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MASTER'S THESIS

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Abstract

A large number of wells will have to be abandoned at the NCS and around the world. NORSOK D-010 states that a well that is permanently abandoned shall be abandoned with an eternal perspective and with zero leakage [1]. This is a challenge. It can be hard to predict downhole properties after a well is abandoned. One of the biggest challenges is to ensure that the barriers will keep their integrity for hundred or even thousands of years. To understand how the reservoir and well acts after it is plugged and abandoned, several mechanisms must be known.

Barriers is affected by parameters like temperature, pressure and different fluids and gasses that are in contact. This thesis will review regulations and requirements for permanent well barriers, verification of permanent well barriers, barrier degradation models and degradation of cement and corrosion of casing steel due to CO_2.

Use of carbon capture and storage is a very popular topic, which is discussed in this thesis. This method is based on pumping CO_2 into reservoirs to store it instead of releasing it to the air. Carbon dioxide is a large contributor for barrier degradation.

This thesis will also look at well barrier leakage and statistics around this. It will be discussed how to cope with the leakage in permanent well barriers after a well is abandoned.

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List of abbreviations

NORSOK	-	Norsk sokkels konkurranseposisjon
UKOOA	-	United Kingdom Offshore Operators Association
WBS	-	Well Barrier Schematics
WBE	-	Well Barrier Element
EAC	-	Element Acceptance Criteria
NCS	-	Norwegian Continental Shelf
HPHT	-	High Pressure High Temperature
API	-	American Petroleum Institute
CBL	-	Cement Bond Log
TOC	-	Top of Cement
PSA	-	Petroleum Safety Authority
P&A	-	Plug and Abandonment
RLWI	-	Riserless well intervention
LWIV	-	Light well intervention vessel
WL	-	Wireline
CT	-	Coiled Tubing
$scCO_2$	-	Supercritical Carbon Dioxide
EOR	-	Enhance Oil Recover
CCS	-	Carbon Capture and Storage
EU	-	European Union
BI	-	Bond Index
HSE	-	Health, Safety and Environment
PWC	-	Perforate, Wash, Cement
WOC	-	Wait on Cement
MD	-	Measured Depth

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1. Introduction

On the Norwegian continental shelf there are over 2500 wells that are in use. On a worldwide basis the number is close to a million [2]. Some time in the future, these wells will have to be plugged and abandoned because they are not being profitable or are non-producing. When a well reaches the end of its life, the pressure will decrease, reducing the production rate. At some point the wells production cost will exceed the profit, which can result in it being abandoned. EOR is a solution to extend life of the well, but even with EOR pressure might become too low at one point, resulting in no other options than to plug it. Plug and abandonment is a very important phase of a wells life since its purpose is to ensure that there will be no leakage in the future.

Plug and abandonment is a non-profitable operation. Hence, companies often delay the plugging in hope of better and less expensive technologies. Only on the Norwegian Continental Shelf, the price is estimated to be as much as 876 billion NOK [3].

For a plugging operation to be successful, several aspects of the operation must be performed perfectly. The most important part of a P&A job is setting of the plugs. Portland cement is the most common used material as permanent plugs, but also there exist many other materials that can be used.

A part of the plug and abandonment procedure is to try to understand how the downhole properties will affect the barriers over time. It is well known that gasses and liquids affect cement and casing steel. Especially carbon dioxide. CO_2 attacks and degrade the cement. It also corrodes steel when it is exposed to it. Because of CO_2-attacks, pathways can be made, and over time continue to expand. To reduce the likelihood, or at least delay pathway buildup, verification of barriers are important.

Stricter regulations and better equipment has made P&A operations much safer and better over time. A large number of wells around the globe suffers with reduced integrity due to old plugging techniques and materials. These wells are a threat for the environment as they pose a larger risk of leaking.

The main goal of this thesis is to investigate the degradation of permanent barriers and leakage pathway buildup. To understand how the barriers are affected, several studies on degradation are investigated to see how the different downhole parameters affect casing steel and cement. Models of flow through pathways are also investigated to see if it is possible to get a reliable prediction of what is happening to barriers after being abandoned.

Well statistics and remedial possibilities if leaks occurs are also discussed in this thesis.

2. Barriers and regulations for plug and abandonment

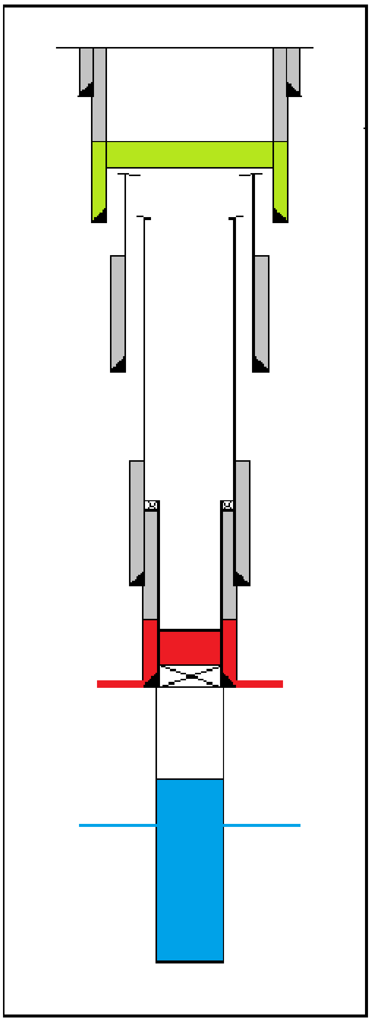
2.1 NORSOK D-010

NORSOK D-010 is a collection of requirements and guidelines for integrity and drilling on the Norwegian Continental Shelf.

2.1.1 Well barrier schematics

A well barrier schematic is mandatory and shall be prepared for each well activity and/or operation. This include well abandonment activities.

A WBS shall consist of a list of well barrier elements for both primary and secondary well barriers. Sometime a WBS consist of a third well barrier, like open hole to surface barrier. Each barrier element has its own EAC number that can be found in chapter 15: Well barrier elements acceptable tables in NORSOK Standard D-010 [1]. A drawing of the well with barriers also has to be prepared.



Well barrier elements	Eac Table
Primary well barrier	
In- situ formartion	51
Cement plug	24
Secondary well barrier	
In-situ formation	51
Casing cement	22
Casing	2
Cement plug	24
Open hole to surface well barrier	
Casing cement	22
Casing	2
Cement plug	24

Figure 1: Well barrier schematic - Permanent abandonment, open hole [1].

2.1.2 Abandonment design

All the well barrier elements used in plugging shall withstand the maximum loads expected and environmental conditions they may be exposed to during the abandonment period [1].

The design should include [1]:

a) Well configuration including depths and specification of formations which are sources of inflow, casing strings, casing cement, wellbores and sidetracks.
b) Stratigraphic sequences of each wellbore showing reservoirs and information about their current and future production potential with reservoir fluids and pressure (initial, current and in an eternal perspective).
c) Logs, data and information about the cementing operations
d) Formations with suitable WBE properties like strength, impermeability, faulting and absence of fractures and faulting.
e) Specific well conditions such as scale buildup, casing wear, collapsed casing, fill, H_2S, CO_2, hydrates, benzene and other similar issues.
f) Placement techniques of downhole barriers.
g) The minimum volume needed to mix a slurry that is homogenous.
h) Surface volume control.
i) Pump efficiency parameters.
j) Fluid contamination.
k) Shrinkage for both cement and/or other plugging materials.
l) Centralization of casing.
m) Heavy slurry support.
n) Degradation of well barrier elements over time.

2.1.3 Temporary abandonment.

Temporary abandonment is when a well is plugged and left, but with intentions of re-opening the well later. According to NORSOK Standard D-010 (2013) there are two categories of temporary abandonment. With and without monitoring.

2.1.3.1 Temporary abandonment – Without monitoring.

Temporary abandonment without monitoring is defined as a "*well status where the well is abandoned and the primary and secondary well barriers are not continuously monitored and not routinely tested"* [1].

The criteria for not monitoring the well, is that the maximum abandonment period shall not exceed three years [1].

For subsea wells without monitoring, a visualization program shall be established. This can be performed by using ROV's for inspection. Visual inspection frequency shall not exceed more than one year [1].

2.1.3.2 Temporary abandonment – With monitoring

Defined as a well status "*where the well is abandoned and the primary and secondary well barriers are continuously monitored and tested"* [1].

If the criteria of continuously monitoring is not fulfilled, the well shall be considered as a temporary abandoned well without monitoring. For a monitored abandoned well, there is no maximum abandonment period [1].

2.1.3.3 Well barrier acceptance criteria

For temporary abandoned wells with monitoring, periodic maintenance testing and monitoring shall be performed on the well barrier elements according to NORSOK D-010 EAC table.

A temporarily abandoned well without monitoring shall have sufficient integrity to last the given abandonment period.

2.1.4 Permanent abandonment

A permanent abandonment is a well status, where the well is plugged and left without possibility to re-enter the well.

2.1.4.1 Well barrier acceptance criteria

Permanent abandoned wells shall be plugged with an eternal perspective. The barriers must therefore withstand high pressures, temperature and the effect from fluids and gasses [1].

Name	Function	Depth position
Primary well barrier	Its function is to isolate possible sources of inflow for both normal and overpressurized formation, and prevent them from migrating to the surface.	The base of barrier shall be positioned at a depth were formation integrity is higher than potential pressure below.
Secondary well barrier	Back-up to the primary well barrier.	Same as for primary well barrier.
Crossflow well barrier	Its function is to prevent flow between multiple formations (where crossflow is not acceptable). May also function as primary well barrier for the reservoir below.	Same as for primary well barrier.
Open hole to surface well barrier.	Its function is to permanently isolate flow from possible conduits after cutting and retrieving casing. The exposed formation can be over pressurized with no source of inflow. No hydrocarbons present.	There is no depth requirements with respect to formation integrity for open hole to surface barrier.

Table 1: Well barrier depth position [3]

Multiple reservoirs in the same area within the same pressure zone can be considered as a single reservoir such that secondary and primary barrier is required to seal them.

If possible, a single barrier can act as a shared barrier between more than one wellbore.

A permanent well barrier shall extend across the full cross section of the wellbore. This includes all annuli, both vertical and horizontal. The barrier shall be placed adjacent to an impermeable formation with sufficient formation integrity for the maximum anticipated pressure [1].

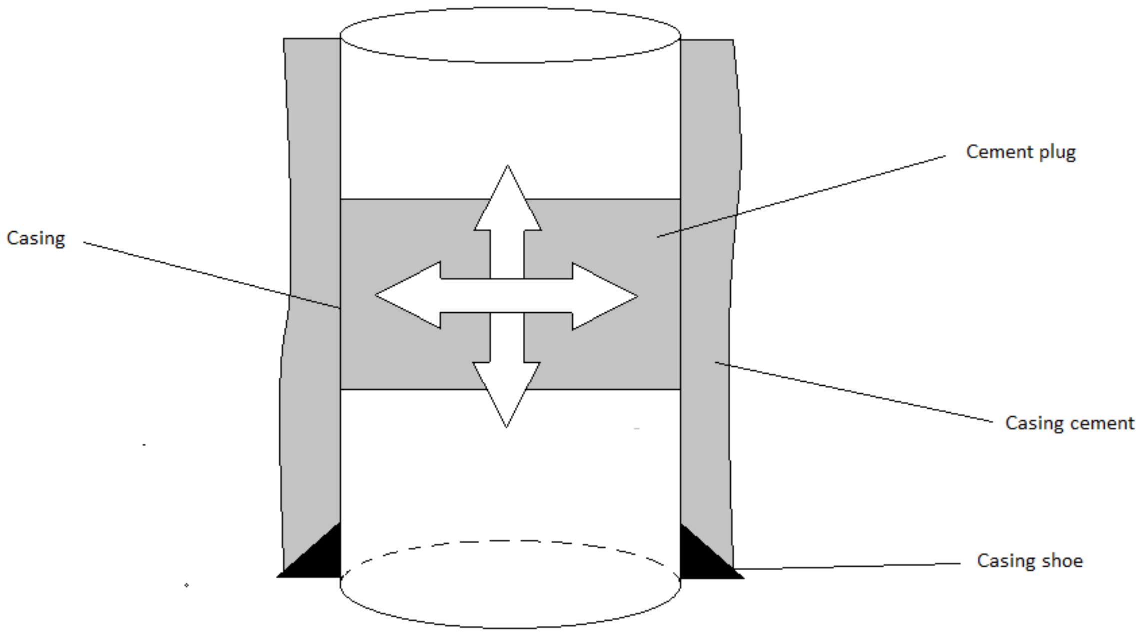


Figure 2: Well barrier design

A permanent well barrier should have following characteristics [1]:

a) The barrier shall provide long-term integrity. Theoretically, eternal perspective.
b) Impermeable.
c) Non-shrinking.
d) Should be able to withstand mechanical loads after being abandoned.
e) Chemical resistant (H_2S, CO_2)
f) Bond to steel.
g) Shall not harm casing or reduce well integrity.

2.1.4.2 Minimum cement plug length

Cement plugs are the most common plugging method on the NCS. The length of the plug is dependent of whether the hole is open or cased, and if it is set on a solid foundation.

Open hole cement plugs	Cased hole cement plugs	Open hole to surface cement plug
100 meters measured depth with minimum 50 m MD above any source of inflow/leakage point. A plug in transition from open hole to casing should extend at least 50 m MD above and below casing shoe.	50 meters MD if set on a mechanical or cement plug as foundation. If not set on a foundation, a minimum of 100 m MD plug shall be set.	50 meters MD if set on a mechanical plug. If not set on a mechanical plug, a plug of minimum 100 m MD shall be set.

Table 2: Minimum cement plug length according to EAC table 24 [3]

2.1.5 Barrier verification

When a well barrier element is installed, the integrity has to:

a) Be verified with application of differential pressure to pressure test WBE; or
b) Be verified by other methods if pressure testing is no possible.

Activation enabled well barrier elements shall be function tested.

Re-verification is aquired if:

c) WBE condition is changed; or
d) The remaining life cycle of well undergoes a change in the load [1].

2.1.5.1 WBE pressure testing

One shall perform WBE pressure test:

a) Before exposure of differential pressure in its operating phase.
b) After replacing WBE components that are pressure confining.
c) Suspicion of leak in barriers.
d) When the pressure/load is different from its original test pressure/load.
e) If differential pressure/load is higher than then original design.
f) Periodically according to NORSOK Standard D-010 EAC tables.

Under pressure testing, the acceptable leak rate shall be equal to zero, or according to given values for specific WBE found in EAC tables. For situations where leak-rate is not possible to monitor, maximum allowable pressure leak shall be established instead [1].

"The test pressure should be applied in the direction of flow towards the external environment. If this is not possible or introduces additional risk, the test pressure can be applied against the direction of flow towards the external environment, provided that the WBE is constructed to seal in both flow directions" [1].

Duration and pressure of pressure test will depend on downhole properties. For low-pressure test, the duration should be 5 minutes with stable reading. Low-pressure tests shall not exceed 20 bar differential pressure. No need for low-pressure test for periodic testing of production/injection phase.

A high pressure test shall be equal or higher than expected differential pressure in well. 10 minutes of stable readings is required for a static pressure test.

Inflow testing should last longer. A minimum of 30 minutes with stable reading. If there are large volumes, fluids with high compressibility or temperature effects present, the duration shall be longer [1].

2.1.5.2 Cement plug testing

Cement plugs have their own verification criteria. These can be found EAC table 24 in NORSOK Standard D-010 (2013).

For open-hole, pressure testing is not necessary. Verification criteria is tagging of TOC. Cased hole requires both tagging and pressure testing. The pressure test shall:

a) *"be 70 bar (1000 psi) above estimated leak of pressure (LOT) below casing/ potential leak off or 35 bar (500 psi) for surface casing plugs; and*
b) *not exceed the casing pressure test and the casing burst rating corrected for casing wear"* [1].

If the cement plug is placed on a solid foundation that is pressure tested, tagging of TOC is sufficient.

2.2 Guidelines for the abandonment of wells

Regulations used for abandonment of wells at UK site.

2.2.1 Temporary abandonment

For temporary abandonment operations, two temporary barriers shall be set in hydrocarbon zones, or over pressurized permeable zones. For water-bearing zones, which is normally pressurized, one single barrier is acceptable.

A temporary barrier should consist of good cement or a pressure-tested mechanical device. For some scenarios, a kill fluid can work as a temporary barrier [4].

Temporary barriers should follow the same principles of a permanent abandonment.

2.2.2 Permanent abandonment

2.2.2.1 Number of barriers

All penetrated zones, which are permeable shall be isolated from each other, and also from surface or seabed. There should be at least one permanent barrier. For permeable zones, there should be at least two permanent barriers [4].

Two barriers can be combined, and therefore be considered as one single barrier. For two barriers to be considered as one large barrier, it has to be as effective and reliable as two single barriers. The barriers have to be verified according to section 6 in guidelines for the abandonment of wells issue 5 (2015) [4].

2.2.2.2 Requirements for barriers

The first barrier shall be set across or above the highest point of inflow. If this is not possible, it should be set as close as possible.

The second barrier, if required (permeable zones with possibility for inflow) shall be used as a backup for the first barrier. It should be positioned such that *"the formation fracture pressure at the base of the second barrier is in excess of the potential internal pressure".* It should also have a relative position of cement in the annulus and shallow permeable zones [4].

A second barrier can work as a first barrier for another permeable zone. As shown in figure 3.

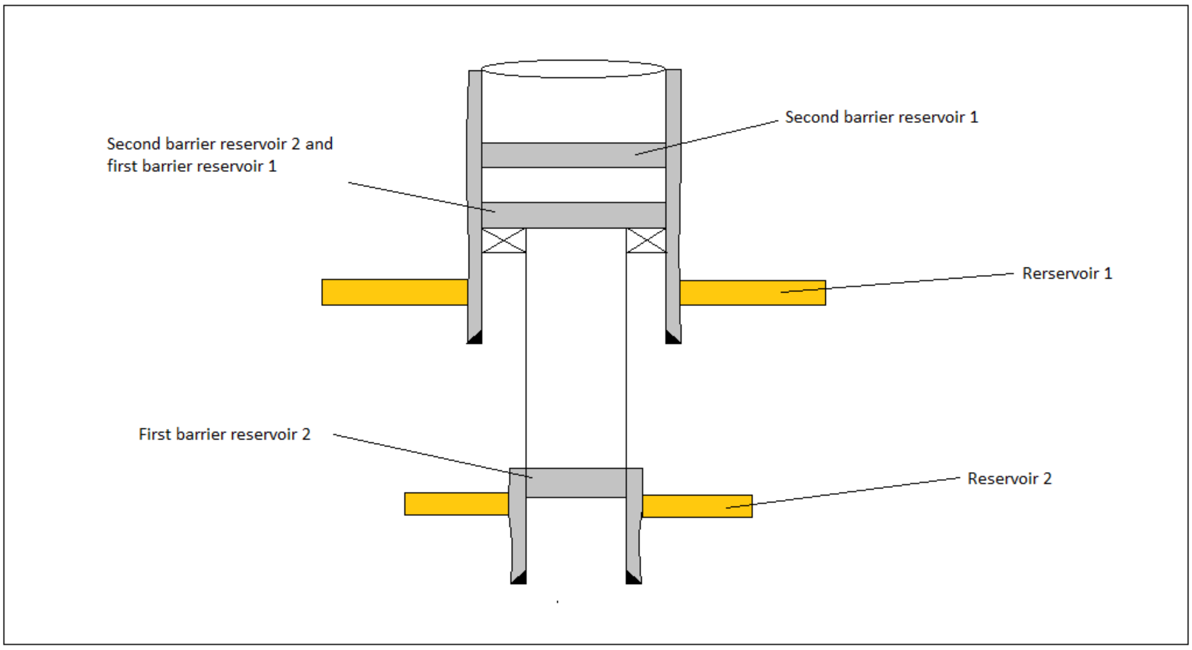


Figure 3: First and secondary barrier combination

2.2.2.3 Minimum length

A permanent barrier should consist of minimum 100 feet measured depth of good cement. If possible, a 500 feet MD barrier should be set, where at least 100 feet MD extend above the highest point of inflow.

Where permeable zones are less than 100 feet apart from each other, a 100 feet MD column of good cement below the base of the upper zone should be sufficient.

At least 100 feet MD of good cement is required in places where casing is a part of a permanent barrier. The internal cement plug must be adjacent to the annular good cement over a cumulative distance of at least 100 feet MD of overlap.

If the first and second barriers are combined and considered as one single barrier, 200 feet MD of good cement is sufficient. A total of 800 feet MD barrier is set. In comparison, two single barriers would consist of two times 500 feet MD barriers as shown in figure 4.

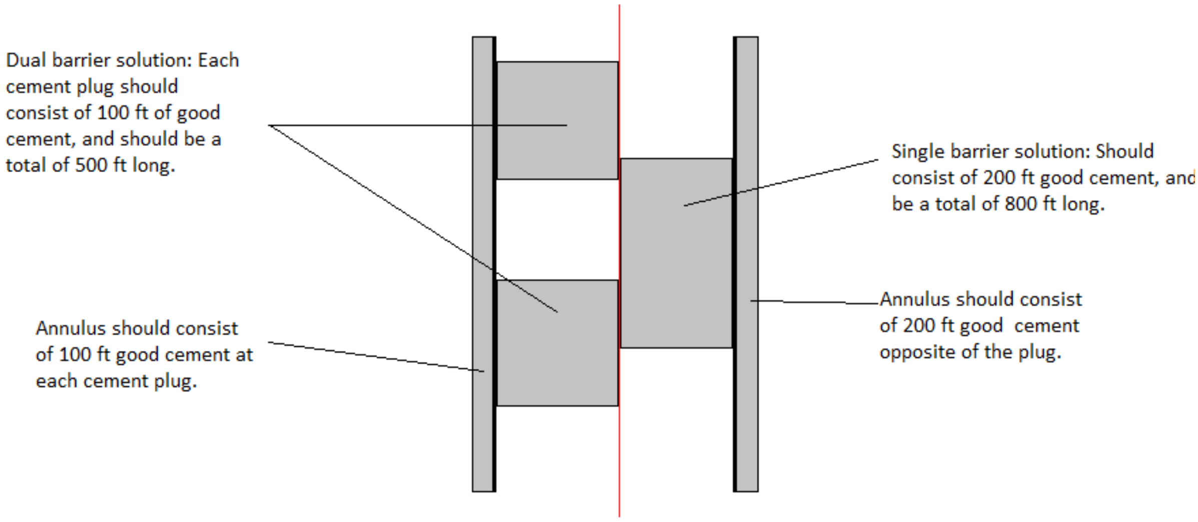


Figure 4: Dual barrier and combination barrier comparsion [4]

2.2.3 Verification of barrier

All permanent barriers shall be verified. This is to ensure that barrier has sufficient integrity and placed at correct depth. Requirements regarding verification of barriers will depend on design and purpose.

2.2.3.1 Wellbore barrier

Installation of barrier shall be well documented. If a cement job is performed, the documentation should include information about the operation, like volumes pumped, return rate during cement, etc. Strength development of cement slurry should be confirmed. Slurry strength is confirmed by samples cured at pressure and temperature that is expected downhole [4].

Cement plugs shall be tagged to verify the depth.

If a barrier is placed in open-hole, it shall be verified with weight testing. Typically, the weight added on drillpipe is between 10 000 to 15 000 lbs. If wireline or coiled tubing is used, weight will be limited by tool.

Cased hole shall also be verified by pressure testing. "*The pressure test should be minimum 500 psi above the injection pressure below the barrier, but not exceed the casing strength minus wear allowance or damage the primary casing cement"* [4]. If several barriers are established and earlier barrier that work as foundation are tested, there is no need for pressure test of the other one.

2.2.3.2 Annular barrier

Annular barriers cannot be verified by tagging. Other types of verification is needed. Top of cement can be verified by running logging tools, or by estimation from records during cementing operation [4].

Sealing capacity of annular barrier can be verified by several methods:

- Logging
- Absence of casing pressure during wells life.
- LOT taken when casing shoe was drilled out.
- Absence of anomalies during cementing operation.
- Centralization, washouts, lead and tail slurry, pressures in annulus, experience from earlier field operations, etc.
- Pressure testing

Table 3 and 4 is taken from Guideline for the abandonment of wells issue 5, and tells verification requirements for different operations.

<table>
<tr><th colspan="5">Single Permanent barriers – Primary and secondary</th></tr>
<tr><th rowspan="3">Type of barrier</th><th colspan="4">Verification method</th></tr>
<tr><th colspan="2">Wellbore/tubing</th><th colspan="2">Annulus cement</th></tr>
<tr><th>Position of barrier</th><th>Sealing capability</th><th>Position of barrier</th><th>Sealing capability</th></tr>
<tr><td>Through-tubing</td><td>Tagging</td><td>Pressure testing</td><td>Minimum of 100 ft. with good cement bonding if it is previously logged. or 1000 ft. above base of barrier if it is estimated from differential pressure</td><td>See section 7.2 and 8.10 for more information</td></tr>
<tr><td>Mechanical barrier through-tubing</td><td>Tagging of cement. Can also measure volume to confirm depth of the barrier</td><td>After the mechanical barrier is released, it shall be pressure tested. Cement in tubing and annulus shall then be pressure tested separately</td><td>Same as for through tubing</td><td>See section 7.2 and 8.10 for more information</td></tr>
<tr><td>Cased hole</td><td>Tagging</td><td>Pressure testing</td><td>Same as for through tubing</td><td>See section 7.2 for more information</td></tr>
<tr><td>Mechanical barrier Cased hole</td><td>Tagging of cement. Can also measure volume to confirm depth of the barrier</td><td>Cement barrier or mechanical barrier shall be tested after being placed</td><td>Same as for through tubing</td><td>See section 7.2 for more information</td></tr>
<tr><td>Open hole</td><td>Tagging</td><td>Not available</td><td>Not available</td><td>Not available</td></tr>
</table>

Table 3: Barrier verification for single permanent barrier [4]

Single Permanent barriers – Primary and secondary				
Type of barrier	**Verification method**			
	Wellbore/tubing		**Annulus cement**	
	Position of barrier	**Sealing capability**	**Position of barrier**	**Sealing capability**
Through-tubing	Tagging	Pressure testing	Minimum of 200 ft. with good cement bonding if it is previously logged. If not, 1000 ft. above base of barrier if it is estimated from differential pressure	See section 7.2 and 8.10 for more information
Mechanical barrier through-tubing	Tagging	After the mechanical barrier is released, it shall be pressure tested. Cement in tubing and annulus shall then be pressure tested separately	Same as for through tubing	See section 7.2 and 8.10 for more information
Cased hole	Tagging	Pressure testing	Same as for through tubing	See section 7.2 for more information
Mechanical barrier Cased hole	Tagging of cement.	Cement barrier or mechanical barrier shall be tested after being placed	Same as for through tubing	See section 7.2 for more information
Open hole	Tagging	Not available	Not available	Not available

Table 4: Barrier verification for permanent combination barrier [4]

3. Plug and abandonment sequences

The plug and abandonment process consist of several steps before even starting to plug the well. Planning of the process is essential to get a successful abandonment. Rigzone has a 10-step sequence for plugging a well [5].

1. Project management.
2. Regulatory compliance and P&A application.
3. Preparation of rig /vessel.
4. Well plugging process.
5. Removal of conductor casing.
6. Mobilization and demobilization of derrick barge.
7. Platform/rig/vessel removal.
8. Decommissioning of pipeline and power cables.
9. Material disposal.
10. Site clearance.

Project management is responsible for operational planning. They also responsible for contracting and review of contractual obligations [5].

Before plugging and mobilization process, an application must be established and approved by the authorities. On the NCS, the regulatory authority of plugging approval is the Petroleum Safety authority. For an application to be approved, the responsible for plugging must show the PSA that the plug and abandonment will be following the regulations in NORSOK Standard D-010.

3.1 Work units

Work units are divided into different categories:

- Mobile offshore drilling unit
- Heavy vessel with riser
- Light well intervention vessel without riser
- Anchor handling vessel

Mobile offshore drilling unit: MODUs are ordinary drilling rigs or ship capable of most well operations, inclusive well plugging. There are several types of MODUs: Jackup, Semi-submersible, submersible, Ultradeep water unit and drillship [6].

Figure 5: Mobile Offshore Drilling Units

Heavy vessel with riser: Vessel designed to do well maintenance, enhancing production and well abandonment procedures. Can support riser system and can run coiled tubing and wireline [7].

Light well intervention vessel without riser: Light well intervention vessel (LWIV). Primarily used for wireline operations in subsea wells. Can also be used for some plugging operations, like preparatory work, setting surface barriers and wellhead cutting and removing.

Anchor handling vessel: Another type of ship that can be used in a variety of well operations. Can do light construction work, P&A operations, IMR and different type of survey work [8]. These types of vessel are also very powerful and can pull heavy weight. Used for towing platforms and rigs.

Which unit that is preferred for P&A will depend on complexity of the operation. Rigs are often preferred when doing plug and abandonment. It has high equipment capacity and is capable of using riser during plugging. Riser will make it possible for full circulation during cementing and well kill phase. Mobile offshore drilling units can do all operations, but has the highest day-rates. Light well intervention vessels without riser can be used in addition to MODUs. The surface plug can be sat with a LWIV while the mobile offshore drilling unit can be relocated to do other operations. The use of light well intervention vessels has some operating limitations. It cannot use riser, thus no circulation during operation stages. It can also have trouble pulling tubing or casing due to weight limitations. Last, it is limited to WL deployed tools [9]. A heavy vessel with riser system might be preferable. It can set deeper cement plugs using coiled tubing instead of wireline.

3.2 Well plugging process

Plugging phase can be categorized into two phases:

Planning phase of the well plugging is the first phase. This phase includes collection of data, preliminary inspection, selection of the preferred abandonment procedure and application submittal [5].

Phase 2 is the execution of abandonment procedures. Abandonment procedures are never completely alike, but many of the sequences can be the same. The first step is to mobilize a work unit. When work unit is mobilized and ready to operate, the first operation is to kill the well. Most used method of killing the well is by bullheading. Bullheading is forcing fluids back into formation with a pressure higher than the pore pressure.

After the well is killed, tubing and lower completion is pulled before plugging sequence can start. Plugging will be done according to local regulations. Methods for well plugging will be discussed in chapter 4. Primary and secondary plugs are placed first. Well logging will determine if casing cement is of good enough quality. Bad casing cement will have to be removed and re-cemented. Removal of casing and cement can be done with milling. If the casing cement is of acceptable quality, plug can be placed in cased-hole [10]. If there are several casings, it might be necessary to cut one casing to have the possibility to log other casings. Today's logging tools are not capable of logging through several casing strings. Well barrier testing is then performed on primary barrier before secondary barrier is placed. After both primary and secondary barrier is set and verified, surface barrier is placed. The need of casing pulling will depend on casing cement quality.

Last sequence before demobilization from location is removal of wellhead and top of casing strings. Preferred method of casing removal is mechanical or abrasive cutting. Use of explosive to remove casing is also acceptable if the risk of damage to the environment around the well is the same as for other casing removal methods. NORSOK Standard D-010 states that *"for permanent abandonment wells, the wellhead and casing shall be removed below the seabed at a depth which ensures no stick up in the future"* [1]. If the wellhead is place it very deep water, it might be sufficient to leave the well without cutting it.

After the well is plugged, unit used in plugging phase is removed, unless it is to be used for site clearance as well. Pipelines and power cables connected to the abandoned wells is then removed. After this is done, other equipment connected to the well is removed, and site is cleared [5].

4. Plug and abandonment: Cement and cementing

When a well is to be abandoned, it is important to install plugs or other barriers that will close the wellbore and prevent hydrocarbons and other fluids migrating up the wellbore. The most common material used today is cement. Cement is often preferred due to low prices and the possibility of manipulation by additives. It has been used for decades, and techniques and routines has been enhanced to gain good cement jobs.

4.1 Plugging materials

Plugging materials used is widely different. As stated, cement is the most used plugging material. However, materials like polymers and special sand are developed to cope with problems ordinary cement cannot withstand.

4.1.1 Portland cement

There are several types of cement used in primary and secondary cementing jobs. The most known and used type of cement is Portland cement. It has its name from Isle of Portland where it was thought that the solidified cement resembled stone quarried from this island [11].

Portland cement is used for almost every downhole cementing operation. Including casing cementing and cement plugs. It is very easily modifiable, and can be set in water. This type of cement is known as a hydraulic cement, due to its ability to gain compressive strength from hydration, and reactions between water and compounds in the cement [12]. When cement is set, it has very low permeability. In addition, it is nearly insoluble in water, which means water will not affect the cement after it is set. Gasses like CO_2 might degrade and reduce cement integrity. This will be discussed later.

Portland cement is divided into API classes. Each class is made for a specific purpose. Some classes can be used only in shallow depths with low temperature and low pressure. While other classes are made to withstand HPHT. The classes will also be graded as of the sulfate resistance. There are three types of sulfate resistance. Ordinary (O), moderate sulfate resistance (MSR) and high sulfate resistance (HSR) [12].

API Classification				
API classification	**Depth (m)**	**Water requirement (l/sk)**	**Slurry density (kg/m^3)**	**Description**
Class A	0 – 1830	19.68	1869.29	Very common or regular cement slurry.
Class B	0 – 1830	19.68	1869.29	Has moderate to high resistance againt sulfate.
Class C	0 – 1830	23.84	1773.43	High to early cement. Good availability.
Class D	1830 – 3050	16.28	Varies	For moderate temperatures and pressures
Class E	3050 – 4300	16.28	Varies	HPHT. Can be used at all depths with use of retarders.
Class F	3050 – 4900	16.28	Varies	Made to withstand extremely high pressures and temperatures.
Class G & H	0 – 2450	G – 18.93 H – 16.28	G – 1893.25 H – 1965.15	Very commonly used cement. Can be used at most depths with use of retarders.

Table 5: Portland cement API classification [13]

Class A: Very basic cement. Only used when there is not any special conditions needed. Is available in ordinary grade.

Class B: Used under conditions where high or moderate sulfate resistance is needed. Both MSR and HSR is available.

Class C: Used when high early strength is needed. Is available in all three grades.

Class E-F: These classes are known as cement with retarders. The intended use of these are deep wells. Can be obtained with both MSR and HSR.

Class G-H: Were developed to improve acceleration and retardation efficiency in cement. Are available in both MSR an HSR. G- and H-classes are the most commonly used cement today [12].

4.1.2 Schlumberger EverCRETE® cement

Well cement developed by Schlumberger to cope with highly corrosive CO_2-gasses. Its intended use is in CO_2 injection/storage wells [13]. In such conditions with CO_2, it is highly possible for degrading of both cement and casing over a long time perspective. Under specific conditions, Portland cement might not be sufficient to use. Figure 7 shows compressive strength of Portland cement and EverCrete® cement over a given period, at a given temperature and pressure.

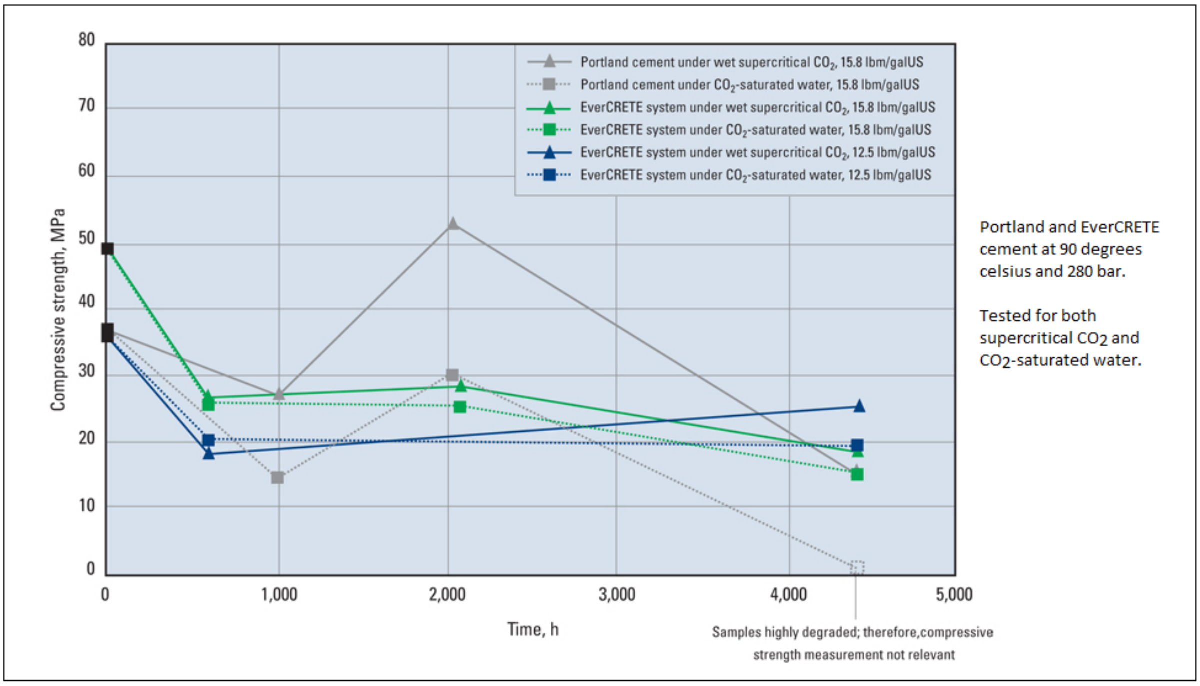


Figure 6: Compressive strength of cement under given conditions [14].

4.1.3 Sandaband®

New well plugging materials are developed to replace cement and to get the best possible plugging result. One of these materials is Sandaband®. Sandaband® is a plugging material that is non-consolidating, non-shrinking and non-fracturing. Its composition is of quartz particles with high strength and Bingham-plastic properties. This makes it good as plugging material. Sandaband® consists of 85% solids and 15% fluids, making it a high density plugging material. The density of Sandaband® is 2150 kg/m^3 [14]. It is suitable for most downhole conditions, and is resistant to HPHT, CO_2 and H_2S [15].

Sandaband® is used for both permanent and temporary P&A. The advantage of using Sandaband® in temporary plug and abandonment, is that the material is non-consolidating. There is no need for milling to remove the plug when re-entering well. It is sufficient to circulate the material out of the well, which is time and cost saving. A Sandaband® plug is pressure tested immediately after being placed, since there is no need to wait for the material to be set [16].

When stresses is higher than stress limit for plugging materials, it will fracture. For Sandaband®, the shape of the plug will change if the stress is too high. Integrity will still be of good quality. "*Quartz is also the hardest and most thermodynamically stable mineral available, thereby ensuring an ever-lasting, flexible pressure seal in both open and cased wells*" [16]. The particle size distribution for Sandaband® is very wide, making it almost impermeable [14].

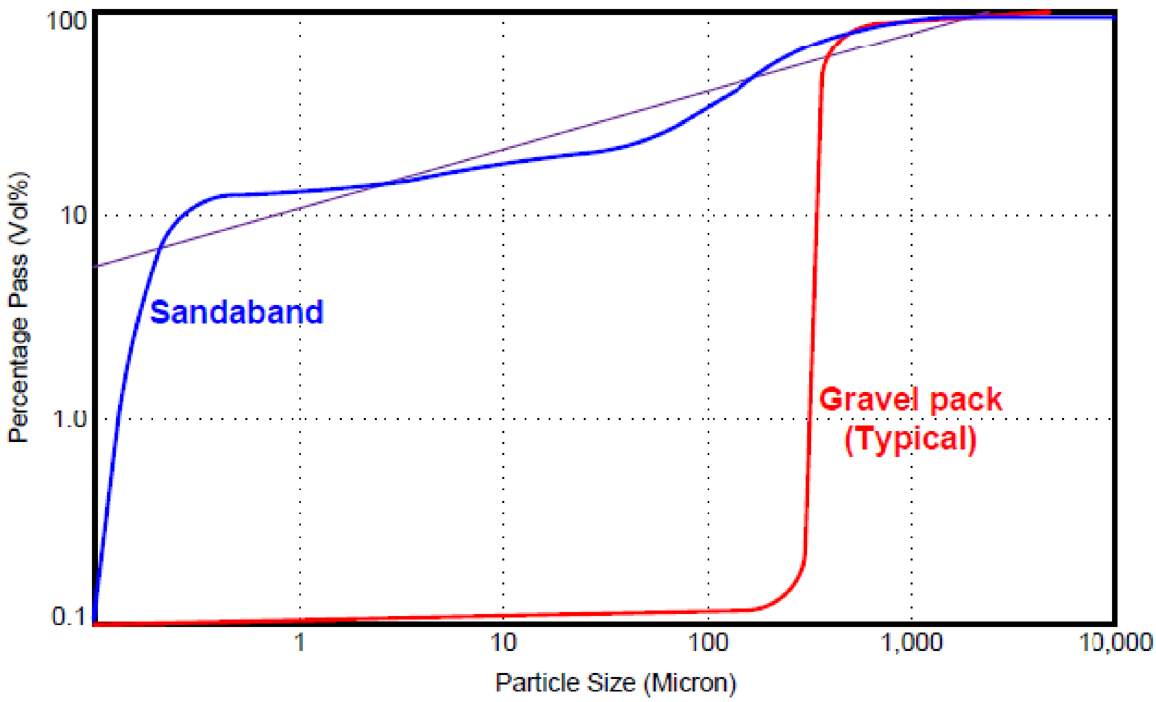


Figure 7: Sandaband particle size distribution [15]

4.1.4 ThermaSet®

Another alternative plugging material is ThermaSet® by WellCem AS. ThermaSet® is a non-reactive polymer, which is a particle free fluid. This material can be used for various applications like lost circulation, compromised wellbore integrity and P&A [17].

ThermaSet® is made to cure and become a very strong and flexible solid. It will withstand both thermocylic expansion and contractions after bonding to casing without cracking. Like Portland cement, setting time for the resin can be modified. It is also possible to adjust density. According to WellCem, the density range is between 0.7 – 2.5 SG [18]. ThermaSet® has the capability to penetrate pores and perforations, minimizing the permeability. Other properties of ThermaSet® is that it will bond to casing and formation. Contamination of ThermaSet® is acceptable up to 50% without compromising the integrity after being set [17]. It is also resistant to methane, crude oil, CO_2 and H_2S.

	Portland	**ThermaSet**
Compressive strength (MPa)	58	77
Flexural Strength (MPa)	10	45
E-modulus (MPa)	3700	2240
Rupture Elongation (%)	0.01	3.5
Tensile Strength (MPa)	1	60
Failure flexural strain (%)	0.32	1.9

Table 6: Portland cement and Thermaset® comparison [19]

ThermaSet® can be used in a large temperature range: -9°C to 150°C. Even though the temperature range is large, the upper limit suggest that ThermaSet® is not made to be sat in HPHT wells. Still it will be resistant up to 320°C after being set. Permeability and compressive strength is dependent of pressure and temperature [18].

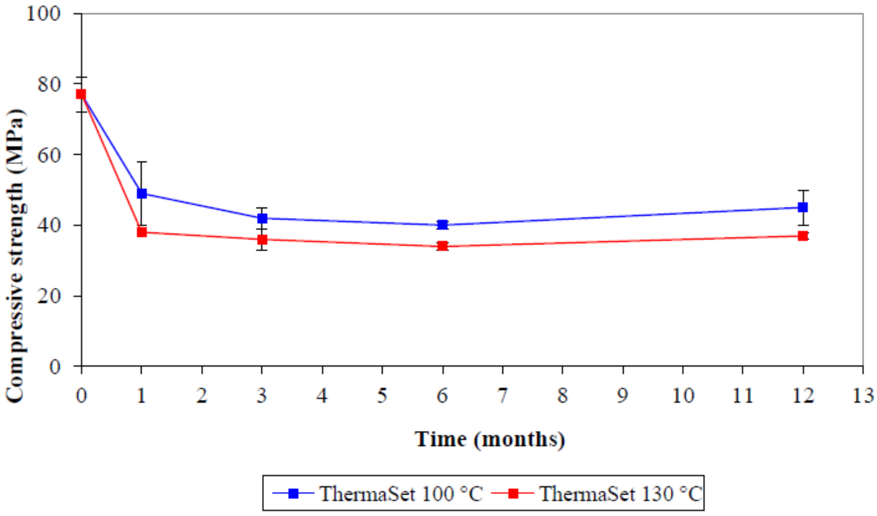


Figure 8: Compressive strength of ThermaSet® at given properties [19]

4.2 Well barrier establishment

Before establishing a well barrier, there are operations needed to maximize integrity of barrier.

4.2.1 Solid foundation

A solid foundation or plug base is essential for almost every plugging operation. By using a base, one will minimize movement and contamination of cement or other plugging materials while being placed [12].

Examples of solid foundations can be:

- Mechanical/bridge plugs
- High viscosity fluids

The principle is the same for both mechanical/bridge plugs and high viscosity fluids; obtain maximum stability and minimal contamination of plugging material.

4.2.2 Milling operations

Sometimes it is not enough to place a cement plug that bonds to casing. If there is poor casing cement or no open-hole access, there might be need for a milling operation. Section milling is removal of casing or/and cement with a milling tool at a certain section of the well. Removal of sections with bad annulus cement makes it possible to re-cement this area [1].

The milling tool is connected to a drillpipe, which rotates at a given RPM. The tool consist of “Knives” or cutter blades that cuts through casing and cement while drillstring is rotating. Residue from casing is called swarf and can be very problematic. It is important that flowrate and fluid viscosity is high enough to prevent bridging or pack-off from the swarf created by the milling operation. Swarf is not only a problem due to bridging and pack-off. It can also damage equipment and be harmful to personnel when being handled.

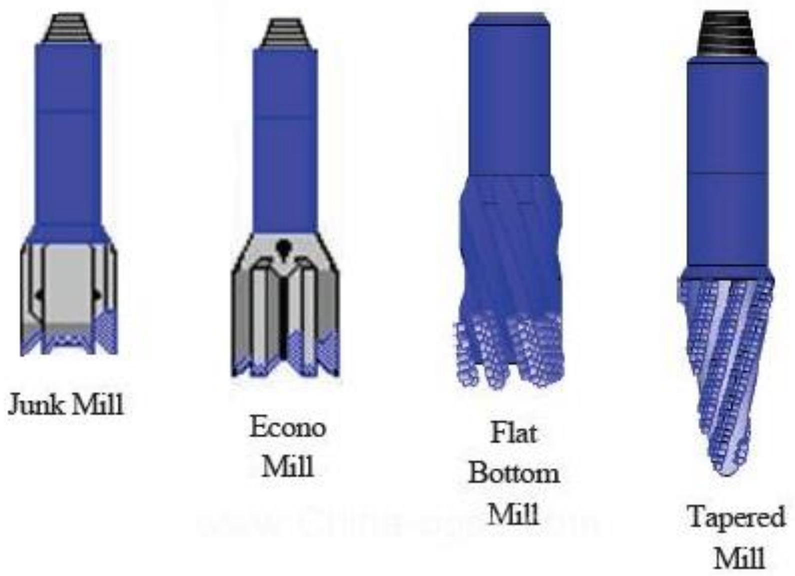


Figure 9: Milling tools [88]

Execution of milling will depend on different parameters according to NORSOK D-010. The first step is to log the casing to verify the bonding quality between casing, formation and cement. If verification of the integrity of the cement is good, and length is acceptable, there is no need for re-establishing the well barrier. If length of annular cement is not long enough to act as a barrier, one must decide if it can act as foundation or not.

If cement length <u>is</u> sufficient to act as foundation: Install mechanical plug and test it in the bonded area. Afterwards one must section mill a given length and underream/wash to expose formation.

If cement length <u>is not</u> sufficient to act as foundation: Install a mechanical plug as close as possible to inflow source and test it. Perforate and perform squeeze cementing at low pressure. This will now act as an external foundation. Section mill and underream/wash to expose the formation [1].

Mill 100 meters: If the milling length is 100 meters, cement plug shall be placed from foundation and be at least 50 meters across window. WOC and perform tagging. Place the second cement plug from the top of the first plug and 50 meters into the casing. Wait on cement and then perform leak of test with 70 bars above the leak of pressure. Primary and secondary barriers are now established.

Mill 50 meters or more: If it is not sufficient to mill 50 meters, an evaluation shall be performed to consider if it is necessary to mill a longer section. If 50 meters is sufficient, a cement plug shall be placed from the foundation and 50 meters into the casing. Wait on cement and perform leak of test with 70 bars above the leak of pressure. Establish the secondary cement plug in the same manner as the first one, and test it with the same properties. Primary and secondary barriers are now established [1].

For full overview, see section 9.6.7 in NORSOK D-010 (2013).

4.2.3 PWC – Perforate, Wash and Cement

A new plugging system invented to eliminate many of the challenges associated with section milling. Like section milling, it is important with high enough mudweight to maintain an overpressure while performing the operation. In this case, a high viscosity fluid is not required, unlike section milling where cuttings and swarf transport can cause problems if fluid viscosity is not sufficient [19].

For PWC operations, wellbore is cleaned both on the inside and outside of the casing. Cleaning process consist of removing mud, formation cuttings and weighted mud materials from annulus and perforations. This process reduces the probability of pack offs, which can be a problem in milling operations. One also prevents HSE issues related to swarf cuttings.

Tool used in PWC operations consist of 50 meter drillipipes installed with a perforation gun with 12 shots per foot in 135/45 degrees phasing angle. The washing tool is located above the perforation gun. Both perforation gun and washing tool is detachable. Perforation gun is released and left in hole after the perforation sequence is completed. The washing tool is detached by releasing a ball. The tool will then be left in the hole and work as the cementing foundation. Placement of washing tool foundation shall be below the perforated section. A cement stinger is placed at the top of the tool. When washing tool is sat as base, the cement stinger is pulled to a position above top perforations and a balanced plug is sat [19].

4.3 Cementation method

A good cementing job is key to a successful plugging. Hence, it is important to choose the right method of well cementing. There are several methods of setting a cement plug when plugging a well. The procedures are different from each other, but the goal is the same: to set a cement plug that will isolate potential permeable zones, and prevent fluid leakage when abandoned.

4.3.1 Balanced plug method

The balanced plug method is the most common cement placement technique. It is pretty straight forward, and results in minimum cement contamination. First tubing is run into the well, down to the depth of plugging base. Spacer fluid is pumped down tubing ahead of cement to prevent contamination. There is also spacer fluid behind cement. It is important that the cement is to be placed on a solid foundation to prevent loss or contamination. Both viscous fluids and mechanical plugs can work as plug base. Volume of cement is calculated in such way that the height of cement in annulus is equal to the height inside the tubing. To prevent mudflow on rig floor while pulling tubing, it is common to under displace the plug. In addition of preventing a mess when pulling tubing, it also allows plug to reach hydrostatic balance. Tubing is pulled after plug is balanced. Excess cement is then reverse circulated out of tubing [12].

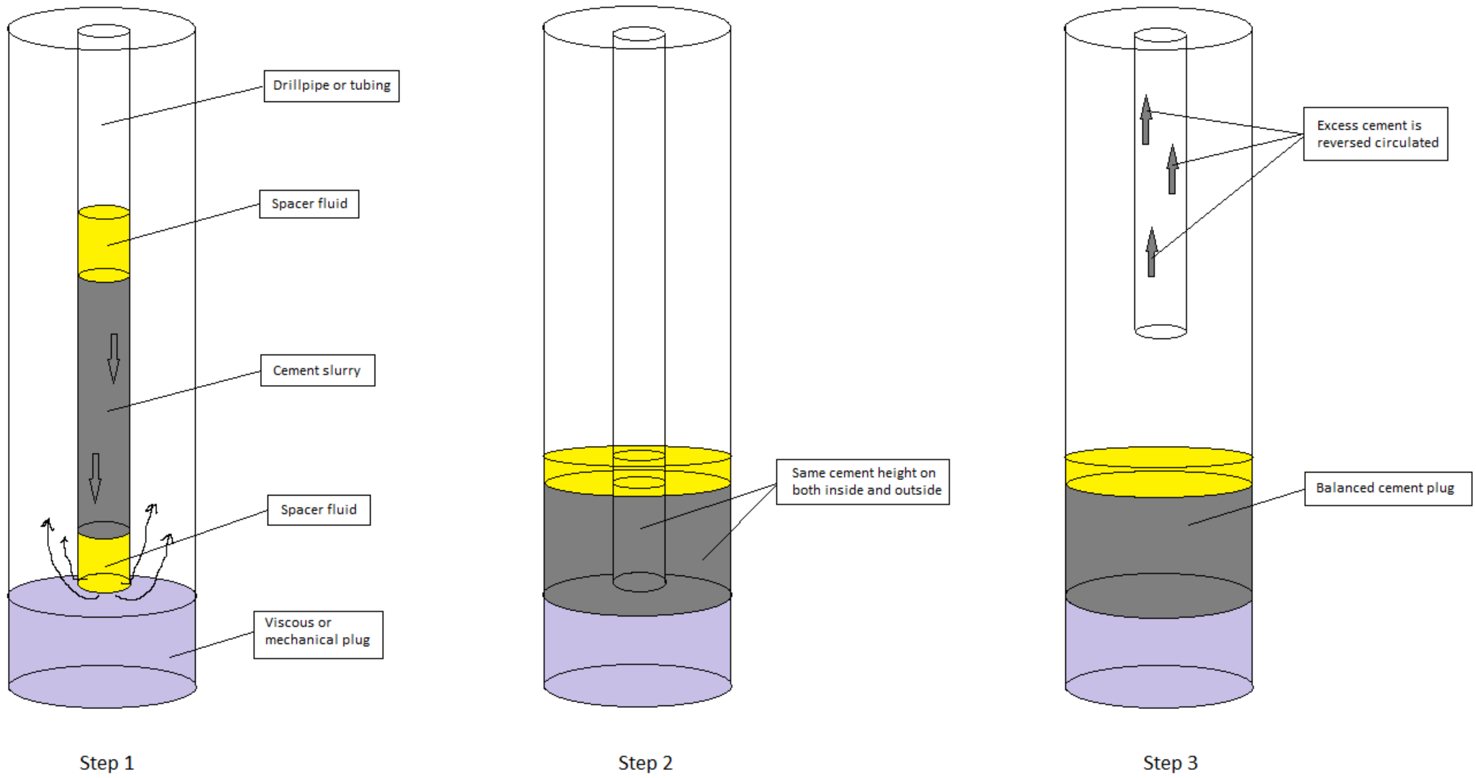


Figure 10: Balanced plug method

4.3.2 Dump bailer method

Dump bailer method is a very plain and simple method of setting a cement plug. A dump bailer attached on either wireline or slickline is lowered into position right above the desired plugging area [20]. The dump bailer contains a given amount of cement slurry which should be placed on a solid foundation.

Volume of cement slurry is limited to cement retainer volume. Additional cement retainer tubes can be added if larger amounts of cement is required [21]. The dump bailer can either be opened by a mechanical, electrical or hydraulic mechanism. Usage of this method is limited to needed volume and depth. Dump bailer method is mostly used in shallow depths, but can be extended by use of retarders. Cement slurry is static in the dump bailer, and will cure over time.

Dump bailer cementing is a cost effective way of setting a plug. However, it is limited considering the amount of slurry carried inside the retainer tube. It is possible to do multiple runs, but this is very time consuming since cement dumped must first be set before placing new cement on top [12].

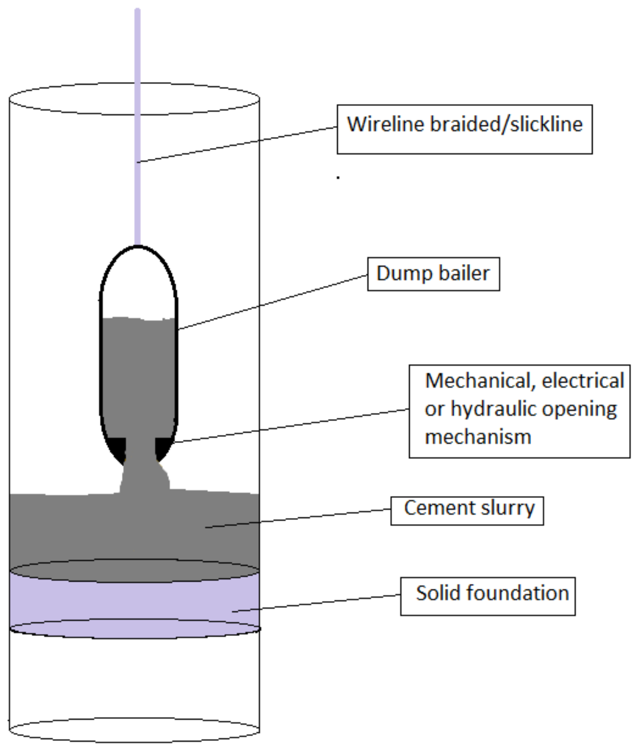


Figure 11: Dump bailer method

4.3.3 Two plug method

It has it name from the use of two wiper plugs/darts in the procedure. One plug on top and one on bottom. Wiper plugs are rubber plugs used to separate cement from other fluids, thus minimizing the contamination. Bottom plug is hollow, and will rupture when a certain pressure is reached. Top plug has a solid core and will land on top of the bottom plug after cement is circulated out in the well [22].

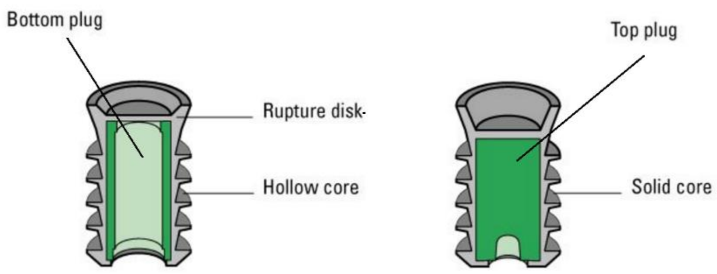


Figure 12: Wiper plugs [23]

A tailpipe connected to a drillpipe is lowered to plugging base. The tailpipe is installed with locator subs that will collect the wiper darts under circulation. Spacer fluid is pumped ahead of bottom plug to clean inside of tubing and isolate cement from drilling fluids. Cement is placed behind bottom plug, forcing it downward until it hits the locator sub. At this point, the bottom plug will no longer move downward. The top plug is pushed down by pump pressure that gives a pressure buildup on top of bottom plug. When a specific pressure is reached, the bottom plug ruptures forcing the cement into well. Top plug will move downward until it reaches top of bottom plug, and becomes stationary [12]. Cementing process is now complete. Figure 14 illustrates the procedure.

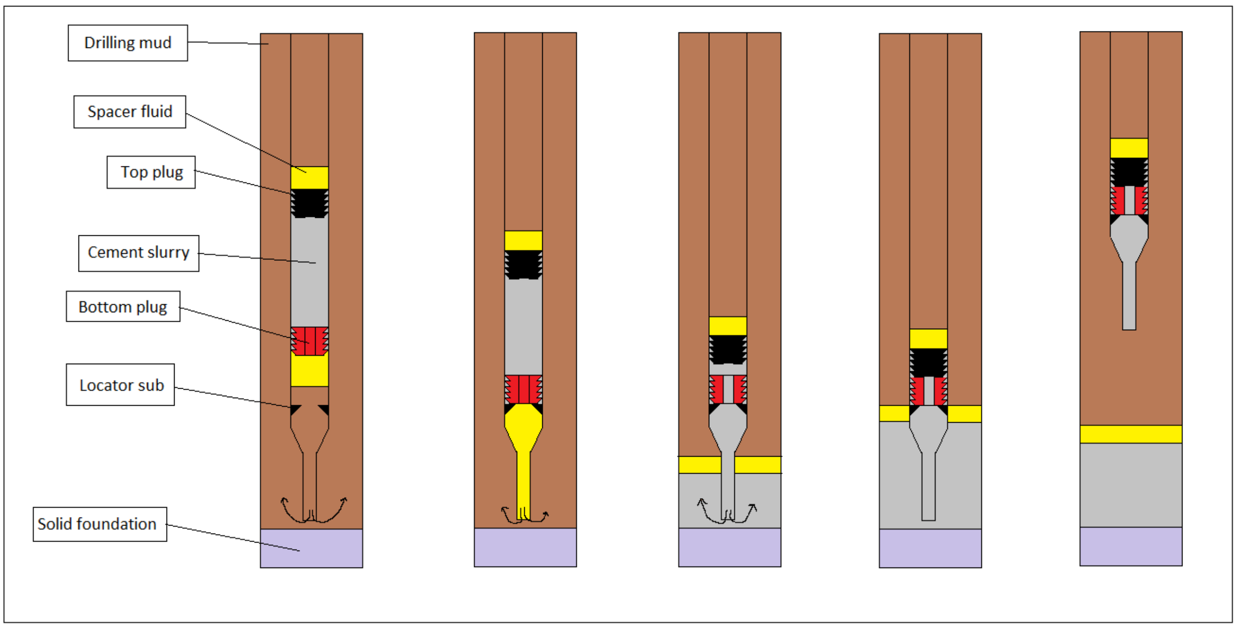


Figure 13: Two-plug method procedure

5. Cement verification and logging

After cement is set it is important to evaluate if the job was successful. There are several methods of evaluating the integrity of cement after being set. Incomplete cementing jobs are critical and should be avoided at all cost. When cement is being set, it should bond to steel and formation to prevent microannuluses or channels. In contact with gasses and fluids, the microannuluses will be primary migration route, which might boost degradation speed.

There are many parameters to take into consideration while choosing evaluation method:

- Temperature and pressure
- Fluid properties
- Size and thickness of casing
- Thickness of cement
- Formation properties
- Centralization of tool

5.1 Cement logging

5.1.1 Cement bond log

One of the most common and used methods of cement evaluation is CBL (cement bond log). CBL is run to determine bonding between cement and casing and bonding between cement and formation. These logs can evaluate channeling in cement, microannuluses and top of cement [23]. The tool has an acoustic transmitter, which transmits either sonic or ultrasonic waves. Conventional logging tools consist of either one or two receivers, while special CBL tools can consist of multiple transmitters and receivers [12].

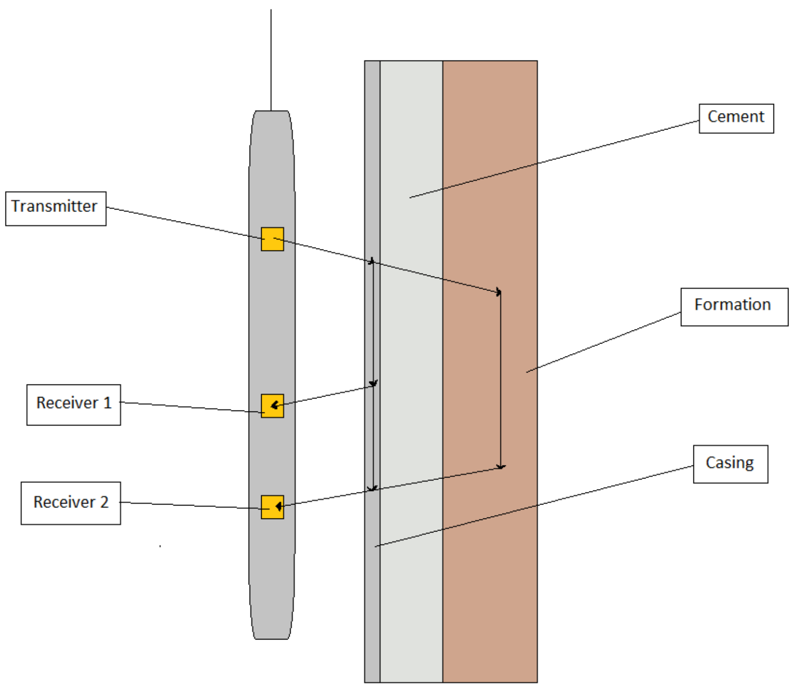


Figure 14: Conventional CBL tool

The transmitter shoots out short bursts of acoustical energy, which travel through casing, cement and formation. The frequency will depend on tool or drillers selection, but frequencies from conventional CBL tools are usually between 20 – 30 kHz. When the waves is transmitted to the receiver, several data is recorded.

- Amplitude
- Travel time
- Transit time

These data can be illustrated as below.

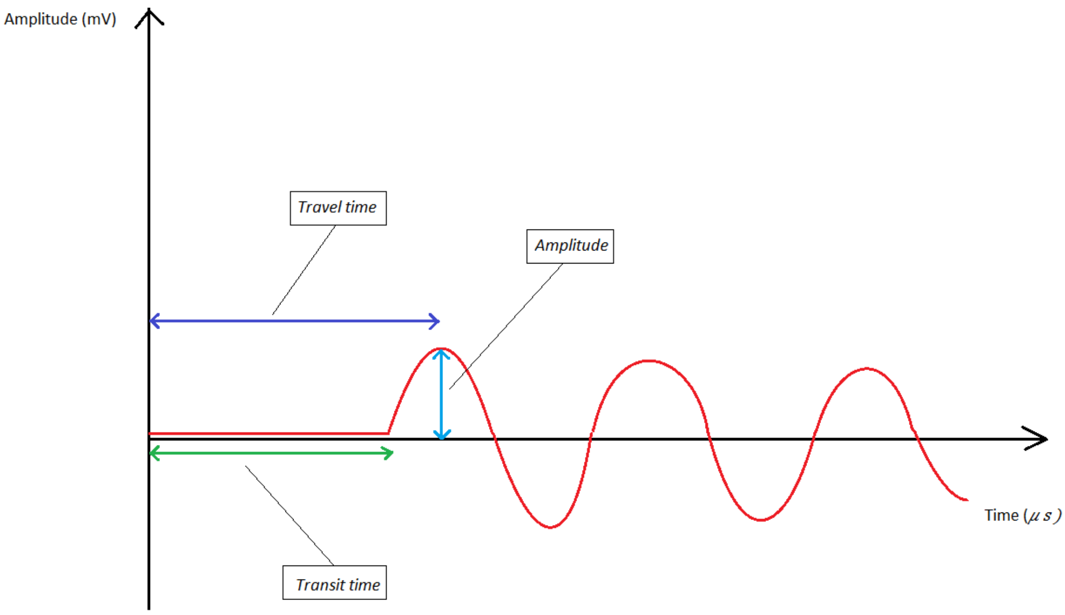


Figure 15: CBL readings [12]

High amplitude will suggest that there is lack off cement, while low amplitude suggests good cementing job. Downhole properties and other parameters can be challenging, which again can result in misinterpretation of the data. Both temperature and pressure affects the velocity and attenuation of sound. Fluid density affects transit time and amplitudes of the wave. It is important to have information about all properties and parameters to avoid misinterpret bad cement bond as good [23].

5.1.1.2 Cement bond quantifying

When logging, it is important to know how good the cement bond is. This can be done my measuring attenuation. Attenuation measures how much signal intensity that is lost from transmitter to receiver. By measuring attenuation, bond index can be calculated. Bond index is the ratio between maximum and measured attenuation. According to Archer, 80% BI is accepted as good cementing job [24].

Bond index calculation

$$BI = \frac{(\log \frac{E_{log}}{E_{FP}})}{(\log \frac{E_{CP}}{E_{FP}})}$$

E_{FP} = Free pipe amplitude
E_{CP} = Cemented pipe amplitude
E_{log} = Measured amplitude

BI = 1: The cement job is perfect and is fully bonded.
BI = 0: No cement

5.1.1.2 VDL – Variable density log

There are two ways of presenting/displaying logged signals. The first method is to show waveform by itself. Using this method, there will not be seen a continuous display with depth. Waveform can only be read for every 2 to 4 feet [12]. This method will not give a continuous picture of the well.

Variable intensity display is the second method of presentation of waves recorded from CBL. For this method, the waves are converted to different shades of gray depending on amplitude. VDL is widely used today, and is good to use in combination with CBL. This helps to give better interpretation of logged data. Abnormalities, like channelings or microannuluses can be identified using the VDL [25]. Appendix A shows a combination of CBL and VDL.

5.1.1.3 Qualitative interpretation

Analysis of the full wave only gives qualitative information of cement job. Good cement to casing bond will result in sonic energy leaving casing and into cement. Further, if there is good cement to formation bond, most of the energy will then travel into formation before propagating and attenuate. Formations are nearly never homogenous, and the logged waves will vary along the wellbore. Some cases are special, and information about these cases is needed while being interpreted [12].

Unconsolidated formations: Often very shallow formation. These formations will attenuate the acoustic sound. No waves is shown on VDL due to very low amplitude.

Fast formations: In these formations, sound will travel faster along formation than casing. Wavy VDL patterns is seen earlier than arrivals from casing.

Salt formations: Formations, which are highly plastic and have little heterogeneity. Regular VDL is seen, but sometimes similar to free pipe.

5.1.1.4 Quantitative interpretation

Figure 17 represents the first cycles that are received from the acoustic transmitter. For acoustic logging, it is normal to label the positive half cycles as E_1, E_2, E_3 and so on. Negative half cycles are shown as even numbers like E_2, E_4, etc.

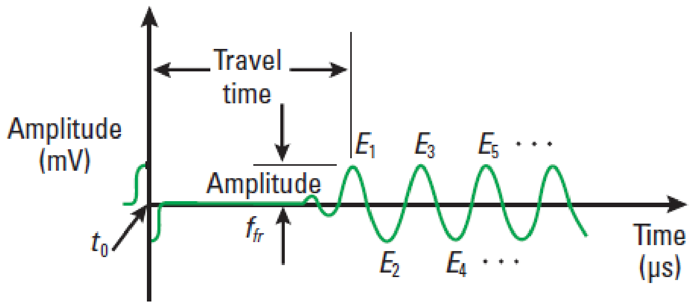


Figure 16: First received acoustic waves

Ideally, the first received cycles indicate casing signal, at least free pipe situations. For cemented pipe, thickness and formation properties can affect the first received signal.

"The underlying premise in quantitative bond logging is that the strength of the casing signal is a function of the material adjacent to the casing" [12]. Following this premise, the earliest detectable wave E_1 should be measured. Theoretically, the E_1-arrival is not the first. E_1 is proceded by very small, almost undetectable cycles. Many schemes have been implemented. Peak amplitudes of positive half cycles, area under half cycle and area of multiple half cycles. This results in different reading for different tools in the same well at the same time. Geometrical and physical parameters affect the readings. Therefore, it is very important that E_1 is measured [12].

First quantitative measurement of the log is the elapsed time between transmitter firing and arrival of first wave with an amplitude that exceeds a given threshold. This time is also called the transit time. The most valuable function of transit time is quality control.

Second quantitative measurement is the wave amplitude. This measurement makes it possible to do a quantitative evaluation of the cement. Arrival time of the peaks are related to the geometry of the tool and casing, and properties to the wellbore fluids. Thus, measurement of the amplitude can be made using either a fixed or a sliding gate. Fixed gate is the most commonly used method today. This method uses the wave amplitude, preferably the E_1 half cycle. It is important that the setting of gate is correct to obtain an amplitude bond-log curve that is acceptable [12].

5.1.1.5 Cement bond log challenges

There are certain parameters that are important considering quality of recorded logs. As mentioned earlier, interpretation is dependent of the first wave arrival. Microannulus width is limited to 0.1 mm for CBL. Other challenges are:

- Wet microannulus affects the logging
- Logging tool must be centralized in well to receive first signal at the same time from all directions.
- Affected by parameters like casing size, fast formation, salt formations and unconsolidated formations.
- No azimuthal resolution [26].
- Cement bond logs does not measure isolation. Bond logs will at best measure annular fill of cement contacting the pipe on the outside.
- Cement must cure before logging. Rule of thumb says 72 hours after being set.
- The bond index will be affected by both annular fill and compressive strength of the cement [27].

5.1.2 Ultrasonic logging

First applied to well logging back in 1969 by Zemanek and Caldwell. They designed what was called a Borehole Televiewer, which is what today ultrasonic logging tools is based on. When conventional CBL runs at 20-30 kHz, the frequency of the ultrasonic tools are between 200 – 700 kHz [12]. The thought behind the ultrasonic tool was to solve the challenges related to conventional cement bond logs. One of the major challenges of the CBL log is detection of fluids in microannuluses. This is less of a problem for Ultrasonic logs, as the liquid filled channels/microannuluses will show on the log.

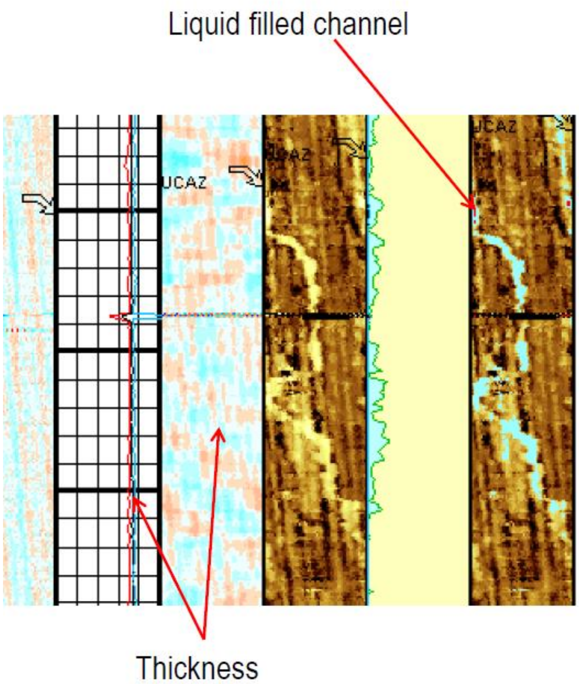


Figure 17: Ultrasonic log example - Liquid filled channel [27]

According to Erik B. Nelson, the idea of ultrasonic logging is *“to make a small area of the casing resonate through its thickness”* [12]. The tool sends out short pulses of ultrasonic sound, which then will give an echo that the tool receives. Solid formation or cement will be detected as a rapid damping of the resonance, while liquid filled channels/microannuluses or lack of cement will result in a long resonance decay [28].

5.1.2.1 Cement evaluation tool

The first generation ultrasonic logging tools used was CET (Cement evaluation tool). CET tools have eight transducer that emits ultrasonic waves. The transducers are evenly arranged around the tool, with transducers every 45^{o}. There is also a ninth transducer measuring the speed of sound in the wellbore fluid [12]. The distance from transducers and casing wall is around 2 inches. Cement evaluation tools are also called pulse echo tool.

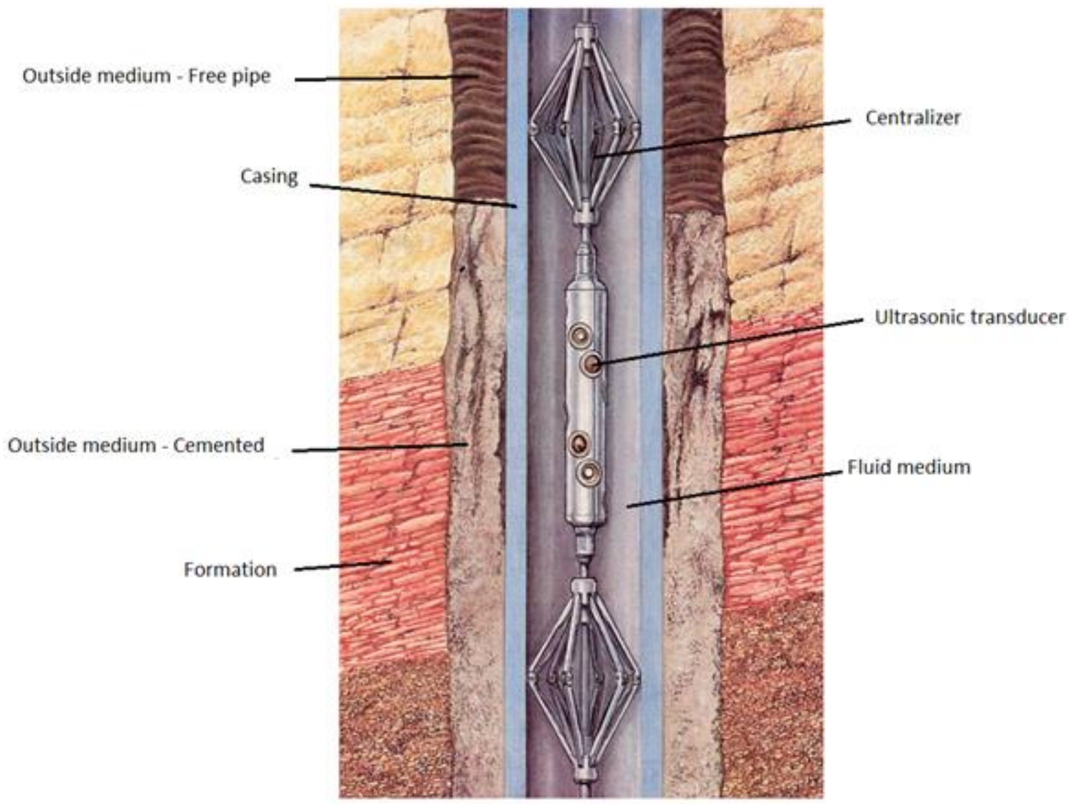


Figure 18: CET layout [12]

The short pulses travels through the wellbore fluid, and the most of the pulse is reflected back to transducer when it hits the first interface, which usually is casing. A small part of the pulse will be reflected back and forth on the inside of casing. While some of it will travel into cemented or free pipe area on opposite site of casing. Response of the ultrasonic pulse can be illustrated as shown in figure 20. ”*Each impulse amplitude is a function of the acoustic impedance in the three media”* [28], which is fluid, steel and outside medium. The first peak is much larger than the other, and indicates signal reflected from casing. The other signals will be shown as opposite of casing signal. Their amplitudes forms decay that is exponential. For free pipe with water in both annulus and outside medium, decay will be slow. Thus for outside medium filled with cement decay is fast due to good acoustic coupling [28].

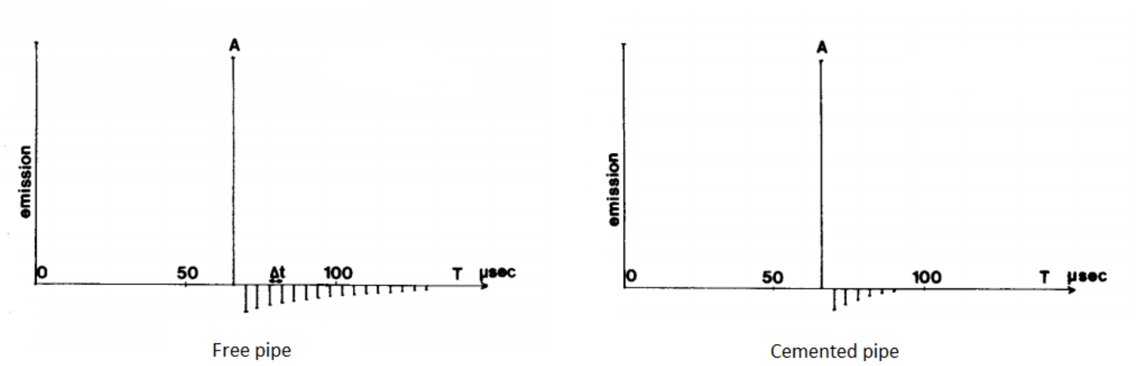


Figure 19: Ultrasonic impulse response [29]

Ultrasonic tools have a frequency rate between 200 and 700 kHz. CET tools run between 300 and 600 kHz. The frequency that is used depends on casing the thickness. Casing thickness is usually between 0.2 to 0.6 inches. For thinnest casing thickness, the corresponding resonance frequency is 600 kHz. Resonance frequency is reduced when casing thickness increases.

5.1.2.2 UltraSonic Imager tool

USI is known as second-generation ultrasonic logging tool, developed by Schlumberger in 1991. The USI tool is a continuously rotating pulse echo tool. It is an improvement to earlier generation tools since it covers almost 100% of the well. Even though it sends pulse signals like CET/PET, the process is still very different.

The tool has a transducer at the bottom, which also works as a receiver. This transducer rotates at 7.5 rounds per second, and can do measures at each five degrees rotation. When the transducer rotates, it emits signals, which then is reflected back and is recorded. USI tools will work for casings sizes from 4.5” to 13 3/8”. Density of drilling mud is maximum 1.9 SG [27].

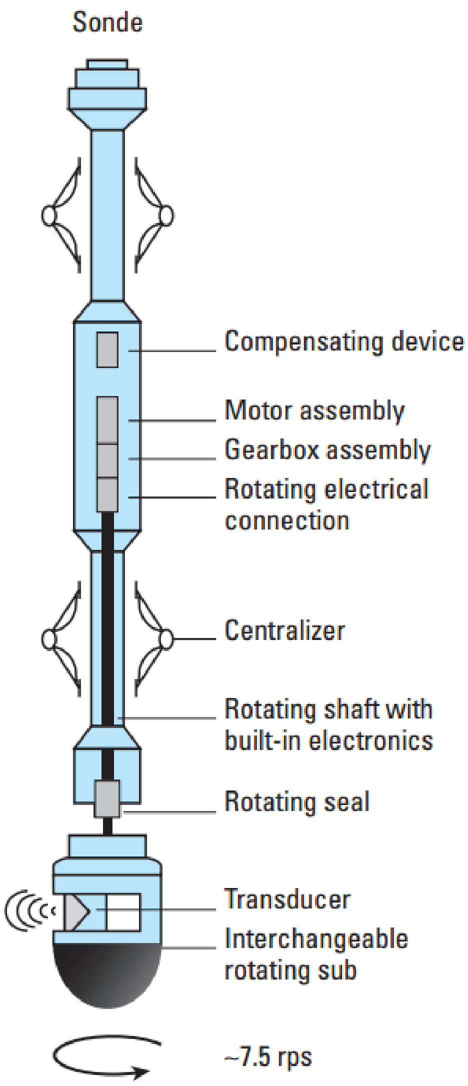


Figure 20: Ultrasonic imager tool [12]

"The rate of decay of the waveforms received indicates the quality of the cement bond at the cement/casing interface, and the resonant frequency of the casing provides the casing wall thickness required for pipe inspection" [29]. With a rotation of 7.5 rounds per second and burst signal frequency every 5 degree rotation, it is capable of emitting 32 400 signals each minute. These signals are recorded, and a computer makes real time USI "maps". Unlike VDL where the waves are converted into different shades of grey, the USI logs are color-coded [29].

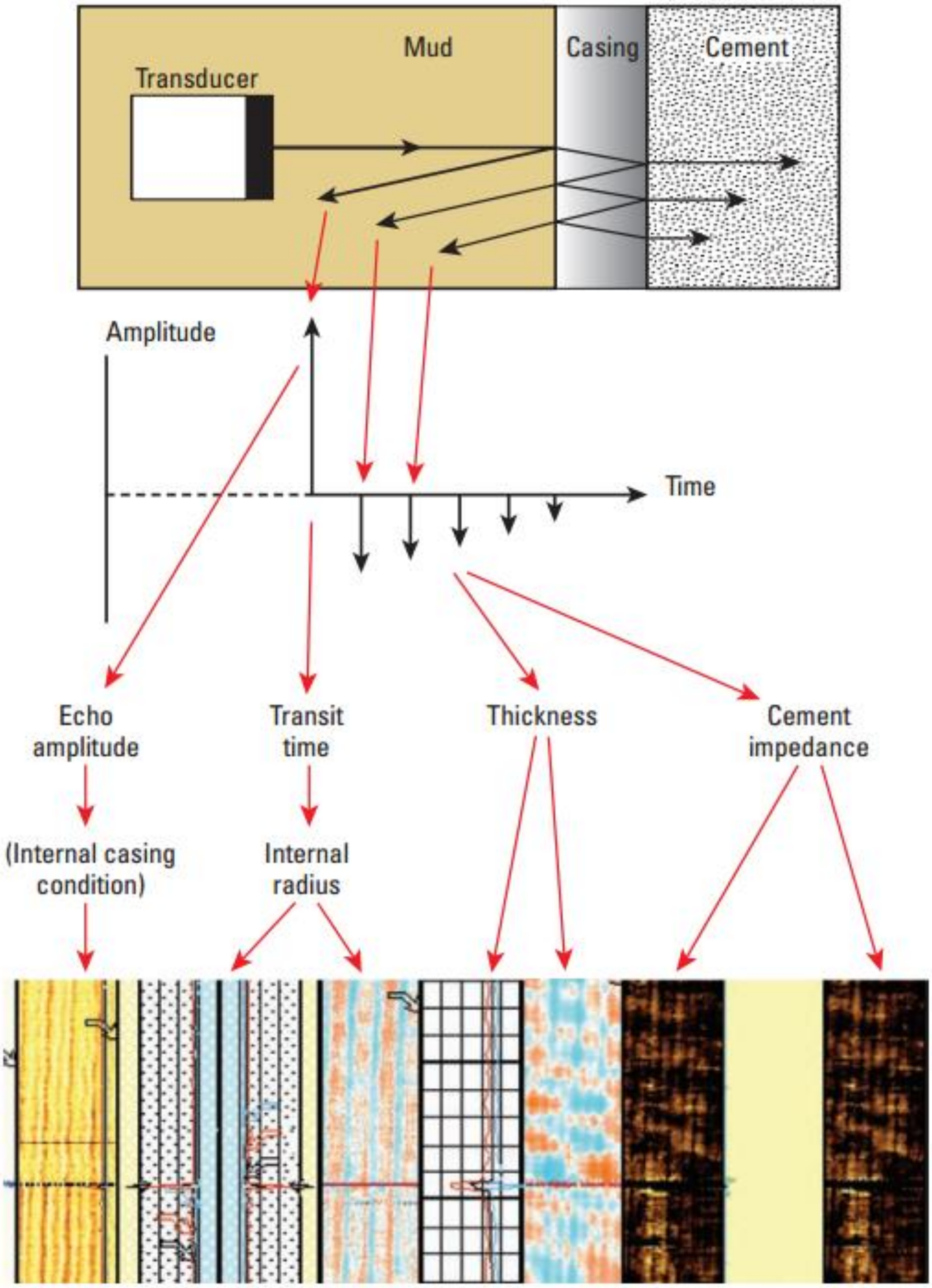


Figure 21: Ultrasonic log [12]

5.1.3 Comparison between CBL and Ultrasonic logging.

There are both pros and cons for both system, but having the possibility to use both will give the best result. While ultrasonic logs are insensitive to microannuluses and is independent of cement properties, it is limited to mudweight. In some situations CBL will be preferred instead of ultrasonic logging, and vice versa. A combination of both sonic and ultrasonic logs provides us with more information than one of them alone.

Sonic logs	Ultrasonic logs
Will work in almost every mudweight.	Has a limited mudweight working range. Mentioned in part X, the maximum MW is 1.9 SG.
Qualitative evaluation of the formation.	No formation evaluation.
Very sensitive to microannuluses.	Insensitive to microannuluses.
Is sensitive to the material in contact with pipe.	Independent of cement properties.
Limited in lightweight cements.	Casing inspection is possible to include during logging.
Average result over 3 feet of wellbore.	No averaging of wellbore.
Resolution of advanced tools is 6 inches.	Ultrasonic tools is preferred cement systems with low strength and low density.

Table 7: Sonic and ultrasonic log comparison [31]

5.1.4 Ultrasound detection

Even though CBL gives a good picture of cement job performed, it still does not certify or confirm fluid isolation of the different zones. Microannuluses can be very small, and according to Archer, 0.1 mm is the detection limit for CBL [24]. 0.1 mm wide microannuluses is still large enough for gas to flow. Another detection technique is needed to determine cement isolation.

Ultrasound detection is a technique to find even smaller microannuluses than with cement bond logging. A tool that detects ultrasound is lowered to wanted position. The tool is run along cemented area and measures sound. For places where there are migration of HC through tight spaces, there will be an ultrasound response. Both liquids and gasses makes a distinctive sound when being choked and forced through a restriction [24].

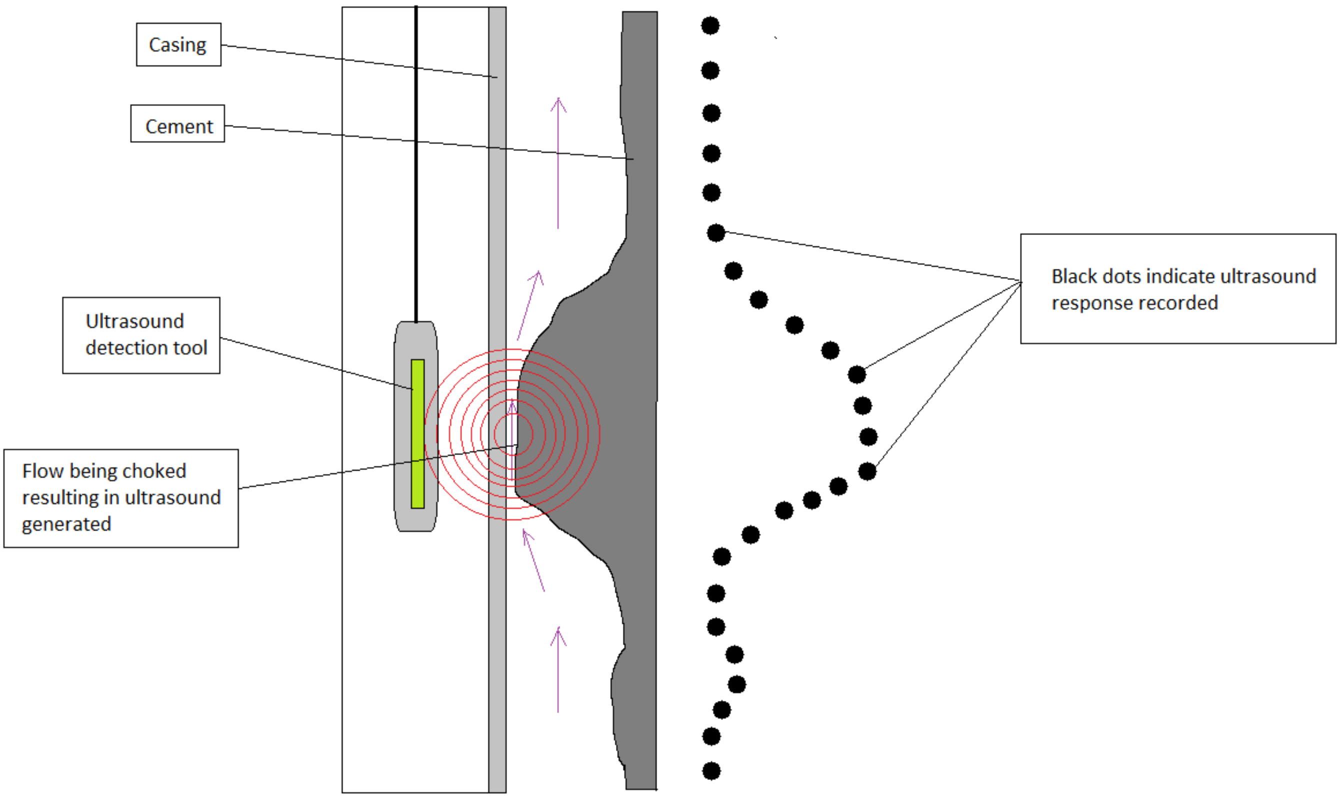


Figure 22: Ultrasound detection

5.1.5 Temperature logging

Temperature logging is used to evaluate primary cementing jobs. Main objective of log is to detect TOC. Can also be used to detect channeling or leaks in cement sheath [12].

Top of cement for primary cement can be verified by exothermic cement-hydration reactions. These reactions will raise the temperature, which results in a deviation from the normal temperature gradient. The readings can be illustrated as in figure 23, and the anomaly will suggest where TOC is. Temperature log is not suitable for long cement sections due to large differential temperature between TOC and bottom [12].

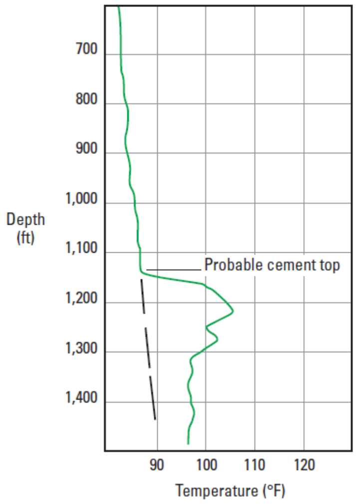


Figure 23: Temperature log survey [12]

Channeling and leak can be detected with use of the Joule Thomson-effect. This effect can be defined as "*the change of temperature that a gas or liquid exhibits during a throttling process, shown by passing through a small aperture or porous plug in a region of low pressure*" [30]. Gasses will typically be cool when expanding, while liquids will be warm if pressure is high.

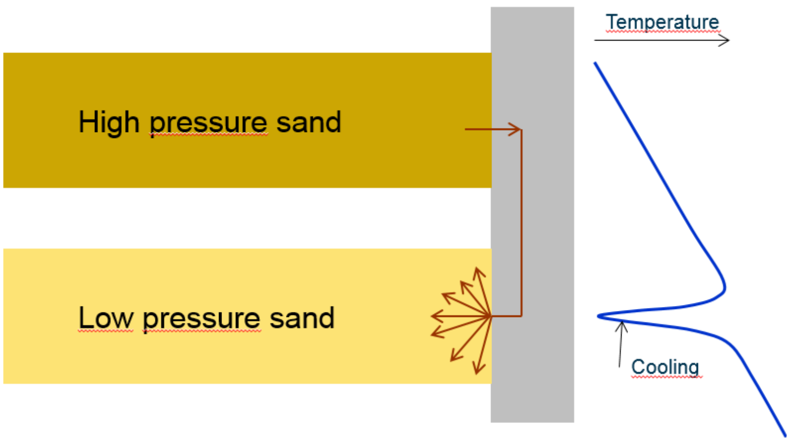


Figure 24: Joule-Thomson effect [25]

5.1.6 General challenges related to bond logs

As mentioned earlier, bond logs have several limitations, and are affected by different parameters. The biggest challenge for a cement evaluation is to understand the objective of the job, and decisions made to determine the success of the operation.

Earlier mentioned parameters:

- Fast formation.
- Salt formation.
- Liquid filled channels and microannulus.
- Centralization of tool.
- Casing thickness.

Cement with density close to density of drilling fluids can be very difficult to separate between solid and liquid. In addition, cement with low compressive strength can be hard to find on a log. Use of special tools and software are needed for these scenarios [31].

As mentioned in chapter 3, todays logging tools are not capable of logging through multiple casing strings. Hence, it might be required to remove casing string to gain access for logging casing behind.

5.2 Cement testing

Cement logging is not sufficient to evaluate integrity of cement. Cement logging is primarily used for evaluating primary cement jobs, since acoustic waves moves sideways into the formation. For plug and abandonment procedures, evaluation of cement plugs or other plugging materials after plug is set is needed.

5.2.1 Hydraulic testing

Hydraulic testing is used to evaluate isolation provided by cement placed in the well. This testing can be performed after both primary and secondary cementing. Most common procedures of hydraulic testing is pressure testing and dry testing.

5.2.1.1 Pressure test

Pressure testing is primarily used to verify casing integrity during completion of the well, but it can also be used to test integrity of cement plugs. This is done by adding a differential pressure between top and bottom of cement plug. Pressure at top shall be larger than bottom pressure. Fluids is pumped down through choke or kill line. Pump is activated until desired pressure is reached. When test pressure is reached, pump is shut down and pressure monitored for a predetermined time. After the predetermined period is over, pressure is bled off to zero psi. Volume of returned fluids is recorded and compared against volume required to pressure up system to wanted test pressure [32].

According to NORSOK Standard D-010 (2013), a pressure of 70 bar above estimated leak-off pressure below casing should be applied for cased holes plug, and a pressure of 35 bar shall be applied for surface plugs. NORSOK Standard D-010 (2013) also states that a pressure test with high pressure should have a duration of minimum 10 minutes with stable readings. For open-hole, there is no requirements for pressure testing of cement plug. [1]

5.2.1.2 Dry test

Dry test or inflow testing is basically the opposite of pressure testing. In this case, the pressure inside casing above the plug is reduced to test integrity of cement plug. Well pressure is monitored over time to see if there is any inflow. Due to higher pressure below plug, a pressure increase above plug will be seen if there is any inflow from below. NORSOK D-010 states that minimum 30 minutes of stable pressure recording is required. It shall last longer if there is large volumes, temperature effects or high compressible fluids [1] .

5.2.2 Tagging

According to NORSOK Standard D-010 (2013), tagging has to be performed for both cased and open-hole plugs, unlike pressure testing which is only required for cased-hole plugs. This is essential to know if plug length is according to the regulations. Tagging of cement plug is a procedure where top of cement is located. This can be done with either wireline, tubing string or other intervention tools [33].

1. To perform a successful tagging, calculated TOC should be known.
2. Tools is then lowered into hole to about 1-2 stands (one stand is usually 90 feet long) above top of cement.
3. Prepare top drive or Kelly (depending on rig setup).
4. Pump rate is lowered.
5. Monitor weight while slowly washing down towards plug.
6. Wash downwards until a solid weight is recorded.
7. Tagging cement plug after being set will prevent in stuck pipe [34].

6. Well barrier degradation

When a well is abandoned, the two main barriers will be cement and steel casing. The most common cement used is Portland class H and G. Both steel and cement is affected by different downhole properties. Gasses and liquids can change the composition of materials, and weaken them, resulting in reduced well integrity.

Several gasses and liquids can affect both casing and cement. In this chapter it will primarily be focused on carbon dioxide. This gas is very abundant and is used in EOR. Carbon dioxide sequestration is also up and coming around the globe, as it can reduce emissions and environmental footprints.

6.1 Carbon dioxide degradation of cement

CO_2 is one of the most known greenhouse gasses. It is produced naturally from exhaling and is also a byproduct from usage of fossil fuels like gasoline. This greenhouse gas is affecting the environment, and stricter regulations regarding emissions is therefore introduced. EU decided in 2015 that the average emission from cars should not exceed 130 grams of CO_2 per kilometer. By 2021, EU wants it to drop to 90 gram per kilometer [35].

Also in the oil business, lower CO_2 emissions is desired. Statoil is working with projects on how to store CO_2 that is produced and reduce the emissions. Sleipner was the world's first large scale method of storing CO_2. This method of CO_2 storage is called CCS or carbon capture and storage [36].

6.1.1 Carbon capture and storage

CCS is capturing the CO_2 that would otherwise be discharged to air and store it some place where it will not escape. Like a depleted gas or oil well. Especially large power plants and refineries have the ability to release large amounts of CO_2.

In Norway, there are several projects that have been implemented for CCS. Sleipner as mentioned, have been storing CO_2 since 1996, and has since then stored up to over one million tons of carbon dioxide each year. The storage at the Sleipner fields has of 2010 stored over 12 million tons of CO_2. This makes it the single largest emission reduction project in Norway. Outside Hammerfest at the Snøhvit field, they are storing over 700 thousand tons of CO_2 annually. Combining these two field, which averaging 1.7 million tons each year, is equivalent to the CO_2 emissions of almost 900 000 cars annually (Calculated with 130 g/km and 15 000 km per year) [37].

CCS is the future of reducing CO_2 emissions, and abandoned or depleted wells seems to be the best way of storing it. However, is it safe? At some point, the amount of CO_2 will reach a point where it might not be possible to inject more. Then these wells will also have to be plugged and abandoned. CO_2 at high pressure might act as a threat due to barrier degradation. A criterion for geological CO_2 storage is that there should be no leakage over hundreds or even thousands of years. Nearby wells might also be affected by the injected carbon dioxide.

6.1.2 CO_2-equilibrium

In wet environments, CO_2 will undergo some reactions. The equilibrium with water is shown below.

$$CO_2\,(g) \rightleftharpoons CO_2(aq)$$

$$CO_2\,(aq) + H_2O \rightleftharpoons H_2CO_3\,(aq)$$

$$H_2CO_3\,(aq) \rightleftharpoons HCO_3^- + H^+$$

$$HCO_3^- \rightleftharpoons CO_3^{2-} + H^+$$

Gas pressure or CO_2 content will directly affect how corrosive the wet CO_2 will be. Increase in both pressure and CO_2 content will lower the environments pH and become very acidic. High acidity is corrosive for steel and cement.

Water salinity is also an important factor when it comes to degradation rate. CO_2 solubility is shown to be reduced with an increase in salinity [38]. Pressure and temperature are also parameters affecting the solubility of CO_2. Figure 25 shows solubility for CO_2 at different temperature, pressure and salinity. Solubility will increase with pressure, but will decrease with higher salt concentration. Figure 25 also suggest that solubility is highest with high pressure, low temperature and low salinity.

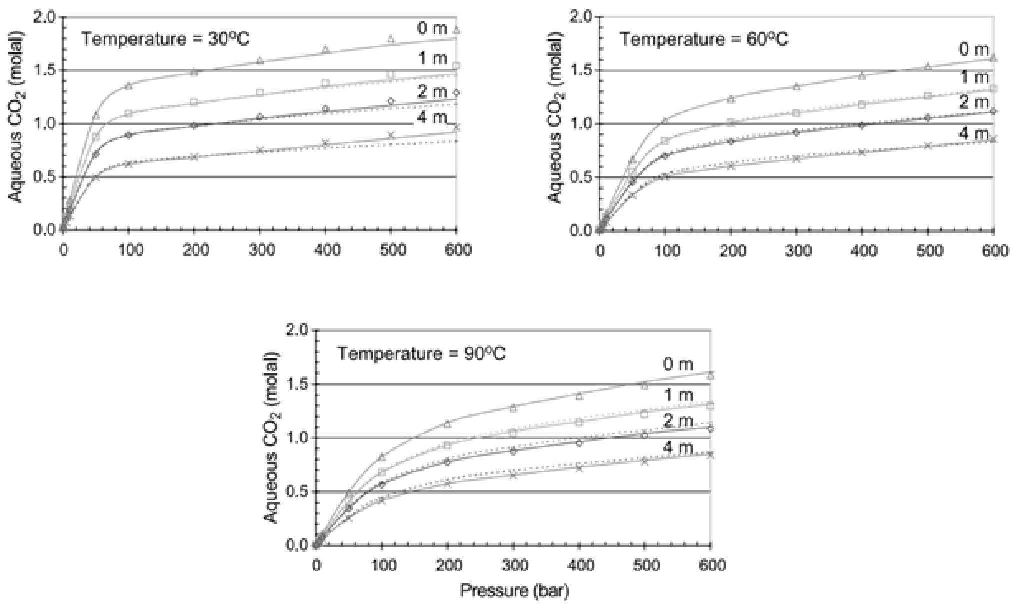


Figure 25: Solubility of CO_2 in different salinity at various pressure and temperature [39]

6.1.3 CO_2 effect on Portland cement

Mentioned in the cementing section, Portland class G and H are the most known and used cements regarding primary and secondary cementing. Portland cement is known to be degraded in contact with CO_2. Several studies have been carried out to study the reactions between Portland cement and carbon dioxide.

Portland cement consist of large amounts of Portlandite (calcium hydroxide). The Portlandite is attacked by CO_2 and the mineral starts a carbonation process. Carbonation is formed by hydration of silicate phase C_3S and C_2S. After the Portlandite is consumed, C_3S and C_2S are decomposed into $CaCO_3$ and SiO_2. The C-S-H phases (C_3S and C_2S) consists of a solid cement matrix and have high strength.

1. $Ca(OH)_{2(aq)} + CO_2 \rightarrow CaCO_3 + H_2O$
2. $C_xSH_y + xCO_{2(aq)} \rightarrow xCaCO_3 + SiO_2 * yH_2O$

This shows that CO_2 can affect the Portland cement in two different ways. The first equation shows that the calcium hydroxide reacts with the CO_2 and produces Calcium carbonate and water. The production of $CaCO_3$ has a positive effect on well integrity. Both permeability and porosity is reduced, which improves the sealing capacity. However, calcium carbonate is soluble in water. Most oil and gas reservoir consists of saline water, which will dissolve the CaCO3 and reduce well integrity. The remaining matrix based on silicates has poor strength. Over time, this process will dissolve parts of the cement sheath and might cause a leakage [39].

3. $CaCO_3 + CO_2 + H_2O \rightarrow H_2O + Ca(HCO_3)_{2(aq)}$

Supercritical CO_2 has been used in production for a long time. Large volumes of $scCO_2$ is pumped down into the reservoir to enhance the production pressure. This type of method is called enhanced oil recovery or EOR. Some wells are also natural CO_2 producers. Supercritical CO_2 is carbon dioxide in a liquid state. This occurs at a given pressure and temperature.

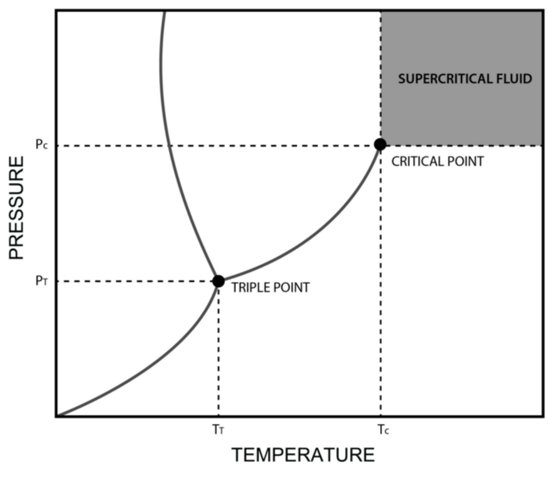


Figure 26: CO2 phase diagram

6.1.4 Barlet-Gouedard et al study

Portland cement containing calcium silicate hydrates and calcium hydroxide were tested by Barlet-Gouedard in 2006. The cement was tested in both supercritical CO_2 and CO_2-saturated water at 90 degrees Celsius and 280 bar. The Portland cement tested was of class G. Carbonation rate for wet supercritical CO_2 was given as [40]:

$$Depth\ of\ CO_2\ alteration\ front\ in\ mm = 0.26\ x\ (time\ in\ hours)^{1/2}$$

Figure 27 shows the degradation over time. Graph is made in Microsoft Excel with the use of the equation above.

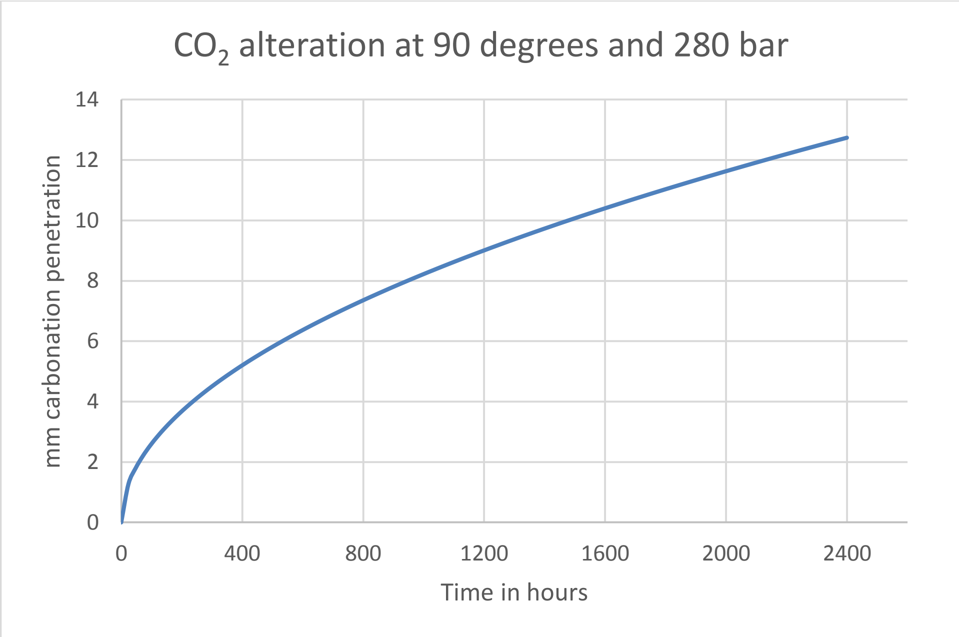


Figure 27: CO_2 alteration at 90 degrees Celsius and 280 bar

Carbonation time of 100 mm

$$100\ mm = 0.26 * Hours^{0.5}$$

$$Hours = (\frac{100\ mm}{0.26})^2 = 147928\ hours$$

For an alteration front of 100 mm to occur, it would take 147928 hours, or roughly 17 years.

The experimental procedure to test CO_2 alteration of Portland cement consisted of several steps. Two different size samples of Portland cement was used:

	Diameter of sample	Length of sample
Sample 1	0.5 inches	1 inch
Sample 2	1 inch	2 inches

Table 8: Sample properties [42]

Preparation of cement slurry were done according to API regulations. Cement was set in a cubic mold and cured for 72 hours at 3000 psi. Slurry was optimized with the use of antifoam agent, retarders and dispersant. Cement was then removed from the mold and placed in water where it was cored into cylindrical form [41].

Test procedure:

1. Identification of core samples, including measuring and weighting them. Placing the samples into test vessel afterwards. Teflon washer used to separate samples if they are stacked on top of each other to prevent fluid capillarity.
2. A given volume of water added into the test vessel.
3. Vessel closed and CO_2 injection line connected to it.
4. Cooling of vessel down to 2-4 degrees Celsius using cooling blanket or icebox.
5. Opening of CO_2 valves connected to tube.
6. Difference in the temperature between vessel and room condensates the CO_2 into a liquid phase. When vessel was fully filled with liquid CO_2, cooling circuit was removed. CO_2 bottle was then closed and vessel isolated.
7. Heating process. Leak valve adjusted the pressure to reach 280 bar at 90 degrees Celsius.
8. Stabilization of temperature for about one hour.
9. Pressure continuously monitored with help of live transfer from cameras.
10. Pressure drops were adjusted with help from CO_2 pump connected between CO_2 bottle and vessel [41].

Result of the study gave the equation used in calculating CO_2 alteration above. The study also concluded that Portland cement is not an effective sealing agent for CO_2 storage. Calculations showed that it would take roughly 17 years to carbonate 100 mm of Portland class G cement. A result of cement carbonation can make it possible for fluids or gasses to migrate to casing. Casing and CO_2 in liquid form is a bad combination, and can result in casing corrosion. This will be discussed later.

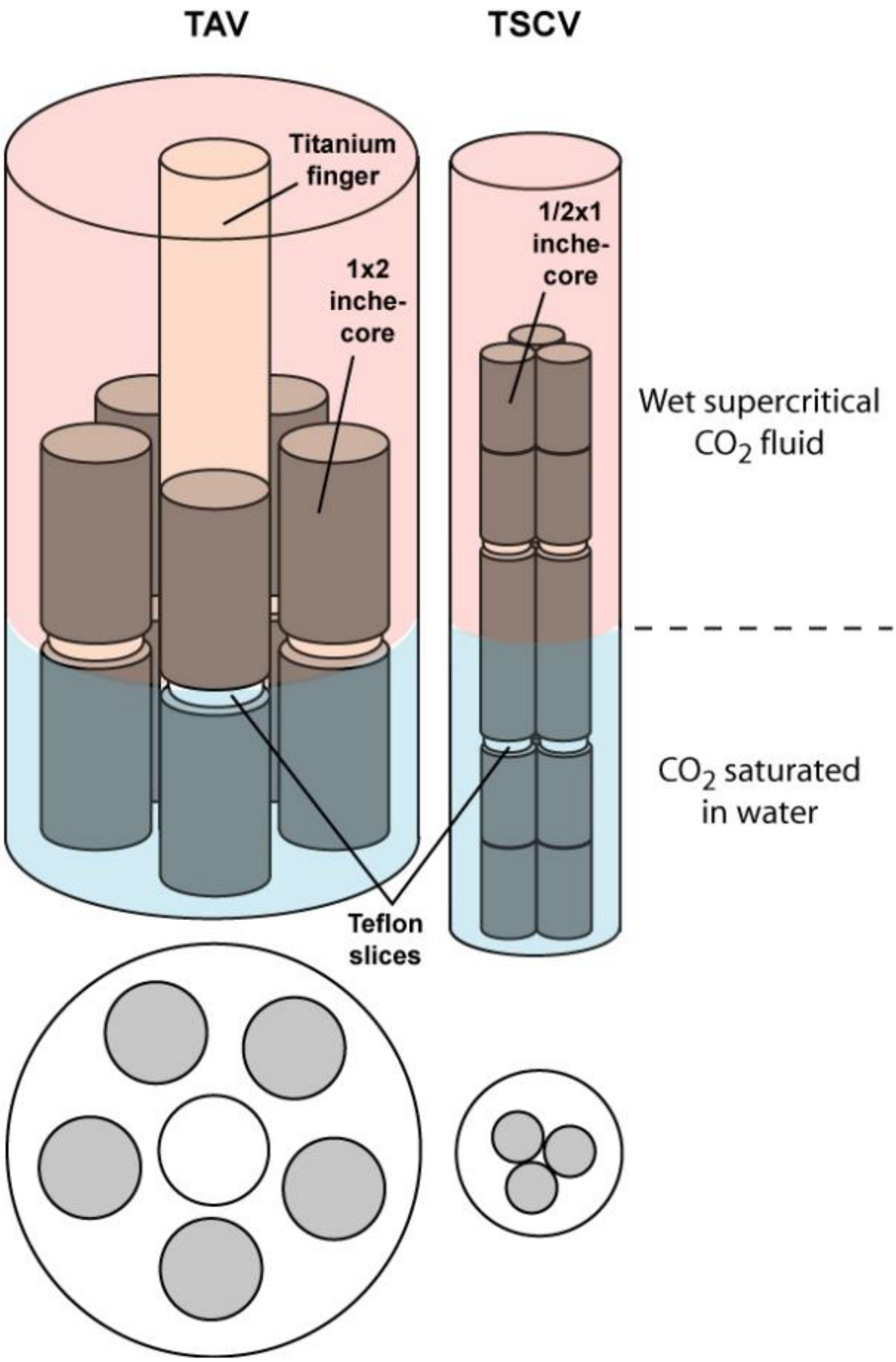


Figure 28: Experimental setup [42]

Barlet-Gouédard et al did a new study with the same properties in 2008. This time they tested multiple types of sealing agents. The basis of the study were motivation and approach regarding storage of CO_2, which can be positive for the climatic challenges. Temperature and pressure used were still 280 degrees Celsius and 90 bar. Duration of test varied between 1 and 6 months [42].

Durability of different sealing agents at 280 bar and 90 degrees Celsius in CO_2 + water					
Sealing agent	**1 week**	**3 weeks**	**1 month**	**3 months**	**6 months**
Magnesum Potassium phosphate					
Calcium Aluminate Phosphate					
Portland Cement					
Portland Fly ash cement type F					
Portland Fly ash cement type C					
Schlumberger EverCrete CO_2 resistant cement					

Table 9: Sealing agent durability [43]

Green: Cement strength is above 20 MPa regardless of the density of the cement. Permeability must also be less than 0.01 mD up to 6 months.

Yellow: Cement strength is above 20 MPa, but no stability is observed under exposure of CO_2.

Red: Cement strength is below 7 MPa. In addition, there are high mechanical degradation and no stability is observed under exposure of CO_2.

The orange marked boxes are a combination of red and yellow. Boxes in white indicates that the sealing agent has not been tested or observed for this duration.

The laboratory studies shows that only Schlumberger EverCrete cement will have acceptable integrity over a 6 months period. Conclusions is that the CO_2-resistant cement is working as it should. The most used sealing agent in Portland class H and G cement is not suitable in sour CO_2 environments over time according to Barlet-Gouédard. EverCrete CO_2-resistant cement is compatible with Portland cement, meaning it is possible to mix them together. Mixture recipe will depend on CO_2 resistance requirements.

6.1.5 Kutchko et al study

This study were performed to test degradation of hardened cement due to exposure of CO_2 for carbon capture and storage. The properties for this experimental setup were a temperature of 50 degrees Celsius, and a pressure of 303 bar. Goal of experiment was to determine the reaction rate between hydrated cement and both supercritical CO_2 and saturated CO_2-brine. Cement used in this experiment were Portland class H cement, which is very similar to class G.

Class H cement was mixed according to API recommended practice 10B. Cement was casted in cylindrical molds. Samples were then lowered into a 1% Natrium chloride brine in a high pressure vessel. Temperature was set at 50 degrees Celsius, and a water pressure of 303 bar. Cement was removed from molds after 3 days, and set to hydrate for 28 days in a brine solution. This curing process were performed to simulate the conditions when setting cement in oil wells.

After the curing process was finished, the samples were partially lowered into the same Natrium chloride solution. Vessel was then pressurized up to 303 bars by injecting CO_2. CO_2 concentration were calculated to be 1.8 M with a pH of 2.9. The unsubmerged part of the samples were supposed to simulate the exposure of supercritical CO_2 injected for storage or production enhancement. Submerged part simulates exposure of CO_2-saturated brine. Conditions inside the vessel were static to simulate formation conditions. Six samples of cement were placed inside a single vessel. The vessel was then depressurized for 6 hours before removing samples.

For best SEM (scanning electron microscope) analysis, the samples were polished first. SEM analysis measured depth of different altered zone in the samples. Deepest alteration point was measured as penetration depth for each sample [43].

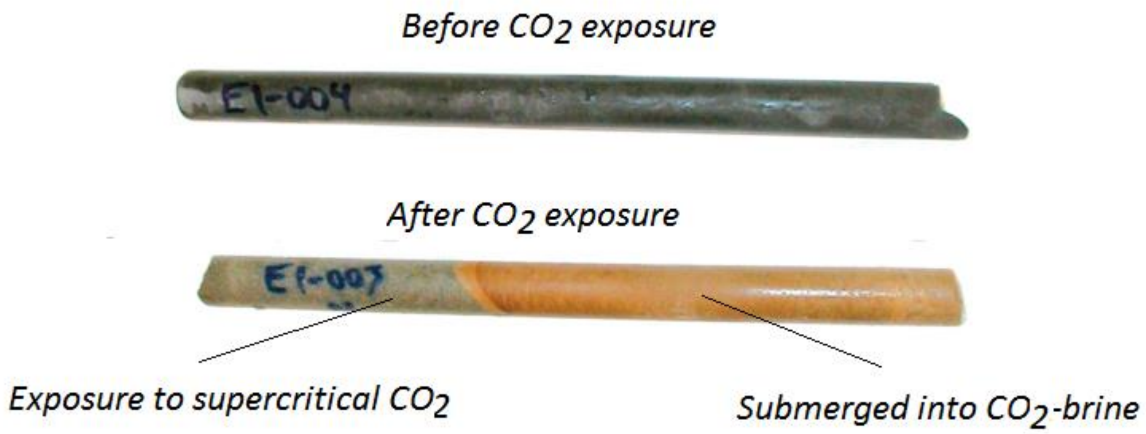


Figure 29: Before and after exposure to CO_2. [44]

As seen on figure 29, the colors differs between supercritical CO_2 and CO_2 brine. The texture of surface for the submerged part of the sampled showed to be very smooth. Unsubmerged part on the other hand, had a very rough texture. Analysis with SEM showed that the CO_2 brine had given the sample three distinctive zones on the surface.

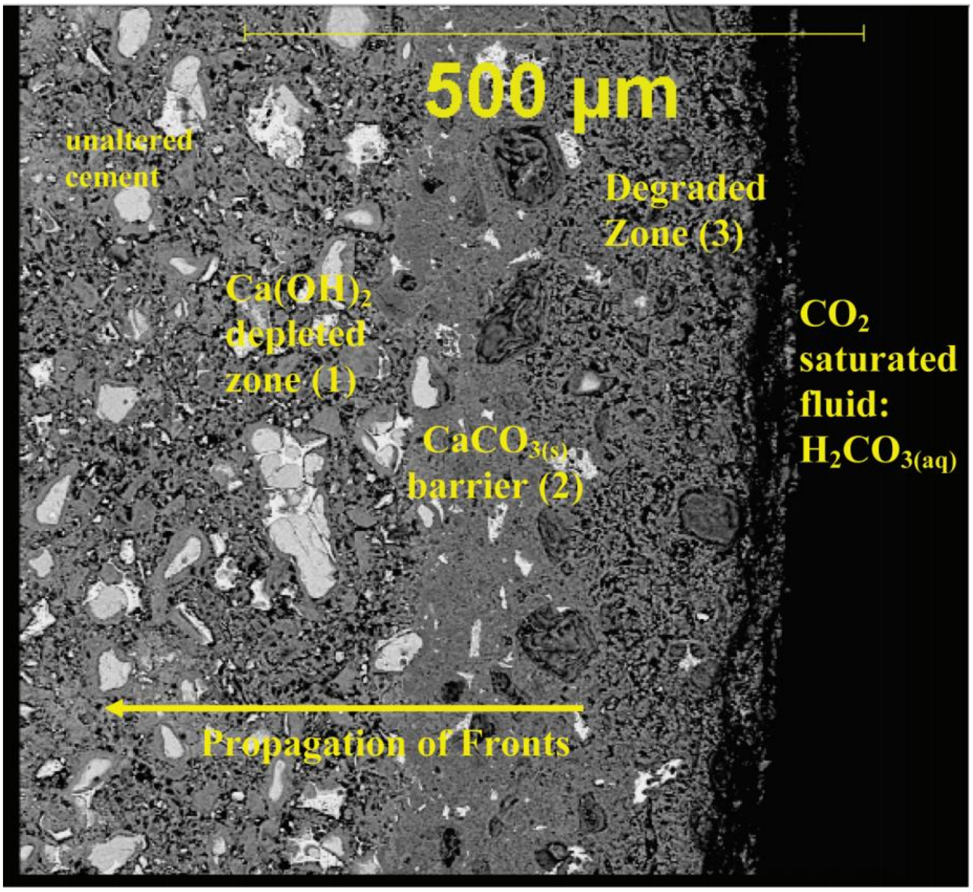


Figure 30: SEM picture of cement submerged into CO2-brine [44]

These zone were exclusive for the submerged part of the sample. Attack from supercritical CO_2 were uniform along the body of the cement sample, with a reaction front of $CaCO_3$. The carbonation front gives a distinctive rough texture. Some parts of the sample exposed to supercritical CO_2 showed deeper penetration, although most of the body had uniform texture. Reasons for these intrusions were concluded to be caused by condensed droplets due to surface moisture from the outer surface of cement sample. These observations were deleted from the measurements.

Carbonation of the submerged part of the sample is limited to the diffusion of the brine. Diffusion of ions are slower than the acid-base carbonation that the samples undergoes during the experiment. Using Fick's second law makes it possible to estimate depth of the carbonation of cement.

Fick's second law

$$L = \alpha * t^{1/2}$$

L = depth of carbonation
t = Exposure time
α = Ionic diffusion rate constant [43]

A Fickian plot would become linear if it was a simple diffusion. Experimental data collected gave values that did not give a linear plot, which suggest diffusion for the cement sample are more complex. This suggest that α is not constant. An Elovich equation was used instead.

Elovich equation

$$\frac{dL}{dt} = a * e^{-bL}$$

$$L = \left(\frac{1}{b}\right) \ln t + \left(\frac{1}{b}\right) \ln (ab)$$

L = penetration depth
t = time (days)

a and b are both constants that are determined from data gathered during the experiment [43].

Due to uncertainties in the Elovich equation, a series of Monte Carlo simulations was performed to determine the range of extrapolated penetration depths for uncertainties in the Elovich parameters. Parameters a and b were determined by the best least-square result. The result from studying the attack of cement by CO_2-brine suggested that it was more of an acid attack rather than carbonation.

For the cement sample attacked by supercritical CO_2, it produced a slow penetration of carbonation. In comparison with the submerged part, this did not show any individual distinct zones. Study suggests that this is due to the lack of water that could diffuse ions out of cement matrix. Experimental data plotted showed a linear behavior, which suggest that it could be Fickian diffusion [43].

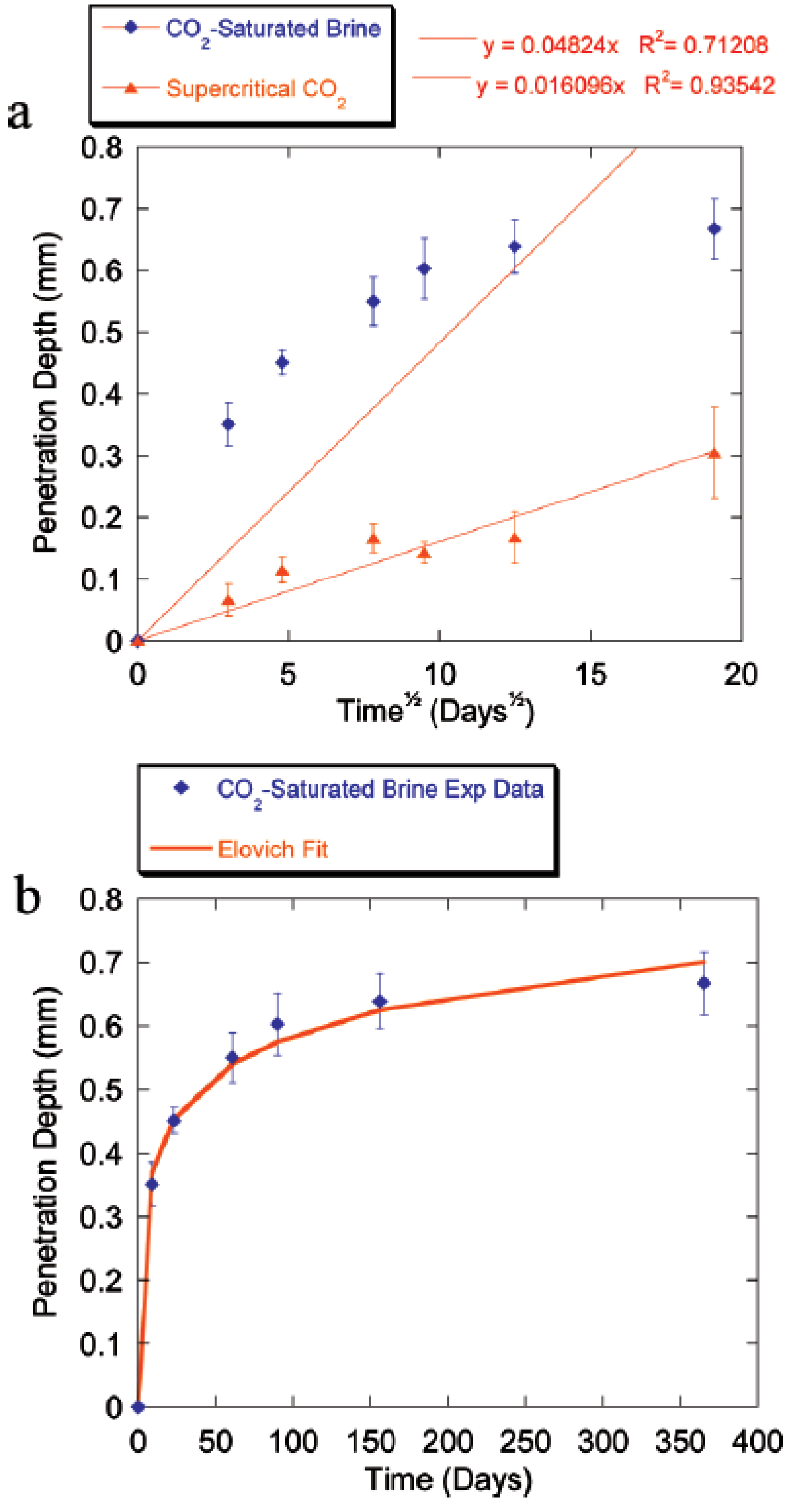


Figure 31: Penetration depth for CO2-satured brine and supercritical CO2 at 50 degrees Celsius and 303 bar [44].

The result from Kutchko's study was compared to a core from a well that was used for enhanced oil recovery. The well was exposed to CO_2 first time back in 1975, and has since then been exposed to 120 000 tons of carbon dioxide that has passed through it. Core sample consisted of neat cement just as in the study. It had been exposed to CO_2-rich brine for 30 years at 54 degrees Celsius and 180 bar. The integrity of the core sample was still good, even after 30 years of exposure to carbon dioxide. Alteration depth from the core ranged from 1 to 10 mm. According to Kutchko et al, the large gap between highest and smallest depth may be due to fluid and cement interface varied in size. It could also be due to variations in cement and water/cement ratio [43]. Result from the study fitted very well in comparison with the EOR site core sample. Calculation shows that for a 30-year period, penetration depth for Kutchko et al. is roughly 1.68 mm for supercritical CO_2, and 1.00 mm for CO_2-saturated brine. This is significantly less than what Barlet-Gouédard et al. discovered in their study.

6.1.6 Comparison between studies

Several other studies have observed the effect of carbon dioxide on cement. It is chosen to go deeper into the ones from Kutchko et al. and Barlet-Gouédard et al. since the experimental setup and properties are very similar. What is very surprising is the result from the two studies.

Results from the two studies are very different. Kutchko et al conclusion is that it is safe to use Portland cement in carbon dioxide storage wells. In Barlet-Gouédard study, only Schlumberger's CO_2-resistant EverCrete cement was sufficient for sour CO_2 environments. The setups are very similar. Cement samples are placed inside a pressure vessel. Half of the sample is submerged into wet CO_2-rich brine, and the other is exposed to supercritical CO_2. Even though, there are differences in the cement slurry composition, pressure and temperature, to name someone.

	Kutchko et al.	**Barlet-Gouédard et al.**
Cement	Portland class H	Portland class G
Pressure and temperature	303 bar and 50°C	206.8 bar and 90°C
Curing time	28 days	3 days
Slurry mixture	Neat class H	Additives like antifoam agent, retarder and dispersant.
Water solution	0.17 M NaCl brine	Deionized water.

Table 10: Comparison between Kutchko et al. and Barlet-Gouédard study [43] [44]

The equation mentioned earlier in Barlet-Gouédard section can be used for calculating penetration depth for most cases.

$$Depth\ of\ CO_2\ alteration\ front\ in\ mm = C\ x\ (time\ in\ hours)^{1/2}$$

The C is a constant that is dependent on parameters used in studies, like temperature, pH, pressure, cement quality, etc. This will never be the same, unless all the parameters will be exactly the same.

6.1.7 Summary of other studies

Over the years, many studies on cement degradation properties have been done to try to get a picture on how fast the attack from carbon dioxide and other gasses works. Under is a table of some of the studies with different properties.

Study	C	Time in years for 25mm degradation	Cement type	P (bar)	T (°C)	Water/cement ratio	Carbonation medium
Barlet-Gouédard (2006)	0.2622	1.0	Portland class G	280	90	0.44	Static water-saturated $scCO_2$
	0.2182	1.5	Portland class G	280	90	0.44	Static CO_2-saturated water
Bruckdorfer (1986)	0.0623	18.4	Portland class A	206.8	79.4	0.38	Static wet $scCO_2$
	0.0513	27.1	Portland class C	206.8	79.4	0.38	Static wet $scCO_2$
	0.077	12.0	Portland class H	206.8	79.4	0.38	Static wet $scCO_2$
	0.0843	10.0	Portland class H plus 50% fly ash	206.8	79.4	0.38	Static wet $scCO_2$
Dugiuid et al. (2004)	0.0336	63.2	Portland class H	1	50	0.38	Flowing carbonated brine
	0.0250	114	Portland class H	1	50	0.38	Flowing carbonated brine
Duguid et al. (2008)	0.00146	33.38	Portland class H	1	20	0.38	Sandstone with static carbonated brine with pH 3
	0.00159	28.30	Portland class H	1	50	0.38	Sandstone with static carbonated brine with pH 3
	0.00031	724.28	Portland class H	1	20	0.38	Sandstone with static carbonated brine with pH 5
Kutchko et al. (2007)	0.040	44.2	Portland class H	303	50	0.38	Static carbonated brine cured at 22°C and 1 bar
	0.030	76.1	Portland class H	303	50	0.38	Static carbonated brine cured at 22°C and 303 bar
	0.032	69.7	Portland class H	303	50	0.38	Static carbonated brine cured at 50°C and 1 bar
	0.015	318	Portland class H	303	50	0.38	Static carbonated brine cured at 50°C and 303 bar
Kutchko et al. (2008)	0.00329	6587	Portland class H	303	50	0.38	Static water-saturated sCO_2
	-	-	Portland class H	303	50	0.38	Static CO_2-satuarted brine
Shen and Pye (1989)	1.3199	0.23	Conventional Portland cement	69	204	0.44	Static wet CO_2 gas

Table 11: Comparison between degradation rates from different studies [45]

The C constant illustrated in the table is the one used in alteration front depth equation. Results from the study gives a very low C-value, under 0.1 for most cases. There are two studies in the table that is extraordinary considering C-value. Barlet-Gouédard as mentioned earlier and Shen & Pye. Both of these have a water/cement ratio of 0.44, suggesting that the cement slurry is modified. At least this is the case for Barlet-Gouédard. What separates Shen & Pye from all the others, including Barlet-Gouédard, is the extreme temperature used in the experiment. The temperature is over 200 degrees Celsius. The C constant is also more than 5 times larger than for Barlet-Gouédard, which might suggest that temperature works as a catalyst in the degradation process.

6.2 Carbon dioxide effect on steel casing

6.2.1 Casing corrosion

CO_2 is not only problematic for cement considering degradation effects. Casing strings are also very exposed to the effects of CO_2. Cement is meant to protect the casing from corrosive environments, but when the cement is degraded, it might lead to corrosion of casing as well. The corrosion of steel is an electrochemical process and it is defined as deterioration of a material. For a corrosive reaction to appear, we must have the presence of [44]:

- Anode
- Cathode
- Electrolyte
- Electrical current

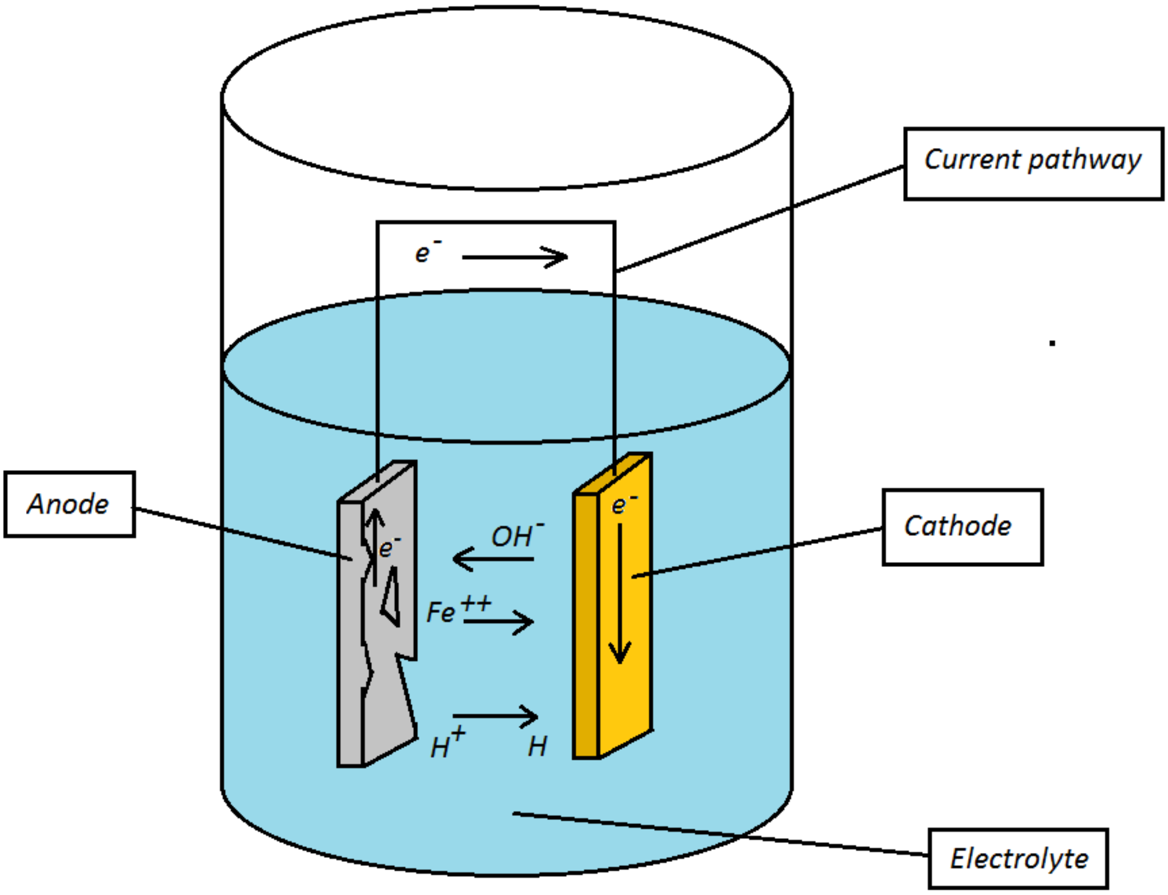


Figure 32: Corrosion cell

Corrosion of steel and other metallic alloys is a huge problem worldwide. Not only does it damage equipment, which then can cause leak incidents or fracture. It is also very expensive to cope with. It costs billions of dollar each year. To reduce the cost of this problem, some measures can be implemented. There are several methods to prevent or reduce corrosion.

Coating and lining: Paint or other materials, which stops reactions between electrolyte and materials. This is a very basic way of protection.

Cathodic protection: Technology where an electrical current is applied a material to prevent corrosion from happening or stop existing corrosion.

Material selection: One of the most important corrosion prevention methods. Choosing the right material can stop or de-accelerate corrosion reaction rate. An acid resistant material should be chosen in environments with CO_2 or H_2S. Reactions between steel casing and carbon dioxide will be discussed later.

Corrosion inhibitors: Can be added to a material or the environmental around the material. Can reduce corrosion reaction rates and extend life of equipment [44].

The corrosion cell displayed in figure 32 is the only fundamental mechanism for corrosion, but there are several modes of corrosion that can occur. These types of corrosion have again different types of distinctive patterns and behavior. Some of the most known types of corrosions are [44]:

- Uniform corrosion
- Galvanic corrosion
- Pitting corrosion
- Erosion corrosion
- Cavitation corrosion
- Stress induced corrosion
- Corrosion Fatigue

Two of the more relevant corrosions considering degradation after abandonment is uniform and pitting corrosion. Uniform corrosion is a very basic type of corrosion where the surface of a metallic material is attacked. Reactions between metal and electrolyte reduces the thickness of the material. How fast the reactions work will depend on environmental properties. The reactions will attack the material uniformly, degrading most of the body exposed to the corrosive material simultaneously. It is assumed that uniform corrosion is the most common type of corrosion [44].

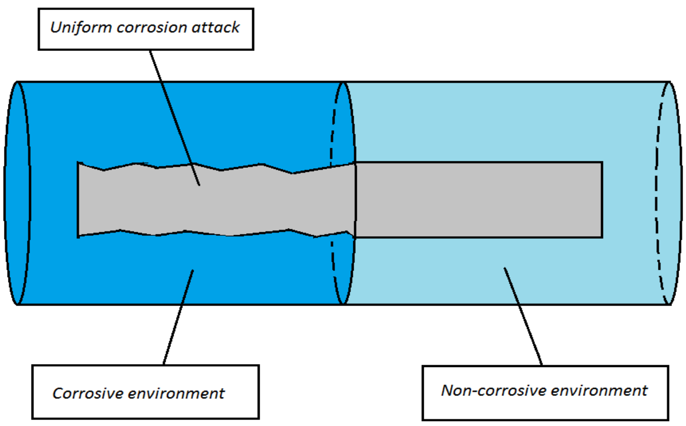


Figure 33: Uniform corrosion

Pitting corrosions has some of the same aspects as uniform corrosion. The same reaction works for this type of corrosion. Surface of material is attacked, and thickness of it will be reduced. One of the major differences between pitting and uniform corrosion is area of attack. While uniform corrosion is spread evenly around the surface of material, pitting corrosion will attack random places on the materials body. Corrosion penetration depth is one of the biggest problems for this corrosion mode. It can penetrate all the way through the material if it is not coped with. Pitting can be frequently found in environments with CO_2 and H_2S.

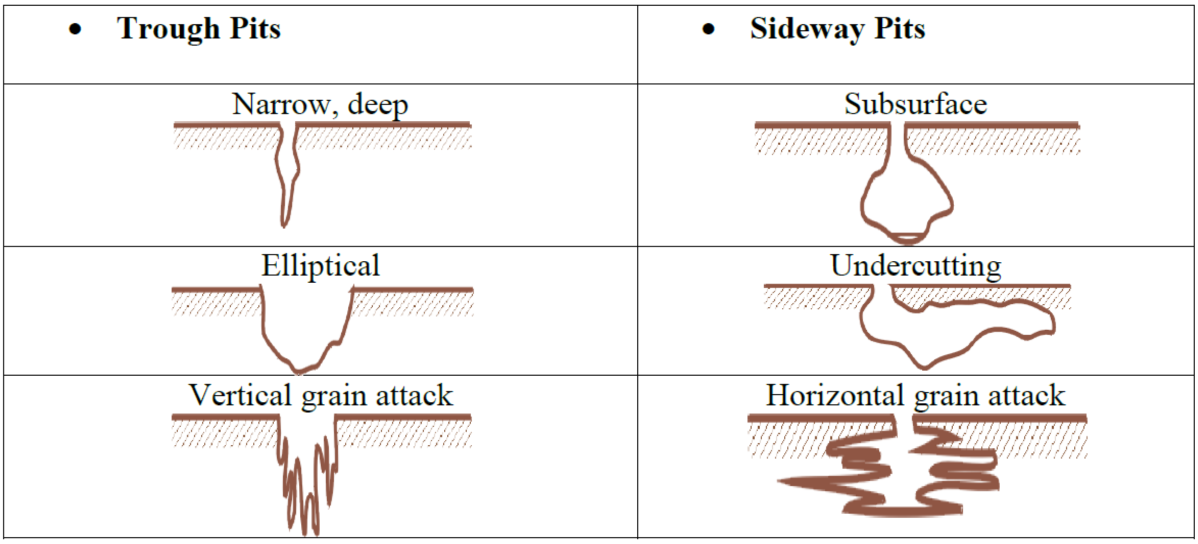


Figure 34: Different shapes of pitting corrosion divided into trough and sideway pits [46]

The reason these two modes of corrosion is discussed considering degradation is because they are common, and due to reduction in material thickness constitutes a threat for leakage pathway buildup. Casing left in hole after abandonment is often protected by cement in the way shown in figure 35 below.

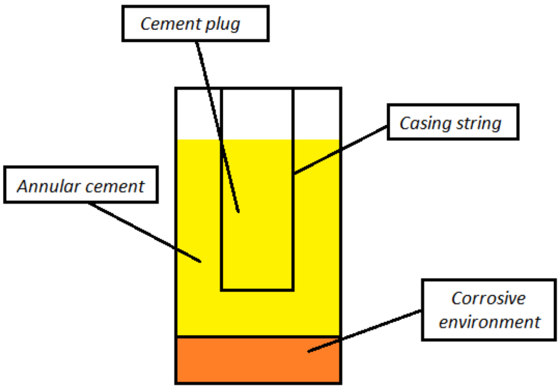


Figure 35: Casing cementing at reservoir depth

Discussed earlier, if cement is degraded or a pathway is created all the way in to the casing, fluids and gasses can migrate, which can result in degradation of casing as well. Casing corrosion can spread along the body of the casing, resulting in a reduction of thickness. This can make excellent pathways for both fluids and gasses. To understand how casing degradation works, reactions and processes will be explained.

6.2.2 CO_2-corrosion on steel casing

Conditions in reservoirs are often anaerobic, which means there is no access to oxygen. CO_2 in reservoirs are also often of supercritical state. A CO_2-dominant environment will trigger different reactions [45].

Cathodic reactions:

$$H_2\,CO_3 \leftrightarrow\ H^+ + HCO_3^-\ \leftrightarrow 2H^+ + CO_3^-$$

$$2H^+ +\ 2e^-\ \leftrightarrow\ H_2(g)$$

Anodic reaction:

$$Fe(s) \leftrightarrow Fe^{2+} + 2e^-$$

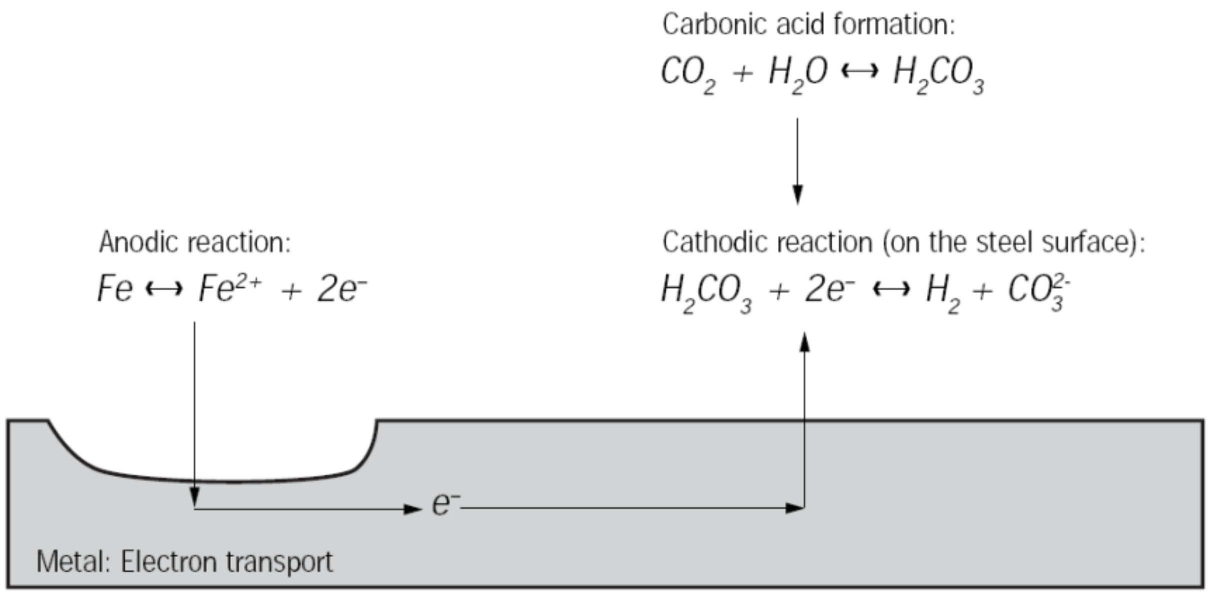


Figure 36: Corrosion of steel in CO_2-dominant environment [45]

Casing corrosion is considered a big problem in the oil and gas industry, and CO_2 is a large contributor to this problem. Behavior of the corrosion is directly dependent on downhole properties like temperature, partial pressure of CO_2, surface coating of steel and flow regime.

6.2.3 Cui et al study

In 2006, Cui et al performed a study on corrosion of pipelines in supercritical CO_2-saturated water. The study was a weight loss experiment for different types of steel qualities at different temperatures. The electrolyte used was a simulated produced water, saturated with supercritical CO_2. Supercritical CO_2 was achieved at a pressure of 1200 psi or 82.74 bar. Further, temperatures for 60, 90, 120 and 150 degrees Celsius were applied for a 144-hour period. Corrosion mode is not mentioned in the paper, but it is interpreted that it is uniform corrosion since the basis of the experiment is weight loss measurement.

Results from the experiments showed that the corrosion rate is very affected by temperature. The rate showed a tendency to decrease with higher temperatures. Corrosion rate decreased with exposure time until a point where the rate became constant. This was after approximately 95 hours. Plotting the results shows that the corrosion rate is somewhere between 0.75 mm to 3.5 mm per year depending on temperature and steel quality [46].

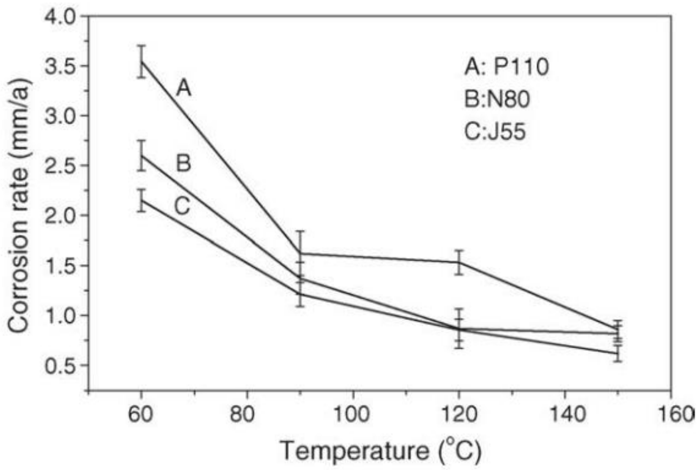


Figure 37: Corrosion rate vs. Temperature [47]

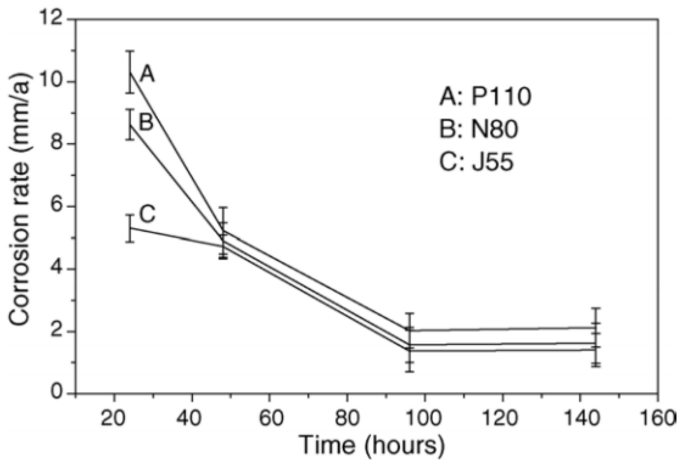


Figure 38: Corrosion rate vs. exposure time [47]

6.2.4 Haitao Fang study

A study performed by Haitao Fang tests the corrosion rate for different temperature and salinities at atmospheric pressure. The study's goal was to determine the effects of salt and temperature on steel casing.

Parameters	**Conditions**
Pressure	1 bar
Temperatures	1, 5 and 10°C
Rotation speed	100, 1000, 2000, 3000, 4000, 5000, 600 rpm
Electrolyte solution	NaCl (3% wt)
pH	4, 5, 6
Steel material	C1018

Table 12: Properties for temperature effect test [48]

Parameters	**Condition**
Pressure	1 bar
Temperature	5 and 20°C
Rotation speed	100, 1000 and 6000 rpm
Electrolyte solution	3, 10, 20, 25 wt% NaCl
pH	4,5,6
Steel material	C1018

Table 13: Properties for salinity effect test [48]

A casing sample with steel quality C1018 was placed in a glass cell. This cell was then filled with deionized water before adding different NaCl concentrations. Oxygen was then removed from cell by injecting CO_2. PH was adjusted to desired value. An electrode was introduced to the environment, and monitoring was established. At last, the rotational speed was set to desired rpm. Measurement was monitored for 20 – 60 minutes.

Results from temperature study showed that corrosion increased with temperature. This is the opposite of the trend found in the Cui et al. study. One of the reasons might be that temperatures used in this study is relatively low compared to Cui et al. Results of this study showed an increase from 0.1 to 2 mm/year when increasing temperature from 1 to 20°C.

For salt concentration test, the results showed an opposite trend in comparison with temperature. Increase in salinity gave decreased corrosion rate. 3 wt% NaCl resulted in 0.25 – 0.27 mm/year depending on flow speed. For 25 wt% NaCl, corrosion rate were as low as 0.05 mm/year. This suggest that salt concentration works as a reaction retarder for steel casing. This is the results from using a temperature of 5°C. For 20°C, corrosion rate ranged from 2.0 mm/year for 3 wt% NaCl, to 0.46 mm/year for 20 wt% NaCl [47].

6.2.5 Zhang et al. study.

A relatively new study that copes with the effects of steel degradation. It studies the effect on N80 steel, which is a very common quality in for both tubing and casing. Goal of the study was to simulate a carbon sequestration scenario to see how casing copes with the corrosive environment.

Parameters	Conditions
Pressure	60, 80 and 100 bar
Temperature	45°C
Steel material	N80
Electrolyte solution	Brine solution with 130 g/l NaCl, 22 g/l $CaCl_2$ and 4 g/l $MgCl_2$
Duration	32 days

Table 14: Properties of Zhang et al. study [49]

According to Zhang et al, corrosion rate is dependent of pressure, temperature, salinity of electrolyte, cement quality, pH, and more. The other studies mentioned in this chapter have shown that this is in fact true [48].

Samples of N80 steel were cut of tubing. For it to be possible to send an electrical connection, a thread was welded to the sample. This would work as an electrode. Samples were then treated and cleaned before being transferred to an autoclave. An autoclave is basically a pressure chamber. Weight of the samples were measure before exposing it to the brine and CO_2. After 32 day, the samples were removed from autoclave, cleaned and weighted to determine mass loss.

Results from the test showed some variations between the different pressures. At most, the corrosion rate showed as much as 6 mm/year. For 80 bar and 45°C, the average rate of corrosion was around 0.06 mm/year. Degradation will at one point be close to constant. The reason is that after a given time, the surface of the steel will get a compact layer that reduces the corrosion rate [48].

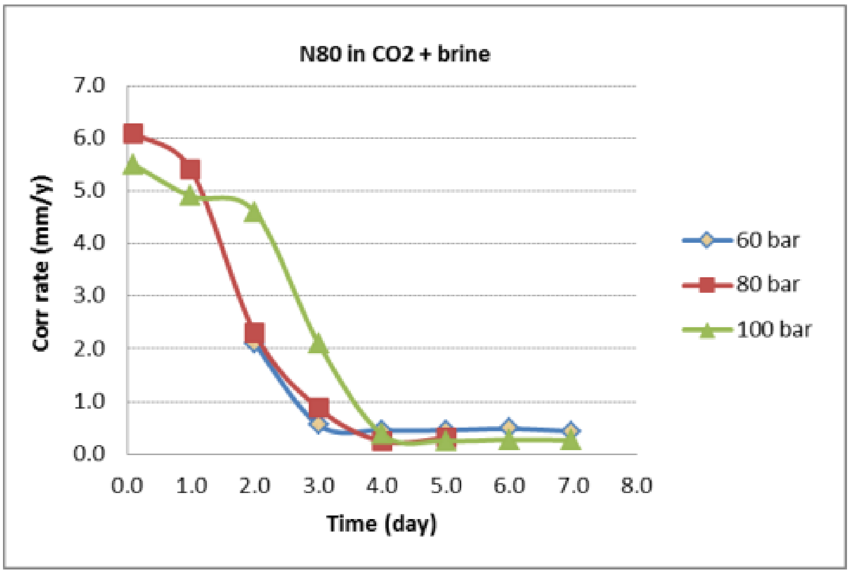


Figure 39: Corrosion rate for N80 steel in CO_2 and brine at different temperatures [49]

6.2.6 Casing corrosion summary

There are a lot drivers to take into consideration for casing corrosion. First of all, there are several types of corrosion. The corrosion types have different drivers when it comes to how they work. However, they can all be coped with. It is either preventing them if possible, or reducing them to a minimum by implementing preventive measures. When the well is in use, corrosion can be coped with by maintaining equipment or changing it if the damage is too big. There are also injection possibilities to reduce corrosive environments [44]. For abandoned wells, the case is different. There are some possibilities for temporary abandonments, but permanently abandoned wells must rely on well integrity for an eternity.

From the different studies discussed in this chapter, there are some inconsistencies, especially considering how temperature affects the corrosion rate. Results from Hui et al. showed that corrosion rates decreased with temperature, while rate increased in Fang's study. What is similar from the studies is that the corrosion rate decreases over time and becomes virtually constant.

Results from the studies is showing a picture of the corrosion rate for environments consisting of CO_2. When casing first is in contact with supercritical carbon dioxide, it will corrode at a very high rate. Results from the studies shows this is up to 6 mm/year. This trend quickly decreases down to a rate between 0.25 – 0.75 mm/year.

It is hard to put a specific number on corrosion rates. There are too many parameters affecting it, making it hard to do a specific corrosion model. Some of the parameters are:

- Temperature
- Pressure
- Salinity
- CO_2 concentration
- Steel quality
- pH
- Flow velocity

Cailly et al did a study of CCS, and claimed that corrosion rates for carbon steel can be as much as 25 mm/year at 65°C and 10 bar, and 250 mm/year at 82°C and 160 bar. Work from Institute for Energy Technology in Norway also states that models made from low-pressure tests are much too high in comparison with real corrosion measurements [49]. Values gained by the studies shows a relatively low corrosion rate. However, bonding between casing and cement will be affected by the slightest reduction in thickness. This can build up over time. A combination of casing corrosion and cement degradation can make up a leakage pathway.

7. Leakage path in well barrier

7.1 Leakage path description

When a well is plugged, it is left with permanent well barriers working as a seal, preventing gasses and fluids from migrating upwards. A cement plug placed in open-hole will bond to formation and work as a seal. For cased-hole, a combination of cement plugs and annular cement work as seal. Theoretically, this should prevent wells from leaking. However, in practice it is much more complicated than that. Chapter 6 proves that CO_2 and other gasses affect both casing and cement over time. Rate varies for different properties, but some degradation finds place in almost every scenario. Hydrocarbon migration, especially migration of gasses is considered a challenge in the oil industry. Gas can migrate through the smallest cracks and microannuluses.

It is very difficult to get a near perfect cementing job. That is why it is very important with cement verification methods. Even here, there are limitations. If a pathway opens, a buildup might continue, expanding the pathway. A pathway can be defined as a zone with low hydraulic resistance. Pathways can originate from improper cementing jobs, or be a result of degradation of well barrier elements. Temperature and pressure might also affect pathway buildup [50]. Even geological movement can work as a leak provider. A combination of all these factors might result in leaks.

Gas can migrate through different types of leakage channels. In an abandonment scenario with cement plug, casing and annular cement, there exists several opportunities for pathways to establish.

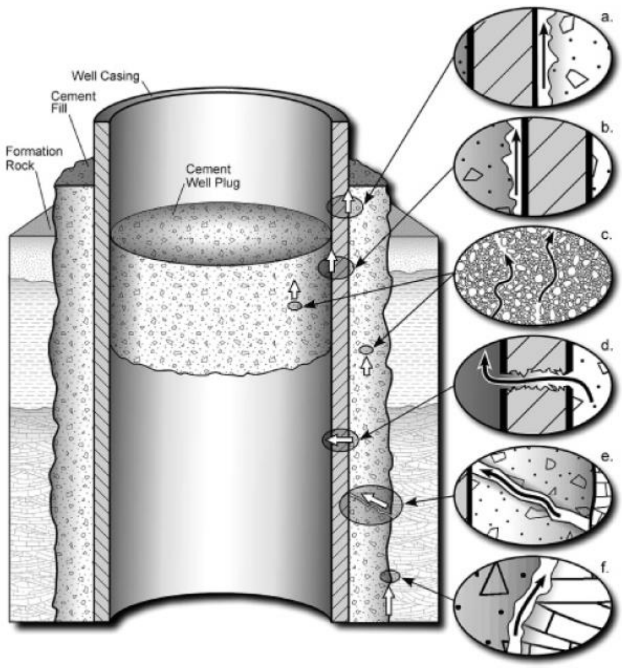


Figure 40: Leakage path possibilities for an abandonment scenario [54]

Figure 40 is a great illustration of the many possibilities for leakage pathways in an abandonment scenario.

a. Microannulus between casing and annular cement.
b. Microannulus between cement plug and casing
c. Cracks or channels in cement plug.
d. Rupture or pits in casing resulting in connection between annular cement and wellbore.
e. Cracks or channels in annular cement resulting in connection between formation and casing.
f. Microannulus between annular cement and formation.

Several mechanism can trigger a pathway for leakage. Guidelines on qualification of materials for the abandonment of wells lists leaks into three categories [51].

- Shift in barrier position.
- Leaks around bulk material.
- Leaks through bulk material.

7.1.1 Shift in barrier position

It is very important that the position of the well barriers is stationary after abandonment. A shift in position is unwanted. Movement of barrier might trigger new pathways, which then can cause leak. Barriers ability to keep its position is dependent on bonding between different materials. Like casing and cement bond [51].

7.1.2 Leaks through bulk material

Chemical degradation, which is discussed in last chapter can cause leaks through bulk material. Carbonation of cement due to exposure to CO_2 produces silicon gel which changes the composition of the cement. The silicate matrix is weak and can often result in leaks since parts of the cement sheath will gradually dissolute [39]. Lesti et al did some experiments on carbonation of cement in contact with liquid and gaseous phase of supercritical carbon dioxide. One part of the test was to test permeability of cement sample before and after exposure to CO_2. The cement samples were tested in supercritical CO_2 at 90 degrees Celsius and 400 bar.

Cement system	**Permeability in mD**				
	Before exposure	**1 month in liquid $scCO_2$**	**1 month in gaseous $scCO_2$**	**6 months in liquid $scCO_2$**	**6 months in gaseous $scCO_2$**
A	<0.0001	0.0083	0.0025	<0.0001	0.089
B	<0.0001	<0.0001	<0.0001	0.0002	0.0016
C	<0.0001	0.0125	0.109	0.288	0.0061
D	<0.0001	<0.0001	0.307	0.554	1.54

Table 15: CO2 effect on permeability [40]

What determines leak rate through bulk material is parameters like porosity, permeability, pore size distribution, fluid saturation, differential pressure, etc. [51]

7.1.3 Leaks around bulk material

Failure modes for leakage around bulk material is according to Oil and Gas UK:

- Debonding
- Dissolution
- Cracking

7.1.3.1 Chemical degradation

There are several root causes for these failure modes. Chemical degradation is one of them. Degradation of cement is discussed in chapter 6, and can cause leakage pathways along bonding between casing and formation.

Steel casing is also affected by chemicals, which will attack surface of the steel and reducing the thickness. This thickness reduction can create microannuluses between casing and cement plug, and between casing and annular cement. On a long-term basis, this might affect casing and cement, as carbon dioxide will migrate upwards through microannulus and expanding the degradation of cement and corrosion of casing.

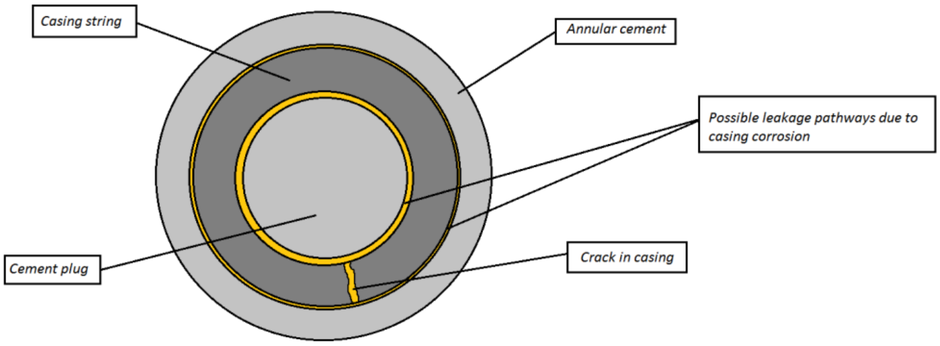


Figure 41: Leakage pathway possibilities due to casing corrosion:

7.1.3.1 Thermal expansion/contraction

Casing strings is not only affected by corrosion. Large cycles in temperature might also affect the integrity of cement-casing bonding. This can be an effect due to injection from nearby wells. Injection wells can be used for different purposes. Like EOR, storage, disposal and CO_2 sequestration. In Enhanced oil recovery operations, fluids and gasses are injected into the formation to increase reservoir pressure. CO_2 and steam, which is used in EOR, can hold a very high temperature [52]. A result of this is downhole temperature is changing. Steel is very sensitive to temperature changes and can expand/contract. Expansion and contraction affects the bonding between casing and cement. Large expansion/contraction can result in similar leakage pathways as for cement degradation.

7.1.3.2 External and internal stresses

External and internal stresses can cause well barrier failures. Pressures shall not exceed strength of the well barriers installed. Too high pressures might also affect material bonding, resulting in microannuluses. Local loads might affect matrix in materials resulting in cracks. For severe cases, the cracks can penetrate all the way through material, making a possible leakage pathway [51].

7.1.3.3 Creep

Creep is a deformation of a material due to loads. This can happen instantaneous or over time. Failure modes for creep is either barrier de-bonding or micro-cracks due to the deformation. If bonding is made by expansion of barrier, creep can act to relax the compressive stresses. An effect of this can be movement of barrier, or even loss of seal [51].

7.1.3.4 Placement quality

The quality of barrier placement is important for two main reasons. Barriers placed poorly can contain leakage channels. Poor placement may also contaminate materials used in plugging processes. This will affect barrier properties.

7.1.3.5 Drilling damage

As a result of drilling of the well, formation around wellbore might have been damaged. Cracks in formation can work as a pathway for fluids, which then can expand to well barrier elements. If leakage occurs through formation, well barriers should be designed to stop further leakage.

7.2 Leakage path models

CCS is described in chapter 6, and storage of carbon dioxide is a big driver in reducing climate emissions. For CCS to be effective, none or minimal leaks should occur. Leakage of carbon dioxide is a threat in places with groundwater and for people in general. CO_2-pollution of drinking water will make it sour, and in worst case undrinkable. Destroying water source for people and livestock.

It is important to remember that CO_2 will always be less dense than formation water when it is injected. This gives carbon dioxide an uplift from buoyance forces. At standard conditions, CO_2 has a density of about 1.87 kg/m^3. In supercritical state, which occurs from 31.1^{o}C and 73.8 bars, the density is between 150 to 800 kg/m^3. Density increases with pressure and temperature. What makes CO_2 dangerous considering leakage is the low viscosity [53].

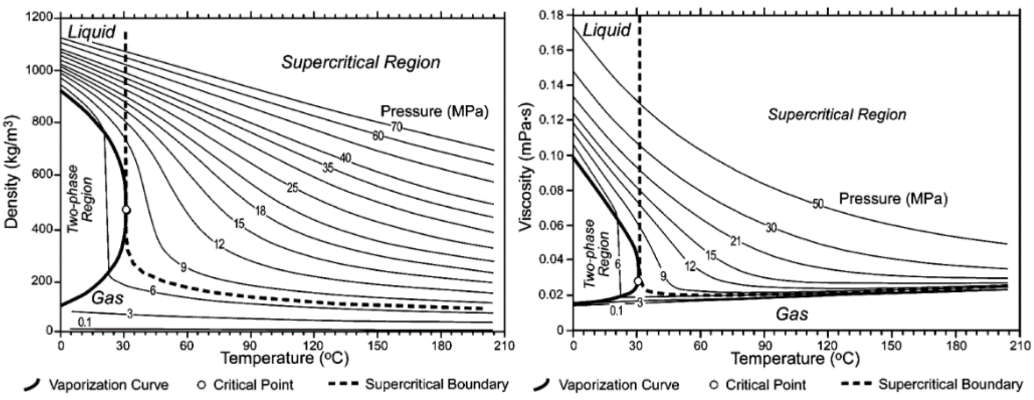


Figure 42: Density and viscosity for CO2 at different temperature and pressures [53]

An important subject considering leakage is to predict its pattern and movement. There are models made that gives an analytical view of the scenario. However, there are many factors and parameters to take into consideration.

7.2.1 Quin Tao et al. simple CO_2-leakage rate model

To success geological storage of carbon dioxide, some goals must be achieved. It shall be injected properly and overlaying reservoir or formations shall remain uncontaminated. Leakage rate shall not be above what the environment can handle without footprints. To predict rate of CO_2 leaking through formation or pathways, it requires a model for fluid and transport properties. The largest issues considering leakage is not through cement itself. Microannuluses and fractures are more of a concern. It is more likely for a leakage pathway along a wellbore where the cement/casing has reacted with CO_2 or CO_2-saturated brine. Mechanical response from the reactions can result in volume changes for the materials, which then will alter the hydraulic conductivity when CO_2 migrates through it [54].

A study done by Tao et al. shows two different models of gas leak. One of them is a sustained casing pressure model. This model is used in calculating leaks for natural gas wells. The other model is a CO_2 leakage model that calculates rate of leakage through existing wells encountered by CO_2 plume from injection well.

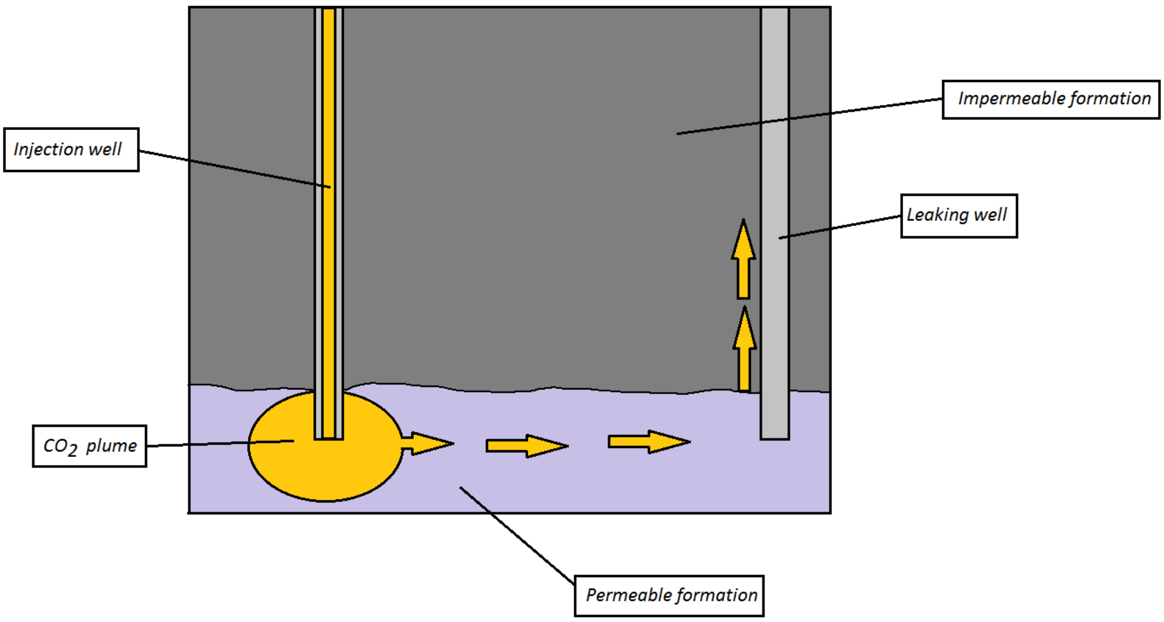


Figure 43: Leakage scenario from CO_2 injection

When CO_2 is injected, the pressure at the base of leakage increases. When injection stops, the pressure decreases. The study uses two types of pathways. One is from wellbore defects like microannulus between cement and casing. The other one is upper part which is porous medium that is water saturated. This model only uses single-phase flow, as it assume that only CO_2 is flowing. The water saturated porous media has no resistance to flow and is open to atmosphere at the top. This gives a pressure of [54]:

$$P_{top} = P_a + \rho_w g L_w$$

P_a = atmospheric pressure
p_w = water density
L_w = Thickness of upper portion of leakage path [54]

Using these values, we get a worst-case scenario of leakage for a long-term perspective. CO_2 properties will vary along the wellbore, and is affected by both pressure and temperature. To cope with these changes, Tao et al. uses Peng-Robinson equation of state, which assume a temperature variation along the pathway. Viscosity of CO_2 is interpolated. There are two scenarios for driving forces [54].

1. Buoyance driven flow. This is after injection is stopped. Buoyance is the main contributor to pushing CO_2 upwards. The CO_2-potential can be calculated as:

$$\nabla\Phi_g = \nabla(\Delta\rho g z)$$

Φ_g= CO_2 potential
$\Delta\rho$ = density difference between water and CO_2
z = depth

For deviated wells, Cos θ can be implemented into the equation. θ is inclination angle of wellbore [54].

2. Pressure driven flow. When CO_2 is injected, pressure rises, forcing the gas upwards through leakage pathways. Buoyance will also work as a driver.

$$\nabla\Phi_g = \nabla(\Delta\rho g z) + \nabla P_c$$

P_c = Capillary pressure

Rest of the parameters is the same as for buoyance driven flow [54].

Implementing these equations into Darcy's law, flow rate for CO_2 can be calculated.

Darcy's law
$q = \frac{kA}{\mu} \nabla\Phi$
q = Flowrate
k = Permeability of medium
A = Cross-sectional area of pathway
μ = Viscosity of CO_2
Φ_g = Driving force of gas [54]

This is a very simple model for CO_2-flow through leakage pathways. It can only be used for single-phase flow, which is not always the case. For multiphase flow, more complex models must be used. This model only calculate flow through pathways, and does calculate buildup rate.

7.2.2 L. Deremble et al. numerical model

Quin Tao et al. model is a very simplified model. It can calculate rate for CO_2 and other gasses through a pathway, but only for single-phase flow.

A more sophisticated model is L. Deremble et al numerical model. This model combines the effects of hydrodynamic, mechanical and chemical mechanisms to predict flow and pathway buildup rate. Pathway buildup is as mentioned earlier a result of several leakage mechanisms. This model uses chemical degradation of cement in CO_2-environment in its calculations. Equations below is targeted for micro-annulus pathways, but can easily be changed to calculate cracks or other pathway geometries by changing some of the parameters [55].

7.2.2.1 Flow calculation

Several assumptions are made for flow calculation:

- Flow will remain laminar.
- High aspect ratio. Length is much larger than the width.
- Width variation is small along the depth length of pathway.
- Temperature is only a function of s.

$v_f = \frac{w^2}{12\mu_f}\left(\frac{\partial P}{\partial s} + \rho g cos\alpha\right)$
v_f = mean velocity of fluid in vertical well (m/s)
w^2 = width of pathway (m)
ρ = density for fluid (kg/m^3)
α = inclination (°)
s = measured length of pathway (m)
P = Pressure (Pa)
μ_f = Effective viscosity of fluid [54]

7.2.2.3 Mechanics

An assumption is that the pathways are set in an elastic system. This suggests that different pressures or stress changes along the length of the pathway might affect width.

$$w_0 = \max\left(\frac{P - P_{open}}{M}, 0\right)$$

w_0 = initial width of pathway (m)
P = pressure (Pa)
P_{open} = Micro-annulus opening pressure (Pa)
M = Elastic coefficient (m/Pa) [54]

7.2.2.4 Chemical mechanisms

Chemical reactions is one of the largest contributors to pathway buildup. Reactions between carbon dioxide and cement is discussed in chapter 6. To understand how fast the buildup rate is, conservation of every component along the pathway must be taken into consideration. Depth of leakage pathway is very large in comparison with width. This large aspect ratio makes it good to separate chemical degradation and flow into their own dimension. This give a 1+1 dimension. Buildup rate can be calculated with implementation of some mass balance equation.

An equation where k' for Ca^{2+}, HCO_3^- and H^+ is implemented. The equation must be calculated respectively for each component [54].

$$\frac{\partial}{\partial \mathrm{t}}\left(w_0 Z_{tot}^{k'}\left(S_f\, \varsigma_f + S_s \varsigma_s\right)\right) + \frac{\partial}{\partial \mathrm{S}}\left(w_0 Z_f^{k'} S_f \varsigma_f v_f\right) = J^{k'}$$

t = time
w_0 = initial width of the pathway (m)
$Z_{tot}^{k'}$ = total mol fraction of component k'
S_f = fluid phase volume fraction
S_s = Solid phase volume fraction
ς_f = molar density of fluid phase
ς_s = molar density of solid phase
$Z_f^{k'}$ = mol fraction fluid phase of component k'
v_f = mean velocity of fluid in vertical well (m/s)
$J^{k'}$ = flux of component k' from reactions between CO_2 and cement (mol/m^2 s) [54]

Conservation equations must also be added. For this scenario four component must be assessed (Ca^{2+}, H_2O, H^+, HCO_3^-) [55].

$$\frac{\partial}{\partial \mathrm{t}}\left(w_0\left(S_f\, \varsigma_f + S_s \varsigma_s\right)\right) + \frac{\partial}{\partial \mathrm{S}}\left(w_0 Z_f^{k'} S_f \varsigma_f v_f\right) = \sum_k J^k$$

Z_f^k= mol fraction fluid phase of component k
J^k= flux of component k from reactions between CO_2 and cement (mol/m^2 s)
$\sum_k J^k$= total flux of all components k from reactions between CO_2 and cement (mol/m^2 s) [54]

Further, n equations for solving flux of component as a result from CO_2 and cement reaction must be solved. n is the number of grid cells in depth.

$J^k\ (Z_{tot}, s, t), L_i\ (Z_{tot}, s, t)$

L_i = width of the layers appearing when CO_2 reacts with cement. i is silica gel and calcite layer (m)

As of now, the main unknowns in the equations are Z^k_{tot} (s,t) and P (s,t). Secondary variables and their dependencies can be written as below. To find the unknowns a number of iteration is ran. This will also solve the equations [55].

$$\begin{cases} w_0(P, s),\ \ S\ (P, Z_{tot}), \varsigma\ (P, Z_{tot}, s), Z_f\ (Z_{tot}, s) \\ \qquad\qquad v_f\left(\frac{\partial \mathrm{P}}{\partial \mathrm{s}},\ \ P, s\right) \end{cases}$$

Even though the contact between cement and CO_2 degrades and create pathways, it can also have a healing effect. As CO_2 is pushing forward along the pathway, it reacts with the cement and creates a layer of silica gel and calcite. At one point, the cement will stop releasing Ca^{2+}. Over time, CO_2 brine will continue to flow and will eventually start eroding the calcite layer. A result of this erosion can be clogging of the flow. This will be positive considering permeability and flow velocity. Clogging effect can be calculated using dimensional analysis. A large number of parameters must be implemented to understand if the pathway will be plugged or not plugged. These equations will not be discussed as this phenomenon is not discussed earlier. [55].

All these equations is part of a simulator. It is solved numerically with help from a computer. Using this model it is possible to predict long term effects downhole as it can predict flow and pathway buildup. However, it has its limitations. It is very dependent on the effective width of path. This data is very uncertain, which can challenge the validity of the model. There are also uncertainties in the clogging calculations.

What this model does not calculate is the rate corrosion rate for casing steel. This might underestimate buildup over time if it is the pathway between casing and cement that is calculated. It will be more correct if it is pathways between cement and formation [54].

8. Environmental impact and sustainable leakage

A big challenge during Plug and abandonment is to predict downhole properties after well is left. The well is left with an eternal perspective, meaning well barriers shall withstand any process or load they are undergoing.

The eternal perspective shall also be verified and documented concerning re-charge of original formation pressure [1].

How much is too much? When plugging a well, the goal is to set barriers that will prevent any fluid or gas from migrating upwards, resulting in zero leakage. Millions of wells are already plugged around the globe, and still we will need to plug even more in the future. How big is the percentage of plugged wells that are leaking? The number of abandoned wells might be much bigger than what is assumed. There are also a large number of wells left without plugs. Primarily onshore wells in North America.

8.1 Well barrier failure statistics

Well barrier failures are the main reason for well leakage. Reduced integrity from a well barrier element can affect the whole barrier, resulting in failure. How large is the percentage of well barrier element failures? The number is very dependent on how old the equipment is. Erosion, degradation and other factors such as temperature and geological disturbances can result in well barrier failure. Older wells also have a tendency not to have proper sealing or bad material quality selection. Proper cement plugging was not performed before 1916. The oil era started for full in 1859 when they found oil in the Drake well in Pennsylvania. Between 1859 and 1916, a large number of wells were drilled with no or bad plugging afterwards. Pollution potential is directly related to age of a well. This is illustrated in King et al's study of well failures [56].

Time	Operation norms	Pollution potential
1820-1916	Drilling with cable tools, no isolation with cement and wells vented to atmosphere.	High
1916-1970	Improvement of cementing jobs.	Moderate
1930-Present	Cable tools replaced by rotary drilling equipment. Also introduction to pressure control and well containment systems.	Moderate
1952-Present	Commercializing of hydraulic fracturing. Better pipe, coupling and cement isolations due to this new operation form.	Low
1965-2000	Improvement of joint make up and gas tight couplings.	Vertical wells show moderate potential
1975-Present	Improvement of cementing. Better design software. Also more data on flow at different temperatures and dynamic cementing jobs.	Lower
1988-Present	Introduction to multi-fracture, horizontal wells and pad drilling. These improvements resulted in pollution footprints up to 90% for onshore drilling.	Lower
2005-Present	Well integrity assessment. Adding additional barriers and introduction of premium couplings.	Lower as of 2010 with stricter state laws in the US
2008-Present	Reduction of fracture chemicals.	Lowest potential yet.

Table 16: Pollution potential vs. Era [57]

Integrity of barrier elements can be improved with workover or maintenance. Old equipment can be replaced with new one, resulting in extending life of a well. An example of this can be taken from a study in Malacca strait in Sumatra. This area has 175 onshore and offshore wells ranging back to the 1980's. Design time of these wells have been surpassed. With none, or insufficient maintenance resulting in well barrier failure of 43% and 4% well failure. Well failure must not be mistaken for well barrier failure. Well failure is when all barriers show failure, resulting in leakage possibilities [56].

A larger study done in several regions by different companies gives a number on how big the well integrity issue is. Failure of well barriers rate varies a lot between the different locations. In the Gulf of Mexico, failure rate is 45% [56]. This may be due to deep-water depths and a large number of HPHT wells. A more shocking statistic is the difference in failure rate between UK and Norwegian site of the North Sea section. Studies done by SPE (UK site) and SINTEF (Norwegian site) resulted in a failure rate of 34% on the UK site and 18% on Norwegian site [56]. UK site wells shows almost twice the rate of failure in well barriers compared to Norwegian site. This may be due to stricter regulations or better maintenance protocols on Norwegian site.

A very detailed study done by Preben Randhol and Inge Manfred Carlsen in collaboration with SINTEF gives a clear view of well barrier leakage on Norwegian sector. According to this study, somewhere between 20-30% of wells on NCS have experienced at least one leakage during their lifetime [38]. Leakage distribution for different barriers is shown below. This study suggest that wellhead failure is the main cause of leakage.

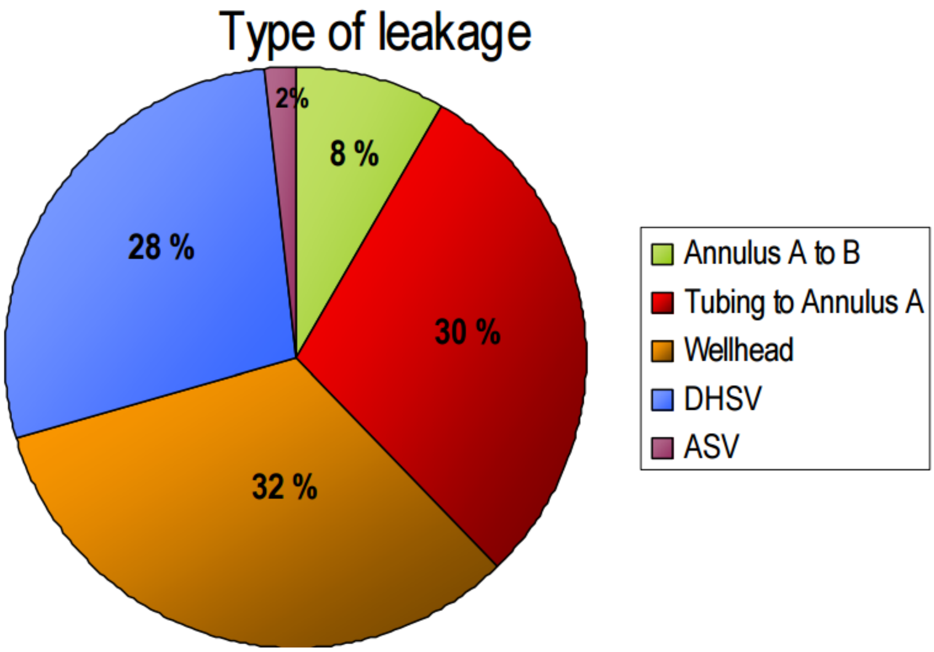


Figure 44: Leakage distribution for different well locations [58]

Well integrity issues is also related to well type. Randhol and Carlsen study shows similar results of what a PSA study from 2006 does. Both studies shows that injection wells have a much higher integrity failure rate than what producers does. For the PSA study, the number for failure for injectors are over 3 times as high as for producers [57].

Well category	Integrity issue percentage for different studies		
	Randhol and carlsen	PSA	Aadnøy and Vignes
Injection well	37%	41%	33%
Production well	19%	13%	15%

Table 17: Percentage integrity problems for injection and production wells from different studies [59] [58].

Bernt Aadnøy and Birgit Vignes performed an investigation of well integrity issues back in 2008 [58]. 406 wells from 12 pre-selected offshore facilities were investigated. The investigation indicates that out of 406 wells, 75 wells have integrity issues/failure. This is approximately 18.5%. The majority of integrity problems were from tubing. From Randhol and Carlsen, wellhead was the main issue to leakage. In Aadnøy and Vignes's investigation, only four wells showed wellhead integrity issues [58].

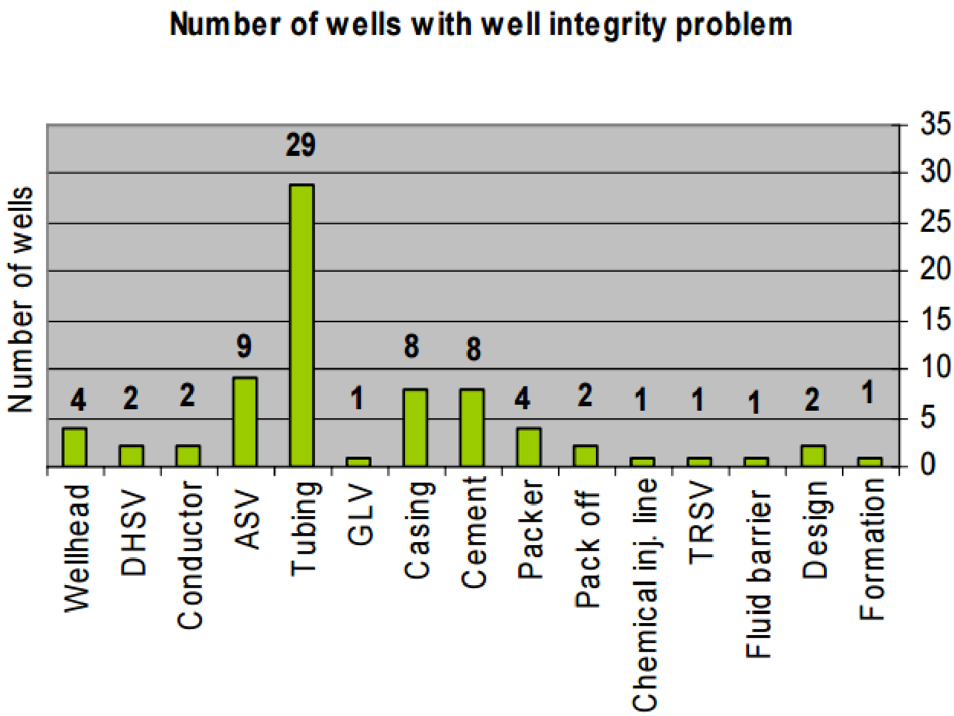


Figure 45: Well integrity problem statistics NCS [59]

The rate of integrity issues shows large differences between the different studies on the Norwegian Continental Shelf. It is hard to give a specific rate of well barrier or integrity failure.

8.2 Naturally occurred spills

Through the years of oil and gas production, there have been several large disasters that has resulted in oil spills and gas releases. Two of the most known disasters from newer times is the Deepwater Horizon and Exxon Valdez. Deepwater Horizon experienced a kick, which then resulted in a blowout. Eleven people were killed and over 3 million barrels of crude oil leaked out into the ocean around the Gulf of Mexico [59]. The other well known accident, the Exxon Valdez, was a large oil tanker that ran aground outside the coast of Alaska. The impact caused a hole in the hull which resulted in 11 million gallons or 350 000 barrels of oil escaping into the ocean. Also on NCS there have been accidents resulting in oil contamination. The largest oil spill disaster in Norwegian history came from Ekofisk B in 1977. Similar to Deepwater Horizon, it experienced a blowout resulting in a spill between 9000 – 20 000 ton oil [60]. The amount of spills from these incidents are large, but how much hydrocarbons are spilled globally?

How big is the percentage of oil and gas spills caused by accidents in the petroleum business? Is it comparable to the amount of natural leaks, or leaks from other sources? According to Woods Hole Oceanographic Institution (WHOI), about 50% of the oil entering coastal areas is a result of natural oil leaks. Large amount of hydrocarbons are leaking from natural oil and gas seeps. A seep is a geological feature where hydrocarbons migrate from a reservoir and upwards a seep conduit. This type of conduit is similar to channels in cement, but is instead made by cracks and faults formed by geological activity. Oil and gas seeps are found in various location around the world. There are often petroleum activity around seeps, which is natural since seeps originate from a HC reservoir [61].

Figure 46 shows how the seep works. Hydrocarbon migrates upwards through cracks in the formation (also known as seep conduits) and is released out into the ocean. The heaviest oil will settle around the crack, while the lightest oil will migrate to the surface. Gasses like methane released from seep will migrate to sea level and then into the atmosphere. The lightest oil will evaporate and enter the atmosphere, while the heaviest hydrocarbon will sink back to seafloor and create what is called a fallout plume [61].

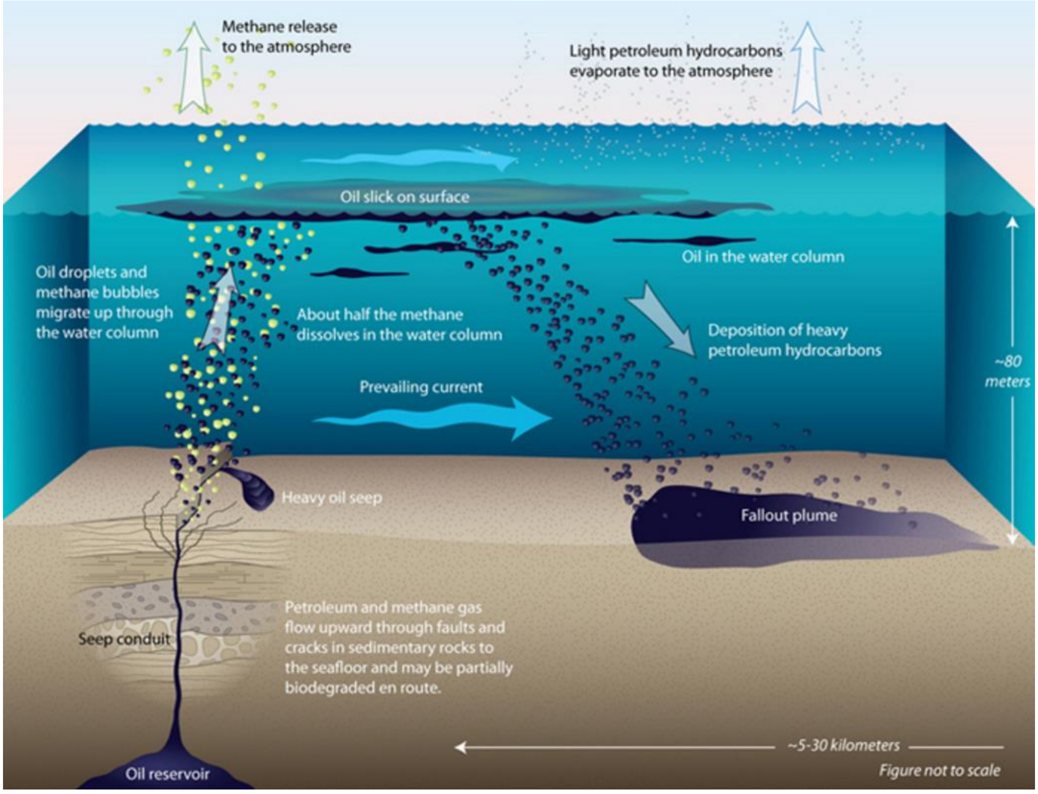


Figure 46: Oil seep scenario [62]

Seeps have generally very low flow rate, and will therefore be less aggressive against the environment in comparison with accidents like blowouts. Since seeps have been around for a long time, organisms around the area have adapted to this environment. Some organisms can feed of released oil, and decompose it. This can also be a scenario for leaking abandoned wells. An abandoned well will leak as long as it is abandoned, or until it is not able to transport HC anymore. Leaks can also be repaired. Organism can over time settle around and handle leakages. How much it can handle will depend on the flowrate from the source, but there are many other parameters considering the amount of oil that an environment can handle. Temperature, static or dynamical weather, waves, sea currents and oil eating organisms are only some of them.

8.2.1 Natural oil spills

WHOI stated that almost 50% of all oil spills at coastal areas comes from natural leaks [61]. A survey done between 1990 and 1999 shows that this might be true. Table below show petroleum leaks from different sources in both North America and worldwide [62]. Numbers are in thousands of tons.

	Best estimate	**Minimum**	**Maximum**
North America	$\frac{160}{260} * 100 = 61.5\%$	$\frac{80}{110} * 100 = 72.7\%$	$\frac{240}{2300} * 100 = 10.4$
Worldwide	$\frac{600}{1300} * 100 = 46.1\%$	$\frac{200}{470} * 100 = 42.6\%$	$\frac{2000}{8300} * 100 = 24.1\%$

Table 18: Oil leaks North America and worldwide

	North America			Worldwide		
	Best Est.	Min.	Max.	Best Est.	Min.	Max.
Natural Seeps	160	80	240	600	200	2000
Extraction of Petroleum	3.0	2.3	4.3	38	20	62
Platforms	0.16	0.15	0.18	0.86	0.29	1.4
Atmospheric deposition	0.12	0.07	0.45	1.3	0.38	2.6
Produced waters	2.7	2.1	3.7	36	19	58
Transportation of Petroleum	9.1	7.4	11	150	120	260
Pipeline spills	1.9	1.7	2.1	12	6.1	37
Tank vessel spills	5.3	4.0	6.4	100	93	130
Operational discharges (cargo washings)	na[b]	na	na	36	18	72
Coastal Facility Spills	1.9	1.7	2.2	4.9	2.4	15
Atmospheric deposition	0.01	trace[c]	0.02	0.4	0.2	1
Consumption of Petroleum	84	19	2000	480	130	6000
Land-based (river and runoff)	54	2.6	1900	140	6.8	5000
Recreational marine vessel	5.6	2.2	9	nd[d]	nd	nd
Spills (non-tank vessels)	1.2	1.1	1.4	7.1	6.5	8.8
Operational discharges (vessels ≥100 GT)	0.10	0.03	0.30	270	90	810
Operational discharges (vessels<100 GT)	0.12	0.03	0.30	nd[e]	nd	nd
Atmospheric deposition	21	9.1	81	52	23	200
Jettisoned aircraft fuel	1.5	1.0	4.4	7.5	5.0	22
Total	260	110	2300	1300	470	8300

Figure 47: Annual releases of petroleum in thousands of tons [63].

Looking at the numbers from the best estimate, the percentage of natural leaks for North America and worldwide is 61.5% and 46.1%. Fairly close to half of the total spills. One must consider that these numbers are from between 1990 and 1999. Newer and environmental friendly technologies exists today, and fewer spill incidents is happening. Cars use less fuel than before and electrical cars are at an all-time high. All these factors resulting in less oil spills. Natural seep leakage is considered the same as of 1990-1999. This may peak the natural spills over half of total spills.

8.2.3 Natural gas spills

Not only is there large amount of oil leaking from seeps. Gasses are also a problem when it comes to polluting the air. CO_2 might be the worst contributor to global warming due to the amount released all around the world, but on a long time basis, methane is up to 86 times worse than CO_2 according to Scientific America [63]. Methane will stay in the atmosphere for about a decade before it is converted into CO_2, which then can exist for up to 800 years before leaving [64].

8.3 Spills from abandoned wells

Abandoned wells represents a risk for leakage. Even the ones that have been plugged using the best possible sealing material and plugging method. The slightest error might result in barrier degradation buildup, which over time can result in leakage. Plugging of wells is done everywhere around the globe, both offshore and onshore.

8.3.1 Spills United Kingdom

United Kingdom has both onshore and offshore wells. A study of 102 wells onshore in UK showed that 30% of the well were leaking methane [65]. Even though the percentage of wells that are leaking is large, the average amount of CH_4 released from each well are less than what a dairy cow produces.

Some of the wells released 10 times more methane than the average [65]. Study calculated that the average amount of methane annually released from the wells were equivalent to 364 ± 677 kg CO_2 [65]. One CH_4-equivalent is equal to 21 CO_2-equivalents.

Leakage onshore UK vs. API RP 14B.

Worst case scenario 364 + 677 kg = 1041 kg/year.

Molecular weight of CO_2 = 44 g/mol

$$1\ kg\ CO2\ =\ 1000g\ *\ \frac{1\ mol}{44g}\ =\ 22.7\ mol\ CO2$$

Leakage came from onshore wells so I will assume T = 15°C = 288.15 K and 1 atm.

$$Volume = \frac{nRT}{P} = \frac{22.7 * 0.0821 * 288.5}{1} = 537\ l$$

1 kg of CO_2 is equivalent to 0.537 m3 at 288.15 K and 1 atm. Annually emission were 1041 kg. Total volume of CO_2-equivalents is 559.03.

API RP 14B is explained in section 8.4 and states that max allowable gas leakage is 0.42 m^3/min. 1041 m^3/year is equal to 0.002 m^3/min. The amount of gas released is much lower than API RP 14B suggests.

8.3.2 Spills North America

Another large study done for abandoned wells in Pennsylvania stated that emission of methane from abandoned wells in the United States is the second largest methane emission source in the country. In Pennsylvania there is no regulations regarding monitoring of abandoned wells. The study revealed that only 5 out of 19 wells inspected were plugged [66]. Old abandoned wells in the United States are a big problem since many of them are abandoned without being plugged. Many of them are also categorized as orphaned wells, which means that owners of the wells are unknown. According to collected data, somewhere between 4 and 7 percent of the total CH_4 emission came from abandoned wells in Pennsylvania [66].

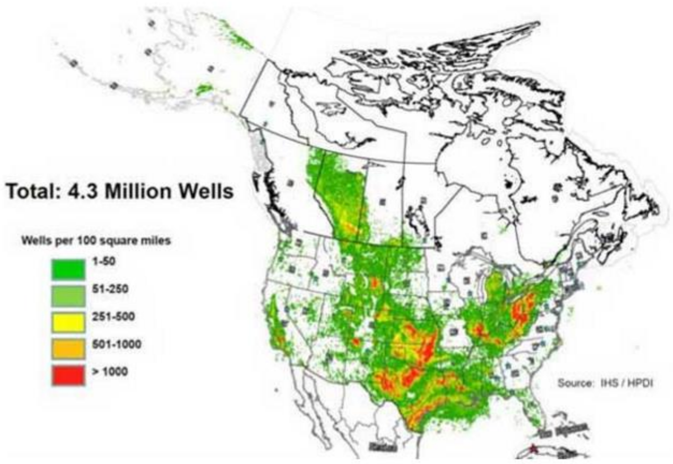


Figure 48: Oil wells in the United States [67].

The average abandoned well in Pennsylvania leaks about 96 m^3 each year. With a total of somewhere between 280 000 and 970 000 abandoned wells, the volume of CH_4 released annually can be up to 93 million m^3. In CO_2-equivalents, it is almost 2 billion cubic meters. This is only in the state of Pennsylvania. As seen on figure 48, about every state in the US has HC activity. The exact number of abandoned wells is impossible to predict since many of the earlier drilled wells were not recorded. There are at least 2.3 million abandoned wells onshore, with some estimates of up to 3 million. [67].

Well Category	Number of Measurements	Mean (g CH_4 h^{-1})	95% UCL (g CH_4 h^{-1})
All wells (entire U.S.)	138	1.38	3.17
All wells (eastern U.S.)	12	14.00	32.87
All wells (western U.S.)	126	0.18	0.41
Plugged wells (entire U.S.)	119	0.002	0.005
Unplugged wells (entire U.S.)	19	10.02	22.47
Plugged (eastern U.S.)	6	0	NA
Unplugged (eastern U.S.)	6	28.01	64.00
Plugged (western U.S.)	113	0.002	0.005
Unplugged (western U.S.)	13	1.71	3.83

Figure 49: Gram CH4/hour leakage per well in various location in the United States [68]

Very recently (October 2015), a very disastrous incident occurred in the mountains of California. More precisely Aliso Canyon Creek. This area is known for its many oil wells ranging all the way back to 1938. It contains 115 oil wells that now works as gas producers. It is known as the largest gas storage facility in the United States.

The 23rd October of 2015 a stream of methane started spewing out of a well. Cause of the leak was a rupture in a 7-inch well casing from well SS25 at approximately 8700 feet below surface. The breach made a migration path that resulted in a gas-blowout [68]. Source of the leak took a long time to locate, and even longer to stop. It took 112 days from the blowout started until it was plugged. To stop the gas leak, a relief well was drilled into the existing well. Heavy fluids were injected to gain control of the well. After the well was under control, cement was pumped down to plug it [69].

Gas leaks exist all around the globe, but few in comparison to this incident. Thousands of people had to be evacuated due to dangers from the gas emission. Too high methane content in air can ignite and cause an explosion. The body is also affected of too high concentrations of methane. A reduction in oxygen level due to high amount of methane can cause nausea, dizziness, headaches and unconsciousness. Worst case scenario is suffocation if O_2 levels drop too much [70].

Roughly 96 000 metric tons of methane leaked into the air during the 112 day period. This amount of leakage can be estimated to the same emission as of what 900 000 cars would produce for an entire year. It has the same emissions as of burning 900 million gallons of gasoline [71]. The aftermath of the incident resulting in several lawsuits and compensations, estimates a cost of somewhere between 250 and 300 million USD.

Out of the 115 wells on the site, 39 of the wells were drilled before 1954. The standard of these well is thought to be very poor considering the age and technology used during this period. It is not unlikely that integrity of some of the wells have been damaged due to degradation. Authorities have said that the wells should be brought up to modern standards to prevent incidents like this in the future.

Figure 50: Infrared photograph from Aliso Valley gas leak [72]

8.4 Maximum allowable spillage

Leak rate shall be as low as possible. Zero if possible. What leakage rate that is acceptable is dependent of several factors. Some environments are better suited for larger leaks. This can be due strong currents or rough waves.

There is one leakage rate criteria that might be suitable for leakage from abandoned wells. According to API RP 14B, the maximum allowable liquid leakage is 0.4 liter per minute. For gas, allowable leakage is 15 Scf/min or 0.42 m^3/min [72]. This rate is for leakage through a closed subsurface safety valve system.

It might be reasonable to use this leakage rate for abandoned wells. The leakage will be ejected in to the same environment for both abandoned wells and for leakage through subsurface valve. If the leakage exceeds this limit, it should be coped with to reduce further escalation of leaks. If it can be verified that there is no presence of HC in the leak, it might be appropriate to accept leaks above this rate [73].

8.5 Well statistics NCS

As of 2016 there have been drilled a total of 5814 wells on the Norwegian Continental Shelf [74]. A large amount is exploration wells, but the majority is development wells. The number of wells drilled were at its all-time high in 2015 with 244 wells.

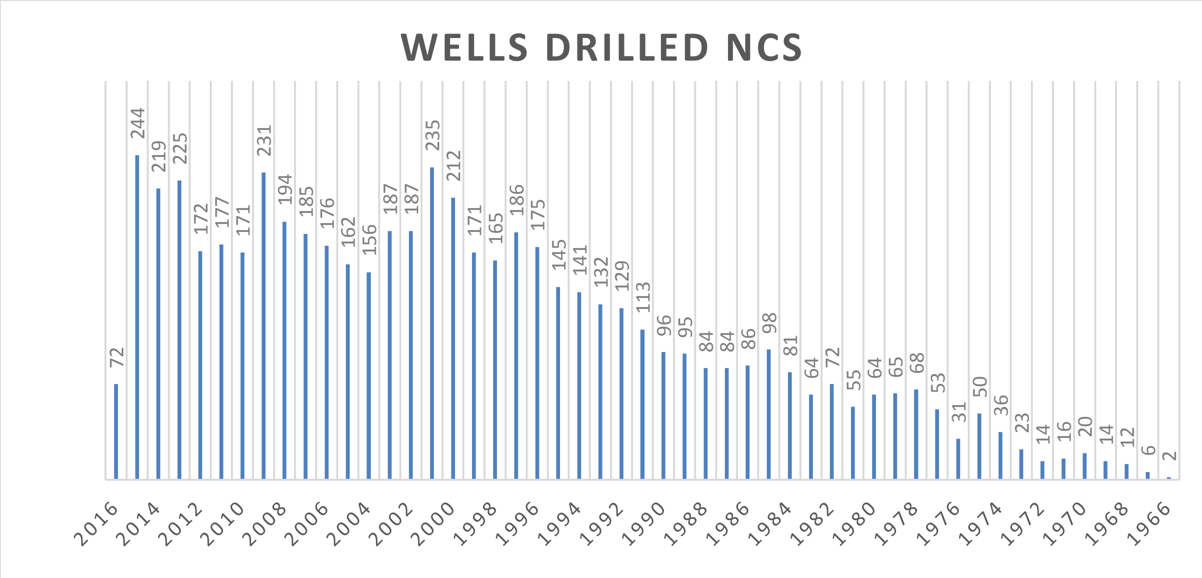


Figure 51: Wells drilled by year [75]

Well category		Well Purpose	
Development wells	4224	Injection	649
		Observation	475
		Production	3100
Exploration	1590	Appraisal	539
		Wildcat	1051

Table 19: Well statistics by well catergory [75]

The Norwegian Continental Shelf is divided into three areas. The Norwegian Sea, North Sea and the Barents Sea. The Majority of wells drilled on the NCS is at the North Sea section. Over 83% of the wells are located here [74].

Area	Number of wells
Norwegian Sea	817
North Sea	4838
Barents Sea	159

Table 20: Well statistic by area [75]

A survey done by Norwegian Oil and Gas (Norog) in 2014, calculated that it would take 40 years to plug all wells on NCS with use of 15 rigs [75]. An estimate of the total cost as of 2014 is up to 876 billion NOK [3]. This is with current plugging technology. According to the survey, over 3000 holes are not plugged at NCS. Sometime in the future, these wells will have to be plugged and abandoned. New wells will also be drilled, and plugging of these will have to be included in the calculation. Plug and abandonment is considered as one of the most boring operations for companies. High prices and no profit from P&A makes operators postpone the plugging sequence in hope for better and less expensive technologies [75].

Another survey done back in 2011 revealed that there are temporary abandoned wells that are over 40 years old on the Norwegian Continental Shelf. Even though they have had temporary abandonment status for 40 years, the regulations states that there is no maximum abandonment duration when the well is monitored and routinely tested. Wells that have been temporary abandoned for over 40 years should be plugged and permanently abandoned to reduce the likelihood of environmental impact.

As of 2014, the Petroleum Safety authorities has received these future plans for plugging (some are already started or finished) [76]:

- Valhall DP: 31 wells are planned to be plugged between 2015 and 2022.
- Ekofisk: Plugging started in 2014 for Ekofisk Alpha. The plugging operation for Ekofisk Charlie will start in 2017.
- Hod: 8 wells planned to be plugged and abandoned between 2015 and 2016.
- Glitne: 7 wells to be P&A'd from 2014 to 2016.
- Heimdal: 12 wells plugged and abandoned in 2014.
- Volve: 7 wells plugged and abandoned in 2015.
- Huldra: 6 wells to be plugged and abandoned in 2016.
- Jotun: 22 wells planned plugged in 2017.
- Statfjord: Plugging at Statfjord A has started.

There is not a total overview of abandoned wells since PSA does not provide any updated overview of them. The Petroleum Safety Authority is relying on information from the operators about the well status. The last total overview stated that there was 282 temporarily abandoned wells on the NCS. PSA states that they want the operators to plug wells on permanent basis instead of temporary [77].

8.6 Leakage abandoned wells on the Norwegian Continental Shelf

Back in 2011 PSA, Sintef and Wellbarrier went together and investigated the integrity of temporarily abandoned wells on the Norwegian Continental Shelf. 193 wells were found to be abandoned temporarily. Mentioned above, some of the wells have been abandoned for over 40 years. Out of the 193 wells, 38% of them had integrity problems.

Production, injection, exploration and other types of wells were investigated. Production and exploration wells had the worst statistics with only 41 and 38 percent acceptable integrity [78].

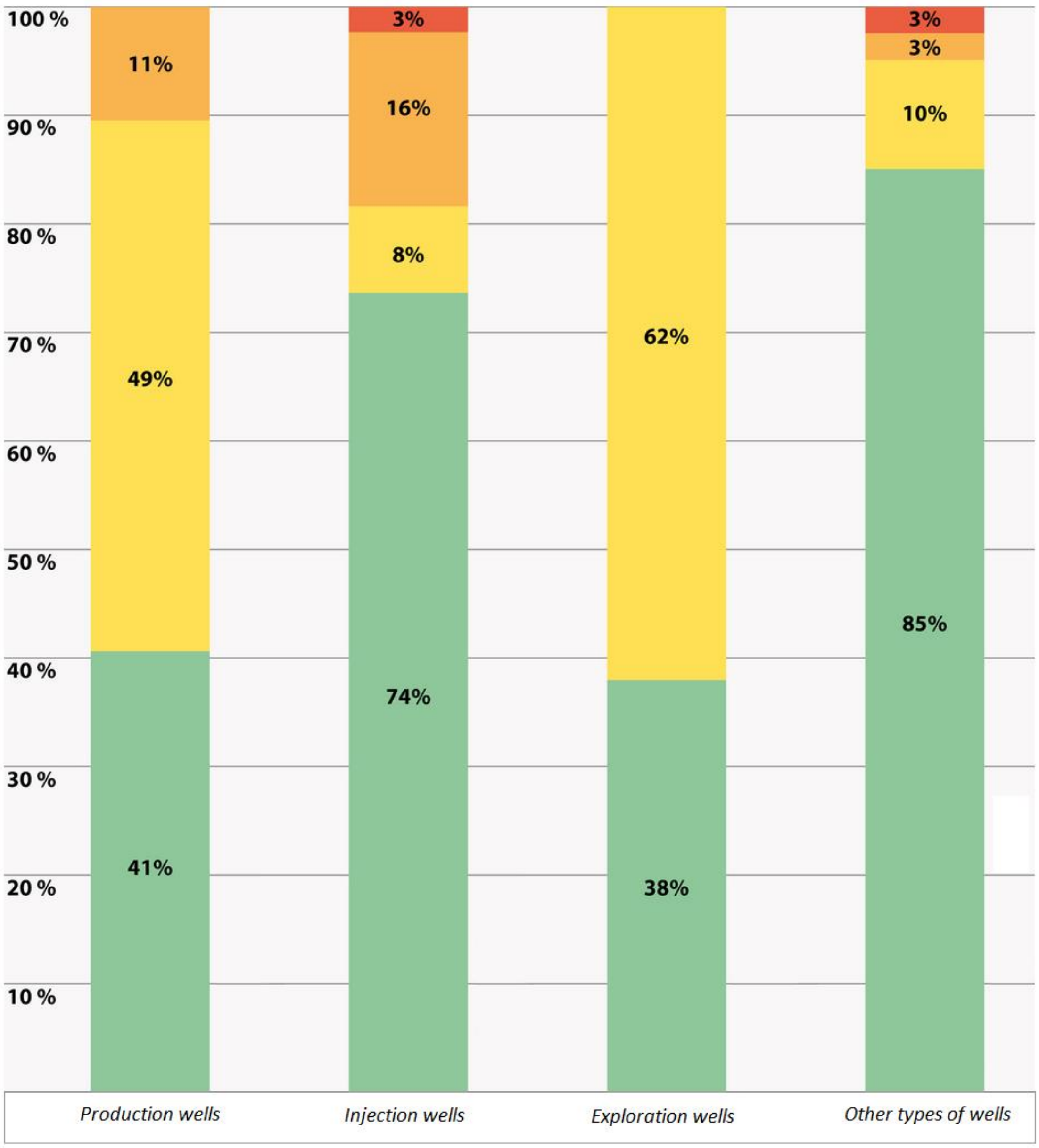


Figure 52: Integrity status of different types of well categories [79]

As seen on figure 52, the well integrity is divided into 4 categories, where green is best outcome and red worst.

Green: Healthy well. None or only minor faults. Both barriers are intact and have full integrity.

Yellow: One barrier has reduced integrity, while the other has full integrity.

Orange: Failure in one barrier, while the other is still intact. One mistake or failure can result in leakage to surface.

Red: Failure in one barrier and the integrity of the other one is either reduced or not verified. Might also be leakage to surface.

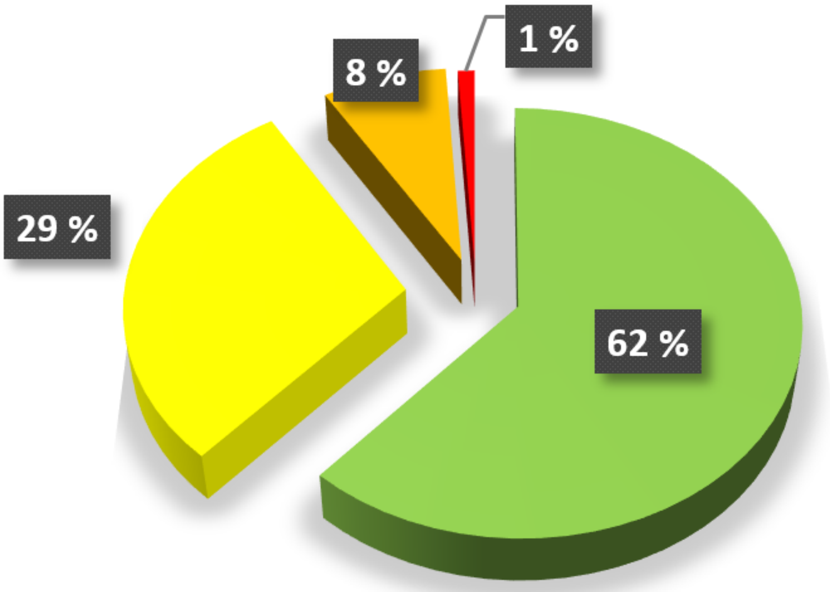


Figure 53: Integrity statistics divided into severity

Only one percent of the wells were in the red-category, but a total of nine percent has damages on both barriers, which can result in leakage. Reduced integrity of one barrier will also accelerate integrity degradation of the second one if there is flow through it. From the survey, it was concluded that wells in the red category had to be coped with as soon as possible to prevent further damages and leakage. The investigation was done according to regulations from NORSOK Standard D-010 and guideline 117 - recommended guidelines for well integrity [78].

9. Solutions to cope with possible well barrier leakage

A well that is to be abandoned shall be plugged and abandoned in a prudent manner. The well shall be sealed, and no leaks of hydrocarbons shall occur. If there should be any problems regarding the well after it is left, it should be possible to repair or reduce the damages it is causing. A leaking well should be repaired, so its leak stops. Mentioned earlier, there are two ways of abandoning a well. Temporary and permanent. Remedial action of these will differ due to entry possibilities. Temporary abandoned wells are left for the purpose of re-entry later on. When abandoning a well permanently, the wellhead is often cut and removed, making it hard to re-enter again.

9.1 Temporary abandonment

Temporary abandoned wells will have to be accessed again at some point. Some wells on the NCS have been abandoned for over 40 years, still, some day they must be abandoned permanently or be used for other purposes. Like starting production again or using it as injection well.

9.1.1 Casing inside existing casing

Some abandoned wells might have to be repaired before it can be used again. A method of regaining integrity of casing is to install a smaller OD casing inside the existing casing. If the cement and casing integrity is bad and leakage can be a problem, installing new casing with new primary cement job can prevent this. It will depend on leakage path of the fluid or gas. One important factor for re-usage of temporarily abandoned wells is that casing has to have good integrity. Especially in the case of fracture stimulation of the well.

There are several challenges while running new smaller OD casing. It is important so that the surge pressure is not too high to prevent fracturing formation or old casing/cement. Another challenge is the diameter of the casing. Too small ID will result in much drag, which will decrease production. If the well is to be used for injection purposes, the injection rate will be limited to the new ID [79].

A good cementing job is crucial while installing new smaller OD casing. If cement job is successful, leakage of fluids or gases can be prevented.

What must be noted is that a smaller OD casing can be problematic for later use of the well. It is important that the ID is compatible with plugging or workover equipment. If it is too small, some tools might not fit through it.

9.1.2 Squeeze cementing

A leakage through casing string can be a scenario due to pitting corrosion. If this is the case, it should be repaired to prevent further leakage. A method of stopping leakage through casing is squeeze cementing. Squeeze cementing can be performed for most stages in well life. During completion or later. If a well is to be abandoned, it is important that it does not leak. There are several reasons to perform a squeeze cementing job [12].

- Repair leakage
- Eliminate water intrusion
- GOR or WOR reduction by isolating gas or water zones from adjacent intervals with oil
- Abandonment of depleted or nonproductive zone
- Protecting against fluid migration into producing zone
- To seal a lost circulation zone

Squeeze cementing is a remedial cementing method. Most times squeeze cementing jobs could be avoided, since it is an operation to fix bad cement jobs. A good cement job would prevent this type of remedial cementing operation. Cement slurry is prepared and pumped down to area with leak. This area will be isolated from the rest of the well under operation. Pressure is then applied to force cement into leak channels. For a squeeze cement job to be successful, good slurry design is important. There are many different shapes and sizes cement shall squeeze into [80]. If casing leak is too small, ordinary cement slurry might not fit the job. Some particles in the slurry can be too large to fit channels. A special designed small particle cement must be used.

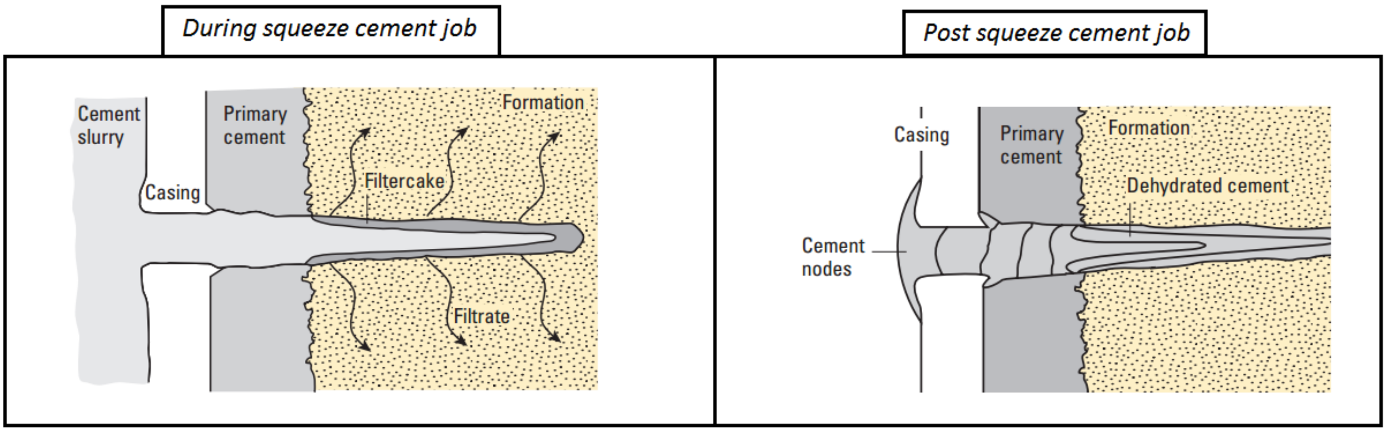


Figure 54: Squeeze cement job during and after [12]

There are six commonly used methods of squeeze cementing according to petrowiki.

1. **Running squeeze:** A method where pumps are continuously running to force cement into wanted zone. It has one of easiest applied designs, but is difficult to control. Final squeeze pressure and pressure rate is hard to determine.
2. **Hesitation squeeze:** Used when running squeeze is not possible. This can be due to void size or when the operation must be done below a critical wellbore pressure. Pumping of cement is stopped and started several times during this type of squeeze method. During hesitation squeeze, operators must design and test the cement to understand how it will behave during pump stops.
3. **High-pressure squeeze:** Cement slurry is pumped with a pressure above fracturing pressure. This method is used when it is necessary to fracture the formation to displace the cement. Fractures creates by overpressure will be cemented.
4. **Low-pressure squeeze**: Most common squeeze cement technique. Pressure is under fracturing pressure during this type of squeeze operation. Can be performed when wellbore fluids can be injected into formation.

5. **Packer/retainer squeeze:** Squeeze method where retainer/packer is used to isolate or work as foundation for cement.
6. **Bradenhead squeeze:** Often used during drilling when problems occurs. This type of squeeze job is performed when there is not any available squeeze tools, or it is not possible to run these tools into hole. Cement is pumped down to squeeze interval through drillstring. Drillstring is then pulled over cement column, before closing backside of wellbore. Pressure is then forced through drillstring to force the cement into the voids [80].

9.1.3 Pressure activated sealant.

Microannuluses might be the most common leakage pathway in abandoned wells due to both casing corrosion and cement degradation works as drivers. Cementing jobs like squeeze cement can be very expensive. A less expensive method can be used to plug microannulus leaks. According to Rusch et al, it can save over one million dollars using this method instead of conventional rig workover [81].

Microannulus leaks can be repaired using a pressure activated sealant. When the sealant reaches the leak area, it experiences a pressure drop. This drop in pressure causes the sealant to polymerize into a solid seal. It can be used to stop leaks at many different barrier elements. When sealant is injected it is in fluid form. After it experiences a specific differential pressure, polymerization will happen. It will cover the entire cross section and become a solid and flexible seal. Excess sealant that is pumped into the well will stay in its liquid form and prevent clogging of other parts of the barrier system.

Since the sealant is in liquid form, it has the possibility to penetrate deep into leakage pathways. It can penetrate pore sizes at a micron level. Its composition is not comparable with cement where there are solids that can be too large to penetrate specific pore sizes. This penetration ability makes it very good to cope with microannulus leaks. To prevent sealant to polymerize too early during microannulus repairs, is to inject it at a slow rate. Injection will keep going until it reaches a point where injection pressure is equal to gasses and fluids that are flowing inside the microannulus. Pressure will then be released from the annulus, which polymerizes sealant.

A test of the sealant shows the ability to reduce the permeability after process is complete. Using Darcy's law, permeability was calculated to be 605 mD for a 4-foot sample. After the sealant was injected and solidified, permeability was calculated again. This time the permeability was 1.6 mD, a reduction of 99.7% compared to before sealant injection. This permeability is lower than cement with full integrity will have. This repair method have been used for several plug and abandonment cases with success [81].

9.1.4 Rigless caing leak repair

For cases where leaks occur during production, the tubing must be pulled before doing a workover. This type of workover is really expensive as it needs a rig or drilling ship to do the repair. For temporary abandonment cases, tubing is often removed before well is plugged. This opens for new and less expensive repair possibilities. Squeeze cementing is mentioned earlier, and is used to seal casing leaks. To seal casing leaks, instead of using squeeze cementing which need circulation to complete, a rigless option might be a better solution.

This method works by lowering a tool on cable down to the leak area. The leak will be repaired by setting a thermosetting resin that is reinforced with carbon fiber. Outer skin of the resin is made of elastomers. To set the seal, the tool is inflated, pusing it agains the casing on all sides. Heat is then transferred to the thermosetting resin, which forms a hard permanent seal. This seal is not corrosion affected [82].

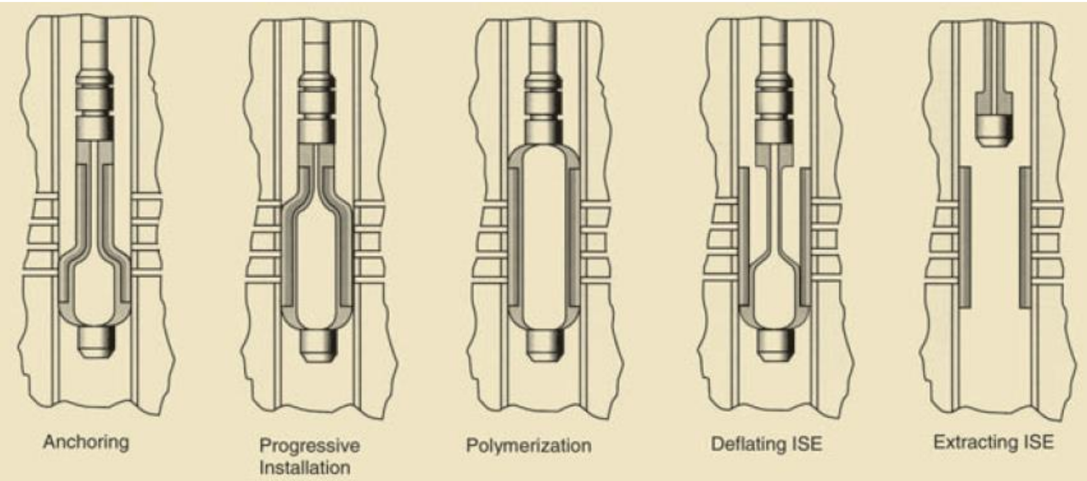


Figure 55: Casing leak repair sequence [83]

9.2 Permanent abandonment

When a well is permanently abandoned there are two scenarios related to wellhead cutting and removal. The first and the most common scenario is cutting the wellhead, conductor and casing strings a few meters below sea floor to prevent it from sticking up in the future. An intact wellhead on the seafloor can twirl around fishing nets and trawl. The second scenario is leaving the wellhead intact if the water depth is sufficient. In the North Sea, the water depth is too shallow most places to leave wellhead on top of the well. For other places like Gulf of Mexico where water depths can reach thousands of meters, the wellhead can be left intact. Wellhead removal has be done according to regulations to move any obstructions for fishing activities. However, some places it is encouraged to leave it intact due to re-entry possibilities. There is no easy way to enter an abandoned well if the wellhead is removed [83].

9.2.1 Relief well

In case of emergencies or the need of re-entering a well post-permanent abandonment where there is no existence of wellhead, there is one solution. Drilling a new well into the old one. For cases like blowouts, a new well drilled into an existing one is called a relief well. A relief well is a well designed for pumping in high-density fluids to force hydrocarbons down into the formation with overpressure. Aliso Valley gas leak mentioned in chapter 8 was plugged after drilling a relief well. Trying to enter a well through a full-scale blowout can be disastrous and worsen the situation. The offshore drilling unit drilling the relief well is placed at a safe distance. One of the major setbacks considering relief well drilling is the amount of time it takes to do it. The time is dependent on depth, but drilling in general is time consuming. Another important factor before executing relief well operations is to decide strategy and well kill design.

Well path	Through the riser to the surface, no drill string in hole.
Simulated rate	350,000 BOPD and 200 mmcfd gas.
Reservoir depth	28,000-ft MD/27,000-ft TVD.
Reservoir pressure	19,500 psi, 13.5 ppg EMW.
Reservoir sand properties	Sand thickness 200 ft, PI = 46 bbl/psi/day
Kill Mud Weight	16.0 ppg WBM
Maximum kill rate	100 bpm from one relief well
Maximum pump pressure	7,500 psi, plus surface line friction
Hydraulic horsepower req'd	18,400 HHP, surface line not included
Kill mud volume req'd	8,000 to 13,000 bbl.
Pump time	2.7 hrs
Maximum ECD at intercept point	16.7 ppg

Figure 56: Example of relief well design [85]

The well structure is often very similar to the old wells design. Direction of the well starts with vertical drilling down until a planned kickoff point where directional drilling begins. According to Drilling Contractor, an entering angle of 3 to 4 degrees is optimal for a first-attempt success. This allows steering of the bit, which makes it possible for multiple attempts instead of plug-back and sidetracking [84].

To stop a blowout, a dynamical kill operations is performed. The goal of the operation is to inject kill fluids at a rate higher than the blowout. Introduction of kill mud raises the density of blowout stream and generates higher friction that reduces the flow speed. If the procedure is done correctly, the blowout is killed, and a bottomhole pressure above pore pressure is generated.Before execution of kill operation, kill mud is prepared to ensure that the density is sufficient. Pumps and fluids are running before drilling out of the line shoe and into the blowout well [84].

Relief wells are usually used in worst-case scenarios. A very well known accident involving relief well drilling is the Deepwater Horizon accident in the Gulf of Mexico. The Deepwater Horizon was a

Semi-submersible MODU owned by Transocean on contract with British Petroleum (BP). On April 20, 2010, it experienced a blowout from the Macondo well more than 18 000 feet below seafloor. The rig caught on fire and capsized in water depth of more than 5000 feet before it sank. It is estimated that 4.9 million gallons of oil were released into the Gulf of Mexico. On April 27, 2010, Minerals Management approved a plan on stopping the blowout with two separate relief well [85]. Relief well drilling started at the 2nd of May. Transocean, the same company that owned the MODU destroyed by the blowout, drilled the relief wells along with BP. Relief wells reached the leaking well early August, and was stopped with a static kill on August 3, 2010. The well was plugged on September 19, approximately 5 months after the blowout started [85].

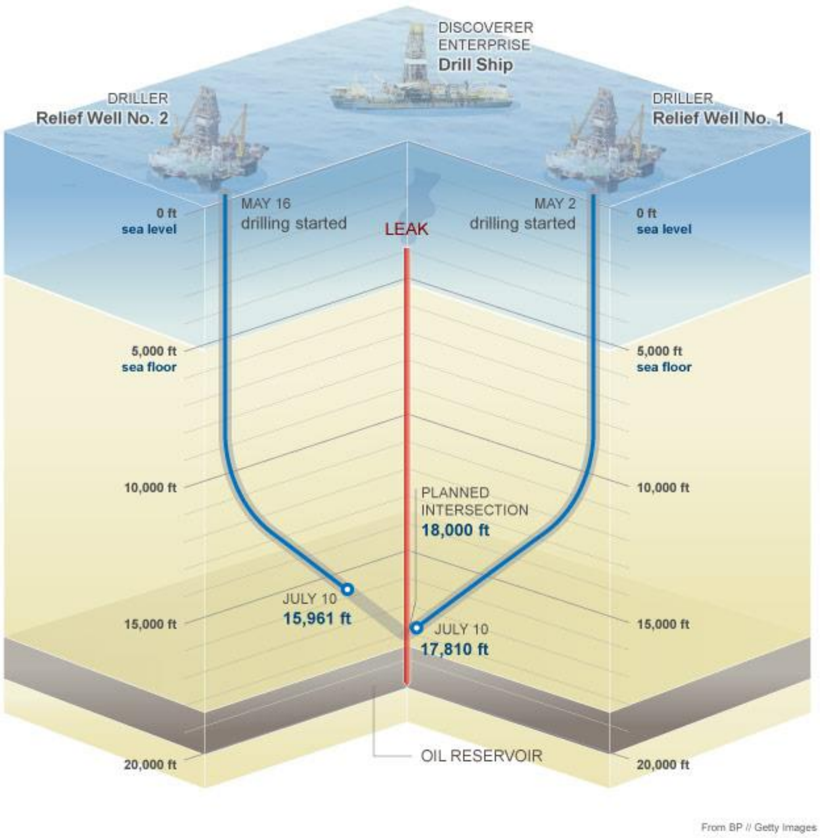


Figure 57: Relief well design Macondo well [91]

10. Discussion

In this chapter, some of the most important aspects of this thesis will be summarized and discussed.

10.1 Verification of barriers

To verify barriers, a large number of tools and methods can be used. Logging tools are a good way of securing that annular cement jobs are successful. This is the first step for relying on integrity to last for an eternity. To ensure that integrity is good, several tools might be needed to get reliable readings. Logging tools have their limitation. One of the biggest concerns for logging might be logging where several casings are present. Today's technology cannot log through several casing.

Microannuluses are unwanted in a cement job, and can be hard to detect using ordinary cement bond log. Ultrasonic logging tools is better to detect liquid filled microannuluses or channels in cement. Ultrasonic tools also have limitations. For best result, a combination of different logging tools might be the solution.

The most common verification method of cement plugs is pressure testing. Differential pressure between bottom and top of cement plug will verify if there is any leakage. What is does not verify is if there is any channels inside the cement sheath. Since these channels is continuous through the plug, pressure test will not detect them. As barriers degrade, these channels can become a part of the migration pathway.

10.2 Degradation of barriers

It is proven that cement and casing steel integrity is affected when in contact with carbon dioxide as all the studies investigated in this thesis shows that. The rate however, is very low in most cases. What is hard to tell from the studies is what downhole parameter that is affecting degradation rate most.

Table 11 in chapter 6 summarizes the degradation rate of several studies. From this summary, Shen and Pye's study has a degradation rate that is much higher than all of the others. The reason is probably the high temperature. Pressure seems to have less effect on the degradation rate than temperature. Kutchko et al used a pressure of 303 bar and 50 degrees Celsius. Barlet-Gouédard et al used a pressure of 280 bar and 90 degrees Celsius. While the pressure is almost the same, the temperature at Barlet-Gouédard is almost twice as high. Degradation rate is over 40 times as high for Barlet-Gouédard et al in comparison with Kutchko et al. Duguid et al (2008) studied effect of different pH and temperature for Portland Class H cement. From the results, it suggest that low pH degrades Portland cement more rapidly. What can also be seen is that for a solution with pH = 3, the degradation rate is lower for 50^{o}C, than for 20^{o}C. Again, making it hard to determine which parameters contributing most to the degradation rate.

A large number of parameters also affects casing corrosion. What is similar between different studies of casing corrosion is that corrosion rate is very high to begin with. After a short time, the corrosion rate will decrease and become close to constant. Reason for this reduction in corrosion rate is a result of chemical reactions between steel and electrolyte. A compact layer is made on the surface, slowing down corrosion rate. Casing is primarily protected by cement, but will eventually be exposed to corrosive fluids/gasses as cement degrades.

10.3 Leakage path

Leakage paths are a result of several well barrier failure modes resulting from different leakage mechanisms. What makes leakage paths hard to predict, is the large amount of variables to take into consideration. In chapter 7, two models are investigated. One very simple made to calculate flow through an existing pathway. In addition, one more advanced model made to calculate flow and degradation rate. However, even the more advanced model is not sufficient to predict a realistic pathway. It only calculates degradation of cement in contact with CO_2. Chemical degradation is only small part of the full picture. Several other failure modes must be considered to get a realistic model.

10.4 Leakage statistics

Statistics shows that lot of wells are suffering from leakage or damaged well barriers. The biggest problem regarding leakage is from unplugged abandoned wells. This is not an issue in Norway since all oil and gas wells are offshore, and has to be plugged before being abandoned. In USA, the scenario is different. Many wells were drilled before regulation were introduced. A result of this is unplugged wells across the country leaking gasses. Statistically, plugged wells are leaking a minimum. Even successfully sat cement will have permeability, but very low. Plugged wells in the US leaks at an average of 0.002 grams methane per hour. Unplugged wells are as high as 10 grams per hour (townsend small).

On the Norwegian Continental Shelf, a large number of wells have integrity problems according to the temporary abandonment investigation performed back in 2011. However, the investigation did not reveal leakage. It is hard to tell if there is any leakage from permanently abandoned wells. According to NORSOK Standard D-010, no monitoring is necessary after the well is abandoned. It can therefore be hard to know if there is any leakage unless wells are inspected or leakage rate is very high and can be seen from the air.

10.5 Leakage repair solutions

If an abandoned well is leaking, there is some solutions that can fix it. Fixing a leak in a permanently abandoned well will be both hard and expensive unless the wellhead is still intact. Leaks in temporary abandoned wells are easier to cope with as the well is designed for re-entering. Even though there are solutions that can cope with leaks, it should not be necessary. Most leaks are a result of improper cementing job during plugging phase. Repairing leaks is also unwanted as it can be very expensive.

11. Conclusion

The main objective of this thesis was to investigate what happens to the well barriers after a well is being abandoned. It can be concluded with that both casing and cement is affected by carbon dioxide over a long time period. The rate of corrosion and degradation will depend on downhole parameters like temperature, pressure, salinity, pH, CO_2-concentration and several others.

What is more surprising is the slow degradation and corrosion rates. For cement in contact with carbon dioxide, the rates were in most cases very low. Barlet-Gouédard concluded that regular Portland class G cement was not suited for corrosive CO_2-environment [42]. Looking at the results from the other studies, this conclusion seems wrong. Especially considering that Kutchko et al study gave similar degradation rates as core samples gathered from a 30-year-old CO_2-injection well. Results from different studies suggests that it is safe to use ordinary Portland cement in CO_2-environment [43].

Casing corrosion rates were also in general very low. The highest measured annual corrosion rate was 6 mm. Institute for Energy Technology stated that corrosion tests with low pressure gave too high corrosion rate [49]. This suggest that the corrosion rates found in different studies might be lower than anticipated.

According to NORSOK D-010, the length of a cement plug shall be minimum 50 meters long. Some cases a 100-meter plug must be sat [1]. Oil and Gas UK states that a plug shall have 100 feet of good cement and be a total of 500 feet long [4]. For most cases, minimum two plugs must be sat before the well can be abandoned. With the rates calculated in the different studies, carbon dioxide by itself will not be the reason for leakage. The length of the plugs are too long, and degradation rate too low. A combination of degradation, bad cement job, geological disturbances and thermal loads might result in leakage over time. Nevertheless, leakage due to corrosion or degradation in contact with gasses and fluids seems highly unlikely.

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Appendix A

Display of both cement bond log and variable density log vs. Depth (From Erik. B. Nelsons Well cementing book) [12].