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ABSTRACT

The useful life of an offshore well is determined by the reserves which it contacts, the pressure support within the reservoir and the continued integrity of the wellbore. When a well has reached the end of its lifetime, plugging operations have to be conducted before permanent abandonment. Conventional Plug and Abandonment (P&A) operations will often require removing a section of the casing in order to create cross sectional barriers for well abandonment.

Recently developed and field tested technology has the potential of efficiently setting cross sectional reservoir barriers without casing removal. Access to the annuli can be achieved through perforation and then the perforated interval can be washed prior to setting a P&A barrier.

By deploying a wireline rig-up it can be possible to set a reservoir barrier prior to removal of the previously installed production or injection tubing. Wireline work can also provide information about the well integrity which can determine the potential for setting further reservoir barriers with minimum removal of tubulars.

Further development of technology necessary to safely abandon wells with minimum removal of tubulars can provide cost efficient and robust plugging methods for abandoning offshore oil or gas fields without the need of deploying a drilling rig.

This thesis will introduce methods of setting P&A barriers with minimal removal of tubulars as the main focus. Descriptions of various plugging operations will be given. Considerations regarding the critical factors encountered during plugging operations will be discussed, more specifically the current condition of wellbore integrity and the barrier envelope necessary to prevent uncontrolled release of hydrocarbons during or after plugging operations.

LIST OF ABBREVIATIONS

API	= American Petroleum Institute
B _c	= Bearden Units of Consistency
BHA	= Bottom Hole Assembly
BI	= Bond Index
BOP	= Blow Out Preventer
CBL	= Cement Bond Log
C _c	= Cubic content
CCL	= Casing Collar Log
DHSV	= Down Hole Safety Valve
ECD	= Equivalent Circulating Density
GLV	= Gas Lift Valve
HUD	= Hold-Up Depth
IADC	= International Association of Drilling Contractors
ISO	= International Standardization Organization
MD	= Measured Depth
MFC	= MultiFinger Caliper
NCS	= Norwegian Continental Shelf
P&A	= Plug and Abandonment
PSA	= Petroleum Safety Authority (Petroleumstilsynet)
PPG	= Pounds Per Gallon
PSI	= Pounds per Square Inch
PT	= Pressure Temperature (gauge)
PWC	= Perforate, Wash and Cement
SPE	= Society of Petroleum Engineers
TCP	= Tubing Conveyed Perforating
TOC	= Top Of Cement
TVD	= True Vertical Depth
UCA	= Ultrasonic Cement Analyzer
VDL	= Variable Density Log
WOC	= Wait On Cement

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1 INTRODUCTION

The drilling of offshore wells on the Norwegian Continental Shelf (NCS) began in the mid-1960s, and in 1967 the first oil was discovered. Since this first discovery, numerous wells have been drilled in the Norwegian sector of the North Sea and as of the 1st of March 2012 there are 70 fields under production on the NCS [1]. However, these hydrocarbon resources are limited, and in the not too distant future even the largest producing offshore oilfields will have to be abandoned. A wells useful life is determined by the reserves which it contacts, the pressure support within the reservoir and the continued integrity of the wellbore. When a well has reached the end of its lifetime, plugging operations have to be conducted before permanent abandonment. License holders have the obligation and responsibility to see to it that regulatory requirements are met in the most effective and efficient method.

Plug and Abandonment (P&A) is the collective operation associated with sealing off the wellbore through the setting of effective abandonment barriers across the wellbore cross section. These operations are designed to prepare the well for eternity post abandonment. Although there is no direct economic benefit in such operations, future financial obligations incurred by leaking barriers which require wellbore re-entry are a great incentive.

Conventional P&A consists of the following operations, which can be divided into three separate phases. The first phase consists of setting the primary reservoir barrier. A combination of wireline work, coil tubing work and sealant pumping

down the production or injection tubing may all be required.

A rig with derrick is usually required in the second phase of the plugging operation. Cutting and retrieval of the tubing is generally in order to set the effective cross sectional abandonment barriers necessary for long term reservoir isolation. In many cases it is necessary for a section of the casing to be removed at the depth where the barrier is to be set. After a section of the casing string is removed, a barrier can be set in the open interval. This will function as the secondary reservoir barrier. If additional shallower sources of inflow exist, they must also be isolated using both a primary and secondary barrier against flow as well. If the distance from the topmost barrier to seabed is great, casing strings may need to be removed in order to set an additional low pressure environmental barrier. Third phase operations include cross-sectional cutting of all remaining casing strings at a determined depth below seabed and retrieving the tubulars above the cut.

This thesis will describe methods for setting pressure isolating abandonment barriers. The introduced methods have been field tested, confirmed as effective and require minimum removal of the installed wellbore tubulars. The thesis will also include discussions of some non-field tested technologies which some are under development. A brief introduction of P&A regulations will be given along with challenges regarding well integrity, barrier materials, equipment and rigs before methods for creating P&A barriers for long term isolation are discussed.

2 REASONS AND REQUIREMENTS FOR PLUG & ABANDONMENT

2.1 REASONS FOR WELL ABANDONMENT

There are many conditions which dictate the need for plugging of individual wellbores and the abandoning of a platform. Production changes which included reduced hydrocarbon deliverability, increases in water production or loss of integrity. These are but a few of the reasons which can lead to abandonment operations.

Maintaining production and or overall production improvement within a field may necessitate slot recovery and re-drill to a higher productivity area within the reservoir. Slot recovery operations include plugging, removing a window of the casing, setting a kick-off plug and then sidetracking the well. Well slots of offshore installations may be recovered multiple times throughout the field lifetime, and for each slot recovery the previous wellbore has to be abandoned.

If a well has integrity issues such as collapsed casing or tubing, extensive damage which is caused by geological activities such as re-faulting or subsidence, the well will be scheduled for plugging operations as soon as possible. A sense of urgency may exist as integrity issues do not improve and generally deteriorate with time. Early stage work can be the best and most cost effective method for achieving a proper primary reservoir barrier. An example of how loss of barrier elements will complicate plugging operations will be discussed in Chap. 6.4.

2.2 WELL INTEGRITY AND REGULATIONS

Plugging operations are preparations for the rest of the lifetime of the wellbore. Well integrity during and after abandonment includes the barrier material, barrier placement and subsequent monitoring of the well. The barriers that are installed during a plugging operation should not fail after abandonment. Plugging operations on the Norwegian Continental Shelf (NCS) are governed by regulations issued by the Petroleum Safety Authority of Norway (PSA). PSA activity and facility regulations are the regulatory framework of every plugging operation in Norwegian Territory. As illustrated by the hierarchy in Fig. 2.1, the industry has a guideline in addition to regulations from the PSA. The guideline is called the NORSOK D-010 standard and the PSA recommends that this standard should be used as a minimum requirement for all well operations, including plugging operations. The NORSOK D-010 standard is based on international standards for petroleum activity such as the ISO standards and API standards issued by the International Standardization Organization (ISO) and the American Petroleum Institute (API) respectively.

According to the PSA facility regulations section 48 the barriers should be *“designed in such that well integrity is ensured and the barrier functions are safeguarded during the wells lifetime. When a well is temporarily or permanently abandoned, the barriers shall be designed such that they take into account well integrity for the*

longest period of time the well is expected to be abandoned”.

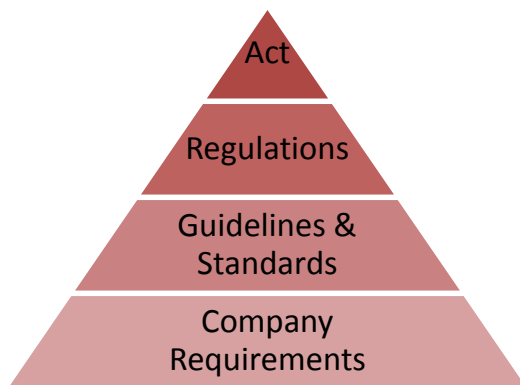


Figure 2.1 – Governing Hierarchy of the petroleum operations.

In addition to facility regulations, PSA activity regulations states *“All wells shall be secured before they are abandoned so that well integrity is safeguarded during the time they are abandoned”*. But what is well Integrity? NORSOK D-010 rev3 defines well integrity as *“an application of technical, operational and organizational solution to reduce risk of uncontrolled release of formation fluids throughout the life cycle of the well”*. The well integrity term is widely used [2] [3] [4] [5] and emphasizes the most important part of the operation, which is preventing uncontrolled movement of formation fluids from the formation to the surface by use of barriers.

The barrier principle is based on the Swiss cheese model introduced by the British psychologist James Reason in 1990 [6]. The model uses slices of Swiss cheese with holes in them to demonstrate the reason of failure. Since no barrier is perfect there have to be more than one barrier reduce risk of failure adequately. The Swiss cheese model principle clarifies how each barrier will prevent failure in its own extent. The origin of a barrier failure could

be organizational; such as lack of procedures or training, human errors or performance; or mechanical; such as failure of technical equipment or plugging materials.

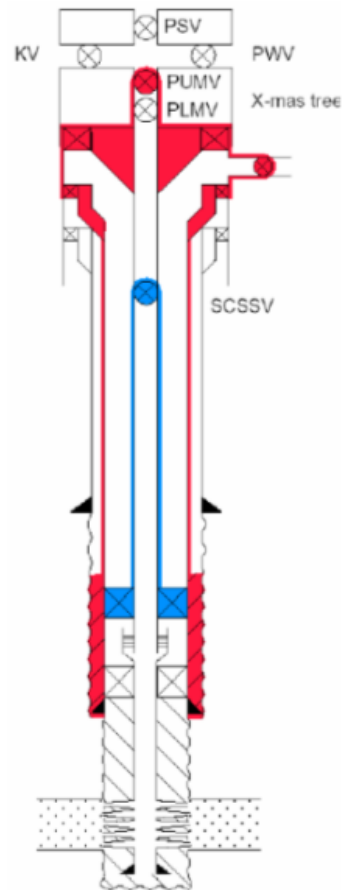


Figure 2.2 – NORSOK D-010 well barrier schematics (Production). [7] For full well barrier schematic and barrier envelopes, see Appendix A.

In a well there are barrier envelopes to prevent uncontrolled release of formation fluids during each operational phase. The barrier envelopes consist of barrier elements. A barrier element can be technical equipment such as drillstring, tubing, casing, gas lift valves or downhole safety valves, or materials such as drilling fluid or set cement. The barrier elements should be operated correctly by verifying, maintaining and monitoring with consistent organizational procedures from

installation to after abandonment or retrieval. A well integrity management system may be necessary to monitor the barriers [2]. The different well barrier envelopes are exemplified by the two drawings from Norsok D-010 rev3 in Fig. 2.2 and Fig. 2.3, for production and abandonment respectively. The primary barrier is marked with blue, and the secondary barrier is marked with red. For an abandoned well there will also be a low pressure environmental barrier slightly below the seabed which is marked with green.

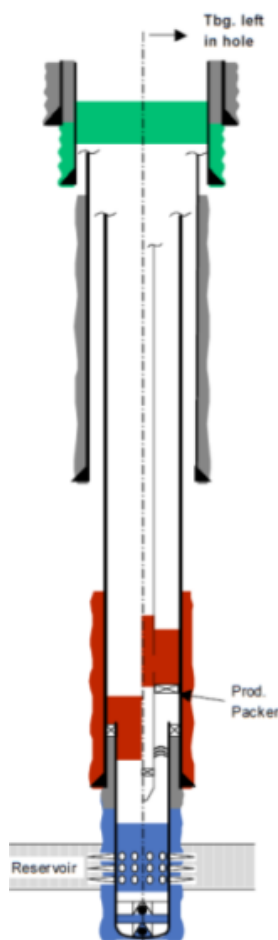


Figure 2.3 – Norsok D-010 well barrier schematic for an abandoned well. [7] For full well barrier schematic and barrier envelopes, see Appendix B.

2.3 REQUIREMENTS FOR P&A BARRIERS

Competent permanent abandonment barriers are necessary to avoid the potential for out of zone hydrocarbon and water movement which can lead to loss of containment and potential release to the environment. A properly planned and executed plug and abandonment program, which places competent and tested barriers at depths with sufficient formation strength to contain fluid movement, can meet the Norsok D-010 requirements for eternal sealing and isolation of an abandoned well.

2.3.1 Plug and Abandonment Guidelines for Barrier Materials

The Norwegian petroleum industry has developed guidelines for barrier materials in Norsok D-010 rev3 Section 9.

“A permanent well barrier should have the following properties

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

Notice that the word *should* is used instead of *shall*. The reason for this may be that it is difficult to guarantee some of the listed properties.

Impermeable implies that no fluid can flow through the barrier material, including over pressurized hydrocarbon gases. To be impermeable, the barrier needs to have an adequate length in the wellbore, and according to NORSOK D-010 rev3 this length is 100 meters or 50 meters if there is a tested mechanical plug below. It is also required that the plug extend 50 meters above any source of inflow, which can be leaks in the casing or perforations through the casing wall. These lengths are not scientifically determined; however by applying this requirement there is a very high probability that a competent seal will be achieved. The barrier must cover the whole cross section of the well, as illustrated in Fig. 2.4.

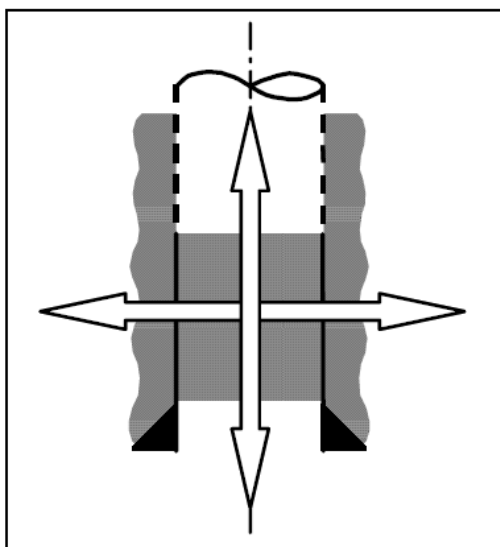


Figure 2.4 – The barrier shall extend across the full cross section of the wellbore and fulfill length requirements. [7]

For materials to be considered for plugging, their composition must remain unaltered by the environment in the well. A material exposed to different types of chemicals may change the mechanical properties of the material. For example, CO₂, CH₄ or H₂S gas dissolved in water can alter the mechanical properties of the

material or metal components that are in contact with the material. A plugging material should be able to withstand this harsh environment without compromising the integrity.

The regulations state that placed barriers should be designed for eternity and the long term integrity of the materials should be documented. An ageing test can be used for proving this; however there are no guidelines or standard for documenting long term isolation capability of plugging materials.

SINTEF, which is an independent research organization, is conducting aging tests on plugging materials. An aging test on epoxy resins was recently completed and will be used as an example of how aging test can be conducted [8]. Two different types of epoxy resin were tested in extreme conditions with the purpose of testing the capability for long term isolation. The materials were subjected to fluids including water, crude oil, CH₄, CO₂ and H₂S. In order to differentiate between the specific effects of the different chemical environments, the tests were conducted separately for each fluid and with relatively high concentrations of fluids compared to reality. In addition to exposure to fluids, the materials were subjected to high temperatures and high pressures. The duration of the test was 12 months. Temperatures were 212 and 266 degrees Fahrenheit (100 and 130 degrees Celsius) and pressure was 7250 psi (500 bars). The aging test will determine permeability and mechanical properties including expansion or shrinkage, compressive and flexural strength, and modulus of elasticity (young's modulus) after the specified time period. The result

of this aging test is confidential. Mechanical properties of cement and other plugging materials will be further discussed in Chap. 3.

Shrinkage of sealants during and after setting is a common problem and may create micro annuli along the formation rock wall, within the plug or along possible tubulars. This will create a channel for flow past any permanent abandonment barrier.

The stratigraphic layers may change over time, and the barrier material should be able to deform in order to keep the sealing properties when subjected to stresses from the environment. In other words, the material needs to be ductile and not brittle.

Regardless of how good the barrier material seals by itself, it needs to bond to the formation rock and the tubulars to keep the barrier in place and prevent micro annuli. Good bonding is a property of the plugging material and the steel or formation rock. Bond will depend on whether the formation rock is water wet or oil wet. Different formation strata have different wetting characteristics, but they may be altered when exposed to surfactants.

The steel properties have to be considered where it is necessary for achievement of

good bond. It could be argued that corroded steel will affect the bonding, since it may have different wetting and surface properties than new steel used in laboratory testing. The bonding is also dependent on washing procedures during placement of the barrier. A good operational plan should include proper cleaning methods to achieve a good displacement when cement is pumped. Contamination is a central issue when performing plugging operations and criteria for cleanliness should be stated in the operational program.

2.3.2 Determining Setting Depth

Before a well is abandoned, the barrier that originally the nature provided should be reestablished, generating a seal that will last forever. The vertical permeability of the adjacent formations should be low, or else fluids may flow through the formation rock at the plugging depth. And like mentioned in Chap. 2.1, the two barrier principle applies for plugging operations as well. If the production interval consists of two reservoir zones with close reservoir pressure, they can be regarded as one. This is illustrated in Fig. 2.5. If there exists a shallower source of inflow such as a shallow gas zone, this has to be isolated with two barriers as well.

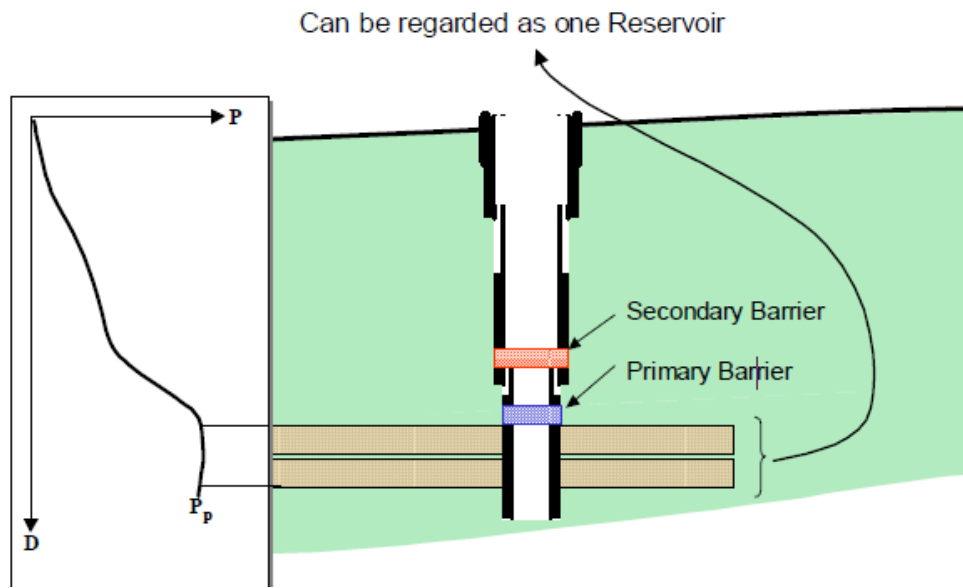


Figure 2.5 – Two barriers isolating two reservoir zones that can be regarded as one due to similar reservoir pressure. [7]

The barrier needs to be set at a depth where the formation rock will not fracture when subjected to pressure from below. If the pressure build-up exceeds the fracturing pressure, the formation rock will fracture, the reservoir fluids will move through the formation rock and the barrier will not seal. The maximum pressure the plug will be subjected to is the pressure at the source of inflow minus the hydrostatic pressure of the fluid column above. By calculating a pressure traverse upwards from the source of inflow, the minimum plugging depth can be estimated. This is illustrated in Fig. 2.6

The pressure at given point x along the well trajectory can be calculated as follows.

$$P_x = P_{res} - P_{hydrostatic} \quad (2.1)$$

Where

$$P_{hydrostatic} = d_{fluid} \cdot g \cdot h_{fluid} \quad (2.2)$$

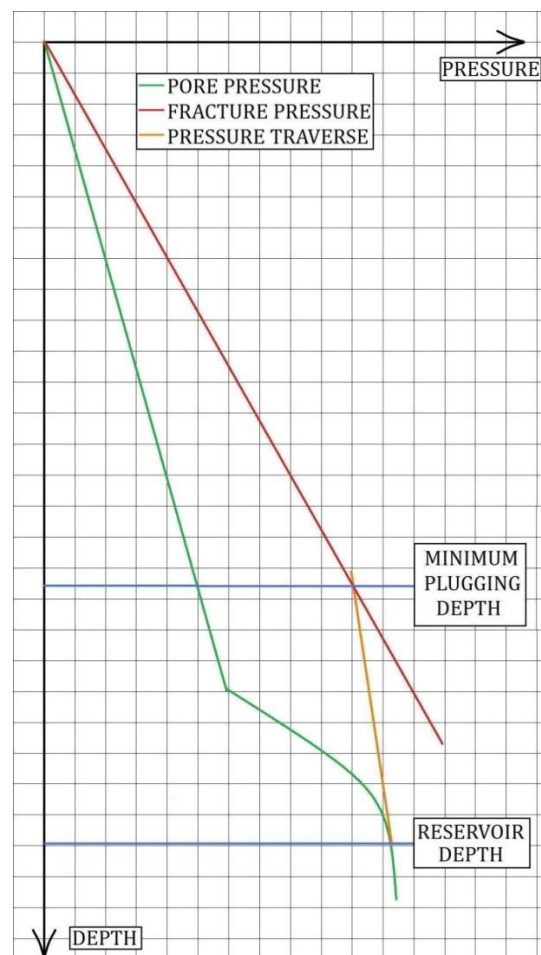


Figure 2.6 – The fracture pressure of the formation rock dictates the minimum setting depth.

P_{res} is the pressure at the source of inflow, d_{fluid} is the fluid density gradient, g is the gravitational constant and h_{fluid} is the height of the fluid column from the given point x to the reservoir depth. h_{fluid} can also be expressed as

$$h_{fluid} = D_{res} - D_x \quad (2.3)$$

where D_x is the depth of the given point. Inserting this into (2.2) yields

$$P_{hydrostatic} = d_{fluid} \cdot g \cdot (D_{res} - D_x) \quad (2.4)$$

where D_{res} is the depth from surface to the reservoir, and D_x is the depth from surface to the given point x .

Now let us say that the D_x will be the plugging depth. The maximum well pressure P_x at the plugging depth will be dictated by the pressure P_{frac} at which the formation rock will fracture.

$$P_x < P_{frac} \quad (2.5)$$

The fracture pressure at the plugging depth can be calculated from data acquired during drilling. From previously conducted leak off tests it will be possible to calculate the average fracture pressure gradient of formation strata, d_{frac} .

$$P_{frac} = d_{frac} g D_x \quad (2.6)$$

Inserting equation (2.1) into equation (2.5) and incorporating equation (2.4) and (2.6), the minimum plugging depth can be obtained.

$$P_{res} - d_{fluid} \cdot g \cdot (D_{res} - D_x) < d_{frac} g D_x \quad (2.7)$$

Rearranging;

$$D_x < \frac{P_{res} - d_{fluid} \cdot g \cdot D_{reservoir}}{g(d_{frac} - d_{fluid})} \quad (2.8)$$

This is the minimum depth at which the base of the plug should be set below.

Any additional source of inflow, such as a shallower gas zone, has to be considered by calculating respective pressure traverse and depth.

To estimate the most probable future pressure traverse, a correct fluid gradient, d_{fluid} , must be assessed. A gas gradient is often used to calculate the maximum expected pressure traverse, but also future drilling activities and reservoir developments need to be considered when assessing P_{res} . A gas gradient is regarded as the worst case scenario at the plugging depth, since the pressure will be closest to the reservoir pressure, P_{res} . By calculating three different pressure traverses, one for initial reservoir pressure, one from reservoir simulation for the future and one from current reservoir pressure, and choosing the highest of the three, one should be on the safe side. The future reservoir pressure and the strength of the formation rock will dictate the lowest point of the barrier. This depth may correspond to an interval along the primary well barrier which may or may not be cemented, which is also something that needs to be addressed before a plugging operation.

2.3.3 Verification of P&A Barriers

Any set abandonment barrier will require verification. The type of barrier and well condition will dictate how the barrier is tested. Requirements for testing a cement plug are included in the NORSOK D-010 rev3 and attached in Appendix C. The

following will include brief descriptions of how abandonment barriers can be verified.

Tagging can be conducted to verify top of the competent barrier. This is done with a workstring or a wireline toolstring run into the well. Weight measurements at surface will indicate resistance, which will indicate TOC. The workstring or toolstring may contain a bailer sampler that will sample the quality of the top of the barrier. The sample will help to assess the cement quality.

An inflow test will confirm that the barrier is isolating. The inflow test is done by exposing the barrier to differential pressure by lowering the hydrostatic pressure above

it. This is done by bleeding off the shut in pressure or displacing the tubing with a lighter fluid. If the barrier isolates, there will be no inflow and no pressure increase is seen at the surface. A failed set barrier will not isolate and will result in inflow of fluids from the reservoir.

Barrier can also be tested to verify strength. A pressure test is conducted as follows. The plug will be subjected to high pressure from above. A pressure differential of 1000 psi (69 bars) above formation fracture pressure will be achieved by pumping. The pressure test should not exceed burst pressure rating for the casing.

3 BARRIER MATERIALS FOR PLUGGING OPERATIONS

The choice of material for use in a barrier will depend on functional requirements and compliance with the method used when creating the barrier. As described in Chap. 2.3.1, there are six requirements for barrier materials in the NORSOK standard. Cement has historically been regarded as the only field proven plugging material, however during the last decade or so other materials have been suggested. Cement has a long track record with the use as a qualified barrier, yet companies supplying alternative sealants argue that the properties of cement are not effective in maintaining long term isolation. The primary focus in this thesis will be on discussing the use of cement; however other barrier materials will be presented and discussed.

3.1 CEMENT

3.1.1 Cement Properties

Cement is the traditional material used for setting creating annular barriers and plugs in hydrocarbon wells, also on the Norwegian Continental Shelf. Cement, or Portland Cement, which is the hydraulic type of cement used for well purposes, is a material that primarily consists of water and a dry mix of chemicals mainly composed of clinker. Clinker consists of pulverized and calcined calcareous and argillaceous materials. Calcareous materials include limestone, calcite and marl and argillaceous materials include materials such as clay, shale, mudstones, fly ash or aluminum oxide. Another ingredient in cement is calcium sulfate (gypsum), which is added at the end of the production process. The final dry mix will primarily consist of calcium silicates and silicon dioxide in addition to smaller

amounts of aluminum oxides, iron oxides and calcium sulfate. When mixed with the right amount of water this created slurry is designed to harden when allowed to set after it has been pumped into final position within a wellbore.

In the industry today there are several classes of Portland Cement with different compositions of materials and application areas. Modified Portland Cement Class G is the cement type most commonly used on the Norwegian continental shelf, but also numerous blends incorporating special additives which will tailor the cement for placement and isolating purposes.

General cement properties including low permeability, durability, reliability, cost efficiency and availability can together with the long track record convince drilling engineers worldwide that cement is the best isolation material for well purposes. The fact that cement properties can be manipulated with additives in order to achieve the preferred properties and still is fairly inexpensive compared to other sealants will also contribute. However, there are several challenges when designing cement for long term zonal isolation. The cement design must consider the rigid environment and take into account all events occurring during the life of the well. This is relevant for both primary cement jobs and plug cementing, because the state of the cement before permanent abandonment will affect how the well should be plugged.

3.1.2 Cement Additives for P&A

When designing cement for plugging operations, one would have to compensate for the properties of cement that are not beneficial for long term isolation through

cement additives. Inadequately designed cement may not maintain integrity after placement in the well. A proper cement design is crucial to comply with the Norsok requirements for long term isolation.

The main challenges when designing a cement slurry for long term isolation are as follows.

- Compressive strength reduction
- Hydration Shrinkage
- Elasticity
- Tensile Strength
- Shear Strength

A proper design of cement slurry with the right manipulating additives will overcome these challenges, making a barrier material fit for long term isolation.

Cement may experience compressive strength reduction in high temperatures [9]. To avoid this reaction, silica flour is added to the cement [10]. This will ensure that the cement maintains compressive strength at temperatures above 110°C (230°F). It is common industry practice to use 35 % or more silica flour in the dry cement mixture.

Cement systems applied for well cementing purposes should include an expanding agent [11] [12]. Hydration shrinkage in a cement sheath may cause tensional stress at the cement-formation interface, while shrinkage within a cement plug may cause tensional stress in the cement-pipe interface. To compensate for hydration shrinkage, expanding agents are added to the cement. The expanding agents will react with adjacent water within the cement matrix and require continuous

contact with water or fluids in order to react. They consist of crystalline growth materials that will expand continuously [10]. The rate of expansion depends on well temperature, water feed and permeability of the cement. The expansion agents will ideally cause a net expansion of the cement instead of net shrinkage which will cause compressive stress instead of tensional stress in the cement interfaces. This is beneficial since the cement is stronger in compression.

The Norsok guidelines require that materials used for permanent abandonment barriers are ductile. Ductile materials will deform when subjected to high stress loads, while brittle materials will fail. Cement is originally a brittle material which cannot be subjected to high stresses without failing. However, if cement gains elasticity through adjustment of the Young's Modulus (E) it will be able to deform elastically when the stresses are below limit of elasticity.

According to Hooke's law, the stress, σ , can be related to the strain, ϵ , by multiplying with E.

$$\sigma = E \times \epsilon \quad (3.1)$$

When the cement sheath is subjected to high levels of strain ϵ , a low E will decrease the stress σ . The cement matrix has a certain limit, ϵ_{max} , of allowable strain. Below this limit the cement will deform elastically, above this limit the cement will fail. The limit can be expressed as

$$\epsilon_{max} = \frac{\sigma_{max}}{E} \quad (3.2)$$

In Equation 3.2, the maximum allowable stress, σ_{max} , describes the level of stress at which the cement will fail. A lower E will

increase the maximum allowable strain, ϵ_{\max} , that cement can tolerate and still behave elastically. E can be adjusted by incorporating additives such as liquid latex, elastomers, or gases to the cement.

Altering elasticity of a matrix by adding particles with higher elasticity is the same principle applied in rubber foam used for chairs and mattresses. Foam used in cushioning incorporates gas in the matrix that makes the material more elastic. The compressibility of gas affects the composite properties of the matrix through lowering the total E. This principle is used when designing cement with lower E. However, higher elasticity through lower E will generally imply lower strength, and thus an optimal ratio of E and strength must be assessed through mechanical modeling.

The tensile strength of cement is relatively low compared with the shear strength. If stronger materials are added, the cement matrix will be able to resist higher tension and shear stresses. These materials must have higher E than the cement itself, and is thus counteracting attempts to make the cement more elastic. A compromise would have to be made, also ensuring low shrinkage. This illustrates the challenging process of designing a plugging material that complies with NORSOK D-010 requirements.

Further improvements of cement properties include adding swelling elastomers that will cause the cement to heal if exposed to hydrocarbons after fracture [13] [14] [15]. Elastomers will swell and fill cracks or small voids within the matrix.

Table 3.1 - Cement additives and their respective effect.

Additive	Effect
Bulk flow enhancers	Reduce packing tendency of bulk cement
Strength Stability	Avoid loss of strength and increase of permeability
De-foamers	Prevent foam
Extenders	Viscosify, tie up excess water, prevent fluid loss
Retarders	Control thickening time
Dispersants	Reduce viscosity, improve fluid loss, prevent gelation, act as retarder
HT stabilizers	Viscosify at high temperatures, control thermal thinning
Fluid loss control agents	Control fluid loss
Gas migration prevention agents	Prevent gas migration during placement
Expanding agents	Expand cement during and after hydration
Gas generators	Produce H ₂ to increase compressibility
Foaming agents	Create stable foam
Nitrogen	Used with foamers to create foam slurries or foam spacers
Weighting Agents	Increase water ratio to make heavy slurries mixable and pumpable.
Lightweight materials	Reduce density
Fibres	Enhance tensile strength, prevent cracking, avoid chunk fall-off
Gel accelerators	Accelerate gel development, make slurry thixotropic
Gel delayers	Prevent gel
Elastomers	Enhance elasticity
Lost circulation material	Mitigate losses

In addition to additives mentioned, additives are mixed into the slurry to aid placement of cement plugs. Some are listed in Table 3.1. The applications of these additives depend on the plug placement method and will be further discussed when describing plug placement methods in Chap. 6, 7 and 8.

3.1.3 Pre-job Evaluation of Cement

After the final cement slurry composition is determined, the cement dry mix (bulk) is sent offshore. The bulk is mixed with water to obtain correct density and added cement additives in the cement unit offshore. To ensure that the final product has the same properties as intended a sample is sent onshore for lab testing. The following properties will be tested and compared to anticipated design. It is crucial that the cement slurry is tested in a simulated environment that correctly represents wellbore conditions.

In order for the testing procedure to be as accurate as possible, independent of location, the guidelines for testing are governed by universal testing standards. Testing procedures used in the industry today are commonly governed by recommended practices issued by the American Petroleum Institute (API) and the International Organization for Standardization (ISO). These recommended practices include approved equipment and recommended measurements.

Ultrasonic Cement Analyzer (UCA) measures compressive strength development as the cement sets in simulated downhole conditions. The measurement will be represented in a graph which shows development of

strength versus time. Typical relevant parameters would be the time for developing a compressive strength of 50 psi (3.5 bars), then 500 psi (35 bars) and then final compressive strength. The UCA test is the only test that verifies the mechanical properties of the well cement prior to the cement job. It can be argued that additional characterization and qualification of the cement matrix prior the cement job should include measurements of other mechanical properties in addition. Measurements of tensile strength, elastic properties and failure criterion when subjected to stress can improve the cement design [11].

The measurement of thickening time tells how long time before the cement reaches a state where it can no longer be pumped. The pumpability of cement is measured in Bearden Units of Consistency (B_C) which is a dimensionless quantity related to the slurry rheology. The term thickening time refers to the time until the slurry has reached a consistency of 100 B_C . When the cement slurry has reached a consistency of 70 B_C it's commonly referred to as unpumpable [16].

The free water test verifies that no water separates from the slurry before setting. Water may separate from the slurry and migrate upwards, creating pockets of water at the top.

The atmospheric stability test verifies that no particles separate from the slurry during setting time. Separation of particles will create indifferences within the column of cement slurry which will affect the integrity of the final set cement.

Test of API Fluid loss describes in which degree the cement slurry is dehydrating when in contact with porous media. Cement slurry consists of particles and filtrate. The filtrate will escape if differential pressure allows it, which will affect the placement operation. The fluid loss is measured in cubic contents (in the preferred volumetric unit) per 30 min (cc/30 min).

The density is tested to verify that the density is the same as anticipated during job design. Control of the cement density is crucial for pressure control during plug placement.

The rheology measurements are made to obtain friction pressure and flow regime calculations. Gel strength and shear rates for various rotational speeds are measured in a viscometer. Accurate temperature and pressure measurements are done prior to testing and should be kept under close supervision during the testing procedure. The rheological properties will determine how the slurry behaves downhole, and it is extremely important to obtain accurate measurements prior to a cement job. For example when setting a cement plug, the cement slurry should be able to displace fluids encountered downhole. The displacement efficiency is a function of fluid properties such as density, gel strength, yield point and viscosity. The spacer should be able to displace mud and cement should be able to displace spacer. A hierarchy of increasing density, gel strength, yield point and viscosity as the fluids displace each other will ensure efficient displacement. If this hierarchy is not achieved the displacement will not be as efficient, the interfaces between fluids will be longer and the fluids will mix

which may result in a “soup” - a contaminated plug unable to seal. This will be further discussed in Chap. 7.2.

3.2 OTHER BARRIER MATERIALS

3.2.1 Epoxy Resins

Epoxy resins, such as Thermaset® and CannSeal sealant, can be used as permanent sealants if verified for long term isolation. Table 3.2 lists up properties of Thermaset®, an epoxy resin sealant developed by WellCem AS [17] which has been certified as a permanent isolation material according to the ISO 14310 V3 standard. This means that the material has been tested for isolation of liquid, resistance against axial stress and temperature cycling. In addition, SINTEF has done an aging test on this material which has been further described in Chap. 2.3.1.

Table 3.2 – Properties of Thermaset® compared to neat Portland G Cement. [17]

Properties	Thermaset	Portland G Cement
Compressive strength [psi (MPa)]	11200 ± 700 (77 ± 5)	8400 ± 600 (58 ± 4)
Flexural strength [psi (MPa)]	6500 ± 400 (45 ± 3)	1500 ± 150 (10 ± 1)
E-modulus [psi (MPa)]	330000 ± 10000 (2240 ± 70)	540000 ± 90000 (3700 ± 600)
Rupture elongation [%]	3.5	0.01
Tensile strength [psi (MPa)]	8700 (60)	145 (1)
Failure flexural strength [%]	1.9 ± 0.2	2 ± 0.04

The Portland G Cement used in Table 3.2 does not include any cement additives and the numbers does not reflect the cement actually designed for plugging purposes. It can however be noticed how superior the epoxy resin is compared to the cement properties that are listed. Thermaset® is stronger and ductile which are properties that are proposed in the NORSOK D-010 guidelines. The standardized verification and long term test indicates that the material is well suited for permanent abandonment barriers.

CannSeal sealant is another epoxy resin which can be used in plugging operations, but has currently not been qualified as a permanent abandonment barrier. The application of CannSeal together with the CannSeal wireline tool will be further discussed in Chap. 9.1.

Epoxy resins are liquid polymers that will set when exposed to high temperatures. They have low permeability, will bond to the steel, are elastic and can withstand high stress levels. Rheology and density can specifically be designed for each purpose. The density of ThermaSet® can be as low as 5.83 ppg (0.70 sg) [17]. The manufacturers guarantee accurate setting time, no shrinkage and no particles that will cause instabilities.

Epoxy resins can be used for isolating perforations, setting of balanced plugs and repairing the cement sheath, however there is limited field experience for these applications compared to cement. After possibly achieving verification for long term integrity, they should definitely be taken into consideration when choosing barrier material prior to a plug and

abandonment campaign; even if it is more expensive than cement.

3.2.2 Sand Slurry

Sandaband Well Plugging AS has developed sand slurry designed for pressure isolation purposes [18] [19]. Unconsolidated sand slurry, or Sandaband®, can be used as a plugging material or in combination with other plugging materials.

The sand slurry consists of as much as 75% particles. The size distribution of the particles is designed to fill any voids within the barrier, making it gas tight. The barrier will hold differential pressure higher than the hydrostatic pressure from the sand slurry column. However, a sufficient column of sand slurry above the source of inflow is necessary to isolate.

The particles are made of microsilica, quartz and crushed rocks and held together with electrostatic forces. The fluid part comprises water, deflocculant and viscosifier. Even with the high percentage of particles, the slurry is pumpable and can be used as barrier material for the bullheading operation described in Chap. 6.2 or in conjunction with the Cannseal annular barrier discussed in Chap. 7.3.4.

The slurry does not set up in the same way as other sealants. It acts like a liquid when pumped, and it will seal when it is left in the well. The column of sand slurry is continuously packed, does not contain any free water and will heal itself. The self-healing properties are unique. When the sand slurry is subjected to stress above the yield point, it will deform plastically and then continue to seal afterwards. Instead of failing, the material will partially change

state to a fluid and then reshape. This means that the slurry will seal even when subjected to high stress levels and tectonic activity.

The sand slurry is qualified through laboratory and field testing for 10 years, and according to the supplier, the Sandaband® product meets all the Norsok D-010 guidelines. The decision to apply this plugging material for any isolating purposes depends on each individual operator.

3.2.3 Formations as P&A Barrier

Before any well is drilled hydrocarbons are kept from leaking to surface with the help of natural isolation material. Formations are the original isolating barriers and can be used for abandonment purposes if the barriers can be verified [20].

During drilling, reactive shale with high clay content can swell and cause hole stability problems when exposed to water based drilling fluids. The swelling reaction can be used as an advantage when setting barriers for abandonment.

Williams et al (2009) [20] have proposed several requirements for how shale formations can be regarded as an annular barrier. These requirements are as follows.

1. The barrier must be shale. Shale fulfills the material properties in issued in the Norsok D-010 [7].

2. The shale must have sufficient strength when exposed to reservoir pressure. This includes calculating the worst case pressure traverse from the reservoir. The strength of the formation must be verified with a leak off test.
3. The formation displacement mechanism which creates the annular barrier must be formation creep. Formation creep is a formation displacement mechanism where the formation rock moves inwards hydraulically in order to seal of the annular space. The mechanism can be compared to a pipe ram that closes and seals around the pipe in a Blow Out Preventer (BOP).
4. The barrier must extend to the full circumference of the pipe and must be of sufficient length to fulfill the barrier length requirements for P&A barriers in Norsok D-010

Formation creep can be used in combination with a balanced plug inside the casing and can act as a long term abandonment barrier. This will be further discussed in Chap. 7.3.3 when introducing the method of setting a balanced plug in cased wellbores.

4 P&A RIGS

Plugging operations can be conducted with a drilling rig or rigless depending on the well configuration, condition and the services and equipment available. The equipment and services employed determines operational progress and ultimately the final cost of the operation. This chapter will discuss the different types of services and equipment available for plugging operations, their capabilities and their limitations. This is intended to provide the reader with a perspective of the conditions under which a plugging operation is conducted.

4.1 WIRELINE

Rigless operations using wireline can provide cost effective means of gathering diagnostic information which is necessary for planning and conducting plugging operations. P&A related operations such as well diagnostics and cement evaluation logging can be executed, and the primary reservoir barrier can be set if the well conditions allows for it.

Wireline work implies deploying a cable or wire with a toolstring attached at the end into the well. Different types of cables or wires include slickline, e-line or braided line. The type of wireline deployed depends on the application, necessity for toolstring electricity and pulling power during operations. Wireline has certain limitations such as no possibility for circulation through a workstring and no jacking power. However by connecting pumps via temporary flow lines to the x-mas tree of the well, fluids including plugging materials can be bullheaded into the formation.

The wireline surface rig-up consists of equipment as illustrated in Fig. 4.1. The

surface equipment must handle all pressures from the well, and includes a wireline blowout preventer (BOP) that will cut the cable and seal the well in case of emergency. The wireline BOP is a secondary barrier element. In Appendix D, the NORSOK D-010 [7] well barrier schematic for running wireline through a surface production tree is attached.

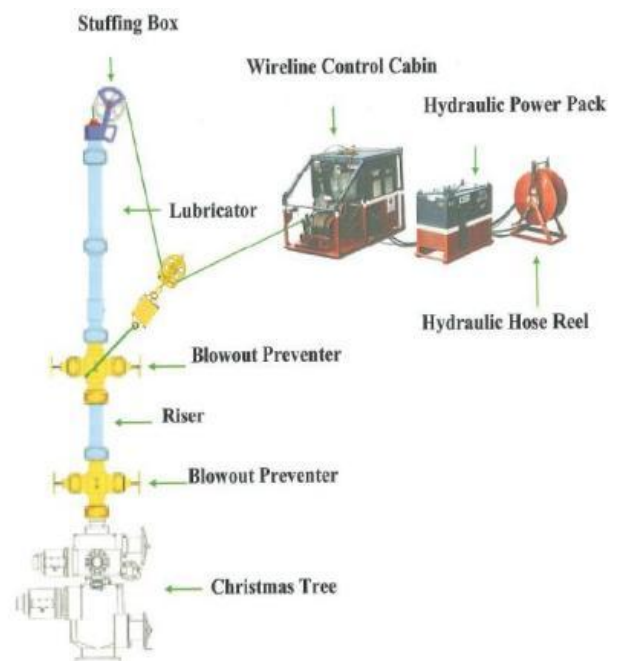


Figure 4.1 – Wireline surface equipment. [21]

A wireline toolstring is deployed in the lubricator and the lubricator pressured up before entering the live well. A typical wireline toolstring consist of a rope socket, stem weights, jar and a running or pulling tool. Additional tools may be deployed instead of the running tool. The toolstring is illustrated in Fig. 4.2.

If the well has high inclinations, a wireline tractor is necessary for running the toolstring in the well. A wireline tractor requires electricity which is supplied from the conductor incorporated within an e-

line. The tractor will pull the toolstring in highly inclined or horizontal sections within the wellbore where gravitational forces do not suffice for movement.



Figure 4.2 – Wireline toolstring. (Courtesy of Halliburton.) [22]

The rope socket is where the slickline, e-line or braided line is attached to the toolstring. It contains a weak point which will make it easier to retrieve the toolstring if the line snaps. The line will snap at the weak point, and the rope socket can be retrieved using the fishneck. The stem

weights are deployed to overcome the upwards pressure forces in the well. The jars will apply weight from the stem weights to create mechanical shocks if the toolstring becomes stuck and the knuckle joint will decrease the risk of becoming stuck. The running or pulling tools, or other designated tools included in the toolstring will serve whichever purpose of the operation, which in plugging related operations would be to retrieve Downhole Safety Valves (DHSV), retrieve or set Gas Lift Valves (GLVs) or dummy valves, drift, leak detection tool, MultiFinger Caliper (MFC) tool, temperature and pressure gauges or cement evaluation tools. Wireline applications for plugging related operations are further addressed in Chap. 5 and 6.

4.2 COILED TUBING

Coiled tubing has many applications which include but are not limited to clean outs, well stimulation, spotting of fluids and plugging materials. For plugging operations coiled tubing can be applied for cleaning out the well prior to barrier setting and to set primary or secondary reservoir barriers [23] [24] [25].

The surface equipment used in a coiled tubing rig-up is illustrated in Fig. 4.3

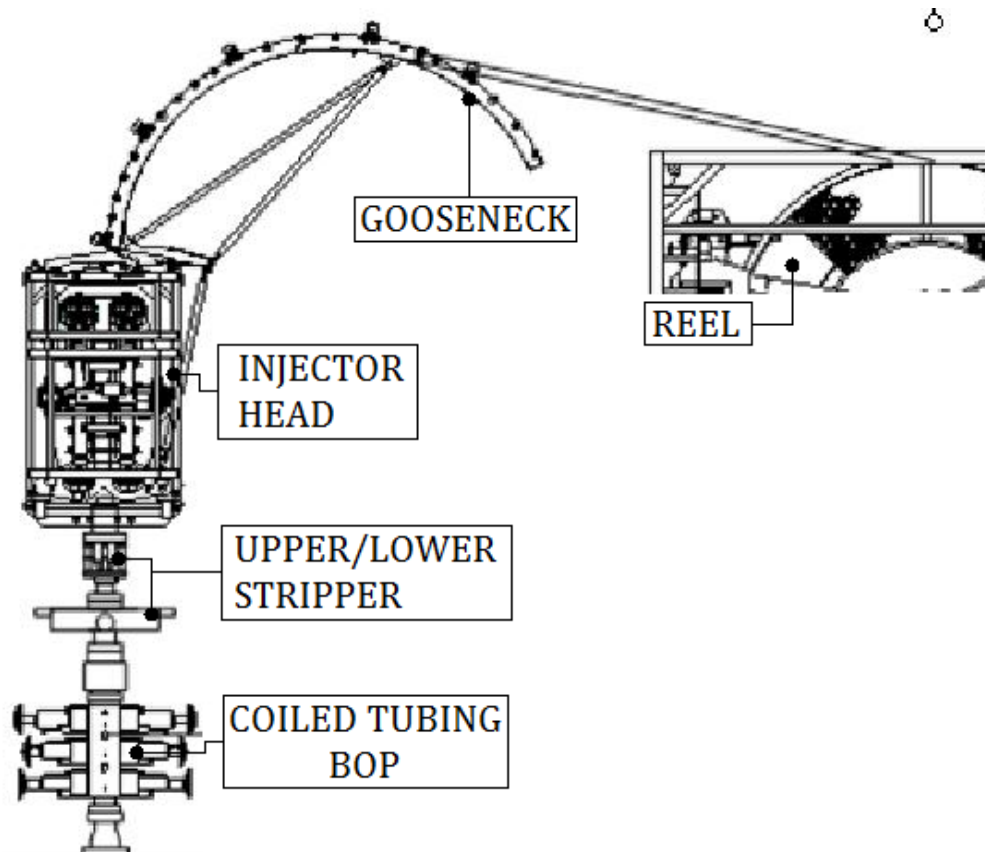


Figure 4.3 - A typical coiled tubing rig-up during well intervention. The coiled tubing is injected by the injector head from the reel, via the gooseneck through the strippers and BOP stack. The safety head and riser, which is not included in this picture, is located at the wellhead deck below along with the x-mas tree [26].

The injector head will force the tubing down the well via the gooseneck with the help of special pipe handling chains, overcoming friction and well pressures. This is further illustrated in Fig. 4.4.

The coiled tubing rig-up is mounted on the well x-mas tree and will need to handle well pressures during well intervention. The designated coiled tubing BOP is employed as a primary barrier element.

Well pressure is contained at the tubing injection point by using rubber strippers that will form a seal around the pipe during injection. The upper stripper is classified as a primary barrier element, while the lower is used for back-up.

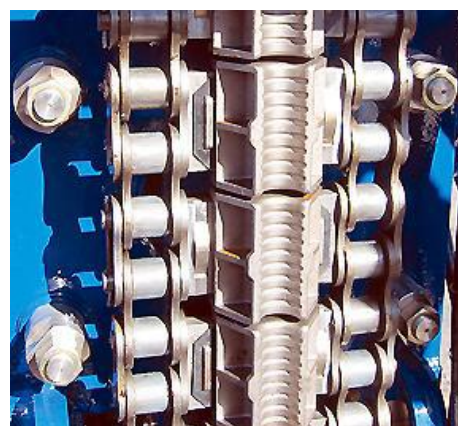


Figure 4.4 – Injector Head used for injecting the coiled tubing into the well. [27]

In addition to the coil BOP, there is a safety head which will act as a secondary barrier. The rams of the safety head can cut the tubing and seal the well in emergencies

and is required as back-up rams because the coil BOP is a primary barrier element. Coiled tubing toolstrings are also required by NORSOK D-010 guidelines to incorporate check valves that will act as primary barrier elements. The NORSOK D-010 rev3 well barrier schematic of a coiled tubing rig-up is attached in Appendix E.

Although the coiled tubing rigs have possibilities for circulation, certain operational restrictions apply when using these types of rigs for plug setting. The thin walls of the tubing will cause some limitations, which are further discussed in Chap. 7.4.

In addition to the possibility for circulation through a workstring other advantages such as tripping speed and cost efficiency is relevant in comparison with conventional drilling towers and wireline rig-ups. The coiled tubing may also pass restrictions in tubing or casing strings. The equipment comprising the components of the rig-up is extremely heavy. Crane capacities have to be taken into consideration when lifting such heavy weight onto an offshore platform.

Recent developments have also suggested that coiled tubing can be incorporated with jacking units or rigless abandonment operation systems to provide cost efficient possibilities for rigless abandonment [28] [29] [30]. By incorporating jacking units the coiled tubing rig-up will be able to cut and retrieve production tubing prior to setting a cross sectional secondary reservoir barrier. This would provide a cost efficient alternative to the use of drilling rigs for plugging operations which will be described next.

4.3 DRILLING RIGS

Drilling rigs which include jack-ups, modular, platform, floating and land rigs comprise the majority of the traditional units used in conventional plugging operations. Offshore platforms which do not have an in place drilling or workover unit, may require the placement of a modular drilling rig or jack-up rig in order to conduct well operations.

Cantilevered jack-up rigs represent the fastest method of rig installation with a minimum of interface time and cost. Cantilevered jack-up drilling rigs are mobile drilling units applicable for water depths below 500 feet (150 meters) [31] that can be towed or carried by transport vessel. Upon arrival at the platform, the supporting legs will be jacked, elevating the hull above the wellhead platform, like illustrated in Fig. 4.5. Then the cantilever will be skidded for placement above the wellhead of the platform. A cantilever system is illustrated on Fig. 4.6.



Figure 4.5 - The jack-up rig Noble Sam Noble, working in the Bay of Campeche, Mexico. [32]

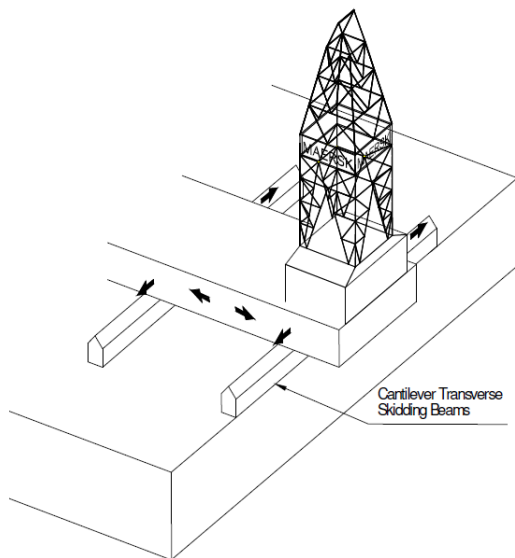


Figure 4.6 – The cantilever can be skidded in place above a wellhead for rig work [31]. *Copyright 2005, SPE/IADC Drilling Conference. Reproduced with permission of SPE. Further reproduction prohibited without permission.*

The cantilevered drilling system comprises the following subsystems [33] which each may have their own respective subsystems.

- Drilling control
- Drilling machine
- Pipe handling
- BOP Handling System
- Mud Supply
- Mud Return

Drilling control, drilling machine and pipe handling systems are all located around the drill floor and derrick. The derrick, sometimes referred to as the drilling tower, is a structure which functions as support for the activities conducted at the drilling floor. The derrick is illustrated in Fig. 4.7 and Fig. 4.8.

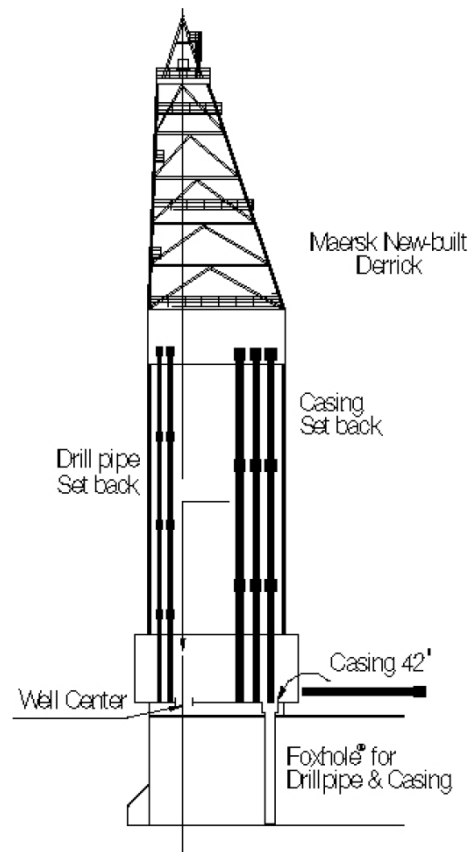


Figure 4.7 – A derrick with automatic pipe handling system [31]. *Copyright 2005, SPE/IADC Drilling Conference. Reproduced with permission of SPE. Further reproduction prohibited without permission.*

The Drilling control system regulates how the work is monitored and operated by the driller and the rig crew. It is controlled by the driller's cabin located close to the rig floor. There are strict legislative requirements on the Norwegian continental shelf of how rig work can be conducted to ensure personnel safety. Human intervention increases risk of accidents, thus the work is mostly mechanized.

The drilling machine subsystem is rotating, hoisting and supporting tubulars that are run into or out of the wellbore. It includes

the crown block, traveling block, hook, top drive, drilling lines and drawworks. The drawworks is a powerful diesel engine incorporated with drilling lines which will provide the pulling power. The drilling lines are lines that are threaded over the crown blocks at the top of the derrick and enable movement and pulling power through the traveling blocks and the top drive within the derrick. The top drive consists of two drilling motors that will provide rotation of tubulars. Traditionally rotation of tubulars is achieved by the rotary table, but this system is only a contingency in modern cantilevered jack-up drilling rigs.



Figure 4.8 – A topdrive located within a derrick. The iron roughneck, mud injection hoses, pipe racks and the travelling blocks can also be seen. [34]

The pipe handling system will transfer the relevant tubulars from the pipe rack to the drill floor and into the well with minimum human intervention. In plugging operations when the strings of tubulars are retrieved, the pipe handling system will handle tubulars in the reverse manner compared to drilling. The system consists primarily of racks of tubulars, iron roughnecks which will make or unmake connections, a fox hole which can prepare stands of tubulars or BHAs while drilling or tripping and a conveyor system to supply the derrick with tubulars in order to optimize tripping speed.

The BOP handling system incorporates installation, testing and application of pressure control equipment. The BOP is located below the drilling floor in a cellar deck. It is mounted on the wellhead through a moonpool below the cantilever.

Mud supply system will store, prepare, and transfer fluids into the well. Fluids include drilling mud, milling fluid, seawater, drilling water, plugging materials or cement slurry. The fluids are stored in tanks on the jack-up rig and can be mixed with a liquid base before pumped into the well via high pressure mud pumps or cement units.

Mud return system includes facilities such as mud logging, disposal, treatment, re-injection and recycling of any wellbore fluids. It consists of shakers and mud pits and connecting flow lines.

A drilling rig has the same operational capability as when the well was drilled, which results in the highest degree of flexibility when conducting well intervention operation such as setting abandonment barriers. Even if a jack-up rig

has a higher rental day rate, the overall cost may be lower if a higher efficiency and reduction of operational days is achieved. Because the unit is self-contained and has a high degree of flexibility, the current risk for remedial operations will also be lowered compared to the rigless approach. If there are several well integrity issues, collapsed wells or deep wells, a rigless approach will currently not be viable.

During periods of high activity, rig availability must be taken into account so that contracts can be negotiated and rig arrival determined to ensure that the desired work window is met. However, there can be limited availability. If drilling rigs are used for P&A instead of drilling, a lower number of wells can be drilled which will ultimately decrease the recovery rate of producing fields.

5 PREPARATIONS FOR A PLUGGING OPERATION

The condition of the well will determine how it can be plugged and abandoned. By assessing the reservoir pressure, the current well integrity and evaluating the annular space, a plugging operation can be planned for efficient well abandonment with minimum removal of tubulars.

5.1 WELL DIAGNOSTICS

Aging production wells may have several integrity issues, and obtaining the bottomhole pressure is crucial for a successful plugging operation. This section will contain information of the operational steps during a well diagnostics operation.

5.1.1 Purpose of Well Diagnostics

There are several purposes for doing a well diagnostics. The first and most important one is to determine if there is access to the reservoir. This is verified by a drift run or by tracking pressure response when injecting fluids. If there is injectivity, the reservoir pressure can be calculated. The reservoir pressure will dictate the design of the plugging material that will be used for plugging and the displacement fluid that will follow the plugging material. If no reservoir pressure can be calculated due to lack of injectivity, the plugging operation will be more complex. Another purpose of well diagnostics is to determine condition of the production or injection tubing. With the intention of plugging, leaks in the tubing or tubing restrictions will increase difficulty and sometimes make it impossible to follow legislative requirements.

5.1.2 Testing of Surface Equipment

Before any well intervention can take place, the well barrier elements on the surface must be tested. During the well intervention the surface barrier elements

will form both primary and secondary barriers, and it is important to verify their integrity before possible exposure to pressure. All barrier elements that can be exposed to pressure should be tested for integrity and functionality, including barrier elements in the secondary barrier envelope. This is done in addition to any regularly testing.

Testing of valves located on the x-mas tree is conducted as follows. The well is shut in by closing the automatic flow line valve before any testing is conducted. Then all the valves are tested separately. This includes the automatic flow line valve, production wing valve, swab valve, service wing valve, automatic master valve and manual master valve. Since well diagnostics includes pumping through the annulus wing valve, this would also be tested. The valves are tested by applying pressure in the direction of flow. The pressure source could be the reservoir pressure or pressure from a pump. If each separate valve can hold pressure, the wireline rigging can start. If there are any leaks, the leak rate must be determined and corrective measures may be taken.

The tubing hanger is a barrier element both in primary and secondary barrier envelope (see Appendix D) during wireline operations. This means that if the elastomer seals in the tubing hanger fail during operations, there could be release of hydrocarbons to the environment. Because of this, the NORSOK D-010 guidelines suggest that the tubing hanger seals are tested prior to any wireline operation as a compensating measure. This is done with a designated testing tool that includes a test pump that will pressure up to verify that

the primary and secondary seals can hold pressure.

5.1.3 Retrieval of Downhole Safety Valve

After the wireline equipment is installed and tested, the downhole safety valve (DHSV) will be opened and retrieved. The DHSV is a fail-safe surface controlled valve which will close in cases of emergencies or to shut in the well. The valve is installed in the upper wellbore. All wells on the Norwegian Continental Shelf are required to have a DHSV at least 165 feet (50 m) below the seabed. Most DHSVs are of the flapper type and can either be tubing retrievable or wireline retrievable. If the valve is tubing retrievable it can only be retrieved by pulling the completion string, and will only be opened during well diagnostics. If it is wireline retrievable it can be retrieved using a designated wireline pulling tool. A wireline retrievable DHSV, which is the most common type in the North Sea, is set in a designated DHSV nipple.

A flapper valve will shut in and seal the well by using a flapper as illustrated in Fig. 5.1. A fail safe spring mechanism controls the flapper, and pressure in a hydraulic control line keeps the spring in tension. Any decrease of hydraulic pressure in the control line will close the valve, including malfunctions and interruptions in the control system. The DHSV is a barrier element during production and is subjected to strict legislative requirements for frequent testing. After the DHSV is pulled the wireline rig-up will handle pressures from the well.

Visual inspection of the DHSV may give some information about issues such as corrosion or scale deposits in the rest of the tubing.

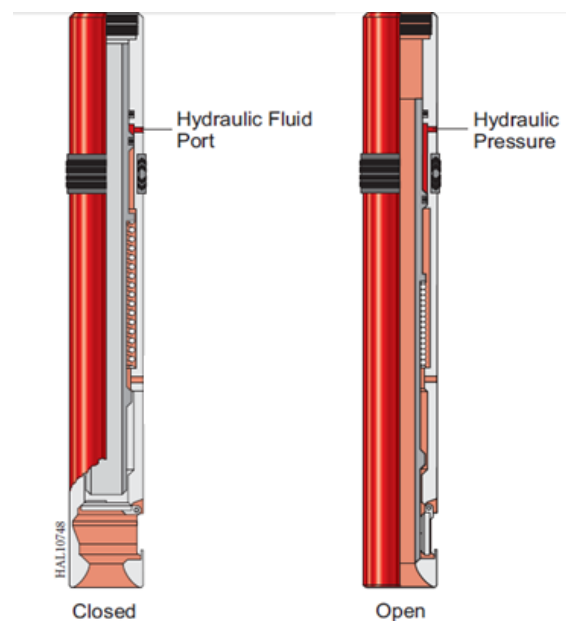


Figure 5.1 – Surface controlled subsurface safety valve. (Courtesy of Halliburton.) [22] (Edited)

5.1.4 Assessment of Tubing Integrity

The next step in the operation is the drift run to assess tubing integrity. This will determine if the tubing is in good shape with no restrictions and measure the maximum inside diameter of the tubing. A drifting tool is lowered into the well. A drifting tool is basically a cylinder with a specific outer diameter. The inside diameter of the tubing, in this case the drift diameter, will dictate the maximum outer diameter of tools that are possible to run into the wellbore later during the plugging operations. If possible the drifting tool is run to tag the very bottom of the well, called the hold-up depth (HUD). If there are restrictions, from events such as scale deposit or tubing collapse, HUD will be further up the well, and a new, smaller drifting tool will be run in order to attempt to pass the restriction. To determine the nature of the restriction a lead impression

block can be run. The lead impression block will indicate the nature of the obstruction, whether it is obstructions such as collapse, debris or parted tubing.

During the drift run a pressure temperature gauge tool (PT gauge) is included in the toolstring. The PT Gauge will accurately measure temperature and pressure in the well. To optimize the measurements seawater is injected to check how the well responds. This injection will give an indication of reservoir access, but this will be further determined by the injection test described in Chap. 5.1.10. The PT gauge will be held above the top of perforation and will monitor the reestablishment of temperature and pressure at this point of the well. The pressure and temperature build-up and reaction measured by the PT gauge will give a good estimate of the temperature.

The tubing, which is a primary barrier element, might be damaged in aging production wells. Events that have occurred throughout the well lifetime such as collapses, corrosion, erosion, scale deposits may be caused by the formation fluids, forces originated from the formation or caused by operation. Wear from intervention operations and lack of maintenance will induce integrity issues in the production tubing. In some cases tubing damages and fatigue will be detrimental for the plugging operation, for example if geological activity such as fault activation or subsidence have subjected the tubing to extensive forces and parted the tubing, scale deposits that will require a cleanup by coiled tubing before the plugging operation or corrosion or wear that will limit the tubing pressure rating.

If restrictions are found, the several questions arise; will it be possible to place plug below the restriction? Are there leaks associated with the restriction? If plug placement is possible, will there be possibilities for verification after the plug has been set? Is the restriction limited to the tubing, or is there damage to the casing as well? If there is no sign of communication with the reservoir and the tubing has parted, how can the well be safely abandoned?

Restrictions, collapses and parted tubing are all examples of well integrity issues. Such issues will often be the determinative factor for scheduling abandonment of the well. A barrier failure will deteriorate with time; it will start with a small tubing restriction and end up with no access or injectivity to the reservoir. By conducting plugging operations when there still is access to the reservoir, a proper well abandonment operation can be done.

If the tubing is parted and shifted, and there is no sign of communication with the reservoir it will be difficult to know if the well is properly isolated and how long the isolation will last. This will depend on the formation rock around the wellbore, and even if it is isolating now - will it hold future pressure build-ups? This question is outside the scope of this thesis, but is problems highly relevant for plugging operations in the Norwegian continental shelf.

5.1.5 Further Wireline Investigation

For further investigation, a Multifinger Caliper (MFC) tool is run on wireline in the well. The MFC tool, illustrated in Fig. 5.2 will accurately measure the inner diameter of the tubing. Thickness of tubing wall will dictate the tubing pressure rating.

The capacity of the tubing can be used for precise volume control. When displacing plugging material during a plugging operation volume control is extremely important. The inner diameter of the tubing might be approximately known from previous well data such as tubing specifications or completion schematics, but the inner diameter of the tubing will change slightly through production because of deposition of scale, erosion, wear and corrosion. The MFC consists of fingers that will slightly touch the tubing wall and measure any increase or decrease in tubing diameter. Fig. 5.3 shows the result of such logging operation; the entire tubular can be examined and modeled in 3D.

After the MFC tool is run, the wellbore trajectory may be accurately measured by running a wireline toolstring with a gyro sensor in the well. A gyro survey might be highly necessary in aging wells where old logging tools was used when drilling and the well path is inaccurate. The gyro run during a well diagnostic prior to a plugging operation will verify older data. Exact well trajectory is important to have if the plugging operation is a part of a sidetrack operation and for future field development and drilling operations.

5.1.6 Plug Tubing

Before a possible plug placement through the tubing the tubing will be tested. This is done by isolating the tubing from the reservoir and then exposing the tubing for differential pressure. Prior to testing, a temporary plug is set in the wellbore. This could be a nipple plug, a wireline



Figure 5.2 – Multifinger Caliper tool. (Courtesy of GOWell Petroleum Equipment Company.) [35]

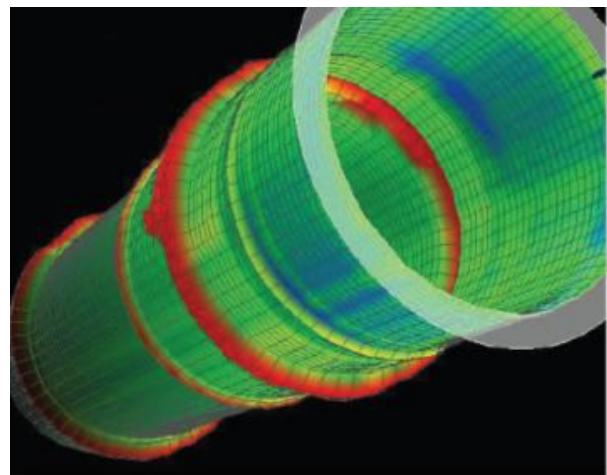


Figure 5.3 – 3D Caliper Image. (Courtesy of BakerHughes.) [36]

retrievable bridge plug or an inflatable plug.

The nipple plug is set in landing nipples, such as no-go nipples or selective nipples. Landing nipples are machined internal surfaces of the tubing that provides a seal and a locking profile. The nipple will function as a seat for the lock mandrel located on the toolstring. Fig. 5.4 illustrates a selective nipple and the part of the toolstring that will latch on to the inner profile. Notice how the locking key fits the inner tubing profile.

A nipple plug is set as deep as possible, typically in a no-go nipple right below the depth of the production packer. Fig. 5.5 illustrates a nipple plug seated in a no-go nipple. The no-go shoulder will prevent the wireline toolstring to pass and the locking keys will anchor the toolstring in place. Below a no-go nipple, the tubing has a slightly smaller inner diameter. The nipple plugs can provide isolation for high differential pressures during testing.

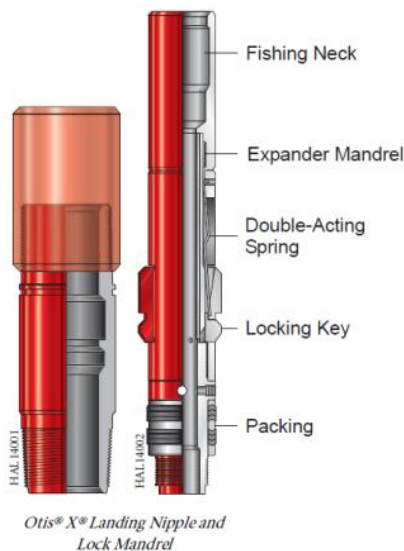


Figure 5.4 – Selective landing nipple. (Courtesy of Halliburton.) [22]

Fig. 5.5 also illustrates an equalizing prong. An equalizing prong is used to make it easier to pull a plug by equalizing the pressure before the plug is retrieved. Because the prong has smaller surface area, the prong requires less force for release. It can be described as a plug inside the plug and is retrieved in a separate run before retrieving the rest of the plug.

Instead of a nipple plug, a retrievable bridge plug can be used for isolation during testing. A retrievable bridge plug is a sealing device that can be installed and

retrieved using wireline. It can be placed anywhere in the well and is not dependent on nipples to set. If there are no nipples available, or if there are problems with corrosion or erosion inside the tubing, a wireline retrievable bridge plug might be better suited for testing purposes.

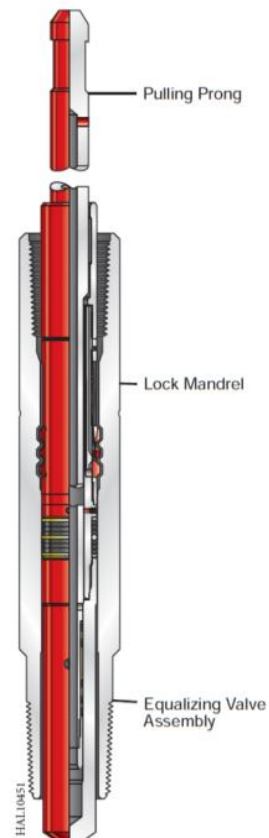


Figure 5.5 – Nipple plug in a no-go nipple. (Courtesy of Halliburton.) [22]

As illustrated in Fig. 5.6 the retrievable bridge plug assembly basically consists of a sealing element (in black), slips for anchoring (in yellow), fishing neck for retrieval, the setting mechanism and a prong. During setting the plug, the slips will slide on the outer body of the plug, increase plug diameter and create an inner tension that will stop the plug from moving.



Figure 5.6 – Wireline retrievable bridge plug and equalizing prong. (Courtesy of Halliburton.) [22]

If there is a tubing restriction, an inflatable plug, which is illustrated in Fig. 5.7, can be used for testing. An inflatable plug assembly will ideally pass through a restriction and expand during setting further down the well. An inflatable plug is similar to the wireline retrievable bridge plug, but is thinner and has a different sealing element that will expand through inflation. The sealing element is similar to a balloon that will be inflated during setting.

To protect the plug from debris while testing, a junk catcher may be installed above the plug. The junk catcher will act as a bucket above the plug collecting debris protecting the plug from dropped objects such as GLV or dummy valves from sidepocket mandrels. This will ensure that the anchoring mechanism is not damaged and is releasable after testing.

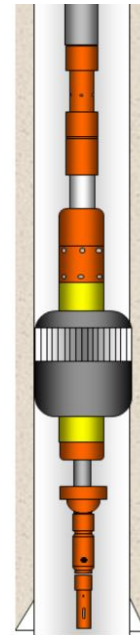


Figure 5.7 – Inflatable bridge plug. [37] Copyright 2010, Society of Petroleum Engineers Inc. Reproduced with permission of SPE. Further reproduction prohibited without permission.

5.1.7 Retrieve Gas Lift Valves and Displace Well with Seawater

During testing, the exact density of fluids inside the wellbore must be known to determine the exact hydrostatic pressures of the tubing and tubing annulus (a-annulus). The fluid density in the well is uncertain, especially if the well has been on gas lift. Gas from gas lift, segregated mud or leaked hydrocarbons will cause uncertainties in the density. It can be necessary to displace both tubing and tubing annulus (a-annulus) with a fluid with known density before any plugging operation. This can be done through creating a communication point between tubing and a-annulus.

If the well has been gas lifted, it is necessary to retrieve the Gas Lift Valve (GLV) to mitigate risk for leaks after

abandonment. A GLV is installed in a side pocket mandrel, and will act as a point of communication between injected gas in the a-annulus and the production tubing during production. If no GLV is installed in any of the side pocket mandrels, a dummy valve will be retrieved to establish communication between tubing and a-annulus. It will be retrieved the same way as the GLV.

The methodology of this operation will be described next. A toolstring containing a kickover tool is run to the depth where a side pocket mandrel with the gas lift valve or dummy valve is located. The kickover tool is illustrated on Fig. 5.8. When the kick over tool reaches the side pocket mandrel there is an orienting slot in the mandrel that will ensure that the arm of the kickover tool will get access to the side pocket in the tubing. After the tool is correctly oriented inside the mandrel, the orienting slot will trigger the arm and the arm will access the side pocket. At the top of the gas lift valve there is a fish neck, which is a specific recognizable top that will fit and lock into the arm of the kickover tool. Then the gas lift valve or dummy valve will be removed by applying a mechanical shock with the toolstring jar or stoker. The retrieved valve will be contained inside the valve catcher while pulling out of hole.

There is now communication between the tubing and the a-annulus through the side pocket mandrel, and this can be used as a communication point when displacing the well with seawater. The volume of the well is calculated and the amount of seawater for circulating is determined. This volume includes both tubing volume and volume of a-annulus. To be certain that the whole

well is displaced 50% extra seawater is pumped through the well.



Figure 5.8 – Kickover tool retrieving GLV or dummy valve from a side pocket mandrel. (Courtesy of Weatherford.) [38]

The seawater often contains chemicals like scale inhibitor, biocide and glycol to prevent scale, bacteria growth and corrosion. The seawater can be bullheaded down the tubing, through the side pocket mandrel and up the annulus or it can be pumped the opposite direction down the annulus. Excess seawater will be circulated through the well and afterwards enter the platform production facility or temporary flowlines connected to the annulus wing valve. After the circulation is finished and the well is displaced to seawater a dummy valve is installed in the side pocket mandrel before testing of tubing and a-annulus.

5.1.8 Test Tubing

The wellbore should be tested with a differential pressure of 1000 psi (69 bars), for both collapse and burst and both tubing and a-annulus independently. This is done by pressurizing the a-annulus until a differential pressure of 1000 psi is reached towards the tubing. The well will be monitored to see if the pressure holds. This will test both the production casing and the tubing.

After the testing the bridge plug or nipple plug is retrieved by first pulling the prong and junk basket, and then releasing the plug.

5.1.9 Leak Detection Tool

If leaks are discovered during testing, a leak detection tool will be run into the well for further investigation. A leak detection tool is an ultrasonic sensor made of a piezoelectric material. The piezoelectric material will generate electricity when subjected to ultrasonic energy, and in this case the source of the ultrasonic energy is a

tubing leak point. Because of turbulent flow created at the leak point, there will be sound waves propagating from the leak point. These will be detected by the piezoelectric sensor, and small voltages proportional to the ultrasonic energy will be generated. The signal from the sensor will then be amplified and filtered through a digital signal process module which will create a digital signal that will get transmitted to surface and interpreted by engineers. If the tool is run on slickline conductor within the line, the signals are recorded in a memory and transmitted when the tool has been retrieved. The typical signal at the point leak will look like the graph illustrated in Fig. 5.9. To maximize flow turbulence at possible leak points, high differential pressures are obtained by bleeding down annulus pressure and establishing high pressures in tubing. If a leak is suspected, measurements will be conducted while manipulating differential pressure to better localize the leak point.

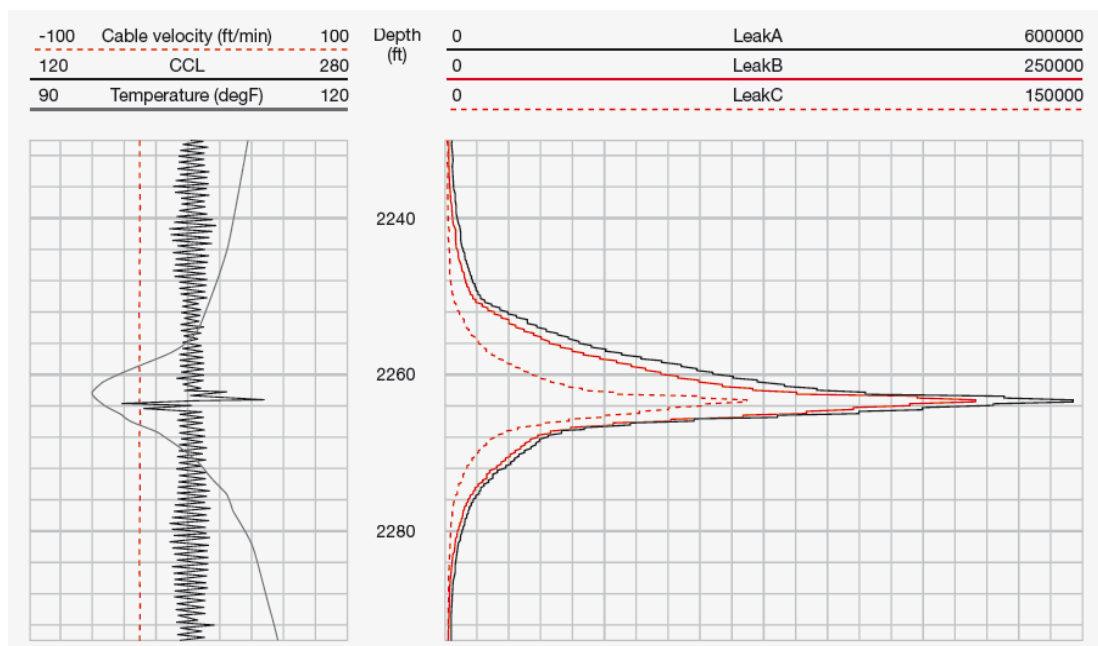


Figure 5.9 - Leak detection in a tubing string connection [39]

As illustrated in Figure 5.9, temperature logs and casing collar logs (CCL) can be run in conjunction with leak detection tools for depth correlation and temperature measurements at the leak point. CCL is a simple casing collar connection log that will react on different steel wall thicknesses due to magnetic induction. In Fig. 5.9 the increase in temperature in addition to ultrasonic energy indicates a leak, and the CCL indicate that the leak is in a tubing string connection.

If a leak is found a decision has to be made for whether or not the leak has to be fixed before plugging. This depends on the leak rate. Low leak rates will not affect a plugging operation done with wireline and in most cases the tubing will be retrieved before further plugging operations. As long as the leak rate does not result in unacceptable high risks, there is no point of fixing it.

If the leak is severe and there are risks for failure during plug placement, a straddle may be the solution for fixing it [40]. A straddle, such as the one illustrated on Fig. 5.10, will isolate the leaking interval of the tubing. A straddle basically consists of two packing elements that will seal above and below the leak in the tubing, spacer tubing and slips that will anchor the straddle inside the tubing.

5.1.10 Injection Test

Before possibly setting the primary reservoir barrier by bullheading plugging material into the perforations, an injection test is conducted. The bullheading operation is further discussed in Chap. 6.



Figure 5.10 – Straddle Assembly isolating leaks in the tubing. [22] (Courtesy of Halliburton.)

The injection test is done by bullheading seawater into the well and then monitoring the pressure at surface after the pumps are stopped.

The purpose of the injection test is as follows.

- Estimation of reservoir pressure.
- Ensuring that there is access to the reservoir; that the perforations are open, not plugged and ready to be isolated.
- Estimation of the pump rate that can be used during plugging operations.

- Estimation of the pressure that will be held after the plugging material is pumped in place, the squeeze pressure.

Before the injection test a pressure and temperature gauge is run into the well on wireline. During injection, when the entire well volume is bullheaded with seawater, the recovery of temperature and pressure is monitored to check how pressure and temperature builds up. A good estimate of the reservoir pressure and temperature can be made and will be used to optimize the properties of the plugging material.

During the injection test minimum 1,5 times the tubing and liner volume is pumped. First the pump rate will be similar to anticipated pump rate for plug placement, e.g. 4 Barrels Per Minute (BPM). After a stable injection rate and pump pressure is established, the pump will be stopped, and the well pressure will be read out from the surface readout system. Then the pumps will be restarted and the rate will be increased in steps to check if a stable pump pressure can be achieved for each pump rate. For each stable pump rate a pressure will be obtained and used as reference for later pumping of plugging material. The injection test will also be used for assessing the maximum pumping rate.

In depleted wells the reservoir pressure may be lower than the hydrostatic pressure of a seawater column. If such wells are displaced with seawater, no pressure is seen at the wellhead at the surface. The seawater will enter the reservoir and this will decrease the fluid level in the well.

Then a wireline running tool can be used to determine the water level in the well, and from the depth of the water level, the reservoir pressure can be determined. A low reservoir pressure will make it difficult to pump plugging material down the tubing, which is further discussed in Chap. 6.3.1.

Different pumping rates are used to check how the reservoir reacts. A pressure increase at surface will indicate communication with the reservoir. Then the reservoir pressure can be calculated by using the following formula:

$$P_{res} = P_{pump} + d_{SW}gD_{top\ perforf} \quad (5.1)$$

P_{res} is the reservoir pressure, p_{pump} is the pressure seen at the surface, d_{SW} is the density of the seawater and $D_{top\ perforf}$ is the depth to the upper perforation. Because the only liquid in the tubing is seawater, the pressure can be calculated quite easily. If the fluid in the well is unknown, or the well is filled with reservoir fluid, the calculation would have to take this into consideration.

When assessing the reservoir pressure by analyzing the response from the reservoir, field experience should be applied when determining the reservoir pressure. Fractures in the reservoir rock may be created, and they could propagate upwards into the overburden. Then the pressure response when injecting will be from the overburden, and not from the reservoir. By taking the overburden pore pressures into consideration, one can recognize if the response is from the reservoir or the overburden.

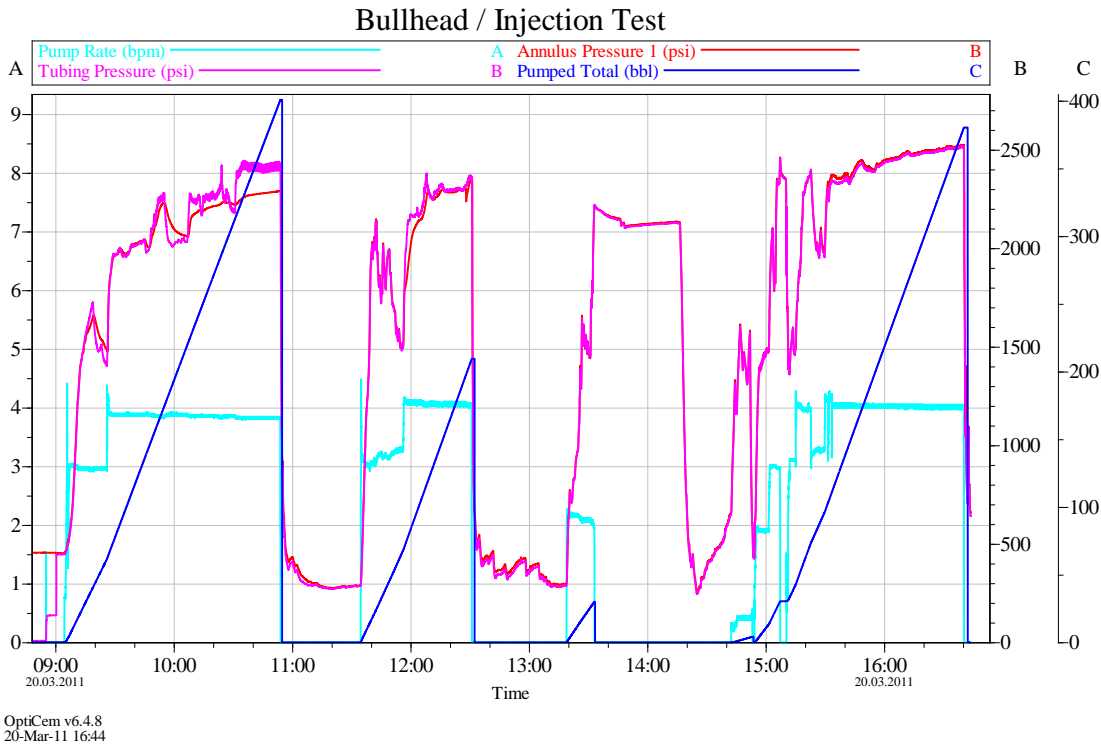


Figure 5.11 – Injection test graphs [41].

The graphs in Fig. 5.11 show how the reservoir responds when fluid is injected. A steep tubing pressure decline after pump stop indicates communication with the reservoir, and the reservoir pressure can be estimated from the stable intervals when pumping with high tubing pressure.

5.2 EVALUATION OF ANNULAR SEALING PRIOR TO P&A

The following chapter will describe how an annular seal created by cement can fail to provide isolation together with two methods of logging behind the casing wall prior to the plugging operation.

5.2.1 Failure of the Cement Sheath

In an ideal well which has the annular space between casing and formation wall isolated, tubular removal is not required during plugging operations. However, this is not the case in aging wells on the Norwegian Continental Shelf (NCS) today. Tubing failure or sustained casing pressure

caused by casing leaks or failure of cement is commonly seen in wells on the NCS [5]. This indicates that any annular seal does not provide hydraulic isolation. In order to responsibly abandon wells the annular isolation must be evaluated. After an evaluation of the annular sealing, planning of the operation required for creating cross sectional barriers can start.

As described in Chap. 2.3.1, the permanent abandonment barrier is required to cover the whole cross section of the well. If the well has a good seal on the outside of the casing, the barrier will consist of the sealing cement together with the casing and the cement plug inside the casing. However, if the cement sheath in the casing annulus has failed to provide isolation fluids may escape through any leak paths within the annular seal.

The annular seal is created during the construction of the well. After each casing

installation, a cement job is conducted, which can be called the primary cement job. During the primary cement job, cement slurry is pumped down the casing and pushed up the casing-formation annulus. It will set and harden to preferably form a cement sheath providing hydraulic isolation and mechanical support for the casing. Long term quality hydraulic isolation is the most difficult property to achieve. If the annular isolation has failed, the plugging operation will include creating a barrier in the casing annulus.

The quality of the primary cement job depends on job parameters such as mud cake removal, mud displacement, mixing of cement, cement design, spacer design, temperature estimation, formation fluids, centralizing and many more factors which will not be discussed in this thesis. Even if the job quality is initially adequate and validated, the cement sheath can fail at a later stage. Quality of the cement sheath in aging wells depends on the ability of the cement to seal under harsh conditions, not only the operational quality of the primary cement job.

As mentioned in Chap. 3.1.2 certain challenges arise when designing cement slurry for well purposes. As the cement technology has been under development the last decades and still is, the cement sheath in an aging well has the quality within the limits of the time when the well was drilled. Sustained pressure seen in wells in the North Sea today is an indication of failure of the annular seal caused by inadequate slurry design for cement used during the primary cement job.

The following sections will discuss some common failure modes of the casing cement. Common failure modes are [10];

- De-bonding.
- Radial cracks.
- Shear failure.

De-bonding is the case where the cement loses contact with the formation rock or casing and a leak path can be created along the formation wall. This is commonly caused by shrinkage during cement hydration or temperature changes in the well. As discussed in Chap. 3.1.2, cement will shrink if no compensating additives are added. Well intervention such as acid stimulation is an example of temperature changes; each time a cold fluid is pumped down the well, the temperature is changed and this will affect the steel. The steel will contract when cooled down and expand when heated. Since the steel is affected more than the cement, the thermal cycling will affect the cement bonding. De-bonding between formation rock and cement is most common, as cement generally has a good bond with steel and the formation rock is significantly stiffer than cement and steel.

Stresses exceeding the tensional strength of the cement will cause the cement to crack radially. This can be caused by a combination of temperature changes, high internal casing pressures and hydration shrinkage. Cracks within the cement matrix will typically propagate and may introduce leak paths for fluids.

Shear failure of the cement sheath will create a crushed zone where the load is highest, which is often closest to the casing string. Shear failure can be caused by loads exerted on the cement from the formation

rock that exceeds the shear strength. As discussed in Chap. 3.1.2, adding fibers to the slurry will make the set cement stronger and additionally prevent propagation of cracks.

Exposure to stresses after placement in the well will contribute to the failure of the cement sheath. It is difficult to predict strength requirements of the cement and how the cement can be designed to maintain a hydraulic seal through the lifetime of the well and after abandonment.

To evaluate casing cement, bond logs are run. This will tell if the cement is bonded to the casing wall and the formation wall. A good bond indicates contact, but does not say anything about the strength of the bond and how much differential pressure or wellbore stresses it can hold in the future. For plugging operations evaluation of old cement in the well will affect how the well will be plugged.

5.2.2 Cement Bond Log

In the Cement Bond Log (CBL) sonic amplitudes of the material behind the casing wall is logged. The CBL will give information about the material behind the casing and indicate if there is contact between cement and the casing wall, the formation rock or both. However, the CBL is dependent on correct interpretation of the received signal. A proper calibration of the tool and correct interpretation of the signal will dictate the quality of the information obtained from the log.

The CBL tool consists of transmitters and a receiver illustrated in Fig. 5.12. The transmitter sends out acoustic sound waves that will create a different type of amplitude dependent on the material and contact between the materials. By

analyzing the amplitude, wave type and travel time of the received signal an impression of the materials behind the casing can be made. Well data such as pressure, well geometry, formation, fluids are all required information for correct interpretation of the cement log. Bond index is calculated from measured amplitudes, and will together with the three tracks of the log give indications of the cement behind the casing.

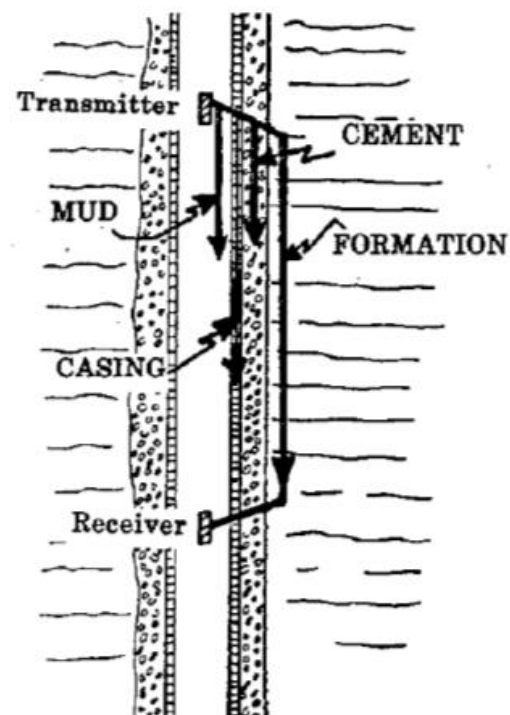


Figure 5.12 – The principle of a CBL tool. [42] Copyright 1985, Society of Petroleum Engineers Inc. Reproduced with permission of SPE. Further reproduction prohibited without permission.

The CBL includes three different tracks of information. The first one is transit time. The transit time is the time from the transmitter sends out the signal until the first signal arrives. This time will also depend on how the signal is detected - if the receiver is measuring amplitudes over a fixed timespan (fixed gate) or if the receiver is measuring the signals when the

amplitude is higher than a set detection level (floating gate).

The purpose of transit time track is mainly to verify that the tool is centered in the casing. The reason for including this track is simply because the slightest eccentricity, such as one quarter of an inch, will cause a signal loss of 50% [42]. The transit time is affected by events such as cycle-skipping or stretch that give fluctuations in the transit time log and most often indicate good bond. This track may also contain Gamma Ray for information about the rock strata, and casing collar log (CCL) for depth correlations and information about casing collar connections.

The second track on the CBL log is the amplitude measurement. This track contains information of the amplitude of the first wave that is detected by the receiver. This wave is most often the one that has propagated down the pipe, and will be affected by the material that is in contact with the pipe (which in this case is the casing). Generally the amplitude will be higher if there is mud or other liquids behind the pipe (free pipe) and low if the pipe is well cemented. Fig. 5.13 shows a general interpretation of this track. The amplitude signal can be compared to ringing a bell. If someone holds around it with their hands, the sound from the bell will be damped, and the amplitude will be significantly lower. It is the same principle when the cemented pipe reacts to sound waves; the waves will have low amplitudes. Special conditions, such as fast formations, gas bubbles, mud particles, pipe thickness, microannulus, may require the logging engineer to modify this general interpretation rule.

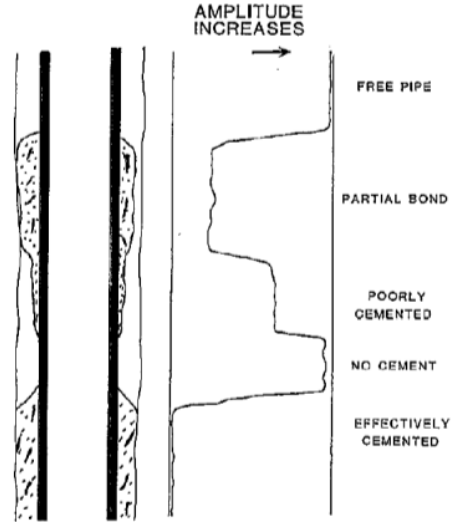


Figure 5.13 – General interpretation of the amplitude track. [42] Copyright 1985, Society of Petroleum Engineers Inc. Reproduced with permission of SPE. Further reproduction prohibited without permission.

The amplitude can also be used in calculating the Bond Index (BI). The bond index can be calculated using Equation 4.1.

$$BI = \frac{A_{fp} - A}{A_{fp} - A_{100\%}} \tag{4.1}$$

A_{fp} is the free pipe amplitude reference dependent of the fluids in the annulus, A is the measured amplitude and $A_{100\%}$ is the amplitude reference for 100% bonding of the specific plugging material or formation rock. The bond index may be calculated automatically and is displayed along with the amplitude track.

The third track on a CBL log is the variable density log (VDL). This track contains the full waveform with depth correlated sound waves. The contrast in this track is dictated by the amplitude, higher amplitude will give higher contrast. An idealistic VDL track is shown in Fig. 5.14; however the VDL interpretation will require more general experience such as knowledge of wave type, interpretation

techniques and factors that affect the amplitudes.

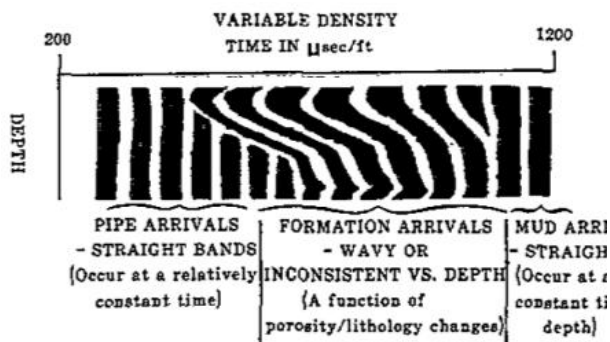


Figure 5.14 – Important features on the variable density display. [42] Copyright 1985, Society of Petroleum Engineers Inc. Reproduced with permission of SPE. Further reproduction prohibited without permission.

From the general example in Fig. 5.14, the straight lines to the left is the first wave received reflected from the pipe, then follows the wiggly lines from the formation which is dependent on the lithology of the formation. Since the fluid travel time is the longest compared to steel and most rocks, it will generally arrive last.

When differentiating between a free pipe section and a cemented interval on the CBL log, the general rule is to evaluate the level of activity. High activity, which means significant variation in both the VDL track and the amplitude track indicates that something is disturbing the signal, which is either cement or formation. Low activity, which means no variation and straight lines in the VDL track means that the pipe can move freely and there is fluid in the annulus.

Fig. 5.15 shows an example of how the CBL looks when there is partial bonding and no annular sealing. The amplitude is low which indicates poor bond and that there is both fluid and cement in the annulus. In the VDL track, starting from the left the straight lines are reflections from the pipe, wavy lines are reflections from the formation and the straight lines are the reflections from the mud arriving last. Notice how the transit time curve in the first track reflects the casing connections.

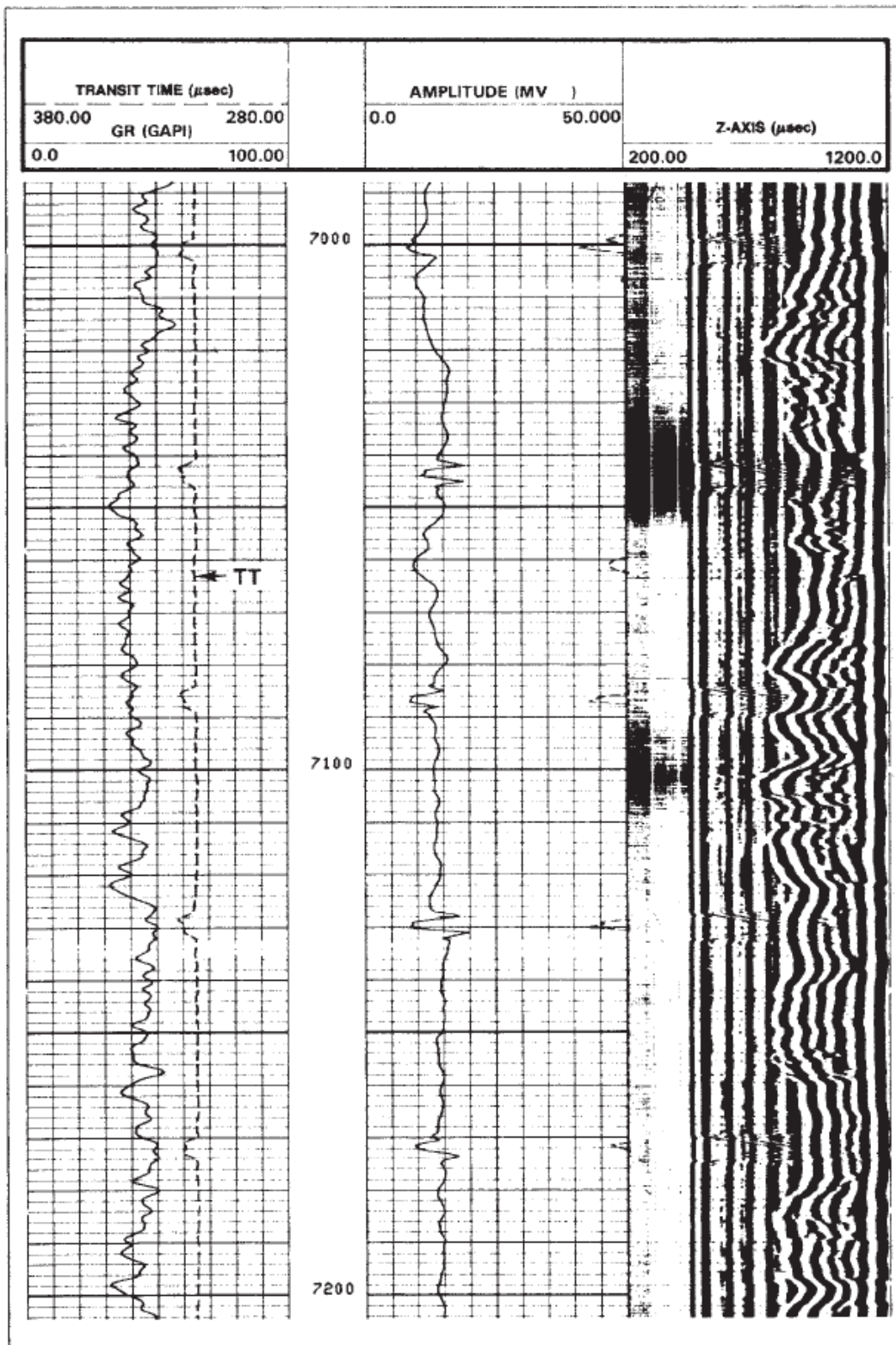


Figure 5.15 – Partial bond in a CBL log. [43] Copyright 1992, SPE. Reproduced with permission of SPE. Further reproduction prohibited without permission.

The CBL will indicate if there is contact between cement and casing or formation rock, but it is difficult to differentiate between mud channeling and a microannulus caused by shrinkage or thermal cycling within a failed cement sheath. This is because the signal is dependent on the annulus pressure. By logging when the casing is pressurized and re-logging when it is not, and then compare the logs, it could be possible to differentiate and further evaluate the cement.

Generally sonic and ultrasonic cement evaluation tools are run together. The two logging methods will complement each other and give a good indication of the conditions of the well prior to a plugging operation.

5.2.3 Ultrasonic Logging

Ultrasonic logging is based on sending out ultrasonic signals that will create resonance that is detected by the tool receiver. The acoustic impedance of the vibration will provide information about the material behind the casing, while the casing thickness can be determined from the signal frequency. Measurements from ultrasonic tools will also provide information about the conditions of the casing such as corrosion and inner diameter.

If there is cement behind the casing, impedance will be higher compared to if no cement. Gas has relatively low impedance, cement relatively high and fluids will be in the middle. The ultrasonic tool will create an image that will represent the distribution of materials present behind the casing wall. This image does not require the same amount of interpretation

skill as the CBL log; it is much like a picture of the casing surface where each color will represent a material. Quality control of the ultrasonic log is assured by transit time in the same way as in the CBL log.

The ultrasonic log may have several logging tracks other than the acoustic impedance dependent on the logging service provider. Inner diameter of the casing, thickness and condition of the inner surface can be some of them.

Segmented impedance curves will indicate impedance relative to the high and the low side of the hole. Fig. 5.16 shows how the pipe is divided into nine segments each with respective letters assigned from A to I. Fig. 5.17 shows how measurements in segmented impedance log can be used to evaluate the material behind each segment of the casing. This is beneficial in deviated holes, as cement may have been unevenly distributed.

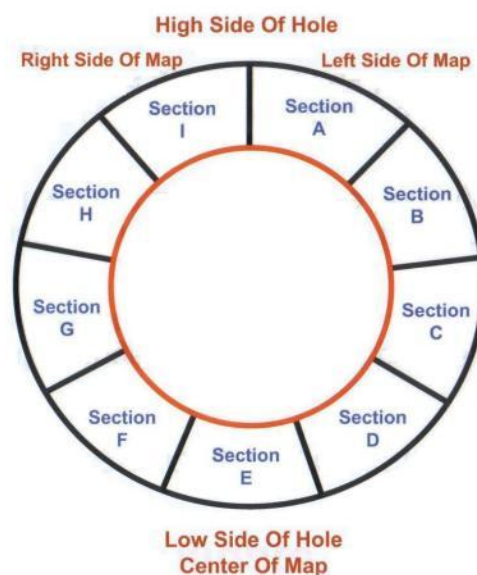


Figure 5.16 – Segments of the pipe in a segmented impedance log [44].

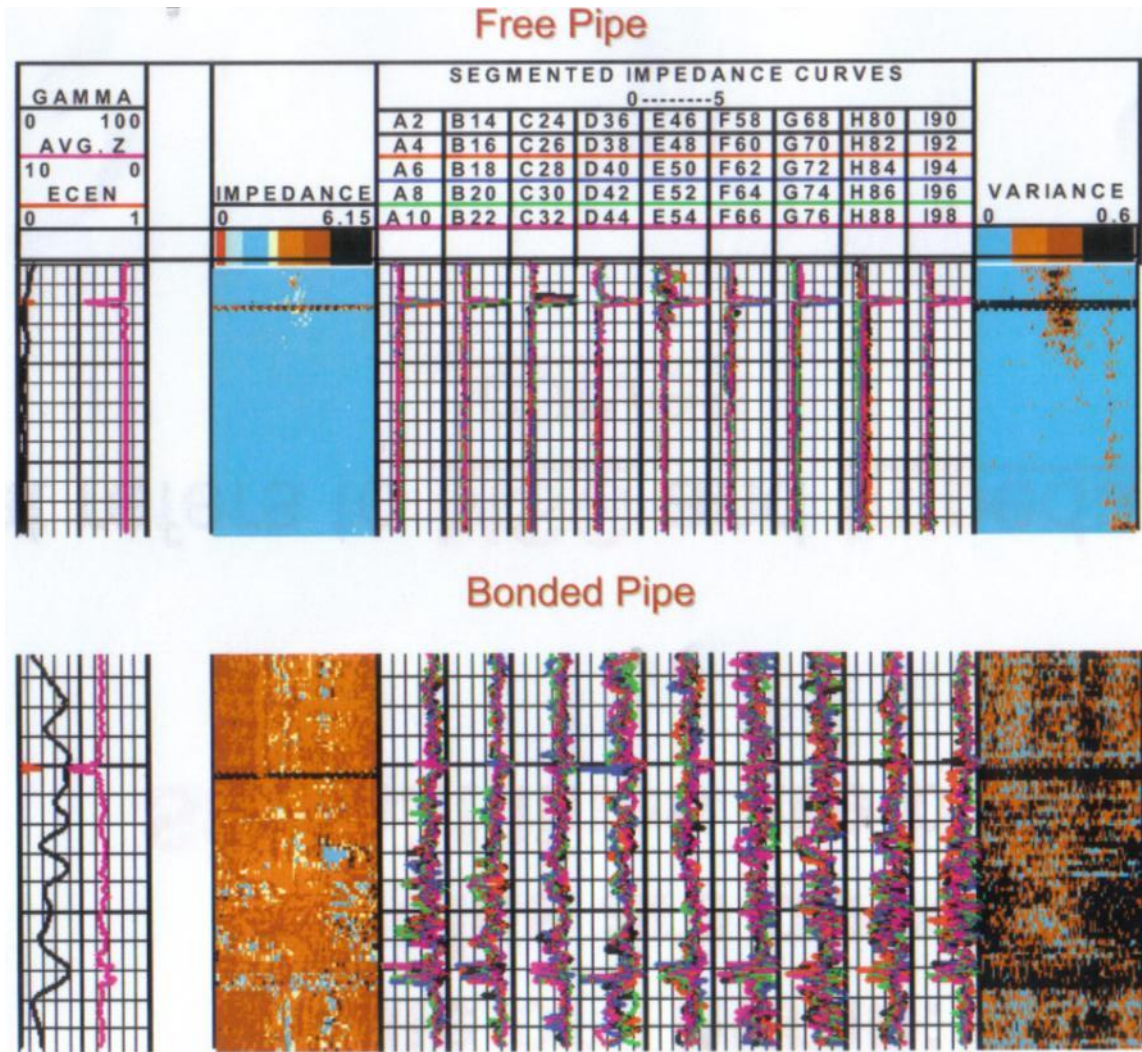


Figure 5.17 – Example of a segmented impedance log [44].

An ultrasonic log is a complete evaluation of the casing condition, but unlike the CBL, the ultrasonic log does not provide any information about the cement formation interface. Hence, it is useful to use both CBL and ultrasonic logs for cement evaluation. Fig. 5.18 shows a log example of an evaluation of a good cement barrier in the annulus where the log

includes both CBL tracks and impedance images. Dark colors on the impedance images and low amplitudes on the CBL track indicates cement, while light colors on the impedance map and high amplitudes on the CBL track indicates free pipe. A logging interval that indicates free pipe is illustrated in Fig. 5.19.

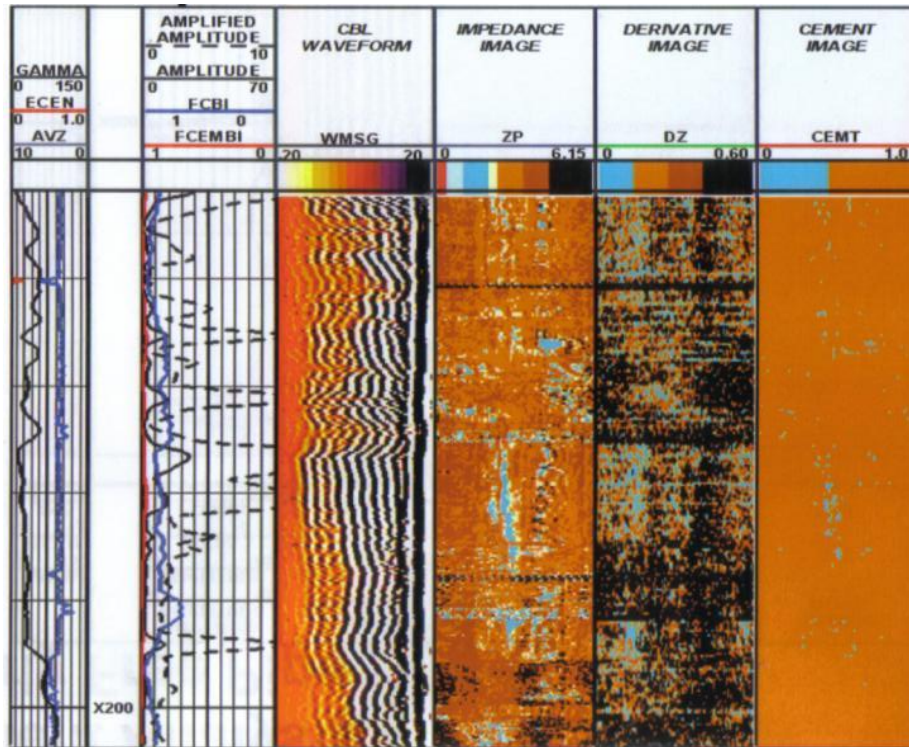


Figure 5.18 - An example of cement evaluation done with an ultrasonic logging tool. This log indicates well cemented pipe [44].

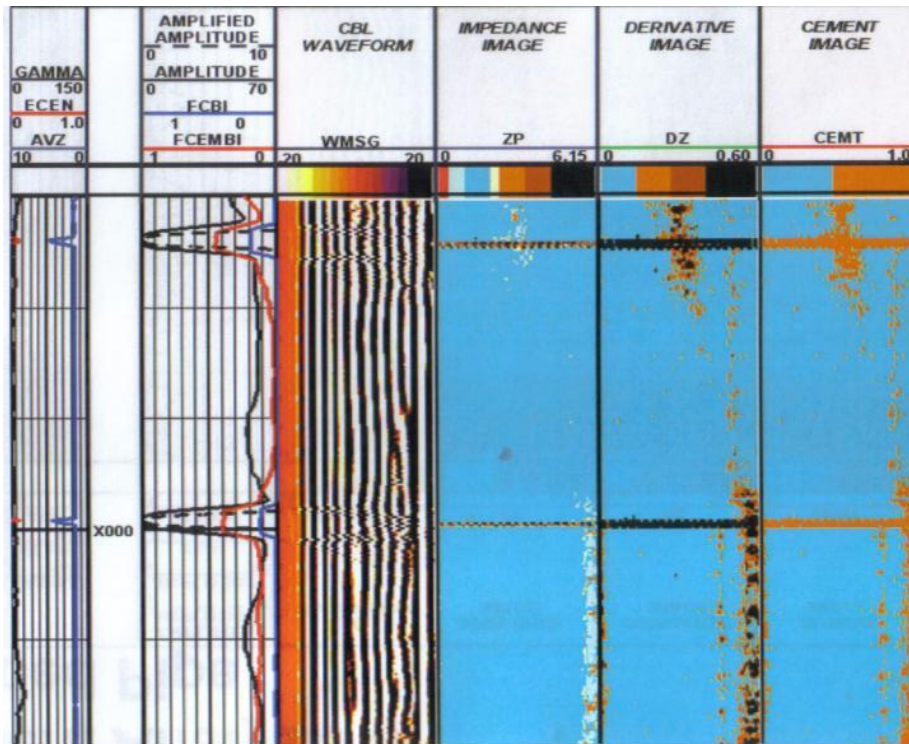


Figure 5.19 – An example of cement evaluation done with an ultrasonic logging tool. This log indicates free pipe [44].

5.2.4 Evaluation of Shale as Annulus Barrier

If there is a potential formation layer of swelling shale in the well, the formation may be used as an annular barrier [20]. The requirements of a potential interval of reactive shale are presented in Chap. 3.2.3. If the alternative is barrier setting after section milling as described in Chap. 7.3.2, significant time and effort can be saved if there already is a barrier in place in the annular space of the wellbore. Reactive shale can cause problems during the section milling as well.

Fig. 5.20 illustrates a potential formation annulus barrier. The formation barrier has to be at convenient depths and must be verified through a pressure test and bond logging in order to function as a barrier. The annular barrier will seal in combination with the casing string and a plug inside the casing string. This chapter will suggest a methodology how a potential formation barrier can be verified.

Williams et al (2009) [20] suggested that the interval should be logged with a CBL and ultrasonic logging tools in order to verify the sealing ability of the formation strata. Changes in steering documentation were proposed, which included logging guidelines for verification. For interpretation of responses of a good barrier it was suggested that 80% of the interval should have low CBL amplitude, the contrasts on the VDL should be low and indicate clear formation arrival and the ultrasonic impedance should be high in all radial sections A through I, as illustrated in Fig. 5.16.

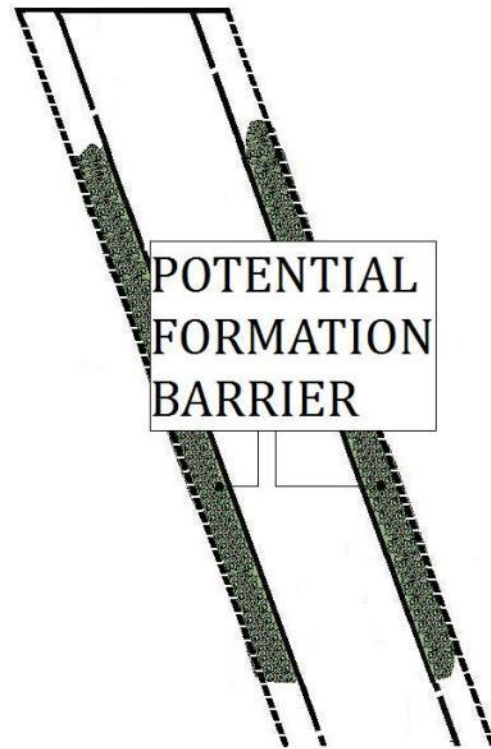


Figure 5.20 - Formation as a potential annular abandonment barrier

If the logs indicate a geological formation with good bond, a pressure test can be conducted to verify that the shale is strong enough to function as a permanent abandonment barrier. The test should be done even if the original leak off test data from drilling indicates that the formation rock is strong enough to handle reservoir pressure. In order to do a pressure test of an annulus barrier, access has to be made to the casing formation annulus. This can be done by perforating the casing string above and below the potential interval of shale. Perforation guns can be deployed on wireline, coiled tubing or drillpipe. A workstring can be lowered into the well and a temporary packer can be set above the lower perforation as illustrated in Fig. 5.21. Pressure can be applied and casing annulus can be monitored at surface.

Pressure increase in the casing annulus will indicate that the barrier is not sealing. A leak of test should be conducted in order to test the strength of the shale layer. A leak of test means that the pump pressure will be increased until a small pressure decrease indicating a formation leak off is seen on the surface.

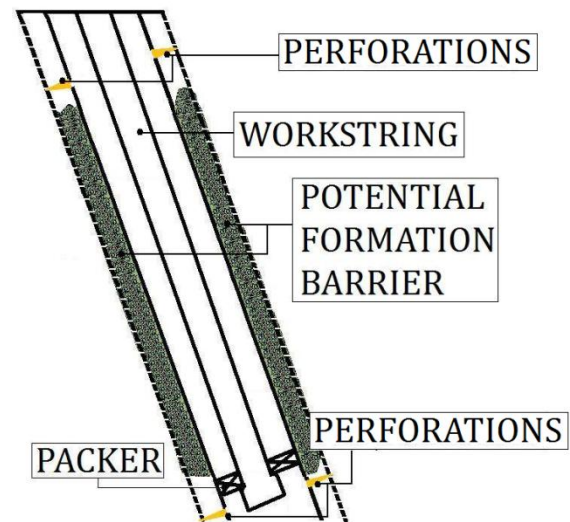


Figure 5.21 – Pressure testing a potential formation barrier

6 BULLHEADING PLUGGING MATERIAL FOR RESERVOIR ISOLATION

Reservoir isolation through bullheading wells can be the first step of the plugging operation. If well diagnostics indicates sufficient tubing integrity, it will not require removal of any tubulars for setting primary reservoir barrier. The operation can be conducted with a wireline rig-up such as the one described in Chap. 4.1 and is often done immediately after well diagnostics. Setting the primary barrier rigless reduces the cost of the operation considerably compared to deploying a drilling rig. In order to comply with NORSOK D-010 section 9, a secondary reservoir barrier must be set. This will be described in Chap. 7 and 8.

Bullheading is the pumping operation where fluids are forced down the well overcoming the reservoir pressure. The following chapter will describe and discuss bullheading of cement. Other plugging materials than cement can be used, such as epoxy resins or sand slurry described in Chap. 3.2. This thesis will focus on cement as barrier material, but most of the design principles can be applied for other materials such as epoxy resins as well.

6.1 CONSIDERATIONS WHEN DESIGNING THE BARRIER MATERIAL

The properties of any barrier material used for reservoir isolation should be tailored to give clear responses on the surface through the pump pressure. For example, if the barrier material is displaced through a restriction in the tubing it should give a noticeable increase in pumping pressure. If the viscosity is kept high, the pump pressure may indicate events downhole such as passing restrictions or small leaks while displacing. The barrier material is

exposed to high temperatures downhole, and if no stabilizing additives are added it will alter the rheology of the material and then no pressure variations may be seen.

Correct estimation of the downhole temperature is crucial for the design of barrier material used for any permanent abandonment barrier. If cement is used as plugging material, cement retarders are used to control the setting time. The estimation of temperature is assessed during well diagnostics.

Cement used for reservoir squeeze jobs has a high fluid loss rate. When the cement has reached its destination at the perforated interval a high fluid loss rate is favorable to ensure a proper squeeze.

The well completion will affect the plugging operation, sand screens or gravel packs may not be ideal for the reservoir squeeze. If the well is completed by a gravel pack, extra fine cement has to be used in order to isolate the gravel packed hole.

A good estimation of the volume is crucial when bullheading the plugging material. For volume calculation, the well volume is divided into parts like simplistically illustrated in Fig. 6.1. In this case the well is divided into the upper tubing volume A , lower tubing volume B , liner volume down to lower perforation C and excess volume D . The volume of plugging material will be equal to $B+C+D$, while the total displacement volume, including spacer, will equivalent to volume A . While pumping, a pump schedule with exact number of barrels pumped is used to monitor depth of the cement. The excess volume is necessary for cement squeeze

and also to fill voids behind the liner at perforated reservoir interval. If the well has been acid stimulated, there might be wormholes or cavity behind the liner at this interval.

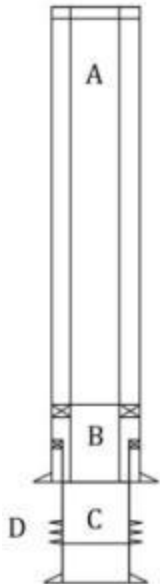


Figure 6.1 – Examples of how the well can be divided into smaller parts during volume calculations.

6.2 BULLHEADING CEMENT

The following chapter will describe how cement is bullheaded down the well for reservoir isolation. After the necessary well diagnostics, volume calculations and displacement simulations are done, the cement can be pumped to isolate the reservoir. Correct assessment of the reservoir pressure and pump rate will increase the chance for a successful reservoir squeeze operation.

The tubing should be as clean as possible before cement is pumped through it. If the well has been producing there will be a thin layer of oil covering the inner tubing wall. Since the cement slurry is water-based, the inner tubing wall must be water-

wet in order to achieve bonding when cement sets. Pumping cement through oil-wet surfaces will also cause problems such as incompatibilities between fluids, contamination and microannulus. Sufficient amount of surfactants in a spacer will remove the oil film. It is common industry practice to use 10 minutes of contact time for cleaning the inner surfaces of a tubular. This means that if the pump rate is e.g 6 bpm, 60 barrels of a wash fluid is necessary to expose each point of the inner tubing wall for 10 minutes. This rule of thumb is used whenever cement is pumped through tubing or pipe.

The pumping sequence for a well filled with seawater is as follows: Spacer is pumped ahead of the cement, then fresh water, then the cement, then fresh water behind the cement. After the fresh water, displacement fluid will be pumped to displace the fluid “train” down the tubing to the targeted depth. The pumping sequence is illustrated in Fig. 6.2.

The spacer ahead of the cement is a seawater pill containing surfactants for cleaning. Fresh water will prevent the cement from mixing with seawater in front or displacement fluid behind. The interfaces between fluids will usually contain a certain length of mixed fluids, and it is important there is enough fresh water to prevent cement from mixing with the other fluids. Seawater will dehydrate the cement and thereby reduce the cement thickening time.

A relatively high pump rate is necessary to avoid that the cement is moving faster than the displacement fluid. Too low pump rate may in addition prevent the cement from covering the whole cross section of the tubing while pumping or cause the cement

to get deteriorated by contamination while pumping.

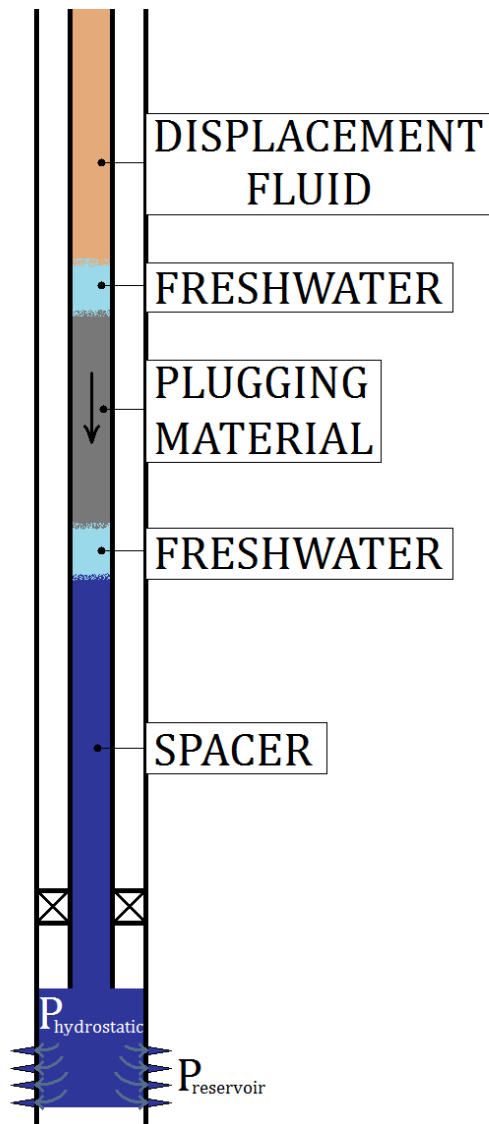


Figure 6.2 – Pumping sequence when bullheading barrier material.

Often seawater is used as displacement fluid, however if the well has low reservoir pressure, seawater cannot be used as displacement fluid. The reason for this is as follows. If the reservoir pressure is low, there will be less resistance when bullheading liquids into the reservoir. The hydrostatic pressure of cement plus seawater can tend to be higher than the reservoir pressure in depleted wells. Then the well will go on vacuum and the cement

will free-fall down the tubing. No pump pressure is seen at surface, and there is no control of what depth the cement actually is. To avoid this, a lighter displacement fluid such as base oil is required for displacing the cement down the well. Increasing amounts of pumped base oil will cause a decreasing hydrostatic pressure at the bottom of the well. The fluid column will consist of more and more displacement fluid as seawater is bullheaded into the reservoir ahead of the cement. Problem with low reservoir pressures are quite common in depleted wells, and will be further discussed in the next chapter.

If there are severe restrictions in the well it may be impossible to verify the top of the cement plug after placement. This will be a problem if no wireline toolstring can pass the restriction. In these cases it is important to have a pump schedule based on correct volume calculations – if the correct amount of displacement fluid is pumped; the cement will be displaced to the targeted depth. Pressure monitoring the tubing annulus (a-annulus) will indicate when the cement passes the tubing restriction. However, when working on a well with a tubing restriction and the well remains on vacuum and thus no tubing pressure is seen, the plug can neither be verified by the pump schedule or by tagging. The Petroleum Safety Authority will require operators to properly document the plugging operation, and will not approve plugging operations to set a plug that cannot be verified. Then the primary reservoir barrier should be set with coiled tubing or with a drilling rig.

If the reservoir pressure is higher than expected, a higher pump pressure is

necessary for displacing the cement down through the tubing. However, the pump pressure must not exceed the rated burst pressure of the tubing which is determined by methods described in Chap. 5.1.5.

The graphs in Fig. 6.3 refer to a-annulus pressure, accumulated pump volume, pump rate and tubing pressure. Following the red curve, it is clear that in this case the reservoir responds almost immediately and the displacement down the tubing is under control. The tubing pressure is generally increasing after reservoir response to maintain a constant pump rate. Event number 5 clearly indicates that the cement passes the restriction through decrease in a-annulus pressure. When the cement is

close to the bottom perforation, the pump rate is reduced for a smoother deceleration and this will lower the well pressure.

When the cement reaches the targeted depth production interval, it will be squeezed into the formation by shutting in the well. While the pressure is held the cement is dehydrating into the formation, which means that it is losing the cement filtrate into the formation. No cement particles are entering the formation rock; that would have required extremely high permeability of the formation. While the cement is setting up, the well will be monitored for a sufficient time before testing. This time is called the Wait On Cement (WOC) time.

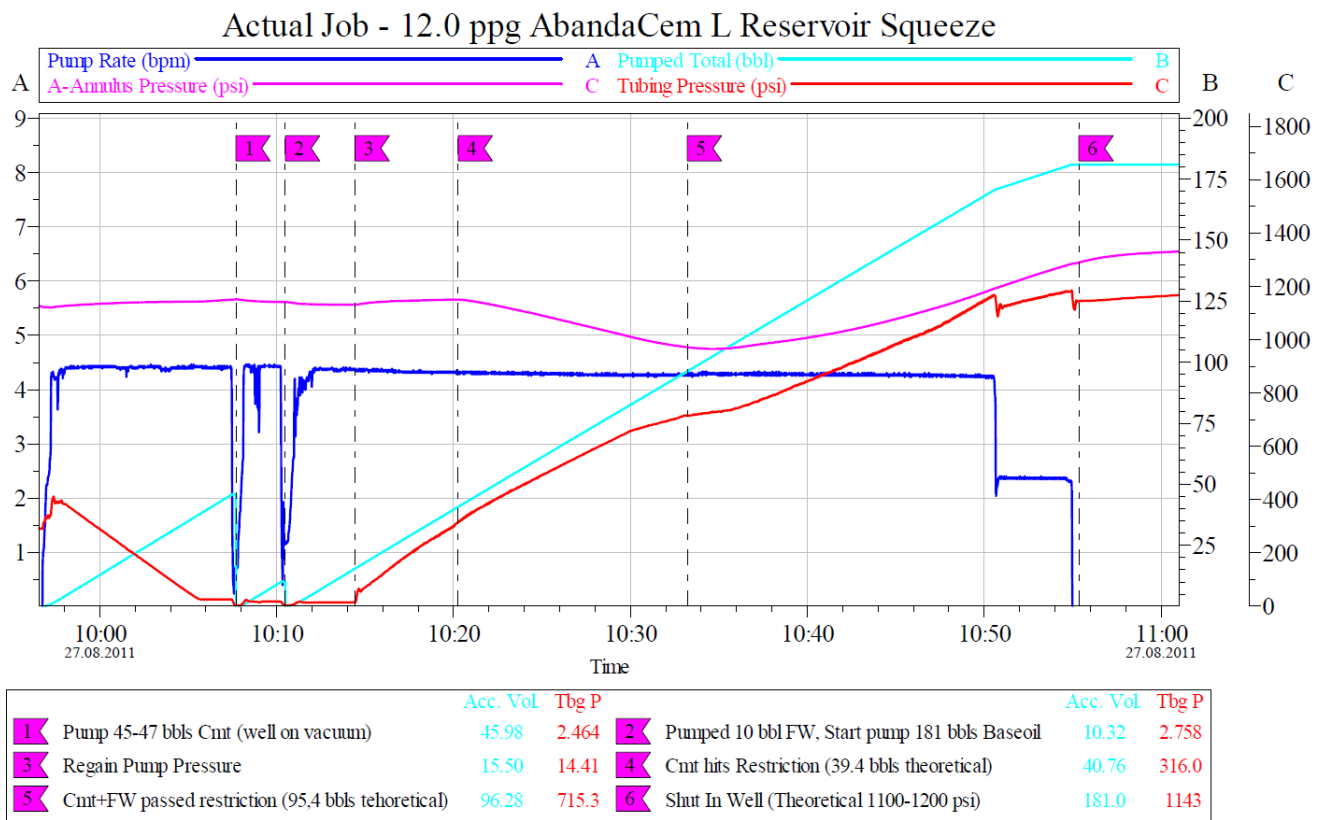


Figure 6.3 – Pumping cement down the tubing.

During WOC time the fluid in the well will be heated up and the pressure will rise. There are two sources of heat, the exothermic reaction of the cement setting and the formation itself. The pressure will be bled down kept within a pre-determined limit. Monitoring the well during WOC time is illustrated in Fig. 6.4. The downwards trends represents the pressure being bled of at surface. The graph in Fig. 6.4 clearly shows when the cement starts to set up. This is when tubing pressure decreases and flattens.

When the well pressure stabilizes the cement plug can be tagged and later inflow and pressure tested. Tagging and testing is described in Chap. 2.3.3.

If the plug is tested too early, the increasing pressure from the temperature trends in the well can be misinterpreted as inflow. To be sure that the cement has set, nothing is done except bleed off pressure before a certain time after pumpstop, eg. 48 hours.

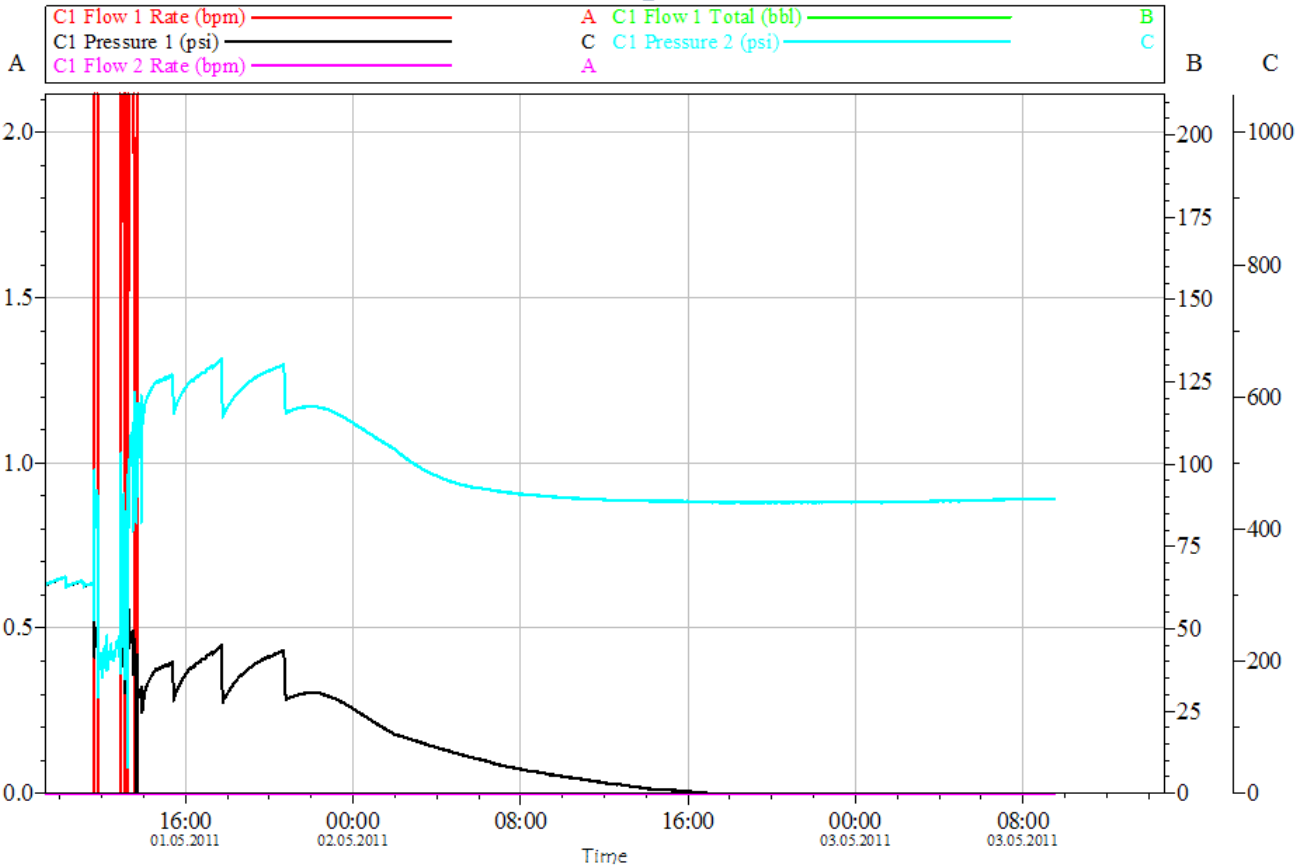


Figure 6.4 – Monitoring the well when the cement is setting up.

6.3 DISCUSSION

6.3.1 Low Reservoir Pressures

During abandonment of depleted production wells, low reservoir pressure will cause challenges when bullheading cement for isolation. This is because the cement is heavy, and might overcome the resistance against injectivity provided by the reservoir. In cases like this, the cement will free fall downwards like described in Chap. 6.2. This is a bigger problem in vertical wells than in horizontal wells. If the injection test indicates low reservoir pressure, there are different approaches for preventing the well to go on vacuum during bullheading. These approaches may include the following.

1. Decrease density of cement

Light weight cement which incorporates particles with lower density than the conventional cement is available. Light weight material may include gases to make foam cement, ceramic particles with high porosity or glass particles.

2. Alternative plugging materials

Epoxy resins can be used as plugging materials and properties such as density and viscosity can be tailored for each plugging operation. The density can be as low as 5.83 ppg (0.70 sg) [17].

3. Decrease density of displacement fluids or spacers

As already discussed in the previous chapter, base oil can be used as displacement fluid instead of seawater. Spacers can be substituted with foamed water or other light weight spacers which have significantly lower density.

4. Pump cement in smaller portions

By splitting up the cement in portions, there will be lower hydrostatic pressures when bullheading. It is however difficult to get achieve isolation because there is a risk for each cement portion to get deteriorated through contamination before final portion is pumped.

5. Use a viscous pill

A viscous pill may function as a “brake” when pumped ahead of cement by increasing the frictional pressure drop. However it would be difficult to avoid the viscous pill to mix with the cement which will lead to plug failure.

If none of these suggested solutions can for setting the primary reservoir barrier when the well has low reservoir pressure is to use coiled tubing or drilling rig.

6.3.2 Top of Cement Verification

Sufficient length of the plug is crucial to achieve long term isolation. The length of the plug is not the only crucial parameter which determines the capability of holding pressure; plugs with significantly shorter lengths can be able to hold pressure in the right conditions. However, a proper length of the plug will reduce risk of leakage. The NORSOK D-010 [7] guidelines section 15, table 24, states the following for plug length requirement. *“It shall extend 50 m MD above any source of inflow/leakage point.”* The measured depth (MD) length of 50 meters, or 165 feet of cement plug above the leakage point, which in this case is the upper perforation, will meet the NORSOK D-010 [7] requirement for permanent isolation. But is this enough to

isolate for eternal purposes? The following drawings and discussion will illustrate how a 165 feet plug may not be sufficient to isolate the reservoir. The drawings do not represent an actual well and are not in scale; they are only illustrative.

Fig. 6.5 shows the difference between measuring plug length in Measured Depth (MD) or True Vertical Depth (TVD). The two red length indicators are approximately the same length, but the right one is measured in MD and the left one is measured in TVD. Comparing these two plug lengths, the final TOC is considerably different. Now let us say that the red length indicator represents 165 feet (50 meter). Even if this may be to

exaggerate, it will illustrate how MD and TVD plug length measurements will be different and that method of length measurement can affect the capability of the plug.

Fig. 6.6 illustrates how a plug would be set if the length is measure in MD. In this case the measured depth from the upper perforation along the well path will not isolate the reservoir section in the long term. Because TOC is below the top of the reservoir, fluids can migrate through a failed cement sheath and a corroded casing string. Even if the cement sheath and casing string has good integrity at the time when the well is plugged, it cannot be guaranteed in the long term.

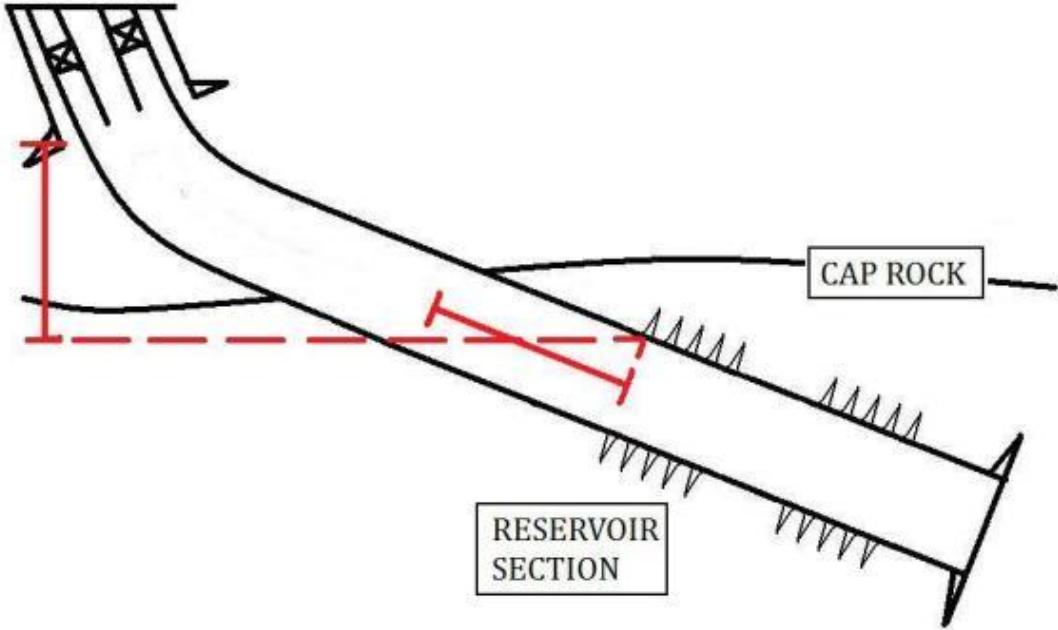


Figure 6.5 – Two possible methods of measuring plug length.

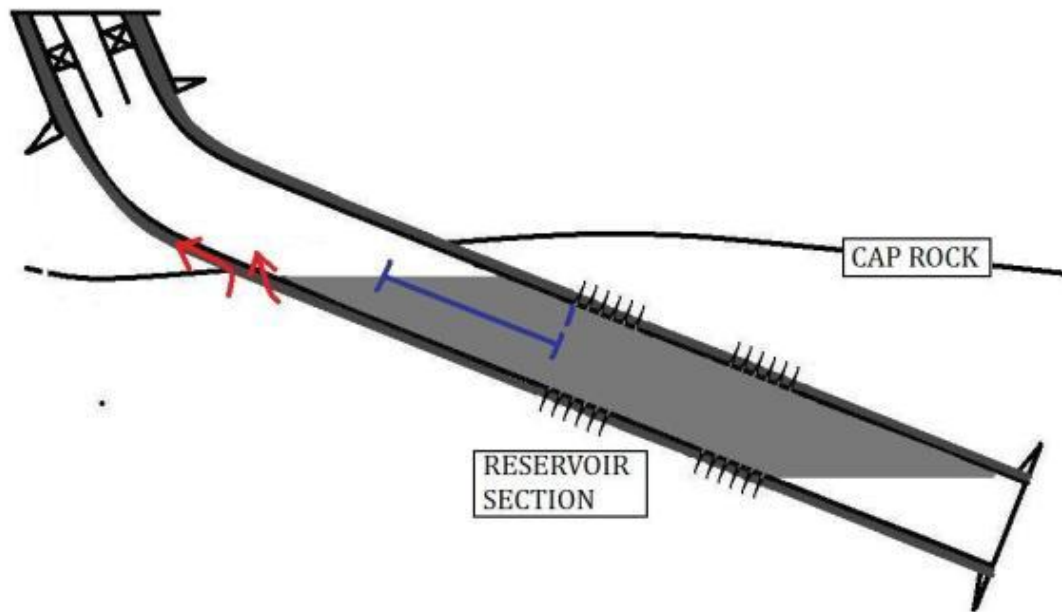


Figure 6.6 – Plug with length 165 feet MD over source of inflow.

As illustrated by the drawing in Fig. 6.7, planning a plug length that is 165 feet TVD will lower risk of leaks after abandonment. The well is better prepared for eternity but eternal reservoir isolation can still not be guaranteed. If the liner

cement fails to isolate, it will cause a migration path on the outside of the liner and the fluid can escape through a corroded casing string higher up in the well.

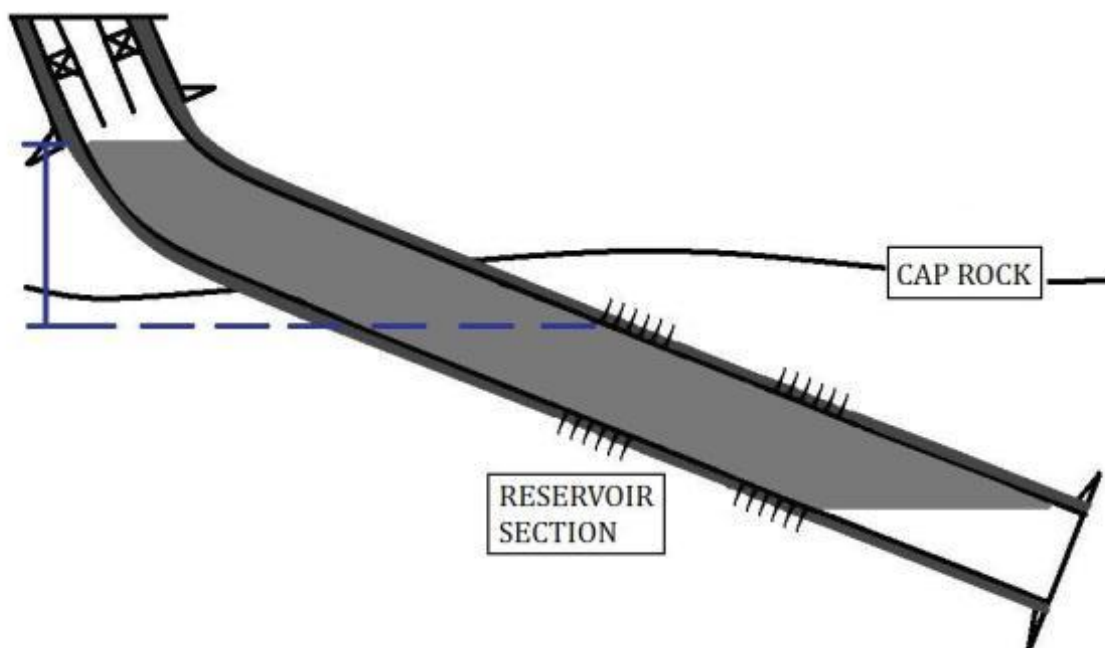


Figure 6.7 – Plug with length 165 feet TVD.

When planning for reservoir isolation plugs the original purpose of the operation must be considered. The reservoir was originally isolated by the cap rock before drilling. Drilling caused a puncture, the well, in the cap rock. Before abandonment, this puncture should be re-sealed to restore the natural integrity of the cap rock. There is no point of setting a plug below the cap rock, since the casing and the cement sheath outside the casing will probably leak at some point as illustrated in Fig. 6.6, regardless of current isolation. It would then be preferable to isolate the reservoir by pumping a capable barrier material up

to a required length from the bottom cap rock depth. This required plug length should be in TVD above bottom cap rock or top reservoir rock, like illustrated in Figure 6.8. A good rule of thumb in this case may be to use the production packer depth as preferred TOC. However, there is no point of restoring the isolation on the inside of the casing, when there is no annular seal. The red arrows in the drawing in Fig. 6.8 illustrate this. This is why the eternal prospect is important during well planning and drilling when planning the well and creating the annular isolation.

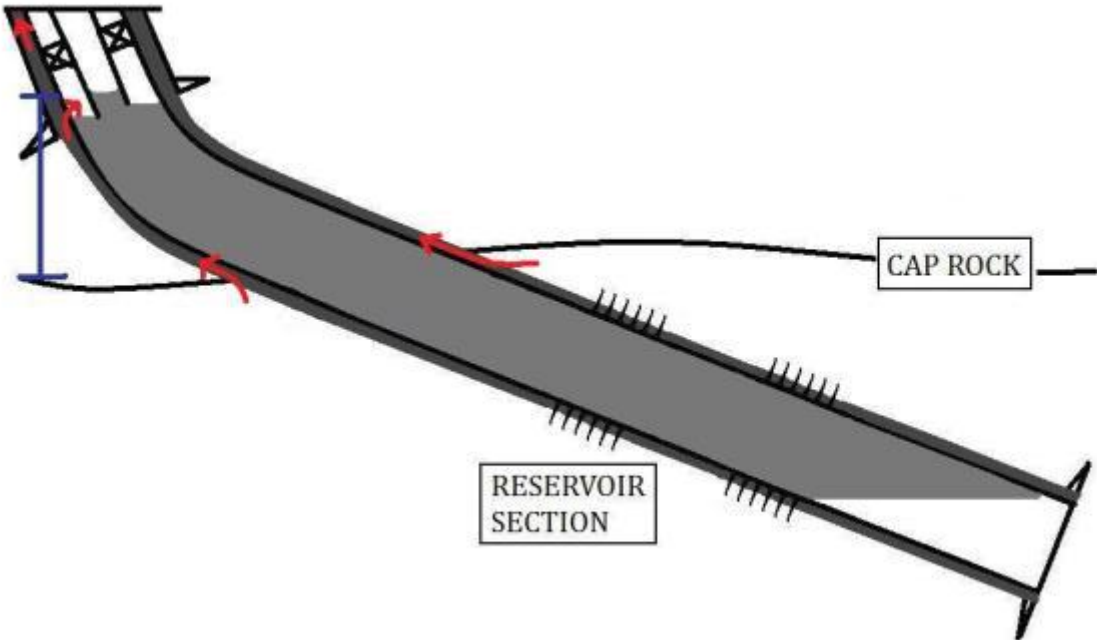


Figure 6.8 – Required plug length measured from cap rock with possible annular leak paths.

6.4 ADDITIONAL BULLHEADING OPERATIONS IN WELLS WITH INTEGRITY ISSUES

As mentioned in Chap. 2.2, Well integrity issues could often be the decisive factor for scheduling a well for plugging operations. The following section will give insight into how a failed barrier element can complicate the plugging operation.

A typical integrity issue is a casing leakage caused by geological activity such as fault activation, collapses or formation creep in the overburden. Formation stresses in the overburden can cause the casing wall to breach. This may cause sustained casing pressure at the x-mas tree resulting in compensating measures that may include shut-in of production. However, as mentioned in Chap. 5.1.4, well integrity issues will tend to deteriorate with time and a sense of urgency may exist to create competent abandonment barriers while it is still possible. Sustained casing pressure is a typical case leading to early stage plugging operations.

The plugging operation will start with the same diagnostic procedure described in Chap. 5.1, which will include assessing the depth of the casing leak with leak detection methods described in Chap. 5.1.9. It is assumed that a primary reservoir barrier is set, which has been described in Chap. 6.2.

After the primary reservoir barrier is set, further plugging operations may require rig operations. A drilling rig will require a drilling BOP to be deployed on the wellhead after the x-mas tree has been removed. The two-barrier principle must be applied in any well operation, but the integrity issues will in this case require the wireline rig-up to set an additional barrier before rig arrival.

An ideal well with both barriers intact is illustrated in Fig. 6.9. The primary barrier is marked in blue. The primary barrier envelope consists of the reservoir plug. The secondary barrier will consist of the casing cement, the casing string, the tubing hanger, and a wireline retrievable plug installed in the tubing hanger prior to tree removal.

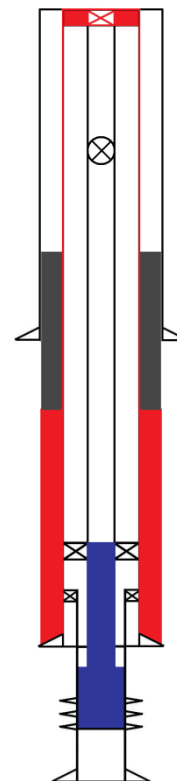


Figure 6.9 – Well barrier schematic when the primary abandonment barrier is set and the x-mas tree is temporarily removed for BOP installation.

If the well has a leak in the production casing the secondary barrier envelope is lost, since the production casing can no longer function as a barrier element. This is illustrated in Fig. 6.10.

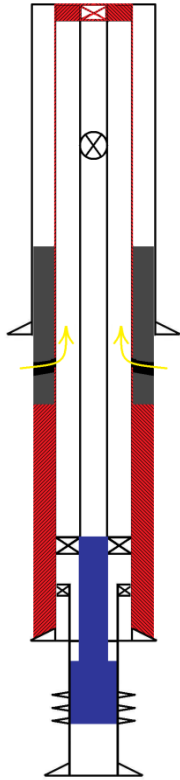


Figure 6.10 – Well barrier schematic when there is a leak in the production casing.

The loss of barriers will require additional wireline work to re-establish two barriers before the x-mas tree can be removed. Using the wireline rig-up kill weight fluid may be circulated into the well. As additional measures, perforations in the tubing can be done using a tubing puncher, a wireline retrievable bridge plug can be set and barrier material can be bullheaded into place in the annulus. This will secure the well before rig arrival. This is illustrated in Fig. 6.11. The barrier is called a temporary balanced set plug, because the level of barrier material has to be the same in the tubing as in the A- annulus while the barrier material is setting up. This barrier is challenging to set, as it has no plug base in the annulus, which may cause the plugging material to move downwards. A high viscosity and yield point of the plugging

material will be necessary to avoid high degrees of fluid mixing and downward movement.

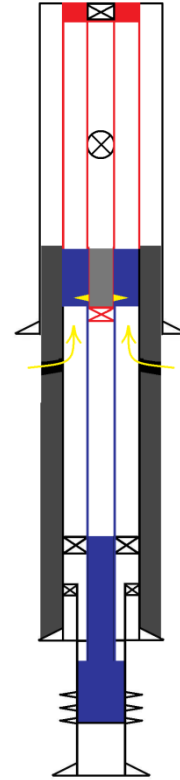


Figure 6.11 – Well barrier schematic when there is a leak in the production casing which has been temporarily fixed

After the additional barrier is set, the primary barrier envelope will consist of the reservoir plug, the tubing up to the recently installed barrier, and the recently installed temporary barrier. The secondary barrier will consist of the wireline retrievable bridge plug, the tubing and the tubing hanger.

Any additional unwanted communication between annuli will make it more difficult to ensure two barrier envelopes preceding BOP installation. Upon rig arrival, the x-mas tree can be removed, the drilling rig

BOP can be installed and further plugging operations can be conducted.

Previously installed temporary barriers will have to be removed prior to tubing retrieval. After the tubing is fished from

the hole, casing leaks must be considered when determining abandonment barrier setting depths.

7 BALANCED PLUG METHOD

The balanced plug method can ensure that a limited volume of cement may be set in the wellbore in order to create solid plug of cement that is not contaminated and is capable of holding pressures. This chapter will discuss placement technique, critical factors which should be considered and plugging applications for the balanced plug method.

7.1 PLACEMENT TECHNIQUE AND TOOLS

The cement will be pumped through the workstring using a spacer to prevent contact with other fluids. The spacer should be compatible with cement and any other fluids encountered in the well such as drilling fluids and formation fluids. The main purpose of the spacer is to efficiently displace any liquid encountered and clean the pipe when pumped ahead of the cement. The spacer contains surfactants that will wash the inner side of the workstring and prevent cement from settling inside the pipe or tubing. The washing requires sufficient contact time ahead of the cement, like described in Chap. 6.2. The contact time is also dependent on surfactant strength. The amount of tail spacer is determined by annular length of the lead spacer to obtain balance.

The principle of placing a balanced plug is as follows. Spacer is pumped followed by cement followed by spacer. The cement slurry will follow the spacer through a stinger and into the wellbore. When the level of cement slurry in the annulus reaches the same level as inside the stinger there is a balance between tubing and annulus fluid levels. The stinger will be pulled out with the correct pulling speed to

keep the fluid levels in balance. This is illustrated in Fig. 7.1. The key is to keep hydrostatic pressures inside and outside equal to avoid u-tubing and avoid too much mixing between the fluids.

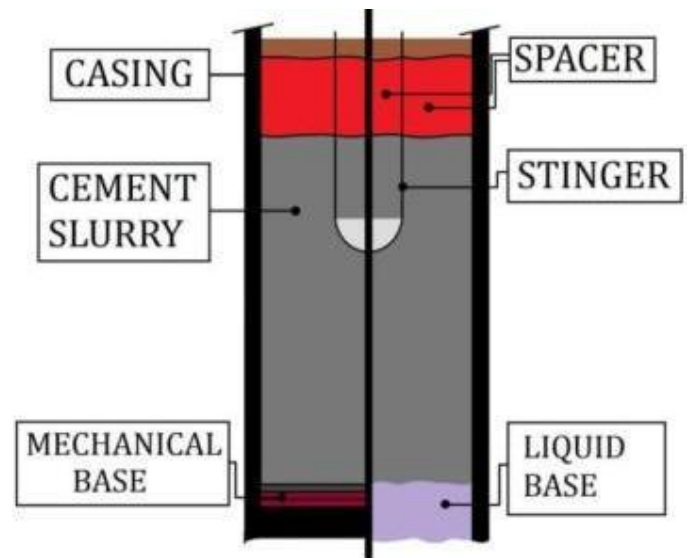


Figure 7.1 – Balanced Plug principle with mechanical or liquid base. (Not in scale.)

A stinger is a tubular with a smaller outer diameter than the remaining cementing assembly. A diverter can be used at the end of the stinger to obtain a stable boundary between the cement slurry and the fluid below and to optimize displacement [45] [46]. In a diverter tool the nozzles point in upwards direction like illustrated in Fig. 7.2. The diverter tool will create an upward axial flow pattern that will optimize sweep efficiency.

Centralizers are important, especially in deviated wells. It will be more difficult to keep the fluids in balance if the stinger is not centralized.

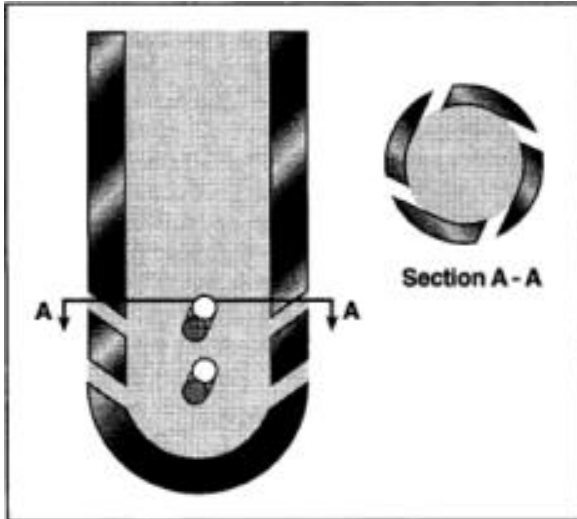


Figure 7.2 – Diverter Tool [47]. *Copyright 1994, Society of Petroleum Engineers Inc. Reproduced with permission of SPE. Further reproduction prohibited without permission.*

A mechanical plug base such as a bridge plug, inflatable packer or an Easy drill Safety Valve (EZSV) is commonly used to avoid that the cement moves downwards before setting up. An EZSV is illustrated in Fig. 7.3. An EZSV is a packer that can be used as a cement retainer in cased or open holes. Fluids can be pumped through it from above and it will hold pressure from below. It is held in place in the casing by anchors in form of slips.



Figure 7.3 – Easy Drill Safety Valve which can be used as a cement retainer (Courtesy of Halliburton.) [48].

A cement umbrella has the same purpose, to provide a base for cement placement [49] in cased holes. The cement umbrella is illustrated in Fig. 7.4. The benefit of this barrier is that it does not require extra tripping time because it is deployed as a part of the cementing assembly or pumped through the workstring. The cement umbrella cannot hold pressure like the EZSV.

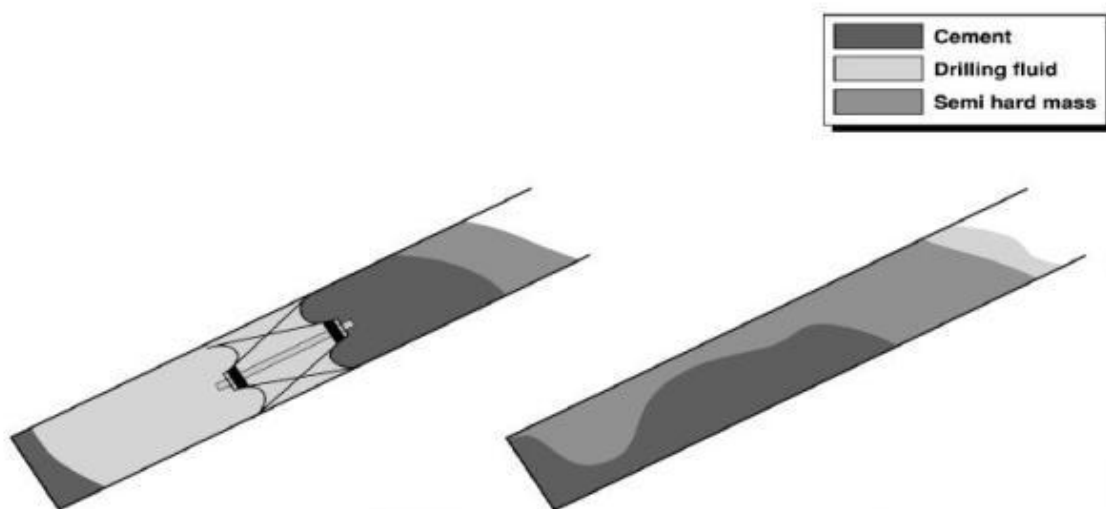


Figure 7.4 – A Cement Umbrella will prevent downward movement during cement placement [49]. Copyright 1997, Society of Petroleum Engineers Inc. Reproduced with permission of SPE. Further reproduction prohibited without permission.

Fig. 7.4 illustrates how contamination of the cement at top of the plug will result in a semi hard mass that will not hold pressure or have compressional strength. Without a mechanical base contamination may deteriorate the whole plug.

To determine successful placement the plug can be tagged and pressure tested. The tagging depth will give a good indication of the degree of mixing that occurred during placement. If the Top Of Cement (TOC) is suspiciously high, it can be assumed that the quality of the plug is low even if it passes the pressure test. The higher TOC will indicate mixing. A contaminated plug could have capability of isolating and holding weight, but most of the cement will not have the desired strength, isolating capability and maintain bond in the long term.

If the plug has been set above a pressure tested EZSV or similar pressure holding mechanical barriers, the plug does not have

to be pressure tested according to NORSOK D-010 rev3. The NORSOK D-010 table for cement plug requirements, including requirements for testing is included in Appendix C.

7.2 CRITICAL FACTORS DURING INSTALLATION

The most common critical factors when setting a balanced cement plug is avoiding contamination, slurry design which includes density contrasts and yield point progression, slurry volume, stability of any liquid base below and temperature estimation. This section will give insight into these critical factors and suggest measures to avoid failure by correct addressing the different challenges of setting a competent balanced plug.

Contamination of the cement slurry during placement can cause failure of setting a competent plug. Contamination is the

process of mixing the cement slurry with other fluids in the wellbore. Drilling mud, spacer, gas, brines and other formation fluids will cause contamination if mixed with cement slurry. The mixing process will change the chemical and physical properties of the cement slurry. The process cannot be reversed [50]. The most severe consequence is longer hydration time but it may cause the cement not to set or harden at all. Only ten percent contamination of the cement plug will lead to three to five times longer cement setting time [46]. Contamination will also decrease the compressive strength of the cement when set. Sensitivity for contamination is especially high when the cement volume is relatively low, which it is during plugging operations. The degree of fluid mixing cannot be assessed until the plug has been weight and pressure tested and will increase rig time significantly if remedial operations are needed. There are four different phases during placement where contamination may occur [51].

1. During flow through workstring
2. During flow up the annulus between workstring and casing
3. During pulling of stinger
4. During hydrating or during placement by fluid swapping at the base of the plug

Contamination during flow through workstring is a problem that is usually avoided by using a spacer or fresh water pill as a separator between cement and displacement fluid. In coiled tubing applications, fluid separators may not always prevent undesired degree of mixing. Then mechanical separators, such as darts or sponge balls can be used in addition.

Well properties such as pressure, temperature, inclination, wellbore geometry and the rheology of slurry and of fluids below and above will contribute to the mixing process. If the fluids are mixed before leaving the workstring there is a high probability of cement settling in pockets and not providing any hydraulic isolation. Especially in deeper wells it can be optimal to use a mechanical separator due to the longer traveling distance and higher temperatures.

To avoid contamination during flow up the annulus between workstring and casing, it is crucial to do a correct calculation of the displacement volume. An incorrect calculation will lead to under-displacement or over-displacement. This is illustrated in Fig. 7.5 and Fig. 7.6.

Overestimating or underestimating the displacement volume will consequently lead to imbalance between fluid levels inside and outside the stinger. The correct pulling speed will be determined by the pump rate and volumes displaced. Ideally the heights of spacer and cement in pipe and annulus are the same, but several operational factors will make it difficult to calculate the volume displaced by cement [16].

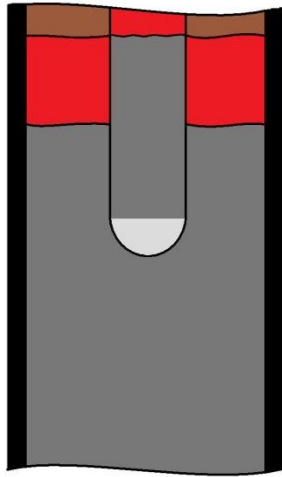


Figure 7.5 - Underdisplacement of cement during plug setting.

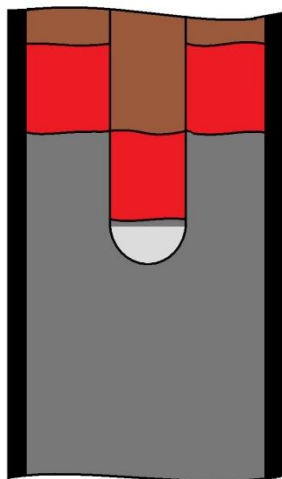


Figure 7.6 – Overdisplacement of cement during plug setting.

Primarily the stinger is smaller than the drillpipe and the flow area is not the same, making the cement flow faster through the stinger compared to the drillpipe. Secondly cement may set on the inner side of the tube during the operation or the abrasive cement slurry may cause erosion on the inner wall, creating small changes in inner tubing diameter, and consequently affecting flow capacity. Thirdly drilling fluids are compressible when exposed to

high pressures in the well and the actual volume pumped is impossible to monitor without knowing the exact pump efficiency. In other words, calculating the exact displacement volume is unrealistic.

Overdisplacement will place spacer or mud in the cement plug before it sets and thereby contaminate the plug. Hence it is common practice to underdisplace. As the stinger is pulled through the upper interface, the cement will be pushed out of the stinger at a higher rate to fill the volume occupied by the workstring as illustrated in Fig. 7.7.

Underdisplacement will create a mixing zone at the top of the plug. This zone containing excess cement and spacer is usually circulated out before the cement thickens. If the cement slurry has already developed a high yield point before the stinger is pulled, the top of competent plug may end up at a lower depth than anticipated.

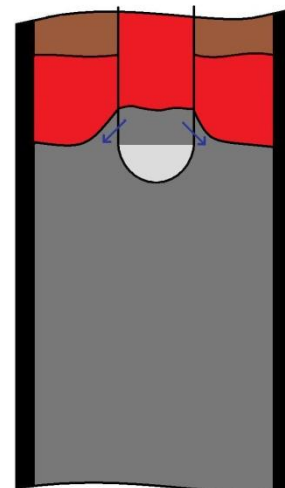


Figure 7.7 – Underdisplacement at the time the stinger leaves the top of the plug.

Yield point progression is one of the reasons for using a cement stinger instead of larger pipe; a smaller pipe will disrupt the interface less than a bigger pipe. To lower degree of mixing it will also help to pull the stinger out slowly. However, pulling out the stinger too slow will induce risk for getting the stinger stuck in the cement. If the conditions in the wellbore are challenging it may even be best to cut the stinger and leave it in the plug [52] [46].

The lower interface at the bottom of the plug is equally important. Not only is this interface a source of contamination, but the interface is also fundamental to prevent the cement slurry moving downwards in the well during placement and hydration if there is no mechanical base for the plug. Not having a mechanical barrier at the bottom will increase complexity of the operation and increase the risk of plug failure.

Because of large contrasts in density at least a fluid base is required to keep the bottom interface stable and to stop gravity from channeling the slurry downwards before hardening. This fluid will need to be placed below the planned cement plug bottom prior to cement placement. It has to have sufficient gel strength to support the gravitational forces which are acting when heavy cement is placed on top. A fluid with proper gel strength will create a barrier for the cement, even when there is large density contrasts.

Gel strength of the fluid below is not the only factor that is affecting this interface. Wellbore inclination, inner casing diameter and slurry design is crucial when placing a plug with no mechanical barrier underneath [53]. It is more difficult to

place cement plug in a deviated wellbore compared to a vertical or horizontal one. The particles in the cement slurry will have a tendency to settle at the lower side of the pipe and slide down, and the more buoyant cement upper layer of the cement slurry will move upward. This effect, called the Boycott effect, will accelerate itself, and create instability within the slurry [46]. It is also harder to keep a stable interface in a larger diameter casing than in a smaller diameter, because it requires higher gel strength to withstand the gravity forces from the heavy liquids above. Cement may penetrate the layer of gel below and move downwards.

When placing a cement plug, using the optimal cement slurry is a major critical factor. The cement slurry should have the right density, be thick enough, optimal yield point progression, have a high yield point, have a reasonable waiting-on-cement (WOC) time, be stable in well conditions and still be able to be pumped through the string and placed in the well. If placed in open holes, fluid loss must be addressed as well.

Correct amounts of water are added to tailor the optimum cement density during mixing. Stabilizers will be needed to keep the particles from settling by sustaining the viscosity. The concentration of retarders should be optimized according to temperature in the specific well. Too high retarder concentration will cause long WOC time and make it difficult to estimate when the cement has settled, or the cement may not set at all. The contrary will cause premature settling and consequently operational problems. The optimal concentration of retarders is dependent on the environment in which the plug shall be

set. Estimating the temperature of this environment is critical for success.

7.3 BALANCED PLUG

APPLICATIONS

This section will include different scenarios for which the balanced plug can be applicable for creating a barrier during plugging operations. The NORSOK D-010 rev3 requirements for a cement plug will depend on the application. Appendix C lists the requirements for a cement plug. The following applications include balanced plugs set with drillpipe or coiled tubing. If the plug is set with coiled tubing, considerations regarding cementing through coiled tubing should be made, which will be further discussed in Chap. 7.4.

7.3.1 Placement in Cemented Casing

One of the most common applications for the balanced plug is setting the plug in a cemented casing after the tubing has been removed. The balanced plug will then act as a primary or secondary reservoir barrier for abandonment, dependent on whether or not the primary barrier has already been set. Fig. 7.8 illustrates a case where the primary barrier has been set as described in Chap. 6 and the secondary barrier is set with the balanced plug method in the casing after tubing retrieval.

To optimize placement, a mechanical barrier such as an EZSV or a cement umbrella can be used as base. If an EZSV is set and pressure tested, no verification of the cement plug is required after placement.

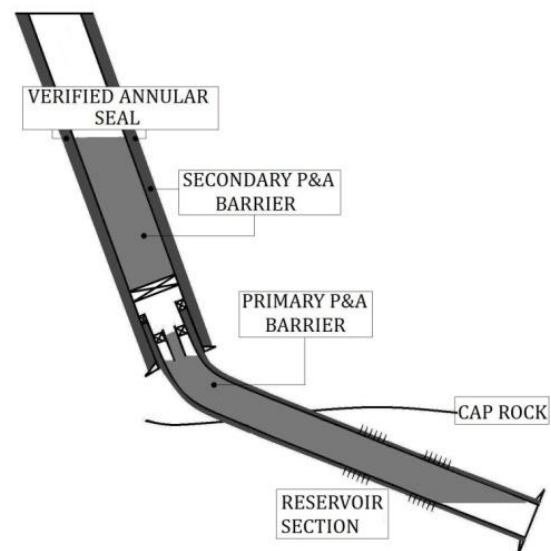


Figure 7.8 – Balanced plug in combination with a verified annular seal forms an abandonment barrier.

The annular seal should be logged prior to setting cement plugs in cemented casing. Logging, which is described in Chap. 5.2, can verify that there is annular isolation and find the top of the casing cement that the plug can be set below in order to create a cross sectional barrier. However logging is not required in the current revision of the NORSOK standard.

7.3.2 Placement in Open Hole after Section Milling

Another common application of the balanced plug is to set the plug in an open hole after a section of the casing is removed and the open hole is enlarged. This will create a solid cross sectional barrier which is anticipated to have good capability for isolation.

This is often referred to as a conventional plugging method, and is traditionally conducted if there are indications of no or poor annular sealing. The casing is removed through section milling after the production or injection tubing has been pulled. The principle of casing removal by

section milling is illustrated by the drawing in Fig. 7.9.

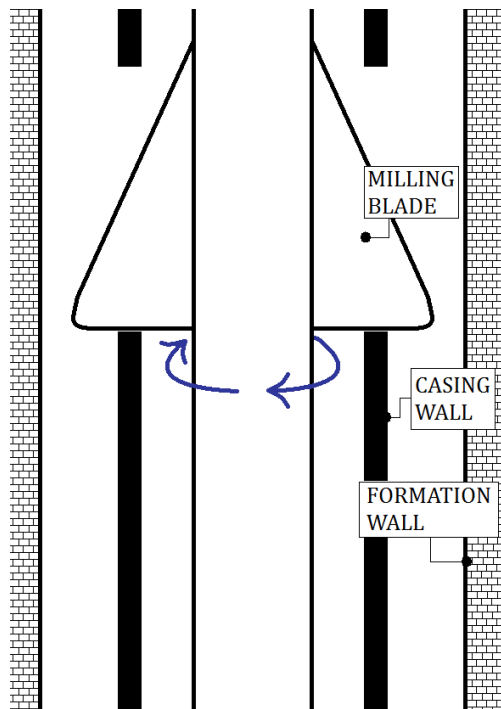


Figure 7.9 – Principle of section milling. Milling blades mounted on a milling assembly are rotated to mill away the casing.

Section milling is a complex operation for many reasons. The primary reason is that during section milling one will get in contact with the formation. This may cause operational challenges, for example if the pressure margin between fracture and pore pressure is narrow.

Suspended particles such as debris and metal cuttings will affect the pressure profile. Formation fracture will lead to fluid losses which will consequently affect removal of cuttings from the milling assembly. This may result in the milling assembly becoming stuck downhole or failure of milling assembly. Design of

milling fluids will require considerations regarding maximum circulation densities, fluid loss and sufficient viscosity to transport the metal cuttings. Fig. 7.10 illustrates a case where the casing metal has surrounded the milling assembly.



Figure 7.10 – “Skimmed casing” - Metal cuttings can cause failure of the milling assembly. [54] Copyright 2011, Society of Petroleum Engineers Inc. Reproduced with permission of SPE. Further reproduction prohibited without permission.

Another issue to be aware of is wear damage of the milling blades [55]. New and worn out milling blades are illustrated in Fig. 7.11. The mill blades typically consists of smaller shaped carbide inserts that are geometrically designed to expose new cutting edges when worn down during

the operation [56]. Often these blades are worn out before the required interval is removed, which will require pulling out of hole and installing new blades. This makes the operation time consuming, since tripping time may be as much as 10 hours.



Figure 7.11 – New and worn out milling blades. [57]

If the margin between fracture and pore pressure is sufficient, it will be possible to transport metal cuttings using loss free circulation densities. Section milling will remove any casing cement in addition to the casing. After casing removal, any debris and metal cuttings are removed from the wellbore and the open hole is enlarged through under reaming. This will make it possible to get in touch with new formation rock, which is good for the cement-formation bond. The balanced plug is set across the wellbore as illustrated in Fig. 7.12. The top of the plug is required by the NORSOK D-010 guideline to be placed above the open hole. This plugging method will be further discussed and compared with an alternative method in Chap. 8.3.5.

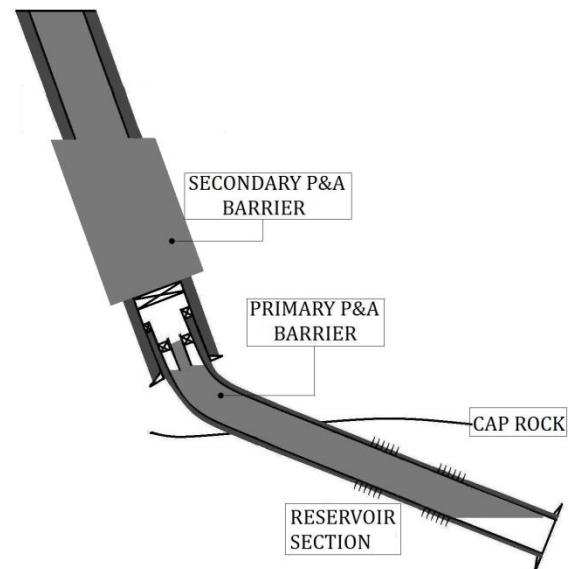


Figure 7.12 – A balanced plug set in open hole after section milling.

7.3.3 Placement in Combination with a Formation Barrier

If there is an interval of swelled shale in the annulus, this will have a potential to be used as a permanent abandonment barrier in combination with a balanced plug. The annular formation barrier should be logged and pressure tested like described in Chap. 5.2.4 prior to the plugging operation.

7.3.4 Placement in the Tubing

The following application is dependent on successful field trial of under development technology which will be further described in Chap. 9.1. Placement of a barrier without removing the production or injection tubing may be done rigless with wireline and coiled tubing.

For a well to be responsibly abandoned with the secondary barrier set inside the tubing the following requirements should apply.

- Good documentation and assurance of the long term isolation capability of the casing cement. The current cement log technology will not be

capable of logging as long as the tubing is in place.

- Excellent integrity of the tubing, minimal corrosion.
- Competent barriers must be set in the tubing annulus prior to balanced plug setting to achieve a cross sectional barrier. The barrier will consist of casing cement, casing string, annular barrier in tubing annulus and the balanced plug set in the tubing.
- The risk of any leak paths through annular barriers after abandonment must be addressed.
- NORSOK D-010 [7] requires removal of any control lines attached to the tubing. Control lines are used to provide hydraulic power for control of completion equipment such as valves or sliding sleeves installed downhole. Control lines introduce risk for leak paths, as the voids around them will be difficult to seal with high viscosity plugging materials.

Tubing removal is common practice in plugging operations in the North Sea today, as tubing removal is deemed to be the most responsible approach. However, if technology is developed and field tested and if considerations for rigless plug and abandonment are made during well

construction this approach could be feasible for plug and abandonment North Sea oil and gas fields.

The CannSeal tool is a wireline tool that incorporates a tubing puncher with a canister containing a barrier material. It is further described in Chap. 9.1. A suggested application of the CannSeal tool prior to balanced plug setting can be as follows. The primary barrier is assumed to be set as described in Chap. 6.2. The tubing can be perforated above the production packer with a tubing puncher. A tubing puncher is a perforation gun designed to perforate the tubing without damaging the casing. Circulation can be done with the wireline rig-up in order to achieve a clean tubing annulus. An extremely viscous sealant, such as epoxy resin contained in the canister within CannSeal tool, can be injected into the perforation from the tool to create an annular barrier at this depth. Then another barrier material, such as sand slurry, can be bullheaded down the annulus. The sand slurry will form an annular barrier with sufficient length and will use the epoxy resin as plug base. Then a balanced plug can be set using coiled tubing in inside the tubing, creating a cross sectional barrier. Considerations regarding cementing through coiled tubing should be addressed and will be further discussed in Chap. 7.4. The method is illustrated in Fig. 7.13.

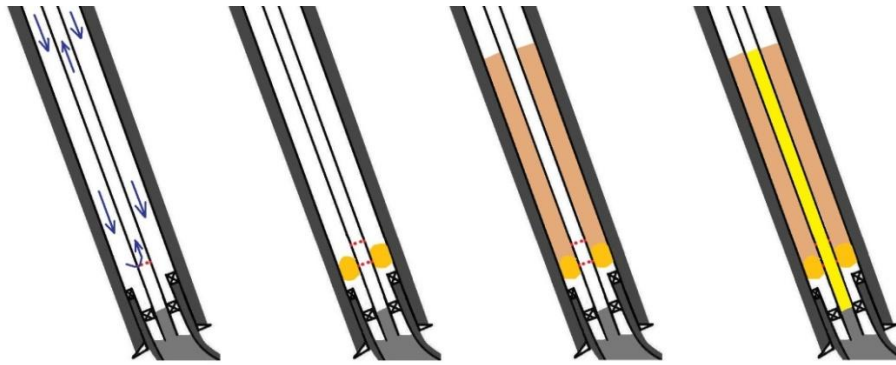


Figure 7.13 – Method for creating annular barriers and setting balanced plug in tubing.

7.3.5 Placement in Perforated Casing

The Perforate, wash and cement system incorporates a further developed balanced plug method which incorporates a cement placement tool when setting cross sectional plugs in a perforated interval of the casing. This will be further discussed in Chap. 8.

7.4 SETTING BALANCED PLUGS WITH COILED TUBING

This section will discuss some precautions that should be taken when setting a balanced plug with coiled tubing. The thin walls of the coiled tubing will cause some limitations. The following restrictions should be taken into consideration when cementing through coiled tubing [24] [58].

- Load cycles exerted on the steel may cause fatigue damage when the tubing is lowered into the well.
- Internal circulating pressures will have to be considered, and the pump rate must be kept below the tubing pressure rating at all times.
- Cement slurry is a viscous fluid that will cause high frictional pressure. Extra contributions to the frictional pressure like restrictions in the BHA should be avoided.
- When cementing with high density cement slurries, the hydrostatic

pressure of the cement should be taken into consideration. Tensional strength of the coiled tubing should be monitored with load cycles taken into account.

- Fluid mixing during cement displacement through the coiled tubing will happen, especially in long tubing strings with small inner diameter. Relative small volumes of cement are vulnerable for contamination. Cement quality can be ensured by the use of chemical barriers such as spacers or fresh water or mechanical barriers such as darts or sponge balls.
- The pump pressure cannot exceed pressure limitations, and this will limit the pump rate. Too low pump rate can cause the cement to free fall down the coiled tubing. Free falling must be kept under control.
- It is reported [58] that the mixing energy exerted on the cement during placement through the coiled tubing may affect the thickening time. This must be investigated and may be taken into considerations when designing cement.

8 PERFORATE, WASH AND CEMENT SYSTEM

In recent years innovative and cost efficient methods for plugging operations in wellbores with uncemented casing strings [54] have been developed. By applying the Perforate, Wash and Cement (PWC) system developed by HydraWell Intervention, casing removal can be avoided when setting abandonment barriers. The PWC system combines known industry technologies and novel technology in order to create cross sectional cement plugs.

The interval in which the plug will be set is perforated to access the annulus. Then the interval is washed with a jetting tool that incorporates swab cups to access all surfaces. The wash will prepare for plug setting. A cross sectional barrier will be set by forcing the cement out through the perforations into the formation wall by applying a mechanical pushing force to the cement. After the plug is set a squeeze pressure may be applied to further ensure a proper placement.

8.1 TOOLSTRING

The PWC system was originally developed for drill string deployment, but the system is in under development for coiled tubing deployment as well. Conversion of the toolstring to coiled tubing deployment will be discussed in Chap. 8.2.4.

All the assemblies that are needed through all parts of the operation can be included in the same BHA. The drawing in Fig. 8.1 illustrates the lower tool designed for drillpipe deployment. Starting at the lower end, the toolstring consists of a Tubing Conveyed Perforating (TCP) gun assembly that will drop after the gun has been fired.



Figure 8.1 – Lower toolstring for the Perforate, Wash and Cement system. (Courtesy of HydraWell Intervention.) [59]

This will require space below the plugging depth, a rat hole for dropping the gun assembly. The 200 feet (60 meter) long TCP gun assembly comprises two basic parts of equipment; a pressure activated firing head and hollow carrier which is loaded with explosives.

The jetting tool consists of swab cups with nozzles in between. The length of the pipe section between the swab cups is 12 inches (0,3 meters). Swab cups are temporary and movable packers that form a seal during the washing operation. They are usually applied for washing perforations during well completion. The outer diameter of the swab cups should be slightly larger to the inner diameter of the casing.

When the jetting tool is run into the well, fluids can bypass the swab cups through channels within the tool. This will make it possible to run the toolstring at higher tripping speeds to save valuable rig time. The swab cups will optimize the washing operation by isolating shorter lengths of the perforated intervals while moving upwards or downwards in the casing during washing. The isolated area will undergo flushing at high fluid velocities to clean inner casing surface, outer casing surface, annular space and formation wall.

The bottomhole assembly includes three different sizes of ball catchers, one for firing the guns, one for initiating the washing procedure and one for conversion to cement stinger. The ball size increases throughout the operation. After disconnecting the swab cups, they will act as a base for the cement plug. The jetting tool and the cement stinger combined comprise the HydraWash™ tool illustrated in Fig. 8.2.



Figure 8.2 – The HydraWash™ tool. (Courtesy of HydraWell Intervention.) [60]

The cement stinger will have similar functions to the stinger described in 7.1, but will additionally incorporate the HydraArchimedes™ tool, which is a cement placement tool. The HydraArchimedes™ tool looks similar to Archimedes’ screw and is designed to optimize cement plug placement [61]. The tool is illustrated in Fig. 8.3. Two rubber impellers are mounted on the stinger and are designed to mechanically push the cement through the perforations as the stinger is pulled by rotation of the string. The rubber impellers have the same diameter as the inner casing. The upper BHA of the PWC system including the HydraArchimedes™ tool is illustrated in Fig. 8.4.

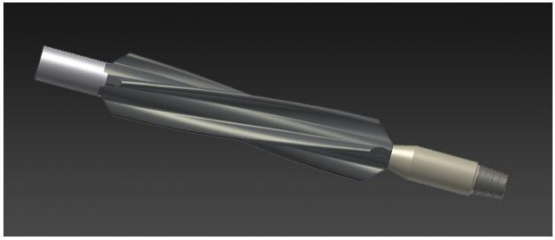


Figure 8.3 – The HydraArchimedes™ tool. (Courtesy of HydraWell Intervention.) [61]



Figure 8.4 – Perforate, Wash, Cement system with the HydraArchimedes™ tool included. (Courtesy of HydraWell Intervention.) [59]

8.2 PLACEMENT TECHNIQUE

In the planning phase before the plugging operation has started, the following has to be considered.

The casing annulus of the planned plugging interval must be evaluated. An Ultrasonic logging tool, which is described in Chap. 5.2.3 is run into the well. Formation strength is estimated from drilling data. Equivalent circulating densities (ECD) are simulated through all parts of the operation. Other well data that is required is such as lithology of the formation, casing specifications and which fluids that occupies the annular space at the plugging interval.

The well pressure must be contained prior to the operation. A verified primary reservoir abandonment barrier such as described in Chap. 6 can function as reservoir isolation. If no such barrier is in place the well has to be killed before entering.

8.2.1 Perforating

The perforations are done as follows. The toolstring including the TCP gun assembly is run in hole. The smallest ball is dropped from the surface. When the ball lands in the ball catching sub all the perforation shots over the 165 feet (50 meter) long interval will be made at the same time. After firing, the perforation assembly will automatically drop. There are 12 shots per feet of casing. The diameter of the perforations is designed to provide sufficient backpressure in order to wash efficiently and to control the ECD and fluid loss during washing and plug placement.

The formation can now be exposed to dynamic pressure and may fracture if total

circulating pressure exceeds the formation strength. To mitigate risk for fracturing, the perforation guns at the upper 7 feet (2.5 meters) of the TCP assembly are designed to perforate slightly larger orifices. This will decrease friction pressure at the beginning and the end of the wash sequence when only limited perforations are exposed to friction pressure between the swab cups. The lower perforations are designed larger as well, to optimize displacement when setting the balanced plug.

8.2.2 Washing

After perforation, the washing assembly is activated by dropping a larger ball. The ball will activate the washing assembly by shifting flow channels from the bypass mode used during tripping to circulation mode for washing. Most of the wash fluids will be directed through the following circulation path:

1. From surface through the workstring.
2. Through nozzles between the swab cups.
3. Through perforations into the annular space outside the casing.
4. Up the annular space.
5. Back into the casing through perforations.
6. To surface.

This is illustrated in Fig. 8.5

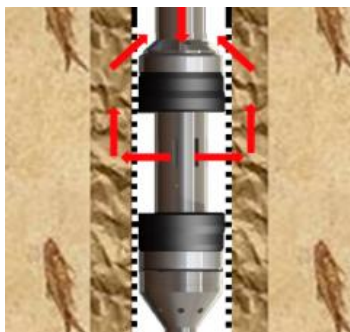


Figure 8.5 – Circulation during the wash sequence. [62]

The wash sequence is the heart of the PWC system. A successful washing operation will remove any fluids or debris that can cause problems during and after plug placement. If the annulus is filled with mud from drilling there could be substantial amounts of old cuttings, segregated weight additives (barite sag), or chunks of cement.

The PWC system can tolerate a certain amount of aged cement in the annulus, but the system is preferably applied to uncemented intervals. If the cement is not sealing because of a combination of cracks, crushed zones, mud channels and free water channels it may be possible to wash it.

Since the formation is exposed there will be fluid loss and risk of fracturing the formation. The fluid used for washing must be designed based on well data and experience.

The following is required from the wash fluid.

- Move any fluid or particle located in the annulus
- Maintain stability and suspending capability even if contaminated
- Flexibility if section milling is needed - conversion to milling fluid
- Compatibility with any fluids encountered during washing
- Easy separable after mixing with any encountered fluids
- Compatible with exposed formation, such as active clays
- Easily displaceable with spacer and cement
- Low fluid loss

A KCl Polymer has the preferred properties and has been used as wash fluid in the PWC system. The polymer contains 30-50 ppb of KCl, and meets the requirements for rheology and fluid loss rate.

To minimize fluid losses, there have to be some particles in the wash fluid. However, too much particles would bridge across perforations, and a thick filtercake of particles would increase risk of cement contamination during and after the plug is set. The added particles will increase the ECD during washing. To avoid formation fracture the particle size distribution can be used as input to simulate a frictional pressure drops. Debris and particles originated from the annular space will also contribute to the ECD. The strength of the formation rock, determined from leak off test during drilling, will dictate the maximum ECD. If the frictional pressure gets too high during the operation, there will be fluid losses to the formation. Fluid losses are closely monitored at surface and the pump rate can be lowered to keep the ECD below the leak off pressure.

The first run of the wash tool will be in downwards direction, starting with the upper larger perforations. In the beginning the pump pressure will be high and unstable because of blocked perforations, settled particles and greasy surfaces. The upper larger perforations will prevent the ECD becoming too high. When perforations begin to open, the pump pressure will decrease at surface. This is because the frictional pressure is dropping. When the pressure is stable and the frictional pressure has dropped to theoretical frictional pressure, it can be assumed that the section is clean, and the

washing assembly can be moved to new perforations. To mitigate the risk for unclean sections the washing assembly is run both downwards and upwards before completed.

The targeted running speed for the washing assembly is 1 feet/minute, however it will depend on what fluids and particles that is occupying the annular space and how fast stable pump rates is achieved during the operation. In the 37 [60] wells this system has been applied for, the washing time has varied from 12 to 48 hours [63].

The washing efficiency will be affected by eccentered casing strings. Ideally the casing string would be centralized in the wellbore, but in reality it will often tend to lay on the lower side in higher wellbore inclinations, like illustrated in Fig. 8.6. This will increase difficulties to obtain clean annular space after washing and the perforations sizes and pattern has to be designed for sufficient perforation backpressure to clean all radial sections of the annular space.

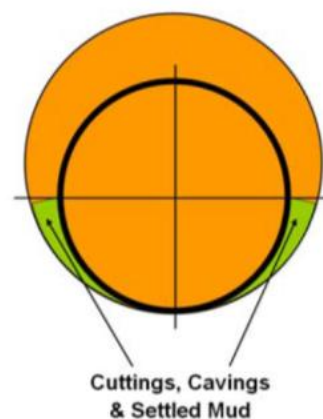


Figure 8.6 – Challenges with eccentered casing. [54] Copyright 2011, Society of Petroleum Engineers Inc. Reproduced with permission of SPE. Further reproduction prohibited without permission.

Except when running through the lower or the upper 7 feet of the perforated interval, the swab cups are designed for exposure to a section containing 12 perforations at the same time. 12 perforations will give a backpressure between 55 and 75 psi (3.8 and 5.2 bar). All perforations will be treated evenly when positioned between the swab cups. To calculate the friction pressure drop through a perforation, the following equation can be used [54].

$$\Delta P_{friction} = \frac{d_{wash\ fluid} \cdot Q^2}{12035 \cdot A^2 C_d^2} \quad (8.1)$$

The equation is also listed in Drilling Data Handbook [64], page G19, for metric units.

For example if there are 12 open perforations, which each has a diameter of 0.32 inches and

$$\begin{aligned} d_{wash} &= 14.5 \text{ ppg} \\ Q &= 210 \text{ gpm} \\ C_d &= 0,95 \end{aligned}$$

The total area of the perforations will then be

$$A = 12 \cdot \left(\frac{\pi}{4} \cdot 0.32^2 \right) = 0,9651 \text{ inches}^2 \quad (8.2)$$

Inserting the area A into equation 8.1, $\Delta P_{friction}$ can be calculated accordingly

$$\begin{aligned} \Delta P_{friction} &= \frac{d_{wash\ fluid} \cdot Q^2}{12035 \cdot A^2 C_d^2} \\ &= \frac{(14.5 \text{ ppg}) \cdot (210 \text{ gpm})^2}{12035 \cdot (0.9651 \text{ inches}^2)^2 \cdot 0.95^2} \\ &= 63,21 \text{ psi} \end{aligned}$$

8.2.3 Cementing

After washing for 12-48 hours, depending on pump pressure indications, spacer will be pumped into the wellbore prior to the cement job. The perforated interval will be

flushed and displaced with spacer in the same manner as with wash fluid during washing. The spacer must be able to water-wet all surfaces during the flush and completely fill the annular space and perforation channels. It is important that the spacer has the correct rheology and density in order to completely displace the wash fluid. At the same time it must be able to be displaced by the cement.

After the spacer is set the well volume above the plugging interval will be circulated with mud to clean out the rest of the cuttings from the washing sequence. The returns from circulating may give indications of how the clean the well us.

The plug interval is now fully displaced with spacer and the surfaces within the interval are water wet. Next, the workstring will be converted to a cement stinger in order to set a plug across the wellbore. The workstring is run past lower perforation. A last and largest ball is dropped, which will release the swab cups below the perforated interval. The swab cups will act as a base for the cement plug and the workstring is now converted to a stinger. Note that there have to be sufficient space below the perforated interval for both the TCP guns and the swab cups. The swab cups are capable of holding the weight of the fluids above.

The cement plug is placed using a further developed version of the balanced plug method described in Chap. 7.1. The cement will enter the annulus at the lower perforations and the displacement will continue upwards as illustrated in Fig. 8.7.

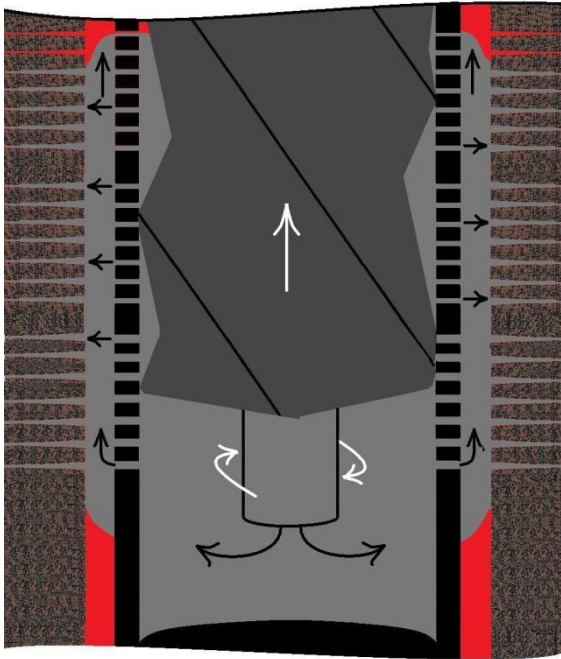


Figure 8.7 – Beginning of plug placement.

A relatively low pump rate will together with rotating the string ensure minimum fluid mixing and maximum displacement efficiency. The density contrast and higher yield point will cause the cement to displace the spacer within the entire wellbore, including perforation channels, while the cement-spacer interface is slowly moving upwards. The stinger will be pulled out of the plug in the same manner as when placing a balanced plug with the fluids in balance to prevent mixing at the top of the plug.

Contamination is still the main concern, and is even more difficult to prevent in this case compared to a conventional balanced plug described in Chap. 7. Since the spacer and cement systems are compatible and designed for this system, fluid mixing should not degrade capability of the plug as long as the mixing is below a certain level. Fluid mixing up to 45 % is acceptable concerning compressional

strength [54]. Hence, the main challenge is to prevent pockets containing unmixed spacer or mud.

After the stinger has left the plug and is located above the plug, the pressure for squeezing will be applied. This pressure is slightly above the leak off pressure but should not induce too large fractures in order to avoid large fluid losses. The pressure will be held for until the cement has developed sufficient compressional strength according to the UCA test. During the time at which the squeeze pressure is held, the slurry filtrate is squeezed into formation matrix and the cement particles will form an impermeable filtrate cake along wall of the perforation channels. This will cause the cement to dehydrate against the formation, forming an impermeable barrier across the wellbore. The stinger is kept in the same position while the cement is setting up and can be used for tagging after the cement has set. The plug will also require a pressure test as described in Chap. 2.3.3.

The main consideration when designing cement for this job is the thickening time. As long as the stinger has not left the plug, there is risk for the stinger getting stuck or the plug contaminated. High fluid loss is also important in order to hold a squeeze pressure. Rheology is important to achieve a good cement displacement, the yield point and viscosity of the cement will dictate how the interface between annular fluids and the cement will behave during placement. The cement must be stable and not segregate, even when contaminated in order to consistently seal the interval.

8.2.4 Coiled Tubing Deployment

The PWC system is under development for coiled tubing deployment. Setting

abandonment barriers with coiled tubing introduces several challenges, like described in Chap. 7.4. When deploying the PWC system for coiled tubing additional challenges will arise.

Like mentioned in Chap. 8.2 the PWC system requires that the well pressure is contained before entering. This is also required when using coiled tubing. The coiled tubing BHA, including the 60 meter long TCP guns will be difficult to run into a live well with regular coiled tubing surface pressure equipment. The lubricator length will not be sufficient for the TCP guns. If the reservoir section has been isolated like described in Chap. 6, the coiled tubing barrier envelope may be redefined and this has to be accepted by the PSA.

The rotation of the stinger when using the HydraArchimedes™ tool will require some extra considerations when deployed on coiled tubing, since no rotation from surface is possible. Rotation with coiled tubing is usually achieved with a hydraulic powered motor that will use the flow through the tubing as power source. Such a motor will not function with the PWC system. The motor will cause too high frictional pressure drops when pumping cement, and furthermore the motor cannot be turned off which will cause problems during washing. A possible solution could be to use an externally mounted turbine for rotation, similar to turbines usually applied for liner drilling.

Another issue one would have to deal with when deploying the system for coiled tubing is circulation of washed particles. In order to lift the encountered particles, there must be sufficient velocity in the annulus on the way up. This can be a problem if the

coil has a low outer diameter, casing has a large inner diameter and there are pump rate limitations. A possible solution to this could be to leave the debris downhole instead of lifting it to surface.

8.3 DISCUSSION

The PWC system has been verified post placement by drilling out the internal cement plug throughout the perforated interval and then re-logging with CBL and Ultrasonic logging tools. The rate of penetration during drilling and the logs indicated high quality cement across the PWC interval. However, there are challenges which must be addressed when using a PWC system and a discussion will follow.

8.3.1 Verification of Annular Space prior to Barrier Setting

The PWC system has certain preferences when deciding the interval for barrier setting. Wireline logging, which is described in Chap. 5.2.2 and 5.2.3 will be used to evaluate the annular space in order to determine a viable depth. The depth has to be below minimum calculated plugging depth like described in Chap. 2.3.2. In order to conduct an efficient washing operation it is preferred to set PWC plugs in an uncemented casing interval, and to avoid formation collapses and formation creep.

8.3.2 Efficiency of Washing

As mentioned the washing is the heart of the PWC system. But the capability of washing behind the casing is dependent on how accessible the annular space is. After perforating with the TCP guns there will be small sections within the plugging interval that is not perforated. This is because the TCP gun string has connections in between where no perforations can be done. The

space behind these sections must be efficiently washed as well, and this is difficult to assure before cement placement. Washing efficiency will depend proper monitoring of pump pressure and simulated and values for frictional pressure drops. The actual efficiency of the washing can be difficult to know for certain.

8.3.3 Spacer Displacement

As the plug is set, the spacer will be displaced by cement. If squeeze pressure is applied, the cement will dehydrate against the formation. If the Hydra Archimedes™ tool is incorporated the cement will be mechanically forced to displace the spacer. Proper design of the fluid system will include optimal rheology to ensure proper displacement and minimum fluid mixing. By pumping larger volumes of cement than necessary any mud pockets and contaminated cement will be displaced with capable uncontaminated cement.

8.3.4 Long Term Effects Regarding the Integrity of the Casing

Perforating of the casing will deteriorate the strength of the casing and this may make the casing more vulnerable when isolating hydrocarbons in the future. The permanent abandonment barrier comprises the casing, annular cement and the cement plug inside the casing. The cement will isolate and support the casing which will protect the casing from corrosion and stresses within the wellbore. The PWC system is designed to set a considerable amount of excess cement above the perforated interval. The height of cement is usually anticipated to be as high as 50 meters above the upper perforation [65]. This will further prevent fluids from entering the casing after plug placement.

8.3.4 Properties of the Cement after Contamination

After the cement has been mixed with spacer, the isolation capabilities of the cement will be affected. The long term isolating capabilities of the cement should be documented with shear strength, tensile strength and shrinkage taken into consideration. The cement slurry should be designed with the best possible cement additives to ensure long term isolation, including expanding agents to avoid bulk shrinkage and fibres to increase tensile strength.

8.3.5 Comparison with Balanced Plug set after Section Milling

The PWC system may be used as replacement for conventional secondary reservoir barrier involving section milling underreaming and open hole set balanced plugs. As mentioned in Chap. 7.3.2 the section milling operation can be time consuming and challenging if the formation fracture pressure is close to the pore pressure. The PWC system is not in the same extent dependent on the fracture pressure and the pore pressure, and will generally require less time for barrier setting. It will probably also be deployable on coiled tubing.

However, the cross sectional barrier is dependent on washing and displacing behind the casing wall, which may be difficult to achieve in some cases. It can be argued that setting barrier in an open hole is a less complex operation than setting the barrier in a perforated interval, and the open hole plug will have a higher probability to cover the whole wellbore cross section.

The possibility of verification should also be taken into consideration. The top of a

plug set after section milling could end up inside the cased hole or below, in the open hole. This is dependent on volume calculations, contamination during the plugging operation, and how long section of the casing that was removed. Regardless of the plug top depth, the plug has limited possibilities for verification. If the top of the plug ends up in the open hole, a pressure test could fracture the formation, and thus no pressure testing is done. If the top of the plug ends up in the cased hole, the plug will still not be verifiable. The pressure test will most probably only test the cement inside the casing and the strength of the actual cross sectional barrier will remain unknown. The quality of plugs set by the PWC system can be more easily assessed by drilling through it

and then logging the plugging interval with sonic tools. This will indicate cement coverage behind the casing and the quality of the cross sectional barrier could be assessed from log interpretation.

The system verification is based on drilling out the plugs of five wells which all indicated good coverage behind the casing wall. Some may argue that this verification of the system is not sufficient and thus a higher amount of plugs should be drilled out in order to get a rate of success based on a wider range of different conditions. Additional operational data will be available in the future, and if the high success rate is maintained, the PWC system would be the better alternative compared to balanced plugs set after section milling.

9 PLUGGING METHODS IN SECTIONS WITH POOR ANNULAR SEALING

The annular sealing will affect plugging operations. As discussed in Chap. 5.2, the casing cement set during well construction can fail to isolate if subjected to temperature cycling and or formation stresses through the life of the well. If the casing cement has failed and there is no uncemented casing at viable plugging depths, the conventional approach would be to remove a section of the casing string by section milling. This chapter will discuss other possibilities which will require less removal of tubulars when the annular sealing has failed to isolate.

9.1 ANNULAR ISOLATION TOOL

AGR CannSeal [66] developed a tool that has a wide application within creating annular barriers for abandonment purposes. Using an electrical operated wireline tool, a cross sectional abandonment barrier can be placed in between two casing strings with poor or no annular sealing, even without removing the tubing.

9.1.1 Tool Description

The idea behind the CannSeal™ tool is to get access to the annulus and isolate it in one run. The tool includes perforation guns, anchors and a canister filled with sealant that can be injected into the annulus for isolation. It is run on standard electric wireline which makes it possible to communicate with the operator during the operation. The sketch in Fig. 9.1 illustrates the principle design of the tool. The tool will be run in combination with a wireline tractor in high well inclinations and horizontal sections.

Starting at the top, the tool has a wireline connector similar to the rope socket described in Chap. 4.1, which will also transmit power to the control module. The

anchor will secure the tool in place while performing mechanical operations such as perforating, stroking and locking the injection pads in place prior to injection. The anchor and stoker is illustrated in Figure 9.2.

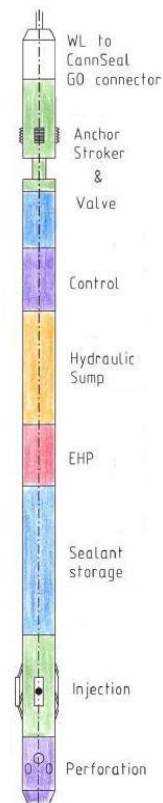


Figure 9.1 – Principle design sketch of the CannSeal™ Tool. [67]



Figure 9.2 – Anchor and stoker module incorporated in the CannSeal tool. [67]

The control module makes the tool able to communicate with the surface. The EHP module, which is powered by surface electric current, includes the drive mechanism that will be used when the sealant is injected. The sealant is forced out of the canister with the help of a piston moving downwards inside the canister. The sealant will then enter the annulus through the injection pads which is extracted against the perforated holes like illustrated in Fig. 9.3. There is rubber sealing elements around the injector head that will prevent sealant leakage in to the tubing when injecting sealant in to the annulus.



Figure 9.3 – Injection module incorporated in the CannSeal™ Tool. [67]

9.1.2 Applications

The CannSeal tool has several applications and can be used in combination with other placement methods. The combination between the CannSeal tool and a balanced plug has already been discussed in Chap. 7.3.4. This section will discuss the possibility to apply the CannSeal tool for recovery of a failed annular cement sheath.

The operation will require a toolstring that is deployable for the relevant casing inner diameter. By injecting a sealant with

extremely low viscosity, it may be possible to access any cracks or channels within the cement sheath, as illustrated in Fig. 9.4. Prior to injection, the annulus has to be accessed by perforating the casing string with the integrated perforation module. The perforations will create a damaged zone and may further deteriorate the cement sheath. This is used as an advantage because any cracks will provide better entrance for the injected sealant. Then sealant can be injected at high pressure. The sealant must be able to bond the any encountered surface such as cement surfaces and formation surfaces. It will also have to displace any fluid that is already occupying the channels or cracks, which could be challenging because of the low viscosity. The annular length which can be recovered is challenging to estimate. If this length is shorter than the required length of a cross sectional barrier, several injections can be made by injecting at additional depths. The annulus must be pressure tested at the relevant differential pressure to determine of the recovery was a success. Then a balanced plug can be set inside the casing to complete the creation the cross sectional abandonment barrier.

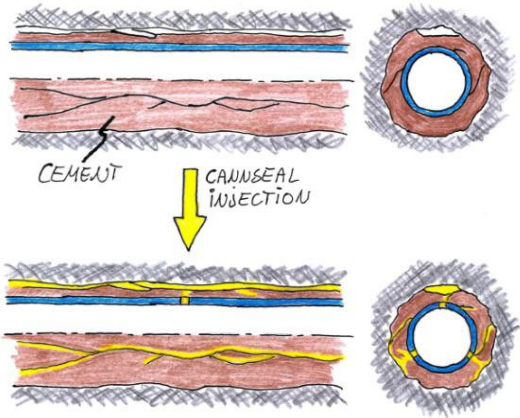


Figure 9.4 – Restore the casing cement integrity by sealant injection. [67]

The CannSeal tool also can be ideal for creating a temporary barrier discussed in Chap. 6.4. This would be a less complex operation than bullheading, because the CannSeal sealant injected from the tool can be tailored for this purpose by making it viscous and less difficult to remove afterwards compared to a temporary balanced set plug made of cement. Setting a CannSeal “donut” in the A-annulus would be similar to creating a production packer consisting of the sealant around the tubing that can function as a temporary barrier element for BOP installation upon rig arrival.

9.2 ABRASIVE CLEANING OF CEMENT

In order to remove the cement without removing any section of the casing, it may be possible to clean out a non-isolating cement sheath by applying a further developed perforate wash and cement (PWC) system. The PWC system can already tolerate some cement in the annulus, and by adding abrasives and increasing the velocity of fluids through the nozzles between the swab cubs it may be possible to clean annular space filled with cracked and shrunken cement. It will however be challenging to transport eroded cement cuttings and the abrasives to the surface without fracturing the formation and to efficiently clean the cemented annulus with nozzles, and to adequately supply the operation with sufficient amounts of abrasives logistically.

10 CONCLUSIONS

- Minimum removal of previously installed tubulars will open for cost efficient plugging operations. The question is – when is it feasible to set cross sectional barriers and still avoid removing tubulars?
- The necessity of tubular removal precludes development of rigless approaches which may include wireline and/or coiled tubing rig-ups for Plug and Abandonment (P&A) operations. For the most part the removal of tubulars will necessitate use of a drilling rig or casing jack.

The following flowcharts in Fig. 10.1 and Fig. 10.2 will illustrate the process of plugging operations and include the methods discussed in this thesis. Different colors indicate deployment methods.

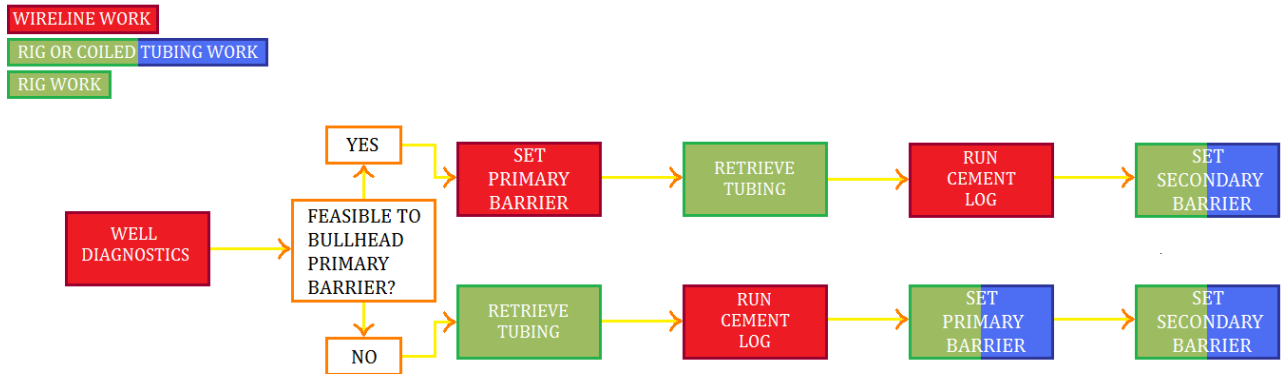


Figure 10.1 – Flowchart to illustrate the progress of a plugging operation

- Well diagnostics conducted with wireline will gather well data and determine the feasibility of bullheading plugging material to set the primary barrier. If the tubing has good pressure integrity, no severe restrictions and if there is low risk of going on vacuum when bullheading, the primary barrier can be set with a wireline rig-up and no removal of tubulars is necessary.
- After the wireline work, the tubing is most commonly retrieved and the state of the annulus will be determined through cement logging. The cement log will determine the condition of the annular space behind the casing wall. Possible annular barriers such as cement or formation creep will determine how further abandonment barriers should be set.
- Well integrity issues will generally complicate plugging operations, tubing integrity, casing integrity and integrity of the annular sealing will dictate the necessary work for plug and abandonment.
- Secondary barriers can be set by using coiled tubing or drillpipe. Coiled tubing is less expensive, but has less flexibility compared to a drilling rig.
- The balanced plug method will place a limited amount of barrier material in the well with minimum contamination. The method has several applications for creating primary or secondary abandonment barriers (plugs) with coiled tubing or drillpipe.

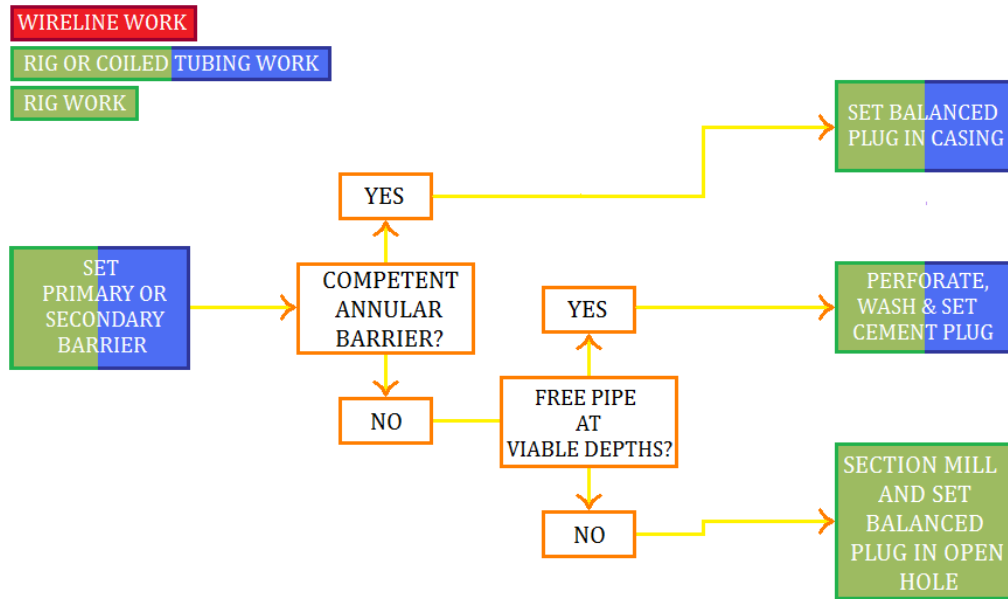


Figure 10.2 – Flowchart to illustrate different plugging methods.

- The two questions which will dictate whether or not removal of the tubulars (casing) is necessary are:
 - Is the annular barrier competent?
 - Are there indications of free pipe at viable depths?
 The answers to these questions can be investigated through cement logging.
- If the annular barrier is not competent and there are no indications of free pipe below minimum plugging depth, section milling, underreaming and setting balanced plug in the open hole is the only method currently feasible.
- If free pipe can be found in a viable plugging depth, the choice would be between deploying the Perforate, Wash and Cement (PWC) system or section mill to remove casing and then set a balanced plug in the open hole.
- The PWC system applies washing and perforation and cementing technology which will make it possible to set cross sectional abandonment barriers without removing a section of the casing. The system is field tested and verified through drilling out and re logging the plugging interval.
- Compared to section milling, the PWC has several advantages when setting abandonment barriers in uncemented casing strings. The PWC system is generally more time efficient, and the plugs can be verified if necessary after placement. The PWC system can be applied in situations where the margin between pore and fracture pressure is narrow.
- Section milling is less time efficient and can introduce several operational challenges. However section milling and underreaming will create open holes to set cross sectional barriers which are not dependent on wash-efficiency and annular displacement of cement. The main drawback is that a plug set after section milling cannot be properly verified.
- The PWC system is recommended to be applied if possible as it will be cost efficient and also coiled tubing deployable. Additional field experience with this system will

open for further development of the washing technology and a wider range of applications. This can make it possible to perform future plugging operations rigless with minimum removal of tubulars in every case and to obtain a promising result regarding long term isolation.

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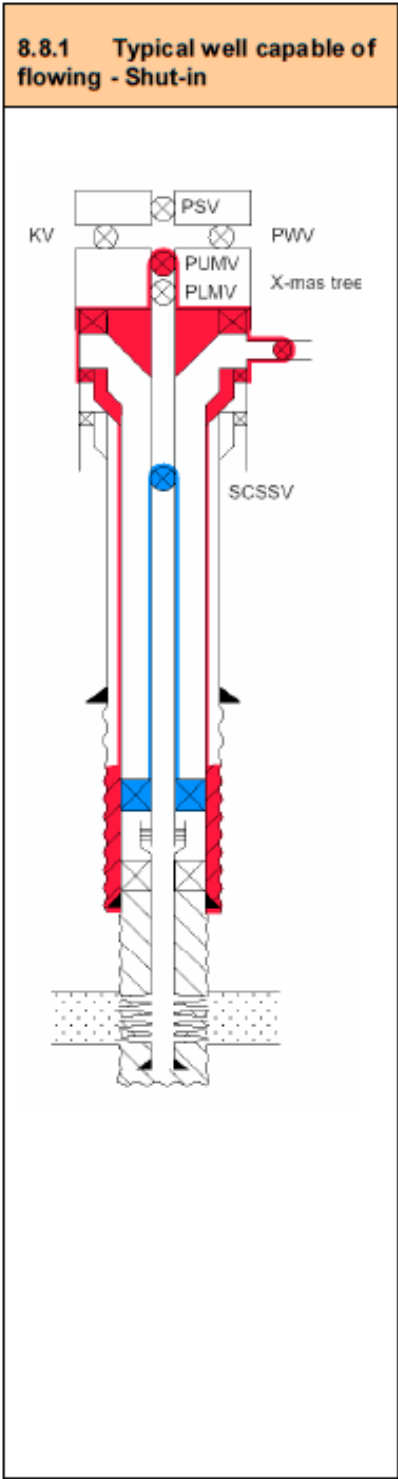
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APPENDICES
APPENDIX A

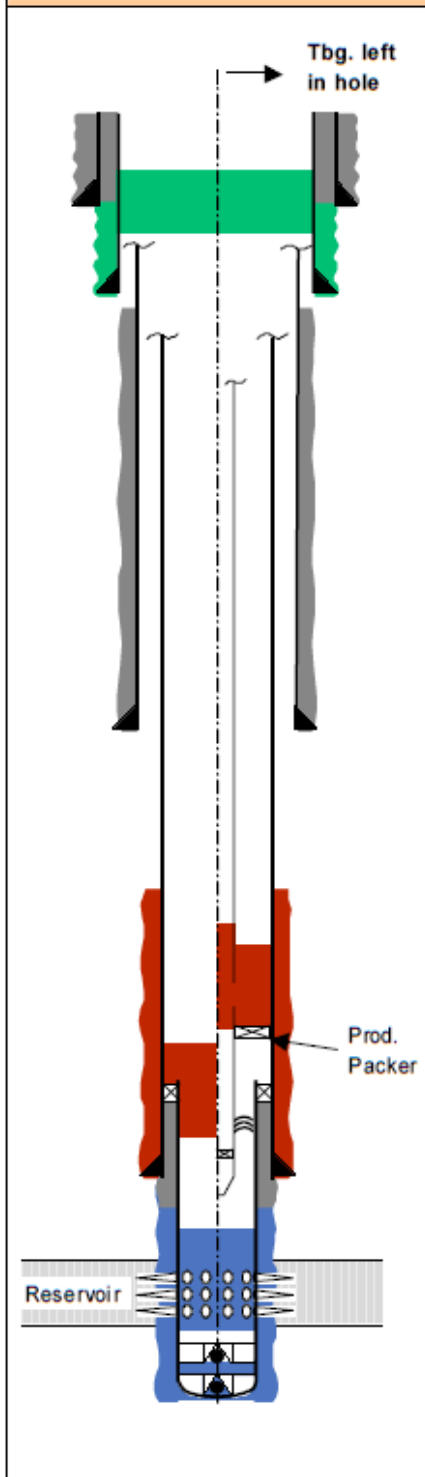


Well barrier elements	See Table	Comments
Primary well barrier		
1. Production packer	7	
2. Completion string	25	Tubing between SCSSV and production packer.
3. SCSSV	8	
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Wellhead	5	Casing hanger, tubing head with connectors.
4. Tubing hanger	10	
5. Annulus access line and valve	12	
6. Production tree	33	Body and master valve.

Note
None

APPENDIX B

9.8.4 Permanent abandonment - Perforated well



Well barrier elements	See Table	Comments
Primary well barrier		
1. Liner cement	22	
2. Cement plug	24	Across and above perforations.
Secondary well barrier, reservoir		
1. Casing cement	22	
2. Cement plug	24	Across liner top.
or, for tubing left in hole case:		
1. Casing cement	22	
2. Cement plug	24	Inside and outside of tubing.
Open holes to surface well barrier		
1. Cement plug	24	
2. Casing cement	22	Surface casing.

Notes

1. Cement plugs inside casing shall be set in areas with verified cement in casing annulus.
2. The secondary well barrier shall as a minimum be positioned at a depth where the estimated formation fracture pressure exceeds the contained pressure below the well barrier.

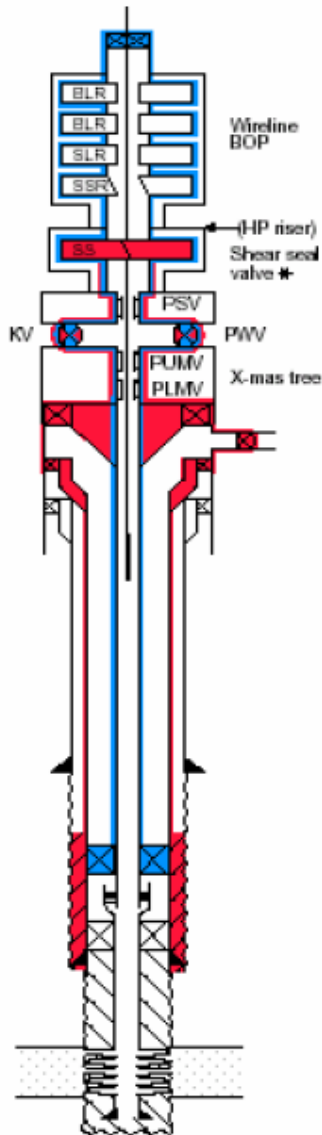
APPENDIX C

15.24 Table 24 – Cement plug

Features	Acceptance criteria	See						
A. Description	The element consists of cement in solid state that forms a plug in the wellbore.							
B. Function	The purpose of the plug is to prevent flow of formation fluids inside a wellbore between formation zones and/or to surface/seabed.							
C. Design, construction and selection	<ol style="list-style-type: none"> 1. A design and installation specification (cementing program) shall be issued for each cement plug installation. 2. The properties of the set cement plug shall be capable to provide lasting zonal isolation . 3. Cement slurries used in plugs to isolate permeable and abnormally pressured hydrocarbon bearing zones should be designed to prevent gas migration. 4. Permanent cement plugs should be designed to provide a lasting seal with the expected static and dynamic conditions and loads down hole 5. It shall be designed for the highest differential pressure and highest downhole temperature expected, inclusive installation and test loads. 6. A minimum cement batch volume shall be defined for the plug in order that homogenous slurry can be made, to account for contamination on surface, downhole and whilst spotting downhole. 7. The firm plug length shall be 100 m MD. If a plug is set inside casing and with a mechanical plug as a foundation, the minimum length shall be 50 m MD. 8. It shall extend 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 below casing shoe. 9. A casing/ liner with shoe installed in permeable formations should have a 25 m MD shoe track plug. 	API Standard 10A Class 'G'						
D. Initial verification	<ol style="list-style-type: none"> 1. Cased hole plugs should be tested either in the direction of flow or from above. 2. The strength development of the cement slurry should be verified through observation of representative surface samples from the mixing cured under a representative temperature and pressure. 3. The plug installation shall be verified through documentation of job performance; records fm. cement operation (volumes pumped, returns during cementing, etc.). 4. Its position shall be verified, by means of: <table border="1" data-bbox="416 1240 1246 1563"> <thead> <tr> <th>Plug type</th> <th>Verification</th> </tr> </thead> <tbody> <tr> <td>Open hole</td> <td>Tagging, or measure to confirm depth of firm plug.</td> </tr> <tr> <td>Cased hole</td> <td> Tagging, or measure to confirm depth of firm plug Pressure test, which shall <ol style="list-style-type: none"> a. be 7000 kPa (~1000 psi) above estimated formation strength below casing/ potential leak path, or 3500 kPa (~500 psi) for surface casing plugs, and b. not exceed casing pressure test, less casing wear factor which ever is lower If a mechanical plug is used as a foundation for the cement plug and this is tagged and pressure tested the cement plug does not have to be verified. </td> </tr> </tbody> </table> 	Plug type	Verification	Open hole	Tagging, or measure to confirm depth of firm plug.	Cased hole	Tagging, or measure to confirm depth of firm plug Pressure test, which shall <ol style="list-style-type: none"> a. be 7000 kPa (~1000 psi) above estimated formation strength below casing/ potential leak path, or 3500 kPa (~500 psi) for surface casing plugs, and b. not exceed casing pressure test, less casing wear factor which ever is lower If a mechanical plug is used as a foundation for the cement plug and this is tagged and pressure tested the cement plug does not have to be verified.	
Plug type	Verification							
Open hole	Tagging, or measure to confirm depth of firm plug.							
Cased hole	Tagging, or measure to confirm depth of firm plug Pressure test, which shall <ol style="list-style-type: none"> a. be 7000 kPa (~1000 psi) above estimated formation strength below casing/ potential leak path, or 3500 kPa (~500 psi) for surface casing plugs, and b. not exceed casing pressure test, less casing wear factor which ever is lower If a mechanical plug is used as a foundation for the cement plug and this is tagged and pressure tested the cement plug does not have to be verified.							
E. Use	Ageing test may be required to document long term integrity.							
F. Monitoring	For temporary suspended wells: The fluid level/ pressure above the shallowest set plug shall be monitored regularly when access to the bore exists.							
G. Failure modes	Non-compliance with above mentioned requirements and the following: <ol style="list-style-type: none"> a. Loss or gain in fluid column above plug. b. Pressure build-up in a conduit which should be protected by the plug. 							

APPENDIX D

10.8.2 Running WL through surface production tree



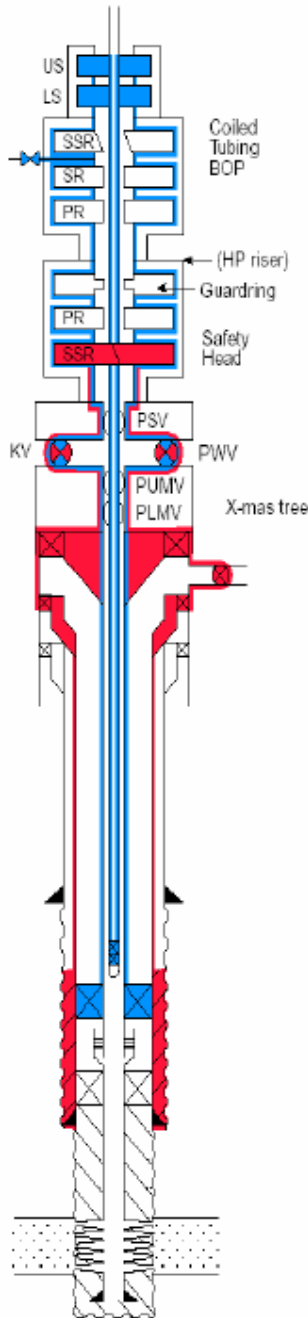
Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing cement	22	
2. Casing	2	Below production packer.
3. Production packer	7	
4. Completion string	25	
5. Tubing hanger	10	
6. Surface production tree	33	Including kill and PWVs.
7. Wireline BOP	37	Body only. Act as back up element to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

Notes

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

APPENDIX E

11.8.2 Running CT through surface production tree



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

Notes

Compensating measures for common WBEs can be:

1. A high pressure line shall be hooked up and leak tested for pumping kill fluid.
2. Sufficient fluid and materials available at the location to efficiently kill the well.