Report

CCS Well Design Requirements

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SUMMARY
The report is prepared as a basis for evaluating the applicability of the NORSOK D-010 standard for wells for CO_2-storage, and in particular to identify specific features as compared to petroleum wells. The review is intended to be used as a decision basis for further work on CCS wells for industry.
The report addresses the following:

- Main differences between CCS and conventional petroleum wells.
- Overview of experience from Sleipner and Snøhvit CO_2 injection wells
- Risk and consequences, differences between CCS and petroleum wells
- Barrier Philosophy considerations, CCS and gas injection well

During the review work SINTEF has received input from Equinor regarding Sleipner and Snøhvit sites.

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Table of contents

1 Objectives and assumptions of the study

Presently, there is a limited experience with offshore Carbon Capture and Storage (CCS) well development on the NCS, and Sleipner and Snøhvit are the only CCS projects with CO_2-storage in operation. Sleipner started injecting CO_2 in 1996, whereas at Snøhvit injection started in 2008 (Eiken et al., 2011; Furre et al., 2017; Hansen et al., 2013). These two pioneering projects have demonstrated the concept of injecting CO_2 for offshore subsurface storage. More recently, the "Northern Lights" project have drilled two wells, specially designed for CCS. These wells are designed similar to oil and gas wells but with increased focus on material specification, cement quality and monitoring. The cost of the wells is not significantly different from conventional oil and gas wells.

The objective of this study is to better understand the differences between CCS wells and conventional oil and gas wells by establishing a general overview of the well design requirements and associated risks that can be mitigated by the well construction, with respect to structural integrity. As such this study will form a basis for the evaluation of the applicability of the NORSOK D-010 standard for wells for CO_2-storage, and in particular to identify specific features as compared to petroleum wells. The scope of the work has been agreed as follows, with respective associated WP (Work Packages) including description of their scope:

1. **Main differences between CCS and conventional petroleum wells (WP1).** Give an overview of the main differences that have impact on design of CCS well design, including material selection, design cases and cement design.
2. **Overview of experience from Sleipner and Snøhvit CO_2 injection wells (WP2).** Overview of experiences from operation of CO_2 injections wells on Sleipner and Snøhvit shall be generated. This should focus on their identified risks related to well integrity and include potential experiences from any registered well integrity incidents with these types of wells. Well monitoring methods used to collect data to detect leakage and mitigate risk of well integrity failure shall be included.
3. **Risk and consequences – differences between CCS and petroleum wells (WP3).** Perform an assessment of differences in risks and consequences between a CCS well and a gas injection well. The objective of this is to map the risk of a well integrity failure for the two types of well design and their intended operation during lifetime of the field. A qualitatively risk analysis shall be done to address the main accidental events for each type of wells. Based on this analysis, quantification of the probability and the consequences of the main accidental events, in a manner which allows comparison with quantitative risk acceptance criteria, shall be done.
4. **Barrier philosophy considerations – CCS and gas injection well (WP4).** Barrier philosophy shall reflect the risk associated with well integrity failure or well control incident. The general principle is to operate with two defined well barrier envelopes against over-pressure and/or flow potential (NORSOK D-010 Chapter 5.2.3). An overview of well barrier philosophy considerations for a CCS well and gas injection well shall be generated. It shall reflect the major risks and consequences identified for these two types of wells throughout the well's life, including abandonment. The following considerations should be included in the evaluations: a) Accept criteria for seal leakage? b) How will a leakage behave? c) Danger for people in area – poisoning? d) Is it sufficient to stop injection? e) Lack of Barriers that require side-track, cost-benefit? f) Monitoring of barriers – method and frequency; g) Equipment for monitoring of CO_2 gas plume, incl. well completion equipment.

The study is based on the following assumptions and limitations, as agreed with the client:

1. Previously abandoned wells to be used for CCS shall not be included.
2. Only subsea well case to be considered in evaluation (but relevant downhole experiences can be gathered from platform wells).
3. Restrict evaluation to well design downhole, from wellhead to reservoir. Subsea solutions not to be included in the study.
4. The period from spud to designed lifetime for well.
5. Operations in a new area (i.e. no previously injected CO_2) and only new injection wells to be considered.
6. Well control is not included in the scope, i.e. exclude wells to be drilled as infill wells (or relief wells) after CO_2 injection has started.
7. Limited to activity related to well design, operation and monitoring (CO_2 injection into well included, but not logistic etc.).
8. Equal geological parameters (cap rock etc.).
9. Exclude issue related to "Danger for people in area – poisoning" as only subsea wells are considered.
10. Exclude issue on "equipment for monitoring of CO_2 gas plume, incl. well completion equipment." On the other hand, monitoring of barriers, especially pressure monitoring for leakage behind the casing is relevant.
11. The NORSOK D-010 ''Well integrity in drilling and well operations" standard which defines requirements and guidelines relating to well integrity in drilling and well activities on NCS is the target for this study. Other relevant documents (journal papers, guidelines, reports, etc.) that have been reviewed are listed in the bibliography.

2 Introduction

2.1 CCS: Why and How?

CCS is proposed as a major contribution to climate change mitigation. The approach is to reduce the emissions of CO_2 from the industrial and energy sectors, while simultaneously supplying the world with modern commodities and energy. The process is to capture CO_2 at large point sources. The CO_2 is then transported in pipelines or vessels from its source and injected via a well into deep underground permeable geological formations for permanent storage. The concept of using reservoirs for storage is not a new one. Underground reservoirs have been used for storage of fluids for many years. Such storage sites have been used as a seasonal buffer for natural gas, as an alternative to constructing large surface-based facilities. CO_2 has also been injected extensively into reservoir for enhanced oil recovery. The two most common types of storage reservoirs are in depleted oil & gas reservoirs or in saline aquifers.

2.2 Well Integrity

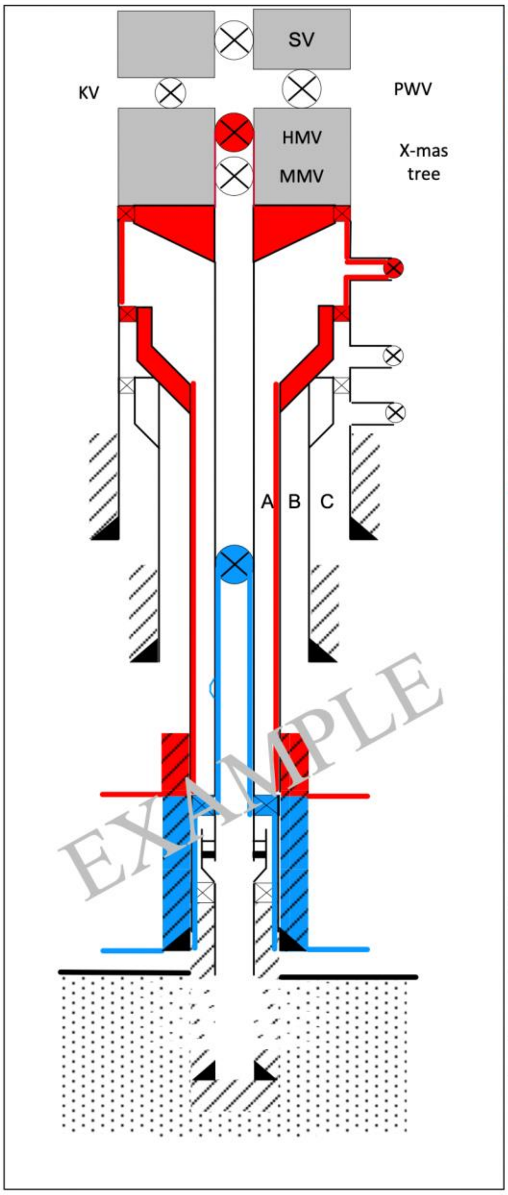
The operation of transporting fluids via wells to and from reservoirs entails handling of potentially harmful or toxic fluids at high pressures. Thus, safety considerations should be prioritized continuously. It is vital to maintain the *zonal isolation* between fluid bearing zones to prevent uncontrolled fluid migration. *Well integrity* is a term used to describe the operations to contain fluids, and it includes technical, operational and organizational solutions for handling the risk of uncontrolled release of fluids. The well integrity is maintained by placing steel casings in the wellbore and cement in the annulus between the formation and the casing. Different standards and guidelines have similar notations and schematics for the well architecture. The well barriers are divided into primary and secondary well barrier envelopes, which are defined as follows (NORSOK D-010, 2021):

1. The **primary well barrier** is the first set of well barrier elements that prevent flow from a source of inflow.
2. The **secondary well barrier** is the second set of well barrier elements that prevent flow from a source of inflow.

The primary well barrier is usually shown in blue colours in the well barrier schematics, whereas the secondary is shown in red colours (NORSOK D-010, 2021). Figure 1 shows an example of well schematics from the NORSOK D-010 standard – an operational well. Well barrier consists of several well barrier elements, such as casing, annular cement, formation, fluid column, downhole safety valves, tubing, packer etc., depending on the well type, operational phase of the well and the barrier itself. For an operational well, the primary well barrier typically consists of formation (caprock), annular cement, production casing or liner, packer, tubing and DHSV (Vrålstad et al., 2015b).

2.3 Well failure modes

Steel casings and cement are non/low-permeable materials respectively. However, due to the high downhole pressure, loss of zonal isolation and leak through a barrier is not uncommon. If leakage occurs in a well, it is important to identify which well barrier elements have failed. Various well barrier elements can, under certain conditions, be prone to degradation. Steel for instance can *corrode* under certain conditions, and if a corroded steel casing is not attended, the ability of the casing to provide well integrity will diminish, and the leakage risk will increase. The same mechanism and consequence apply for downhole safety valves and wellhead/X-mas tree. Cement and steel can also crack or burst if they are strained outside the intended operational boundaries. *Temperature and pressure cycling* could lead to fatigue and fracturing or debonding in the materials and increase leakage risk for these materials. Another potential factor for leakage risk is whether the well was drilled and completed properly. *Channels of drilling fluid or gas can be formed in the cement* during curing, and these could act as leak pathways during operation. The same applies to regions in the wellbore with extensive washout, as it can be difficult to achieve a successful fluid displacement during the primary cementing operation. Another risk are micro-annuli between the cement and formation.



WBE	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Annulus cement (shoe to production packer)	22	
Casing (below production packer)	2	
Production packer	7	
Completion string	25	
Completion string component	29	
DHSV (including control line)	8	
Secondary well barrier		
In-situ formation	51	
Annulus cement (above production packer)	22	
Production casing (above production packer)	2	
Production casing hanger with seal assembly	5	
Wellhead (annulus valve)	12	
Tubing hanger (body seals)	10	
Wellhead (WH/Tree Connector)	5	
Tubing hanger (neck seal)	10	
Surface XT	33	

Figure 1. Example of well barrier schematics for a well in operational phase from the NORSOK D-010 Chapter 9.8, Figure-22 — Platform production/injection/observation well capable of flowing (p.77). Reused with permission from Standard Norge.

As an example of some possible leakage paths through the primary and the secondary well barrier in a production/injection well is illustrated in Figure 2, (Vrålstad et al., 2015b). In this example, failure of the annulus cement (as a common WBE for the primary and secondary barrier) could lead to external leakage into the neighbouring formations, or leakage along the casing all the way to the surface. This kind of failure would be denoted as *sustained casing pressure* or *Surface casing vent flow*. Packer or tubing failure could result in internal leakage (within the well).

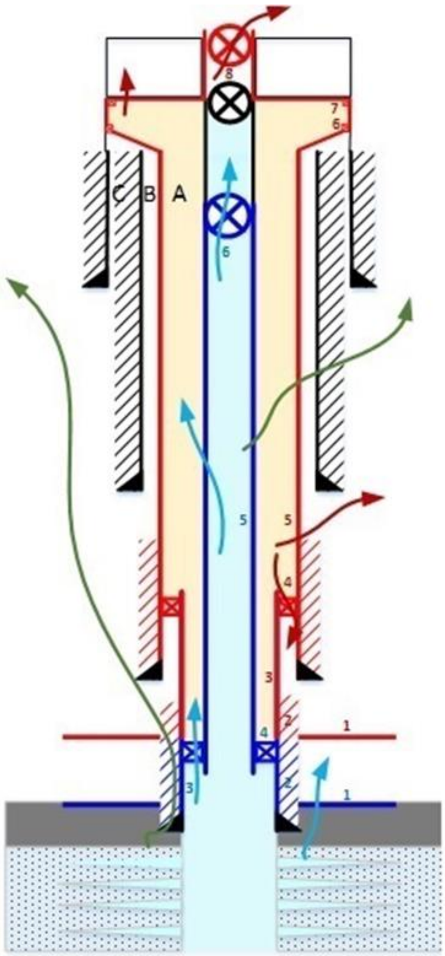


Figure 2. Illustration of possible leakage paths in a production/injection well, adopted from (Vrålstad et al., 2015b). The blue arrows indicate failure in the primary WBE, the red arrows indicate failure in the secondary WBE. The green arrows indicate failure of multiple WBEs.

The appearance of a leak through a well depends on the specific circumstances. The resulting leakage severity is governed by the combination of the mobility of the fluid and the properties of the flow path. A low viscosity and density gas phase exhibits larger volumetric flow rate compared to that of a heavy crude oil liquid in an otherwise comparable case. The driving force for fluid flow through the well is impacted by the differential pressure between the reservoir (including potential depletion) and surface or over-burden formations. In terms of the properties of the flow path, the aperture of the flow path is important, but other important factors are the length and tortuosity of the flow path, and the confinement stress acting on the flow path (Anwar et al., 2019; Corina et al., 2019; Hatambeigi et al., 2023; Moghadam et al., 2022; Stormont et al., 2018).

2.4 Well types

In the petroleum industry, the term "well" is divided into several subcategories such as exploration, appraisal, production, monitoring or injection. In addition, during the lifetime of the well it could be active, suspended, temporarily abandoned and permanently plugged & abandoned. Wells can also be used to serve various purposes, such as production of hydrocarbons, exploitation of geothermal energy and storage of natural gas, CO_2 or hydrogen. Thus, depending on the intended usage of the well, the requirements for different wells might not be directly comparable. A CCS well is not directly comparable with an injection well, neither is a CCS well directly comparable to a natural gas storage well. An injection well used for CO_2-EOR operations might not experience similar injection rates, and thus, cyclic changes inside the wellbore compared to a CCS well since fluids are injected to the reservoir for displacing another fluid for production. Thus, the profile of pressure build-up in a CCS well can in most cases be different. Likewise, a well to be used for natural gas storage underground can experience on-off cyclic changes during injection/production relevant enough for comparing with a CCS well, but the chemical conditions downhole are not comparable. Another potential difference is when a natural gas storage site is due to be abandoned, the stored gas will with all likelihood be extracted from the reservoir. Thus, the driving force for fluid mobility (pressure) is decreased, as opposed to CO_2 storage where the intent of the reservoir is to maximize the available storage potential.

2.5 CCS wells

The considerations on CCS well design are similar to other well types in terms of construction principles and operations. The assessment of a well to be used for CCS will be cover many parameters, though it is likely that the following four aspects will be important:

- The lifetime of the operation
- The specific conditions of the underground; both for the formation and the fluid(s)
- The design of the injection well
- Over-pressured conditions during storage relative to the initial reservoir conditions.

Considering the lifetime for a CCS well comes from the fact that any requirement, whether regulatory or other, will expect that the well will provide sufficient well integrity for several years. The Environmental Protection Agency (EPA) of the United States anticipates that the timescale for the operation of CO_2 storage will be in the order of thousands of years (EPA, 2010). An operational well for either petroleum extraction or CO_2 injection will have access to the resources and infrastructure necessary to mitigate any detected loss of well integrity during operation of the field. It may be more difficult to mitigate loss of integrity of a well that is abandoned after the injection is stopped and field is abandoned, especially, for a CO_2 storage field. However, it should be noted that this study does not include the P&A phase.

Another important point is the large amount of fluids involved in both petroleum extraction from a reservoir and CO_2 injection into a reservoir, and the difference in time when the well will exhibit peak fluid volume/pressure at the wellbore location (Rentsch and Mes, 1988). For instance, at the time of abandonment for a petroleum well accessing a depleted reservoir, the wellbore materials will be subjected to depleted reservoir pressure conditions. However, assuming that the reservoir will over time re-pressurize back to virgin pressure, the well barrier materials for P&A need to be qualified for such pressure (NORSOK D-010, 2021). This order could be opposite for a CCS well, where during injection and immediately after the injection is stopped, before the CO_2 plume has migrated away from the wellbore and secondary trapping mechanisms become more dominant, the pressure will be potentially higher in the near-wellbore region, potentially exerting more strain on the wellbore materials (Ivandic et al., 2015; VoThanh et al., 2018).

The potential different roles of a well and associated requirements have the potential for contradictory design choices and material selection. The materials selected for conditions during the injection phase could be less suitable for the conditions during the storage phase, and vice versa. A material should for instance have sufficient mechanical strength to withstand the downhole stresses, but at the same time also be sufficiently chemically inert to *maintain* its properties. The overall engineering work for a CO_2 storage well should therefore cover the following two phases:

- Injection
- Post-closure

The post-closure phase includes a longer intermediate storage phase during which the effects of the CO_2 on the reservoir and the near wellbore region could be mapped before the well is assigned to permanent abandonment, after which lower levels of monitoring of the well integrity might be required. For reference, regulatory requirements for monitoring of wells on NCS are described in (HAVTIL Regelverk, 2018).

An example of classification of specific CCS wells comes from the United States Environmental Protection Agency. In order to protect underground sources of drinking water the US EPA developed a classification system for regulating injection wells, where wells are categorized into six different classes. (Duguid et al., 2018; EPA, 2010; Syed and Cutler, 2010). The Classes I, III, IV and V are not valid for CO_2 storage wells. Class II is intended for wells for injecting CO_2 related to EOR for oil and gas production. The newest addition to this classification is Class VI, which was included for CO_2 storage in deep saline formations. The regulation specifically states that the objective is to protect underground drinking water from contamination from unintended fluid migration, and the relatively strict requirements of well design and monitoring are reflected from this (Duguid et al., 2018; EPA, 2010). However, there are some significant differences between CCS wells in the US and on NCS – for example onshore (US) vs. offshore (NCS), and differences in depths and pressure/temperature conditions.

2.6 Considerations for CCS wells

The properties of CO_2 and hydrocarbons are in some respects very different, although there are also some similarities. CO_2 is like any fluid mobile and transportable through pipelines and pores assisted by upstream pressure boosting (using pumps and compressors). CO_2 is also subjected to phase changes, as hydrocarbons in the wellbore can exhibit a range of different properties from methane to heavy crude oils. One aspect that should be noted is that the stored CO_2 at the preferred underground pressure and temperature conditions exists in liquid phase or dense phase. Understanding the phase transition of CO_2 is also an important consideration to safely transport and store CO_2 in a reservoir. In case of rapid depressurization, a CO_2 fluid might boil into gas phase, exhibit cooling due to the Joule-Thompson effect and formation of CO_2-hydrates might occur. Some key differences in properties and concerns are summarized in Table 1 below.

Table 1. Key properties and concerns for methane and CO_2.

Property/concern	Methane	CO_2
Flammable	Yes	No
Heavier than air	No	Yes
Severe Joule-Thomson cooling	No	Yes
Phase transition in operational region	No	Yes
Forms a corrosive environment	No	Yes

CO_2 in the form of carbonic acid can chemically react with many commonly used wellbore materials such as casing or cement (Carey et al., 2007; Crow et al., 2010). The composition of neat Portland cement, for instance, can change when calcium hydroxide reacts with CO_2 to form calcium carbonate, a process known as carbonation. This step on its own might not be detrimental, since the cement becomes less porous and less permeable. The reactivity of this system could also be mitigated by injecting dry CO_2. The second step however, where calcium carbonate dissolves into a CO_2-rich brine (i.e. low pH water) may be detrimental to the cement. This step can lead to increasing porosity and permeability of the cement (Carroll et al., 2016; Duguid and Scherer, 2010; Kutchko et al., 2007; Zhang and Bachu, 2011). These processes are illustrated in Figure 3. The observations above have been primarily based on laboratory experiments. On the other hand, Carey et al. have shown that cement from an old well in the SACROC CO_2-EOR field maintained its integrity in-spite of evidence of reaction with CO_2 (Carey et al., 2007). These contradictory points highlight the importance of better-controlled and systematic tests at relevant conditions. Many of the laboratory experiments might be designed and performed at conditions that do not sufficiently reflect in-situ conditions and could indicate overly severe consequences. Note that this brief overview focuses on the behaviour of neat Portland cement in a CO_2-containing environment – which is a basis for understanding of effects of such an environment on more complex cement systems, as use of additives for different purposes is a common practice in well cementing (Nelson and Guillot, 2006). Moreover, to mitigate risk for CO_2-degradation at unknown CO_2-brine conditions, the industry has developed CO_2-resistant cement systems that can withstand CO_2-rich conditions.

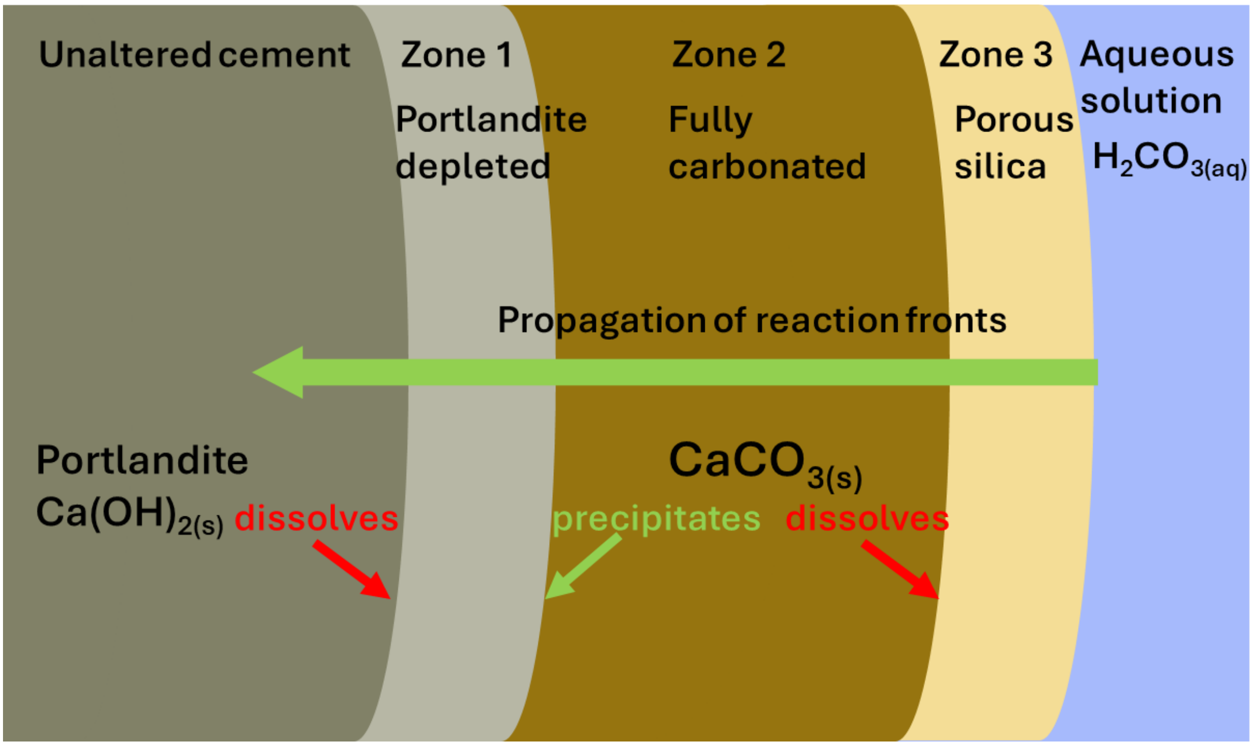


Figure 3. Interaction between cement and dissolved CO_2, adapted with permission from (Kutchko et al., 2007). Copyright 2024 American Chemical Society.

A special feature on the flow properties of brine-CO_2 through a cement matrix is the concept of self-healing existing fractures or micro-annuli. This effect has been studied extensively, and predictive models have been developed. The mechanism is the precipitation of calcite ($CaCO_3$) within narrow channels and voids. As shown in Figure 4, depending on the residence time (fluid flow rate) and the initial fracture opening, a fracture might be further degraded, or the fracture could have the potential to self-heal by calcite precipitation (Brunet et al., 2016). The conditions for self-healing have been investigated and can occur for different cement properties and reservoir conditions (Guthrie et al., 2018).

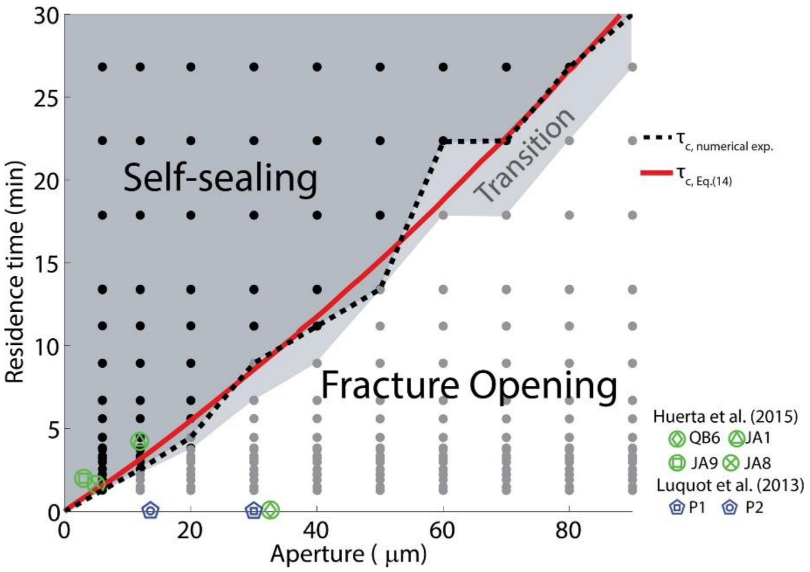


Figure 4. Prediction of self-sealing or fracture opening fir CO_2 flooding experiments with varying residence time and micro-annuli aperture size, adopted from (Brunet et al., 2016). Reused with permission from Elsevier.

In addition to storing CO_2 downhole by sealant materials, CO_2 might also be retained through so-called secondary mechanisms, such as solubility, residual gas trapping and mineral trapping (Bachu, 2008; de Coninck and Benson, 2014). Secondary trapping is not a substitute and cannot become a substitute to the physical well barrier materials in ensuring storage of CO_2, but they can contribute in a "positive" manner towards lower fluid mobility in the longer run, and thus lower driving force for fluid leakage through the wellbore. As shown in Figure 5, these mechanisms will contribute over time to reduce the burden on the well barrier materials (Benson et al., 2005; de Coninck and Benson, 2014).

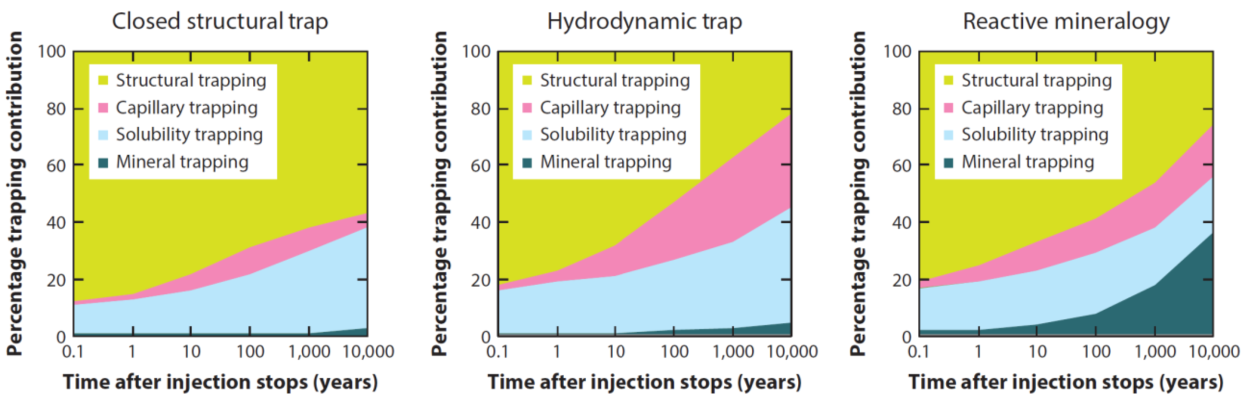


Figure 5. Schematical illustration of different trapping mechanisms relevant for the long-term storage of CO_2, adopted from (de Coninck and Benson, 2014). Reused with permission from the authors.

3 Main differences between CCS and conventional petroleum wells

3.1 Differences that impact well design

The main focus of this chapter is to provide an overview of the main differences between CCS and conventional petroleum wells that *have impact on design* of CCS wells. We based our review of the main differences on the most relevant publications on this topic, to the best of our knowledge. Where applicable, we reflected on field experience with CCS wells from previously or currently active CO_2 pilot/storage sites or CO_2 field research sites (e.g. Ketzin pilot site – Germany; CMC's Field Research Station in Alberta, Canada; Sleipner and Snøhvit – Norway). In the following, the main differences between CCS wells and conventional petroleum wells are listed with considerations regarding operation, lifetime, chemical environment, etc., guided by the overviews provided by (Ceyhan et al., 2022; Haigh, 2009; Iyer et al., 2022; Ringrose et al., 2022; Syed and Cutler, 2010; Toempromraj et al., 2022).

1. **Increased risk with time - during and post-injection.**
    a. **The highest pressure at the end of CO_2 injection.** In conventional petroleum wells, the reservoir and bottomhole pressure are highest at the beginning of production which is followed by pressure decline during the rest of production lifetime. In contrary, for CCS wells, the reservoir and bottomhole pressure are increasing with CO_2 injection until reaching a pressure limit, or injection rate limit (Ceyhan et al., 2022). The initial and end-of-injection pressures depend also on where the CO_2 is injected – into an aquifer or a depleted oil or gas reservoir. In the latter case, the initial pressure is low (if there was no EOR-related injection) which gives a higher pressure margin to operate with than in the case of aquifer injection. More details on the complexity of CO_2 injection can be found in the paper by (Ringrose et al., 2022). The highest pressure and the highest CO_2 amount at the end of injection and/or after abandonment indicate that a long-term perspective of integrity assurance is important for CCS wells.
    b. **CO_2 migration with time.** The injected CO_2 could migrate to shallower plays with time. This was observed for example at Sleipner (Hermanrud et al., 2009; Ringrose et al., 2022) after many years of injection, which is discussed in more details in **Chapter 4**. CO_2 migration increases the risk that wellbore elements higher up in the well (e.g. cement, casings, cement plugs – after abandonment) will be exposed to CO_2, most probably dissolved in brine. This situation can apply both to CO_2 injection and monitoring wells, as well as other wells on the path of migrating CO_2. This is an irreversible situation, as the injected CO_2 will remain ''permanently'' underground as well as the residual elements of the wellbore.
    c. **Differences between uncontrolled release of CO_2 vs. oil & gas.** Here we consider solely the potential for uncontrolled release of CO_2 from an operating CO_2 injection well, not due to well-control loss during drilling into a CO_2-filled reservoir. If the pressure containment is lost, two main processes occur simultaneously: a) As supercritical CO_2 (potentially mixed with other substances present in the reservoir) enters the tubing it converts to gas with significant volume expansion, accordingly accelerating as it moves upward in the tubing; b) The wellbore and the fluid stream rapidly cool due to CO_2 expansion (Munkejord et al., 2020; Skinner, 2003). The more CO_2 is injected and the higher the reservoir pressure (i.e. approaching the safety margin) the greater the risk for uncontrolled release may become. Potential long-term consequences of an uncontrolled release of CO_2, even if the incident itself is successfully remediated, are impact on the wellbore elements that experienced sudden pressure/thermal load and potentially corrosive environment (see points **2 – 6.** below for further details). Therefore, this factor may have an impact on CCS well design.

2. **Corrosive environment.**
   a. **Casing/tubing corrosion.** It is expected that wellbore barrier elements made of steel that are in contact with the humid CO_2 (due to evaporation of formation water or water impurity in the CO_2 stream itself), will experience some degree of corrosion (Anwar et al., 2019; Cai et al., 2006; Gawel et al., 2017; Iyer et al., 2022; Mubarak et al., 2023; Tyusenkov and Nasibullina, 2019; Yan et al., 2012). The impact of corrosion will be especially important for the tubing throughout the operative well lifetime, as tubing will be exposed to *all* of the injected CO_2 and it is also found more likely to fail than other wellbore elements (Vignes and Aadnøy, 2009). For the casings/liners, the most exposed sections during CO_2 injection would be those belonging to the primary well barrier, and later on, sections higher up the well could be externally exposed to the migrating CO_2, especially in the long-term perspective after the P&A phase. As an example of material selection for enhanced robustness, at the Ketzin pilot site different grades of steel were used for well construction of both injection and monitoring wells including K-55 for intermediate casing, stainless steel (13Cr80) with an external fiber-glass-resin coating for production casing, and C-95 with internal coating for the tubing (Prevedel et al., 2014, 2009).
   b. **Cement degradation.** Wellbore cement carbonation and degradation by CO_2 dissolved in brine is a well-known issue in the O&G industry (Carey et al., 2007; Carroll et al., 2016; Crow et al., 2010; Duguid and Scherer, 2010; Iyer et al., 2022; Kutchko et al., 2007; Zhang and Bachu, 2011). Cement degradation depends on many factors such as cement chemistry, cement placement, presence of cracks, debonding from formation, micro-annuli at the casing interface, presence of corrosive chemicals (e.g. CO_2, H_2S), pressure gradient that could drive the upward flow of the acidic brine or dry CO_2. For example, in a diffusion-driven process, cement degradation by the carbonated brine is a rather slow process (Duguid, 2009; Duguid et al., 2011; Matteo and Scherer, 2012), especially if the cement is of good quality - assuming there are no potential flow paths or fractures. However, under flow-through conditions, where there is a pre-existing leakage pathway and a pressure gradient driving the flow of the carbonated brine, cement reacts much quicker e.g. (Brunet et al., 2016; Carey et al., 2010; Carroll et al., 2016; Huerta et al., 2016). Cement degradation may become more extensive in CCS wells compared to conventional O&G wells due to the amount of CO_2 and the potentially complex chemistry in the storage reservoir, especially at the time scales that are relevant for CO_2 storage (including post-P&A monitoring phase). Alternative wellbore sealants, potentially more resistant to CO_2, can be also considered for CCS well design. All these factors are important for CCS well design, both for sealing of the annuli and eventually permanent plugging.
   c. **Packer stability in contact with CO_2.** Packer materials (e.g. elastomers) are known to be vulnerable to acid attack e.g. (Iyer et al., 2022; Zhu et al., 2017) and this should be considered in the well design phase (Syed and Cutler, 2010). Moreover, the packer would be exposed to *all* of the injected CO_2, primarily in dense or liquid phase. Hence, the excessive long-term exposure as well as pressure and temperature variations need to be considered for the choice of packer materials.
   d. **Other wellbore elements.** Potential impact of exposure of other wellbore components (e.g. DHSV, subsea XT, casing connections, tubing hanger, sand control screens, monitoring elements such as fiber-optic cables, etc.) to the CO_2 stream or carbonated brine is another important factor to consider in the well design phase (NORSOK D-010, 2021; Syed and Cutler, 2010).

3. **Pressure loads/cycling.** CO_2 injection, especially offshore, will most likely be facing intermittent operation– the intermittency dependent on the supply of CO_2 (by ship or pipeline) and its buffer capacity. This implicates that the pressure will be higher during injection intervals, and lower during idle waiting-for-CO_2 intervals. The complexity of pressure and thermal loads (see the next point) needs to be taken into account for the wellbore design, especially for the well barrier elements that will directly experience these loads (e.g., those belonging to the primary well barrier and wellhead/XT). These factors can have a direct impact on well integrity by for example creating micro-annuli behind the casing, fractures in the cement sheath and/or in the formation, and debonding from the formation e.g. (Duguid et al., 2018; Moghadam et al., 2022, 2020; Skorpa and Vrålstad, 2021; van Oort, 2022; Vrålstad et al., 2019; Wu et al., 2020).
4. **Thermal loads/cycling.** Thermal loads, thermal cycling and CO_2 phase transitions are expected e.g. (Behmanesh et al., 2023; Martens et al., 2014; van Oort, 2022) to occur during CO_2 injection, which depend on the injection strategy (liquid vs. dense phase vs. gaseous CO_2) and other factors such as tubing size, reservoir type (aquifer vs. depleted), reservoir temperature and pressure. Potential effects of thermal loads/cycling are similar to the effects of pressure loads/cycling e.g. micro-annuli, fracturing, debonding (De Andrade et al., 2014; Duguid et al., 2018; Rangriz Shokri et al., 2021; Vrålstad et al., 2021, 2015a). Understanding potential CO_2 phase transitions during CO_2 injection along the well and into the reservoir, is important from both the injectivity and the well integrity perspective. Another factor that has an impact on the CO_2 phase transition is the purity of the injected stream.
5. **Impurities in the CO_2.** Effects of impurities on the well integrity are complex both due to different types of chemicals and their varying amounts that can be present in the CO_2 stream (A. Razak et al., 2023). The critical point of CO_2 is dependent on the type and amount of impurities in the CO_2 stream (A. Razak et al., 2023; Al-Siyabi, 2013; Ceyhan et al., 2022; Ringrose et al., 2022). For example, adding 5 % of methane into the CO_2 changes the critical point by about 3 °C. Both at Sleipner and Snøhvit the injected CO_2 contained 0.5 – 2 % of methane, but the major difference was in the water content – in the latter case CO_2 was dry with less than 50 ppm of water (Eiken et al., 2011). Impurities and their content also have an impact on the CO_2 density (A. Razak et al., 2023; Al-Siyabi, 2013; Morin, 2013), which is superimposed to the effect of P/T conditions on the density (Bachu, 2008). Impurities can have impact on the CCS well design, which are correlated through the implications of phase behaviour of CO_2 with a particular composition during injection, and chemical reactivity of the impurities on the mechanical integrity and chemical durability of wellbore components. The impurities may be corrosive on their own – like H_2S, or when mixed with CO_2 – like water. For example, choice of materials for directly exposed WBEs may be correlated with pressure/thermal loads related to phase transitions and corrosion potential of the fluid/gas mixture. Tubing diameter may be affected as well: how large tubing is required to maintain desired CO_2 phase during injection? Moreover, some questions may arise: 1) How accurate are the predictions of CO_2 phase transitions for a stream with known impurities and case-specific well & reservoir conditions? 2) How flexible/robust is the injection well design with respect to changes in the CO_2 stream composition (e.g. different impurities in various amounts) during the entire injection interval?
6. **Load cases for production casing/liner and tubing specific for CO_2 wells.** In addition to standard load cases for petroleum wells (e.g. annulus pressure build-up, kick, pressure test, lost circulation, packer fluid leak) which are also relevant to CCS well design, some other load cases are suggested to be specific for CO_2 wells (Ceyhan et al., 2022):
   a. **Early and late life CO_2 injection.** This is applicable to tubing and exposed casing/liners and is analogous to gas injection load cases in conventional O&G and gas storage wells.

b. **Early and late life shut-in and tubing leak.** During shut-in, it is expected that the tubing will be filled with CO_2 or mixture of the reservoir fluid and CO_2. This load is related to the tubing. Tubing leak during shut-in is a load that is considered for the production casing above packer.
c. **Bullhead-kill.** This load case is applicable both to tubing and production casing. This is typically considered for gas storage wells and is also relevant for CCS wells.
d. **Accidental release due to loss of surface containment.** Loss of containment at the surface (e.g. compressor failure) can potentially result in uncontrolled flow of CO_2 in the tubing. Temperature and pressure conditions may then lead to a collapse load on tubing.
e. **Pressure test of production casing.** The production casing should be able to withstand the maximum predicted shut-in pressure.

The primary consideration in this list of differences was the case of a new CO_2 injection well, as this is the limitation of this study. However, some of these differences, especially CO_2 migration, corrosive environment and load cases, can be relevant for other types of CCS wells (e.g. monitoring, water production wells).

3.2 Other considerations for CCS well design

Correlation between well integrity, reservoir capacity and injectivity may affect CCS well design (Haigh, 2009). Some of the challenges related to these aspects are potential for formation damage, efficiency of perforations, flow assurance through the well and into the reservoir, predicting phase behaviour of the CO_2 which can also be dependent on the type of reservoir. Type of storage reservoir (aquifer vs. depleted vs. depleted with a history of EOR) can affect pressure loads that the production casing and tubing need to be competent to withstand, temperature ranges that the well will experience during operation (e.g. BHT, WHT) and potential for corrosion e.g. (Toempromraj et al., 2022). These factors can have direct impact on well design especially regarding choice of materials and their properties related to corrosion resistance and pressure/thermal loads. The examples mentioned here are not covering all relevant aspects related to the impact of storage reservoir on CCS well design but are meant to raise awareness of this factor.

Precipitation of solids (e.g. hydrates, salt) in the well or near-wellbore zone can have impact on CO_2 injectivity and efficacy of the injection operation. Potential for hydrate formation or salt precipitation depends also on the type of the reservoir (e.g. aquifer vs. depleted vs. depleted with a history of EOR) which is directly related to its water content, reservoir P/T conditions and water content of the CO_2 stream itself. However, it is unclear to what degree precipitation of solids may impact the well integrity of CO_2 wells (Iyer et al., 2022). Potential correlation between injectivity impairment due to precipitation of solids and well integrity is not well studied to date. Therefore, at present there are no strong indications that precipitation of solids should play a role in CCS well design.

3.3 Summary

In CO_2 storage as opposed to O&G production, the highest pressure and the highest concentration will be achieved at the end of CO_2 injection and maintained at similar levels after permanent abandonment of the injection wells. Therefore, CCS wells need to be designed for a long operation time (e.g. 20 – 30 years of injection) and thereafter a long endurance time (after shutdown/permanent P&A and during the monitoring phase) – which is expected to be in the order of hundreds and thousands of years (EPA, 2010; Ringrose et al., 2022). Long-term processes such as diffusion-driven cement degradation, upward migration through potential leakage pathways in the cement or at the interfaces, casing corrosion, CO_2 plume development and migration in the reservoir and potentially through the caprock need to be considered in the design phase. CO_2 phase behaviour, including impact of the impurities on the CO_2 phase transitions and density, is another important factor to consider in the design phase. How robust will the wellbore components be towards varying and potentially unpredictable P/T loads and CO_2 stream composition? Type of the storage reservoir (aquifer vs. depleted vs. depleted with EOR history) also plays an important role, as the presence of brine contributes to many of these factors. In depth reservoir related considerations are however, beyond the scope of this work.

4 Overview of experience from Sleipner and Snøhvit CO_2 injection wells

This chapter will discuss the experiences from the commercial CO_2 activities at Sleipner and Snøhvit (see Figure 6). These two offshore storage projects, active since 1996 and 2008 respectively, offer a lot of relevant experience and documentation. The subsurface of both Sleipner and Snøhvit have been studied extensively, with a plethora of academic papers available. Thus, with this level of resources invested into the projects, the experiences could be viewed as a best-case scenario proxy for future large-scale CCS/CCUS projects. Also, both projects/fields offer different perspectives relevant for future projects. The fields differ in terms of surface conditions, storage depths and although reservoir pressure and temperature conditions at both sites give supercritical conditions, the conditions in Sleipner are closer to the critical point. The chapter provides a review of a selection of the available literature and additional information about the sites obtained from Equinor.

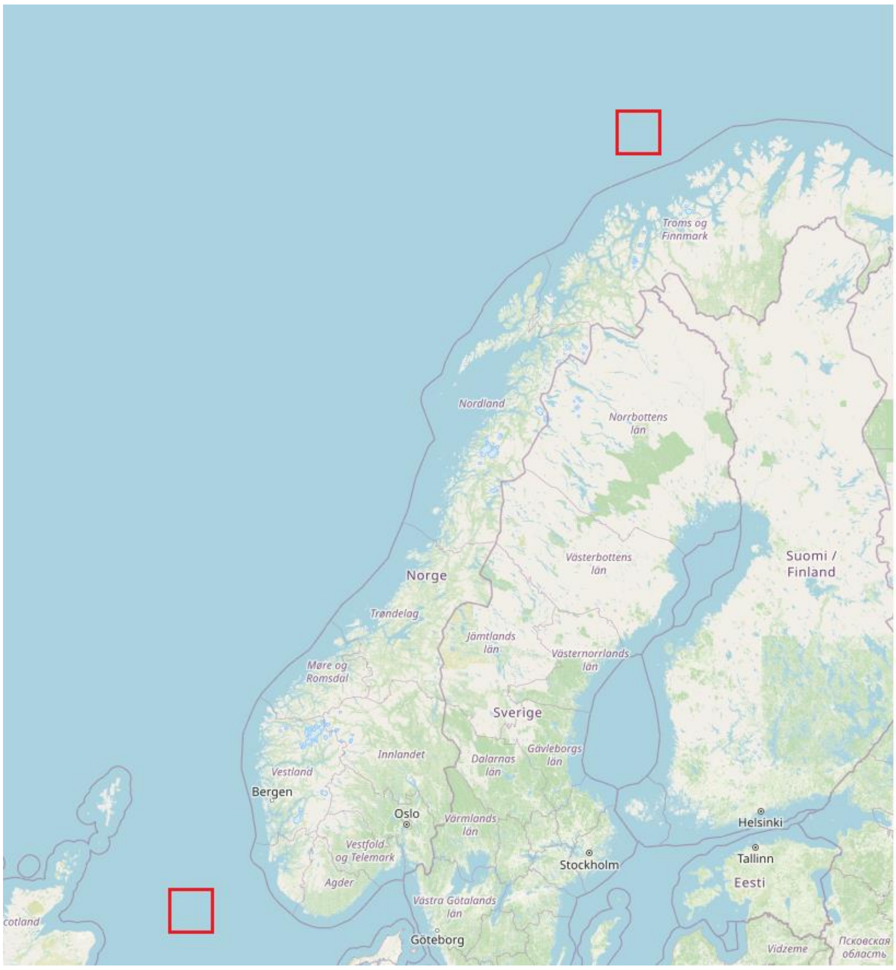


Figure 6. Location of Sleipner and Snøhvit on the Norwegian Continental Shelf; Sleipner in the North Sea and Snøhvit in the Barent Sea. Map details obtained from OpenStreetMap. The data is available under the Open Database License, https://www.openstreetmap.org/copyright.

4.1 Experiences from Sleipner

The Sleipner Vest gas field was discovered in 1974 and is one of the world's most well-known CO_2 storage projects. CO_2 has been injected into a porous saline aquifer reservoir since field operations started in 1996. The high-pressure Sleipner production gas stream has a CO_2 content close to 9 %, giving surplus CO_2 after purification of the gas before sale in the commercial market (Korbøl and Kaddour, 1995). A new Norwegian carbon tax at the time of development implied that venting this surplus CO_2 to the atmosphere would be costly. Thus, a specific gas treatment platform was designed to incorporate CO_2 stripping and processing facilities for the re-injection of CO_2 into the reservoir. After an extensive survey campaign, the subsurface region of Sleipner were deemed to be proper for (re)injection of CO_2 into the Utsira formation. At a reservoir depth of 1050 to 850 meters below the seafloor, eight potential layers were discovered and assessed for CO_2 storage. In these conditions the CO_2 would be still supercritical (see Figure 7), a condition favourable for the long-term storage of CO_2 (Ringrose, 2020; Ringrose et al., 2022).

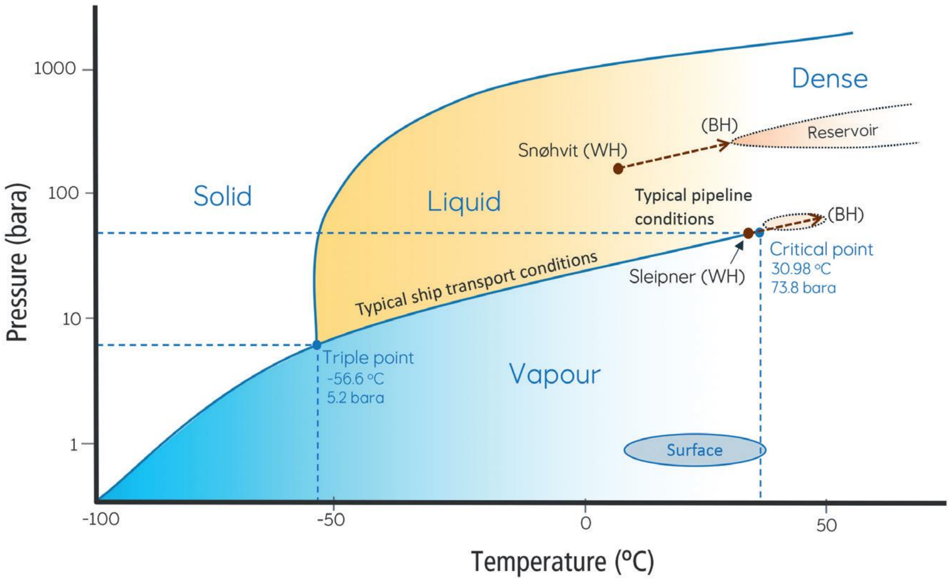


Figure 7. CO_2 phase diagram with wellhead and bottom hole conditions from both Sleipner and Snøhvit (Ringrose, 2020; Ringrose et al., 2022). Reused with the permission from the authors.

The key elements of the well design are a long-reach horizontal well with a sail angle of 83 °. The injection tubing, and the exposed sections were made of high Chromium (25 % Cr) stainless steel (Hansen et al., 2005). The rationale for the choice of materials was the more corrosive environment expected for a CO_2 injection well (Baklid et al., 1996). Moreover, the CO_2 condition is "wet" – CO_2 is injected together with produced water from Sleipner Vest (Hansen et al., 2005; Korbøl and Kaddour, 1995). A small fraction of methane is also present in the CO_2 stream (0.5 – 2 %) (Eiken et al., 2011). No specific documentation on the design of the cement formulations was found. Due to the novelty of the project, being the first industrial offshore CCS project on the NCS, there were no monitoring guidelines or regulations in place at startup. A wide variety of methods were used with frequent repetitions and a high level of coverage to mitigate the potential risks of the project. A dedicated monitoring well was considered during the planning phase, but due to a combination of cost increase and containment risk this was not included in the final project plan. The project solely focused on remote geophysical monitoring methods.

Apart from initial challenges related to injectivity caused by sand influx from a weakly consolidated sandstone, the injection rate was stable at 0.9 Mt per year during the first years of operations, with decreasing rates as the gas production from Sleipner decreased. After 10 years of injection, the CO_2 migrated into nine layers upwards in the Utsira formation, as shown in Figure 8 (Hermanrud et al., 2009). The injection well was not equipped with downhole pressure gauges, due to technical limitations of such equipment at the time of drilling and completion of the well. Pressure, temperature and injection rates are monitored at the wellhead. Due to CO_2 being at the liquid/gas phase boundary at the wellhead, it was not possible to convert the wellhead pressures to bottom-hole pressure without knowing the gas-liquid ratio of the injected fluid. However, a clear recommendation from the project was to include downhole pressure and temperature gauges for future projects. The surrounding seabed was surveyed with high-resolution acoustic imaging, photo mosaic for leakage, in addition to chemical sampling of sediments and the water column to investigate any potential leakage. None of the techniques found any indication of leakage from the Sleipner site, neither were any significant well integrity issues reported (Furre et al., 2017).

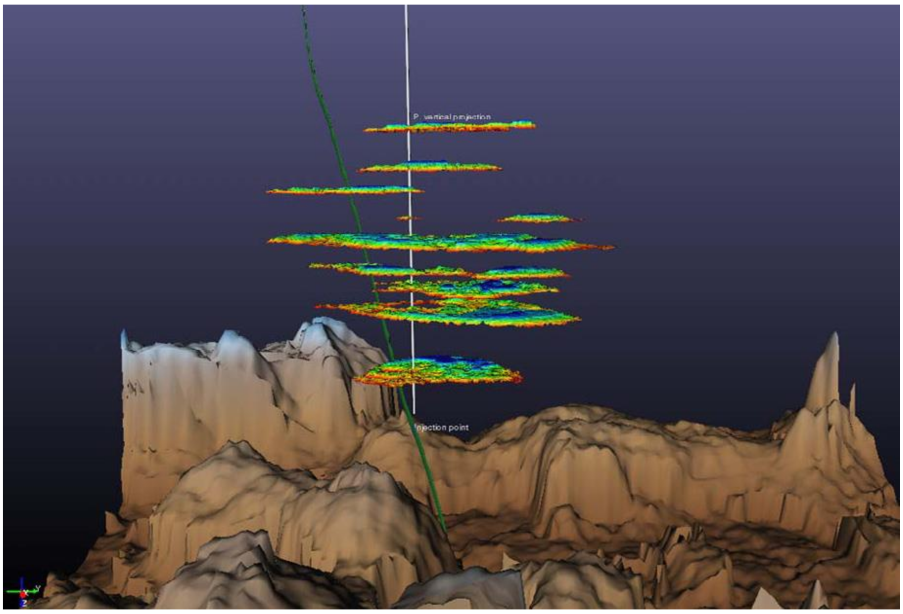


Figure 8. Sleipner: CO_2 migration into nine layers upwards in the Utsira formation, adopted from (Hermanrud et al., 2009).

4.2 Experiences from Snøhvit

The Snøhvit gas field was discovered in 1984 and production was established in 2007. The gas stream from the reservoir contains between 5 and 8 % CO_2 which must be separated. Due to parameters such as weather conditions in the Barents Sea and water depth, the field is designed as a subsea solution where the reservoir stream is transported through a 153 km pipeline for processing onshore (Eiken et al., 2011; Maldal and Tappel, 2004). At the onshore facilities, the CO_2 is separated, compressed and pumped back to the subsea injection point for injection through a single well. Building on the experiences from Sleipner, an extensive characterization of the subsurface was performed. The target for CO_2 injection was in the saline Tubåen formation located at 2600 meter below the seafloor. The reservoir temperature was at 95 °C, and wellhead temperature was at 4 °C, meaning that the CO_2 warms into the formation and cools the well materials as it is transported during the transport down to the reservoir (see Figure 7). This effect gives a temperature gradient and increases the risk of stresses on the materials and could give thermal fractures. Tubåen formation was chosen based on the experiences of using saline reservoirs from Sleipner and the specific reservoir conditions. The initial design proposed injection of dry CO_2 by restricting the water content below 50 ppm, and with an injection capacity of 0.7 Mtons/year.

Based on core data and extended leak-off testing the maximum injection pressure was set at 390 bars. The injection well was drilled from a subsea template with four slots, making future production wells relatively easier (Eiken et al., 2011). The well was drilled with a maximum inclination of 27° and was equipped with downhole pressure and temperature gauges for continuous monitoring at the onshore operation centre. The strategy for the reinjection of separated CO_2 was to maintain continuous injection rates. There were two identified scenarios for injection issues. The first being the available pore volume for CO_2 storage, with the major contributing factors being size of the reservoir and the porosity. The other scenario being injectivity issues in the near-well region. There were three backup solutions for the operations in case of injection issues – perforation of more zones, perforation of new reservoirs and drilling new structures.

There were initial issues with supply of CO_2 from the onshore processing plant due to operational challenges (Eiken et al., 2011). There was also initial pressure increase during injection. The root cause for the injectivity issues were assessed to be a combination of drying out the sandstone formation with dry CO_2 and thus increasing the salt concentration in the remaining water to a point where salt precipitation would occur (Hansen et al., 2013). These issues were resolved by adding a protocol of injecting Methyl Ethyl Glycol (MEG) at regular intervals (Grude et al., 2014). Another interesting operational experience occurred during a three-month injection halt due to maintenance work on the onshore site. The reservoir pressure decreased *slower* than the model was predicting. The model was updated and preparations for well intervention were planned. Surveys with 4D seismic monitoring also indicated that the reservoir was more homogeneous than originally expected. Four interventions were performed in total to reduce the injection pressure. However, the interventions did not achieve injection rates at desired levels. Due to reservoir heterogeneities the effective permeability in proximity to the well was lower than what was suggested from core data. Finally, the Tubåen injection storage reservoir was sealed by two plugs in the 7'' liner after injection of about 1.1 Mt of CO_2, and the same well was perforated at the Stø formation in a shallower level (Hansen et al., 2013).

4.3 Summary

The experience from Sleipner and Snøhvit illustrates that designing and operating CCS wells can be performed successfully on the NCS with the current standards; no serious well integrity issues have been reported. The Snøhvit and Sleipner fields have been operational for many years, and can be considered as a success, but at the same time the cost of these pioneering projects has been considerable with significant resources set aside for these projects. Even though the lessons learned from these projects could be used as proxies for future fields, it would be beneficial for future large scale CCS projects to still plan for the unexpected. For instance, the learning from the Sleipner field was implemented when the Snøhvit field was in the planning stages. However, the high-permeable reservoir in the Sleipner field was not fully representative for the Snøhvit case, which had a more complex and heterogeneous reservoir properties. Figure 8 shows how the CO_2 migrated into different layers in the reservoir in the Sleipner field (Hermanrud et al., 2009).

The limitations of this study were to focus on the well design downhole from wellhead to reservoir, so a complete review of reservoir phenomena is outside the scope of this work. But the behaviour of the reservoir during CO_2 injection becomes relevant to the well design in terms of having a well design *and injection* philosophy with the unexpected in mind. The project should have contingency plans for start-stop in injection in case of injectivity issues, pressure build-up in the near-well region and well interventions. Even with the experience from the Sleipner and Snøhvit the understanding on how CO_2 behave in a CCS well/reservoir is not fully understood because every project will have a unique geology, which will affect the design principles and operations of the well(s). This further highlights the importance of extensive monitoring, both with downhole gauges and surface surveys.

5 Risk and consequences – differences between CCS and petroleum wells

5.1 Risk assessment approaches

Risk assessment is an integral part of the general term *risk management*, and is introduced to implement strategies, workflows and control measures to eliminate or reduce potential detrimental consequences. The purpose of the risk assessment in this context is to identify the risk associated with CCS wells and potential consequences of well design, and to discuss which risks need extra attention or a more detailed analysis compared to well design of "conventional" O&G wells. The *risk assessment* can be performed in a stepwise manner using two different types of analysis:

- A *qualitative* risk analysis is scenario-based and will discuss the potential threats, uncertainties and impact, and the likelihood and severity will be given a score for comparison with other risks.
- *A quantitative* risk analysis will try to assign an objective or measurable value to an identified/selected risk from the qualitative risk analysis.

Many different approaches have been used in risk assessments and some commonly used methods are fault tree, bow-tie, scorecard, risk assessment matrix (RAM), failure mode and effect analysis, event tree, if-else, Monte Carlo simulation and Bayesian network analysis. The method chosen in this work is the consequence/impact and probability assessment. The assessment starts with identification of all possible scenarios of failure in a tabulated risk register, where each risk is assigned an Identification (ID) number, description of the risk in terms of threat, cause and consequence. The identified risk are the differences between an O&G and a CCS well, with a score on the risk value on the *well integrity*. The risk value of well integrity and further consequence on HSE, reputation, well objective and economics has not been discussed in detail in the RAM. Finally, all risks (IDs) will be plotted in a risk matrix (shown in Figure 9). The full risk assessment matrices are shown in the Appendix (Figure A - 1, Figure A - 2).

Risk matrix

Consequens						
	E - Very serious	E1	E2	E3	E4	E5
	D - Serious	D1	D2	D3	D4	D5
	C - Moderate	C1	C2	C3	C4	C5
	B - Small	B1	B2	B3	B4	B5
	A - Very low	A1	A2	A3	A4	A5
		1 - Very low	2 - Low	3 - Medium	4 - Large	5 - Very large
		Probability				

Legend

RED		Unacceptable risk. Measures must be implemented to reduce risk.
YELLOW		For assessment. Measures shall be considered.
GREEN		Acceptable risk. Measures can be considered.

Figure 9. Example of Risk picture from a Risk Assessment Matrix (RAM).

The sequence of the assessment in this work was to first identify the different phases and related risk markers of *conventional* well design, drilling and operations according to the limitations explained in section 1. The risks are sub-grouped accordingly within each phase and the "Threat", "Cause" and "Consequence" are discussed. Then a comparison between conventional O&G wells and CCS wells is performed for each sub-group, and scenarios with differences are identified for further detailed risk analysis. The detailed risk analysis on *the differences between* an O&G well and a CCS well has been performed by first identifying each potential "Threat", and the related "Cause" and "Consequence", which "existing safeguards" are implemented for a conventional O&G well, and finally a risk value is given if these safeguards are to be utilized for a hypothetical CCS well. Then risk reducing mitigation measures are discussed for the case of a hypothetical CCS wells and an updated risk value is indicated.

It should be noted that systematic studies on the evaluation of well integrity with a sufficient database have not been found. Results from publicly available surveys are valuable, but do not give a statistically significant base for accurate/non-speculative conclusions. Many of the available studies make use of open databases with relevant, but indirect details such as well age, cement height, type and so on. But given the complex nature of the underground *and the* drilling process, each well is unique in its own way, and it is not easy to determine whether experienced loss of well integrity is due to unsuccessful primary cementing, cement design, corrosion from operational choices or a combination of several factors.

5.2 Phases of O&G field development

The development of a field, and thus well(s), consist of various stages:

- An ***Access phase*** where the different geological options are considered, such as continent, specific country and specific areas within a country. This decision will affect the political, economic and social framework for the future operations.
- The ***Exploration phase*** where potential site-surveys (geological and seismic) are performed and if a site is deemed interesting, the drilling of an exploration well commences. Upon the finalization of the exploration well a decision gate occurs. If an exploration well has encountered hydrocarbons, the development might progress to the next phase.
- The ***Appraisal phase*** where the underground structure is further investigated to optimize the technical development by reducing uncertainties regarding producible volumes of hydrocarbons.
- When a site has been found viable the ***Development phase*** commences. In this phase the site is planned in further detail. This includes deciding on aspects such as the objectives of the development, operational principles, proposal for detailed design of surface and subsurface facilities, installation of facilities and commissioning of plant and equipment.
- The **Production phase** starts when hydrocarbons are flowing though the wellhead for further transport and processing for sales in the market. In the initial part of this phase more wells are drilled to be able to maximize the production of the site. In the middle part of the phase the production has reached a plateau, and the length of this plateau various from field to field and between gas and oil fields. In the last part the production is declining as fewer new wells are drilled and the older ones are decommissioned.
- The site reaches the end point in its life when the net cash flow becomes negative and /or the cost of maintaining the production is not considered worth the investment in resources (personnel, equipment, capital cost). In the ***Decommissioning phase*** the wells are finally plugged and abandoned, and the facilities are either removed or left in place (Jahn et al., 2008).

The limitations for this study were to perform an assessment "... from spud to designed lifetime of well" and limited to well design, operation and monitoring (CO_2 injection into well included, but not logistic etc.).". Thus, the obviously relevant phases to be included for further discussion are the "Development phase", "Production phase" and "Decommissioning phase". However, well design is also influenced by the political climate and regulatory framework associated with the location of the well. With that in mind, elements from the "Access phase" have been included in this analysis. Due to the limitations mentioned above, the *Exploration* and *Appraisal phases* will not be covered in this report. It should be noted though that any potential exploration well should be properly abandoned to not compromise CO_2 storage cap rock integrity.

5.3 Common markers of risk for wells

Risk assessment of wells and well integrity has been performed for many years and relevant literature is available. The general risk assessment on well integrity (Abimbola et al., 2016; Bachu and Watson, 2009; Kiran et al., 2017; van Oort, 2022) has identified the following common important markers for the likelihood for increased risk:

1. Well age
2. Well type
3. Cyclic loads
4. Temperature in the wellbore environment
5. Geological / geomechanical / geochemical factors
6. Wellbore deviation
7. Composition of the produced/injected fluid (impurity content)
8. Combination of risk factors

The **first point** (well age) is of less relevance in this discussion since the stated limitation for this work was to consider *new wells*. The **second point** is relevant, as well type will be discussed with the two different usages in mind; that is, a *CCS injector* to be compared with a *conventional oil and gas production well*. Injection wells are also flagged as a well type more prone to well integrity issues. The **third point (cyclic loads)** is an important factor as the large-scale *injection* of CO_2 will most likely differently affect a well compared to *production* of hydrocarbons from a reservoir. The **fourth point on temperature** is also relevant in terms of the behaviour of CO_2 downhole and the risk of debonding from temperature changes, phase transition and the Joule-Thomson effect. The **fifth point** addresses the inherent properties within the wellbore, either from mechanical stresses and chemical factors like presence of H_2S, formation water and so on. The **sixth point** on wellbore deviation is equally relevant for both kinds of well types, both CCS and for conventional well designs. The **seventh point** (impurities) is very relevant for CCS wells, but it is approached from another perspective than impurities in produced HCs from conventional O&G wells.

5.4 Risk assessment of O&G wells

During the development of the drilling technique over the decades, many of the initial issues and challenges have been dealt with. A large fraction of the issues was directly or indirectly associated with the capability of placing *cement* as a barrier in the downhole. Table 2 shows a summary of the commonly encountered threats during the Development phase, and their associated causes and consequences. Successful placement of cement, i.e. primary cementing, has been in the focus through many research initiatives.

Table 2. Identified potential well integrity threats from the *Development phase.*

Threat	Cause	Consequence
Incorrect choice of materials	Poor planning, lack of or incorrect data on the underground conditions, insufficient experience	Degradation of material. Loss of containment. Workover. Side-track drilling. Cost escalation.
Near-wellbore damage, washouts	Drilling induced damage from weak formation, incorrect procedure/drilling plan or choice of drilling fluid	Difficult to achieve primary cementing.
Logging tool failure	Defect tool, incorrect calibration, inexperienced user	Incorrect decisions on design (procedure and materials) and during operations.
Micro-annuli in cement	1. Unsuccessful primary cementing due to lack or misplacement of casing centralizers, formation washouts, insufficient hole cleaning, unexpected temperature variation during cement curing 2. Cement slurry contamination with formation fluid 3. Incorrect cement slurry properties can lead to gas invasion during curing.	Higher risk of flow path for fluids. Loss of zonal isolation. Sustained casing pressure.
Cement barrier length not sufficient for containment	Insufficient cement slurry volume by calculation or fluid loss.	Higher risk of conductive flow path for fluid leakage.
Poor formation-cement-casing bond	Cement shrinkage from incorrect cement system design	Loss of zonal isolation. Sustained casing pressure.
Debonding of cement-formation	Insufficient spacer/washer design and operation, not sufficient use of scratcher before cementing, formation damage	Loss of zonal isolation. Sustained casing pressure.

Table 3 gives an overview of the well integrity issues from the Production phase. Like in the development phase, many of the common threats are associated with the performance of cement. Even though cement itself has a low enough permeability to withstand flow, the cement can chemically degrade. It is also possible that cement itself is fully functional, but the *interface* to either casing or formation is not bonded sufficiently. There are no standardized testing protocols for investigation (or for qualitative/quantitative comparison) on *cement bond strength*.

Table 3. Identified potential well integrity threats from the *Production phase.*

Threat	Cause	Consequence
Degradation of cement from stimulation techniques	Use of HCl and/or HF acids to improve formation permeability can negatively affect the cement	Dissolution of residual calcium carbonate and filter cake to form channels (micro-annuli)
Debonding of cement-casing	1. Mechanical loads (pressure difference from injection/production, hydraulic fracturing) 2. Thermal stimulation of wellbore, injection shut-in, injection cycling	Loss of containment. Sustained casing pressure. Induced differential stress between casing and cement.
Fracturing of cement	Thermal stimulation of wellbore, cyclic loads	Loss of barrier, sustained casing pressure.
Casing deformation (and possible collapse)	Frequent changes between production and injection; cyclic loads in connection with high annulus pressure from formation	Loss of containment, sustained casing pressure. Loss of barrier element.
Casing corrosion	Presence of water and ions in formation water (and well fluids) giving favourable conditions for metal corrosion	Loss of containment; sustained casing pressure
Tubing corrosion	Injection of aerated and corrosive water; contamination of HC stream with corrosive fluid components (e.g. H_2S, CO_2)	Loss of containment, sustained casing pressure
Packer failure	1. Damage from placement during drilling & completion 2. Corrosive environment, inadequate choice of materials	Loss of containment, sustained casing pressure
Degradation of cement (micro-annuli, fracturing)	Increased temperature with or without combination of chemical conditions leading to strength retrogression and/or changes in permeability	Loss of containment, sustained casing pressure
Existing (older) wells used beyond intended and original design	Advancements in production technology means that it could be financially attractive to extend lifetime of well	Degradation of materials, barrier failure, loss of containment, workover.
Stretching the limits of WBE materials	Utilization of unconventional resources; wellbore conditions with more severe pressure, temperature and chemical conditions	Degradation of materials, barrier failure, loss of containment, workover.
Insufficient testing of DHSV*	Missing level of differential pressure across during time of	Loss of containment, sustained casing pressure

	testing leading to choice of no testing, or testing at conditions different than during operations phase	

*Reference to EAC Table-8 in (NORSOK D-010, 2021).

The performance of the other Well Barrier Elements is also important. Casing, tubing and DHSV can degrade due to corrosion. However, these phenomena are relatively well known to the industry, and mitigative efforts have been developed over the last decades. The development of testing protocols for chemical degradation is well established. Thus, the occurrence of corrosion related issues has decreased over the years.

5.5 Differences in requirements for risk assessment of CCS wells compared to O&G wells

There are many similarities between a CCS well and a conventional O&G well. Both types of wells are meant to contain mobile fluids, from reservoir to surface or in the opposite direction, at elevated pressures and isolate the interior of the well. A similar drilling rig will be utilized, as will the drilling technology be similar. Also, the mentality/focus on barrier philosophy to maintain the zonal isolation is similar. An important distinction between conventional wells and CCS wells is the operation of *injecting fluid mass for permanent containment for CCS wells* and the operation of *extracting fluid mass* for a conventional oil & gas well. However, numerous examples exist also for natural gas injection wells as part of the development of O&G fields. Another important factor is the difference in fluid properties and behaviour of CO_2 (including presence of water/brine) with that of hydrocarbons. The following sections discuss the differences in requirements for risk assessment of CCS wells compared to conventional petroleum wells, and for simplicity of the analysis and subsequent discussion, they have been grouped into the subcategories of:

- Factors from the Development phase
- Factors from Production phase
- Other factors

5.5.1 Development phase

The following sections discuss in further detail the identified threats originating from the Development phase in the risk analysis. A summary showing the risk register is shown in Table A - 1 in the Appendix.

Threat ID 1.1 Insufficient amount of data for assessing storage site conditions

The production assessment for O&G field will drill several wells and perform surveys to get details on the subsurface, such as reservoir and caprock properties and the properties of the formation fluid. This would be in contrast to most CCS projects were the financial and HSE drivers would plan for as few wells and surveys as possible (Ringrose et al., 2022). Additional wells would be costly, and the motivation is to limit the number of penetrations through the caprock. This could lead to a less comprehensive assessment of a site, and thus with less information on the actual conditions a well might encounter. Another potential risk is to encounter shallow gas during the drilling. It should be noted that the likelihood for such an event is low, given the regulatory framework on the NCS. A possible mitigation strategy to avoid suboptimal well design could be to design the well in a robust manner with a worst-case scenario in mind.

Threat ID 1.2 Time scale of projects

An O&G field development and operation will in most cases have a shorter active time scale than a CCS project, while storage monitoring for CCS should have longer post-injection phase, with a high likelihood for long post-injection monitoring. The typical timescale for an O&G project is 10 to 30 years. *Well age* is listed as a common marker for well integrity issues, both in terms of actual performance of well barrier materials and from lack of data of good quality. However, a lot of positive development in terms of data gathering, sensor and IT systems have benefitted the industry since the turn of the century, so this phenomenon might decrease for O&G wells in the future. For a CCS project the time scale for the injection period is on the order of 25 years, and the post-injection period could be in the range of 50 years and longer. This longer time scale means that knowledge sharing between *generations* of personnel becomes an important factor and further demonstrates the necessity for good handling of *data quality & availability* (Ringrose et al., 2022). As highlighted in the report from the Aliso Canyon incident, a risk reducing procedure would be to "institute a complete and standardized records management system" (Freifeld et al., 2016).

Threat ID 1.3 Degradation of injection tubing and casing

The mechanisms of metal degradation under wellbore conditions are well-known for both casing and tubing. There is a plethora of literature available on the subject, and the experiences from Sleipner and Snøhvit have shown that the awareness of corrosion was high. Presently there are a lot of laboratory infrastructure, procedures and standards available for detailed case study assessment of new or alternative materials (Teodoriu and Bello, 2020). The tubing will be the most susceptible to corrosion since this well barrier element would be in direct contact with the well stream. A mitigation measure would be to use casing types with proven material compatibility for the given conditions in the wellbore.

Threat ID 1.4 Degradation of Cement

Historically there has been less focus on cement and degradation compared to that of casing corrosion. In the early years it was often "assumed" that cement would be chemically inert with most wellbore fluids. Increased research focus over the last decades has shown that cement can degrade in certain chemical environments. The mechanism of carbonation in Ordinary Portland Cement (OPC) systems is well known, showing the cement can degrade upon CO_2 exposure. However, the level of *relevance* of laboratory studies is under discussion as many of the tests are performed in a "worst case scenario" with cement specimen fully immersed. This would not be the case for cement in the wellbore, where the cement would be placed e.g. between the formation and the casing. Field studies are also confirming the ability of cement to withstand relatively long-term CO_2 exposure, such as the example from the SACROC study, where cement from a well with 30 years of CO_2 injection for EOR was cored and studied (Carey et al., 2007; Crow et al., 2010). There are also commercial CO_2 resistant cement formulations available. One important issue regarding CO_2 resistant cement systems to be discussed is whether the CO_2 resistant cement formulations are better than conventional and *more* reactive cements systems. Commercial CO_2 resistant cements have been developed and are currently used by the industry, but an important feature of cement and CO_2 interactions is the ability to self-heal and close minor fractures. In the case of *smaller* fracture aperture, the self-healing effect would be beneficial to reduce the impact from an imperfect cement. This effect could be diminished if self-healing cement systems are used. Furthermore, there is also ongoing work within the industry and standardization entities on improving the standardization of testing procedures for CO_2 exposure on cement.

Threat ID 1.5 Degradation of Packer

The packers are made of elastomers and are known to be susceptible to degradation in the wellbore conditions (Iyer et al., 2022; Zhu et al., 2017). The packers would be directly exposed to the well fluids (i.e.

injected CO_2). Thus, proper choice of packer material is important to achieve successful zonal isolation during well operations.

Threat ID 1.6   Degradation of other wellbore elements

The material choice for wellbore elements such as DHSV is another important factor to consider in the well design phase (Syed and Cutler, 2010). The material choice for the other elements should be with harsh conditions (acidic) in mind in order to avoid issues with well integrity.

5.5.2 Production phase

The following sections discuss in further detail the identified threats originating from the Production phase in the risk analysis. A summary showing the risk register is shown in Table A - 2 in the Appendix.

Threat ID 2.1   Cyclic loads to the wellbore

The cyclic loads from both temperature and pressure changes in the wellbore are important factors. In the worst case such loads can affect the entire barrier envelope (casing, cement and rock) by creating micro-annuli or even full fractures outside the casing. The cyclic loads will be different for CCS injection wells compared to petroleum injection wells and petroleum production wells. There is currently no standardized testing to investigate this phenomenon. Thus, the laboratory work and model description are in at a relatively early phase (Moghadam et al., 2022; Stormont et al., 2018; Vrålstad et al., 2021, 2019). It should also be noted that a lot of the laboratory work has been focusing on identifying the safe ranges for operational parameters, and that worst-case scenarios have been designed to determine the safe ranges. An example of experimental study on the impact of increasing pressure load is shown in Figure 10. Thus, efforts on establishing performance prediction models have been made, still for qualitative, to better understand how different rock and cement properties behave upon pressure changes. A potential mitigating strategy for this effect could be a combination of robust well design and a careful injection plan aligned to the material properties of the well. Drilling induced damage to the caprock is an identified occurrence, and great care is taken to avoid this during drilling.

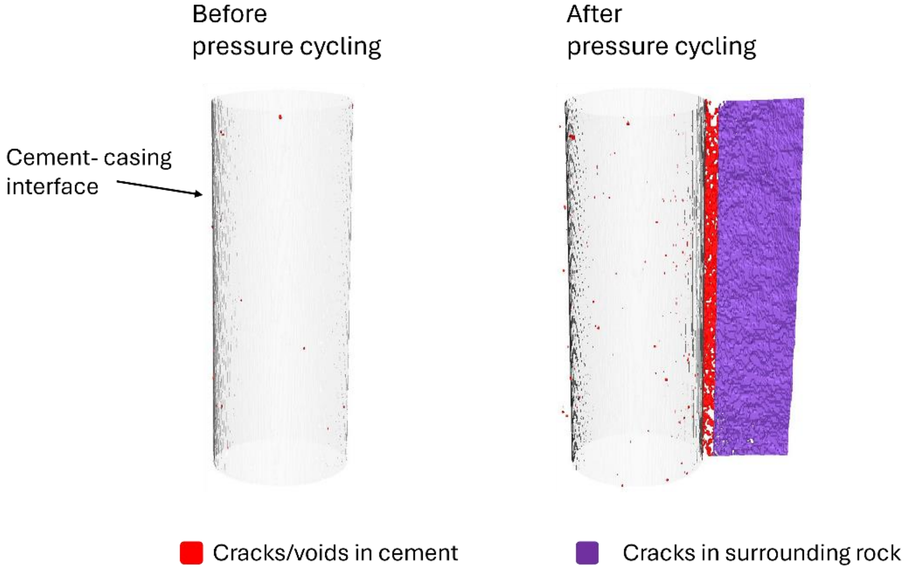


Figure 10. 3D visualization of cement sheath integrity during inner casing pressure increase showing how the cement sheath and surrounding rock can fracture at higher pressures. Similar experiment as presented in (Vrålstad et al., 2021, 2019).

Threat ID 2.2 Quality and purity of CO_2

The goal is that CO_2 ends up in a supercritical phase for the long term in the underground. It is important to have control on the phase transition for the CO_2 in the wellbore and transportation pipeline, and also to be able to predict the corrosion rate of metal components in the well. The viscosity and density for supercritical CO_2 is different compared the fluids of "conventional" O&G systems. In order to have predictable properties of the wellbore fluids it is important to have control of the quality of the fluids. Presence of trace chemicals in the fluid might alter the behaviour of the CO_2 fluid (A. Razak et al., 2023; Al-Siyabi, 2013; Morin, 2013; Ringrose et al., 2022), and small changes in salinity of the associated water phase in the injected non-pure CO_2 fluid will also have an impact on the corrosion rate. The differences in the impurity content of the CO_2 fluid to be injected arise from different point sources of the CO_2 (A. Razak et al., 2023).

Threat ID 2.3 Highest pressure in the reservoir (and near well region) at the end of injection

Unlike conventional petroleum wells the pressure during operation will increase as the fluid (mass) is injected into the reservoir. For CO_2-EOR operations the pressure build-up from injection is balanced with the production and resulting pressure decrease. The same principle is valid for natural gas storage sites, although at different injection rates. The increased pressure will give extra stresses on the wellbore materials.

Threat ID 2.4 Deviations from injection plan

Changes in the injection will affect the well and the wellbore materials. Increase and decrease in for instance well pressure will induce stresses. In order to minimize the effect of cyclic stresses on the wellbore (thermal and pressure), a plan for steady injection is preferred. Changes in injection could come from well interventions, but also from topside issues, such as the case was for Snøhvit process plant maintenance. Supply chain shortage from point capture sources could also be a reason for not being able to maintain a steady injection plan. A robust well design would mitigate this, but establishment of a CO_2 buffer would prevent unsteady injection and reduce the risk for cyclic stress.

Threat ID 2.5 Prediction of fluid behaviour in the reservoir

Prediction of fluid behaviour in the reservoir was not explicitly defined in the scope/objective of this work, but in the worst case this can affect the *well integrity* and is considered relevant for the discussion on well design with a two-barrier philosophy in mind. The point to be made is that the well should be designed with unforeseen fluid behaviour in the reservoir in mind. A hypothetical case is if the permeability / injectivity will not behave as predicted from the surveys and modelling. This will necessitate the further well intervention, investment or in the worst-case drilling through the caprock to establish additional wells for storage (Jenkins et al., 2012; Ringrose et al., 2022).

5.5.3 Other factors

A summary showing the risk register for the other factors is shown in Table A - 3 in the Appendix.

Threat ID 3.1 Extrapolation of current experiences: upscaling of Sleipner and Snøhvit

The experiences from the Sleipner and Snøhvit projects are undoubtfully valuable and give direct feedback and knowledge on the large-scale implementation of CCS. However, as noted in **Chapter 4**, the pioneering Sleipner and Snøhvit projects were allocated a lot of resources during the development phase. The subsurface was also regularly mapped during the operational phase. These circumstances in combination with the *proposed scales* of coming commercial CCS projects raise the question to what degree upscaling from Sleipner and Snøhvit is recommended. The proposed magnitude of the coming storage operation (i.e., the engineered storage capacity and/or injection rate) is significant compared to the ongoing and finalized pilot and ongoing industrial projects. Accordingly, the relationship between project storage capacity/injection rate, reservoir and near well region behaviour versus the resources allocated to a new CCS project should be addressed. As shown in the complex behaviour on the Sleipner reservoir (Figure 8), and the injectivity issues in the Snøhvit reservoir, it is important to sufficiently monitor the actual reservoir behaviour and the near well region. Models on reservoir behaviour and pressure build-up in the well are continuously updated when new experiences are encountered. It should also be mentioned that the Sleipner and Snøhvit projects were developed as a part of an O&G operation. Whether a "pure" CCS project, i.e. stand-alone without an adjacent infrastructure from O&G operations, would have similar resources available for proper management remains an open question. A possible strategy to mitigate this risk could be to implement guidelines for robust well design.

Threat ID 3.2 Stability of project economy

Projects on hydrocarbon extraction are focussed towards generating profit by exploiting a commodity to be sold in the market. Thus, if a field or well is deemed non-profitable it will be re-engineered towards stimulation for increased profitability or towards abandonment. The economical drive behind CCS wells and fields is slightly different, as the *current* market is driven by tax incentives via government involvement. Both the market on O&G prices, *and* the political climate are subjected to frequent changes, and as shown by Bachu and Watson, there is a potential link between industry drive (such as oil price) and the average quality of well integrity (Bachu and Watson, 2009). The trend found in that study was that wells drilled and completed during time of high oil price had more well integrity issues (e.g. SCP) compared to well finalized with "normal" or lower oil prices. The possible explanation discussed was that during high activity, the engineering solutions are sub-optimal due to constraints with regard to time and/or equipment during both planning and drilling (Bachu and Watson, 2009). The same mechanism could thus be relevant for a hypothetical CCS well on the NCS; unfavourable political/financial conditions during the development phase leading to hasty, short-sighted and potentially unfavourable solutions.

Threat ID 3.3 Lack of suitable & available rig / vessels for project

In the case of implementation of CCS on a large scale on the NCS, a risk is that certain equipment (i.e. rigs, vessels, etc.) will be fully booked, especially if there is a simultaneous high activity of "conventional" O&G exploration and production. This could pose a challenge on a hypothetical project to complete its goals. This challenge could be dealt with by longer waiting time for project initiation, or it could lead to premature finalization of a project, with the risk of lack of relevant logging etc. to save time.

5.6 Summary of risk assessment

In this chapter the differences of risks and consequences between CCS and petroleum wells have been analysed and discussed. The differences between a conventional well and a CCS well lie mainly with the choice of materials; the CCS environment is known to be potentially long term detrimental to “ordinary” well barrier materials. An important risk reducing measure is to make sure that the materials chosen for the specific well are suitable for the given conditions. The choice of materials is relevant with respect to CO_2 stream composition and reservoir/downhole conditions, but also regarding the mechanical properties necessary to withstand cyclic changes of pressure in the wellbore. Robustness should be a major priority during the design process for future carbon capture and storage projects.

Further recommendation is that monitoring, logging and mechanical integrity testing should have a top priority to lower risk of well integrity issues by the use of multiple diagnostics, and not a single method. This is to eliminate conclusions being based on indirect measurements. For instance, a cement bond log can identify integrity defects, but not necessary the extent of the leakage, raising a need for a complementary integrity testing method.

There are differences between the final consequences of emission from a natural gas storage, petroleum or CCS wells. A low level of containment loss for offshore hydrocarbon wells can be dealt by microorganisms e.g. (Brooijmans et al., 2009; McGenity and Laissue, 2023) without any further severe impact on the surrounding environment. On the other hand, a higher level of emission will have a severe impact on the marine environment downhole, either by higher levels of toxic substances, or disturbing the existing ecosystem by feeding a certain group of microorganisms with excessive methane. CO_2, on another hand, is not directly a toxic substance. In a localized atmosphere the major impact is that it is an asphyxiating gas, meaning that it replaces oxygen without any detection without sophisticated sensor equipment. In the marine environment it can dissolve and acidify the environment locally (Tarakanov, 2022). Depending on the severity of the leakage, this locally elevated acidity could have a significant impact for the water quality and thus, the local wildlife e.g. (EPA, 2023; Mollica et al., 2018). However, leak from storage reservoirs could also have severe impact from the accumulated uncontrolled release of trace chemicals, such as H_2S, or residual hydrocarbons in the case a depleted O&G reservoir is used.

Lastly, in order to ensure world-wide public acceptance for future CCS, it is vital that uncontrolled release of stored CO_2 should be avoided/kept at a minimum. In the case of CO_2 release from a hypothetical single well or from several fields with combined and accumulated unacceptable leakage rates, a potential consequence could be severely damaged reputation for CCS. The key question at this point is what could be the long-term effect on public acceptance towards CCS if a major failure were to occur.

6 Barrier philosophy considerations – CCS and gas injection well

6.1 Review of NORSOK D-010

Barrier philosophy for CCS wells shall reflect the risk associated with well integrity failure or well control incident. The general principle is to operate with two defined well barrier envelopes against over-pressure and/or flow potential (NORSOK D-010, 2021). An overview of well barrier philosophy considerations for CCS wells is presented in this chapter.

6.1.1 Review of NORSOK D-010 Chapter 5.2.3

As requested in the project scope, NORSOK D-010 Chapter 5.2.3 ''Well Barrier Requirements'' is reviewed in this sub-chapter with respect to application to CCS wells.

Minimum number of well barrier envelopes (5.2.3.1, p.14). We start with **5.2.3-Table 1** (p.15) which describes the minimum number of well barrier envelopes required for the different lifecycle phases of a well. This table is adapted here in Table 4, including both the original contents and our evaluation and suggestions regarding application of the present approach to determine the minimum number of well barrier envelopes for the CCS wells. The present contents of the columns ''Pore pressure'' and ''Source of inflow'', creating specific cases of pressure vs. inflow, in **5.2.3-Table 1** (Table 4) may not be entirely suitable for CO_2 storage case and different types of CCS wells. We suggest that this table is revised for CO_2 storage and CCS wells – considering different cases of storage: in aquifers, depleted reservoirs and depleted reservoirs with a history of EOR, and different well types (e.g., injection, monitoring, pressure relief).

Under the category of ''normal pressure'', Case a) is generally not relevant for CCS wells as a storage target. It can be relevant in the Drilling, Completion, and P&A phase – that is if a well crosses such an interval. We interpret an interval with no hydrocarbons and no flow potential as a low-permeability interval at hydrostatic pressure – which may correspond to the caprock for a storage complex. In that sense, it is relevant for a CCS well which is crossing it, and one well barrier is expected to be sufficient in this case. Case b) is relevant for CCS wells and may correspond to a storage interval (depleted reservoir, may be with history of EOR). Aquifers may be included under this case as well, as storage intervals. Note that if an injection well is targeted to a normal pressure interval (e.g., aquifer initially at hydrostatic pressure or depleted reservoir with EOR history), it may transition into the category of ''over pressure'' in the course of CO_2 injection and due to corresponding pressure increase. Case c) is not relevant as a storage interval, as CO_2 injection wells, in principle, are not targeted to shallow zones with water flow potential. CO_2 injection wells may however, cross a shallow water-bearing zone, which makes this case relevant during Drilling, Completion, and P&A phase. Moreover, stored CO_2 may migrate higher up, to shallower zones, after many years of injection and/or after P&A. Hence, this case is also relevant for CO_2 monitoring wells.

The ''over pressure'' category *per se* is not relevant for CO_2 injection wells – as they will not be targeted into over-pressurized intervals to begin with. It is common understanding that exceeding maximum/safe pressure is to be avoided in a CO_2 storage reservoir. This category may be relevant to CCS wells from other perspectives:

1) If well trajectory crosses an over-pressurized oil/gas reservoir (Drilling, Completion and P&A phase);
2) If CO_2 is stored in an aquifer which eventually becomes over-pressurized (Production/ Injection/ Disposal Operations);
3) If pressure relief wells (water production) are needed after some amount of CO_2 is injected (aquifer storage), to allow injection to continue without reaching the maximum safe pressure;
4) If monitoring wells are drilled into an over-pressurized formation where CO_2 may migrate with time;
5) Adding new injection wells into an already active storage reservoir.

In more detail, Cases d) and e) are not relevant as target intervals for CO_2 injection wells. They can be relevant in the Drilling, Completion and P&A phase (point **1)** in the list above) – if a CCS well crosses such an interval, or for monitoring of CO_2 migration (for e)). Case f) is not specific enough for CCS wells. If it is a producing HC interval, it can be relevant in the Drilling, Completion and P&A phase. Over-pressurized interval with flow potential needs to be specified to whether it contains HCs or CO_2, or both. Therefore, we added Case g) that covers situations when CO_2 is present in an over-pressurized interval. This case is applied to aquifer storage and injection, monitoring or relief wells; or monitoring of CO_2 migration into shallower reservoirs. Case g) covers points **2-5)** in the list above.

An additional category of ''under pressure'' is suggested to reflect CO_2 storage in depleted reservoirs. Within this category we suggest three cases of sources of inflow – interval with: h) no flow potential; i) limited flow potential; and j) flow potential. Additional inflow cases describing existing CO_2 storage reservoirs may be also added under this category. Note that if an injection well is targeted to an under-pressurized interval, it may transition into the category of ''normal pressure'' or ''over pressure'' in the course of CO_2 injection and due to corresponding pressure increase.

Columns distinguishing between different phases and operations can also include CO_2 monitoring and water production/injection operations (Notes 11, 12 and 14 in Table 4). In case of new CCS wells and new storage reservoirs, the assumption is that there is no *a priori* CO_2 during drilling and completion phase (Note 10 in Table 4). If so, different cases in ''sources of inflow'' column would not include CO_2 as a potential inflow fluid. On the other hand, in the P&A phase there will most probably be some CO_2-containing intervals in the vicinity of a CCS well. This may result in different number of necessary well barriers during Drilling & Completion compared to P&A phase. Moreover, adding new wells into or drilling through already operating storage reservoirs means that CO_2 is expected in the ''sources of inflow''. All these considerations make the analysis of the number of barriers for CCS wells more complex, and some of the rows and columns in **5.2.3-Table 1** may need to be split or extended accordingly.

Well barrier selection and construction principles (5.2.3.2, p.16). The list of capabilities for well barrier envelopes and WBEs is robust/general enough to be applied to CCS wells as well.

Annulus cement in primary and secondary well barriers (5.2.3.3, p.16). The present contents are also applicable to CCS wells. No comments or proposed changes for the guidelines here.

Common well barrier elements (5.2.3.4, p.17). The present contents are also applicable to CCS wells. No comments or proposed changes for the guidelines here.

Verification of well barrier elements (5.2.3.5, p.17). The present contents are also applicable to CCS wells. Additional specifications may be added regarding activities which could expose WBEs to unexpected higher loads (e.g. intermittent CO_2 injection) and regarding changes of environment that could lead to degradation (e.g. water content changes due to water evaporation into the CO_2 stream, affecting the CO_2 stream composition in terms of amount of impurities).

Leak testing of well barriers (5.2.3.6, p.18). The present contents are also applicable to CCS wells. The general guidelines for leak testing (5.2.3.6.1-8.) are robust enough to cover the differences in CCS wells. However, we have a comment to the statement in **5.2.3.6.2** – for HCs, the acceptable leak rate is set to zero, unless otherwise specified in EAC tables. This guideline may be revised for CO_2, as CO_2 has different effects on the environment compared to HCs (e.g. toxicity and chemical reactions are different).

Well barrier monitoring (5.2.3.7, p.22). No comments or proposed changes for the guidelines here.

Well barrier impairment (5.2.3.8, p.22). No comments or proposed changes for the guidelines here.

Table 4. The minimum number of well barrier envelopes required for the different lifecycle phases for a well – applied to a CCS well. Table 1 from NORSOK D-010 5.2.3 is adapted here: the original content (cells with blank background) is presented together with our evaluation regarding application of this approach to CCS wells. The comments are added in the coloured cells (grey) under the original cells. Comments and suggested revisions are added in and below the table in red font. Additional ''Under pressure'' case is suggested for CCS wells – this is covering depleted reservoirs and potentially aquifers.

Pore pressure	Source of inflow	Minimum number of well barrier envelopes		
		Drilling, Completion & P&A Phase[10]	Production[9]/ Injection/ Disposal Operations[11]	After Permanent P&A
Normal pressure Note that local over-pressured shallow hazards may occur in this interval.	a) Interval with no hydrocarbon and no flow potential	One[1,2]	Not relevant[3]	Not relevant[4]
	Case a) is not relevant as a target interval for CO_2 injection wells. It can be relevant in the Drilling, Completion and P&A phase – if a well crosses such an interval (e.g., caprock).	One[1,2]	Not relevant[3]	Not relevant[4]
	b) Interval with hydrocarbon and flow potential (included depleted reservoir)	Two[2]	Two	Two[5]
	Case b) is relevant for CCS wells and may correspond to a storage interval (depleted reservoir, may be with history of EOR). Aquifers may be included here as well, as storage intervals. Note that increasing amount of CO_2 (i.e. increasing pressure) is expected over the years of injection, which may be also labelled in the case description.	Two[2]	Two	Two[4,5]
	c) Shallow water flow potential	Two[2,6]	Two[6]	One
	Case c) is not relevant as a target interval for CO_2 injection wells. It can be relevant in the Drilling, Completion and P&A phase – if a well crosses such an interval, or for monitoring wells.	Two[2,6,12]	Two[6,12]	One[12]
	Additional cases describing existing CO_2 storage reservoirs may be added here.			

Over pressure	d) Interval with no flow potential (with or without HC)	Two	One[7]	One[8]
	Case d) is not relevant as a target interval for CO_2 injection wells. It can be relevant in the Drilling, Completion and P&A phase – if a well crosses such an interval.	Two	One[7]	One[8]
	e) Interval with limited flow potential (with or without HC)	Two	Two[8]	Two[8]
	Case e) is not relevant as a target interval for CO_2 injection wells. It can be relevant in the Drilling, Completion and P&A phase – if a well crosses such an interval, or for monitoring wells.	Two[12]	Two[8,12,13]	Two[8,12,13]
	f) Interval with flow potential (including reservoir)	Two	Two	Two
	Case f) is not specific enough for CCS wells. Does it contain HC and/or CO_2? If it is a producing HC interval, it can be relevant in the Drilling, Completion and P&A phase – if a well crosses such an interval. It may be also relevant for monitoring of CO_2 migration. Over-pressurized aquifer is distinguished in added Case g) below.	Two	Two	Two
New case	g)[14] Interval with flow potential and an increasing amount of CO_2, including reservoir (without HC). This case is applied to aquifer storage and injection, monitoring or relief wells; or monitoring of CO_2 migration into shallower reservoirs.	Two[12]	Two[12]	Two[4,12]
Under pressure[15]	h)[14] Interval with no flow potential (with or without HC). This may correspond to an unsuccessful CO_2 injection well, or a monitoring well.	Two[12,13]	Two[12,13]	Two[12,13]

	i)[14] Interval with limited flow potential (with or without HC). This may correspond to a temporarily successful CO_2 injection well, or a monitoring well.	Two[12]	Two[12,13]	Two[12,13]
	j)[14] Interval with flow potential (with or without HC). This corresponds to storage reservoir and successful CO_2 injection wells, but it can also be applied to monitoring and other CCS wells.	Two[12]	Two[12]	Two[4,12]
	Additional cases describing existing CO_2 storage reservoirs may be added here.			

Note 1: This interval may be drilled with seawater providing a risk evaluation finds this acceptable.
Note 2: A pilot hole is considered an acceptable method of de-risking potential shallow hazards, see 6.7.2.2.
Note 3: Surface casing should be cemented to surface during construction.
Note 4: An open hole to surface plug is required.
Note 5: A pilot hole with confirmed shallow gas should be cemented back to surface.
Note 6: One barrier may be acceptable based upon a specific risk evaluation considering well/template/installation stability.
Note 7: Casing and seal assembly. A specific risk evaluation of sustained casing pressure shall be performed, and mitigations incorporated in the well design or operating guidelines.
Note 8: For overburden formations, with limited or no flow potential, the required number of barriers may be reduced by one providing a risk assessment demonstrates an acceptable risk level. The risk assessment shall cover all plausible load scenarios (including sustained casing pressure) and account for operational limitations and uncertainties in fluid type, pore-pressure, barrier conditions, etc.
Note 9: Gas-lift gas require two barrier envelopes.
Note 10: Assumption is that there is no CO_2 in the targeted formation during drilling and completion. But, there may be CO_2 in the P&A phase. Hence, this column may be split if this implicates different number of well barriers.
Note 11: Monitoring operations can be added for CO_2 storage, i.e. CO_2 monitoring wells. Water production and water injection wells can be added also, which are mostly relevant in the case of CO_2 storage in aquifers. For depleted reservoirs, injection and monitoring wells are the most relevant.
Note 12: This may be a CO_2 monitoring well.
Note 13: May be reduced by one based upon a specific risk evaluation considering potential for CO_2 leakage and migration.
Note 14: Suggested new inflow cases relevant for CCS wells (g-j).
Note 15: Suggested additions to **5.2.3-Table 1** related to CCS wells. Under-pressurized case can be valid for both aquifers and depleted reservoirs as storage formations. Assumption here is that there is **no CO_2 from before** in the discussed intervals in the cases (h, i, j).

6.1.2 Acceptance criteria for seal leakage

EAC tables in the Annex C of NORSOK D-010 specify the acceptance criteria requirements for each wellbore component to be qualified as a WBE. In addition to the acceptance criteria, there are technical and functional requirements which are described in the standards and/or are specified by the operating company. We reviewed the most relevant EAC tables with respect to application of respective WBEs in CCS wells[1]. This is

[1] The EAC tables will be further evaluated for CCS wells during revision of NORSOK D-010 Standard.

presented in Table 5. The selected WBEs are also connected to the applicable threats which were identified in **Chapter 5**.

Acceptance criteria for C) ''Design, construction and selection'' may not be entirely suitable to CCS wells, as their function will be different – injection or monitoring as opposed to production, and the direction of flow is opposite. The injection strategy itself may also have an impact on the acceptance criteria (e.g., liquid vs. supercritical vs. gas, continuous vs. intermittent, potentially long shut-in intervals). The main challenge is to correctly predict the (cyclic) loads, P/T conditions along the well and in the near-wellbore region of the reservoir, and CO_2 phase and density for different injection strategies. There are many different factors that come into play (see **Chapter 3**). For example, sustained casing pressure (i.e. annulus pressure build-up) is an important factor that needs to be included in the design (NORSOK D-010, 2021). These various parameters and risk factors can affect the WBE design, construction and selection (e.g. placement and installation) as wells as technical and functional specifications. Note that evaluation of other potential requirements for verification and monitoring of well barrier elements in CCS wells during operation was out of scope of this study.

Table 5. Comments on the acceptance criteria in the EAC Tables from Annex C, NORSOK D-010 for the selected WBEs that are most relevant in CCS wells. In the last column, the selected WBEs are connected to the threats identified in Chapter 5.

EAC Table	WBE	Comments on the Acceptance Criteria	Related Threat ID from Chapter 5
2	Casing	Very general guidelines in all sections, applicable to CCS wells.	1.2, 1.3, 2.1, 2.2, 2.3
5	Wellhead	Very general guidelines in all sections, applicable to CCS wells.	1.2, 1.6
7	Production packer	*Section C* 3) & 5): It may be challenging to estimate pressure and temperature ranges that the packer could experience.	1.2, 1.5, 2.1, 2.2, 2.3
8	DHSV	*Section C:* 1) Optimal setting depth may be different for CCS wells. 2) The statement here can be applied to CCS wells, although predicting P/T profiles and likely location for hydrate formation may be challenging. 5) It may be challenging to determine the highest density of the CO_2 in the annulus (related to P/T conditions and impurities). 6) This point is addressing closing function at the maximum production rate, but in the CCS wells the direction of flow will be opposite, so additional considerations may be necessary here. *Sections D-F* are applicable to CCS wells.	1.2, 1.6, 2.1, 2.2, 2.3
10	Tubing hanger	Very general guidelines in all sections, applicable to CCS wells.	1.2, 1.6
22	Annulus cement	Very general guidelines in all sections, applicable to CCS wells. *Section C:* 7) It is still a knowledge gap how to determine necessary length of annulus cement. What could 200 m of annulus cement mean for a CCS well at CO_2 storage timescale? Under which conditions would this be adequate?	1.2, 1.4, 2.1, 2.2, 2.3

		Additional point may be added for cement slurry design for CCS wells – when is use of CO_2 resistant cements recommended?	
24	Cement plug	Very general guidelines in all sections, applicable to CCS wells. *Section C:* 9) It is still a knowledge gap how to determine necessary plug lengths, and this would be especially the case for CCS wells. To be on the safe side, these may be longer than in the present standard. To gain a better understanding of plug lengths, large scale laboratory testing as well as leakage modelling is necessary.	1.2, 1.4, 2.3
25	Completion string	Very general guidelines in all sections, applicable to CCS wells. *Section C*: 1) The requirements should incorporate long-term CO_2 exposure.	1.2, 1.3, 2.1, 2.2, 2.3
28	Mechanical tubular plugs	Very general guidelines in all sections, applicable to CCS wells.	1.6, 2.3
31	Subsea XT	Section C: 2) Consider to add some further specifications for CO_2 injection, related to accidental, unexpected or extreme pressure loads which can be potential consequence of intermittent injection strategy.	1.2, 1.6, 2.2
51	In-situ formation	Very general guidelines in all sections, applicable to CCS wells.	1.1, 2.1, 2.2, 2.3, 2.5
55	Alternative barrier material	Very general guidelines in all sections, applicable to CCS wells.	1.2, 1.4, 2.1, 2.2, 2.3

6.2 Additional considerations

6.2.1 Monitoring of barriers

Monitoring of barriers in CCS wells was a side point in WP4 and as such had a limited extent within the scope of this study. Thus, this topic is briefly addressed in this section. Techniques for monitoring of CO_2 storage performance and integrity assurance need to be tailored to each storage site (Haigh, 2009). In CO_2 storage, the following monitoring activities may be included in the overall measurement, monitoring and verification programme (MMV) (Haigh, 2009):

1. The volume of injected CO_2
2. CO_2 reservoir pressure and change of pH with time
3. CO_2 concentration
4. Migration of CO_2 within the storage reservoir
5. Migration/leakage of CO_2 into other formations
6. Potential interaction of the CO_2 with predetermined fragile locations in the subsurface (e.g. abandoned wells, faults)

Monitoring of reservoir pH is normally not carried out in practice today, as this would significantly increase the costs and complexity of operations. On NCS, for example, instead of pH monitoring, the corrosion resistant steel grades are more commonly used.

The in-well specific monitoring techniques which may be included MMV programmes for CCS wells were classified and simplified by Haigh (2009) as listed in Table 6.

Table 6. List of suggested in-well monitoring techniques that may be included in-well MMV programmes, adapted from Table-3 in (Haigh, 2009). Table contents reused with permission from SPE Offshore Europe.

In-well monitoring techniques	Measurement parameter
Pressure measurement using fibre optics (see comments under)	Formation pressure, wellbore pressure gradient, behind wellbore pressure gradient, annulus pressure, groundwater aquifer pressure
Temperature gradient measurement using fibre optics (see comments under)	Formation temperature, wellbore temperature gradient, behind wellbore temperature
Water composition	CO_2 / HCO_3 / CO_3^{2-}, major ions, trace elements, salinity
Well logs	Brine salinity, sonic velocity, CO_2 saturation
Vertical seismic profiling and cross well seismic profiling	Brine salinity, sonic velocity, CO_2 saturation
Passive seismic monitoring	Location, magnitude and source, characteristics or seismic events
Electrical and electromagnetic techniques	Formation conductivity, electromagnetic induction

For more details on the measured parameters and potential applications of these techniques, take a look at the original publication (Haigh, 2009). For example, methods for testing mechanical integrity (both internal and external) of CCS wells are briefly summarized in (Syed and Cutler, 2010). Regarding monitoring methods using fibre optics (e.g., DTS, DAS) – various applications have been tested in O&G wells, e.g., (Cannon and Aminzadeh, 2013; Hemink and van der Horst, 2018; Johannessen et al., 2012; Sadigov et al., 2017; Sookprasong et al., 2014; Weaver et al., 2005; Xiao et al., 2014). Moreover, DTS and DAS are typically used at field research sites and not only related to CO_2 storage e.g., (Behmanesh et al., 2023; Ekechukwu and Sharma, 2021; Martens et al., 2014; Prevedel et al., 2014) as they provide more detailed datasets leading to a deeper understanding of CO_2 behaviour during injection and other near or in-wellbore processes. However, a cost-benefit analysis is necessary prior to any potential recommendation for use of fibre optics methods in CCS wells in large-scale storage operations.

Regarding monitoring of wellbore components, we find that the following considerations may be especially important for CCS wells:

1. Periodic monitoring of the tubing and production casing/liner for leakage and corrosion.
2. Monitoring packer and annulus cement integrity especially in the later phase of CO_2 injection, as these WBEs are required to withstand the corrosive environment with cyclic loads during the entire injection phase (i.e. a couple of decades).

3. Monitoring transient pressure and temperature during shut-ins and start-ups for intermittent CO_2 injection strategy, which should be accompanied by risk assessment for WBE failure due to pressure/thermal loads.
4. Monitoring changes in CO_2 composition (injected stream and mixing with reservoir fluids), especially regarding substances that could increase corrosion potential (e.g. water, H_2S).
5. Monitoring cycling (radial) loads to wellbore – however, there is no standardized measurement method for this yet.
6. Well integrity testing should use multiple methods and not rely on a single diagnostic e.g., Aliso Canyon incident (Blade Energy Partners, 2019; Department of Energy, 2016; Freifeld et al., 2016).

Regarding suggested monitoring of tubing, production casing/liner, packer and annulus cement it is important to note that this is not straightforward (i.e. implies in-wellbore intervention) and may be beyond the state-of-the-art of existing monitoring methods and technologies. A cost-benefit analysis would be necessary prior to decisions on any potential requirements for (periodic) monitoring of these WBEs during CO_2 injection.

6.2.2 Lack of barriers that require a side-track

An important question that we attempt to address in this section is under which conditions side-track would be required, that is when the required number of barriers cannot be reduced upon detected failure of a WBE, and the wellbore needs to be abandoned and a new one drilled. On one hand, drilling a side-track presents additional costs, but on the other hand proceeding with a known WBE failure (assuming that reducing number of barriers is acceptable) may incur additional costs in the future. We base our discussion on the examples found in the literature that broaden the perspective on this matter. A generic example for lack of barriers that require a side-track would be bad cement job in the annulus, which is proven by logging and cannot be remediated. In this case, if the requirement is to have two barriers, a side-track would be necessary. Generally, condition of WBEs that are difficult to repair or replace would be a major decision factor on whether a side-track is necessary. These include formation, cement and casing/liner both in the primary and secondary barrier, among others. In the following, we present some examples of field experience with CCS and gas storage wells that could shed some light on this matter.

An example where lack of the second well barrier resulted in an accident of uncontrolled release is a gas storage well in California. Gas storage wells are similar to CCS wells (Ceyhan et al., 2022; Freifeld et al., 2016) – in a sense that they can be new injection wells or converted production wells, and the gas is typically injected into a depleted reservoir. The pressure is built up to storage pressure, which is then followed by cycles of withdrawal and injection. The mentioned incident of uncontrolled HC release occurred in a gas storage well at the Aliso Canyon gas storage field in California in 2015 (Blade Energy Partners, 2019; Department of Energy, 2016; Freifeld et al., 2016). The well was initially drilled in 1953-1954 and used as a conventional oil producer, and thereafter converted to gas storage in 1973. The well failed due to undetected corrosion in the production casing, and lack of a secondary barrier or a functioning DHSV (which belongs to the primary well barrier). The well was killed using a relief well after the initial kill attempts failed. This example demonstrates the importance of having two functioning barriers, especially for a long lifetime of service.

Several important examples of errors made during CCS well construction are provided by (Duguid et al., 2018) for three different storage sites in the US (Mississippi, Illinois Basin, Ohio River Valley). Duguid et al. (2018) provide detailed descriptions of well construction, including materials that were used. For example, for well cementing, ordinary Portland cement, Portland cement with pozzolan additives and CO_2 resistant cements were used, in various combinations. The first example was US DOE funded project ECO_2S in Kemper County (Mississippi), where three monitoring wells were drilled. The wells were completed as monitoring wells following the UIC regulations for the construction of Class VI injection wells. In one of the wells (MPC 26-5#1), there was an issue with cement pumping, as this new cement system was not properly characterized for field operations, which resulted in mud contamination of the cement sheath. For another well (MPC 34-1#1), there was loss of circulation during cementing which led to loss of cement into formation, and finally resulted in lower cement top than what is required for Class VI wells. This well was remediated some months later, which means that additional investment was necessary.

Another case presented by Duguid et al. (2018) was a CO_2 injection well in Illinois Basin, which was part of Decatur CCS project. In this well, cement placement was satisfactory (i.e. all the way up to the surface) but micro-annuli between the cement and the casing were detected by logging in the bottom part of the well where a CO_2-resistant cement was placed. Yet, these micro-annuli were evaluated as no threat for the well integrity, and the well was indeed used for CO_2 injection over a period of three years, injecting almost 1 Mt in total. In the last case, at Mountaineer site (Ohio), three wells were completed as Class V injection wells. One of the wells (AEP-1) proved to have a significant lack of annulus cement or patchy cement at the injection (production) casing in the upper part of the annulus. This was mostly likely caused by gas intrusion and/or packer inflation. Moreover, micro-annulus was detected along the injection casing which was correlated with acid treatment at high pressure right after cementing the well. According to the regulations, the injection casing should be cemented to the surface, hence the requirement was not fulfilled, plus the primary/secondary barrier could have been compromised because of the micro-annuli, but the well was still used for CO_2 injection over a period of two years. Sustained casing pressure was indeed detected in AEP-1 well during the injection interval, but gas analysis showed that it was mostly methane leak – not CO_2 at all. This may indicate that the compromised primary cement in the injection zone was competent enough, or that there was no sufficient pressure drive for CO_2 flow. The Illinois and Mountaineer CO_2 injection wells are real case examples of relaxing the number of barriers, despite detected WBE breach, and where drilling a side-track was avoided.

In these particular CO_2 storage cases described in (Duguid et al., 2018), the potential benefits of using CO_2 resistant materials (e.g. for cementing and casings) were overshadowed by the fact that drilling and completion was carried out without sufficient care (e.g. poor hole cleaning, poor cement placement, micro-annuli formation, cement contamination, gas intrusion). The wells were nevertheless put into operation (monitoring, injection), but the question is how long would they last without integrity issues? As the time span of these three storage projects was rather short (2-3 years of injection followed by a short monitoring interval), this question remains unanswered. If we extrapolate these cases to a real CO_2 storage site where megatons (not kilotons) will be injected, it remains a question whether such compromised annulus cement will endure decades of CO_2 injection? In summary, this study provides good examples of importance of proper well construction and establishment of competent well barriers.

Another interesting example is a blow-out from a natural CO_2 field in Bečej (Serbia) that occurred in 1968 (Vrålstad et al., 2015b). The blow-out happened during drilling of an exploration well and was essentially a well-control incident, and as such had nothing to do with well integrity or well design. However, one of the important lessons learned from this incident is that it took several decades to completely remediate the uncontrolled release of CO_2 (Karas et al., 2016; Lakatos et al., 2009). One of the measures taken was drilling of relief wells which could access the collapsed wellbore and be used to inject sealants and monitor leakage. Research and development of potential sealants that could stop the leakage was also required during the remediation efforts, which added to the total cost.

As the risk of WBE failure and leakage for CCS wells increases with injection time and amount of injected CO_2, relaxing the requirements for number of barriers may prove to be more costly in the long-term than drilling and completing side-tracks in the short-term. There may be situations when relaxing the requirement for the number of well barriers is a viable option (e.g. safely reduce from two to one barrier in case of detected failure of a WBE), but this needs to be evaluated in depth, especially if such considerations would be integrated into the existing standards.

7 Summary

CCS and conventional wells currently, and in all likelihood will in the future, have many shared features. They are designed according to the same principles; similar rigs and equipment will be used for construction and the wells will be operated under similar principles. Wells are used for getting access to the underground for a variety of purposes, such as "conventional" O&G production, CO_2-EOR and natural gas storage. The safe operation windows for wellbore materials are also continuously being broadened by the development of materials and solutions for unconventional resources, where stringent specifications are imposed on the materials to be able to perform adequately at extreme pressures and temperatures and chemically aggressive environments.

The experience from Sleipner and Snøhvit illustrates that designing and operating CCS wells can be performed successfully on the NCS with the current standards. It would be beneficial for future large scale CCS projects to still plan for the unexpected. For instance, the learning from the Sleipner field was implemented when the Snøhvit field was in the planning stages. However, the high-permeable reservoir in the Sleipner field was not fully representative for the Snøhvit case, which had a more complex and heterogenous reservoir properties. This further highlights the importance of extensive monitoring, both with downhole gauges and surface surveys.

The main differences between CCS wells and conventional petroleum wells that *have impact on design* of CCS wells are found to be as follows:

1. Increased risk with time - during and post-injection.
    a. The highest pressure at the end of CO_2 injection.
    b. CO_2 migration with time.
    c. Differences between CO_2 blowouts and oil & gas blowouts.
2. Corrosive environment.
    a. Casing/tubing corrosion.
    b. Cement degradation.
    c. Packer stability in contact with CO_2.
    d. Other wellbore elements.
3. Pressure loads/cycling.
4. Thermal loads/cycling.
5. Impurities in the CO_2.
6. Load cases for production casing/liner and tubing specific for CO_2 wells.

Based on the review of literature on CCS well design, we found that:

- Different well designs may function equally well for CO_2 injection based on the experience from the Sleipner and Snøhvit projects on the NCS, and from CO_2 pilot storage sites in the US where in practice different classes of wells (by plan or execution) were used for injection (Duguid et al., 2018).
- One recommendation for CCS well design is to start with the completion (Ceyhan et al., 2022). Thermal and flow analyses of the injected CO_2 (including impurities) are necessary to perform prior to the completion design. There are several other constraints that are important at this step such as BHP, wellhead pressure and desired injection rate to optimize the tubing size.
- Due to the extra/special circumstances for a CCS well due to fluid mobility it would be of high importance to achieve correct cement placement initially, and multi-barrier isolation procedures are of high importance for CCS wells (Duguid et al., 2018; NORSOK D-010, 2021; Ringrose et al., 2022).
- Proper material selection for tubing and production casing, as well as other metal components, (e.g. 13 % or 25 % Cr steel, Cr CRA) is important especially for CO_2 storage in aquifers (Ceyhan et al., 2022;

Ringrose et al., 2022; Syed and Cutler, 2010). For the tubing, the internal corrosion is a concern when injecting wet CO_2 (> 100 ppm water). As for the production casing, external corrosion is a greater concern, especially in aquifer storage or in the permeable intervals where the CO_2 is expected to migrate.

- Elastomers used in packers and seals need to be qualified for CO_2 exposure (Ringrose et al., 2022; Syed and Cutler, 2010).
- Evaluation of use of CO_2 resistant cements or alternative sealants (Ceyhan et al., 2022; Ringrose et al., 2022; Syed and Cutler, 2010) for annulus sealing is recommended taking into account both their potential benefits and drawbacks. As some field studies show (Carey et al., 2007; Crow et al., 2010) conventional cement may perform fairly well when subjected to long term CO_2 exposure, whereas poor cement job may defeat the purpose of modified/CO_2-resistant cements (Duguid et al., 2018).
- Special materials that may and probably will be required for certain components of the CCS wells are at odds with a low-cost aspirations for CCS business model (Ringrose et al., 2022).
- In-well instrumentation may be required as part of the monitoring and verification procedures, which would add to the cost and/or complexity of the well design (Ringrose et al., 2022).
- Mechanical loads from for instance thermal gradients from cooling and re-warming (during shut-in periods or due to intermittent injection) need to be considered and potentially mitigated by using cement with sufficiently elastic mechanical properties. Required surveillance, as part of monitoring and verification plans, may require certain in-well instrumentation that will add cost or complexity. All-in-all, CO_2 injection well designs are 'the same but different' from O&G well design, and the differences are often larger than at first assumed.

The NORSOK standard has a generalized language and focuses more on the *end-result of having achieved zonal isolation* rather than on dictating workflows and procedures. This offers the operators on the NCS a lot of freedom to utilize "alternative" materials and solutions if viable, but also generates a framework where correct usage of "conventional" materials and solutions can be successfully implemented for CCS wells. Regarding, the minimum number of well barrier envelopes required for the different lifecycle phases for a well (Table 1 from section 5.2.3 of NORSOK D-010), we found that the existing approach is incomplete for CCS wells and additional cases may be necessary to cover specific situations that can arise for CCS wells with respect to pressure category and sources of inflow. However, our analysis resulted in no significant impact on the number of barrier envelopes. Acceptance criteria for seal leakage (EAC tables in the Annex C of NORSOK D-010) are very general for the reviewed WBEs, and can be applied to CCS wells, with potential minor additional specifications. As shown from the Sleipner and Snøhvit projects, it is possible to successfully inject CO_2 using existing standards, with that in mind, no major changes to the NORSOK standard are considered necessary.

A potential difference with CCS wells that could suggest changes to the standard is the factor of project time scale and data management. The point to be made here is to make it easier for "future" engineers to find relevant data (i.e. well reports, survey reports) and make the engineering assessment less time-consuming and/or with lower levels of uncertainty. Suggested changes here is to formulate requirements for what data to store and under which format. The issues with data quality for the future decades might be different from data issues of the previous decades. The issues of data management of the previous decades were more inclined towards *too little* data, whereas a potential issue for the modern era is the issues of *data overload* and difficulties in finding the exact information that was needed.

Some of the differences in properties of CO_2 versus hydrocarbons suggest that the *consequence of* a CO_2 leak could be less detrimental. CO_2 is not a flammable fluid and has different toxicologic properties compared to hydrocarbons. Features such as trapping mechanisms and self-healing also illustrates that CO_2

in a well is a different fluid compared to hydrocarbons. However, converting the NORSOK to a tiered-based standard based on the reservoir/well fluid might complicate matters. There is still a potential for leakage of harmful trace elements, and leakage from a depleted O&G reservoir might also contain a fraction of hydrocarbons.

8 Abbreviations

CCUS	Carbon Capture, Utilization and Storage
CCS	Carbon Capture and Storage
CRA	Corrosion resistant alloy
DAS	Distributed Acoustic Sensing
DHSV	Downhole Safety Valve
DTS	Distributed Temperature Sensing
EAC	Element Acceptance Criteria
ECO_2S	Establishing an Early Carbon Dioxide Storage Complex
EOR	Enhanced Oil Recovery
HC	Hydrocarbon
MMV	Measurement, Monitoring and Verification
NCS	Norwegian Continental Shelf
OPC	Ordinary Portland Cement
O&G	Oil & Gas
P&A	Plugging and Abandonment
RAM	Risk Assessment Matrix
UIC	Underground Injection Control
US EPA	United States Environmental Protection Agency
US DOE	United States Department of Energy
XT	Christmas tree
WBE	Well Barrier Element

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10 Appendix

10.1 Risk assessment matrices

Risk matrix "Well integrity" with existing safeguards for O&G wells						
Consequens	E - Very serious					
	D - Serious					
	C - Moderate			1.3, 2.1, 2.2, 2.5		
	B - Small		1.5, 1.6, 2.3, 2.4			
	A - Very low	1.1, 2.6, 3.2, 3.3	1.4, 3.1			
		1 - Very low	2 - Low	3 - Medium	4 - Large	5 - Very large
		Probability				

Risk matrix "Well integrity" with additional measures for CCS wells						
Consequens	E - Very serious					
	D - Serious					
	C - Moderate					
	B - Small	2.2	2.1			
	A - Very low	1.1, 1.2, 1.3, 1.4, 1.6, 2.6, 3.2, 3.3	1.5, 2.3, 2.4, 2.5, 3.1			
		1 - Very low	2 - Low	3 - Medium	4 - Large	5 - Very large
		Probability				

Figure A - 1. Effect of safeguards on Risk assessment matrix for ”Well integrity” aspects; risk using existing safeguards for O&G wells (above), risk with additional measures for CCS wells (below).

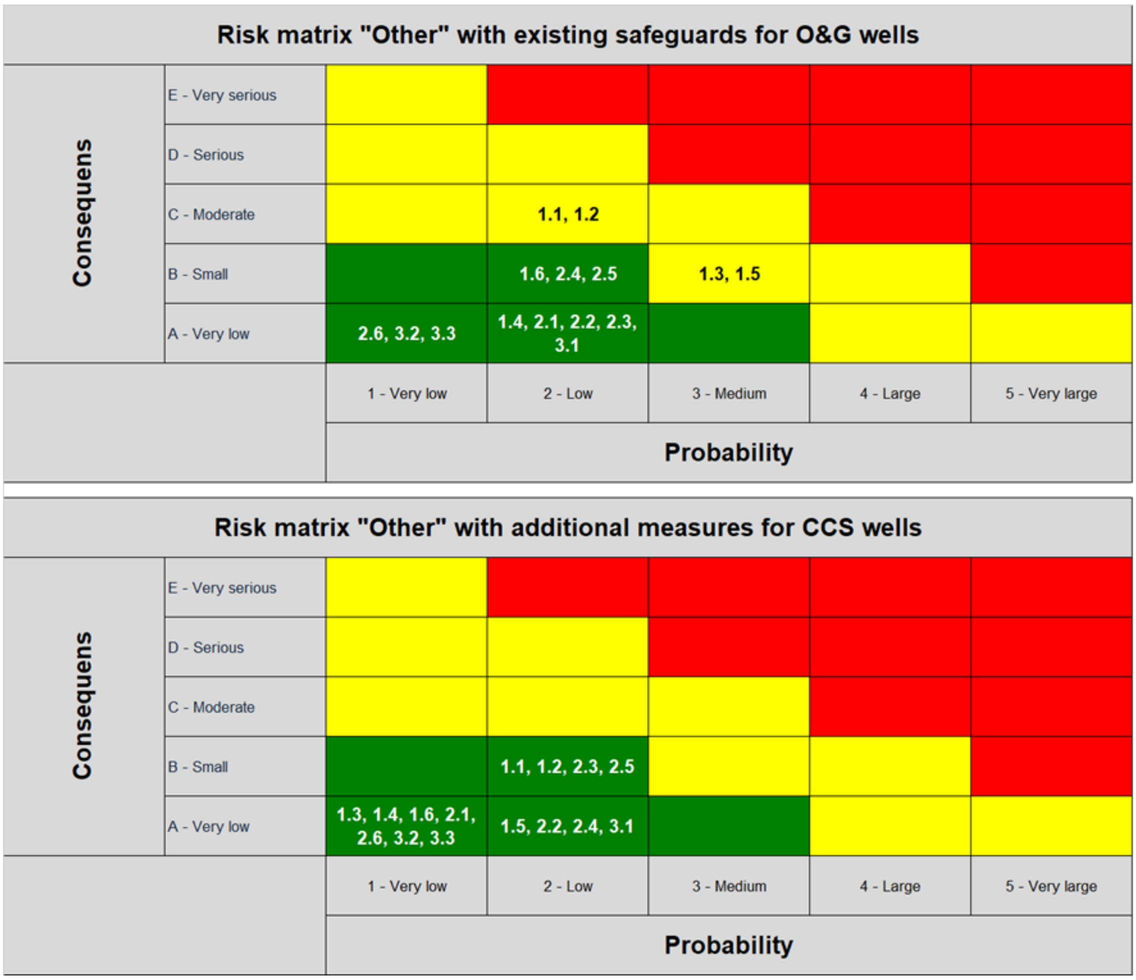

Figure A - 2. Effect of safeguards on Risk assessment matrix for ”Other” aspects; risk using existing safeguards for O&G wells (above), risk with additional measures for CCS wells (below).

10.2 Risk register tables

Table A - 1. Risk register of threats from the Development phase.

	Description of risk (difference between O&G and CCS well)				Risk value		Risk mitigation	Risk value	
Id	**Threat**	**Cause**	**Consequence**	**Existing safeguards for a "standard" O&G well**	Well Integrity	Other	**Proposed additional measures to reduce risk for a CCS well**	Well Integrity	Other
1.1	Insufficient amount of data to assess storage site	An O&G field will aquire wells to get details on reservoir (and caprock) properties. For CCS wells the desire is to penetrate the caprock as little as possible, and also limit expenditure from a large number of wells.	Well Integrity:Wellbore conditions not as foreseen. Frequent injectivity issues. Well design and injection plan not for purpose, loss of containment and/or frequent well interventions Other: effect on well objective	Rigourous regulatory framework for minimum requirements for well integrity	**A1**	**C2**	Well design (and operational procedures) made for robust solutions and utiilization. Downhole pressure and temperature gauges. Alternative injetions interval.	**A1**	**B2**
1.2	Decision processes during lifetime of well based on inexperience and /or lack of data	Long timescale of project. Project last over several decades, meaning multiple personell changes. Also potential changes in operator.	Well integrity: less relevant Relevant for Other risk: Insufficient data quality and availability making future decision processes more uncertain or costly. In the worst case premature P&A.	Knowledge sharing and handling of (easy-access) database for information		**C2**	Ensure standardization in documentation, document stoarge, and easy-access to relevant data for CCS operation		**B2**
1.3	Degradation of injection tubing and casing	Corrosion of tubing due to incorrect material choice/unforeseen severe conditions	Well Integrity: unknown loss of containment, further detoriation of well integrity Other: Loss of containment, inefficient operations; workover.	Robust well design with proven material compability; either field proven or laboratory testing	**B3**	**B3**	Additional testing of materials during selection of materials for the known conditions downhole. Suffienct plan for frequent verification of WBE using mulitple techniques.	**A1**	**A1**
1.4	Degradation of cement	Inproper choice of cement due to incorrect material choice or severe conditions	Well integrity and other: Potential loss of containment, inefficient operations; workover.	Robust well design with proven material compability; either field proven or laboratory testing	**A2**	**A2**	Establishment of database with appropriate materials for CCS	**A1**	**A1**
1.5	Degradation of packer	incorrect material choice for packer	Well integrity: Potential loss of containment Other: inefficient operations; workover.	Robust well design with proven material compability; either field proven or laboratory testing	**B2**	**B3**	Establishment of database with appropriate materials for CCS	**A2**	**A2**
1.6	Degradation of DHSV etc	Inproper material choice for DHSV etc	Potential loss of containment, inefficient operations; workover.	Robust well design with proven material compability; either field proven or laboratory testing	**B2**	**B2**	Establishment of database with appropriate materials for CCS	**A1**	**A1**

Table A - 2. Risk register of threats from the Production phase.

	Description of risk (difference between O&G and CCS well)						Risk mitigation		
Id	Threat	Cause	consequence	Existing safeguards for a "standard" O&G well	Risk value: Well Integrity	Risk value: Other	Proposed additional measures to reduce risk for a CCS well	Risk value: Well Integrity	Risk value: Other
2.1	Cyclic loads to wellbore, either Pressure and/or temperature	Cyclic loads from T and P on wellbore leading to micro-annuli or fractures in cement and / or rock formation	Well integrity: Potential loss of containment/barrier, Other: inefficient operations; workover.	Rigourous regulatory framework for minimum requirements for well integrity. Robust well design.	B3	A2	Testing of materials for their resistance to cyclic loads and fatigue. Injection plan according to material properties.	B2	A1
2.2	Quality and purity of fluid (CO_2)	Changes in fluid to be injected; presence of trace elements	Well integrity: increased corrosion rate. Other: Phase behavior of fluid (CO_2). Uncontrolled expansion. Inefficent operations. Workover	Robust well design.	B3	A2	Establishment of procedure for fluid QA/conformance prior to injection	B1	A2
2.3	Highest pressure in reservoir (wellbore) at the end of injection	Unlike conventional petroleum wells the pressure during will increase as fluids (mass) is injected into the reservoir	Well integrity: Stress on wellbore materials will increase with injection. Other: Well intervention(s)	Robust well design that must be able to account for worst case scenarios in later stages of lifetime	B2	A2	Frequent surveys and logging of well barrier elements	A2	B2
2.4	Deviations from injection plan	CCS supply chain restrictions; shut-down while waiting for CO_2. See point 2.1	Well integrity: Unneccesary start/stop to injection. Pressure/Temperature changes. Extra strain on casing/cement for fatigue and formation of micro-annuli. See point 2.1	Robust well design that must be able to account for worst case scenarios in later stages of lifetime.	B2	B2	Sufficent buffer topside for maintaining stable injection plan.	A2	B1
2.5	Prediction of fluid behavior in reservoir	Unforeseen reservoir conditions/properties uncovered in combination with uncareful injetion plan.	Unexpected migration of CO_2 fluids beyond caprock (or through faults) and back into wellbore. Potential loss of barrier.	Monitoring of reservoir behavior (and wellbore pressure). Important to place secondary barrier at approprate depth	B3	B2	Complete/full cementation of wellbore. Frequent surveys and monitoring of downhole pressure.	A2	B2
2.6	Unfavourable decision making and engineering solutions.	Operations staff has little or no CO_2 operating experience. Lack of knowledge leads to poor operability	Potential loss of containment; inefficient operations	Knowledge sharing and handling of (easy-access) database for information. Robust regulatory regime for operators.	A1	A1	Dedicate training/certification	A1	A1

Table A - 3. Risk register of threats for the Other factors.

	Description of risk (difference between O&G and CCS well)						Risk mitigation		
					Risk value			Risk value	
Id	Threat	Cause	Consequence	Existing safeguards for a "standard" O&G well	Well Integrity	Other	Proposed additional measures to reduce risk for a CCS well	Well Integrity	Other
3.1	Extrapolation of current experiences: upscaling of Sleipner & Snøhvit	Less resource made available for CCS project that are larger than e.g. Sleipner without sufficent understanding on reservoir and well properties	Poor decision making in well design phase. Loss of containent. Well interventions and workover(s). Cost escalation.	Rigourous regulatory framework for minimum requirements for well integrity. In O&G develoment phase the current understanding is the the underground is heterogenous in its properties.	A2	A2	Well design (and operational procedures) made for robust solutions and utiilization. Downhole pressure and temperature gauges	A2	A2
3.2	Stability of project finance/economy	Changes in financial/political climate during well design and operational phase.	Poor decision making in well design phase. Less focus on quality. Potential failure, Level of contingency increases	Rigourous regulatory framework for well integrity	A1	A1		A1	A1
3.3	Lack of suitable & available rig / vessels for project	Large number of CCS wells to be implemented on NCS with still high conv.O&G activity	Premature finzliation, lack of logging work etc. to save time. Lack of documention for future well itnegrity assessment. Delays to schedule workover, and/or increased cost	Rigourous regulatory framework for well integrity	A1	A1	Develoment and installation of more comprehensive monitoring and more easily accesible data	A1	A1

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