CO_2CARE

CO_2 Site Closure Assessment Research

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D1.2 Report on the current site abandonment methodologies in relevant industries

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Abbreviations / Definitions

API:	American Petroleum Institute
CRA:	corrosion resistant alloy
EOR:	enhanced oil recovery
ft:	feet
m:	meter
MD:	measured depth along borehole
P&A:	plugged and abandoned
Permanent well barrier:	well barrier with well barrier elements that individually or in combination create a seal that has a permanent characteristic
WBE:	well barrier element
WAG:	water alternating gas
WBS:	well barrier schematic

Executive Summary

Site abandonment of oil and gas fields is described and defined as the activity of the operator to close and leave a site according to safety and environmental requirements. It can generally be divided into two main activities, i) the abandonment of the wellbores drilled during operation, including plugging of wells, and ii) the removal of surface installations (e.g. well equipment, production tanks and associated installations) and surface remediation.

This report provides an overview of current practices in relevant industries, mainly from the oil and gas industry. In site closure operations, well abandonment and ensuring long-term integrity of wellbores are considered very important in terms of secure geological storage of reactive substances. Therefore, the major goal of this report is to highlight main issues in current well abandonment procedures in CO_2 environments and particularly in geological CO_2 storage.

Additionally, recommendations and guidelines for future activities are provided, since the potential for subsequent alternative utilisation of oil and gas fields is not generally considered at the time of abandonment. This might lead to important issues when a field is being considered for subsequent geological storage of CO_2.

Chapter 1 describes the scope of the report and introduces the general aspects of site abandonment. Current site abandonment methodologies in relevant industries are summarised in Chapter 2. This provides the basis for an overview of permanent well abandonment (activities) with respect to acid gas disposal, which is summarised in Chapter 3. Chapter 4 presents the best practice for the abandonment of CO_2 storage sites, and is followed by recommendations for future abandonment activities and regulations in Chapter 5.

1 Introduction

Site abandonment in the oil and gas industry is defined as any actions taken by the operator to close down a previously operated field. It can generally divided into two main activities, i) the abandonment of the wellbores drilled during operation and ii) the removal of surface installations. Site abandonment typically includes the plugging of wells; removal of well equipment, production tanks and associated installations; and surface remediation.

Among these processes, well abandonment is considered as the most important. Proper well abandonment for isolation of subsurface reservoirs should:

1. prevent all physical hazard potentially induced by the well;
2. prevent any migration of contaminants between various formations;
3. prevent the possibility of hydrologic communication between originally separated aquifer systems.

Regulatory guidelines as well as industry best practices specify the requirements for proper abandonment with respect to long-term safety of the sites. Proper abandonment should also regard the reason for abandonment of a site/well and the condition and construction details of the wellbore. Several industry practices have been considered in this report mainly from Europe, e.g. the Norwegian NORSOK D-10 (2004) guideline and the Guidelines for the Suspension or Abandonment of Wells from UK Oil and Gas Association (UKOOA) (2011). Furthermore, relevant technical papers have been considered. The first two sources provide a general overview of the current state-of-the-art of abandonment methodologies in the oil and gas industry. International and national regulations for site abandonment are discussed in the related CO_2CARE Deliverable D1.1, “International regulatory requirements on CO_2 geological storage and site abandonment” and are not discussed in this report (CO_2CARE, 2011a).

In accordance with the scope of the CO_2CARE project, this report mainly focuses on the time period corresponding to the site closure and post-closure phases. However, it should be noted that for proper abandonment, the operational history of the wells has to be taken into account to gain information on the state of the wellbore materials at the time of abandonment.

Generally, this report will highlight the current practice in site abandonment and particularly well abandonment methodologies, since wellbores are considered as the most important safety issue in side abandonment practices. This report extends and complements the comprehensive overview of well abandonment practices until 2009 published in the IEA-GHG report “Long term integrity in underground CO_2 storage – well abandonment” (IEA-GHG, 2009).

1.1 General aspects of site and well abandonment

Risk assessment and operational phase issues with respect to safe long-term containment of CO_2 are outside the scope of this report. However, given the relevance of these subjects for site abandonment approaches, this section provides a brief introduction and refers to relevant references for further details.

Site abandonment guidelines and regulations state that a risk analysis and risk reducing measures shall be applied to reduce the risk as much as possible (e.g. NORSOK D-10). In terms of well integrity, risks shall be assessed related to the effects of pressure changes in the reservoir, material degradation, sinking of weight materials in well fluids, etc. on well barriers.

For further information on risk management during well abandonment the reader is referred to the earlier published CO_2CARE reports "Draft and updated plan for risk management supporting site abandonment (CO_2CARE, 2011b)" and "Draft and updated criteria for decision making in site abandonment (CO_2CARE, 2011c)" and to relevant publications regarding risk management in site abandonment, e.g. the CO_2WELLS report (Det Norske Veritas, 2011).

1.1.1 Impact of the operational history on well abandonment

1.1.1.1 Drilling

Drilling should be performed according to regulations and best practices which are valid at the time and place of operation. The NORSOK D-10 guideline provides a comprehensive description of drilling guidelines. The critical issue in relation to well abandonment is that sufficient documentation (see Section 2.2.4) has to be collected during the drilling process, as this will be necessary in order to evaluate the state of the well prior to abandonment.

1.1.1.2 Completion

The well completion must ensure the internal and external integrity, such that no leaks in packers, casings or tubings; or upward flow into overlying aquifers can occur (Syed and Cutler, 2010). Special attention has to be paid on the steel and cement quality, especially in corrosive environments, such as where CO_2 may be in contact with brine (see Chapter 4).

Analogous to drilling, well completion should be performed according to local regulations and best practices (e.g. AERCB directive 20 and 59 (AERCB 2010, 2012)) including sufficient documentation especially for casing and downhole equipment installation, cement jobs and cement evaluation. Possible alternative future use of the wells should be considered during the design phase, to optimally perform completion activities. For instance the installation of permanent downhole sensors like distributed temperature sensing (DTS) in combination with a heating cable (heat pulse method) behind casing enables a continuous temperature and saturation monitoring. This may not be required for typical hydrocarbon production, but adequate monitoring will be obligatory for CO_2 storage operations as stated in the EU CO_2 Storage Directive, Annex II (2009). This so-called "smart well completion" was performed at the Ketzin CO_2 storage pilot site and will be used for post-abandonment and near-well monitoring in the post-operational phase (Prevedel *et. al.*, 2008). Completion with respect to CO_2 storage requirements is discussed in more detail in Section 4.2.

1.1.2 Monitoring

Monitoring is outside the scope of this report. For recent monitoring methodologies and monitoring plans for CO_2 storage sites please refer to relevant literature, e.g. Chadwick *et al.* (2008), IEA-GHG (2012). On the other hand, it is important to state here that monitoring information is very valuable in providing a record of the operational history of wells and in order to evaluate its impact on well abandonment. In particular information on reservoir pressure and chemistry, plume propagation as well as well monitoring data are essential for the evaluation of risk related to wells penetrating the storage area. Therefore, an appropriate risk-based site specific monitoring plan, usually designed during the site qualification and updated throughout the period of operation, is required for geological storage projects, proving necessary information to be considered during the site abandonment.

2 Current site abandonment methodologies in the oil and gas industry

This section provides a general overview of current well abandonment practices, mainly referring to NORSOK-D10 and other European guidelines. Guidelines like the UK Offshore Installations and Wells (Design and Construction, etc.) Regulations (1996) and the UK PONS No. 5 are not discussed in this report as they provide very general information on appropriate well abandonment practices. Well abandonment particularly suited to CO_2 environments will be addressed in chapter 4.

2.1 Removal of down hole equipment

In general, it is recommended to remove downhole equipment before the final abandonment of a hydrocarbon field. However, it is not a necessary step, unless it is jeopardising the function of the permanent well barriers, e.g. cement plugs. Then the borehole should be cleared of obstructions prior to abandonment, if possible. Obstructions such as pumps, pipes, wiring, and air lines shall be pulled (PA DEP, 2001). Control cables and lines should also be removed before abandoning the well, because potential leakage pathways might form along these.

PA DEP (2001) recommends that well preparation may also involve fishing obstacles out of the borehole. The casing should be pulled, as long as the operation does not compromise the integrity of the borehole. Before this operation, the well should be cemented next to the bottom of the casing. This will at least provide some seal, if the well collapses after the casing is pulled (PA DEP 2001).

Nested or telescoped casing strings can complicate well abandonment activities. Inner strings should be removed when possible, in circumstances that the operation does not compromise the integrity of the wellbore. If inner strings cannot be removed and sealing of the annular space is required, then the inner string should be vertically split (plastic cased wells) or cut (metal-cased wells) at intervals necessary to ensure complete filling of the annular space (PA DEP 2001). High risk wells may have to be re-entered in order to apply appropriate abandonment methods (see Section 2.3).

2.2 Well abandonment practices in the oil and gas industry

Most guidance and practices recommend certain well barriers to prevent migration of fluids towards shallow formations or to the surface through the wellbore. This section describes the principal well barrier concept, explains its functions and requirements.

2.2.1 Well barriers

Well barriers consist of one or several well barrier elements (WBEs) preventing the migration of fluids or gases from a formation or reservoir into another formation or towards shallow areas. The well barrier(s) need to be specified before any activity or operation takes place, providing description of the required WBEs to be put in place and the specific acceptance criteria considered (NORSOK D-10).

2.2.1.1 Well barrier acceptance criteria

Well barrier acceptance criteria are technical and operational requirements that need to be fulfilled in order to qualify the well barrier or WBEs for their intended use (NORSOK D-10). Generally, well barriers should be durable and of low-permeability (see Section 2.2.2.3) so that the integrity of plugged wellbores can be ensured for the envisaged abandonment period, which can vary between days or months (e.g. shut-in wells) and thousands of years (e.g. CO_2 storage).

2.2.1.2 Function and number of well barriers

NORSOK D-10 states that the function of the well barrier and WBEs shall be clearly specified. At least one barrier is required during all well operations, including the suspension or abandonment of wells, in places where pressure differential that may cause uncontrolled fluid flow into the wellbore between formation zones is identified.

Two well barriers are required during all well activities and operations, including suspended or abandoned wells, in places where the pressure regime present could cause uncontrolled fluid flow out of the well to the surrounding environment (NORSOK D-10).

2.2.1.3 Well barrier design principles

A well barrier should be designed, selected and/or constructed such that (NORSOK D-10):

- it can withstand the maximum anticipated mechanical load it may be exposed to;
- it can be leak and function tested or verified by other methods;
- a single failure of a well barrier or WBEs does not cause uncontrolled cross-flow from the wellbore to the external environment;
- a lost well barrier can be re-established;
- it can operate competently and withstand the environment it may be exposed to over time;
- its physical location and integrity status is known at all times when such monitoring is possible.

The primary and secondary well barriers are not allowed to have common well barrier elements and have to be independent of each other. In case common WBEs are used, a risk evaluation should be performed and proper risk mitigation measures applied to reduce the risk to an acceptable level.

2.2.1.4 Initial verification of the well barrier

When the well barrier has been installed, according to NORSOK D-10, it is required to verify its integrity and function by means of:

- leak testing by application of a differential pressure; please note that this test is not being performed by some companies and in countries as it can be the cause of well failure, if performed improperly;
- function testing of WBEs that require activation;
- verification by other specified methods (e.g. tagging).

For further details on leak and function testing of well barriers please refer to Table A 1 and Table A 2 in the Appendix, and NORSOK D-10 (specifically Section 4.2.3.5).

2.2.2 Permanent abandonment

This section covers requirements and guidelines applicable to well plugging for permanent well abandonment (or side track/slot recovery). Several guidelines propose the application of well barriers by use of WBEs and additional features required to execute this activity in a safe manner, with special attention on the isolation of permeable formations, reservoirs or other sources of inflow (NORSOK D-10).

The acceptance criteria for temporary and permanent abandonment are principally the same. However, of the design of WBEs may vary in terms of abandonment time, work over activities, or finally abandoning a previously temporary abandoned well.

2.2.2.1 Well abandonment design

Abandonment of wells should be part of the original design consideration prior to spudding the well. A good well design should take into account the lifetime of the well from construction, production / injection, intervention and to abandonment.

Any potential loads (functional and environmental) have to be considered and should be combined in the most unfavourable way to a worse-case scenario. In case of permanently abandoned wells, the specific gravity of well fluid shall maximum be equal to a seawater gradient (NORSOK D-10). Table 1 lists load cases, which should be applied for the abandonment design. In general minimum design factors are precisely described in industry practices, e.g. in Section 5.6.4 and 7.6.4 of the NORSOK D-10.

Table 1. Relevant load cases for permanent abandonment (from NORSOK D-10).

Item	Description	Comments
1	Minimum depth of primary and secondary well barriers for each reservoir/potential source of inflow, taking the worst anticipated reservoir pressure for the abandonment period into account.	Not shallower than formation strength at these depths. Reservoir pressure may for permanent abandonment revert to initial/virgin level.
2	Leak testing of casing plugs.	Criteria as given in Appendix Table 2
3	Burst limitations on casing string at the depths where abandonment plugs are installed.	Cannot set plug higher than what the burst rating allows (less wear factors).
4	Collapse loads from seabed subsistence or reservoir compaction	The effects of seabed subsistence above or in connection with the reservoir shall be included.

2.2.2.2 Function and type of permanent well barriers

For wells with several sources of inflow, permanent abandonment cannot be done with the usual, one primary and one secondary well barrier. The following Section describes the well barriers and the functions they have to fulfil in abandonment scenarios.

Table 2. Function and purpose of individual or combined permanent well barriers (from NORSOK D-10).

Name	Function	Purpose
Primary well barrier	First well barrier against flow of formation fluids to surface, or to secure a last open hole.	To isolate a potential source of inflow from surface.
Secondary well barrier, reservoir	Back-up to the primary well barrier.	Same purpose as the primary well barrier, and applies where the potential source of inflow is also a reservoir (w/ flow potential and/ or hydrocarbons).
Well barrier between reservoirs	To isolate reservoirs from each other.	To reduce potential for flow between reservoirs.
Open hole to surface well barrier	To isolate an open hole from surface, which is exposed whilst plugging the well.	“Fail-safe” well barrier, where a potential source of inflow is exposed after e.g. a casing cut.
Secondary well barrier, temporary abandonment	Second, independent well barrier in connection with drilling and well activities.	To ensure safe re-connection to a temporary abandoned well, and applies consequently only where well activities has not been concluded.

Generally, the functions of a well barrier and a plug can be combined unless only one of the above mentioned objectives is fulfilled. A secondary well barrier for a certain reservoir formation can principally act as a primary well barrier for another shallower formation or reservoir, given the well barrier is installed to meet the requirements of both formations. On the other hand, a secondary well barrier can never become an acceptable primary well barrier for the same reservoir (NORSOK D-10).

OKOOA (2011) proposes the same requirements concerning the number of required well barriers. A permanent combination barrier can replace the two barrier concept, where practicable.

2.2.2.3 Permanent well barrier properties

Permanent well barriers shall be installed across the entire cross section of the well, including the existing annuli. It has to seal in vertical and horizontal direction (Figure 1). When a WBE is placed inside of a casing, a WBE with verified quality has to be set in all annuli at the same depth interval in order to provide an adequate permanent well barrier.

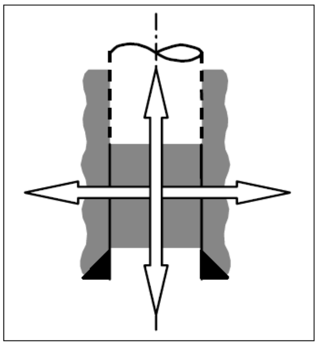


Figure 1: Permanent well barrier specifications (from NORSOK D-10).

NORSOK D-10 (2004) and UKOOA (2010) agree that a permanent well barrier should have the following properties:

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

The main properties of set cement (i.e. very low permeability and capability to withstand stress cycling) are favourable for long-term sealing, but could be affected by shrinkage or chemical degradation. Most industry practices state that a steel tubular is not considered as an acceptable permanent WBE. It has to be supported by cement inside and outside the casing. Elastomer seals or packers used as sealing components in WBEs are not sufficient for a permanent well barrier (NORSOK D-10).

2.2.2.4 Positioning requirements

The NORSOK Standard D-10 provides specific well abandonment regulations. This document requires wells to be plugged and maintain their integrity over geological time scales. At least one well barrier is required between a potential source of inflow and the surface, unless a reservoir contains hydrocarbons in which case two well barriers are required.

Well barriers should be installed as close to the potential source of inflow as technically possible, sealing all possible leak paths. The primary and secondary well barriers shall be placed at a depth where the estimated formation fracture pressure at the base of the plug is in excess of the potential internal pressure (NORSOK D-10). The final location of the well barrier/WBEs has to be verified.

Where casing is part of the permanent barrier, a column of intact cement in the annulus is required as a permanent barrier. A cement plug must be set along the same interval. An open-hole cement plug can be considered a proper well barrier between reservoirs. It should also be used as a primary well barrier, if technically feasible, see Table A 2 in the Appendix. These practices and well configurations are in line with the methodology recommended in UKOOA (2009).

When well completion tubulars are left in hole and permanent plugs are installed through and around the tubular, appropriate practices to install and verify the position and quality of the plug inside the tubular, and between the tubular and the casing shall be used. Multiple reservoir zones/perforations within the same pressure regime, isolated with a well barrier placed in between them, can be considered as one reservoir for which a primary and secondary well barrier shall be installed as shown in Figure 2.

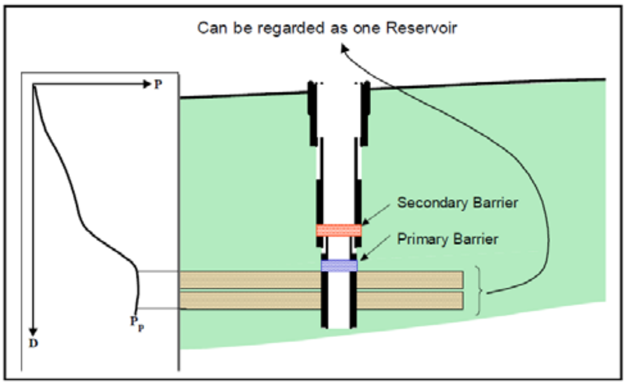


Figure 2: Well barrier requirements for stacked reservoirs in the same pressure regime (from NORSOK D-10).

2.2.2.5 Length requirements

In UKOOA (2011) a cement column of at least 100ft MD (30 m measured depth along borehole) of intact cement is considered as a sufficient permanent barrier. If possible, a 500ft MD (150 m) is set. If permeable zones are less than (100ft) MD apart, good cement of 100ft MD should be set below the base of the upper zone, if applicable. The first barrier should fill at least 100ft MD above the shallowest point of potential flow.

According to NORSOK D-10, plugs must extend at a minimum 50 m above a source of outflow or leakage point and must be at least 100m total length. Plugs that are placed in the interval from open hole to casing should extend at least 50m below the casing shoe. Plugs set inside the casing using a mechanical plug as a basis should have a minimum length of 50 m. When two permanent barriers are combined in one plug, length requirements for the two barrier concept are doubled. According to NORSOK D-10 the possible length of (the combined) cement plugs is extended to 500ft MD (see also Table A 1 and Table A 2 in the Appendix).

2.2.2.6 Testing and verification

When inflow testing or leak testing of a well barrier is not applicable, or when the results are not conclusive, other means of ensuring proper installation of a well barrier shall be used (NORSOK D-10). Verification through assessment of job planning and actual job performance parameters are options available (NORSOK D-10). Inflow tests shall be documented.

In order to verify the along hole integrity of a WBE, the position and pressure integrity of the casing cement shall be tested. The cement in annulus will not qualify as a (lateral) WBE across the well if there is no tested cement plug present across this interval (e.g. UKOOA, 2009). For detailed specifications and requirements see Table A 1 in the Appendix.

NORSOK D-10 states that cement in the liner lap, which has not been leak tested from above (before a possible liner top packer has been set) shall not be regarded as a permanent WBE. The position of plugs should be verified by tagging or pressure tests. If a cement plug is placed on top of a mechanical plug then only the mechanical plug requires verification (CO_2CARE, 2011a).

2.2.3 Well barrier schematics (WBS)

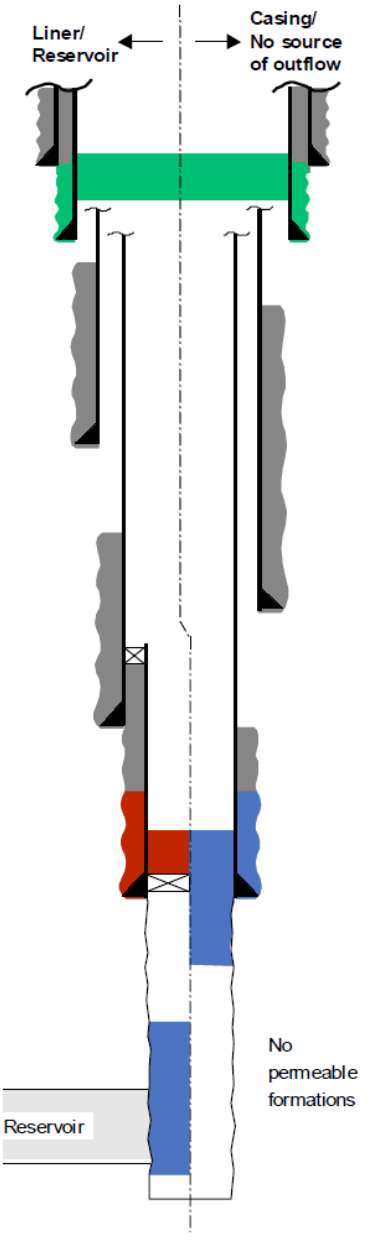
WBSs are used in most of the relevant industry practices for well abandonment. NORSOK D-10 recommends that WBSs should be used as a practical method to demonstrate and visualise defined primary and secondary well barriers in the wellbore. In Table 3 a number of typical scenarios are listed, some of which are also presented as illustrations (Figure 3 and Figure 4). In addition to these general fact sheets, schemes for the actual situations during well operations should be made.

Table 3: Typical well abandonment configurations (from NORSOK-D10).

	Description	Comments
1	Temporary abandonment – Non- perforated well.	Non-completed well.
2	Temporary abandonment – Perforated well with BOP or production tree removed.	With well completion installed.
3	Permanent abandonment - Open hole.	
4	Permanent abandonment – Perforated well.	
5	Permanent abandonment - Multibore with slotted liners or sandscreens.	Covers permanent zonal isolation of multiple reservoirs.
6	Permanent abandonment - Slotted liners in multiple reservoirs.	Applies also to slot recovery/ side tracks, etc.
7	Suspension - Hang-off/disconnect of mariner riser.	Hang-off drill pipe.

For items 3 and 6 in Table 3 well barrier schematics are provided below.

9.8.3 Permanent abandonment - Open hole



Well barrier elements	See Table	Comments
Primary well barrier		
1. Cement plug	24	Open hole.
or, (“**primary well barrier, last open hole**”):		
1. Casing cement	22	
2. Cement plug	24	Transition plug across casing shoe.
Secondary well barrier, reservoir		
1. Casing cement	22	
2. Cement plug	24	Cased hole cement plug installed on top of a mechanical plug.
Open hole to surface well barrier		
1. Cement plug	24	Cased hole cement plug.
2. Casing cement	22	Surface casing.

Notes

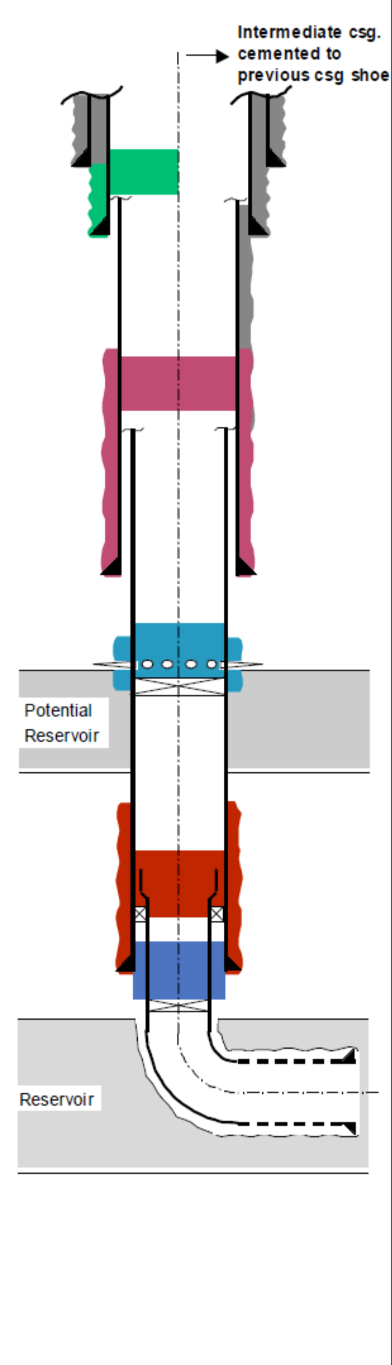
a. Verification of primary well barrier in the “liner case” to be carried out as detailed in Table 22.

b. The well barrier in deepest casing shoe can for both cases be designed either way, if casing/liner cement is verified and O.K.

c. The secondary well barrier shall as a minimum be positioned at a depth where the estimated formation fracture pressure exceeds the contained pressure below the well barrier.

Figure 3: Example of a well barrier schematic for an open hole abandonment (from NORSOK D-10).

9.8.6 Permanent abandonment - Slotted liners in multiple reservoirs



Well barrier elements	See Table	Comments
Primary well barrier, deep reservoir		
1. Cement plug	24	Through liner and across casing shoe/Open hole transition.
Secondary well barrier		
1. Casing cement	22	
2. Cement plug	24	Across liner top.
Primary well barrier, shallow reservoir		
1. Cement plug	22	Squeezed into perforated casing annulus above potential reservoir.
Secondary well barrier, shallow reservoir		
1. Casing cement	22	
2. Cement plug	24	
Open holes to surface well barrier		
3) Cement plug	24	Cased hole.
4) Casing cement	22	Surface casing.

Notes

1. Secondary well barrier shall not be set higher than the formation integrity at this depth, considering that the design criteria may be initial reservoir pressure, which may develop over time.
2. The case on the right hand side indicates that the intermediate casing string is cemented into surface casing, i.e. with no open annulus to surface. Hence, no open holes to surface well barrier is required.

Figure 4: Example of a well barrier schematic (WBS) for a cased wellbore abandonment (from NORSOK D-10).

2.2.4 Well data

NORSOK D-10 requires that the following information should be gathered as a basis of the well barrier design and abandonment programme (from NORSOK D-10):

a) Well configuration (original, intermediate and present) including depths and specification of permeable formations, casing strings, primary cement behind casing status, well bores, side-tracks, etc.
b) Stratigraphic sequence for each wellbore showing reservoir(s) and information about their current and future production potential, where reservoir fluids and pressures (initial, current and in an eternal perspective) are included.
c) Logs, data and information from primary cementing operations in the well.
d) Estimated formation fracture gradient.
e) Specific well conditions such as scale build up, casing wear, collapsed casing, fill, or similar issues. The design of abandonment well barriers consisting of cement should account for uncertainties relating to:
    - downhole placement techniques,
    - minimum volumes required to mix a homogenous slurry,
    - surface volume control,
    - pump efficiency/ -parameters,
    - contamination of fluids,
    - shrinkage of cement.

2.2.5 Cement placement techniques

The principal technique applied to create an impermeable barrier between two zones is plugging the well. In the oil and gas industry the most common material used for plugging wells is Portland cement. The American Petroleum Institute (API) has classified Portland cements into six cement types (denoted from A to H) for different temperature and pressure (depth) ranges. H and G cements are the most common types used today (for details refer to API Specification 10A, 2002).

Several different techniques have been developed to emplace the cement in the well, such as the balanced plug method, the dump bailer method and the two-plug method. Well plugs can be either cement or mechanical plugs. Specifications of well plugs and abandonment are prescribed by regulatory authorities.

API specifies that an adequate cement plug should have a compressive strength of at least 1,000 psi (~69 bar) and a maximum liquid permeability of 0.1 mD. The different classes of API cement are based on the downhole temperature at the depths where the cement is to be placed.

Various methods of plugging wellbores with cement are known in the industry. The most common is the Balance Plug Method. A short description of the most common method is provided below. For an exhaustive list please refer to Nelson and Guillot (2006) and the EPA guidelines (US EPA, 1994).

2.2.5.1 Balance Plug Method

This simple technique involves setting a cement plug at a predefined location. A cement slurry is pumped down the well and balanced amount of cement is placed inside and outside the pipe (Figure 5) using a bridge plug.

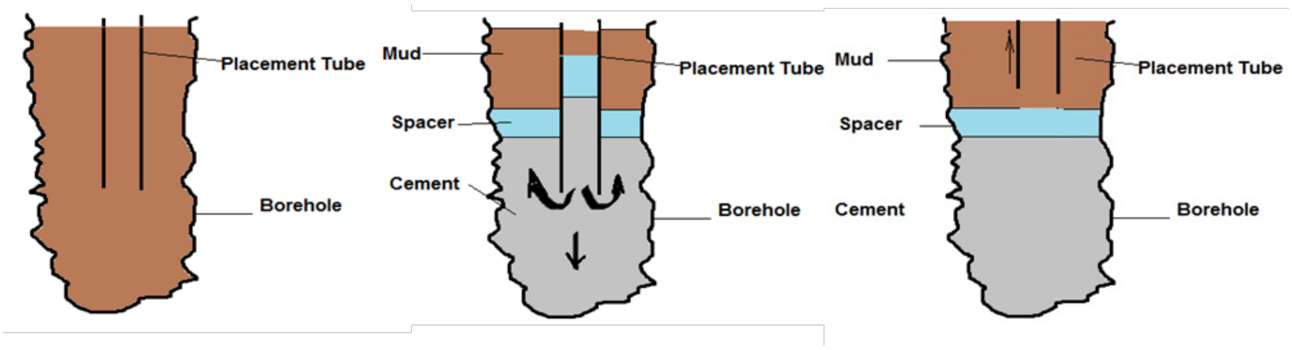


Figure 5: Balance plug principle: Placement tubing runs into hole with drilling mud (left), cement placement starts (middle), level of cement is balanced (right).

The mud system must be in static equilibrium because any fluid movement may cause a poor plug (EPA, 1994). For a balanced plug job, proper calculations are required before cement placement to determine the adequate amount of cement and heights of fluid. This is the cement placement method most commonly applied to hydrocarbon wells (IEA-GHG, 2009).

2.2.5.2 Cement Retainer Method

First a cement retainer (packer) plug is installed within a cased hole. By displacing the cement through the retainer, the cement can be squeezed into formations below the retainer. Then the cement retainer is closed and the cement pipe is separated from the top of the retainer. Cement can then be placed on top of the retainer by slowly withdrawing the cement pipe above it (US EPA, 1994).

2.2.5.3 Two Plug Method

This method uses a special tool to place the cement plug at the target depth and is applied in open holes. The operation ensures a high accuracy and limits the possibility of cement contamination. The procedure is complex, setting two separated plugs where the first plug cleans the well. For a comprehensive description of this practice please refer to Nelson and Guillot (2006)

2.2.5.4 Dump Bailer Method

This method is only applied at shallow depths. A dump bailer is a tool that can be lowered into the well by a wireline and deployed on top of the permanent plug. Before cement placement, a bridge plug or cement basket is placed in the hole at the target depth. The bailer opens upon contact with the bridge plug and places a known amount of cement slurry at this location as it is raised (US EPA, 1994).

2.2.5.5 Cement Squeeze Method

Squeeze cementing involves pressurised forcing of cement at a pre-determined depth coinciding with perforations in the casing. The pressure forces the liquid of the slurry into the formation, leaving the cement to form a seal. This technique is often used as a remedial measure for flawed or damaged primary cement (see also following Section).

The cement used for a squeeze cementation must have certain physical properties. It must be of relatively low viscosity, so that it can be squeezed into the fissures and leak paths in the primary cement. It needs to have low fluid-loss characteristics and an ultra-fine grind from the mill, to prevent the solids build-up when the cement is squeezed, causing the cement to set before it has travelled far enough to seal the annulus, leading to failed remediation. It must have sufficient strength to provide an adequate hydraulic seal between the formation fluids across it.

Of these five placement techniques, the two-plug method provides a maximum of accuracy and a minimum of cement contamination.

After the well is plugged, testing is required to ensure that the plug is a placed at the proper level and provides zonal isolation. The plug can be verified by tagging its top, pump pressure testing or swab testing (see also Sections 2.2.1.4 and 2.2.2.6).

2.3 Work over practices

Remedial work would only need to be performed on operational wells where there is or was evidence of poor primary cementation or mechanical failure. Wells that are currently under production or under construction are the easiest to perform remedial work on, because this work could be done while operations are under way, or during the abandonment phase of the well. The abandonment procedure may have to be modified to account for any deficiency in the integrity of the well.

The majority of remedial work involves re-introducing a properly functioning hydraulic seal into the wellbore. Cement placement is the most common application to do this. A plan is required that defines how a failing well barrier can be re-established or, if required, how an alternative well barrier has to be set.

2.3.1 Re-establishment of fluid well barrier

The remediation methods, e.g. killing the well or re-establishing a fluid well barrier, need to be specified prior to operations where the fluid column is one of the well barriers or is defined to be a contingency well barrier (NORSOK D-10).
There are several methods to kill a well:

- “Wait and Weight Method”
- “Driller’s Method”
- “Volumetric Method”
- “Bullheading Method”.

Data required for re-establishing the fluid well barrier has to be recorded and regularly updated ("Killsheet"), and should include the information listed in Table 4.

Table 4: Parameters required for re-establishing the fluid well barrier (NORSOK D-10).

<table>
<tr><th>Parameter</th><th>Description</th><th>When</th></tr>
<tr><td>Pump pressure</td><td>Circulation through the drill pipe at different slow flow rates.</td><td rowspan="2">• Drilling out of casing/liner.
• Change in the tubular configuration (size, BHA configuration).
• Change in fluid density or rheology.
• Every 500 m MD of new formation drilled or every shift.</td></tr>
<tr><td>Pump pressure</td><td>Circulation down the drill pipe/test tubing/tubing and up the choke or kill line at different slow flow rates.</td></tr>
</table>

2.3.2 Remedial methods

Poor annular cementation of the wellbore casing is the most common issue that would need to be dealt with. If the casing-cement-formation bond fails, or is weak, a potential leak path is available for either fluid or gas to percolate to shallower horizons.

An azimuthal acoustic log is the optimal method of determining the strength of a cement sheath. It is run through the casing after the cement job is complete, and it images the cement bond through 360º over the well bore. The image created indicates the varying degrees of cement bond after the cement job. Another method of checking for a leak path is to monitor the annular pressure between casing strings. If there is pressure build up, which does not bleed down to zero, then there is a strong likelihood that a leak path has been established. Annular pressures can be monitored during operations, with the exception of subsea wells. If a leak path has been established, there are various methods for remediating the situation, as described in the next Sections.

The two main categories of remedial cementing include squeeze cementing and the placement of cement plugs in case a leakage inside the wellbore has been observed.

If a leak path has been established, there are various methods of remedying the situation, described in the following.

Several descriptions of standard remedial operations have been published in the literature. The following is taken from McEwan et al. (2005) and Wojtanowicz *et al*. (2001).

2.3.2.1 Cement T-Plug method

For a Cement T-Plug, the casing is cut and the upper section is recovered. An abandonment cement tee plug is then set across the cut casing to seal the well (Figure 6).

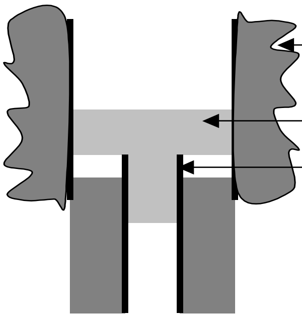


Figure 6: Cement Tee Plug configuration (from McEwan et al., 2005).

2.3.2.2 Top up cementation

Top up cementation is one of the simplest ways to seal leak paths in the casing annulus. Cement is pumped into the casing annuli directly from the surface. As soon as the primary cementation is completed, a cement stinger is lowered between the casings and cement is then injected into the annulus (Figure 7). This method is only recommended for surface - conductor casing strings, and is basically only used to secure the wellhead.

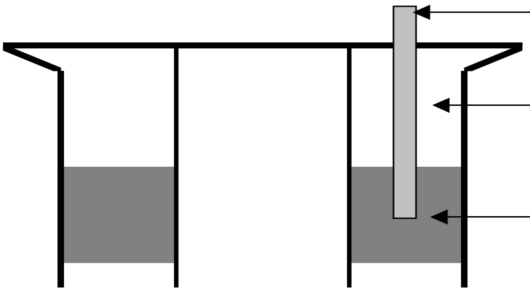


Figure 7: Top up cementation practice (from McEwan et al., 2005).

2.3.2.3 Hole Punch Method

If a leak path through the cement is detected at deeper levels, the Hole Punch Method is applied. The casing needs to be perforated to punch holes into the casing at the point where the leak is located (detection is made using sonic or ultrasonic logs). Perforating guns are usually used to shoot holes into the casing and to establish a communicating annulus. After the punch is removed a cementing string is lowered down to the perforated zone. Under high pressure cement is then squeezed through the perforations into the leaking annulus. After the

squeezing job, the cement plug which has remained in the casing must be drilled out. Finally, the quality of the new cement plug has to be verified by a pressure test (Figure 8).
This remedial practice generates a weakened casing string, and an additional potential leak path through the holes in the casing. Inserting a casing patch placed over the holes is a method that can be used to seal potential leakage pathways. However, this can cause a bore restriction in the wellbore.

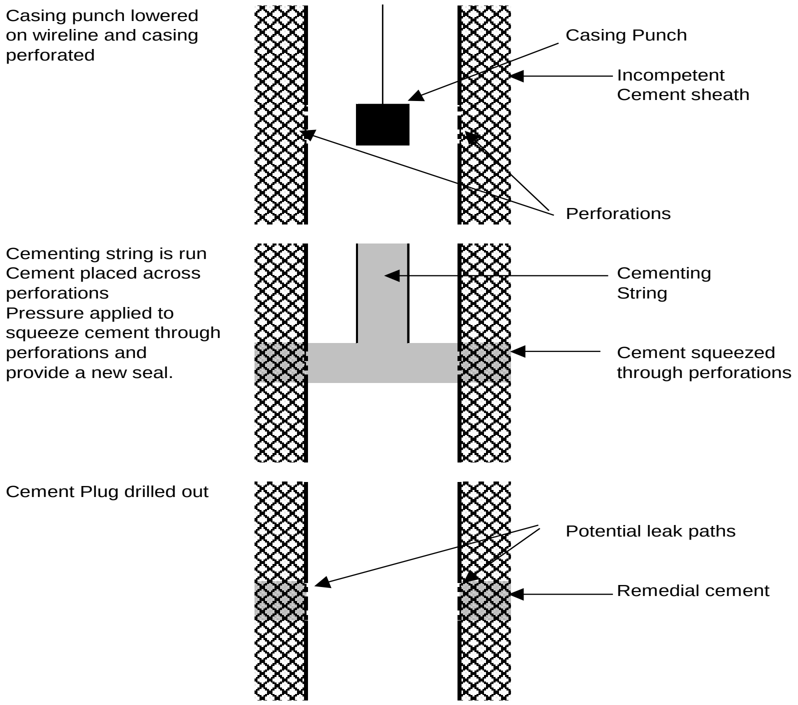


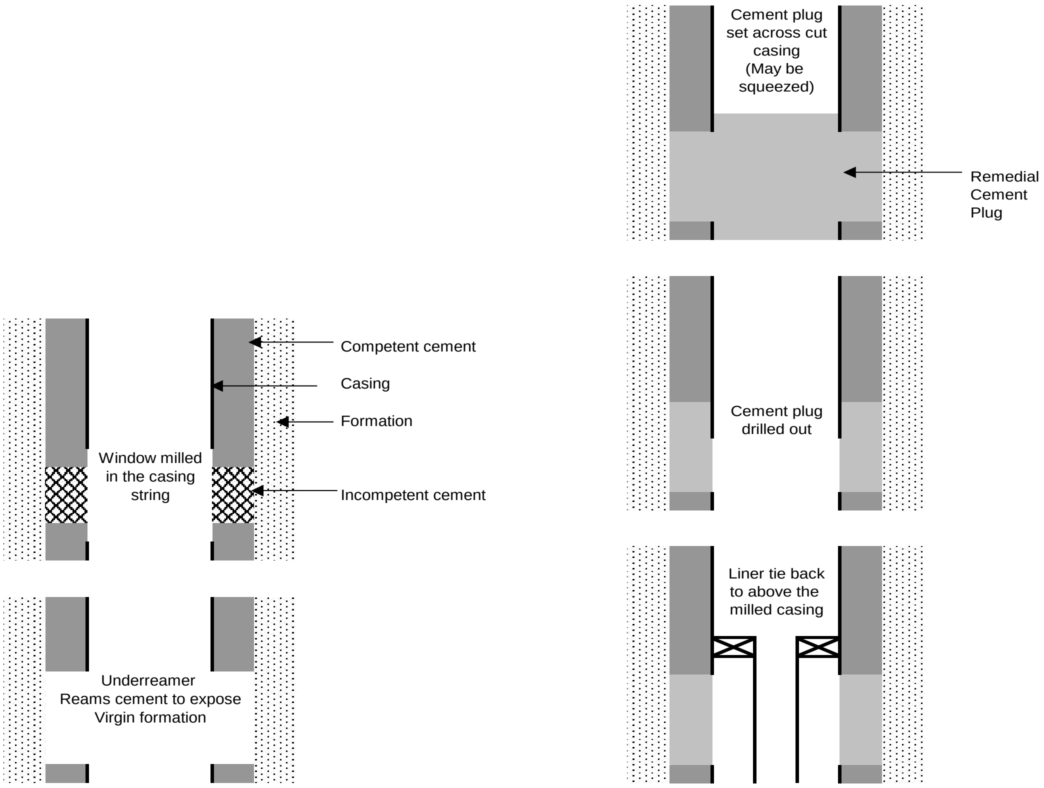
Figure 8: Well remediation using the “Hole Punch” method (from McEwan et al., 2005).

Another disadvantage of this remediation methodology is that the squeezed cement may not fill the entire leak paths in the weak cement, because the combination of perforating and cementing is difficult to control and can lead to incompetent cement during the remedial job.

The Hole Punch Method is generally performed in intermediate depths. Due to the potential risk imposed by this technique, it is usually not applied in a production string.

2.3.2.4 Section milling

Section milling is a preferred practice to seal leaks in the annulus when they are present between the casing and the formation. The method comprises locating the source of leakage (e.g. by running an ultrasonic log), milling the casing where the leak is located and setting a cement plug across the created open hole section. The target should be plugged 20–30 m above and 15–20 m below the milled out and cemented area (Figure 9a).



a) remediation process b) final configuration

Figure 9: Section milling process and final configuration (from McEwan et al., 2005).

If required, the uncured cement plug can be squeezed into the formation after the cement stinger has been pulled above the cement plug. The cement stinger is then removed and the residual plug inside the casing is milled out. The placed plug must be tested for integrity. A casing patch can be installed to cover the milled casing, or (if a liner is used in the well) a tie back can be placed between the top of the liner and the milled casing section, which ensures full wellbore integrity (Figure 9b).

2.3.2.5 Sustained Casing Pressure remediation

The methods listed above are useful for wells that can be easily re-entered. Producing wells that have sustained casing pressure in an annulus are usually just monitored, or there is a regular bleed-off cycle and the pressure is released at the surface. If the pressure build-up in the annulus is monitored a remediation plan is designed to cure the leakage when the wellbore is finally abandoned.

The common remedial practice to mitigate sustained casing pressure is to cyclically lubricate (fill a known volume of heavy fluid into the annulus, equivalent to the detected pressure bled off) the annulus, over a long time span. Depending upon the miscibility of the fluid in the annulus, and the injected fluid, the results can range between excellent to no effect. An immiscible combination between the kill fluid and original fluid delivers the best results to remedy sustained casing pressure (Wojtanowicz *et al.*, 2001).

2.3.2.6 Responsibility for well remediation

Any latent failures or defects identified in current production wells are the responsibility of the field operator.

These failures would be managed during the production life either by:

- Accepting, as they do not pose a significant production, safety, environmental or (if required) final well abandonment risk; or
- Working over the well, correcting and then putting the well back on production.

The costs for the type of interventions described above are very dependent on the failures. Although these costs might impact on the actual cost of the final abandonment, they would normally be included in the on-going operational costs of a field.

2.4 Removal of surface installations

The removal of surface facilities maintained during field operations is the last step in the actual site abandonment process. According to AERCB (2010) surface abandonment encompasses the cutting off of casing string(s) and the capping of a well. Surface equipment, cement pads, debris, and produced liquids associated with the well licence must be removed after the cutting and capping operation.

For permanent abandonment of offshore wells, the wellhead and the top section of the casings have to be removed, so that no parts of the well appear above the seabed (NORSOK D-10). A cutting depth below the seabed should be always considered, and be based on local conditions. The recommended cutting depth varies from country and regulation in place. NORSOK D-10 stipulates a general cutting depth of 5 m below seabed while AERCB (2010) recommends cutting the well at a minimum of 1-2 m below final contour elevation.

For offshore wells the use of explosives to cut casing is acceptable in certain countries (e.g. UK PONS No. 5).Considerations have to be made to reduce risk to the surrounding environment to the same level as with other means of cutting casing (NORSOK D-10). These operations should not have any impact on subsequent drilling and well activities.

3 Well abandonment in CO_2 environments

3.1 *Acid gas disposal and CO_2-EOR practices*

The CO_2 EOR industry is an industry with a proven track record of safely injecting and storing residual CO_2 into geologic formations.

After years of experience with CO_2 floods, oil and gas operators can ensure that the CO_2 left in the ground when oil production ends will stay permanently stored there, assuming the wells are properly plugged and abandoned (NETL, 2010).

CO_2 EOR technology and equipment requirements parallel those envisioned for CO_2 storage, with similar surface infrastructure and wells, similar handling of supercritical (high pressure/low temperature) CO_2, and comparable subsurface simulation and characterisation tools (well logs, three-dimensional (3-D and 4-D) seismic, petrophysical analysis, etc.). The biggest differences between the two are intent (minimising CO_2 use in EOR vs. maximising CO_2 containment for permanent storage) and regulatory concerns (monitoring, verification, responsibility and accounting of the CO_2 over the very long term; NETL, 2010).

Hydrocarbon reservoirs traditionally contain varying contents of CO_2 and oilfield practices and materials have evolved based on engineering studies and experience to ensure a level of integrity that assures that environmental, health and safety risks are controlled.

Typical oil field standards, procedures, techniques and equipment are used to drill, complete, produce and eventually abandon wells with either high levels of CO_2, CO_2 injection or into CO_2 fields (e.g. US EPA, 1994; Smith, 1993).

Hovorka and Tinker (2010) summarise the achievements of 38 years of CO_2-EOR and refer to the relevance and importance of experiences on CO_2-EOR for safe geological storage of CO_2. The authors provide implications for reservoir management, monitoring and risk assessment in CO_2 sequestration, but only address well integrity issues and abandonment in generic terms.

Another recent review paper has been published by Syed and Cutler (2010) summarising the material improvement of wellbore materials used in the CO_2-EOR industry. A brief description of the achievements of the CO_2-EOR technology is provided in the following Sections.

3.2 *Use of advanced materials and techniques*

Due to the corrosive nature of dissolved or supercritical CO_2, special requirements are needed in order to guarantee a safe long-term performance of well materials that get in contact with the CO_2 phases. NORSOK D-10 states that well barrier materials shall withstand the load and any conditions they may be exposed to following abandonment. Tests have to be conducted to ensure long-term integrity of materials used.

The CO_2-EOR industry improved the design and operating methodologies in terms of CO_2 injection wells, particularly in the following fields (Parker *et al.*, 2009):

- Selective use of corrosion resistant materials and alloys for surface piping, metal component trim and specialty coating applications;
- Use of CO_2 resistant elastomers, teflon, and nylon for packer elements and seals;
- Use of novel tubular coatings or liners using plastic, epoxy resin or fibre glass/resin materials;
- Use of specialty cements and additives;
- Use of automatic controls and real time monitoring systems.

The IEA-GHG report "Corrosion and Material selection in CCS" (IEA-GHG, 2010) provides a comprehensive overview of materials that should be used in CO_2 injection and storage. Table 5 lists materials used in modern CO_2-EOR operations.

Table 5: Recommended materials (by API) for CO_2 injection well design and construction (mostly WAG services; modified after Meyer, 2007).

Component	Materials
Christmas Tree (Trim)	316 SS, Electroless Nickel plate, Monel
Valve Packing and Seals	Teflon, Nylon
Wellhead (Trim)	316 SS, Electroless Nickel plate, Monel
Tubing	Glass Reinforced Epoxy (GRE) - lined carbon steel, Internally plastic coated carbon steel, Corrosion resistant alloy (CRA)
Tubing Joint Seals	Seal ring (GRE), Coated threads and collars (IPC)
ON/OFF Tool, Profile Nipple	Nickel plated wetted parts, 316 SS
Packers	Internally coated hardened rubber etc. Nickel plated wetted parts; corrosion resistant alloys particularly in old wells to improve sealing to worn casings
Cements and cement additives	API cements and/or acid resistant cements

3.2.1 Cement and other sealing agents

Laboratory experiments on cement degradation under the influence of CO_2 published by Duguid and Scherer (2010) showed similarities to the analysis of cement cores from a well in Texas that had been exposed to CO_2 for 30 years (Carey *et al.*, 2007) and from another 30-year old production well in a natural CO_2 reservoir in Colorado (Crow *et al.*, 2009, 2010). The recent work at SACROC (Texas) suggests that due to the limited contact area between the CO_2 and the cement, the impact is limited and the cement retains its overall sealing qualities (Carey *et al.*, 2007). Generally, these studies indicate that Portland cement based wellbore systems, if properly completed and abandoned, can prevent leakage of CO_2 from reservoirs for long periods of time (Zhang and Bachu, 2011).

Nevertheless, research has also focused on enhancing the resistivity of Portland cement in CO_2 environments by reducing the permeability of the cement matrix, lowering the concentration of reactive materials in the cement that react with CO_2, or replacing the conventional Portland with special cements (Benge, 2009). Reducing the permeability of the set cement is easily achieved by reducing the water-cement ratio and increasing the amount of cement. Non-reactive additives that reduce the amount of reactive materials in CO_2 environment include specifically shaped particles, fly ash, silica flour or latex as a diluent (Syed and Cutler, 2010).

CO_2-resistant cement systems can also be generated by using non-Portland cements. Examples of non-Portland cements include calcium sulfoaluminate-based cements, geopolymeric cements (alkali aluminosilicates), magnesium oxide cements and hydrocarbon-based cements (Benge, 2009). A very resistant species is calcium aluminate cement that is immune to CO_2 attack and has been applied particularly in acid gas injection wells in the US (Benge and Dew, 2006). Non-Portland cements are not compatible with regular cements and much denser at the same time. Their ingredients are less abundant and expensive, which limits the application in some circumstances and fields.

Also, ceramics have been tested as cement additives and showed promising results, but can only be used in shallow, low temperature reservoirs (Ross, 2007).

The development of self-healing cements is also a promising approach to provide CO_2 resistant wellbore sealants. These cements are designed to interact with gas to stop the fluid flow, but have, so far, not extensively been tested under CO_2 storage conditions (Benge, 2009).

Adding elastomeric and fibre materials to the cement can also improve mechanical strength of the cement and enhance the amount of deformation that cements can withstand (Randhol and Cerasi, 2009).

Furthermore, techniques to fill and seal microcracks with special cements have been developed in recent years (e.g. Rush *et al*., 2004, Slater, 2010). Recent innovations in sealing annular cement microfracture leaks have appeared on the market. One method called Seal-Tite atomises a pressure activated sealant which is injected into the annular microfractures with repeated applications (Rush *et al*., 2004). This material seals under the application of a differential pressure (Figure 10), and can penetrate micropore spaces down to 1 micron. The material has been used successfully on downhole safety valves, wellhead equipment, packers, casing packoffs, riser connections and umbilicals as well as annular cement sheaths. It has also been applied in sour-gas environments and does not show any deterioration during operations (Rush *et al*., 2004). However, the long-term resistivity against CO_2 attack is unknown.

Another innovation is the use of Ultra Low Rate Cement Squeezing Techniques in order to seal existing leaking wells (e.g. Slater *et al.*, 2001; Slater, 2010). Generally, microfractures occur at the cement – casing or cement – formation interfaces. The microannuli can be as small as a few microns, but this is sufficient to allow gas leakage. In order to penetrate these gaps, a microcement slurry with very small particle size, efficient fluid loss control, very thin filter cake, low rheology, zero free water and no sedimentation under downhole conditions has been developed.

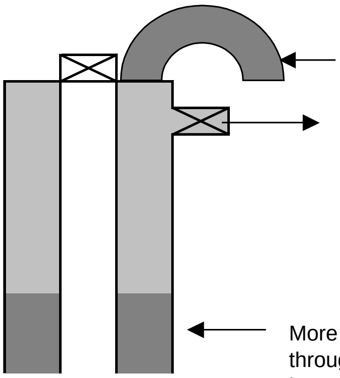


Figure 10: Seal-Tite methodology to seal annular cement micro-fractures (after Rush *et al.*, 2004).

The placement method is as critical to the sealing process as the cement slurry composition. The slurry needs to be injected at very low rates. This reduces the friction pressure generated in the gap, which in turn reduces the differential pressure across the slurry and decreases the chance of bridging. Once the slurry is in place, it must remain undisturbed until it sets. This is done by continuously pumping the slurry at very low rates until the thickening time has been attained, and the slurry sets. This optimised microcement system slurry design and placement technique has proved very successful in remedial cementation of leaking annuli in Western Canada. Again the long term sealing properties of this microcement in CO_2 environments is unknown.

3.2.2 Tubulars

Common industry standards for tubulars (casing and tubing) materials used in CO_2 wells have been developed e.g. standards by the American Petroleum Institute (API) or the Canadian National Association of Corrosion Engineers (NACE) (also see Table 5).

For corrosive environments such as CO_2 wells (injection or production), all surfaces which are contacted by the corrosive fluids are typically made of a high Chrome material (commonly Cr13 or Cr28). However the material requirements are dependent on the fluid composition – CO_2, formation water salinity, etc., pressures and flow rates. Therefore, a specific study for each field is required. Carey *et al.* (2010) observed steel corrosion induced by flow through a cement–casing micro-annulus. The steel casing reacted to form calcium and iron carbonate precipitates. Although steel corrosion can occur in relative short time periods, precipitation of reaction products may protect the steel and significantly reduce the corrosion rate (Carey *et al.*, 2010).

Alternative materials have been used for casings and tubings, such as glass-reinforced plastic (GRP), or fibreglass. Fibreglass and fibreglass-lined tubing has been frequently selected for water-alternating-gas (WAG) injection wells for shallow CO_2-enhanced oil recovery (EOR) projects in the USA. However, fiberglass is not suitable at temperatures above 90°C and pressures over 34 MPa, due to the issue of tensile loading, and so this application is generally limited to relatively shallow depths (IEA-GHG, 2010).

A comprehensive overview of materials used in sour environments is provided in the IEA-GHG report “Corrosion and material selection in CCS systems” (IEA-GHG, 2010).

The API (Meyer, 2007) provides detailed recommendations for materials suitable for CO_2 injection wells including polymers or packer material that shall be used (Table 5).

3.2.3 Reinstallation of seal integrity by backfilling of salt

Another technique that may be capable of effectively reinstalling caprock integrity is presently being investigated, exploiting the special material properties of rock salt. In areas where rock salt forms the sealing layer above potential CO_2 storage reservoirs, the salt creep behaviour under high P/T-conditions can be used to generate an impermeable, durable wellbore plug closing potential pathways in the wellbores (Orlic *et al.*, 2008). In order to use this phenomenon for permanent plugging of wellbores, a section of casing should be milled-out at the rock salt formation depth, so that the salt can creep into the inner wellbore. The main benefit of this method would be to actually reinstate the caprock, with no engineering materials, material interfaces or annuli present at the sealing level. The natural creep process can be accelerated by backfilling of crushed rock salt into the wellbore or the presence of fluids. Presently a field study is being conducted at the Altmarkt gas field, Germany. First findings indicate that the salt sealing process can occur quickly under downhole conditions and might even work without filling the wellbore with crushed salt, just due to the creep ability of the penetrated halite layers (Hou *et al.*, 2011).

3.2.4 Intentional clogging of the near-well reservoir

To protect the wellbore against CO_2 attack and thus prevent an initial CO_2 migration into the well, the near wellbore area could be clogged with CO_2-resistant materials or substances with swelling or adsorbing properties upon CO_2 contact. Different practices have been developed for this purpose, e.g. using expansive gels (Hout *et al.*, 2011) or bio-mineralization (Cunningham *et al.*, 2011). The substances are designed to be long-term CO_2 resistant (hundreds to thousands of years). However, the performance of these substances under long term CO_2 storage conditions is unknown.

Recent research in the CO_2CARE project investigates the use of salt(s) to establish a permanent barrier for the stored CO_2 (CO_2CARE, 2012 in preparation). This can be achieved by alternating brine and CO_2 injection prior to abandonment, which leads to dissolution of already existing or placed salt and in a re-precipitation of salt in the intended area (CO_2CARE, 2012, in preparation).

4 Well abandonment requirements with respect to underground CO_2 storage

The plugging and abandonment objective for CO_2 containment wells is essentially the same as that for conventional petroleum wells, i.e. well abandonment should isolate all discrete permeable zones penetrated by the well from each other and from the surface (or seabed) using permanent barriers. However, CO_2 containment wells differ from standard petroleum wells in that, when abandoned, they may be in a higher pressure regime than they were originally designed for and have to be able to withstand corrosive fluids for very long timeframes.

When oil and gas production wells are initially abandoned, the reservoir is normally depleted and the reservoir pressure may be much less than the original levels. The fluids in the reservoir tend to have insufficient energy to flow to surface. If there are any over-pressurized zones left behind the casings, then they are normally of low volume: i.e. isolated permeable zones with either limited areal extent (volume) or formations with very low permeability which has made the recovery in the zones uneconomic.

However, due to aquifer drive, over an extended time period the pressure in many of these depleted hydrocarbon reservoirs may increase and the pressure reverts to the original pressure gradient. The abandonment of wells in depleted hydrocarbon reservoirs should take this into consideration (also see Section 2.2.1.3). However, this is not always explicitly identified. Also, these wells are abandoned with the expectation that they will contain the hydrocarbons even if the pressures increase and for extended periods – hundreds / thousands of years.

Additionally, the injected CO_2 (in combination with the reservoir brine) will chemically attack borehole materials. Tubulars can be corroded and cements and other sealants might be degraded and could lose their seal integrity (e.g. Carey, 2007) (also see Section 3.2.1).

The EU CO_2 storage directive prescribes the reinstallation of seal integrity at the existing caprock level(s) for every well perforating the storage complex. This can routinely be considered when abandoning accessible and future wells, but is mostly difficult to ensure for previously abandoned wells that actually may be plugged at depths other than the CO_2 storage reservoir's caprock (also see Section 4.1). The latter well type requires more extensive, specialised considerations. Therefore, in general, previously abandoned inaccessible wells, on the one hand, and accessible or future wells, on the other, should be distinguished with respect to CO_2 storage and are separately described in Sections 4.1 and 4.2.

4.1 Managing previously abandoned wells

Previously abandoned - and therefore practically inaccessible - wells have been considered to be the major concern regarding long term safety and integrity of CO_2 storage in depleted hydrocarbon fields (e.g. IEA-GHG, 2009 and references therein).
In such cases, drilling, completion and plugging were performed at a certain time in the past and not from the viewpoint of long-term storage of CO_2. It is uncertain whether the current state of the wellbore materials is still of adequate quality (along the caprock level). Chemical degradation of wellbore materials, pressure and temperature cycles during (huff-and-puff) production and depletion of the reservoirs could have induced mechanical defects on the primary cement sheath (and its interfaces) of former production wells.

Extensive risk assessment, including an accurate evaluation of the actual state of the wellbore materials, has to be performed in order to ensure that the quality of the well barriers matches the safety requirements for geological CO_2 storage. In case of lacking data and/or if the current state of the wellbore materials do not fulfil the requirements for CO_2 storage, the well would require remediation in order to match safety standards that are sufficient for long-term geological storage of CO_2. This would involve locating, re-entering and re-abandoning the previously abandoned well. Although technically challenging, this may be feasible, but would introduce high costs. If an abandoned well was found to be of inadequate integrity for CO_2 storage, the same standard state-of the art abandonment practices as for accessible wells have to be implemented after the re-entry is carried out successfully.

Often, previously abandoned wells do not match safety standards for CO_2 storage. If (adequate) regulations were in place at the time of abandonment, a proper evaluation of the actual state of the well barrier materials is challenging. Consequently, the integrity of old wells, particularly if critical data is missing, is difficult to predict.

Well integrity management systems (WIMS) have been applied for many years in the industry and are currently being further developed in order to provide a risk-based methodology to assess the integrity of (abandoned) wells with respect to CO_2 storage requirements (e.g. Le Guen *et al*.,2009, 2011). These tools present a promising solution for a quantitative evaluation of wellbore materials, but still have to be improved, particularly in terms of accuracy, uncertainties and transparency, taking into account the latest experimental and numerical results on material integrity under site-specific in-situ reservoir conditions. WIMS are not discussed further this report.

A review paper summarising the recent knowledge with respect to the integrity (evaluation) of old, inaccessible wells in CO_2 environments has been published by Zhang and Bachu (2011).

4.2 Abandonment of CO_2 injection wells

Certain aspects of drilling and completion provide boundary conditions for proper abandonment. For CO_2 injection wells the following issues should be considered during the initial design of the well:

- Casing and tubing design and material selection;
- Primary cementing of the casing annuli from the CO_2 injection zone to above the shallower hydrocarbon zone – material selection and placement;
- Monitoring of the integrity of the annulus seal between the CO_2 injection zone and the hydrocarbon zone;
- Contingency and / or ability to intervene to remediate the annular cement seal prior to the final abandonment of the well;
- The final well abandonment including - the location and size of internal cement plugs – requirement to cut and retrieve casings.

Recent studies (Randhol and Carlsen, 2008) indicate that injection wells are more prone to leakage than production wells and should therefore get special attention when being finally abandoned.

4.2.1 Casing and tubing design.

The design of CO_2 injectors does not require fundamental changes compared to regular oil and gas wells, since dry CO_2 is expected to be injected. (Nygaard, 2010). However, in a CO_2 injection well, the principal well design considerations should include pressure, corrosion-resistant materials and production and injection rates (IPCC, 2005).

For safe CO_2 injection the injectors should comprise of at least two casing strings (Figure 11). The advantage of the 2 casing string option is that the hydrocarbon zone can be separated from the CO_2 injection zone. Any operational problems can be dealt with separately. With this design the cementing of the casing can be managed to provide the optimum solution for achieving good cementing across the hydrocarbon zone. This might require lightweight cements and might be different from those which should be used over the CO_2 injection zone. Also, the longer the zone which is cemented in a single operation, the more contamination occurs at the interface between the cement and the mud. Carrying out the cementing operations separately gives the best chance of good cementing across the important intervals.

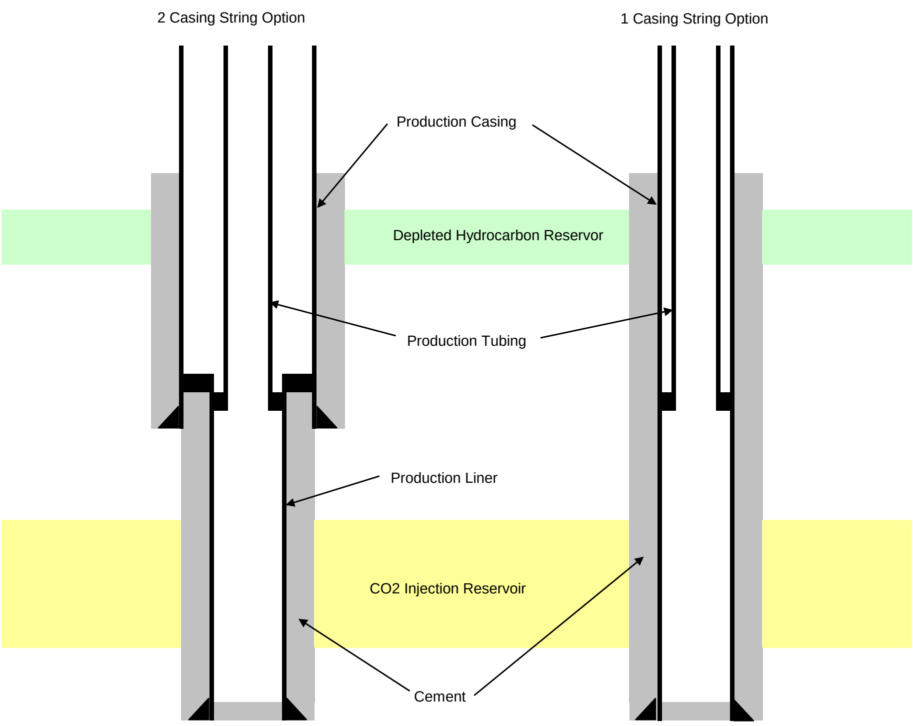


Figure 11: Design of CO_2 injection wells.

The casing which runs across the CO_2 injection reservoir should be Corrosion Resistant Alloy (CRA) material. The exact composition should depend on the final chemical specification of the injection fluids and the estimated temperatures and pressures.

This would require the liner in the 2 casing string design above to be of CRA material, but the upper production string could be of a different and cheaper material. For the single string design, then a mixed string would likely be used, e.g. standard casing material at top and CRA material below the tubing packer seal.

The tubing string used for injection and the packers / completion used to isolate it from the upper casing should also be of CRA material.

4.2.2 Casing mechanical properties

The mechanical properties – tensile strength, burst, collapse, etc. - of the casing need to be designed not on the basis of (depleted) reservoir conditions but considering the estimated future conditions as the pressure regime will be different compared to conditions at the start of the CO_2 injection.

4.2.3 Primary cementing of the casing annuli

The primary cementing of the annulus is critical. The cementing material must be suitable to provide a long term seal and be installed correctly. The optimum procedures for obtaining the best cement job are adequately described in the oilfield literature (e.g. US EPA, 1994, Nelson and Guillot, 2006). The first priority is to drill a borehole which is uniform in diameter. The drilling fluid needs to be optimised to help provide a uniform borehole but also to allow the drilling fluid and any filter cake to be removed prior to the cementing operation. All major well cementing companies are capable of mixing and dispensing the cement into place using suitable spacers to separate the mud from the cement. They can also provide the optimum displacement rates, standoff of casing from wellbore; clearance between wellbore and casing, rotation and reciprocation of casings, etc.

The amount and along-hole-length of the cement should be such that, if some limited failure or degradation due to chemical attack (CO_2 on the cement) occurs, there is still a sufficient redundancy to ensure that the barrier remains intact.

Development is ongoing and it is likely that more advanced products will be available during the timeframe considered for future CO_2 injection projects. ExxonMobil have reported successful use of CO_2 resistant cements when drilling wells for acid gas injection in Wyoming, US (Herbertson *et al.*, 2011). However, these have only been used since 2005 and the long term properties are not known.

Adherence to industry “best practice” as developed by the major well cementing service companies will ensure a properly functioning cement barrier.

Furthermore, changes in the temperature and pressure regime due to operational activities (especially temperature or pressure cycles) and/or poor cement jobs can cause de-bonding and/or formation of (micro)cracks as a result of mechanical deformation of the cement sheath. This could lead highly permeable migration pathways for the injected CO_2, particularly at material interfaces. Randhol and Cerasi (2009) provide an overview of mechanical factors that can deteriorate the integrity of the wellbore cement sheath.

A combination of chemical alteration and mechanical failure of the annular cement is being considered as the main threat for the long term integrity of wells in CO_2 underground storage (e.g. IEA-GHG, 2009).

4.2.4 Intervention during the injection phase

Interventions are likely to be required on CO_2 injection wells in order to maintain their integrity. BP have reported that in their Sheep Mountain CO_2 field, they have replaced the tubing on 18 of the 29 wells and had to make wellhead repairs on a further 4 wells. Duncan *et al.* (2008) reported on several incidents (and their remediation) during 37 years of CO_2 EOR operations in the US including some with significant consequences like blowouts.

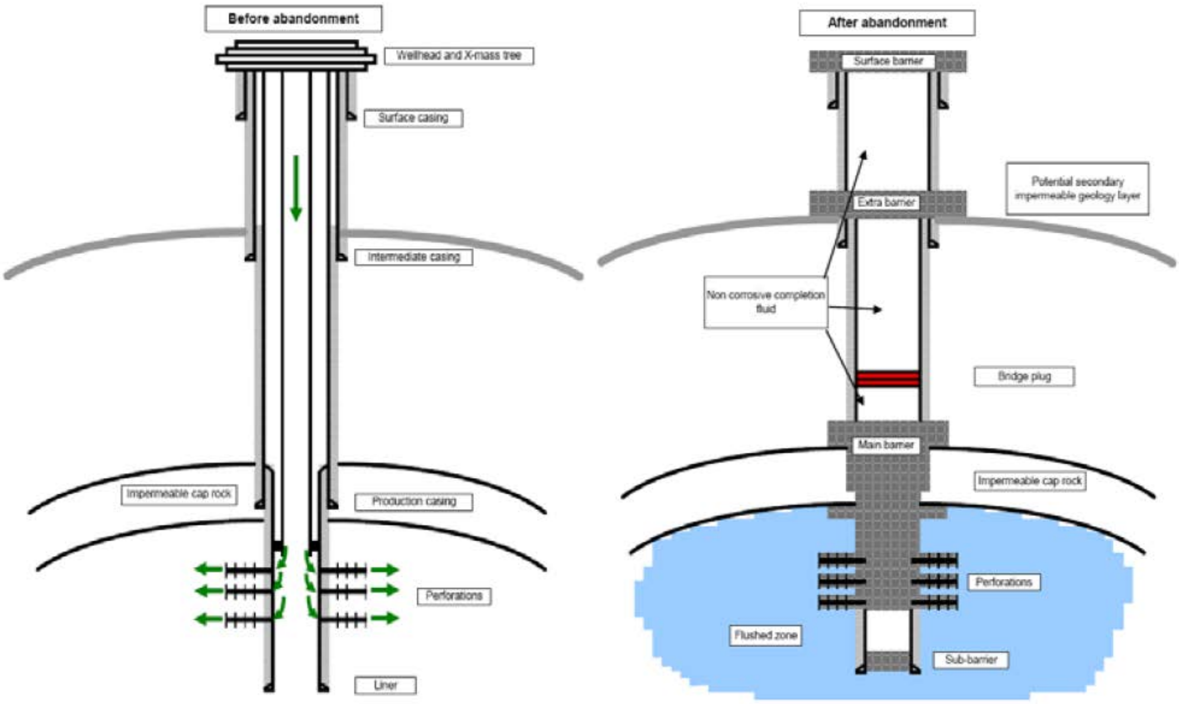
Especially in subsea wells, intervention options are limited. Intervention can generally be done both faster and easier in completed wells on-shore. If there is tubing to annulus communication, then on an on-shore completed well it is relatively simple to run a deep-set plug using wireline to seal off the injection zone. This prevents further deterioration of the failure and reduces the risk of corrosion on the production casing. Later, an intervention might be carried out using a rig. For subsea wells, a rig might need to be mobilised straight away for an immediate remediation which would reinstall wellbore integrity. On an on-shore well, failures on the inner B & C annuli can be identified and early action taken – e.g. cutting and patching casing. As these annuli cannot be monitored on subsea wells, then the failures might not be easily identified or only identified during the final well abandonment when remediation might be more challenging.

4.3 Final well abandonment of accessible wells

The initial design of the well should make the final well abandonment as simple and secure as possible. Technology and the understanding of the containment process – e.g. cement quality and deterioration - have reached a very high standard with regard to long-term containment of the stored CO_2 and will still improve with time.

Current techniques and testing methods allow for proper placement of abandonment plugs of sufficient thickness (50 to 100 m). Application of Portland cement for cement plugs is appropriate for CO_2 storage considering the low degradation rates due to corrosion by CO_2. Cement plugs have to be tested and quality checked with respect to integrity after placement. It should be noted that bridge plugs do not contribute to the long-term sealing of the CO_2 injection zone, since they consist of metals and elastomers and are thus expected to be corroded within a short period of time. The application of in-casing abandonment plugs requires a good quality of primary cement sheath. Therefore, cement bonding and mechanical integrity of the cement needs to be verified. If necessary, cement squeeze behind the casing can improve the quality of the cement sheath. Although unlikely, pervasive corrosion of the casing between the cement plug and primary sheath cannot be excluded completely, posing a risk of development of a leakage pathway along the well, bypassing the cemented casing.

Det Norske Veritas (2011) recommends for abandoned wells that penetrate the CO_2 storage complex at least two barriers above the target storage formation and, if part of the casing or cement sheath(s) may be exposed to CO_2, that the abandonment should include a pancake plug. The pancake plug should be placed at caprock level and immediately below the injection reservoir to increase long-term integrity of vertical wells as proposed by Carlsen and Abdollahi (2007) (Figure 12). This technique involves the removal of downhole equipment before placing a cement plug at the bottom of the well. A polymer is injected into the reservoir to clog the near wellbore region and prevent the CO_2 to get in contact with the wellbore materials. The well is then filled with non-corrosive completion fluid.



a) b)

Figure 12: CO_2 storage injection well before (a) and after abandonment (b) using a pancake-type plug (after Carlsen and Abdollahi, 2007; In: Randhol *et al.*, 2007).

Setting Pancake-type plugs involves milling out casing steel, primary cement sheath and some rock over an interval of several tens of meters and subsequent filling this cavity with cement (Figure 12). If properly emplaced, a pancake plug can ensure adequate isolation of the CO_2 storage compartment. Placement and pressure-testing of such a plug would give again full control on the cementing, including the original primary cement sheath. Furthermore, it would erase the corrosion sensitive steel phase and also eliminate cement-steel material interfaces along the milled interval. These form the most critical leakage pathways in regular abandonment configurations, potentially forming annuli or zones of enhanced CO_2 migration. Therefore, it is advised to consider the placement of pancake plugs at abandonment for all vertical wells. On the other hand, a proper placement of a pancake type of abandonment plug is technically complex or even impossible in deviated wells as cement does not set appropriately in such. In certain cases, several attempts might be needed to adequately put a pancake plug in place, leading to high costs or, if the operation fails, to reduced zonal isolation. All used wellbore materials should resist the corrosive environment and should provide sufficient bond strength.

If secondary seal intervals are present, an additional cement barrier should be placed at this level (IEA-GHG, 2009).

The same requirements would apply for the abandonment of all other wells in the storage complex, e.g. monitoring and brine production wells, if there is a certain probability that they will get in contact with the injected CO_2. This should be assessed in preceding migration path studies.

5 Recommendations and challenges

In site abandonment of CO_2 storage sites, well integrity is considered to be a critical aspect with respect to long term sealing efficiency of the storage compartment. Requirements to ensure safe CO_2 containment for hundreds of years differentiate from the methodologies of regular oil and gas site abandonment mainly due to the repressurization of the reservoir, the corrosive nature of the stored CO_2, and the long time frame involved.

However, for well integrity in CO_2 environments, mechanical processes appear to be more significant than chemical degradation of wellbore cement, since chemical degradation is considered to be based on diffusion and is too slow to be an issue. Fractures or other pathways through the cement present high-permeable pathways for the CO_2. The behaviour at interfaces in the wellbores remains an issue, particularly if chemical, mechanical and physical processes interact. Potential leakage pathways could arise along these interfaces as a result of processes such as debonding. However, recent research has shown that even degraded cement maintains its mechanical strength and low permeability. Calcite healing of induced fractures or micro-annuli is also considered likely. However, this could be governed by local chemical equilibria dictated by the formation water composition and mineralogy.

The experiences from CO_2 storage site demonstration projects and CO_2-EOR industry applications indicate that, in principle, CO_2 storage can be performed safely with respect to site abandonment, provided that certain aspects have been taken into account:

- A proper site characterisation;
- A comprehensive, repeatedly updated risk assessment through the entire lifetime of the storage project;
- An accurate well integrity assessment, which has to be part of the site and risk assessment;
- Operation activities performed according to industry best practices, particularly proper cement placement and well operations;
- Design of a risk-based monitoring plan;
- Design of a risk-based remediation plan;
- Execution of predefined prevention and mitigating measures, if required.

Besides a thorough planning of the CO_2 storage operation, it is important to consider recommendations and challenges drawn from industry practices and related experience. Special attention should be paid in relation to the long term performance of well barrier materials exposed to the corrosive CO_2 environment.

It is recommended that guidelines on practices related to CO_2 geological storage should provide more specific guidance in terms of

- How to abandon a CO_2 storage well properly, including obliged reinstallation of the caprock integrity and removal of the tubing.

- The materials which are recommended for use in injection, production, monitoring and abandonment of wells. New, CO_2-resistant materials, such as sealing gels or CO_2-resistant cements should be tested extensively in CO_2 environments before considering their application in CO_2 storage activities.

Considering that particular care has to be paid to both cement sheath placement (after drilling) and cement plug placement at abandonment, it is recommended that more detailed procedures describing cement (sheath) evaluation and integrity test activities should be provided:

- Pancake plugging of the wellbores is thought to provide a promising solution to plug the wellbore adequately, but it is not a standard procedure. In case the operation fails, the placement has to be repeated (if possible) and/or even higher leakage risks could be generated. In such cases, the remediation operations will be technically challenging and expensive.

- Particularly the highly deviated wells may pose integrity problems due to improper cement placements and should be carefully evaluated by state of the art monitoring tools (e.g. ultrasonic or calliper tools), if considered as injectors. Especially in highly deviated wells placing an effective pancake cement plug will be impossible.

Finally, it is advised to that guidelines regarding the implementation of appropriate monitoring schemes, particularly during the period between site closure and the transfer of responsibilities from the operator to the authorities/site owner, have to be defined depending on site-specific criteria.

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Appendix

Table A 1: Requirements and specifications for casing cement (from NORSOK D-10, Table 22)

Features	Acceptance criteria	See
A. Description	This element consists of cement in solid state located in the annulus between concentric casing strings, or the casing/liner and the formation.	
B. Function	The purpose of the element is to provide a continuous, permanent and impermeable hydraulic seal along hole in the casing annulus or between casing strings, to prevent flow of formation fluids, resist pressures from above or below, and support casing or liner strings structurally.	
C. Design, construction and selection	1. A design and installation specification (cementing programme) shall be issued for each primary casing cementing job. 2. The properties of the set cement shall be capable to provide lasting zonal isolation and structural support. 3. Cement slurries used for isolating permeable and abnormally pressured hydrocarbon bearing zones should be designed to prevent gas migration. 4. The cement placement technique applied should ensure a job that meets requirements whilst at the same time imposing minimum overbalance on weak formations. ECD and the risk of lost returns during cementing shall be assessed and mitigated. 5. Cement height in casing annulus along hole (TOC): 5.1 **General:** Shall be 100 m above a casing shoe, where the cement column in consecutive operations is pressure tested/the casing shoe is drilled out. 5.2 **Conductor:** No requirement as this is not defined as a WBE. 5.3 **Surface casing**: Shall be defined based on load conditions from wellhead equipment and operations. TOC should be inside the conductor shoe, or to surface/seabed if no conductor is installed 5.4 **Casing through hydrocarbon bearing formations**: Shall be defined based on requirements for zonal isolation. Cement should cover potential cross-flow interval between different reservoir zones. For cemented casing strings which are not drilled out, the height above a point of potential inflow/ leakage point / permeable formation with hydrocarbons, shall be 200 m, or to previous casing shoe, whichever is less. 6. Temperature exposure, cyclic or development over time, shall not lead to reduction in strength or isolation capability. 7. Requirements to achieve the along hole pressure integrity in slant wells to be identified.	ISO 10426-1 Class ‘G’
D. Initial verification	1. The cement shall be verified through formation strength test when the casing shoe is drilled out. Alternatively the verification may be through exposing the cement column for differential pressure from fluid column above cement in annulus. In the latter case the pressure integrity acceptance criteria and verification requirements shall be defined. 2. The verification requirements for having obtained the minimum cement height shall be described, which can be • verification by logs (cement bond, temperature, LWD sonic), or • estimation on the basis of records from the cement operation (volumes pumped, returns during cementing, etc.). 3. The strength development of the cement slurry shall be verified through observation of representative surface samples from the mixing cured under a representative temperature and pressure. For HPHT wells such equipment should be used on the rig site.	
E. Use	None	
F. Monitoring	1. The annuli pressure above the cement well barrier shall be monitored regularly when access to this annulus exists. 2. Surface casing by conductor annulus outlet to be visually observed regularly.	WBEAC for “wellhead”
G. Failure modes	Non-fulfilment of the above requirements (shall) and the following: 1. Pressure build-up in annulus as a result of e.g. micro-annulus, channelling in the cement column, etc.	

Table A 2: Requirements and specifications for cements plugs (from NORSOK D-10, Table 24)

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>A. Description</td><td>The element consists of cement in solid state that forms a plug in the wellbore.</td><td></td></tr>
<tr><td>B. Function</td><td>The purpose of the plug is to prevent flow of formation fluids inside a wellbore between formation zones and/or to surface/seabed.</td><td></td></tr>
<tr><td>C. Design, construction and selection</td><td>1. A design and installation specification (cementing program) shall be issued for each primary casing cement job.
2. The properties of the set cement plug shall be capable to provide lasting zonal isolation
3. Cement slurries used in plugs to isolate permeable and abnormally pressured hydrocarbon bearing zones should be designed to prevent gas migration.
4. Permanent cement plugs should be designed to provide a lasting seal with the expected static and dynamic conditions and loads down hole
5. It shall be designed for the highest differential pressure and highest downhole temperature expected inclusive installation and test loads.
6. 6. A minimum cement batch volume shall be defined for the plug in order that homogenous slurry can be made, to account for contamination on surface, downhole and whilst spotting downhole.
7. The firm plug length shall be 100 m MD. If a plug is set inside casing and with a mechanical plug as a foundation, the minimum length shall be 50 m MD.
8. It shall extend minimum 50 m MD above any source of inflow/ leakage point. A plug in transition from open hole to casing should extend at least 50 m MD below casing shoe.
9. A casing/ liner with shoe installed in permeable formations should have a 25 m MD shoe track plug.</td><td>API Standard 10A Class 'G'</td></tr>
<tr><td>D. Initial verification</td><td>1. Cased hole plugs should be tested either in the direction of flow or from above.
2. The strength development of the cement slurry should be verified through observation of representative surface samples from the mixing cured under a representative temperature and pressure.
3. The plug installation shall be verified through documentation of job performance; records fm. cement operation (volumes pumped, returns during cementing, etc.).
4. Its position shall be verified, by means of:
<table>
<tr><th>Plug type</th><th>Verification</th></tr>
<tr><td>Open hole</td><td>Tagging or measure to confirm depth of firm plug.</td></tr>
<tr><td>Cased hole</td><td>Tagging, or measure to confirm depth of firm plug
Pressure test, which shall
a. be 7000 kPa (~1000 psi) above estimated formation strength below casing/ potential leak path, or 3500 kPa (~500 psi) for surface casing plugs, and
b. not exceed casing pressure test, less casing wear factor
which ever is lower
If a mechanical plug is used as a foundation for the cement plug and this is tagged and pressure tested the cement plug does not have to be verified.</td></tr>
</table></td><td></td></tr>
<tr><td>E. Use</td><td>Ageing test may be required to document long term integrity.</td><td></td></tr>
<tr><td>F. Monitoring</td><td>For temporary suspended wells: The fluid level/ pressure above the shallowest set plug shall be monitored regularly when access to the bore exists.</td><td></td></tr>
<tr><td>G. Failure modes</td><td>Non-compliance with above mentioned requirements and the following:
a. Loss or gain in fluid column above plug.
b. Pressure build-up in a conduit which should be protected by the plug</td><td></td></tr>
</table>