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Plug and abandonment Using "Perforate, Wash and Cement" Technique And Verification Of The Plug

By

Sofie Stange Erland

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Abstract

When a well is permanently plugged and abandoned (P&A), a plug has to be set over the entire cross section of the well. The conventional method to perform a P&A operation is to mill the casing and pull it to surface before plugging the well, which is a time consuming and expensive method. The perforate, wash and cement (PWC) method is a very interesting technology. It has the possibility to be both faster and more cost effective than a milling operation.

Today the main challenge for the PWC technology is the time consumption on the verification of the plug. For a milling operation the cement will always cover the entire plugging area, as this is an open hole. When plugging a well with the PWC technology the cement is forced through small perforations into the annulus or both annuli. Continuous cement in the annulus has to be verified to approve the plug. For a single casing, this can easily be performed by drilling the plug and logging the annulus. The challenge arises when two casings are cemented, because currently there are no technologies available to log through two casings. Reducing the time used on drilling the plug and logging the cement is the key for the PWC technology to become a cost effective P&A method. When operators have set enough successful plugs to rely on the PWC technology, there will be no need to drill out the plug and log the annulus anymore. The verification of the plug can then be performed according to NORSOK D-010 requirements, which is pressure testing and tagging of the plug. So for now the largest challenge is to verify continuous cement in two annuli, and finding a technology to get a faster and more accurate result when pressure testing the plug.

The main scope with this thesis is to give an insight into the PWC technology, discuss the verification challenges, and suggest solutions for future verification methods. It also gives an insight into the regulations and requirements that a P&A operation needs to fulfill. The thesis is divided into four parts; description of NORSOK D-010 regulations and requirements for a P&A operation, general theory for cementing and verification, the PWC technology, and finally a verification, discussion and conclusion part.

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List of abbreviations

BOP	blow out preventer
CBL	cement bond log
ECD	equivalent circulation density
HSE	health, safety and environment
ID	inner diameter
LOT	leak off test
MD	measured depth
NCS	Norwegian continental shelf
OBM	oil based mud
OD	outer diameter
POOH	pull out of hole
PIT/FIT	pressure/formation integrity test
RIH	run in hole
PWC	perforate, wash and cement
RPM	rotation per minute
SPF	shots per foot
TCP	tubing conveyed perforating
TD	true depth
TOC	top of cement
TRL	technology readiness level
TVD	true vertical depth
VDL	variable density log
WBE	well barrier element
WBS	well barrier schematic
WOC	wait on cement
XLOT	extended leak-off test

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1. Introduction

The oil adventure started up in 1966 on the Norwegian Continental Shelf (NCS) (Khalifeh, Hodne, Saasen, & Vralstad, 2013). Since this year, 5334 wells have been drilled, and a large amount oil and gas have been produced. 3855 of these wells are production wells, while 1479 are exploration wells (2014). As time is passing, a vast amount of the production wells are reaching the end of their productive life. Oil production is dependent on a high enough pressure in the well to be able to produce, so water injection and other enhanced oil recovery methods are used in order to maintain pressure. However at some stage there is not enough oil produced compared to the expenses incurred from keeping the well alive. P&A is solely driven by the economics, so when operating expenses becomes higher than operating incomes it is time to permanently abandon a well (Desai, Hekelaar, & Abshire, 2013).

When permanently abandoning a well, the full cross section of the well bore shall be covered by an impermeable mass. This includes covering all annuli, and the mass shall seal both vertically and horizontally, as shown in Figure 1. If cement is lacking in annulus, it has to be accessed and filled with cement. Traditionally access to annulus is achieved by milling the casing. The well is then cleaned to remove swarf and other debris. Afterwards the section is under reamed to expose new formation enabling the cement to achieve good bonding to the formation.

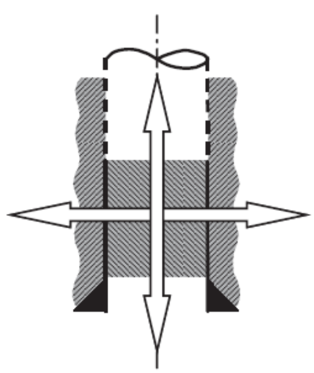


Figure 1: Permanent well barrier (NORSOK D-010, 2013)

Swarf debris created from milling may lead to a lot of problems in the well and with equipment. Swarf is defined as metal filings or shavings removed by a cutting tool. These have sharp angular surfaces which can damage equipment and people (T. E. Ferg et al., 2011). In the well the cuttings can pile up from total depth to the top, and create a ‘bird nest’ as shown in Figure 2. Well control is also a large issue as the swarf can cause damage to the blow out preventer (BOP). In addition to difficulties with cleaning the well, handling of swarf also introduces Health, Safety and Environmental (HSE) challenges. With the traditional P&A method the time consumption is approximately 20-60 days, on average 35 days per well is used (Khalifeh, 2014). So for future wells to be abandoned on the NCS and say 15 rigs are available to P&A, the time to P&A all the wells will be 40 years with the traditional method (Straume, 2013).

Figure 2: ‘Birds nest’ of metal swarf around drillpipe (T. Ferg, 2013)

There is a unified perception in the industry that P&A is one of the major challenges to be resolved in the future. There is a large interest to decrease the cost of P&A as it may contribute to as much as 25% of the total drilling exploration well cost on the NCS. Especially now, since the number of wells that need to be plugged is increasing. (Khalifeh et al., 2013) The amount of wells to be permanently abandoned for Statoil is escalading rapidly from today towards 2030. During the last years companies have been working on a new technology where milling can be avoided. With the new technology it is possible to perforate, wash and cement all in one or two trips. By avoiding handling of swarf, reducing tripping time and eliminating the time used on milling, a large amount of time and money is saved.

Statoil is currently in the starting phase with P&A and is utilizing three different methods. These are:

- Cut and pull
- Milling (Top down or section)
- Perforate, Wash and Cement

The main goal for the future in Statoil is to verify methods and technology which along with improved knowledge and competence will significantly reduce the time consumption, and consequently the cost (Strøm, 2013). The PWC technology is capable to do this. However, to be able to implement this technology there is a large challenge for Statoil today to verify the plug set across two annuli when permanently abandoning the wells.

In this thesis the new technology for P&A, PWC will be looked into. There is also some basic theory included for cementing and verification of a plug. The verification of the plug after placing it with the PWC technology is discussed thoroughly and a suggestion for a future solution is made. In addition it covers all the rules and regulations NORSOK D-010 provide for P&A operations on the NCS.

2. P&A in general

Plugging is defined as the "operation of securing a well by installing required well barriers", and a well barrier as an "envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment" by NORSOK D-010. So P&A is about leaving a well, or a reservoir target, for good, in a safe manner, by ensuring the cap rock has the same sealing ability it had before it was drilled through.

When abandoning a well there are three different phases. The first phase involves abandoning the reservoir. This is considered to be a drilling job, where the primary and secondary barrier is set to isolate all producing or injection zones. The tubing can be left in the well partly or fully retrieved. There is a requirement that a bond between tubing steel and cement have to be created, to prevent leakage in the future. The second phase is also a drilling job, called intermediate abandonment. In this phase liners are isolated, milling is performed and the casing is retrieved. Barriers are set against intermediate hydrocarbon or water-bearing permeable zones, and a near-surface cement plug may be installed. In the third and last phase, the wellhead and conductor is removed. The conductor casing is cut and pulled, the wellhead is removed and the crater is filled with cement. This last phase can be performed by a vessel instead of a drilling rig. (Khalifeh, 2014)

Flow potential requirements in overburden zone in P&A activities are set to zero in NORSOK D-010. This is 'impossible' to relate to, especially since it should be defined to have a flow potential if in doubt. Due to this it is important to establish a common understanding of 'overburden challenges' when planning a P&A operation. The 'overburden challenge' is zones above the reservoir which have flow potential, but not much pressure. Their flow potential must be looked into, to find a P&A procedure for them. Examples are Lista in the Tampen area, Grid/Skade and Shetland/Viking Graben (Strøm, 2013). If they have a flow potential that has to be considered and sealed off when P&A the well, it leads to more time and money being used. Investigating their potential of flow could therefore result in a large amount of money being saved.

2.1. Time consumption during a P&A operation

Time consumption during a P&A operation was looked into and it was found three large time consuming operations. In Figure 3 it is shown that most of the time is used on casing, tripping and milling. So, to reduce the time and cost of P&A operations, removing or at least reducing time spent on these operations, will have the largest effect on the economics. This is where the PWC technology comes to good use. Avoiding milling, pulling of casing and tripping results in 79% of the total time consumption being removed. From 2000-2010 this would result in 3890.5 saved hours. Of course this is a rough number, because it does not account for perforation time which comes in addition, but it gives a good picture of how much could be saved. Statoil ASA wants to take existing methods and technologies into daily use and contribute to the development of new "game changing" technologies. PWC could be a useful alternative.

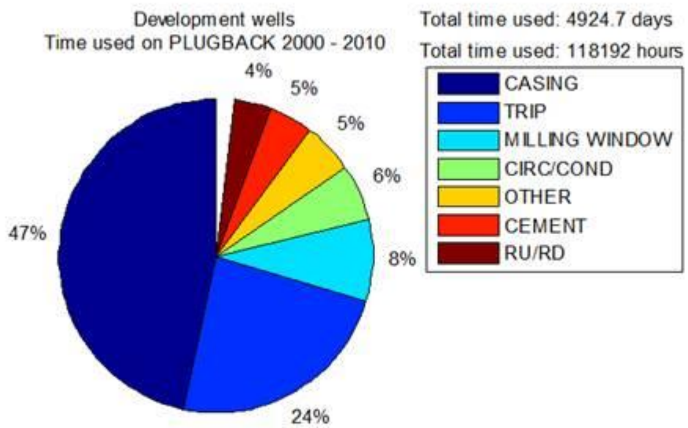


Figure 3: Time consumption during P&A (Strøm, 2014a)

As an example Halliburton have used the HydraWash system to perforate, wash and cement wells in a single trip. In total they saved 414 rig days while plugging 67 wells. By eliminating the need to mill, pull casing and tripping Halliburton saved the operator for $18 million per well on 50 of these 67 wells. (Halliburton, 2013)

When designing a subsurface well today, a drilling and well design basis shall be prepared according to NORSOK D-010. This includes that all plug and abandonment solutions should be assessed and documented. This is a very important part of the new revision of NORSOK D-010.

Involving P&A early in the completion phase may reduce the final cost when the well is to be P&A. A problem with old wells today, is that the documentation is very bad. In many cases, the information about the cement job is very inaccurate, if not lacking completely. With good documentation and verification of cement behind casing, there might not be a need to log the annulus before permanently P&A. Thus saving time and money during the P&A operation.

2.2. Well abandonment challenges

In addition to cost there are other challenges when P&A a well. Each well is unique and has its own history, making the operation very complex. Many wells have problems with collapsed casings; other wells have bad cementing jobs, while the next may have high pressure and high temperature. So no general procedure can be made for P&A on the NCS. A large challenge is still to make the operation economically sustainable for the operators.

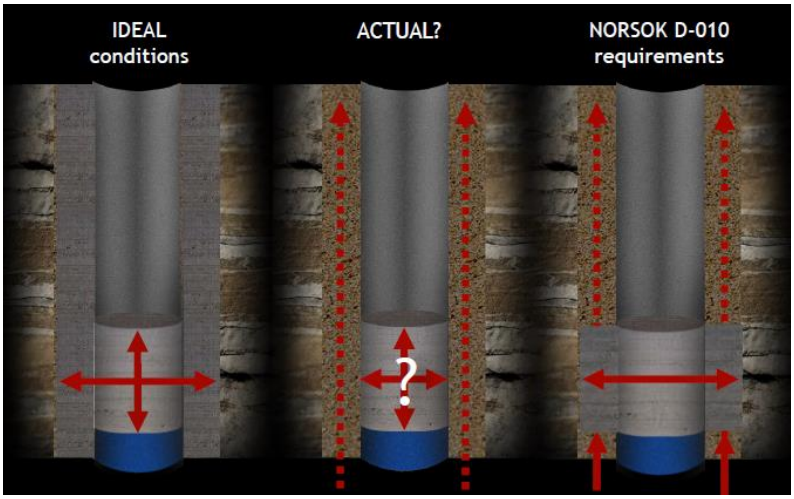


Figure 4: Conditions for P&A (Hydrawell, 2014a)

Before a P&A operation is started, the ideal conditions in the well is a fully cemented annulus, where a cement plug can just be placed inside the casing, see Figure 4. Unfortunately the sealing capacity can be very poor in the annulus of some wells, after unsuccessful cement jobs. So to fulfil the requirements of NORSOK D-010, a plug has to be set that seals the entire cross section of the well. This involves placing cement outside the casing. The conventional method is milling, but with the PWC technology a Tubing Conveyed Perforating (TCP) gun shoots holes and cement is squeezed into the annulus after a washing sequence that removes the debris in the annulus. The technology is described in more detail in Chapter 7.

3. P&A definitions, rules and regulations

Element acceptance criteria (EAC) tables referred to in this chapter can be found in Appendix A.

The government representative Norwegian Petroleum Safety Authority (PSA) regulates all petroleum activities in the Norwegian industry (Khalifeh et al., 2013). They are responsible for safety, emergency preparedness and the working environment on the NCS. All operating companies have full responsibility themselves for operating acceptably, and thus PSA is only there to enhance the awareness (2014). With the support of the Norwegian Oil and Gas Association and the Federation of Norwegian industries, the Norwegian petroleum industry, as a part of the NORSOK initiative, has developed the NORSOK standards. One standard, NORSOK D-010, is developed with requirements and guidelines related to well integrity in drilling and well activities, on the Norwegian continental shelf. It focuses on establishing well barriers by using well barrier elements (WBE). It defines the WBEs acceptance criteria, their use and how they should be monitored, to preserve their integrity throughout their life cycle. The standard also covers well integrity management and personnel competence requirements. This is the standard used for P&A operations on the NCS.

The wave of P&A operations appears to have come unexpected to the industry as well as the government. After NORSOK D-010 rev. 3 was published in August 2004, the time used on P&A increased significantly. In this revision there was a new demand that the WBE had to extent over the entire cross section of the well. The latest revision of NORSOK D-010, rev.4, was published in June 2013. Then P&A became a part of the design basis for a well, where the plug and abandonment solutions have to be assessed and documented. Earlier P&A was not considered until the well had to be plugged. More regulations and rules regarding P&A also increase the cost of the operation. Many of these were also included in NORSOK D-010 rev.3, and led to an increased cost then. So considering increased regulations, cost and a wave of P&A jobs coming up, there is a rush to get a cost effective technology approved for use.

3.1.The well completion

Figure 5 gives an overview over casing and annulus in a completed well. The inner annulus of the well is called A-annulus, the second; B-annulus, the third C-annulus and this continues to the outer annulus. The reservoir at the bottom is a permeable formation containing hydrocarbons.

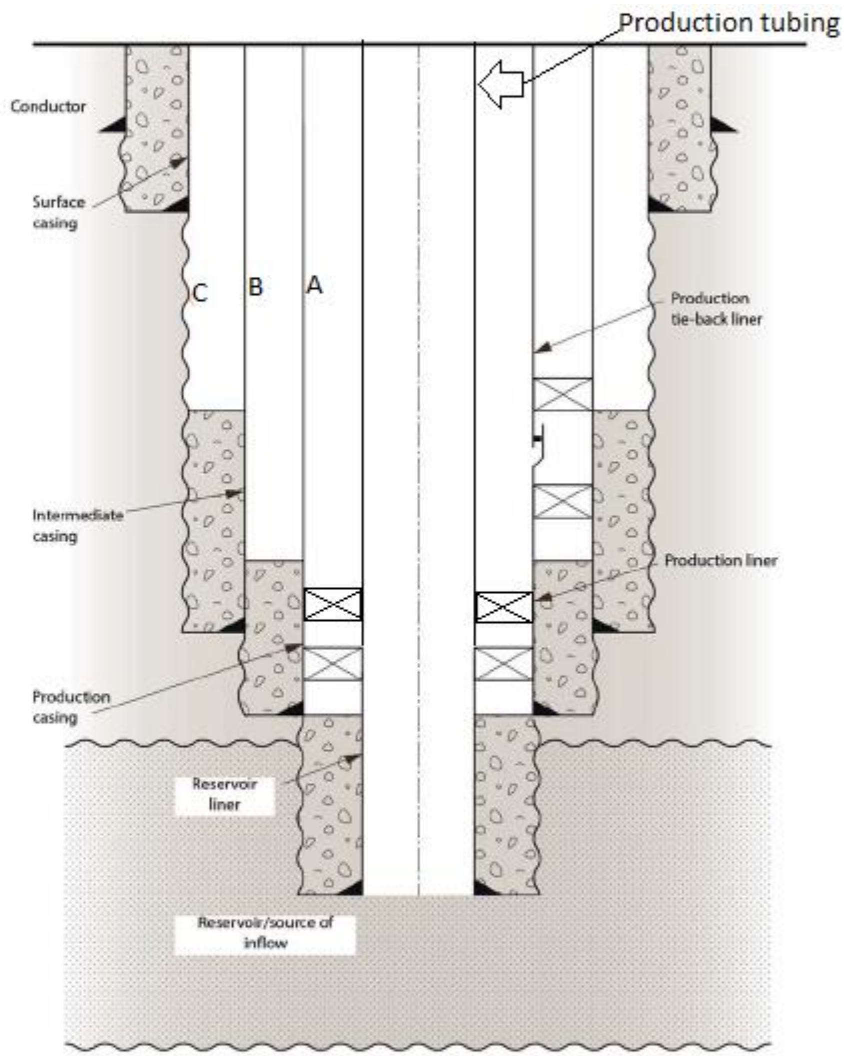


Figure 5: Casing/liner naming convention

The reservoir is the zone that shall be sealed off during a P&A operation. In addition there might be zones above the reservoir containing pressure as described in Chapter.2. Before plugging the reservoir it has to be killed first. This is done by injecting a heavy fluid and afterwards the plugs are set across the entire cross section of the well. For the overburden zone, the pressure has to be evaluated and then barriers are set according to the pressure and regulations in NORSOK D-010. The required amount of WBE with regard to pressure for different sources is described in Table 1.

Table 1: Function and number of well barriers (NORSOK D-010, 2013)

Minimum number of well barriers	Source of inflow
One well barrier	a) Undesirable crossflow between formation zones b) Normally pressured formation with no hydrocarbon and no potential to flow to surface c) Abnormally pressured hydrocarbon formation with no potential to flow to surface (e.g. tar formation without hydrocarbon vapor)
Two well barriers	d) Hydrocarbon bearing formations e) Abnormally pressured formation with potential to flow to surface

3.2. Well barriers requirements

NORSOK D-010 states that well barriers shall be defined prior to commencement of an activity or operation. This involves identifying the required WBE which needs to be in place, their specific acceptance criteria and monitoring method. This is done by making a well barrier schematic (WBS), and it should be made:

a) " when a new well component is acting as a WBE;
b) for illustration of the completed well with XT (planned and as built);
c) for recompletion or workover or workover on wells with deficient WBEs; and
d) for final status of permanently abandoned wells."

In addition it should contain the following information:

e) "A drawing illustrating the well barriers, with the primary well barrier shown with blue color and secondary barrier shown with red color.
f) The formation integrity when the formation is part of a well barrier
g) Reservoirs/potential sources of inflow.
h) Tabulated listing of WBEs with initial verification and monitoring requirements.

i) All casings and cement. Casing and cement (including top of cement (TOC)) defined as WBEs should be labeled with its size and depth (True vertical depth (TVD) and measured depth (MD))
j) Component should be shown relatively correct position in relation to each other.
k) Well information: field/installation, well name, well type, well status, well/section design pressure, revision number and date, "Prepared by", "Verified by"
l) Clear labeling of actual well barrier status – Planned or as built.
m) Any failed or impaired WBE to be clearly stated.
n) A note field for important well integrity information (anomalies, exemptions, etc.)"

3.2.1. Casing cement in primary and secondary well barriers

It is possible for the same casing cement to become WBEs in both the primary and secondary well barriers as long as the acceptance criterions in EAC 22 are fulfilled. This states that the cement length for a qualified WBE shall be 2 x 30 m MD, which is obtained by bond logs that have been verified by qualified personnel. The casing cement will then not be defined as a common WBE, but two distinct intervals, that are defined as the primary and secondary well barrier.

3.2.2. Common well barrier elements

When designing a well, all well barriers shall be designed, selected and constructed with the aim to be independent. Two dependent well barriers should be avoided, but this might not be possible to establish for all well activities. If two dependent barriers occur NORSOK D-010 states that "a risk analysis shall be performed and risk reducing measures applied. This shall include additional precautions and acceptance criteria when qualifying and monitoring the common WBE."

3.2.3. Verification of well barrier elements

NORSOK D-010 has defined the following verification rules for WBE. “When a WBE has been installed, its integrity shall:

a) be verified by means of pressure testing by application of a differential pressure; or
b) when a) is no feasible, be verified by other specified methods.

Well barrier elements that require activation shall be function tested.” If the condition of any WBE is changed or loads for the remaining life cycle of the well is changed, then a re-verification should be performed.

A WBE must be able to withstand a differential pressure of $\Delta P = P_1 - P_2$, where P_1 is the formation pressure and P_2 is the pressure above the plug as shown in Figure 6. In addition to the differential pressure, the length must be 50 m inside the casing and in annulus, or 30 m verified cement in the annulus.

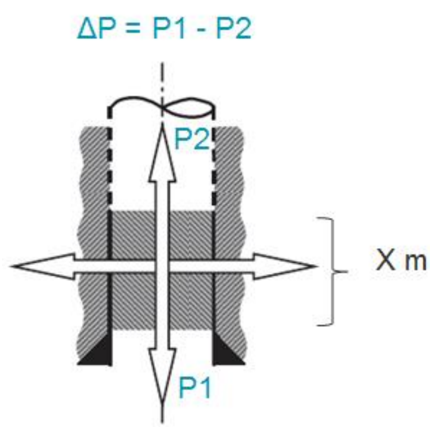


Figure 6: Verification of a barrier

The acceptable leak rate for a WBE is zero, but other can be specified in EAC’s. “For practical purposes acceptance criteria should be established to allow for volume, temperature effects, air entrapment and media compressibility. For situations where the leak-rate cannot be monitored or measured, the criteria for maximum allowable pressure leak (stable reading) shall be established.” (NORSOK D-010, 2013)

Pressure test direction

When performing a pressure test to verify the integrity of the WBE it shall always be applied towards the external environment, which is the direction of flow. This is usually not possible to do, so the pressure can be applied against the direction of flow, as long as the WBE is constructed to seal in both flow directions. (NORSOK D-010, 2013)

Test pressure values and duration

For a high pressure test, pressure applied shall be equal to, or higher than the maximum differential pressure that the WBE may be exposed to. For an approved test, a static test pressure shall be observed and recorded for minimum 10 minutes with stable reading. (NORSOK D-010, 2013)

For a negative pressure test, NORSOK D-010 states that it should last for a minimum of 30 minutes, with stable readings. This time should be increased if there are larger volumes, high compressibility fluids, or temperatures effects.

To qualify a pressure test the following should apply according to NORSOK D-010:

a) “consider the monitored volume when setting the test acceptance criteria;
b) establish maximum acceptable deviation from test pressure (x bar deviation from test pressure, e.g. 5 bar for a 245 bar test);
c) establish maximum allowable pressure variation over the defined time interval (e.g. 1% or 3.45 bar for a 345 bar test over 10 minutes);
d) A condition for the criteria in b) and c) is that the pressure change over time ($\Delta P/\Delta T$) is declining.”

3.2.4. Well barrier positioning

When permanently abandoning a well, the main objective is to restore the well back to its natural isolation between geological layers, which is the cap rock of the reservoir (Nelson & Guillot, 2006).

To achieve the natural isolation, individual or combined well barriers shall be set. All barriers required are shown in Figure 7. First of all the primary well barrier is set to isolate the source of inflow from surface. The position of the barrier shall be at a depth where the formation integrity is higher than the potential pressure of inflow.

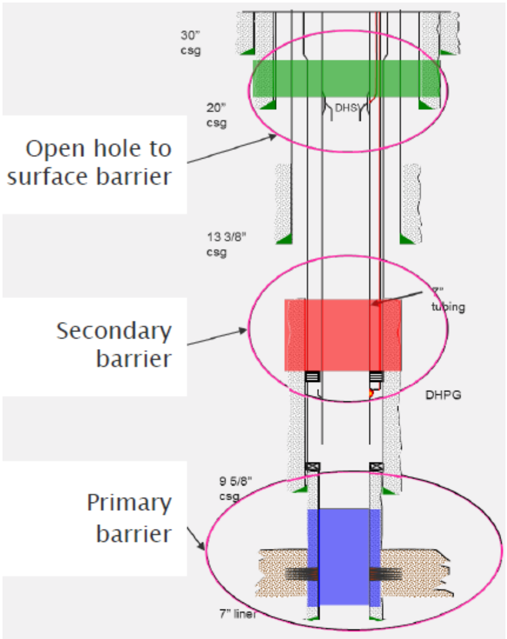


Figure 7: Barriers required when permanently abandoning a well (Hemmingsen, 2014)

The formation integrity is defined as the capability to withstand pressure applied by wellbore-, injected-, or formation fluids from the permeable formations in the well. To qualify a formation as a barrier element, sufficient formation integrity shall be defined and documented. For a P&A operation the requirement for the depth of the permanent barrier is the minimum formation stress. So the primary and secondary plug shall be positioned at a depth were the formation integrity is higher than a potential pressure from below (Statoil ASA, 2013).

A secondary well barrier is set to act as a backup for the primary well barrier. If there are several formations in the well, fluids will flow between them. If the formations are in different pressure regimes this cross-flow have to be prevented. This is done by installing a cross-flow well barrier, which also functions as a primary barrier for the reservoir. Two reservoirs within the same pressure regime can be regarded as one reservoir, as shown in Figure 8.

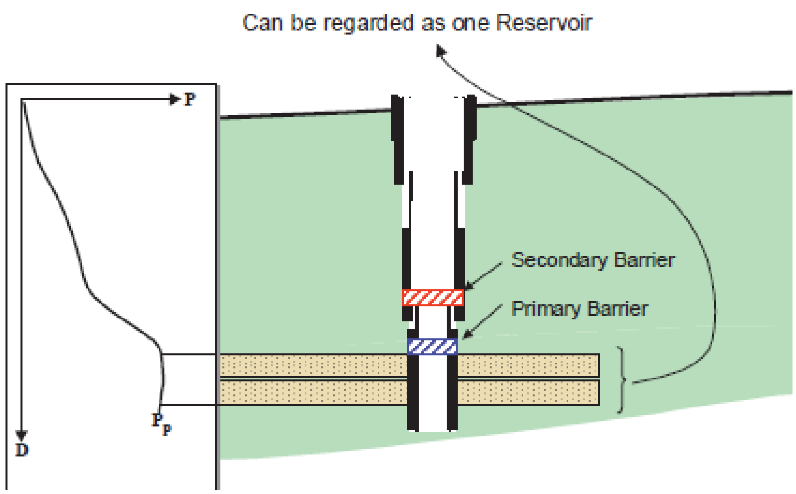


Figure 8: Multiple reservoirs (NORSOK D-010, 2013)

At the top of these reservoirs an open hole to surface well barrier is set, as an environmental plug. This plug has no depth requirements with respect to formation integrity. It is set to permanently isolate flow conduits from exposed formation above the secondary well barrier, and contain environmentally harmful fluids. The exposed formation can be over pressured, but not contain any source of inflow. When leaving a well, there shall be no traces of there ever being anything there. The X-mas tree is removed, the top 5 m of the conductor and casing is pulled, wellhead is removed and everything is filled with soil. (NORSOK D-010, 2013) For deep water wells it might be enough to just leave or cover the wellhead/structure.

The removal of equipment on the seabed has a lot to do with fishing activities on the NCS. So in deep water these subsea constructions will not be an obstacle because there is no fishing activity here. The equipment can then be left on the seabed if there are not any regulations in that specific area.

Formation integrity

Normally the formation integrity is defined while drilling the well to ensure well integrity. The formation integrity is commonly defined by a pressure/formation integrity test (PIT/FIT), a leak-off test (LOT) or an extended leak-off test (XLOT). In Figure 9 all tests are described by a pressure vs time curve.

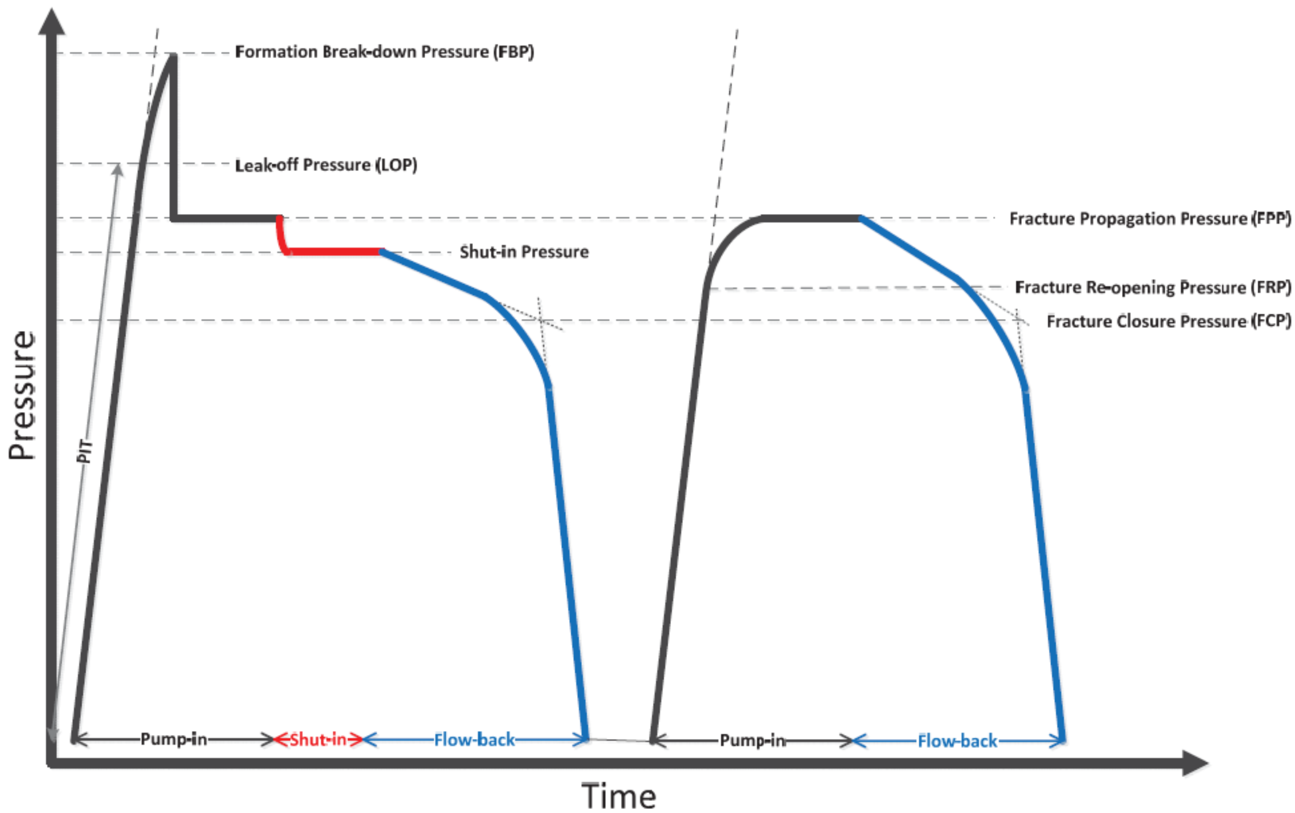


Figure 9: XLOT pressure graph (NORSOK D-010, 2013)

A PIT/FIT test is performed to confirm that the formation and the casing cement is capable to support a pressure that is pre-defined. It is performed by applying that pre-defined pressure to the formation and observe if it stays stable.

To find what pressure the wellbore wall and casing cement is capable to support a LOT is performed. This test is performed by applying a pressure, and once there is a deviation from the linear pressure vs volume curve, the test is stopped. The deviation point is the LOP shown in Figure 9.

A XLOT determines the minimum in-situ formation stress. An example of the pressure during the test is shown in Figure 9. This test propagates a fracture into the formation and establishes the fracture closure pressure (FCP).

3.3. Abandonment design

When planning to abandon a well, all sources of inflow shall be identified and documented. All WBEs used shall be able to withstand the load and environmental conditions they may be exposed to for the abandonment period.

According to NORSOK D-010, "the design and placement of WBE consisting of cement or alternative materials should account for uncertainties relating to:

a) down hole placement techniques;
b) minimum volumes required to mix a homogenous slurry;
c) surface volume control;
d) pump efficiency/ -parameters;
e) contamination of fluids
f) shrinkage of cement or plugging material
g) casing centralization;
h) support of heavy slurry; and
i) WBE degradation over time."

3.3.1. Load cases

When designing a P&A job, both functional and environmental loads have to be designed for. In Table 2 different scenarios with requirements are described:

Table 2: Load cases (NORSOK D-010, 2013)

Item	Description	Additional requirements
1.	"Pressure induced by migration of formation fluids into the wellbore based on a worst anticipated reservoir pressure and lowest anticipated fluid density of the abandonment period	For permanent abandonment, increase of reservoir pressure due to natural re-pressurization to initial/virgin level, re-development scenarios (injection) or gas storage shall be accounted for and documented. The eternal perspective with regards to recharge of formation pressure shall be verified and documented.
2.	Pressure testing in casing plugs	Criteria as given in EAC 24
3.	Temporary abandonment plugs: induced internal pressure by migration of formation fluid into the wellbore	Ensure the induced internal pressure is less than the burst rating of the casing (including wear) at the plug setting depth
4.	Collapse loads from seabed subsidence or reservoir compaction	The effects of seabed subsidence above or in connection with the reservoir shall be included
5.	Damage to primary cementation (crack forming) due to pressure test	Load cases do not include damage to primary cementation due to pressure testing"

3.3.2. Well control action procedures and requirements

Before a well operation all possible situations are thought through, evaluated and a safety assessment is done. Measurements are always done to increase the safety of the operation. Each operation is gone through step by step, and every step that may go wrong is evaluated and a well control procedure is made.

Table 3 gives overview over some given incidents that may occur under different procedures done in a well. There should be well control action procedures available to deal with these if they occur.

Table 3: Well control action procedures (NORSOK D-010, 2013)

Item	Description	Comments
1.	“Cutting of casing	Fluid losses or trapped gas pressure in annulus
2.	(Subsurface well - SSW) Pulling casing hanger seal assembly	Fluid losses or trapped gas pressure in casing annulus
3.	Re-entry of suspended or temporary abandoned wells	Account for trapped pressure under shear ram or under plugs due to possible failure of temporary plugs”

Cutting or perforating the casing, or retrieving seal assemblies are situations where the well integrity is at stake. There are large forces present, and it is not clear what might actually be behind with regards to pressure. Due to this, NORSOK D-010 require active pressure control equipment to be in place to prevent uncontrolled flow from annuli and into the well and/or riser.

3.3.3. Temporary plug and abandonment

Temporary abandonment is accomplished by inserting retrievable plugs at different depths in the well (Zwaag, 2013). A well is typically temporary abandoned when there is uncertainty regarding the well situation, before the well is decided to be permanently abandoned or if the rig has to be moved away from the well.

Definition and requirements

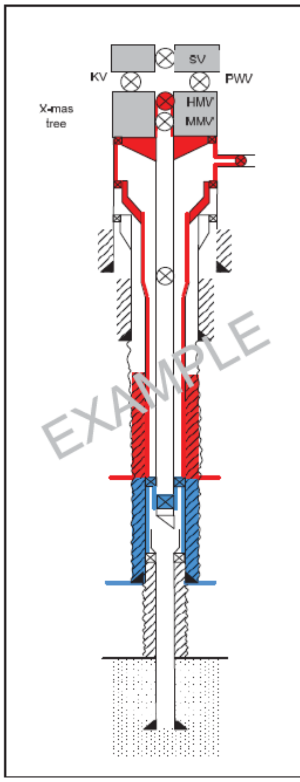
In NORSOK D-010 temporary abandonment is defined in two different ways, one with monitoring and one without monitoring:

a) A well where the primary and secondary well barriers are continuously monitored and routinely tested, is temporary abandoned. If this can not be accomplished, the well shall be categorized as a temporary abandoned well without monitoring. For temporary abandoned wells with monitoring, there is no maximum abandonment period.
b) The well is temporary abandoned without monitoring when the primary and secondary well barriers are not continuously monitored and not routinely tested. For a temporary abandonment without monitoring the maximum abandonment period shall be three years.

Before temporary abandoning a well NORSOK D-010 require a documented plan for the well regarding the future plans for the well and the durations of the abandonment. Also it shall be possible to re-enter the well in a safe manner for the planned duration.

When a well is temporary abandoned with monitoring, the WBE has to be monitored and tested periodically according to the respective EAC table. For those without monitoring the WBE material(s) shall have sufficient integrity to hold the planned abandonment period.

In Figure 10 an example of a production well is shown. It is temporary abandoned with a deep set mechanical plug and is continuously monitored.



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement (up to prod packer)	22	
Casing (up to prod packer)	2	
Production packer	7	
Deepset plug	6	
Secondary well barrier		
In-situ formation (at prod packer)	51	
Casing cement (above prod packer)	22	
Casing	2	
Casing hanger (with seal assembly)	5	
Annulus access valve	17	
Tubing hanger (with seals)	10	
Surface production tree valves/connector	31	
Surface production tree body	31	

Figure 10: Example of production well temporarily abandoned with monitoring (NORSOK D-010, 2013)

3.3.4. Permanent plug and abandonment

Permanent abandonment is defined in NORSOK D-010 as “a well status, where the well is abandoned and will not be used or re-entered again.” It states the well barrier acceptance criteria: “Permanently abandoned wells shall be plugged with an eternal perspective taking into account the effects of any foreseeable chemical and geological processes. The eternal perspective with regards to re-charge of formation pressure shall be verified and documented”. If there is any source of inflow potential above the formation these shall also be assessed with regards to abandonment requirements.

To be able to achieve complete isolation with a plug all equipment that can reduce or cause loss of well integrity has to be removed. This accounts for all control lines and cables, which are installed in the well. In addition the well barrier shall be placed adjacent to an impermeable formation that has sufficient formation integrity to hold the maximum anticipated pressure.

A permanent well barrier shall according to NORSOK D-010 have the following characteristics:

a) "provide long term integrity (eternal perspective);
b) impermeable;
c) non-shrinking;
d) able to withstand mechanical loads/impact;
e) resistant to chemicals substances (H_2O, CO_2 and hydrocarbons);
f) ensuring bond to steel;
g) not harmful to the steel tubular integrity."

Well barrier element acceptance criteria

Some additional requirements and guidelines to casing, cement and in-situ formation from EAC 2, EAC 22, and EAC 51 is defined and is listed in Table 4:

Table 4: Additional EAC requirements (NORSOK D-010, 2013)

Table no.	Element name	Additional features, requirements and guidelines
2	"Casing	Steel tubular WBE shall be supported by cement or alternative plugging materials
22	Casing cement	Cement in the liner lap or in tubing annulus can be accepted as a permanent WBE when the liner is centralized in the overlap section. The casing cement in the liner lap shall be logged.
51	In-situ formation	The in-situ formation (e.g. shale, salt) shall be impermeable and have sufficient formation integrity."

Due to the eternal perspective criteria for a permanent WBE, elastomer sealing components are not acceptable. When completion tubulars are left in the well, NORSOK D-010 requires that the position and integrity of WBE installed in tubing and annulus shall be verified:

a) "The casing cement between the casing and tubing shall be verified by pressure testing.
b) The cement plug (inside tubing) shall be tagged and pressure tested."

External and internal WBE

Figure 1 illustrated that a permanent barrier shall create a vertical and horizontal seal over the entire cross section. This cross section can be divided into an external section, normally casing cement and an internal section which is isolated by a cement plug.

Verification of the external WBE shall be done to ensure both vertical and horizontal seal, with a requirement of 50 m formation integrity. If this is verified by logging minimum 30 m with acceptable bonding is required. To ensure the casing cement is good enough, the information from the well completion of the well should be checked. If this is a critical cementing job, the casing cement shall be logged. This also applies when the same casing will be a part of the primary and secondary well barrier.

The internal WBE shall be positioned over the entire interval where a verified external WBE exists. If the plug is set on top of a mechanical plug or cement as foundation it shall be minimum 50 m. Placing a plug without a foundation requires 100 m of cement to be placed. For any other case it will be according to EAC 24. (NORSOK D-010, 2013)

Section milling to establish a cement plug

If casing cement is not verified as a barrier, access to annulus must be created to establish new well barriers. Milling is one method of achieving this access, and the following example shown in Figure 11 can be applied when section milling is required.

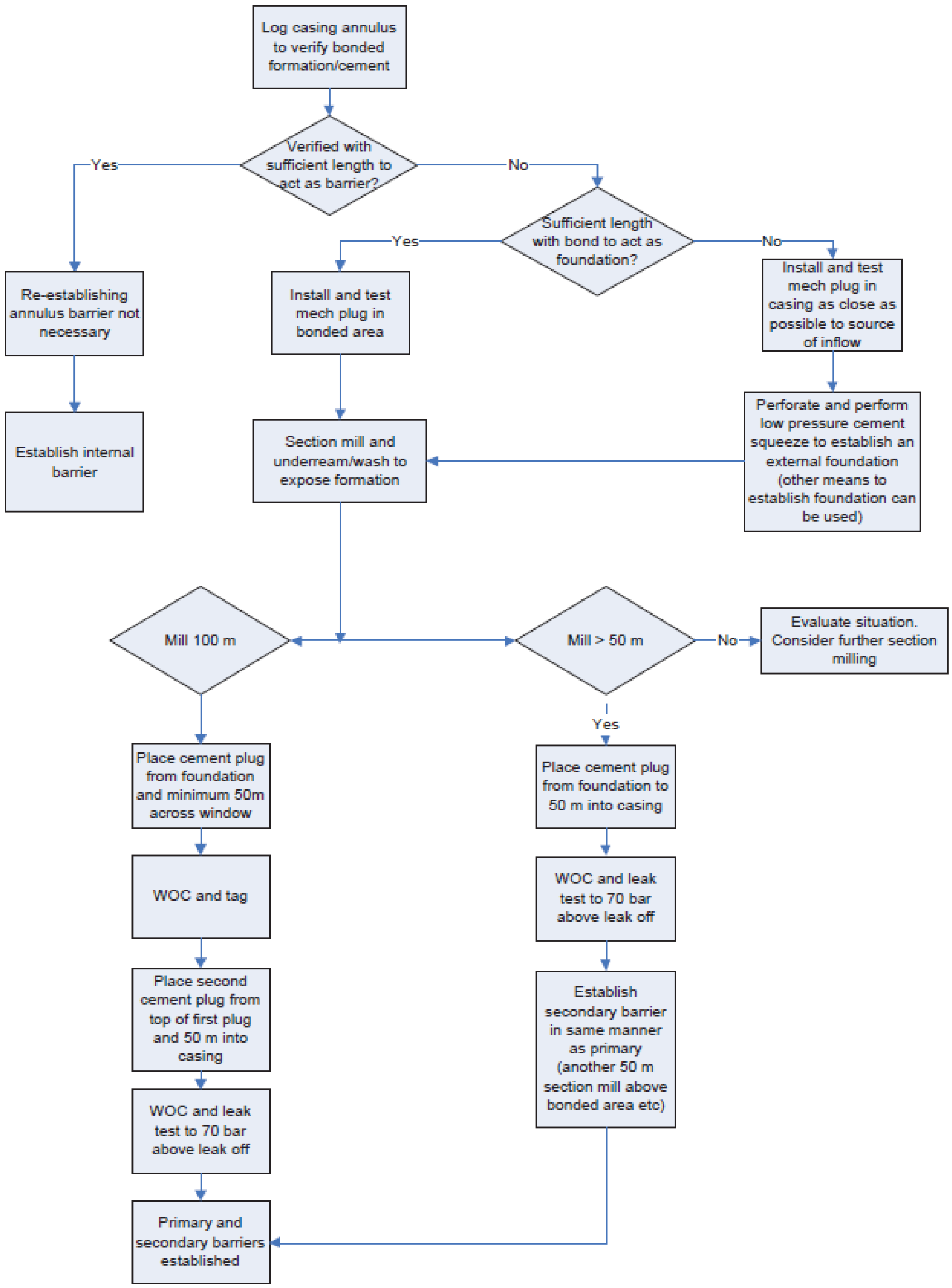


Figure 11: Section milling to establish plug (NORSOK D-010, 2013)

Alternative method to establish a permanent well barrier

The following example shown in Figure 12 can be applied for wells with poor casing cement, and is an alternative method to milling the casing.

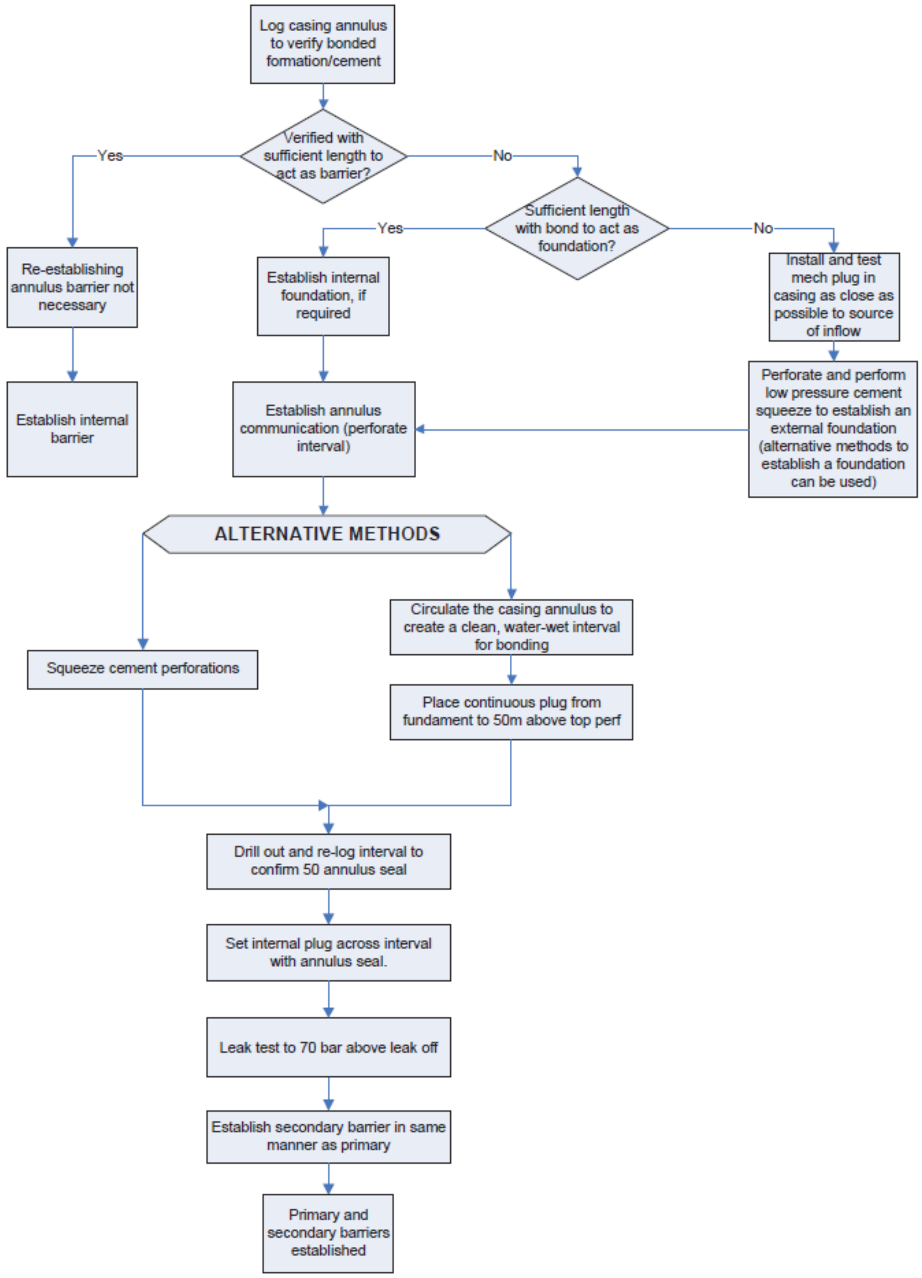


Figure 12: Alternative method to establish a permanent well barrier (NORSOK D-010, 2013)

Example of permanent well abandonment

In Figure 13 an example of a simple permanent abandonment is shown. This is the situation if the cement behind the casing is good, where minimum 50 m of cement is known to be in place, or 30 m of cement is verified by logging.

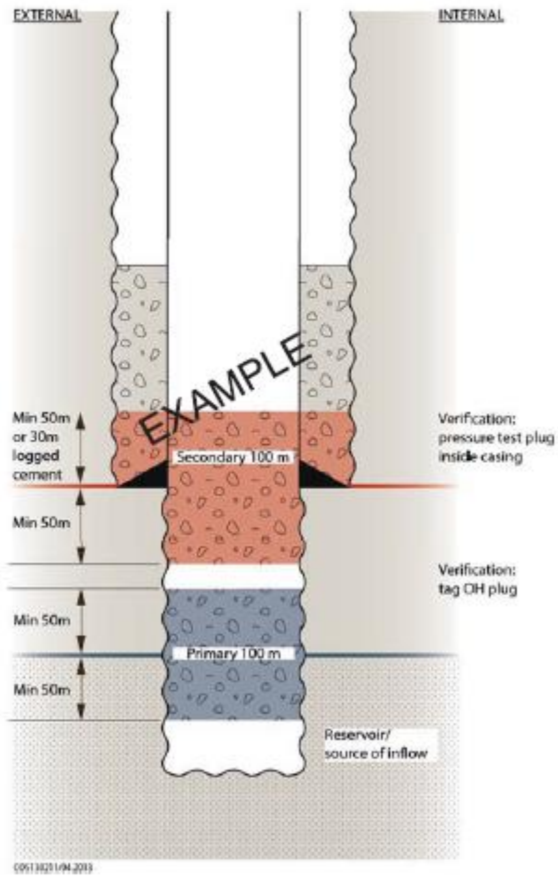


Figure 13: Permanent abandonment of an open hole and inside casing plugs (NORSOK D-010, 2013)

The primary plug is set in an open hole, above the reservoir. The plug must be minimum a 100 m long, and it is verified by tagging since it is in an open hole. The secondary plug must be placed inside the casing, across the casing shoe. Minimum 50 m of cement must be placed in the open hole and minimum 50 m of cement inside casing. This plug is pressure tested since it is placed inside the casing.

Figure 14 shows a more complicated well. In this well the cement in the annulus is not good enough, so the casing has to be milled to establish a horizontal barrier across the well. It can be permanently abandoned in two different ways: either with a continuous plug or with two separated plugs.

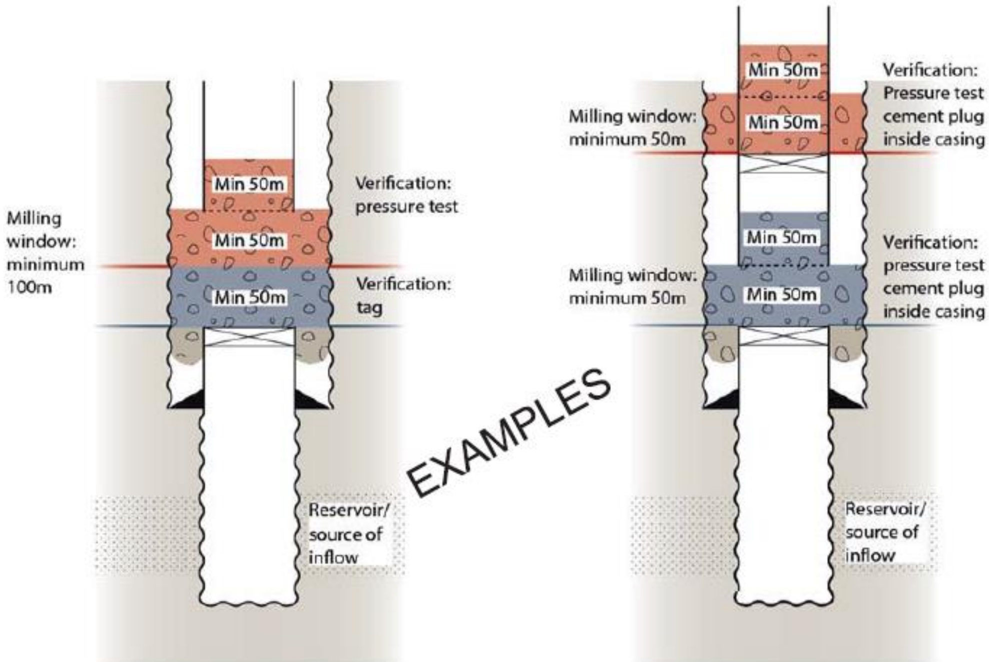


Figure 14: Permanent abandonment using section milling (NORSOK D-010, 2013)

To create a continuous plug, 100 m of the casing is milled, and the swarf is circulated out of the well. There is some cement in the annulus, which can work as a base for the new cement. Inside the casing a mechanical plug must be set to act as a base for the cement plug. The primary plug is cemented, with minimum 50 m. This is verified by tagging. Then the secondary plug is cemented, with minimum 50 m in the open hole, and minimum 50 m inside the casing. This plug is verified by pressure testing since it is inside the casing.

Two separate sections of the casing must be milled to create two separate plugs. A section of 50 m is milled for each plug. The procedure is the same as for a continuous plug, except now both plugs have to enter minimum 50 m into the casing above. Both can therefore be verified by pressure testing in addition to tagging.

Slot recovery

A slot recovery is when a new well path is drilled out from the original path. The original well path then has to be permanently plugged and abandoned. A new well is drilled out from the original path by setting a whipstock and drilling a sidetrack. Slot recovery enables the operator to reach a new part of the reservoir, without drilling and completing a new well. The same well slot is also used, saving the operator a lot of money. (Zwaag, 2013) This has not been discussed more in this thesis.

3.3.5. Risks

In the design phase of a well all the risks and possible worst case scenarios must be considered to ensure the safety of the environment and people working on the well. NORSOK D-010 has made a list over typical risks that should be accounted for in the design and operation:

a) "pressure and formation integrity uncertainties;
b) time effects:
    1. long term development of reservoir pressure;
    2. deterioration of materials used;
    3. sagging of weight materials in well fluids.
c) scale in production tubing;
d) H_2S or CO_2;
e) release of trapped pressure;
f) unknown status of equipment or materials;
g) environmental issues."

4. Squeeze cementing

Normally, squeeze cementing is used to fill channels behind the casing or permanently block the entry of undesired fluids to the wellbore. It is also used to shut off watered-out perforation intervals.

Squeeze cementing is a process where the cement slurry is forced under pressure, through holes or perforations into the casing or the wellbore annular space. This method ensures a good bonding between the cement and formation by forcing the slurry against the permeable formation and into the formation matrix. As the cement filtrate enters, the solid particles are filtered out on the formation face. If the formation is fractured during squeeze cementing a filter cake must develop on the fracture face and/or bridge the fracture to ensure good sealing.

When the cement slurry is pumped down into the formation it is subjected to differential pressure and a cake of partially dehydrated cement is formed as water is lost to the permeable formation. Slurry dehydration decrease at a rate directly related to the fluid-loss rate. Slurry with high fluid-loss against a permeable formation dehydrates quickly and may choke the wellbore. To build up a uniform filter cake, an ideal squeeze slurry must be mixed to control the rate. (Nelson, 1990)

4.1. Placement techniques

Squeeze cementing jobs are divided into two different classifications by (Nelson, 1990):

- *Low pressure squeeze*: which is when the bottomhole treating pressure is maintained below the formation fracturing pressure
- *High pressure squeeze*: which is when the bottomhole treating pressure exceeds the formation fracturing pressure

4.1.1. Low-pressure squeeze

In a low-pressure squeeze only a small amount of cement slurry is used, as the aim of the squeeze is only to fill the perforations and voids with dehydrated cement. Perforations and channels must be clear of mud or other solids to ensure a successful cement job.

4.1.2. High-pressure squeeze

In some cases there is need for more pressure to enter small cracks and/or micro annulus with the cement slurry. Then a high-pressure squeeze is performed. In these small cracks and micro annulus gas can flow easily through, but to enter with more viscous cement slurry the channels must be enlarged. This is accomplished by injecting high-pressurized fluids into the fractures, which break down the formation. The slurry is then displaced into the fractures, applied pressure to and dehydrated into the formation walls. (Nelson, 1990) The problem with this method is that the location and orientation of the fracture and cement slurry is not known.

4.1.3. Bradenhead placement technique (No packer)

This is the most used technique for low-pressure squeeze, and when the casings capacity is known to withstand the squeeze pressure. The technique is shown in Figure 15 and is a simple technique where open-ended tubing is run to the bottom of the perforation.

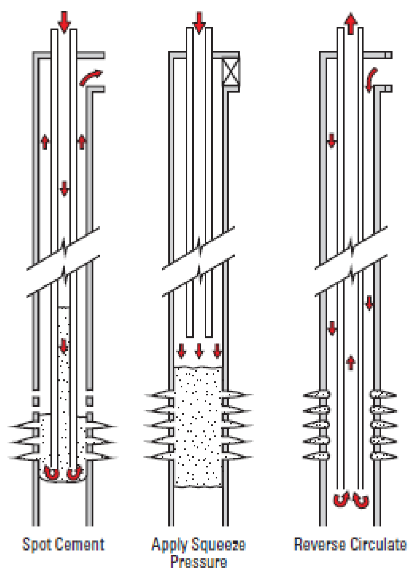


Figure 15: Bradenhead squeeze technique (Nelson & Guillot, 2006)

A bridge plug may also be required to isolate other open perforations in the hole. The BOP rams are closed to perform the injection test. The cement slurry is then injected into the perforations. (Nelson, 1990) Tubing is pulled out above the cement once the perforations are filled, BOP is closed and pressure is applied.

4.1.4. Squeeze Tool Placement techniques

Squeeze tools are used when the main objective is to isolate the casing and wellhead while applying high pressure downhole. The placement is done using either the retrievable squeeze packer method or the drillable cement retainer method.

Retrievable squeeze packer method

The retrievable squeeze packer has the advantage that the packer can be set and retrieved many times. For squeeze cementing, compression- or tension-set packers are used, which allows circulation while running in hole (RIH) and once the packer is set. This feature with bypass valves prevents a piston or swabbing effect while RIH or pull out of hole (POOH), it also allows cleaning of the tools after the cement job, reversing out excess slurry without excessive pressure. (Nelson, 1990)

Drillable cement retainer

Though the drillable cement retainer is not as flexible as the retrievable squeeze packer method, it is used when isolation is needed. It is a drillable packer provided with a valve operated by a stinger at the end of the work string. Cement retainers are used to prevent backflow when a high negative differential pressure may disturb the cement cake or when no cement dehydration is expected. With this drillable retainer it is possible to place the packer closer to the perforations. (Nelson, 1990)

4.1.5. Running squeeze pumping method

With the running squeeze pumping method the cement slurry is pumped continuously until the desired squeeze pressure is reached. The pressure is then monitored. If the pressure drops, more slurry is pumped to maintain the final surface squeeze pressure. (Nelson, 1990) The pressure drop is a result of additional filtration of the cement and formation interface. Once this pressure maintains stable for several minutes, the cement job is complete. This method usually requires a large volume of slurry.

4.1.6. Hesitation squeeze pumping method

The hesitation squeeze pumping method is the only procedure to dehydrate small quantities of cement into perforations of formation cavities. As shown in Figure 16 the procedure involves intermittent application of pressure, at a rate of ¼ to ½ bbl/min. (Nelson & Guillot, 2006) Pressure is applied every 10-20 minutes after leak off into the formation due to filtrate loss. The initial leak off is normally fast because there is no filter cake, but as the cake builds up, and the applied pressure increases, the filtration period becomes longer and the differential pressure between the initial and final pressure becomes smaller. In the end of the pumping job the pressure leak off becomes negligible.

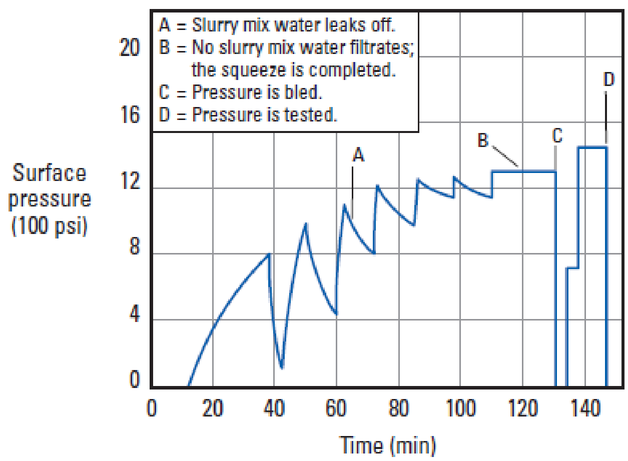


Figure 16: Hesitations squeeze pressure behavior (Nelson & Guillot, 2006)

4.2. Reasons for squeeze-cementing failures

The reasons for an unsuccessful squeeze-cementing job can be many; therefore whenever it fails to meet the objective, an investigation must be conducted to analyze the job. By finding the reason why it occurred, the design and procedure of the squeeze-cementing operation can be improved.

4.2.1. Misconstructions

If the pressure applied to the formation exceeds the formation fracturing pressure, it will fracture the formation and lead to lost control over the cement slurry down hole. Worst-case scenario, the slurry can extend across different zones and create communication between previously isolated zones. It is only the mixed-water and dissolved substances that are able to penetrate the pores. The solids accumulate on the formation face, because they are too large for the pores, and they create a filter cake.

4.2.2. Plugged perforations

If the perforations are not thoroughly cleaned there may be residues of mud cake, debris, scale, paraffin, formation sand, pipe dope, rust, paint etc. All this can cause plugging of the perforations and an unsuccessful squeeze-cementing job. Washing of the perforations before the squeeze job, mechanically or by chemical means, can be very useful to prevent failure.

4.2.3. Improper packer location

Residues of mud and completion fluid can contaminate the cement slurry as it flows through. This is especially the case if the packer is set too high above the perforations. Problems can be reduced by using a compatible spacer fluid in front and behind the slurry.

4.3.Cement failure

Designing the cement slurry is an important job to ensure a proper cement plug. The cement plug can fail because of many different reasons, listed below:

- Wrong density can lead to a permeable cement plug, which opens for migration of gas and oil.
- Poor removal of mud- and filter-cake can result in a migration path between the formation and cement.
- Premature gelation and excessive fluid loss can also lead to a failed cement job.
- Significant shrinkage of the cement can cause cracking and poor bonding.
- Stress on the cement after it sets can lead to cracking which also ruins the integrity of the cement.

In Figure 17 the different cement failure modes are shown. There are a lot of factors playing a role for a successful cement job and experts estimate that a high portion of seals placed in wells may be faulty (Barclay et al., 2001/2002).

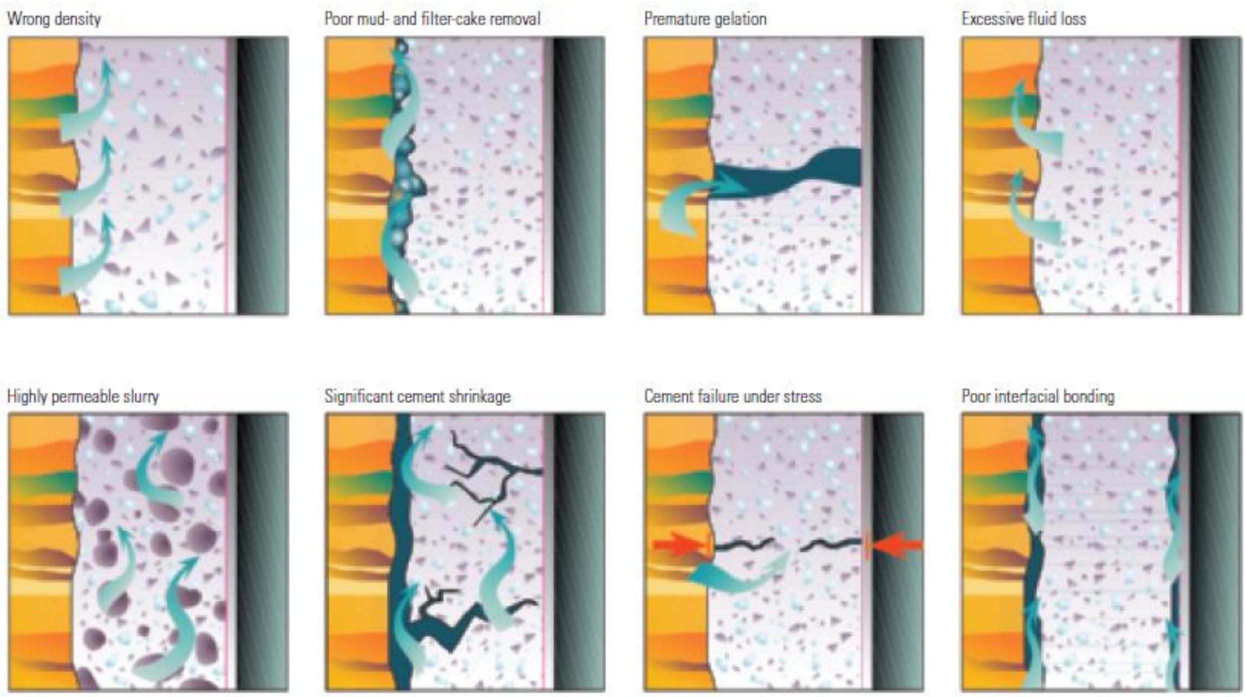


Figure 17: Cement failure (Barclay et al., 2001/2002)

5. Cement job evaluation

After the new revision of NORSOK D-010, every plug set on the NCS, need to be verified and documented. Logging is one method to verify the integrity of a plug. The log is run to determine cement to casing bonding, cement to formation bonding and to evaluate the cement conditions; channeling, compromised cement and TOC (Khalifeh, 2013). In addition to logging, there are several other techniques available to evaluate cement jobs. There is hydraulic testing, nondestructive methods like temperature, nuclear, and noise logging, and acoustic, sonic and ultrasonic cement logging. In the following chapter the different evaluation methods are described.

5.1. Hydraulic testing

Hydraulic testing is a technique used to test the sealing capacity of a cement plug. It can be performed after a primary cement job or after remedial cementing. The two most common methods are positive pressure testing and negative pressure testing, also known as inflow test.

5.1.1. Positive pressure testing

Pressure testing is regularly used to verify the mechanical integrity of the casing during well completion. Also it is used to leak test the well barriers. The test is performed by creating a differential pressure across the plug, P1<P2, as shown in Figure 18.

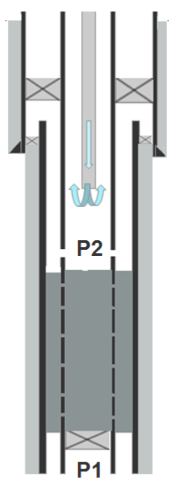


Figure 18: Leak testing of a well barrier

P2 which is the pressure inside the casing is pressurized after the cement is set. The test time depends on whether it is a high pressure test or a low pressure test. For high pressure, NORSOK D-010 states that there should be a static pressure with stable readings over 10 minutes. For a low pressure test, nothing is stated in NORSOK D-010. Statoil has a practice to pressure test for 5 minutes (Strøm, 2014b).

5.1.2. Negative pressure testing

During negative pressure test the pressure is reduced above the plug to test the mechanical integrity of the cement plug. It is also known as dry testing and is essentially the opposite of positive pressure testing. The pressure inside the casing and annulus is reduced, P1>P2, as shown in Figure 18, and the pressure is monitored to check for leakage. No change in the downhole pressure indicates a successful test, and verifies the integrity of the plug. NORSOK D-010 states that the test should last for a minimum of 30 minutes depending on volume, compressibility of fluids and temperature.

5.2. Acoustic logging measurements

Today acoustic logging is the most used and efficient method to evaluate the quality of a cement job. It was developed in the late 1950's and has since that time been used and advanced further to give a better picture of the well. The technique used today that utilizes both cement bond log (CBL) and ultrasonic data to evaluate the cement was not proposed before the year 2000. The CBL variance that allows differences between free, partially bonded, and bonded pipe to be computed, uses a statistical analysis. Adjunct to the CBL log a variable density log (VDL) is run to offer better insight to the interpretation. (Nelson & Guillot, 2006) Presentation of the acoustic waveform at a receiver of a sonic or ultrasonic measurement could also be used, but is not discussed here.

A critical part of logging measurements is the analysis. Detailed information regarding well geometry, formation characteristics and the cement job will make the interpretation easier. Good quality control of the log, good estimate of relevant cement properties and the knowledge of the well and casing, helps to give a more meaningful interpretation. Looking into earlier cement-job events and pre- and postjob well history will also help give a sense of the well integrity of the well.

5.2.1. Acoustic properties of formations

Cement is only one of the many parameters that can affect the log response. It is also affected by the acoustic properties of casing and formation, and the quality of the acoustic coupling between casing, cement and formation.

Acoustic property of a formation refers to the sound velocity of the formation. There are fast formations and slow formations. This refers to the cement-evaluation purpose, whether the sound travels faster or slower through the cement, than it does along the casing. This is used for the interpretation of the CBL and VDL logs. (Nelson & Guillot, 2006)

5.2.2. Acoustic properties of cement

During the life of the well, the acoustic properties of the cement will change, while for formations they remain constant and are well known. (Nelson & Guillot, 2006) Cement is also exposed to large temperature differences as it is placed along the casing wall at different depths. This also gives a strong difference in the log response.

5.3.The Cement bond log and variable density log

In Figure 19 a CBL-VDL tool is shown. The tool is a buildup of a gamma ray detector, an acoustic transmitter and two receivers. In some designs there is only one receiver.

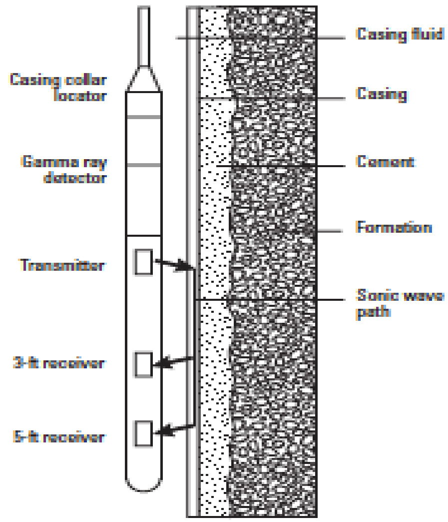


Figure 19: CBL-VDL tool configuration (Nelson & Guillot, 2006)

5.3.1. Log measurement

The transmitter fires a signal emitting an approximately spherical front, which is refracted according to Snell's law as it strikes the inside wall of the casing. If there is fresh water in the well, the wave is refracted straight down the casing, at a critical angle of about 16.5°. The portion refracted at this critical angle determines the amplitude and transit-time measurements on the log. (Nelson & Guillot, 2006) Some of the emitted wave goes directly through the mud and other parts travel into the annulus and through the formation.

There are two quantitative measurements performed on the full wave. First measurement is the transit time, which is the elapsed time between the transmitter firing and the arrival of the first part of the wave, as shown in Figure 20. The value of the transit time depends on the threshold level (detection level) and the use of positive or negative peaks. The casings inner diameter (ID), the outer diameter (OD) of the tool, and the speed of sound in the borehole fluid, will also have an effect on the transit time. Second quantitative measurement is the wave amplitude, which is how a quantitative cement evaluation can be made. A quantitative cement evaluation can again be done in two different ways because the arrival time of the peaks is related to the geometry of the CBL tool and the casing, and to the wellbore fluid properties. The evaluation can be performed using the fixed gate or sliding gate technique, where fixed gate is the most common. (Nelson & Guillot, 2006) This is not discussed more in this thesis.

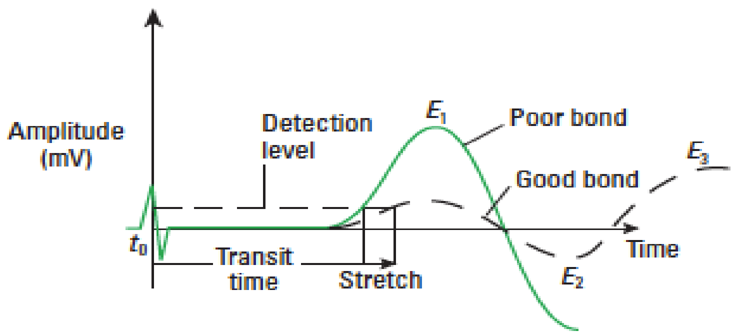


Figure 20: Transit time stretch in the well-bonded casing (Nelson & Guillot, 2006)

Attenuation of the amplitude represents the magnitude of loss. It is known that the loss to the formation is low and constant, so the loss to the annulus is the variable factor. (Nelson & Guillot, 2006) The strength of the amplitude is a function of the material adjacent to the casing. The wave loses energy to both annulus and the borehole as it propagates downwards to the receivers. This loss is caused by shear coupling with the adjacent materials, and the greater the shear coupling is, the greater the attenuation. So a good bonding between casing and cement results in a large attenuation, resulting in low amplitude, as shown in Figure 20. With fluids in the annulus, there is little attenuation on the casing signal, so large amplitude represents poor bonding. This is how a microscopic gas gap of a few thousandths of an inch, micro annulus, between the pipe and cement sheath has a strong effect on the signal and can be discovered.

The arrival times in Figure 21 show that the wave refracted through casing arrives first, this is usually the case. This is because of the high sound velocity of steel and the relative short distance the signal has to travel. The wave refracted through the mud is usually the last to arrive, because of the low sound velocity of fluids.

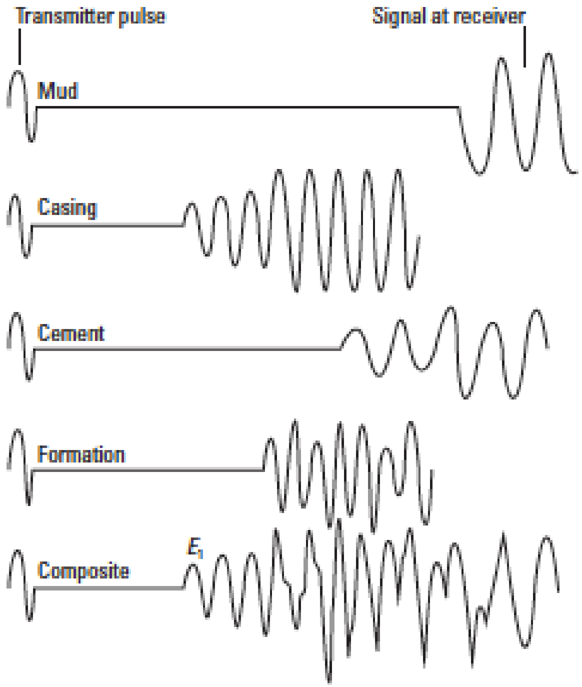


Figure 21: Sonic-wave paths (Nelson & Guillot, 2006)

5.3.2. Description of the full acoustic wave display: VDL

In Figure 22 a full waveform after a logging sequence with CBL is shown. It is a variable intensity display where amplitudes of the waveform are converted into a grey or color scale. The figure on the left has a color scale where grey represents amplitude of zero. Positive amplitudes become blacker as they increase, and negative amplitudes become whiter as they decrease. In the industry the figure on the right side is used. This is a continuous and discrete (five level) intensity scale. Here the negative amplitudes are colored against dark blue, positive amplitude towards red, and zero in a green color. This display is continuous with depth, so it is easier to read.

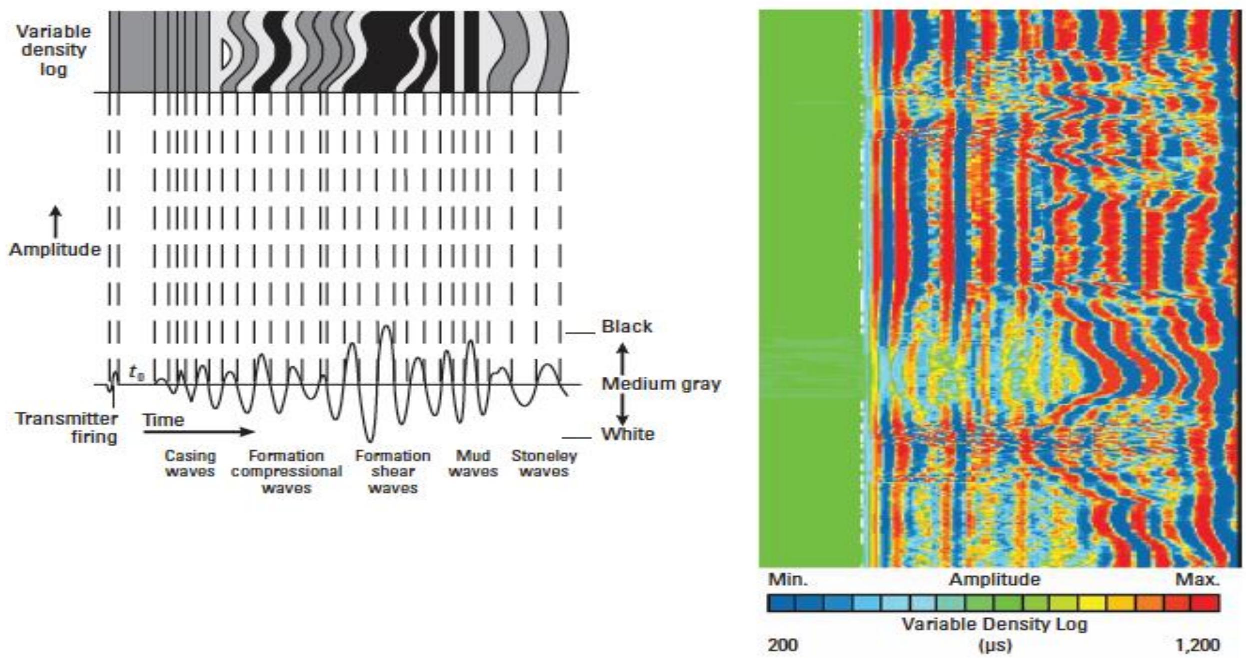


Figure 22: Presentation of the complete waveform signal from the CBL tool (Nelson & Guillot, 2006)

5.3.3. CBL and VDL: Qualitative interpretation

Only qualitative information about the cement job can come from the analysis of the full wave display. The cement-to-casing bond is good if most of the sonic energy leave the casing and pass into the cement. This results in a casing wave with low amplitude. The cement-to-formation is good if the energy goes through the cement into the formation. Then the sonic wave will propagate and attenuate through the formation.

6. Plug cementing – techniques and placement

In the following chapter different techniques to place a cement plug will be described shortly.

6.1. Balanced plug

Balanced plug method is the most common method to place a plug. To avoid cement contamination during the placement of a plug, displacement fluid and spacer fluid is pumped in front and behind the cement slurry. To place a balanced plug the volumes have to be in an amount so the same height in annulus and inside the pipe is achieved. Figure 23 shows how all the fluids are in balance before the pipe is slowly pulled out of the cement. Also a viscous fluid is placed as a base to avoid downward migration of the cement plug, in addition to the spacer in front and back of the cement. This is to reduce the main problem with this method, which is contamination of the cement.

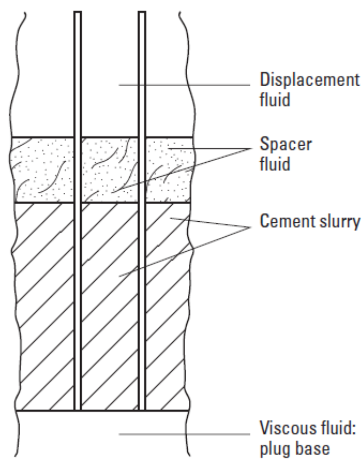


Figure 23: Balanced plug (Nelson & Guillot, 2006)

6.2.Dump bailer

The dump bailer method has the advantage that it is easy to control the depth and it is relatively inexpensive. A bridge plug is placed at the bottom of the desired plug interval and works as a base for the cement. The cement is lowered down in a dump bailer, which is a vessel containing the amount of cement slurry needed for the plug. When the dump bailer touches the bridge plug, it opens, and the cement slurry is dumped on the plug as shown in Figure 24. The bailer is then pulled slowly upwards for a proper placement.

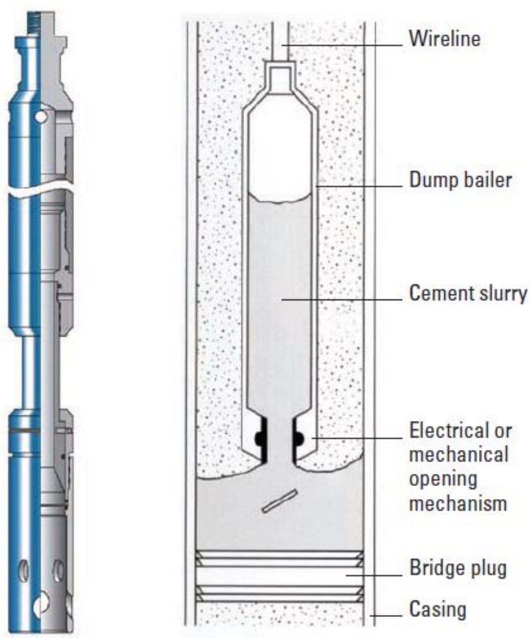


Figure 24: Dump-bailer tool and method (Nelson & Guillot, 2006)

6.3.Two-plug method

The two-plug method places the plug at a calculated depth with high accuracy, and with low cement contamination. This is performed with a special tool made up with a bottomhole sub installed at the lower end of a drillpipe, an aluminum tailpipe and a bottom and top wiper plug.

As Figure 25 shows, the procedure is as following:

1. Spacer fluid is pumped, followed by a wiper dart, which cleans the drillpipe to prohibit contamination of the cement. Cement slurry follows the bottom plug.
2. Pressure is increased to break the shear pin on the first dart which is placed.
3. Cement is pumped down through the tailpipe followed by a second wiper plug. When this dart arrives at its seat, the pressure increases.
4. The drillpipe is pulled up so that the tailpipe is placed on top of the calculated depth for the cement plug.
5. To open a reverse circulation path, a shear pin between the catcher sub body and the sleeve is broken, sliding the sleeve down.
6. Excess cement is circulated from the hole

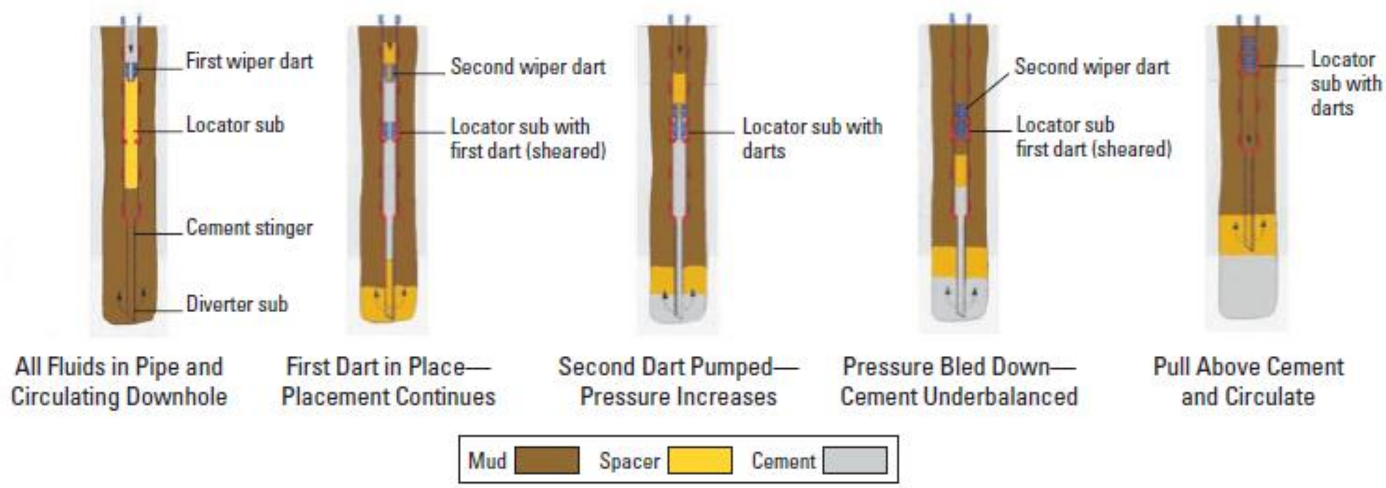


Figure 25: Two-plug method (Nelson & Guillot, 2006)

6.4.Contamination

To achieve good sealing capacity for the plug it is important to avoid contamination of the cement slurry. The thickening time has to be known for placement and clean up, this depends on the down hole temperature.

The main concern of the cement properties is the setting time and the mechanical properties. A change in setting time could result in tools getting stuck in the well, or other fluids could start migrating through if the cement sets too slowly. This could result from unstable interfaces caused by density differences, at the base or top of the cement slurry. The cement slurry and other wellbore fluids could get mixed during the setting of the plug as shown in Figure 26.

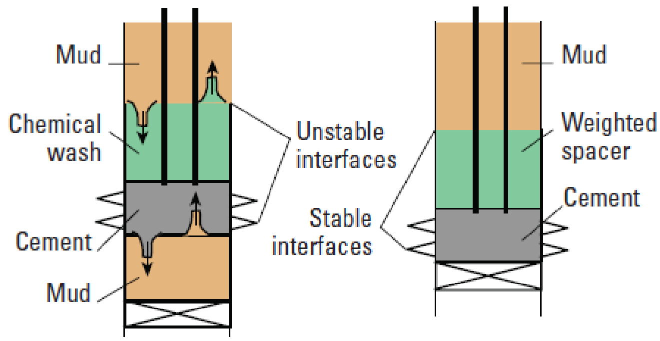


Figure 26: Illustration of stable and unstable cement plug (Nelson & Guillot, 2006)

6.4.1. Reducing measurements

Different mechanical devices are used to create a blockage from the fluid in the well, resulting in reduced contamination or in best case complete avoidance of contamination.

A bridge plug, which was used for dump-bailer, prevents heavy cement slurry from sinking through less denser fluids below. When a tailpipe or a stinger is used to set the cement, it reduces the contamination while POOH because the volumes involved are much smaller. A tailpipe or a stinger is used in the balanced plug method. This method is also used in horizontal wells to avoid the cement slurry from slumping.

For the two-plug method darts was used in the front and back of the cement slurry to provide barriers. Also different types of mechanical plugs or balls have been used as a barrier while the cement slurry flows down hole. When the cement slurry exits the pipe, contamination could occur as the falling cement may flow into the viscous gel, if this is what serves as a base. To avoid this, the tip of the pipe is equipped with a diverter tool which redirects the flow in an outward or radial direction.

6.5. The 'U-tube' effect

The 'u-tube' effect is a consequence of losing pressure in the drillpipe. During a cement job, the cement inside the drillpipe is higher than in annulus. While POOH, stands must be disconnected at deck. When a drillpipe is disconnected the pressure inside the pipe is lost, the cement inside the drillpipe will drop and the cement in annulus will rise, until they reach an equal height. After this happens, it is not favorable to pump cement anymore as it may lead to contamination. If this happens and more cement must be pumped, the drillpipe must be filled first. It can easily be seen from the pump pressure when the fluids in annulus have started to move. Even though it is possible to pump further, it involves a high risk of contaminating the cement.

7. HydraWell's PWC technology

When the large need for plugging and abandonment was discovered, HydraWell was one of the companies that started looking for an effective method to plug wells. HydraWell managed to reduce the plugging time by 7.5 days, from 10.5 to 3 days, and by doing so saving tens of millions per plug, and changing the entire way of doing P&A. One of the largest time savers is that there is no need for milling the casing. Earlier 50 m of steel had to be milled per plug, where about 25% of the swarf came up with the mud, the rest remained in the well and BOP (Taraldsnes, 2013). During a milling operation of 50 m 9 5/8" casing, a total of 4 tons of swarf is created. In total HydraWells technology has saved the industry for 293 tons of swarf/cuttings (Hydrawell, 2014f). All the swarf removed during a milling operation through the BOP can be damaging. To avoid well integrity issues because of a failed BOP, it has to be dismantled, inspected and repaired at considerable expenses. The new PWC method has a one-trip system where you perforate, wash and cement all in one run. There is also a two-trip system where the perforating part is done in a separate run. With the two-trip system the operation takes 4.5 days, saving 6 days from the traditional method. The plug is then verified by a pressure test and tagging.

The PWC system is run all on one assembly if the one-trip system is run, and for the two-trip assembly, the perforating gun is run separately. Typical time consumption for perforating is 6-8 hours for the one-trip system and 1.5 days extra for the two-trip system. Before the PWC tool is run, the annular space has to be evaluated and a setting depth determined.

7.1. Annular Space evaluation

The annular space is evaluated by cement-evaluation logs. This is done to determine if the annular cement is good enough, if there are micro channels, collapsed formation around the casing or no cement at all. On the basis of this evaluation, a setting-depth interval for the plugs is chosen. Usually the depth is chosen where there is free pipe and on the basis of setting depth requirements. (Denney, 2012) Setting depth requirements were described in Sub.Sect. 3.2.4.

7.2. HydraWash

As stated earlier, typical P&A methods are time consuming and costly. HydraWash is one of HydraWells inventions where a well with one annulus is PWC and can be abandoned. Before this procedure the production tubing is cut and pulled, and also casings have to be removed if there are several annuli.

7.2.1. The tools

The HydraWash system consists of one run assembly connected to the TCP guns and the workstring. TCP gun is positioned at the bottom of the HydraWash tool shown in Figure 27. The guns have a disconnect function which drops it after firing. The HydraWash tool has bypass channels for running in and elastomer cups to direct the flow during washing. Above the wash tool a cement stinger is placed for cementing the section after it is cleaned (Hydrawell, 2014e). Two HydraArchimedes tools (or more, depending on the length of the interval) are connected above to improve the cement job.

Figure 27: The HydraWash tool (Hydrawell, 2013d)

The HydraWash cups have a larger OD than the casings ID to ensure sealing during the washing operation. The tool for a 9 5/8" casing is shown in Figure 28. The cups are squeezed into the casing ID, when RIH, to seal properly during washing. This also ensures a proper sealing base for the cement when the HydraWash tool is left in hole. (Denney, 2012)

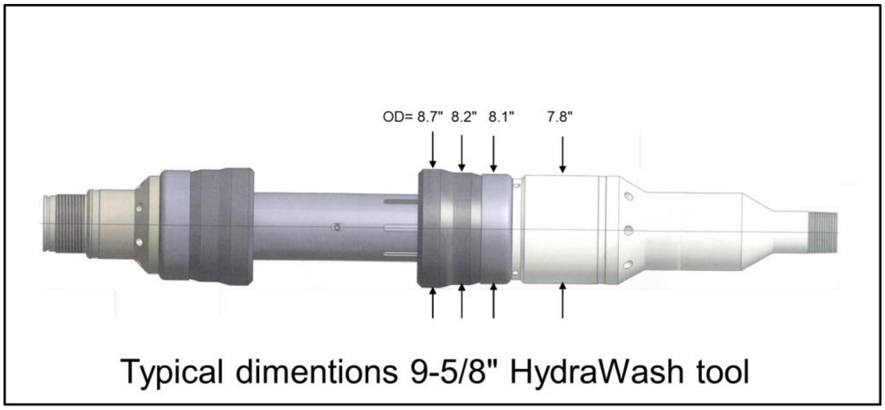


Figure 28: Wash cups on the HydraWash tool (Hydrawell, 2014f)

If the rat hole is large enough, the one-trip system is run where the TCP guns are left in hole. Rat hole is the available section in the well beneath the interval to be abandoned. If this is long enough, tools can be left in the well. Because of the large OD of the swab cups on the wash tool, it is not possible to rotate the tool. There has also been made a drillable version of the cups, to be used when doing a casing shoe repair job, and if the drilling operation shall continue afterwards through the same casing (Larsen, 2014b).

Features/Benefits of HydraWell (Hydrawell, 2013d):

- One-trip or two-trip plugging system
- No milling required
- Field proven
- Allows for circulation while tripping in and out
- Simple design and operation
- Base for plugging material
- Available for all casing sizes.

Archimedes tool

HydraArchimedes, shown in Figure 29, is connected directly above the wash tool, which can be the HydraWash or the HydraHemera jetting tool, and it helps to circulate and squeeze the cement in place into the perforations. It works as a spatula and a downhole pump and is rotated at high RPM while POOH. Two or more is used on the HydraWash if the treating interval is longer than one drillpipe stand. Each HydraArchimedes tool treats 25 m of perforations.

Figure 29: HydraArchimedes tool (Hydrawell, 2013a)

The Archimedes tool ensures that the entire perforated section is cemented before a drillpipe stand has to be disconnected during POOH. The pressure inside the pipe is bled off when disconnecting a stand, and the cement ‘u-tubes’. After this no more cement should be pumped, to avoid contamination with mud in the cement. What the Archimedes tools does is that after the cement is pumped through the pipe and upwards in the interval, the BHA is POOH while rotating. By using several Archimedes tools, the entire perforated interval of 50 m is cemented when POOH 30 m, which is a stand length. So when the stand is disconnected and the cement ‘u-tubes' the entire section is already treated with the two Archimedes tools, and no more cement has to be pumped.

7.2.2. How HydraWash works

Once the assembly is in position, the perforating guns are fired, dropped automatically and left in the well, or POOH, depending on the well configuration. To initiate the washing process a ball is dropped. This seals the bottom of the wash tool, shifting a sleeve, and the flow is directed into the area between the wash cups. (Denney, 2012) The washing starts at the upper part of the perforations and goes down into the lower part while the fluid flow is directed through the wash cups and into the annular space. The flow cleans thoroughly; removing debris, old mud, barite, old cuttings and cement traces. This continues until the tool is back at the top of the perforation and leaves the annular space with clean mud. Before starting to pump the spacer, the wash tool is run down to the deepest perforation, inserting spacer fluid from the bottom and up (Hydrawell, 2014e).

After the entire annular section is filled with spacer, a deactivation ball is dropped to disconnect the washing tool and leave it in the well as a base below the bottom perforation. The cement stinger is then positioned above the top perforation, and the pumping starts at maximum loss-free rate, while rotating at 100-120 RPM (Denney, 2012). This is done to clear the wellbore for any remaining material left between the top perforation and the surface. A balanced plug is set as the cement is pumped down through the cement stinger, which is now placed at the lower perforations, and is forced into the perforations with help of the Archimedes cementing tool. A uniform plug is created by the force of the Archimedes tool, as the assembly is slowly POOH. In some cases, depending on the cement-job design, squeeze cementing is performed (Hydrawell, 2014e).

7.2.3. Perforation requirements and design for HydraWash

TCP size is set up as a function of limited entry, wash rate, rheology and equivalent circulation density (ECD). The ID is normally between 0.30 – 0.50” depending on the conditions in the well and the surrounding formation. (Hydrawell, 2014a)

The TCP gun is 50 m long. For a single casing, it shoots 12 shots per foot (SPF) in a 9 5/8" casing, with a 135/45 degree phasing as shown in Figure 30. This means that inside the casing, one perforation is shot every 135 degree, moving 1" downwards for every perforation. This results in perforations with a distance of 45 degrees between each, when moving up or down the casing. For every foot, which equals 12", there are 12 perforations, because there is one perforation for every 1". Through experience a 13 3/8" casing needs 18 SPF to ensure proper cleaning and cementing. This is also the case when cementing two annuli with HydraHemera. The phasing may vary, but 135/45 degree gives a very good spread. It is important to get the right combination of large enough perforations and sufficient amount of holes to ensure proper cleaning and to ensure a good cementing job.

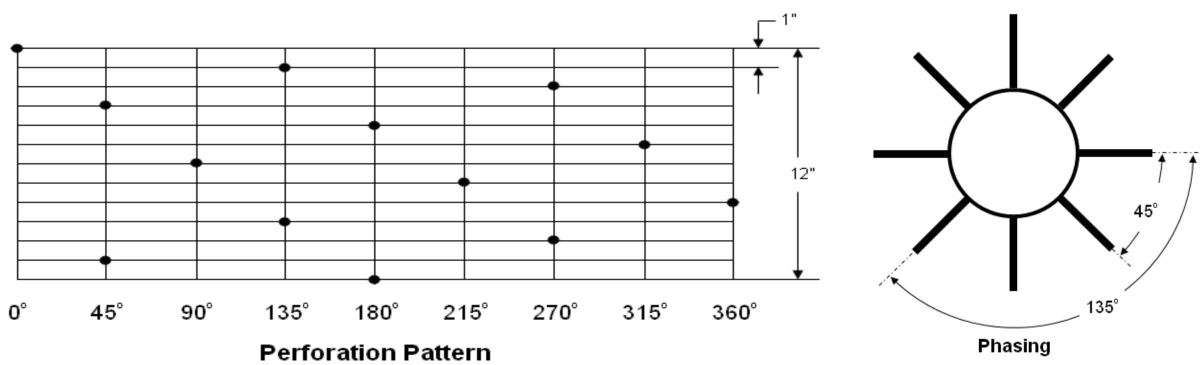


Figure 30: Perforation pattern and phasing (Hydrawell, 2014a)

Upper 2 m and lower 2 m of the perforations are perforated with a larger diameter. For the top perforations this is to initiate the washing behind the casing without creating a pressure that exceeds the fracture pressure of the adjacent formation. At the bottom the larger perforations are there to ease the displacement of mud by the cement spacer and then displacement by cement during the plug-setting operations. The middle part of the perforations, the remaining 46 m, has a diameter based on limited entry perforating backpressure design principles (Denney, 2012).

During perforation a sharp burr is created inside the tubing caused by the backfire of steel during perforation, in addition to the steel that is ripped outwards. The perforation gun works as a blowtorch and the steel does not disappear, it is only moved. An illustration is shown in Figure 31. The burr created on the inside of the casing may damage the swab cups on the HydraWash tool. Between each perforation interval there is a blank section of 50 cm. The distance between the swab cups is 30 cm, so during the washing process the integrity of the cups is verified whenever going through the blank sections. (Larsen, 2014b)

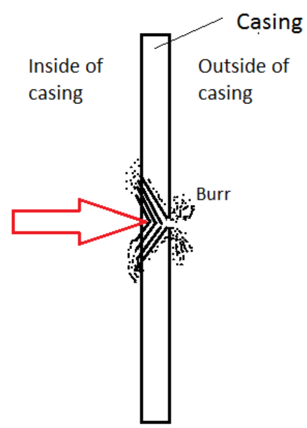


Figure 31: Illustration of burr created during perforation

7.2.4. Washing with HydraWash

The design of the wash tool is optimized to get as good and thorough cleaning as possible. The cups isolate for the washing process, and wash 1 ft of the casing in one continuous movement. A backpressure between 55 to 75 psi is designed to be created when pumping through the perforations (T. E. Ferg et al., 2011). For the washing process, both oil based mud (OBM) and water based mud (WBM) is used. OBM allow for a higher washing rate, but experience has shown that it may contaminate the cement. For this reason WBM is mostly used, besides it is cheaper than OBM.

Washing is the most time consuming process as it can take from 12-48 hours. The better and more cement there is in annulus before the washing sequence starts, the longer it takes. When using HydraWash with wash cups, the process is controlled by the use of pressure readings, and also the result can be seen on the mud shakers (Larsen, 2014b). As the washing cups moves downwards the pressure increases when the perforations are closed with cement and other debris. Then the drillstring is stopped until the pressure stabilizes. The stabilization does not have to be at same pressure level as before. As show in Figure 32, after a peak there is a decrease in pressure, until it stabilizes the washing tool is stopped. As the wash cups continue to move downwards the pressure increases again when exposing plugged perforations. Increase in pressure is an indication that the tool is washing over closed perforations while a decrease in pressure is an indication that the perforations are opened and the debris removed.

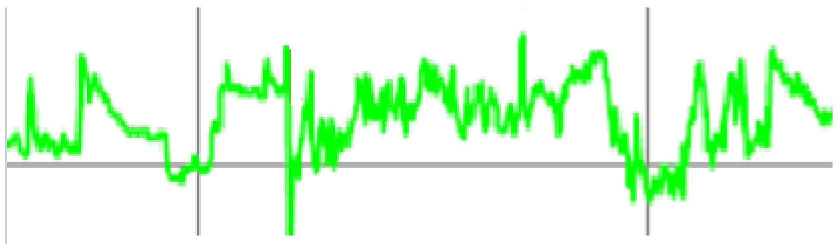


Figure 32: Typical washing pressure curve (Hydrawell, 2014a)

The washing rate is determined by the ECD, which is a function of fracture gradient, fracture pressure, well geometry and rheology. The ECD also determine the perforation diameter, because the diameter is a function of limited entry, wash rate and rheology (Hydrawell, 2014a). The pressure over the perforations is calculated by Equation 1.

Equation 1: Differential pressure over perforations (Hydrawell, 2014a)

$$\Delta \boldsymbol{P}_{perf} = \frac{MUD_{ppg} \cdot Q^2}{12035 \cdot A_{perf}{}^2 \cdot C_d{}^2}$$

Where

ΔP_{perf} - Differential pressure over the perforations [psi]

MUD_{ppg} - Mud weight [ppg]

Q - Flow of fluid [gpm]

A_{perf} - Area of perforations [in^2]

C_d - Dimensionless factor = 0.95 – which accounts for a perforated hole, instead of a perfect circular hole.

Example 1: Calculation of differential pressure given by amount of perforations open (Hydrawell, 2014a)

*As an example of differential pressure over perforation, assume the casing have perforations interval with **12 SPF**. The well is washed with a rate of **1400 l/min** (9 barrels/min). The perforation **ID** is **0.42"** then the differential pressure will be:*

ΔP_{perf} *= 4 bar = 60 psi*

*Then RIH with 15 cm/6", and expose new perforations **6 SPF,** and the new perforations are plugged .Then the differential pressure during washing will be:*

ΔP_{perf} *= 18 bar = 260 psi*

So the pressure increases with 14 bar = 200 psi if the wash cups comes over 6 new perforations which are plugged.

To apply a higher washing rate to the formation, the diameter of the perforations has to be increased. Before increasing the perforation diameter it is important to consider the formation strength and keep the pressure under the fracture gradient of the formation. As stated in the beginning of Sub.Sect. 7.2.4, the pressure drop over the perforation should be between 55 and 75 psi to achieve a high enough pressure to remove debris and low enough to not fracture the formation. Usually the plugging interval is within a cap rock which provides good strength, enabling it to handle the high washing pressure.

The important ratio between perforation diameter and pressure drop over perforations can be seen in Figure 33, which is based on the numbers in Table 5. It illustrates pressure fall over perforations vs. amount of open perforations. The graphs are of two different ID perforations, 0.33" and 0.52", and a constant rate. Looking at a washing situation where the casing has 12 SPF, and 4 perforations are plugged with debris. When the perforation diameter is 0.33", a differential pressure of 70 psi will be seen on the plugged perforations vs. a differential pressure of 11 psi with a 0.52" perforation hole. So to achieve a high enough pressure to wash the perforations open, a diameter of 0.33" is ideal.

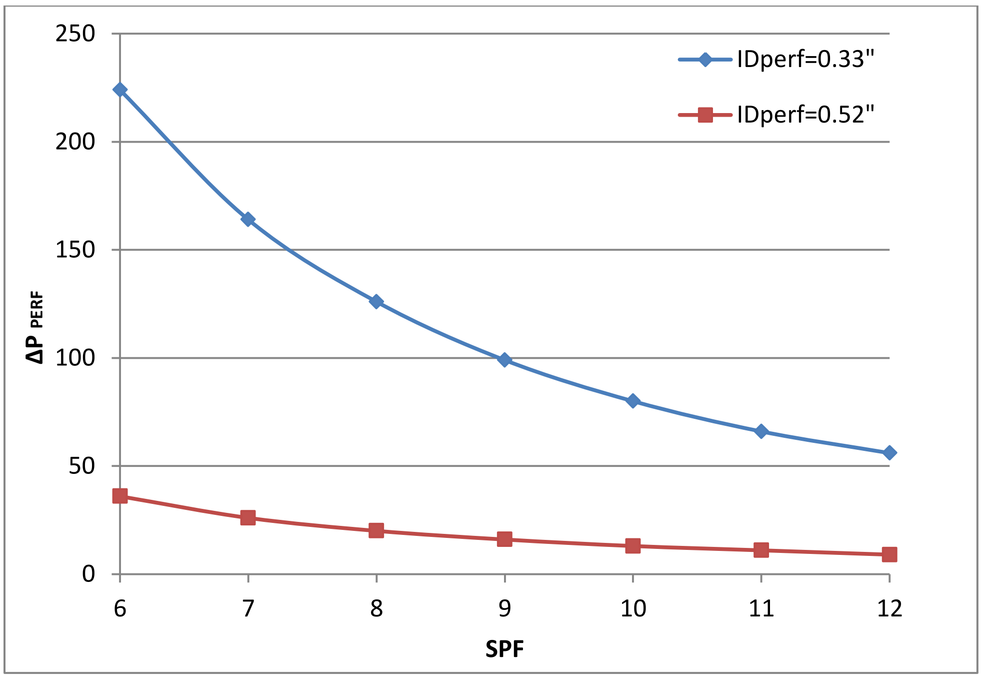


Figure 33: Pressure difference over perforations vs. SPF open

Table 5: Differential pressure for different ID perforations (Larsen, 2014c)

SPF	ΔP_{perf} [psi] when ID_{perf}=0.33"	ΔP_{perf} [psi] when ID_{perf}=0.52"
6	224	36
7	164	26
8	126	20
9	99	16
10	80	13
11	66	11
12	56	9

Increasing the diameter of the perforated holes and keeping the same rate, will most likely result in channels developing inside the annulus. This is because the differential pressure will not get high enough, and fluids always take the easiest way. Increasing the washing rate will help the cleaning, but there is also a risk of exceeding the formation strength here. It is important to consider limited entry. So to increase the washing rate, the ID of the perforations also has to be increased. In Table 6 calculation of washing rate Q is shown for different ID perforation sizes to achieve a differential pressure of 55 psi and 75 psi, with Equation 1. Both calculations are while washing over 12 perforations. An illustration is shown in Figure 34. To maintain the same differential pressure range over the perforations, the washing rate has to be increased whenever the perforation size is increased.

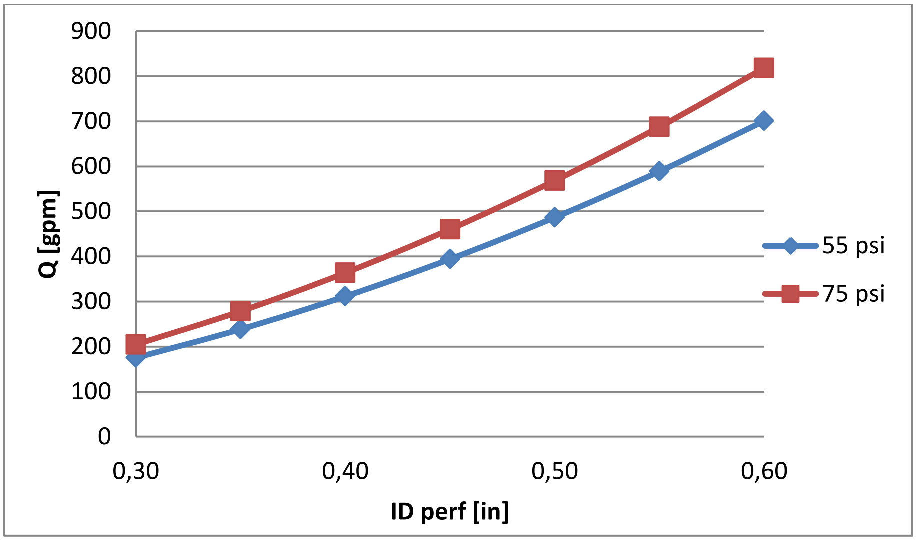


Figure 34: ID_{perf} vs washing rate at different differential pressure

Table 6: Calculation of washing rate needed when 12 open perforation and 14 ppg mud

		55psi		75 psi	
ID_{perf} [in]	A_{perf} [in^2]	Q [gpm]	Q [bpm]	Q [gpm]	Q [bpm]
0,30	0,85	175	4,2	205	4,9
0,35	1,15	238	5,7	278	6,6
0,40	1,51	311	7,4	364	8,7
0,45	1,91	394	9,4	460	11,0
0,50	2,36	487	11,6	568	13,5
0,55	2,85	589	14,0	688	16,4
0,60	3,39	701	16,7	818	19,5

7.2.5. Track records

So far (pr. 15.05.2014) there has been performed 84 HydraSystem jobs. In Table 7 the amount of plugs set pr. year is shown, and Table 8 shows in which casing size the plugs were set. So far 2012 was the busiest year, but 2014 seems to become busier. Most plugs are placed inside 9 5/8" casings.

Table 7: Amount of plugs set pr. year (Hydrawell, 2014f)

Year	Amount of plugs
2010	2
2011	17
2012	31
2013	17
2014	17

Table 8: Casing size plugs have been placed in (Hydrawell, 2014f)

Casing type	Amount of plugs
(inside 9 5/8") in 7"	7
(inside 10 3/4") in 8 5/8"	4
9 5/8"	65
10 ¾"	5
11 ¾"	1
13 3/8"	2

7.3.HydraHemera

With the HydraHemera system it is possible to perforate, wash and cement two annuli at the same time. The challenge with this technology is to verify a continuous cement plug over the entire cross section. Today it is only possible to log one annulus, so this type of plug has to be verified using positive and negative pressure tests (Hydrawell, 2014d). A full well test has been performed at IRIS where a real life model of a well section was PWC, and then POOH. The well integrity of the cemented section was verified by cutting the section into small pieces that was inspected closely. This is described in Sub.Sect. 8.3.1 under "ULLRIG testing"

Today the HydraHemera procedure consists of three steps. First a plug has to be set inside the casing, then the HydraKratos and a TCP gun is run, and last the jetting and spray cementing tool is run. The HydraKratos is only run if there is a need for a base for the cement to be placed in annuli. These trips are currently being worked on to be reduced to fewer trips. (Larsen, 2014a)

7.3.1. The tools

The HydraHemera tool is shown in Figure 35. The assembly consists of a bullnose with circulation at the bottom, a jetting tool for washing and placing of spacer, cementing tool with nozzles and the Archimedes tool. The cementing tool has a spray cementing function to reach all annuli with cement. It also has a valve function to avoid the 'u-tube' effect while removing stands. These tools ensure the centralization and proper placement of cement in the annuli. (Hydrawell, 2014d)

Figure 35: HydraHemera tool (Hydrawell, 2013b)

Features/Benefits of HydraHemera (Hydrawell, 2013b):

- Two-trip plugging system
- No milling required
- Allows full flow when tripping in and out
- Simple design and operation
- Ideal for cleaning multiple annuli
- Available in all casing sizes

HydraKratos

This HydraKratos is used before running the HydraHemera if there is no annular cement barrier in both annuli to hold the new cement. It consists of the Hydrakratos casing expander and is run together with the TCP gun. The TCP gun is placed in the P&A area with the HydraKratos below. The tool is activated by a ball launched from a ball drop head. The energy from the explosion of the HydraKratos is calibrated to expand both casings, to ensure a casing to formation wall fit, as shown in Figure 36. This provides a base for the cement plug in the inner and outer annulus. After the perforations and HydraKratos are shot, the drillstring is POOH. The perforation shots are as large and tightly spaced as the casing allows them to be. (Hydrawell, 2014d)

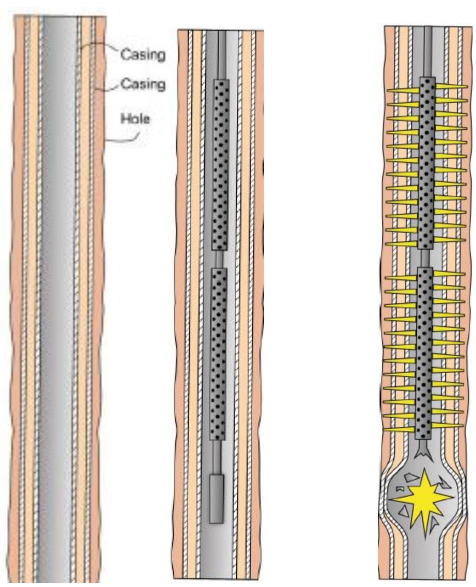


Figure 36: HydraKratos sequence (Hydrawell, 2014a)

7.3.2. How HydraHemera works

After the TCP guns, with or without the Hydrakratos, is POOH, the HydraHemera is run. A sequence is shown in Figure 37, but here the HydraKratos is not needed and the TCP gun is run alone before HydraHemera.

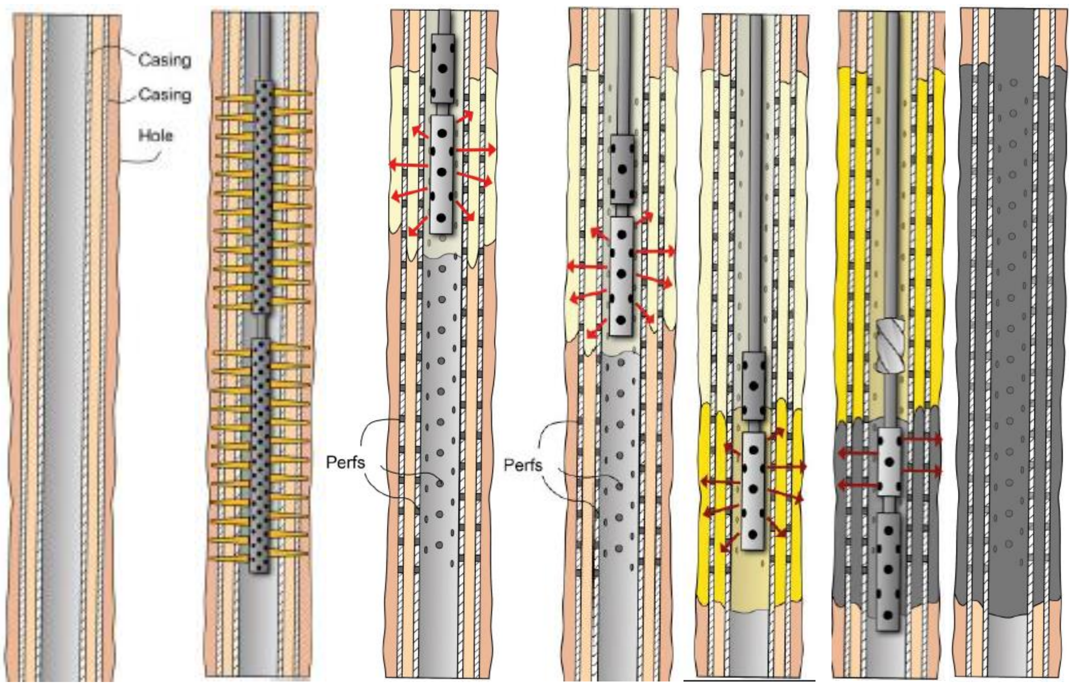


Figure 37: HydraHemera sequence (Hydrawell, 2014a)

Once the string is in position, a ball is dropped to initiate the circulation through the jetting tool. The washing process then starts from the top of the perforations, down, and then up again to ensure proper cleaning of both annuli. The flow is directed through nozzles, which create high-energy jets of mud.

When the annuli are cleaned and the assembly is positioned at the bottom of the perforations, the jetting tool is used to displace the spacer fluid into the area. A second ball is dropped, diverting the flow through the cementing tool, which features a nozzle area optimized for cement to avoid dehydration (Hydrawell, 2014d). The pressure is increased and the Hemera Spray cementing valve is opened. Cement is pumped and the spray cementing starts. Rotation of the Archimedes tool forces more cement through the perforations to ensure a uniform plug through the perforations and into the annuli, as shown in Figure 38. The assembly is POOH one stand length while the lower interval is spray cemented. Before disconnecting one stand, the pumping is stopped and the pressure is bleed off. When doing this the Hemera spray valve closes. The stand is disconnected, and the operation continues. Pressure is then increased, the valve opens, cement is pumped and the spray cementing continues. This can be repeated until the entire interval is cemented. After this the assembly is POOH to above TOC, and the waiting on cement (WOC) begins. (Hydrawell, 2014a)

Figure 38: HydraHemera in action (Hydrawell, 2014a)

With the Hemera spray valve the 'u-tube' effect is avoided. This valve makes it possible to continue pumping cement after removing a stand, without being concerned about contaminating the cement.

7.3.3. Washing with jetting wash tool

When using the jetting wash tool the washing process is observed by looking at returns over the shakers. The nozzles on the tool are engineered into an optimal configuration and exit velocity. They are positioned in irregular angles enabling the jets to penetrate through the casings, between the different annuli, cleaning all voids and cavities of old mud and movable debris. (Hydrawell, 2014d)

7.3.4. Cement

With the HydraHemera tool the cement is sprayed out through nozzles. These need a larger diameter than the nozzle of the washing tool to avoid cement dehydrations and consequently, plugging of the nozzles. In addition the velocity to be used during spray cementing has to be chosen to minimize abrasion of the nozzles while cementing. This will not be discussed further in this thesis.

7.3.5. Track records

So far (pr. 09.05.2014) there have been performed 13 HydraHemera job. Table 9 shows in which casing size the plugs were set. The HydraHemera has also been used for plugging one annulus, when there is a restriction in the well.

Table 9: Casing size plugs have been placed in (Hydrawell, 2014f)

Casing type	Amount of plugs
7” x 9 5/8” casing	3
8 5/8” x 10 3/4” casing	1
9 5/8” casing with restriction	7
9 5/8” casing	2

A typical HydraHemera plug is set in 4.5 days. However a 7” x 9 5/8” HydraHemera two-trip plug was set in just under 3.5 days last fall, 2013. This included WOC and testing of the cement by pressure and tagging. (Hydrawell, 2014f)

7.4.Spacer

The spacer has two functions during a plugging job. It helps to reduce the differences in density and viscosity and to avoid contamination of the cement. In addition it helps to change the wettability of the formation if OBM or synthetic-based mud (SBM) have been used in the well. (Bogaerts et al., 2012) In PWC jobs a standard water based spacer for water based drilling fluid applications has been used. It contains a surfactant package to be able to handle OBM, which might be left in the well after drilling. (T. E. Ferg et al., 2011)

7.5. Using HydraHemera jetting tool for single casing

Using the Hemera jetting washing tool may have some advantages over the HydraWash tool. It is not possible to monitor the pressure while washing with the jetting tool, but there is no chance of wearing out any wash cups either. They should last for at least 48 hours, and everything over that is a bonus. In case studies from Statoil, described in Sect. 7.12, a little time was lost due to worn out wash cups. The procedure when using the jetting tool is shown in Figure 39.

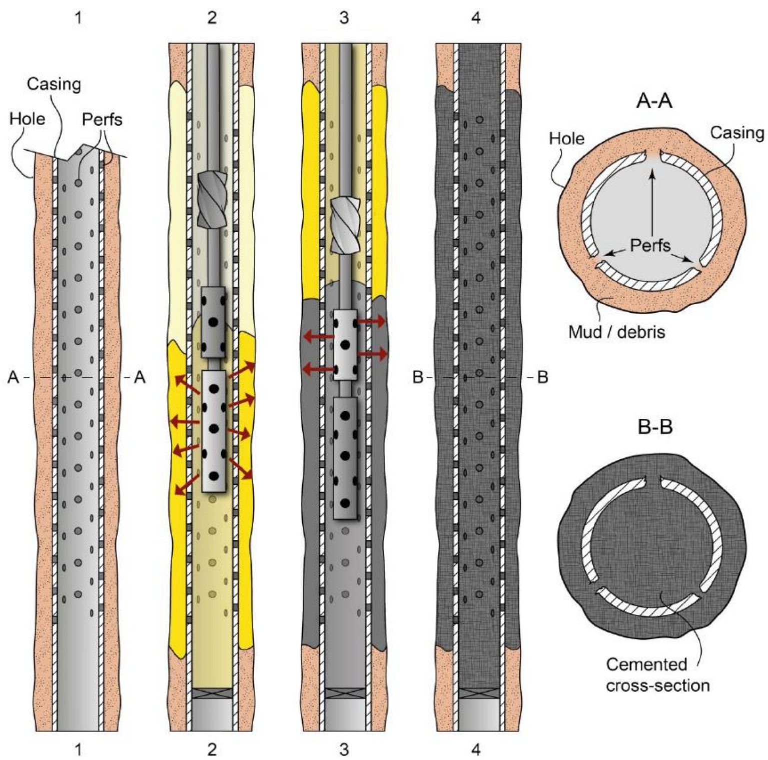


Figure 39: HydraHemera in one casing (ConocoPhillips, 2013)

The jetting tool has the same function as the wash cups, as the nozzles work the same way as the perforations. When using these nozzles the perforation diameters are larger, and the nozzles are placed with all different angles to reach both annuli. For wells where there already is some cement in the annulus, the jetting tool might clean and cement the annulus better than the HydraWash tool. The jetting tool also had the advantage of a smaller OD. This enables the jetting tool to enter slightly collapsed wells, which would not work with the larger OD HydraWash tool.

7.6.Cement

The cement design is made especially for each operation. There are always different conditions to consider, like fluid loss and gas migrations which are controlled with appropriate cement additives. Low fluid loss to avoid bridging across perforations or high fluid loss to obtain squeeze pressure after placement, are scenarios that have to be considered for the cement properties to be correct. To avoid shrinkage of the cement a post set expansion material has to be included (T. E. Ferg et al., 2011). Testing of the plug set with the PWC technique has shown that the plug has a high bond quality and hydraulic isolation. (Hydrawell, 2014e)

After the cement is set in place, and while it sets, the cement goes through a phase change. The phase change is over a pressure change as shown in Equation 2. It depends on the difference between the cement weight and the water weight, and the height of the cement column.

Equation 2: Pressure change while cement sets (Hydrawell, 2014c)

$$\Delta \boldsymbol{P} = (\boldsymbol{Weight_{cement}} - \boldsymbol{Weight_{water}}) \cdot \boldsymbol{Height_{cement}}$$

This pressure change has to be compensated by applying an overpressure at the cement column while it sets to ensure the cement is not flowing while setting up. (Hydrawell, 2014c)

The cementing procedure is the most critical part of the entire plugging operation. During the cementing procedure it is very important to always know where the cement is, and to avoid contamination of the cement. A base for both the internal plug (inside the casing), and the external plug (inside annulus), can make it easier to know where the cement will set, and to reduce contamination risk. The annulus is always logged before plugging a well. First of all to check if there already is an external barrier and if not, it verifies if there is some cement, settled barite or formation, that can function as a base for the cement to be pumped. For the internal base a plug is set as a base for the cement. This could be the HydraWash tool or a mechanical plug.

7.6.1. Volume calculations

Cement volume needed for a plug is a basic volume calculation for the inside of the casing and annulus. The length of the cement plug inside the casing is 110 m, where 10 m is from the HydraWash tool left in the well and up to perforation interval, 50 m in the perforation interval, and then 50 m on top of that. In addition the volume of annulus must be calculated. Normally 25% is added to account for washouts towards the formation. If the plug needs to be squeeze cemented, an additional volume must be added. (Larsen, 2014b)

7.6.2. Squeeze cementing

Squeeze cementing may be applied after setting the cement in the perforated hole. The decision to apply squeeze pressure and additional cement is made by the main contractor and the operator. It is very important to know the formation before doing this operation, because there is a high risk of fracturing and have losses to the formation.

7.7.Setting depth and rat hole

The length of the rat hole must be around 85 m, to drop the TCP gun and log the well. Because the TCP perforating gun is 65 m, a logging tool needs 15 m to do a proper logging operation, and 3 m distance from the lowest perforation. Taking these into account a depth of at least 83 m is needed, and then a safety margin gives us a depth of 85 m. The logging tool needs 15 m depth because the top sensor needs to go deeper than the lowest perforation, and it must gain a constant velocity before the logging starts. (Larsen, 2014b)

The minimum setting depth also has to be accounted for, described in Sub.Sect. 3.2.4. This is the minimum depth were the plug and the formation is capable to hold the pressure from the reservoir. It is important to remember that the secondary plug must be placed at this depth. To find the minimum setting depth the original reservoir pressure has to be accounted for together with the formation strength.

The amount of plugs to be set should be known, and maybe one extra plugging interval should be accounted for if one of the plugs set should fail to seal properly. This has to be accounted for with respect to how the plug is going to be run. If each plug is set with the one-trip system, the needed rat hole is minimum 83 m for each. By running the two-step PWC procedure, the deep rat hole is no longer needed. Then only the drop of the washing assembly has to be accounted for, which is about 10 m.

7.8. Time and cost

The time saved by doing P&A with the PWC technique is significant compared to the conventional way of doing P&A operations. So far (15.05.2014) 514 days has been saved by using PWC technology on P&A jobs, compared to milling operations. (Hydrawell, 2014f)

7.8.1. Time and cost when PWC single casing

As stated earlier a normal P&A operation with one annulus takes 10.5 days, but most people working in the industry say it takes up to at least 14 days. Taking into account the shortest time looking at Figure 40, a P&A operation with section milling two intervals, clean out and cementing (A) takes 10.5 days. This operation can be reduced to (B) where the two-trip PWC technology is used. This takes 4.5 days, where the well is perforated first, then the guns are POOH and the wash and cement is RIH. It can be reduced down to only 3 days, (C), where perforation, wash and cement is done all in one trip.

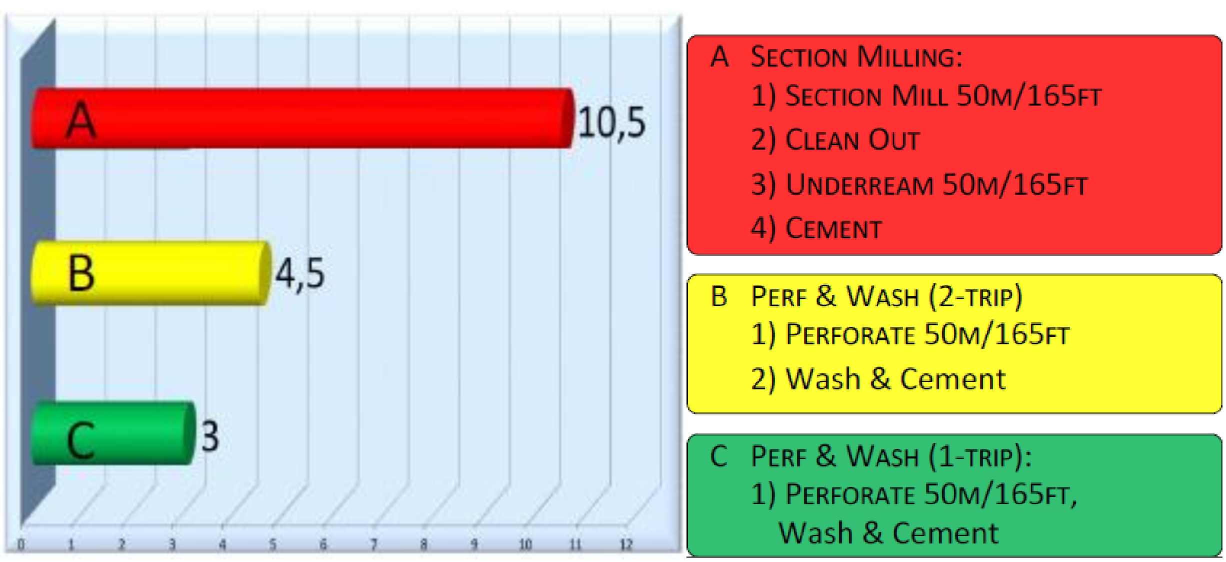


Figure 40: Time of different P&A scenarios (Hydrawell, 2014a)

7.8.2. Time and cost when PWC double casing

A milling and under reaming job in a multi casing section of a well takes a minimum of 24 days. With the HydraHemera and HydraKratos the operation takes 4.5 days, saving 19.5 days. Most of the saved time is from avoiding milling, and pulling of casing. (Hydrawell, 2014a)

7.9.Track records

HydraWell have set a lot of plugs all over the world. As stated in Sub.Sect. 7.2.5, a total of 84 plugs have been set. The total of all HydraWells records shows a tool success rate of 99.3%, and a system success rate of 97.9%. This is a very good success rate. Most plugs are set on the NCS, but there are four plugs placed in the UK sector, two plugs in the Danish sector and one plug in the US. (Hydrawell, 2014a) Not all of these jobs have been drilled, but they are verified by tagging and pressure testing, according to NORSOK D-010 requirements.

7.9.1. Logging

To verify the annular integrity of the plug, the set cement plug can be drilled out and a cement evaluation tool can be run. Usually a USIT/CBL log is run or a SBT, and the new log is compared to the old to assess the annular plug quality. Afterwards the internal casing is just cemented to regain the cross sectional plug integrity. (T. E. Ferg et al., 2011)

Wells that have been drilled and logged can be found in Table 10. For the HydraWash technique, 10 of 16 were approved without any issues, but 6 of them had some issues. Some issues were that the cement in annulus did not show much improvement. All plugs that have been logged are set in single casing, as it is not possible to log though two casings today. Two plugs were placed in well P39 at Snorre, and two plugs were placed in well B42 at Statfjord. In Sect. 7.12, these are described in more detail. One plug was set with the HydraHemera technique and was approved by logging.

Table 10: Logging records of HydraWash and HydraHemera (Hydrawell, 2014f)

	Type	Plug	Size	Log	Results
2010	HydraWash	Miocene 1	9-5/8"	USIT	Approved
2011	HydraWash	Miocene 1	9-5/8"	USIT	Approved
2012	HydraWash	Miocene 1	9-5/8"	USIT	Approved
	HydraWash	Reservoir 1	9-5/8"	USIT	Approved (some issues)
	HydraWash	Reservoir 1	9-5/8"	USIT	Approved (some issues)
	HydraWash	Reservoir 2	9-5/8"	USIT	Approved (some issues)
	HydraWash	Reservoir 2	9-5/8"	USIT	Approved (some issues)
	HydraWash	Reservoir 1	9-5/8"	USIT	USIT
	HydraWash	Reservoir 2	9-5/8"	USIT	USIT
2013	HydraWash	Casing Repair	13-5/8"	SBT	Approved (some issues)
	HydraWash	Casing Repair	13-5/8"	SBT	Approved (some issues)
	HydraWash	Casing Repair	10-3/4"	USIT	Approved
	HydraWash	Casing Repair	10-3/4"	USIT	Approved
	HydraWash	Casing Repair	10-3/4"	USIT	Approved
	HydraWash	Reservoir	9-5/8"	SBT	Approved
2014	HydraWash	Reservoir 2	9-5/8"	USIT/CBL	Approved
	HydraHemera	Miocene 1	9-5/8"	USIT/CBL	Approved
	HydraWash	Reservoir 1	9-5/8"	USIT/CBL	Approved
	HydraWash	Reservoir 2	9-5/8"	USIT/CBL	Approved
	HydraWash	Reservoir 3	9-5/8"	USIT/CBL	Approved
	HydraWash	Reservoir 4	9-5/8"	USIT/CBL	Approved
	HydraWash	Miocene 1	9-5/8"	USIT/CBL	Approved
	HydraWash	Miocene 2	9-5/8"	USIT/CBL	Approved

7.10. Deviated wells

In many wells there is a long horizontal section, called 'sail' section as shown in Figure 41. This may be several kilometers long, and creates problems for the transport of debris to surface while washing. The casing is assumed to lie on the low side of the hole in a non-vertical well due to gravity. For the same reason all debris also settles on the low side. The settling of debris above the wash tool will eventually block the well during washing. HydraWash has been able to perform jobs in deviated wells up to 81 degrees due to the new tool, HydraSwivel, which was created to handle the accumulation of debris (Hydrawell, 2014a).

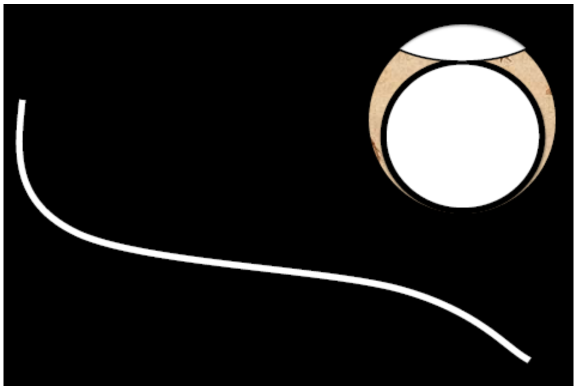


Figure 41: Sail section (Hydrawell, 2014a)

When there is a high angle in the well it is also very critical to engineer the number of exposed perforations between the opposing wash cups and the diameters. A backpressure must be created to divert the wash fluid through all the perforations to ensure proper cleaning also behind the casing. (T. E. Ferg et al., 2011)

7.10.1. HydraSwivel

HydraSwivel enables the upper string to be continuously rotated while pumping treatment fluid through the tool at high differential pressure. It is possible to rotate the drillpipe with 130 RPM. It optimizes the hole cleaning process while HydraWash is washing the perforations by ensuring circulation in the low side of the hole along the sail section. When rotating the pipe, all debris on the low side will rotate with the drillpipe and be circulated into the flow on the top side of the well and be transported away with this flow. This prevents plugging of the well while washing, which could result in the tools getting stuck in the well. The tool is connected straight above the

HydraWash tool, and beneath the work string (Hydrawell, 2013c). HydraSwivel is shown in Figure 42 and its technical data are described in Table 11.

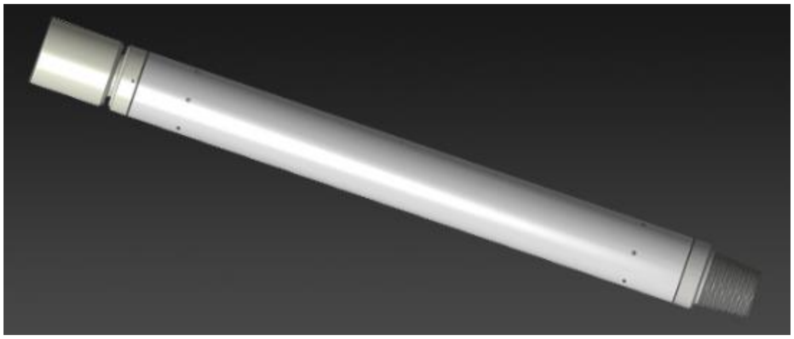


Figure 42: HydraSwivel tool (Hydrawell, 2013c)

Table 11: Technical data for HydraSwivel (Hydrawell, 2013c)

Technical data	
Size	4 ¾"
OD	4 ¾"
ID	2"
Length	1,3 m 4,5 ft
Treads (can be ordered differently)	3 ½" IF box x pin
Max pull (static)	200 klbs/90 ton
Rotation	140 RPM
Pressure rating (static)	5 0000 psi/245 bar
Pressure rating rotation	2000 psi/138 bar

Features/benefits of HydraSwivel (Hydrawell, 2013c):

- Simple operation
- Back up seals incorporated
- Pressure and temperature balanced
- Large ID
- OD equal to tool joint size
- Slick ID for ball drop

- Rigid design
- Field proven

7.10.2. Cementing in a deviated well

A deviated well makes the cementing process a bit more challenging. A micro annulus can easily be created at the top side of the well, as gravity drags the cement towards the low side. When the cement starts to set, the water will evaporate making the cement lighter (Larsen, 2014d). This can result in upwards migration of the cement. Due to this and to avoid micro annulus a pressure must be applied to the cement while WOC. About 200-300 psi is needed, so about 500 psi is applied for safety reasons.

7.10.3. Track record

One well at the NCS was plugged with 4 plugs at 37 degrees in 17.2 days. The two first was plugged with the two–trip system and the two last with the one-trip system. The time used is shown in Table 12. The time is specified for the TCP operation and the HydraWash operation. The cumulated time includes all the time between the specific operation and afterwards, until the next operation begins.

Table 12: PWC procedure in an inclined well (Hydrawell, 2014a)

		RIH	OOH	Time	Cum Time
Plug 1	TCP	03:00 23-Jul-13	00:00 23-Jul-13	21 hrs	21 hrs 0.9 days
	HydraWash	03:00 24-Jul-13	06:00 27-Jul-13	72 hrs	96 hrs 4.0 days
Plug 2	TCP	10:00 28-Jul-13	06:00 28-Jul-13	20 hrs	137 hrs 5.7 days
	Hydrawash	10:00 29-Jul-13	01:00 1-Aug-13	63 hrs	214 hrs 8.9 days
Plug 3	Hydrawash w/TCP	09:00 2-Aug-13	07:00 5-Aug-13	70 hrs	316 hrs 13.2 days
Plug 4	HydraWash w/TCP	15:00 7-Aug-13	09:00 9-Aug-13	41 hrs	413 hrs 17.2 days

Table 13 shows several HydraSystem jobs that have been performed in deviated wells. The PWC technology has been performed in wells with angles from 0 to 81 degrees.

Table 13: Hydrasystem jobs in deviated wells (Hydrawell, 2014a)

Equipment	Plug	Size	Angle
HydraWash 2	Reservoir 1	9-5/8"	81
HydraWash 2	Csg shoe repair 2	10-3/4"	62
HydraWash 2	Csg shoe repair 3	10-3/4"	62
HydraWash 2	Csg shoe repair 3	10-3/4"	62
HydraHemera	Miocene 1	7"x9-5/8"	41
HydraHemera	Miocene 2	7"x9-5/8"	41
HydraHemera	Miocene 1	9-5/8"	25
HydraHemera	Miocene 2	9-5/8"	25
HydraHemera	Miocene 2	9-5/8"	25
HydraWash 2	Overburden	11-3/4"	0
HydraWash 2	Reservoir 1	9-7/8"	37
HydraWash 2	Reservoir 2	9-7/8"	37
HydraWash 2	Miocene 1	9-7/8"	37
HydraWash 2	Miocene 2	9-7/8"	37
HydraWash 2	Reservoir	9-5/8"	62
HydraWash 2	Reservoir 2	9-5/8"	21
HydraWash 2	Miocene 1	9-5/8"	22

7.11. Failure modes

A plugging operation may fail because of many different things. The formation can collapse, the cement can get contaminated and may set to fast, or not set at all. The BHA can get stuck in the well and so on. A positive thing about using the PWC technology is that the casing is not destroyed. After setting the plug, it can easily be drilled out and logged. This is a problem with the milling technology. Drilling through the cement when the casing is removed, can easily lead the drill bit to deviate from the original path and result in sidetracking the well.

7.11.1. Contingencies

Alternative 1

If the cement settles to early it is quickly detected on drill deck when POOH. All drillpipes are connected with tool joints that have a larger OD and a shoulder. So if the cement has started to set up while POOH, cement residues will pile up on this shoulder. In the well after the drillpipe has been POOH, the cement will probably be inside the annulus. Inside the casing there will most likely be a layer along the walls, and a hollow space in the middle cored out by the drillpipe when POOH.

A contingency action if this happens is to drill out the cement remaining inside the casing. The annulus has to be logged to verify continuous cement in annulus and good bonding to the casing. The plug is re-set inside the casing by placing a balanced plug.

This scenario might be a little unrealistic because normally if the cement has started to set, the drillpipe will get stuck. Then the situation will be completely different. The drillpipe must then be cut and as much as possible of the drillpipe is POOH.

Alternative 2

If the plug fails a pressure test, one contingency can be to just set a new plug above. This depends on whether or not the configuration and the integrity of the well allow it. The new plug can be set with the PWC technology, or milled if this is desired.

Alternative 3

Another contingency if the plug fails the pressure test can be to drill out the plug and re-set another by section milling the same interval. This can be a problematic approach, because it is not really known how the mill cutters will react while milling the perforated hole. They might break by the impact going through the holes in the casing. This will not be discussed further in this thesis.

It is also possible to log the annulus to check the quality of the cement here. It might be the internal cement that was the problem during testing. If this is the case, an internal plug can be re-set inside the casing just like in Alternative 1.

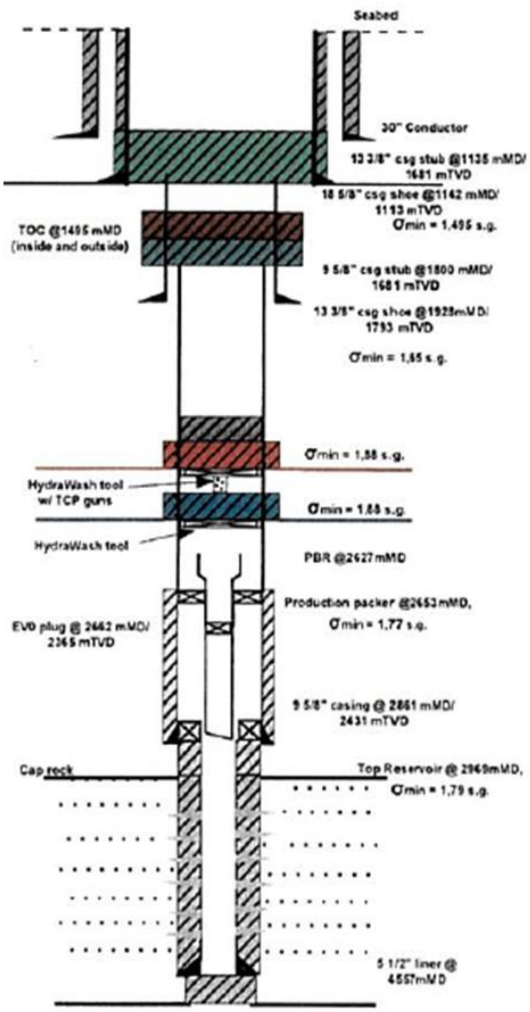
7.12. Case studies

The PWC technology has been tested on Statfjord and Snorre for Statoil ASA. All of the plugs installed were eventually accepted, even though the log results did not show large improvements.

This led to an optimization of the cementing technique, where a pump-pull and rotate operation was the solution. The technique was described under Sub.Sect. 7.2.2.

7.12.1. Snorre well NO 34/7-P-39

Hydrawash was used on Snorre A, well NO 34/7-P-39 in August 2013. The main objective of this P&A and slot recovery was to plug the well back to the 18 5/8” casing to prepare it for a sidetrack. Both the primary and secondary barrier towards the reservoir was set using HydraWash technology, see Figure 43. (Beskaeva, 2013) The area to be plugged had no cement behind the casing. (Wersland, Ekberg, & Hundsnes, 2012)



PRIMARY – Reservoir section		
Formation @ primary cement plug	N/A	LOT = 1,88 s.g.
9 5/8" cement plug (inside and outside of perforated casing)	24	140 bar w/ 1.46 s.g. Annulus cement verified by log
SECONDARY – Reservoir section		
Formation @ secondary cement plug	N/A	LOT = 1,88 s.g.
9 5/8" cement plug (inside and outside of perforated casing)(2)	24	140 bar w/ 1.46 s.g. fluid Annulus cement verified by log

Figure 43: Well barrier schematic of Snorre well P-39 (Beskaeva, 2013)

Primary barrier against the reservoir

An interval from 2556 – 2607 m MD was perforated in the 9 5/8" casing. A LOT was performed, and defined a 96 bar leak-off pressure. The HydraWash tool was left down hole as a base, and a balanced cement plug was set with AbandaCem slurry and squeezed into this 50 m long interval (Beskaeva, 2013). It was performed with the two trip system. Both the washing process and cementing operation went as planned. (Wersland et al., 2012)

Verification of the barrier was made by drilling out the cement and logging the cement behind the casing with USIT/CBL log (Wersland et al., 2012). The interpretation of the log showed moderate bond quality, and moderate hydraulic isolation. A balanced plug was re-set inside the casing, tagged and pressure tested to 140 bars for 10 minutes. (Beskaeva, 2013)

In total the operation took 12.8 days, where 8.5 days were spent to verify the job by drilling, logging and re-setting a new cement plug (Wersland et al., 2012). So without the verification process, the two-trip system would only take 4.3 days.

In Figure 44 some improvement can be seen after the PWC job, but overall it was disappointing USIT/CBL results. 52 m with hydraulic isolation was achieved and the plug was approved. (Ekberg, 2012) A more detailed description of the log interpretation is given in Table 14.

In the author's opinion, the results are good if 52 m with hydraulic isolation is achieved. NORSOK D-010 only requires 30 m external bonding verified by logging. Also the logging results show a decrease in fluid channels according to the USIT log. The VDL also indicate better bonding to the casing.

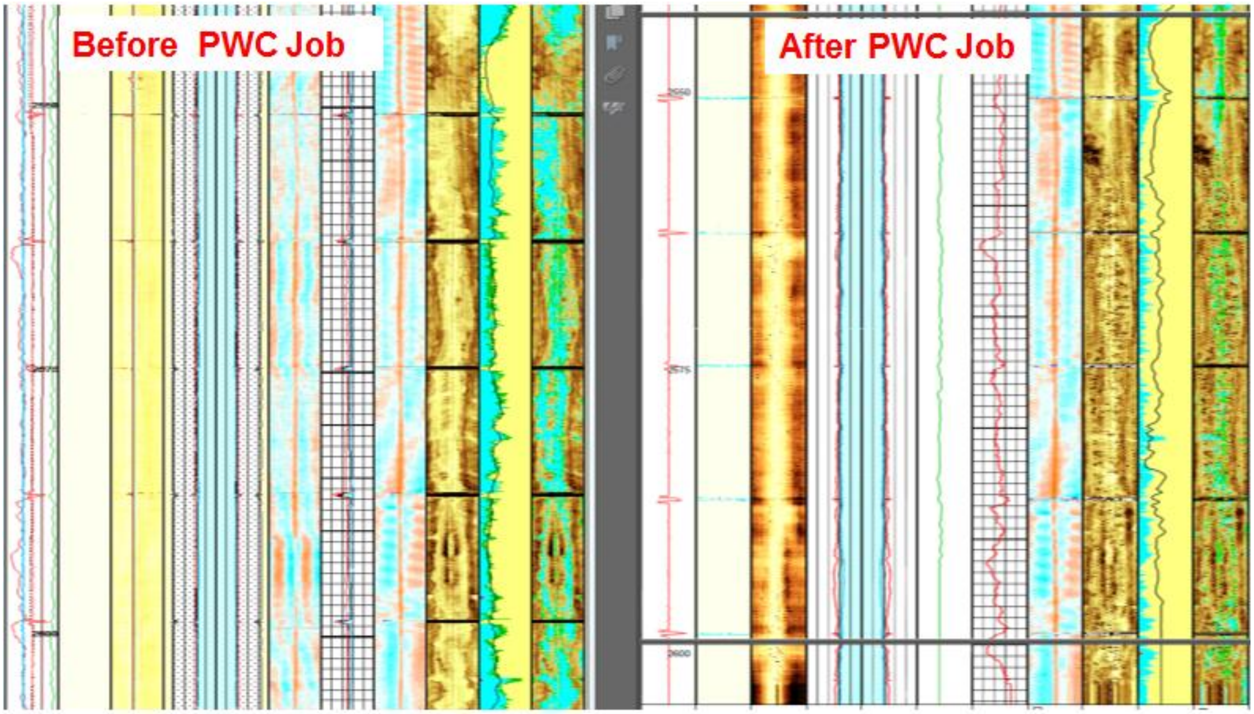


Figure 44: USIT/CBL logging results of plug number 1 Snorre P-39 (Ekberg, 2012)

Table 14: Interpretation of log, plug number 1 Snorre P-39 (Ekberg, 2012)

Top Interval (mMD)	Bottom Interval (mMD)	Bond Quality	Hydraulic Isolation	Comments
Above perforations				
2485	2553			Log response as in July 2011 – does not seem to be affected by HydraWash operation
HydraWash interval				
2553	2605	moderate	yes	Impedance map more homogeneous than before HW – fluid channel seems to have disappeared (USIT). VDL indicate better bonding – CBL just slightly affected (improved)

Secondary barrier against the reservoir

The 9 5/8" casing was perforated from 2416-2467 m MD. The second P&A plug was set with the one-trip system, adding the HydraArchimedes tool above the washing tool. A balanced cement plug was set with AbandaCem slurry while rotating HydraArchimedes tool 50-100 RPM while POOH. The cement was squeezed with 20 bars afterwards, and bled off in 9 hours. (Ekberg, 2012)

2 m^3 less cement was pumped on plug number 2. The well was under displaced with 3.5 m^3 instead of 1.5 m^3. An excessive backflow of 930 liter was observed on plug number 2 when bleeding back after WOC, which most likely jeopardized the cement quality of the second plug.

Tagging of the plug hit hard cement at 2333 m MD. It was tagged with 10 tons and pressure tested to 140 bars for 10 minutes. Soft cement was found at the top perforation, so had to WOC for 6 additional hours. Afterwards it was tagged with 10 tons. The plug was drilled out to run a USIT/CBL log, which initially was not the plan. This showed medium to poor bond quality and non to probable hydraulic isolation over the perforated area. The re-set plug was tested to 140 bars for 10 minutes.

In total 10.6 days were spent, which included 6.8 days spent to verify the job by drilling the cement, logging and re-setting cement plug (Wersland et al., 2012).

The USIT/CBL log results after the PWC job are shown in Figure 45. The results were disappointing. Probably 35 m of hydraulic isolation was achieved. In Table 15 a deeper interpretation is given. The ‘interpretation discussion’ for interval 2418-2453 m MD is not included in this thesis.

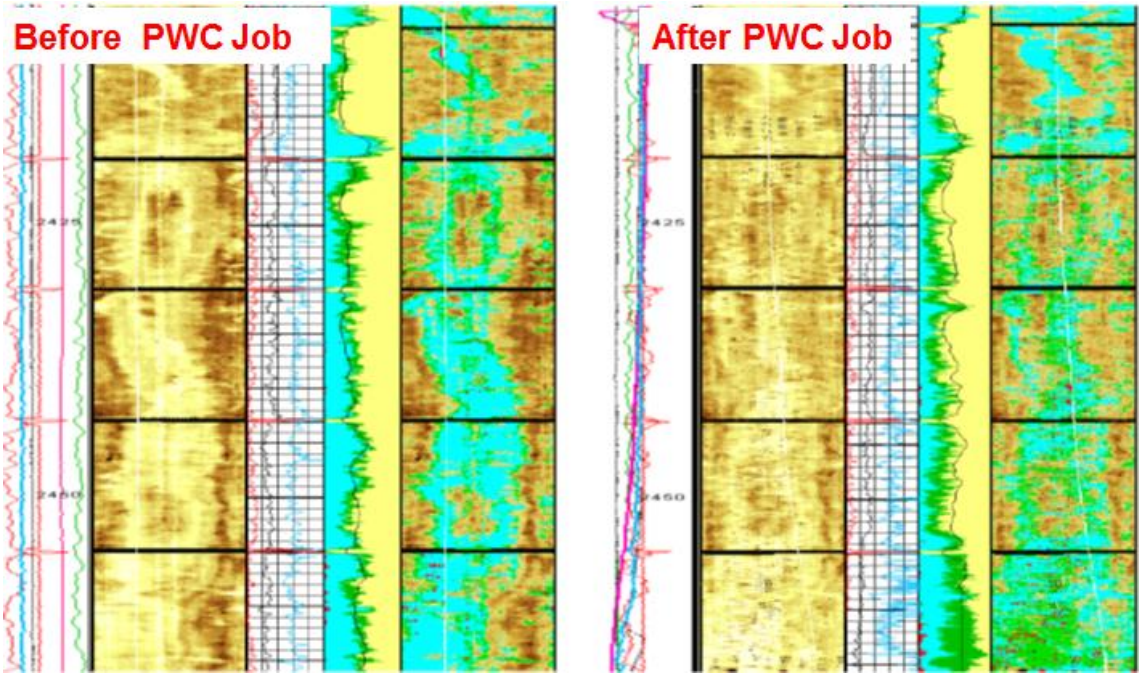


Figure 45: USIT/CBL logging results of plug number 2 Snorre P-39 (Ekberg, 2012)

Table 15: Interpretation of log, plug number 2 Snorre P-39 (Ekberg, 2012)

Top Interval (mMD)	Bottom Interval (mMD)	Bond Quality	Hydraulic Isolation	Comments
2415	2418	Poor	No	No change compared to the baseline log in this interval.
2418	2453	Medium	Probably	See interpretation discussion above.
2453	2466	Poor	No	Very little bonded cement solids. But the fact that the log shows that the good cement in the baseline log has 'disappeared' again points to a micro debonding effect, however with such little bonded cement shown on the log it is impossible to tell 1) if there is any improvement in this interval or 2) to make any conclusion with respect to isolation.

Issues/learning from using HydraWash

The plugs set captured the following experiences (Wersland et al., 2012):

- Try to use standard G cement slurry instead of AbandaCem
- Slow strength development on cement slurry increased WOC time.
- Perforate larger holes to allow for higher circulation rate.
- Increase the perforation interval
- Did not achieve the washing pressure that was simulated before operation.
- Excessive backflow of 930 liter that was observed on plug number 2 when bleeding back after WOC, most likely jeopardized the cement quality.
- Unsure if the use of HydraArchimedes actually improved the cement job in this plug.
- The use of swivel to allow rotation of the string above washing tool improved hole cleaning in highly deviated wells.
- Inject additional 2-3 m^3 cement into perforations after pulling BHA to above TOC.
- Plug number 2 showed that the squeeze pressure on plugs set with the PWC technology must be maintained until cement is set. (Beskaeva, 2013) ‘

The issues/learnings are discussed further under Sect. 9.3.

In Table 16 the time used to set and verify the plugs is shown. A lot of time can be saved if the time spent on verification is reduced. For the primary plug the verification was 66.4% of the entire operation and for the secondary plug it was 64.2%.

Table 16: Time used on setting plugs with and without verification on Snorre P-39

	Comment	With verification [days]	Verification [days]	Without verification [days]
Primary plug	Two-trip system	12,8	8,5	4,3
Secondary plug	One-trip system	10,6	6,8	3,8

7.12.2. Statfjord well NO 33/12 B-42

The objects of the operation were to P&A the well, B-42, to stop pressure build-up and hydrocarbons in the B-annulus and create a barrier against reservoir and against the Lista formation. The procedure was performed in February 2012. The well design before and after the P&A job is shown in Figure 46. A challenge in the well was that it experienced losses during the 9 5/8" cement job, so the cement behind the casing was probably not good. In addition this is an inclined well as shown in Figure 47. The primary and secondary plug set in the 9 5/8" casing against the reservoir was placed with the HydraWash technique. A primary and secondary plug was also set in the 11 ¾" casing against the Lista formation, but here a balanced plug was set inside the casing. (Obrestad, 2012)

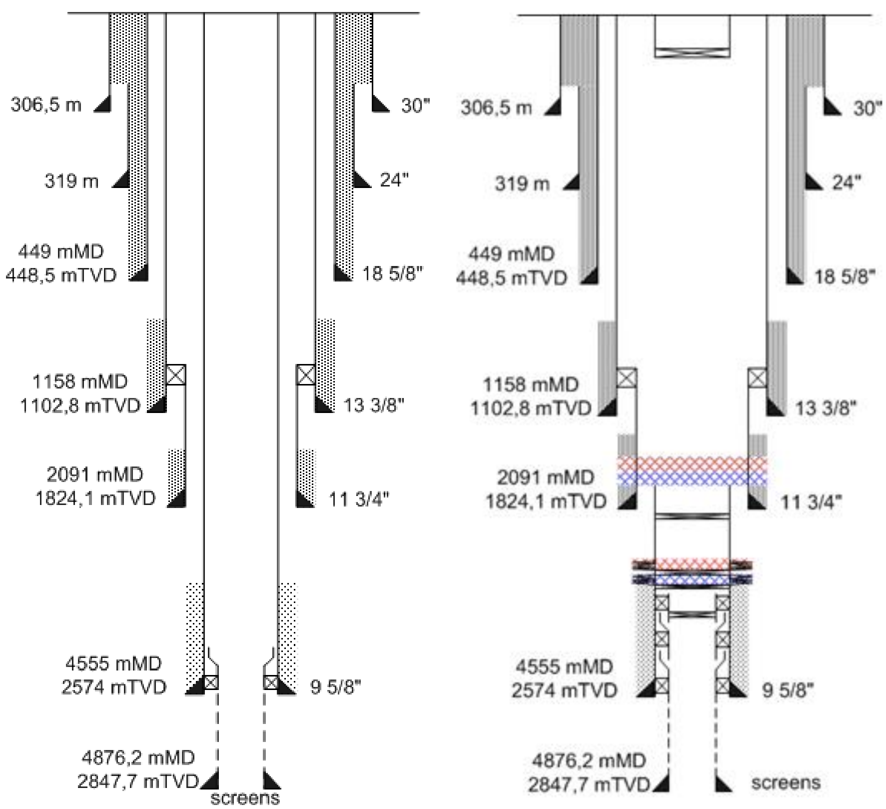


Figure 46: Statfjord Well B-42 design, before and after P&A operation (Statoil, 2012)

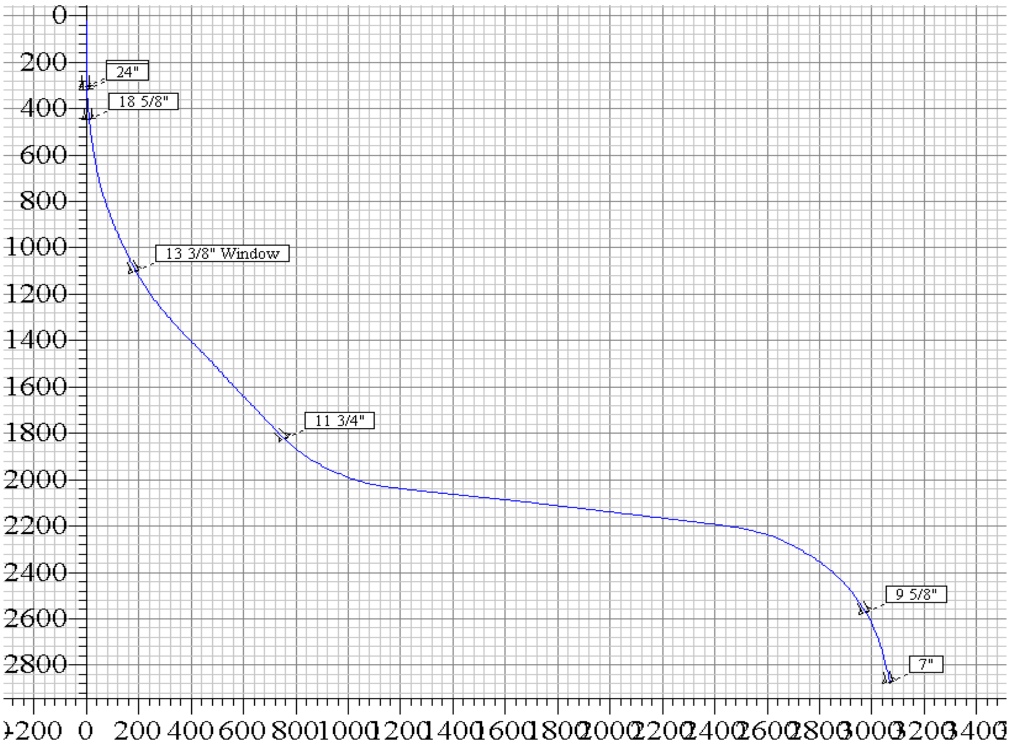


Figure 47: Inclination of Statfjord well B-42 (Statoil, 2012)

The operation started with pulling the production tubing, and logging the 9 5/8" casing for reference for improvements after using HydraWash. Two HydraWash plugs were set in the 9 5/8" casing at approximately 4000 m MD, one primary and one secondary barrier towards the reservoir. Then the 9 5/8" casing was pulled from 1900 m MD and the 11 ¾" liner and 13 3/8" casing was logged. A cement plug was set against the Lista formation in the end. (Statoil, 2012)

Primary barrier against the reservoir

An interval was perforated from 4075 – 4126 m MD. The washing process downwards took 12 hours and 9 hours up. So a total of 21 hours was used washing. A power shut down occurred on the platform after pumping the spacer, so before the cementing started, a new wash job had to be performed. This because the shutdown lasted for several days and the spacer did not last that long and settled behind the casing. This extra washing sequence took 33 hours down and 19 hours up, so a total of 52 hours extra was used, and major formation issues were experienced. After this the BHA got stuck inside the casing due to settled barite and debris between the casing and drillpipe in the most horizontal section of the well. 21 hours was used to get free with rotation and circulation, and in the end the cups were worn out as they were not designed for rotation. 12 m^3 of AbandaCem was used to set a balanced cement plug. The plug was squeezed afterwards and a pressure of 40 bars was held while WOC. After this the plug was drilled and cement behind casing was logged. Three conventional internal cement plugs were set before the plug was approved after being pressure tested to 170 bars. In total from RIH to the re-set plug was tested, 27 days was used. 52 hours could be removed from these 27 days as the power loss resulted in a new washing sequence. (Statoil, 2012)

The logging results are shown in Figure 48. Small improvements can be seen after the PWC job. Channels with fluid has been blocked, so there are no continuous micro annulus, but a continuous plug was not achieved either. A closer interpretation is described in Table 17. An interval of 17 m of hydraulic isolation, and possibly an additional 18 m was achieved. Also probably 20 m above the perforations was set.

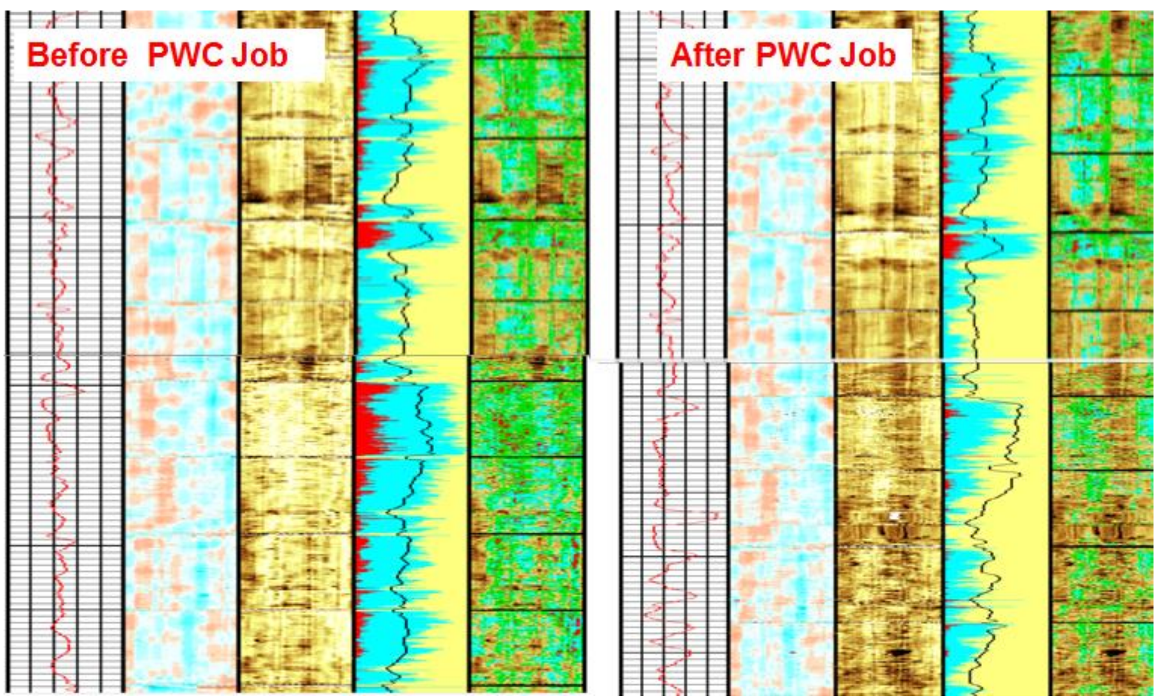


Figure 48: USIT/CBL logging results of plug number 1 Statfjord B-42 (Ekberg, 2012)

Table 17: Interpretation of log, plug number 1 against reservoir (Statoil, 2012)

Top Interval (mMD)	Bottom Interval (mMD)	Bond Quality	Isolation		Comments
9 5/8" casing					
3860	4048				No change from before HydraWash
4048	4055	Poor	No		No change from before HydraWash
4055	4075	Moderate +	Probably		Possibly slightly higher impedance than before HW
HydraWash interval					
4075	4092	Poor	no		Higher impedance than before HW (USIT) – but CBL/VDL data is similar as before HydraWash
4092	4099	Moderate +	Probably		Higher impedance than before HW – less difference on the CBL/VDL data
4099	4117	Moderate	Possibly		Clearly higher impedance than before HW – less difference on the CBL/VDL data
4117	4127	Moderate +	Probably		Clearly higher impedance than before HW – less difference on the CBL/VDL data

Secondary barrier against the reservoir

An interval from 3979 – 4030 m MD was perforated. The first wash downwards took 30 hours, afterwards the cups started leaking, and another run had to be performed. This took 49 hours down, and 33 hours up, resulting in a total 112 hours spent washing. The washing sequence is supposed to take between 12 and 48 hours, but due to collapsed formation it was more difficult to clean the annulus. The washing sequence upwards indicated an unstable formation. This second plug was set using two HydraArchimedes tools to improve the cement plug quality compared to the first plug. Also the HydraSwivel tool was used to improve the washing in the deviated well. 13 m^3 of AbandaCem cement was pumped while rotating. One stand was pulled while cement squeezing was performed with pressure up to 116 bars. The plug was drilled out and logged afterwards. The re-set plug was pressure tested to 112 bars and approved. It took 19.5 days from RIH and until the re-set plug was tested. (Statoil, 2012)

The logging results are shown in Figure 49. The results show that a micro annulus has been blocked, and annulus is sealed off. 33 m of hydraulic isolation was achieved along the perforated interval and 14m above the perforations. A closer interpretation is shown in Table 18. The plugs were initially not approved, but the annulus pressure disappeared and the annulus ceased flowing so the plug was approved.

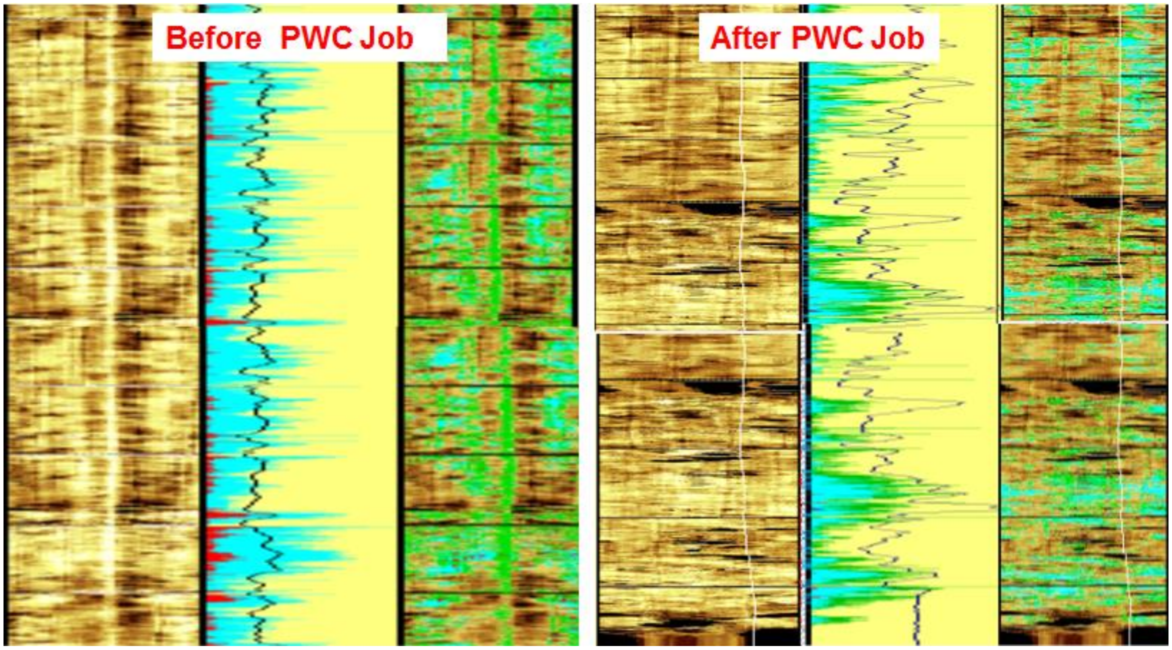


Figure 49: USIT/CBL logging results of plug number 2 Statfjord B-42 (Ekberg, 2012)

Table 18: Interpretation of log, plug number 2 (Statoil, 2012)

Top Interval (mMD)	Bottom Interval (mMD)	Bond Quality	Isolation		Comments
9 5/8" casing above HydraWash perforations					
3935	3965	variable			No change from before – used as calibration interval
3965	3979	Moderate	yes		Generally the same impedance profile but higher absolute value – isolation improved after HydraWash based on USIT data. CBL profile does not indicate any improvement
HydraWash perforated interval					
3979	3981.5	good	yes		Clear improvement on both logs
3981.5	3994	moderate	yes		Patchy bond – probably slightly better than before HydraWash
3994	4003	poor	no		Less high impedance material than before HydraWash
4003	4009	moderate	yes		Patchy bond – better than before HydraWash
4009	4017	poor	no		Less high impedance material than before HydraWash
4009	4021	moderate	yes		Slightly better than before HydraWash

Barrier against Lista formation

After the 9 5/8”casing was cut and pulled, the 13 3/8” casing and 11 ¾” liner was washed. The cement behind 11 ¾” liner was verified by logging to be good, so a balanced plug was placed inside the liner. The plug was tagged and pressure tested to 180 bars. (Obrestad, 2012)

Issues/Learnings from using HydraWash on Statfjord

The plugs set captured the following experience:

- Drillpipe stuck in settled barite and formation in high sail angle due to low pump rate and no rotation of pipe.
- Problems with shearing the HydraWash tool – it had to be pressured up several times.
- Worn out cups on HydraWash tool after excessive rotation
    - Needed to re-wash the whole interval for plug number 2 due to worn out «heavy duty» cups. Took 88 hours extra.
- Broken blade on HydraArchimedes
- Leaking cement plugs (AbandaCem)
- Guns/perforation size 4 5/8” in 9 5/8” casing
- 52 hours could have been saved if the power did not go out on the first plug

It was learned from this job that two HydraArchimedes have to be used for perforations over 50 m. The drillpipe has to be pulled and rotated after pumping the cement. (Hydrawell, 2012) These issues/learnings are discussed further in Sect. 9.4.

Table 19 shows the time usage on setting plugs with the PWC technology on Statfjord B-42. Without the extra washing and BHA stuck on the primary plug, the verification was 62.5% of the total time used. For the secondary plug, the verification was 50.6% of the total time used. This increases the cost of P&A significantly. The percentage of the total time spent on verification shows that a lot of time and money can be saved by eliminating the time it takes to drill the plug, log it and re-cement the plug afterwards.

Table 19: Time used on setting plugs with and without verification on Statfjord B-42

		Hours	Days	With verification [days]	Verification [days]	Without verification [days]
Primary plug	Initial washing	21.3	0.9			
	Extra washing due to power shut down	51.7	2.2			
	BHA stuck	21	0.9			
	Total time used	93.9	3.9	27	15	12
	Time without extra washing and BHA stuck	21.3	0.9	24	15	9
Secondary plug	Initial washing	22.5	0.9			
	Extra washing due to leaking cups	88	3.8			
	Total time used	110.5	4.6	19.5	8	11.5
	Time without extra washing	22.5	0.9	15.8	8	7.8

In Table 20 the pressures and weight used to verify all the re-set plugs are shown. The acceptance criterion for the test is set by the operator. The NORSOK D-010 requirements are described under Sub.Sect.3.2.3. Normally setting a balanced plug inside the casing is a straight forward procedure, but due to problems with the well and unknown issues, one had to be re-set three times.

Table 20: Verification pressures and tagging for internal re-set cement plug (Obrestad, 2012)

Plug	Pressure tested [bar]	Bled [bar]	Time [min]	Tagging [tons]	Status
HydraWash primary number 1	200	25	10	10	Not approved
HydraWash primary number 2	200	42	4	4	Not approved
HydraWash primary number 3	170	1,4	10		Approved
HydraWash secondary	180			7	Approved
Balanced plug	180			10	Approved

8. Verification

A proper verification is necessary to ensure that the well barriers are effective. It is done according to NORSOK D-010 requirements. 30 m external bonding must be verified by logging, and the plug must be tagged and pressure tested. HydraWell operates with a pressure test over 30 minutes and has good experiences with this. (Larsen, 2014d) NORSOK D-010 pressure values and durations are described in Sub.Sect.3.2.3.

In Table 21 the time used on a PWC operation with and without logging is shown together with section milling operations. The PWC operation without logging is how the operations should be performed in the future once a faster verification method has been set for Statoil. The PWC operations performed on P-39 was a little slower than the section milling performed on P-29. What not appears from this table is how these wells were, and if there were any problems during the operation. For well P-39, where the PWC operation was performed, it is described in Sub.Sect. 7.12.1 that the operation experienced some problems that increased the time usage. Regardless of this, PWC without logging is capable of treating several more meters/day than a section milling operation.

Table 21: Time savings PWC vs. Section milling (Ekberg, 2012)

Well/job type	Meters	Days	Meter/day
P-29 Section milling	120	23.6	5
P-10 Section milling	27	14.2	1.9
P-39 PWC including logging	85	18	4,7
PWC without logging	85	9.8	8.7

8.1. Pressure testing the plug

Baker might have some wireline tools available for pressure testing a smaller volume in the well. There is an ongoing discussion about which tools that can be used and how to use them. (Baker Hughes, 2014)

Being able to reduce the volume when a pressure test is performed could reduce the time spent on verification and improve the results. Pressure testing a smaller volume will make it easier to know exactly where the pressure is applied, and what section of the well that is exposed. Also less temperature effects and a faster reaction time is achieved. It is important to be careful when testing only a small volume, because if inflow occurs it could result in significant problems. In Figure 50 pressure testing of HydraHemera is shown. In this example brine is injected, for a negative pressure test of the plug. If the volume above and around the drillpipe could be reduced in Figure 50 the pressure test would get the result of a leakage faster.

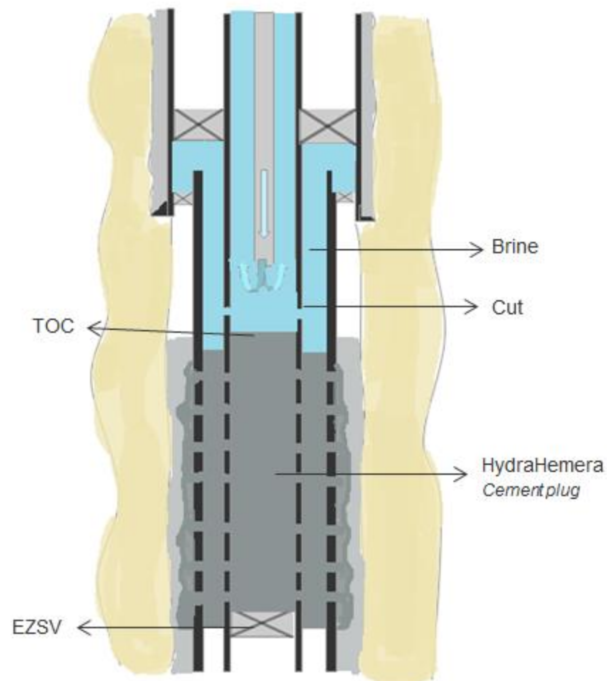


Figure 50: Pressure testing HydraHemera plug

A positive pressure test is performed for all plugs, both single and double annuli. This test is easier to perform than a negative pressure test, because normally heavier fluids are already in the well. (Larsen, 2014d) As described under Sub.Sect 3.2.3 casing cement shall be verified by pressure testing and it shall be done in the direction of flow. Since the negative pressure test is more difficult to perform and the plugs seal in both directions, a positive pressure test is performed on all plugs. A negative pressure test is performed to check if the plug set in two annuli seals properly. The test is described in Sub.Sect. 5.1.2. The issue with this test is how long the pressure must be stable before the plug can be approved. This test is performed to qualify the HydraHemera method to be used regularly in a well, since it is not possible to log it. So in the future also the plug set over two annuli will only be tested with a positive pressure test (Larsen, 2014d)

8.2.Pressure testing cement in annulus

It is not conclusive to drill out and pressure test a HydraSystem job from below. This is because the length of the cement from the lower perforation and down in annulus might not be more than a few centimeters (Hydrawell, 2014b). The same applies for the cement in annulus from the top perforation and upwards. Figure 51 shows the procedure of installing a straddle in the well. A straddle is basically a pipe with packers in both ends. In this case one packer is placed at the bottom of the cement in annulus, and one packer at the top of the cement in annulus. The plug set with the HydraSystem is drilled out and the casing is punched above and below the cemented annulus. The straddle assy is installed and the plug can be pressure tested.

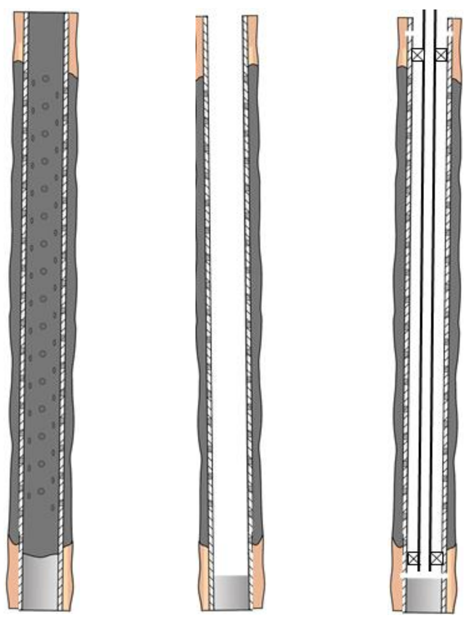


Figure 51: Installing straddle in the well (Hydrawell, 2014b)

The pressure testing of the cement in annulus with a straddle can be performed as described, but the results will not be conclusive. If the pressure holds the plug can be approved to seal, but if it leaks, the plug might still be good. This is because the annulus is not cemented far from the perforation at the top or bottom. If it holds, it is know that the entire plug seals. But a leakage during this test only proves that there might be a small leakage around the top or bottom perforation, which is a small interval of only a few centimeters. Figure 52 shows the leak path when the cemented annulus is pressure tested from below. Figure 53 shows the leak path when the cemented annulus is pressure tested from above

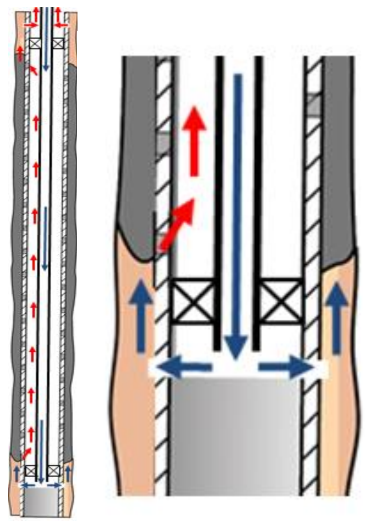


Figure 52: Pressure testing HydraSystem plug from below (Hydrawell, 2014b)

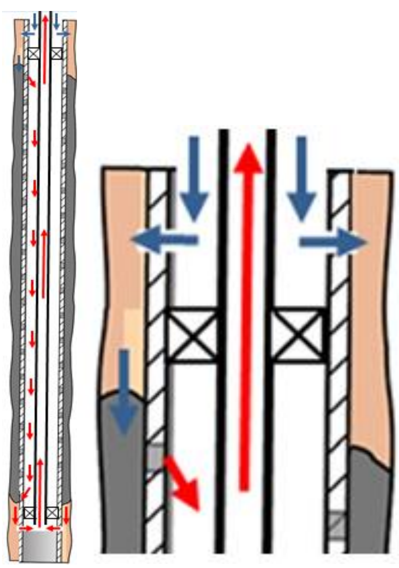


Figure 53: Pressure testing HydraSystem plug from above (Hydrawell, 2014b)

8.3.HydraWell

HydraWell recommends drilling out and logging plugged wells for new customers and new fields. Also, if any problem should occur, the plug is drilled and logged, and improvements are made. With the PWC technique it is possible to tag and pressure test the TOC right after the cement has reached its strength (Larsen, 2014d). After several tests have been performed onshore and offshore the verification process will be a quicker affair. Then the verification can be performed by only pressure testing and tagging the plug.

To pressure test the plug, a predefined number meters of the cement is drilled out above the plugged area. This length is set by the operator. 50 m of cement is needed above the top perforation. An example on how to pressure test and log the plug is shown in Figure 54. An RTTS (Retrieve Treat Test Squeeze) plug is run on drillpipe and the cement plug is pressure tested from above. This is a plug that can be set and retrieved. The drillpipe is then displaced by light fluid, and back-pressure is kept on return. Pressure is then bled back in stages over the choke. A negative test can then be performed if required. If there are any doubts, the plug inside the casing can be drilled, and the interval in annulus can be logged as shown in Figure 54. The interval is plugged afterwards by setting a balanced plug. (Hydrawell, 2014b)

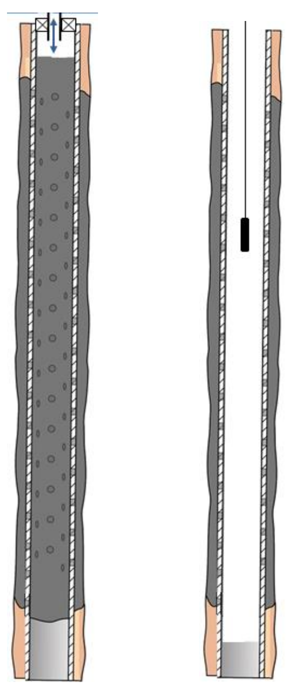


Figure 54: Pressure testing and logging of a HydraSystem plug (Hydrawell, 2014b)

8.3.1. HydraHemera

To verify that the HydraHemera plug seals, pressure tests are performed. This year, spring 2014, a negative pressure test with 1800 psi over 24 hours was performed. This test was successful with no pressure buildup (Hydrawell, 2014f). An offshore test is currently ongoing with the HydraHemera technique. The plug is going to be tested for 100 days with a negative pressure test of 1000 psi, to check if it seals properly. The plug was set in 7" x 9 5/8" casing. (Larsen, 2014d) A single casing plug has been placed using the HydraHemera technique. This has been logged to verify a good cement-to-formation bonding, and it was approved. (Hydrawell, 2014f)

ULLRIG testing

A verification test of the HydraHemera system has been performed at ULLRIG, Stavanger. A real life model was made with a 7” casing cemented off center inside a 9 5/8” casing with a mixture of 25% cement and 75% barite. This was installed inside a 13 3/8” casing, which represented the formation. The casings were lowered through the rotary and landed in the wellhead and a HydraHemera operation was run. The well was washed with KCL mud, spacer was sprayed into the annuli and finally the entire interval was spray cemented with AbandaCem. Afterwards everything was brought up to surface, and cut into 7.5 cm pieces as shown in Figure 55. Every piece was evaluated and checked for cavities and micro annulus, and the test turned out very good. In Figure 56 and Figure 57 the lighter colored parts is the new cement filling the inside of the 7” casing, and outside of the 9 5/8” casing. The dark cement is the old cemented part with cement and barite. See that the annulus between the 7” and 9 5/8” casing is filled with some new cement and there are small cavities with no cement. None of these cavities have a depth to be concerned about (T. Ferg, 2013).

Figure 55: The casing cut into 7.5 cm pieces (Hydrawell, 2014f)

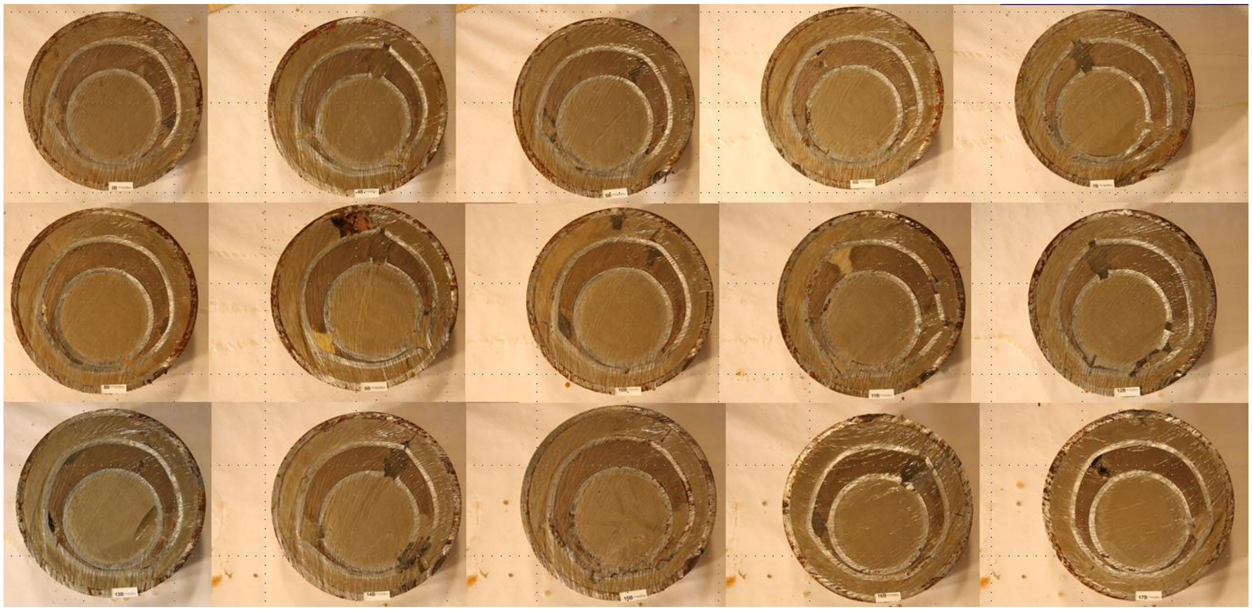


Figure 56: First half with cross sections (T. Ferg, 2013)

Figure 57: Second half with cross sections (T. Ferg, 2013)

New verification methods

Other tests than pressure testing can be performed to verify the HydraHemera technology. Today there is one method to log a plug set in two casings. The procedure is shown in Figure 58. First, the plug inside the casing must be drilled out before the inner casing is milled away. A washing sequence must also be performed before the outer annulus can be logged. Afterwards the plug is re-set.

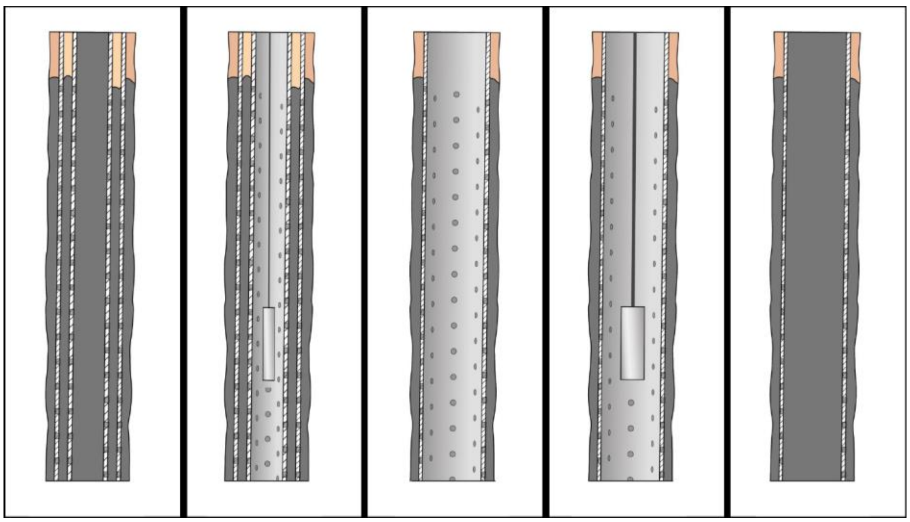


Figure 58: Possibility to mill and log after HydraHemera job (Larsen, 2014a)

There is a large uncertainty around this process if the result will be any good at all. The milling operation is tough on the casing and cement, and can damage the cemented outer annulus. Hence, further investigations must be done prior to proceeding with this approach according to HydraWell.

8.4. Camera

It might be possible to observe leakage using a camera. By doing a negative pressure test, while filming the top of the plug, there might be a possibility to see if there is a leakage through the plug.

Vision iO has developed a HD camera, that provides good film down hole. Normally the fluid in the well has to be displaced with water or Nitrogen. The advantage with their technology is that they also have the possibility to bring the clean fluid into the well with the camera, this way avoiding displacing the entire well. Their vision readycam is an inspection system for subsea completion and P&A activity. (Vision iO)

8.5. Statoil future verification plans

It is currently a top priority in Statoil ASA to get a proper verification method for P&A. A technology development and implementation (TDI) process is currently ongoing for through tubing production casing logging.

8.5.1. HydraWash

The PWC technology is currently being worked on in Statoil to get the proper verification methods. The HydraWash technology has to be tested more where the plug is drilled and logged. If good results are achieved, it might be possible to just pressure test the plug as other operators are doing at the moment.

8.5.2. HydraHemera

A TDI process is ongoing for the HydraHemera technique in Statoil. A plug is going to be set with the HydraHemera method on Statfjord well A-1 in July. Here the plug can be monitored for a long time after it is set. The HydraHemera technique is now to be looked at as the primary method to be used for the Lista formation on Statfjord. (Strøm, 2014c)

Currently, pressure testing is the best verification method for HydraHemera. In addition to this a firm base for the cement must be set, and the volume needs to be controlled during the operation. By also tagging the plug in the end, this should be enough to trust the sealing ability of the plug. (Strøm, 2014b) In principle there are no requirements in NORSOK D-010 on how to verify it, but it is stated that the external WBE "shall be verified to ensure a vertical and horizontal seal". For internal WBE it is stated under EAC 24, that for a cased hole it shall be verified by tagging and pressure testing. Currently in Statoil, the HydraHemera technology is at qualification level Technology Readiness Level (TRL) 3, and it has to be at TRL4 to be approved for 1st use, this should be done within June 2014. Other operators have already used the technology for 13 plugs.

8.5.3. Logging through two annuli

According to NORSOK D-010 logging operations are mandatory for qualification of cement as a barrier. This is when the cement job is a part of both the primary and the secondary barrier, or if it is a critical casing cement job. Statoil ASA is currently working on developing and qualifying a method to log two casings. This new development has priority number one in Statoil ASA. The downhole technology is not new, but it is a new way of processing and interpreting data records. Through tubing production casing logging is a sonic – ultrasonic well diagnostic and investigation wireline based technology. It can be used for well integrity evaluation of a plug when both tubing and casing are in place, evaluating both the cement to casing bond and casing integrity. The technology consist of seismic data processing methods which is applied over data collected with existing angled and normal incident ultrasonic beams technology which is currently in use. The results are presented for the interpreter in standard industry single casing cement evaluation formats. Currently the method is at level TRL3. Hopefully it will reach TRL 4 in June, and then it is qualified for use. First use is planned in August 2014. (Merciu, 2014)

Tests have been performed on Statfjord, where two annuli have been logged and interpreted. Afterwards one casing has been cut and pulled, and the outer casing has been logged. These log interpretations have then been compared to verify that the same results for the outer annulus have been found for both methods. For now Statoil is validating the method of cement bond log in two annuli when the first annulus is filled with fluid. Interpretation of data has revealed that the operational focus must be guided towards methods for placing cement between two pipes, where the current technologies are lacking developments. (Merciu, 2014)

9. Discussion

In this section the main topics regarding the PWC technology, verification methods and future goals will be discussed.

The largest challenge with P&A is still to make the operation economically sustainable for the operators. This can be solved by reducing the verification time after setting a plug with HydraWash or HydraHemera, since the time to set the plug already is fast.

The reason there is a challenge verifying the plug set by the PWC technology compared to the plug set after milling the casing away, is the cement in annulus. When the casing is removed, it is easy to know that the cement will cover the entire cross section of the well, because it is basically just an open hole. With the PWC method good bonding must be achieved to both the formation and to the casing. The area in annulus is small and rough. Cementing a continuous section in this area, through small perforated holes is not a straight forward method.

9.1. Advantages for PWC vs. milling

The first part of the thesis involved a comparison between the conventional milling technology and the new PWC technology. Following are the advantages of the PWC technology with regards to HS&E, the BOP and well control/well integrity. In addition to these, the PWC technology is not more expensive. This because there is shorter rig time, it avoids swarf handling and BOP maintenance, and reduce the tripping time for not pulling casing. In Figure 3 it was shown that pulling and tripping of casing was the most time consuming processes. Milling is at third place. The fact that these are eliminated with the PWC technology is a huge plus towards this technology.

The traditional method with milling destroys the casing. This makes re-entry of the well more or less impossible if any problems should develop during the operation or in the future. Using the PWC technique the casing is left intact and the well can be re-entered if any problems should develop. This makes it possible to verify the plug afterwards. This possibility is lost when milling the casing. The main issue is not really the technology, but how the plug set can be verified with an easier and cheaper method.

9.1.1. HS&E

A large HS&E advantage for the PWC technology is no swarf handling. By wearing personal protective equipment to protect hands and eyes, some of the risk is reduced. But still there are environmental issues created from the collection point and to the final disposal site. By using the PWC technology, the handling of swarf is completely removed.

9.1.2. BOP

As mentioned earlier, in most wells only 25% of the swarf is circulated out. A lot of it is left in the well, or it settles in the BOP. The BOP is a very important well barrier to maintain the integrity of the well. Due to this, after swarf has flowed through, it must be cleaned, tested and verified before any operations can continue. This is an expensive procedure, and also during the milling operation, a WBE is reduced.

9.1.3. Well control/well integrity

In the annulus there might be trapped gas, which is released once the casing is perforated or milled through. With the HydraWell technique, the BOP is intact all the time. If there is gas in the well after perforation it is just circulated out, and the BOP is ready if any well control incident should occur. During a milling operation, the swarf is in the well and flows through the BOP. If there is gas when you get through the casing the situation is worse. With a gas kick during milling, a lot of cuttings can block the BOP which is critical during a gas kick. (Larsen, 2014b)

With the PWC system there is an advantage of optimum well control through all phases while placing a plug. With the bypass channels in the tool, surge and swab effects is also reduced. Also these channels enable the tool to run at a higher speed, reducing time spent running in hole.

9.2. The industry

A large issue with the technology is to verify the plug. For the plug set over one annulus verification can be done by logging, but over two annuli it is not that easy. It is particularly difficult to implement the technology because the industry is very conservative. The main thought is what has been done has been working, so just continue to do it this way. This way no mistakes are made, but no improvements are done either. Also the opinion to «save money today, and rather use them later», should be shifted towards «do more today and save money later». Ignoring the problems today, have never helped to get a better solution for the future.

With regards to P&A it is important to do it right the first time, or it can get really expensive. But the same really accounts for the well construction process. If the casings had been properly cemented and verified from the beginning, at lot of time and money could have been saved. There might not even be a need for placing cement outside the casing. Now the cement behind the casing has to be logged and verified. To do this the production tubing must be pulled. If the cement is not good, a proper barrier in the annulus has to be set. With the new NORSOK D-010 requirements that the P&A phase has to be taken into account when planning the well this might be taken more into consideration. Involving the P&A phase in the design and construction of new wells has a potential to reduce later P&A to an absolute minimum if it is done correct. Proper cement jobs will do a lot for future P&A operations, together with proper verification and documentation. An idea might be to install centralizers for the cement job, which most likely will help to improve the quality of the cemented section.

Control lines are also an important factor in the P&A operations. As described earlier these control lines, in combination with the plastic coating/sheet currently used, can create small micro annuli if they are left in the hole. By considering control lines and all objects placed in a well together with P&A, there might be a way of creating a solution that ensures a faster plugging and abandoning of the well. This might be to create sections in the well where a plug can be set in the future, with no control lines, or valves.

9.3. Experience from Snorre case study

Overall the result from plugging the well with the PWC technique showed improvements on the log. A better bonding was developed and the channels with fluid were reduced. NORSOK D-010 requirement of 30 m verified continuous cement was also fulfilled. Learnings from the well plugged at Snorre were to apply squeeze pressure and add more cement before squeeze cementing. Also the WOC time was a critical factor here, since the cement had not set when the plug was drilled through. There was a suggestion to use standard G cement slurry with optimization to reduce WOC, instead of the AbandaCem. This will not be good because the standard G cement will shrink as it sets. AbandaCem has the quality to expand back to its original volume after shrinking. This way AbandaCem is capable of creating a good bond to one casing and/or two casings.

Also according to (Merciu, 2014), the standard G cement slurry will not achieve good bonding to the casing. The cement issue will not be discussed further, but the Technical Requirement (TR) documents in Statoil have to be followed to ensure a proper cementing job. Most plugs set with the PWC technology have used AbandaCem, but every well is unique, the formation varies and the bonding to cement can differ, so the cement slurry to be used have to be properly analyzed before it is injected into the well.

The interval to be plugged in this well, was deviated, and had a long ‘sail’ section. The HydraSwivel was used and helped to clean out the well and avoided plugging. Increasing the perforation interval to be plugged is not really a good improvement as this in the author’s opinion will lead to more problems with more cleaning and a longer section to cement. Especially when considering the ‘u-tube’ effect while removing stands. The interval of 50 m should be enough to achieve a continuous cement plug of minimum 30 m verified by logging. Increasing the perforation hole was also an improvement suggestion. This must be looked into for every well as the limited entry and ECD has to be considered. There was also an uncertainty whether or not the HydraArchimedes tool improved the cement job. But this is a necessary tool to avoid the ‘u-tube’ effect and consequently contamination of the cement.

The excessive backflow of 930 liter should not have been bled off on plug number 2. When bleeding back after WOC, the volume to be bled should be known, or it can be easily calculated. When the volume bleed of exceeded the volume that actually can be contained above the plug, the bleeding should have stopped. This is an indication that something is leaking, or that the cement has not set. This excessive bleed of most likely jeopardized the cement quality.

The reason for the large disappointment on the logs might have been that extremely good results were shown from other plugs set with the PWC technique, and this was the anticipated result for this well also. All considered this operation went as planned, and it would only have taken 4.3 days on plug number 1 and 3.8 days on plug number 2 if the drilling, logging and re-setting of plug had not been done. So the time to plug the well does not take long. The verification time accounts for 66% and 64% of the total time used on the plugs. There is a large improvement potential to shorten the time spent on placing a plug by reducing the verification time.

9.4.Experience from Statfjord case study

From Statfjord well experience, some unforeseeable things happened that increased the P&A time a lot. These have to be disregarded when looking at the PWC technology. Placing the first plug, 52 hours extra had to be used on the washing sequence due to power shut down on the well, which lasted for several days. The drillpipe got stuck in settled barite and formation in high sail angle – resulted in using HydraSwivel for the next plug placed. This was 9% of the total time used on this plug.

When looking into the issues/learnings from this operation the shearing of the HydraWash tool was not really an issue. One extra circulation of the well sheared the tool, which is often done in similar operations. The worn out cups is not a problem as these are designed to hold for 48 hours and everything over this is a bonus. The Archimedes tool had a broken blade after the operation. This is not of any concern as the Archimedes tools are not reused after an operation. The high sail angle also caused the drillpipe to get stuck in the well. The HydraSwivel tool has been developed for these situations and has been working very good.

The primary plug set at Statfjord took 27 days with an extra washing sequence and stuck in the well, mostly due to a power shut down on the rig. Without this the operation took 24 days, where 62.5% of the time was used on verification. For the secondary plug set, there was also some extra washing, which increased the time spent to 27 days. Without the extra washing the operation would have taken 24 days, where 50.6% of the time was spent on verification. This clearly shows that the verification process is too time consuming.

9.5. General thoughts about the PWC technology based on the case studies

The procedure used on both Statfjord and Snorre was the same as the one that was used on Ekofisk for ConocoPhillips. Since Snorre and Statfjord is very different from Ekofisk, an own program should have been made for these wells, especially since the PWC technology did not have much success with the same procedure. At Snorre and Statfjord there have been more and better quality cement behind the casing.

A lot of changes have been made to the technology since the plugs placed on Snorre in 2013 and Statfjord in 2012. In addition only 4 plugs were set. Now 84 plugs have been set for different oil companies all over the world, and with a large success rate. So no result can be based on these experiences only, but they can give some guidelines for further development.

After the two wells that were plugged with the HydraWash PWC technology, Statoil ASA did not find that the technology proved to give consistent good logging results. The objective to achieve good cement behind the casing was only partly met. But the method does show potential to reduce the time and to improve the quality of P&A compared to section milling. The cement design has proven high bond quality and hydraulic isolation, but this was in those specific conditions and in that particular formation where the test was performed. Every well is unique, with a different formation and this could affect the bonding and isolation qualities. Contamination is also an important factor for success, and has to be avoided while setting the plug to get a good result.

Looking at the testing from Snorre and Statfjord, it might also be possible that cementing is not really the problem, but the washing. If the washing sequence is not done properly, a lot of residual cement and debris are left in the annulus. This could contaminate the new cement that is injected, which increases the possibility of a failed plug. To improve the washing in annulus it could be an idea to try the use of HydraHemera jetting tool for both single and double annulus. As this washes in a different method and works more as a high pressure washer.

Shown from earlier experience, circulation of cement is not a good thing according to (Ekberg, 2012). The Archimedes tool circulates the cement and might reduce the quality of the cement job. The type of cement used also have to be considered, but is not a discussion for this thesis. The perforated hole for the cement job is small, and it is difficult just by rotation of Archimedes to displace the spacer with cement. One method that may overcome this problem is to cement with the washing tool. Then the cement is forced in from the bottom perforations and the tool can move up one section at the time. The use of the Archimedes tool is necessary when the interval is cemented with the cement stinger, to avoid contamination after the ‘u-tube’ effect. HydraWell have designed a cementing tool, but no operators have seen the requirements for this so far.

The HydraSwivel tool has shown in Statfjord and Snorre to improve the circulation of debris when washing a deviated well. This is a very useful tool, and should be used in every operation involving washing and transport of debris in a ‘sail’ section.

9.6. Collapsed wells

Many wells on the NCS have a collapsed section in the upper area. This reduces the ID and might result in trouble for some tools to enter the well. The swab cups on the washing tool which already have a larger OD than normal to ensure proper sealing, will most likely experience some problems when RIH. It is not the washing cups that is the problem but rather the maximum OD on the steel. There is a profile in the steel Thimble, which on a 9 5/8” tool have an OD of 8.125” and the cups have 8.78” but these are made of elastomers to be flexible. Here it is possible to enter with the jetting tool instead which is the wash tool on HydraHemera. This has a smaller OD than HydraWash, so it is less likely to get stuck in the well. This increases the usability of the PWC technology, as there are many collapsed wells on the NCS.

9.7. NORSOK D-010 requirements

The HydraWash system complies with all Norwegian regulations, which are among the strictest in the world. NORSOK D-010 requirement for verifying a plug is that every plug shall be pressure tested by applying a differential pressure, and when this is not feasible it shall be verified by other specified methods. For every plug to be verified an acceptance criteria should be established. This is really an opening in NORSOK D-010 to allow for some leakage rate during the testing, as long as it is not to large or that it declines over time. The leak rate acceptance criterion is zero, but allows for temperature and volume effects for practical reasons. The operator must set their maximum acceptable deviation from the test pressure, and be confident that this ensures that the plug will seal eternally. For a negative pressure test it must be tested for 30 min with a stable reading and for a high pressure test, it is minimum 10 minutes. Since all plugs set on the NCS are designed to seal in both directions it is not necessary to apply the pressure in the direction of flow. It is not possible to tag the cement annulus, so this is only pressure tested, but cement inside casing must be tagged in addition to pressure testing to be verified.

9.8. Approving the technology

ConocoPhillips have used the HydraWash technique multiple times and is now only verifying the plugs by pressure testing. They have also used the HydraHemera technique a lot and are working on creating a faster verification method for this as well. Currently they are performing a negative pressure test that is going to last for 100 days. If this is successful, they may only need to perform a positive pressure test and tagging to verify a plug set over two annuli.

The main difference between ConocoPhillips and Statoil in this area is that ConocoPhillips have already had a large need to P&A a lot of wells. In addition they have had many good candidates. For Statoil the need does not seem to be as large as first anticipated. A lot of the wells have good cement in annulus, so only a balanced plug has to be placed inside the casing. Many wells also have so low pressure it would be hard to verify a leakage. So for Statoil, more candidates need to be found to use the technology on, to verify the HydraHemera technique for future use. For the HydraWash technique the plugs have to be drilled and logged, and if good results are seen, only pressure testing and tagging will be necessary for the future. For the HydraHemera the new logging technology, described in Sub.Sect. 8.5.3, can be tested or a long term negative pressure test should be performed if a proper candidate is found.

9.9. Verification methods today

A faster verification method has to be approved for use in Statoil, for HydraWell's technology to be preferred above the milling technology. Today, when the plugs must be drilled out and logged, HydraWells technology is at the same level as milling when it comes to time and expenses, but HydraWell does have the advantage of avoiding swarf handling.

Today four basic verification methods exists, pressure testing, logging, tagging and long term negative pressure testing. Logging can currently only be done for one annulus, so for HydraHemera pressure testing, negative pressure testing and tagging are the options. Hopefully the through tubing production casing logging will be approved for use so logging can be performed for the HydraHemera plug as well.

A test was performed by placing a plug in a single annulus, using the HydraHemera technique. The plug was drilled and logged and showed good results. This is a good indication that the technology works. The negative pressure test performed over 24 hours with a differential pressure of 1800 psi also turned out successful. This does at least prove that the cement has been set in both annuli.

Pressure testing with a reduced volume might be a possibility to reduce the time spent on verification and also improve the results. When pressure testing a smaller volume, one knows more exact which section of the well is exposed, and the test can be interpreted faster. One possibility might be to pressure test A- annulus and B- annulus separately first. Then go into the well with a tool that seals off the well a given number of meters above the plug inside the casing and pressure test the inside. Another option might be to seals off a small section within the casing. A tool like the wash cups on the HydraWash tool could be used for this sealing. Placing it between the cement placed in annuli, and pressure up. But this would require the plug inside the casing to be drilled out. A last option can be to open up to both annuli and create an underbalance in the well by displacing to a light fluid and negative pressure test a small volume. Any leak (gas/oil/water) will tend to move in the direction of lowest pressure, which in this case will be inside the well bore. It is important to remember that it is not possible to drill out and pressure test a HydraSystem job from below, as described in Sect. 8.2. The cement in annulus will not be cemented further than a few centimeter from the lower perforation. This is not long enough to seal over a differential pressure if the cement inside the casing is removed.

Another option is the method described in Sub.Sect. 8.3.1 under “New verification method”, where the outer annulus can be logged by milling away the inner casing. The problem here is the unknown consequence the milling will have on the cement quality in the outer annulus. It will be both time consuming and expensive, and the effect it will have on the cement is probably not good.

The largest challenge for double casing does not seem to be the verification part, but how to actually achieve good bonding between the cement slurry and the casing. When the cement is injected between two casings, it will shrink as it sets and a micro de-bonding to the casing will occur. So the cement will not bond to the casing and a micro annulus migration path will be developed. This is why AbandaCem was developed. It has the quality that after it shrinks, it expands until it is back to its original volume. The cement must be analyzed together with the well, before it is injected. The logging method is good, but there is really no point in logging, as long as the cement slurry is not capable to bond to the casing. Per now, a lot of information was not available for the author to look deeper into the subject. Whether or not the cement sets, is not a discussion for this thesis, but how to verify if it has set, and created a bond to the casing is.

If the through tubing production casing logging technology becomes available, the verification problem for a plug in two annuli is practically solved. By logging a specified number of plugs, which shows improved cementing, will verify the sealing capacity of the plug set with HydraHemera over two annuli. The amount of plugs to be approved with good logs must be decided by the operator. After this the plugs can be verified by pressure testing and tagging. Today the verification process for plugs is slow in Statoil because there are really no good candidates at the moment.

It is important with an open dialog between the companies, where the expectations to the product and delivery and well information is in an open flow. Considering that every well is unique the procedures have to be specified for each well.

If there is large skepticism around the technology, there are a lot of contingencies to do if it does not work. A PWC operation does not break the casing so the plug can easily be drilled out and logged. This is not an option if the casing is milled away, as a lot of the contingencies are lost.

9.10. The challenge of eternity sealing

The real challenge related to P&A activities, with respect to HSE, is the prospect of eternity, seeing that all wells P&A shall remain sealed with an eternal perspective. The work with this thesis and with a background of a lot of geology courses, from the author's point of view no one can really be sure whether the methods used today will prevent flow from abandoned wells for eternity. How the casing and cement will or can deteriorate during tens and hundreds of years is very hard to predict. But the cap rock drilled through, to access the reservoir is not guaranteed to hold for eternity either. The Lithosphere is constantly in movement, developing new faults in the rock, generating new traps for a reservoir, or forming a migration path for the hydrocarbons to migrate towards the seabed. This will happen to the reservoir regardless if it has been drilled through or not. The only thing known for certain is that the NORSOK D-010 requirements are very strict, and if these are followed; the plug quality should be good enough.

10. Conclusion

In this thesis HydraWells PWC technology has been looked into, and verification methods for plugs set in single and double annuli have been discussed. The conclusions are based on the discussion conducted in Chapter 9.

The verification is the main challenge for Statoil when it comes to P&A. The PWC technology has been proved to work. Since the casing is not removed, it is difficult to be 100% sure that the cement is continuous in the annuli. Testing must be performed to ensure that the plug will seal.

For the single casing plug set with the HydraWash technology, the verification methods are available. There is need for more testing, where the plug must be set, tagged, and pressure tested. Afterwards it must be drilled out and logged to verify the sealing capacity of the cement in annulus. If the log interpretations and the pressure tests both show good results for a specified number of wells, at least the technology is working, and the plug seals. Then the next step is to find the right tool that can pressure test the plug, with a smaller volume. There is an ongoing discussion with Baker to develop this. For the double casing plug set with HydraHemera technique, some testing has started. The large test on ULLRIG was very successful. The next step is now to see how the Hemera plug will seal on Ekofisk over 100 days. If this turns out to be successful, the technology has proven to seal over time as well. If the through tubing production casing logging becomes available by June, this is the verification method that should be used, and the verification process should continue the same way as with the single casing plug.

Given that the cement is capable to bond to a single casing and a double casing, the PWC technology seems to be a valid option for a faster and more cost effective P&A method. At least if/when tests and logging results have verified that good bonding between casing and cement is achieved and a continuous plug is created. After this, verification can be performed by pressure testing a small volume of the well, and tagging the plug.

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Appendix A

All the tables in this appendix is from NORSOK D-010

Table 22: EAC 2 Casing

Features	Acceptance criteria	See
A. Description	This element consists of casing/liner and/or tubing in case tubing is used for through tubing drilling and completion operations.	
B. Function	The purpose of casing/liner is to provide an isolation that stops uncontrolled flow of formation fluid or injected fluid between the casing bore and the casing annulus.	
C. Design construction selection	1. Casing/liner strings, including connections shall be designed to withstand all loads and stresses expected during the lifetime of the well (including all planned operations and potential well control situations). Any effects of degradations shall be included. 2. Minimum acceptable design factors shall be calculated for each load type. Estimated effects of temperature, corrosion and wear shall be included in the design factors. 3. All load cases shall be defined and documented with regards to burst, collapse and tension/compression. 4. Casing design can be based on deterministic or probabilistic models. 5. Casing exposed to hydrocarbon flow potential shall have gas-tight threads. Exception: Surface casing which is exposed or can be potentially exposed to normal gradient shallow gas.	ISO 11960 ISO 13679 ISO 10405
D. Initial test and verification	1. Casing/liner shall be leak tested to maximum differential pressure. 2. Casing/liner that has been drilled through after initial leak test shall be retested during completion activities. 3. The leak test of casing shall be performed either when cement is wet (immediately after pumping) or after cement has set up. No pressure testing should be performed while the cement is setting up.	
E. Use	Casing/liner should be stored and handled properly to prevent damage to pipe body and connections prior to installation.	
F. Monitoring	1. The A-annulus shall be continuously monitored for pressure anomalies. Other accessible annuli shall be monitored at regular intervals. 2. All casing strings shall be logged for wear after drilling if simulation indicates excessive wear which exceeds allowable wear based on casing design. Metal shavings should be collected by the use of ditch magnets.	
G. Common well barrier	1. During drilling operations with surface BOP, the annulus outside the current casing shall be monitored continuously and alarm levels be defined. 2. Actual status of the casing shall be known and confirmed capable of withstanding maximum expected pressure after expected wear. 3. Pressure test should include safety margin to cover expected wear after testing. 4. Magnet shall be in the mud return flowline to measure metal and assess changes in the nature of the metal filings. 5. If drilling through an old casing: a) Prior to drilling activity commences, casing wear log(s) should be run (calliper and/or sonic). The logs shall be verified by qualified personnel and documented. b) Logs that can identify localised (1 m interval between measurements) doglegs (gyro or similar) should be run.	

Table 23: EAC 22 Casing cement (1)

Features	Acceptance criteria	
A. Description	This element consists of cement in solid state located in the annulus between concentric casing strings, or the casing/liner and the formation. NOTE The shoe track cement is covered in table 24.	
B. Function	The purpose of the element is to provide a continuous, permanent and impermeable hydraulic seal along hole in the casing annulus or between casing strings, to prevent flow of formation fluids, resist pressures from above or below, and support casing or liner strings structurally.	
C. Design, construction and selection	1. A cement program shall be issued for each cement job, minimum covering the following: a) casing/liner centralization and stand-off to achieve pressure and sealing integrity over the entire required isolation length; b) use of fluid spacers; c) effects of hydrostatic pressure differentials inside and outside casing and ECD during pumping and loss of hydrostatic pressure prior to cement setting up; d) the risk of lost returns and mitigating measures during cementing. 2. For critical cement jobs, HPHT conditions and complex/foam slurry designs the cement program shall be verified independent (internal or external), qualified personnel. 3. The cement recipe shall be lab tested with dry samples and additives from the rigsite under representative well conditions. The tests shall provide thickening time and compressive strength development. 4. The properties of the set cement shall provide lasting zonal isolation, structural support, and withstand expected temperature exposure. 5. Cement slurries used for isolating sources of inflow containing hydrocarbons shall be designed to prevent gas migration, including CO_2 and H_2S, if present. 6. Planned casing cement length: a) Shall be designed to allow for future use of the well (sidetracks, recompletions, and abandonment). b) **General**: Shall be minimum 100 m MD above a casing shoe/window. c) **Conductor**: Should be defined based on structural integrity requirements. d) **Surface casing**: Shall be defined based on load conditions from wellhead equipment and operations. TOC should be at surface/seabed. e) **Production casing/liner**: Shall be minimum 200m MD above a casing shoe. If the casing penetrates a source of inflow, the planned cement length shall be 200m MD above the source of inflow. a. Note: If unable to fulfil the requirement when running a production liner, the casing cement length can be combined with previous casing cement to fulfil the 200m MD requirement.	API RP 10B ISO 10426-1

Table 24: EAC 22 Casing cement (2)

Features	Acceptance criteria	
D. Initial verification	Cement should be left undisturbed until it has reached sufficient compressive strength. 1. The cement sealing ability shall be verified through a formation integrity test when the casing shoe/window is drilled out. 2. The cement length shall be verified by one of the following: a) Bonding logs: Logging methods/tools shall be selected based on ability to provide data for verification of bonding. The measurements shall provide azimuthal/segmented data. The logs shall be verified by qualified personnel and documented. b) 100 % displacement efficiency based on records from the cement operation (volumes pumped, returns during cementing, etc.). Actual displacement pressure/volumes should be compared with simulations using industry recognized software. In case of losses, it shall be documented that the loss zone is above planned TOC. Acceptable documentation is job record comparison with similar loss case(s) on a reference well that has achieved sufficient length verified by logging. c) In the event of losses, it is acceptable to use the PIT/FIT or LOT as the verification method only if the casing cement shall be used as a WBE for drilling the next hole section. (This method shall not be used for verification of casing cement as a WBE for production or permanent abandonment.) 3. Critical casing cement shall be logged and is defined by the following scenarios: a) the production casing/production liner when set into/through a source of inflow with hydrocarbons; b) the production casing/production liner when the same casing cement is a part of the primary and secondary well barriers; c) wells with injection pressure which exceeds the formation integrity at the cap rock. 4. Actual cement length for a qualified WBE shall be: a) above a potential source of inflow/ reservoir; b) 50 m MD verified by displacement calculations or 30 m MD when verified by bonding logs. The formation integrity shall exceed the maximum expected pressure at the base of the interval. c) 2 x 30m MD verified by bonding logs when the same casing cement will be a part of the primary and secondary well barrier. d) The formation integrity shall exceed the maximum expected pressure at the base of each interval. e) For wells with injection pressure exceeding the formation integrity at the cap rock: The cement length shall extend from the upper most injection point to 30 m MD above top reservoir verified by bonding logs.	
E. Use	None	
F. Monitoring	1. The annuli pressure above the casing cement shall be monitored regularly when access to this annulus exists. 2. Surface casing by conductor annulus outlet should be observed regularly.	
G. Common well barrier	It is not acceptable for use as a common WBE. When casing cement is a part of the primary and secondary well barriers, this is defined as critical casing cement and the criteria in D. Initial verification applies.	

Table 25: EAC 24 Cement plug (1)

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>A. Description</td><td>The element consists of cement in solid state that forms a plug in the wellbore.</td><td></td></tr>
<tr><td>B. Function</td><td>The purpose of the plug is to prevent flow of formation fluids inside a wellbore between formation zones and/or to surface/seabed.</td><td></td></tr>
<tr><td>C. Design, construction and selection</td><td>
1. A program shall be issued for each cement plug installation.
2. For critical cement jobs, HPHT conditions and complex slurry designs the cement program should be verified by independent (internal or external) qualified personnel.
3. The cement recipe shall be lab tested with dry samples and additives from the rigsite under representative well conditions. The tests shall provide thickening time and compressive strength development.
4. Cement slurries used in plugs to isolate sources of inflow containing hydrocarbons should be designed to prevent gas migration and be suitable for the well environment (CO_2, H_2S).
5. Permanent cement plugs should be designed to provide a lasting seal with the expected static and dynamic conditions and loads.
6. It shall be designed for the highest differential pressure and highest downhole temperature expected including installation and test loads.
7. A minimum cement batch volume shall be defined to ensure that a homogenous slurry can be made, taking into account all sources of contamination from mixing to placement.
8. The minimum cement plug length shall be:
<table>
<tr><td>Open hole cement plugs</td><td>Cased hole cement plugs</td><td>Open hole to surface plug (installed in surface casing)</td></tr>
<tr><td>100 m MD with minimum 50 m MD above any source of inflow/leakage point. A plug in transition from open hole to casing should extend at least 50 m MD above and below casing shoe.</td><td>50 m MD if set on a mechanical/ cement plug as foundation, otherwise 100 m MD</td><td>50 m MD if set on a mechanical plug, otherwise 100 m MD.</td></tr>
</table>
9. Placing one continuous cement plug in a cased hole is an acceptable solution as part of the primary and secondary well barriers when placed on a verified foundation (e.g. pressure tested mechanical/cement plug).
10. Placing one continuous cement plug in an open hole is an acceptable solution as part of the primary and secondary well barriers with the following conditions:
a. The cement plug shall extend 50m into the casing.
b. It shall be set on a foundation (TD or a cement plug(s) from TD). The cement plug(s) shall be placed directly on top of one another.
11. A casing/liner shall have a shoe track plug with a 25 m MD length.
</td><td>API Spec 10A Class 'G'</td></tr>
</table>

Table 26: EAC 24 Cement plug (2)

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>D. Initial verification</td><td>

Cased hole plugs should be tested either in the direction of flow or from above.
For the shoe track to be used as a WBE, the following applies:
<ol type="a">
the bleed back volume from placement of casing cement shall not significantly exceed the calculated volume; and
it shall be either pressure tested and supported by overbalanced fluid (see EAC 1) or inflow tested.

The strength development of the cement slurry should be verified through observation of surface samples from the mixing, cured on site in representative temperature.
The plug installation shall be verified through evaluation of job execution taking into account estimated hole size, volumes pumped and returns.
The plug shall be verified by:

<table>
<tr><th>Plug type</th><th>Verification</th></tr>
<tr><td>Open hole</td><td>Tagging.</td></tr>
<tr><td>Cased hole</td><td>Tagging.
Pressure test, which shall:
a) be 70 bar (1000 psi) above estimated leak off pressure (LOT) below casing/ potential leak path, or 35 bar (500 psi) for surface casing plugs; and
b) not exceed the casing pressure test and the casing burst rating corrected for casing wear.
If the cement plug is set on a pressure tested foundation, a pressure test is not required. It shall be verified by tagging.</td></tr>
</table>
</td><td></td></tr>
<tr><td>E. Use</td><td>None.</td><td></td></tr>
<tr><td>F. Monitoring</td><td>For temporary abandoned wells: The fluid level/pressure above the shallowest set plug shall be monitored regularly when access to the bore exists.</td><td></td></tr>
<tr><td>G. Common well barrier</td><td>If one continuous cement plug (same cement operation) is defined as part of the primary and secondary well barriers, it shall be verified by drilling out the plug until hard cement is confirmed.
1. An open hole cement plug extended into the casing shall be pressure tested.</td><td></td></tr>
</table>

Table 27: EAC 51 In-situ formation

Features	Acceptance criteria	See
A. Description	The element is the formation that has been drilled through and is located adjacent to the casing annulus isolation material or plugs set in the wellbore.	
B. Function	The purpose of the in-situ formation is to provide a permanent and impermeable hydraulic seal preventing flow from the wellbore to surface/seabed or other formation zones.	
C. Design construction selection	The following applies for the formation at the required depth: 1. The formation shall be impermeable with no flow potential. 2. The wellbore shall be placed away from fractures and/or faults that may lead to out of zone injection or crossflow. 3. The formation integrity shall exceed the maximum wellbore pressure induced. See 4.2.3.6.7 Table 2 – Formation Integrity requirements. 4. The formation shall be selected such that it will not be affected by changes in reservoir pressure over time (depletion, compaction, fracturing, re-activation of faults). 5. The formation shall bond directly to the casing/liner annulus material (e.g. casing cement) or plugs in the wellbore. 6. If the formation is bonding directly to the casing (e.g. the formation has extruded into the casing annulus), then the requirements in table 15.52 Creeping formation also shall apply.	
D. Initial test and verification	Formation integrity pressure shall be verified by one of the following methods (See 4.2.3.6.7): 1. a PIT; 2. a LOT should be followed by a shut-in phase; 3. an XLOT, if the minimum formation stress is not already known; or 4. a documented field model.	
E. Use	None	
F. Monitoring	None	
G. Common well barrier	None	