Zero emissions platform

CO_2 Storage Safety in the North Sea: Implications of the CO_2 Storage Directive

TWG Collaboration across the CCS Chain

Workstream 1 Report

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Executive Summary

Key messages

- CO_2 underground storage is a safe and mature technology ready for broad implementation, as evidenced by over twenty years of successful storage offshore in Norway, combined with more recent onshore storage in Canada and the USA. In Europe, CCS benefits from a clear set of regulations and requirements under the 2009 EU CO_2 Storage Directive that ensure the identification of appropriate storage sites and the safety of subsequent operation.

- CCS is required for rapid and large-scale decarbonisation of major point sources. CCS provides robustness to decarbonisation strategies, especially for industrial clusters, and enables a just transition for industrial communities. CO_2 transport and storage is required for a large variety of emissions sources, tackling process emissions and addressing the concept of 'unavoidable emissions' that would otherwise continue to be emitted to the atmosphere.

- For climate stabilisation, CO_2 must be captured and permanently prevented from reaching the atmosphere. For a typical offshore North Sea storage site, the report concludes that both the likelihood and the potential volumes of released CO_2 in a theoretic incident are very low and decrease with time. It can be expected that 99.99% of the injected CO_2 remains in the subsurface. In the extremely unlikely event of a small CO_2 leak, this will have a minor localised influence on the marine environment, as these ecosystems are naturally resilient to minor fluctuations in CO_2 concentrations. With adequate remediation, even an extremely unlikely major leakage event will have a limited and temporary and local effect on marine ecosystems in a range limited to the km scale. The minor risks to the local marine environment presented by CO_2 storage have to be balanced against the serious impacts that climate change and related ocean acidification are having today on the marine environment. These negative impacts will continue to escalate unless large-scale, rapid CO2 mitigation – including through the largescale deployment of CCS – is implemented.

- Since 2009/10, fewer CCS projects have been implemented than envisaged. This has largely been due to a number of factors such as the lack of a business case. Furthermore, concerns over the financial liabilities for CO_2 storage development and the lack of clarity over how regulatory authorities will implement these measures have limited industry interest in applying for storage permits in a number of countries. Under the EU CO_2 Storage Directive (and as interpreted under Guidance Document 4), operators of a CO_2 storage facility are required to provide significant financial securities prior to operations to cover normal decommissioning obligations and ongoing monitoring operations. However, the Directive also requires taking account of extremely low probability incidents and there is a risk that licensing authorities would include the full impact of these incidents without taking probability into account. The consequent financial burden such combined securities add to each individual project undermines project economics, causing reluctance of the private sector to invest, with as a consequence increasing societal cost for reducing emissions at scale (ZEP, 2017).

- Involved parties should develop and agree on a Monitoring, Measuring and Verification (MMV) program that is fit for purpose for the identified risks (addressing both impact and probability). Clarification and recognition of the difference between monitoring requirements for various types of storage sites in Guidance Document 4 is required, e.g. techniques for pre- and post- closure of storage in pressure depleted structures compared to aquifers are different. Moreover, a clear split between the essential elements of the Financial Security (decommissioning obligations, conformance monitoring) and extremely unlikely elements (leakage, non-conformance monitoring), would help the industry to accelerate deployment without undermining monitoring and safety mechanisms. The former should be detailed and required under each storage permit. The latter could be arranged on a country or sectoral basis where the competent authority would make arrangements with the industry to set aside a fund to cover such unlikely events.

- Getting initial CO_2 transport and storage infrastructure built in Europe is critical to generate economies of scale that deliver major cost savings, support industrial decarbonisation and encourage innovation through R&D and the deployment of new technologies. As with other technologies, the costs of undertaking CO_2 storage operations and monitoring will be further reduced with growing market for CO_2 storage and greater competition for services and technology providers.

Background

This report was prepared under the European Zero Emission Technology and Innovation Platform (ZEP) project 'Collaboration across the CCS Chain' and is the result of the workstream focusing on CO_2 storage-related risks. Carbon Capture and Storage (CCS) is a set of technologies, which extract the CO_2 from: process emissions generated through the manufacture of products such as steel, chemicals and cement; combustion production from energy production (fossil or bio-fuelled) and waste-incineration; as well as from emissions in gas processing, refining, hydrogen production and direct air capture, and store the CO_2 securely and permanently underground to stop emissions from entering the atmosphere[1].

The objectives of the report are to: 1) Analyse the most relevant risk areas associated with geological CO_2 storage in the North Sea; 2) Estimate the risk level of such storage; 3) Summarise major learning from current projects; 4) Identify areas of major uncertainties or gaps in knowledge; and 5) Discuss the legislation (EU Storage Directive) requirements for CO_2 leakage risk monitoring, mitigation and liability.

[1] An introduction to Carbon Capture and Storage (CCS) can be accessed via the following link: https://iopscience.iop.org/book/978-0-7503-1581-4.

Analysis and findings

Geological storage of CO_2 has been demonstrated in Europe and farther afield for over 20 years. A key concern for Governments is understanding the real and perceived risk associated with storing CO_2 in the subsurface, in order to introduce policies which will enable the scale-up of CCS activity in Europe. Risk in this report is defined as the product of probability of occurrence of a "risk event" multiplied by consequences were the event to take place.

This report is based on a summary of experience from global CO_2 storage projects to date (such as Statoil's Sleipner project and Total's Lacq project) along with published risk estimates, unpublished risk studies for North Sea storage sites, and further evaluation by a group of industry and research specialists with expertise in CO_2 storage.

The North Sea Basin contains oil, condensate and gas trapped in a large variety of reservoirs. There are numerous extensive caprocks that are known to be effective seals for oil and gas, and these can be expected to be similarly effective at containing CO_2. Importantly, for most CO_2 storage sites, stored CO_2 becomes even safer over time, meaning the longer it has been in the subsurface the lower the risk of a leak, as more CO_2 is immobilised (trapped in isolated bubbles in pores, dissolved in the pore water, and bound chemically in minerals to the surrounding rock). Once the CO_2 storage site is closed, and injection of CO_2 stops, the risk of CO_2 release reduces significantly.

The analysis reported here assesses several types of risk under two broad categories. One, the containment risk, relates to the concern that is probably most present in the public mind, addressing the possibility of a CO_2 leak from the designated storage site. The other refers to site performance risks, including; the possibility that less CO_2 can be stored than expected, other operational risks that are comparable to those experienced in oil and gas development operations with the same health and safety requirements being applied, and commercial/financial risks, particularly relating to the financial penalty required by the operator with respect to the risk profile of CO_2 leakage.

This report assesses ten theoretical CO_2 leakage scenarios in light of the containment risk, assessing their probability, impact, duration, and cost implications. These scenarios are set out in the table below and address a range of possibilities from minor leaks to major store failure. The assumed case is a national storage site injecting a total of 100 Mt tonnes at 2000-3000 m depth, over a period of 50 years. The site includes one injection well and one abandoned well. The conservative probabilities listed in the table relate to the likelihood of the specified events to occur during a period of 500 years from injection commencement. The amounts listed are the theoretically estimated quantities of CO_2 lost to the linked ocean-atmosphere system during the specified event. It is important to note that the ten scenarios cannot take place at the same time, as some events are mutually exclusive.

Additionally, it should be noted that the environmental consequences of a CO_2 leak vary depending on the size and location of the leak. Carbon dioxide does not combust, nor does it create oil slicks. It is naturally present in the atmosphere and once diluted released CO_2 is indistinguishable from natural CO_2. To escape from the primary geological store deep underground, CO_2 would first have to percolate through natural pathways in the overlying rocks or anthropogenic pathways such as well bores. Much of the CO_2 would be trapped or dissolve in overlying formation waters before reaching the seafloor, reducing the magnitude of any leak. Marine ecosystems are naturally resilient to CO_2 fluctuations, though prolonged exposure to increased CO_2 concentrations affects marine communities by lowering the pH of the surrounding seawater. Concentrations from high leakage rates are, however, highly unlikely to occur even in the incident of a CO_2 leak (see table below). Any leak or seepage will however be localised, and the footprint of disruption will be 100-1000's of times smaller than current habitat destruction from other anthropogenic activities, such as trawling or offshore aggregate mining.

Scenario	**Probability over 500 years including lifetime of the project and post closure (%)**	**Peak leakage rate (t/d)**	**Duration of leak**	**Total mass leaked (tonnes)**	**Risked leaked mass (tonnes)**	**Total remediation cost (including ETS costs) (€m)**	**Risked cost (€)**
Minor leakage; fault & fracture	0.2	100	50 years	1,825,000	3,800	97	194,000
Moderate leakage; fault & fracture	0.05	700	12 years	3,066,000	1,550	178	89,000
Severe leakage; fault & fracture	0.005	5,000	4 years	7,300,000	365	589	29,450
Active well leakage	0.5	50	250 days	12,500	62.5	10.4	52,000
Active well blowout	0.15	5,000	250 days	1,250,000	1,875	93	139,500
Abandoned well blowout	0.1	3,000	1 year	1,095,000	1,100	88	88,000
Seepage in abandoned well	0.5	7	100 years	255,500	1,250	34	170,000
Severe well problem, no repair successful	0.005	6,000	2 years	4,380,000	215	524	26,200
Leak from installation	0.25	100	5 days	500	1.25	15	37,500
Undesired plume spread	0.03	0	N/A	N/A	N/A	110	15,000
Total					10,219	1,838	**840,650**

Two key conclusions can be drawn from this table:

- The probability of any of these ten scenarios occurring is extremely low.
- Adding together the risked cost for all scenarios – and therefore assuming the possible simultaneous occurrence of mutually exclusive incidents – results in a total possible risked cost for one storage project of €840,650 – less than €1 million. As

described below, this is several orders of magnitude less than the above defined worst-case scenario cost of €589 million, which owners and operators are required to set aside Financial Security to cover in the EU CO_2 Storage Directive.

For all currently operational projects, no geological release of CO_2 to the surface or the sea floor has been detected. In addition, these operational projects all highlight the importance of utilising stringent Monitoring, Measuring and Verification (MMV) as well as maintenance and remediation procedures. Based on this experience of CCS projects over the past decades, as well as the available knowledge of the subsurface and the above findings of the conducted analysis, this report expects over 99,99% of injected CO_2 to remain in the subsurface for at least 500 years including during the operation phase and post closure. This assessment is consistent with the 2005 IPCC Special Report on CCS which found that "*the fraction [of CO_2] retained in appropriately selected and managed reservoirs is very likely to exceed 99% over 100 years and is likely to exceed 99% over 1000 years*".

In case of a CO_2 leak, under Guidance Document 4 (Financial Security and Liability) of the EU CO_2 Storage Directive, the owners of a CO_2 storage site are liable for the cost of leaked CO_2 equivalent to the carbon price under the EU Emissions Trading Scheme at the time of leakage multiplied by the volume of CO_2 released. It is highlighted in this report that applying the defined worst-case scenario, could require remediation and associated ETS costs for each individual CO_2 storage site in the order of €600 million. The probability of such a severe event is estimated at less than one in 10,000 projects.

Taking into account the findings on the probabilities of the containment risk associated with CO_2 storage this report suggests that the total risk cost for one storage project amounts to less than €1 million (even taking into account mutually exclusive incidents). This can be considered as a typical risk for a well-planned and developed North Sea storage project, and is several orders of magnitude less than the defined worst-case scenario cost of €589 million.

Requiring operators to set aside Financial Security to cover a worst-case scenario remediation cost in the current magnitude will place a heavy burden on any storage business case and obstruct the development of CO_2 storage projects. In fact, no individual operator can afford to set aside funds to cover such highly unlikely events for every project, and no other ongoing business operates under an equivalent requirement. In other industries (e.g. oil and gas industry) similar risks are usually absorbed by an insurance system. Such an insurance or guarantee system, initiated by the authorities, for sharing the risk for the CCS industry would significantly reduce the barrier of entry currently faced by first-mover projects and proactively encourage CCS deployment. An alternative approach could be a fund held centrally with contributions according to the probability-weighted risk costs. As there initially will be too few projects for an operative insurance system, the liability will initially need to be shared between Government and the private sector. Practical experience to date demonstrates that Governments will need to exercise considerable flexibility in defining the Financial Security. Mechanisms for sharing of leakage-related liability and economic risks across the CCS chain need to be developed to encourage investment into CO_2 geological storage. A ZEP report exploring the latter issue will be released shortly.

Conclusion

Through the EU CO_2 storage directive, a clear and comprehensive framework exists to assess, monitor and safely operate a CO_2 storage site. The directive's provisions lay out significant technical and financial prerequisites for the development of CCS in Europe that ensure operators have to take the highest safeguards. Based on the analyses of this report, the containment risk (i.e. the risk of a leakage of CO_2) can be considered minor – with scenario probabilities ranging between 0.005% and 0.5% – and over 99.99% of injected CO_2 is expected to remain underground for at least 500 years. It is important to note that as a general rule the longer CO_2 remains in the ground, the safer it becomes as it gets trapped in pores, dissolves in brine and binds with pre-existing minerals in the subsurface. In addition, operational experience to date demonstrates that geological CO_2 storage is proven technology, ready for wider implementation. CCS can therefore be counted upon as a key climate mitigation solution.

However, as the EU directive also transfers full financial responsibility for potential incidents to the operator, financial securities have to be established that cover costs for all potential eventualities for each individual project site before operation. It is important that the financial securities are based on realistic scenarios that reflect the minor risk of leakage from CO_2 storage sites. Developing a proportionate approach to managing financial securities is an important step to encouraging greater private sector investment in CCS projects, supporting deployment of this important technology and helping to achieve the Paris Agreement goals of limiting the global temperature increase to well-below 2°C.

1. Context

This report has been prepared under the ZEP project 'Collaboration across the CCS Chain' by a workstream focusing on geological storage risks. The project's overall objective is to lay out experience developed from over half a century of oil and gas production and twenty years of CO_2 storage in the North Sea, thereby helping and enabling the development of European offshore CCS projects.

This document will be used as technical basis for the second workstream ('Risk sharing across the CCS Chain') operating under the research project 'Collaboration across the CCS Chain'. This workstream focuses on outlining available options for sharing or allocating risks and liabilities associated with CCS projects between the chain actors in different organisational models (comprising multiple sources and multiple storage sites).

The objectives of this report are to: 1) Analyse the most relevant risk areas associated with geological CO_2 storage in the North Sea; 2) Estimate the risk level of such storage; 3) Summarise major lessons learned from ongoing projects; 4) Identify areas of major uncertainties or gaps in knowledge; and 5) Discuss the legislation (EU CO_2 Storage Directive) requirements for CO_2 leakage risk monitoring, mitigation and liability.

The analysis revolves primarily around technical issues and risked cost, but the report also touches on European legislation. The CO_2 Storage Directive requires that CO_2 storage sites are only selected if there is no significant risk of leakage or damage to human health or the environment. Regulators cannot approve a CO_2 storage project unless its risk for CO_2 leakage is extremely low and the operator can prove in any eventuality that they are capable of handling it in a predictable manner. The estimated risk level in this report should be seen as a typical risk for a well-planned North Sea storage site. For evaluating and permitting an individual storage site, a specific assessment of the relevant site has to be performed.

Intergovernmental panel on climate change (IPCC) reports have consistently, over many years, identified CCS as a central tool to mitigate climate change. More recently, the IPCC showed CCS to be critical to reach the targets set out in the Paris Agreement (IPCC 2018). Also, the European Commission's Long Term Vision 'A Clean Planet for All' that called for a climate neutral Europe by 2050 stressed the need for enabling a CO_2 structure and CCS for Europe's heavy industries (Directive 2003/87/EC, 2018). Industry currently emits about 20% of total EU emissions. Particularly the cement, steel and chemical sectors require CCS to deeply decarbonise their processes, lacking alternative or timely emission reduction technologies. As outlined in ZEP's report on *the Role of CCUS in a below 2 degrees scenario*, CCS can thereby play an essential role in facilitating a Just Transition for Europe's resource intensive industry and can help safeguard millions of jobs in the value-chain (ZEP, 2018). However, there has been much less CO_2 storage development activity in Europe than anticipated when the EU established the Storage Directive in 2009. The analysis in this report identified the economic and financial risk of CO_2 storage as a potential key reason for the limited industry interest in applying for storage permits. Under the EU CO_2 Storage Directive (in particular Guidance Document 4), operators of a CO_2 storage facility are required to provide significant financial securities prior to operations to cover both necessary and normal obligations as well as large amounts for extremely low probability incidents. The consequent financial burden such securities add to each individual project undermines project development, causes a potential barrier to entry for companies wanting to offer these services. In turn, a lack of investment in CCS projects increases the perceived risk. This issue will be explored in more depth in the report.

It is expected that oil and gas companies with broad offshore experience are naturally suited to be operators for early CO_2 storage projects. Additionally, the development of a European CCS industry would ensure new, sustainable opportunities to employ the skill-set of people currently working in the oil and gas industry. The transportation and the storing of CO_2 requires the same full system engineering knowledge in infrastructure, reservoir appraisal, well drilling, and monitoring equipment that is currently applied in the offshore oil and gas industry. The European oil and gas industry conduct their operations with a high level of Health Safety and Environment (HSE) performance and will bring this experience and expertise to CO_2 storage activities.

It is important to note that the consequences of a release of CO_2 from a geological store are significantly lower than for oil or gas seen from a personal safety and a local environmental perspective (Scandpower/NGI, 2012). CO_2 does not combust, nor does it create oil slicks. It is naturally present in the atmosphere and marine ecosystems, and once diluted released CO_2 is indistinguishable from other CO_2. All leakages may not reach the sea floor, many CO_2 leaks out of the storage reservoir will be trapped in overlying rock formations. Leakages, if they reach the sea floor, unless in large concentrations pose a low and limited risk to the environment (see section 2.3).

The hazard risks from an operators' perspective posed by CO2 storage are varied, but when linked to release into the ocean-atmosphere system can be split into three parts:

(i) Obligation to execute a "corrective measures" plan – i.e. limit the quantity released
(ii) . Direct requirement to purchase ETS allowances at the prevailing cost at the time of release, which is likely to be higher than at the time of injection.
(iii) Obligation to continue to monitor the system until it can be shown that there will be no more leakage.

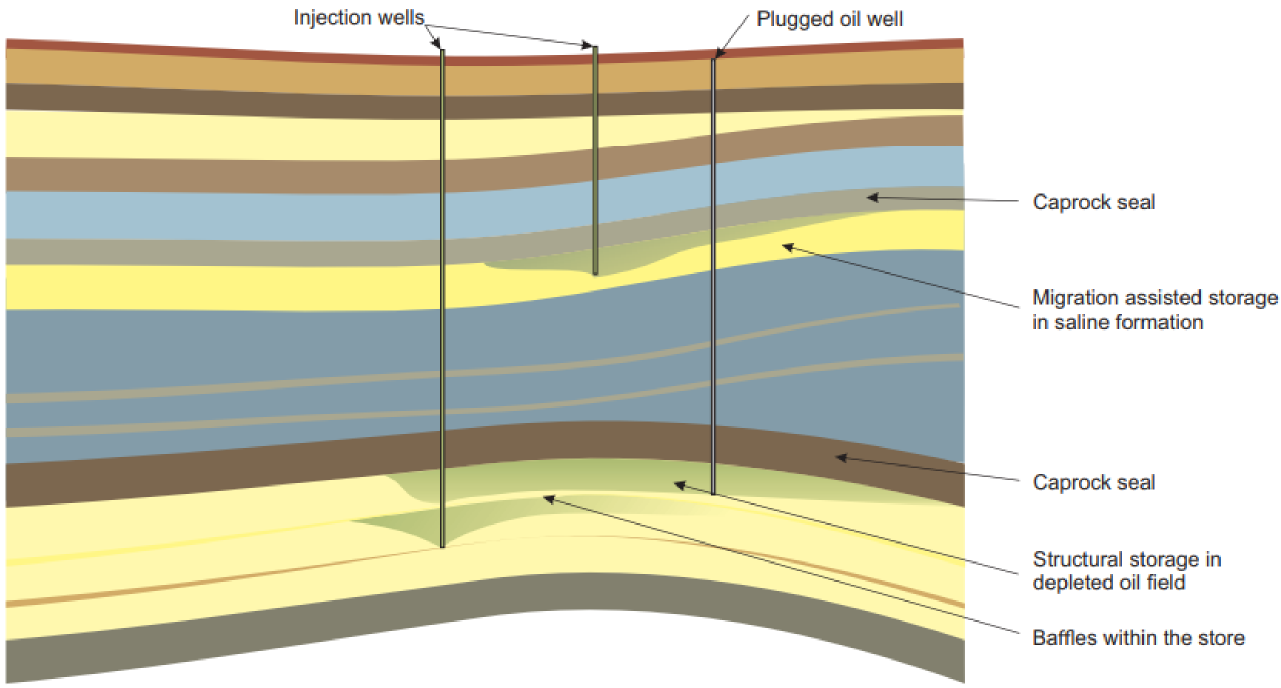
In addition, even if CO_2 does not reach the ocean-atmosphere system, there is an obligation to execute steps (ii) and (iii) if the CO_2 is shown to have left the subsurface volume designated for storage (the "storage complex" as defined in Article 3 of the 2009 EU CCS Directive).

2. Introduction to CO_2 storage

2.1 CO_2 storage principles and definitions

To reduce the emissions of CO_2 to the atmosphere from essential industrial processes, CO_2 must be captured before it is emitted, transported to a suitable storage site and injected there. The CO_2 must be stored so that it will remain indefinitely within a defined location, where it will not create any adverse impacts. To make sure the CO_2 remains, it must be injected into a storage formation with defined boundaries through which it will not flow out - the store. The storage medium itself is typically a traditional reservoir rock (i.e. a rock formation with a pore space to store in and sufficient permeability so it can be injected into). When the CO_2 is injected into the store rock, it will displace the existing fluids and migrate or 'plume' upwards due to buoyancy. The injected CO_2 will partially mix with the formation waters or in the case of a depleted gas field mix with any residual natural fluids. To prevent the CO_2 from migrating out of the designated store, the store must be capped by an impermeable rock formation: a sealing cap rock. When the CO_2 cannot migrate further up, it will spread sideways beneath the cap rock (figure 1). It is therefore beneficial that the cap rock forms a trap with sufficient lateral extent to accommodate the injected CO_2 plume.

Figure 1: Schematic of CO_2 storage. CO_2 plume in green (from Tucker, 2018).



Article 3 of the EU CO_2 Storage Directive lists the following definitions:

- 'Geological storage of CO_2' means injection accompanied by storage of CO_2 streams in underground geological formations;
- 'Storage site' means a defined volume area within a geological formation used for the geological storage of CO_2 and associated surface and injection facilities;

- ‘Leakage’ means any release of CO_2 from the storage complex, however, mostly understood as release to the atmosphere-ocean system;
- ‘CO_2 plume’ means the dispersing volume of CO_2 in the geological formation;
- ‘Storage complex’ means the storage site and surrounding geological domain which can have an effect on overall storage integrity and security; that is, secondary containment formations.

Under these definitions, CO_2 might migrate out of the storage site but stay in the storage complex. The leak out of the storage complex is covered in the Storage Directive and the leak to the linked ocean-atmosphere system is regulated under the ETS Directive.

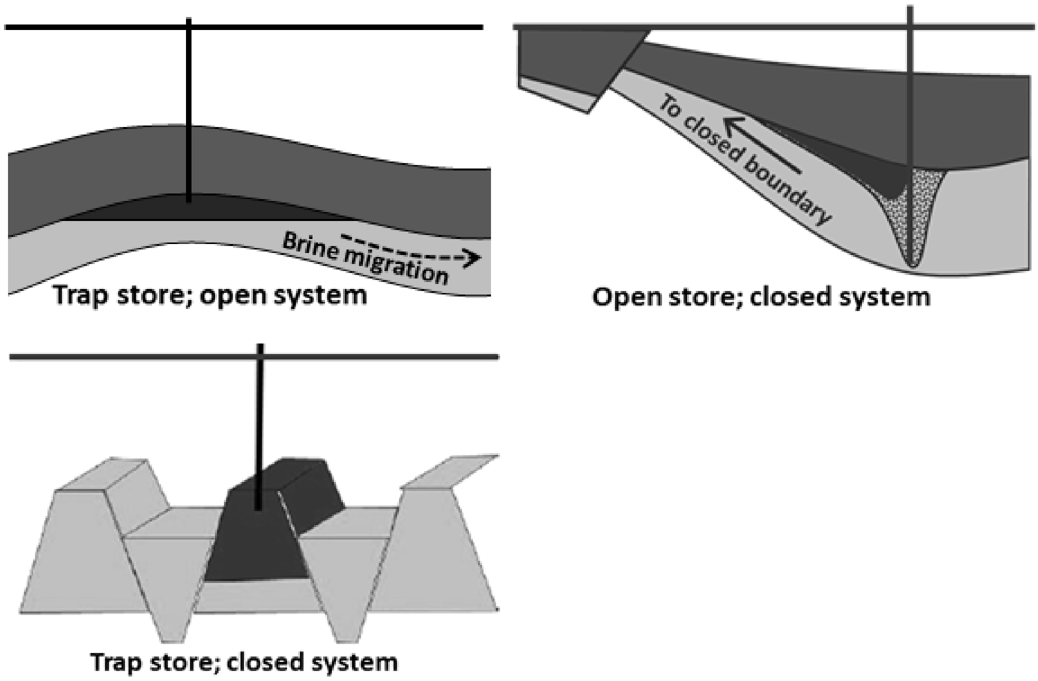
The following requirements must be fulfilled by a storage site:
1. Capacity: the storage site must have sufficient capacity to store the required mass/volume of $CO_{2.}$
2. Injectivity: the project must be able to inject CO_2 into the geological store at a sufficiently high rate to handle the quantities delivered to the project.
3. Containment: the injected CO_2 must remain safely contained in the geological store (the storage complex as defined by the project).
4. Monitoring and remediation: the project must be able to show that the store is performing as expected, and be able to repair anything that does not perform as required.

A demonstration of these elements will be required to obtain an injection and storage permit awarded national authorities who will likely seek the opinion of the EU Commission. A rigorous assessment of the storage project risks is an essential part of the application process. These risks, and their quantification, are discussed in chapters 3 and 4.

Geological storage sites for CO_2 in general consider several broad categories (figure 2):

- Store type (aquifer storage or storage in depleted oil or gas fields)
- Store structure (storage in a closure (or trap) or a store with an open structure);
- Store pressure (storage sites at hydrostatic (native) pressure or sites with reduced pressure below hydrostatic, e.g. due to hydrocarbon production at (or near to) the selected storage site.
- Store boundaries (isolated storage with closed pressure boundaries (sealing faults or rock variation prevents the release of pressure from the store) or stores with partial or fully open boundaries);

Figure 2. Typical CO_2 storage sites and pressure systems.



Carbon dioxide storage differs from most hydrocarbon production scenarios in that there is usually a net addition of material to the subsurface, as opposed to a net removal of material. But the details depend on the exact configuration of the storage project, so it is important not to generalise from one type of project to another.

For pure CO_2 injection into a saline formation, like the Sleipner case (see Chapter 5.2), CO_2 is injected into pores in the rock that are already filled with highly saline water. This addition of CO_2 increases the subsurface pressure and pushes water away. The subsurface is left with higher pressure than before injection started. In large aquifers like Sleipner the pressure increase is hardly measurable. For primary hydrocarbon production, oil or gas is removed from pores in the rock and the pressure reduces.

In many cases there are more aspects than those described above. For hydrocarbon development, water is often pumped into the subsurface to flush oil and gas out, and the reservoir pressure can be managed. Similarly, water can be extracted as CO_2 is injected; which is what is intended for the Gorgon CO_2 storage development in Western Australia. The pressure can be maintained at, or below, a target pressure, through this extraction of water. CO_2 can also be injected into a depleted oil or gas field for storage, re-pressuring the reservoir.

Most of the risks associated with CO_2 storage are common to all types of storage, although some risks are inherently higher or lower for a particular storage type, as discussed throughout this document. There are also many similarities between hydrocarbon extraction and CO_2 storage, in terms of development and operational activities and facilities, and the risks associated with these. Consequently, the relatively immature CO_2 storage industry will inherently be linked to the wealth of experience and incident data from the hydrocarbon industry to assess and manage storage project risk, given an understanding of where CO_2 storage and hydrocarbon extraction differ, and which data can be appropriately used.

2.2 Definitions of Leakage

The EU CO_2 Storage Directive defines a leakage as CO_2 which is released from the 'storage complex'. A storage complex means the storage site and surrounding geological domain which can have an effect on overall storage integrity and security; that is, secondary containment formations. For many low rate leakage and seepage events, much of the CO_2 escaped from the primary storage reservoir will be trapped in overlying formations.

Key definitions used:

Leakage: defined in this report are all to the ocean-atmosphere system (be that the ocean-floor for geologic leakage and some well leakage; or atmosphere for some well leaks).

Seepage: Minor flow in geologic pathway around a storage site. Mostly spread over a significant area. Hard to detect and monitor. Geologic seepage is uneconomic to remediate; well seepage from active wells can be repaired. Typically, less than 5 tonnes/day. This level of CO_2 release is often equivalent to the natural flux of CO_2 from the North Sea sea floor today without any CO_2 storage.

Minor leakage: Minor flow along a geologic fault or leakage pathway, as well as a quite restricted/controlled leak in a well. Geologic leakage in this magnitude is difficult or uneconomic to repair – well leaks can normally be repaired by a standard well work over. Typically, 1-50 tonnes/day.

Moderate leakage: Significant flow along a geologic fault, leakage pathway, or in a well. Geologic leakage can be remediated by controlling injection patterns and if unresolved, remediated with a relief well, well leaks from operational wells can normally be repaired by a standard well work over. Typically, 100-500 tonnes/day.

Major leakage: High flow along geologic fault, leakage pathway, or in well under normal pressures. Will require mitigating action, by controlling injection patterns and subsurface pressure, and if unresolved remediated with a relief well. Typically, 700-2000 tonnes/day.

Severe leakage: Full flow along a fault or geologic pathway or full uncontrolled well blow out. Requires immediate action and/or relief well. Typically, 5000 tonnes/day or even higher.

2.3 Environmental impact of leakage

For deep subsea storage in Europe, much of the CO_2 from a seeping to moderate leak at depth will be trapped or dissolve in overlying formation waters before reaching the seafloor. The impacts of such leakage have been investigated in the Quantifying and Monitoring Potential Ecosystems Impacts of Geological Carbon Storage (QICS) research project (Blackford et al., 2015).

Marine ecosystems are particularly tolerant to fluctuations in CO_2 concentrations and subsequent short-term variations in seawater acidity. The most vulnerable organisms are those which rely on a calcified shell such as crustaceans, however even these can withstand short periods of moderate acidification. An acidification causing a seawater change of 0.1pH units is considered to have an impact above seasonal background variation. The environmental impact of a CO_2 leakage will depend on both the severity and longevity of the leak. A small seepage or leak (<1 tonne/day- 10 tonnes/day) will only have a sea floor footprint (delta > 0.1 pH) of a few tens of meters, minor enough that most organisms will relocate before major disruption occurs. A very large leak (>100 ton/day) will have a more regional effect, with a km scale footprint and large subsea plume. In extreme cases this could result in death of organisms however this is unlikely (Jones et al., 2015).

These effects on the sea floor ecosystem, even with a large leak, are 100s-1000s of times smaller than current North Sea habitat destruction caused by activities such as trawling and aggregate mining (Blackford et al., 2018). Research has shown that the possible leakage impact is insignificant when compared to the current path of ecosystem collapse predicted by climate change (Blackford et al., 2018).

2.4 Human impact of leakage

Depending on the size and character of a leakage, it is possible, however unlikely, that some CO_2 will reach the sea surface, after which it will be dispersed by the wind. For such a leakage to represent a danger to human health, two conditions must occur:

1. The leakage must be large enough and in a high enough concentration to release a cloud which is of substantial volume and concentration.
2. The humans who come into contact with this low-lying cloud must be inside it for a long enough period of time to suffer adverse consequences.

Leakage events through the subsurface and water column are spread over large areas and will not be able to develop large concentrated CO_2 clouds on the sea surface. Most of the CO_2 leaked will be trapped by geological formations, or dispersed in the water column.

Carbon dioxide leakage from a severe well blowout are more likely to produce a large gas plume in the water column which may reach the surface and produce a significant concentration and volume of CO_2. If vessels are in close proximity to the CO_2 it poses a threat, as once the CO_2 reaches the surface it will 'pool' on the sea surface as it is denser than air, until it is dispersed by the wind. It is highly unlikely that concentrations will reach significant levels for extended periods of time.

The final risk to CO_2 leakage to humans is during the drilling and topside work on dedicated vessels. This is similar to current risk for oil and gas activities, except CO_2 is not flammable, but may cause asphyxiation. Suitable contingency plans to handle possible blowouts of CO_2, or escape from CO_2 bearing pipelines must be in place for storage operations.

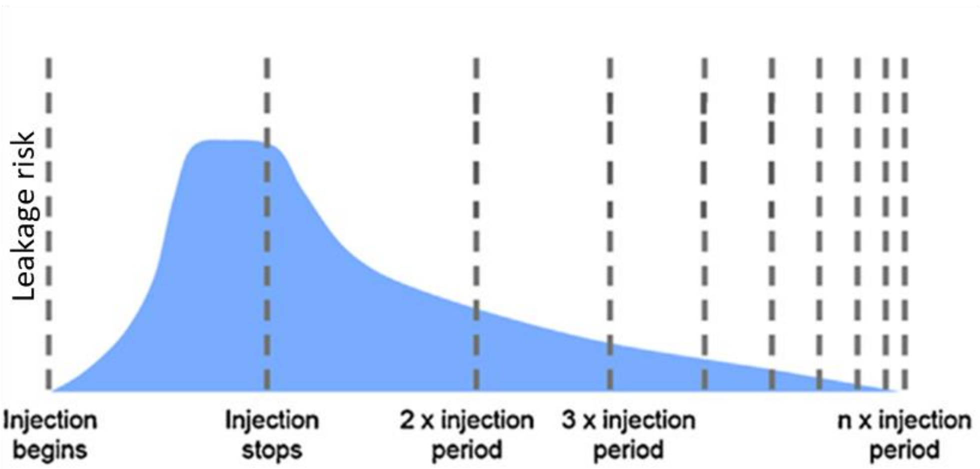
3. Risk assessment

3.1 *Major risk areas*

This chapter will outline the major risk events and their consequences. Risk is defined as the product of probability multiplied by consequence. The risks are set out below under two main categories:

- **The containment risk** [does it leak?] covers all events where CO_2 escapes out of the storage complex in an unplanned way. This includes failure of caprock, wells and equipment, as well as unforeseen migration through porous formations or faults (Rubin & De Coninck, 2005). This risk is relevant from the start of injection, builds throughout injection, and may remain beyond closure (figure 3). Leakage to the oceans and atmosphere can affect the local environment as well the global atmospheric CO_2 balance, whereas subsurface leakage outside the storage complex which does not reach the atmosphere or oceans, can affect the project economics. This report concentrates on containment or leakage risk.
- **The site performance risk** [does it meet expectations?] is linked to successful development and operation of the storage project during appraisal and injection stages, particularly with respect to capacity, injectivity and induced microseismicity. Mitigation of this risk will primarily be additional data acquisition in the appraisal stage and proper monitoring for performance throughout the injection stage. Site performance risk does not influence containment risk and CO_2 leakage; poor site performance will most likely be addressed using current oil and gas production techniques to improve reservoir conditions. Consequences can be modifications to wells and facilities, new wells or in the worst-case, cancellation of the project. In all circumstances it will create additional costs to the operator or site owner.

Figure 3. Theoretical development of leakage risk during and after CO_2 injection (DECC, 2012).



3.2 Containment risk

It is essential to any storage location that the caprock (or multiple layers of rock that make up the caprock system) provides complete closure and seal of the storage reservoir and that faults, if present, are not flow pathways. A good-quality caprock is more than adequate to isolate CO_2 in the subsurface. Caprock integrity needs to be studied carefully in the appraisal phase using technologies similar to those deployed for oil and gas exploration. In the absence of direct evidence for sealing (like the presence of an oil or gas field) there will always be some residual risk that some migration paths might exist through a caprock. This risk will reduce as monitoring of the CO_2 injection takes place.

Typical caprocks such as shales can theoretically be damaged by pressure increases above their fracture pressure. The likelihood of fracturing the caprock as a result of CO_2 injection depends on the regional stress regime, the magnitude of differential stress, formation pore pressures, and the presence of pre-existing brittle fracture features. As long as the pressure does not approach the fracture pressure, the risk is not regarded as significant. The thicker the caprock the less impact such fracturing will have on leakage risk. The potential of reactivation of existing faults is poses another risk to containment as, depending on lithology, movement of a fault plane could lead to the creation of a flow path. A geomechanical risk assessment is used to place limits on the operating parameters of the store – mostly pressure but sometime also temperature – to manage both the tensile fracture risk and the fault reactivation risk. A store where the operational parameters are kept within the gemechanically dictated containment capability of the caprock would not be expected to fail. This is similar to operating a pipeline within its design parameters. This risk can therefore be managed in the same way as in other industrial operations. Selection of subsurface injection locations, injection rate controls, and pressure management by extracting formation waters (water production) during CO_2 injection are all tools that can be used to manage caprock fault and fracture risk. In addition, pressure management and the management of the injection pattern can even steer the CO_2 plume away from potential risks, such as abandoned wells or fault zones. Any produced formation waters can be monitored and/or treated then disposed into the ocean, as is the current practice in many water-producing oil and gas fields.

In most North Sea cases there will be other aquifer formations overlying the caprock, which could accommodate potential leaked CO_2 volumes. These overlying aquifers are included in the EU CO_2 Storage Directive definition of a storage complex together with the individual caprocks above them. The geology of the North Sea means that it is very unlikely that large volumes of CO_2 will find a highly permeable pathway all the way from the storage reservoir at storage depths of 1000-3000m to the sea floor. Small volumes of CO_2 seeping out at the sea floor will have a lower environmental impact than the natural hydrocarbon seeps we have today in the North Sea. Small volumes of CO_2 might influence marine life a few meters from the exit point (Jones et al. 2015). Flow in a pathway through the subsurface is difficult or impossible to mitigate – hence remediation needs to be applied to the source of the CO_2. Pressure release from the storage formation through production of formation water, halting injection or changing the injection pattern or rates might be the only solution. A major leakage into the sea will typically require immediate cessation of injection, most likely permanently, and consequently delay or prevent the development of a new local storage site.

Seismicity refers to the occurrence or frequency of earthquakes. Seismicity is caused by movement on faults and fractures. The industry divides seismicity into natural, induced and triggered:

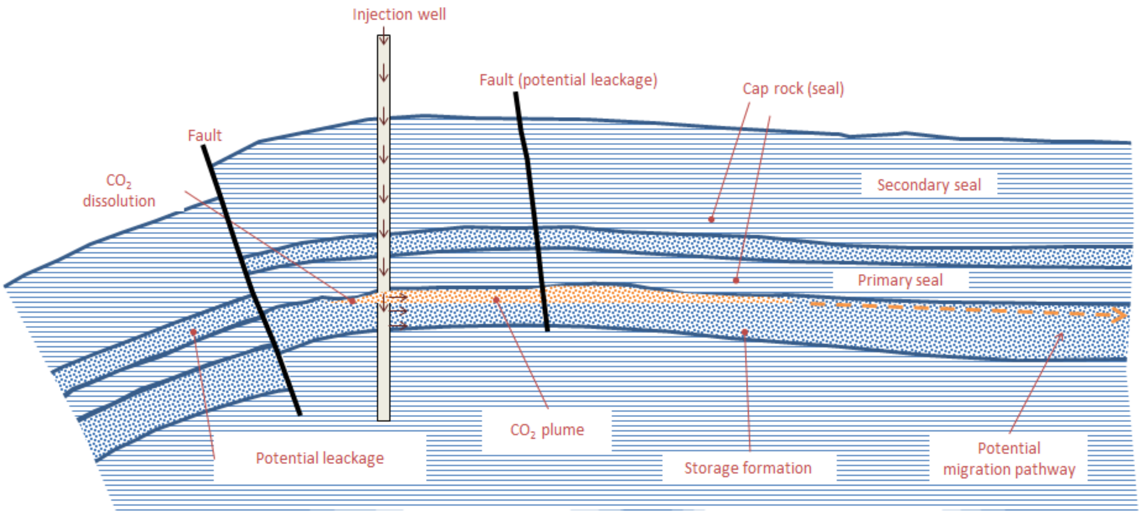
- Natural seismicity occurs as a result of the natural movement of the Earth over geologic time. The North Sea exhibits natural seismicity but at a low level when compared to other areas of the world on active plate tectonic boundaries like the Mediterranean.
- Induced seismicity occurs as a result of human activity, be it groundwater extraction, mining, building dams, removing oil and gas, or injecting fluids (including water or CO_2). The energy comes from the activity itself and generally leads to low energy seismicity or microsesimicity.
- Triggered seismicity has been observed in water disposal operations, this takes place when the human activity "gives nature a push" and triggers natural seismicity. These events can be larger because they have access to the energy produced by natural processes.

The process of seismicity involves the formation of a fracture or movement of rocks on each side of a fault. Therefore, it is conceivable that there could be fluid flow along the fracture or fault (figure 4). Induced micro seismicity, like that from CO_2 injection operations, does not affect the seals because it is associated with extremely small movements over small length scales, this has been backed up by the experience in current storage sites. Significant fracturing and leakage created by induced seismicity has not been observed in ongoing CO_2 storage projects. Part of permitting a storage site in the EU is an assessment of the risk of triggered seismicity and it is unlikely that a site with a high risk of triggered seismicity would be permitted.

Sites have also been observed to be secure under exposure to natural seismicity. In Japan, storage sites have been exposed to large natural earthquakes and have not leaked. This makes intuitive sense as oil and gas fields exist in areas of natural seismicity, like California, Italy, Japan, New Zealand and Indonesia to name but a few.

Wells are deliberately designed to transport fluids and gasses across geological seals. Detailed analysis, such as that done for the former Peterhead CCS project, show that wells are the elements of a storage site considered to have the largest potential leakage risk. Wells can be divided into different categories depending on the stage in their lifecycle and their design parameters; during drilling and completion; during injection or production; after plugging and abandonment. Wells can be drilled for oil and gas activities or by other users of the subsurface. They can have modern construction techniques or be over one hundred years old. In the North Sea Basin, the first wells were drilled in the mid-1960s.

Figure 4. Illustration of a geological storage with potential pathways for leakage.



A key part of any CO_2 storage appraisal and subsequent permitting activity is to identify all wells in the area that will be impacted by the development and assess their integrity. Any site that has a risk of the CO_2 connecting with a well of unknown status or one assessed to have a high risk of leakage (i.e. one which does not have effective subsurface isolation plugs) will not be permitted unless the wells are repaired or monitored in combination with an effective remediation plan should it be required (further information can be found in Tucker, 2018).

If flow via wells does occur, the flow will normally take place with limited volumes and rates via restricted leak routes (outside casing, through poorly emplaced sections of cement etc). During the development phase (when a drilling rig is on site) it is possible, were all safeguards to fail, for a full bore well flow to take place. This is often termed a blowout. When this occurs, the full bore is open to flow and the operator then has to cap it, perform a "top kill", or drill a relief well to stop the flow.

The risk of blowouts in CO_2 wells during the appraisal and development phases will be significantly lower than for oil and gas wells, as the target of CO_2 wells are either water filled or depleted reservoirs. A blowout during regular injection in wells with modern completions is also unlikely. The highest blowout risk is during activities such as well repairs and recompletions in the late injection phase, when well equipment has aged and reservoir pressure increased. Nevertheless, it should be noted that no such events for CO_2 storage injection are yet known. For a theoretical CO_2 storage site, with purpose drilled CO_2 injection and observation wells, the higher probability leakage scenarios will result in limited leakage rates either just outside the casing, or resulting from equipment failures in the well itself, during the late life of the well or after closure.

A challenging aspect in containment assessment is evaluating the leakage potential of abandoned wells penetrating the storage site. When the abandoned wells were plugged they would have followed regulations and best practice guidelines applicable at the time of decommissioning. These rules would not have been written with the possibility of future CO_2 injection in mind, therefore some abandoned wells may not seal off the storage reservoir against CO_2 entering the well, and could facilitate subsurface cross flow between permeable formations. It is currently not feasible, or is extremely costly, to re-enter and repair these abandoned wells. If there are uncertainties about the condition of an abandoned well, the best course of action is to select storage sites away from it. Depleted hydrocarbon fields may have one or more such abandoned wells, which require particular attention and care. Luckily nature helps to seal old wells. Many rock formations are ductile and, under the immense pressure creates by hundreds or even thousands of meters of overlying rock, move or “creep” slowly and fill in gaps around wells or even close open wellbores. The phenomenon of shale creep, and also squeezing salt is well documented, and these processes generally mean that old wells become a steadily reducing risk. The challenges is that this process is not well characterised for abandoned wells hence the time horizon is uncertain for any particular combination of well penetration and geology.

Minor leakages related to wells in operation can normally be repaired. In many cases a drilling rig will be required, which makes mitigation relatively costly, but it is routine. Although extremely unlikely, a full blowout is a very serious matter. In the worst case a relief well must be drilled, which can take around three months with a drilling rig, releasing a significant volume of CO_2 for which equivalent ETS allowances must be purchased. Ironically, though a full well blowout is spectacular, the fact that it only takes a few months to repair, means that it will release a limited quantity of CO_2. The withdrawn Shell Peterhead/Goldeneye project in 2015 assessed this to be less than half a million tonnes of CO_2 for their scenario. A minor leakage related to an abandoned well which typically cannot be repaired by re-entering the well, might also require a relief well with associated costs.

CO_2 plume migration out of the storage complex might occur if the injected CO_2 does not behave as expected. This should be considered in the case of an open storage unit with no structural trap (examples of such storage are Sleipner, Quest, Aquistore, and the Decatur/IBDP projects), or where the targeted closure (or trap) is incomplete. For storage reservoirs where the seal continues laterally with good quality over a relatively flat and wide area around the storage complex, this might not be a concern. The plume must be monitored however, mostly by repeat seismic reflection surveying, though the frequency and exact nature of monitoring will be determined by the site-specific risk assessment.

If the CO_2 plume migrates out of the bounds of the storage complex it will enter areas where there is an increased possibility of encountering fluid pathways to the surface via faults, abandoned wells or hydraulic connection with other reservoirs. These boundaries will be characterised during the site appraisal, and safeguards will be designed to ensure that such migration does not take place. These safeguards are likely to be a combination of comprehensive flow modelling and monitoring combined with preventative of reactive actions such as regulating or adjusting the quantities, pressures, and locations of subsurface injection of CO_2 and/or the extraction of brine. These safeguards are designed to lower the risk of undesirable migration significantly and form part of the containment risk assessment required by the storage permit.

As with the transport and management of any gas or liquid, leakage can also occur from pipelines, subsea installations and other facilities. Such events will be comparable to experience from the oil and gas industry with similar probabilities, mitigations and consequences. With effective design such leakages can be limited and stopped on relatively short notice. Repairs might, however, take some time and require expensive equipment. No major consequences for the environment are expected, but there may be economic consequences if there is a liability towards the CO_2 suppliers.

Monitoring is an important measure for controlling the injected volumes and is the basis for creating safeguards that preventing leaks. The reality of working in the subsurface under kilometres of rock means that it is all but impossible to see or measure every kilogram of CO_2 injected once it is in the store, regardless of how extensive the monitoring program is. Evaluators rely on a combination of monitoring, geology and fluid flow physics, to assess that the CO_2 is effectively contained and not leaking out. There has been significant technological progress monitoring CO_2 plume migration and modelling the flow physics over the last 20 years, exemplified by work at the Sleipner storage facility in the North Sea (see Section 5.2). The best strategy is to identify the parameters which can give warnings at an early stage and develop a program for measuring these at realistic intervals. It must further be considered that CO_2 is part of any natural environment and can have other sources than the storage site.

3.3 Performance risk

The performance risk relates to the storage site performing to the predicted levels, this is dependent on the presence and quality of storage rock, seal, and trap, and is separate to CO_2 containment risk. This risk/uncertainty can be considerably reduced through data acquisition and analysis during exploration and appraisal prior to injection. Additional wells, seismic surveys and expert studies for mapping purposes are expensive and will load the project with more costs upfront. If the results are negative and do not allow a storage development, these early costs will be sunk. The consequences, of limitations in storage performance will be experienced in the operation phase and can result in well modifications, drilling new wells (including potentially developing a second store) and reduced injection rates or total quantities. Performance risk must be regarded primarily as an operator risk. The consequences will impact on the economics of the project, and in the worst case require abandonment of the project and the selection of a new site.

The forecast storage resource is the best engineering estimate based on the current, but always limited, knowledge of the subsurface. The knowledge is limited because we have to extrapolate from a few boreholes and from geophysical remote sensing. Once injection starts, or additional borehole or geophysical data become available, the forecast of capacity will always alter.

Experience from the oil and gas industry shows that volumetric forecasts can go up or down. If the storage formation is smaller or less connected than expected, or the underground structure turns out to have a different shape than that interpreted the forecast can go down. If the opposite occurs, it can go up. Operators manage this risk by using ranges, defining the most probable case, low probability case, and high probability case.

Where there is timely recognition of the performance issue, appropriate actions can be taken, such as reducing injection rates or plume steering by producing formation waters. This illustrates the importance of adequate monitoring during the early stages of the injection phase. The consequence of reduced capacity may require the development of alternative storage capacity, which might have a large economic impact for operators and owners.

4. Studies on magnitude of CO_2 storage risk

Several publications give recommendations in respect of risk assessment (Rajesh et al., 2005; DOE/NETL, 2017). Quantitative approaches are challenging due to the very wide ranges of key parameters, multiple methodologies, large technical uncertainty, and very low probabilities. Because there have been so few leaks in CO_2 injection projects there is therefore little industry experience with leakage estimation. Reliable quantification of leakage and leakage risk requires better calibration of models and input parameters from real historic experience. However, a view of the risk and risk-level has been formulated based on the results of available studies.

Available studies are largely based on raw data and methodology from the oil and gas storage industries. These industries work in the same geologic provinces and formations, and perform the same or similar operations. Two studies, which cover a broad range of aspects, are referred here:

- DECC/AGR report: CO_2 Storage Liabilities in the North Sea (DECC, 2012)
- Gassnova's leakage risk studies (Scandpower/NGI, 2012)

Both studies focus on quantifying the probability of events and listing possible consequences and potential mitigating measures. In this report, the cost of consequences and corrective measures will be additionally estimated and the risk level and structure illustrated. The probability of leakage quoted in this report is defined for the lifetime of the respective projects including the post-closure period. All leaks to which costs are allocated are leaks to the ocean-atmosphere system. The basis for both studies is statistics and data dossiers including extensive North Sea oil and gas activity.

DECC and Gassnova data provide representative assessments (rate and frequency) which are used in this report. The scale of the risk is representative but actual risk for any project will vary depending on site (existing wells and geology), storage concept (water or hydrocarbon filled site, operating and final pressures) and development (e.g. number and operating life of active wells). The cases discussed (DECC, Gassnova and document case) all have different injection phase durations and well numbers.

4.1 DECC/AGR report

The DECC/AGR study (2012) focused on four main possible pathways for potential leakage identified in previous research, namely faults, caprocks, operating and abandoned wells. The purpose was to develop an expert view on representative parameters for offshore UK North Sea storage (i.e. hazards, leak rate, duration, dynamic controls, probability of leakage) for the four main pathways. The key results are summarised below (table 1).

The numbers are based upon earlier work performed by SINTEF on North Sea statistics (Randhol & Carlsen, 2008). They are estimated assuming a notional storage project development with five injection wells, injecting a total of 200 Mt over a 20-year injection period.

Table 1 gives summary parameters and scenarios for potential leakage from active wells. The chosen scenarios illustrate the span of potential leakages. Active wells are defined as all wells utilised for injection, observation and water extraction as well as wells under drilling or interventions.

Table 1. Leakage parameters for two leakage scenarios with five active wells (DECC, 2012). Probability quoted for leak event occurrence is over 20 year injection period.

Scenario	Low level leakage	Uncontrolled blowout
Probability of leakage event (%)	0.01-0.1	0.001-0.01
Flow rate, tonnes/day	0.1- 10	5000
Duration	0.5-20 years	3-6 months
Dynamic control	Well shut in/reduced	Injection halted
Potential leakage amount	18-73,000 tonnes	0.45-0.9 Mt
% of stored volumes	0-0.036	0.22-0.45
Long term consequences	Injection reduced or stopped	Injection halted until remediation completed
Corrective measures	Work over with rig	Relief well drilled, 60-90 days

Abandoned wells penetrating the storage reservoir pose a risk of leakage because they represent a direct, albeit impeded, pathway to the surface. Both pre-existing wells from oil and gas activities and abandoned CO_2 wells are considered. Records for abandoned wells are not always complete and available, and methods adopted have varied over time and between different operating companies. The potential storage formation might not have been the target for hydrocarbon production and therefore abandoned wells may not have been plugged to an acceptable standard. Previously active CO_2 wells will be plugged in a "fit-for-purpose" manner and represent an extremely low risk of leakage. Table 2 gives summary parameters for two scenarios representing potential leakage from six abandoned wells in a 200Mt storage case with probability of leakage over 100 years.

The paper by LeGuen et al., (2009) has been used to provide probabilities of a variety of potential leakage scenarios.

Given the geology of the North Sea, migration of CO_2 through caprock is not considered a material leakage risk for any storage site permittable under the CCS Directive. The North Sea basin contains oil, condensate, and gasses (including CO_2) trapped in a large variety of reservoirs. There are numerous extensive caprocks that are known to be effective seals for oil, natural gas and CO_2. Their thicknesses and geology are well known; many are 100s to 1000+ m thick. Different seal formations are present in different regions of the North Sea. They assessed as likely to be highly effective at containing carbon dioxide. The geological controls on caprock continuity must, however, be understood to ensure that the seal is present and continuous across the storage site, and is not absent locally.

Table 2. Leakage parameters for two leakage scenarios in six abandoned wells (DECC, 2012). Probability quoted for leak event occurrence is over a period of 100 years.

Scenario	**Low level leakage**	**Complete breakdown of plugging system**
Probability of leakage (%)	0.12-0.5	0.0001-0.01
Leakage rate, tonnes/day	0.6 – 6	1000
Duration of leakage	1-100+ years	3-6 months
Dynamic control option	Manage reservoir pressure	Halt Injection temporarily
Potential amount lost	220-220,000 tonnes	90-180,000 tonnes
% of stored volume lost	0.0001-0.1+	0.045-0.09
Immediate consequence	Consider reducing injection	Halt injection until well repaired
Corrective measures	Re-entry very difficult; observe and consider relief well	Relief well to intersect leaking well
Variation of risk	Increasing over injection phase	

Faults and fractures are considered to be the main potential geological conduits for the movement of CO_2 beyond the boundaries of the storage site through the seal. Leakage of CO_2 may occur by migration along pre-existing pathways in the form of a fault, fault zone, or fracture system, by reactivation of a pre-existing pathway, by fracturing to create a new pathway resulting from CO_2 injection, or induced by natural seismicity.

The nature of faulting and fracturing will depend on the specific geological structure, tectonics and structural evolution. Faults and fractures are more prevalent in older and deeper formations in the North Sea, but it is unusual for them to extend all the way from the depths of a potential CO_2 storage through overlying seals to the seafloor. This is important as the lack of a direct route substantially reduces the risk of fault leakage. The presence of faults is not necessarily a sign of leakage or potential leakage. There are widespread occurrences in the North Sea where oil and gas has remained contained over millions of years in a reservoir under a faulted caprock or where the faulting provides the very structure and trap that holds the hydrocarbons. These provide evidence that many faults are sealing. Faults, fault zones, and fractures have been studied and have been shown to be highly variable in their ability to transmit fluids. This underlines the need for an assessment of the site-specific leakage potential for any potential storage development. The modelling of flow along and across faults is not a new problem when trying to understand the hydrodynamics of the subsurface; however, modelling results often are associated with high degrees of uncertainty.

A published range of CO_2 leakage rates via faults from appropriate natural analogues to storage sites gives 0.006 and 0.3 $t/yr/m^2$ (Busch, 2010). Faults are expected to be significantly more permeable close to reactivation pressure, and the significance of the fault zone as a leakage conduit is driven by the reservoir pressure. The critical period is therefore during the injection phase, with the probability of reactivation increasing with the injected volume, and decreasing after injection ceases. Where the storage reservoir is connected to a large aquifer, the aquifer might absorb the injected volumes without significant increase in reservoir pressure over long timeframes, and thereby delay the risk development.

Fault reactivation is often initiated by externally induced seismic events. The probability of such events is very low in the North Sea. Fault reactivation does not mean that a fault becomes a flow path – for flow to occur the fault has to remain both open and not clogged by sealing rock types. The shale gas industry knows this well and has to "prop open" fractures with sand of engineered proppant materials otherwise the fractures close up again. Additionally, a potential CO_2 leakage cannot occur unless the CO_2 plume migrates to the open fault/fracture. Seabed seepage of hydrocarbons at a potential storage site might be an indication of pathways and requires particular investigation; even if such hydrocarbon volumes mostly come from shallow sources. Table 3 summarises leakage parameters for faults and fractures.

Table 3. Leakage parameters for three leakage scenarios in existing and activated faults (for a 200Mt storage site DECC, 2012). Probability quoted for leak event occurrence is over a 20 year injection period and 80 year post closure period.

Scenario	Existing faults, low flow	Existing faults, moderate flow	High flow, activated fault, enhanced by injection
Probability of leakage	Highly site specific, very low in geologically well-defined storage sites		
Potential rates (t/day)	1-50	50-250	1500
Duration of leakage	100 years	1-5 years	1-5 years
Potential leakage amount	0-1.8 Mt, over 100 years	0.018-0.46 Mt including remediation	0.55-2.7 Mt, including remediation
Potential corrective measures	Stop injection, de-pressuring	Stop injection, pressure management, Possible relief well	

Pressure relief and management of the storage reservoir can be achieved by production of water from the reservoir. The risk of leakage through reactivated faults and fractures is considered as very low (<0.01%) for sites permittable under the CO_2 Storage Directive. Risk is here defined as risked mass leaked (frequency x leak rate x leak duration) in million tonnes (Mt) of CO_2 leaked from the storage site.

The DECC report (DECC 2012) underlines that there are considerable uncertainties involved in the presented results and that the assessment incorporates a high degree of judgement by the authors.

4.2 Gassnova assessment

Gassnova has performed assessments of leakage risk for several saline aquifer storage sites (Scandpower/NGI, 2012; Scandpower, 2010). The results were presented at various conferences (Hansen, 2012; Christensen, 2013; Høydalsvik, 2014).

A large number of leakage scenarios with faults, fractures and seal failure were assessed. Potential leakage paths were generated in the form of event trees and branch probabilities established based on expert judgement. An intact seal is not regarded as a leakage risk.

Table 4 shows some representative scenarios investigated for a deep site with several seal layers. The closure is partly bound by major faults, which juxtapose a sealing shale formation with the target storage reservoir. The faults extend into the primary seal formation (caprock), but terminate far below the top of the caprock. The calculations are based on a storage development with 160 Mt injected in total over a period of 50 years, followed by 500 years after site closure. Reservoir pressure is limited to 40 bar above initial (less than 15% above initial). Fault permeability of 10 - 1000 mD and fault lengths of 1 - 5 km were used. Vertical leakage rates were calculated for the faults. For severe leaks corrective measures are expected to be initiated almost immediately, while the smaller seepages will continue until they cease naturally.

Four elements were investigated: two major faults, induced fractures and subseismic faults (faults unseen by the coarse resolution of a typical seismic survey). The theoretical leaked quantities were calculated for a considerable number of scenarios (branches of a risk tree) for each of the four elements, with each scenario having a probability of occurrence assigned to it. Only two selected scenarios for each of the four elements are shown in table 4 to illustrate the span. The leakage rates modelled were dynamic over the duration of the leakage period. This means the peak leakage rate is not constant over the duration of the leak, as the rate naturally increases and decreases over time. Summation of all risked leaked amounts for the scenarios for an element yielded the total theoretical amount leaked for the element (last column in table 4), provided as a fraction of the total injected quantity. The summarised total risked leakage volumes of all scenarios and elements are 0,009% of the injected volume.

The blowout potential and risk for active wells were estimated. The calculated release rate of a blowout from a natural CO_2 containing reservoir at the Sheep Mountain Field in 1982 was 10,378 tonnes per day (200 million standard cubic feet per day). It should be noted that Sheep Mountain is a natural CO_2 gas field, penetrated for extraction, rather than a CO_2 storage site where increased pressure by injection is controlled. This example indicates that a leakage rate of 9000 tonnes per day for a full flow blowout of CO_2 can be possible. Based on this and Scandpower's (Scandpower/NGI, 2012) data dossier for frequency and length of blowouts during drilling, gas injection and workover operations, table 5 was established with two scenarios for 50 years of injection to illustrate the span. With these data the total expected leakage volume from active wells is calculated to be 0.00123% of injected volumes (Scandpower/NGI, 2012).

Table 4. Leakage parameters of a selection of leakage scenarios in various faults and induced fractures of a deep North Sea aquifer storage (Scandpower/NGI, 2012). Probability quoted for leak event occurrence is over the 50 years injection project lifetime and 500 years post closure period.

Elements/ events	Probability of leakage (%)	Peak leakage rate (tonnes/day)	Total leaked amount (Mt)	Theoretical amount leaked (% of injected CO_2)	
				Per Scenario	Element/ Event Total
Major fault 1	0.0007	192	13.77 Mt	0.00006	0.00013
	0.000009	4041	90.5 Mt	0.000005	
Major fault 2	0.0007	767	55.08 Mt	0.00024	0.00037
	0.000009	3660	104.4 Mt	0.000006	
Induced fracture	0.00004	95.9	8.57 Mt	0.0000021	0.0000045
	0.0000000045	8191	120.5 Mt	0.0000000034	
Subseismic faults	0.0146	49	4.3 Mt	0.00039	0.0083
	0.00018	1632	24 Mt	0.000027	

Table 5. Leakage probabilities and parameters for two scenarios of flow in active wells over a 50 year injection period (Scandpower/NGI, 2012).

Scenario	Probability (%)	Flow (tonnes/day)	Duration (days)	Lost amount (Mt)
Full well flow	0.225	8640	63	0.54
Restricted flow	0.55	2160	63	0.14

For abandoned wells, which are exposed to the injected CO_2 plume, the quality of the plugging and the available information are critical for assessing leak risk. Work done for DECC (DECC 2012, Appendix A1) indicates high leakage probabilities for poorly plugged wells hit by a CO_2 plume. However, the probability for a total breakdown with free flow is assumed to be very low; in the range of 0.01 – 0.001%. In a specific scenario where the abandoned well is located not far from the potential injection well, it was evaluated that as much as 0.1% of injected CO_2 volumes could be released. The most effective way to reduce this risk is to place the injectors in a location where the probability for the CO_2 to reach any abandoned well with poor, or unknown conditions is low.

Potential storage sites might be in the vicinity of hydrocarbon producing fields, introducing a risk of impacting production via CO_2 migration. One such case was assessed, where a potential flow pathway to a shallower hydrocarbon-bearing reservoir was identified. The speed of migration is dependent on dip, permeability, pressure gradient etc. In this case, the communication point lays 30-40 km away from the injection well and the dip is relatively low. The simulation of the storage development showed that the migration of CO_2 plume would take over 200 years to reach the potential communication point. It must be noted that this is the plume tip reaching the risk location, the majority of the CO_2 will be nearer the injection location as illustrated in figure 12-18 of the Dynamic Modelling Report for the Peterhead CCS project (Shell, 2014). The risk for significant CO_2 migration was estimated to 0.05%. The uncertainty of such an assessment is high. However, dynamic simulation showed that the migration of the CO_2 plume could be controlled in a predictable manner by using water production wells.

4.3 Risk assessment for representative storage in broad CCS implementation

The purpose of this section is to illustrate the risk structure of CCS projects. We estimate total risk for an assumed case, and illustrate the relationship between probability and remediation cost for various events by assessing relevant conceptual leakage scenarios. The term remediation cost in this report includes costs for remediation to occur and costs incurred by the release of CO_2 to the ocean-atmosphere system. Scenarios are based on the work described previously (in chapters 4.1 and 4.2) and the associated quantitative figures (probability, rates, costs) have been estimated by interpolation (table 6). The values in table 6 have been derived, using conservatism and best judgement. A more detailed explanation for the interpretation of these values is given in Appendix A.

Event probabilities and consequence data covered in this section assume an aquifer storage site in the North Sea. It is worth noting that the containment risks are site-specific and influenced by storage site type (as discussed in chapter 2). Additionally, the risk is dependent on the planned development, e.g. a larger number of injection wells leads to a greater chance of well leakage, or pressure management via water production might decrease fault and fracture leak risk or well failure risk, but increase risk of leak via plume migration to water producer. Despite this inherent variability the risks quoted below are representative of the approximate scale of the containment risk for a general CO_2 storage project.

The assumed case is a notional storage site injecting 100 Mt at 2000-3000 m depth, over a period of 50 years. The site includes one injection well and one abandoned well. The probabilities listed in table 6, relate to the likelihood of the specified events to occur during the project lifetime of 500 years. The amounts listed are the theoretically estimated quantities of CO_2 lost in the connected ocean-atmosphere system during the specified event.

As previously mentioned, table 6 was developed using data interpolation. For instance, for the ‘moderate leak’ scenario (number two in the table), input data was taken from tables 4 and 5 respectively; probability 0,0007% and 0,01%; rate 200-800 tonnes/day, and 50-250 tonnes/day, duration 1.5 years and 50 years. This example also shows that the span in the input data is significant and that a conservative approach was utilised.

Table 6. Leakage parameters for leakage scenarios or potential events in a North Sea CO_2 storage. Some of these events might not be relevant for depleted gas fields. Probability quoted for leak event occurrence is over the project life time including post closure period. CO_2 cost is to be paid for ETS allowances.

No.	Scenario	Probability of leakage (%)	Peak Leakage Rate (t/d)	Duration (in years or days)	Total Mass Lost to surface (tonnes)	Risked lost mass (tonnes)	Consequence *(always add CO_2 ETS cost)*
1	Minor leakage; fault & fracture	0.2	100	50 years	1,825,000	3,800	Monitoring
2	Moderate leak: fault & fracture	0.05	700	12 years	3,066,000	1,550	Relief well + monitoring
3	Severe leakage; fault & fracture	0.005	5000	4 years	7,300,000	365	New site+ depressurise
4	Active well leakage	0.5	50	250 days	12,500	62.5	Well workover
5	Active well blowout	0.15	5000	250 days	1,250,000	1,875	Relief well
6	Abandoned well blowout	0.1	3000	1 years	1,095,000	1,100	Relief well
7	Seepage in abandoned well	0.5	7	100 years	255,500	1,250	Monitoring
8	Severe well problem, no repair successful	0.005	6000	2 years	4,380,000	215	Depressurise & new site
9	Leak from installation	0.25	100	5 days	500	1.25	Shut-in and repair
10	Undesired plume spread	0.03	0	N/A	N/A	N/A	Water production (no CO_2 ETS cost)
Sum of risked lost mass						10,219	

It should be noted that the severe events (scenarios 3 and 8 in the table) are very unlikely to happen in a store permitted under the EU Storage Directive. They are, however, included to maintain the conservative approach for our estimate.

The scenario “Seepage in an abandoned well” (scenario 7) also illustrates an event of limited impact on third parties (e.g. a neighbouring oil or gas field), and for which a compensation is paid. Undesired plume spread (a subset of migration risk, scenario 10) constitutes a more significant impact on a third party. The probability is set to 0.03% when action must be initiated and the plume actively managed by water production (derived from above referred studies).

Figures for leakages from installed seabed facilities are based on utilised statistical data from oil and gas activities. The probabilities presented in this report are conservative estimates, as shown by recent reports, which estimate pipeline failure risks are lower than expected (Duncan & Wang, 2014).

The arithmetic sum of risked leakage amounts for all scenarios in table 6 equals approximately 10,200 tonnes CO_2 or just more than 0.01% of the injected volume. Thus, including the conservative treatment of leakage risk, we can presume 99,99 % of injected CO_2 is expected to remain in the subsurface for at least 500 years including the injection and post closure periods.

The two studies on which these calculations are based (chapters 4.1 and 4.2) utilise a broad basis of statistics from petroleum activity in the North Sea. They were performed in technical environments by experienced companies. The results of the two studies are internally consistent. This gives confidence that the results are in the right order of magnitude. However, as there is limited experience with CO_2 handling, data could only to a limited degree be calibrated to actual CO_2 operations.

A study published in 2018, which takes both a regional and generic approach to broad implementation of CCS utilising a worldwide database, gives somewhat higher numbers for leakages (Alcalde et al., 2018). Regional models and regional data were used. Their base case estimates for release during 100, 1000 and 10000 years respectively in a well-regulated region like the North Sea is approximately 0.02, 0.07 and 0.5% of the injected quantity. A Monte-Carlo simulation gave 0.04% and 0.2% for 100 and 1000 years at a probability of 50% that leakage remains below 0.0008% per year. It is important to note that the two studies, which served as basis for this report, used selected well-suited sites for their analyses. For CO_2 storage sites in the future in Europe, only well-suited sites will also be selected as to comply with the CO_2 Storage Directive (or future equivalent).

There are studies giving recommendations for detailed cost estimation for storage related issues (IEAGHG, 2017). However, cost levels change between countries, fluctuate dependant on market situation, are different for different types of facilities, and vary with water and reservoir depth. The cost numbers used are therefore approximations based on general experience in the UK and Norway. The cost assumptions are listed in table 7.

The development of an additional storage site includes two purposely drilled wells, a subsea installation and a 100 km pipeline. If an existing, produced field with intact facilities and wells could be utilised, the costs would be considerably lower. However, such a candidate may not be available on short notice were the primary storage to fail. For drilling and workover activities the use of a floating vessel is assumed. In shallow waters a jack-up drilling rig could be used and the cost reduction would be considerable.

The costs for the consequences of the scenarios listed in table 6, have been calculated based on table 7, and are shown in table 8. For monitoring cost estimation, it is assumed that the monitoring frequency goes down over time, as we learn more every time we monitor.

Table 7. Cost assumptions used for risk calculations.

Cost category/Operation	Cost assumption
Drilling and completion of one well	€50 million
Yearly operation cost for one well	€2.5 million
One well workover activity	€10 million
Additional seismic services for monitoring	€5 million
Repair of an installation (pipeline/subsea equipment)	€15 million
The development of an additional storage site	€300 million
Average ETA allowance cost (“CO_2 price”)	€30/tonne

One third of the remediation costs are made up by payment for ETS allowances. The risk is split equally between geological events, operative wells and abandoned wells. For sites with a larger number of wells the risk will be increased accordingly.

Remediation costs and risk for the various scenarios or events are shown in figures 5 and 6 below.

Table 8. Remediation cost for the leakage scenarios or potential events defined in table 6. Probability quoted for leak event occurrence is over the project life time including post closure period. Note many scenarios cannot simultaneously occur.

No.	Scenario	Corrective invest (€M)	CO_2 quota cost (€M)	Operation cost (€M)	Total Remediation cost (€M)	Probability (%)	Risked cost (€)
1	Minor leakage; fault & fracture	0	57	40 (8 seismic surveys)	97	0.2	194,000
2	Moderate leak: fault & fracture	50	93	25+10	178	0.05	89,000
3	Severe leakage; fault & fracture	320	219	50	589	0.005	29,450
4	Well leakage	10	0.4	0	10.4	0.5	52,000
5	Blowout	50	38	5	93	0.15	139,500
6	Abandoned well blowout	50	33	5	88	0.1	88,000
7	Seepage in abandoned well	0	7	25 (5 seism. surveys)	34	0.5	170,000
8	Severe well problem	320	129	75	524	0.005	26,200
9	Leak from installation	15	0	0	15	0.25	37,500
10	Undesired plume spread	50	0	50+10 (2 seis. surveys)	110	0.03	15,000
	Arithmetic Sum	865	576	295	1838	0.51	840,650

Figure 5. Remediation costs and risked costs for the scenarios defined in table 6.

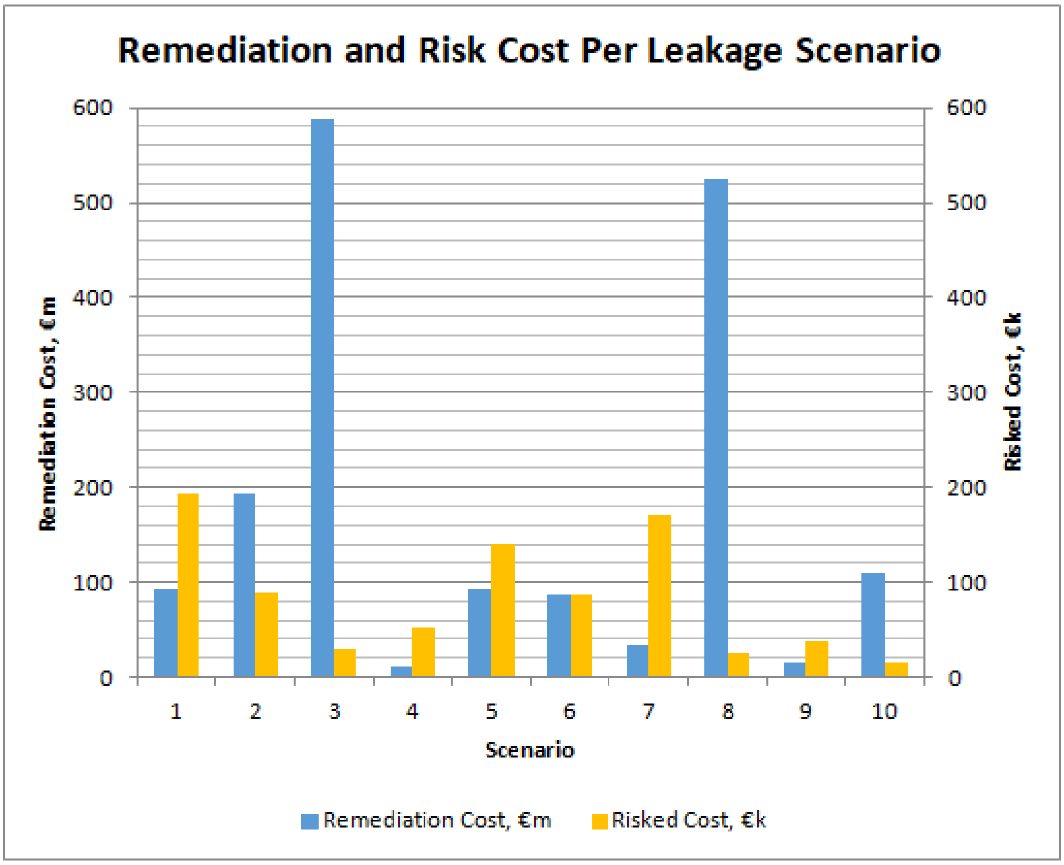
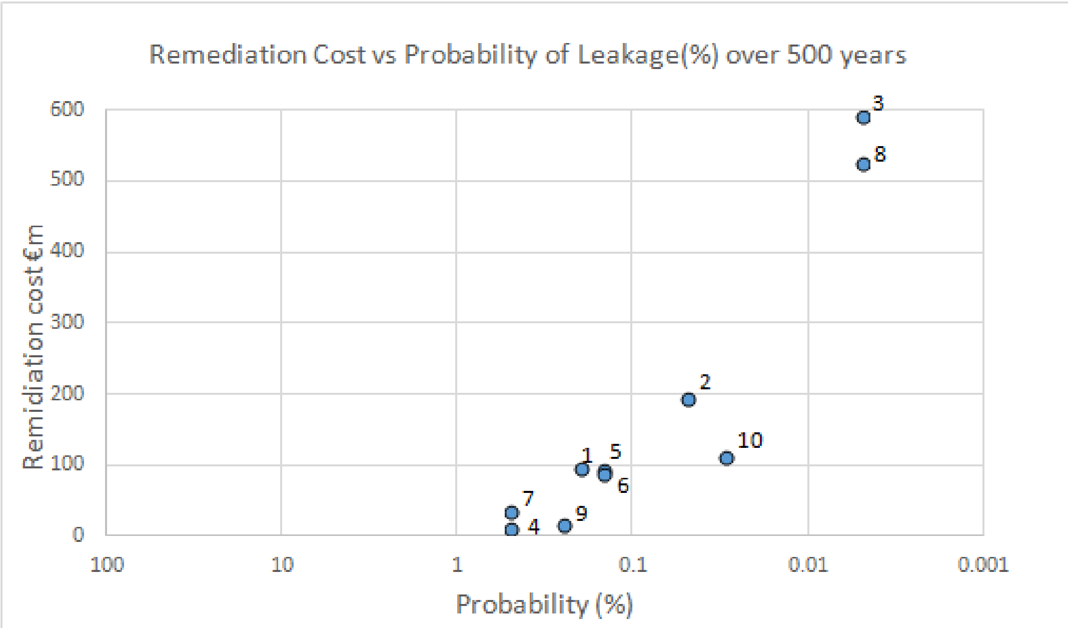


Figure 6. Remediation costs for the events numbered in table 6, related to their probability of leakage in a storage site over 500 years (including the injection and post-injection phases).

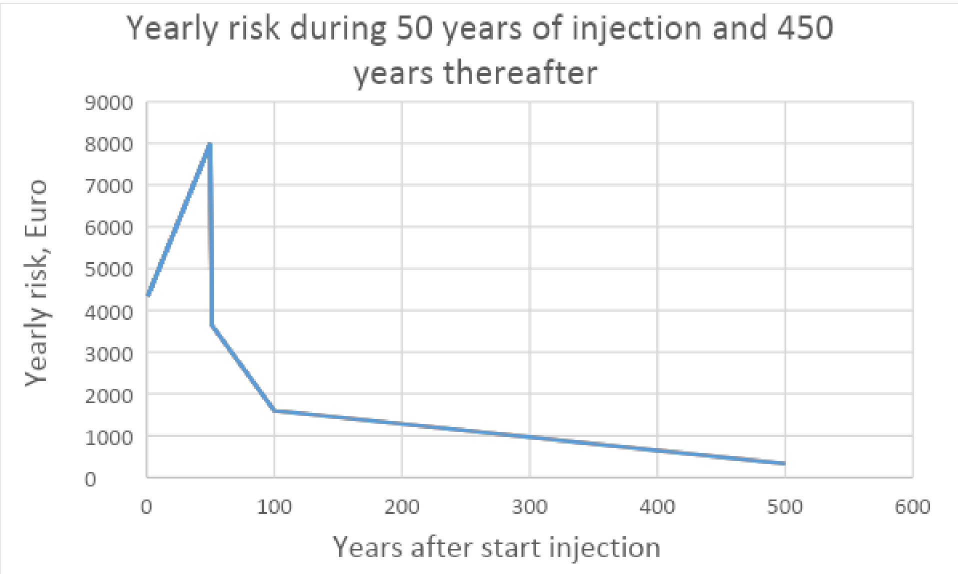


Our analysis shows that the total risk for the entire assessed storage project, taking event probabilities into account, amounts to €0.85 million. This is to be regarded as the class risk for a well planned and developed North Sea storage project. This amount is dramatically less than the theoretical worst-case remediation cost for a single case, which is in the order of €589 million (see scenario 3 in table 8 & figure 5). However, such a severe event is expected to happen only in less than one of 10,000 projects (figure 6). Remediation cost for more frequent events, which are expected in one of several hundred to thousand projects, are up to a magnitude of €100 million.

Figure 7 illustrates the risk distributed over the life of a project, including injection and post-closure. Here, the costs of risk elements applicable to the injection phase (events 4, 5, 6, 8 and 9) are averaged over the 50 years of injection. It is common to assume progressively increasing risk during the injection phase, as the amount of CO_2 in the storage site becomes larger, which raises the probability of a leak and the potential amount of CO_2 that can leak. This can be a reasonable approach based on the available data at the time of project planning. However, as injection proceeds and more data are gathered, site understanding, plans and strategies are continuously improved to minimise risk.

The costs of the remaining risks, which are applicable for the entire life of the project, are distributed over 250 years for simplicity. The leakage risk for aquifer CO_2 storage projects diminishes over time because more and more CO_2 will be immobilised (Rubin & De Coninck, 2005; DECC 2012). This is indicated as a trend in the figure. Figure 7 shows a more theoretically based risk development, where the risk declines exponentially after closure of the storage site. If this trend is applied, the remaining risk 50 years after closure is less than 20% of the total, indicating a liability of less than € 150,000.

Figure 7. Yearly risk for a typical North Sea aquifer storage based on the calculations in this chapter for 50 years of injection and 450 years post-closure.



The important message from this graph, however, is that the yearly risk is at a magnitude of several thousand Euros during the injection phase and shrinks thereafter. The integral under the curve corresponds to the cumulative risk during the entire project of € 840,650.

In some scenarios where closed structural traps will be the primary trapping mechanism for CO_2, the CO_2 may take longer to become immobile. Nonetheless, over 100s-1000s of years this will become immobile within the storage formation (Snippe and Tucker, 2014).

4.4 Depleted Oil and Gas Fields

The risk assessment performed above (chapter 4.3) is based on saline aquifer storage sites. These storage types are likely to be the most common. However, for the first storage projects which may operate with limited capacity, depleted gas and oil fields might be even better candidates. Such candidates might require lower investment and risk. For this reason, a risk scenario for a depleted field is developed. It is a theoretical scenario based on the same input as the assessment above, but modified for differences in properties, features and behaviour rather than on specific data from such depleted fields.

For this depleted field assessment, it is assumed that the reservoir/storage pressure stays well below the initial value (max. 80-90% of initial pressure). The integrity of the structure itself is therefore not likely to be affected. Wells are the most likely source of leakage, particularly in abandoned wells.

Table 9 shows the evaluated leakage scenarios and events applicable for a depleted oil or gas field and their estimated remediation costs. For the above reasons, the following leakage scenarios in the general assessment (table 8) are disregarded here:

- Severe leakage through faults and fractures
- Blowout in abandoned well
- Severe well problems

The probabilities of the remaining well related events were reduced by 1/3 because of low storage pressure and a detailed insight in the behaviour of the storage reservoir that is the result of the period of hydrocarbon production. In this case a storage capacity of 20 Mt is assumed, which is 20% of the capacity of the first assessment. The injection period lasts for 10 years.

Table 9 shows that if everything goes wrong in this depleted field scenario at the simultaneously, (which cannot happen as some events are mutually exclusive) the remediation cost could be €166 million, including €39 million in payment for ETS allowances. The analysis shows that the total risk for this entire assessed storage project, taking event probabilities into account, amounts to approximately €150,000.

Table 9. Remediation cost for the leakage scenarios or potential events applicable for a depleted field. Probability quoted for leak event occurrence is over the project life time including post closure period.

Scenario	Corrective investment (€m)	CO_2 quota cost (€m)	Operation cost (€m)	Total (€m)	Probability (%)	Risked cost (€)
Minor leakage; fault & fracture	monitoring	11	10 (seismic surveys)	21	0.2	42,000
Moderate leak: fault & fracture	50 (relief well or new site)	19	5+2	76	0.05	3,800
Well leakage	5 (repair)	0,1	0	5,1	0.5	25,500
Well blowout	20 (well sidetrack)	7,6	5	33	0.05	16,500
Seepage in abandoned well	monitoring	1,4	5 (seismic surveys)	6,4	0.2	12,800
Leak from installation	3 (repair)	0	0	3	0.25	7,500
Undesired plume spread	10 (compensation)	0	10+2 (seismic surveys)	22	0.03	6,600
Arithmetic sum		39		166		148,900

5. Operational experience

This chapter assesses experiences from ongoing and completed projects with a focus on challenges, how these were addressed, and lessons learned. A case study from a natural gas storage facility leak has been included as a worst-case analogy for a potential CO_2 storage site.

The chapter can be summarised as follows:

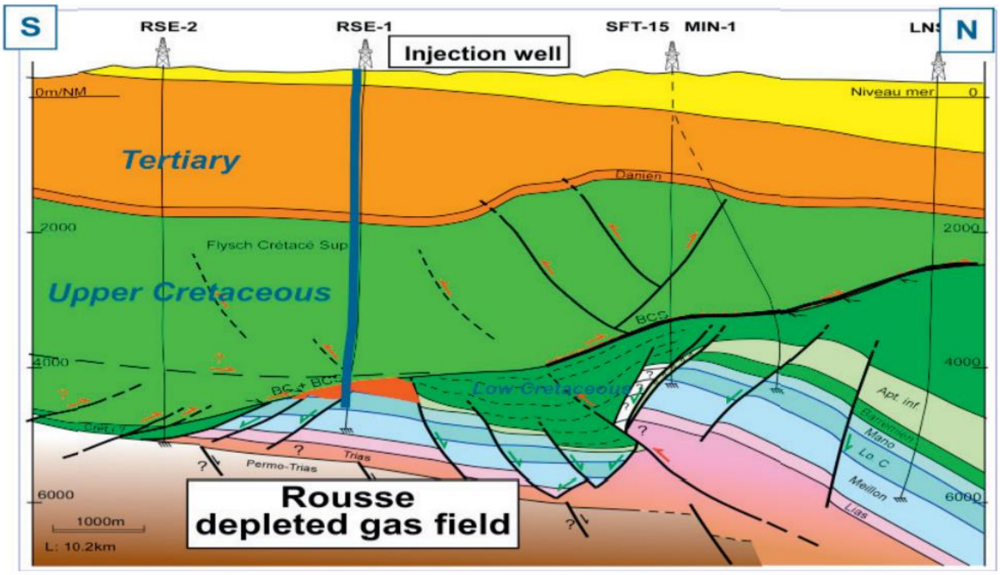
- No geological leakage to the surface has been detected so far;
- No blowout in modern CO_2 storage wells is known: one leakage in an exploration well without required safety equipment and old completion (1953, USA) has been observed;
- Few projects experienced restricted injectivity, which could be improved by well interventions. In one case a new injection well was required;
- Well completion can withstand long-term CO_2 injection;
- No effect on rock integrity is observed by injected CO_2;
- Seismic surveys have proved to be a reliable tool to monitor plume behaviour;
- Positive experience is gained with a broad suit of monitoring techniques;
- Thorough assessment before implementation and regular risk assessments are essential;
- Numerical models for simulating behaviour are developing rapidly.

5.1 Lacq, France

In 2006, Total decided to invest €60 million to launch the first end-to-end industrial chain CCS project comprising the capture, transport and injection of CO_2 into the depleted gas reservoir of Rousse in the southwest of France. Operated by Total Exploration Production France, the project demonstrated the technical feasibility and reliability of an integrated CCS chain. This CCS pilot was located in the Lacq-Rousse Gas Field in the Aquitane Basin, approximately 800 kilometers SW of Paris. The depleted deep gas reservoir (unprecedented in Europe) was chosen as storage site, located onshore five kilometers south of the town of Pau.

The Rousse field reservoirs are located in the Mano and Meillon formations of Upper Jurassic age (figure 8). They are composed of fractured dolomites and dolomite breccias (Biteau et al 2006). The two reservoirs are separated by argillaceous limestones of the Lons and Cagnotte formations, which is both the seal for the Meillon reservoir and the main hydrocarbon source rock. Only the Mano reservoir is used for CO_2 storage. The basal Upper Cretaceous interval overlapping the Rousse trap constitutes the reservoir seal. Three main Upper Cretaceous seal units and associated lithological types have been identified (Monne & Prinnet, 2013).

Figure 8. Schematic of the Lacq storage site in Rousse depleted gas field (Monnet & Prinnet, 2013).



A 4500m deep injection well was drilled. The main injection phase covered a two-year period with about 360 days of CO_2 injection at an average rate of 90 t/day, and 110 days at an average rate of 65 t/day.

Conclusions on the assessment of risks performed before injection are as follows; CO_2 injection was carried out in a depleted gas field, whose seal quality had been proven by the preservation of a hydrocarbon accumulation for millions of years. The knowledge acquired during many years of operation in the Rousse field, complimented by new additional characterization work (3D seismic, reservoir modelling including evaluation of geochemical and geomechanical effects) allowed for qualifying the site for CO_2 injection. Furthermore, injection operations were performed with a very high safety margin to prevent any possibility of injection-induced mechanical damage or leakage. The injection conditions (timing, flow rate, type of gas) help ensure that the gas plume will remain confined in the reservoir, at a pressure well below the initial pressure, with no risk of migration into the reservoir caprock. Procedures for well control and possibilities of intervention allow mitigating through corrective actions the risk of propagation of any defect in the completion, which could lead to a significant loss in well integrity and create a leakage pathway. The main risk was that of a highly unlikely free well blowout during the injection phase.

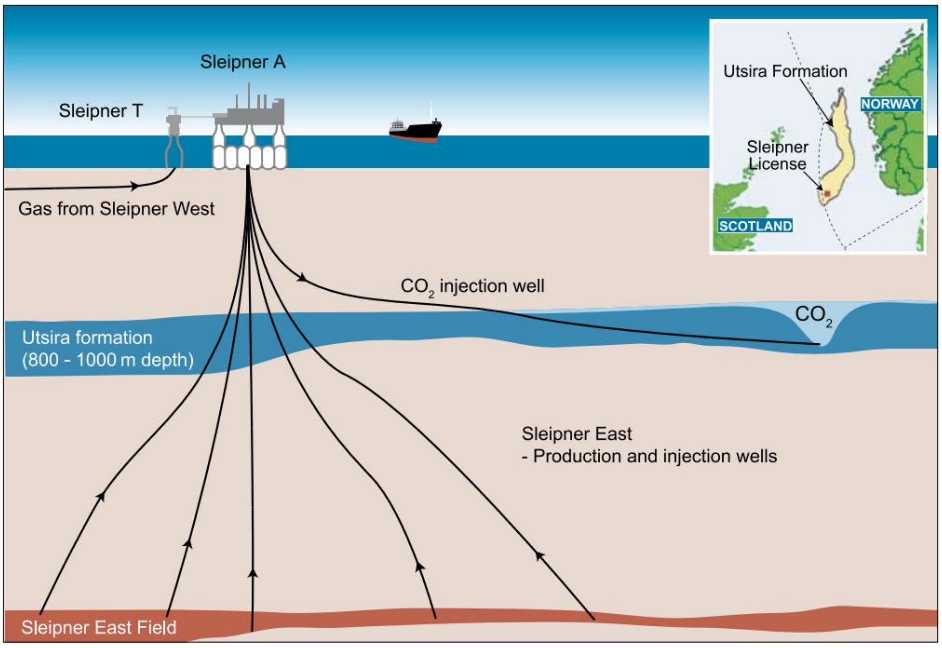
Total successfully demonstrated the feasibility of safely storing CO_2 in a depleted underground reservoir by injecting over 51,000 metric tonnes of CO_2 (GCCSI, 2015). The operability of a fully integrated carbon capture and storage scheme based on the oxy-combustion CO_2 capture process has been proved.

A resulting R&D challenge is selecting the right parameters, methods and equipment for a safe, economically and technically viable, long-term efficient onshore storage monitoring program.

5.2 Sleipner, Norway

Carbon dioxide associated with gas produced from the Sleipner Vest field in the North Sea has since 1996 been separated at the Sleipner T facility and injected into the saline formation waters of the sandy Utsira Formation nearby (figure 9). At the end of 2017, a total of 17.2 Mt of CO_2 had been injected. Initially, CO_2 storage at the Sleipner Field was approved as an integrated part of the development plan for the field. After introduction of national regulations for CO_2 storage, the site was transferred to a CO2 storage permit in 2016.

Figure 9: Simplified schematic of the Sleipner CO_2 Storage site in the Utsira Formation, Norway (IPCC 2005).



The Sleipner CO_2 storage site has been an operational site for offshore saline aquifer storage at industrial scale and has been widely used for research and technology development, particularly within monitoring and reservoir simulation technology. Monitoring activities have covered a broad range of technologies (Liebscher & Münch, 2016; Furre et al 2017) and especially seismic surveys have been acquired at high frequency (on average almost every 2nd year); this breadth and intensity of monitoring activity is far above operational requirements. The applied monitoring technologies have successfully mapped the subsurface distribution of CO_2 in the storage formation. There are no indications of leakage into the cap rock or to the sea floor, which provides evidence for containment of CO_2 in the storage formation.

The injection project initially experienced operational challenges related to insufficient injectivity in spite of a highly permeable formation (Hansen et al., 2005). The cause was interpreted as being due to sand ingress into the wellbore. The perforated interval of the liner was thus supplemented by sand screens (300 microns hole diameter), which improved injectivity somewhat but not sufficiently. Subsequently, an additional interval was perforated with downward-oriented perforation, supplemented with gravel pack and screens (200 microns), which established sufficient injectivity. Thus, well injectivity has been achieved applying standard industry well intervention methods. These interventions incurred additional costs, but these were limited due to access to the well from the injection platform. Further, CO_2 tax had to be paid for the emitted CO_2 related to the interventions.

The permitting process in 2016 included a risk assessment (Miljødirektoratet, 2016). The risk for leakage from the storage site was a major element of this assessment and the probability for leakage was estimated to be in the order of 0.01% during the injection period and 0.1% in the first 50 years after injection end. The rise in probability over time is due to the progressive spreading of the CO_2 plume which may reach abandoned wells.

5.3 Snøhvit, Norway

The Snøhvit Gas Field is a subsea field development in the Barents Sea with processing of the well stream onshore at the Melkøya LNG facility. Injection of CO_2 separated from the produced gas started in 2008. At the end of 2017, almost 5 Mt of CO_2 has been injected. Snøhvit CO_2 storage was initially approved as part of the development plan for the Snøhvit hydrocarbon field. Approval was renewed in 2016, now based on the national regulations for CO_2 storage introduced in 2014.

Initially, CO_2 was injected at approx. 2650 m below sea level into the fluvio-deltaic Tubåen Formation, a saline reservoir unit deeper than the producing reservoir unit at the Snøhvit Field (the Stø Formation) and separated from it by approx. 60 to 100 m largely finer-grained sedimentary rocks of the Nordmela Formation. A few months after the start of injection the downhole pressure gauge indicated rapid pressure increases which were interpreted as reduced injectivity due to salt precipitation in the near wellbore formation. Regular injection of batches of a MEG-water mixture improved injectivity (Hansen et al,, 2013).

However, the reservoir pressure still showed an overall rising trend, increasing faster than the (base case) reservoir model predicted. When observed pressure approached the formation’s fracture pressure a well intervention was carried out. First, shallower levels of the Tubåen Formation were perforated but this did not result in substantially reduced injection pressure at the required injection rates. Therefore, the Tubåen Formation was plugged in 2011 after injection of in total 1.09 Mt CO_2 and the well was perforated in the shallower shallow-marine Stø Formation, which was a fall-back solution provided for during well planning in case of low injectivity.

As a measure to increase operational flexibility and resilience, in 2016 an additional well was drilled for injection of CO_2 into a saline formation water-filled part of the Stø Formation at a depth approx. between 2500 and 2600 m below sea level. This also reduced the risk for contamination of the produced gas by CO_2 migrating from the injectors towards the producers. Since late 2016 all regular injection has been into the 2nd well.

CO_2 storage has been accompanied by a monitoring program which served both operational and research purposes. Its main component is time-lapse seismic 3D monitoring with four repeat surveys so far. The seismic monitoring data were instrumental for the understanding of rising pressure in the Tubåen Formation. No leakage from the target formations has been observed.

5.4 K12-B, Netherlands

In 2004 a demonstration project commenced at the K12-B field, offshore The Netherlands, where CO_2 that was separated on-platform from the produced gas was re-injected into one of the compartments of the field (Vandeweijer et al., 2011). The goal was to investigate the feasibility of CO_2 injection and storage in depleted natural gas fields.

The K12-B gas reservoir is so far the only gas reservoir in the Netherlands into which captured CO_2 has been re-injected. The K12-B gas field is located in the Dutch sector of the North Sea, some 150 km northwest of Amsterdam. Discovered in 1982, gas production started in 1987. Gas is produced from the Upper Slochteren Formation (Rotliegend), consisting of siliciclastic sediments of Permian age. The gas contains 13% CO_2, which is removed from the gas stream directly offshore on the platform. The reservoirs are at a depth of approximately 3800 meters below sea level; the temperature of the reservoirs is approximately 128 °C. The cap rock consists of hundreds of meters of rock salts from the Zechstein Super Group, making the most likely migration pathway for any gas, should migration occur at all, migration along the well bores.

The K12-B structure consists of several compartments, which are separated by faults or fault zones. CO_2 injection started in the northern, single-well compartment, compartment 4, by re-use of the B8 well, in 2004. Several injection and back production tests have been carried out in this compartment. Since 2005, over 100,000 tonnes of CO_2 has been re-injected, mostly into the central, multi-well compartment, compartment 3, by re-use of the B6 well.

Over the years, the K12-B reservoirs have served as a field lab, in which a variety of experiments and monitoring activities have been carried out. Research mainly focused on the conditions of the wells over time, which is of key importance for safety issues. Another goal was to gain a better understanding of the behaviour of the CO_2 in the injection wells and the migration of the CO_2 in the reservoir. CO_2 migration in the reservoir is relevant for the assessment of the potential for enhanced gas recovery (EGR) through CO_2 injection.

Monitoring at the production wells provided valuable information on gas composition; chemical tracers enabled the detection of breakthrough at producer wells and investigation of CO_2 migration in nearly depleted gas fields. It also proved vital to have sufficient downhole pressure and temperature data, as the CO_2 can be subject to large density variations. Overall it can be concluded that observations are supported by detailed reservoir model predictions.

The experience at K12-B provides confidence that well integrity can be assured throughout long periods of CO_2 injection. In the case of this field, this is partly based on the favourable properties of the salts from the Zechstein Super Group, the primary seal. K12-B experience helped select efficient and effective well logging tools.

In 2017, production from the two compartments used for the CO_2 injection and back production tests stopped. All CO_2 related operations at the K12-B field were conducted without major complications, supporting the conclusion that safe and secure underground storage in nearly depleted gas reservoirs is technically feasible. During the many projects at this field, several techniques were tested and many processes investigated. Information on the CO_2 injection activities at K12-B can be found in Vandeweijer *et al*. 2011.

5.5 Ketzin, Germany

At the CO_2 sequestration site near Ketzin, Germany, CO_2 was injected into a saline aquifer from June 2008 until August 2013. This is the first on-shore geological storage site in Europe, where a total of about 67,000 tonnes of CO_2 were injected. The main goal of the Ketzin site was to improve the understanding of relevant in-situ processes associated with CO_2 storage and to gain practical experience for future CO_2 storage sites. Investigations at the site started in 2004 with site characterisation and baseline surveys, drilling and well instrumentation, set-up of the injection facility and implementation of monitoring techniques (Bergmann et al., 2016). Two observation wells, Ktzi 200 and Ktzi 202, were drilled prior to injection to a depth of 750 m to 800 m at a distance of 50 m to 100 m from each other. At the far monitoring well (Ktzi 202) breakthrough of CO_2 was observed in March 2009.

A seismic monitoring system was designed and implemented, consisting of vertical and horizontal geophones and hydrophones at different locations along a line and at different depths (Arts et al., 2011). This system has been used to continuously record passive seismic data (Paap & Steeghs, 2016).

The entire operation of geological storage of CO_2 at the Ketzin site was conducted safely and reliably (Martens et al., 2015; Liebscher &Münch, 2016). The spatial distribution of CO_2 could be imaged with a site-specific combination of geochemical and geophysical monitoring techniques. Fluid-rock interactions induced by the injected CO_2 showed no significant effects at the Ketzin pilot site and do not affect the integrity of the reservoir and cap rocks.

5.6 In Salah, Algeria

The In Salah CCS project in central Algeria is a pioneering onshore CO_2 capture and storage project (Ringrose et al., 2011). Injection commenced over a seven-year period from 2004 to 2011 subsequently storing over 3.8 Mt of CO_2 in a 20m thick aquifer in the subsurface (Mathieson et al, 2010; Zeboudj, 2017). Carbon dioxide from several gas fields is removed from the gas production stream in a central gas processing facility; the CO_2 is compressed, transported and stored underground in the 1900m deep Carboniferous sandstone unit at the Krechba field. Three horizontal injection wells are used to inject the CO_2 into the down-dip aquifer leg of the gas reservoir. The storage performance has been monitored using a diverse portfolio of geophysical and geochemical methods, including time-lapse seismic, micro-seismic, wellhead sampling using CO_2 gas tracers, down-hole logging, core analysis, surface gas monitoring, groundwater aquifer monitoring and satellite InSAR data. Routines and procedures for collecting and interpreting these data have been developed, and valuable insights into appropriate Monitoring, Modelling and Verification (MMV) approaches for CO_2 storage have been gained.

Prior to injection start-up, a pre-injection risk register was prepared as part of the initial site assessment and used to design the monitoring programme. Most of these planned monitoring activities were implemented. A key feature of any monitoring programme is the ability to use the monitoring data to respond to field performance and operational developments. The In Salah CCS demonstration project has been important for understanding the value of various monitoring methods applied. Several Quantified Risk Assessments (QRA) have been conducted during the operational phase, integrating all available data to assess both the storage integrity and effectiveness of the storage complex. In 2008, the QRA identified two dominant risks for special focus: (i) the risk of migration to the north, and (ii) the loss of well integrity. The 2010 QRA identified a new dominant risk concerning the potential for vertical leakage into the caprock, based on the results of the integration of the new seismic, satellite data and dynamic/geomechanical models. These risks were in the initial risk register, but new data led to more precise definition of the risks and to approaches for risk mitigation.

Considerable attention has been focused on injection performance and plume development around injection well KB-502, where a fault or fracture zone behaved as a flow conduit for CO_2 and acted as a focal point for rock failure (in either tension or shear mode). Although all the processes involved are not fully understood, integration of all the available data has led to many new insights into the rock mechanical response to CO_2 injection. It is clear that CO_2 injection has stimulated natural fractures at this location, and may have introduced new hydraulic fractures. Although these fractures do propagate upwards into the 300m thick lower caprock, they are unlikely to propagate further through the 600m thick upper caprock. No leakage has been observed and all indications are that the CO_2 remains safely contained within the storage complex. In June 2007 some tracers were detected at the wellhead of an appraisal well (KB-5), furthermore, raised CO_2 concentrations were also monitored around KB-5, this well is now fully plugged and abandoned (Ringrose et al, 2009; Ringrose et al, 2013). Following the 2010 QRA, the decision was made to reduce CO_2 injection pressures in June 2010. Subsequent analysis of the reservoir, seismic and geomechanical data led to the decision to suspend CO_2 injection in June 2011.

Some important general lessons learned can be drawn from this project, as follows:

1. Monitoring should be part of the Field Development Plan (FDP) and routine field operations.
2. The suite of monitoring technologies to be deployed at any CO_2 storage site mainly comprises standard oilfield techniques and practices, with surface monitoring methods derived from standard geotechnical and environmental monitoring practices.
3. Satellite InSAR data has been especially valuable in understanding the geomechanical response to CO_2 injection, but needs to be integrated with high quality reservoir and overburden data and models.
4. The storage monitoring programme needs to be designed to address site-specific leakage risks identified in the selection phase, but also needs to be adapted during the operational phase.
5. Abandoned and suspended well integrity is a key leakage risk that has to be effectively managed.
6. Acquisition, modelling and integration of a full suite of baseline data, including the overburden, are vital for evaluating long term storage integrity.
7. CO_2 plume development is far from homogeneous and requires high resolution data for reservoir characterisation and modelling.

8. Injection strategies, rates and pressures need to be linked to detailed geomechanical models of the reservoir and the overburden. Early acquisition of geomechanical data in the reservoir and overburden, including extended leak-off tests, is advisable.
9. Regular Risk Assessments should be conducted to inform the on-going operational and monitoring strategies.

Probably the most valuable lessons from the abandoned In Salah project will be the pioneering development, deployment, and interpretation of an unique set of MMV technologies.

5.7 Aliso Canyon, California U.S.A.: analogue

Aliso Canyon is a natural gas store in California, which utilises a depleted oilfield including the conversion of some of the abandoned oil wells into gas injectors / producers. From October 2015 to February 2016 blowout of a converted injection well caused a severe leakage of stored natural gas in one of the largest greenhouse gas releases in the US (0.13 GSm^3 reported: Lindeberg et al. 2017). This case study is often cited as an analogy for a worst case scenario for a well blowout in a CO_2 storage site. It must be emphasised that the production well was drilled in 1953, and converted in the 1970s to a lower standard compared to wells in the North Sea, and a CO_2 storage site today would not be permitted to store in a similar location in Europe. Nonetheless, the leakage as a result of gas injection and the associated remediation process are transferable to a CO_2 leakage scenario.

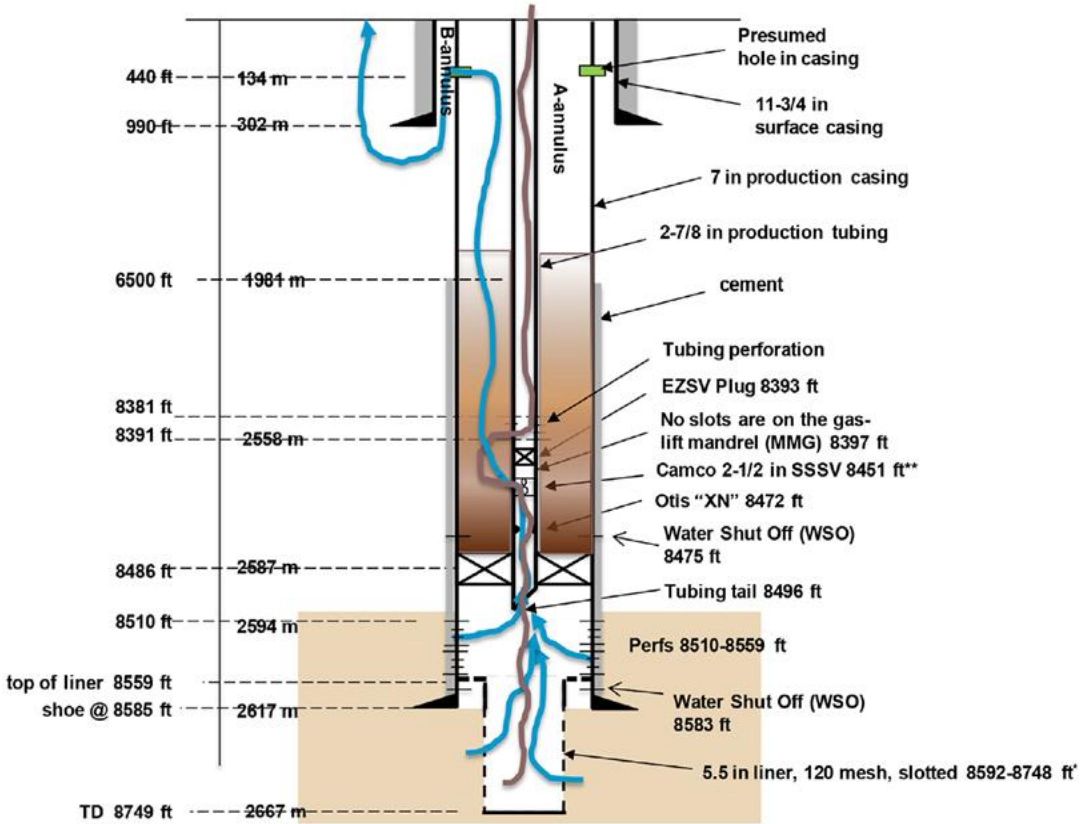
The stored gas had been odorised using Mercaptons, as is common for residential gas supplies, and this bad smell from the released gas led to the displacement of many local residents from their homes. The gas leak was widely publicised in the global press, and has triggered a new focus on the safety and regulation of gas storage activities in the US (PIPES act 2016 to require the establishment of minimum safety standards).

It has been modelled that if a similar leakage was to occur in a CO_2 storage site over the same period of time, the total volumes and rate of leakage would be lower with CO_2 gas compared to natural gas. This is due to the differing physical properties of the gases. In total 2.8% of the stored natural gas was lost during the Aliso Canyon leak, the equivalent loss from a CO_2 storage site would have been at most 0.37% of the stored volume (Lindeberg et al., 2017).

The leak developed in a converted abandoned oil well that was drilled in 1953, and converted to gas storage in 1973. The leak was caused by a rupture of the corroded seven-inch production casing which was being used, in addition to the well tubing, to inject gas (Blade Energy Partners, 2019). Injection via the annulus is not permitted for CO_2 storage. The A-annulus is monitored, so any leak from the tubing to the annulus should be detected – with the likely consequence being the suspension of injection then emplacement of a deep-set plug and then repair of the tubing along.
The attempted remediation activities (top well kills) resulted in the formation of a large crater around the wellhead. The gas leak was eventually stopped by drilling a relief well, that was able to intersect with the damaged well below the annulus leak point; finally, a mud

compound followed by cement was injected to permanently plug the well in the subsurface. The drilling of the relief well took nearly 40 days (Dec 4th 2015 to Feb 11th 2016).

Figure 10. Sketch of the Aliso Canyon SS-25 well and interpreted flowpaths of the leaking hydrocarbon gas (blue) and kill fluid (brown) during one of the unsuccessful well kill attempts. Note that the interconnections between the tubing and the casing resulting from perforations above the tubing plug at 8383 ft) (U.S. DOE National Laboratories, 2016).



The Aliso Canyon case highlights the importance of good monitoring, maintenance and remediation procedures for all wells which penetrate the storage reservoir (both abandoned and operating). Although the development was maintained in accordance with the limited regulatory framework, the cost to the reputation to the operating company and goodwill of the local residents, as well as the financial cost of drilling a relief well, will have been considerable.

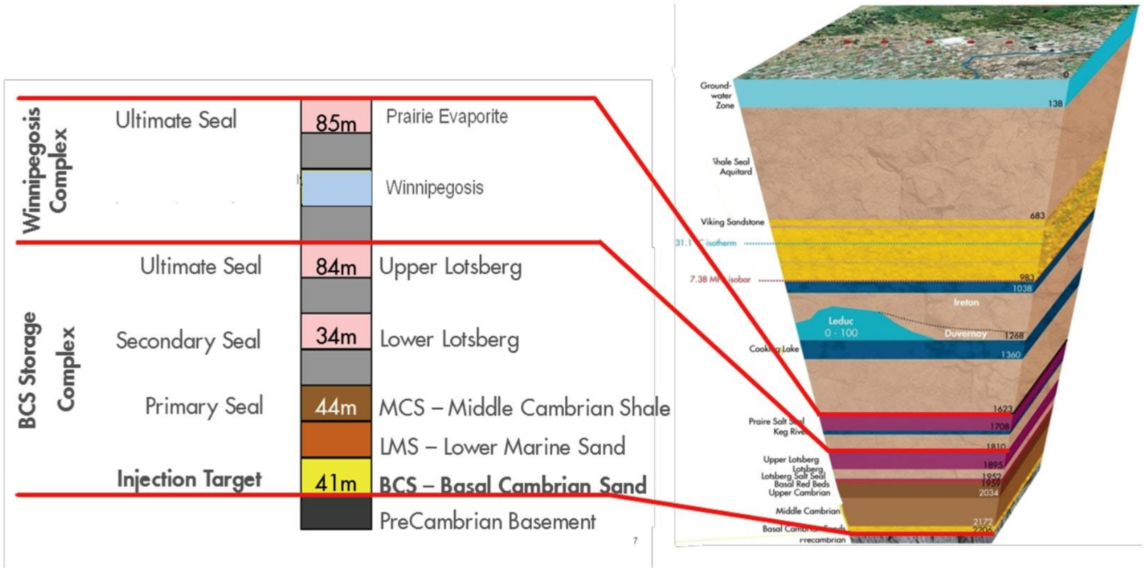
The blow out was finally stopped after 111 days. This is consistent with the timings for relief well drilling used in this report.

It must be reiterated that the EU storage regulations would not have permitted injection well configurations like those used in Aliso Canyon.

5.8 Quest, Alberta Canada

The Quest CCS facility is operated by Shell on behalf of the Athabasca Oil Sands Project, near Edmonton in Alberta (Canada), and has demonstrated that CCS and storage in an open structure can work. In its first three years of operations, Quest captured and safely stored 3 Mt of CO_2, and achieved this milestone ahead of schedule (Alberta Department of Energy, 2016). At the time of writing in summer 2019 Quest has passed the 4 Mt milestone. Carbon dioxide generated at the Scotford upgrader hydrogen manufacturing units has been captured and stored in the subsurface since 23rd of August 2015. The CO_2 is transported to the storage site by pipeline, and then injected into the basal Cambrian sandstone, more than 2000m below the surface (figure 11), at an approximate rate of around 1 Mt per year. The project injected up to 1.2 Mt of CO_2over a one-year period, which is the most stored in one calendar year by a CCS project to date.

Figure 11. Quest storage complex, showing target storage horizon, Basal Cambrian Sand, and overlying seal formations (from Bacci et al., 2017).



The storage site was developed with three potential injection wells. To date the wells have performed beyond expectation, with injectivity comparable to the pre-development high case, and limited overpressure development. Repeat vertical seismic profile (VSP) monitoring has been able to visualise the developing CO_2 plume subsurface, which has not been detected beyond the expected area.

The project has been using two of these wells for injection, with the third well reserved for monitoring observations and as a spare to maintain injectivity should one of the injection wells require shut-in for maintenance or remediation. One well injects at a constant rate, while the other varies to meet the storage demand from the hydrogen manufacturing unit. This scheme simplifies the reservoir response for the well injecting at a constant rate, optimizing the monitoring and learning potential.

Reservoir performance to date (analysis of reservoir pressure response), along with injectivity assessments, indicate the project will be capable of sustaining adequate injectivity for the duration of the project life; therefore, no further well development should be required (Alberta Department of Energy, 2016). Operational challenges have been minor; for example, corrosion of a wastewater pipe at the capture location caused by the acidity of the Quest wastewater, and minor facility leaks, none of which were significant.

Using only two wells for injection has reduced project operating expenditure (reduced power and compression requirements), as well as monitoring costs. The compressor is able to operate at lower power, utilizing 13-15 MW versus 18MW as per the full design. The pre-development appraisal campaign allowed the project to develop sufficient confidence to reduce the initial project well count from eight to three. Given the excellent reservoir properties and pressure dissipation demonstrated, it could be possible to use a single well to inject the entire CO_2 stream.

A phased development might have reduced capital expenditure by drilling only two initial injection wells, and then following this by drilling another well as required based on the injection performance of the first two wells (a spare well is always required to ensure continuous site injection capability). However, in the case of the Quest project all three wells were needed from the project outset to provide the required injectivity performance guarantee that allowed the project to qualify for government capital investment.

6. Experience with Financial Security and Liability

Financial security has been a key point in discussions between prospective operators and authorities in the permit processes of all storage projects and the preparation of such projects in Europe. Article 19 of the EU CCS Directive requires Member States to ensure potential operator's evidence financial security as part of their application for a storage permit to cover both foreseen and unforeseen events and costs, the latter related to leakages of CO_2, and for extra monitoring, remediation throughout all phases of project etc. As noted in Chapter 1 these requirements may be considered a barrier to entry for entrants into the CCS industry.

Guidance Document 4 (GD4) for the CO_2 Storage Directive gives strict interpretation of the Directive in respect of Financial Security. One aspect requires all obligations under the CO_2 Storage Directive to be defined and cost estimated, however, probability weighted reduction of costs is not allowed. As documented in Chapter 4 of this report the probability for leakages is so small that less over 99.99% of the inject CO_2 will remain stored over 500 years. The GD4 might also allow for a more flexible approach by each competent authority as its first page includes the following words; "the aim of the guidance is to strike the right balance between full coverage of obligations as required while at the same time not overpricing the risks in relation to these obligations for early movers

This chapter reviews experience with application and approval processes with national authorities and presents an example of the liability issue faced by an applicant for a CO_2 underground storage permit. Member States have shown a broad variation in how they apply the regulations in respect of Financial Security as illustrated by the following examples.

In Norway, there have been CCS operations with CO_2 storage at Sleipner and Snøhvit for more than 20 years, commencing in 1996 and 2006 respectively. The permits for these activities were granted prior to the existence of any CCS specific legal framework. The 2009 EU CCS Directive was implemented in Norway in 2014, through a new chapter in the Petroleum Activities Regulations (PAR), a new chapter in the Pollution Control Regulations (PCR) and a new instrument, namely the CO_2 Storage Regulations (Storage Regulations).

Originally, CO_2 storage at Sleipner and Snøhvit was permitted subject to the Petroleum Activities Act (PA) and the detailed operations stipulated by the production license and plan for development and operation (PDO), as well as the requirements imposed by e.g. the permits granted subject to the Pollution Control Act (PCA).

Subject to the new legal framework for CCS, Equinor (then Statoil) applied for new CO_2 storage permits for both Sleipner and Snøhvit by 1 January 2016, subjecting the activities to the new provisions in the PCR. Consequently, after a dialogue with the Norwegian Ministry of Petroleum and Energy, Equinor applied for new permits in October 2015. The new permits were granted by the Norwegian Environmental Agency in 2016. The 2016 permits replaced parts of the permits originally granted, imposing stricter requirements regarding e.g. monitoring, post closure operations and financial securities than previously required under the emissions permits. However, no new requirements or criteria were imposed in the production licenses as such and no dedicated fund for Financial Security was required to be set aside up front.

In the negotiation of the storage permit for Goldeneye the British authority also exercised considerable flexibility. An agreement was reached on terms regarded as reasonable by the operator. As this permit was not concluded, detailed terms are unknown. The relevant operators for Norwegian and British projects are some of the largest oil companies in the world and they might have given a parent company guarantee for the CCS operation.

Unlike Norwegian and British authorities, the Dutch authorities chose to follow the Guidance Document 4 to the letter with the permit for the TAQA storage project P18-4. In this case the Financial Security covers 100% probability events such as decommissioning and monitoring as well as low-probability events assuming that they will occur. This results in large security amounts of more than €60 million over the initial five-year period as set out in the permits. The class risk for a similar, however twice as large storage site, estimated in Chapter 4.4 is € 150,000 for the low probability events. The entire un-risked remediation costs for all potential events of this larger site amounts to €150 million disregarding abandoned wells.

With a total capital investment for the storage part of the original ROAD project (P18-4) of around €30 million, the Financial Security of more than €60 million imposes a heavy burden on the business case of the storage project. All of the low probability elements are extremely unlikely to occur and many cannot physically happen simultaneously.

The P18-4 field is almost fully pressure depleted and structurally isolated and sealed (Ministerie van Economische Zaken, 2013 Article 16.2). Its original pressure was 348.5 bar, its current pressure is 20 bar, and its final fill pressure at end of CO_2 injection will not be more than 320 bar according to permit. There are no abandoned wells in the structure. The only well in this storage site is the injection well itself, which supplies the only realistic leakage pathway until it gets permanently plugged.

Under the permit there is a requirement to review the Financial Security at intervals, July 2018 being the first opportunity. The permit application includes preliminary elements, recognising that understanding of risk, mitigation and impact would evolve, particularly as the equipment selection, design and operating procedures were not yet defined, just a preliminary concept. As the CO_2 Storage Directive asks for review/update of the entire permit five years after issuing, it is anticipated that a review will begin soon.

A general discussion of the Financial Security topic follows in Chapter 7.

7. Discussion

7.1 Leakage risk

As demonstrated in Chapter 4, the risk of leakage from a European CCS project in the North Sea Basin to the ocean or atmosphere is extremely low, and its potential consequences limited. For a representative, hypothetical case evaluated in this report (160 Mt CO_2 injected in total over a period of 20 years, 1 injection well, 1 abandoned well) it can be expected that 99,99 % of injected volumes will remain securely underground for at least 500 years. The class risk of leakage from a well-planned and well-developed European storage projects is hereby suggested to be 0.01% of total injected amounts.

Leakages from wells, facilities or underground features, as well as other events are expected to be very rare, if the requirements set out in the EU Storage Directive and relevant oil and gas industry standards from the North Sea are applied. The estimates indicate that less than one in one hundred projects will face such unplanned accidents or challenges, and only at low leakage rates and very limited total leakage amounts. A worst-case leak from an offshore storage site is expected in only one of 10,000 projects. The financial consequences could be significant to very high, but impact to people and the environment will be minimal in the short and longer term.

Wells are widely considered as the most likely source of leakage until permanent site closure. The least predictable wells are abandoned wells (old, plugged wells), because their condition is often uncertain. Such wells should be given particular attention. Leakage via a fault, even given reactivation through increasing injection pressure, carries a lower assessed risk. Caprocks are normally ductile, and this property could prevent even a reactivated fault from providing a leakage pathway to the surface.

The yearly risk related to containment in financial terms is less than €10,000 (figure 7) when event probabilities are taken into account and allowing for some uncertainty in the performed estimates. This number reflects ideally the average yearly basis payment for insurance (administration etc in addition). The total risked cost for unplanned events amount to €0,84 million for one project (table 8). Because of the low probabilities this is far lower than the remediation cost for most single events, which can reach several hundreds of millions of Euros. 50 years after closure the residual risk for most projects will be minor.

The two studies which form the basis for these calculations use a broad range of statistics from oil and gas activity in the North Sea. They were performed in experienced technical environments by companies with a well-earned reputation. The results of the two studies are internally consistent. This gives confidence that the results are of the right order of magnitude.

There are a great number of saline aquifers and depleted oil and gas fields suitable for CO_2 storage particularly in the North Sea. A large quantity of relevant data is available for planning and assessing potential sites. Oil and gas companies, which are the most likely operators for early storage, are operating similar projects today with high level of safety and environmental performance. These companies possess the competence, knowhow and capacity to develop and operate CO_2 storage projects.

A number of projects have already been successfully implemented or completed. Some were pilots and others were established for separation of CO_2 from natural gas before sale. Some of these projects are described in Chapter 5. Some have had injection interruptions because of problems with capture technology (at Rousse) or injectivity; however, these were solved using standard industrial technology. In the meantime, the site owners had to pay for ETS credits or may be liable for CO_2 taxes for released volumes. These projects confirm that geological CO_2 storage is proven technology, ready for wide implementation.

7.2 Liability and Financial Security

As illustrated in chapter 6, European nations apply different approaches in defining the Financial Security. Norway and the UK appear to have exercised considerable flexibility so far.

A major challenge is the absence of a functioning market for CO_2 storage. The CO_2 price, such as EU ETS allowances or CO_2 emission tax at present or expected levels, will not cover the cost of capture, transport and storage of CO_2. For projects deployed in advance of a comprehensive European framework to deliver a net zero society, the anticipated earning margins for storage site operators will necessarily be kept so low that they in many cases cannot alone carry the liability for extremely unlikely events.

The focus on risk can, however, lead to an extremely cautious approach concerning setting aside Financial Security with the storage permits. In the case of P18-4 in the Netherlands the regulators requested a Financial Security figure large enough to cover all events, routine or unplanned, regardless of probability, for a notional monitoring period of 50 years. However, most of the risk events are extremely unlikely to occur and many cannot happen simultaneously. This way of calculation thereby undermines any storage business case unnecessarily and obstructs the development of a sound CO_2 storage infrastructure.

No individual operator can afford to set aside working capital to cover all such unlikely eventualities for every project, and no other ongoing business operates under an equivalent requirement. In other industries similar risks are usually absorbed by an insurance system (e.g. in the oil and gas industry). A guarantee or insurance system, initiated by the authorities, for sharing the risk for the CCS industry would significantly reduce the burden currently carried by first-mover projects and proactively encourage CCS deployment. As there initially will be too few projects for an evolved insurance system, this liability will initially need to be shared between government and the private sector.

The EU CCS Directive was reviewed in 2014. The conclusion of this evaluation was that the overall need for CCS to decarbonise particularly industry in Europe remains genuine and urgent. Fewer CCS projects have been implemented than envisaged in 2009/10. There was general agreement that given the lack of practical experience in Europe it would not currently be appropriate, and could be counterproductive, to reopen the Directive for significant changes. However, this report highlights that some clarifications and softening of interpretation in Guidance Document 4 (GD4) could be valuable.

The review states (quote from the EC review) further that there are some serious concerns among developers regarding the levels and procedures for handover from developers to the Member States' competent authorities and the financial securities related to future monitoring and leakage from storage sites. The only European CCS project with practical experience of going through the integrated permitting process including storage is ROAD. In 2013, the project developers agreed workable solutions with the Dutch CA that both parties appeared to accept until the first routine review was due. This single example suggests that there is still enough flexibility to allow procedures to be agreed and projects to be advanced. Care needs to be taken that the accompanying Guidance Documents do not become over prescriptive, as concluded in the summary report for the European Commission.

The referred concerns relate to articles 19 and 20 of the EU CO_2 Storage Directive and also GD4. It appears that articles 19 and 20 were written in such a way as to give a relatively high level of flexibility to the competent authorities of the Member States in deciding when handover should occur and what Financial Security site operators should provide. GD4 is intended to help provide some further guidance on these issues. It appears that GD4 is being used as more than guidance, which is leading to calls that the more detailed procedures it suggests will impose high costs on projects. This makes CO_2 storage projects more difficult to progress.

In summary, CCS is a relatively straightforward technology benefiting from a clear regulatory safety framework that, however, imposes a heavy legislative and financial burden on the operators this, in turn increasing the perceived risk, as the lack of large full-scale CCS projects is misconstrued to be based on its high cost and technical immaturity.

7.3 Storage types and their relative leakage risk

Several storage types are listed in chapter 2. The available data is not comprehensive or plentiful enough for a quantitative comparison between different storage types. The assessments in Chapter 4 are broadly based on aquifer sites, for which there is the most available data. A qualitative comparison indicates that empty petroleum fields in hydraulic contact with an aquifer, will offer similar or slightly lower risk for a storage development because of the availability of static and dynamic data, and mostly reduced reservoir pressure. Isolated depleted oil and gas fields are perceived to have the lowest risk, since they are not in hydraulic communication with any surrounding geological features to leak to as long as pressure is kept below initial pore pressure. If facilities and wells are still intact on the existing fields and can be reused, development and operation costs might also be substantially reduced.

For the various types of storage sites the following can be said:

- Depleted pressure sites will in general have a lower leakage risk than sites with initial pressure. Fracturing processes and reactivating of faults are pressure and stress driven. Structures are expected to be intact (e.g. faults sealing) at their initial state. Furthermore, flow can only take place from higher to lower pressure, meaning CO2 injected into a pressure depleted store cannot move into any surrounding formations which have higher pore pressure. Most old oil and gas fields are depressurised, often to a large extent. Similarly, the pressure in many North Sea aquifers has been reduced by the far-reaching pressure footprint of oil and gas production.

- Many abandoned wells at a potential storage site may increase the leakage risk. Normally these wells are more numerous in abandoned oil and gas fields than at aquifer sites. However, abandoned oil and gas field wells have typically been more carefully plugged than dry abandoned exploration wells. The standards for plugging and abandoning of wells have in general become more stringent over time, and relevant technology has evolved, which implies that older abandoned wells might bear a larger risk than newer ones.
- Depressurised sites (including both abandoned oil or gas fields or aquifer sites) may cause drilling challenges though there is ample industry experience with drilling in depleted formations. Such drilling challenges are not exclusively related to CO_2 leakage possibility.
- The consequences of a CO_2 leakage from an abandoned oil or gas field are potentially more severe than from a saline aquifer, this is due to the risk of carrying remnant hydrocarbons to the surface. However, as mentioned, these sites are often pressure depleted and thus less prone to leakage.
- In strongly depleted abandoned oil or gas fields, where pressure is reduced far below the surrounding formations, the migration of CO_2 or formation water out of the storage complex is highly unlikely. This reduces risk of impact on, or leakages into, nearby areas. These fields will have leakage-related risk below the estimates given above.
- Sites with fixed storage boundaries, where pressure can be maintained below initial (e.g. isolated, depleted gas fields), also require less monitoring than a store utilizing a field or aquifer with undefined boundaries and large areal extent. For small projects, depleted and isolated gas fields might be the most economic candidates for storage, however for large volumes aquifers or fields associated with aquifers seem a suitable alternative.

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9. Working group participants

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Appendix A: Decision making for values in Table 6

The scenarios in the two studies from DECC (2012) and Gassnova (Scandpower/NGI, 2012) are not exactly the same. Furthermore some of the scenarios are presented in different ways and in some cases the parameters are slightly different. The numbers which characterise the scenarios in table 6 could therefore not be derived from the figures in the basic studies just by averaging. The numbers in the table 6 had therefore to be derived by using best engineering judgement. Some conservatism has been applied as numbers have been rounded upwards.

The sets of parameters for the scenarios in table 6 are explained below. For each scenario the parameters from the basic studies and those used in table 6 are shown in a table and compared, (probabilities in these tables are in decimal fraction not percentages):

Scenario 1, Minor leakage through fault and fracture:

	Probability	**Leakage rate t/d**	**Duration**	**Lost amount, Mt**
DECC	very low (10^{-4})	1-50	100 years	Up to 1.8
Gassnova	10^{-6}-10^{-3}	50-200	50-200 years	4-14
Table 6 case	2×10^{-3}	100	50 years	1.9

The DECC study states that the probability for leakage through fault and fractures is very low (10^{-4}) in geological well-defined North Sea storage sites as we discuss here. The DECC study does not differentiate between low and major leakage rate in this respect. In table 6 probability is set higher for minor leakage than for moderate or high leakage as shown underneath. The choice of duration relates to injection period and total injected volume. Lost amount is calculated by use of the parameters of this case.

Scenario 2; Moderate leakage through fault and fracture:

	Probability	Leakage rate t/d	Duration	Lost amount, Mt
DECC	very low (10^{-4})	50-250	1-5 years	Less than 0.46
Gassnova	10^{-6}-10^{-4}	800-1700	30-100 years	25
Table 6 case	5×10^{-4}	700	12 years	3.1

The same approach is used as above. The probability is set slightly higher than average in the studies to maintain conservatism. The rest of the values are approximately set as average between results of the studies.

Scenario 3, Severe leakage through fault and fracture:

	Probability	Leakage rate t/d	Duration	Lost amount, Mt
DECC	Very low (10^{-4})	1500	1-5 years	0.55-2.7
Gassnova	Typically 10^{-8}	4000	30 years	100
Table 6 case	5×10^{-5}	5000	4 years	7.3

The same approach is used as scenario1. The probability was set lower than for moderate leakage in scenario 2. The leakage rate is set relatively high as it is assumed here that the leakage rate is highest at the beginning of the leak and then declines over time. Mitigation measures are implemented early and have effect within shorter time than in the Gassnova scenario.

Scenario 4, Active well leakage:

	Probability	Leakage rate t/d	Duration	Lost amount, Mt
DECC	10^{-4} – 10^{-3}	1-10	0.5-20 years	Max 0.7
Gassnova	5.5×10^{-3}	2200	60 days	0.14
Table 6 case	5×10^{-3}	50	250 days	0.012

The scenarios in the basic studies are quite different and reflect only to some degree the table 6 case. The table 6 case is defined as a moderate leak in an active well, which gets repaired through the well itself. Some conservatism is applied for the duration as such operations are often challenging and organising large scale unplanned logistics can be a lengthy process. The lost amount is calculated based on the parameters of the case.

Scenario 5, Active well blowout:

	Probability	Leakage rate t/d	Duration	Lost amount, Mt
DECC	10^{-5}-10^{-4}	5000	3-6 months	0.5-0.9
Gassnova	2.2×10^{-3}	8600	60 days	0.54
Table 6 case	15×10^{-4}	5000	250 days	1.25

This case covers an uncontrolled well blowout, which is mitigated by a relief well. The probability and leakage rate are combined, and approximately reflects the average between the two basic studies. The duration given in the basic studies is derived from the oil industry. The time for concluding a CO_2 blowout is longer and more conservative, as experience tells organising large-scale unplanned logistics involving a rig, particularly if rigs are occupied and distant, can be a very lengthy process. CO_2 would be regarded much less threatening to people, environment and economy than hydrocarbons.

Scenario 6, Abandoned well blow out:

	Probability	Leakage rate t/d	Duration	Lost amount, Mt
DECC	10^{-7}– 10^{-4}	1000	3-6 months	Max 1.8
Gassnova	less 10^{-4}			0.54
Table 6 case	10^{-3}	3000	1 year	1.1

This scenario reflects an aquifer storage in a hydrocarbon explored region of the North Sea. These regions are covered with old exploration wells, of which many may be poorly plugged in respect of the potential storage formations or where abandonment documentation is incomplete. The best would be to avoid such wells, however, with a broad CCS implementation this might not be fully possible. In this scenario the storage site has an old exploration well in its neighbourhood. As there is no experience with poorly plugged exploration wells in contact with a storage site, this scenario is assessed conservatively; both probability and leakage rate approximately 60% of an active well (scenario 5). The DECC scenario is regarded too optimistic in light of the lack of experience. A repair might not be possible and in an extremely unlikely scenario the storage formation might have to be depressurised by a relief well. A well repair, if possible, will take longer than for an active well as the well path and leakage area must be exactly located before repair.

Scenario 7, Seepage in legacy well:

	Probability	Leakage rate t/d	Duration	Lost amount, Mt
DECC	$1\text{-}5 \times 10^{-3}$	0.6 - 6	1-100 years	Max 0.22
Table 6 case	5×10^{-3}	7	100 years	0.25

This scenario reflects seepage in an old legacy well, it might be an exploration well or an abandoned production well in a depleted field. The parameters are taken from the DECC study. The conservative side of the band is thereby applied.

Scenario 8, Severe well problems:

	Probability	Leakage rate t/d	Duration	Lost amount, Mt
DECC	10^{-7}– 10^{-4}	1000	3-6 months	Max 1.8
Gassnova	2.2×10^{-3}	8600	60 days	0.54
Table 6 case	5×10^{-4}	6000	2 years	4.3

This scenario represents a worst case situation; where the well cannot be fully repaired and where the site must be given up, depressurized and replaced by a new site. This scenario is very unlikely, however not unthinkable and included for the assessment to be complete. Probability and leakage rate combined, it reflects approximately the average between the two basic studies. The duration given in the basic studies is derived from oil industry statistics. The time for halting the CO_2 blowout and producing back CO_2 might realistically require more time than indicating by the both studies.

Scenario 9, Leak from installation:

	Probability	Leakage rate t/d	Duration	Lost amount, tonnes
Gassnova	0.0025	100	5 days	500

These numbers are based on operational statistics from the North Sea (Scandpower/NGI, 2012).

Scenario 10, Undesired plume spread;

The number is based on a specific site (Scandpower/NGI, 2012). This scenario is, however, entirely dependent on the geology of the specific site, general numbers cannot be given.