Deep Geological Storage of CO_2 on the UK Continental Shelf

Containment Certainty

February 2023

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Quality Control

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Richard has 33 years of industrial experience as a consultant in energy and natural resources, primarily in the extractive industries, hydrocarbon exploration and production, and energy distribution. With a background in structural geology, he has expertise in faulting and fault rocks, and the characterisation of fracture networks for fluid flow modelling. Richard began working with CCS in 2008 with a focus on storage site appraisal and containment risk as part of the ETI UK Storage Appraisal Project. He has also worked with other areas of the energy transition including ground monitoring of geothermal power plants and gas storage sites, subsurface analysis of abandoned coal mines for mine-water heating, and monitoring peat erosion for carbon budget modelling. Richard is managing director of Geospatial Research Ltd. and a director of GeoEnergy Durham, and a Research Fellow at Durham University.

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Neil is a subsea engineer with Crondall Energy with 38 years' experience in consultancy, subsea well equipment design and subsea systems engineering. He has extensive experience in design and operation of subsea equipment and tooling and in the management of engineering teams. Neil has worked on the front-end development of several large subsea projects and has a particular interest in making sure that the individual subsystems are optimised and hang together to meet overall system objectives. Neil has a continuing interest in new technology and the risk and reliability implications of its introduction. Neil is involved in how subsea systems can be adapted during the energy transition from oil and gas service to CCUS, hydrogen and hydrogen carriers such as ammonia.

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Executive Summary

The UK Government has committed to reach Net Zero by 2050. Carbon Capture and Storage (CCS) is expected to play a critical role in delivering the UK's Net Zero Strategy, reducing carbon dioxide (CO_2) emissions, and ensuring that the UK meets this target.

The effects of climate change are already evident, both globally and here in the UK. The UK Climate Change Committee (the UK's independent climate advisory body) has described CCS as 'a necessity, not an option' for the transition to Net Zero [1]. CCS offers a way to mitigate climate change whilst progressing towards the decarbonisation of energy, transport, and industry, and is critical to achieving the UK's 2050 Net Zero target. The government aims to establish four CCS industrial clusters by 2030, capturing 20-30Mt CO_2 across the economy (equivalent to annual emissions from 4.2 to 6.3 million British households). Two clusters have already been selected for 'Track-1' negotiations, with a view to becoming operational by the mid-2020s (HyNet and the East Coast Cluster).

Deep geological storage of CO_2 is the secure containment of CO_2 in CCS systems. The 2019 Global CCS Institute (GCCSI) Report [2] states that 260Mt CO_2 has already been safely stored (this includes in storage sites within saline aquifers and depleted fields, and Enhanced Oil Recovery), and estimates indicate a current storage rate of around 40Mt per year globally [3]. However, there is not yet sufficient direct experience to extract reliable statistics on long-term containment certainty. This report provides an up-to-date synthesis and estimation of the containment certainty of CO_2 in deep geological storage sites on the UK Continental Shelf (UKCS). Relatively few studies have estimated leak rates, probabilities and durations as has been done here, although many studies address part of the picture.

Estimates of containment probabilities for two example sites modelled over 25 years of injection operations and 100 years of post-injection monitoring indicate that more than 99.9% of the injected CO_2 will be retained within the storage complex. The two modelled sites are designed to reflect the features of 'typical' UK offshore sites, for depleted fields and saline aquifer stores within permitted storage complexes. While the risks will vary on a site-specific basis, the results (see summary table of results below) indicate a very high level of confidence in the long-term security of CO_2 containment in typical CCS storage complexes on the UKCS.

Containment risks are divided into geological and well leakage pathways. A containment issue via a well leakage pathway is likely to be faster to remedy than via a geological leakage pathway. The type of storage site also has an impact on the containment risk. Typical sites can be within depleted oil or gas fields or saline aquifers (sites that contain saline water instead of oil or gas). Whilst containment risks for both well and geological pathways are extremely low, generally, depleted field storage sites have a higher likelihood of a well containment issue occurring than a geological containment issue. A saline aquifer store may have higher geological risk than a depleted oil or gas field store because there is less familiarity with the storage site and its geological sealing characteristics. However, irrespective of CO_2 store type, the well containment risk may be lower if fewer wells have been drilled in the past at the storage site. Wells that were decommissioned prior to CCS being planned for the site are likely to have a higher risk. It is also possible for leakage paths to be a combination of well and geological leakage paths.

The leaks that are more likely to occur, for both geological and well leakage pathways, are at lower leak rates. The authors interpret the possibility of major or moderate leakage rates from geological features on sites that have been awarded a storage permit in the UK to be improbable from either a depleted field or a saline aquifer store. Significant loss of containment events (at higher leakage rates) via well pathways are very improbable and unlikely to happen, particularly where the injection wells are designed and constructed to modern standards and operated within the requirements of the NSTA (North Sea Transition Authority) storage permit. Thus, the risks associated with containment are not significant for a site that has a storage permit, compared to the net benefit of industrial scale deep geological storage of CO_2, which is critical to deliver on the UK 2050 Net Zero Strategy.

The combined risks for each individual site will be specific to the geology and well history at that site. The UKCS is a well-regulated environment, and a CO_2 storage site will only be granted a CO_2 storage permit if the NSTA is satisfied that under the proposed conditions of use of the storage site, there is no significant risk of leakage or harm to the environment or human health [4]. This further reinforces the degree of confidence in CO_2 containment that may be placed in a storage site that has received a permit.

To calculate the statistical probable ‘worst-case’ leakage from an example storage complex over its injection life and post closure period, the maximum probability of occurrence and maximum leak rate have been used. This provides a conservative calculation of the risked estimate of overall leakage. The overall leakage calculation also assumes the maximum leak rate continues for the full duration until remediation is accomplished (recognising that some geological leaks may be of longer duration, albeit at a low rate). This is a conservative approach as the majority of well leaks can be shut in (i.e. mechanically isolated from the external environment) relatively quickly using other valves or installing temporary plugs. This approach therefore gives confidence in the security of CO_2 containment in deep geological storage sites in the UK continental shelf, and that in reality the degree of containment may be better than the levels stated in this study.

Store Type (Permit Awarded)	Description	Estimated worst-case amount as % of store capacity (125Mt CO_2)
Depleted Field Store	Leakage from all wells	0.070%
	Leakage from all geological features	0.002%
	Total leakage from storage complex	0.072%
	Total estimated contained mass at storage complex	99.928%
Fully or Partially Confined Saline Aquifer Storage Site	Leakage from all wells	0.064%
	Leakage from all geological features	0.024%
	Total leakage from storage complex	0.088%
	Total estimated contained mass at storage complex	99.912%

Statistical estimates of reasonable worst-case leakage amount from two 'typical' CO_2 storage complexes that have been awarded a storage permit in the well-regulated UKCS regime.

This report was commissioned by the Department for Business, Energy & Industrial Strategy (BEIS) from a group of independent expert advisors under contract to BEIS as part of its CCUS delivery programme (through the WSP CCUS Technical Framework contract).

The main report is written for a non-technical audience, to inform on the containment certainty of CCS. The supplementary notes provide the technical syntheses, analyses and assessments underpinning the summarised results within the main report and are written for a technical readership.

1 Introduction

Deep geological storage of CO_2 is the long term containment of captured CO_2 in geological formations in Carbon Capture and Storage (CCS) systems. CCS technologies involve the separation and capture of CO_2 from large-scale industrial processes to prevent CO_2 from being released into the atmosphere. In CCS, the captured CO_2 is then transported, possibly via pipeline or ship, offshore to be securely stored deep underground in geological formations. Sometimes CCS is referred to as CCUS, Carbon Capture, Utilisation and Storage. CCUS includes captured CO_2 being either stored or used as a resource or feedstock for other industrial processes and the food industry. However, as CO_2 utilisation does not result in deep geological storage, CCS will be the term used for the remainder of this report.

A public perception study on CCUS commissioned by BEIS in 2021 [5] found that public support for CCS was conditional on it being a safe and effective strategy to reduce CO_2 emissions. The safety of storage of CO_2 beneath the seabed was of particular interest to participants in the study, with induced earthquakes, containment risks of storage and potential harm to marine life highlighted.

This report seeks to understand and provide a quantification of the likelihood of CO_2 containment associated with deep geological storage and, conversely, the possibility of a loss of containment (taking current proven mitigation techniques into consideration). Recent studies and additional sources of information are used to refine estimates of leakage rates, amounts, and probabilities for various loss of containment scenarios, relating to both geological and well risks. The report will also explore when these risks may develop within the lifecycle of a storage site (spanning development, CO_2 injection operations, and post-closure). Two example storage sites have been used to provide an illustration of how the geological and well containment risks are combined, and the overall (geological + well) leakage probability for these sites has been calculated.

The containment probabilities and leakage rate estimates provided in this report are underpinned by work summarised in the Supplementary Notes.

1.1 Previous Summaries of CO_2 Storage Risk

The 2005 IPCC Special Report on CCS [6] found that the fraction of CO_2 retained in appropriately selected and managed storage sites is very likely to exceed 99% over 100 years and is likely to exceed 99% over 1000 years. This is consistent with a report from the Zero Emissions Platform (ZEP) published in 2019 [7] which states that for a typical North Sea storage site, over 99.99% of injected CO_2 is expected to remain stored deep underground for at least 500 years.

The 2012 independent report commissioned by the UK Department for Energy and Climate Change (DECC) on "CO_2 Storage Liabilities in the North Sea" [8] provided an improved technical understanding of the CO_2 containment risks and potential leakage amounts from a storage site, as well as the options for taking corrective measures to control a containment issue, were it to occur. The 2012 independent report [8] did not include quantitative probabilities for geological leakage paths, and therefore cannot be used to derive percent containment values in the same way as the IPCC [6] and ZEP [7] reports.

1.2 Carbon Emissions

There are a number of processes through which naturally occurring CO_2 can be emitted into the atmosphere [9]. Volcanic emissions of CO_2 are estimated to be about 300Mt per year globally, and relatively minor emissions due to natural seepage of volcanically sourced CO_2 also occur from sedimentary basins, along faults and through springs. These naturally occurring emissions have taken place over the millennia prior to the industrial revolution and were balanced by absorption of CO_2 through the carbon cycle. However, in comparison, CO_2 emissions from human activities in 2019 were over 30 billion tonnes, 100 times greater than that emitted from volcanic regions, and therefore the natural sequestration systems are unable to cope, meaning that the CO_2 remains in the atmosphere.

1.3 Why is CCS Necessary on a Global Scale?

The IPCC Climate Change 2021 (The Physical Science Basis) report [10] states that "human influence on the climate system is now an established fact", and it is clear that in order to achieve climate stabilisation pending transition from a carbon-based economy, anthropogenic (man-made) CO_2 emissions must be captured and permanently prevented from reaching the atmosphere. The effects of rising global temperature are already evident, both globally and here in the UK, with the UK recording its hottest ever day in July 2022, exceeding 40°C for the first time [11].

Trends in global surface temperature show a steady rise since the end of the 19th century (Figure 1). Anthropogenic activity (i.e. human activity), in particular the combustion of coal, oil and gas, which releases CO_2, a powerful greenhouse gas, into the atmosphere, is largely responsible for this rise in global temperatures. Industrial activities which produce CO_2 by combustion or chemical processes, have increased the quantity of anthropogenic CO_2 emitted from less than 5 billion tonnes per year in 1900 to over 30 billion tonnes in 2019 [12], causing CO_2 concentrations in the atmosphere to rise from around 280 ppm (parts per million) to an average of 415 ppm in 2021 [13], with a corresponding surface temperature increase of more than 1°C. The strong positive correlation between increasing atmospheric CO_2 concentration and rising global surface temperature between 1880-2019 is shown below (Figure 1).

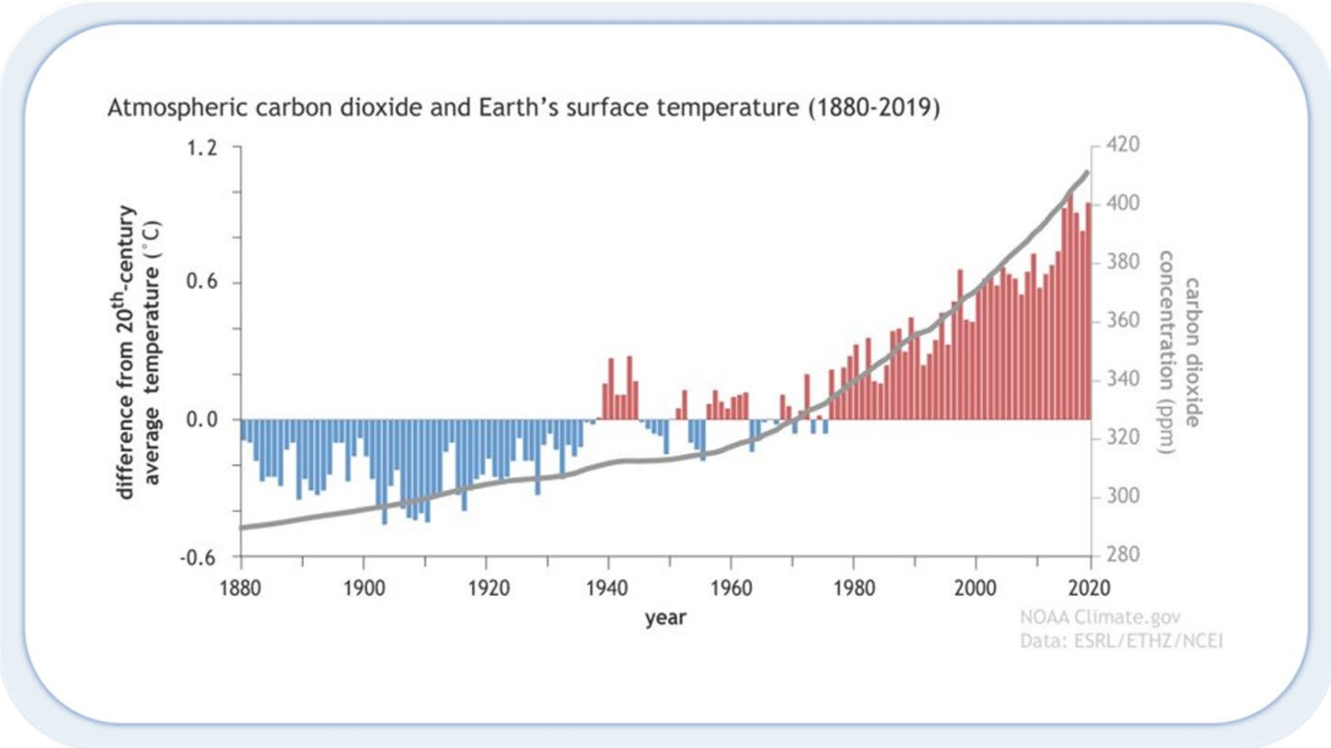


Figure 1. Correlation between atmospheric CO_2 concentrations (grey line) and global surface temperature (red and blue bars) between 1880-2019 (Reproduced from the NOAA website [14])

Recent modelling presented in the IPCC Climate Change 2022 (Impacts, Adaptations and Vulnerability) [15] report suggests that if the current trend of global warming continues there is at least a greater than 50% likelihood that global warming will reach or exceed 1.5°C by 2040, and without stringent and rapid mitigation of greenhouse gas (GHG) emissions, global surface temperatures can be expected to rise by around 4°C by 2100 [16].

Although UK GHG emissions have been steadily falling since 1990, total global emissions are still rising, highlighting that climate change is a global issue. Industrial CCS is critically important for the decarbonisation of energy-intensive industries such as chemical, steel and cement, for which there are limited other options to reduce emissions. These industries release CO_2 from non-combustion sources as well as fuel combustion, so options such as fuel-switching only offer a partial solution to reducing emissions [17].

The IEA suggests that to reach Net Zero by 2050, 3.5 billion tonnes (i.e. 3.5 Gt) of CO_2 emissions from fossil fuel combustion must have been cumulatively captured and injected by 2050 [18]. The transition to Net Zero is a race against time, and it is the potential for the relatively quick capture and storage of large amounts of industrial emissions without widespread industrial upheaval that is the core benefit of implementing CCS, allowing removal of emissions from current process technologies while sustainable processes are developed and implemented.

1.4 UK Net Zero Targets and the Role of CCS

In 2019, the UK Government accepted the findings from a report published by the UK Climate Change Committee [1] (CCC, the UK's independent climate advisory body), and pledged to reach Net Zero and to end the UK's domestic contribution to man-made climate change by 2050. Following subsequent amendments to the Climate Change Act 2008, the UK then became the first major economy to pass legislation and commit to a legally binding target of reducing net emissions by 100% of 1990 levels (Net Zero) by 2050.

The Climate Change Act [19] also requires the government to set legally binding 'carbon budgets' which act as milestones towards reducing emissions and achieving the 2050 target. The first and second carbon budgets (2008-2012 and 2013-2017) were met, and the UK is on track to meet the third (2018-2022). CCS in the UK is necessary to meet the subsequent three carbon budgets which aim to reduce emissions to 78% of 1990 levels by 2035 [20].

In October 2021, the UK Government published 'Net Zero Strategy: Build Back Greener' [21] which builds on both the Energy White Paper 'Powering our Net Zero Future' [22] and the 'Ten Point Plan for a Green Industrial Revolution' [23], and outlines policies and proposals for decarbonising all sectors of the UK economy so that the UK will meet the target of Net Zero by 2050. These documents highlight that the government expects CCS to play a critical role in decarbonising industry, helping the UK to reduce greenhouse gas emissions and deliver the strategy to reach Net Zero by 2050 (see Figure 2).

The government aims to establish four CCS industrial clusters by 2030, capturing and storing 20-30Mt CO_2 across the economy, including 6Mt CO_2 of industrial emissions per year. However, in order to achieve Net Zero by 2050, the 6th Carbon Budget [24] published by the CCC in December 2020 suggests that the UK needs around 58Mt of engineered CO_2 removals per year by 2050, using CCS and other engineered gas removal technologies such as BECCS (Bioenergy with CCS) and DACCS (Direct Air CCS).

In October 2021, following Phase 1 of the Cluster Sequencing process, HyNet and the East Coast Cluster were confirmed as the two Track 1 clusters to be taken forwards to negotiations (with the Scottish Cluster as reserve). HyNet is aiming to be operational by 2025 and capturing up to 10Mt CO_2 per year by 2030 [25], and the East Coast Cluster (ECC) aims to capture 10Mt CO_2 per year from Teesside and 17Mt CO_2 per year from the Humber region by the mid-2030s [26].

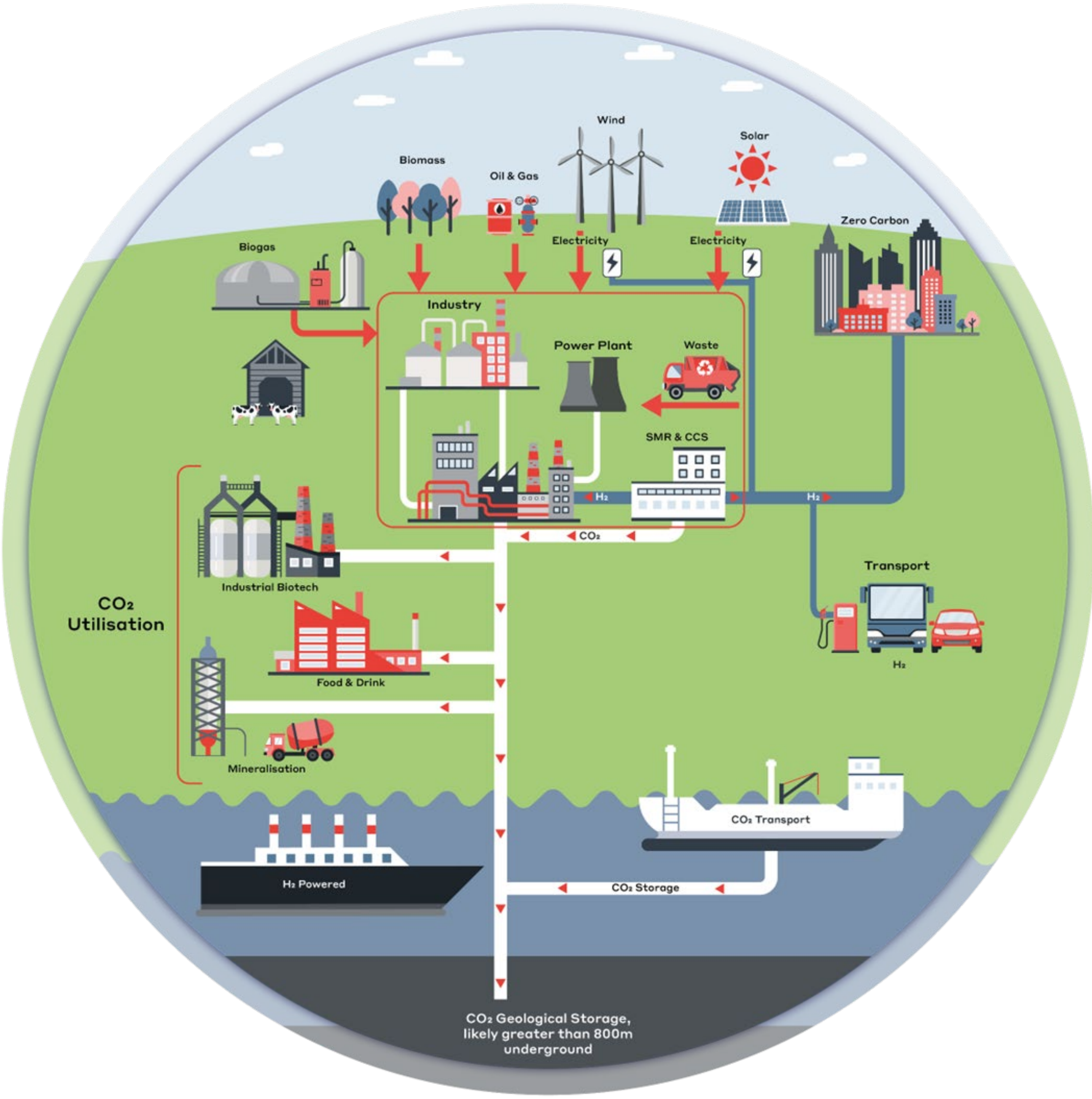
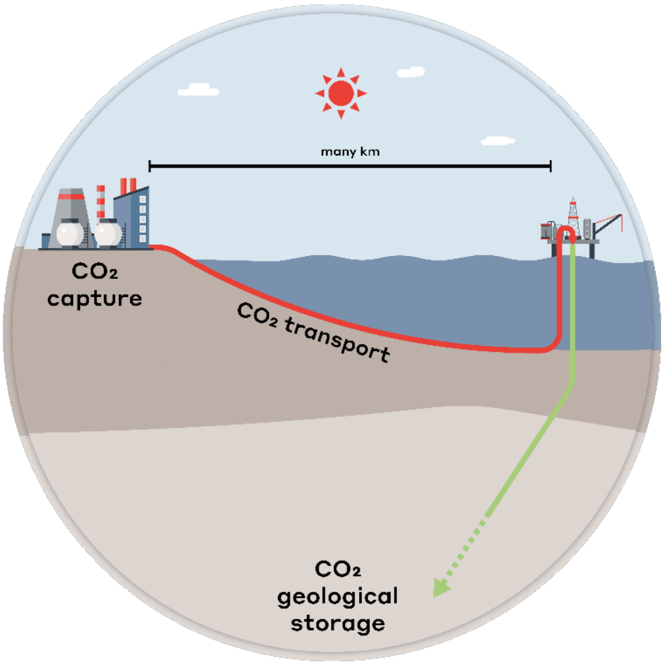


Figure 2. CCUS as part of the UK Net Zero Strategy

2 Deep Geological Carbon Storage

2.1 Overview / Introduction

The UK's national CO_2 storage database, CO2Stored [27], identifies over 500 potential sites for the geological storage of CO_2, with an estimated theoretical CO_2 storage capacity for the UK continental shelf (UKCS) of 78 billion tonnes (as reported in 2014), in either deep saline aquifers or depleted oil and natural gas fields (see Section 2.2 for further explanation). The UKCS also has numerous hydrocarbon fields with a naturally high CO_2 content, including the Brae North and Miller fields (Northern North Sea, up to 35% and 28% CO_2 respectively), the Rhyl field (East Irish Sea Basin, up to 37% CO_2), and the Oak & Fizzy fields (Southern North Sea, about 50% CO_2), providing inherent evidence to prove that UK geology can naturally safely retain CO_2 over geological timescales. The CO_2 to be stored will be captured from industrial processes, including hydrogen production and power generation and engineered removal processes, and transported offshore via pipeline, or potentially by ship, to be permanently stored deep underground in geological formations (Figure 3).



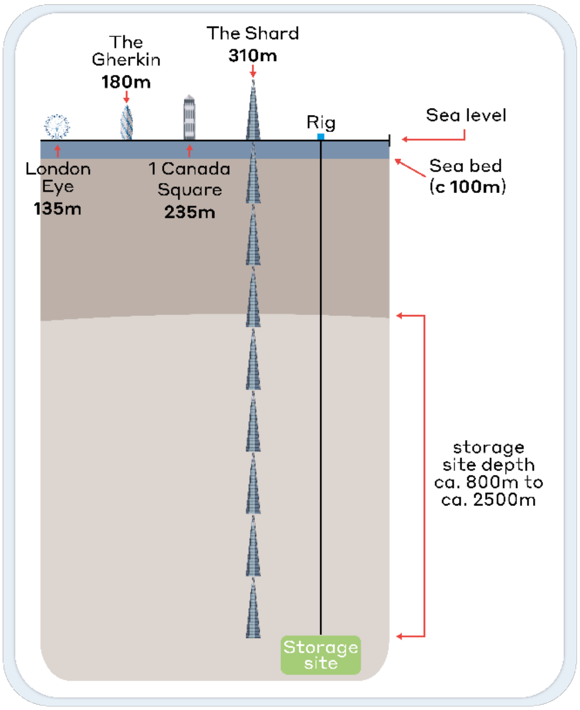


Figure 3. Left: Overview of UK CCS; CO_2 capture, transport (shown via a pipeline, but shipping is also a possibility), injection and storage. Note the depth to storage site and distance from shore are depicted schematically, not proportionately. Right: A proportional schematic to indicate likely depths of a storage site below surface. A suitable storage site will be approximately 800m or more below the seabed, but most potential UKCS CO_2 storage sites are at greater depths than this, up to 2.5km below the seabed (see Section 2.2)

2.2 The Storage Site and the Storage Complex

The definitions in UK legislation of the Storage Site and Storage Complex (as referred to in The Storage of Carbon Dioxide (Licensing etc.) Regulations 2010 [4]) are based directly on those in the EU Directive on Geological Storage of Carbon Dioxide (2009/31/EC) [28], and are summarised in Figure 4 below.

- The **Storage Site** is the defined volume area within a geological formation (shown by the red dashed line in Figure 4) used for the geological storage of CO_2 and any associated surface and injection facilities (e.g. platforms, active CO_2 injection wells). The geological formation intended to store the CO_2 can also be referred to as the storage formation or reservoir.
- The **Storage Complex** is the storage site and surrounding geological domain which can have an effect on overall storage integrity (including any secondary storage (see below) or seal formations shown by the green dashed line). A storage complex is likely to extend up to the shallowest sealing rock type above the storage site but may not extend right to the seabed. Within this report leakage is considered from the storage complex.
- The **Monitored Volume** is within the orange dashed line and is the area that will be monitored during and after injection operations to track and ensure containment of the injected mass of CO_2 (sometimes referred to as the CO_2 ‘plume’) within the storage formation and complex over time (this is discussed in more detail in Section 3).

Suitable sites for the storage of CO_2 can be found both onshore and offshore, but the focus for UK CCS opportunities is offshore, in geological formations deep beneath the seabed. A storage permit is a consent granted under a licence, authorising the use of a place as a CO_2 storage site. A storage complex which has been granted a permit to safely and permanently store injected CO_2 underground will include a storage formation (or reservoir unit), and at least one overlying and continuous sealing formation that covers the full storage complex (which in the UKCS are typically regionally continuous, far wider than the extent of a storage site), commonly referred to as the caprock (or top seal). Additional seals and/or a secondary storage formation may also be present within the storage complex.

Storage sites in the UK are found in both deep saline aquifers and depleted oil and natural gas fields where the storage formations contain naturally occurring brine (not potable water) and in the case of depleted oil and natural gas fields, some irrecoverable oil and/or gas. In both potential storage site types, the storage formation is typically a porous and permeable sedimentary rock such as sandstone, with sufficient space to store CO_2 within the interconnected pore spaces between the sand grains (see Figure 5). In contrast, the seal is usually comprised of multiple layers of very fine-grained and impermeable rock such as shales or evaporite (salt) deposits, often hundreds of metres in thickness, which provide a barrier to retain CO_2 and keep it permanently in the store. Evaporites are a particularly effective sealing layer as they ‘creep’ and usually seal any faults that cut through them. There are extensive evaporite deposits under the UKCS.

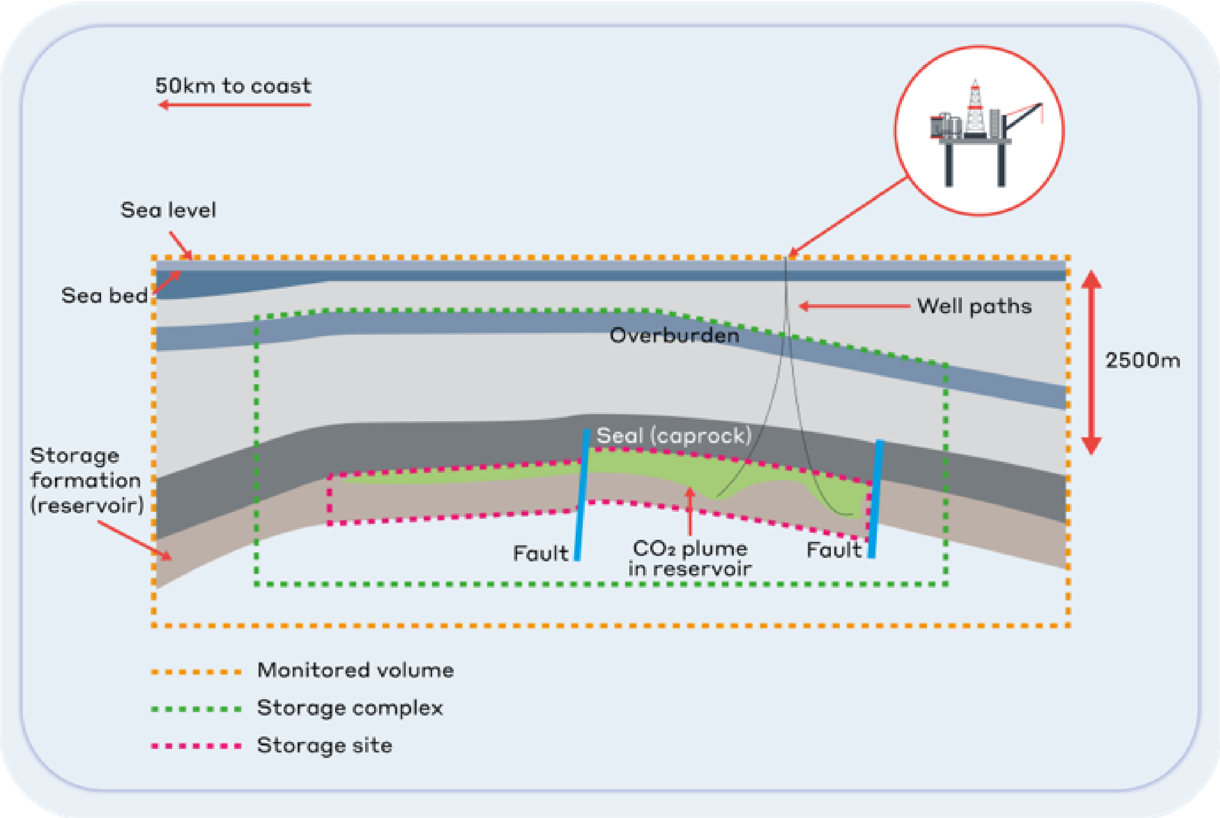
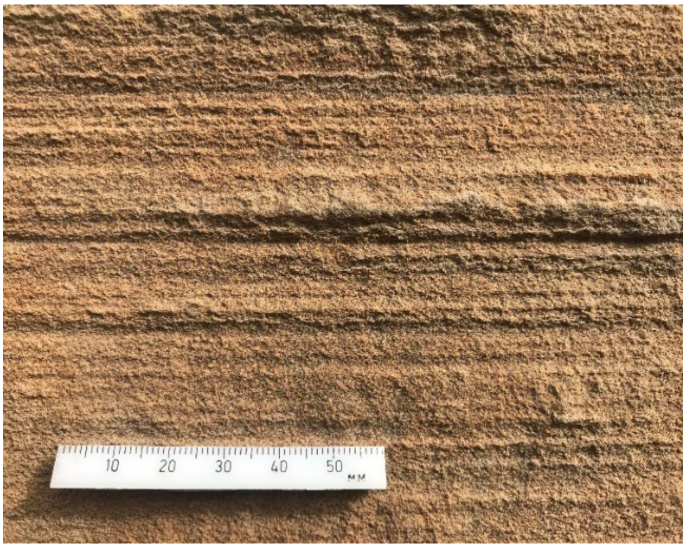


Figure 4. Schematic of example CCS infrastructure and storage site/complex

Storage sites can be differentiated by considering whether the CO_2 plume is confined within geological lateral boundaries or whether it may be able to keep moving over greater lateral extents within the storage formation after injection has ceased (the caprock would keep it from rising up to seabed). Sites can be fully open without any geological constraint on movement within the storage formation; partially confined (with a geological confinement as shown in Figure 4 where a geological structure confines lateral movement) with a hydraulic connection to a wider aquifer; or fully confined where impermeable geological margins confine the site above, below and laterally. Storage sites in depleted fields are either fully confined or partially confined (with a geological confinement). Saline aquifer sites can be fully open, partially confined or fully confined. In all storage sites the CO_2 cannot migrate above the storage formation.

In the UKCS a suitable storage site will typically lie at a depth of around 800m or more below the seabed, where the natural increase in temperature and pressure with increasing depth in the Earth's crust allows the CO_2 to be stored in a dense state. Storing in dense state allows much greater quantities of CO_2 to be stored in a given volume than if the CO_2 was at shallower depths, for example in gaseous state. Sites shallower than 800m may still have sufficient storage efficiency to be viable (and would be subject to the same regulatory assessment as any other site). Deep geological storage provides a substantial thickness of rock and hence barriers between the stored CO_2 and the seabed, possibly even with secondary containment formations overlying the primary site, significantly reducing the potential for CO_2 to reach the seabed in the event of any leakage out of the primary storage site.



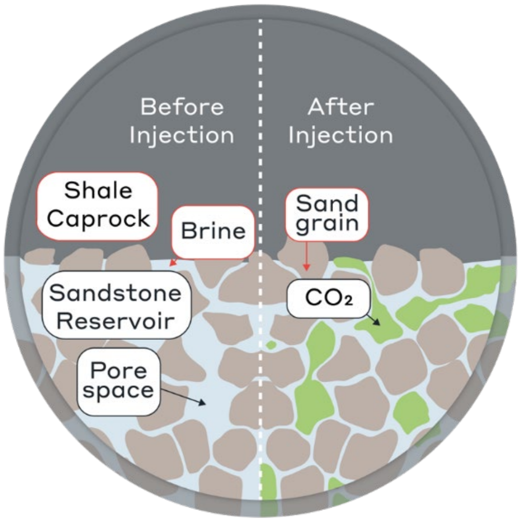


Figure 5. Left: Photo showing a permeable sandstone. Right: diagram to illustrate what happens in a saline aquifer storage site when CO_2 is injected

When CO_2 is injected into the storage formation, the fluid in the pore spaces is displaced by the CO_2, causing the fluid pressure to increase. Dense-phase CO_2 has a lower density than brine and is therefore buoyant. The pressure increase will initially be greatest around the point of injection, then will transmit across a wider extent than the CO_2 plume. After the end of injection operations, the pressure will equilibrate with the wider surroundings, dissipating towards the original pressure. The rate and any difference between equilibrated and original pressure will be site-specific, linking to properties such as permeability and the extent of connected fluid volumes (in the storage formation and any permeable underlying rocks), and could vary from a few months to hundreds of years. For depleted oil and gas fields it is likely that injection will be designed such that the final fluid pressure within the storage formation will be lower or similar to the initial pressure prior to oil and gas production. This is because the pressure in the reservoir after oil and gas production is likely to have been lower than before production. In saline aquifers, which have not undergone depletion (due to the production of hydrocarbons, for example), the injection of CO_2 may lead to an overall increase in pressure. Consequently, at saline aquifer sites the pressure may be managed through extracting brine from the wider storage formation beyond the storage site. In vast permeable saline formations, the pressure changes due to injection may not be deemed significant. The pressure in the storage site will be monitored both during and, if appropriate, after injection operations to ensure that the reservoir pressure remains within predetermined and authorised safe operating limits and so will not exceed the failure pressure of the caprock.

Once injected, the CO_2 is securely stored in the reservoir through a number of trapping mechanisms, all of which can start to occur simultaneously during injection, but their importance changes with time and the evolution of the CO_2 plume. The injected CO_2 is more buoyant than the fluid within the pore space of the storage formation, so the CO_2 plume will migrate upwards through the porous storage formation until it becomes trapped beneath an impermeable caprock layer or sealing fault (see Figure 4). This structural trapping is likely to be the primary trapping mechanism of CO_2 during the first few decades of injection operations.

Also important in the early stage of injection is residual trapping, which refers to CO_2 that becomes trapped (isolated) in the pore spaces as the CO_2 plume migrates through the rock. As the plume migrates away from the higher pressures that occur near the injection site, residual trapping becomes more prominent and can be significant over the scale of a reservoir that could be 100m thick and several kilometres wide. Some of the trapped CO_2 will dissolve into the formation brine and become trapped indefinitely (dissolution trapping), with the CO_2 saturated brine eventually sinking to the bottom of the storage formation due to its greater density. Chemical reactions between the injected CO_2, formation brine and reservoir rock can lead to the formation of new minerals. This process, called mineral trapping is probably slow because the CO_2 must first dissolve in the brine before a reaction can occur. So, although it locks the CO_2 into a solid mineral permanently, it may take decades, centuries or even millennia for the process to be completed. Therefore, as a result of these mechanisms the amount of CO_2 capable of leaking is reduced, with further reductions as time progresses.

In terms of operations there will be several differences between depleted field and saline aquifer CO_2 storage sites. Depleted field sites at low pressures are likely to require a gradual increase in injection rates, possibly over several years after starting injection operations. The initial pressure of depleted fields will vary from site to site depending on the level of hydraulic support from the wider aquifer. For example the UK East Irish Sea gas field Hamilton, proposed to be included in the HyNet Cluster, is at low pressure since gas production (4.5 bar, which is ~5% of original reservoir pressure, [29], [30]), whereas the UK Central North Sea former gas field Goldeneye, proposed to be included in the Scottish Cluster, is at pressures closer to original pressures (185 bar, which is ~70% of original pressure [31]). Saline aquifer storage sites on the other hand are likely to be at or close to original pressures and might be able to be injected at 'full capacity' from much earlier in the site life (with or without pressure management through brine production wells).

2.3 Wells

Wells are a collection of concentric pipes (casing, liner and tubing), cement, seals and valves that form multiple barriers between well fluids and the outside environment. A series of casings and liners are cemented in place to reach from the surface to the subsurface target (deep geological CO_2 storage formation). At the surface (either on a drilling rig, platform or at the seabed) these concentric casings and liners are held in place by a wellhead. A dedicated steel pipe called a completion is run inside these concentric casings and liners to enable the CO_2 to be injected from the surface to the CO_2 storage reservoir. The completion consists of tubing, valves to control the flow in addition to pressure and temperature gauges to monitor the well performance. At the bottom it has a circular packer surrounding the tubing; this is a seal that is used to isolate the inside of the completion and parts of the well in contact with CO_2 from the outer annuli created by the concentric tubing and casings. At the surface an assembly of isolation and control valves (called a Xmas tree) is installed on the wellhead to enable controlled injection into the completion tubing. The well schematic in Figure 6 provides an overview of the main elements in a well.

Offshore wells may be platform or subsea wells. A platform well is drilled through a platform structure supported on the seabed and the wellhead and Xmas tree are located on the platform well above the sea level. For platform wells the wellhead and Xmas tree can be accessed by people on the platform for maintenance. Subsea wells are drilled directly into the seabed, the wellhead and Xmas tree are located at the seabed. Maintenance of the subsea wells requires dedicated vessels and remotely operated vehicles (ROVs). It is common for the platform and subsea wells to be monitored and operated using telemetry and control systems from dedicated control rooms. For both well types the key components, well barriers, construction and remediation techniques are the same. The potential for leaks outside the well envelope is the same for both well types and no distinction is made in probability, leak rate and duration in the work for this report.

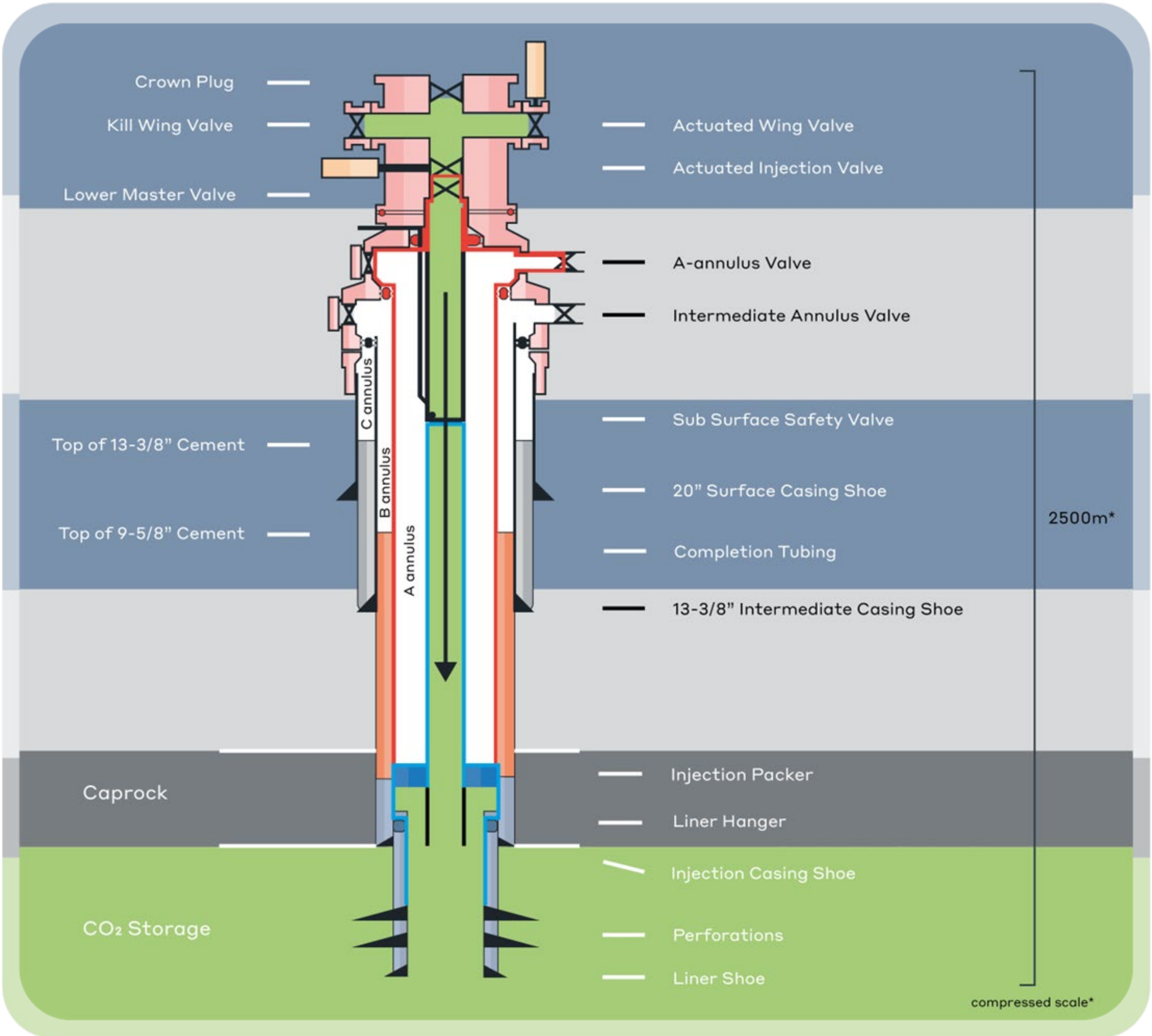


Figure 6. CO_2 injection well (modified from ISO 16530-1)

Well integrity is generally defined as “maintaining full control of fluids within a well at all times by employing and maintaining one or more well barriers to prevent unintended fluid movement between formations with different pressure regimes or loss of containment to the environment.” Accepted processes to assure well integrity over the life cycle of the well are fully defined in documents such as OEUK Well Life Cycle Integrity Guidelines [32] and the standards ISO 16530-1 Well integrity - Part 1 Life cycle governance [33] or NORSOK D-010 Well Integrity in Drilling and Well Operations [34].

Well barriers consist of different elements that may be active or passive. Active barriers such as valves can enable or prevent flow, while passive barriers are fixed structures such as casing, packers, and cement. Performance standards are established for each barrier and barrier element during the design phase of the well to ensure the hazards and risks associated with the well construction, operation and decommissioning can be managed. These performance standards are then used during the well operating phase, to support monitoring, maintenance and testing to verify the condition of the barriers.

In the UK wells are required to have a minimum of two independent barriers; if one barrier fails the second barrier can prevent the leak or hazard from occurring while the first barrier is repaired. Figure 6 shows a well schematic for an injection well in the operating phase with the two well barriers and the elements that make-up those well barriers highlighted in red and blue.

Once the well is no longer required for injection operations, monitoring or brine production it will be decommissioned. To decommission a well, permanent barriers, for example cement plugs or alternative materials of similar quality, are installed in the well to prevent fluid movement between formations with different pressure regimes or loss of containment to the environment (see Figure 7). The permanent barriers used when the well is decommissioned are designed, installed and tested so that no further inspection is required [33]. The surface wellhead, Xmas tree and the upper sections of casing are removed so the surface location can be returned to the original condition. Decommissioned wells are referred to as inactive wells in this report in comparison with active wells used during injection operations for injection, monitoring and brine production. At the end of the injection period, all active wells are decommissioned and become inactive for the post-closure period.

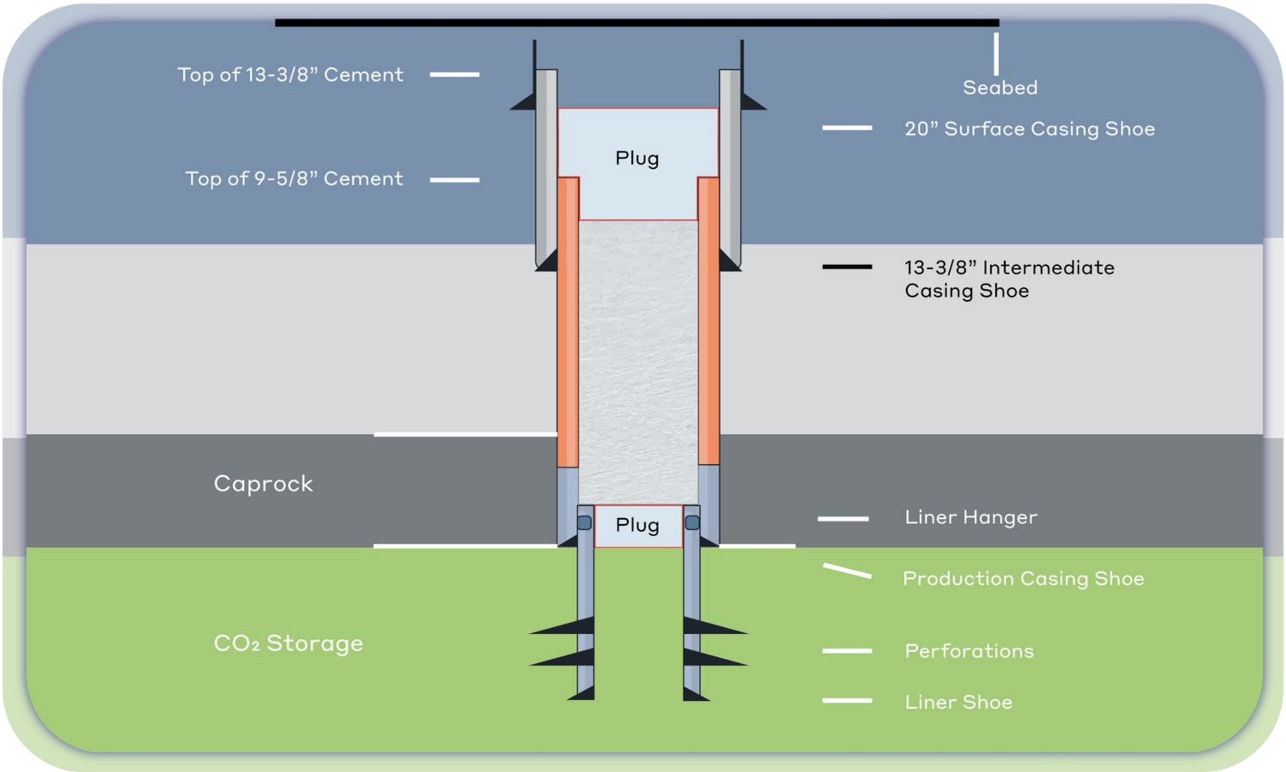


Figure 7. Inactive well schematic

In this report wells drilled through the CO_2 storage caprock will be referred to as either active or inactive wells:

- Active wells are related to the CO_2 storage project: CO_2 injectors, CO_2 monitoring wells or brine producer wells (specifically for pressure management support with saline aquifer storage).
- Inactive wells comprise all wells within and around the storage site that are not related to the CO_2 storage project. These wells are typically decommissioned or will be decommissioned prior to starting injection. This can include oil and gas wells from an earlier phase of hydrocarbon exploration and development, exploration and appraisal wells for this storage reservoir or other deeper subsurface targets (some reports refer to these as legacy wells) plus those active wells decommissioned at the end of the injection period.

3 Permanent Containment of CO_2 at a Storage Site

3.1 Overview

The regulations relating to the geological storage of carbon dioxide in the UK are intended to ensure the permanent and environmentally safe storage of CO_2, and a person intending to carry out certain activities relating to geological storage of CO_2 is required by the Energy Act 2008 to obtain a licence. More detailed requirements about licensing are found in the Carbon Dioxide (Licensing etc) Regulations 2010 [4], the Storage of Carbon Dioxide (Termination of Licences) Regulations 2011 [35], and the Storage of Carbon Dioxide (Access to Infrastructure) Regulations 2011 [36]. The UK storage regulations state that before granting a storage permit, the licensing authority must be satisfied that under the proposed conditions of use there is no significant risk of leakage or harm to the environment or human health (leakage is defined as "any release of CO_2 from the storage complex" [28]).

3.1.1 Containment Certainty of Storage Sites: Permit Requirements & Approvals

The regulatory and licensing regime governing CO_2 storage is established in the Energy Act 2008 [37] and associated regulations (see above), [4]. The North Sea Transition Authority (NSTA) is responsible for the regulation of offshore CO_2 storage in the UK and is the licensing authority for offshore storage (except the territorial sea adjacent to Scotland, which is authorised by Scottish ministers). In addition to applying for a storage licence to allow the site appraisal to be carried out, developers must also obtain a storage lease from The Crown Estate or the Crown Estate Scotland. Once the licence for a prospective storage area has been granted, an appraisal period begins, during which the licence holder has the right to assess the storage potential of the licensed area (which includes the prospective storage site and complex) before making an application for a storage permit.

To demonstrate to the NSTA that under the proposed conditions of use of the storage site, there is no significant risk of leakage or harm to the environment or human health, the licence holder will require sufficient data about the site to satisfy the NSTA and must carry out a full geological characterisation of the storage site to identify any potential leakage risks from the storage complex. This will include (but is not limited to) an assessment of the geological structure of the site and complex which includes faults (including their sealing capacity and potential to act as leakage pathways), sealing properties of the caprock, and interaction of CO_2 with the storage site geology. Operators will perform laboratory tests and/or modelling under reservoir conditions to verify that the caprock will be impermeable to CO_2 in dense or gaseous phase as appropriate. Site-specific monitoring during and after operations and any corrective measures will be agreed as part of the storage permit application (as described in Section 3.1.2).

The licence holder must also provide an assessment on the condition of any existing inactive wells (suspended or decommissioned) that pass through the storage complex as well as other active or inactive wells in the vicinity to determine their integrity and any associated risk. To evaluate the environmental validity of the proposed activities, the licence holder must provide data on the natural habitats and wild flora and fauna in proximity, on the sensitivities of species to potential leakage events and worst case environmental and health impacts [28]. These data will be reviewed by the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED).

The licence holder will propose an operator within their permit application, to be approved to carry out or control the activities at the storage site. The operator, according to CCS regulations, must be 'technically competent…, financially sound and can be relied upon to carry out the functions of an operator', with suitable technical and professional development available to their staff [4].

HSE states that relevant GB health and safety legislation was not designed to regulate CCS and so the applicability and suitability of the existing framework are being assessed. Currently, CCUS projects already have duties to reduce and manage risk adequately to comply with the Health and Safety at Work etc Act, 1974 [38], and the ALARP principle (as low as reasonably practicable), and existing major hazard accident legislation can provide a useful template to demonstrate compliance. In relation to wells which are a key component in designing and operating any CCS storage complex, the key UK Government statutory legislation that exists are:

- The Offshore Installations and Wells (Design and Construction, etc) Regulations 1996, as amended, (DCR) which apply to wells both onshore and offshore.
- The Offshore Installations (Offshore Safety Directive) (Safety Case etc) Regulations 2015 (SCR 2015) which apply offshore in external waters of the UKCS.

The award of the permit by the NSTA provides an impartial conclusion (independent of BEIS and the licence holder) that at the time the permit is issued the storage site is safe for the long-term storage of CO_2, and that all appropriate monitoring and potential mitigations against leakage will be in place.

3.1.2 Safe Operations and Monitoring Requirements

The containment risks identified as a result of the site characterisation will provide the basis for site-specific measurement, monitoring and corrective measures plans which form part of the storage permit application.

The agreed monitoring plan will be used to demonstrate secure containment of the injected CO_2 within the storage site during and after injection, and to ascertain that no unexpected migration or leakage is occurring through either geological or well leakage pathways.

Together, the monitoring and corrective measures plans are designed to increase the confidence that early identification of leakage or irregularities can be followed by successful low-risk remediation to avoid high-risk/high-cost remediation. Remediation strategies may range from strategies to manage pressure within the reservoir, to temporary or permanent closure of the storage site in an extreme case. Well interventions can be undertaken to remedy issues as described in Section 3.2.7 below.

The safe well operating envelope will be developed during the well design phase, based upon the individual well components and predicted reservoir properties; it will then be updated during well commissioning. To ensure that the wells operate within their safe operating envelope during well start-up, normal operations and well shutdown, monitoring of the injection rate, pressures and temperatures will be required. Routine well maintenance and integrity testing will be included in the annual well maintenance plan to be followed by the operator. The results of the integrity testing will be compared against a pre-defined performance standard to verify and demonstrate the integrity of the well barriers. Any failures or anomalies will be acted upon promptly to maintain the integrity of the well.

A range of techniques exist for monitoring CO_2 storage sites. Deep-focussed techniques can be used to monitor the reservoir and overlying geological formations (overburden) and track the movement of the CO_2 plume within the reservoir over time. Pressure measurements from the wells can be used to monitor pressure build-up and hydraulic communication across the storage site. Shallow focussed monitoring systems can be used to detect any leakage of CO_2 at the seabed or in the water column. It is expected that specialist logging tools may be utilised periodically, for example every 2-4 years, to record the saturation and movement of the CO_2 in the storage site at the well location. The measurements from the individual well logs combined with the reservoir and seismic models will enable the growth of the CO_2 plume to be tracked, with predictions made on how it will change as more CO_2 is injected and stored.

3.1.3 Responsibility for Store Integrity

The CCS permit is designed to ensure integrity of the storage site through the actions of the operator and as a last resort, through the actions of the licensing authority (NSTA).

It is the operator's obligation to monitor the storage complex. This includes a specified minimum post-closure period of monitoring by the operator (normally not less than 20 years) after the site is decommissioned. At any time if leakages or 'significant irregularities' are detected, the operator has a duty to immediately notify the NSTA, and any failure to do so would constitute a breach of the storage permit (which could result in revocation of the storage permit and licence). Once the minimum post-closure period has elapsed, in accordance with existing regulations, responsibility for the site will be transferred to the government as long as:

- The operator has sealed and removed all injection facilities from the site (which involves sealing the storage site through decommissioning wells and removing any surface injection facilities) and fulfilled their mandatory contribution towards post-transfer costs.
- The NSTA is satisfied that 'all available evidence indicates that the stored CO_2 is completely and permanently contained' [35].

3.1.4 Risk and Uncertainty Profiles of a Storage Site

The CO_2 containment risk assessment of a geological storage complex will reflect an evaluation of the probability of any kind of unplanned release of CO_2 from the complex and the severity of that release. Risk is quantified in this instance as the product of probability of occurrence and severity of occurrence. This section considers how these risks might vary through time, and also considers how uncertainty might vary through time.

Section 3.3 of this report considers the magnitude of the probability and severity of a number of potential well and geological leakage pathways, based on the amount of CO_2 leaked from a notional typical storage complex during injection operations and for 100 years after closure.

The outcomes and probabilities of a particular occurrence, or risk, are known and can be mitigated with appropriate measures. Uncertainty applies to a situation where the status, outcomes and probabilities are not known and cannot be quantified.

Uncertainty Profile

Uncertainties relating to the storage site will decrease with time as knowledge of the site increases, through data gathered during the pre-permit site characterisation phase, and knowledge gained through injection operations, including from the operational and post-closure monitoring of the site (see Figure 8). Generally, saline aquifer storage sites are likely to have more initial uncertainty related to fluid flow than depleted fields, as saline aquifer sites do not have a history of production from the site, which will translate to the crossover point in Figure 8 being further to the left in a depleted field (i.e. it will be reached sooner).

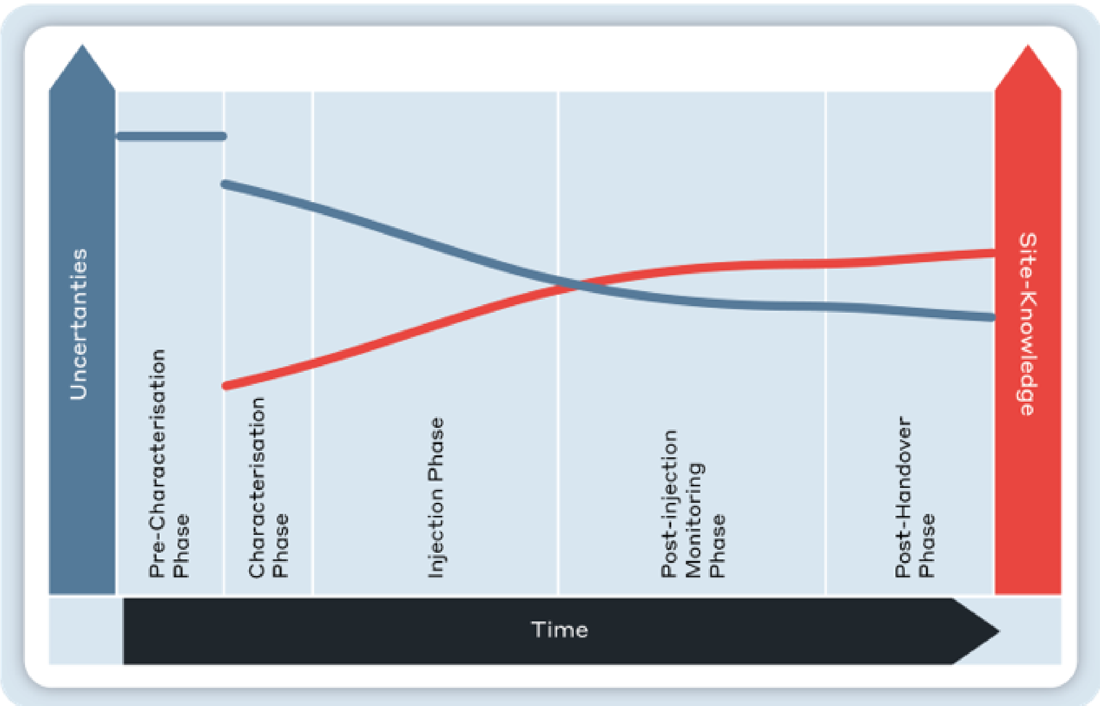


Figure 8. Illustration of uncertainty levels through the stages of a CO_2 storage site (from Pawar et al., 2015 [39])

Geological Containment Risk Profile

There are containment risks associated with injecting and storing CO_2 in a deep geological storage site. These risks will not remain constant throughout storage site life, but, as the amount of CO_2 injected increases the pressure changes, and the CO_2 plume migrates during injection, so the containment risk of a site changes through the operational life and beyond.

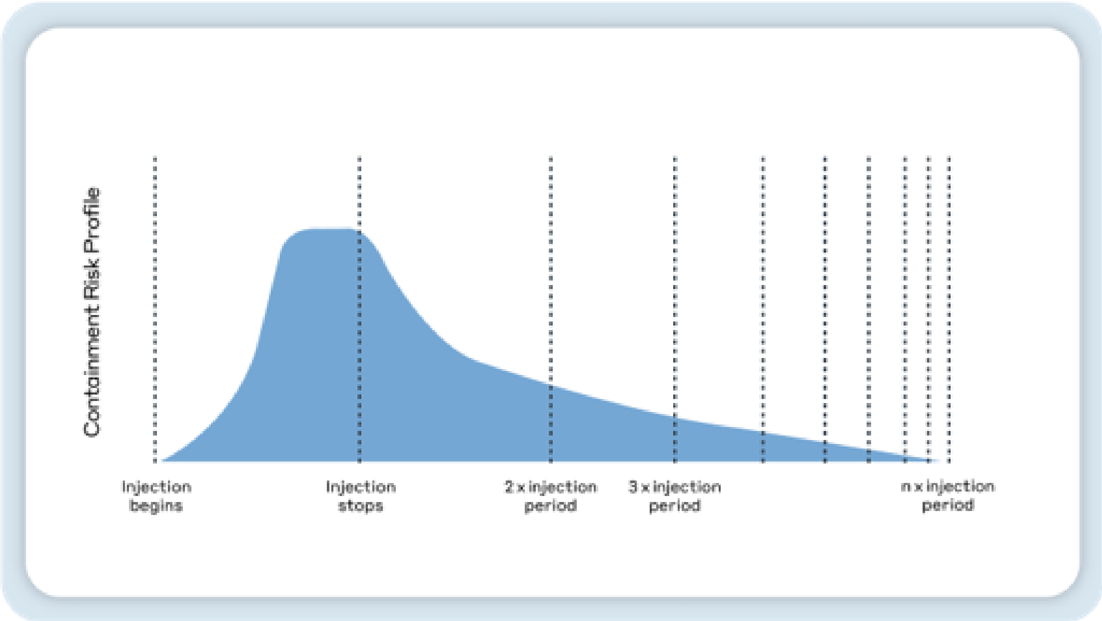


Figure 9. Schematic of likely geological containment risk over time for a CO_2 storage complex, based on Benson 2007 [40]

Figure 9 provides an example of how geological containment risks might vary for one storage complex. For a leak to occur there must be an erroneous assumption relating to an uncertainty at some location within the complex, or a lack of integrity within a well. The geological containment risk profile starts at zero as captured CO_2 could not leak from the storage complex prior to being injected. As increasing amounts of CO_2 are injected, the pressure increases and the containment risk increases (the probability and severity of a leak both increase), being greatest towards the end of operations and for a while after operations. This coincides with the highest pressures, highest concentrated free phase CO_2 (CO_2 that is free to flow) and while the plume is reaching its widest extent.

Data collected during injection will improve understanding of the behaviour of the site, improving the accuracy of the forecast and ways to manage and reduce the risk associated with greater amounts of CO_2 within the storage site and greater plume extent [7]. These data could alternatively indicate that an assumption that was important in deriving the containment risk profile was incorrect to the extent that the risk is higher than previously identified. This could have consequences for the operational life of the storage site. However, the forecast modelling will mean that this is likely to be identified as an issue prior to any leakage. After CO_2 is injected, the pressure in the reservoir will begin to equilibrate with the surrounding geology and any free CO_2 will become more securely trapped (see discussion of trapping mechanisms in Section 2.2).

Figure 9 shows risk over a prolonged period, including after injection operations have stopped, as example of how geological containment risks might vary for one storage site. Actual risks will vary on site specific basis. To transfer the storage site into the care of the government after the post-closure period, it is anticipated that the operator will submit a report through which it can be demonstrated that the stored CO_2 is completely and permanently contained. This report is likely to demonstrate the following:

- that the actual behaviour of the injected CO_2 conforms with the forecast behaviour,
- that there is an absence of leakage, and,
- that the storage site is evolving towards long-term stability [41].

Well Containment Risk Profile

The overall contribution from the wells to the containment risk profile depends on the number of active and inactive wells. Before injection operations begin, the active well barriers will have been tested to confirm that they meet the required performance standards. Once CO_2 injection begins, the well will be operated within the safe well operating envelope.

The literature has little to say on the well containment risk profile over time. On the one hand it could be assumed for both active and inactive wells, that the risk of degradation (cement & seals) and corrosion (steel) causing loss of containment may increase as the length of time that the well materials (cement, seals and steel) have been in contact with CO_2 extends. However, observed leakage from oil and gas wells suggests that quality of construction has a significant influence and suggests if a well is likely to leak it will be apparent very soon after operations start. This uncertainty implies a need for monitoring.

When an active well is decommissioned (becomes inactive), typically at the end of the injection period, the contribution of the well to the containment risk profile will decrease. Permanent barriers are installed in the well and tested to prevent fluid movement between formations. It is possible that these permanent barriers, for example cement, will degrade over long periods of time. Field studies in the US where CO_2 is injected to support oil field development suggest that in the presence of competent original cement, reactions with CO_2 do not adversely affect the cement’s capability of preventing migration of CO_2 [42].

3.2 Potential Leakage Pathways

3.2.1 Overview

By design, the permitting process will screen out sites with significant risk of leakage. The probability of any leak occurring is therefore judged to be very low (very unlikely) at the time of awarding the permit. In Section 3.3 the probability of a leak occurring is estimated. To derive these estimates of probability and severity, we first consider the theoretical mechanisms of leakage (the leakage pathways, Sections 3.2.2, 3.2.3 and 3.2.4), detection of a leak (Section 3.2.5), likely impact (Section 3.2.6) and remediations (Section 3.2.7). After the likely leaked rates, durations (Section 3.2.7) and probability of occurrence are estimated, the net benefit that CCS could provide in removing large quantities from atmospheric circulation as compared with potential leaked volume can be considered (see Section 3.3.3).

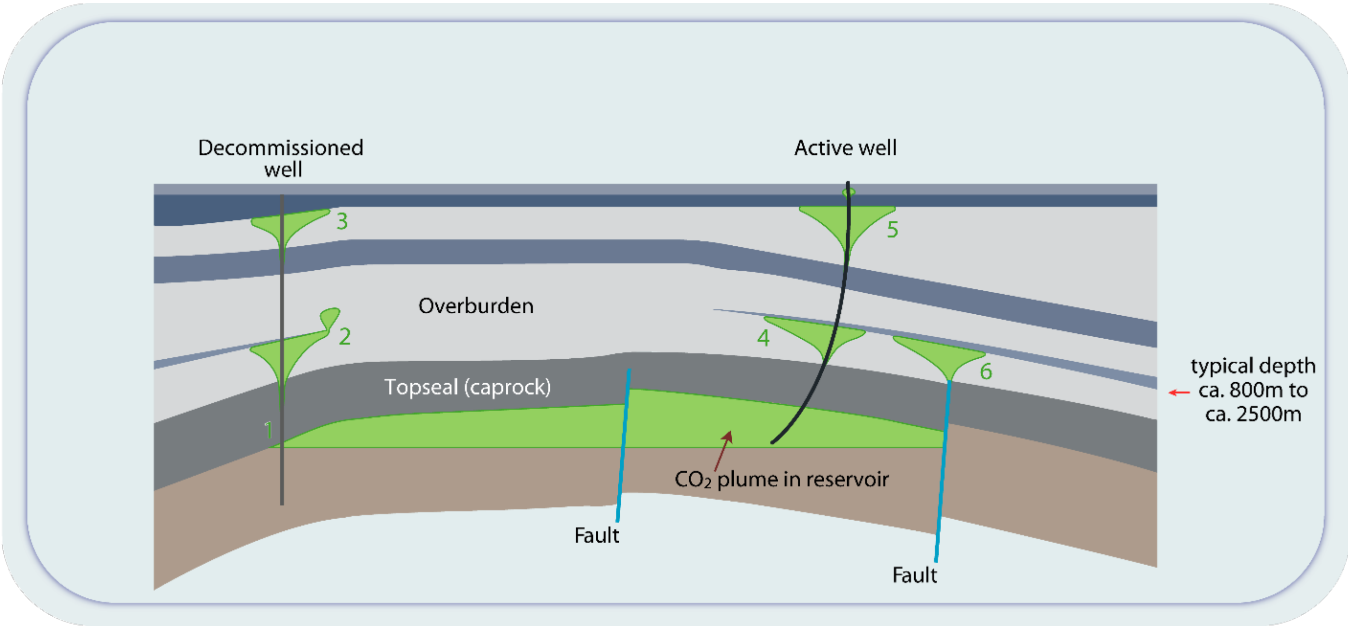


Figure 10. Diagram to illustrate potential CO_2 leakage pathways. Example leakage pathways are numbered:
(1) CO_2 plume has extended across the reservoir to a decommissioned well – the well is then exposed to the risk of CO_2 migrating through any conduits; (2) & (3) CO_2 has escaped from the well and pooled in the overburden, against a discontinuous fine grained layer, like a mudstone (2) or below a fine grained layer immediately below seabed (3); (4) & (5) the CO_2 has migrated along an active well and escaped into the surrounding geology; (6) the CO_2 has escaped along a fault. (Note: minor leaks through relatively small fault and fracture networks or through caprock are not shown).

The definition of leakage in a regulatory sense is 'any leakage of CO_2 from the storage complex' [43]. A storage complex is likely to extend up to the shallowest sealing rock type above the storage site but may not extend right to the seabed (Figure 4). This means that even after an unlikely event of a leak beyond the storage complex, because all or part of the leaked CO_2 may undergo residual trapping in the overburden, CO_2 may not be released at the seabed and may never reach the atmosphere. To escape from a geological storage complex deep below the seabed, the injected CO_2 would need to bypass the top seal (caprock) and any secondary seal(s), using either a natural leakage pathway such as a fault, or through a man-made pathway such as an active or decommissioned wellbore (see Figure 10), or via a combination of pathways.

3.2.2 Potential Well Leakage Pathways

In the context of wells, a leak would occur if fluid from the well were no longer contained by the well envelope (comprising casing, valves and cement). This could be the fluid being injected into the well, or backflow of fluids from the storage site. Once outside the well envelope, the fluid could migrate to the surface, although if the leak occurred deep in the well it would still have to find a way to reach the surface: this could be finding a leak path at the interface between the rock surrounding the wellbore and the casing cement that is connected for hundreds of metres, or leaking into the overburden and migrating through hundreds of metres of overlying rock formations (see Section 3.2.4) to reach the surface. Fluid from within the well envelope would have to breach at least two barriers to escape the storage complex and migrate to surface, although in practice it may be more.

Any wells which are drilled through the caprock of the storage formation have the potential to provide a leak path for CO_2 from the storage site to the wider environment, in the unlikely event of a loss of integrity. All wells drilled through the caprock will be included in the overall CO_2 storage containment assessment of any CO_2 project (initially by the developer and subsequently reviewed by the NSTA during the permitting process).

A well has several phases during the full well lifecycle (see bullet points below). During each of these phases the general principle of having two barriers to prevent flow outside the well envelope is rigorously applied:

- Well drilling and construction
- Operating phase – when CO_2 is injected
- Well workover/intervention phase – when tools are run in the well for surveillance or to repair any well equipment (intermittently during injection operations)
- Decommissioning and post-closure.

Wells are designed to have multiple barriers to protect the surrounding environment from contamination by produced or injected fluids, and to prevent flow between different subsurface formations. The potential leakage pathways are through:

- the cement sheath (micro-annulus) between the production casing and the surrounding rock
- the two independent barriers in the well:
    - for an active well (see Figure 6 the blue and red lines)
    - for an inactive well (see Figure 7 the blue and red lines)
- the additional barriers used during a well intervention when different, temporary barriers are used
- the well barriers used during well drilling and construction.

In this work an analysis has been carried out to assess the probability of different amounts of CO_2 leakage occurring and how quickly any leak can be identified, with an estimate of the time taken to stop the CO_2 leak. Categories of CO_2 leakage rates have been derived from inspection of the spread of available data in combination with maintaining a measure of consistency with how leaks have been categorised in the previous literature. These have been divided into the categories in Table 1. The same categories are used when considering levels of consequence (see Sections 3.2.6 and 3.2.7). For comparison of CO_2 leakage amounts, one UK household emits 4.8 Tonnes of CO_2 every year (1 Tonne every 2.5 months).

Category	Leak Rate (t/d)	Description
Seep	Less than 1	Low level nuisance leaks through micro cracks in casing cement or tiny gaps in valves or seals [44]. Whilst there is no minimum reportable leakage rate in the regulations, these may be considered easily dispersed or absorbed into seawater with limited impact on their surroundings. Detected through testing or targeted monitoring. Expected to be unlikely to be remediated once established.
Minor	1 – 50	Failure of well barrier components in active wells or cement plugs in inactive wells resulting in a minor leak that can be addressed by well intervention and component/plug replacement. Detected through regular testing of the pressure build-up/fall-off through barriers or wellhead area monitoring. The leak is resolved within six-months of discovery as securing the equipment required (e.g. a rig) may be deemed non-urgent based on impact. For active leaks the well can usually be shut-in until fixed to either stop the leak or reduce leak rates by reducing the pressure at the leak location. This shut-in would only include the leaking well, injection could continue in the remaining wells.
Moderate	50 – 1000	Similar to the minor leak scenario except that there is an escalation in the rate of the leak. The concentrations of CO_2 could be at a level to make a well intervention unsafe for drill crews. Temporary plugging techniques can usually be deployed on active wells to stop the leak which may allow a well intervention or reduce the volume leaked while mobilising for repair. If the leak rate cannot be stopped or reduced it is assumed that an emergency relief well is required to stop the flow. Typically, it takes four months to drill the relief well as the increased impact of the leak would justify an expedited approach to securing the rig.
Major	Greater than 1000	Represents an unconstrained flow rate. Major leaks are more likely to occur during drilling & well intervention operations but are still rare as well control equipment is installed to prevent uncontrolled flow from the well. A major leak could also be the result of structural failure and so may be difficult to shut in pending repair. The force of release and volumes involved may make it impossible to intervene on the well directly via the wellhead to temporarily or permanently remediate, requiring an emergency relief well to stop the flow. Typically, this takes four months to drill assuming that a rig can be sourced with priority given the severity of the leakage rate.

Table 1. Well leak categories

3.2.3 Potential Geological Leakage Pathways

In the context of geological leaks, an escape of CO_2 from the storage complex would be considered as a leak (Section 2.2). Not all leakage pathways will result in a leak to the seabed, however, if they do, the resulting leaks are likely to be diffuse [45]. The main pathways, for which probabilities are derived in Section 3.3, are discussed below. At the end of this section, a summary of the different leakage pathways and scales over which they extend is given in Table 2. Table 3 links potential leakage rates, pathways and consequences.

1. Through Caprock (or Top Seal)

To assess the CO_2 containment capability of an intact caprock it is essential to fully understand the physical properties and general integrity in relation to CO_2. The pre-permit site assessment requires the operator to describe the sealing capacity of the primary caprock and any secondary seals, and to gather core and fluid samples to demonstrate that the caprock is likely to seal, without any detrimental reactions with injected CO_2.

There are many caprocks in the UK which have the proven ability to trap buoyant fluids with typical thicknesses of hundreds to thousands of metres, that extend across many kilometres and are well understood from several decades of oil and gas exploration. Research indicates these hydrocarbon seals are likely to have equivalent impermeability to CO_2 [46]. In some hydrocarbon fields on the UKCS, these seal rocks trap hydrocarbons with a naturally high CO_2 content (see Section 2.1). The great majority of typical UK seal rocks are expected to prevent leakage indefinitely.

For the minority that do not provide a completely perfect seal, seepage rates of CO_2 are extremely slow and only significant over geological timescales (i.e., tens of thousands to millions of years).

Another potential risk element could arise if the properties of a caprock change laterally such that its sealing capability is reduced. In regions such as the UK, with a long legacy of geological investigation, this represents a low risk for a site that has a storage permit (although this might be more significant in other regions of the world where the lateral continuity of caprocks is less well understood). As the likelihood of this occurring on a large scale is negligible, this risk assesses the probability that leakage could occur from only a small proportion of the caprock.

2. Faults / Fracture Network

A geological fault is a surface between two blocks of rock that have moved relative to each other. Faults exist at every scale and range from a few millimetres to thousands of kilometres in length and tens of kilometres in depth. Faults occur across the globe and can be active or inactive, sealing or allow fluid flow. The UK does not experience large earthquakes. In this report, the potential leakage pathway via faults or fracture networks considers the potential for fluid flow along a pre-existing fault / fracture network. The risk of leakage pathways along faults is considered in the context of their size. The sizes of the different fault categories are given in Table 2.

Many oil and gas fields in the UKCS have sealing faults and non-sealing faults, sometimes both within the same field, however faults that do not seal are not likely to extend beyond the caprock, as that would have allowed the accumulated oil and gas to escape (by virtue of having an oil or gas field the containment is proven).

Most pre-existing inactive faults on the UKCS do not extend to the seabed. Larger faults can be detected by seismic surveys. Proposed sites in which large faults reach the seabed, or even cross the primary seal, are unlikely to be viable for CO_2 storage unless it can be demonstrated that the fault has sealing properties (this would be subject to significant scrutiny from the licensing authority).

Small faults or fracture networks that are not visible on seismic but that extend as an interconnected network through the full thickness of the caprock are possible and might seal or allow fluid flow. (Typically, sub-seismic refers to features less than ca. 15-50m). This may be more significant in saline aquifer sites compared with oil and gas reservoirs, which have retained hydrocarbons for millions of years. Loss of containment of CO_2 from networks of small-scale faults and fractures could only occur once the migrating CO_2 plume intersected them. Increasing pressure above original pressure (pre-production pressures in the case of depleted fields) could increase the tendency of faults and fractures to leak (and conversely the rate of leakage through a fault may decrease with time, as the pressure dissipates through leakage [47], unless connected to a vast aquifer).

Additional to considering the leakage risk through fracture networks, the rate of leakage that could occur is relevant. In general, the larger the fault is, the larger the displacement and the damage zone will be [48] [49] with the potential to support higher leakage rates than smaller faults (however any larger faults would be identified and scrutinised in advance). Fracture and fault networks that are sub-seismic will have limited potential leakage rates (see Section 3.3.2).

3. Induced Faulting

Induced faulting considers the potential for fluid flow associated with active faulting / fracturing. Faults can be induced or activated if there are significant changes in the pressure. If the pressure exceeds a critical threshold, existing faults may slip or be reactivated, or new fractures in the caprock may be created. Leaks, if they occur, would be anticipated to be at low-rates or over a diffuse area, making detection difficult. The leak would likely continue until the pressure dropped below the critical threshold.

The critical pressures likely to activate or induce faults can be defined within a known range. Operating conditions will need to be defined to limit CO_2 injection to well below this range.

In saline aquifers, the injection of CO_2 displaces the formation brine and increases the pressure in the storage formation. The pressure may dissipate quickly or slowly or be relieved by brine extraction, however all injection activities will be designed to remain within pre-defined safe operating limits. In depleted field storage sites the fluid pressure is likely to remain below or around the original pressure of the reservoir, so this risk is even lower.

The pressure within a storage site is likely to be constantly monitored and the risk is mitigated by the operator's knowledge of permeability, structure, pressure communication and pore fluids (or gas) around the complex. The most likely time for this risk to occur is during and just after cessation of injection and will decrease with time as the pressure in the storage formation reduces due to pressure equilibration across the storage site [47].

Induced seismicity that can be felt is linked to induced faulting but at dramatically lower frequency and is relatively uncommon offshore UK [50]. As operating conditions will limit CO_2 injection to below the pressure range likely to induce any fault activity, the risk of induced seismicity that can be felt is extremely low.

4. Gas Chimneys / Pipes

Vertical or sub vertical geological features with higher permeability could act as seal bypass systems (such as 'gas pipes', sand injectites, and pockmarks). If these features are large enough, they will be visible on seismic data and will constitute a significant risk of leakage if they extend through the caprock. (These features can occur at shallow levels in response to shallow gas, so do not always represent a containment risk from the reservoir.)

In this report 'gas chimneys / pipes' refers to features that could enable escape to surface but are below the threshold of what is visible in seismic analysis (sites with extensive visible features are assumed unlikely to be awarded a storage permit).

5. Lateral Migration

When CO_2 is injected into the storage site, the CO_2 will displace the existing fluids and migrate upwards. When it reaches the seal (or an intermediate layer) and can no longer migrate up, it will spread sideways beneath the caprock. Dynamic modelling (forecasting) will be carried out prior to injection to demonstrate that the storage complex can securely contain all of the injected CO_2. However, if, for example, the migrating plume of CO_2 encounters a high-permeability layer not previously identified, it is possible that CO_2 could migrate laterally along this layer beyond the storage complex. There are several factors that influence this, including the relief of the seal and permeability contrasts between geological layers. This would not lead directly to leakage at the surface, with hundreds of metres of rock separating the storage complex from the seabed.

The risk increases later in operational life and during the early post-closure period. It can be mitigated by monitoring early in injection operations. In this report the risk of lateral migration is assessed only for fully or partially confined sites (as defined in Section 2.2, see Section 3.3.2 for further explanation).

Potential Geological Leakage Pathway	Sub-category	Scale
Fault and fractures *(Pre-existing inactive features)*	Major tectonically/volcanically active fault zone	Do not occur in UK.
	Large block-bounding fault zone	Likely upwards of tens of km long and over km tall.
	Map-scale faults	Upwards of ca. 50 m tall.
	Sub-seismic scale faults & fracture network	Up to ca. 50m tall (depends on resolution of seismic)
Induced Faulting *(Active faults whether new or reactivated)*	Reactivation of pre-existing faults	Up to several hundred metres tall (or network of smaller faults).
	Initiation of new faults/fractures	Up to several hundred metres tall (or network of smaller faults).
Gas chimneys / pipes	None	Assumed sub-seismic, greater visibility on seismic if active

Table 2. Summary table of scales of fault and gas chimney potential leakage pathways

Geological Leakage Rates

This study includes analysis of the probability of CO_2 leaks occurring. Leak rates for different geological pathways have been categorised in Table 3 and have been categorised similarly to those for the well leaks. Direct remediation of geological leakage pathways is challenging, more detail is provided in Section 3.2.7.

Leak Category	Leak Rate (t/d)	Description
Seep	Less than1	Possible geological leakage pathways include pre-existing pathways (fault & fractures, induced fractures, gas chimneys /pipes including combined pathways with lateral migration) and induced faults or fracture networks. Leaks are easily dispersed or absorbed into sea water. Detected through testing and targeted monitoring. If they occur they are expected to be continuous and difficult to remediate.
Minor Leak	1 – 50	Possible geological leakage pathways include pre-existing pathways in a depleted field (up to ~3 t/d) or saline aquifer (up to 50 t/d) and induced faults or fracture networks (up to ~30 t/d). Detected on repeat seismic survey (once accumulated at sufficient concentration), or seabed / water column monitoring if the leak has extended to surface.
Moderate Leak	50 – 1000	Possible geological pathways include leakage along a large fault (a large block-bounding fault, major tectonically active fault zones are not present in the UK). Sites along a large fault are unlikely to be viable CO_2 storage sites, they would require significant regulator scrutiny to prove they were sealing (for example, evidence of different fluid regimes across the caprock). Detection by seismic survey, or seabed / water column monitoring.
Major Leak	Greater than 1000	Possible geological pathways include leakage along a large fault (a large block-bounding fault, major tectonically active fault zones are not present in the UK). Sites along a large fault are extremely unlikely to be viable CO_2 storage sites, they would require significant regulator scrutiny to prove they were sealing (for example, evidence of different fluid regimes across the caprock). Detection by seismic survey, or seabed / water column monitoring.

Table 3. Geological leakage rates and leakage pathways

3.2.4 Combined Well and Geological Leakage Pathways

It is also possible for leak paths to be a combination of well and geological leak paths. This is because both well and geological potential leak paths can be considered as a series of discrete barriers. Where a barrier in a well or the subsurface geology blocks a leak path, the leak may migrate laterally until it finds a different route to surface, although the likelihood of this happening reduces for each additional barrier encountered by the leak. Some theoretical examples of this are:

- The CO_2 could enter the storage formation through an injection well and laterally migrate from the storage site (via a geological pathway). The CO_2 could then come into contact with a leakage pathway through a different well, finding a pathway to surface through the cement sheath around the well or through the well itself. Depending on the location of the CO_2 plume, the second well may not penetrate the storage site or otherwise be a part of the storage complex. It could be an active well related to injection or it could also be an inactive well previously drilled for other purposes. It could also conceivably be an active well that is part of adjacent oil and gas fields.
- The reverse is also true, that active or inactive wells which penetrate the caprock of the storage site could form a leak path, but multiple casings and cement may stop the leak going any further within the well. The leaked CO_2 might then find a route to the seabed through a geological pathway such as a fault or chimney or permeable overburden.

The probability of combined leak paths occurring will be lower than for individual well or geological leakage pathways as the path would require the occurrence of two leakage pathways with migration between them.

The risk of combined leak paths, as with legacy wells, is site specific as it depends on the geological and man-made features that exist around the storage site and complex. For example, if the caprock above the storage site inclined upwards through areas with (decommissioned or still active) wells, this would suggest the potential for combined leak paths. Alongside the other containment risks, the potential for combined migration paths will be a consideration in the selection and permitting of storage sites.

3.2.5 Detection of Leaks: Measurements and Observations

Monitoring is required to demonstrate both:

- **Containment**: demonstrating that the injected CO_2 has been securely stored, and
- **Conformance**: showing that forecast models and observations agree and that storage processes at the site are understood, providing confidence in future long-term secure storage of CO_2 after site closure.

Deep-focussed measurement and observation techniques can be used to monitor the reservoir and deeper overburden and are critical for early detection of any unexpected CO_2 migration or leakage from the storage complex. Shallow-focussed techniques can be used to detect CO_2 at the seabed and in the water column. Injection wells may be continuously monitored, and dedicated monitoring wells will also be used to monitor conditions in the reservoir.

Wells

There is significant experience in monitoring well integrity from the oil and gas industry; the CO_2 injection, monitoring and brine production wells will, as discussed in Section 3.1.2, be likely continuously monitored by electronic gauges measuring key parameters such as pressure and temperature for changes that could represent integrity loss. Routine well maintenance and integrity testing of well barriers, which is part of the current oil and gas regulatory requirement for operation, is expected to be extended to CCS wells as good practice and be included in an annual CCS well maintenance plan. Any failures or anomalies will be acted upon promptly by the site operator to maintain the integrity of the well, reduce the risk of a leak or minimise the duration of the leak.

Deep Focussed Monitoring: Seismic Surveys

Seismic reflection surveying is a geophysical technique that provides an image of the rock formation in the subsurface; artificially generated sound waves are reflected from different structures or objects beneath the seabed which have contrasting acoustic properties. Three-dimensional seismic surveys can cover large areas and provide a three-dimensional image of the subsurface structure down to multiple kilometre depths with a minimum resolution of tens of metres. This makes it an ideal technique for containment monitoring over the whole of the storage complex and repeat surveys over the lifetime of the storage site enable the movement of the CO_2 plume within the reservoir to be tracked and monitored over time (4D seismic monitoring).

A series of three-dimensional seismic surveys have been carried out over the Sleipner CO_2 injection saline aquifer storage area in the Norwegian sector of the North Sea. Figure 11 shows the baseline seismic survey acquired in 1994 prior to any CO_2 injection, and a later survey acquired in 2013, after 17 years of injection. The velocity of sound in CO_2 is very different from that of brine, allowing the development of the plume geometry with time to be 'seen' and monitored. The clear difference in reflectivity (brighter red and blue horizons) between the baseline and the later surveys is due to the presence of CO_2 in the pore spaces of the reservoir rock. The images in Figure 11 show that the injected CO_2 plume has migrated to the top of the reservoir (Utsira Sand formation) and spread out laterally at the base of the caprock.

The Sleipner CO_2 injection was developed initially as a pilot project, so regular 3D surveys were carried out every 2 years for research purposes. For containment monitoring it is expected that an operator would acquire a high-quality baseline 3D survey prior to CO_2 injection, and if time-lapse monitoring of the plume is appropriate for the site, carry out repeat 3D surveys at appropriate intervals to monitor plume development and migration.

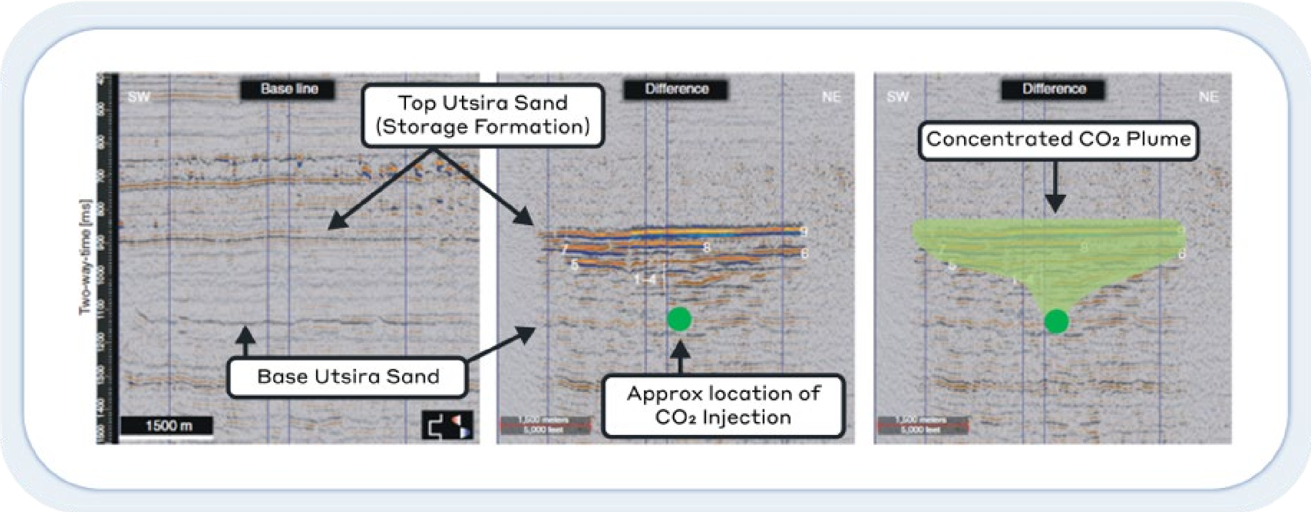


Figure 11. Seismic images showing development and migration of the injected CO_2 plume after 17 years of injection at Sleipner (injection depth of CO_2 is around 1000m below the seabed (green dot), thickness of the Utsira Sand reservoir is around 250m at the injection site). Modified from Furre et al., 2017 [51]

Shallow Focussed Monitoring

Shallow focussed monitoring techniques deployed using mini-Remotely Operated Vehicles (mini-ROVs) involve a combination of geophysical, chemical, and biological sampling methods to detect any CO_2 leaked through the seabed. A variation of sonar technology can be used to detect changes in the seabed or image streams of CO_2 bubbles in the water column, and chemical sampling methods aim to detect and characterise changes in the shallow sediments or seawater column that could indicate CO_2 leakage. Monitoring of changes in seabed flora and fauna may also detect changes caused by elevated CO_2 concentrations [52].

3.2.6 Impact of Leaks

The impact of any leaks that occur will depend on leak rate and duration of the leak.

A summary of the extent of likely environmental impacts of leaks is presented in Table 4 (categorised in the same leak rate ranges as referred to for probability of leakage). The extent of impact presented in Table 4 relates in the main to the magnitude of the reduction in pH of the seawater in the vicinity of a leak due to the volume of CO_2 dissolved. The variation of the pH of seawater is used by Blackford et al. [53] as a “proxy of impact” meaning that the area around a leak with a reduction in pH of greater than 0.1 represents the maximum distance from the leak at which an impact on marine organisms would occur. The exception to this derivation is for the seep rate category in Table 4 where the impact information includes data from a physical experiment performed using ~1 t/d leak rate, where intermittent physical changes were measurable up to 25m from the leak location [54].

Category	Leak Rate (t/d)	Extent of Environmental Impact of Leak [55]	Equivalent Emissions in UK Households [56] [1]
Seep	Less than 1	For a leak of <1 t/d at the seabed experimental analysis [54] showed there was an intermittent effect on marine organisms at sites 25m distant from the epicentre, however the effect was short-term and recovery within days to weeks of cessation of the leak.	75
Minor	1 - 50	The pH of the sea is estimated to have reduced by 0.1 since 1750 [57] to 8.1. Reduction in pH was used to assess the area of impact for different leak rates [53]: "most ecosystems are robust to slightly larger reductions, especially if short-lived" as would be the case for leaks from wells at these rates. For a leak rate of 50 t/d the area within which the pH was modelled to decrease by 0.1 is ~250m in radius.	3,800
Moderate	50 - 1000	Using the same analysis as for minor leaks, for a leak rate of 1000 t/d the area within which the pH was modelled to decrease by 0.1 is ~4km in radius. However, as discussed in Section 3.2.7, it is likely that such leaks from wells will be of a short duration and the effects would be short-lived. For geological leaks of this magnitude the probability of occurrence in the UK is extremely low, only considered plausible from a saline aquifer site with a large block-bounding fault, if the site were to be granted a permit.	75,000
Major	Greater than 1000	Using the same analysis as for minor leaks, for a leak rate of 5000 t/d (used in Section 3.3 as the maximum rate from a major leak) the area within which the pH was modelled to decrease by 0.1 is ~16km in radius. However, as with moderate leaks from a well, well related leaks will most likely be of a short duration (see Table 5). For geological leaks of this magnitude the probability of occurrence in the UK is improbable, only considered plausible from a saline aquifer site that included a large fault (tens to hundreds of km long), if the site were to be granted a permit.	380,000

Table 4. Likely extent of environmental impact for different leak rate categories

[1] The equivalent number of UK households' greenhouse gas emissions to this category of leak. However, in most categories it is unlikely that the majority of leaked CO_2 will reach the atmosphere due to dissolution or chemical binding of CO_2 in the overburden or sea. The exceptions being shallow moderate leaks and major leaks.

Whilst the extent of impact appears to be high, it must be remembered that this is a highly conservative assessment, with the pH reduction of 0.1 as modelled at a leak location being below the level at which experimentally measurable impacts are observed. In addition, as described above, potential sites will be subject to detailed scrutiny by both the operator and NSTA and a permit will only be issued if, at that time, the NSTA is satisfied that all available evidence shows that leakage will not occur.

During operation the storage complex will be closely monitored and mitigating action taken if its behaviour is not as predicted. On identification of any leaks or an indication of an increased risk of leakage a risk assessment would be performed, the outcome of which would be to ensure appropriate protective measures were put in place to reduce risks as low as reasonably practicable and the regulators (NSTA, OPRED and HSE) would be involved in determining if these measures were optimal. These measures would likely include imposition of an exclusion zone and efforts to control the leak pending full remediation. Finally, the likelihood of moderate or major leaks of a geological nature in a site with a storage permit are very small indeed, as will be discussed in Section 3.3.2, and whilst well leaks greater than 50 t/d do occur on rare occasions they tend to be of very short duration as described in the next section, 3.2.7.

3.2.7 Remediation of Leaks

The origins of well and geological leaks are very different, therefore the ways in which the leak may be stopped or the leak controlled, the remediation, also vary.

A. Well Leak Remediation

If there has been a loss of containment or leak from a well because both the primary and secondary barriers have failed, the first priority is to stop the leak, and restore two independent barriers. The actions required to achieve this will depend on whether wells are active or inactive.

For active wells: stopping injection and closing the well valves may stop or reduce the rate of the leak. If it is safe to rig-up well intervention equipment on to the well then weighted fluids (the hydrostatic pressure of the fluid is greater than the storage reservoir pressure) can be pumped into the well and downhole plugs can be installed as temporary barriers to stop the leak. If the leak rate from the well exceeds the threshold value, and it is not safe to rig-up equipment onto the well, then a drilling rig will be required to drill a relief well that intersects the active well and set additional plugs (most commonly cement plugs) to stop the leak.

For inactive wells: this can be achieved by using a drilling rig to drill a relief well that intersects the inactive well and set additional plugs (most commonly cement plugs) to stop the leak.

The size and type of leak from the well will determine whether it is safe to rig-up well intervention equipment on to the well to avoid exposing the personnel and equipment to high levels of CO_2; the threshold value assumed in this report is 50 t/d. If it is not possible, then a relief well will be drilled. To drill a relief well the rig is offset from the leaking well and therefore the personnel and rig itself will not be exposed to the leaking CO_2. There is no significant difference between a relief well drilled on an active or inactive well.

Once the well integrity with two independent barriers has been restored and the leak contained, then the well operator can propose to the relevant regulatory authorities (NSTA, HSE, OPRED and Ofgem) whether to re-instate or decommission the well.

An assessment of expected duration of CO_2 leaks can be estimated from comparable hydrocarbon releases from reported incidents from 1992 to 2015 as documented in the HSE Hydrocarbon Release data for 1992-2016 [58]. The longest leak duration was 51 days, which was for a major, well-publicised incident. The next longest leak duration was 2.4 days, with more than half the well releases recorded being for less than 5 minutes. In the calculations presented here, it has been assumed that a control of the leak pending remediation has not been possible and so they are based on the conservative assumption that once a leak occurs it will continue until remediation activities are complete for the well.

The calculations in this report are based on a time to contain the leak outlined with their assumptions in Table 5. The assumptions have been derived by the authors based on knowledge of remediation of equivalent leaks in oil and gas wells and consideration of the differences CO_2 leaks will present.

Leak Category	Leak rate (t/d)	Maximum Time to Remediation (Days)	Active Wells Assumption	Inactive Wells Assumption
Seep	Less than 1	Continuous	No safety or environmental impact and potentially higher risk to remediate.	No safety or environmental impact and potentially higher risk to remediate.
Minor	1 – 50	Up to 180	Routine light or heavy well intervention. Duration set by lead time for rig for short campaign, most interventions can be executed within 3 months.	Relief well, not-expedited, to remediate the leak.
Moderate	50 – 1000	Up to 120	Assumed too high a leak rate for an intervention unless it can be shut in. Expedited relief well to minimise loss of fluid to the environment.	Expedited relief well to minimise loss of fluid to the environment.
Major	Greater than 1000	Up to 120	Expedited relief well to minimise loss of fluid to the environment.	Expedited relief well to minimise loss of fluid to the environment.

Table 5. Time from leak identification to remediation for active and inactive wells

B. Geological Leak Remediation

There is more uncertainty associated with the successful outcome of the remediation and the duration for geological leaks than well leaks. In most cases remediation of a geological leak will involve trying to control what enters the leakage pathway rather than repairing the leakage pathway itself. (This is because if 'repairing' a location along a geological leakage pathway, a repair is unlikely to seal all of an extensive geological weakness and the CO_2 is likely to bypass the repair.) An implication of this is that geological leaks could endure for significantly longer than well leaks. The monitoring plan is likely to mean that any potential issues will be identified and mitigated whilst CO_2 is contained within the complex, before becoming a leak.

For any CO_2 detected at surface, the source of the CO_2 will need to be proven to make sure it is not naturally occurring. Depending on the severity of the leak there may be a decision to pause injection into the whole or part of the site whilst the leak is assessed, which may require acquisition of further monitoring data. All detected leaks will be evaluated by the operator and mitigating actions must accord with the permit and regulations as appropriate for the site. Examples of mitigations are given in Table 6.

Mitigation	Example scenarios that might be treated	Continued injection into storage site?
Revised injection strategy (e.g. injecting at different rates or into different parts of storage site, maybe with more wells)	Issues that are localised (relating to specific features), or relate to pressure dissipation away from wells, or avoiding certain horizons.	Yes, if revised strategy stabilises issue, albeit possibly at revised injection rates from plan.
Relief well for a geological leak (e.g. to introduce material to reduce permeability of the leak path)	May be used to reduce leak rate or stop leak along a fault.	Case-specific.
Permanent closure of the storage site	Minor, moderate or major rate leak along a fault. As pressure drops around the leak pathway may self-seal.	No.
Brine management (Wells that produce brine from beyond the storage site to reduce pressure within the storage site. Brine would need safe disposal. Likely several years to implement if not pre-planned. Unlikely for depleted field sites.)	Moderate or major leak rates that do not naturally abate with time. Could reduce leak rate or tendency to leakage from leaks associated with faults and some gas chimneys/pipes.	Maybe. Would depend on storage stability after pressure management system in place.

Table 6. Example mitigation strategies for geological leaks

The most difficult leaks to mitigate would be those primarily driven by buoyancy of the CO_2 across a relatively permeable conduit (for example a non-sealing fault). Whilst this could have a long duration, only a small proportion of the areal extent of the plume is likely to come into contact with the relatively small conduit. Additionally, there are less well-established mitigation techniques and concepts that are not mentioned in this report, but in time may be proven for such scenarios.

In determining the best course of action, the current and prognosed future rate of leakage (severity) would be considered. The suitable remediation options available will depend on the leakage path, whether the leak is driven by fluid pressure, the type and geological setting of the storage site (e.g. saline aquifer, fully or partially confined or open, the volume that is hydraulically connected and the rate of pressure transmission across the volume) and the time over which leakage rates may start to abate naturally compared with what might be achieved with remediation.

Leak rate (t/d) & Category	Leak Duration (Years)	Pathway	Assumptions for reasonable worst-case scenario
Less than 1 Seep	Continuous once begun, 100 years	Any	Leak rate is stable and unlikely to increase, no safety or environmental impact and potentially higher risk to remediate.
1 – 50 Minor	100 years	Via an existing pathway (e.g. a non-sealing fault or fracture network or gas chimney) or lateral migration beyond the complex.	Cannot be remedied by revising injection strategy + decision taken to continue injection. (In reality, leak might be shorter-lived, and/or site could close prematurely.)
50 – 1000 Moderate *And* Greater than 1000 Major	25 years	Via existing large faults that extend over hundreds of metres (or major tectonically /volcanically active fault zone which do not occur in the UK)	Leak will be visible within 5 years on seismic survey (or at next seabed survey if leak to surface), injection stopped and site closed, a proportion of the CO_2 that was injected in the 5 years since leak began until identified would leak out until stabilised. Brine management might be considered.

Table 7. 'Reasonable worst-case' leak durations for geological leaks. (Note: leak durations could be much shorter.)

The calculations in this report are based on a time for remediation outlined with the assumptions in Table 7. Moderate and major leak rates are likely to reduce with time. Durations are capped at 100 years to allow for a reasonable worst-case scenario (that is, a worst plausible scenario) where leakage begins towards the end of injection operations and may continue for a long time (durations could be much shorter, even for leakage that begins towards the end of injection operations). There is significant uncertainty beyond this, the durations are not known (and will be site and event specific). The duration estimates will feed into Section 3.3.3 to derive leakage volumes for typical CO_2 storage sites which are modelled over 125 years total time (25-years injection operations followed by 100-years post injection and aligns with the previous study basis).

The volumes derived from Table 7 do not reflect the probability of occurrence of leakage. By design, any store that has been granted a permit will have all potential leakage events with low probabilities. To understand the combined total significance of these potential different leakage events for a store, it is necessary to combine probability of occurrence for the different leakage pathways.

3.3 Containment Certainty Results

3.3.1 Well Leakage Risk Results

Two approaches have been taken to estimate well leakage risks. A review of leakage data in technical literature has been carried out and secondly an analysis of failure data from the commercially available Peloton WellMaster database [59] has been carried out. The results from these are presented below.

Well Leakage Probabilities and Rates from Literature Review

Large scale geological storage of CO_2 has yet to be undertaken on the UKCS and so estimating the risk of leakage from CO_2 wells cannot rely on failure data from operational sites. However, the topic of potential leaks from CCS wells has been the subject of considerable study over several decades, and CO_2 injection has been undertaken worldwide for about 50 years for enhanced oil recovery [60] and 25 years for CO_2 storage [51]). There is also a variety of different studies on aspects of leakage from oil and gas wells from fugitive emissions, loss of integrity data and major loss of containment events. There is therefore a significant body of research that can be used to estimate the probability of different sizes of leak from a well penetrating the caprock of a CO_2 geological storage site.

In reviewing and comparing the data from these diverse sources, we have established four categories of leak: seep, minor, moderate and major as described in Section 3.2.2 above.

The results from the literature review are presented for active wells (CO_2 injection, monitoring and brine production wells) and inactive wells in the following tables.

Active Well Results

Leak category	Leak rate (t/d)	Duration	Probability of defined leak rate occurrence/well Maximum	Probability of defined leak rate occurrence/well Minimum
Seep (continuous)	Less than 1	Continuous	1 in 10	1 in 1000

Table 8. Leakage probabilities for active wells at <1 t/d derived from literature review

Leak category	Leak rate (t/d)	Duration (months)	Probability of defined leak rate occurrence/ well/annum Maximum	Probability of defined leak rate occurrence/ well/annum Minimum
Minor	1 - 50	Up to 6	1 in 1000	1 in 100,000
Moderate	50 - 1000	Up to 4	1 in 10,000	1 in 100,000
Major	Greater than 1000	Up to 4	1 in 100,000	1 in 1 million

Table 9. Leakage probabilities for active wells at minor, moderate and major leak rates derived from literature review

Inactive (Decommissioned) Well Results

Leak category	Leak rate (t/d)	Duration	Probability of defined leak rate occurrence/well Maximum	Probability of defined leak rate occurrence/well Minimum
Seep (continuous)	Less than 1	Continuous	1 in 10	1 in 1000

Table 10. Leakage probabilities for inactive wells at <1 t/d derived from literature review

Leak category	Leak rate (t/d)	Duration (months)	Probability of defined leak rate occurrence/ well/annum Maximum	Probability of defined leak rate occurrence/ well/annum Minimum
Minor	1 – 50	Up to 6	1 in 1000	1 in 10,000
Moderate	50 – 1000	Up to 4	1 in 10,000	1 in 100,000
Major	Greater than 1000	Up to 4	1 in 100,000	1 in 1 million

Table 11. Leakage probabilities for inactive wells at minor, moderate and major leak rates derived from literature review

Active wells include the CO_2 injection wells while operational. After the storage site is closed, they are plugged and decommissioned and become inactive.

Active wells also include other types of well in the storage complex used for monitoring or in the case of saline aquifer storage sites, wells used to draw off excess brine to manage reservoir pressure as CO_2 is injected. In both cases, during normal operations these types of wells will not be in contact with CO_2 so although the well constructions and barrier design will be similar and the leak probabilities and leak rates are relevant, the fluid leaked is most likely to be brine rather than CO_2.

Well Leakage Probabilities and Rates from Peloton Failure Modelling

The Peloton WellMaster database has 38 years' worth of well equipment reliability data covering 6,000 wells with 70,000 components and 45,000 well service years from 34 operators from around the globe. The operators provide this data so that they can use it to drive uptime and reliability improvements in the design and operation of their wells. The majority of the data is from oil, gas and water wells however, there are some data from the Norwegian CO_2 injection wells. Software linked to the WellMaster database can be used to calculate failure rates for well equipment. The calculated failure rates for the well equipment can be combined using a Monte Carlo simulator to estimate the failure rate for each of the two independent barriers. The failure rate of each independent barrier is then combined to generate the probability of a leak from a well. This approach has been applied to two well types;

- An active injector to represent wells that will be used in the CO_2 storage project; CO_2 injector wells, monitoring wells and brine producer wells because they will be directly connected to the Storage Reservoir.
- A decommissioned well to represent the exploration, appraisal and development wells that have penetrated the storage reservoir caprock and been decommissioned, plus those active wells used in the CO_2 storage project that will be decommissioned once the CO_2 storage reservoir is closed.

The results from this analysis can be seen in Table 12 and Table 13. Further detail on this analysis can be found in the Supplementary Note C.

Using the WellMaster database has enabled a leak frequency for a well to be generated using the failure rates of constituent parts of a well, which in combination would lead to a leak. This is an alternative source to the data reported in different papers and studies. The WellMaster database provides consistent information across a very large population size for failures versus the papers which often focus on specific events and small populations requiring a large degree of extrapolation due to the rarity of the events under consideration.

As can be seen, for active wells there is a slightly higher frequency of failure using WellMaster than is derived for the minor leak category from the papers and studies reviewed. There is no associated leak rate with the WellMaster data, as it records individual failures that could cause a single barrier failure. The trigger for an equipment failure is typically approximately one tonne per day based on standard acceptance criteria for well equipment tests. Therefore, the WellMaster data is generally showing failures of one tonne per day, which is towards the lower end of the range for a minor leak and could be seen as broadly supporting the proposed frequencies and leak rates.

Active Well Results (Peloton)

Leak category	Leak rate (t/d)	Duration (months)	Probability of defined leak rate occurrence/ well/annum Maximum	Probability of defined leak rate occurrence/ well/annum Minimum
Minor	1 – 50	Up to 6	1 in 500	N/A

Table 12. Leakage probabilities for active wells at minor leakage rates derived from Peloton analysis

Inactive (Decommissioned) Well Results (Peloton)

Leak category	Leak rate (t/d)	Duration (months)	Probability of defined leak rate occurrence /well/annum Maximum	Probability of defined leak rate occurrence /well/annum Minimum
Minor	1 – 50	Up to 6	1 in 2000	N/A

Table 13. Leakage probabilities for inactive wells at minor leakage rates derived from Peloton analysis

Conservative Assumptions Made in Well Risk Probabilities and Leak Rates

The probabilities and leak durations for each of the leak categories have been selected from an analysis of the data. The selection also includes some assumptions. These have been made with a deliberate conservative bias so there will be confidence in the overall well risk results. The following conservative aspects to the selected probabilities are noted:

1. Large amounts of the data come from onshore Canadian or USA wells. UK wells, whether new or legacy, could be expected to have lower failure rates due to a regulatory regime which encourages risks to be driven down to as low as reasonably practicable.
2. The source data for the probabilities and leak rates covers a broad range of well types and service. Wells constructed specifically for CO_2 storage are likely to have a lower probability of failure and will have considerable focus on leak prevention.
3. CO_2 storage complexes will have a lower leakage risk from decommissioned wells than the global population of decommissioned wells. This will be due to increased permitting scrutiny for legacy decommissioned wells and the CO_2 injection wells that will be decommissioned at site closure benefitting from improvements in decommissioning methods which have evolved since the beginning of North Sea offshore activity.
4. Monitoring wells and brine producing wells will not be in contact with CO_2 for full lifecycle, so the risks are over-stated.
5. Seep leakage is primarily, but not exclusively, related to quality of cement bonds. New CO_2 injection wells are likely to be in the lower part of the probability range selected as a result of more careful cementing techniques.
6. Very large major leakage events are very rare, so probability estimates are influenced by the size of the data sample.

7. One data source [61] concluded that due to the different fluid properties of CO_2, the event would release only around 60% of the fluid mass released in a comparative gas leak.
8. Because of the simple construction after decommissioning with two or more cement plugs requiring to fail in a manner to create full bore flow, major inactive well leak events are considered practically unfeasible.
9. It is suspected that the vast majority of minor and moderate leaks are at the smaller end of the range and that larger leaks at the other end of the range are much less likely.
10. Studies from the oil and gas industry are generally focussed on loss of integrity (e.g., sustained casing pressure or known loss of a barrier) rather than leaks. Loss of a single barrier does not cause a leak, but is more frequently reported and skews data to higher frequency.

Discussion

The data behind the results presented above are diverse and it has been a challenge to extrapolate and compare data. It is useful for readers to understand the context of the data used and so the following points are raised to highlight the nature of the process. It is also worth highlighting that the underlying assumption behind this work is that future CCS wells in the UK will perform analogously to oil and gas wells during the long history of that industry. This should be a minimum expectation and improvement is certainly possible.

Studies are often very broad or very focussed. So, it is unclear if the results are directly applicable. Relatively few studies have estimated leak rates, probabilities and durations as has been done here, often they only contain part of the picture. Often leak rates are descriptive only and assumptions have been made on how those descriptions relate to the leak rate categories used in this report.

Many of the data sets were not collected for the purpose to which they have been put in this report and were not in the form required. Some extrapolation of data has been undertaken to process probabilities into consistent units (per well per annum) and similarly where leak rates were quoted for gas leaks these have been converted to the same mass in tonnes per day (t/d) of CO_2 at standard conditions.

Seeps are almost unmeasurable, so the probability that between 1% and 10% of wells leak is perhaps not unreasonable. Another reason the probability is so high is that the risks associated with remediation can be significantly greater than the risks of doing nothing, therefore careful analysis is performed prior to intervening on a well with such low leak rates. It is an extremely rare occurrence to have a major leak; these occurrences are readily detected, and given the magnitude there is a great deal of news flow on the efforts required to remediate the leak, providing anecdotal evidence to support the proposed range of probabilities for major events.

Intermediate leak rates in the literature often focus on loss of integrity, i.e., single barriers rather than leakage. This reflects the fact that the data (almost exclusively) comes from the oil and gas industry where the focus is on reliability rather than loss of containment. Probability of leakage is not often presented and is inferred from the likelihood of the second barrier failing whilst the first is compromised and before it is repaired.

Seeps can develop over time, but often they are a feature of the quality of the initial cementing operation. Minor and moderate leaks are generally the result of equipment degradation and develop slowly over time. Major leaks tend to be due to a sudden failure of equipment. To some extent most leaks can be prevented by careful construction, regular monitoring and integrity testing.

The role of cement to provide and maintain well barriers to prevent fluid flow between formations during the active period of a well, and when the well decommissioned, is critical in preventing leaks. This can be controlled by well design (limited deviation), cement operations and verification of successful cement operations by logging prior to decommissioning the wells. A strong focus on well cementing to assure high quality of cement seal would reduce the probability of seep leakage by at least one order of magnitude.

CO_2 injection wells are a relatively new concept for the industry. Currently, it has been assumed they will be constructed in a similar way to gas wells; however, this doesn't have to be the case. As designs mature and risk assessment and flow modelling are applied there may be design improvements that can be used with CO_2 to reduce the probability or impact of major loss of containment and indeed more minor leak events.

3.3.2 Geological Leakage Risk Results

Deep geological storage of CO_2 is not currently present in the UK, and although globally there are few sites at industrial scale, there are no reported geological leaks to surface from any current or former CCS project. Calibrating leakage risk probabilities and magnitudes cannot be established from operational CO_2 injection sites. The following assessment of typical ranges of probabilities and quantities of CO_2 leaked from the storage complex via geological pathways has been informed by published articles based on analogue scenarios (including natural gas storage sites, petroleum reservoirs, naturally occurring CO_2 accumulations), models or expert opinion, including for actual and proposed CCS sites. As with well leakage risks, there is a significant body of research that has been drawn upon, and in time this will become better calibrated with direct experience.

In this section ‘typical’ probabilities and associated severities (defined in terms of leakage amounts) are assessed for potential geological pathways that could be found in a generic fully or partially confined UK offshore storage site that has a storage permit and is subjected to the scrutiny, monitoring and mitigations as described in the sections above. Fully open storage sites (sites that do not rely on geological structures or strata to contain the CO_2) are not discussed in this section. The leakage risks at specific open sites may be higher or lower than those at confined sites (whether fully or partially confined). Site-specific evaluation of CO_2 migration pathways and containment mechanisms over a large areal extent to establish leakage risks will be even more critical than for confined sites.

Deriving Leakage Rates

Leakage rates have been constrained from a wide variety of data sources looking at analogous leakage rate data: from background natural leakage rates above hydrocarbon basins and fields e.g. [62] [63]; natural CO_2 seeps [64]; controlled CO_2 leakage experiments [64]; calculated hydrocarbon leakage rates via faults e.g. [65] [66]; and flow of hydrocarbons along faults [67]. There is a more comprehensive reference list and discussion in Supplementary Note B.

As depleted fields have been proven to contain hydrocarbons over geological time, they are assumed not to have any pre-existing geological leakage pathways that could allow rates of leakage greater than a few tonnes per day.

Deriving Leakage Probabilities

Probability estimates have been defined using two main types of publication: published risks given for specific proposed and actual deep geological storage sites, and data from indirect analogue scenarios (storage of natural gas and UK hydrocarbon exploration success rates [68]). Leakage probabilities are provided as a total probability of an event occurring over the period of injection operations plus 100 years post-closure, during which time the risk of geological leakage is likely to have reduced from its peak, Figure 9.

Published risks from actual and proposed storage sites are site-specific and may not be representative of other sites.

Unintentional releases of natural gas at underground storage facilities can be used as an indirect analogue of potential releases at CO_2 storage sites as both can involve underground storage of a buoyant substance in pore spaces in depleted fields or saline aquifer storage sites. Data are available that allow distinction between events that occurred in depleted fields and saline aquifers due to geological causes (e.g. [69], [70]). Even when the data are filtered by geological leakage pathway and site type there are substantial differences in the regulation and conditions of use that mean the occurrence rates and frequencies cannot be directly applied [71]. However, they are taken to provide an upper limit on the overall geological leakage risk for UKCS deep geological storage sites.

The risk tolerance for CO_2 storage sites is very different to hydrocarbon production (see Section 3.1.1). The oil and gas exploration business model accommodates a substantial risk that an exploration well does not encounter oil or gas. For injection of CO_2 substantial risks cannot be tolerated, even a relatively small risk of leakage will mean that the storage site is rejected. Never-the-less UK data on exploration well successes (e.g. [68]), has relevance as another indirect analogue for predicting secure containment of CO_2 in saline aquifer sites that have not been proven to retain buoyant substances over geological time. An absence of hydrocarbons could indicate that the site has leaked, or it could indicate hydrocarbons never reached the site. Research indicates that generally the operators are good at identifying the main risks impacting a prospective field [68], which means that many sites that are suitable for hydrocarbon exploration would be recognised as unsuitable for CO_2 storage [71].

As depleted fields have been proven to contain buoyant hydrocarbons over geological time, they are assigned a low probability of leakage. Similarly, a saline aquifer storage site in which the fluid regime within the storage site and above the caprock are shown to be different are likely to have a lower probability of leakage than a saline aquifer site that cannot demonstrate this.

Linking Leakage Rates to Probabilities

Finally, the probabilities of leakage events were linked to the leakage rates. Some sources included this, otherwise geological knowledge about the potential leakage pathways was used to make an interpretation.

Lower leakage rates have higher probabilities of occurrence (geological populations often have many more small features than large, for example, faults and fractures typically have logarithmic size distributions, e.g. [72] [73]).

Risk Estimations for Geological Pathways

Note: Well leak rates have been calculated in tonnes per day. Geological leakage rates are measured less accurately and so derived in tonnes per year, and then divided by 365, hence there are some odd numbers of leakage rates.

1. Leakage Risks Through Caprock

Through caprock leakage risk refers to any leakage through the intact caprock (i.e. not through faults or fractures), including variations in caprock grain size (see Section 3.2.3). The leakage rate is given in tonnes per km^2 after 100 years. The amount leaked will depend on the area of the caprock that is not sealing; the flow rates through a seal are likely to be sufficiently slow that the seal will not be breached for several decades or longer. This leakage pathway would be extremely difficult to mitigate, which is why such emphasis is to be placed upon the seal in the permitting process (Section 3.1.1). Caprocks that creep (such as halite and some mud rocks) will typically have probability of leakage close to the minimum value in Table 14.

Storage Site Type	Geological pathway	Leak category	Leak rate (t / d / km^2 after 100 years)	Typical probability of defined leak rate occurrence per storage complex Maximum	Typical probability of defined leak rate occurrence per storage complex Minimum
Depleted Fields	Diffusion	Seep	Less than 1	Negligible in the UK	Negligible in the UK
	Capillary flow	Seep	Less than 1	Negligible in the UK	Negligible in the UK
	Lateral Variability	Minor per km^2 of leak through caprock	4-43	Negligible in the UK	Negligible in the UK
Confined Saline Aquifers	Diffusion	Seep	Less than 1	Negligible in the UK	Negligible in the UK
	Capillary flow	Seep	Less than 1	Negligible in the UK	Negligible in the UK
	Lateral Variability	Minor per km^2 of leak through caprock	4-43	1 in 200	1 in 2,000

Table 14. Estimates of potential leakage through caprock. (Estimates are applicable per storage site, over operational life and post closure.) Saline aquifer store types refer to fully or partially confined sites.

2. Leakage Risks Through Faults (and Fractures)

Faults and fractures leakage risk refers to any pre-existing faults or fractures having sufficient permeability to flow the relatively buoyant injected CO_2 upwards along the fault or fracture (or network of faults and fractures, see Section 3.2.3). In depleted fields any faults are proven not to leak beyond the storage site and so maximum leakage rates from all size faults are capped. Faults greater than a few tens of metres can be visible on seismic data, so even in saline aquifers low risk larger faults can be monitored. Even with a high-rate fault leak to surface in one part of the storage complex, the vast majority of the injected CO_2 would remain securely contained within the reservoir (due to residual trapping, assuming only a small proportion of the plume would contact the fault). If the fault were in the middle of the plume location, the leak would be discovered early, and the site likely shut early in the planned operational life, as a means of reducing the overall leakage from the site.

Storage Site Type	Geological pathway	Leak category	Leak rate (t / d)	Typical probability of occurrence per feature per store Maximum	Typical probability of occurrence per feature per store Minimum
Depleted Fields	Major tectonically / volcanically active fault zone	Major - Minor	25 - 5500	Negligible for UKCS	Negligible for UKCS
	Large block-bounding fault zone	Minor	Less than 5	1 in 10,000	1 in 100,000
	Map-scale faults	Seep	Less than 1	1 in 1,000	1 in 3,500
	Map-scale faults	Minor	Less than 5	1 in 3,500	1 in 10,000
	Sub-seismic scale faults & fracture network	Seep	Less than 1	1 in 400	1 in 5,000
	Sub-seismic scale faults & fracture network	Minor	Less than 5	1 in 5000	1 in 10,000
Confined Saline Aquifers	Major tectonically / volcanically active fault zone	Major - Minor	25 - 5500	Negligible for UKCS	Negligible for UKCS
	Large block-bounding fault zone	Minor	1 - 50	1 in 1,000	1 in 1,100
	Large block-bounding fault zone	Major-Moderate	50 - 1400	1 in 1,100	1 in 2,000
	Map-scale faults	Seep	Less than 1	1 in 100	1 in 200
	Map-scale faults	Minor	Less than 30	1 in 200	1 in 1,000
	Sub-seismic scale faults & fracture network	Seep	Less than 1	1 in 80	1 in 300
	Sub-seismic scale faults & fracture network	Minor	Less than 30	1 in 300	1 in 1,000

Table 15. Estimate of typical leakage risks through faults and fractures. (Estimates for faults that are map scale or larger are applicable per feature. Estimates for sub-seismic risks are applicable per storage site, over operational life and post closure.) Saline aquifer store types refer to fully or partially confined sites.

3. Leakage Risks Through Induced Faults (and Fractures)

This risk refers to the assessment of whether faults might be activated (either for the first time or reactivated) as a consequence of injection of CO_2 and form a leakage pathway (see Section 3.2.3). As these leakage pathways would not be transmissive until they were induced, the leakage rates are not capped on depleted fields, but reflect the estimation of most likely maximum leakage rate. Saline aquifers are judged to have higher probabilities for this due to greater uncertainty about pressure transmission within the storage site.

Storage Site Type	Geological pathway	Leak category	Leak rate (t/d)	Typical probability of occurrence per feature per storage complex Maximum	Typical probability of occurrence per feature per storage complex Minimum
Depleted Fields	Reactivation of pre-existing faults	Seep	Less than 1	1 in 1,000	1 in 2,000
	Reactivation of pre-existing faults	Minor	1-30	1 in 2,000	1 in 10,000
	Initiation of new faults/fractures	Seep	Less than 1	1 in 1,000	1 in 2,000
	Initiation of new faults/fractures	Minor	1-30	1 in 2,000	1 in 10,000
Confined Saline Aquifers	Reactivation of pre-existing faults	Seep	Less than 1	1 in 100	1 in 200
	Reactivation of pre-existing faults	Minor	1-30	1 in 200	1 in 1,000
	Initiation of new faults/fractures	Seep	Less than 1	1 in 100	1 in 200
	Initiation of new faults/fractures	Minor	1-30	1 in 200	1 in 1,000

Table 16. Estimates of leakage risks through induced faults and fractures. (Estimates are applicable per storage site, over operational life and post-closure.) Saline aquifer store types refer to fully or partially confined sites.

If induced faults or fractures were discovered to be leaking during injection of CO_2, and injection were stopped (which might be decided upon for the higher leak rates in Table 16), it is likely the leak would stop as the pressure dissipates (over some years or decades). Active pressure management (through removing brine) may stabilise pressures and allow injection to continue.

Unexpected compartmentalisation of the storage site could lead to increasing pressure and potentially induced fracturing of the seal. This situation is more likely for a saline aquifer than a depleted field storage site as the presence of compartments would be known from previous hydrocarbon production. Monitoring the pressure would allow mitigating actions prior to fracturing the seal, ranging from revising injection strategy to premature site closure.

4. Leakage Risks Through Gas Chimneys and Pipes

This risk refers to leakage via vertical or sub vertical geological features, which could begin when the CO_2 plume encounters a feature (see Section 3.2.3), and/or pressure is above a threshold at which flow begins. The leakage rate is assumed proportional to the size of the feature. These features are below seismic resolution, so leakage rates are likely to be minor. Depleted fields have the leakage rate capped, to reflect proven retention of hydrocarbons.

Storage Site Type	Geological pathway	Leak category	Leak rate (t/d)	Typical probability of defined leak rate occurrence per feature per storage complex Maximum	Typical probability of defined leak rate occurrence per feature per storage complex Minimum
Depleted Fields	Gas chimneys / pipes	Seep	Less than 1	1 in 400	1 in 4,000
	Gas chimneys / pipes	Minor	1-5	1 in 4,000	1 in 10,000
Confined Saline Aquifers	Gas chimneys / pipes	Seep	Less than 1	1 in 100	1 in 333
	Gas chimneys / pipes	Minor	1-10	1 in 333	1 in 1,000

Table 17. Estimates of leakage risks through gas chimneys and pipes. (Estimates are applicable per site, over operational life and post-closure.) Saline aquifer store types refer to fully or partially confined sites.

5. Leakage Risks Through Lateral Migration

The risk of lateral migration is assessed only for fully or partially confined sites (see Section 3.2.3). This risk will be site specific and is anticipated to vary significantly between sites. The probabilities and leakage rates for this have been derived simply by averaging the other geological pathway probabilities and rates (rather than evaluating site-specific details).

Major changes in CO_2 plume migration within the storage site are likely to be evident in early monitoring data, enabling revision of the injection strategy in advance of CO_2 escaping beyond the storage complex [74]. In extreme situations if the migration could not be constrained this could prompt closure of the storage site. This risk is subject to greater uncertainty in fully open aquifer storage sites.

If the CO_2 plume were to migrate laterally along the storage formation beyond the boundaries of the storage complex, it would still be contained at depth. However, the plume might come into contact with a potential vertical pathway, for example, a decommissioned well (see Section 3.2.4)

Storage Site Type	Geological pathway	Leak category	Leak rate (t/d)	Typical probability of defined leak rate occurrence per feature per storage complex Maximum	Typical probability of defined leak rate occurrence per feature per storage complex Minimum
Depleted Fields	Lateral migration	Seep	Less than 1	1 in 400	1 in 1,600
	Lateral migration	Minor	1-30	1 in 1,600	1 in 6,000
Confined Saline Aquifers	Lateral migration	Seep	Less than 1	1 in 60	1 in 200
	Lateral migration	Minor	1-30	1 in 200	1 in 550

Table 18. Leakage risks through lateral migration. (Estimates are applicable per site, over operational life and post-closure.) Saline aquifer store types refer to fully or partially confined sites.

Discussion

The aim of this assessment has been to make reasonable worst-case choices for durations of leakage (that is, the duration of a leak via a geological pathway could be a lot shorter) within a total modelled time-frame of 125 years, and to be 'realistic' in identifying probabilities. In Section 3.3.3, multiplying the maximum probability by the maximum leakage rate to derive the risked estimated leaked volumes provides a conservative upper limit.

In general, fully or partially confined saline aquifers storage sites are perceived as having higher geological risk than depleted field storage sites for two principal reasons:

- Secure containment has not been proven through retention of hydrocarbons over millions of years.
- At the start of injection operations there is no historical production from saline aquifers so there is greater uncertainty over reservoir responses within the storage site itself.

A saline aquifer storage site in which the fluid regime is different to that above the caprock is likely to have a lower probability of leakage than a saline aquifer site that cannot demonstrate this. Similarly, saline aquifer storage sites with pressure management (e.g. brine removal) to limit pressures would be lower risk than a site developed above original pressures. Although it is unlikely, it is possible low pressures during later production in depleted fields could have allowed the storage formation to compact slightly [75].

Moderate and major leakage rates are only thought to be applicable for relatively large faults in saline aquifers. Of the two sub-categories of relatively large pre-existing faults only one, block bounding faults, are present in the UK.

3.3.3 Containment Certainty at 'Typical' UKCS CO_2 Storage Complexes

To provide an illustration of how geological and well leaks could combine to produce an overall view on the total amount and probability of leaks during the operational and post closure life, two 'typical' storage complexes have been conceived and overall containment probabilities derived. The illustration incorporates parameters that may represent typical stores, captures the probabilities of occurrence (from Section 3.3), reasonable worst case leakage rates and durations (from Section 3.2.7) to estimate the worst-case leaked mass of CO_2.

The key parameters of the typical storage complexes are shown in Table 19, below. 25 years has been chosen as the injection period and 100 years as the modelled post injection period (which includes both the time that the site is under the care of the permit holder and a period of time after handover to the government). These durations were chosen as 25 years may reflect a typical project duration, and 100 years is significant in human terms and meaningful in the context of reducing CO_2 emissions to limit global warming to well below 2 degrees Celsius (as stated in the Paris Agreement). Should this time span be extended, the total probability of a containment issue through a geological leakage pathway would probably remain approximately the same, bearing in mind the time profile of containment risk for a typical site, which indicates geological containment risks to reduce with time after a peak plateau (see Section 3.1.4).

As in Section 3.3.2, the saline aquifer storage sites considered here are either fully or partially confined storage sites, not fully open. Parameters that allow direct comparison between the different types of storage site have been selected except where this seems unlikely, for example brine production is unlikely to be useful on a depleted field site. A greater number of decommissioned wells has been chosen on the typical depleted field storage site than the saline aquifer storage site (having been used to explore for and produce from the field). Given the obligation to prove no significant risk of leakage in order to achieve a permit, the typical saline aquifer storage site has been conceived without any faults visible in seismic data (e.g. [76]). If this were not the case the probability of a containment issue at the saline aquifer storage site could be higher. Observations about the saline aquifer site, such as the type of caprock or whether there is evidence to indicate separate fluid regimes across the caprock, are not considered for these typical storage sites.

	Depleted Field Storage Site	Fully or Partially Confined Saline Aquifer Storage Site
Storage Capacity (Mt)	125	125
Depth (m)	2500	2500
Area (km^2)	100	150
Number of Active Wells	5	5
Number of Monitoring wells	1	1
Number of Brine Producing Wells	0	2
Injection Rate per well (Mtpa)	1	1
Number of Legacy Wells	5	2
Years of Injection Operations	25	25
Years Post Closure	100	100
Caprock thickness (m)	400	400
Number of large block-bounding fault zones	1	0
Number of map-scale faults	4	0

Table 19. Parameters used to define ‘typical’ UK storage complexes for modelling containment certainty

Table 20 provides a risked estimate of the worst-case amount of CO_2 to be leaked by the well and geological pathways from complexes within depleted field and saline aquifer storage sites (using maximum leakage rates multiplied by maximum probability and durations from Table 5 and Table 7). This figure is also presented as a percentage of the total CO_2 storage capacity of each site (125Mt). Subtracting the total risked estimate of worst-case amount of CO_2 to be leaked from the total injected yields the 'Total estimated contained mass'. That is, in a depleted field storage site with capacity of 125Mt, the risked estimated contained mass is 124.91Mt, greater than 99.9% of the injected CO_2. In a saline aquifer storage site, the risked estimated contained mass is 124.89Mt, also greater than 99.9% of injected CO_2. Figure 12 shows these percentages schematically.

The derivation of these results is broken down more fully in Table 21 and Table 22, with maximum (as in Table 20, maximum leakage rates multiplied by maximum probability and durations) and minimum (minimum leakage rates multiplied by minimum probability and durations from Table 7) risked estimates of leaked mass from the store via the individual leakage pathways. This quantifies the range of risked estimates of leaked amounts from the typical sites (that is, it could be as little as 379 tonnes from a depleted oil and gas field store, or 694 tonnes from a saline aquifer store).

Conservative Assumptions in the Overall Example Project Calculations

- To calculate estimated worst-case leakage for the typical storage complexes over the injection life and a further 100 years, the maximum probability of occurrence and maximum leak rate have been used. This provides a very conservative calculation of the risked estimated overall leakage.
- The overall leakage calculation also assumes the maximum leak rate continues for the full duration until remediation is accomplished (recognising that some geological leaks could continue beyond the timescale modelled, although worst-case long duration leaks are assumed). This is conservative as the majority of well leaks can be shut in relatively quickly using other valves or installing temporary plugs. For example, our analysis of HSE gas release data 1992-2015 [58] extracted all well loss of containment with leak rates of 1-50 t/d. Many of the leaks were very small and all were contained within 1 day. The overall leak calculation would assume these leak for 180 days.

Storage Site Type	Description	Risked estimate of worst-case amount (Tonnes)	Estimated worst-case amount as % of store capacity (125Mt CO_2)
Depleted Field Storage Site (with a storage permit)	Leakage from all wells	87,800	0.070%
	Leakage from all geological features	2,000	0.002%
	Total leakage from storage complex	89,800	0.072%
	Total estimated contained mass at storage complex	124,910,200	99.928%
Fully or Partially Confined Saline Aquifer Storage Site (with a storage permit)	Leakage from all wells	79,800	0.064%
	Leakage from all geological features	30,000	0.024%
	Total leakage from storage complex	109,800	0.088%
	Total estimated contained mass at storage complex	124,890,200	99.912%

Table 20. Summary of reasonable worst-case leakage amounts from two 'typical' CO_2 storage complexes with a storage permit in the well-regulated UKCS regime

Discussion

The results shown in Table 20 for the parameters detailed in for typical UKCS CO_2 storage complexes with a storage permit indicate that:

- The total estimated risked contained mass over 25 years of operations and 100 years post closure is greater than 99.9% of the CO_2 injected into both the typical saline aquifer storage site (fully or partially confined) and the depleted field storage site. This percentage will vary depending on the exact features at the sites, also if projected over longer or shorter timespans.
- The geological containment risk is likely to be greater in a saline aquifer than a depleted field storage site.
- The well containment risk is likely to be greater in a depleted field than a saline aquifer storage site.
- For the typical sites, probabilities of moderate and major leakage rates due to geological causes are not provided. This does not mean that such leakage rates are impossible, but that the authors have interpreted the possibility of major or moderate leakage rates from geological features on typical sites that have been awarded a storage permit in the UK to be improbable from either a depleted field or a saline aquifer storage site. A major or moderate leak is only considered to be feasible from a leak along a large, block bounding fault in a saline aquifer, or from small areas of unexpectedly poor quality caprock in a saline aquifer (Sections 3.2.3, 3.3.2).

Comparing the earlier well and geological leakage results (Sections 3.3.1 and 3.3.2):

- The leaks that are more likely to occur, for both geological and well pathways, are at lower leak rates.
- At a depleted field storage site, leakage via well pathways is more likely than leakage via geological pathways. This means that it is easier to ensure compliance by appropriate design, and any loss of containment is more feasible to remediate. (This is true of historical losses of containment at oil and gas fields and natural gas storage sites too, e.g. Keeley 2008 [66]). The relative proportion of well to geological leakage risks at a saline aquifer storage site is more sensitive to the number of wells and geological faults (as the risks associated with faults is greater and there may be fewer legacy wells at a saline aquifer storage site).
- The highest leakage rates (moderate and major leakage rates) are more likely to occur via a well than a geological pathway for a UK storage complex with a storage permit.

Further details on the derivations of the leakage rates and probabilities are available in the Supplementary Notes.

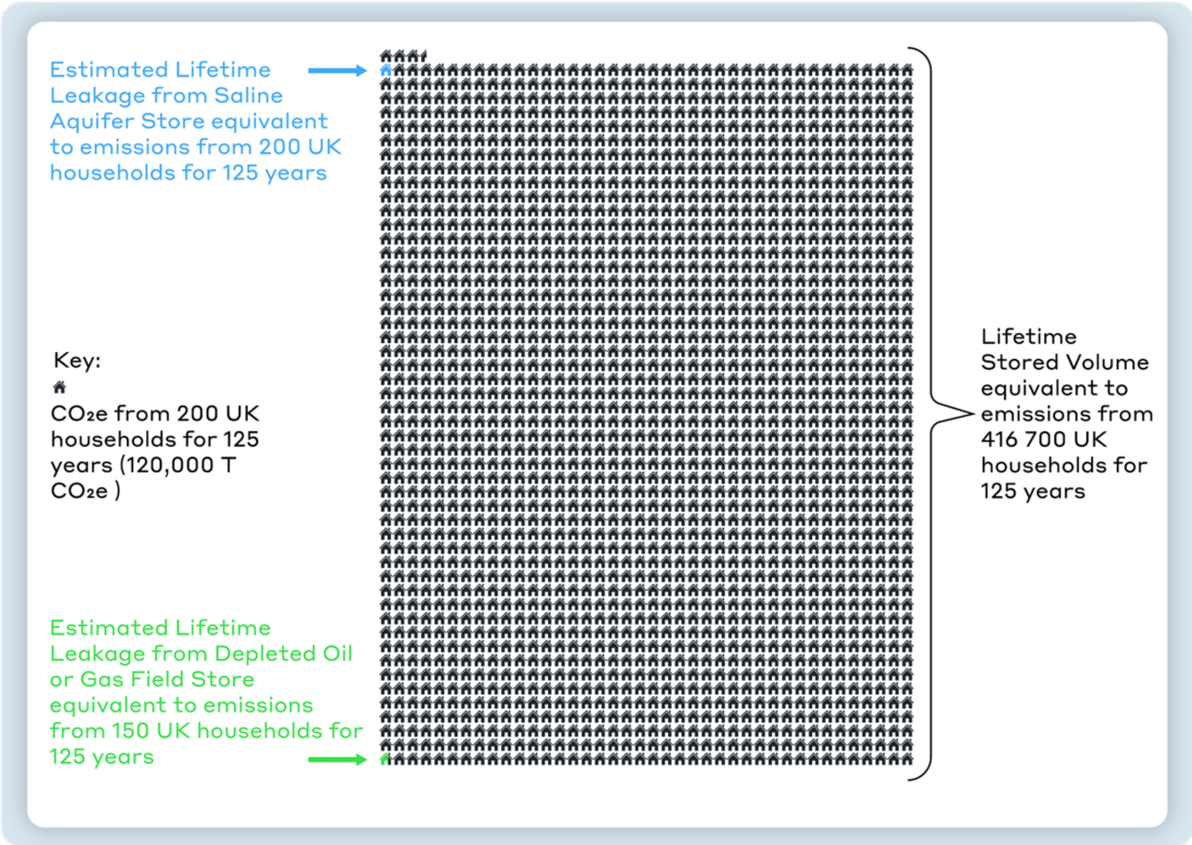


Figure 12. Statistical expectation of stored CO_2 versus leaked volumes from a saline aquifer and depleted oil and gas field storage site - Representative chart to compare in terms of Average UK Household Emissions [56] lifetime leakage per storage site type (results of Table 20 with lifetime injected amounts for the typical storage complexes each of 125 Mt capacity)

Depleted Oil and Gas Field Storage Site Overall Results / Leakage pathway	Leak sub-pathway	Leak rate category	Risked estimate of amount leaked during store operations +100 years (Tonnes)		Estimated risked maximum leakage amount as % of 125 Mt full capacity of CO_2	Estimated risked minimum contained amount as % of 125 Mt full capacity of CO_2
			Max (Tonnes)	Min (Tonnes)		
Active Wells including Monitoring Wells	N/A	Seep	5,475	5	0.004%	99.996%
	N/A	Minor	1,369	0	0.001%	99.999%
	N/A	Moderate	1,825	9	0.001%	99.999%
	N/A	Major	913	18	0.001%	99.999%
Decommissioned Wells	N/A	Seep	44,713	45	0.036%	99.964%
	N/A	Minor	11,178	22	0.009%	99.991%
	N/A	Moderate	14,904	75	0.012%	99.988%
	N/A	Major	7,452	149	0.006%	99.994%
Through caprock	diffusion	N/A	0	0	0.000%	100.000%
	capillary flow through intact caprock	N/A	0	0	0.000%	100.000%
	lateral variability in caprock lithology	N/A	0	0	0.000%	100.000%
Faults (and fractures)	major tectonically/volcanically active fault zone	N/A	0	0	0.000%	100.000%
	large block-bounding fault zone	Seep to Minor	3	0	0.000%	100.000%
	map-scale faults	Seep	146	11	0.000%	100.000%
		Minor	110	15	0.000%	100.000%
	sub-seismic scale faults & fracture network	Seep	91	0	0.000%	100.000%
		Minor	20	4	0.000%	100.000%
Induced faulting	reactivation of pre-existing faults	Seep	37	5	0.000%	100.000%
		Minor	523	4	0.000%	100.000%
	initiation of new faults/fractures	Seep	37	5	0.000%	100.000%
		Minor	523	4	0.000%	100.000%
Gas chimneys/pipes	N/A	Seep	91	1	0.000%	100.000%
	N/A	Minor	27	4	0.000%	100.000%
Lateral Migration	N/A	Seep	134	1	0.000%	100.000%
	N/A	Minor	226	2	0.000%	100.000%
		Total	**89,795**	**379**	**0.072%**	**99.928%**

Table 21. Breakdown of leakage risks calculations per typical permitted depleted field storage site, further details are provided in Supplementary Note A

Saline Aquifer Storage Site Overall Results / Leakage pathway	Leak sub-pathway	Leak rate category	Risked estimate of amount leaked during store operations +100 years (Tonnes)		Estimated risked maximum leakage amount as % of 125 Mt full capacity of CO_2	Estimated risked minimum contained amount as % of 125 Mt full capacity of CO_2
			Max (Tonnes)	Min (Tonnes)		
Active Wells including Monitoring & Brine Producers	N/A	Seep	7,300	7	0.006%	99.994%
	N/A	Minor	1,825	0	0.001%	99.999%
	N/A	Moderate	2,433	12	0.002%	99.998%
	N/A	Major	1,217	24	0.001%	99.999%
Decommissioned Wells	N/A	Seep	38,325	38	0.031%	99.969%
	N/A	Minor	9,581	19	0.008%	99.992%
	N/A	Moderate	12,775	64	0.010%	99.990%
	N/A	Major	6,388	128	0.005%	99.995%
Through caprock	diffusion	N/A	0	0	0.000%	100.000%
	capillary flow through intact caprock	N/A	0	0	0.000%	100.000%
	lateral variability in caprock lithology	Moderate to Major	11,779	118	0.009%	99.991%
Faults (and fractures)	major tectonically/volcanically active fault zone	N/A	0	0	0.000%	100.000%
	large block-bounding fault zone	N/A	0	0	0.000%	100.000%
	map-scale faults	Seep	0	0	0.000%	100.000%
		Minor	0	0	0.000%	100.000%
	sub-seismic scale faults & fracture network	Seep	457	3	0.000%	100.000%
		Minor	3,355	37	0.003%	99.997%
Induced faulting	reactivation of pre-existing faults	Seep	365	52	0.000%	100.000%
		Minor	5,234	37	0.004%	99.996%
	initiation of new faults/fractures	Seep	365	52	0.000%	100.000%
		Minor	5,234	37	0.004%	99.996%
Gas chimneys/pipes	N/A	Seep	365	11	0.000%	100.000%
	N/A	Minor	901	37	0.001%	99.999%
Lateral Migration	N/A	Seep	517	6	0.000%	100.000%
	N/A	Minor	1,402	12	0.001%	99.999%
		Total	**109,819**	**694**	**0.088%**	**99.912%**

Table 22. Breakdown of leakage risks calculations per typical permitted fully or partially confined saline aquifer storage site, further details are provided in Supplementary Note A

4 Conclusions

Climate change is happening now [10]. Reducing atmospheric CO_2 will help to achieve climate stabilisation, and implementing CCS is important for industries such as steel and cement, hydrogen production, power generation, and engineered removal processes, and provides the potential for the relatively quick capture and storage of large amounts of emissions without widespread industrial upheaval. The UK Climate Change Committee has described CCS as a 'necessity, not an option' for the transition to Net Zero [77] and is critical to achieving the UK's 2050 Net Zero target. The government aims to support the delivery of four offshore CCS industrial clusters by 2030, capturing 20-30 Mt CO_2 across the economy, including 6 Mt CO_2 of industrial emissions per year. However, in order to achieve Net Zero by 2050, the 6th Carbon Budget published by the CCC in December 2020, suggests that the UK needs to remove around 58 Mt CO_2 per year by 2050 [24] .

Any storage sites will have to be granted a CO_2 storage permit by the appropriate licensing authority, (in this instance the NSTA, except within the territorial sea adjacent to Scotland, which is authorised by Scottish ministers), to cover injection operations and a period of at least 20 years post-closure before the government takes over the site. The process of scrutinising sites to decide whether to grant a permit is rigorous. Permits will only be granted if, at the time of permit issue, the regulator is satisfied that under the proposed conditions of use of the storage site, there is no significant risk of leakage or harm to the environment or human health. The permit will be linked to the specified conditions of use including monitoring the storage complex for any early indications of potential loss of containment or other significant irregularities.

Whilst very unlikely, loss of containment could potentially occur via two broad categories of pathway: via a well pathway, or a geological pathway. A potential loss of containment from a well is more readily remedied than a loss of containment through a geological pathway. In the event that there is a potential loss of containment via a geological pathway this may be remediable through varying the injection strategy (such as altering the injection rates, drilling additional wells), managing the pressure by producing brine from the reservoir beyond the storage site, or in extreme circumstances permanently closing the storage site. However, the monitoring plans tailored for each site will enable many potential losses of containment from both geological and well pathways to be prevented from occurring.

The UKCS is well-regulated, and anticipated CCS regulations will be designed to reduce the likelihood and likely leakage rates from any loss of containment of CO_2 associated with a storage site that has been awarded a storage permit.

4.1 Likely Containment Associated with 'Typical' UK Permitted Storage Sites

Significant loss of containment events are very improbable and are unlikely to happen during injection operations and in the post closure period, particularly where the injection wells are designed and constructed to modern standards and operated within the requirements of the NSTA storage permit. Estimates of leakage risks for depleted field and fully or partially confined saline aquifer storage sites that have a storage permit (that might reflect typical UKCS storage sites) indicate that in depleted field storage sites, a potential containment issue via a well pathway is more likely to occur than via a geological pathway. This means that despite significant containment issues being very unlikely to occur, those which are more likely to occur will be relatively readily remedied. In saline aquifer storage sites, the relative proportion of well to geological risks will depend on site specific details.

Before the NSTA grants a carbon dioxide storage permit, it must be satisfied that at such time and under the proposed conditions and use of the storage site, there is no significant risk of leakage. This consideration will include the suitability of proposed monitoring and corrective measures plans. This report concludes that major or moderate leakage rates via geological pathways for the 'typical' offshore storage sites are judged to be improbable. A moderate or major leak rate is only considered plausible from a saline aquifer site that included a large fault (tens to hundreds of km long), or a minor area of poorer quality caprock. Both of these risks would be mitigated by significant scrutiny at the point of permit award. The leaks that are more likely to occur, for both geological and well pathways, are at lower leakage rates, i.e. very small amounts of CO_2, representing a very small fraction of the overall stored quantity even if they were to leak for 125 years (25-years of injection operations plus 100-years post-injection), see Figure 13 and Figure 14.

The total estimated risked minimum contained amount over 25 years of operations and 100 years post closure is greater than 99.9% of the CO_2 injected into both the 'typical' confined saline aquifer and depleted field storage sites. This is represented graphically in Figure 13 and Figure 14 where the coloured sliver (which is too small to see when drawn to scale) represents the proportion of injected CO_2 leaked by well and geological mechanisms and the grey represents the injected CO_2 remaining in the store over time; the bar key to the right shows the relative proportion of leaked CO_2 by each leakage pathway within the coloured sliver, gold/yellow for well and blue for geological pathways. The total estimated risked minimum contained mass would vary if there were differing numbers of potential leakage pathways (e.g. more wells, large faults) in the site.

In depleted field storage sites, a potential containment issue via a well pathway is more likely to occur than via a geological pathway (Figure 13). Any potential loss of containment via a well pathway is more feasible to remediate than via a geological pathway. In saline aquifer storage sites (Figure 14) the relative proportion of well and geological risks will depend on site parameters (including the number of wells, number and size of faults). The geological containment risk is likely to be greater in a saline aquifer site than a depleted field site (as the site containment has not been proven by retention of buoyant hydrocarbons over millions of years and there is more uncertainty over the behaviour of fluid and pressure across the storage complex), however the well containment risk is likely to be greater in a depleted field than a saline aquifer (as there are likely to be more wells that penetrate a depleted field storage site than in a saline aquifer storage site).

The values for probabilities and leakage rates used in this report are conservative with respect to well risks and in the way that both well and geological risks are combined (i.e., matching maximum probability with maximum leakage rate to derive risked estimated worst-case leakage amounts), at the upper end of expectations (although there is little calibration on the risk values for geological risks). This approach therefore gives confidence in the security of CO_2 containment in deep geological storage sites in the UK continental shelf, and that in reality the containment levels may be better than these levels.

Risks associated with containment are not significant for a site that has a storage permit compared to the net benefit of industrial scale deep geological storage of CO_2, which is critical to deliver on the UK 2050 Net Zero target.

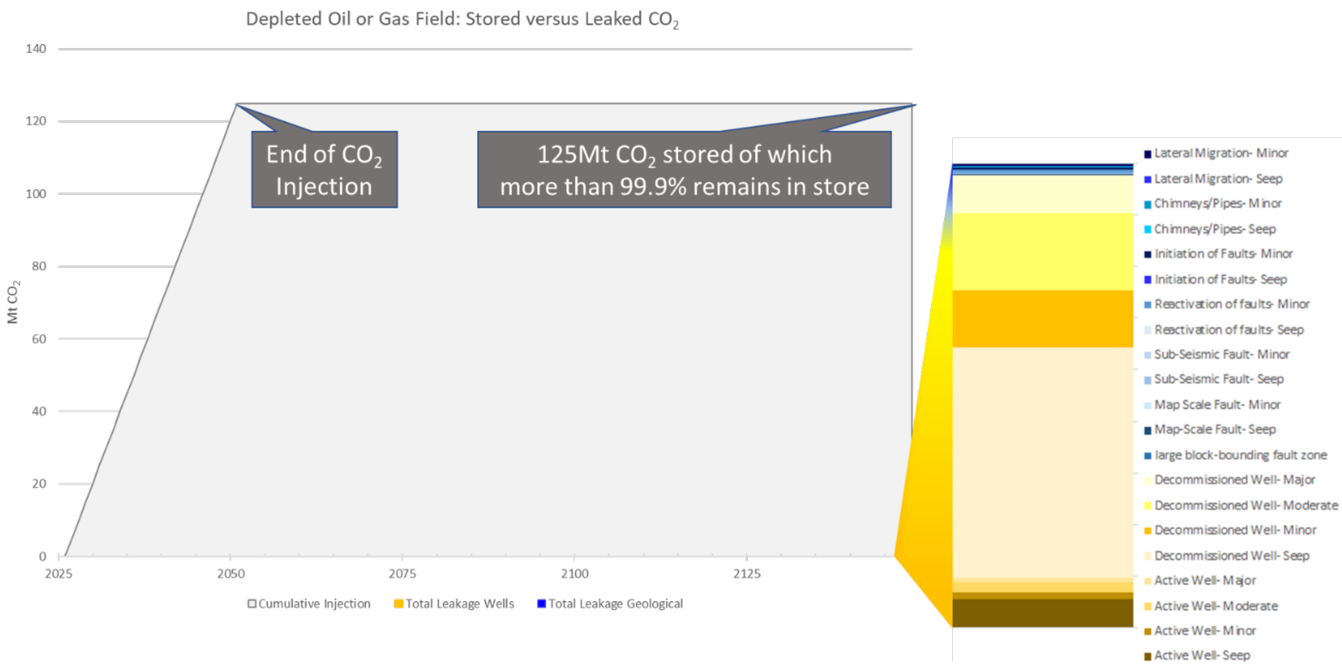


Figure 13. Statistical expectation of stored CO_2 in a depleted oil and gas field versus risked estimates of leaked CO_2.

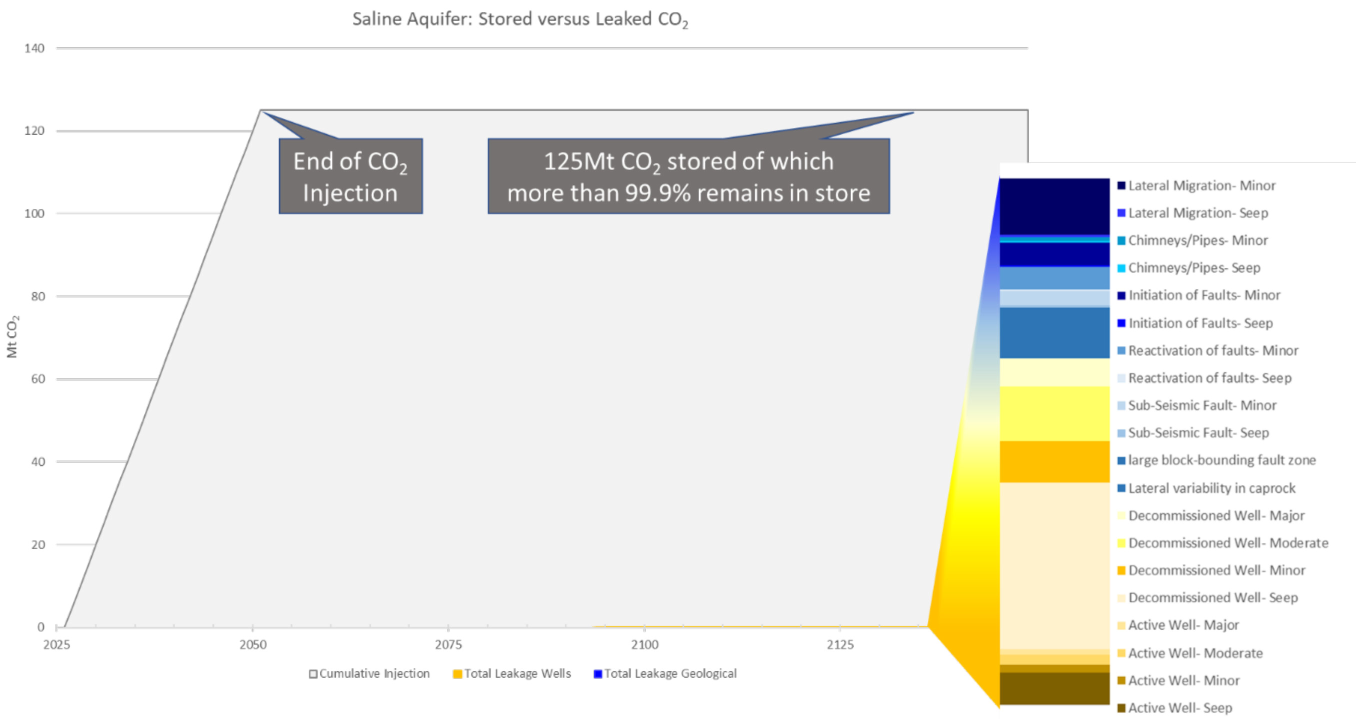


Figure 14. Statistical expectation of stored CO_2 in a fully or partially confined saline aquifer store versus risked estimates of leaked CO_2.

5 Glossary

The authority: the authority responsible for fulfilling the duties established under the Storage of Carbon Dioxide (Licensing etc.) Regulations 2010.

BEIS: Department for Business, Energy & Industrial Strategy, UK Government.

Brine: salty water not suitable for drinking.

Caprock (or top seal): A relatively impermeable rock that forms a barrier or seal above and around the reservoir rock, such that fluids (e.g. CO_2, water) cannot migrate beyond the reservoir.

Carbon Capture and Storage (CCS): The process of capturing CO_2 emissions (from fuel combustion, industrial processes, or directly from the atmosphere) and storing them in geological formations deep underground.

Carbon Capture, Utilisation and Storage (CCUS): The same process as CCS, but with captured CO_2 not only stored but also sent for use, e.g. carbonated drinks, food preparation.

Casing: A steel pipe run inside the well from the wellhead, commonly cemented in place, to protect freshwater formations, or isolate formations with significantly different pressure gradients. A well may have several casing strings, the inner most casing string (the last one to be installed) is often referred to as the Injection Casing.

Casing cement: Cementing is the process of mixing a slurry of cement and cement additives with water and pumping it down through the casing so that it fills the space between the casing and the formation.

Casing shoe: The bottom of the casing.

Cement plug: A plug made from cement that is used to form a barrier to isolate between different zones.

Confined / open storage sites: Storage of CO_2 in a ‘confined’ storage site relies on trapping of the CO_2 by a structural or a stratigraphic feature in the subsurface. Fully confined sites have impermeable geological features above (the impermeable caprock), below and laterally, whilst partially confined sites have impermeable geological features above and laterally. In a ‘fully ‘open’ site there is no specific structural target, and the CO_2 can migrate laterally beneath an impermeable caprock.

CO_2: Carbon dioxide.

CO_{2e}: Carbon dioxide equivalent of greenhouse gases.

CO_2 plume: The dispersing volume of injected CO_2 within the storage formation.

Decommissioned well: A well that is no longer used for injecting, producing or monitoring and has been made safe by removing seabed infrastructure and isolating the surface from the subsurface hydrocarbon, brine or CO_2 bearing formations.

Dense phase CO_2: CO_2 at a pressure and temperature above the critical point where it is not possible to distinguish if it is liquid or gas. In dense phase the density of the fluid is high, but the viscosity is low.

Depleted Oil and Gas Field (DOGF) store: A former oil and/or gas reservoir which has reached the end of its producing life and is re-purposed for storage of CO_2.

Embedded emissions: The emissions generated as a consequence of developing the CO_2 storage site. These could be the emissions generated in manufacturing the equipment, steel and cement; emissions from transportation of equipment and personnel; or emissions from the equipment and vessels used to install the facilities/pipelines or drill the wells.

Enhanced Oil Recovery (EOR): A process that increases the amount of oil that can be extracted from an oilfield, usually by injecting water or gas into the oil reservoir to increase pressure and force the oil out of the rock.

EOR: Enhanced Oil Recovery (in this case oil recovery is enhanced by injecting CO_2 into the reservoir, increasing the overall pressure and driving the oil towards the production wells).

ETS: Emissions Trading Scheme, here the UK ETS.

Evaporite: A rock formed by evaporation from a fluid, such as seawater. Certain evaporite minerals such as halite are excellent seal rocks, due to their very low permeability and tendency to self-heal.

Gas chimneys / pipes: Vertical or sub vertical geological features with higher permeability that could act as seal bypass systems (such as ‘gas pipes’, sand injectites and pockmarks).

Geological formation: A body of rock with distinct characteristics, which distinguish it from the surrounding rock layers.

Geological storage: Injection of captured CO_2 emissions into rock formations deep underground where they will be removed from the atmosphere and permanently stored.

GHG: Greenhouse gas emissions.

HSE: The Health and Safety Executive, Britain’s national regulator for workplace health and safety.

IEA: International Energy Agency.

IPCC: Intergovernmental Panel on Climate Change.

Leakage: Any release of CO_2 from the storage complex.

Leakage pathway: A pathway by which CO_2 can move from the storage site and complex to the seabed if a leak were to occur (this could be via a natural leakage pathway such as a fault, or through a man-made pathway such as a wellbore, or via a combination of pathways).

Liner: A type of well casing string where the shallowest point of the liner is inside a previous casing string and not in the wellhead.

Loss of containment: The movement of process fluids, here focussed on CO_2, outside of the system designed to contain them, for example a pipeline, a storage site or a well.

Migration: The movement of CO_2 within the storage complex.

Monitored volume: the area that will be monitored during and after injection operations to track and ensure containment within the storage formation of the plume of injected CO_2 over time.

Mt CO_2: Mega tonnes, or million tonnes of CO_2.

Net Zero: The condition of ‘Net Zero’ emissions is reached when the amount of anthropogenic greenhouse gases emitted is equal to the amount removed from the atmosphere over a specified period of time. This can be achieved by a combination of both reducing emissions and actively removing greenhouse gases.

NSTA: North Sea Transition Authority, who are responsible for the licensing and regulation of offshore CO_2 storage in the UK (the trading name of the Oil and Gas Authority, or OGA).

Offshore: Activities or operations (in this case related to related to CCS) that are carried out at sea or under the seabed.

Ofgem: The Office of Gas and Electricity Markets, Great Britain’s independent energy regulator.

Onshore: Activities or operations (in this case related to CCS) that are carried out on land.

OPRED: Offshore Petroleum Regulator for Environment and Decommissioning.

Performance Standard: a statement, which can be expressed in qualitative or quantitative terms, of the performance required of a system, item of equipment or well barrier element which is used as a basis for managing the risk of a major accident event.

Permeability: How easy it is for a fluid (e.g. brine or CO_2) to pass through a material, in this case a geological formation (e.g. the storage formation or caprock).

Pipeline: a pipe used for transporting fluids, here CO_2, long distances, either onshore or offshore.

Post-closure: The period after closure of a storage site, including the period after the transfer of responsibility to the government.

Pressure regime: Related to the pore pressure of the geology: whether the pressures are aligned with or different to those that would be expected for a column of saline water (the hydrostatic gradient).

Relief well: A relief well is drilled from a safe location to intersect a well that has lost containment, for example is experiencing a blowout, once intersected heavy fluids can be injected and plugs installed to prevent any further loss of reservoir fluids.

Reservoir: A body of rock with sufficient porosity and permeability to store and transmit fluids (e.g. CO_2, water).

Saline Aquifer store: Any saline water-bearing geological formation used to store CO_2.

Seal: A relatively impermeable barrier or seal through which fluids (e.g. CO_2, water) cannot migrate beyond the reservoir, this could be a sealing fault or caprock.

Seep: a seep is a low flow rate of any gas or liquid. In this report it is specifically a low flow rate (< 1 Tonne per day) of CO_2 from a well or the CO_2 storage site.

Seismic Reflection Survey: a geophysical survey that measures the response of the earth to a controlled seismic source of energy to form a representation of the rock in the subsurface; artificially generated sound waves are reflected from different structures or objects beneath the seabed which have contrasting acoustic properties.

Significant irregularity: any irregularity in the injection or storage operations or in the condition of the storage complex itself, which implies the risk of leakage or risk to the environment or human health.

Storage complex: the complex includes the storage site and surrounding geological domain which may impact the overall storage integrity and security (i.e. secondary containment formations).

Storage formation: a porous and permeable sedimentary rock such as sandstone, with sufficient space to store millions of tonnes of CO_2 within the interconnected pore spaces between the sand grains.

Storage Licence: Allows the holder to appraise an area for deep geological storage of CO_2.

Storage Permit: Required by storage license holder to allow injection of CO_2 into a storage site during the operational phase of the carbon storage license. A Storage Permit is issued by the NSTA and specifies the conditions under which CO_2 storage can take place.

Storage site: the volume area within a geological formation used for the geological storage of CO_2 and any associated surface and injection facilities (e.g. platforms, active CO_2 injection wells).

Surface Controlled Sub-Surface Safety Valve: (SCSSSV) A safety device installed in the upper part of the well completion, to automatically shut in the flow of a well in the event surface controls fail or surface equipment becomes damaged.

t/d: Tonnes per day.

Tubing: a steel pipe or tube run inside the injection casing as part of the well completion.

Trapping mechanism: Processes by which the injected CO_2 is securely contained (e.g. mineral trapping, solution trapping, residual trapping, structural trapping).

UK Continental Shelf (UKCS): United Kingdom Continental Shelf, the region of waters surrounding the UK as defined in section 1(7) of the Continental Shelf Act 1964.

Valves (Manual): A valve that requires an operator to manually open or close.

Valves (Actuated): The valve can be opened or closed remotely, it is common for actuated valves to be connected to an Emergency Shutdown system.

Well: A borehole drilled from surface to a subsurface target. It is made up of casings, cement, liners, tubing, SCSSVs, wellhead and Xmas tree.

Well barrier: system of one or several well barrier elements that contain fluids within a well to prevent uncontrolled flow of fluids within or out of the well envelope.

Well integrity: maintaining full control of fluids within a well at all times by employing and maintaining one or more well barriers to prevent unintended fluid movement between formations with different pressure regimes or loss of containment to the environment.

Wellhead: the component at the surface of a well that provides the structural and pressure-containing interface for the drilling and production equipment.

Well completion: used to convey the injected CO_2 from surface to the reservoir; consists of tubing plus other components such as surface controlled Sub-Surface Safety Valve, downhole pressure gauge and production packer. The well completion is run inside the Injection Casing.

Well operator: The company that has responsibility for the well.

Xmas tree: an assembly of valves connected to the wellhead, used to control the flow into and out of the well completion.

4D seismic (or Time Lapse Seismic): 3D Seismic surveys acquired over the same extent ideally with the same acquisition parameters, that are compared to a baseline to monitor changes in a volume of rock (e.g. the extent of a CO_2 plume).

6 Supplementary Notes

Supplementary Note A: Breakdown of Combined Well and Geological Storage Risks for Typical Storage Sites

Supplementary Note B: Geological Leakage Risks

Supplementary Note C: Well Analysis Using Peloton WellMaster Database

Supplementary Note D: Well Leakage Risks

Supplementary Note E: Deep Geological Storage of CO_2 Containment Certainty Wells References and Source Data

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