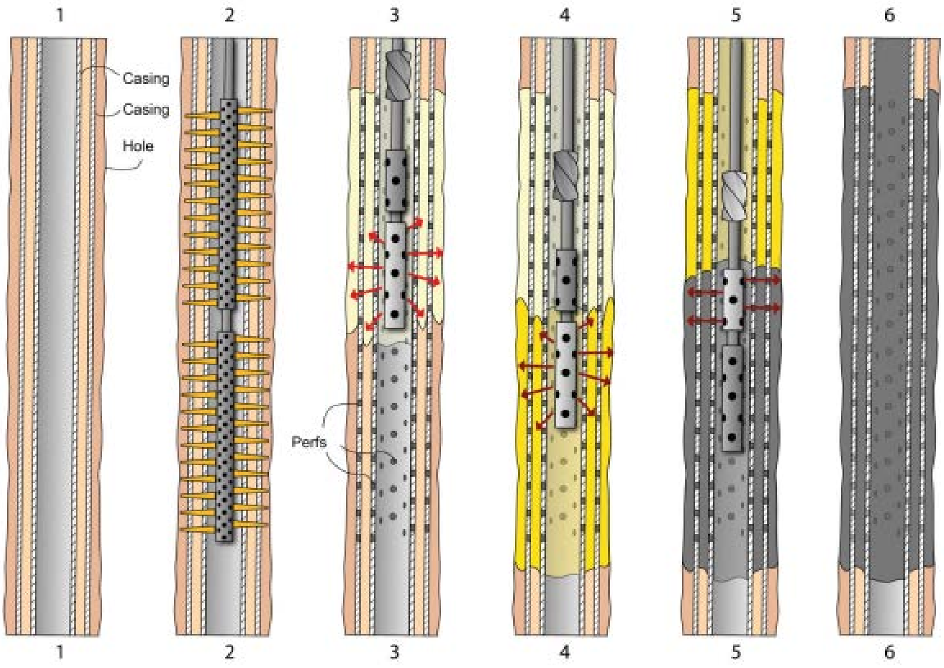

Figure 3.7: The PWC placement method [24].

Plug placement technique

The BHA includes perforating guns, a washing tool & a cement stinger. By including all tools in one BHA, the operation can be carried out in one run. The BHA is lowered into the well with a drill pipe. When reaching the plug placing depth the perforating guns are activated by a ball drop. After the perforation is performed, the guns are deployed in the well. A rat-hole is therefore necessary.

After dropping the perforating guns, the washing tool is lowered to the perforated section. The washing tool has a lower and upper cup, which forces the washing fluids into the annulus through the perforations and upwards towards the surface. Washing of the annulus ensures good bonding conditions for the cement plug.

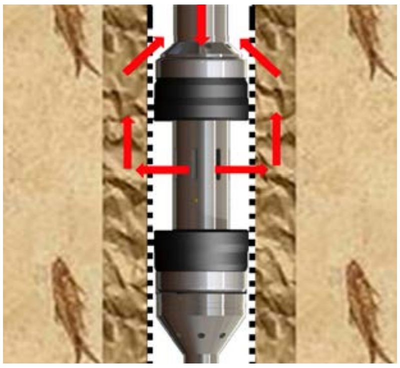

Figure 3.8: The washing tool forces fluids through the bottom perforations and upwards [2].

When the washing is completed, the washing tool is released, and pushed below the desired plug depth. The top cup then acts as a base for the following cement plug. The cement stinger is then positioned for the placement of the plug. The plug is placed as a balanced plug and the cement is squeezed through the perforations. After finishing the displacement, the string is left in hole to await the setting of the cement plug. When the cement has set, it can be washed, tagged and pressure tested. If desired, the plug can be drilled through and the cement in the annulus can be logged. If the log verifies good bond, the drilled section will again be cemented, and the plug tested before concluding the work [23].

3.3 Cementing Materials

Cement is by far the most important oil-well binding material in terms of quantity produced. The most know type of cement is the Ordinary Portland Cement (OPC). OPC is produced mainly by pulverized clinker and other additives. Clinker consists primarily of hydraulic calcium silicates, calcium aluminates and calcium aluminoferrites. Gypsum is also ground into the material in order to make the finished product. The gypsum prevents the cement from “flash setting”, or quick setting, which can prevent proper placement [18].

API has identified nine types of cement according to composition and properties [25]:

- Classes A and B (Portland Cement)
- Class C (High early strength cement)
- Classes D, E and F (Retarded cement)
- Classes G and H (Basic cement)
- Class J (Special cement)

3.3.1 Portland Cement

Portland cement is the most common type of cement, and is the most used isolation material in the oil industry. It is defined as a hydraulic cement, meaning that it hardens when reacting with water and at the same time forms a water resistant material. In the European standard EN-197-1 Portland cement is defined as a CEM1 and CEM2, where CEM1 mainly consist of clinker, while the different CEM2 types has various additives [26]. Se appendix C for complete cement table.

3.3.2 Alternative Isolation Materials

Lately there has been a lot of research carried out regarding the development of isolation materials. Cement is a strong and durable material, but it also faces challenges. It is a brittle material, and can break if subjected to too high stress. Curing of cement is greatly influenced by the temperature; HPHT-wells therefore present a problem. The high temperature can induce an irreversible premature stiffening of the cement, called "flash setting" [18].

A good alternative to traditional cement is the Thermaset® polymer, which is developed by the Norwegian company WellCem. The material already has field proven results. It is a non-reactive particle free solution, which can be pumped down hole using the same methods as for cement. Its gravity can be adjusted from 0.7-2.5 s.g, depending on the formation properties. Operation temperature range from -9°C to 150°C. When it is cured it is resistant to 320°C [27].

Thermaset® curing is triggered by the temperature in the well. Meaning that it can be designed to fit for each specific well. When the fluid reaches the designed depth the curing process starts, and the setting time can take from a few minutes to several hours. This can also be regulated.

Thermaset® is also more resistant than the Portland cement concerning compressive, flexural and tensile strength (see Table 3.1).

	Portland Cement	Thermaset®
Compressive Strength (MPa)	58	77
Flexural Strength (MPa)	10	45
E-modulus (MPa)	3700	2240
Rupture Elongation (%)	0.01	3.5
Tensile Strength (MPa)	1	60
Failure Flexural Strain (%)	0.32	1.9

Table 3.1: Properties of Portland Cement vs. Thermaset® [27].

4. Casing Centralization

"One of the most important aspects of the displacement efficiency of the drilling fluid by the cement slurry is the casing centralization in the well. The cement slurry tends to pass by the zone of least resistance to the flow, that is, through the widest part of the well-casing annulus, forming thus preferential circulation channels. This problem is critical for highly deviated wells" [28].

Correct use of centralizers along the casing joints is critical in order to achieve a good cement job. Centralizers are tools that are attached to the outside of the casing. By installing them in appropriate intervals, a good casing centralization can be achieved. In 2010, the oil industry experienced one of the world's worst oil related disasters. The drilling rig "Deepwater Horizon", which was drilling for BP in the Gulf of Mexico, experienced a blowout. This initiated an explosion, which in turn led to the rig sinking. 11 persons lost their lives, and 17 got injured [29]. One of the reasons for the blowout was insufficient use of centralizers, preventing a good cement job. This topic will be discussed later.

Good centralization of the casing depends on several parameters. Well path, hole size, casing size, buoyancy factor, but most importantly the placement of centralizers. Centralization is measured in percentage standoff. 100% standoff indicates that the casing is perfectly centralized in the wellbore/outer casing. If the casing is touching the outer casing or the formation, the standoff is 0%. Standoff is calculated by dividing the gap between the casing and the wall by the difference between the hole radius and the casings outer radius (Figure 4.1). The industrial standard is to obtain a minimum standoff of 70% prior to cementing [30].

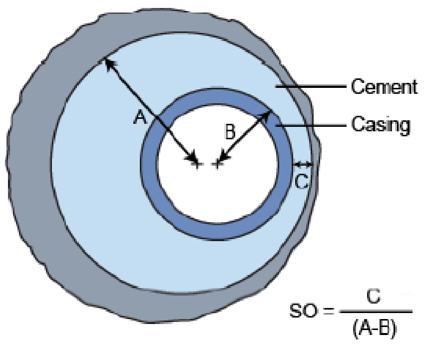

Figure 4.1: Calculation of standoff [30].

4.1 Centralizers

There exist several centralizers on the market, each with different properties regarding functionality, properties and appearance. The bow spring type is the most common one, but alternatives like rigid centralizers and semi rigid centralizers are widely used. However, they all provide the casing with the desired standoff, if distributed correctly. Improper or lack of centralizer usage can lead to poor bonding of the cement sheath. A standoff value below 70 % can prevent a proper displacement of the drilling fluid. The drilling fluid will then create small channels in the cement sheath, which prevents the cement from creating a tight seal.

The use of centralizers also helps avoid differential sticking when running the casing into the well. This is because the contact area between the casing and the mud cake on the wellbore wall is reduced.

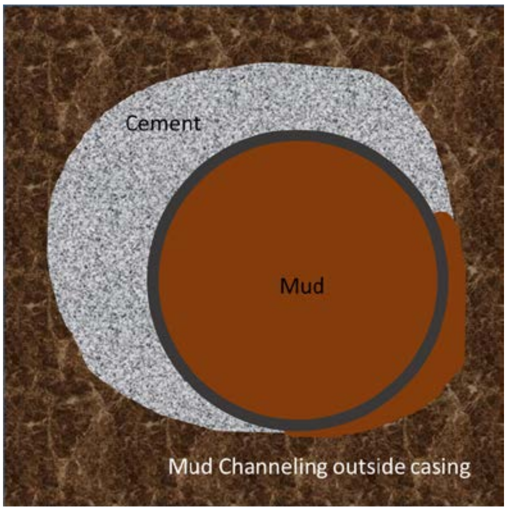

Figure 4.2: Bad centralization of casing can cause mud channels in the annulus.

4.1.1 Bow-Spring Centralizer

The Bow-Spring Centralizer is the most common centralizer and the first to be developed. Two collars are connected by bow-shaped springs. These springs have an OD, which is slightly larger than the wellbore ID, making them force the casing away from the wellbore wall. This allows the cement to be evenly distributed around the casing. The standoff provided depends on the restoring force of the springs, and the spacing between the centralizers.

Bow-Spring centralizers come in welded and non-welded styles. The non-welded centralizers come with hinges, which attaches the centralizer to the casing. According to Halliburton, both of them provide the following advantages [31]:

- They help center the casing in the wellbore, allowing even distribution of cement around the casing.
- They help reduce casing drag on the wellbore during casing running operations.
- They help prevent differential sticking of the casing.
- They increase fluid turbulence at the tool, helping remove filter cake from the wellbore.
- They can be run through hole restrictions in the wellbore or through smaller casing strings that are cemented in the well, thereby centering the casing below the restriction.

Bow-spring centralizers do, however, provide less support in highly deviated wells, as they do not support the weight of the casings very well [32].

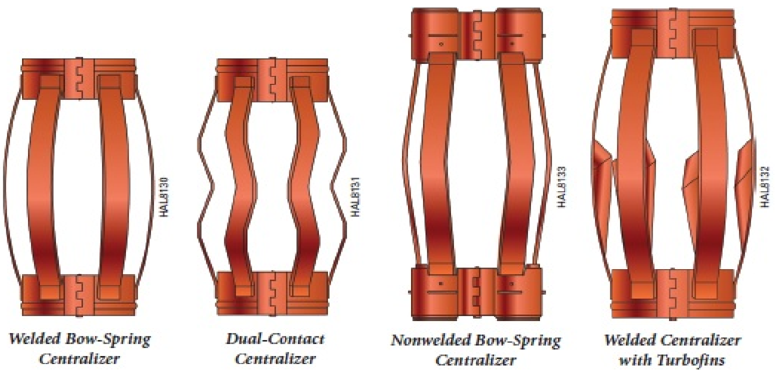

Figure 4.3: Bow-Spring Centralizers [31].

4.1.2 Rigid Centralizer

The rigid centralizers serves the same purpose as the bow-spring type, but with some deviations. The rigid centralizers has no moving/flexible parts, making them more prone to being stuck. If the well is not in excellent condition, it can cause problems for the centralizer. When running rigid centralizers one must have a margin between the wellbore ID and the Centralizers OD, in order to prevent stuck pipe. This makes it impossible to achieve a 100% standoff, but this is of course not necessary.

The high strength of the rigid centralizers makes them very beneficial for use in highly deviated or horizontal wells. The centralizer can be installed between two stop collars. The centralizer can then move freely between these collars. This also allows the casing to rotate without needing to rotate the centralizer. Rotation of the casing improves the fluid displacement. Another option is centralizers with integral setscrews [33].

Rigid centralizers come in different types; solid body, straight blade and spiral blade centralizers.

Figure 4.4: Rigid centralizer with spiral blades [33].

4.1.3 Semi Rigid Centralizer

The semi rigid centralizers utilizes the concept from both the rigid and the bow-spring type. Initially the unit acts as a bow-spring centralizer. As the side force increases the, and the bow is compressed, it turns itself into a rigid type. The bows then acts as blades not very different from the rigid type [30]. The Dual-Contact centralizer from Figure 4.3 is a typical semi rigid centralizer.

4.1.4 Protech CRB™ Centralizers

Centralizers are subject to a lot of wear and tear when run into hole. It can be destroyed or get stuck during the running operation.

The Protech CRB™ (Casing Resin Blend) solution is an alternative to the more traditional centralizers. The technology is developed by Halliburton together with Eni S.p.A [34]. The concept is to attach a high resistant resin blend onto the casing. This forms a solid type centralizer, which is applicable to whatever casing size. With good thermal properties as well as being H_2S and CO_2 resistant, it makes a good alternative to traditional centralizers.

The blend is bonded to the casing at the yard before shipped to the site. Time used to install centralizers and welding them on is then eliminated, which contributes in streamlining the operation.

This technology also applies to drillpipe and is called Protech DRB™ (Drillpipe Resin Blend) [34].

Figure 4.5: Protech CRB™ blend attached to a pipe [34].

4.2 Deepwater Horizon & the Macondo Blowout

The Deepwater Horizon was a semisubmersible drilling rig owned by Transocean. In 2010 it operated for BP at the Macondo prospect in the Gulf of Mexico. The 20th of April it experienced a blowout, which led to the rig exploding and sinking. The accident claimed the lives of 11 persons, and injured 17 [29]. Several barriers were breached, which resulted in this catastrophic incident.

The well spilled oil into the Gulf of Mexico for several months, and was not completely abandoned until 5 months later. It has then managed to become the worst offshore oil spill in U.S history, with 206 million gallons of oil spewed [35].

Figure 4.6: A sinking Deepwater Horizon [36].

4.2.1 Course of Events

The course of events described here is taken from BP's internal investigation report [29].

The Macondo well was spudded with Transocean's Marianas rig the 6th of October 2009. In January 2010, the Deepwater Horizon rig arrived Macondo to replace the Marianas rig. On the 9th of April, the TD of 18 360 ft. was reached, and a 9 7/8" x 7" casing was planned ran into the well. Appendix D can be viewed for the full casing program.

The 20th of April hydrocarbons escaped from the Macondo well. The rig crew and BP well team failed to gain control over the situation, which eventually lead to the rig sinking. The key events leading up to the catastrophe is described below.

The annulus cement barrier did not isolate the hydrocarbons

Halliburton's OptiCem™ program was used to simulate the cement job and the required number of centralizers needed. The program concluded that 21 centralizers was required in order to achieve 70% standoff in the planned cemented section. The cement was planned to have a TOC 500ft above the shallowest hydrocarbon zone.

The 7" section of the casing was delivered with six inline centralizers; not enough to provide the desired standoff. An order of 15 additional bow spring centralizers was placed the 15th of April, and these were delivered to the rig the next day. The well team did however, believe that they had received wrong centralizers, and was concerned that they would fail during running of casing. The centralizers were correct, however, the team decided not to install them, and ran the casing with only the six inline provided centralizers.

The casing was run, and cement pumped. Full returns was observed, indicating no fluid losses. After the cement job was completed the well team had discussions about running a cement evaluation, but they concluded that it was not necessary. This decision combined with the decision not to run the recommended amount of centralizers may have contributed to the cement not sealing the annulus; allowing hydrocarbons to migrate towards the surface through said annulus and into the casing.

Float collar did not isolate the hydrocarbons

The float collar is a component in the lower part of the casing, mentioned in chapter 3.1.1. This component is a flapper, which serves as a mechanical barrier, preventing unwanted backflow. This component failed, allowing the hydrocarbons to migrate upwards through the casing.

A negative-pressure test was accepted although well integrity was not established

10 ½ hours after the cement job the drill crew started the pressure testing of the mechanical barriers. The positive-pressure test was conducted and proved successful.

When doing a negative-pressure test the well is brought into underbalance, and the sealing capability of the well can be tested.

The negative pressure test did however indicate that flow path communication existed, but this was faulty interpreted by the rig crew and the BP leaders. They concluded that the test was successful and that well integrity had been established.

Influx was not recognized until hydrocarbons were in the riser

After the negative-pressure test was finished and accepted, the well was brought into overbalance again, preventing further influx. Later when the well was about to be temporary abandoned, the heavy mud in the well was replaced with seawater, under-balancing the well. This allowed hydrocarbons to migrate upwards through the production casing, and passed the BOP. The pressure increase in the drill pipe should have been noticed, but counteractions where not done until 40 minutes later, when hydrocarbons where rapidly flowing to the surface.

Well control response actions failed to regain control of the well

Some minutes before the hydrocarbons reached surface, witnesses observed mud flowing uncontrollably onto the rig floor. The annular preventer was closed, but it was too late as hydrocarbons had already entered the riser. The annular preventer did not properly seal the annulus, so the hydrocarbons continued to enter the riser.

The fluids entering the riser was diverted to the mud-gas separator, but this was quickly overwhelmed by the amounts, and failed to control the hydrocarbons. Some minutes later the drill pipe pressure rose from 1200 psi to 5730 psi! This was likely caused by the sealing of the annulus caused by the variable bore rams in the BOP. At approximately 21:49 hours, a couple of minutes after the pressure increase, the explosions occurred, followed by fire.

Attempts were made to activate the emergency disconnect sequence (EDS). This would have sealed the well and disconnected the riser. The EDS did not activate.

Diversion to the mud gas separator resulted in gas venting onto the rig

When the rig crew noticed the hydrocarbons above the BOP, they diverted the flow to the MGS. The MGS was not designed for the high amounts of gas, and was overwhelmed. This led to the gas being diverted directly to the rig floor, creating a highly flammable environment.

The fire and gas system did not prevent hydrocarbon ignition

The fire and gas system is designed to detect hydrocarbon gas when they exceed a predetermined concentration. When activated the system shuts down electrical devices, which can act as an ignition source. Because of the unlikeliness of hydrocarbons, being present when there is no producing wells, the Deepwater Horizon only had small areas that was electrically classified. Therefore, the system did not prevent the hydrocarbons from being ignited.

The BOP emergency mode did not seal the well

The last option to seal of the well and kill the blowout was to activate the Blind Shear Ram (BSR). If activated, the BSR cuts through the drillpipe and seals off the wellbore. If the EDS system had been working properly the BSR would already have been activated, but damaged cables prevented this.

33 hours after the explosion a ROV managed to activate the BSR. Although the BSR had been activated it failed to seal of the well.

Conclusions

The Macondo blowout was a result of human and technical errors. Several barrier was breached, which could have been maintained with proper well design and equipment maintenance. In this thesis, it is natural to focus on the first key failure, which was the primary cement not isolating the hydrocarbon-bearing zone. Proper centralization of the casing followed by methods of verification could have prevented the biggest oil spill in US history.

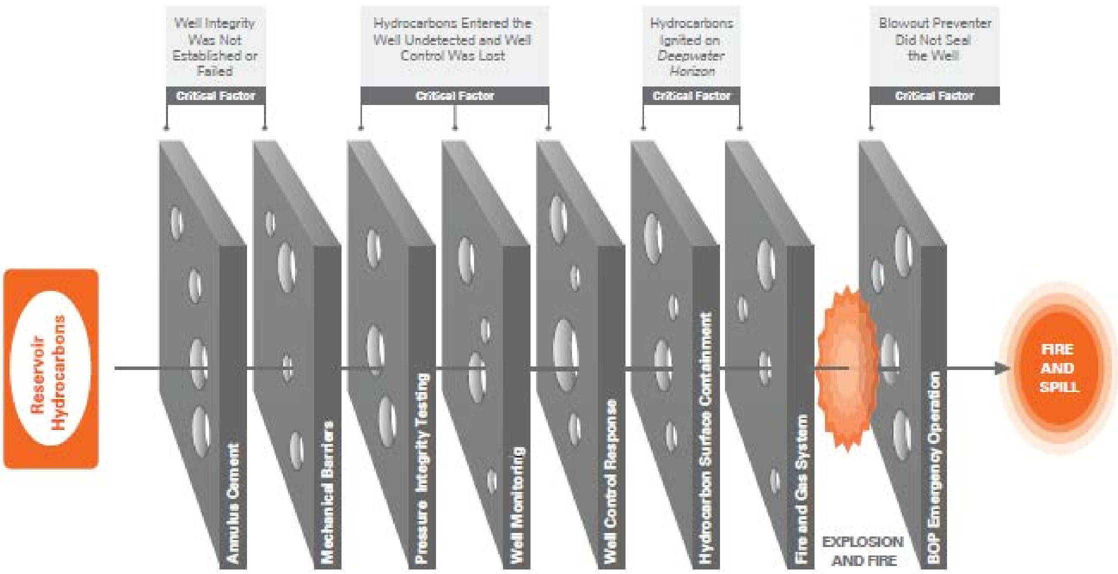

Figure 4.7: Several barriers were breached [29].

5. Optimizing Centralizer Distribution

By optimizing the distribution of centralizers along the casing, it is possible to acquire the desired standoff. It is especially important to obtain a good centralization in the section, which is to be cemented. Poor centralization here may cause poor circulation, which can lead to mud not being removed. If there is still mud in the well when the cement is being pumped it will contaminate the cement. This reduces the quality of the cement, making its sealing properties poor. Poor cement jobs is causing great cost to operators, as remedial cementing is required.

Optimal placement of centralizers depends on several parameters. When these parameters are known, several different methods for calculating the optimal distribution exists. One of them is the OptiCem™-Module, which is included in the WELLPLAN™ program developed by Landmark, Halliburton. This module will be used in this thesis for simulating the optimum distribution of centralizers, and the spacing between them.

5.1 Well Trajectories

A parameter, which is very important in regards to centralizer placement, is the well's trajectory. A perfectly vertical well would in theory have no need for centralizers, whereas highly deviated and horizontal wells would need several centralizers in order to centralize the casings.

Several things govern the well trajectory design. Especially on offshore installations, well trajectory design is a key to reach the desired production zones. The platform has a restricted set of well slots, and must try to cover the reservoir by the use of these. All the wells have almost the same origin, and it is important to plan the wells with high precision to avoid colliding with and destroying other wells.

Well trajectory design also affects the possibility to reach remote reservoirs, which are too small to economically support the development of a platform or subsea template.

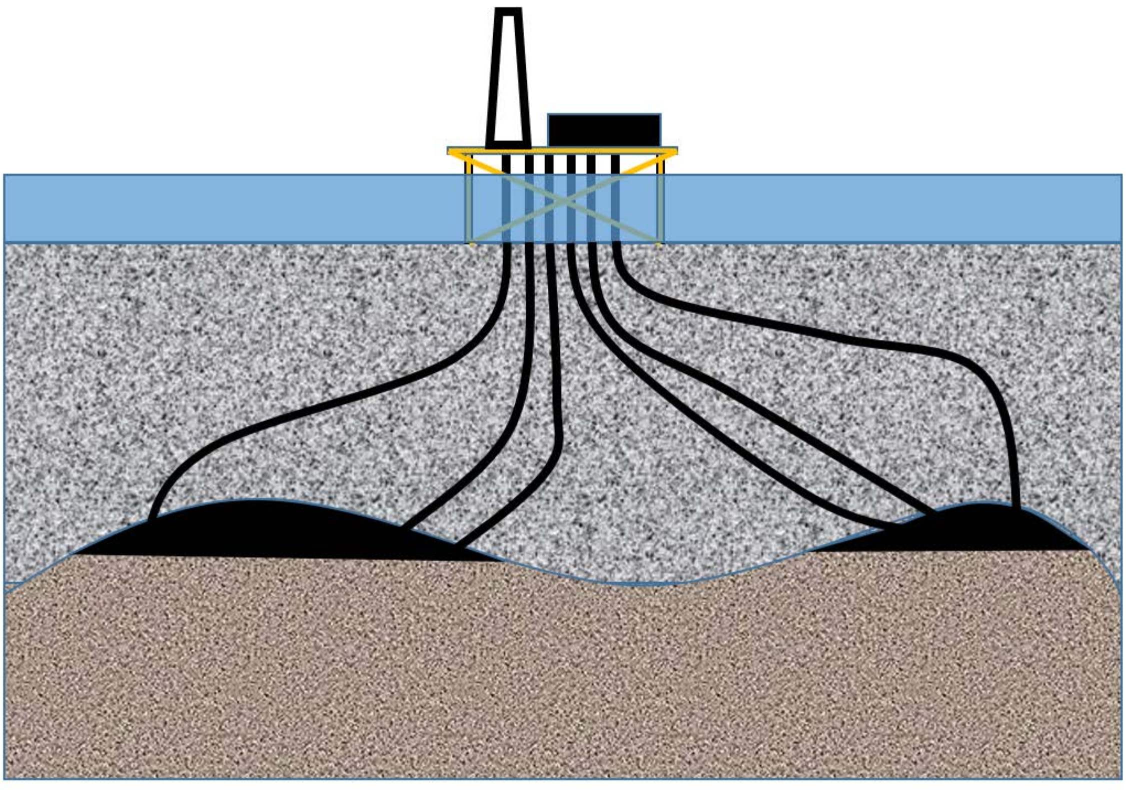

Figure 5.1: Well trajectories below a fixed offshore platform.

5.1.1 Vertical

Vertical wells are the simplest wells to design. The risk of experiencing mud channeling due to bad centralization is small, and centralizers is not required, in theory. A well is however, never completely vertical, and centralizers should be applied to ensure good standoff values before cementing.

5.1.2 Build & hold

The build & hold well has a kick off point at a shallow depth. Often right after the surface casing has been set. The well then goes into a build section where the wells inclination is increased. After the build section, the well enters the sail section, which it holds until it reaches the target depth.

The use of centralizers in the build and sail section is crucial in order to get a good cement job.

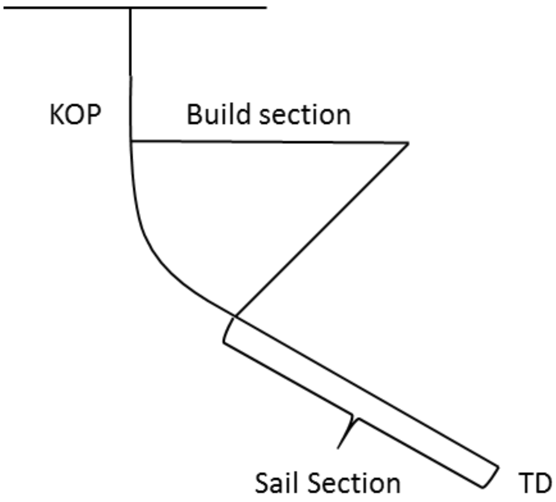

Figure 5.2: Build & hold profile.

5.1.3 Build, hold & drop

This type of well is similar to the build & hold type, but the angle drops after the sail section. This type of well design may be necessary when the TD is located away from the slot and reservoir properties dictates that a vertical entry angle is beneficial.

Centralizers are necessary in the build and drop section as well as in the sail section.

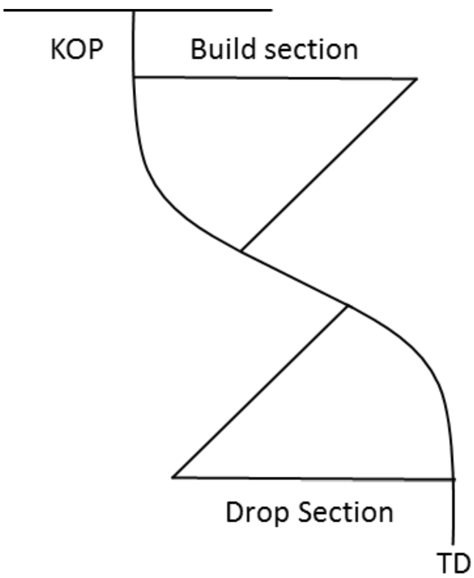

Figure 5.3: Build, hold & drop profile.

5.1.4 Horizontal

Horizontal wells are beneficial in thin reservoirs where vertical wells would be unsatisfactory. By drilling horizontal into the reservoir the drainage area is increased, which enhances productivity and lowers cost. The horizontal profile does, however, create problems related to the centralization of the casings. Without centralizers, the casing or liner will just rest on the wellbore floor. If centralizers are used, it is important to have the correct spacing in order to achieve the desired standoff. If the spacing is too large the casing will bend, and touch the wellbore wall in the middle between the centralizers.

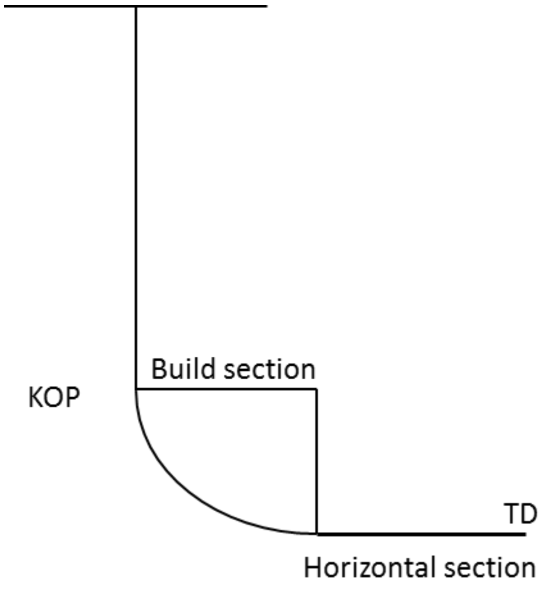

Figure 5.4: Horizontal profile.

Correct centralization of a horizontal well will aid the spacer in cleaning the hole, and the cement to create a good bonding to the formation.

The four well types described above will be used as a base for the simulations in OptiCem™.

5.2 OptiCem™ Simulations

OptiCem™ is a simulation software developed by Landmark. It was previously a stand-alone application, but is now implemented as a part of the Wellplan package. By using this program, one can simulate cement jobs, but also the optimal distribution of centralizers prior to a cement job.

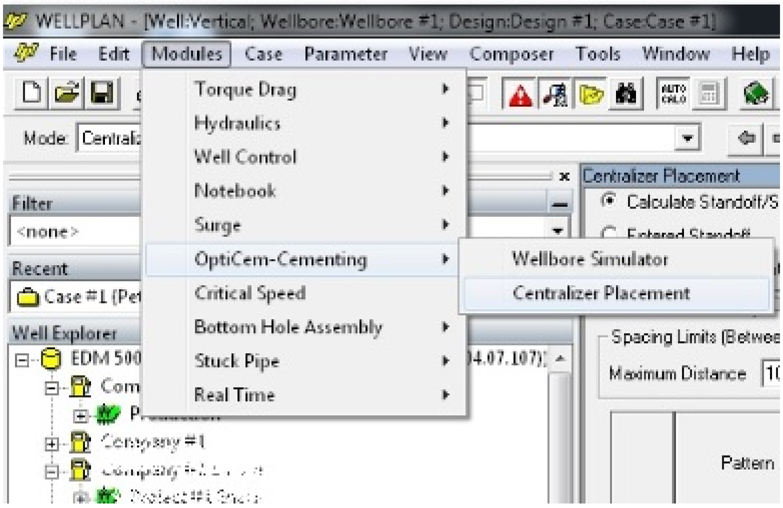

Figure 5.5 Starting the OptiCem™ centralizer module.

In order to simulate you have to provide the application with some input data. First, you need a survey. The survey defines the wells path, and is the most critical for centralizer placement. If the user do not have an actual survey available he can enter some data points, and the application will create a survey by interpolation. This is done by using the minimum curvature method. This method uses the inclination and direction of a lower and upper point in the well, and creates a smooth arc between the points. This method is considered to be the most accurate method [37].

Next, you have to define the wellbore. If there is casings already in place, these have to be entered. The module has a catalog of casings, which includes size grade weight & connection type. This is however not very relevant to the distribution of centralizers. If there is an open hole section this must also be defined here.

After defining the wellbore, the user defines the string, which is to be run into the hole. In these cases, this string would be a casing string. The casing is chosen from the same catalog as before.

It is also possible to define the fluid, which is in place while running the casing. This fluid will provide buoyancy, which effects the number of centralizers in some degree. However, the effect of the fluid is rather small, so the density will be set to 8,5 ppg during all simulations.

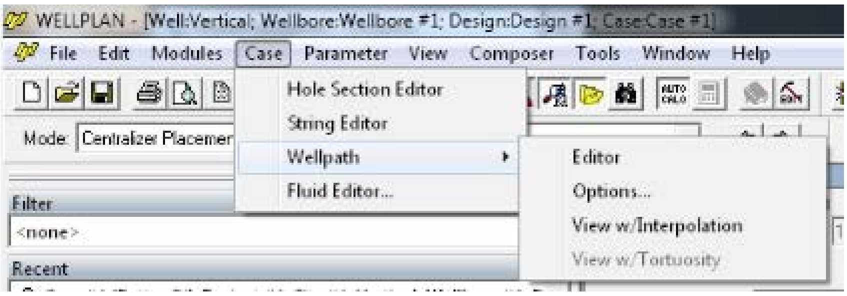

Figure 5.6: The data needed for calculations must be entered under the "case" menu.

After all these parameters are in place, it is possible to choose centralizers. The centralizers are also chosen from a catalog. The casing string, which is going to be run, alters the catalog, so that only the centralizers suited for the hole and casing are listed. When a centralizer type is chosen, it is possible to choose desired standoff or to specify the spacing between them. The module then calculates the number of centralizers, and the standoff respectively.

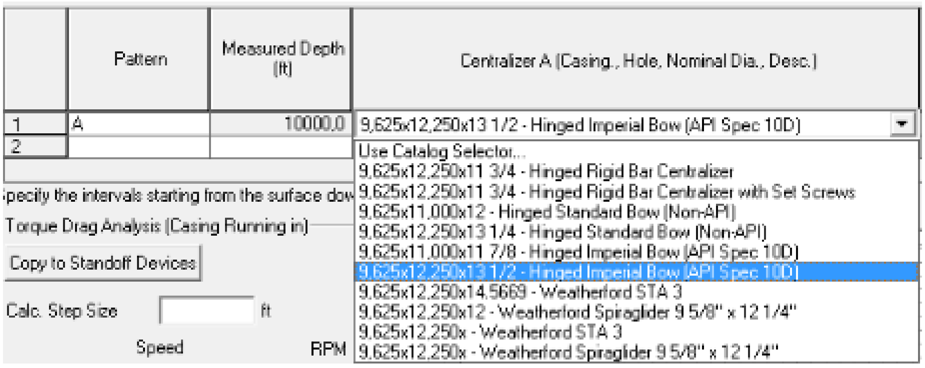

Figure 5.7: Centralizers are picked from the catalog.

5.2.1 Centralizing a vertical well

One would suspect that a vertical well would not have any demand for centralizers in order to keep the casing centralized. The tension in the casings provided by their own weight should ensure proper centralization. It is however, interesting to see how the OptiCem™ software responds to the input.

We start by entering the well path. Since this is a completely vertical well only two data points is necessary; start point and the TD.

Measured Depth (ft)	Inclination (°)	Azimuth (°)	TVD (ft)
0	0	0	0
10000	0	0	0

Table 5.1: Vertical survey data

After defining the well path and let the module create a survey using the minimum curvature method, the hole sections can be defined. For this simulation we will have a cased off section going down to 5000 MD. This will be a casing with an OD of 13 3/8”. The casing is followed by an open-hole with an OD of 12 1/4”, which continues down to TD.

There would normally be casings set prior to the 13 3/8”, but they are left out, as they do not affect the centralization of the next casing.

Section Type	Measured Depth (ft)	Length(ft)	OD(in)	ID(in)	Weight (ppf)
Casing	5000	5000	13 3/8	12,347	72
Open Hole	10000	5000	-	12,25	-

Table 5.2: Vertical hole section

Now that the well is defined with a survey and previous casings, it is possible to define the string, which is to be run into the hole. A 9 5/8” casing will be chosen as the next casing.

Section Type	Length(ft)	OD(in)	ID(in)	Weight (ppf)
Casing	10000	9 5/8	8,681	47

Table 5.3: Vertical casing string

All the data necessary to choose centralizers is now available in the module. By chosing the "Centralizer Placement" option available under the "Parameter" tab, the user can start simulation by entering desired standoff, or by specifying the spacing between the centralizers.

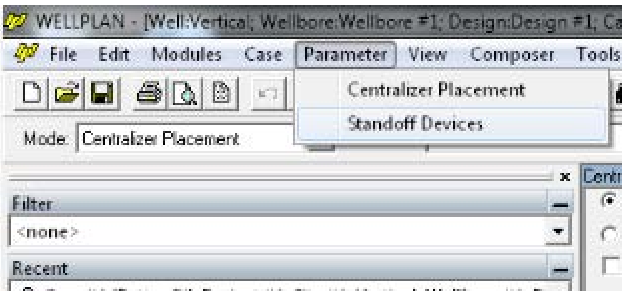

Figure 5.8: Centralizer simulation is carried out in the "parameter" section.

For this example with a vertical well, one would expect that no centralizers are required to get a good standoff value. By using this application, we can confirm this.

First, a bow spring type will be used to centralize the well.

Pattern	Centralizer A (Casing, Hole, Nominal Diameter, Description)	Required Standoff (%)
A	9,625 x 12,25 x 13 1/2- Hinged Imperial Bow (API Spec 10D)	70

Table 5.4: Centralizers in the vertical well.

In Table 5.4 the centralizer is defined. The pattern defines the pattern if different centralizers are used. Here we only use one type, so the pattern is A. If we had a mix of two different centralizers, we could have patterns like AB, AAB, and AAAB etc.

The numbers in front of the centralizer defines the casing it will be hinged on, the hole size and the nominal diameter of the centralizers itself. Note that the nominal diameter is larger than the hole. This is normal for bow spring types, as the springs get compacted when ran into the hole.

The user can choose the required minimum standoff. Here 70% is used as it is the industrial standard [30].   .

After selecting the centralizer, the module produces a standoff chart, which represents the standoff value of the casing along the depth of the well. For this example, a value of 100% is obtained along the entire wellbore, as one would expect.

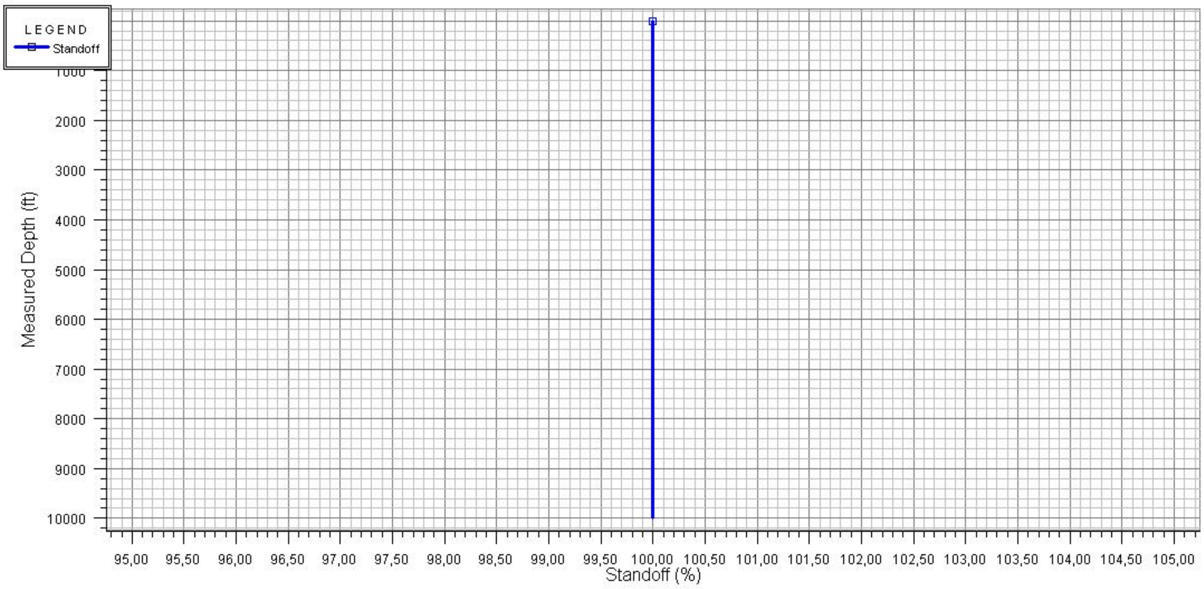

Figure 5.9: Standoff chart for the vertical well.

After selecting centralizers the user can open the “Standoff Devices” section and gain knowledge about how many centralizers are needed. In this case, the simulation tells us that two centralizers are enough.

It is also possible to define the spacing of the centralizers manually. The result is the same, giving standoff value close to 100%. However, a small change can be observed close to 5000 feet where the well changes from cased to open hole. This is because of the small change in the hole diameter.

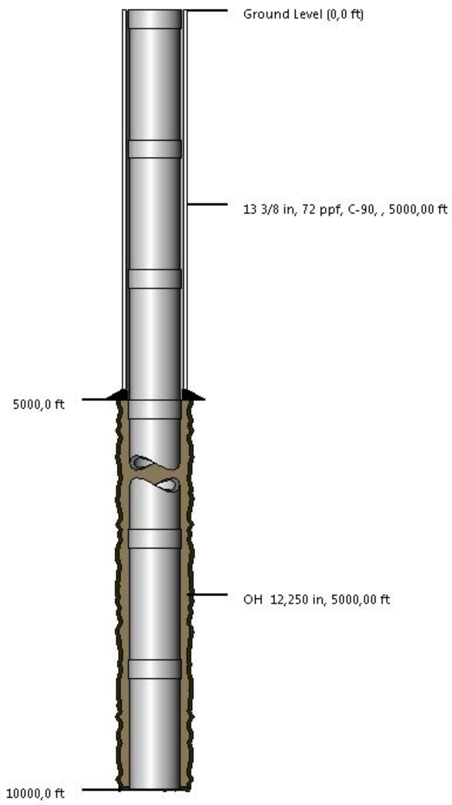

Figure 5.10: Well schematic for the vertical well.

5.2.2 Centralizing a build & hold well

When the well profile gets more complicated, the number of centralizers required increases. Especially in the build and the sail section one would expect that a great number of centralizers is necessary. The section above the KOP would not be that critical, but the weight of the underlying casing will try to drag the casing against the wellbore wall.

By looking at Figure 5.11 we see how we would expect the casing to behave in the well if no centralizers were used. The vertical section would be centralized, but in the build section the casing would be dragged towards the roof of the casing (red lines) wall because of the weight of the casing below. When we reach the start of the sail section, the casing would have a point where it is completely centralized before it starts decentralizing against the wellbore floor (blue lines).

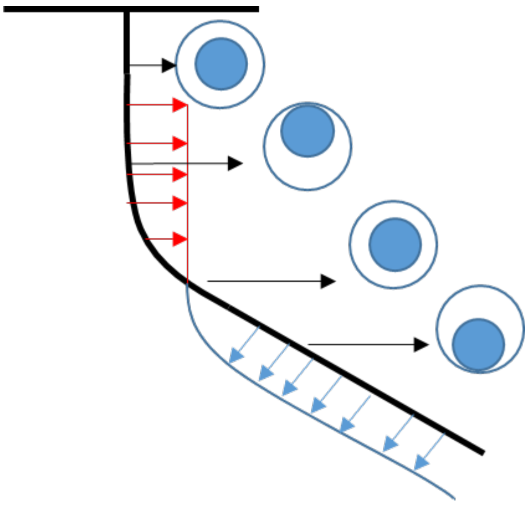

Figure 5.11: A build & hold well without centralizers.

In order to investigate this profile in OptiCem™ we need a survey, which is easy to compose. By entering a set of values, the module calculates a survey using the minimum curvature method. This example will only be two dimensional, letting the azimuth be 0 degrees at all depths. The well will kick off at 3500 ft and build inclination until it is 45 degrees. Then it enters the sail section, which continues down to a TD of 10000 ft.

Measured Depth (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	DLS (°/100ft)
0	0	0	0	0
1000	0	0	1000	0
2000	0	0	2000	0
3500	0	0	3500	0
4000	10	0	3994,9	2
4500	20	0	4477,3	2
5000	30	0	4929,9	2
5500	40	0	5338,9	2
5750	45	0	5523,2	2
6000	45	0	5700	0
1000	45	0	8528,4	0

Table 5.5: Survey data for the build & hold well.

By entering the above data into OptiCem™, it creates a complete survey. The well path created can be viewed in Figure 5.12. Before it is possible to do any simulations on centralizers, some data on the casings in the hole are needed. Previous casing and the casing to be run need to be specified. The same casing dimensions will be used for this example as for the previous one with the vertical well.

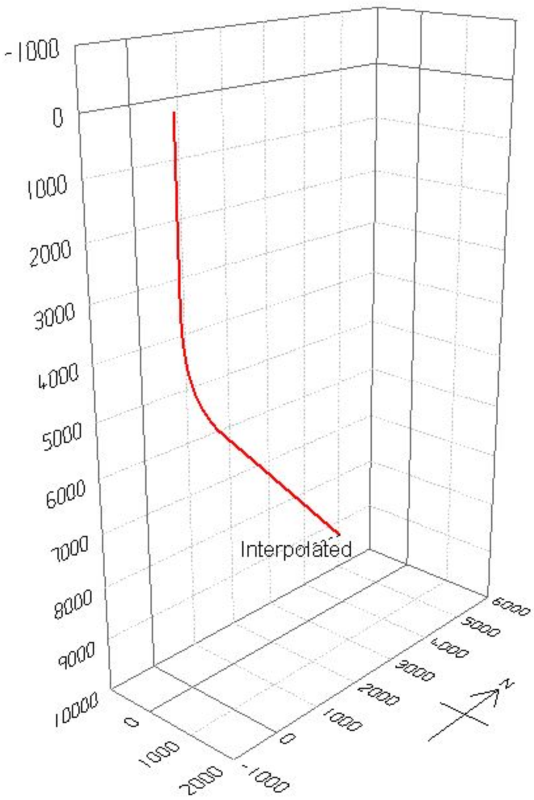

Figure 5.12: 3D plot of the build & hold well.

For this well the 13 3/8” will be at the same measured depth as for the vertical well.

Section Type	Measured Depth (ft)	Length(ft)	OD(in)	ID(in)	Weight (ppf)
Casing	5000	5000	13 3/8	12,347	72
Open Hole	10000	5000	-	12,25	-

Table 5.6: Build & hold hole section

The following casing to be set is a 9 5/8” casing, which continues down to a TD of 10000 ft.

Section Type	Length(ft)	OD(in)	ID(in)	Weight (ppf)
Casing	10000	9 5/8	8,681	47

Table 5.7: Build & hold casing string.

The same centralizer as for the previous example will be used. The required standoff will be defined so that it will meet the requirements.

Pattern	Centralizer A (Casing, Hole, Nominal Diameter, Description)	Required Standoff (%)
A	9,625 x 12,25 x 13 1/2- Hinged Imperial Bow (API Spec 10D)	70

Table 5.8: Centralizers in the build & hold well.

The defined settings result in the following standoff profile seen in Figure 5.13. Here it is possible to observe that the casing is completely centralized until it approaches the KOP where there is a sharp change in standoff value. This standoff is, however, kept stable along the build section, and increases only when entering the sail section.

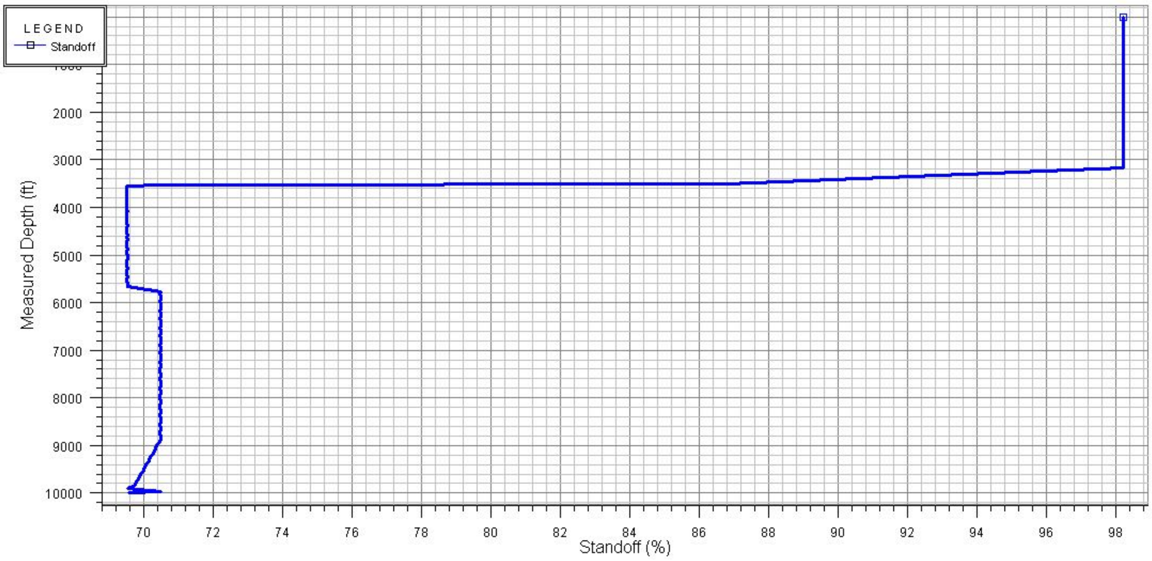

Figure 5.13: Standoff chart for the build & hold well.

In this example, a minimum standoff value of 70% was achieved using 140 centralizers. The centralizers are however, unevenly spaced to achieve this result, and this is something that can be difficult to achieve when installing the centralizers out in the field.

Section	Depth interval (ft)	No. of centralizers	Cent./100ft
Vertical	0-3500	6	0,17
Build	3500-5750	50	2,22
Hold	5750-10000	84	1,97

Table 5.9: Distribution of centralizers in the different sections in the build & hold well.

From Table 5.9 we can observe that the build section is the section that requires the most centralizers per 100 ft. in order to acquire a minimum standoff value of 70%. The sail section has a lower value, while the vertical section has almost no demand for centralizers.

As mentioned above, it can be complicated to install the centralizers in the manner required in the example above. An easier approach could be to install them with a constant spacing. For example one centralizer on every casing joint (approx. 40ft) [38].

Spacing (ft)	Standoff $\geq$ 70%	No. of centralizers	Problem area
50	No	200	Build Section
40	No	250	Build Section
30	Yes	300	N/A

Table 5.10: Constant distribution of centralizers along a build & hold well.

The above results show that a good standoff is harder to achieve when a constant spacing is applied. The result is satisfactory when using 300 centralizers with a constant spacing of 30 ft. The installment of these centralizers are, however, easier to implement, but the number centralizer is more than doubled relative to the first example, so this is something that should be evaluated by the operator.

When using a spacing of 50 ft. the standoff is satisfactory in every section but the build section. Here the standoff reaches a low point at about 35% at the kick off point. This section would normally not be cemented, as it is high above the casing shoe. Therefore, this result could have been considered. A spacing of 60ft. is, however, unsatisfactory in all sections but the vertical, and is not a recommended option.

An alternative solution is to divide the well into three parts. The vertical, build, and the hold section all have different demands with respect to centralizers. A spacing of 30 can for example be considered redundant in the vertical section. By implementing different spacing for the different sections, the amount of centralizers is reduced, while installation still is kept simple.

Depth Interval (ft)	Spacing	Standoff ≥ 70%	No. of centralizers
0 - 3500	3500	Yes	0
3500 - 5750	30	Yes	75
5750 - 10000	50	Yes	85

Table 5.11:Various distribution of centralizers along a build & hold well.

Table 5.11 shows the result of dividing the well into different sections. This result yields a total amount of 160 centralizers, which only is 20 more than for the optimal solution shown in Table 5.9. The fact that this solution is easier to implement, makes it a preferable solution. By looking at Figure 5.14, one can see that this solution is satisfactory concerning standoff values.

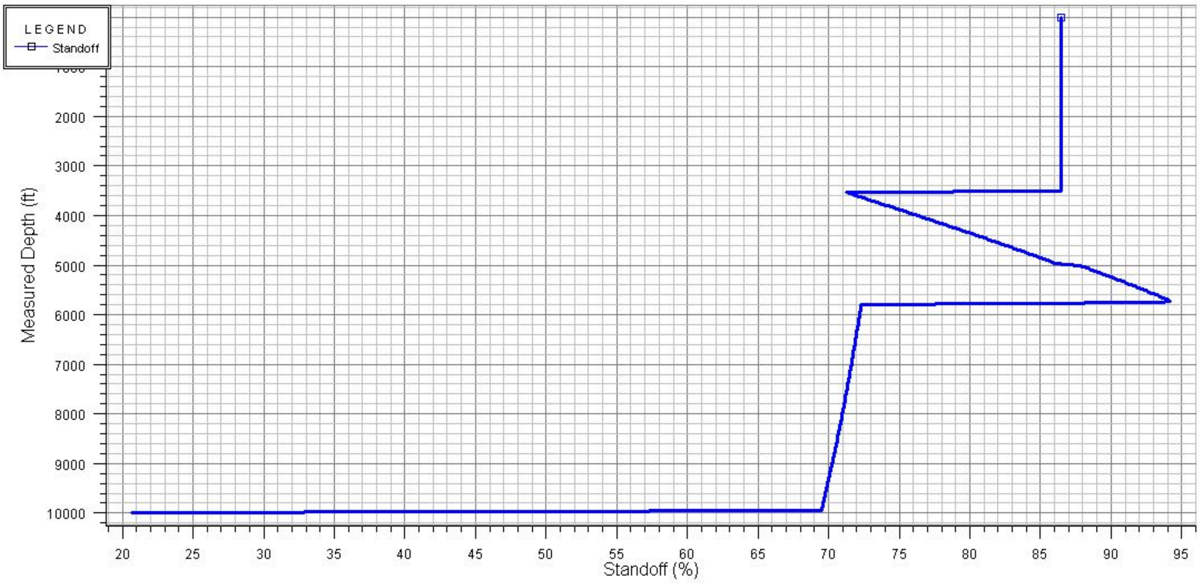

Figure 5.14: Standoff chart for various distribution of centralizers along the well.

5.2.3 Centralizing a build & hold well with azimuth

A parameter it can be interesting to look at is the azimuth. So far the well profile have only been in two dimension, leaving the azimuth at 0 degrees. If all other parameters is left equal, but with an increase in azimuth along the build section, it is possible to see how this affect the number of centralizers needed.

Measured Depth (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	DLS (°/100ft)
0	0	0	0	0
1000	0	0	1000	0
2000	0	0	2000	0
3500	0	0	3500	0
4000	10	40	3997,5	2
4500	20	80	4480,9	2,77
5000	30	120	4936,6	3,83
5500	40	160	5351,0	4,91
5750	45	180	5536,1	5,74
6000	45	180	5712,9	0
10000	45	180	8541,3	0

Table 5.12: Survey data for the build & hold well with azimuth.

By entering the above data into OptiCem™, it creates a complete survey. The same casing dimensions and setting depths will be used for this example as for the previous one. The 13 3/8” casing is the previous casing set at 5000 ft. while the 9 5/8” is the casing to be run to TD.

First, we let OptiCem™ find the optimal distribution of centralizers, by defining our desired standoff. The desired standoff is 70% as before. The same bow spring type as in previous examples will be used. OptiCem™ creates a good standoff profile using 179 centralizers. However, as in the previous example, it is an uneven distribution and may be hard to carry out in practice. To simplify this we split the well into three parts, the vertical, build, & the hold section.

Depth Interval (ft)	Spacing	Standoff ≥ 70%	No. of centralizers
0 - 3500	3500	Yes	0
3500 - 5750	20	Yes	114
5750 - 10000	50	Yes	85

Table 5.13: Various distribution of centralizers along a build & hold well with azimuth.

For this example, a total of 199 centralizers is necessary to achieve a standoff value above 70%. Again 20 centralizers more than for the optimal solution, but again easier to install. The azimuth does make it harder to get a good standoff value, as expected, and more centralizers are required.

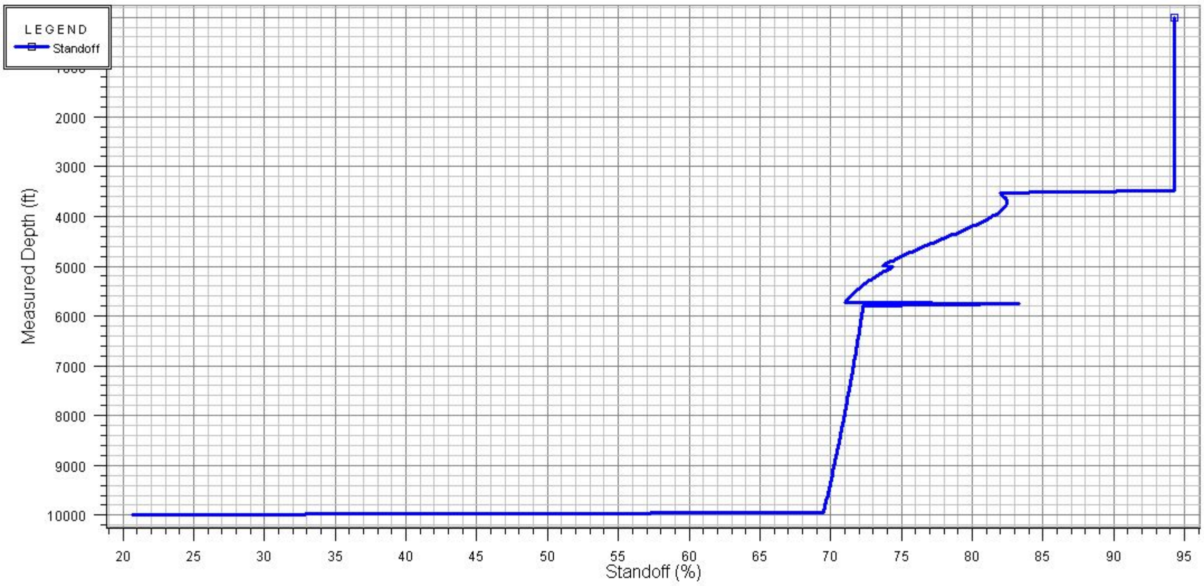

Figure 5.15: Standoff chart for various distribution of centralizers along the well.

5.2.4 Centralizing a build, hold & drop well.

In this section, we will see how a build, hold & drop well will affect the number of centralizers necessary.

Again, in Figure 5.16 we see how the casing would behave in this type of well, if no centralizers had been used. It will be interesting to see how much the drop section will affect the number of centralizers.

By maintaining a well length of 10 000ft and also entering the drop section at an earlier point, we can see how this affect the standoff, and number of centralizers.

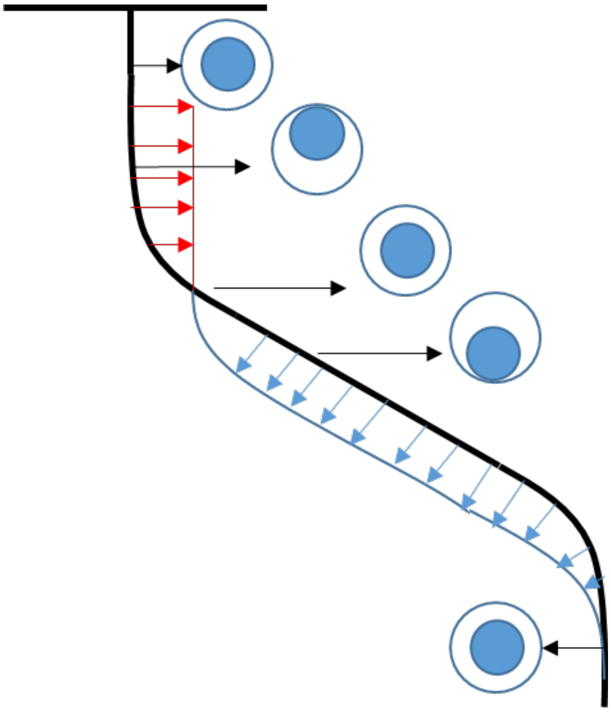

Figure 5.16: A build hold and drop well without centralizers.

OptiCem™ will again be used for simulations. All parameters but the survey will be kept the same. This time the azimuth will be kept at zero, in order to compare the result to the build & hold well with no azimuth change.

Measured Depth (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	DLS (°/100ft)
0	0	0	0	0
3500	0	0	3500	0
4000	10	0	3997,5	2
4500	20	0	4479,8	2
5000	30	0	4932,4	2
5500	40	0	5341,5	2
5750	45	0	5525,7	2
7000	45	0	6409,6	0
7500	35	0	6792,1	2
8000	25	0	7224,6	2
8500	15	0	7693,8	2
9000	5	0	8185,6	2
9250	0	0	8435,3	2
10000	0	0	9185,3	0

Table 5.14: Survey data for the build, hold & drop well.

By entering the data in Table 5.14 into OptiCem™, a complete survey is created. The well path can be viewed in Figure 5.17. Before it is possible to do any further simulations, the module needs information on the casings in hole, and the casing to be run. This will be the same as in previous examples, but will be shown again for clarification.

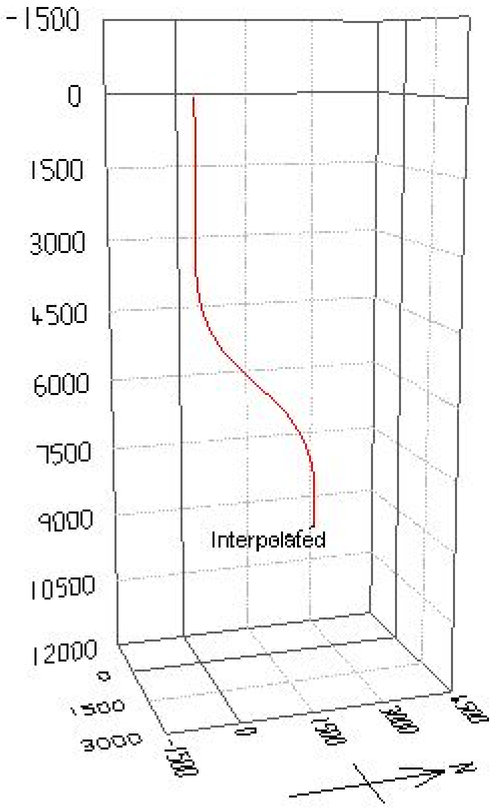

Figure 5.17: 3D plot for the build, hold & drop well.

Section Type	Measured Depth (ft)	Length(ft)	OD(in)	ID(in)	Weight (ppf)
Casing	5000	5000	13 3/8	12,347	72
Open Hole	10000	5000	-	12,25	-

Table 5.15: Build, hold & drop hole section

The following casing to be set is a 9 5/8" casing, which continues down to a TD of 10000 ft.

Section Type	Length(ft)	OD(in)	ID(in)	Weight (ppf)
Casing	10000	9 5/8	8,681	47

Table 5.16: Build, hold & casing string.

The same centralizer as for the previous example is used. The required standoff will be defined so that it will meet the requirements.

Pattern	Centralizer A (Casing, Hole, Nominal Diameter, Description)	Required Standoff (%)
A	9,625 x 12,25 x 13 1/2- Hinged Imperial Bow (API Spec 10D)	70

Table 5.17: Centralizers in the build, hold & drop well.

Now the module has enough data to run a standoff simulation. Again, the casing is completely centralized until it reaches KOP. Here the casing need support by centralizers along the remaining sections of the well. The standoff profile can be viewed in Figure 5.18.

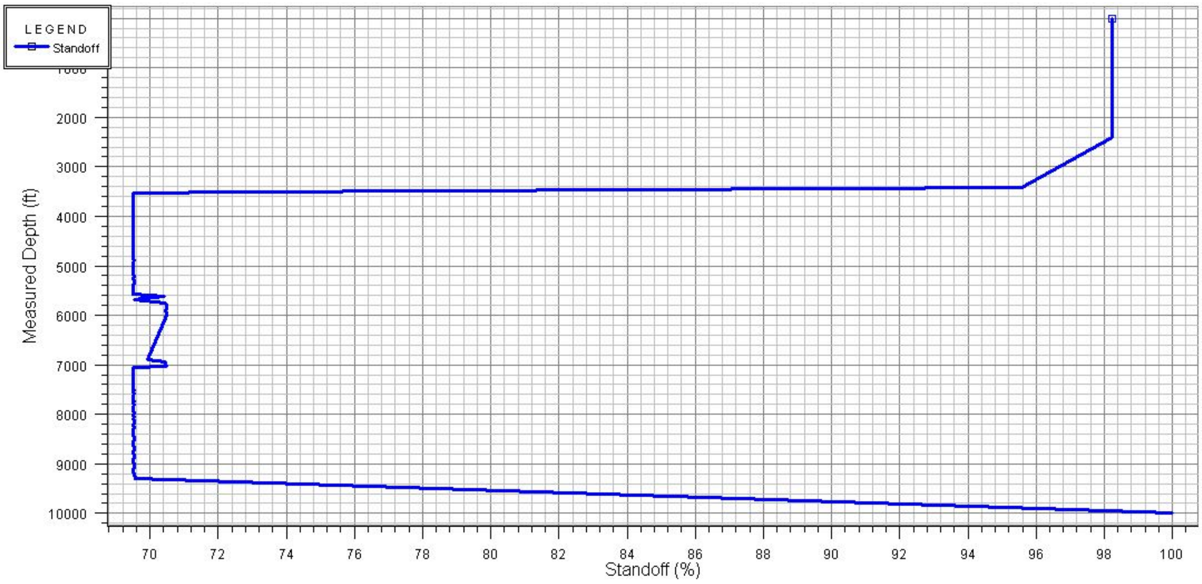

Figure 5.18: Standoff chart for the build, hold & drop well.

In this example, a minimum standoff value of 70% was achieved using 139 centralizers. The centralizers are however, unevenly spaced to achieve this result, and this is something that can be complicated to achieve when installing the centralizers out in the field.

Section	Depth interval (ft)	No. of centralizers	Cent./100ft
Vertical	0-3500	4	0,11
Build	3500-5750	58	2,58
Hold	5750-7000	24	1,92
Drop	7000-9250	52	2,31
Vertical	9250-10000	1	0,13

Table 5.18: Distribution of centralizers in the five sections of the build, hold & drop well.

The results shown in Table 5.18 states that the build section has the highest demand for centralizers, followed by the drop section. The vertical section has very little demand, while the hold section has almost the same need as the sail section in the build & hold example in chapter 5.2.2.

As previous mentioned the distribution of the centralizers is very irregular, and could be hard and cumbersome to carry out in practice. Again, to divide the well into parts and define centralizer spacing within them could be a better solution.

Depth Interval (ft)	Spacing	Standoff $\geq$ 70%	No. of centralizers
0 - 3500	3500	Yes	0
3500 - 5750	25	Yes	91
5750 – 7000	50	Yes	25
7000 – 9250	30	Yes	76
9250 – 10000	750	Yes	0

Table 5.19: Various distribution of centralizers along a build, hold & drop well.

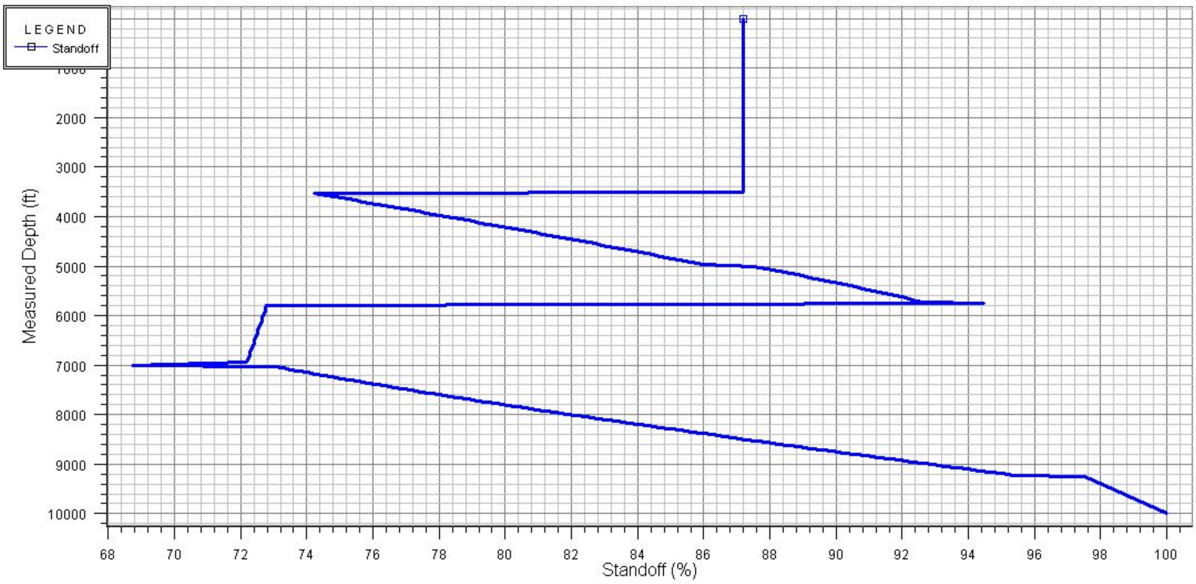

Figure 5.19: Standoff chart for various distribution of centralizers along the well.

By looking at the chart in Figure 5.19, we observe that the standoff value is ok. It is however, not an optimal solution. 192 centralizers is needed, which is 38% more than for the OptiCem™ optimal solution concerning 70% standoff. By comparing the standoff charts, we see a clear difference. The line in Figure 5.18 has a smooth profile, which indicates that the centralizers is well distributed, while the line in Figure 5.19 is very irregular, which indicates an uneconomic distribution of centralizers. The latest example would, however, be easier to install, which is a factor that should be considered.

We also observe that the standoff value drops slightly below 70% at the drop point at 7000 ft. MD. This should however, not cause any problems concerning cementing, as it is not normal to cement 3000 ft. above the casing shoe.

5.2.5 Centralizing a horizontal well

Proper centralization of casing/liner in a horizontal well is the key to success. It aids the spacer in cleaning out the well prior to cementing, and the chance of getting a successful primary cement job increases with increasing standoff values.

If none or too few centralizers are used, the casing will rest on the low side of the wellbore wall. When circulating fluids through the well, the fluids will flow in the path of least resistance, which in this case will be the high side of the well. This results in poor hole cleaning, and a bad cement job, which in practice only leaves one with a very expensive hole in the ground.

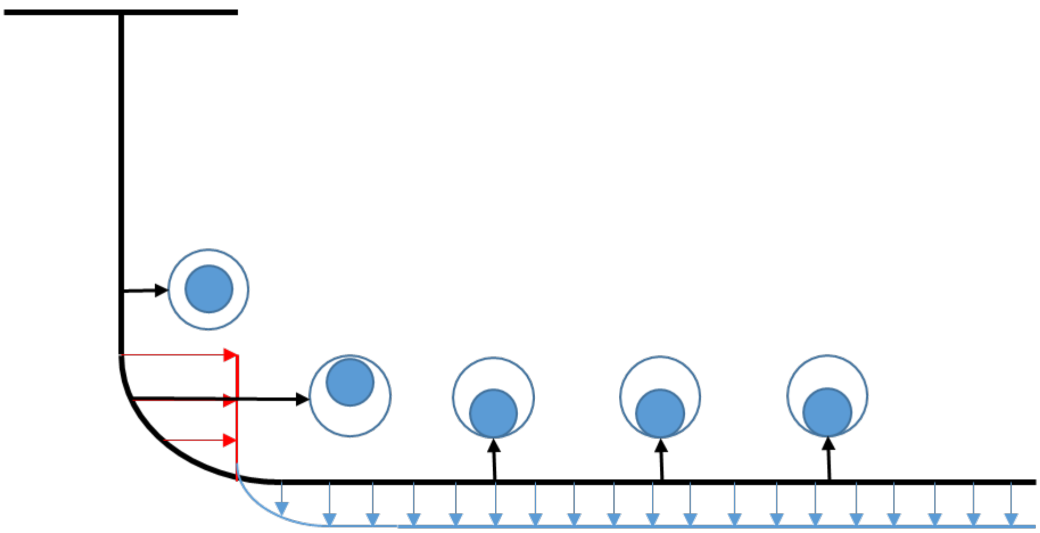

Figure 5.20: A horizontal well without centralizers.

It is possible to do OptiCem™ simulations on a horizontal well if survey data and other necessary well data is provided.

Measured Depth (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	DLS (°/100ft)
0	0	0	0	0
6000	0	0	6000	0
7000	20	0	6979,8	2
8000	40	0	7841,5	2
9000	60	0	8481,0	2
10000	80	0	8821,3	2
10500	90	0	8864,8	2
15000	90	0	8864,8	0

Table 5.20: Survey data for the horizontal well.

Survey data for a horizontal well can easily be created in the OptiCem™ module. By entering the data in Table 5.20 into the software, the software creates a survey using the minimum curvature method. The result is a survey with data points every 30ft. The resulting well path can be viewed in Figure 5.21

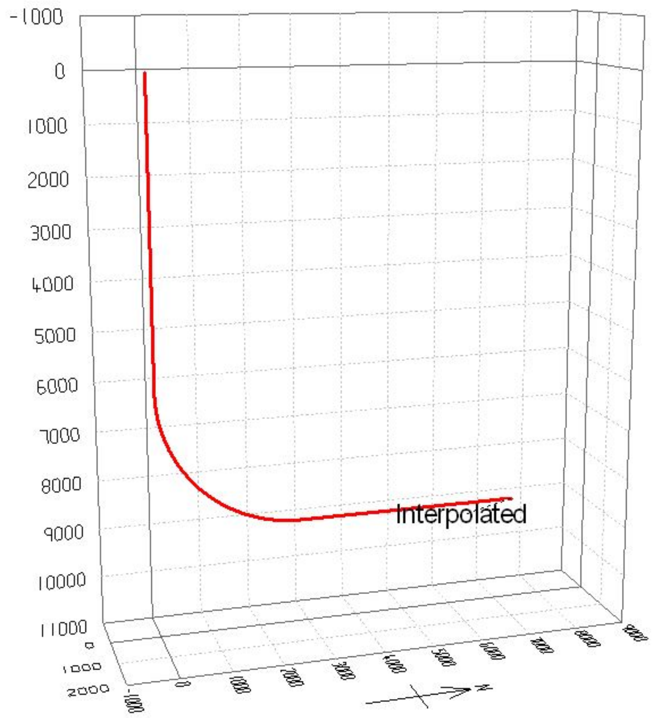

Figure 5.21: 3D plot for the horizontal well.

First, we define the hole as it is with its latest casing, its setting depth, and the current depth of the following open hole.

Section Type	Measured Depth (ft)	Length(ft)	OD(in)	ID(in)	Weight (ppf)
Casing	10000	10000	9 5/8	8,681	47
Open Hole	15000	5000	-	8,50	-

Table 5.21: Horizontal hole section.

This example is different from the previous as we now have the 9 5/8" casing as the previous one. This is because it is not very likely that the 13 3/8" casing continues all the way down to 10 000ft. Hence, the next casing needs to be of a lesser OD.

Section Type	Length(ft)	OD(in)	ID(in)	Weight (ppf)
Casing	15000	7	6,094	32

Table 5.22: Horizontal casing string.

In this example with the horizontal well, it can be interesting to see how different centralizers affect the number of units needed, but also how different spacing and specified standoff alters the number of centralizers. Centralizers will be used from the KOP at 6000 ft. and down to TD at 15000 ft. Bow-spring centralizers will be used in this first example.

Method	Spacing 40 ft	Spacing 35 ft	Spacing 20 ft	Specified Standoff 70%
Number of Centralizers	225	258	450	226
Good Standoff	**No**	Yes	Yes	Yes
Easy Installation	Yes	Yes	Yes	**No**
Economics	Yes	Yes	**No**	Yes

Table 5.23: Bow-spring centralizers in the horizontal well.

By looking at the above results, we see that the specified standoff alternative gives a low amount of centralizers, equal to the 40 ft. spacing alternative. The 40 ft. spacing alternative does, however, not provide good standoff, while the specified standoff alternative may be a difficult-to-follow spacing program. The 35ft. spacing program is easy to install and provides adequate standoff. The amount of centralizers needed is not dissuasive, and it looks like the best solution for this well.

Section	Depth interval (ft)	No. of centralizers	Cent./100ft
Vertical	0-6000	0	0
Build	6000-10500	100	2,22
Horizontal	10500-15000	126	2,80

Table 5.24: Distribution of centralizers in the sections of the horizontal well.

In Table 5.24, we see how the density of centralizers is distributed in the different sections of a horizontal well. The horizontal section requires more centralizers than the build section.

Since this is a horizontal well, it could be beneficial to use rigid centralizers. These centralizers are more robust than the bow spring types, which may be relevant when the pipe is to be run to a total depth of 15 000ft.

Unlike the bow spring type, the rigid centralizers provides the same standoff regardless off hole angle, but the casing does off course sag between the units. Bow spring types also creates a lot of friction if the casing is to be rotated when tripping into the well. This is because of the restoring force in the springs, which push against the wellbore wall. At some point, the operator may experience that he is unable to push the casing further, leading to an unsuccessful operation.

Rigid centralizers are however, more vulnerable to being stuck. They require a high quality hole condition in order to prevent stuck pipe, key seating etc.

Method	Spacing 40 ft	Spacing 30 ft	Spacing 25 ft	Specified Standoff 70%
Number of Centralizers	225	300	360	278
Good Standoff	**No**	**Debatable**	Yes	Yes
Easy Installation	Yes	Yes	Yes	**No**
Economics	Yes	Yes	**No**	Yes

Table 5.25: Rigid centralizers in the horizontal well.

The results show that more centralizers is necessary if the rigid type is to be used. However, it may be necessary to choose this solution because of the high torque created by bow spring types. Too high torque may cause difficulties when rotating the casing, which may lead to the driller twisting off casing joints.

Horizontal wells have a lot of contact with the reservoir, and are unique in that way. This makes cementing even more complicated. In order to meet requirements the section must be cemented thoroughly, in addition to at least 200 m of good cement above the reservoir section [1]. Therefore, good standoff values must be obtained not only throughout the horizontal section, but also further up in build-up section. The 30ft. spacing alternative does provide good standoff values in the horizontal section, but does have problems when exiting the build section. This is shown in Figure 5.22.

A 25 ft. spacing solution is therefore preferable for the horizontal well, as this provides an acceptable standoff value in the build section. The number of centralizers is increased by 60, but the remedial cost of an unsuccessful cement job would probably be of a higher cost.

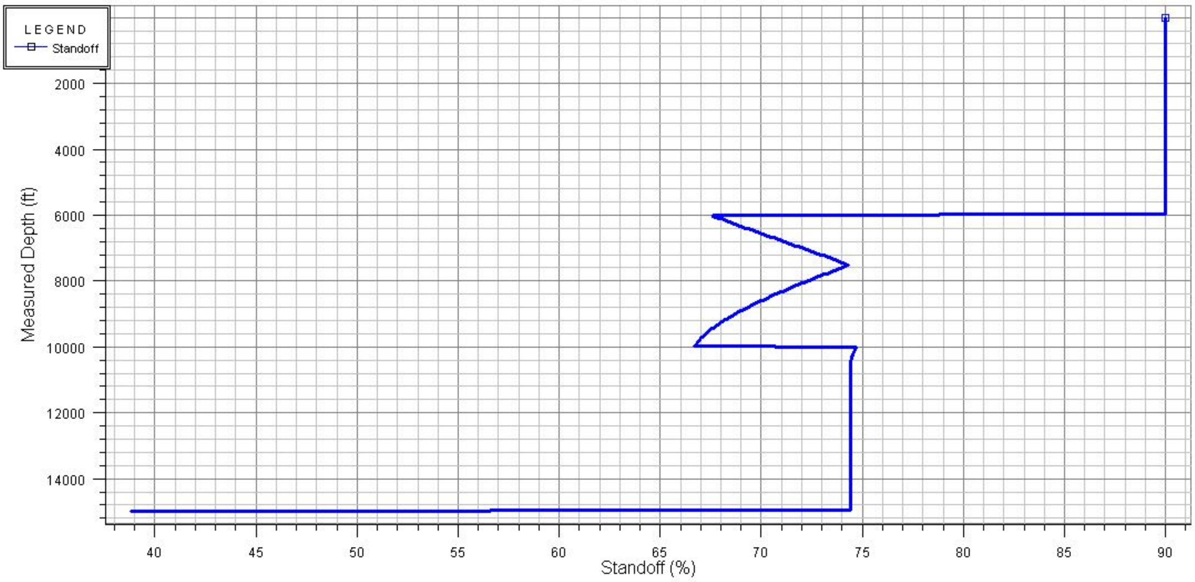

Figure 5.22: Standoff chart for 30ft. distribution of centralizers along the horizontal well.

5.2.6 Dogleg severity's and angles effect on standoff values

In the previous examples, various well profiles have been used as base for standoff simulations. A common trait all the wells share is that the build section is critical. This section demands the densest distribution of centralizers, and it seems that the amount increases with increasing dogleg severity.

DLS severity is a term, which describes the increase in inclination over a predetermined distance. DLS in a well can be created intentionally or unintentionally. If the dogleg is created unintentional, remedial operations can be carried out. This includes reaming or under-reaming of the problem section, or sidetracking in extreme situations. The units used to describe dogleg is °/100ft, or in SI-units °/30m. A higher dogleg indicates a more rapid change in the well trajectory. If the dogleg is too severe it may be impossible to run tools into the well [39].

It can be interesting to see how dogleg values affects the standoff value in a well. This is also possible to do in OptiCem™. By looking at a 1000ft. 12 ¼" open-hole section and variyng the angle from 0 to 90 degrees, it is possible to see how the dogleg affects the number of centralizers needed to center a 9 5/8" casing inside the hole.

To be able to compare the results all parameters but the angle must be constant.

- 12 ¼" Open hole from zero to 1000ft. MD.
- 9 5/8" casing with a weight of 47 ppf. and grade C-90, for all examples.
- The centralizer to be used is a 9,625x12,250x13 ½ - Hinged Imperial Bow.
- The amount of centralizers is governed by a 70% standoff requirement

After entering these parameters into OptiCem™, it is possible to alter the angle of the 1000 ft. section, and thus altering the DLS. Although it is possible to have a build section that exceeds 90 degrees, it is rather rare, and is not considered in this example. The angle have been altered from zero to 90 degrees.

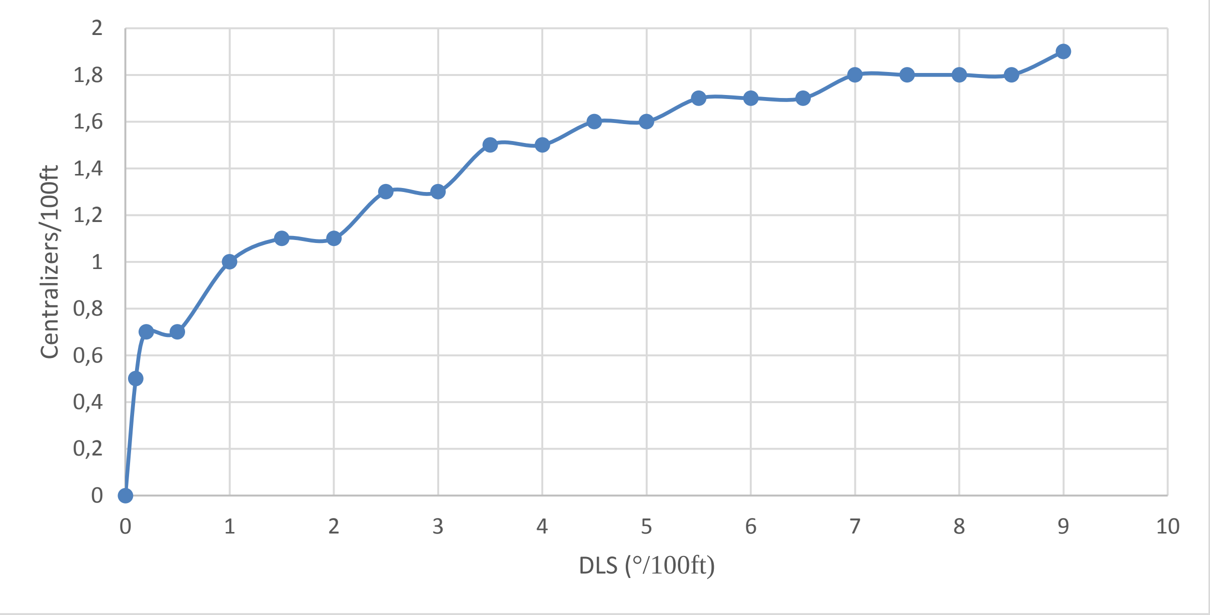

Figure 5.23: Density of centralizers along the 1000ft. curve.

The results are shown in Figure.5.23. Here we see that the density of centralizer increase rapidly as the well path starts building angle. The density does however, reach a sort of saturation around 1,8 - 2,0 centralizers per 100 ft. at the point where the angle is 90 degrees. A DLS value of 9°/100ft is, however, very high, and could cause problems when running into the hole with for instance a long BHA.

If the build section where longer than 1000 ft. it would not be necessary with such a high DLS in order to reach 90 degrees.

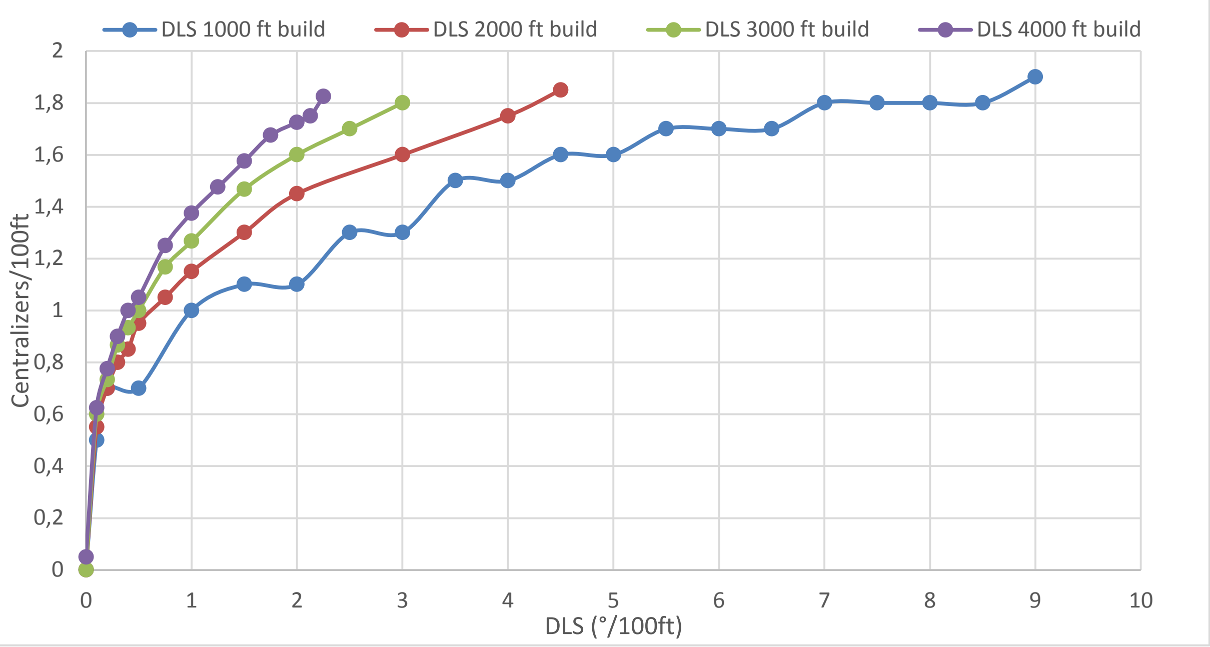

Figure 5.24: Density of centralizers along various curves (DLS plot).

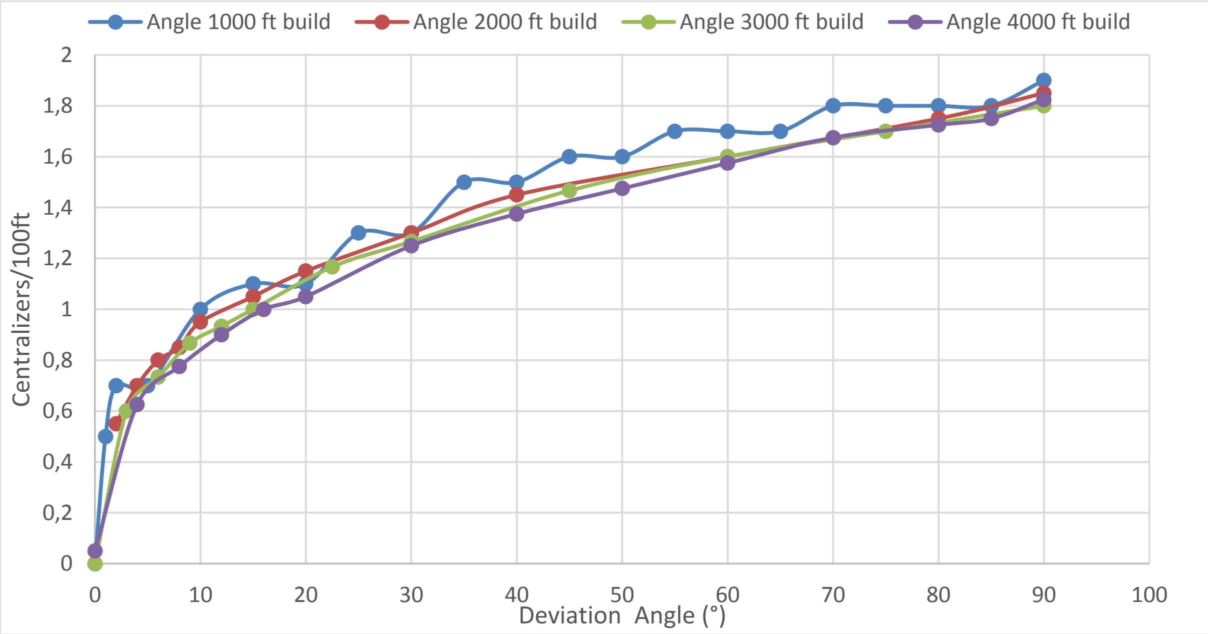

Figure 5.25: Density of centralizers along various curves (Angle plot).

By observing and comparing Figure 5.24 and Figure 5.25. we see that the density of centralizers in a build section is mostly governed by the angle rather than how rapid the angle is built (DLS). Shortening of the build section does of course reduce the amount of centralizers, but might again cause difficulties in following operations.

Some reduction in density can, however, be seen when the curve is enlarged, and this can be investigated by increasing the curve even further.

By looking at Figure 5.26, we see that an increase in well path bending leads to a decrease in centralizer density. A radius of 7000 ft. does, however, give a bend length of almost 11 000ft. and does not seem very realistic

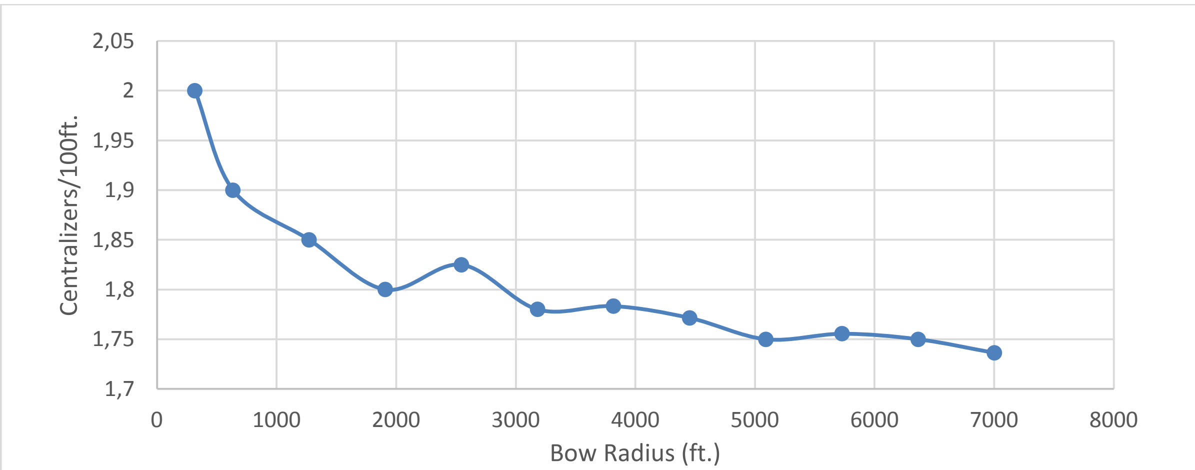

Figure 5.26: Radius' effect on centralizer-density.

5.2.7 Casing weight's effect on standoff and centralizer density

A parameter that have been left unaltered so far is the weight of the casing. A casing with higher weight might cause it to sag more between centralizers, but increased thickness of the pipe would also increase the moment of inertia and then the stiffness of the pipe.

The moment of inertia of a hollow pipe is given by equation 5.1

$$I = \frac{\pi \cdot (OD^4 - ID^4)}{64} \tag{5.1}$$

This equation states that an increased thickness leads to an increased moment of inertia. The stiffness is again a function of the moment of inertia and the elastic modulus. If the same material is used (with same elastic modulus) the stiffness increases with increased moment of inertia.

For this simulation, we will look back at the 10000 ft. long build-hold-drop example. By choosing casings with an OD of 9 5/8", but different ID and weight, we can see how the number of centralizers varies. In the first example, a bow-spring type centralizer will be used, and a specified standoff value of 70%.

OD (in)	ID (in)	Grade	Weight (ppf)	Centralizers
9.625	8.535	C-90	53.50	144
9.625	8.681	C-90	47.00	137
9.625	8.755	C-90	43.50	133
9.625	8.835	C-90	40.00	129
9.625	8.921	K-55	36.00	125
9.625	9.001	H-40	32.30	121

Table 5.26: Weight's effect on Bow-Spring centralizers.

In Table 5.26 we see that the number of centralizers is somewhat reduced when the weight of the casing is reduced. This is most likely because of the force required to push the casing away from the wellbore wall is reduced; therefore the number of centralizers is reduced. It can therefore be interesting to see the effect when using rigid centralizers. These centralizers are not compressed in the way bow-spring types are, so this effect should not be seen.

OD (in)	ID (in)	Grade	Weight (ppf)	Centralizers
9.625	8.535	C-90	53.50	135
9.625	8.681	C-90	47.00	135
9.625	8.755	C-90	43.50	134
9.625	8.835	C-90	40.00	134
9.625	8.921	K-55	36.00	134
9.625	9.001	H-40	32.30	133

Table 5.27: Weight's effect on rigid centralizers.

Here we see that the rigid type centralizer is less prone to the casings weight, and that this centralizer is preferable, with respect to the number of units, when using the heaviest casing type.

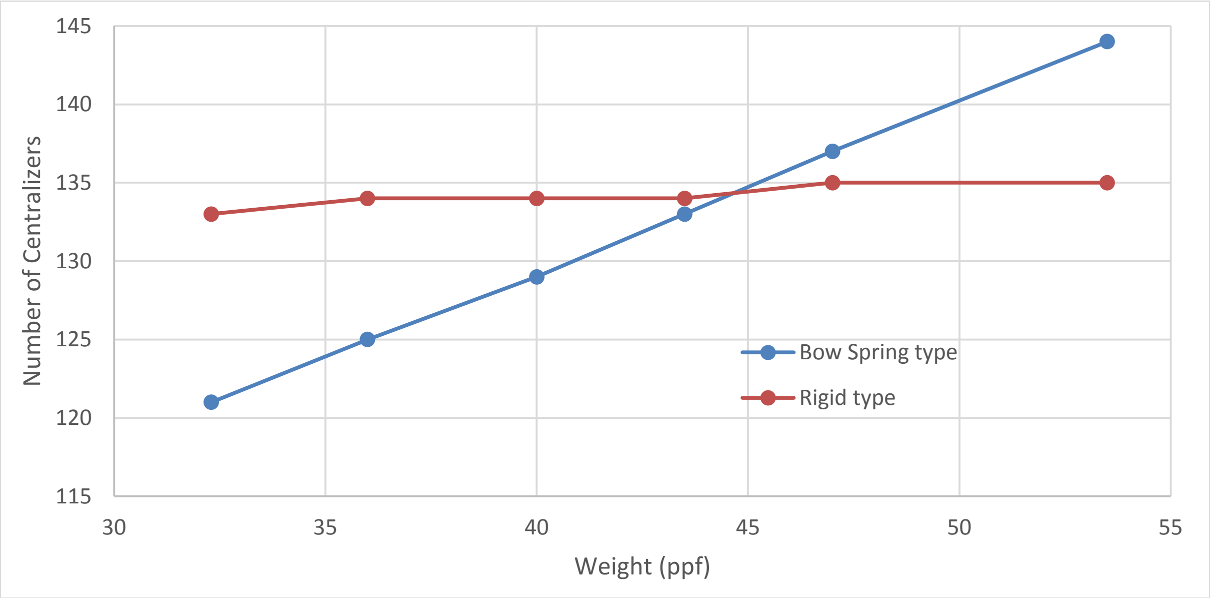

Figure 5.27: Bow Spring vs. Rigid centralizers.

Figure 5.27 illustrates that the necessity for bow spring centralizers increases approximately linearly with increasing weight, while the rigid type is almost unaffected by the weight of casings.

It is worth noting that The OptiCem™ module do not take into account the effect of friction between centralizers and the wellbore wall. The number of centralizers is for example unaffected by the friction factor. A value of 0 and 0,3 produces the same amount of centralizers. This is probably because the effect is so small that it is not decisive when calculating the standoff and number of centralizers. It seems that the module focuses mainly on the gravitational forces. This is confirmed by looking at the deviation angle-density plot in Figure 5.25. Here we see that the density increases with increasing angle. The gravity force has increasing effect when angle is increasing, and reaches it maximum at 90 degrees – demanding a higher centralizer density.

6. Conclusion

Good centralization of casings in wells is the key to a successful primary cement job. If the casing is not properly centralized, the spacer will not be able to clean the wellbore properly prior to the cement stage. When cement then enters the annulus, it will not be able to create a complete seal around the casing due to residual mud, or just uneven distribution. Fluids do tend to flow through the path of least resistance, and to create an equal-resistance flow path is the key task for centralizers. By obtaining a standoff value of minimum 70 %, we provide the cement with good working conditions, and increase the chance of getting a successful job [30].

The OptiCem™ simulations have shown that centralization of casing is hardest to obtain in build sections. The density of centralizers increases with increasing build angle, but by increasing the build sections radius, the density is also reduced in some degree. The results show that centralizer distribution should be around 2-3 units per 100ft in order to provide an adequate standoff value. When a casing joint has a length of 40 ft. it means that a centralizer should be placed on every joint, or at least 2 units on every 3 joints. This coincides with the practice preferred by the industry, which strengthens the validity of the results in this thesis and the reliability of the OptiCem™ software. Simulations also show that Bow-Spring centralizers are more prone to the weight of the casing than the rigid types.

In 2010, the Deepwater Horizon rig sank due to a blowout. This was due to several reasons, where bad centralization of the liner was only one of them. It can, however, be used as an example to emphasize the importance of proper centralization prior to a cement job.

It is important to remember that simulations never will be able to create a complete presentation of what will happen when actually performing the job. It does however, provide the user with some information on what to expect, guidelines on how to do it, and some assurance on the success of the job. It is of course better to do mistakes in a simulation software than in the real world, and by doing this; it aids the user in doing the job right the first time.

7. Acknowledgment

This thesis marks the end of my studies at the University of Stavanger, and the start of my professional career as a drilling engineer in ConocoPhillips.

I would like to thank all my fellow students, professors and friends for making my 5 years at UiS so remarkable, and a special thanks to everyone who spent most of their spring this year in room E-350. Some of you I will continue to work with in ConocoPhillips, and the rest I wish the best of luck in your professional and personal life.

Thanks to Professor Erik Skaugen, which provided me with help not only during this thesis, but also during the writing of my bachelor's. I would also like to thank Mesfin Belayneh Agonafir for giving me some help in getting to know WELLPLAN™ and OptiCem™

Finally yet importantly, I want to thank my family for making my studies in Stavanger possible. Without their support, the road would be a lot harder.

Stavanger, May 2014

Petter I. Erland

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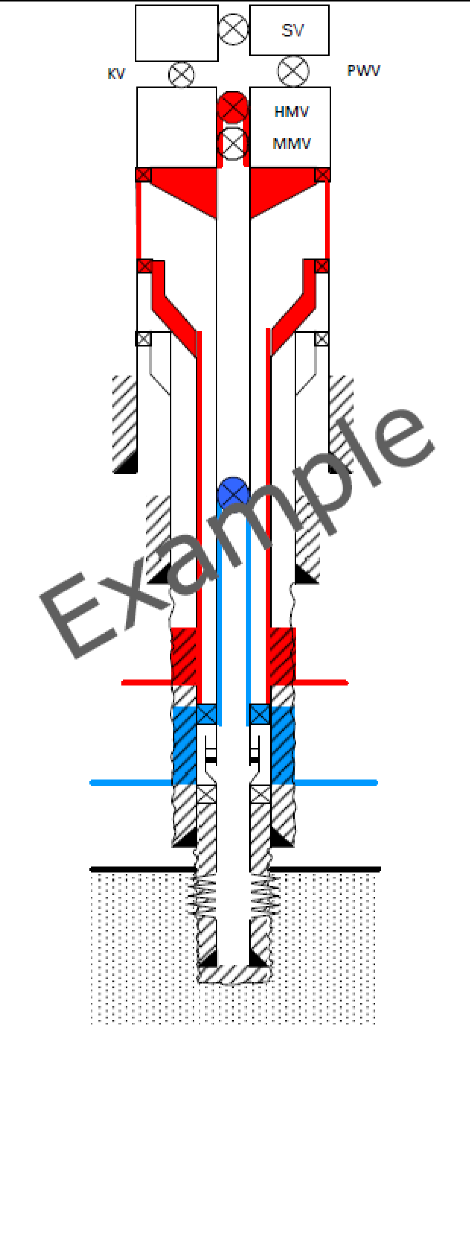
List of Abbreviations

API	**=**	**American Petroleum Institute**
ASV	**=**	**Annular Safety Valve**
BHA	**=**	**Bottom Hole Assembly**
BSR	**=**	**Blind Shear Ram**
CIV	**=**	**Chemical Injection Valve**
DHSV	**=**	**Down Hole Safety Valve**
DLS	**=**	**Dog Leg Severity**
FIT	**=**	**Formation Integrity Test**
GLV	**=**	**Gas Lift Valve**
ID	**=**	**Inner Diameter**
KOP	**=**	**Kick -Off Point**
LOT	**=**	**Leak of Test**
LWD	**=**	**Logging While Drilling**
MGS	**=**	**Mud Gas Separator**
MW	**=**	**Mud Weight**
MWD	**=**	**Measurement While Drilling**
NCS	**=**	**Norwegian Continental Shelf**
NPD	**=**	**Norwegian Petroleum Directorate**
OD	**=**	**Outer Diameter**
OPC	**=**	**Ordinary Portland Cement**
PDC	**=**	**Polycrystalline Diamond Compact**
PDO	**=**	**Plan for Development & Operation**
PDQ	**=**	**Production Drilling & Quarters**
PSA	**=**	**Petroleum Safety Authority of Norway**
PWC	**=**	**Perforate Wash & Cement**
ROP	**=**	**Rate of Penetration**
ROV	**=**	**Remotely Operated Vehicle**
RPM	**=**	**Revolutions per Minute**
RSS	**=**	**Rotary Steerable System**
SPM	**=**	**Side Pocket Mandrel**
TD	**=**	**Target Depth**
TTRD	**=**	**Through Tubing Rotary Drilling**
WBE	**=**	**Well Barrier Element**
WBS	**=**	**Well Barrier Schematic**

List of Figures

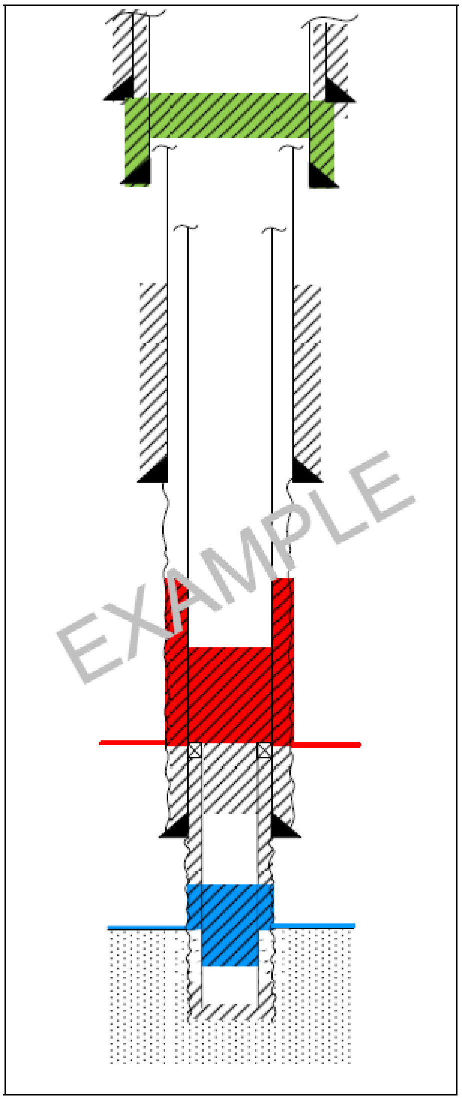
List of Tables

Appendix A



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement (below production packer)	22	
Casing (below production packer)	2	
Production packer	7	
Completion string	25	
Completion string component	29	
DHSV / control lines	8	
Secondary well barrier		
In-situ formation	51	
Casing cement (above production packer)	22	
Casing (above production packer)	2	
Wellhead (Production casing hanger with seal assembly)	5	
Wellhead annulus valve	12	
Tubing hanger (body seals)	10	
Wellhead (WH/XT Connector)	5	
Tubing hanger (neck seal)	10	
Surface production tree	33	

Appendix B



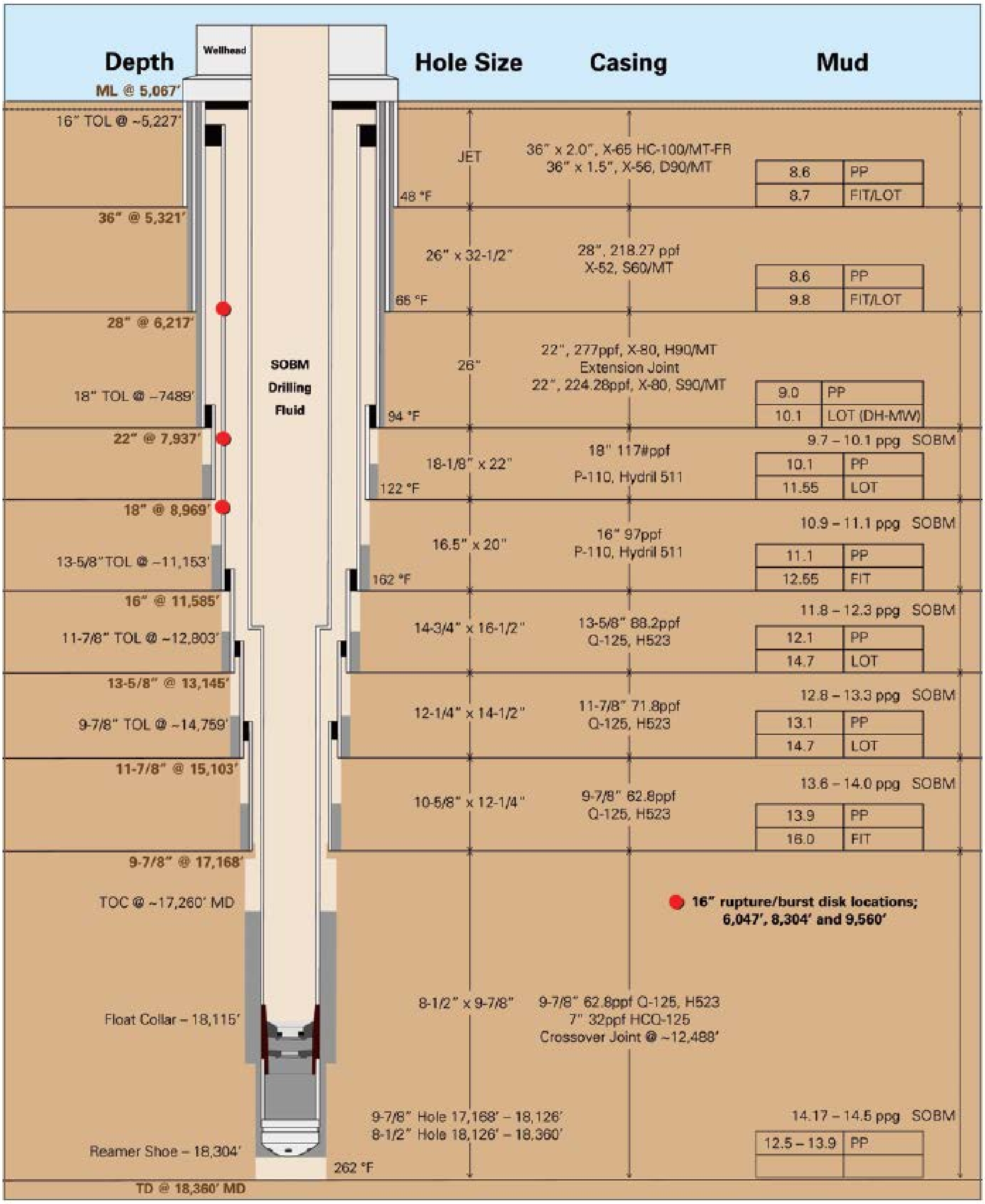
Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing	2	
Cement plug	24	
Secondary well barrier		
Formation in-situ	51	
Casing cement	22	
Casing	2	
Cement plug	24	
Open hole to surface well barrier		
Cement plug	24	
Casing cement	22	

Appendix C

Main types	Notation of the 27 products (types of common cement)		Composition (percentage by mass [a])										
			Main constituents										Minor additional constituents
			Clinker	Blast-furnace slag	Silica fume	Pozzolana		Fly ash		Burnt shale	Limestone		
						natural	natural calcined	siliceous	calca-reous				
			K	S	D [b]	P	Q	V	W	T	L	LL	
CEM I	Portland cement	CEM I	95-100	–	–	–	–	–	–	–	–	–	0-5
CEM II	Portland-slag cement	CEM II/A-S	80-94	6-20	–	–	–	–	–	–	–	–	0-5
		CEM II/B-S	65-79	21-35	–	–	–	–	–	–	–	–	0-5
	Portland-silica fume cement	CEM II/A-D	90-94	–	6-10	–	–	–	–	–	–	–	0-5
	Portland-pozzolana cement	CEM II/A-P	80-94	–	–	6-20	–	–	–	–	–	–	0-5
		CEM II/B-P	65-79	–	–	21-35	–	–	–	–	–	–	0-5
		CEM II/A-Q	80-94	–	–	–	6-20	–	–	–	–	–	0-5
		CEM II/B-Q	65-79	–	–	–	21-35	–	–	–	–	–	0-5
	Portland-fly ash cement	CEM II/A-V	80-94	–	–	–	–	6-20	–	–	–	–	0-5
		CEM II/B-V	65-79	–	–	–	–	21-35	–	–	–	–	0-5
		CEM II/A-W	80-94	–	–	–	–	–	6-20	–	–	–	0-5
		CEM II/B-W	65-79	–	–	–	–	–	21-35	–	–	–	0-5
	Portland-burnt shale cement	CEM II/A-T	80-94	–	–	–	–	–	–	6-20	–	–	0-5
		CEM II/B-T	65-79	–	–	–	–	–	–	21-35	–	–	0-5
	Portland-limestone cement	CEM II/A-L	80-94	–	–	–	–	–	–	–	6-20	–	0-5
		CEM II/B-L	65-79	–	–	–	–	–	–	–	21-35	–	0-5
		CEM II/A-LL	80-94	–	–	–	–	–	–	–	–	6-20	0-5
		CEM II/B-LL	65-79	–	–	–	–	–	–	–	–	21-35	0-5
	Portland-composite cement [c]	CEM II/A-M	80-94	<------------------ 6-20 ------------------>									0-5
		CEM II/B-M	65-79	<------------------ 21-35 ------------------>									0-5
CEM III	Blastfurnace cement	CEM III/A	35-64	36-65	–	–	–	–	–	–	–	–	0-5
		CEM III/B	20-34	66-80	–	–	–	–	–	–	–	–	0-5
		CEM III/C	5-19	81-95	–	–	–	–	–	–	–	–	0-5
CEM IV	Pozzolanic cement [c]	CEM IV/A	65-89	–	<-------- 11-35 -------->					–	–	–	0-5
		CEM IV/B	45-64	–	<-------- 36-55 -------->					–	–	–	0-5
CEM V	Composite cement [c]	CEM V/A	40-64	18-30	–	<---- 18-30 ---->			–	–	–	–	0-5
		CEM V/B	20-38	31-50	–	<---- 31-50 ---->			–	–	–	–	0-5

a The values in the table refer to the sum of the main and minor additional constituents.
b The proportion of silica fume is limited to 10 %.
c In Portland-composite cements CEM II/A-M and CEM II/B-M, in pozzolanic cements CEM IV/A and CEM IV/B and in composite cements CEM V/A and CEM V/B the main constituents other than clinker shall be declared by designation of the cement (for example see clause 8).

Appendix D



Depth
Wellhead
Hole Size
Casing
Mud
ML @ 5,067'
16" TOL @ ~5,227'
JET
36" x 2.0", X-65 HC-100/MT-FR
36" x 1.5", X-56, D90/MT
8.6 PP
8.7 FIT/LOT
48 °F
36" @ 5,321'
26" x 32-1/2"
28", 218.27 ppf
X-52, S60/MT
8.6 PP
9.8 FIT/LOT
66 °F
28" @ 6,217'
SOBM
Drilling
Fluid
26"
22", 277ppf, X-80, H90/MT
Extension Joint
22", 224.28ppf, X-80, S90/MT
18" TOL @ ~7489'
9.0 PP
10.1 LOT (DH-MW)
94 °F
22" @ 7,937'
9.7 – 10.1 ppg SOBM
18-1/8" x 22"
18" 117#ppf
P-110, Hydril 511
10.1 PP
11.55 LOT
122 °F
18" @ 8,969'
10.9 – 11.1 ppg SOBM
16.5" x 20"
16" 97ppf
P-110, Hydril 511
13-5/8" TOL @ ~11,153'
11.1 PP
12.55 FIT
162 °F
16" @ 11,585'
11.8 – 12.3 ppg SOBM
14-3/4" x 16-1/2"
13-5/8" 88.2ppf
Q-125, H523
11-7/8" TOL @ ~12,803'
12.1 PP
14.7 LOT
13-5/8" @ 13,145'
12.8 – 13.3 ppg SOBM
12-1/4" x 14-1/2"
11-7/8" 71.8ppf
Q-125, H523
9-7/8" TOL @ ~14,759'
13.1 PP
14.7 LOT
11-7/8" @ 15,103'
13.6 – 14.0 ppg SOBM
10-5/8" x 12-1/4"
9-7/8" 62.8ppf
Q-125, H523
13.9 PP
16.0 FIT
9-7/8" @ 17,168'
TOC @ ~17,260' MD
16" rupture/burst disk locations;
6,047', 8,304' and 9,560'
8-1/2" x 9-7/8"
9-7/8" 62.8ppf Q-125, H523
7" 32ppf HCQ-125
Crossover Joint @ ~12,488'
Float Collar – 18,115'
9-7/8" Hole 17,168' – 18,126'
8-1/2" Hole 18,126' – 18,360'
14.17 – 14.5 ppg SOBM
12.5 – 13.9 PP
Reamer Shoe – 18,304'
262 °F
TD @ 18,360' MD