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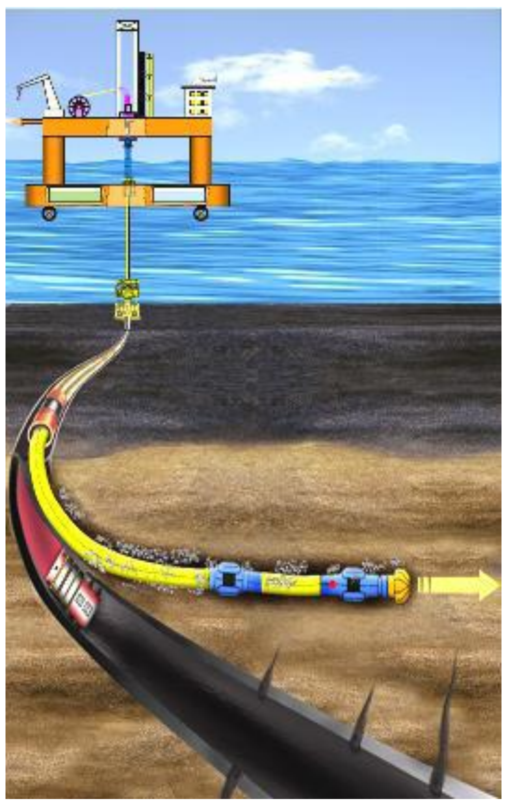
PLUG AND ABANDONMENT ON THE NORWEGIAN CONTINENTAL SHELF

BY VIBEKE HENRIKSEN

2013



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Abstract

More and more wells all over the world are reaching the end of their productive life and will in near future be ready for Plug and Abandonment (P&A). How this operation is performed is dependent on many factors like the well condition, the cement status behind casing, the numbers of potential inflows etc. Where the P&A operation is carried out is also affecting this process. Different countries operate with different regulations and requirements and a company is by law obliged to make sure the P&A operation is completed according to regulations and requirements of the particular area.

Different materials, placement techniques, cement evaluation tools and vessels are available for conducting the P&A operation today. The process of completing a successful P&A is a costly affair for the operator and the search for new methods to make this process more efficient and therefore less costly is an ongoing activity in the industry today. Most wells today, that are ready for P&A, have not been designed with this in mind and this leads to extra challenges when preparing the well for abandonment. New traditions, for including this already at the earliest stages of well designing, is needed and the industry is discussing what changes can be implemented to improve this process.

This thesis has been written to give insight in to the process of plugging and abandoning a well. It is written for students on Master in Petroleum of Technology at the University of Stavanger and the focus is on P&A operations on the Norwegian Continental Shelf (NCS). It will give an insight into the regulations and requirements that a P&A operation needs to fulfill, different types of plugging material that are available for plugging operations, traditional methods used to complete a P&A operation today, the procedure of P&A and new techniques that might be used in the future.

Table of Contents

List of Abbreviations

API	=	American Petroleum Institute
B_c	=	Bearden
BHA	=	Bottom Hole Assembly
BHCT	=	Bottom Hole Circulating Temperature
BOP	=	Blow Out Preventer
CAST-V	=	Circumferential Acoustic Scanning Tool – Visualization
CAT B	=	Category B Vessel
CBL	=	Cement Bond Log
CET	=	Cement Evaluation Tool
CT	=	Coiled Tubing
DHSV	=	Downhole Safety Valve
ECD	=	Equivalent Circulating Density
FCP	=	Fracture Closure Pressure
Frac	=	Formation Fracture Pressure
HPHT	=	High Press High Temperature
HSE	=	Health, Safety & Environment
LVI	=	Light Well Intervention
MD	=	Measured Depth
NCS	=	Norwegian Continental Shelf
NORSOK	=	Norwegian Petroleum Industry Standard
OVB	=	Overburden Stress
PET	=	Pulse Echo Tool

P&A	=	Plug and Abandonment
POOH	=	Pull Out Of Hole
PSA	=	Norwegian Petroleum Safety Authority
PWC	=	Perforate, Wash and Cement
RIH	=	Run In Hole
RLWI	=	Riserless Light Well Intervention
Sh	=	Minimum formation stress
TOC	=	Top Of Cement
TTOC	=	Theoretical Top of Cement (calculated from job records)
TVD	=	True Vertical Depth
USI	=	Ultrasonic Imager
UWRS	=	Universal Wellhead Retrieving System
VDL	=	Variable Density Log
WBE	=	Well Barrier Element
WH	=	Wellhead
WI	=	Well Integrity
WL	=	Wireline
WOC	=	Wait On Cement
XLOT	=	Extended Leak-Off Test
XT	=	X-mas Tree

1 Introduction

The development and production of oilfields on the Norwegian Continental Shelf (NCS) started in the beginning of the 1970’s, today there are approximately 500 offshore installations on the NCS. Since then a large number of wells have been drilled. Many of these wells are reaching the end of their productive life and as many as 2200 wells on NCS will have to be plugged and abandoned in the coming years. There are many reasons for shutting down a well as it matures. When the well no longer is profitable we have two options; one could either remove the wellhead (WH) and permanently plug and abandon the well, or one can plug the mother bore and reuse the slot to drill a sidetrack.

The key goal of plug and abandonment (P&A) is to seal and isolate the well forever. This long term sealing requirement is crucial for successful abandonment. The cost of re-abandoning a leaky well is tremendous and the environmental input and subsequent cleanup is also a concern for most operating companies. It has therefore become more and more important for operators to upgrade their abandonment practices to ensure that abandoned wells are permanently sealed and that the environment is protected.

The Norwegian Petroleum Safety Authority (PSA) has prepared a guideline, NORSOK D-010: Well Integrity in Drilling and Well Operation, which they recommend to be used as a minimum requirement for all well operations, included plugging operations. Operators are obliged to follow certain rules and requirements in order to prepare the well bore for eternity post abandonment, these regulations and requirements will be presented in Ch. 3.

Most old wells were not designed with abandonment in mind and this results some extra challenges when the well is ready for P&A. Considering well abandonment in the earliest stages of well design, may be very beneficial because the quality of the cement between the formation and the casing may play an important role in achieving a successful abandonment later on [1]. In most cases this has not been taken into consideration and some extra precautions and work have to be taken when planning and implementing the P&A process.

Portland cement has long been considered the most reliable and best plugging material. It is long-lasting, reliable, inexpensive and available worldwide, but shrinkage of the cement, as it sets, may create small cracks in the cement through which oil and gas can flow. New types of materials, to be used for plugging, have been developed and some of these will be investigated in Ch. 4. The goal of new technology is to improve efficiency and enhance the P&A operation, reducing the overall cost whilst ensuring the well is permanently isolated.

There are different techniques to place plugging material downhole and different methods to evaluate the placement material afterwards. The applications of the most used plugging methods will be discussed in Ch. 5 and some of the most common evaluation methods will be presented in Ch. 6.

The P&A process is not straight-forward. The process is dependent of many factors like the well condition, the formation, the cement behind the casing and many more. Whilst there is no standard P&A operation there are some activities and steps that are common to most operations. These activities along with a real-life example are presented in Ch. 7.

In Ch. 8 different vessels that can be used for P&A are presented. Here will both vessels in use today and a new kind of vessel that is coming in near future be addressed. The limitations and benefits of the different vessels are also discussed.

The ongoing process and need to improve the P&A operation is the base for the last chapter, Ch. 9. Here will some issues that are thought to improve and reduce the cost of future abandonments be addressed.

2 An introduction to Plug and Abandonment

2.1 The Issue of Plug and Abandonment

The decision to P&A a well is mainly based on economics aspects. When the production rate falls off to a level where the operating expenses are higher than the operating income the well becomes a candidate for permanent abandonment [2]. According to Segura [3] the "economic limit" of a well is defined as "the production rate below which the net revenue from the production will not meet the expenses, including taxes". When the decision to P&A the well has been made the most economical way of performing this will be evaluated. There are lots of things to consider but choosing the method that takes the least time, retrieving the WH without damaging it, so it can be reused, and doing it right the first time are some of the main concerns. In some cases the upper portion of the well can be reused to drill a sidetrack. The top infrastructure is then reused while the bottom of the well is permanently abandoned. This is considered to be a cost-effective alternative to permanently P&A the whole well.

The main goal of P&A is to ensure that we have no unwanted flow between subsurface formation and surface, or between two or more subsurface formations. The plugging shall be designed so that the well barrier elements (WBE) take into account the well integrity (WI) for the longest period the well is abandoned [4]. This means that the well barrier is able to withstand the load and the environmental conditions that it is exposed to for as long as the well is abandoned. WI is a key parameter in achieving this, and it is closely related to P&A. So what is WI? In NORSOK D-010 WI is defined as "an application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of the well" [5]. WI means to plan and design the well in such a way that it always has robust and reliable barriers in place, and to have a contingency in place in case the barriers fail. There are certain rules and regulations that have to be followed in order to ensure full Win wells that are plugged and abandoned. These rules and regulations are given by the Norwegian Petroleum Safety Authority (PSA), and will be discussed in this paper.

According to NORSOK D-010 P&A are mainly divided into two groups: temporary abandoned wells and permanently abandoned wells. A temporary abandoned well is a well that is abandoned in such a way that it is not covered by the regulations for a permanently abandoned well. It is possible and necessary to re-enter the well at a later stage. A temporary well abandonment is sometimes referred to as a suspension. The term suspension is often applied when the abandonment is for a short period. A permanently abandoned well shall be plugged with an eternal perspective, keeping in mind any geological or chemical processes that might occur in the well after placing the well barriers in the well. Fig. 1 shows a simplified illustration of how a permanent abandoned well is thought to be plugged. It should however be mentioned that a barrier placed during abandonment may not necessarily be one covering the inside of the casing, it will often include annulus cement and in some instances other plugging materials.

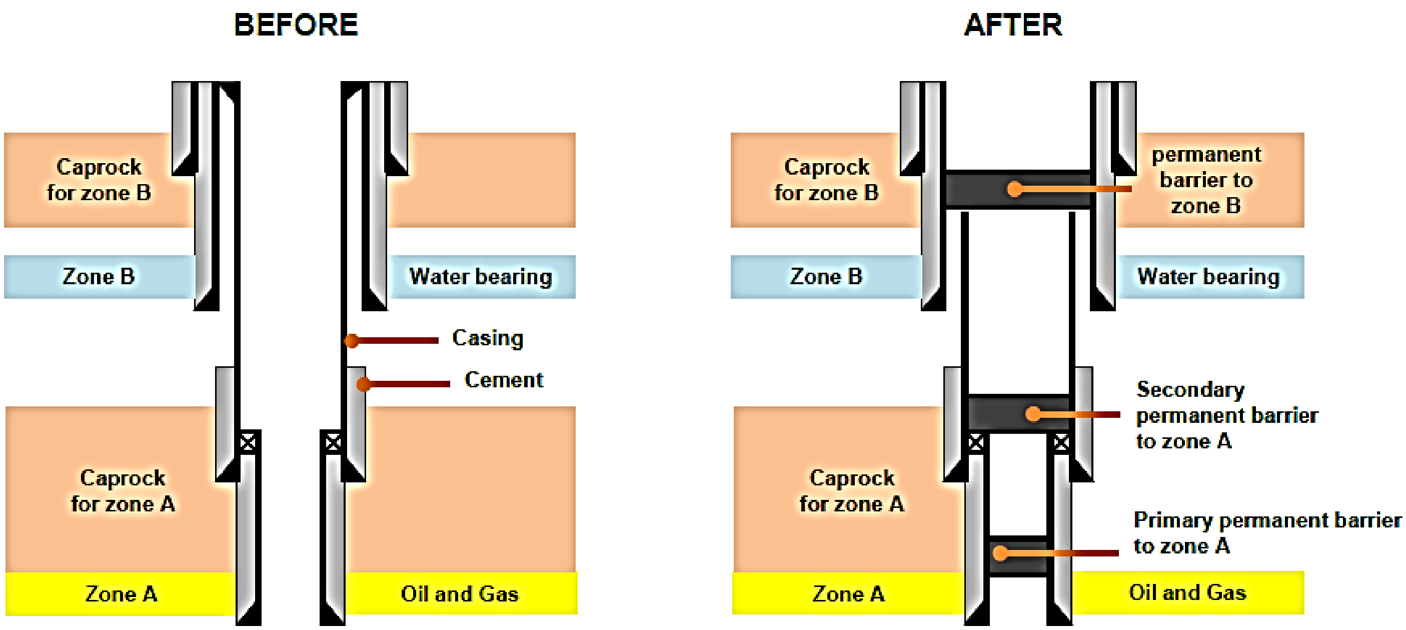


Figure 1 - A simplified illustration of a permanent abandonment with barriers in place.

3 Rules and Regulations + Definitions

3.1 Introduction

The operating company is, by law, responsible for plugging and abandoning a well in such a way that there will not be any leaks from the well. They are also held responsible in case there is a leak after abandonment, and they have to take the cost of cleaning up.

The PSA is the regulatory authority for technical and operational safety in the industry, and P&A operations on the NCS, among other things, are controlled by the PSA. The NORSOK standards are developed to make sure all petroleum related activities on NCS are carried out in a safe manner. The NORSOK D-010 describes the minimum requirements for maintaining WI through well design, planning and execution of well operations in Norway, and it is each company's responsibility to choose a solution that fulfills these requirements. This means that the person who plans and design the well operation is responsible for ensuring the WI throughout the whole life of the well and that the design meets the minimum requirements of the standard.

The NORSOK D-010 standard includes information about all the different stages of drilling and completing the well, but the overall goal of this standard is [6]:

- Prevention of hydrocarbon leakage to surface.
- Prevention of hydrocarbon movement between different strata.
- Prevention of contamination of aquifers
- Prevention of pressure breakdown of shallow formations.

3.2 Well Integrity

WI means to have the barriers in place, to understand and respect them and to test, verify, monitor and maintain them throughout the lifetime of the well. The personnel planning the different operations in the well is obliged to identify the solutions that give safe well life cycle design that meets the minimum requirements [7]. The operator is obliged to make sure that the equipment planned to be used is in accordance with standard and if not, the equipment need to be improved and qualified before use [7]. If a solution differs from the standard then this solution needs to be equivalent or better than what is required. A contingency plan must be in place in case a barrier fails. Issues related to the well barriers can occur during all phases of the well's lifecycle and specific considerations should be taken for each phase. WI at the abandonment stage is probably the most difficult to handle. The well has now been through many different phases and a large amount of information has been gathered. In many cases WI has not been taken into consideration during the planning and designing stage of the well.

Important information like pressure data might be incomplete or at worse totally absent. This can have a large influence on risk management when planning how to abandon a well.

One of the main objectives of WI evaluation is to identify potential hazards that can occur at the different phases. Integrity problems can be a result of formation- induced problems like pressure, temperature, formation fluid (flow rate, chemistry, sand and particles) which again can lead to material erosion, corrosion and degradation. It can be operational induced problems, such as operating the well and equipment above the design limits, lack of maintenance, installation failures, equipment failures and failures related to testing and verifications [8]. Leakage is the main concern for the P&A phase, and operational changes can affect the pressure and temperature level in the well when plugging the well.

WI is of importance throughout the life cycle of the well, and WI should be in the heart of the Well Integrity Management System. The Well Integrity Management System should have a set of policies, guidelines and procedures as a fundament when planning for WI. A basement for an effective Well Integrity Management System is a common data and information management system to make sure WI is considered at all times [9].

3.3 Barrier

A barrier is defined as a measure which reduces the risk of an accident to happen or limit the consequences in case of an accident [10]. This could be a leakage of hydrocarbons to the surface or to another formation or any safety or health incidents to personnel. The Management Regulations Section 5 [4] says that a barrier shall be established to: “a) reduce the probability of failures and hazard and accident situations developing, b) limit possible harm and disadvantages” and “When more than one barrier is necessary, there shall be sufficient independence between barriers”. The barrier is often described as a safety or emergency response function allowing the industry to perform petroleum activities. A barrier consists of one or several barrier elements and the overall system is often called a barrier envelope. The barrier elements can be of different types; they can be technical, operational, organizational or human components [8]. The barriers can have many definitions like primary or secondary, temporary or permanent and active or passive [8]. The quality and the dependability of the barriers, as well as the independency between different barriers are all important factors in maintaining the safest barrier. The barrier must be inspected, monitored, tested, verified and maintained in order to function properly.

3.4 Well Barrier

According to NORSOK Standard D-010 well barriers are: “envelopes of one or several dependent WBEs preventing fluids or gases from flowing unintentionally from the formation, into another formation or to surface” [5]. We need to establish well barriers for all activities in a well like drilling, testing, completion, production and when plugging and abandoning the well. It is important to design a well barrier such that the WI is ensured and the well barrier is secured throughout the lifetime of the well. If the well is temporarily or permanently abandoned one has to design the well barrier so that one takes into account the longest period the well is expected to be abandoned [4]. In wells where there is a possibility of flow to the surface, in addition to flow between formation zones, two well barriers are required. These two barriers are called primary and secondary well barriers. They should as far as possible be independent of each other with no common WBE. (A WBE is defined as “an object that can not prevent flow from one side to the other side of itself” [5].) If a common WBE is present it could be accepted if a risk analysis is performed, and the risk is reduced as much as possible[5]. For wells that are plugged and abandoned these two well barriers may not be sufficient. A combination of several well barriers has to be considered.

3.4.1 Well Barrier Schematic

The well barrier schematic (WBS) is developed to show the presence of the different well barrier envelopes. An example of a WBS is seen in Fig. 2. The primary well barrier, shown in its normal working station, is usually marked with blue. This is the first barrier to prevent unwanted flow of fluid and it provides closure of the well barrier envelope. The secondary well barrier, shown in its ultimate stage, is usually marked with red. This barrier is often located outside the primary well barrier and its main function is to withstand any well pressure or flow of fluid in case the primary well barrier fails. For permanently abandoned wells it is usually not enough with two well barriers. It is also required to have an open hole to surface barrier and a barrier between reservoirs. The open hole to surface barrier shall isolate the hole from the surface and act as the final barrier against flow. In Fig. 2 the open hole to surface well barrier is shown in green.

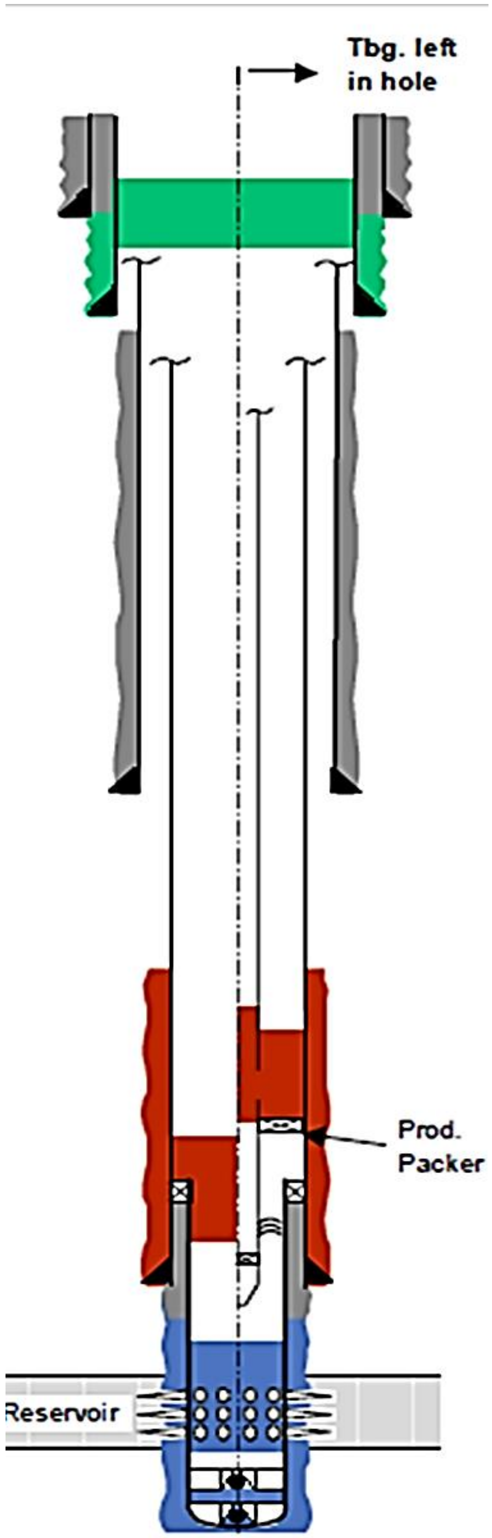


Figure 2 - Well barrier schematic of a permanent abandoned well [5].

Fig. 3 shows an example of a real life WBS. It is a very important document in P&A operations and hence it is important to be able to understand what information it provides. The different parts of the WBS will be described in the following [11]:

Well Data:
This area provides information related to the well and the situation for which the schematic was made.

Well Barrier Elements:
This column describes the different WBEs included in the well barrier envelope.

Ref. Table NORSOK D-010:
This column gives references to tables in NORSOK D-010 which give complete descriptions of the general acceptance criteria for each WBE.

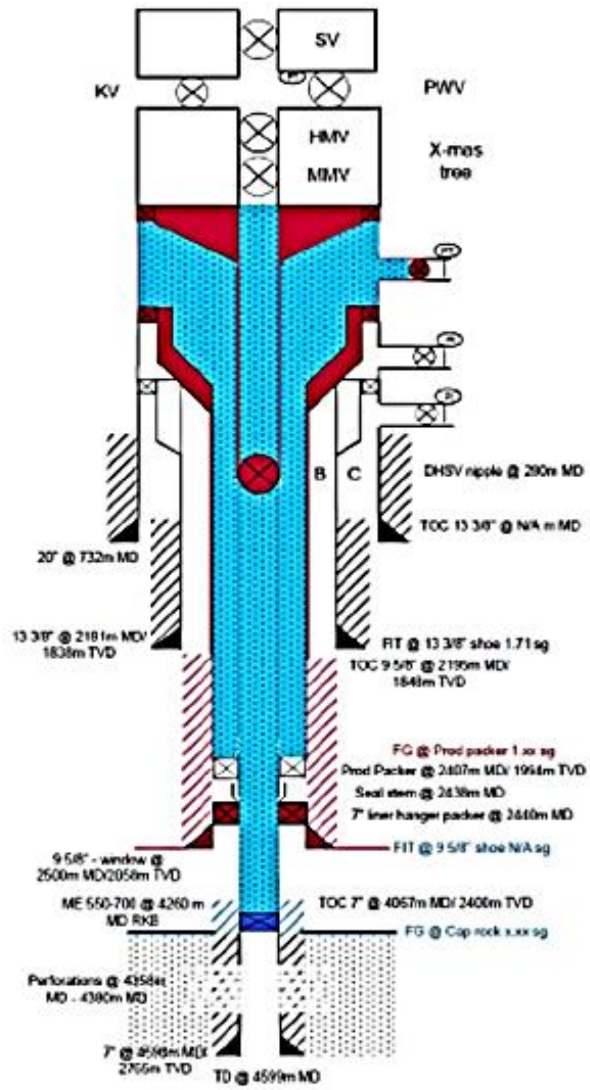
Verification of barrier elements:
This column describes what the requirements for testing given in NORSOK D-010 are.

Primary:
The WBE that make up the primary well barrier envelope are listed here. In the WBS the corresponding elements are colored blue.

Secondary:
The WBE that make up the secondary well barrier envelope are listed here. In the WBS the corresponding elements are colored red.

WELL BARRIER SCHEMATIC

Well status when N/D XMT.



Well data			
Installation/Field:			
Well no:		Completed date:	
Well type:		ex WAG	
Well design pressure:		250 bar	
Revision no:	0	Date:	24.03.2011
Well status:		Operating	
Prepared:			
Verified:			

Well barrier elements	Ref WBEAC tables	Verification of barrier elements
PRIMARY		
Cap rock	n/a	
7" liner cement	22	
7" liner	2	PT: 345 bar with 1.54 sg (DBR 19.03.2002)
Deepset ME 550-700	6	
1.2 SG Brine below 900 m MD RKB	1	
1.03 Water above 900 m	1	
SECONDARY		
Formation at prod packer	n/a	
9 5/8" Production casing cement (above prod packer)	22	TOC: 212 m MD > prod. packer Method: FWR/ estimated
9 5/8" Production casing (above prod. packer)	2	PT: 345 bar with 1.03 sg (DBR 23.03.2002)
9 5/8" Production casing hanger with seal assembly	5	PT: 345 bar with 1.03 sg (DBR 23.03.2002)
WH/Annulus valve	12	IT: 335 bar (DBR 23.03.2002)
Tubing hanger with seals	10	PT: 450 bar with 1.03 sg (DBR 23.03.2002)
Tubing hanger neck seal	10	
7" tubing above DHSV	2	
DHSV	8	

Notes:

1. Caliper log 01.01.2009 indicated 50% reduction in wall thicknesss due to corrosion. Estimated burst rating: 330 bar (new tubing has a burst rating of 649 bar).
2. TOC 7" estimate 3808m MD from DBR 18.03.2002. Value in schematic is from old matrix FWR.
3. BTC threads in 13 3/8" casing. Not gas tight.

Risk Status Code marked (X):

			X	

1. WSIWI – Well shut in with well integrity problems.
2. BARREDC – Tubing corroded. Barrier element reliability reduced

Disp. no. well integrity issues	Comment
85467 – not accepted	Continued injeciton in well with reduced wall thickness in tubing.

Figure 3 - Real life well barrier schematic [12].

3.4.2 Well Barrier Acceptance Criteria

There are certain design criteria that the well barrier has to follow in order to be approved. These are given in NORSOK D-010 [5] and states that a well barrier shall be designed such that:

- it can withstand the maximum anticipated differential pressure it may become exposed to,
- it can be leak tested and function tested or verified by other methods,
- no single failure of well barrier or WBE leads to uncontrolled outflow from the borehole/ well to the external environment,
- re- establishment of a lost well barrier or another alternative well barrier can be done,
- it can operate competently and withstand the environment for which it may be exposed to over time,
- its physical location and integrity status of the well barrier is known at all times when such monitoring is possible.

A leak test of the WBE's shall be performed before the well barrier is exposed to a differential pressure. In the leak test a pressure is applied to the WBE equal to or higher than the maximum differential pressure that the WBE can be exposed to. The acceptable leak rates shall be zero, unless other values are given.

A function test of the WBE shall be performed after installation, after the WBE has been subject to unusual loads and after repairs. The function test is performed to demonstrate that the WBE inhibits sealing properties at a rated pressure in the well. If possible the barrier should be tested in the flow direction. See App. 1 for description of how to perform a function test.

Table 1 shows examples of common WBE that are accepted according to NORSOK D-010 [5].

Table 1 – Well barrier elements acceptance criteria.

Element name	Additional features, requirements and guidelines
Casing	Accepted as permanent WBE if cement is present inside and outside
Casing Cement	Accepted as a permanent WBE together with casing and cement inside the casing.
Cement plug	Cased hole cement plugs used in permanent abandonment shall be set in areas with verified cement in casing annulus.
Completion string	Accepted as permanent WBE if cement is present inside and outside the tubing.
Liner top packer	Not accepted as a permanent WBE.

NORSOK D-010 also says that the well barrier has to be monitored for prevention of uncontrolled flow. The methods and frequency of the controls have to be documented.

3.5 Temporary Abandonment

A temporary abandoned well is defined as “all wells/ all wellbores except all active wells and wells that are permanently plugged and abandoned according to the regulations” [13]. An active well is a well that is currently in production or injecting. There are some situations where we choose to temporary abandon the well:

- During a long shut-down
- When pulling the blow out preventer (BOP) for a repair
- When skidding rig to do higher priority well work
- While we are waiting for a work over
- While we are waiting on field development or redevelopment
- When converting a well from an exploration to a development well
- Re-entry at a later stage to perform sidetrack

There are some differences in the regulations and requirements between a temporary and permanently abandoned well but the main importance of a temporary abandoned well is that we have to be able to re-enter the well in a safe manner.

For temporary abandonments the WH and template is usually left subsea. These have to be protected from external loads like fishing activities or other seabed activities. For deep water wells this requirement could be omitted if confirmation of no such activity in the area is present [5]. For wells abandoned for more than a year the pressure in tubing and annulus above the well barrier has to be monitored. If this is not possible an acceptable solution is to set a deep well barrier plug.

3.6 Permanent Abandonment

A very important requirement for permanent well barriers is that they have to cover the full cross section of the well, both vertically and horizontally, as seen in Fig. 4.

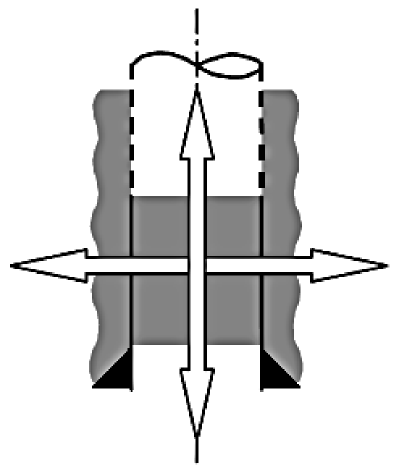


Figure 4 - A permanent well barrier must cover the whole cross section of the wellbore [5].

A WBE set inside a casing must therefore be at a depth interval with verified cement or equivalent WBE in the annuli. In NORSOK D-010 a set of recommended, but not required, properties for a permanent well barrier are given [5]:

a) Impermeable.
b) Long term integrity.
c) Non shrinking.
d) Ductile – (non brittle) – able to withstand mechanical loads/ impact.
e) Resistance to different chemicals/ substances (H_2S, CO_2 and hydrocarbons).
f) Wetting, to ensure bonding steel.

The barrier must be impermeable to prevent flow of hydrocarbons and over pressurized fluid through the barriers. Fluid movement is however a natural process and this phenomenon will also occur in a permanent barrier. The rate of fluid movement is an important factor. As long as the fluid movement is the same or lower than in the cap rock it is acceptable. The permeability of the cap rock is usually between 0,001 – 1 micro Darcy [14]. There are lots of factors influencing the permeation rate. Pressure may change due to redevelopment of an abandoned well, thermal changes may occur due to fluid injection, gas storage or CO_2 injection in previously abandoned fields and mechanical stresses may act on the barrier material. In order to stay impermeable for eternity the length of the barrier must be sufficiently long. According to NORSOK D-010 the required length of the cement plug is 100m measured depth (MD) if the plug is set inside a casing and 50m MD if a mechanical plug is used as a foundation. It is also required that the plug should extend minimum 50m above any source of inflow or leakage point.

It is required that the permanent barrier provides long term integrity. This means that the material must remain its sealing capability: i.e. the material must be able to retain its initial properties after long-term exposure to downhole conditions. It is difficult to document and verify the long-term isolation of a material, but ageing tests are used to estimate the long-term performance of the material [14]. The long-term integrity and the resistance to different chemicals/ substances requirements need to be evaluated simultaneously. So when performing aging tests, on the material to determine the long-term integrity, the material should be exposed to relevant downhole chemicals at downhole pressures and temperatures. In ageing tests the material is exposed to the most likely worst-case downhole conditions and selected properties are measured several times. The tested properties are different for different materials, but could for instance include tensile strength, mass, volume, visual appearance, chemical conditions and permeability [14]. The ageing test should be carried out using three test specimens from the same material with testing periods of three, six and twelve months. The test specimens should be stored in autoclaves at a pressure and temperature which reflects the worst-case downhole scenario, in contact with in situ fluids.

The material must be non-shrinking to prevent flow between the barrier-plug and the casing annulus. If the materials shrinks after placement micro channels are created in the material and fluids are able to migrate through these channels. Shrinkage may occur during curing or as a result of aging.

The material is required to be ductile/ non-brittle. After settled at the right position in the well the barrier must be able to withstand the external loading it is exposed to without losing its function as a permanent barrier. Variations in pressure, temperature and mechanical stress are some conditions that the barrier must withstand.

It is also required that the material is able to bond to the casing or the formation, in which it is placed. If there is no bonding between the plug and the casing a microannulus is formed and this will act as a potential leakage pathway for fluids.

3.6.1 Material

The recommendations of the well barrier properties, given in NORSOK D-010, do not specify a specific plugging material for the WBEs. So it is each operator's choice to select a material that meets the NORSOK requirements. It is important to choose a material that can withstand any chemical interaction in the well. Chemicals like CO_2, CH_4 or H_2S gas dissolved in water might interfere with the mechanical properties of the plugging material or metal components. The composition of the chosen plugging material must not change due to interactions with these chemicals. Tests to verify long term integrity of the plugging material must be performed and documented. This could either be inflow testing or leak-off testing.

Some limitations to the plugging materials have been given in NORSOK D-010:

- Steel tubular must be supported by cement, or a similar plugging material, in order to be accepted as a permanent WBE.
- Elastomer seals are not accepted as a permanent WBE.
- Control cables and lines shall be removed in the areas where the WBE is placed, because they might cause leaks in the well barrier.
- Mechanical barrier elements are not allowed as permanent barriers alone, because it may degrade over time

3.6.2 Position of Well Barrier

The setting depth of the permanent plug is dependent on the pressures and fluids in the permeable formations, and the fracture gradients above the source of inflow. Plugs must be set at a depth where the formation rock will not fracture when exposed to a pressure below. A permanent well barrier should be placed as close to the source of inflow as possible and it should cover all possible leak paths.

When we plug and abandon a well we need to know how strong the formation around the well is in order to know how much pressure it can withstand. It is important that we stay below this pressure to not create a fracture into the formation potentially inducing communication to the surface. This information is usually found when we first drill out the well. According to NORSOK D-010 [5] the primary and the secondary barrier should be placed at a depth where the potential internal pressure is less than the estimated formation pressure. A more strict practice used by Statoil is to set the plug at a depth where the potential pressure is less than the minimum formation stress. The process of finding the minimum formation stress is similar to an extended leak-off test (XLOT). Fig. 5 shows an example of an idealized pumping pressure curve for XLOT.

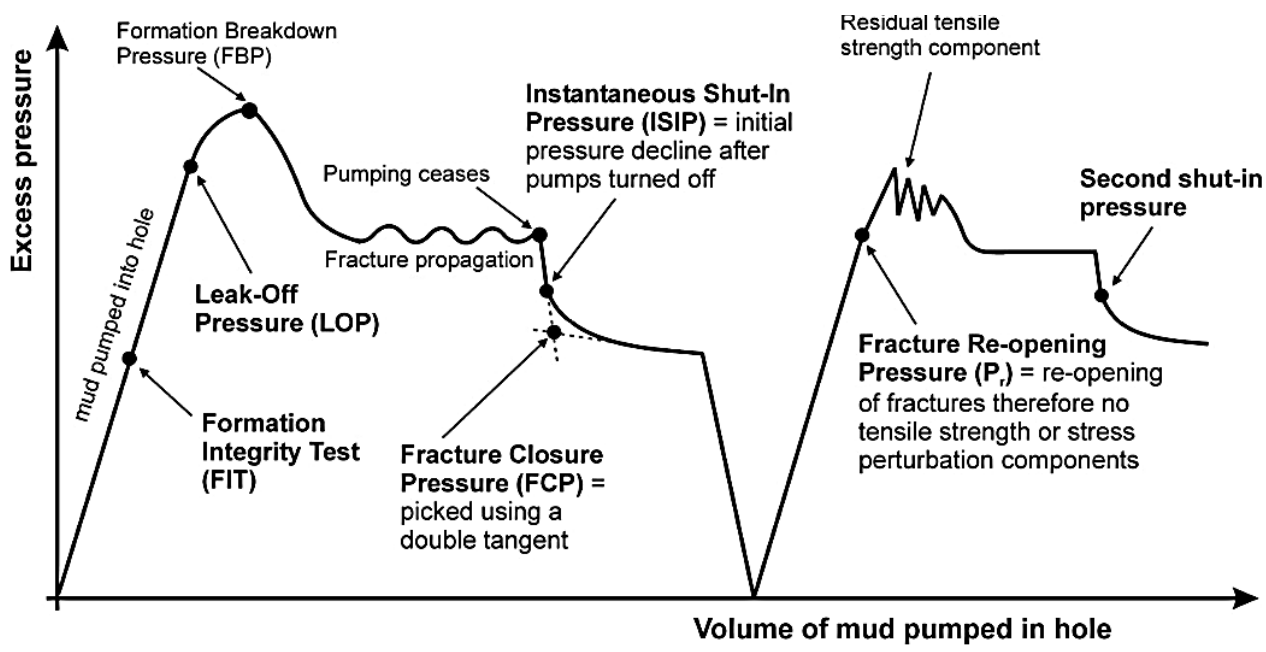


Figure 5 - Extended Leak-Off test [15].

The XLOT is carried out after the set cement has been drilled out below the casing shoe. The casing shoe is then pressurized by pumping mud with a constant rate into the wellbore while monitoring the pressure. The straight increasing line at the beginning of the graph shows the pressure when the formation is still intact, but when this line starts to deviate the leak- off pressure (LOP) is reached, and the fluid starts to leak out somewhere. This could be a leakage around the casing shoe, around the cement or it could be a sign that the formation starts to show weakness. The pumping is continued until the formation fails and crack open, resulting in a pressure drop in the well. On Fig. 5 this is marked as the formation breakdown pressure (FBP). The pumping continues until the pumping pressure stabilizes at an approximately constant level. Then after the pump stops the backflow of the fluid leads to a reduction in the pressure and when the fracture closes the Fracture closure pressure (FCP) has been reached [16]. This pressure is also known as the minimum formation stress and this is the pressure we know the well can withstand without any leakage of hydrocarbons into the formation. This information is used to determine where to place the barrier in the well.

The information from the XLOT is added to the pore pressure plot to determine the minimum plug setting depth. In Fig. 6 the pore pressure plot is presented as gradients. This is the most common way of presenting the plot during the drilling phase of the well. On this plot the depth, true vertical depth (TVD), is seen on the y-axis and the pressure gradient on the x-axis. In addition the type of formation found throughout the different depths is illustrated on the left hand side. In order to find the minimum setting depth of plugs in the P&A phase the pore pressure plot must be presented as pressure curve as seen in Fig. 7. On the pressure plot the depth (TVD) is seen on the y-axis and the observed pressure is seen on the x-axis. In Fig. 6 and Fig. 7 OVB means overburden pressure, Sh means minimum formation stress and Frac is the formation fracture pressure.

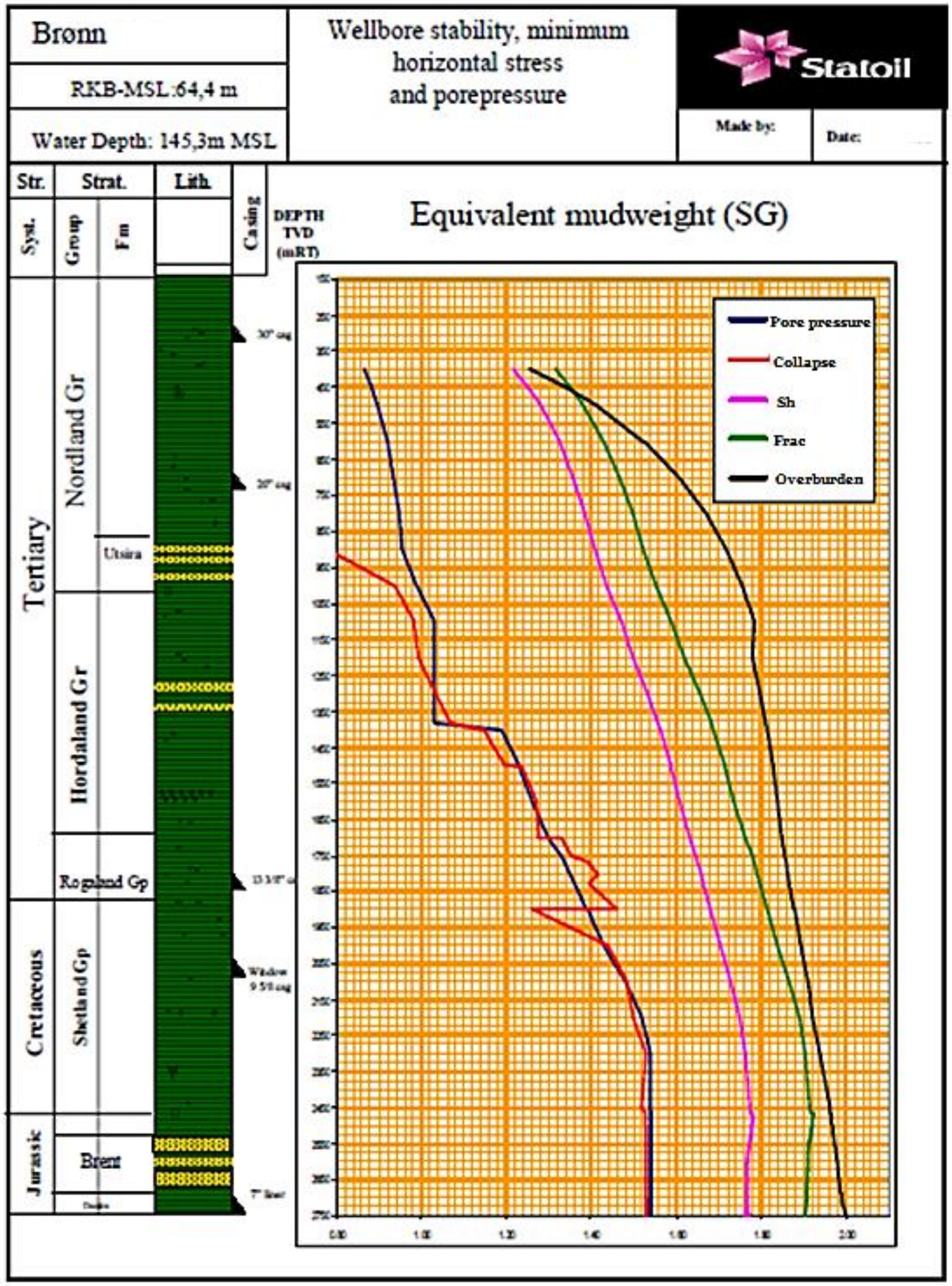


Figure 6 - Pore pressure plot shown as gradient curve[12].

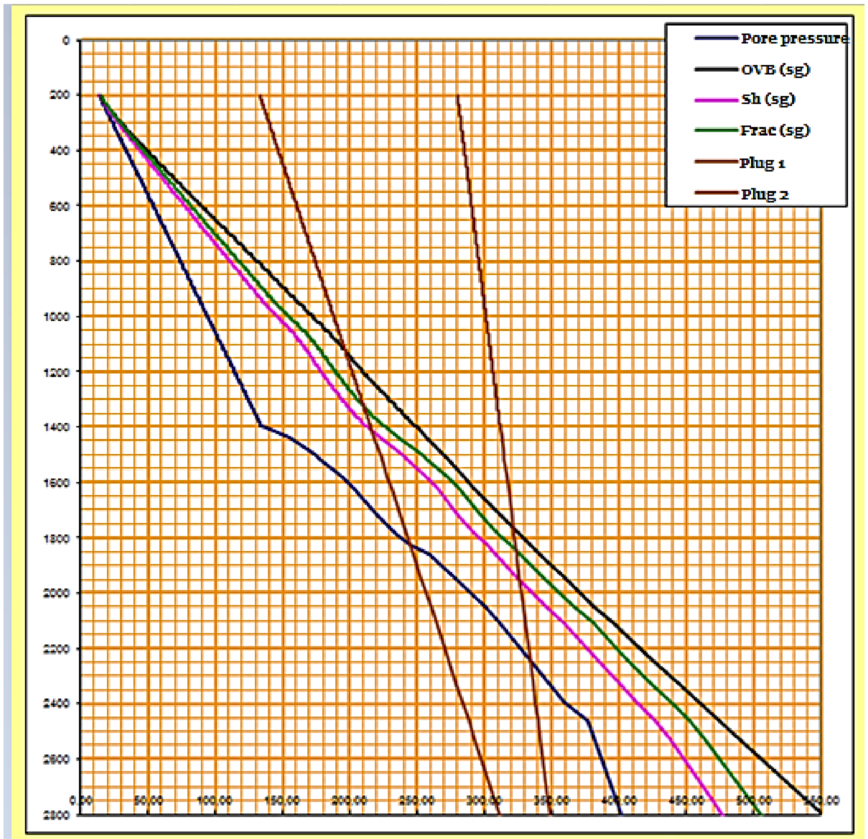


Figure 7 - Pore pressure plot shown as a pressure curve [17].

The graph named plug 1 in Fig. 7 is found from the following Eq. [18]:

$I_{res} = P_{res} - 0{,}0981 * \rho * (D-X)$ 3-1

where I_{res} is the influx pressure exerted by the reservoir, P_{res} is the future reservoir pressure, ρ is the density gradient of the inflowing fluid, D (mTVD) is the depth to top reservoir and X (mTVD) is the depth in the well. Plug 2 is found by the same Eq., but now $I_{\text{potential source of inflow}}$ and $P_{\text{potential source of inflow}}$ replaces I_{res} and P_{res}.

The intersection between this line (plug 1 for the first equation and plug 2 for the second equation) and the minimum formation stress (Sh) gives us the minimum setting depth. If the plug is set shallower than this we cannot be sure that the formation will hold and a leak to surface may occur.

3.6.3 Verification of Barriers

All abandonment barriers must be verified to make sure they are placed at a required depth and that they have the required sealing properties. How the barrier is tested is dependent of what type of barrier is set.

Cement barrier:

Several actions should be taken to verify the cement:

1. The installation must be documented including the operational steps during placement like the volume of the pumped cement, the return during cementation, water-wetting, pills etc.
2. The strength development of the cement should be tested ahead of placement at downhole temperature and pressure.
3. After curing the position of the cement plug should be verified by tagging. According to NORSOK D-010[5] this is done by:
   - Open hole: Tagging or measure to confirm depth of firm plug.
   - Cased hole: Tagging or measure to confirm depth of firm plug.
     Pressure test, which shall:
     1. Be approximately 1000 psi above estimated formation strength below casing/ potential leak path or approximately 500 psi for surface casing plugs
     2. Not exceed casing pressure test.

     If a mechanical plug is used as foundation for the cement and this is tagged and pressure tested it is not necessary for the cement plug to be verified.

Casing cement:

The position of the top of cement (TOC) should be verified by:

- Logs (described in Ch. 6)
- Estimation based on records from the cement operation like volumes pumped, returns during cementing, differential pressure etc.

In addition should the sealing capability of the casing cement be verified, this is done by:

- Logs (the same ones as for determining TOC).
- Monitoring the casing pressure during the life cycle of the well.

- Leakoff test during drilling out the shoe.

Unconsolidated well plugging material

Verification of top of sand cannot be performed in the same manner as for verification of TOC. The compression strength of concentrated sand slurry is not strong enough to allow verification by tagging. Instead verification and documentation of sand slurry placement is performed by placing the bottom of the drill string at the planned top of sand and circulating up while observing the returns [19]. A benefit of this verification over tagging is that waiting for cement is avoided and hence time and money is saved.

3.7 Slot Recovery

When the cost of producing from a well becomes higher than the operating income the well is often permanently abandoned. A cost effective way to enhance production and provide for reservoir stimulation is to permanently abandon the bottom of the well and to use the existing slot to sidetrack the well to reach new targets. The cost can often be cut in half when sidetracking an existing well instead of drilling a new horizontal well [20]. This way the top infrastructure may be reused to drill multiple wells. This process is known as slot recovery. When a sidetrack is drilled to access more productive targets it is a requirement to permanently abandon the lower section of the well and to use the upper section to sidetrack as seen in Fig. 8. Abshire et al. [2] describes a common way of performing a sidetrack, ref. Fig. 8:

1. Plug the reservoir by placing a cement plug in the production tubing below the packer.
2. Pull production casing above the polished bore receptacle.
3. Install a secondary barrier, usually a cement plug above lower completion inside the production casing.
4. Cut and pull production casing; 9 5/8″ and 10 3/4″ casing.
5. Perform sidetrack through intermediate casing.

The P&A procedure will be further addressed in Ch. 7.

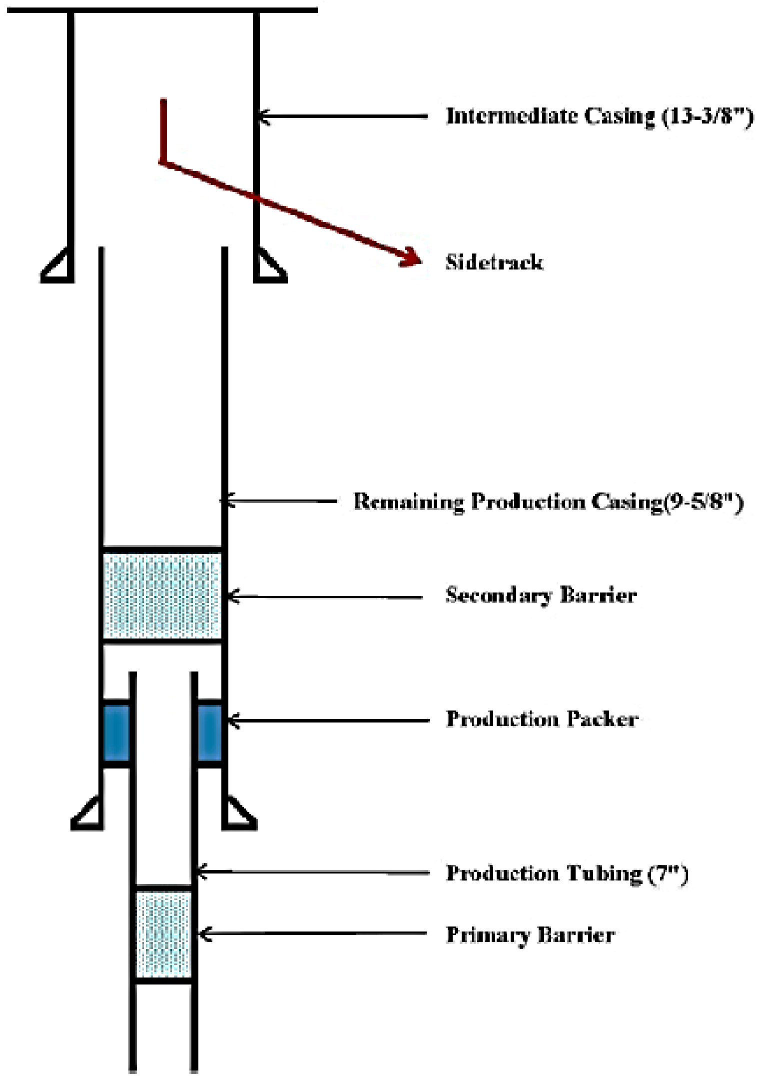


Figure 8 - Sidetrack an old well [2].

4 Plugging Material

Portland cement has been the most used plugging materials for decades, and it has been considered the most appropriate material for P&A. It is reliable, durable, available worldwide and it is cheap, but there are lots of concerns regarding cement as a plugging material, and other materials have been taken into consideration for plugging. Even though Portland cement is a long-lasting material it is known that its long-term integrity is weakened due to downhole temperatures and environmental conditions such as the presence of CO_2 .

Today shale is probably considered to be the best plugging material. It is a much cheaper alternative to other plugging materials and valuable rig-time is saved when sufficient shale-bonding is present outside the casing. How shale as a plugging material is achieved and how its integrity is determined will be discussed in Ch. 4.2.

Other laboratory – made materials will also be discussed. Since Portland cement still is, and probably will remain, the most used plugging material for some time on the NCS, this will be studied in more detail.

4.1 Well Cementing

Well cementing is the process of placing a cement slurry at a predetermined position in the well or in the annulus. This involves the process of determining the amount of cement slurry required for that specific job and the design of the cement slurry. The cement is premixed before it is pumped down to the correct position. After some time, often between 6-8 hours, the cement sets and develops the desired properties, an almost impermeable, durable and solid material that is capable of bonding to formation and steel casing. A successful cement job is dependent on many factors like proper selection of placement rate, type and amount of spacer and the appropriate cement slurry design, but the well is a dynamic place, giving challenges to the set cement throughout the lifetime of the well. If the cement is allowed to set undisturbed it exhibits very low matrix permeability, but during production the cement is subjected to several severe conditions that may reduce this permeability drastically. "Cracking" is a process where the cement is expanding and extracting causing the cement to crack. This condition may arise due to thermal or pressure changes in the well during the productive phase. A second condition that may cause implications for the cement is called "debonding". This is the situation when the bond between the cement/steel or the cement/rock fails. There are many situations where this can occur: pressure reduction after pumping cement, due to pressure reduction in the well while producing, casing movement caused by subsidence, shrinkage due to temperature and pressure changes and when stimulated (for instance hydraulic fracturing). The third condition, called shear failure, is failure of the cement sheath caused by movements in the well. These movements are naturally occurring when the reservoir is depleted. All of these conditions may create micro annuli in the cement and thereby increasing the permeability. This is reducing the cements ability as a zonal isolation between different formations and to the surface, and is one of the main reasons why other plugging materials are being considered.

Cementing the casing and the liner, called primary cementing, is one of the most important operations in development of a well. This is the base foundation for further operations in the well like drilling, completion or abandoning. For abandoning a well the procedures for plugging is much easier if the well has a successful primary cement. The main objective of the primary cement is to give complete and permanent isolation of the formation behind the casing. In order to achieve this, the mud behind the casing must be fully displaced and cement must fill the whole annulus. When cement is in place it is necessary that the cement hardens and develops the necessary mechanical strength to maintain a hydraulic seal that lasts throughout the life of the well. The hydraulic seal must be created both between the casing and the cement and between the cement and the formation, and there must not form any channels in the cement through which fluids could migrate. In addition to primary cementing we have additional cementing jobs called secondary or remedial cementing. This includes squeeze cementing and plug cementing. Squeeze cementing is the process of placing cement in the annulus behind the casing or sometimes in the formation by use of hydraulic pressure. Plug cementing is done by placing a smaller amount of cement at a specific position in the well to function as a seal or a plug. The remedial cementing is operated to cure several well problems. For P&A operations remedial cementing may be necessary for placing a plug before abandoning the well or sealing annular leaks that may exist. A lot of different techniques for carrying out a remedial cementing job are possible today and some of these techniques will be discussed later in this text.

4.1.1 Cement Properties and Cement Slurry Design

The most used plugging material on the NCS today is Portland cement. The main components of Portland cement is clinker which primarily consists of hydraulic calcium silicates, calcium aluminates and calcium aluminoferrites [21]. Portland cement is a hydraulic cement. This means that the cement sets and develops compressive strength as a result of chemical reactions between water and the compounds present in the cement. This strength development happens in both air and under water and it is predictable, quick and uniform. In addition to clinker several additives are added to the cement to give it the desired properties according to the downhole conditions.

Cement systems must be designed so that they can withstand extreme temperature differences ranging from below freezing point in permafrost zones up to 350°C in recovery wells. It also has to withstand large pressure differences, over pressured formation fluids, corrosive fluids and weak or porous formation [21]. In order to maintain the integrity of the cement and provide zonal isolation it has been necessary to mix in additives to modify the behavior of the cement. Many different additives may contribute to improvement of the cement slurry, and there are some specific concerns that have to be taken into consideration when designing a cement slurry for abandoning.

The thickening time is the time it takes from the initial mixing of the cement with water until the mixture achieves a final consistency of 100 B_c, (Bearden) units of consistency. (Since the cement slurry is a non-Newtonian fluid it is more appropriate to use the dimensionless unit B_c, as viscosity index, than poise). The viscosity increases with time and when the viscosity becomes too high the slurry becomes unpumpable. If this happens the well and the pumping equipment could be damaged. It is therefore important that the thickening time is long enough to place the cement at the desired position, but at the same time it is necessary for the cement to develop compressive strength rapidly to save rig time.

Retarders: are used to prolong the thickening time of the cement slurry and to prevent it from setting in the casing prematurely. At the same time it will delay the strength development of the cement, though not reduce it. Some of the most common retarders are lignosulphonate, cellulose derivatives and sugar derivatives.

The well temperature and pressure condition is important factors when determining the thickening time of the cement. This is especially important in high pressure, high temperature (HPHT) wells where both temperature and pressure pose a large impact on the cement. The boundary of a HPHT well is given by the following [22] :

- Drilling mud density above 1,8 sg.
- A bottom hole temperature exceeding 149°C

Special considerations for HPHT wells have to be taken when designing cement slurry for this environment and hence this will be studied in more detail later on.

The strength of the cement is usually referred to as compressive strength. A strength of 500 psi is usually considered adequate. The strength of the set cement is dependent on several factors like the cement-water ratio, curing time, the temperature during curing, the pressure during curing and the additives in the cement. The strength will increase with increased curing time, temperature, pressure and when adding accelerators, but when temperature exceeds 200°C the strength development will reverse.

Accelerators are added to the cement slurry to reduce the setting time, to accelerate the strength development, or both. They are most commonly used for shallow, low-temperature wells or when the cement setting time is longer than the required time to mix and pump cement. This way the time to wait on cement (WOC) is reduced. The most common accelerators are Calcium Chloride ($CaCl_2$) and Sodium Chloride (NaCl). Higher concentrations of these accelerators act as retarders.

The specific weight of the cement slurry is one of the most important properties of the slurry. The cement slurry's specific weight should be as high as possible without breaking the formation during placement. A neat cement slurry consists of a mixture of water and cement, and the density of the slurry is specified by the amount of water added to the slurry. The maximum amount of water that can be added to the cement slurry is the amount that will still keep the particles suspended in the slurry until the cement has fully set. If a larger amount of water is used then the cement slurry will have difficulties to harden properly and the result might be channels of water inside the set cement. Different additives may be added to reduce/increase the density of the slurry.

It is possible to reduce the specific weight of the cement slurry by adding more water but this can only be accomplished within the minimum-maximum limitations of the water-cement ratio set by the American Petroleum Institute (API) standards [23]. Another way to lower the density of the cement slurry is by adding *lightweight particles*. The lightweight particles reduce the density of the slurries because they are lighter than the cement particles. Some of the lightweight particles that are used for this purpose are expanded perlite, gilsonite, powdered coal and bentonite. In some cases it may not be possible to reduce the specific weight enough by use of the materials mentioned above. In very weak formations nitrogen can be added to the slurry to prepare a competent cement system with low enough density. A cement slurry with nitrogen added is called foam cement. The density of the nitrogen is very low compared to the density of the base cement slurry so the density of the cement slurry can be adjusted by varying the nitrogen concentration [21].

Some well conditions require the use of a slurry with high density; high pore pressure, unstable wellbores and deformable or plastic formations. The density of the slurry can be increased by reducing the amount of the mixing water. This will however make it difficult simultaneously to obtain adequate fluid-loss control, acceptable slurry rheology and no solids settling [21]. If appropriate fluid-loss control is absent the risk of slurry bridging is higher. Solids settling will lead to non-uniform compressive strength and bonding across the cemented interval.

Weighting agents are added to increase the density of the slurry. According to Nelson & Guillot [21] there are several criteria the material must meet in order to qualify as a weighting agent:

- The particle-size distribution of the material must be comparable with the cement. Large particles tend to settle out of the slurry, while small particles tend to increase slurry viscosity.

- The mix water requirement must be low.
- The material must be inert with respect to cement hydration and compatible with other cement additives.

Ilmenite, hematite, barite and manganese tetraoxide are the most common weighting agents.

Cement plugs placed downhole for P&A must have low permeability and plugs placed in open-holes must have sufficient fluid-loss control. When the cement slurry comes in contact with the formation the pressure differential between the slurry and the formation leads to invasion. The aqueous phase of the slurry will tend to migrate into the formation leaving the solid phase behind. This may either create a filtercake on the formation wall or leave more of the particles suspended in the slurry. This will further lead to dehydration of the slurry and premature setting.

Fluid loss control additives are added to the slurry to prevent fluid loss to the formation. The fluid loss control additives help the slurry retain its key characteristics like the viscosity, thickening time, rheology and comprehensive strength-development. There are two classes of fluid-loss additives; finely divided particulate materials and water-soluble polymers.

The cement plug will be exposed to chemical interactions from wellbore fluids like hydrocarbons and brines, and substances injected from the surface. For the cement plug to provide zonal isolation for eternity it is essential that it is resistant to any chemical attacks downhole. Silicone-based material like silica is added to the cement system for this purpose. There are namely two forms of silica normally added to the cement system; silica sand with a particle size of approximately 175-200 µm or silica flour with a particle size of approximately 15 µm. Silica sand has the lowest surface area and therefore is the easiest to mix, and hence the preferred form.

Sufficient bonding of the set cement is another requirement to ensure durable isolation. Poor bonding can be a result of inadequate mud removal, expansion and contraction of the casing caused by internal pressure and cement contamination. These conditions will usually lead to a small gap, a microannlus, between the casing and the cement or between the formation and the cement. Cement systems that expands slightly after the cement has set will improve the bonding due to tightening of the cement against the pipe and the formation. The most common expansive additive is ettringite crystals. An expanding cement system tends to increase in volume to a significantly greater degree than a conventional Portland cement does. The limitation of this system is its curing temperature which is 76 $^{\circ}$ C.

Special considerations have to be taken when designing a cement slurry for a HPHT well. Like any other well the wellbore conditions must be considered, but for these wells temperature is the most critical factor. When placing the cement downhole the bottom hole circulating temperature (BHCT) has the greatest impact on the properties and behavior of the fluid system.

It is therefore necessary to get an accurate and valid measurement of the BHCT. Most of the commonly used additives in a conventional cement slurry do not have the upper temperature limits as high as the temperature in a HPHT well. Tests performed on these cement slurries have shown that the slurry becomes very thin when exposed to these conditions. The particles in these slurries start to settle out, making the slurry unstable. Special stabilizers developed for HPHT wells will sustain the viscosity of the slurry and give support to the solids in the slurry.

The slurry is very sensitive to high temperature and starts hardening very quickly, hence making the design more challenging. Another factor that has to be taken into consideration when designing a cement slurry for the HPHT well is the pressure. It is important that the hydrostatic pressure of the wellbore fluids meets or exceeds the formation pressure at all time to ensure control over the well at all time. Therefore a slurry with high density should be used. This is normally achieved by adding large amounts of weighting material but this can lead to slurry sedimentation. Sedimentation is the process when larger particles in the slurry tend to settle out of the fluid and come to rest at the bottom towards a barrier. By maximizing the packing volume, by choosing a multimodial particle size distribution, this can be avoided.

Often the placement operation of the cement slurry in HPHT wells may take several hours and so the slurry must be retarded to be able to complete the placement successfully. The high temperatures retarders are often very sensitive to the temperature change and the amount added to the cement, and the change in working temperature of as little as 10 °C may dramatically change the pumping time of the slurry. Today there exist two types of retarders; organic based and synthetic based retarders. The synthetic based retarder is operational under much higher working temperatures than the organic based and its sensitivity to temperature changes in the well much lower. The synthetic based retarder is therefore often the preferred one.

4.1.2 Squeeze Cementing

Squeeze cementing jobs are performed for many different reasons and abandoning a nonproductive or depleted zone is one of them. Squeeze cementing could either be performed during drilling or completion of a well or at a later stage. Regardless of timing the main purpose of the squeeze cementing is to remedy an undesirable well condition. Before a well can be abandoned annular leaks must be sealed [24]. Squeeze cementing forces cement into holes, splits or fissures in the formation or through perforations in the casing, under sufficient hydraulic pressure. When the cement is forced into channels in the formation it loses some of its mixing water and a filter cake builds up on the interface between the fluid and the permeable rock [25]. This filter cake will harden and function as an almost impenetrable seal.

Conventional cement is usually not suited for squeeze cementing, because the particles in the conventional cement are often too large for the channels where the cement is squeezed. Instead a small particle -size cement is used for the squeeze job. This cement includes Portland cement, blast furnace slag (iron) and other blends. The particle size of this cement is often between 4 to 15 µm [21]. This cement behaves in almost the same manner as the conventional cement but it has an improved ability to penetrate and flow through tight channels and perforations. During the squeezing operation most particles in the cement slurry are too large to penetrate the formation, and the particles sets on the surface of the channel creating a filter cake, see Fig. 9. Continuing the squeezing process leads to filling the perforated channel properly with cement as seen in Fig. 10.

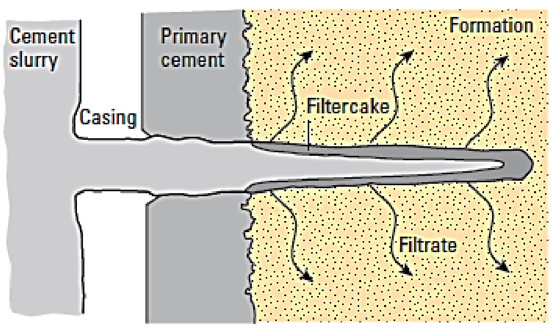


Figure 9 - Filtercake buildup into a perforation channel [21].

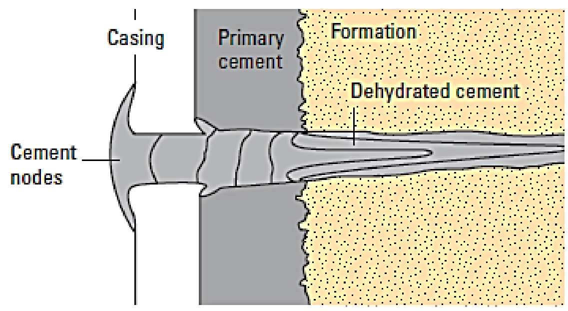


Figure 10 - Perforation channel properly filled with cement [21].

It can be shown mathematically how the filter cake builds up.

Solid volume fraction:

$$\mathbf{f_{Sv}} = \frac{\mathbf{V_{solids}}}{\mathbf{V_{slurry}}} \qquad 4\text{-}1$$

Conservation of volume:

$$\mathbf{V_{slurry}} = \mathbf{V_{filt}} + \mathbf{V_{fc}} \qquad 4\text{-}2$$

Where V_{filt} is the liquid filtrate volume passing into the medium and V_{fc} is the filtercake volume.

Cake porosity:

$$V_{fc} = (\phi \times V_{fc}) + V_{Solids} \quad \text{4-3}$$

Inserting Eq. 4.1 and 4.2 into Eq. 4.3 one gets V_{fc} = ϕV_{fc} + f (V_{filt} + V_{fc}) from where one can obtain the cake volume as a function of filtrate volume:

$$V_{fc} = \frac{f_{sv}}{1 - f_{sv} - \phi} V_{filt} = w\, V_{filt} \quad \text{4-4}$$

The factor

$$w = \frac{f_{sv}}{1 - f_{sv} - \phi} \quad \text{4-5}$$

is called the deposition factor w. It corresponds to the ratio of the filter cake volume to the filtrate volume and can be measured by a fluid loss test. It has been observed that this factor is almost constant when the differential pressure is varied, indicating that the filtercake is incompressible and hence the permeability is constant at all pressures [21].

There are two different cement squeeze classifications which are mostly used today: high-pressure squeeze and low-pressure squeeze. Low-pressure squeeze operations are the one with the highest success factor and therefore the preferred one. It also requires the least amount of cement and one has better control over the placement by using this technique. There are however some situations where low-pressure squeeze operations are not suited for accomplishing the job objective. When the channels in the formation is not in direct contact with the perforation and when the channels are filled with some kind of fluid a high-pressure squeeze job is required. But there are several disadvantages by using this technique. Not only does it require a much larger cement volume to be able to fill the additional space created by the fracture, it might also be difficult to create a filtercake and to obtain the required squeeze pressure.

4.1.3 Plug Cementing

There are many reasons for setting a downhole cement plug, and abandoning a well is one of them. Placing several cement plugs in a well is the most common practice for abandoning a well, but several studies show that many plug- cement jobs have had a significant failure rate. Interaction between the fluid systems in the well and problems with the cement slurry due to improper pre job planning and execution are some of the main reasons for failure.

To make sure the cement plug fulfills its intended objectives, there are certain things that have to be considered [21]:

- Placement.
- Prevent cement contamination.
- Adequate thickening time to complete the placement.
- Ensure that the pressure and mechanical – strength limits are not exceeded.

The main objective of plug cementing is to restore the natural isolation between geological layers which was present before we started drilling. So the most natural place to set the cement plug is where the cap rock first was, however additional lost- circulation plugs must be placed nearby the loss- zones.

Contamination during cementing is a serious problem. It can lead to a dramatic increase in the setting- time of the cement and a degradation of the mechanical properties of the cement. Per definition a fluid is contaminated when its physical and chemical properties are irreversibly mixed with another fluid in a way so that it cannot flow in the desired regime or be placed downhole as designed, and thus it will not function as intended. Cement contamination can occur for different reasons: during placement of the cement, due to mud in washed- out zones, while pulling the pipe out and when reversing the excessive cement. There are many ways for preventing contamination. A bridge plug is used to prevent the heavy cement from falling through the less dense fluid below and mechanical plugs like darts and balls will function as a barrier between fluids as they flow downwards.

Excess or contaminated cement must be circulated out. When the correct amount of cement is placed at the correct position it is important to perform a clean- out job to make sure no cement is left in the drill string. Contaminated cement must be circulated out before the cement sets or before heavier particles in the cement starts to sediment. In all cases it is important that the cement plug itself is not disturbed.

During all stages of cement placement it is important to control the basic safety constraints [21]:

- "The dynamic fluid pressure in front of the formation must be less than the formation fracturing pressure.
- To prevent formation- fluid entry, the static fluid pressure in front of the formation must be higher than the pore pressure.
- The differential pressure across the various tubulars must be less than their burst or collapse pressure."

4.2 Shale as Barrier

During and after drilling, in some formations the rock might start to close off the well, creating a seal in annulus. This has for a long time been considered a problem during drilling and casing running, but in terms of abandonment it is a good thing. The fact that shale are cap rock for many reservoirs makes it an excellent barrier material, but there are certain requirements the shale has to satisfy before using bonded shale as a barrier:

- The barrier must be shale.
- The location of the formation must be in accordance with the requirement for setting depth.
- The sealing ability of the shale must be in accordance with the requirements.
- The interval length of the bonded shale must fulfill the same requirements as for the cement plug. Meaning the shale must cover the whole circumference of the casing and over a certain interval.

There are also certain properties the displaced formation must have in order to be qualified as an annular barrier. It must have sufficient rock strength and a very low permeability to fluids.

By logging we make sure the formation has collapsed all around the wellbore and that both the lengths and positioning meets the requirements. Two independent logging tools must be applied. Two logs that are often used for this purpose today are the cement bond log (CBL) and the Ultrasonic log. These two logs are traditionally run for evaluating the cement behind the casing and they will be further described in Ch. 6. If bonded shale is observed on the bond log a pressure test must be applied to ensure the formation has sufficient strength to act as a barrier. The pressure test will also be further described in Ch. 6.

Bonded shale cannot be predicted, but if it happens you are lucky. You should however always plan for using other barrier materials outside the casing, but if you observe sufficient bonded shale it is often a preferred solution for abandonment. However in known fields they can expect to achieve bonded shale most commonly with green clay.

4.3 Unconsolidated Well Plugging Material

A new type of plugging material, a Bingham-plastic unconsolidated plugging material with a high concentration of solid, is being considered as a better alternative to cement. This plugging material addresses the problems that one might experience with cement: shrinkage or gas migration during setting, fracturing after setting or degradation due to exposure of temperature and chemical substances in the well.

One type of unconsolidated well plugging material that have been developed and that will be studied is Sandaband.

4.3.1 Theoretical Considerations

4.3.1.1 Permeability

Darcy's law describes the flow of fluids through a porous medium. It states that the velocity of an incompressible fluid through a porous mass is proportional to the net pressure gradient and inversely proportional to the velocity of the flowing medium [19]. Eq. 4.6 shows the pressure drop as a function of the velocity

$$\frac{\Delta P}{\Delta L}=\frac{\mu}{k}v \qquad \text{4-6}$$

Where ΔP is the pressure drop, ΔL is the length over which the pressure drop is taking place, μ is the viscosity, k is the permeability of the medium and v is the velocity of the flowing fluid.

The flow through a packed sand bed can be found from Black-Kozeny Eq.,

$$\frac{\Delta P}{\Delta L}=\frac{150\mu}{d_p^2}\frac{(1-\varepsilon)^2}{\varepsilon^2}v \qquad \text{4-7}$$

Where d_p is the sand particle diameter, ε is the bed non-solid fraction and the factor 150 is an empirically adjusted factor.

By combining Eq. 4.6 and Eq. 4.7 we get an expression for the permeability k of the porous medium:

$$k=\frac{\varepsilon^2}{(1-\varepsilon)^2}\frac{d_p^2}{150} \qquad \text{4-8}$$

The sand slurry consists of a mixture of particles with different sizes. The smaller particles will fill the pore space between the larger particles, down to particles with micron size. So the permeability of the system will be defined by the smallest particles.

4.3.1.2 Pumpability

The right mixture of larger and smaller particles in the sand slurry, by making the smaller particles fit into the free space between the larger particles, makes the sand slurry pumpable. It is important to find the right ratios of smaller and larger particles. An excessive amount of small particles will make the slurry non-flowable and too much water will make an excessive amount of larger particles segregate and therefore also unpumpable. The viscosity can be controlled by adding solids with different particle-sizes and particle shapes. Slurries with a broader particle-size distribution have a higher packing fraction (the viscosity value at when flow is impossible) because the smaller particles will fit into the space between the bigger ones. There is however a limitation on the amount of large particles before the viscosity is reduced. From Fig. 11 we can see that this reduction in relative velocity is seen near a fraction of 0.6 of large particles. This is known as the Farris Effect.

The relative viscosity is seen as a function of the particle size fraction. The slurry illustrated here is a mixture of two monodisperse particle sizes where the larger particles are five times the size of the smaller particles. The lines represent different volume fractions of the particles. It can be seen from Fig. 11 that the particle size distribution has a great impact on the viscosity and therefore is of great importance when designing the plugging material.

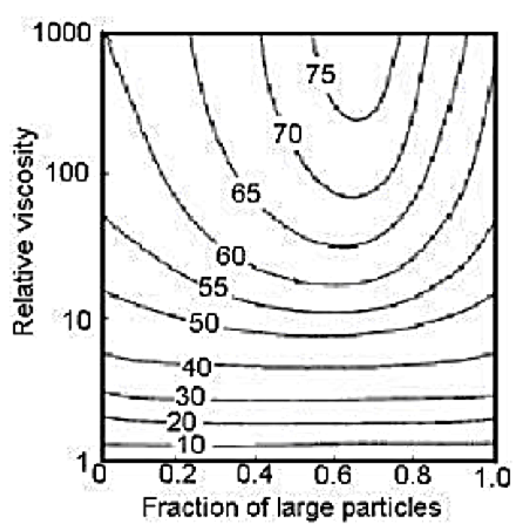


Figure 11 - The Farris effect. Relative viscosity as a function of the particle size fraction for different loading fractions [26].

4.3.2 Sandaband

The main ingredients of Sandaband are quartz and water. They are the contributing parts in forming the impermeable barrier. In addition the Sandaband concentrated sand slurry is made up of crushed rock, microsilicia, deflocculant and viscosifier. Lubricant and/or antifreeze may also be added.

As seen in Fig. 12 the sand slurry normally consists of approximately 85% solids. If an excessive amount of water is added to the slurry the inter-particle distances in the slurry would become too large and particles will start to segregate. So designing the right slurry is relevant for achieving the appropriate properties of the plugging material.

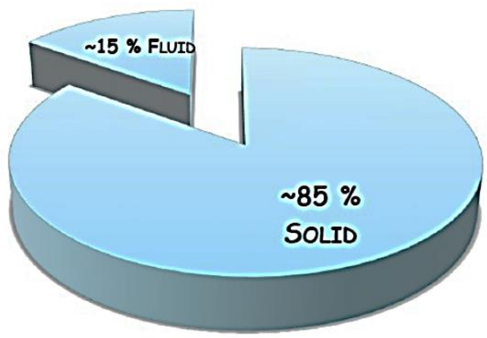


Figure 12 – Sandband is pumpable at large solid concentrations [27].

Some of the WI problems experienced with cement are solved by using unconsolidated well plugging material. The plug is thermodynamically-stable because the sealing ability is only determined by the solid particles and the bound water. Because there will not exist any free water the material will form a homogenous plug with a continuously distribution of particles. This will create a permanent gas-tight seal that lasts forever. As mentioned an unconsolidated well plugging material is a Bingham-plastic material. This means that it is liquid as pumped and solid at rest, see Fig. 13.

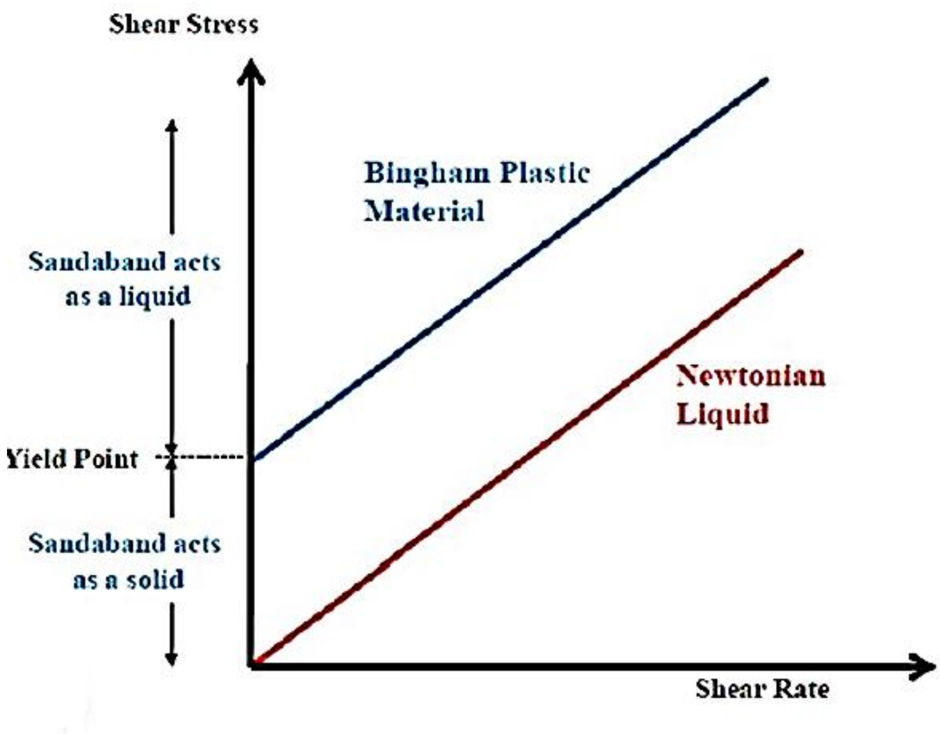


Figure 13 – Sandaband properties at different yield points [27].

In addition to the ones mentioned above Sandband have the following properties [28]:

- Yields if stress exceeds strength
- Non-shrinking
- Non-fracturing
- Non-segregating
- Chemically inert
- Needs a solid floor – will sink if placed on a fluid

4.3.2.1 The Benefits of using Sandaband

Since cement is the most used plugging material it is natural to compare alternative materials to cement. Some of its benefits are directly related to its properties. It is more reliable because it will not set up prematurely. It is ductile and adaptable because it does not fracture and therefor will not leak. It is robust and non- complex because it relies purely on physical properties. Since it is chemically inert there will not be a problem with downhole fluid contamination and the material will stay effective for eternity. It experiences no losses to formation. When cement is used as the plugging material it is necessary to wait between 8-12 hours before one can tag the cement. This is not necessary when using Sandaband so lots of time and money are saved. For temporary abandonment there is additional time to save when using Sandaband as plugging material. For HTHP operations it is possible to fill the entire reservoir section with a sand slurry. When it is time to continue operations in the well the sand can easily be washed out of the well with the completion rig, and significant operation time can be saved [26].

4.4 Thermaset

The development of Thermaset started in 1990, to find a better alternative to cement as plugging material. Sintef, the largest independent research organization in Scandinavia, performed a study on different materials and found that Thermaset exhibits initial properties that are favorable over Portland Type G cement properties: the tensile strength is much higher, Thermaset can withstand approximately 6 times the flexural strain, E-modulus show a far superior elasticity , rupture elongation is 6 times higher for Thermaset and the compressive strength is higher [29]. Table 2 shows a comparison of the two plugging material revealed from several tests carried out to compare the material properties and the long-term WI of the two materials.

Table 2- Mechanical properties of Thermaset and Portland Type G cement [29].

Properties	Portland Type G cement	Thermaset
Compressive Strength (MPa)	58 ± 4	77 ± 5
Flexural Strength (MPa)	10 ± 1	45 ± 3
E-modulus (MPa)	3700 ± 600	2240 ± 70
Rupture Elongation (%)	0,01	3,5
Tensile Strength (MPa)	1	60
Failure flexural strain (%)	$0{,}32 \pm 0{,}04$	$1{,}9 \pm 0{,}2$

Thermaset is a non-reactive polymer with a curing process activated by temperature. It is possible to design the curing on-set and curing time to suit pre-determined temperatures, and the material can be tailor-made with regards to viscosity and density. The viscosity ranges from 10 to 2000cp and the density ranges from 0.7 to 2.5 sg. Ahead of plugging, temperatures in the well are logged. This information makes it possible to design a suitable slurry for the intended plugging-interval. The material has a low viscosity so it is easily pumpable. The same pumping equipment that is used for cement can be used for Thermaset so the equipment is usually already available on the rig. After Thermaset has set its properties changes. Compared to conventional cement it does not shrink during curing, so this makes it ideal for permanent plugging.

4.5 Geopolymer

New types of cement slurries consisting of geopolymeric materials have been developed as alternative to the conventional lightweight cement slurry. Geopolymers are made of aluminium and silicon and they exhibit superior mechanical and chemical properties compared to the Class G cement. Geopolymers can provide a material with specific properties from a range of cement/flyash/aluminiosilicate component ratios. This gives a lightweight slurry with high compressive and flexural strength thought to replace the conventional lightweight cements containing silica fume. Silicia fume has traditionally been added to the lightweight cement slurries, but there are some disadvantages related to the use of Silicia fume in cement slurries; Silicia fume in the slurry increases its need for water which may lead to shrinkage problems in the cement, it can be difficult to handle in raw condition and it has become more expensive to use. Geopolymers have been developed with the intention of being cheaper and more environmentally- friendly than Silicia fume and according to Mahmoudkhani et al. [30] the new geopolymer-cement systems can offer the following:

- Variable densities from 1200 to 1900 kg/m^3
- Thickening times from several minutes to several hours
- Superior early and late strength development
- Fast gel strength development
- Controlled fluid loss
- Enhanced flexibility and elasticity
- Zonal isolation through strong bonding to formation and casing
- Ease of operation and handling
- Compatibility with most comment cement admixtures and additives
- Significantly reduced CO_2 and water footprints
- Cost savings

The aluminium in Geopolymers has replaced calcium in conventional cement. Aluminium in nature is not present as carbonates so when it is blended with water it will not release vast amounts of CO_2, hence by use of this material the emission of Green House Gases will be reduced considerably. Tests performed on Geopolymers and API class A and G cements showed that Geopolymers are superior when it comes to compressive and flexural strength. Compressive strength is a materials ability to withstand axial loads. The compressive strength of a material is the value of uniaxial compressive stress that is reached when the material fails completely. As a result the material will be compressed or shortened as seen in Fig. 14.

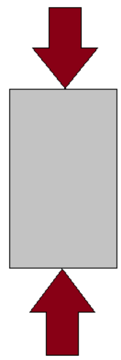


Figure 14 – Compression

The flexural strength or bending strength is a materials ability to resist mechanically failure when loaded, as seen in Fig. 15.

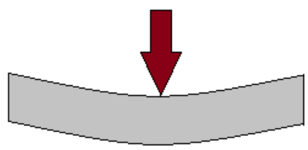


Figure 15 – Bending

Both compressive strength and flexural strength defines the mechanical properties of the cement. Fig. 16 shows a comparison of the compressive strength development over 7 days for a neat cement and geopolymer-cement, both with a density of 1400 kg/m³. From the figure it is observed that the geopolymer-cement develops a much faster and larger compressive strength than the neat cement. In the same study it was also shown that the flexural strength of the geopolymer-cement was twice as high as the flexural strength of the neat cement. It was also shown that the geopolymer-cement exhibit fast-setting behavior making it suitable for wells with potential gas migrating problems.

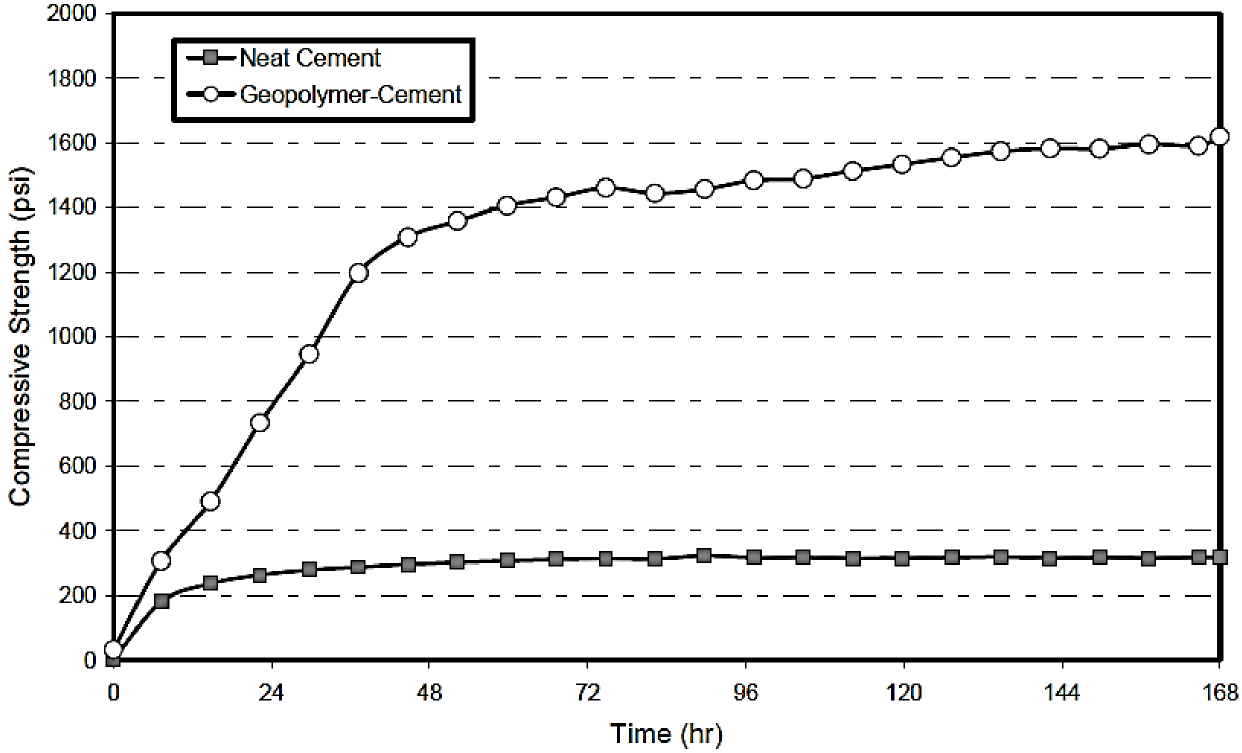


Figure 16 - Difference compressive strength development over 7 days in neat cement and Geopolymer-cement with density of 1400 kg/m³ [30].

5 Placement Methods

5.1 Squeeze Cementing

Squeeze cementing is the process of placing cement into fists and perforations and according to Nelson & Guillot [21] it has several applications. The ones applied for P&A operations are:

- Repairing a primary cement job that has failed because of mud channeling or insufficient cement height in the annulus
- Repairing casing leaks caused by corroded or split pipe
- Abandoning a nonproductive or depleted zone
- Sealing lost-circulation zones

Fig. 17 shows an overview over the six most common squeeze cementing placement methods. They will be briefly discussed in the following.

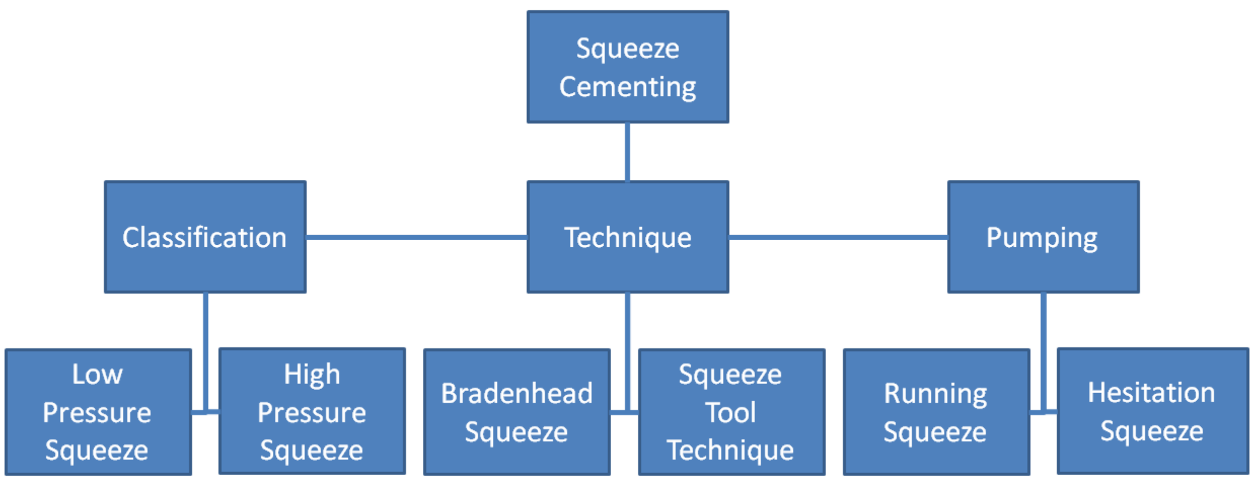


Figure 17 - Overview over the different squeeze placements techniques.

5.1.1 Low-Pressure Squeeze and High-Pressure Squeeze

The main difference between these two methods is the size of the bottomhole treating pressure. In the low-pressure squeeze operation the bottomhole pressure is kept below the formation fracturing pressure to avoid fracturing the formation. This is the most common method and it is applicable whenever a clean wellbore fluid is injected into the formation. If the channels are contaminated with mud or other solids it may be necessary to clean the perforations before the squeeze job. Small volumes of cement are required for this operation and a thin filtercake will build up inside the casing. This method requires a careful design of the cement slurry to avoid excessive filtercake development which can completely fill the inside of the casing.

The high-pressure squeeze method applies pressure above the fracture pressure and is performed when fracturing is necessary. Channels behind the casing might not be in direct contact with the perforation and high pressure may be necessary to displace the cement and seal off formations. Sometimes the perforations may be plugged with fluids or debris and a low-pressure squeeze is insufficient for removing these. Fluid in channels is displaced when pressure is applied behind the cement slurry. Pressure is maintained until after the slurry has filled the whole space leading to a dehydration of the slurry against the formation wall. Large volumes of cement slurry are required to fill the whole void created by the fracture, and the cement should be placed as close as possible to the wellbore. A fluid with high fluid-loss, such as water or a weak hydrochloric acid solution, should be pumped ahead of the cement slurry to open smaller fractures and to clean perforations. As a result a lower squeeze pressure is required.

5.1.2 Bradenhead Squeeze and Squeeze-Tool Technique

The Bradenhead technique is performed when there is no doubt that the casing can withstand the squeeze pressure. This technique requires no special tools. The Bradenhead technique is performed by circulating cement down to the squeeze interval and apply pressure to squeeze the cement into the perforations. It is often a preferred technique due to its simplicity.

Squeeze tools are used to isolate the squeeze interval while applying pressure downhole. Drillable cement retainers or retrievable squeeze packers is placed in an open hole section to seal off the open wellbore below the target and reduces the amount of cement needed [31]. The retrievable packer has a bypass valve to allow for circulation while running in the hole and after the packer is set. This allows for cleanout after the cement job and reversing out excess slurry without the need for extra pressure. In addition it is retrievable, so it can be used several times. A drillable packer prevents backflow of the cement after pumping and providing the operator with more confidence of setting the packer close to the perforated area.

5.1.3 Running Squeeze and Hesitation Squeeze

Running squeeze is the process where continuous pumping of the cement is maintained until the final desired squeeze pressure is reached. The running squeeze is easy to apply, but it is difficult to control the rate of pressure increase and to determine the final squeeze pressure. The pressure is monitored after the final pressure has been reached and the pumps are stopped. If the pressure falls the pumping is continued until the final squeeze pressure is maintained also after pump shutdown. Since large amount of slurry is needed to complete the running squeeze the pump rate is often held low to avoid fracturing the formation.

A hesitation squeeze is often performed when a running squeeze is not possible because of the size of the void, lack of filtrate control or when the squeeze must be performed below a critical wellbore pressure [31]. During a hesitation squeeze the rate of the cement filtrate leak into formation is lower than the minimum pump rate of the field equipment so the pumping is started and stopped several times until the final squeeze pressure is reached. The design of the cement for a hesitation squeeze must be thoroughly designed and tested to understand the properties changes of the cement during the shut-down period. Usually a much smaller amount of cement is required for a hesitation squeeze than for a running squeeze and this technique will therefore often be a less expensive and more effective technique.

5.2 Plug Cementing

Plug cementing involves the process of placing several cement plugs in the wellbore. This involves the process of pumping cement slurry down an open-ended tubing/ drill pipe with return in the annulus. In an ideal operation the tubing/ pipe would be centered in the wellbore, the cement would make a complete reversal flow on the annulus side of the tubing/ pipe and the spacer and the cement would have a uniform placement as seen in Fig. 18. A spacer is any liquid, usually chemically treated water, used to separate the drilling mud from the cement slurry. The spacer contains surfactants that will wash the inside of the workstring and prevent particles in the cement from settling inside the pipe or the tubing.

This is however seldom the scenario one experiences in real life plug placement operations. Several conditions downhole are affecting the placement procedures and this will often result in an unsuccessful result. Several techniques can be applied to improve the result, and some of them will be discussed below.

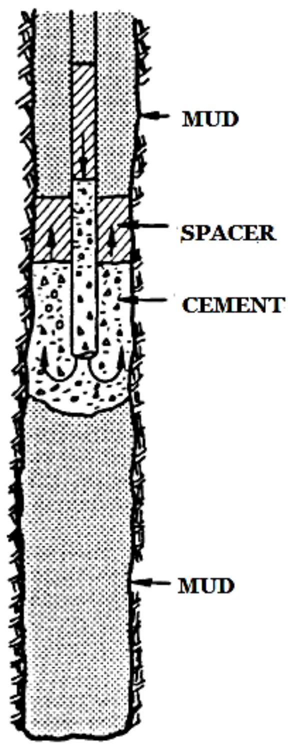


Figure 18 - An ideal cement plug placement.

5.2.1 Balanced Plug

Balanced plug technique is the most common placement method used in abandonment operations today. A tubing or a drill string is lowered to the desired depth for the plug base and the cement slurry is pumped until the cement slurry level is the same inside and outside of the string. One of the main problems that often occur during this operation is contamination of the cement. Poor mud-removal in the area where the cement is to be set can give rise to channels through the plug caused by the drilling fluid. In order to avoid this a spacer is often pumped before and after the cement slurry to wash the hole and to segregate the drilling fluid and the cement from each other. When the cement height is the same on the inside of the tubing as in the annulus the drillpipe is slowly pulled out. The drillpipe will be pulled out with a speed so that the fluid level is balanced at all time, see Fig. 19. When the pipe reaches the cement-spacer interface, no mixing between the spacer and the cement will occur because the interfaces between the fluids are the same both inside and outside the pipe.

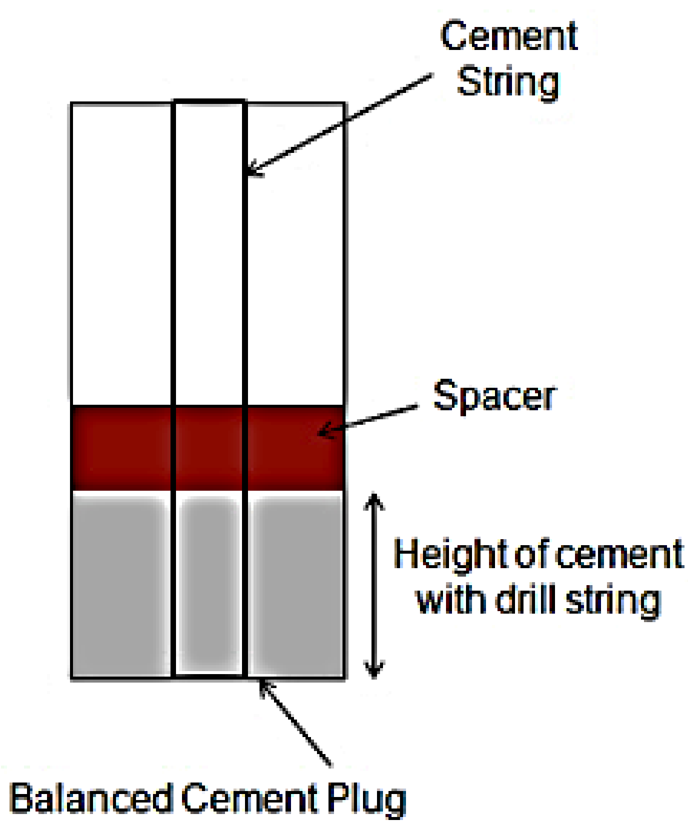


Figure 19 - Balanced plug principle.

An illustration of a centralizer is seen in Fig. 20. The use of centralizers is important in the balanced plug method, especially for deviated wells. Casing centralizers are used for many different reasons, but the main purpose is to keep the casing positioned at the center of the well in deviated or crooked holes. It would be very difficult to balance the fluids inside and outside the pipe without centralizers.

Figure 20 – Centralizer.

The cement plugs set in P&A operations are set at specific places in the well and rarely at the bottom of the wellbore. A common problem related to this has been the downward movement of the cement after placement. Because the cement slurry usually is more dense than the well fluid the cement slurry tends to move downward the wellbore leaving the TOC deeper than anticipated [32]. This could lead to contamination of the cement and the quality of the cement is degraded. This can be avoided by use of mechanical devices or by placing a fluid with high gel strength as a base. Mechanical plugs or bridge plugs are used to provide a mechanical barrier between the heavy cement slurry and the less heavy well fluid. A diverter tool is a tool that is used in a combination with a gelled fluid. It is placed on the tip of the pipe and it helps to keep the cement slurry at its specified place. The tool consists of two umbrella- shaped parts that changes the flow of the fluids from vertical and downward to horizontal and upward [33]. When the diverter tool is surrounded by fluid, the tool will not be able to create any movement or collapse by the fluid interface. Fig. 21 shows how the cement is contaminated without any use of a diverter tool and how the cement and fluid is separated when a diverter tool is used.

It is relevant to emphasize that this diverter tool is not a hydraulic barrier but it works as a floating piston. If there are any losses further down in the wellbore the diverter tool will move downwards with the flow of fluid.

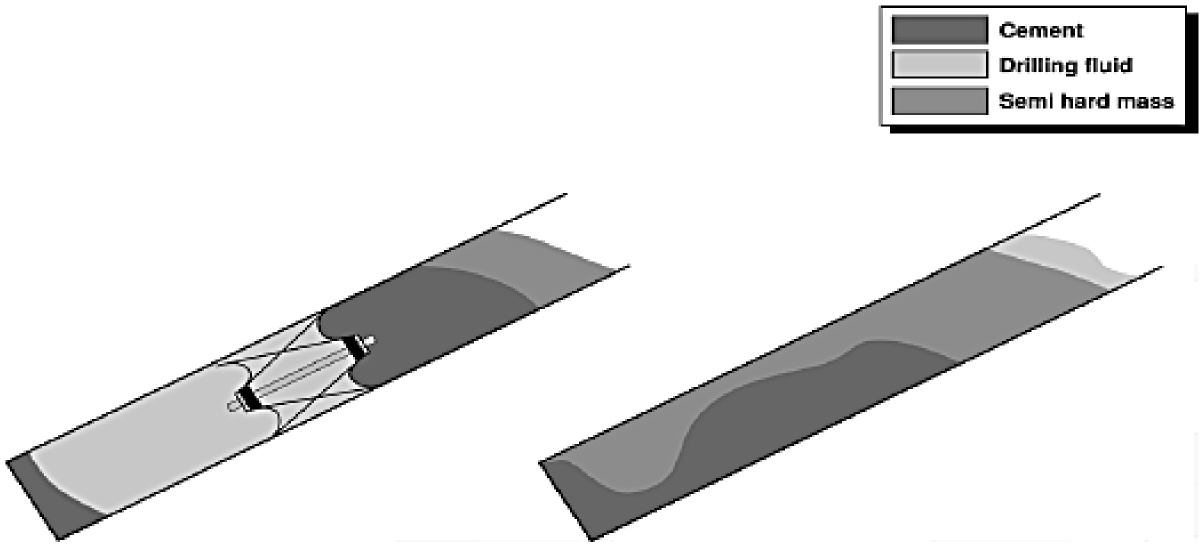


Figure 21 - The illustration shows the differences in cement placement when a diverter tool is used downhole and when it is not used. The picture on the right side shows a cement placement with a diverter tool and the one on the left side shows a cement placement [32].

5.2.1.1 Critical Placement Factors

The placement of a successful balanced cement plug is a challenging task and lots of different factors have to be taken into consideration. Many studies, on how to plan and perform the balanced plugging operation, have been carried out and they sum up the main considerations that have to be taken related to this operation. The main concern when setting a balanced cement plug is contamination of the cement. Any contamination of the cement slurry used downhole for plugging operation will have a severe effect on the hydration of the cement slurry. It may lead to longer hydration time of the cement or sometimes the inability of the cement to set. As little as 10 % contamination of the cement slurry shows that the WOC can be increased three to five times. Contamination of the slurry will also reduce the final compressive strength of the cement. Fluid contamination is a complicated process including not only the volume of each fluid, but also the chemical interaction between the fluids with temperature and pressure changes. It gets more complicated the deeper the well is because the volume of the displacement fluid becomes much larger than the volume of the cement slurry, and hence the contamination becomes more severe. Often the only solution to avoid cement contamination in deep wells is using physical barriers, such as a spacer. The mechanical barrier separates the slurry and the displacement fluid and contamination is avoided. According to Diaz et al. [34] there are four main sources of contamination for the fluids in a plug cementing operation:

1. Contamination in flow down the working string
2. Contamination in flow up in the annulus
3. The effect caused by the pipe as it is pulled out the hole
4. Fluids swapping at the base of the plug due to failed support

Contamination of the slurry as it travels down the pipe can be the major source of cement contamination, especially in deep wells. The intermixing between the different fluids depends on hole deviation, the internal geometry of the pipe, flow velocity and the rheological properties of the fluids. If no actions are taken to avoid this, premature set cement or stuck tubing stinger may be the result [35]. Contamination may be avoided by using a spacer, foam ball or darts.

Another source of contamination occurs when the pipe is pulled out of the hole. As the pipe is pulled out of the cement an intermixing with different fluids in annulus may occur. To avoid this problem it is normal to underdisplace the cement. There are many reasons for underdisplacement. It may be difficult to calculate the displacement volume and an overdisplacement of the cement slurry may lead to severe contamination of the cement. To avoid overdisplacement accurate calculation of the displacement volume is necessary, but there are many factors that make this calculation uncertain. The actual conditions downhole are often different from an ideal situation;

- When a stinger is used the diameter is not uniform.
- The diameter in openhole sections is not uniform.
- The internal pipe diameter is often unknown due to wear and cement layers in the pipe.
- When the fluids are subjected to pressure the volume will decrease. It is assumed that the thermal expansion will compensate for this reduction, but this assumption is very unsure.
- Lost-zone will make the calculations even more uncertain.

An underdisplacement of the cement volume, as seen in Fig. 22 will lead to a contaminated cement at the top of the plug. This mixture of cement and spacer will be circulated out before the cement sets. If the cement slurry develops a too high yield strength before the stinger is pulled the TOC may be situated at a lower depth than anticipated. It is normal practice in the industry to underdisplace by one to five barrels at the end of the displacement to allow for the fluid interface to balance themselves while pulling out of the hole.

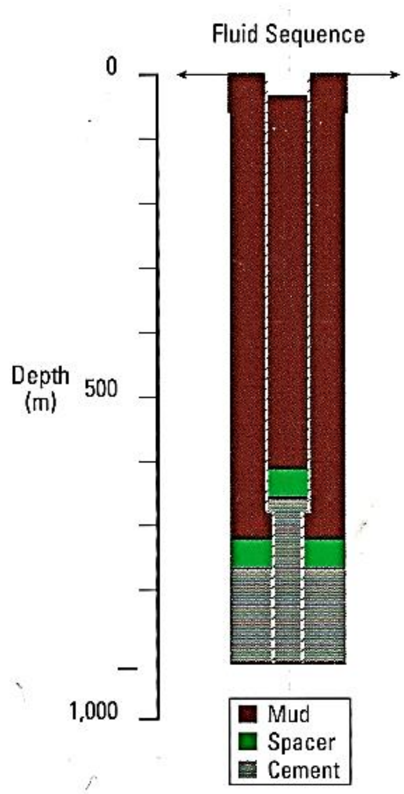


Figure 22 - Underdisplacement of cement [21].

Yet another common contamination issue is the placement of a heavy weight cement plug on top of a light weight mud. When a heavy weight cement slurry is left on top of a light weight mud it will form an unstable interface which will tend to flow due to gravitational forces. The intermixing of the mud and cement occurs differently in deviated and vertical holes. In Fig. 23 we can see how the heavy weight mud tend to move its way down the rathole creating a stationary layer at the cement/mud interface. The intermixing in vertical wells progresses in a totally different manner. As seen in Fig. 24 the slurry is roped from the bottom of the plug in a circular pattern. The flow continues until the leading edge of the cement slurry reaches the bottom of the hole leading to a helical pattern of cement and mud. For large volumes of cement this will lead to a small but competent cap of cement on top, but smaller volumes of cement will usually not develop a competent plug at all. For thinner muds the slurry would tend to pile up in the middle until it reaches a state of equilibrium [36]. The mud and cement mixture tend to gel or thicken upon contact and may in some cases lead to a stable cement plug, but quite often the plug is soft. Several things can be done to avoid this problem; Reduce the density difference between the cement slurry and the drilling fluid, increase the yield point and/ or the gel strength of the drilling fluid below the cement plug and place a spacer between the cement slurry and the spacer.

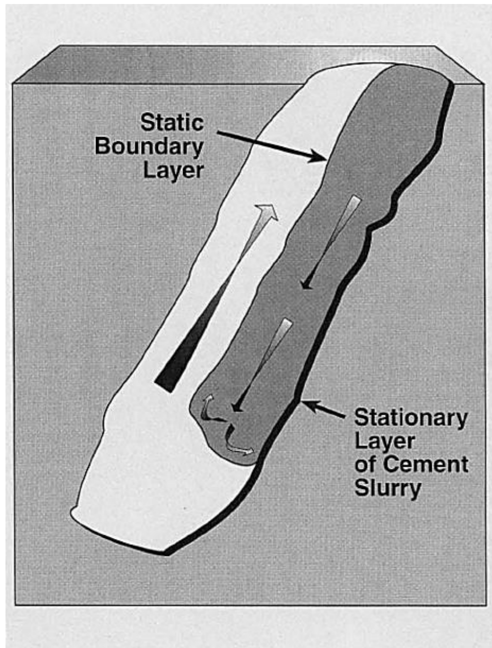


Figure 23 - Fluid intermixing in deviated holes [36].

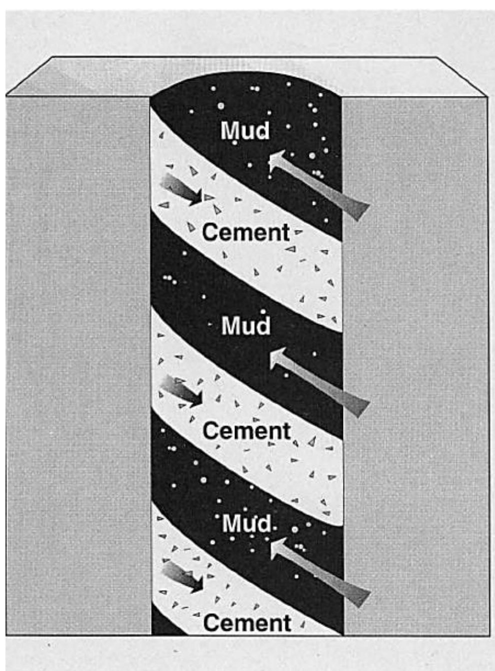


Figure 24 - Spiral flow pattern caused by intermixing of fluids in vertical holes [36].

Drilling on the NCS is often performed in HPHT and highly deviated wells. This complicates the balanced cement plug setting and it is often difficult to plan and execute a successful plug placement. The downhole conditions are challenging and difficult to predict, and hence placement-calculations become very uncertain. A study [34] on using a placement simulator software along with best practice recommendations greatly improved the success rate of the plug placement. The best practice recommendation is shown in App. 2. The main purpose of the computer software is to determine the challenges related to each job, to determine the depth of the top of the uncontaminated cement after placement, to determine the efficiency of each placement technique by investigating the reduction in cement contamination of other fluids and to allow for a mitigation of wet pipe pullout [34]. Since contamination is the main concern during the plug placement it is essential for the engineer to determine which method provides the least contamination of the cement slurry. The only elements that the engineer is able to control due to prevention of contamination is the rheological properties, densities and pumping rates, and with these inputs into the computer the engineer is able to display the resulting in-pipe contamination and vary these inputs to design the most suited operation. The software evaluates the best method to optimize the slurry and spacer interfaces and it calculates the underdisplacement volume that is best suited due to the desired pull out of hole (POOH) depth. The software allows the engineer to simulate pumping with and without a mechanical barrier and provides the risk of contamination in each case. The software is able to provide a visual and quantitative representation of the fluid mixing during placement and the impact on the cement due to this mixture. The design phase process of the plug placement operation is shown in Fig. 25 and is briefly described below. The model contains four main activities [34];

1. Contingency planning:
   In some openhole situations the need for a sidetrack is necessary. This is usually not known in advance, but the engineer should always predesign the fluid system with this in mind.
2. Data gathering:
   When it has been decided to place a plug the engineer needs to collect data for the software simulation. The required information for building a model is; well geometry and hole conditions, drilling fluid properties, working string availability, kickoff point depth and bottomhole temperatures. The latter is extremely important in HPHT wells.
3. Building the model:
   When the required information have been gathered and put into the computer model the fluid volumes and densities for flushes and cement slurry can be defined.
4. Sensitivity analysis:
   The length of the uncontaminated cement plug will provide support for the sidetrack and so the engineer runs different scenarios, changing the cementing fluids specifications, to determine the maximal length of the plug.

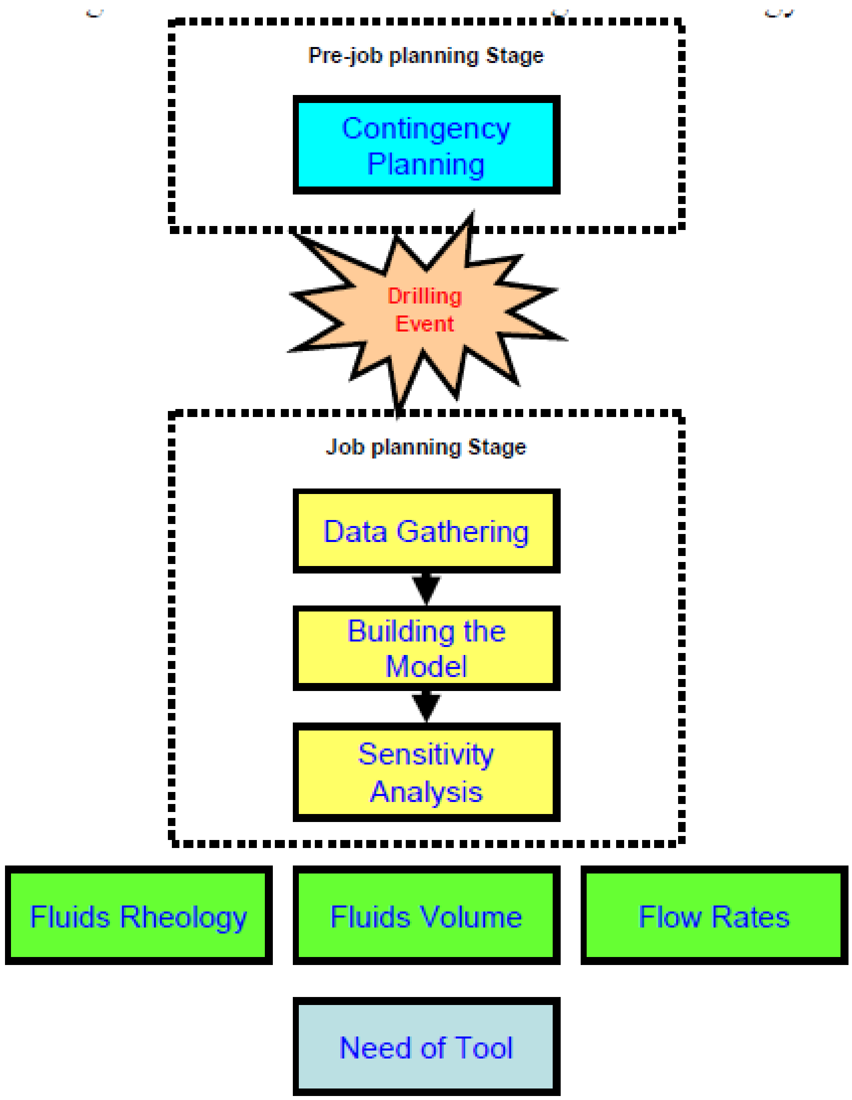


Figure 25 - Work flow of the design phase [34].

5.2.2 Dump Bailer

The dump bailer technique is usually used for shallow depths. It allows the placement of small amounts of cement by using Wireline (WL). A dump bailer is a small vessel that holds the cement slurry. Usually a permanent bridge plug is set just below the point of the desired plug interval. The dump bailer is lowered down the wellbore and when it reaches the bridge plug it is opened either electronically by the WL operator or mechanically by tagging the bridge plug.

When the dump bailer is raised again the cement slurry is placed on top of the bridge plug as seen in Fig. 26.

The cement is often static in the dump bailer, during descent, so special cement slurry- design considerations must be taken. Premature development of gel strength is undesirable and may occur while the cement is still inside the bailer. Gel strength development is the internal rigidity of the cement system and it can prevent the slurry from flowing out of the bailer. White et al. [37] found that a delayed-gel-strength additive would successfully add viscosity to the slurry and at the same time inhibit settling during descending of the bailer. In addition the gel strength development was delayed so the slurry could easily flow out of the bailer when it reached its placement depth. The additive is also non-retarding to the cement slurry so it is applicable over a wide temperature range.

The advantages of using the dump bailer method is that it is relatively fast and inexpensive, the depth control is good and it reduces the chance of cement contamination. The disadvantages are the depth limitations, the cement limitations due to the size of the bailer and the WL expenses are often higher than the pumping charges.

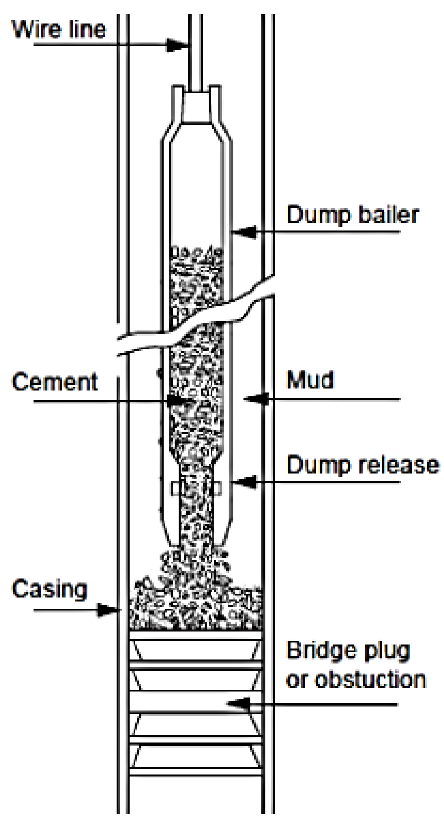


Figure 26 - The dump bailer method [38].

5.2.3 Two-Plug Method

Two-plug method, or single-stage cementing, is the most common plug placement technique used today. Using of a special tool, often called the cement head, the cement is pumped with high accurately to a calculated depth with minimum contamination of the cement. The tool, placed at the lower end of the drillpipe, usually consists of an aluminum tailpipe, a bottom wiper plug (which contains a dart or a ball) and a top wiper plug [21]. The procedure is shown in Fig. 27 and is executed as described below:

1. The casing is circulated clean before the cement operation begins.
2. The bottom plug is released and pumped down to clean the inside wall of the casing. A spacer follows the bottom plug before the cement slurry.
3. The top plug is pumped ahead of the cement slurry to prevent any contamination of the cement from the displacement fluid.
4. Then the displacement fluid is pumped to place the cement at the desired location
5. WOC.

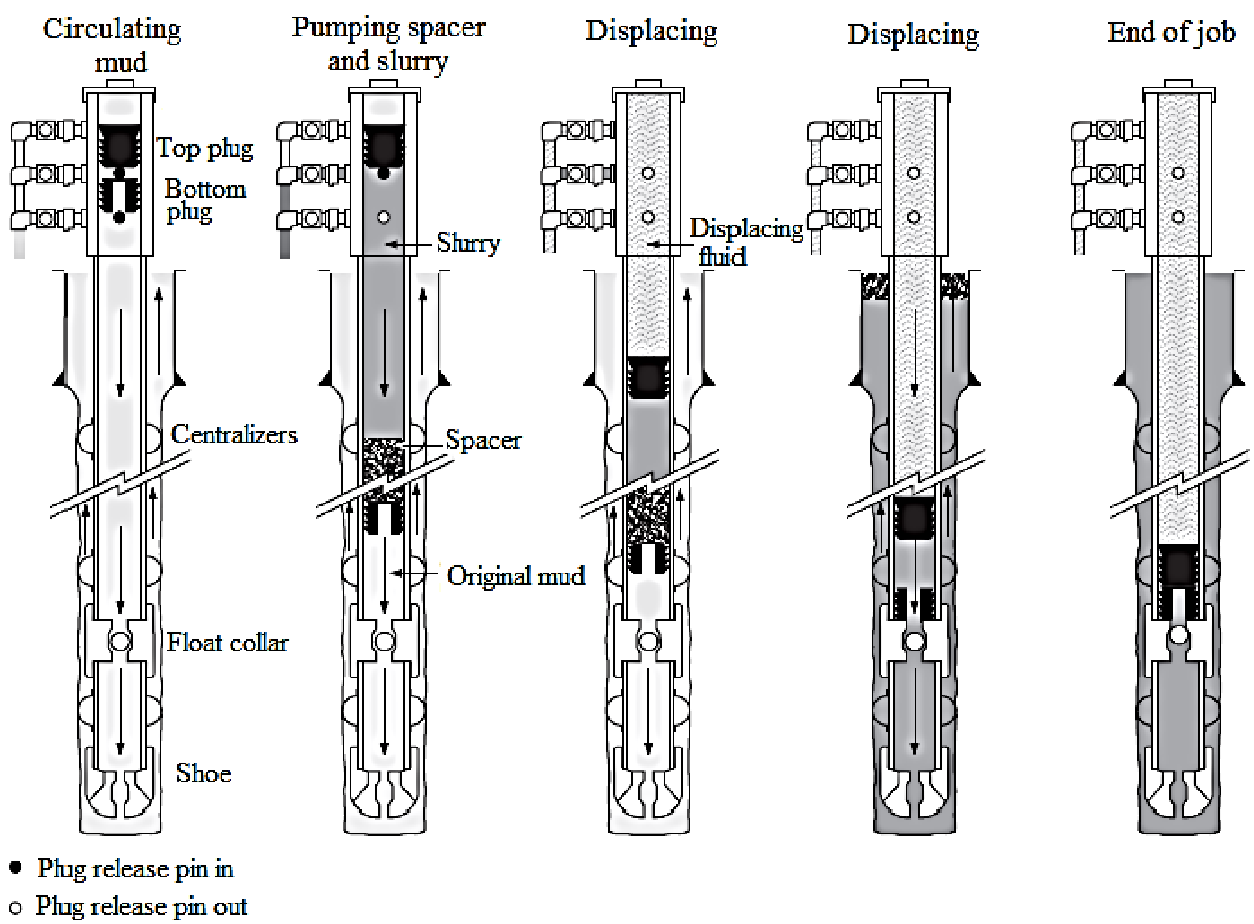


Figure 27 - Two-plug method [38].

When enough pressure is applied to the top plug, which has landed on the float collar, it will rupture and the spacer and the cement slurry is allowed to flow through the plug, around the shoe and up the annulus. When the bottom plug lands on top of the top plug the displacement will stop. Fig. 28 shows the different configurations of the bottom plug and the top plug. The top plug is solid to prevent contamination of the cement.

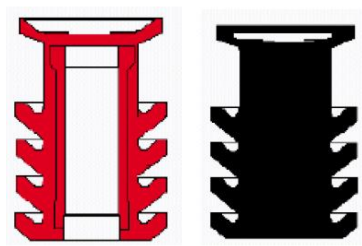


Figure 28 - The bottom plug (left side) is hollow and the top plug (right side) is solid [38].

The cement operation should be carefully monitored to ensure that the formation has not been broken down. The volume of the displacing fluid should be calculated ahead of the cement operation and the mud return from annulus, after complete displacement, will give an indication of any formation breakdown. If the mud return slows down or stops too soon this will be an indication of a breakdown, and further action should be taken.

6 Evaluation

6.1 Cement

It is important to choose the most appropriate tool and method in order to achieve the best evaluation of the cement sheath. In order to determine the presence and the integrity of the cement the tool needs to be operative under the specific wellbore conditions and there are lots of factors to be considered for obtaining the most accurate results; casing size, well deviation, fluid type and fluid weight during the logging operation. Some reservoir properties are also of great importance; the water contact in the given area, the drive mechanisms and the isolation between the productive zones.

Misinterpretation of the given log response is a big pitfall for getting the correct information out of the log. An adequate interpretation of the cement job- evaluation can only be achieved when there is correspondence between the expected and the actual log response. Knowledge about the well and casing, the cement-job events and the pre- and post-job well history is of great importance for achieving this. For the log to be trustable quality control should be a natural part of the cement- job evaluation. This includes measurements repeatability and calibration summary [21]. The environment the tool has to operate under is often very harsh so the log should be repeated over a selected interval to verify that the given information is credible. If the reading is the same for both runs the information can be assumed to be valid.

The most traditional tools and methods that have been chosen for the evaluation of the cement jobs are the sonic Cement bond log (CBL) and the Ultrasonic tool. When we combine these two tools we will in most cases achieve the most accurate logging of the cement sheath and the bonding between the cement/pipe and/or between cement/formation. Both sonic CBL and Ultrasonic cement evaluations are defined as acoustic logging measurements. The response of the acoustic logging tool is related to the acoustic properties of the surrounding environment; casing, fluid, cement and formation [21]. Acoustics is the science of sound and for logging operations this means the propagation of sound waves. The propagating wave in acoustic measurements could either be longitudinal waves or shear waves as seen in Fig. 29.

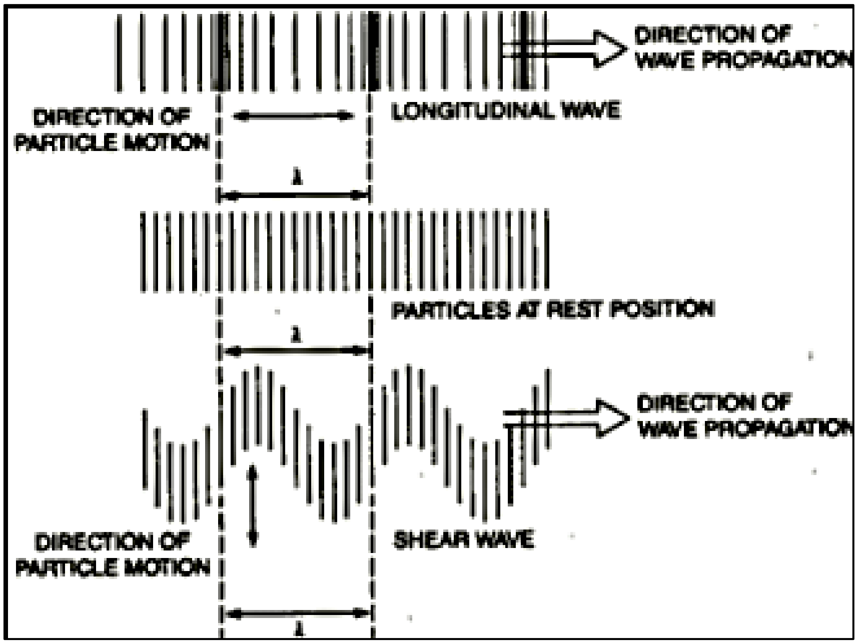


Figure 29 - Illustration of propagation of longitudinal and shear wave[28].

The main difference between these two wave modes is their direction and their applications. Shear waves needs an acoustically solid material to propagate and therefore are not transmitted through fluids or gasses. This is why shear waves are of main interest in logging.

6.1.1 Cement Bond Log

The CBL tool was the first tool that was used to quantify the vertical isolation of the cement sheath. The intention of using this tool is to evaluate the hydraulic seal. It measures the loss of acoustic energy as it propagates through the casing. This energy loss can be related to the fraction of cement that is in direct contact with the casing. The acoustic tool is logging the amount of cement bonded to the casing and is capable of detecting channels in the cement of type I and II as seen on Fig. 30. In combination with the Ultrasonic tool it is one of the most used tools in the oil industry today.

The main objectives of performing a CBL are to determine:

1. The presence or the absence of cement over a certain depth interval.
2. Whether cement is bonded to the pipe, the formation or both.

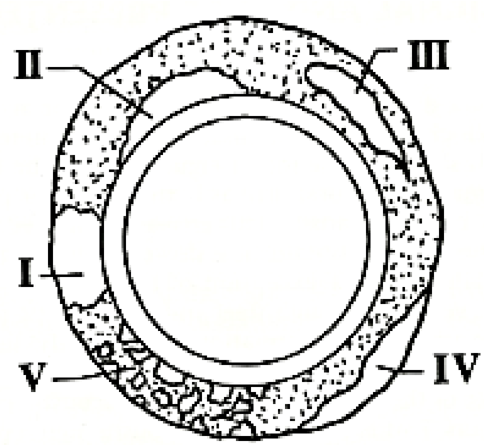


Figure 30 - Different types of channels that can be developed in cement [39].

The traditional CBL tool consists of a transmitter and one or two receivers. A part of the tool is also several centralizers to make sure the transmitter/ receiver in the tool always stay in a centered position. This is important for the tool to function properly. The transmitter sends a compressional wave in all direction and when these waves pass the different materials they will be influenced by the specific material as seen in Fig. 31. The different materials will affect the wave velocity, amplitude and frequency of the original compressional wave sent out by the transmitter. When the wave strikes the inside of the casing wall parts of the wave will be refracted and continue its way down the casing. The portion of the wave that is refracted by the casing wall will determine the amplitude and transit-time first seen on the log. Parts of the original wave will continue straight down the pipe through the mud, but despite its shorter travel-path this wave will arrive at the receiver later than the former one because sound travels faster in steel than in fluid. Another part of the original wave will refract into annulus and into the formation. The logging system will record the waveform created by the vibration and log them along with the pipe-amplitude.

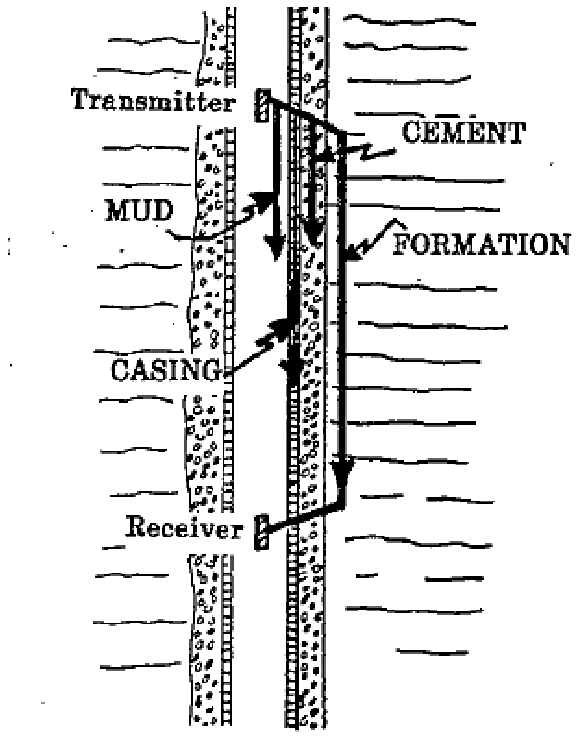


Figure 31 - The cement bond log tool principles [40].

The waves detected at the receiver are normally either compressional waves or shear waves. As the waves propagate through different materials it will lose some energy due to shear coupling with the specific material; the greater the shear coupling, the greater the loss of energy into the specific material. The shear coupling to the formation is low and constant and fluid has no shear coupling, so the signal will not be affected by this. The loss to annulus is the variable and hence the focus of our interest.

6.1.1.1 The Pipe Amplitude

The amplitude measurements hold information about the amount of energy received at the receiver. During propagation through the different mediums the wave loses energy. This energy loss is termed "attenuation". The attenuation rate is linearly related to the percentage of the casing circumference bonded by the cement [21]. A bond index is calculated from the measured amplitude to determine the percentage of bonded cemented area. The percentage bonding ($I_{\%\ bond}$) can be calculated using Eq. 6-1

$$\mathrm{I}_{\%\ \mathrm{bond}} = \frac{\mathrm{E}_{\mathrm{fp}} - \mathrm{E}_{\mathrm{meas}}}{\mathrm{E}_{\mathrm{fp}} - \mathrm{E}_{100\%\ \mathrm{cement}}} \qquad \text{6-1}$$

where E_{fp} is the free pipe amplitude reference dependent on the fluid in the annulus, E_{meas} is the measured CBL amplitude and the $E_{100\%\ cement}$ is the CBL amplitude corresponding to 100% bonding of the plugging material or the formation to the cement.

Fig. 32 shows the general interpretation of the amplitude curve. High amplitude will often imply that the pipe is relatively free to vibrate. This is an indication of a poorly or unsupported bonding, meaning that there are mud or other liquids behind the pipe. If the well is cemented this will give a low amplitude. There are some conditions that may give rise to incorrectly amplitude interpretations and that may require that the logging engineer modifies the general interpretation rule. Some of these conditions are:

- Gas bubbles – will decrease the acoustic signal.
- Microannulus – increases the amplitude.
- Tool eccentering – reduces the amplitude.
- Changes in pipe thickness – may give different amplitude magnitudes.
- Void spaces in the cement sheath – will increase the amplitude.

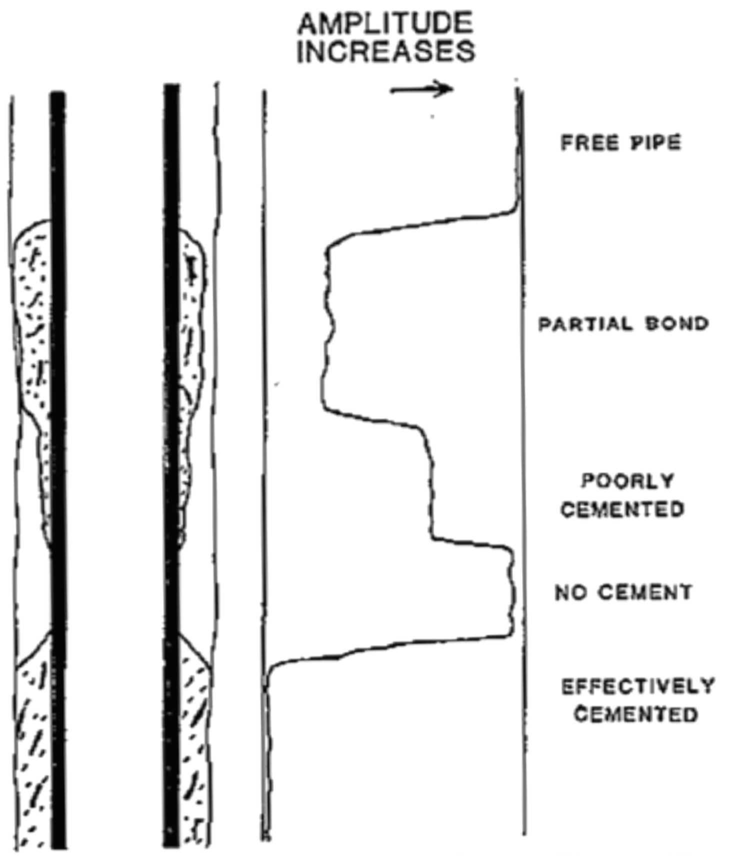


Figure 32 – General interpretation of the Amplitude curve [40].

6.1.1.2 Quantitative Measurement

There are two ways to quantify bond logging; by transit-time and by considering the wave amplitude. In both methods the half-cycles derived from the amplitude-logging are labeled E_1, E_2, E_3 etc. where odd numbers refer to the positive peaks while the even numbers refers to negative peaks. E_1 represents the first casing signal. The perception in quantitative bond logging is that the strength of the casing signal is affected by the material closest to the casing. There are many different ways to perform this operation and this may result in completely different curves depending on the chosen method.

The transit time is the time it takes from the transmitter sends out a signal until the first signal reaches the receiver, see Fig. 33. This measurement will be used to check the centralization of the tool. For a well-centered tool the log will show a straight value for the uncemented pipe except for threaded and coupled casing collars. This measurement requires the engineer to set a threshold detection level to avoid random noise. This is normally done while running in hole with the tool, and the threshold value is normally set below 50% of the maximum free pipe amplitude [40]. The transit- time curve does not give any specific information about the cement, but it is a valuable quality control. The measured transit time is compared to the expected transit time and the following information can be found:

- Shorter transit time: could be an indication of either poor centralization of the tool or a fast formation.
- Slightly longer transit time: is often an indication of good bonding and should be consistent with low amplitude.
- Longer transit time: is called cycle skipping and is often a result of good bonding between cement and casing.

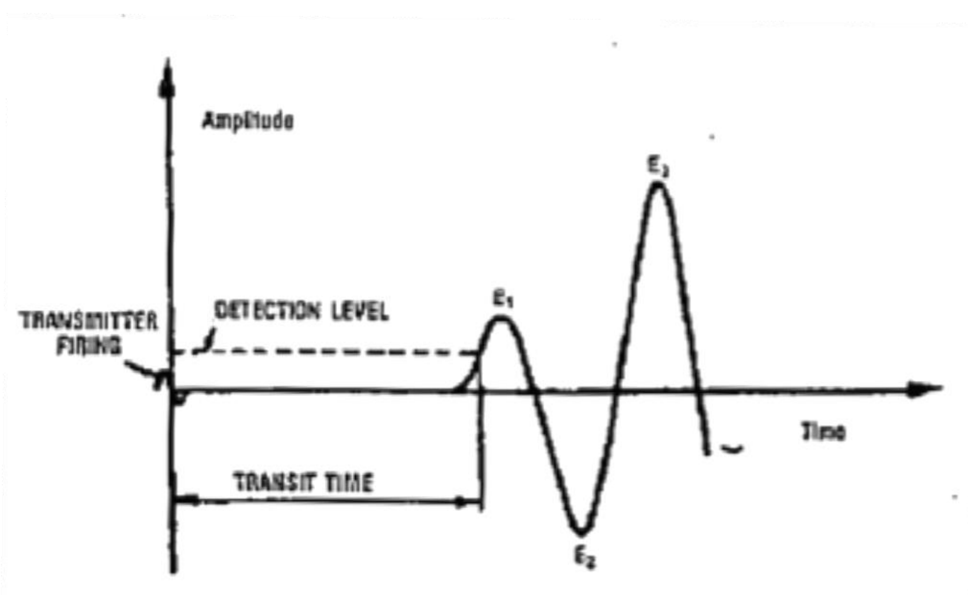


Figure 33 - Transit time measurement [40].

Measuring the wave amplitude is the second quantitative measuring method. This measurement can be carried out in two ways, either by using a fixed gate or a sliding gate. The most common method is to use a fixed gate where the time interval is held constant relative to the moment the transmitter is fired. To make sure the most precise window is chosen for this measurement the gate is set in the least-bonded interval of the pipe, but the gate must be reset due to changes in the pipe size and in pipe weight. Setting a correct gate is of the utmost importance for obtaining a valid amplitude curve.

6.1.1.3 Variable Density Log

Information about the waveform received at the receiver can be displayed in two ways; as a full waveform or in a variable intensity display. As shown in Fig. 34 the full waveform shows the actual waveform as observed on the log. It might be difficult to interpret the given information due to intermixing of the waveforms so this presentation is rare today. Instead the variable density log (VDL), showing the amplitude in varying shades from white to black (or in different colors), is often used today. The general interpretation of the VDL today is that disturbances along the logging path, like formation or cement, will give rise to positive amplitudes. On the VDL positive amplitudes becomes darker as they increase. For uncemented pipe, with fluid in annulus, the VDL will often show straight lines with lighter colors.

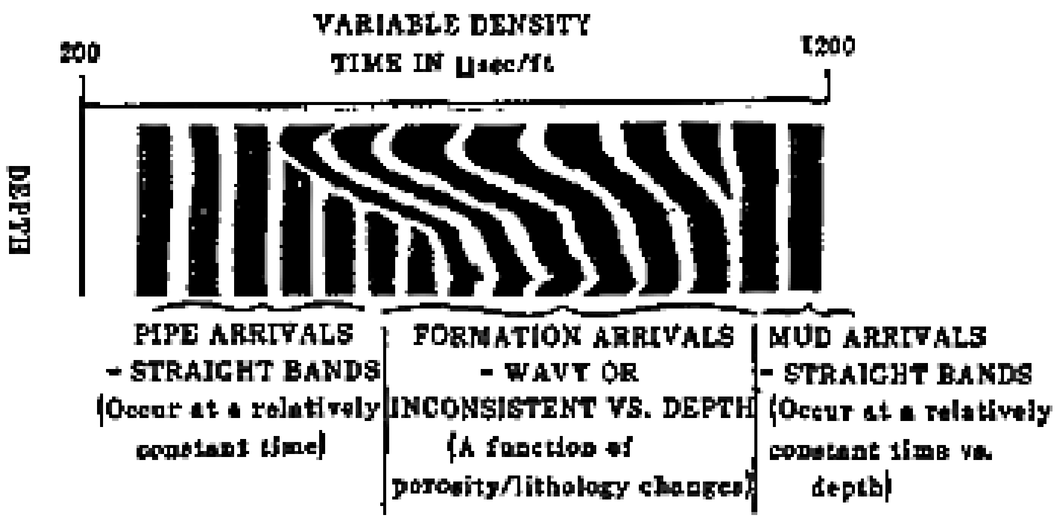


Figure 34 - A general interpretation of the waveforms on the variable density log [40].

Fig. 34 shows a general interpretation of a VLD. It can often be difficult to distinguish the different wave patterns from each other, but if the pipe, formation and the mud can be identified on the VLD, a practical determination of the presence or absence of cement can be determined.

6.1.1.4 Comparing the different logs for the CBL

Fig. 35 shows an example of how the wavetrain, the VDL and amplitude appear at different conditions downhole. The uppermost part shows how the acoustic signal “rings” loud where there is free pipe. This signal dominates totally due to the acoustic impedance mismatch between the pipe and the fluid outside [39]. Acoustic impedance is the product of a materials density and the velocity of sound through that material. One can therefore assume that different materials, like water, drilling mud, cement or gas exhibit constant acoustic impedance [41]. The signal is trapped inside the pipe and little energy leaves the pipe. At the bottom section the bonding is good so the casing is not free to move and hence the pipe signal is low. In intervals of the pipe where only parts of the pipe are bonded, both pipe and formation signals may be seen.

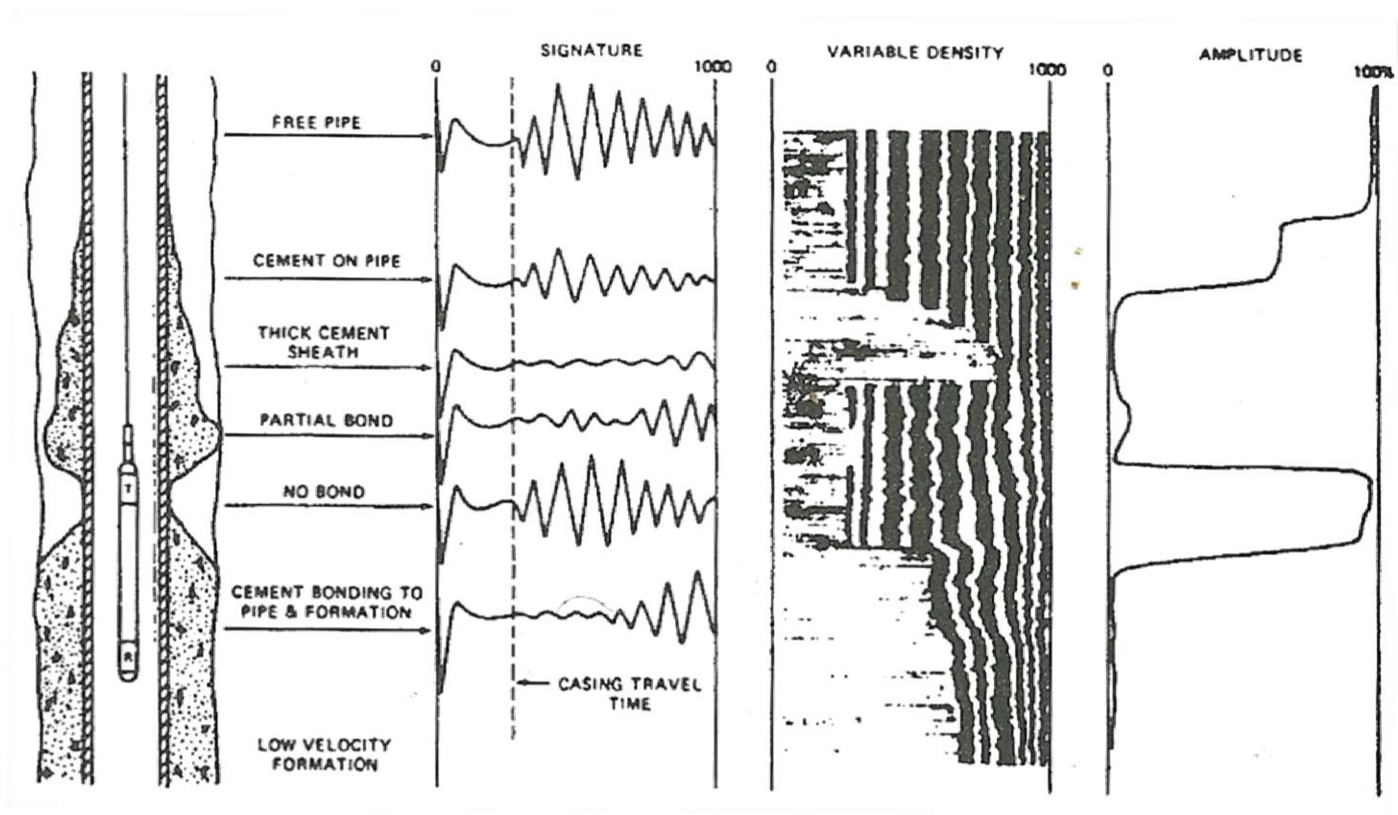


Figure 35 –Cement bond log; comparison of wavetrain, variable density log, and amplitude for different cement conditions [39].

6.1.1.5 Challenges Related to CBL

The interpretation of the CBL is dependent on the amplitude of the first wave arriving at the receiver. Usually low amplitude is an indication of cement while high amplitude indicates free pipe. This general rule of interpretation along with the tool configuration, give rise to some challenges.

- The CBL tool needs to be centralized at all time to ensure a simultaneous first arrival from all directions.
- Because of the necessity of good shear coupling to the cement a microannulus (even a very small one) between the pipe and the cement will appear as bad bonding on the log even though this annulus between the pipe and the cement is hydraulically secure.
- The omnidirectional characteristic of the tool makes it difficult to distinguish a high-strength cement with a channel, from a low-strength cement because the amplitude will often be the same in both cases.
- The compressional velocity in hard formation will often be larger than the one in steel so the first arriving wave will no longer be the casing wave, hence the calibration is no longer valid.

6.1.2 Ultrasonic Cement Evaluation

The Ultrasonic cement evaluation was first introduced in the beginning of the 1980's to overcome the challenges related to the classical CBL. The main issues related to the CBL that these pulse echo tools shall overcome are; verification of a good hydraulic-bond in the presence of a microannulus, achieve sufficient circumferential resolution to permit the detection of channeling and if possible to achieve an evaluation of the formation bonding [42]. A microannulus is a small fluid-filled gap between pipe and cement which occurs after the pressure inside the pipe is released when the cement sets.

There are mainly two different tools that have been developed for this purpose. The first-generation tools consist of the cement evaluation tool (CET) and the pulse echo tool (PET), while the second-generation tools consist of the ultrasonic imager (USI) and the circumferential acoustic scanning tool - Visualization (CAST-V).

The principle idea of the Ultrasonic technique is to make the casing resonate in its thickness mode [43]. The tool sends out a short pulse of ultrasound and records the echo containing the resonance. The lack of cement behind the casing will tend to "ring" while the presence of cement behind the casing will tend to damp the resonance. Since the wave motion is normal to the casing wall shear coupling becomes unimportant and microannulus has little effect on the measurements. There is however some limitations related to the ultrasonic method as well. The

Ultrasonic technique is restricted in heavy mud because of attenuation of the relatively high-frequency ultrasound and pipe rugosity and roughness can affect the cement measurements. So the Ultrasonic technique is not a replacement of the sonic technique, but rather a supplement to it.

6.1.2.1 Cement Evaluation Tool

The configuration of the CET is shown on Fig. 36. The tool consists of eight transducers that are arranged in a helical spiral around the sonde, 45° from each other. Each transducer measures an area of the wall about 1 in. in diameter. A ninth transducer is placed in the axial direction and is used to measure the speed of the sound in the borehole fluid. The transducers are fired in sequences with an ultrasonic pulse of about 500 kHz. The ultrasonic transducer sends out a wave towards the casing wall and the main part of this wave is reflected back to the transducer as seen on Fig. 36. The wave passes back and forth between the transducer and the casing wall and every time it reflects from an interface it loose some energy. The series of waves that is returning to the transducer is the basis for the interpretation of the pulse echo tool. The frequency and the amplitude of the oscillations are dependent of the impedance of the fluid in the borehole, the casing and the cement behind the casing. There is a linear relationship between the impedance and the compressive strength of the casing. The signal from all the transducers can provide information about the cement quality.

The configuration of the CET provides examination of the casing circumferentially at each depth and it is the impedance behind the casing that is measured. The measurements detected by the tool are dependent on the acoustic impedance of the cement. The acoustic impedance can be transformed into cement compressive strength and so the tool is calibrated to present the measurements in terms of cement compressive strength which enables a presentation of the cement distribution around the casing [43]. The CET provides different outputs from its measurements [43]:

- The mean diameter is determined from the average of the eight transit times
- The casing ovality is given from the difference between the largest and the smallest diameters and gives indication of casing corrosion, wear or collapse.
- The tool centering is measured to ensure proper centralization inside the casing.
- The compressive strength will provide information about the medium behind the casing.

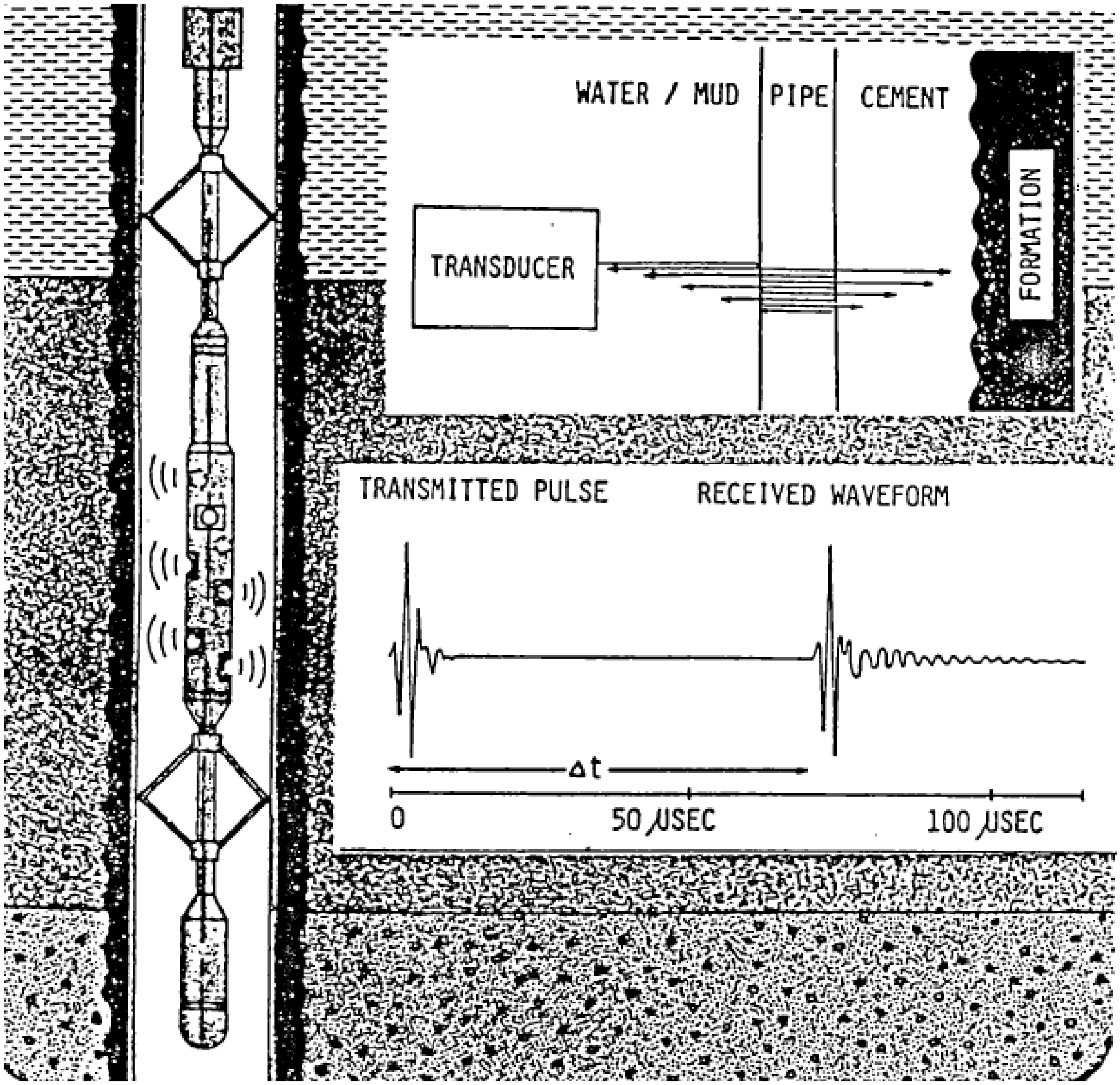


Figure 36 – Cement evaluation tool configuration on left side and the reflected wave signal on right side [44].

6.1.2.2 Ultrasonic Imager

USI is another rotating pulse echo tool, but it is an improvement of CET in the sense that is provides a nearly 100% coverage of the casing wall. The processing of the USI is quite different from the CET. As seen in Fig. 37 the USI has a rotating transducer positioned at the bottom of the tool. The transducer functions as both sender and receiver. After the transducer has sent out an ultrasonic pulse it will switch over to receiver mode and the echo of that pulse will be detected by the same transducer. Logging samples can be taken as frequently as every five degree rotation and 1,5in. of depth [39].

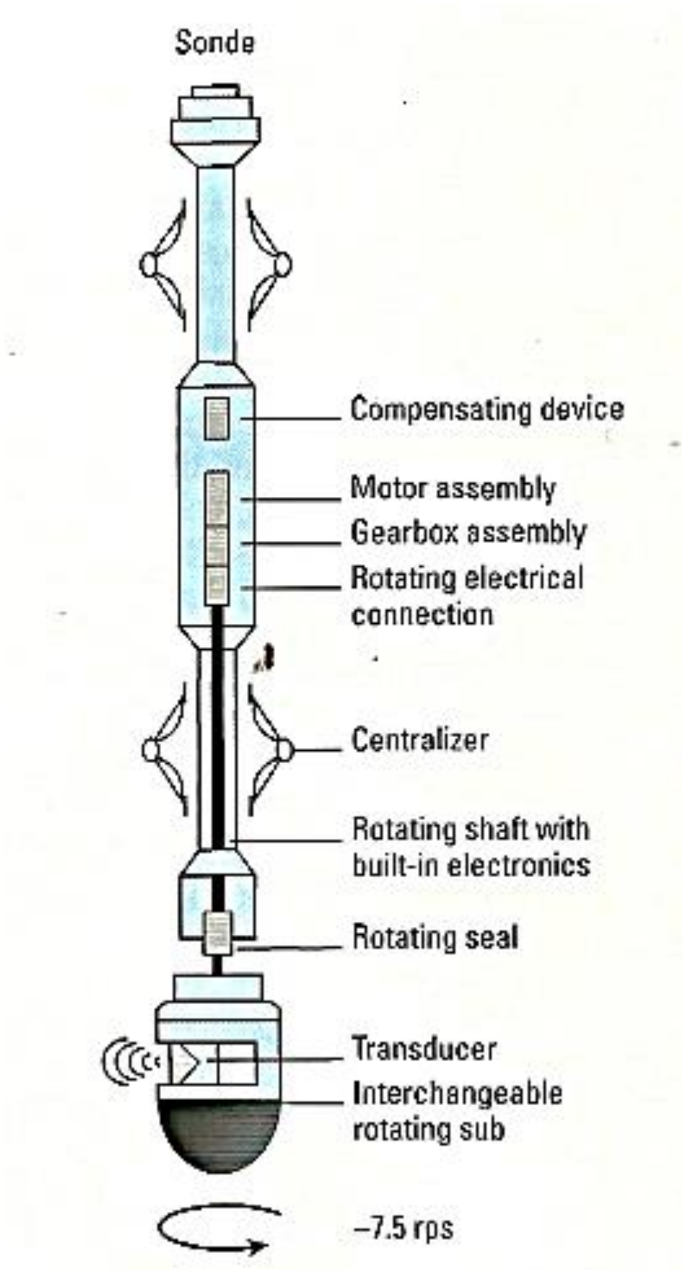


Figure 37 – Ultrasonic Imager Tool [21].

Four measurements are provided by the USI as seen in Fig. 38:

1. The Echo amplitude provides information about the casing condition.
2. The Internal radius is calculated from the transit time of the echo.
3. The Casing thickness is calculated from the resonant frequency.
4. The Cement impedance behind the casing is calculated from the form of the resonance.

The cement evaluation is based on the acoustic impedance. The amount of reflected and transmitted energy depends on the acoustic impedance of the materials at the interface and can be calculated from the following Eq.:

$$Z=\rho v \qquad 6\text{-}2$$

Where Z is the acoustic impedance, ρ is the bulk density ν is the acoustic velocity. The acoustic impedance is usually expressed in units of MRayl (1 Rayl = $1\mathrm{kg.m^{-2}.s^{-1}}$) [45]. The impedance is calculated the same way for the 1^{st}. generation Ultrasonic tool.

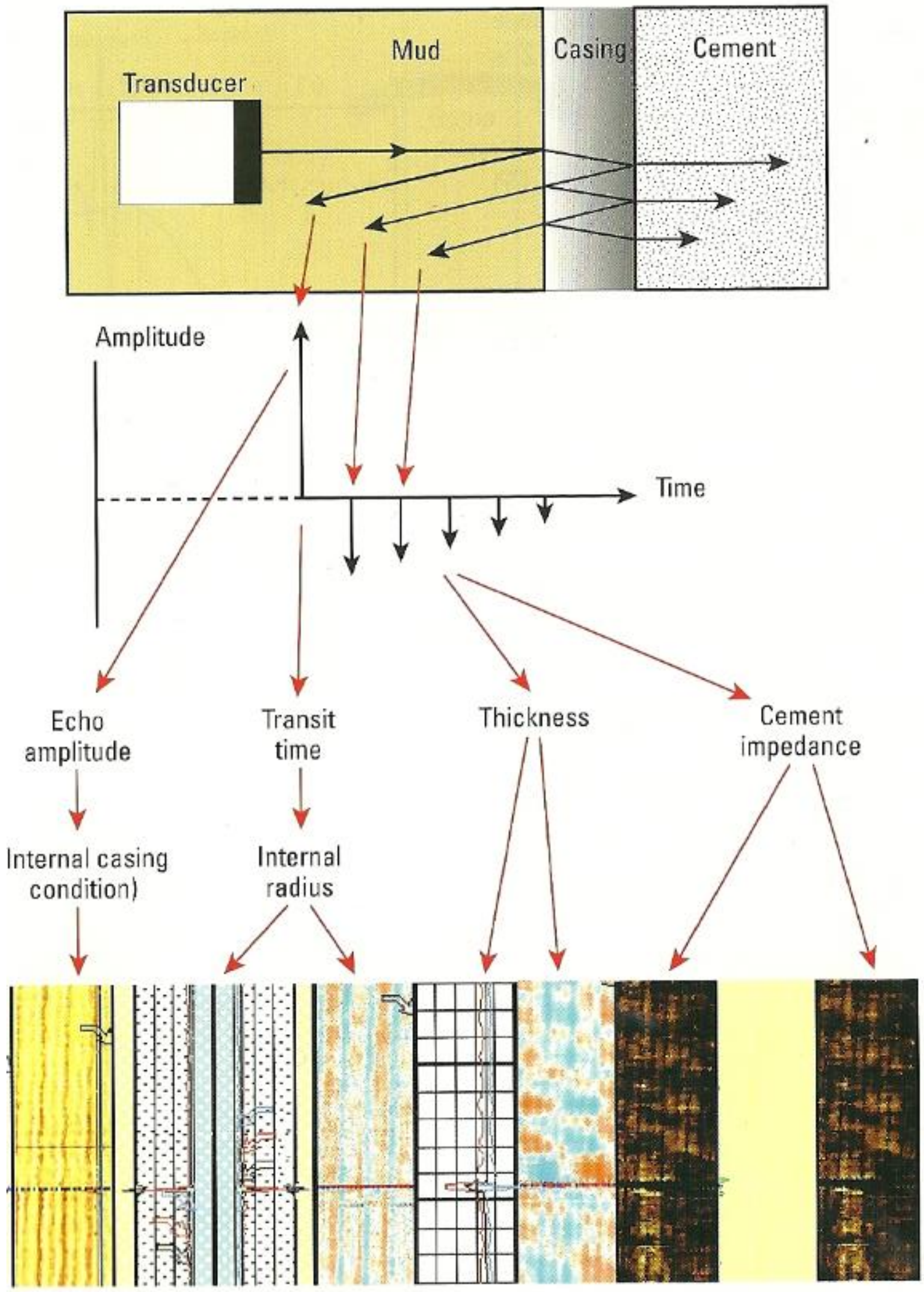


Figure 38 – Ultrasonic wave path and measurements [21].

Like the CET, USI emits a wave perpendicular to the casing, and the reflected waves are logged. The emitted wave will travel through the wellbore fluid before it strikes the casing wall. Most of the first wave is reflected back to the transducer, but a small fraction of the energy continues into the casing. This process will continue and the wave will lose a small fraction of energy for each turn. The amount of energy that is transmitted and reflected is dependent on the difference in acoustic impedance across the casing wall. The acoustic impedance of the casing and the well fluid is approximately constant so the reflected signal is dependent on the material behind the casing. Fig. 39 shows the different ultrasonic responses in the annulus when water and cement are present behind the casing. When the reflected signal reaches the transducer high amplitude is detected, and the signal gets weaker and weaker for each turn.

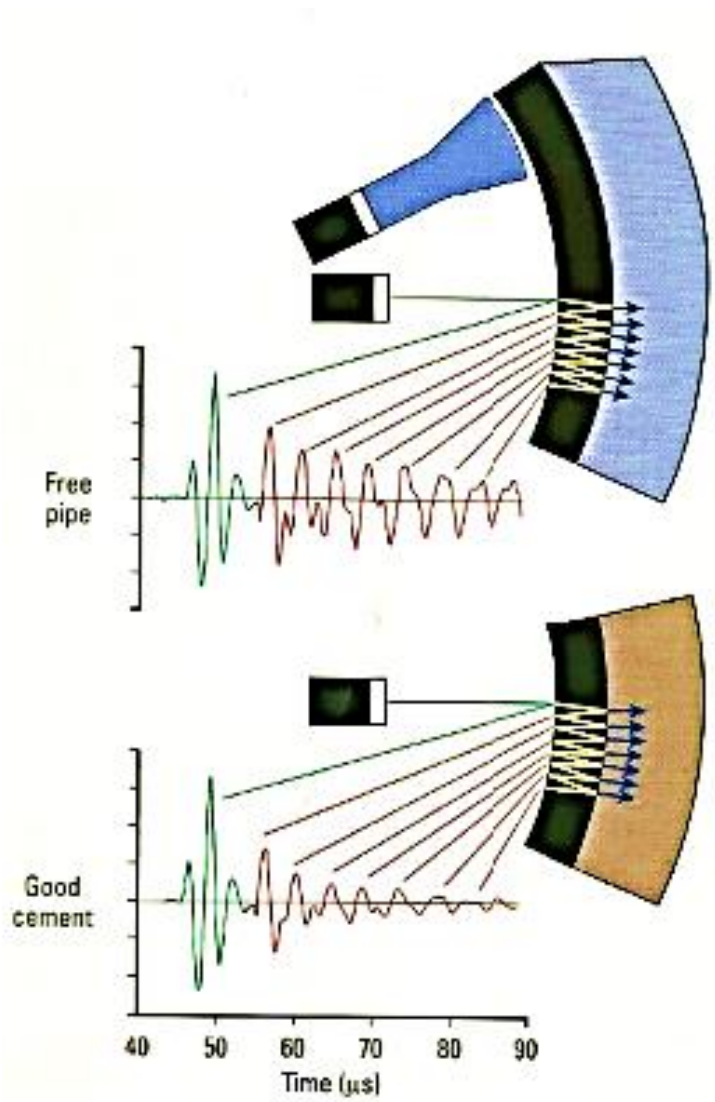


Figure 39 - Ultrasonic response to different materials in the annulus [21].

6.2 Shale

Traditional sonic and ultrasonic bond logging can show solid material behind the casing far above the theoretical top of cement (TTOC). Clear correlation in the log pattern to shale can give an indication of the presence of shale behind the casing. In this way traditional bond logging, used for cement evaluation, can give a clear answer whether the formation has sealed off the annulus.

According to Williams et al. [46] the following observations on the bond log will support the assumptions about formation displacement:

- Good bond log response far above the top of the theoretical cement.
- Good quality bond correlates with shale rich intervals.
- Large and sometimes frequent changes in bond log response at the same depth as geological changes.
- Above the casing shoe of an outer casing string the log response changes from good quality bond to free pipe as the formation can no longer impinge onto the inner casing string.
- Sinusoidal patterns on ultrasonic bond log images imply geological beds impinging on the outside of the casing.

To make sure the observed shale on the bond log is sufficiently strong to act as a barrier it must be pressure-tested. The pressure test must be performed below or nearby the potential barrier, and the test pressure must exceed the maximum expected pressure the barrier potential may be exposed to. Normally the pressure test will be performed with the leak-off pressure. When a pressure test has shown a successful result for a shale- horizon this test result can be used in subsequent wells. This means that a bond log response is adequate for the shale to be qualified as an annular barrier. The pressure test can be performed in many ways, and some of these methods are described by Williams et al. [46]:

- Perforate the casing at the base of the potential barrier identified from logs. Apply pressure in the well until either a pressure response is seen at the casing annulus at surface, or a leak-off response is seen.
- Perforate the casing at the base of the potential barrier identified from logs. Perforate the casing at the top of the potential barrier. Run a test string and packer. Set the packer between the perforations. Apply pressure in the test string until either a pressure response is seen at the test string annulus, or a leak- off response is seen.
- Run a cased hole formation tester with pump-in capability. Make a hole in the casing at the base of the potential barrier. Monitor formation pressure to ensure no connectivity to other pressured zones. Pump into the hole until leak-off pressure is reached. Repeat the measurement to ensure good quality.

7 Operational Procedure for Plug and Abandonment

Describing the procedure of a P&A operation is not a straight forward task. Neither written literature nor engineers working within this field can give a straight forward description of this process. How the P&A operation needs to be carried out is dependent on several factors; the well condition, the cement status, the numbers of potential inflows, type of well and more. According to NORSOK D-010 [5] the following information should build a basis for the well barrier design and abandonment program:

1. Well configuration (original, intermediate and present) including depths and specification of permeable formations, casing strings, primary cement behind casing status, well bores, side-tracks etc.
2. Stratigraphic sequence of each wellbore showing reservoir(s) and information about their current and future production potential, where reservoir fluids and pressures (initial, current and in an eternal perspective) are included.
3. Logs, data and information from primary cementing operations in the well.
4. Estimated formation fracture gradient.
5. Specific well conditions such as scale build up, casing wear, collapsed casing, fill or similar issues.

Even though each P&A job has to be planned and carried out in its own way there are certain steps that most P&A jobs include and that will be discussed in the following subsections:

- Determining well conditions
- Test surface equipment
- Prepare the well for Plug and Abandonment
- Kill the well
- Pull the tubing and the upper completion
- Wellbore cleanout
- Log, cut and pull casing and set plugs
- Remove upper part of surface casing and the WH and cover the hole

7.1 Determining Well Conditions

Before starting the P&A operation it is required to know the potential inflow from both reservoir and overburden. In addition to the producing reservoir, other formations with flow potential at shallower depths must be identified and taken care of. According to NORSOK D-010 it is not stated what a potential inflow is, but Statoil sets a permeability above 0,1mD to be considered a potential inflow. When the potential inflow in the well has been determined the setting depth of the plugs must be determined. The plugs must be set with their base at a depth where the upward pressure does not exceed the fracture gradient of the formation. How this is determined was described in Ch. 3.6.2. The cement status at these depths needs to be established prior to the P&A operation. In order for the operator to determine the quality of the annular cement, logs need to be run in the well. These logs are able to determine whether the annular cement is good or if the formation has collapsed around the casing. Sometimes the conditions present in the wellbore result in the barrier being placed at a depth where the casing is uncemented. In order for the barrier to cover the whole cross section of the wellbore the most common operation is to section mill this interval and place cement over the whole interval. As described in Ch. 7.7.1 section milling is considered an unpopular operation in the industry during P&A operations today. A new technique for cement placement in the annulus has been developed and is growing in popularity. This technique is called a perforate, wash and cement (PWC) systems and is addressed in Ch. 7.7.2

7.2 Test Surface Equipment

Prior to any activities taken place during the P&A operation the surface equipment and the wellbore equipment, that act as barrier during the P&A operation, must be tested. During the well intervention the surface equipment will function as both primary and secondary barrier and it is important that their integrity is verified. Every barrier elements that may be exposed to pressure should be tested for functionality and integrity.

7.3 Prepare the Well for Plug and Abandonment

When the WL equipment has been installed the downhole safety valve (DHSV) can be retrieved. All wells on the NCS are required to have a DHSV installed minimum 50m below the seabed. A DHSV is installed in the upper part of the well to provide emergency shut-down in case of an emergency. There are two types of subsurface safety valves available: surface-controlled and subsurface controlled. Both types are designed to be fail-safe, so in case there is any system failure or damage to the surface control facilities the wellbore will be isolated. Fig. 40 shows the DHSV in open and closed position.

After the DHSV has been retrieved the WL rig-up will deal with the well pressure.

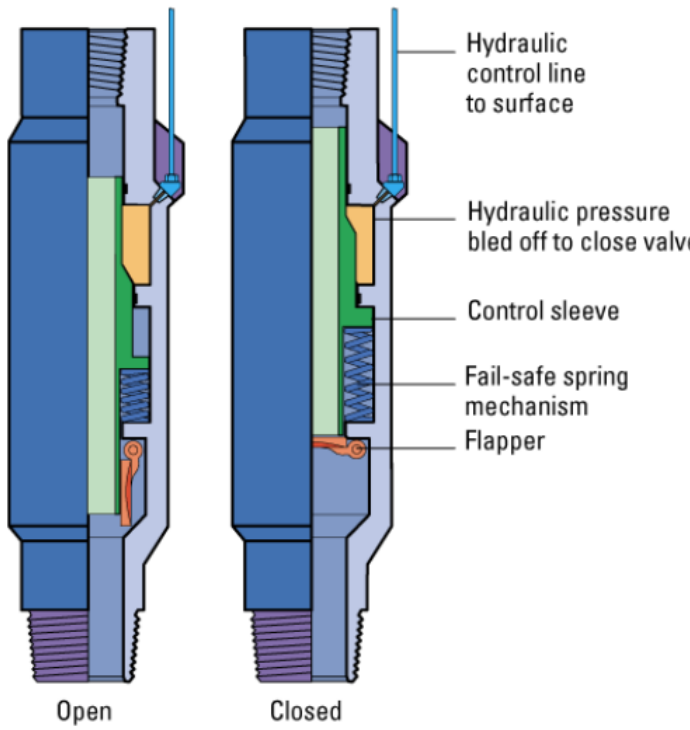


Figure 40 - The Down Hole Safety Valve in open and closed position [47].

The wellbore is inspected using a slickline unit to check for any obstructions in the well, check the wellbore geometry and to confirm MD. A slickline unit is a machine that consists of a hydraulically controlled spool of wire used to place and retrieve tools and flow-control equipment downhole. The slickline unit can also be used to pull the safety valves in case this is needed. During production the tubing might be damaged due to several events that can take place; collapses, corrosion, erosion or scale deposits. Wear during interventions and lack of maintenance may lead to serious damage to the tubing that might be crucial for the plugging operation. The tubing is a primary barrier element and cleanouts might be required prior to a plugging operation. In addition the tubing must be tested before plug placement. This is done by placing a plug downhole to isolate the tubing from the reservoir, expose the tubing to pressure and monitor to see if the pressure holds.

7.4 Kill the Well

Before the well is ready for the plugging operation the well needs to be killed. Well killing is carried out by placing a column of heavy fluid in the wellbore to prevent any flow of reservoir fluids without the need of using pressure control equipment at the surface. The procedure is based on the principle that the weight of the kill fluid will be high enough to overcome the pressure of the reservoir fluids. It is however important that the pressure that builds up during the killing process does not exceed the WH pressure rating, tubing or casing burst pressures or the formation gradient, cause this will in best case lead to a very insufficient kill job [48]. There are several methods to perform the well kill operation, but reverse circulation and bullheading are the two most common methods.

Reverse circulation is performed by pumping kill fluid down the annulus and up through the tubing just above the production packer. This requires a communication point, often a perforated interval, through were the kill fluid can travel. The kill fluid will displace the lighter wellbore fluids and leave behind a well full of kill fluid.

Bullheading is the process when fluid is pumped into the well against pressure [48]. When bullheading is used to kill the well the kill fluid is pumped down the well to compress the fluid in the tubing. This way the wellbore pressure will exceed the reservoir pressure and the gas leaks back to the formation. Pumping of kill fluid will continue until all of the gas has been displaced and the tubing is left with only kill fluid. Now the WH pressure has vanished and the plugging can start. Since the volume that is required to kill the well is limited, i.e. approximately the tubing plus wellbore volume, bullheading is a quick and efficient way to kill the well.

7.5 Pull the Tubing and the Upper Completion

Most offshore wells consist of a conductor, several casing strings, the production packer and lots of downhole tools to complete the well. Fig. 41 shows an example of how the lowest part of a well can look like. The interval below the production packer is referred to as the lower completion. During P&A operation this interval is often plugged, while the tubing and the completion above this packer is pulled out of the hole (the lower completion can be retrieved if necessary) prior to plug placement. In some cases it might be difficult to pull the tubing. One possibility is to cut the tubing above the packer and leave the tubing in the well.

Figure 41 - Lower completion [49].

When well completion tubulars are left in the hole there is a need to use reliable methods and procedures to install and verify proper barriers inside and around the tubulars. According to the “guidelines for the suspension and abandonment of wells”, given by Oil&Gas UK [50] there exists no accurate method of determining TOC in both tubing and annulus. One method to confirm the presence of the barrier is to combine tagging with quality control of the cement and pressure testing of both annulus and tubing. Quality control could be; measurements of volumes/losses, base for plug, cement density or strength development. Fig. 42 shows an example of a through tubing abandonment. It must be emphasized that the required length of cement on the figure is based on UK requirements and that the requirements for the NCS differ from this sketch.

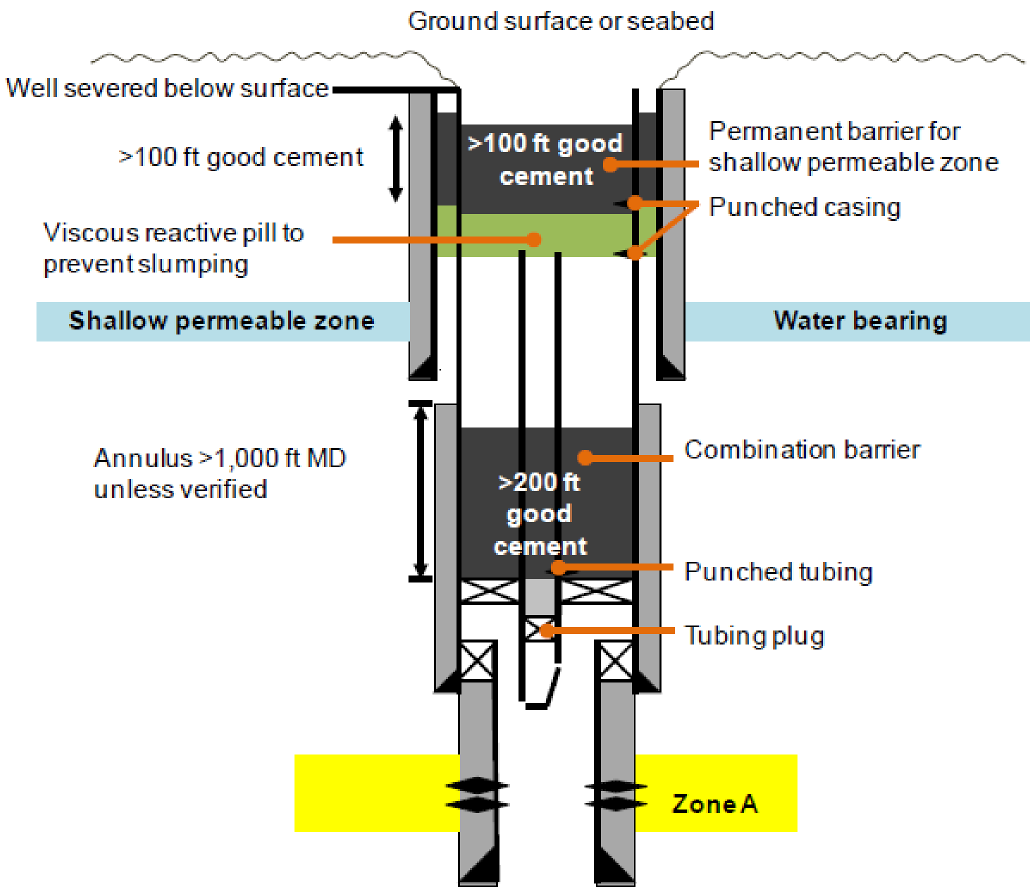


Figure 42 - A through-tubing cased hole abandonment [50].

7.6 Wellbore Cleanout

When the tubing and the upper completion have been removed the wellbore must be cleaned with cleaning fluids down the tubing and up the annulus to remove sludge, fill, scale and other debris that fill unplugged perforations. Cleaning the wellbore prior to plug placement is a critical activity in the P&A operation because seals within the wellbore can shift if sludge or other material moves after cement placement [51]. The cleaning fluid used for cleaning the wellbore is required to have a sufficient density in order to control the subsurface pressure. It must inhibit physical characteristics capable of removing unwanted material [52]. It may be necessary to use additional tools or additives for proper cleaning. High-pressure jetting system has proven to be an efficient and environmental friendly method for cleaning the wellbore, because the generation of waste is kept to a minimum.

7.7 Log, Cut and Pull Casing and Set Plugs

Where and how the different barriers (to plug the reservoir, other potential inflows and the surface barrier) are placed downhole for P&A is dependent on many factors described previously in this text. What kind of material to be used, what kind of placement technique to use and at what depth to place the plug is based on the regulatory restrictions of that particular area and the well condition at the time of P&A. Logs are run in the well to determine the quality of the annular cement. If these logs show sufficient cement according to requirements cement plugs can be placed inside the casing, and then the annulus cement, casing and the cement plug will function as one barrier. If the planned plugging interval shows poor or no cement bonding in annulus the casing needs to be cut and pulled before plug placement. Usually section milling or use of a new technique called PWC is carried out to complete this operation.

7.7.1 Section Milling

The traditional way of placing a cement plug in intervals of the well without cement behind the casing is by removing sections of the casing by milling, cleaning the open hole from swarf (swarf is the metal filing or shavings when cutting through the casing) and other debris, and placing a balanced cement plug in the open hole section. In section milling, the milling tool is lowered to the desired depth before cutting knives are extended, to cut through the section wall. Next the knives mill down to remove the casing, in addition to any cement, settled mud or debris present. There are several challenges related to this operation and it is an unpopular operation during P&A due to many reasons:

- It is a time consuming operation leading to high cost (rig time)
- The process of lifting the swarf to the surface requires a highly viscous drilling fluid to be used during the milling operation. The density of the swarf-laden fluids are usually greater than the fracture gradient in open hole resulting in an equivalent circulating density (ECD) above the fracture gradient. This may lead to lost circulation, swabbing, poor hole cleaning and packing off the bottom hole assembly (BHA). This again may lead to sticking of the milling tool, clean out or underreaming BHAs because not all swarf, cement or other debris may be removed from the hole.
- Surface equipment may easily be damaged when metal-laden fluids pass through it.
- Challenges related to health, safety and environment (HSE) due to handling and disposal of the generated swarf and debris. The returning metal often has sharp surfaces and personal protection must be worn by the operating personnel to protect skin and eyes. In addition large amount of metal debris require special surface handling equipment.
- Testing of the set cement plug placed using section milling is a challenge. There are two ways to place a cement plug when section milling: 1) By leaving the TOC inside the casing above the milled window, or 2) By leaving the TOC in the open hole [53]. When the TOC is found inside the casing the cement can be tagged, weight tested and then pressure tested. This method will only give information regarding the quality of cement inside the casing and no determination of the quality of the cement in the annulus or in the open hole. When the TOC is left in the open hole the position of the plug can be verified with tagging, but in most cases it is impossible to do a pressure test. Both scenarios will not provide any information of the sealing capability of the plug.

In order to overcome some of the challenges addressed above the industry has re-developed the tools used in section milling. Fig. 43 shows the tool used for section milling, the old cutting design and the new cutting design.

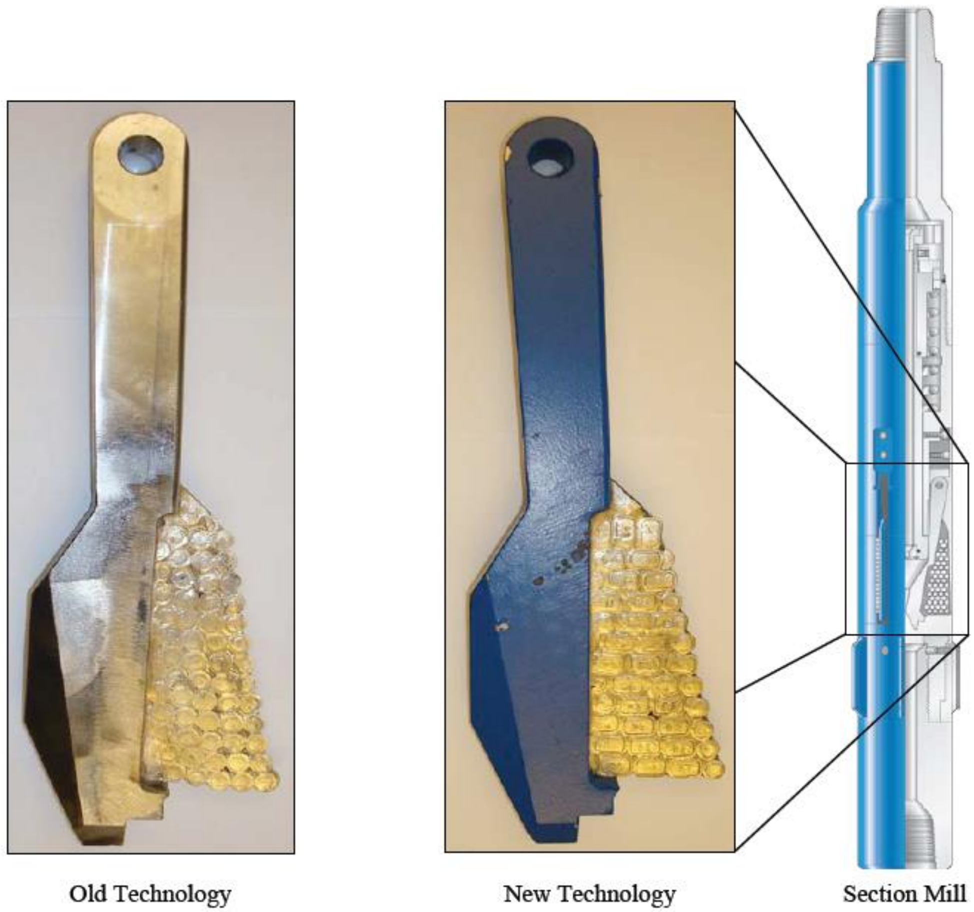


Figure 43 - Old cutter design, new design and section milling tool [54].

The milling tool is composed of several knives on pivots that are rotated out of the tool body with a hydraulically activated cone. Circulation pressure provides adequate force required for the knives to mill through the casing. When the knives have cut through the casing they are locked in the extended position and with weight, applied from the surface, the desired interval is milled. According to NORSOK D-010 the required interval that needs to be milled prior to plug placement is 50 m. Tungsten carbide is the best material available for downhole steel cutting or milling tools and it has been used for this purpose since the 1930s. Carbide cutting material, with randomly shaped pattern, used to be the main building blocks of the cutters, see Fig. 44.

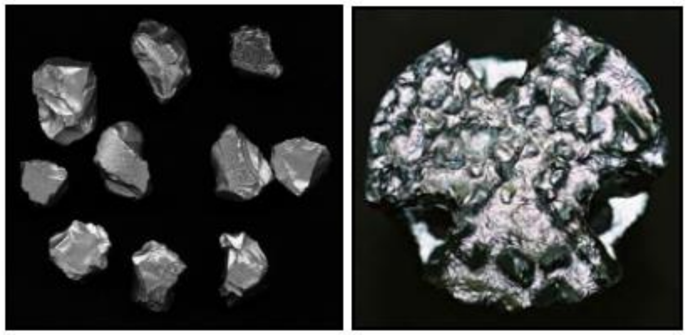


Figure 44 - Randomly shaped particles used for milling tools [55]

Today tungsten carbide powder is mixed with cobalt powder to form a powdered metallurgical structure. The new material is formed to perform like crushed carbide, but it is no longer randomly shaped. Several different shapes of the cutters have been evaluated before the latest one was introduced as the most optimized one. The latest cutter design is seen in Fig. 45. The new shape provides a more even loading of the cutters compared to the round shaped cutters. The new cutter exhibits a much higher level of impact resistance and hence a longer life. This means that fewer trips have to be included in order to complete the milling operation. In addition the new design of the chip breakers on the cutters delivers smaller, more consistent cuttings in some cases [55]. The smaller cuttings are more easily circulated back to the surface, reducing the chance of pack-offs during the milling operation.

Figure 45 - New cutter design [55].

Downhole optimization sub is another new application that has been developed to improve the milling operation. The optimization system consists of an optimization sub, power and a communication sub and is placed directly above the section mill, placing the sensors only 15 ft. away from the milling blades. The optimization sub gathers downhole information like weight on tool, torque, RPM, bending moment, vibrations, pressure and temperature to get a clearer picture of what happens around the section mill [55]. The downhole measurements are transmitted to surface for evaluation. When the real-time ECD and pressure-data are monitored pack-offs can be recognized and located, and appropriate actions may be taken before pack-offs take place.

7.7.2 Perforate, Wash and Cement

A new system has been introduced as a better alternative to section milling. A new system known as PWC was developed to eliminate many of the problems related to section milling. As seen in Fig. 46 the lowest part of the tool (right side) consists of a 50 m pipe-conveyed perforating gun with 12 shots per foot in 135/45 degree phasing [53]. The perforating gun is used to perforate the designated interval. When the perforating, wash and cement tool (PWT) has reached the desired plug setting depth the guns are fired. The jetting tool, just above the perforating gun, consists of two or four swab cups with nozzles in between. The swab cups are placed with a distance of 0.3 m between, and they will function as a seal during the washing operation. This will force the washing fluid to travel through the perforation. The short distance between the swab cups will optimize the washing operation. The tool will move upward and downward while a circulating fluid with high velocity washes the inner casing surface, the outer casing surface, formation wall and the annulus removing old mud, formation cuttings and settled mud weighting material. After the perforated interval has been sufficiently cleaned it is time to cement the perforated interval.

Figure 46 - The perforate, wash and cement tool.

The PWC operation can be conducted as a single trip, a two trip or a three trip operation. If there is sufficient space below the PWT the perforating gun and the washing tool can be released and left in the rathole, and hence the operation can be executed in a single trip. If the interval, where the cement is to be placed, is very deep much time will be saved on not tripping out and in of the hole to remove these parts of the tool. A cement stinger is revealed when releasing this tool. A two trip job is one where the pipe is POOH and the perforating gun is released before the washing and cementing tool is run in hole (RIH) to complete the job. In a three trip job the pipe is POOH twice removing first the perforating gun and then the washing tool before the hole is cemented.

The cement is placed at the desired depth as a balanced cement plug. Depending on the cement job design, the cement can then be squeezed into the perforation and the pressure maintained until the cement has fully set. Unlike section milling the PWC system procedure creates an abandonment plug which can be verified in the annulus. After placement of cement the plug can be drilled out and the annulus cement can be logged to provide competence verification. After the verification of good cement in annulus a new cement plug is placed inside the casing to regain cross sectional integrity.

The benefits of using a PWC operation over section milling are many. In addition to allowing for the verification of annulus cement the PWC system provides a safer working environment for the operating personnel. The PWC system limits the exposure of swarf and metal associated with milling. It also reduces the need for additional surface handling equipment due to the milling debris. It has also been proven that significant time and money are saved by using the PWC technique over section milling. Several jobs performed with either section milling or PWC system shows that an average time of 7,9 days per set plug is saved when using PWC system instead of section milling [53].

7.8 Remove Upper Part of Surface Casing and Wellhead and Cover the Hole

The focus on reducing rigtime, by making the different activities required for P&A of a well more efficient, have led to the development of several tools and techniques that are able to cut and recover either the casing string or the WH in one trip. Usually three or more trips were required to remove each intermediate casing. The first trip was required to retrieve the casing hanger seal from the WH. On the second trip the casing was cut and a third trip was needed to remove the casing and the casing hangar from the well. This three-trip operation would have to be repeated for each intermediate casing string [56]. After all the intermediate casing strings had been retrieved, the conductor string was cut and the WH was recovered. Another focus when developing the “cut & pull” technology was the ability to remove the WH without damaging it. Subsea WH equipment is costly and the operators would like to recover them for reuse in other wells [3]. Minimizing or eliminating the damage to the polished bore or the internal diameter profile is essential, because this is where the seal assembly and other equipment are seated. Several tools and techniques that address these issues, are available today, and two techniques that will be presented are the abrasive water jet cutting and the multi-function fishing tool. The multi-function fishing tool is one out of many tools used for casing strings and WH recovery on drilling rigs, while the abrasive water jet cutter is applicable for vessel sand subsea cutting and recovery, making it a cost efficient alternative compared to the tools that requires a drilling rig.

According to NORSOK D-010 [5] equipment above seabed should be removed such that no parts of the well ever will protrude the seabed. The required cutting depth below seabed should be considered in each individual case, but the cutting depth should not be shallower than 5 m. It also states that no obstructions should be left on the seabed.

7.8.1 Multi-Function Fishing Tool

The multi-function fishing tool consists of several parts that are necessary for cutting and pulling the intermediate casing string, and at the same time preventing WH damage. The system consists of a Universal Wellhead Retrieving tool, a multi-string casing cutter, a hydraulic casing spear and a combined marine swivel/seal extractor [56]. The tool is able to cut and recover the WH in one trip, but each intermediate string still requires one trip each. Fig. 47 shows the multi-string cutter used to cut the intermediate casing strings. When the cutter reaches its destination circulation through the cutter produces a pressure differential across large piston in the cutter that forces the knives against the casing. Rotary speed and pump pressure are increased until the knives have cut properly through the casing. The operator monitors the differential pressure during the cutting operation, and a sudden pressure drop indicates that the cut is complete.

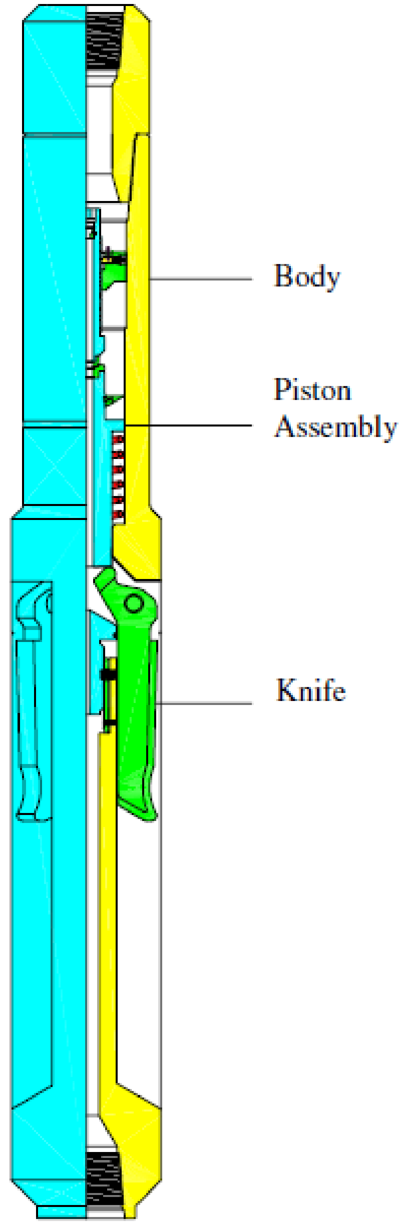


Figure 47 - Multi-String Cutter [56].

The combined marine swivel/ seal extractor, seen in Fig. 48, is designed to provide a stationary position for the cutter during the cutting process. The casing string is cut while the hangar seal is locked in to the WH and this will prevent the hangar from moving after the cut. Movement of the hangar can lead to costly damage of the WH. The swivel contains a seal-pulling adapter which allows for the seal to be removed after the cutting process is completed.

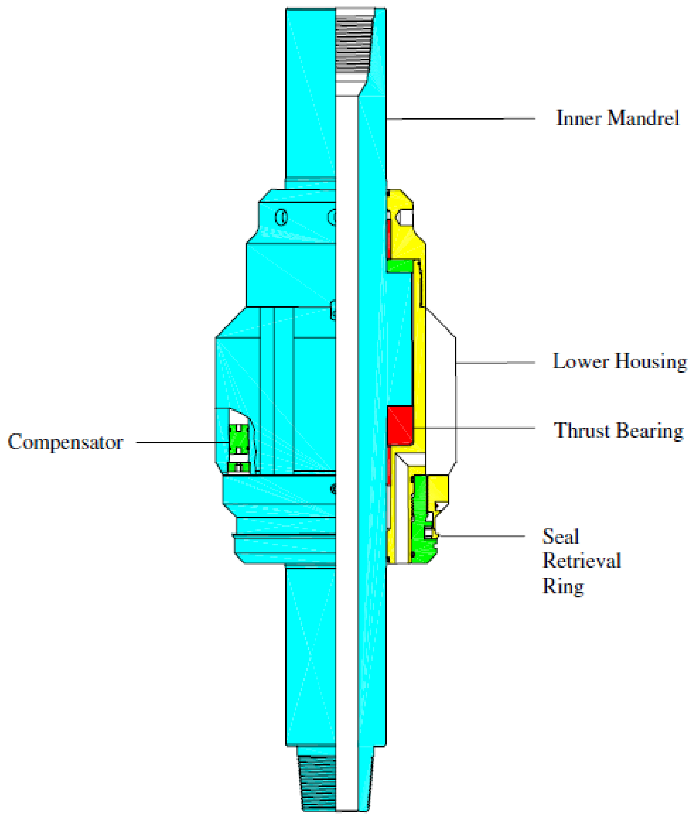


Figure 48 - The combined Marine Swivel/Seal Extractor [56].

The hydraulic casing spear is the last component of the one trip cut-and-pull system for the intermediate casing string. It is hydraulically operated and is indifferent to right- or left- hand rotation when setting or releasing the seal.

The universal wellhead retrieving system (UWRS), Fig. 49, is placed above the multi-string cutter. The UWRS is placed above the multi-string cutter to protect the WH during the cutting process and to recover it after it has been cut from the conductor [56]. When placing the UWRS on the WH the collet system is engaged to a shoulder beneath the wellhead polished bore. A quarter turn rotation will allow the mandrel to be raised, locking the collet into the mandrel [56]. By lowering the inner mandrel the collet will be released again. Cutting of the conductor is performed with the multi-string cutter under tension. Cutting the casing under tension will make the cut more efficient by keeping the knives in position during the whole cut. The length of the knives needs to be long enough to be able to complete the cutting operation of the large casing. By increasing the fluid circulation the differential pressure across the piston in the cutter is increased and hence the knives are pushed towards the casing until they have cut properly through the casing.

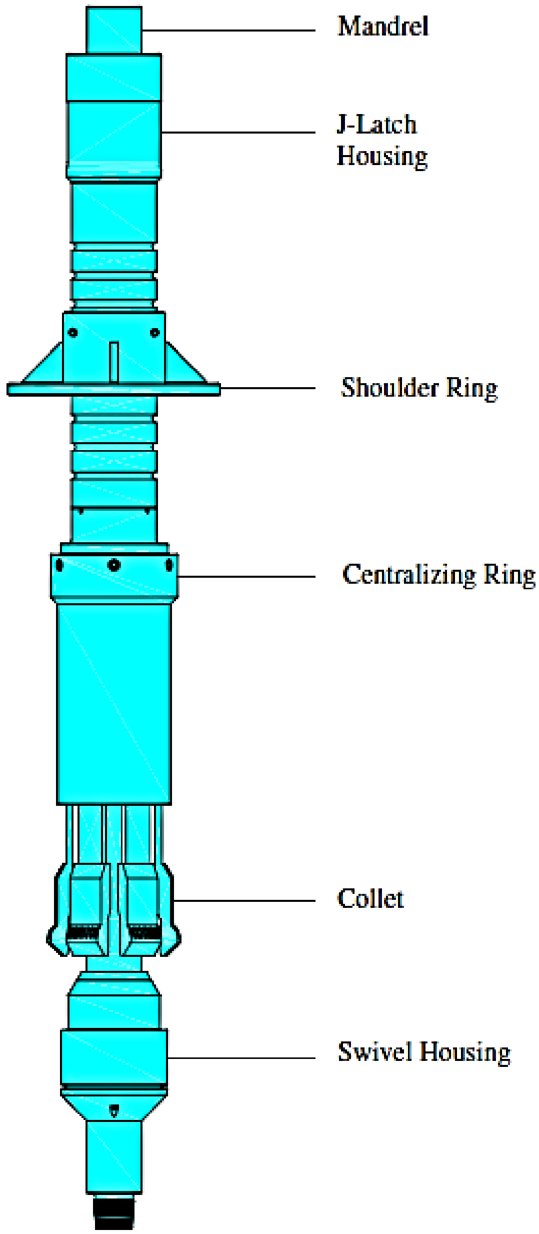


Figure 49 - Universal Wellhead Retrieving System [56].

7.8.2 Abrasive Water Jet Cutting

Fig. 50 and Fig. 51 show the principles of the abrasive water jet cutting. The basic idea of the water jet cutting is to pressurize water up to between 60 MPa and 120 MPa, add abrasive water particles and pump this slurry through a nozzle to create a thin jet of water. This high velocity abrasive water jet has the ability to cut through multi strings from 7″ casing and up to a 36″ conductor in one run [57]. One tool that uses the abrasive water jet cutting for this purpose is the Subsea Wellhead Picker, which is a combination of the water cutter and a connector that is latched onto the WH. The subsea wellhead picker can be operated from designated vessels and is deployed from a heave compensated crane over the vessel side or through the moonpool. The water cutter is lowered to the cutting depth (5 m below seabed) where it performs the multistring cut. When the WH is cut it can be lifted and recovered by use of the lifting connector. The study performed by Sørheim et al. [57] showed that as long as two WHs or more are removed in one WH cut it will be cost efficient to use a vessel for this purpose.

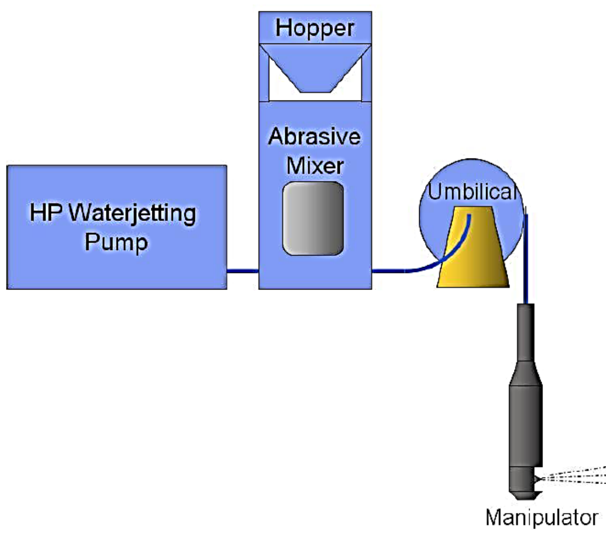


Figure 50 - Overview over the water jet cutting [57].

Figure 51 - The abrasive water jets leaving the nozzles [57].

7.9 Case Study

In this chapter the sequence of a P&A operation performed on one of Statoil's wells in 2011 will be presented. App. 3 shows the WBS for each activity from this P&A operation. The detailed operation is from a permanent P&A program prepared prior to the operation and is based on the planned operation of this well, included contingencies [12]. It shows how many uncertainties a real-life P&A operation includes and how much that have to be taken into consideration when planning for a P&A. It will differ somehow from the general procedure described throughout Ch. 7 due to the uncertainties and differences one can experience in each well:

1. Remove X-mas tree (XT), Nipple up BOP and riser.
2. Pull upper completion
    a. Primary option: Pull upper completion above packer
    b. Option 2: If it is not possible to pull the tubing then cut and pull the tubing on drillpipe
3. Install barrier in 7″ liner against reservoir
    a. Primary option: If good cement behind liner set cross sectional cement plug on top of the mechanical plug
    b. Option 2: If bad cement, but good formation bonding;
        i. Test and qualify formation as barrier
        ii. Set cement plug on top of mechanical plug
    c. Option 3: If bad cement and formation bonding behind the liner
        i. Install and pressure test mechanical plug
        ii. Perform section milling
        iii. Set cement plug on top of mechanical plug
4. Nipple down C-section
        i. Install shallow set mechanical plug
        ii. Nipple down BOP, nipple down C-section and Nipple up BOP
        iii. Pull shallow set mechanical plug
5. Cut and pull 9 5/8″ casing
        i. Perform cleanout run
6. Run USIT/CBL log in 13 3/8″ casing
7. Install barrier in 13 3/8″ casing (Install EZSV and set cement plug)
    a. Primary option: If good cement behind 13 3/8″ casing:
        i. Set and pressure test 13 3/8″ mechanical plug close to top of 9 5/8″ cut.
        ii. Set cement plug on top of mechanical.
    b. Option 2: If bad cement but good formation bonding:
        i. Test and qualify formation as barrier.

        ii. Set cement plug on top of mechanical plug.
    c. Option 3: If bad cement and formation bonding
        i. Install and pressure test mechanical plug
        ii. Perform section milling
        iii. Set cement plug on top of mechanical plug
8. Nipple down BOP, nipple down B-section and Nipple up BOP
9. Cut and pull 13 3/8″ casing
        i. Perform cleanout run
10. Install barrier in 20″ casing (Install EZSV and set cement plug)
11. Displace to sea water
12. Nipple down BOP and install cover

8 Plug and Abandonment Vessels

A plugging operation may be completed with a drilling rig or a rigless vessel dependent on the equipment needed, included the downhole tools and the surface units. The choice of configuration largely determines the cost of the plugging operation and hence the planning of this process is of great importance. In many situations the cost of the P&A operation may be reduced by transferring some of the P&A activities from the rig to dedicated vessels. The objective of transferring these activities to the vessel is to allow the drilling rig to continue with their core activity, drilling and completing wells [57]. It is also assumed that there is a significant HSE benefit of transferring these activities to designated vessels. On a rig the P&A activities will be run simultaneously with other activities while on a vessel the activities are the main focus, performed by specialized personnel. According to Sørheim et al. this will represent a slightly reduction in HSE risk [57]. Some P&A activities may not be conducted by a vessel, and hence a rig is required, but in most cases it is beneficial to perform some of the activities by a vessel before the rig takes over the operation. Which activities that may be performed by a vessel and which that requires a rig will be discussed below. A new type of vessel; a category B vessel (Cat B) is coming in near future. The Cat B is thought to fill the gap between the light well intervention (LVI) vessels (category A vessel) and the conventional rigs (category C vessels). The Cat B vessel is designed for Statoil to perform well services on their fields all year round. It will among other things be possible to perform Coiled Tubing (CT) operations from this vessel and this will make the use of CT more comprehensive and in many situations a better alternative to use of a conventional rig.

8.1 Rigless Option

LVI (Fig. 52), or more precisely riserless light well intervention (RLWI), has been used for intervention operations for a period of ten years and has proved to be a cost efficient alternative for well interventions on subsea wells. The most common one is the mono hull vessel which uses WL for intervention operations. They have been used for P&A work and compared to a semi-submersible rig it has a much lower day rate and it can move much faster between locations [58]. According to Halvorsen et al. the type of operations these vessels can perform consists of the following [59]:

- Data gathering (PLT)
- Perforating/ re-perforation
- Zone isolation (plug/straddle)
- Inspection/Repair/Installation of insert DHSV
- Milling of short scale bridges
- Camera runs: visual x-ray

- Well killing operation
- Pumping operations/Scale treatments
- Selective tracer injection or sampling
- Change-out of gas lift valves
- Sleeve operations – DIACS valves
- Change out of subsea trees
- P&A operations of subsea wells

Figure 52 - A Light Well Intervention vessel [60].

8.1.1 Wireline

WL involves running or pulling tools or measurement devices into and out of the well to perform well interventions. A continuous, small diameter cable with the attached equipment is run in or out of the hole by use of an electro-hydraulic or diesel-powered winch. There are two different cable systems used in WL, slickline and braided line. Slickline is used for mechanical operations, while the braided line, that comes with or without an electric cable, is used for tractor applications and logging. Fig. 53 shows the surface equipment included in WL operations using a slickline. The surface equipment for the braided line and the slickline is almost the same, but where the slickline operates with a stuffing box the braided line uses a grease injection top. The surface WL equipment is designed to control the pressure exerted by the well. The pressure control equipment needs to handle the following situations [61]:

- Create a seal surrounding the wire during both static and dynamic conditions
- Maintain sealed against maximum WH pressure
- Shut in well and seal in case of an emergency
- Cut the WL in case of an emergency
- The lubricator must be able to handle a test pressure against any maximum WH pressure before opening to the well and allowing the pressure to be adjusted to WH pressure before valves are opened

- Allow for the lubricator pressure to be shut down in a safe manner before the main valve is shut down.

The use of WL has some limitations. It is not possible to circulate when using WL. There is however one option to connect pumps to temporary flow lines to the XT and then bullheading is possible. On Fig. 53 the WL is run through the XT. The BOP functions as a primary barrier when run on WL, see App. 4. It has one ram that can be closed across the slickline at closed in conditions. It is used when there is a leakage in the components above the BOP and when maintenance has to be carried out at the pressure sealing components above the BOP.

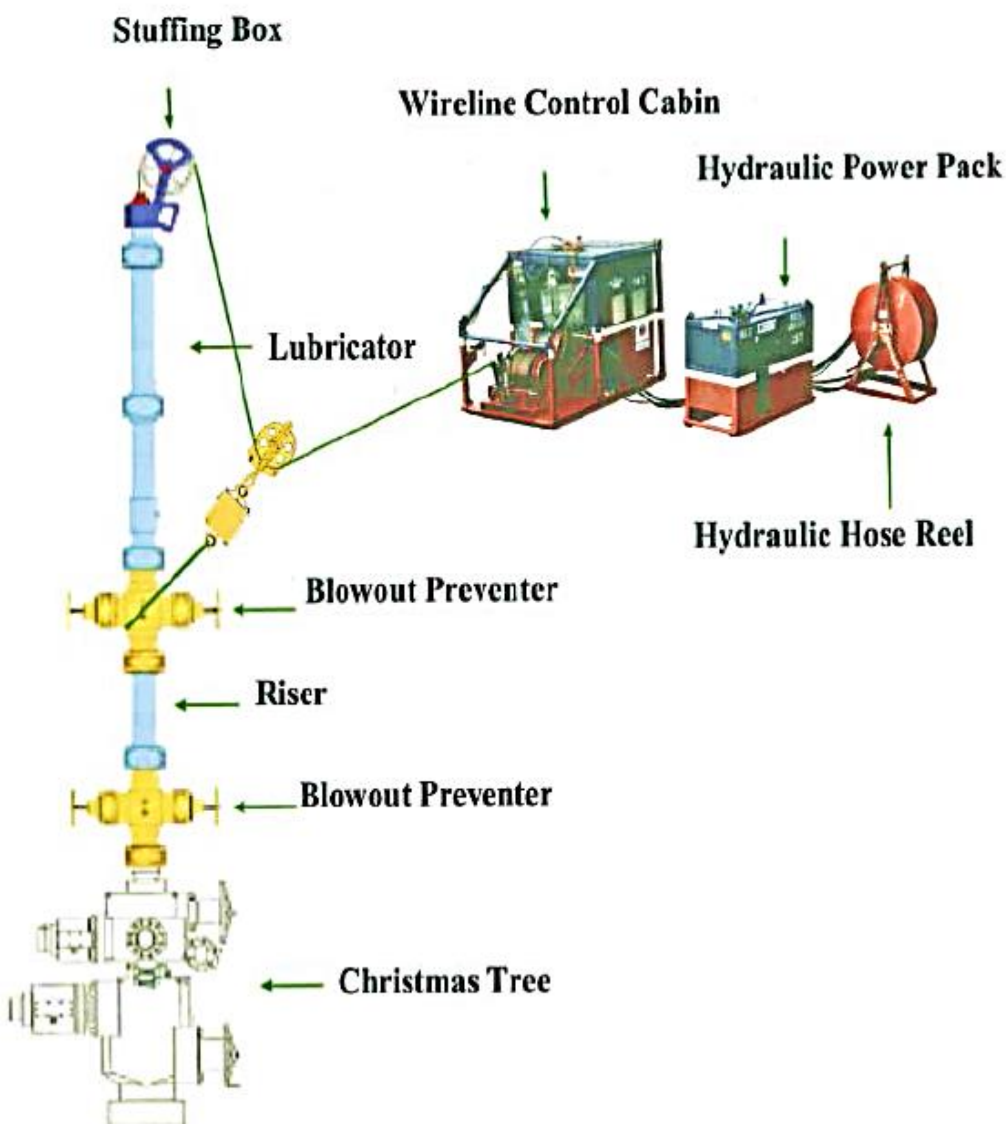


Figure 53 - Surface wireline equipment [62].

The WL toolstring is situated in the lubricator and the lubricator is pressured up before entering a live well. A typical toolstring is seen in Fig. 54. It consists of a rope socket, stem, jar and different running or pulling tools.

Figure 54 - A typical wireline toolstring [63].

Highly deviated or horizontally wells used to require the use of heavy-equipped and more expensive CT for performing well interventions. Today a well tractor can be used to push the equipment over longer distances using WL. The tractor is usually placed at the front of the WL toolstring and it is run with electricity. The tractor will descend down the wellbore due to gravitational forces until it comes in contact with a highly deviated (>70°) casing, after which the tractor is activated. The advantages of using a tractor in well completions are many. In addition to be a cost-effective solution it allows for many operations to be carried out with WL. It is quick to rig up and standard WL equipment can be used. Some of the P&A related operations that can be carried out using this device are:

- Logging
- Milling
- Perforation
- Setting/Retrieving plugs

There is however some challenges related to the use of a well tractor; problems entering the well may be caused due to scale deposit, geometry changes and damaged tubing. There might also arise some difficulties with the cable and leakages in the tractor.

8.2 Coiled Tubing

CT is the process where a flexible steel pipe (without connections) is run into and out of the well to perform different operations. In plugging operations the CT may be used for cleaning out the well prior to a plug placement and for setting primary, secondary and surface barriers [64]. The basic surface equipment used in CT is shown in Fig. 55.

The injector head is the main engine of the CT. It contains a mechanism that forces the tubing down the well overcoming friction and well pressure. It consists of a special chain assembly that uses hydraulic power for injecting the CT into the well. The tubing guide (also called gooseneck) will guide the coil into the injector. Below the injector, a rubber stripper is placed to form a seal around the pipe during injection. The stripper is classified as a primary barrier, and the upper one is active during operations while the lower one is a backup. The BOP is located below the stripper and it functions as a pressurized tunnel down to the XT. The BOP gives the ability to cut the CT and seal the well bore. When CT is run through the surface production tree the BOP will function as a primary barrier, see App. 5. NORSOK D-010 requires that the CT string contains check valves, to prevent leakage inside coil, which will act as barrier elements. The BOP used for a CT operation is different from the common BOP. The CT BOP consists of several rams that have their own functions.

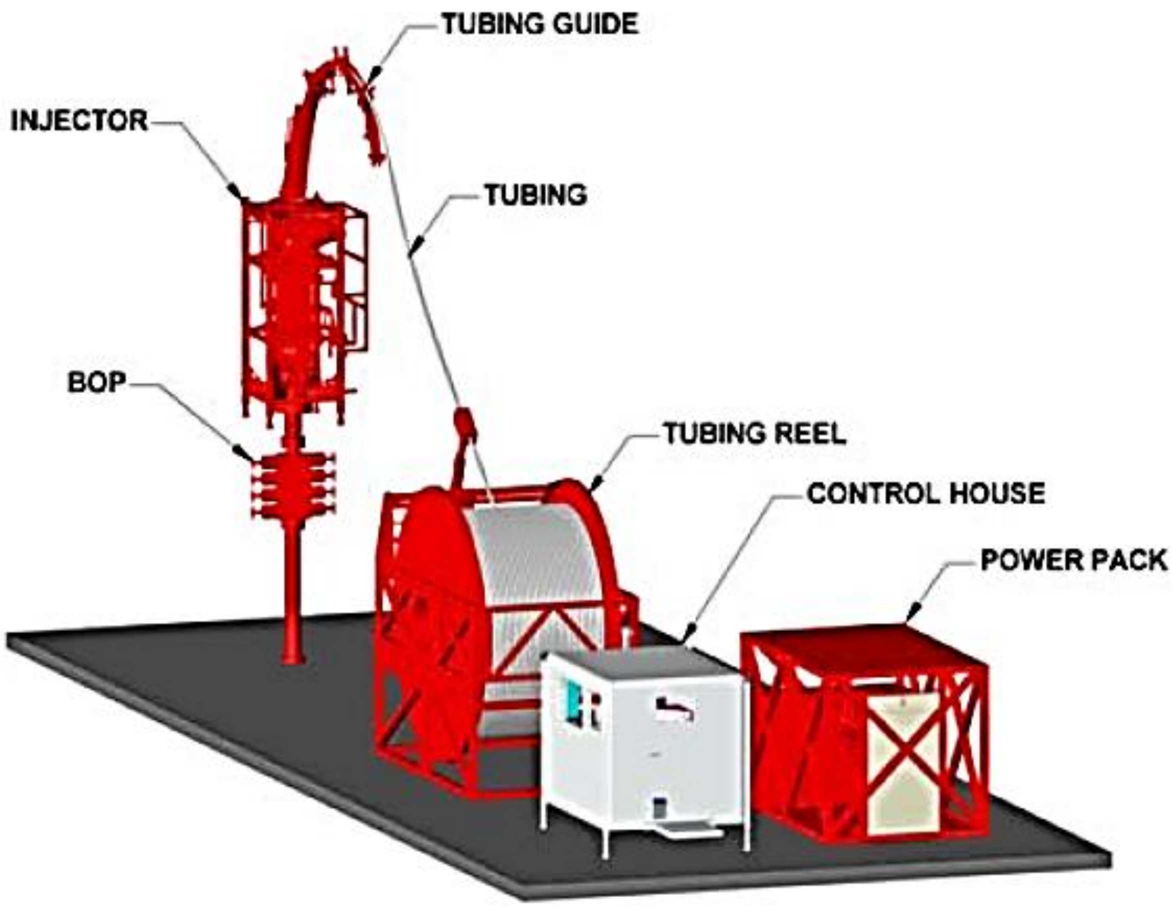


Figure 55 - A typical coiled tubing rig-up during well intervention [65].

CT was first developed to be able to work on live wells, but today there are many more advantages of using CT for interventions. Compared to a rig as another alternative the CT will save both time and money when performing the same activities. It is much faster to rig up and down the CT than if you should mobilize a rig, and it requires less personnel in operations. Because the operator will not have to stop to connect/disconnect for each joint, as on a conventional operation, additional time is saved.

8.2.1 Vessels for Coiled Tubing

CT is usually performed through the drilling derrick on the platform or through a self-supporting tower on rigs with no drilling facilities. CT performed on subsea wells can be accomplished by a semi-submersible rig or a drillship, to support all the surface equipment and personnel. A new type of vessel, a Cat B, will be operative from approximately 2015. This is a semi-submersible rig designed for all-year round well interventions. It will have integrated equipment on the rig like WL and CT. An illustration of the Cat B is shown in Fig. 56.

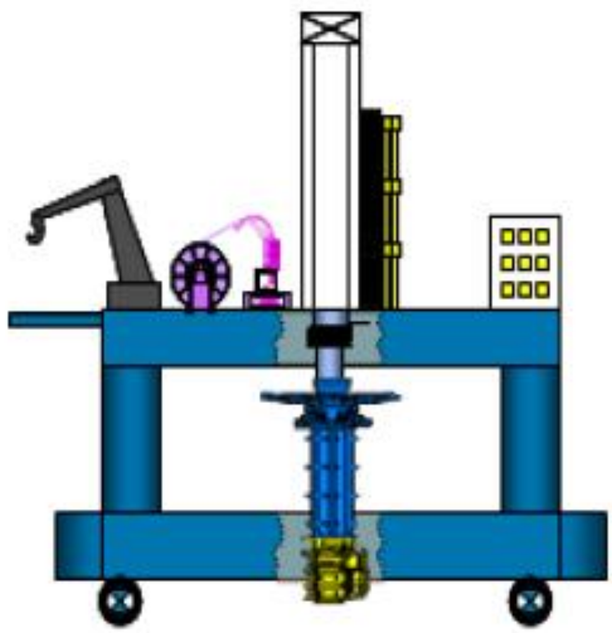


Figure 56 - Category B vessel [60].

8.3 Drilling Rigs

A drilling rig is capable of performing all of the operations required to securely plug and abandon a well, and it completes most of the conventional plugging operations. It consists of a derrick or mast, drawworks and surface equipment (circulation system, rotating equipment, hoisting system, well control equipment, power system, pipe and handling equipment, and any additional heavy equipment required) [52]. The rig either has an existing drilling derrick that is already onsite or it can be a small workover rig that is brought to the site. A conventional drilling rig is seen in Fig. 57.

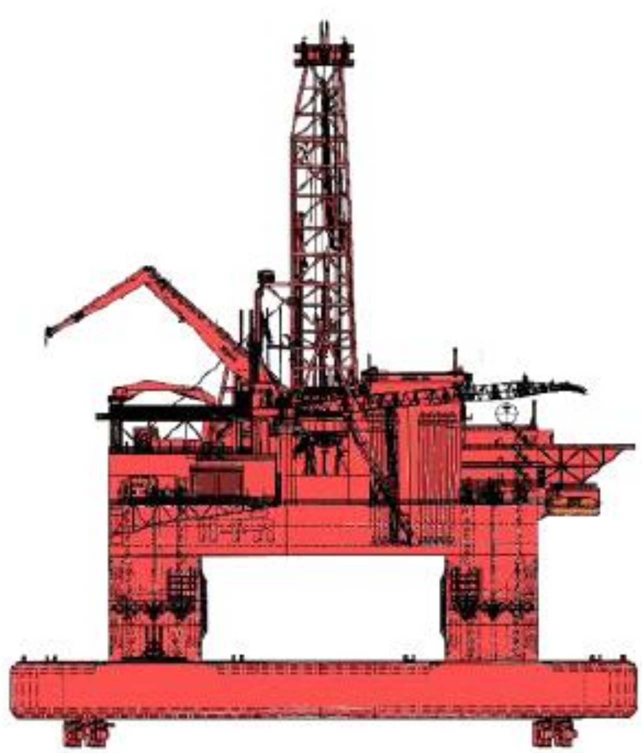


Figure 57 - A conventional rig [60].

8.4 Comparing the Different Configurations

P&A operations can be divided into three phases: reservoir abandonment, intermediate abandonment and WH and conductor removal [58]. In the first phase the reservoir is plugged and often tubing is retrieved from the well. The second phase includes plugging of overburden potential inflows while the third phase includes cutting and retrieval of casing strings, conductor and the WH 5 m below the seabed. In addition a phase prior to the P&A operation, for preparing the well for P&A, can be included in this comparison. The aim of dividing the P&A process into phases is to be able to discuss the possible combinations of configurations used during the P&A operation.

Rig:

As already mentioned the drilling rig is capable of executing all of the four phases included to complete the P&A operation. This is however not always the most cost-effective choice. In addition to consider the cost, saving rig time for drilling and completion is also of great importance [58]. The rig market is tight so the rigs should often be used for drilling new wells if other alternatives for the P&A activities are available.

LWI and Cat B (in the future):

CT (on Cat B) as a rigless abandonment operation is thought to provide a cost-effective and more flexible option than the use of a conventional rig. CT is able to circulate while operating. This way it is possible to place cement downhole. It would be possible to place cement in the annulus or as plugs in the liner. Hence CT can be used to permanently abandon the lowest part of the well and drill sidetracks in the liner. If WL on LWI and the Cat B is combined to complete the P&A operation it will be possible to liberate even more rig time for drilling and production. For heavier operations, where tubing needs to be cut and pulled, a conventional rig is required.

LWI and Rig:

WL on LWI is capable of killing the well by bullheading. It has the equipment to log the well and to install permanent mechanical plugs in the well. It is also capable of cutting and retrieving the conductor, casing and the WH 5 m below the seabed. This means that WL is capable of completing phase one and phase zero (the preparation phase) of the complete P&A operation. One option, that is widely used today, is to combine the WL and rig on the P&A operation. The WL can prepare the well for plugging before the rig completes phase two and three. Phase four can be completed by either one. In this way the cheaper LWI vessel can be used for some of the P&A activities liberating time for the rig to do drilling- and workover- operations.

9 Abandonments ahead

Several new techniques for enhanced, more safe and more cost-efficient P&A have been presented in this text and will probably become more popular in future P&A operations. The oil- and gas producers are always aiming for improved solutions and even newer techniques will most likely be developed in the future. The requirements for properly isolation of the well and reestablishment of the downhole conditions require extensive plugging operations, and proper planning, prior to the P&A operation, is mandatory for doing a successful job.

PSA held a seminar in 2012 regarding P&A of wells, where the industry was asked to give input on recommendations for improvements on this area for future operations. A report presenting these improvements was made and includes the following [66]:

1. Document competent formation
   There should be a requirement to document that the formation can withstand the pressure from below a barrier.
2. Document good cement behind casing / plugged section
   It should be a requirement that there is cement with good bond/ isolation in areas where a cement plug is set.
3. The value of no annulus pressure in old wells
   In old wells with no annulus pressure it should be proven that the cement in annulus is an acceptable well barrier.
4. Improve logging tools and interpretation methods
   The logging tools used in the industry today have certain limitations and the interpretation of these logs is often dependent on personal judgment. The vendors should come up with new tools that provide clearer results that are less dependent on personal interpretation of the logs.
5. Qualification of formation as well barrier
   Guidelines on how to qualify formation as well barrier should be developed.
6. Monitoring of geology
   The industry should have plans for monitoring the geology to make sure that no migration takes place due to pressure buildup in shallower zones.
7. "Sensors" in cement
   One should consider adding additives to the cement which makes it easier to interpret the log with regards to homogeneity and bonding between the formation and the casing.
8. Qualification of new isolation materials
   Oil & Gas UK has a qualification plan with regards to establishment of new materials known as "Guidelines on qualification of materials for the suspensions and Abandonment of wells, issue 1, July 2012". Norway should establish one as well.

9. Integrated planning of P&A
   One of the main objectives for the operator, in charge of a well to be abandoned, is to make the P&A operation as cost-effective as possible, because they must pay their P&A cost with current fund and no income on the operation. There is however several legislative requirements and environmental regulations that need to be considered and fulfilled in order to secure and isolate the reservoir for eternity. Probably the most cost-effective way of abandoning a well is to plan for abandoning when the well is constructed. This includes proper isolation of the producing zones with cement and placing the production packer below the top of the cement in the production casing. There need to be enough space above the packer to place competent cement plugs to seal of the well. If the packer is placed too high, remedial cementing may be required and this will increase the risk and cost during the P&A [67]. During P&A there has to be set one or two cement plugs above the production casing shoe to make sure other potential inflows are sealed and isolated. Usually this includes placement of long intervals of cement behind the production casing. This operation requires that the cement is circulated behind the casing. This procedure is often easier accomplished during the initial construction than during the abandonment- phase when the production tubing also is in place.

The fact that PSA encourage the industry to come up with solutions of how to improve the P&A operation show that there is a need for development within this field. PSA is demanding more reliable and safe procedure when abandoning a well and the operator is aiming for more cost-effective solution to an unpopular, but necessary operation. Since there is more and more P&A to be carried out in the coming years even better solutions will most likely come in the future.

Definitions

Balanced Plug: A plug of cement or similar material placed as a slurry in a specific location within the wellbore and which is set to provide a means of pressure isolation or mechanical platform

Barrier: A measure which reduces the risk of an accident to happen or limit the consequences in case of an accident.

Cement Bond Log: A presentation of the integrity of the cement job, evaluating the hydraulic seal of the cement.

Cement slurry: A suspension of cement and possibly other granular materials in water which flows as a liquid.

Coiled Tubing: A long, continuous length of pipe wound on a spool which provides several services within the well intervention mode.

Compressional wave: An elastic body wave or sound wave in which particles oscillate in the direction the wave propagates.

Contamination: Per definition a fluid is contaminated when its physical and chemical properties are irreversibly mixed with another fluid in a way so that it cannot flow in the desired regime or be placed downhole as designed, and it will not function as intended.

Dump Bailer: A WL or slickline tool used to place small volumes of cement slurry, or similar material, in a wellbore. Typically, the slurry is placed on a plug or similar device that provides a stable platform for the low-volume cement plug.

Geopolymer: A new type of cement slurry that are made of aluminum and silicone.

Good cement: Cement that has been verified as to position, quantity and quality according to the requirements.

HPHT well: A well with the given boundary condition:

- Drilling mud density above 1,8 sg.
- A bottom hole temperature exceeding 149°C

Leak testing: Application of pressure to detect leaks in a well barrier, WBE or other objects designed to confine pressurized fluids (liquid or gas) [5].

Neat cement: A cement slurry consisting of water and cement.

Perforate, wash and cement systems: A new approach of placing cement in the annulus by perforating, washing and cementing the wellbore in one operation.

Permanent abandonment: The action taken to ensure the permanent isolation from surface and from lower pressured zones, of exposed permeable zones, fluids and pressures in any well that will not be re-entered [50].

Plug cementing: The process of placing a small amount of cement at a specified depth of the well.

Potential source of inflow: Formation with permeability, but not necessarily a reservoir

Primary Cementing: The process of placing a cement sheath around a casing or a liner.

Primary well barrier: The first obstacle against undesirable flow from the source.

Remedial Cementing: Cementing operations performed to repair primary-cementing problems or to treat conditions arising after the wellbore has been constructed. This could either be plug cementing or squeeze cementing.

Sandaband: A Bingham-plastic unconsolidated plugging material.

Secondary well barrier: This barrier is often located outside the primary well barrier and it prevents further unwanted flow should the primary barrier fail.

Sedimentation: The process when the suspended particles in a slurry starts to settle out of the fluid until it comes to rest at a bottom barrier. In drilling the term sag is used for sedimentation of particles.

Sidetrack: A secondary well drilled away from an original well.

Spacer: Any liquid, usually chemically treated water, used to separate the drilling mud from the cement slurry.

Squeeze Cementing: The process of forcing a cement slurry through holes or splits in the casing or liner.

Temporary abandonment: All wells/ all wellbores except all active wells and wells that are permanently plugged and abandoned according to the regulations.

Thermaset: A non-reactive polymer developed in the 90-ties as an alternative plugging material to conventional cement.

Ultrasonic Cement Evaluation: An acoustic logging measurement developed to overcome some of the challenges related to the Cement Bond Log.

Well Barrier: Envelopes of one or several dependent WBEs preventing fluids or gases from flowing unintentionally from the formation, into another formation or to surface.

Well Barrier Element: A component of the well barrier that alone cannot prevent flow from one side to the other.

Well Integrity: An application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of the well

Well life cycle: The time interval from a well's conception until it is permanently abandoned.

Wireline: Deployment method of lowering into and retrieving tools and devices from a well by use of a wire.

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Appendices

Appendix 1

FUNCTION TEST (From Ch. 8.11 in "Guidelines on qualification of materials for the suspension and abandonment of wells" [14]):

A function test is required to demonstrate that the material can perform a sealing function at a rated pressure in a well bore. This is to be done using an at-surface test configuration, as shown in Fig. 10. The test follows the principles of ISO 14310 without temperature cycling.

For the function test, a 7″ casing joint will be erected at an angle of 45° to be filled with a "test barrier" comprising 30 ft. of the potential permanent barrier material. The casing joint should be steel and have a weight between 43 and 52 kg/m (29 and 35 lb./ft.) compliant with the required pressure rating. The construction will comply with regulations regarding pressure vessels. There will be a gas/water injection nipple at the bottom and a pressure recording at the top. There will be further pressure recordings made along the casing, such that extrapolation of measurements can be used to establish the pressure rating of a longer plug. The pressure measurement will, as a minimum, be taken at the high-side of the casing. Other instrumentation may be added to assist in validating calculations and modeling.

Prior to filling, the roughness – "rugosity" - of the inner surface of the casing joint should be characterized in accordance with the method described in ISO 11960. The results of surface roughness characterization should be documented.

Before placement of the material, the casing is heated to a specified temperature (+/- 5 °C) that simulates the anticipated downhole conditions. This temperature is normally maintained during the entire duration of the functional test. The actual temperature is to be documented. To suit particular operating conditions, another qualification temperature can be chosen.

Before applying the load, the product must have reached a stable condition, i.e. has set, been cured, developed full strength, and is fully bonded to the casing.

A test with water will be used for the first test sequence. The water pressure selected will be the expected hydrostatic pressure in the envisaged application. Nitrogen will be used for a second test sequence; this is intended to simulate methane gas. The gas pressure used should reflect the likely reservoir pressure. The water or gas pressure will be increased in 10 steps to the rated pressure over a period of 10 hours. An observation period should exceed three days.

Where pressure and temperature fluctuations are anticipated subsequent to abandonment, it may be appropriate to include an evaluation of barrier material performance under the anticipated fluctuating conditions.

A log of all activities with a timeline is to be documented.

The test conditions which should be specified are the test pressure rating, the maximum and minimum temperature, whether the material should be filled with brine, water or oil prior to testing, and what test fluids are to be used (nitrogen, water etc.). The results of the test should be reported in terms of whether the test barrier withstood the test pressure for at least 3 days, the pressure profile through the length of the barrier, and the rate of flow thorough the barrier, if any.

If the material to be characterized evolves heat during or after placement is conducted, or requires heating during placement, instrumentation should be included to permit monitoring of barrier temperatures. The maximum temperature reached and the duration of elevated temperature should be documented. With respect to heat evolution, adequate consideration must be given to the effects of scaleup, to allow for differences in temperatures attained by a real barrier relative to experimental results, and the consequent differences in expansion and possible deterioration processes.

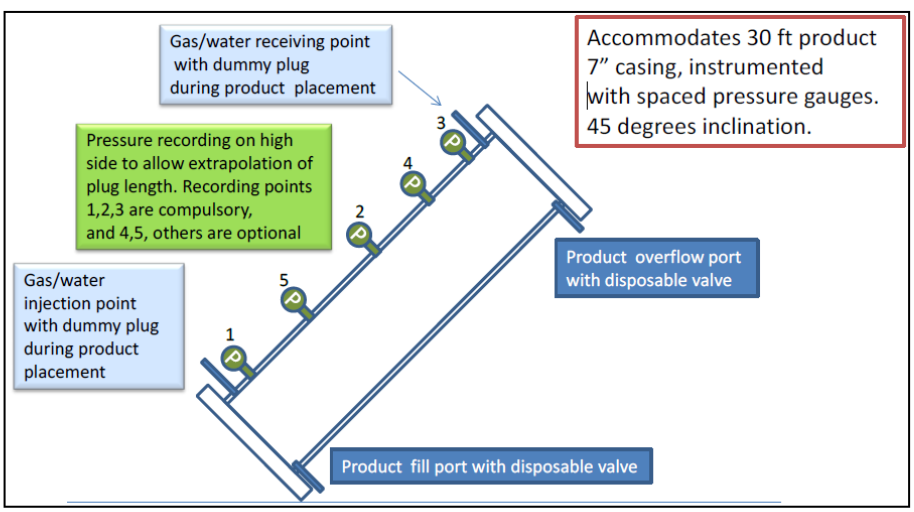


Figure 10. Configuration for a functional test.

Appendix 2

Industry Recognized Techniques and Considerations When Setting Cement Plugs [33]:

Before cementing

1. Determine well circulating temperature accurately at the depth that the plug will be set.
2. Caliper the interval: accurately determine hole volume to calculate slurry volume.
3. Choose location to set plug from logs and drilling rate curve. Select in-gauge section of hole. The best location is across a sand or lime that had a fast drilling time. Avoid hard formations (if kicking off) and washed-out hole sections.
4. Obtain samples of mud and mix water from location, and run compatibility tests.
5. Circulate the well slowly to obtain uniform mud properties and to minimize the chance of breaking the gel strength of the mud below the point of circulation. The preferred properties of mud are a funnel viscosity of 45 to 80 seconds, a plastic viscosity of 12 to 20, a yield point of 1 to 5, and a fluid loss that is as low as practical.
6. Ensure that the wellbore is completely static – i.e., no gas percolating, flowing fluids, or lost circulation.

Spacer Design

1. Use a spacer fluid ahead of and behind cement to improve displacement and minimize contamination.
2. The volume of spacer should be 152 to 244 m (500 to 800 ft.) of annulus column depending on the condition of the wellbore and the compatibility of mud and cement. Balance spacer fluid behind cement to equal the height of spacer in the annulus when cement is just out of drillpipe.
3. The type of spacer fluid should be compatible with the cement and the drilling mud. There should be no excessive gelling when mixed with either. For low-density, water-based muds, a wash is recommended. Washes cannot be weighted-up but can have low fluid loss and are excellent for air- or gas-drilled holes (to reduce treating pressures). Water can be used also. For high-density, water-base muds, a spacer is recommended. These can be weighted with flyash, barite and other weighting materials, and also can have low fluid loss. Oil-based muds require spacer capable of displacing oil-based muds. They generally contain surfactants. A water-wetting surfactant is recommended to increase bonding.
4. Spacer fluid has a density that is 60 to 120 kg/m^3 (0.5 to 1 lbm/gal) heavier than mud. If possible, have the spacer density and viscosity in the range between that of the mud and cement slurry.

5. Placement of spacers and washers: pump under turbulent flow conditions if possible; pump shutdowns should be minimized in number and duration.

Cement Slurry

1. Use Class A, C, H or G. Where possible, use viscous, high yield point cement slurries and thixotropic cements that gel fast. Minimize usage of slurry thinners. For temperatures above 110°C (230°F), use silica flour or silica sand.
2. Generally, slurry densities range from 1869 to 2097 kg/m³ (15.6 to 17.5 lbm/gal). Slurry weight should always be higher than spacer weight.
3. The pumping time should be no more than the job time plus ½ hour.
4. The size of cement plug should be 91 to 183 m (300 to 600 ft.) of wellbore, depending on the requirements of the plug. (As a kickoff base in hard formations, use a greater plug length than that used in softer formations). In out-of-gauge or washed-out-holes, use 25 to 50 % excess cement.
5. Batch mix cement: if continuous mixing of cement is necessary, use a pump rate that allows best control of cement density. Pumping into a holding tank before going down is recommended whenever possible.

Placement

1. Use balanced- or two-plug method. If two-plug method is used, do not slit bottom plug.
2. Pump cement at slow rates (plug flow) if possible.
3. Rotate drillpipe while spacer and cement are moving; do not reciprocate. After plug is in place, disturb as little as possible; pull out slowly; break connections carefully.
4. Use small diameter tailpipe (smooth joint) on end of drillpipe. Use centralizers on lower part of tubing to center. Use rotary scratchers to clean wellbore if not washed out.

WOC Time

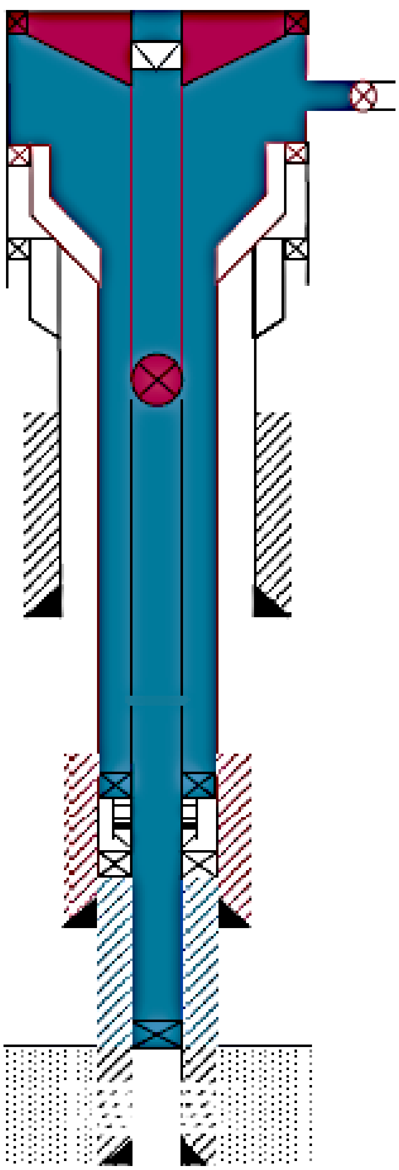
1. Allow ample WOC time; 12 to 24 hours. For every 1 hour thickening time, allow 4 hour or more WOC time. By adjusting thickening time to job time plus one-half hour, the WOC time can be reduced to a minimum.

Appendix 3

Well Barrier Schematics [12] to the Case Study presented in Ch. 7.9 (Confidential information has been removed from the drawings).

B.1.5 Barrier drawing prior to nippling (pulling X-mas tree)

Status: N/D XMT and NU BOP



Well Data			
Installation			
Well ID			
Well Type		Revision:	
Revision nr	0	Date	
Prepared			
Verified			
Approved			

Reference documentation:
Well Schematics, Well Programme, Norsok D-010

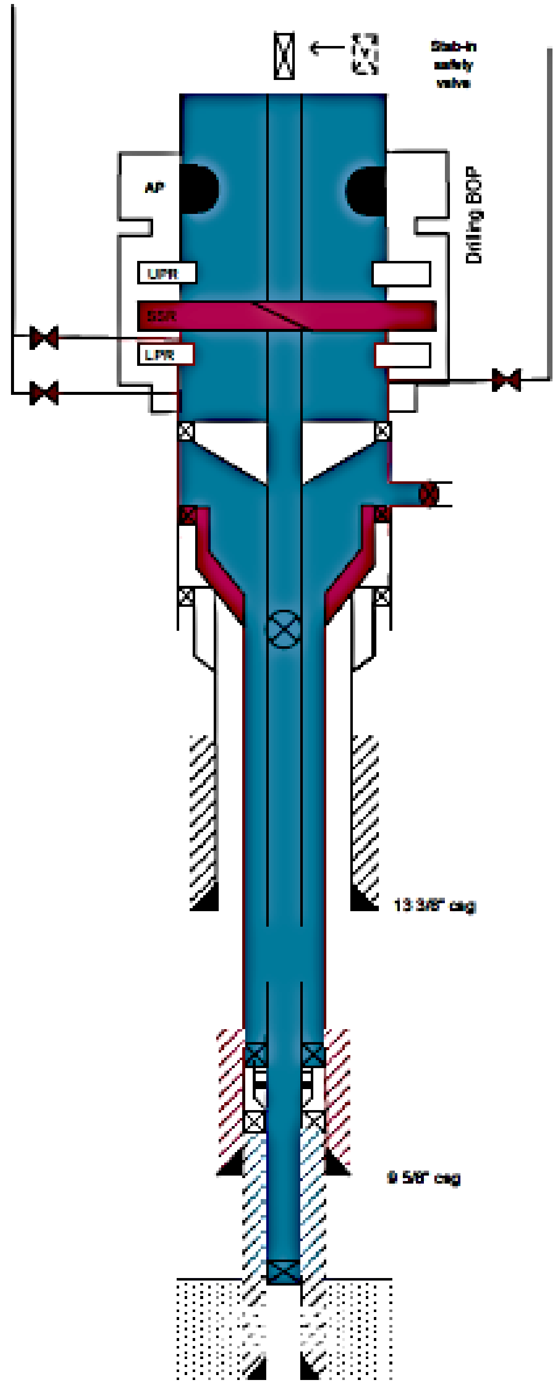
Well barrier elements	Ref. WBEAC tables	Verification of barrier elements	
Primary well barrier			
1. Bridge plug	28	PT: 220bar	
2 Fluid column	1		
3. Production packer	7		
4. 7" casing	2		
5. 7" casing cement	22		
Secondary well barrier			
1. DHSV	8	PT: 70 bar	
2. 7" tubing above DHSV	25	PT: 70bar	
3. Wellhead	5		
4. Annulus access line and valve	12		
5. 9 5/8" casing	2		
6. 9 5/8" casing cement	22		

Notes:

- 9 5/8" casing does not have gas tight threads

B.1.6 Barrier drawing for pulling upper completion from PBR

Status: Pull tubing



Well Data

Installation			
Well ID			
Well Type		Revision:	
Revision nr	0	Date	:
Prepared			
Verified			
Approved			

Reference documentation:
Well Schematics, Well Programme, Norsok D-010

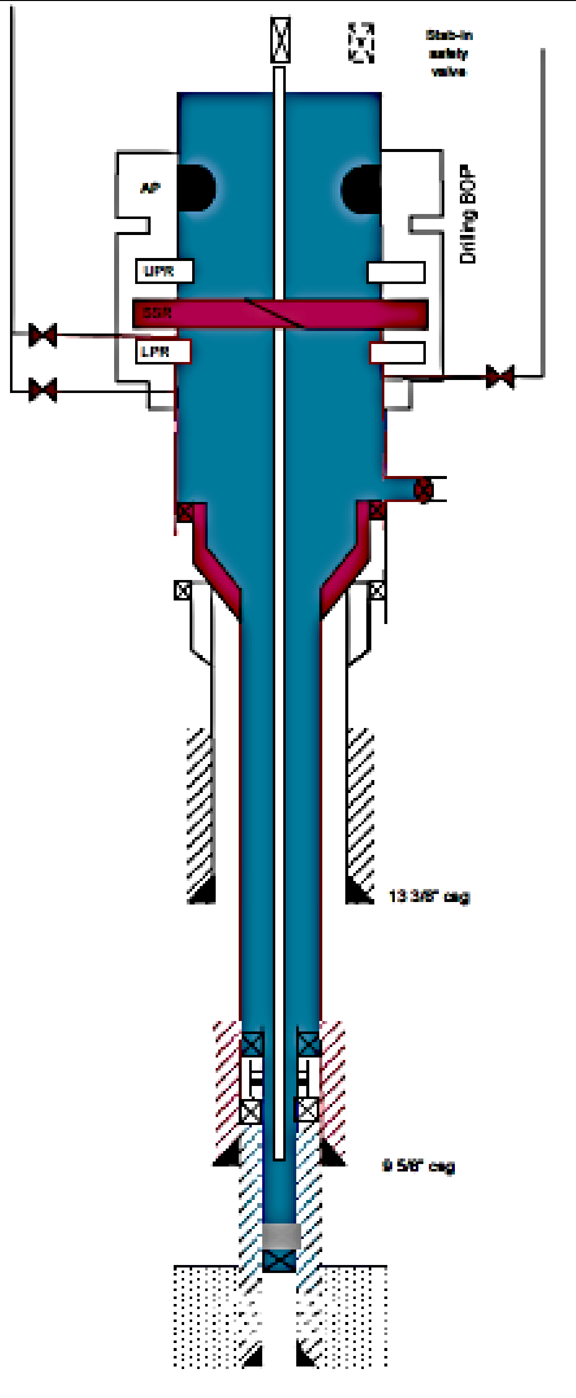
Well barrier elements	Ref. WBEAC tables	Verification of barrier elements	
Primary well barrier			
1. Fluid Column	1		
2. Bridge plug	28	PT: 220bar	
3. Production packer	7		
4. 7" casing	2		
5. 7" casing cement	22		
Secondary well barrier			
1. 9 5/8" casing	2		
2. 9 5/8" casing cement	22		
3. Wellhead	5	9 5/8" casing hanger w/ seal assy	
4. Annulus access line and valve	12		
5. Riser	26		
6. Drilling BOP			
7. Stab in safety valve + 7" swedge	40		

Notes:

- 9 5/8" casing does not have gas tight threads
- Stab in safety valve is ready on drill floor

B.1.7 Barrier drawing for setting cement plug in 7" liner

Status: Set cement plug



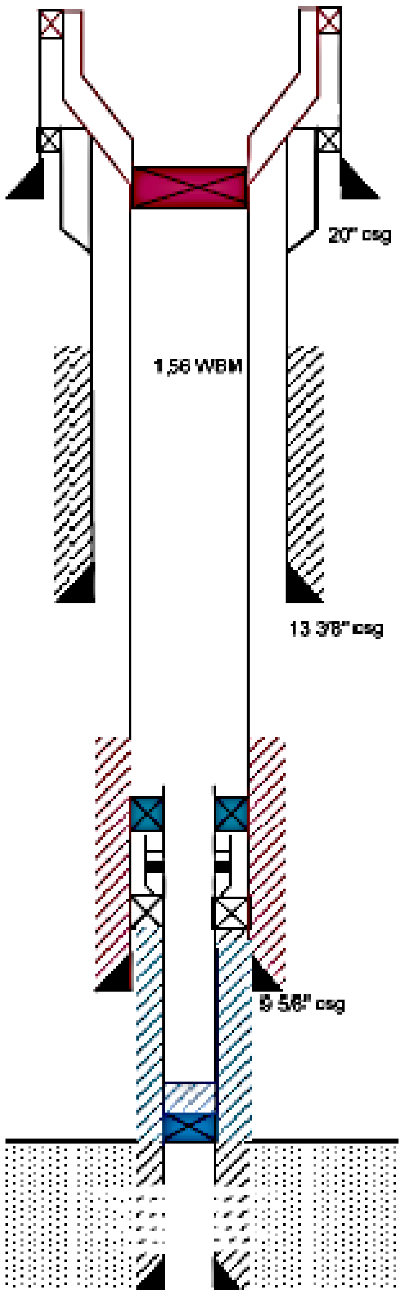
Well Data			
Installation			
Well ID			
Well Type		Revision:	
Revision nr	0	Date	
Prepared			
Verified			
Approved			
Reference documentation: Well Schematics, Well Programme, Norsok D-010			
Well barrier elements	**Ref. WBEAC tables**	**Verification of barrier elements**	
Primary well barrier			
1. Fluid Column	1		
2. Bridge plug	28	PT: 220bar	
3. 7" casing	2		
4. 7" casing cement	22		
5. Production packer	7		
Secondary well barrier			
1. 9 5/8" casing	2		
2. 9 5/8" casing cement	22		
3. Wellhead	5	9 5/8" casing hanger w/ seal assy	
4. Annulus access line and valve	12		
5. Riser	26		
6. Drilling BOP			

Notes:

- 9 5/8" casing does not have gas tight threads
- Stab in safety valve is ready on drill floor

B.1.8 Barrier drawing N/D C-section

Status: N/D BOP and C-section



Well Data			
Installation			
Well ID			
Well Type		**Revision:**	
Revision nr	0	**Date**	
Prepared			
Verified			
Approved			
Reference documentation: Well Schematics, Well Programme, Norsok D-010			

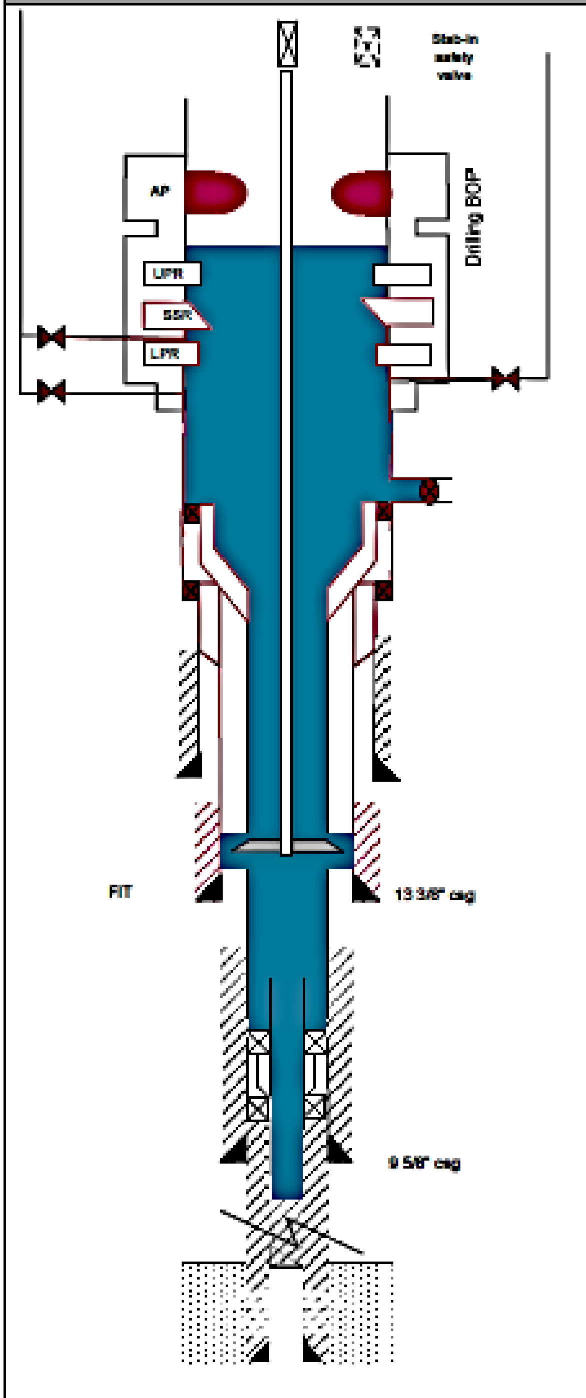
Well barrier elements	Ref. WBEAC tables	Verification of barrier elements	
Primary well barrier			
1. Bridge plug	28	PT: 220bar	
2. Cement plug	24	200 m	
3. Production packer	7		
4. 7" casing	2		
5. 7" casing cement	22		
Secondary well barrier			
1. 9 5/8" casing	2		
2. 9 5/8" casing cement	22		

Notes:

- 9 5/8" casing does not have gas tight threads
- Due to shallow plug it is not possible to monitor fluid column.

B.1.9 Barrier drawing for cut 9 5/8" casing

Status: Cut 9 5/8" casing



Well Data			
Installation			
Well ID	:		
Well Type		Revision:	
Revision nr	0	Date	
Prepared			
Verified			
Approved			
Reference documentation: Well Schematics, Well Programme, Norsok D-010			

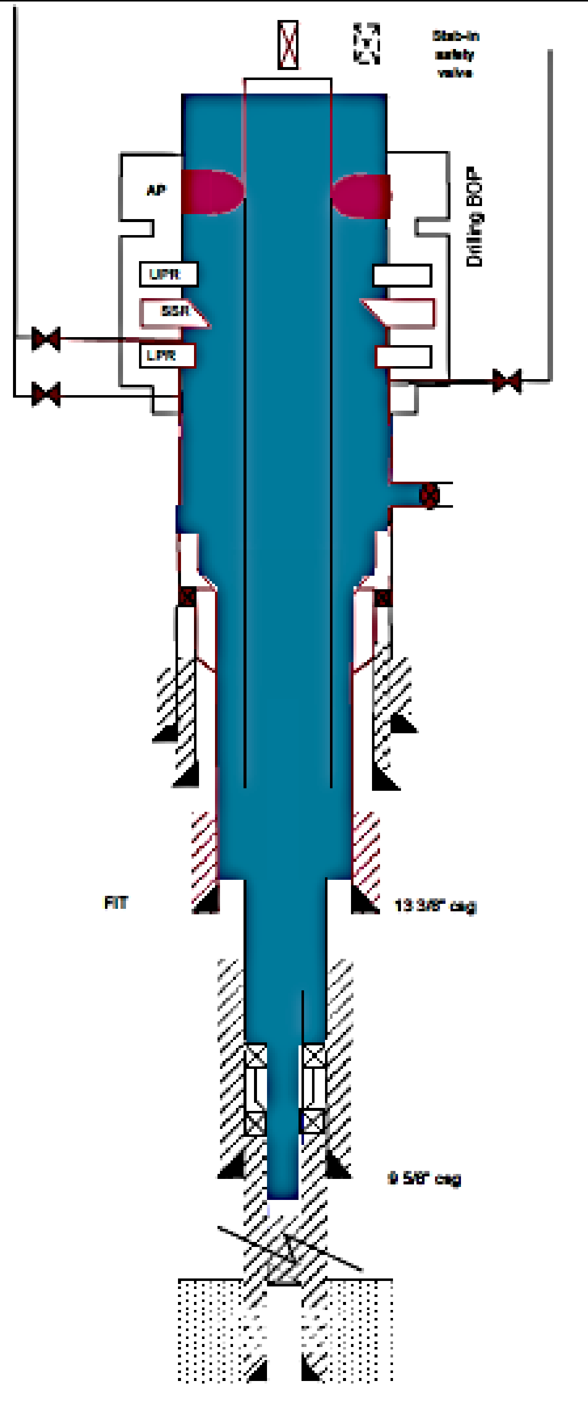
Well barrier elements	Ref. WBEAC tables	Verification of barrier elements	
Primary well barrier			
1. Fluid Column	1		
Secondary well barrier			
1. Formation integrity at 13 3/8" shoe	NA	FIT= 1,71 SG	
2. 13 3/8" casing	2		
3. 13 3/8" casing cement	22		
4. Wellhead	5	9 5/8" casing hanger w/ seal assy	
5. Annulus access line and valve	12		
6. Riser	26		
7. Drilling BOP			

Notes:

- Stab in safety valve is ready on drill floor
- Old IOM mud behind 9 5/8" casing

B.1.10 Barrier drawing for pull 9 5/8" casing

Status: Pull 9 5/8" casing



Well Data			
Installation			
Well ID			
Well Type		Revision:	
Revision nr	0	Date	
Prepared			
Verified			
Approved			
Reference documentation: Well Schematics, Well Programme, Norsok D-010			

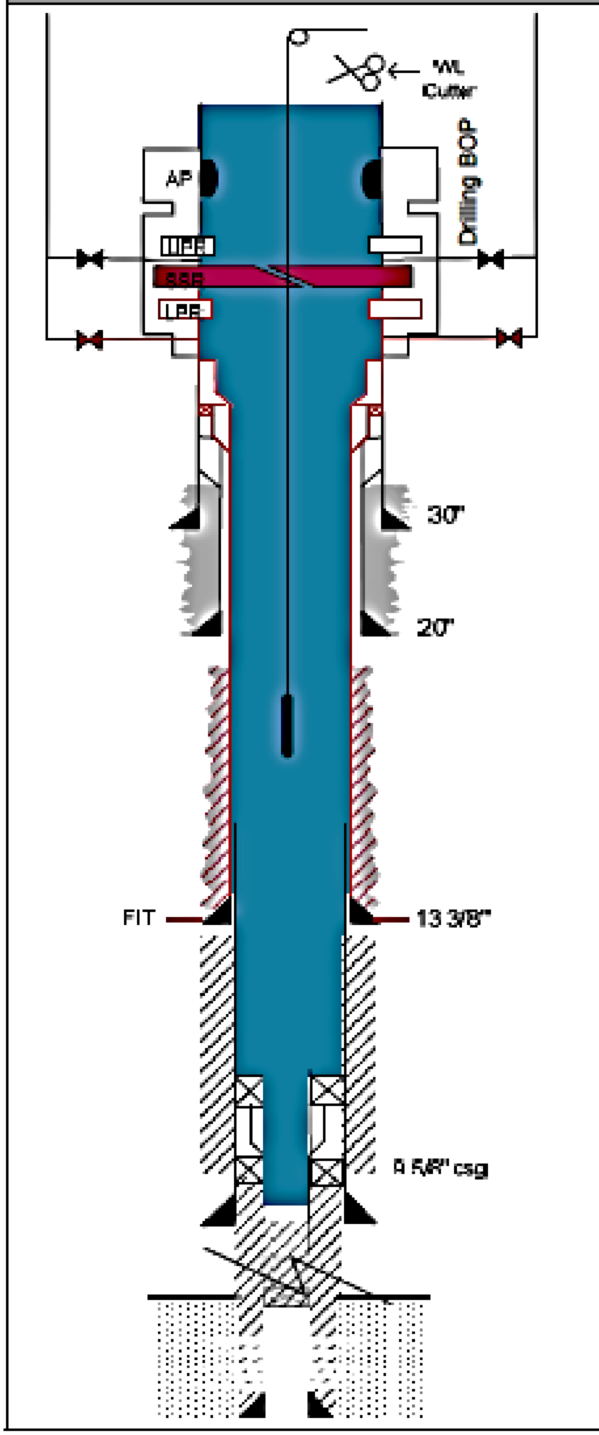
Well barrier elements	Ref. WBEAC tables	Verification of barrier elements	
Primary well barrier			
1. Fluid Column	1		
Secondary well barrier			
1. Formation integrity at 13 3/8" shoe	N/A	FIT = 1,71 sg	
2. 13 3/8" casing	2		
3. 13 3/8" casing cement	22		
4. Wellhead	5		
5. Annulus access line and valve	12		
6. Riser	26		
7. Drilling BOP			
8. Stab in safety valve + 9 5/8" swedge	40		

Notes:

- Stab in safety valve is ready on drill floor
- Old IOM mud behind 9 5/8" casing

B.1.11 Barrier drawing for running USIT/ CBL in 13 3/8" casing

Status: USIT/ CBL in 13 3/8" casing



Well Data

Installation			
Well ID			
Well Type		Revision:	
Revision nr	0	Date	
Prepared			
Verified			
Approved			

Reference documentation:
Well Schematics, Well Programme, Norsok D-010

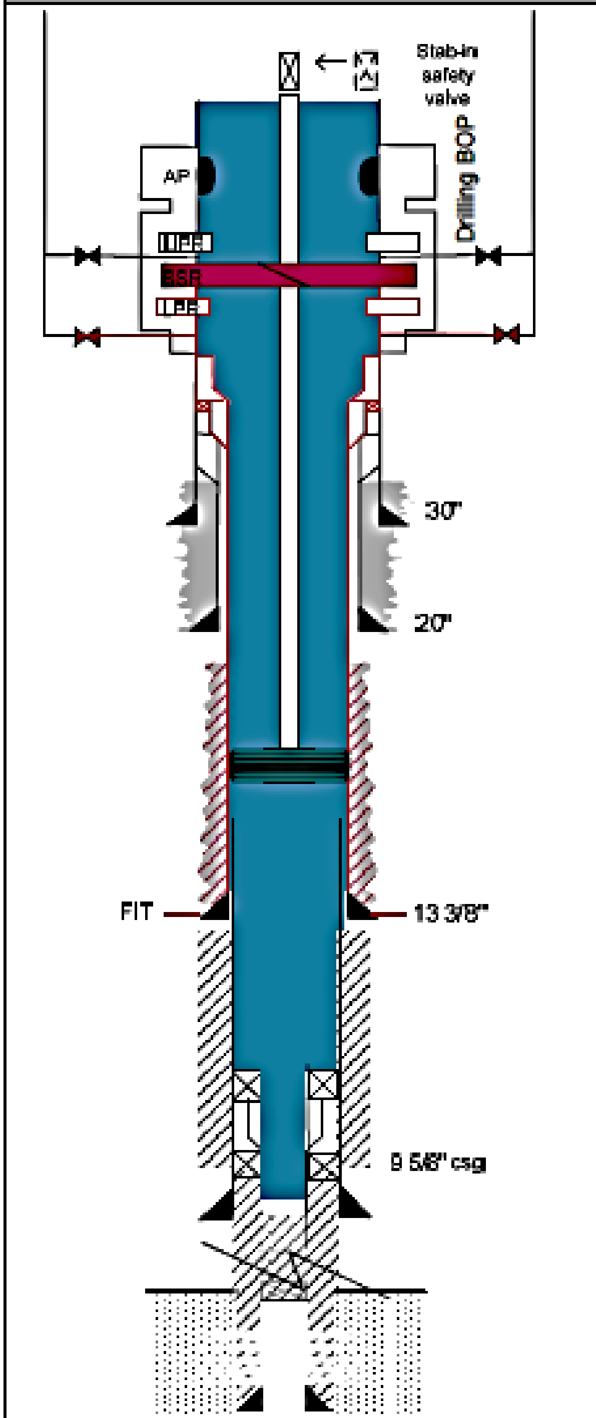
Well barrier elements	Ref. WBEAC tables	Verification of barrier elements	
Primary well barrier			
1. Fluid Column	1		
Secondary well barrier			
1. Formation integrity at 13 3/8" shoe	N/A	FIT= 1,71 sg	
2. 13 3/8" casing	2		
3. 13 3/8" casing cement	22		
4. Wellhead	5	13 3/8" casing hanger w/ seal assy	
5. High pressure riser	26		
6. Drilling BOP			

Notes:

- 13 3/8" casing does not have gas tight threads
- Equipment for cutting WL cable present on drill floor during logging

B.1.12 Barrier drawing for installing 13 3/8" EZSV

Status: Install 13 3/8" EZSV



Well Data			
Installation			
Well ID			
Well Type		Revision:	
Revision nr	0	Date	
Prepared			
Verified			
Approved			
Reference documentation: Well Schematics, Well Programme, Norsok D-010			

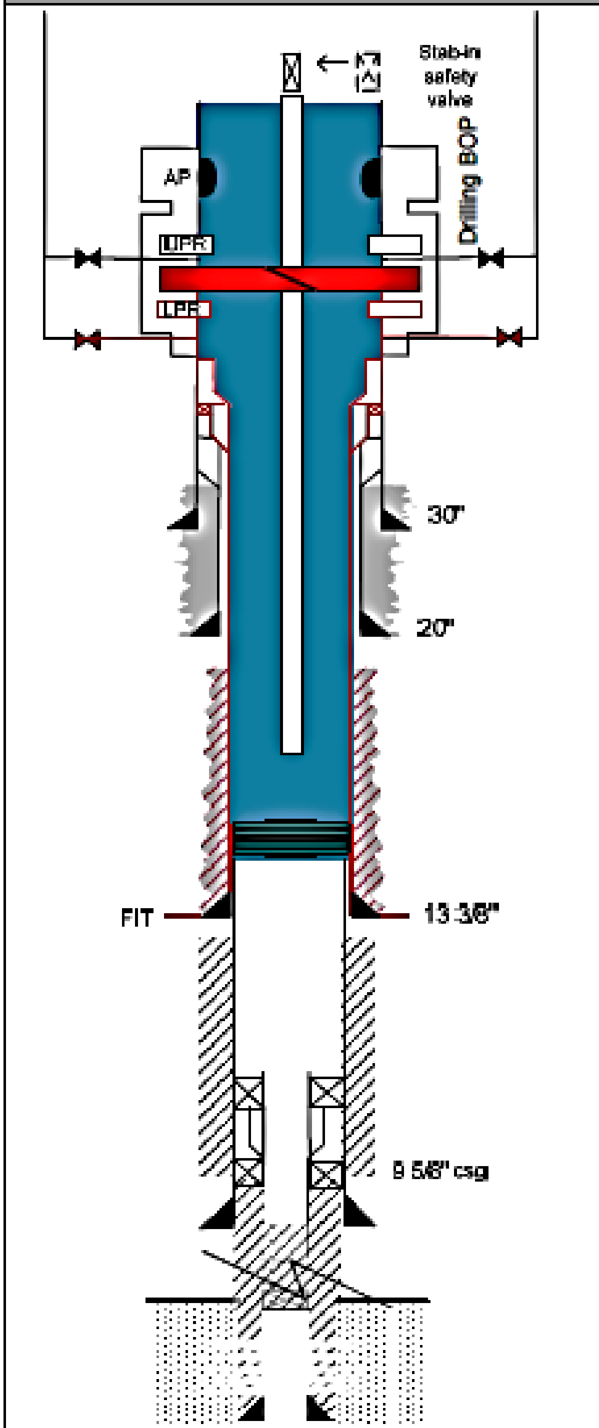
Well barrier elements	Ref. WBEAC tables	Verification of barrier elements	
Primary well barrier			
1. Fluid Column	1		
Secondary well barrier			
1. Formation integrity at 13 3/8" shoe	N/A	FIT=1,71 sg	
2. 13 3/8" casing	2		
3. 13 3/8" casing cement	22		
4. Wellhead	5	13 3/8" casing hanger w/ seal assy	
5. High pressure riser	26		
6. Drilling BOP			

Notes:

- 13 3/8" casing does not have gas tight threads
- Stab in safety valve is ready on drill floor

B.1.13 Barrier drawing for setting cement in 13 3/8" casing

Status: Set cement in 13 3/8" casing



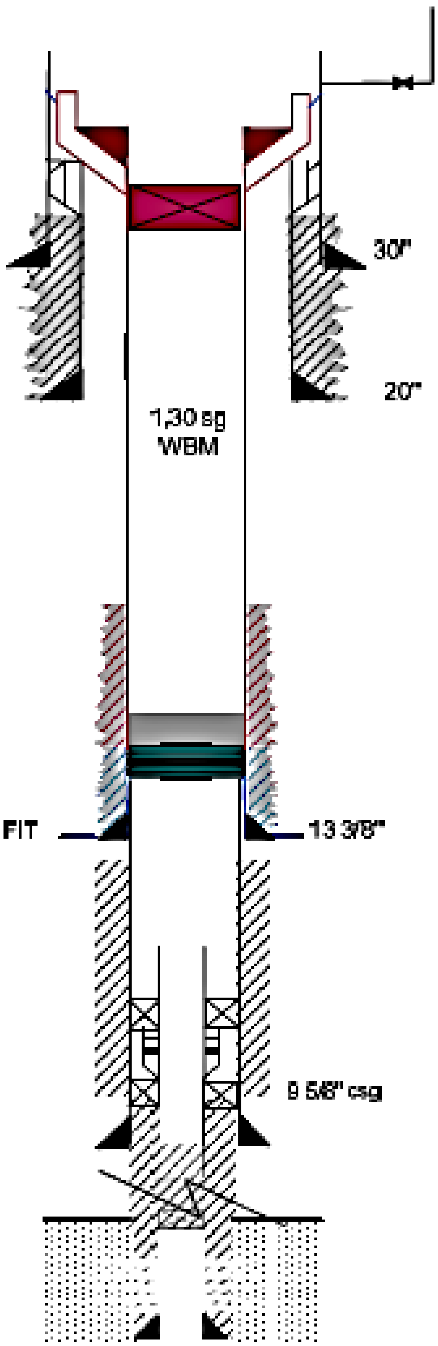
Well Data			
Installation			
Well ID			
Well Type		Revision:	
Revision nr	0	Date	
Prepared			
Verified			
Approved			
Reference documentation: Well Schematics, Well Programme, Norsok D-010			
Well barrier elements	Ref. WBEAC tables	Verification of barrier elements	
Primary well barrier			
1. Fluid Column	1		
Secondary well barrier			
1. Formation integrity at 13 3/8" shoe	N/A	FIT= 1,71 sg	
2. 13 3/8" casing	2		
3. 13 3/8" casing cement	22		
4. Wellhead	5	13 3/8" casing hanger w/ seal assy	
5. High pressure riser	26		
6. Drilling BOP			

Notes:

- 13 3/8" casing does not have gas tight threads
- Stab in safety valve is ready on drill floor

B.1.14 Barrier drawing for N/D B-section

Status: N/D BOP, Install B section, N/U BOP



Well Data			
Installation			
Well ID			
Well Type		**Revision:**	
Revision nr	0	**Date**	
Prepared		:	
Verified			
Approved			
Reference documentation: Well Schematics, Well Programme, Norsok D-010			

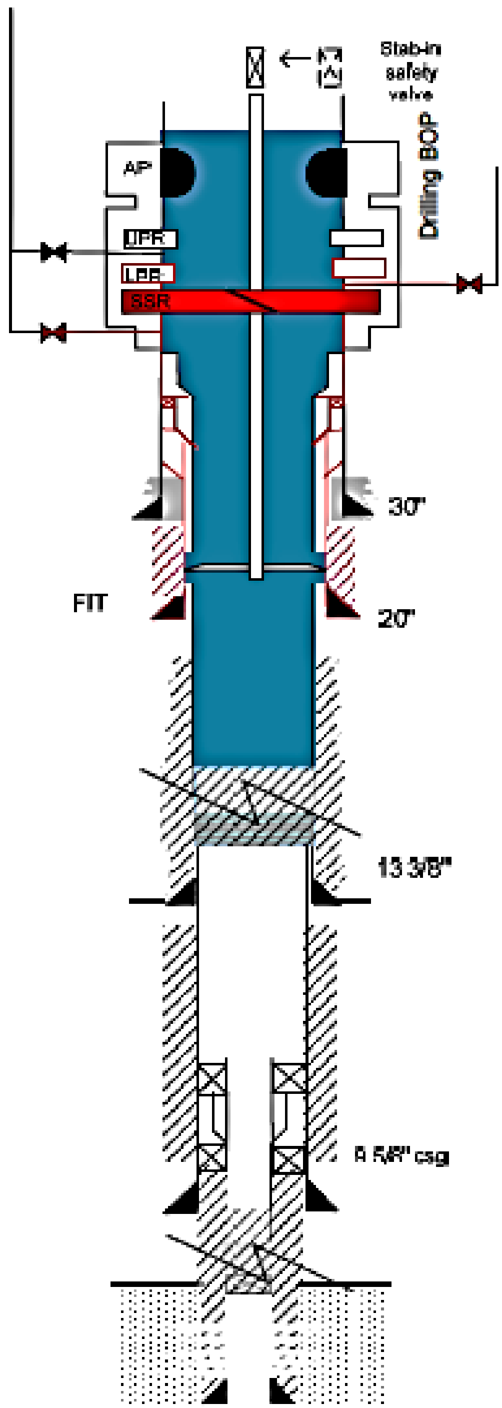
Well barrier elements	Ref. WBEAC tables	Verification of barrier elements	
Primary well barrier			
3. 13 3/8" casing	2	FIT= 1,71 sg	
4. 13 3/8" cement	22		
5. wellhead	5	13 3/8" casing hanger	
Secondary well barrier			
1. Shallow plug	28		
2. 13 3/8" casing	2	FIT= 1,71 sg	
3. 13 3/8" cement	22		
4. wellhead	5	13 3/8" casing hanger	

Notes:

- 13 3/8" casing does not have gas tight threads
- Due to shallow plug it is not possible to monitor fluid column.

B.1.15 Barrier drawing for cutting 13 3/8" casing

Status: Cut 13 3/8" casing



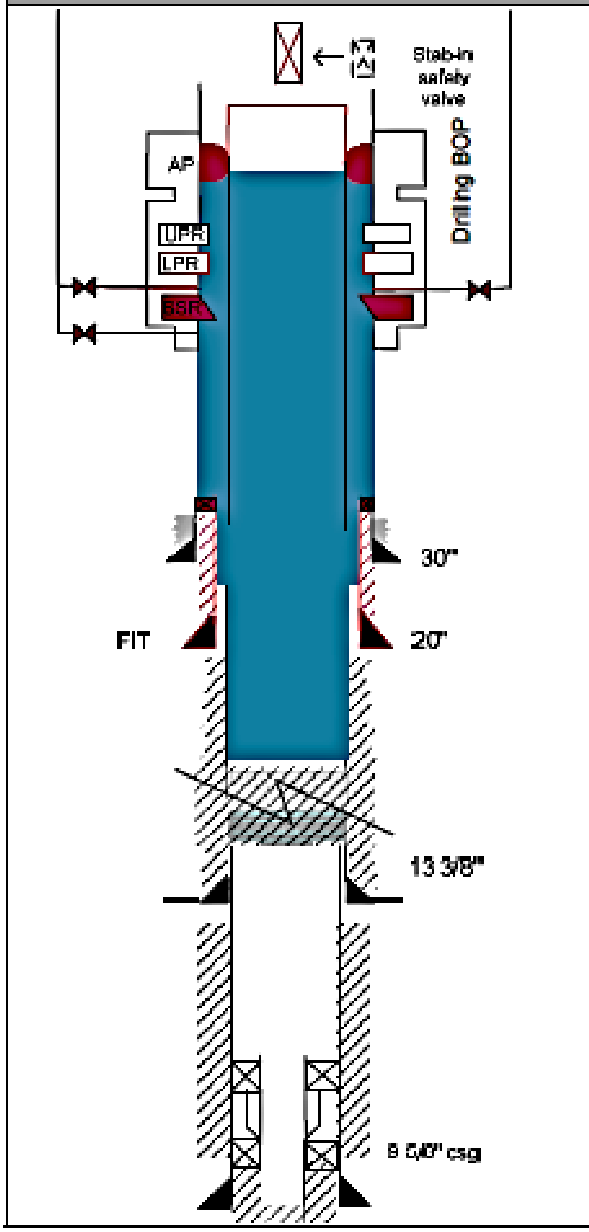
Well Data			
Installation			
Well ID			
Well Type		Revision:	
Revision nr	0	Date	
Prepared			
Verified			
Approved			
Reference documentation: Well Schematics, Well Programme, Norsok D-010			
Well barrier elements	**Ref. WBEAC tables**	**Verification of barrier elements**	
Primary well barrier			
1. Fluid Column	1	Mud weight 1,30 sg	
Secondary well barrier			
1. Formation integrity at 20" shoe	N/A	FIT= 1,43 sg	
2. 20" casing	2		
3. 20" casing cement	22	TOC not verified	
4. Wellhead	5	20" casing hanger w/ seal assy	
5. High pressure riser	26		
6. Drilling BOP			

Notes:

- 13 3/8" casing does not have gas tight threads
- Stab in safety valve is ready on drill floor
- Old IOM mud behind 13 3/8" casing

B.1.16 Barrier drawing for pull 13 3/8" casing

Status: Pull 13 3/8" casing



Well Data

Installation			
Well ID			
Well Type		Revision:	
Revision nr	0	Date	
Prepared			
Verified			
Approved			

Reference documentation:
Well Schematics, Well Programme, Norsok D-010

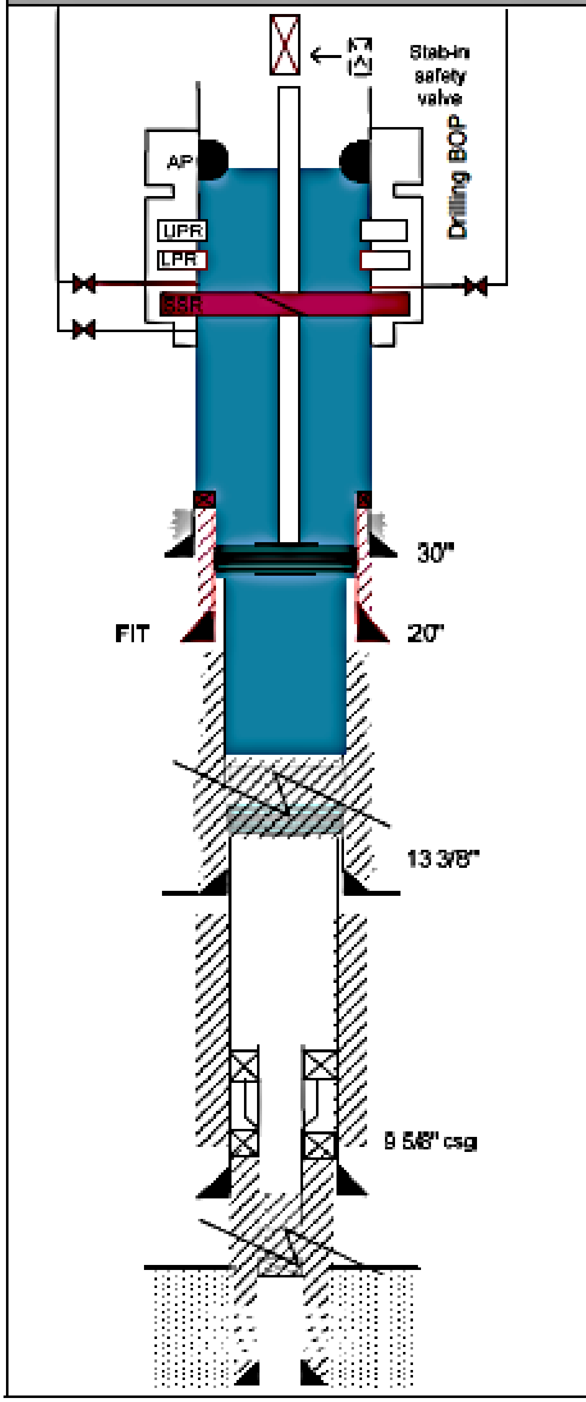
Well barrier elements	Ref. WBEAC tables	Verification of barrier elements	
Primary well barrier			
1. Fluid Column	1	1,30 sg WBM	
Secondary well barrier			
1. Formation integrity at 20" shoe	N/A	FIT= 1,43 sg	
2. 20" casing	2		
3. 20" casing cement	22		
4. Wellhead	5	20" casing hanger w/ seal assy	
5. Annulus access line and valve	12		
6. Riser	26		
7. Drilling BOP	4		
7. Stab in safety valve + 13 3/8" swedge			

Notes:

- Stab in safety valve is ready on drill floor
- 20" casing does not have gas tight threads
- Old IOM mud behind 13 3/8" casing

B.1.17 Barrier drawing for installing 20" EZSV

Status: Install 20" EZSV



Well Data			
Installation			
Well ID			
Well Type		Revision:	
Revision nr	0	Date	
Prepared			
Verified			
Approved			
Reference documentation: Well Schematics, Well Programme, Norsok D-010			

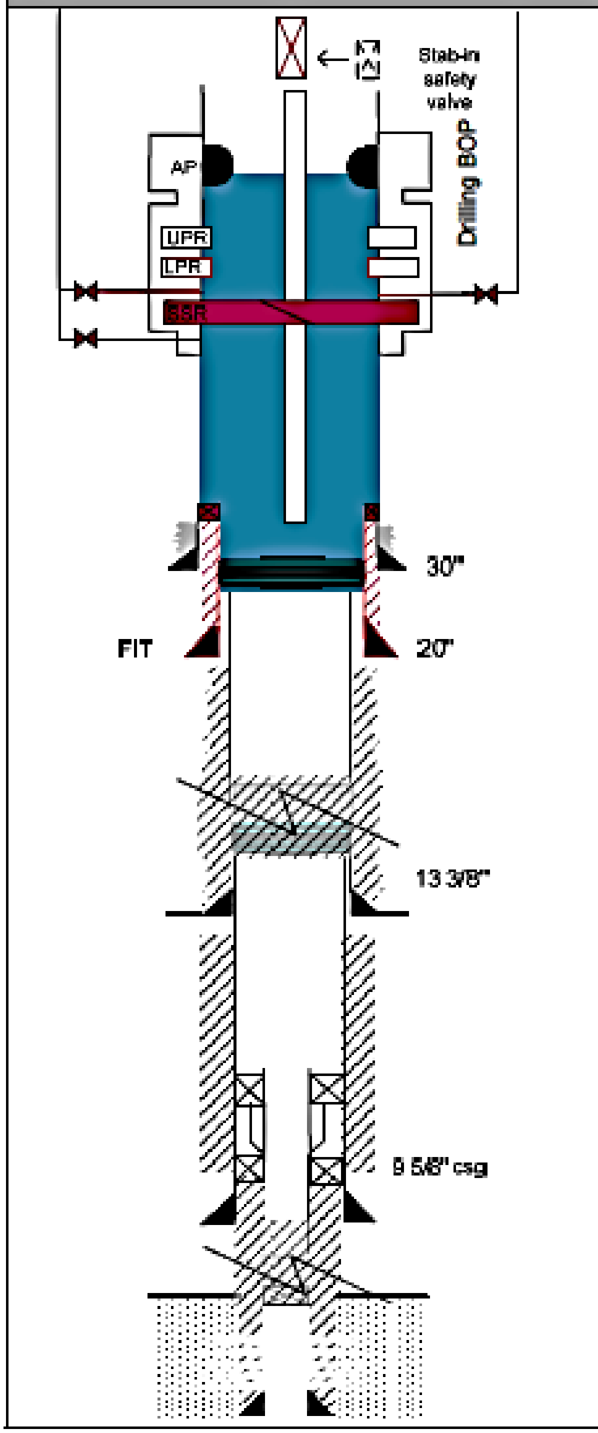
Well barrier elements	Ref. WBEAC tables	Verification of barrier elements
Primary well barrier		
1. Fluid Column	1	1,30 sg WBM
Secondary well barrier		
1. Formation integrity at 20" shoe	N/A	FIT= 1,43 sg
2. 20" casing	2	
3. 20" casing cement	22	
4. Wellhead	5	20" casing hanger w/ seal assy
5. Annulus access line and valve	12	
6. Riser	26	
7. Drilling BOP	4	
8. Stab in safety valve + 13 3/8" swedge		

Notes:

- Stab in safety valve is ready on drill floor
- 20" casing does not have gas tight threads
- Old IOM mud behind 13 3/8" casing

B.1.18 Barrier drawing for setting cement plug in 20" casing

Status: Set cement plug in 20" casing



Well Data

Installation			
Well ID			
Well Type		Revision:	
Revision nr	0	Date	
Prepared			
Verified			
Approved			

Reference documentation:
Well Schematics, Well Programme, Norsok D-010

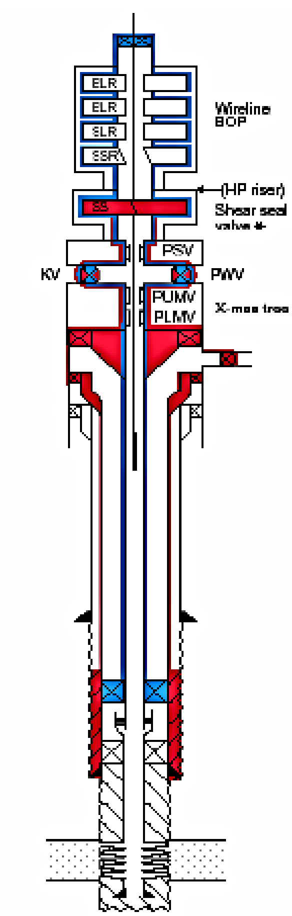
Well barrier elements	Ref. WBEAC tables	Verification of barrier elements	
Primary well barrier			
1. Fluid Column	1	1,30 sg WBM	
Secondary well barrier			
1. Formation integrity at 20" shoe	N/A	FIT= 1,43 sg	
2. 20" casing	2		
3. 20" casing cement	22		
4. Wellhead	5	20" casing hanger w/ seal assy	
5. Annulus access line and valve	12		
6. Riser	26		
7. Drilling BOP	4		
8. Stab in safety valve + 13 3/8" swedge			

Notes:
- Stab in safety valve is ready on drill floor
- 20" casing does not have gas tight threads
- Old IOM mud behind 13 3/8" casing

Appendix 4

Well barrier schematics (from NORSOK D-010) showing wireline BOP as primary barrier when run through XT.

10.8.2 Running WL through surface production tree



Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing cement	22	
2. Casing	2	Below production packer.
3. Production packer	7	
4. Completion string	25	
5. Tubing hanger	10	
6. Surface production tree	33	Including kill and PWVs.
7. Wireline BOP	37	Body only. Act as back up element to the wireline stuffing box/grease head.
8. Wireline lubricator	44	
9. Wireline stuffing box/grease head	39	
Secondary well barrier		
1. Casing cement	22	Common WBE with primary well barrier.
2. Casing	2	Common WBE with primary well barrier below production packer.
3. Wellhead	5	Including casing hanger and access lines with valves.
4. Tubing hanger	10	Common WBE with primary well barrier.
5. Surface production tree	33	Common WBE with primary well barrier.
6. Wireline safety head	38	Common WBE with primary well barrier.

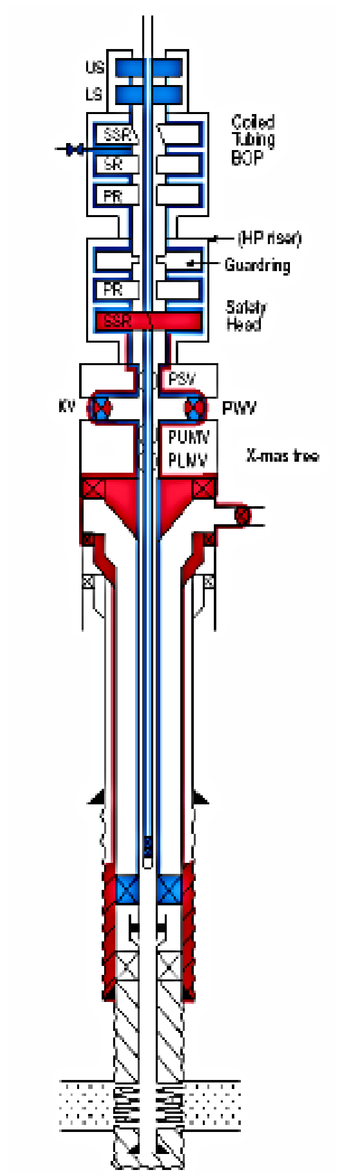
Notes

1. See 10.4.3 for compensating measures for common WBE.
2. The WL safety head should be rigged up as close as possible to the surface production tree.
3. If a triple or quad wireline BOP including a safety head is used, but is not installed as close as possible to the surface production tree, than a separate WL safety head should be installed.
4. Legend:
   - BLR = WL BOP cable ram
   - SLR = WL BOP slickline ram
   - SSR = WL BOP cut valve, integrated in WL BOP
   - SS = WL safety head (shear/seal ram) rigged up close to Xmas tree

Appendix 5

Well barrier schematics (from NORSOK D-010) showing coiled tubing BOP as primary barrier when run through XT.

11.8.2 Running CT through surface production tree



Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing cement	22	
2. Casing	2	Below production packer.
3. Production packer	7	
4. Completion string	25	
5. Tubing hanger	10	
6. Surface production tree	33	Inclusive kill and PWVs.
7. Coiled tubing safety head	16	Body
8. High pressure riser	26	
9. Coiled tubing BOP	14	Body w/kill valve.
10. Coiled tubing strippers	17	
11. Coiled tubing	13	Below stripper.
12. Coiled tubing check valves	15	
Secondary well barrier		
1. Casing cement	22	Common WBE with primary well barrier.
2. Casing	2	Part below production packer is a common WBE with primary well barrier.
3. Wellhead	5	Inclusive casing hanger and access line with valves.
4. Tubing hanger	10	Common WBE with primary well barrier.
5. Surface production tree	33	Common WBE with primary well barrier.
6. Coiled tubing safety head	16	Safety head body common WBE with primary well barrier.

Notes
Compensating measures for common WBEs can be:
1. A high pressure line shall be hooked up and leak tested for pumping kill fluid.
2. Sufficient fluid and materials available at the location to efficiently kill the well.