

A Review of Developments in Carbon Dioxide Storage

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Abstract

Carbon capture and storage (CCS) has been identified as an urgent, strategic and essential approach to reduce anthropogenic CO₂ emissions, and mitigate the severe consequences of climate change. CO₂ storage is the last step in the CCS chain and can be implemented mainly through oceanic and underground geological sequestration, and mineral carbonation. This review paper aims to provide state-of-the-art developments in CO₂ storage. The review initially discussed the potential options for CO₂ storage by highlighting the present status, current challenges and uncertainties associated with further deployment of established approaches (such as storage in saline aquifers and depleted oil and gas reservoirs) and feasibility demonstration of relatively newer storage concepts (such as hydrate storage and CO₂-based enhanced geothermal systems). The second part of the review outlined the critical criteria that are necessary for storage site selection, including geological, geothermal, geohazards, hydrodynamic, basin maturity, and economic, societal and environmental factors. In the third section, the focus was on identification of CO₂ behaviour within the reservoir during and after injection, namely injection-induced seismicity, potential leakage pathways, and long-term containment complexities associated with CO₂-brine-rock interaction. In addition, a detailed review on storage capacity estimation methods based on different geological media and

trapping mechanisms was provided. Finally, an overview of major CO₂ storage projects, including their overall outcomes, were outlined. This review indicates that although CO₂ storage is a technically proven strategy, the discussed challenges need to be addressed in order to accelerate the deployment of the technology. In addition, beside the necessity of techno-economic aspects, public acceptance of CO₂ storage plays a central role in technology deployment, and the current ethical mechanisms need to be further improved.

1 Introduction

The anthropogenic emissions of CO₂ and other greenhouse gases (GHGs) have been identified as the main contributor to global warming and climate change [1]. The atmospheric concentration of CO₂ has increased from 280 ppm, in the mid-1800s, to nearly 404 ppm in 2016, and caused almost 1 °C increase in mean earth temperature, from pre-industrial levels [2,3]. This temperature rise, only between 1901 and 2010, led to a 20 cm increase in global mean sea level [4]. It is recognised that the mean earth temperature rise from pre-industrial levels should be kept well below 2 °C by 2100 in order to mitigate severe events of climate change [5]. Accordingly, European Union and the G8 have targeted to reduce GHG emissions by at least 80% from the 1990 baseline by 2050 [6–8].

Power plants and energy-intensive industries are considered as the major CO₂ emitters, and are obligated to drastically cut their CO₂ emissions. The high carbon intensity of the power sector (42%) is attributed to the large share of coal-fired plants in the global electricity supply. In addition, the emergence of shale gas in North America has led to higher American exports of coal. Consequently, it caused a considerable reduction in coal price, which in turn led to a

higher tendency for coal-based electricity production [9]. Hence, decarbonisation of power and industrial sectors is essential in order to meet emission reduction targets.

Carbon capture and storage (CCS) is considered as the key strategy for decarbonisation of the power and industrial sectors [10]. It is estimated that CCS alone can contribute almost 20% reduction in emissions by 2050, and the exclusion of CCS can cause up to 70% increase in global cost of achieving emission reduction targets [11]. Permanent sequestration of CO₂ is the last step in the CCS chain and can be implemented using a variety of strategies, mainly mineral carbonation, oceanic, and underground geological storage including saline aquifers, depleted oil and gas reservoirs, unmineable coal seams, and other geological media. The main characteristics of a feasible CO₂ storage option are net reduction in CO₂ emission, large storage capacity, long-term isolation of CO₂ (at least several hundred years), reasonable cost and energy penalty, and minimised environmental impact [12]. On the other hand, public acceptance/embracing is another key factor that can significantly affect the deployment of the technology [13].

There have been several reviews that discussed different aspects of CO₂ storage [14–33]; see **Table 1**. However, some aspects have not been covered yet or analysed in detail. Despite CO₂ storage being a technically proven technology, further deployment of the technology is delayed by some uncertainties and challenges associated with estimation of storage capacity, tracking verification and monitoring of CO₂ during and after injection, characterisation of potential injected-induced seismicity, standardisation of storage evaluation criteria, and effective ethic mechanisms. In addition, CO₂ storage is a fast-developing field and recent progress and development need to be reviewed and discussed.

Table 1: Summary of review studies on carbon storage

Source	Review Scope
Bai et al. [14]	Review on well integrity issues for CO ₂ storage and enhanced gas recovery highlighting mechanisms responsible for loss of well integrity, well integrity criteria, determination of well integrity for operational wells, and risk-based approaches for abandoned wells.
Abidoye et al. [15]	Detailed review on geosequestration of CO ₂ in relation to two-phase flow in porous media highlighting aquifer storage capacity, sealing integrity of caprock, displacement of brine by supercritical CO ₂ , simultaneous flow of free and buoyant phases of CO ₂ , and various trapping mechanisms.
Bachu [16]	Review of CO ₂ storage efficiency in deep saline aquifers highlighting storage efficiency and capacity, factors that affect CO ₂ injection and plume evolution (such as boundary conditions, driving forces and fluid properties, displacement characteristics of CO ₂ -water systems in sedimentary rocks, and aquifer characteristics), storage efficiency coefficients for volumetric estimates of storage capacity, and pressure and time effects on storage efficiency.

De Silva et al. [17] Review of geochemical aspects of CO₂ sequestration in deep saline aquifers highlighting solubility trapping (effective factors for trapping, and experimental and modelling studies), and mineral trapping (trapping in sandstones, reactions in potassium- and sodium-rich feldspars, and experimental and modelling studies).

Boot-Handford et al. [18] CCS update highlighting capillary trapping and multiphase flow (pore-scale properties and natural analogues), regional assessment of storage capacity (definition of storage reservoirs and storage complexes, challenges to the concept of large-volume storage, and CO₂-EOR (enhanced oil recovery)).

Burnside and Naylor [19] Review of CO₂/brine systems, highlighting estimates and measurements of relative permeability and residual saturation (experimental procedures and experimental biases).

Carroll et al. [20] Review of environmental issues for sub-seabed geological storage of CO₂, highlighting physical data processes (natural CO₂ levels/concentrations and fluxes, shallow seabed geophysics and geology, CO₂ seepage and seabed sediment-water chemistry, reservoir storage chemistry and water-rock reactions).

- Godec et al. [21]** Review of the status and global potential for CO₂-ECBM (enhanced coalbed methane) highlighting factors influencing CO₂ storage and enhanced gas recovery in coal seams, CO₂-ECBM storage trials in San Juan Basin, USA, and estimate of global CO₂ storage capacity in coal seams.
- Humez et al. [22]** CO₂ intrusion in freshwater aquifers highlighting isotopic (C and O) methods as tracer tools for CO₂ presence, and potential application of ‘non-traditional’ isotopes of dissolved species to CO₂ storage.
- Tang et al. [23]** Review of CO₂ sequestration projects and application in China highlighting major geosequestration options.
- Li et al. [24]** Review of progress in CCS in the Chinese Academy of Sciences (CAS) highlighting identified major storage options and opportunities in China.
- Song and Zhang [25]** Review of caprock sealing mechanisms in geological CO₂ storage highlighting various leakage paths (diffusion, capillarity and faults).
- Liu et al. [26]** Review of CO₂-brine-caprock interactions and reactivity experiments with the Eau Claire Formation, Midwest USA region, highlighting observed mineral reactions from laboratory experiments and safety function of caprocks from insights in geochemical modelling work.

- Pires et al. [27]** A brief introduction to CO₂ storage options.
- Zahid et al. [28]** Review on present and future prospects for CO₂ geological storage highlighting major trapping mechanisms, capacity estimation of storage sites, monitoring techniques, and simulation tools used for storage projects.
- Zhang and Bachu [29]** Review of integrity of existing wells highlighting in-situ conditions for geological storage, and determination of carbonation rates relevant to CO₂ storage through laboratory and field studies.
- Shukla et al. [30]** Review of studies on CO₂ sequestration and caprock integrity highlighting major sequestration projects in operation, geosequestration systems, and CO₂ migration in reservoir formation rocks (CO₂-brine-rock interaction, and caprock integrity).
- Abu-Khader [31]** Review of progress on CO₂ sequestration with a brief introduction to geological storage.

White et al. [32] Review of CO₂ sequestration in coal with ECBM recovery highlighting monitoring and verification of geologically-sequestered CO₂ (lessons from underground storage of methane, pressure monitoring and methods, leak detection using soil gas measurements, chemical tracers, and reservoir simulators).

Voormeij and Simandl [33] Technical review on geological, ocean, and mineral CO₂ sequestration, highlighting storage in oil and gas reservoirs, coal seams, deep ocean, salt caverns, and mineral carbonation.

This review aims at gathering information on past and recent developments, challenges, and uncertainties of CO₂ storage to identify potential opportunities to assure timely deployment of the technology and CCS chain. The first part of the review will focus on different storage options and their associated challenges and opportunities. In the second part, the critical factors for selection of storage sites will be discussed. The third part will explain the associated issues with CO₂ containment in the reservoir during and after injection, and review the past and recent proposed methods for estimation of storage capacity. Finally, the major CO₂ storage projects worldwide, including their potential challenges and lessons learned, will be outlined.

2 Options for CO₂ Sequestration

In the CCS framework, the potential options for CO₂ sequestration are underground geological storage, deep ocean storage, and mineral carbonation [5], in which underground geological storage itself comprises several options including saline aquifers, depleted oil and gas reservoirs, unmineable coal seams, hydrate storage, and CO₂ within engineered geothermal systems [34–36]. This section provides a comprehensive discussion on each storage strategy, and correspondingly, outlines the possible future studies that can advance the current understanding.

2.1 Underground Geological CO₂ Storage

Underground geological storage has been considered as the most viable sequestration approach. There are several factors that make geological storage the superior sequestration strategy, in comparison with carbonation and oceanic storage, including economic aspects, site accessibility (in the case of ocean and mineral sequestration), and associated concerns regarding the security of stored CO₂ and negative environmental impacts of mineralisation and

ocean storage. There are several potential geological storage options (**Figure 1**) that will be comprehensively discussed in this section.

2.1.1 Saline Aquifers

CO₂ storage in saline aquifers is considered as one of the most feasible technology deployment options [37–40], probably because it provides the largest potential storage volume [36]. In addition, the majority of saline aquifers are currently not suitable for other synergic or conflicting applications [41], particularly in the framework of densely populated countries [42]. However, from an economic aspect, many saline aquifers are currently less desirable as a storage option due to the absence of necessary infrastructure, such as injection wells, surface equipment and pipelines, and the capital cost associated with developing such infrastructure [43,44].

There has been much research carried out around the world on the potential of CO₂ storage in saline aquifers [45], mostly in conjunction with EOR fields (such as the Boundary Dam-Apache case). These studies involve factors such as site selection criteria, site characterisation and future planning [46], as well as the variation of synergic and/or conflicting uses of the subsurface [42,47].

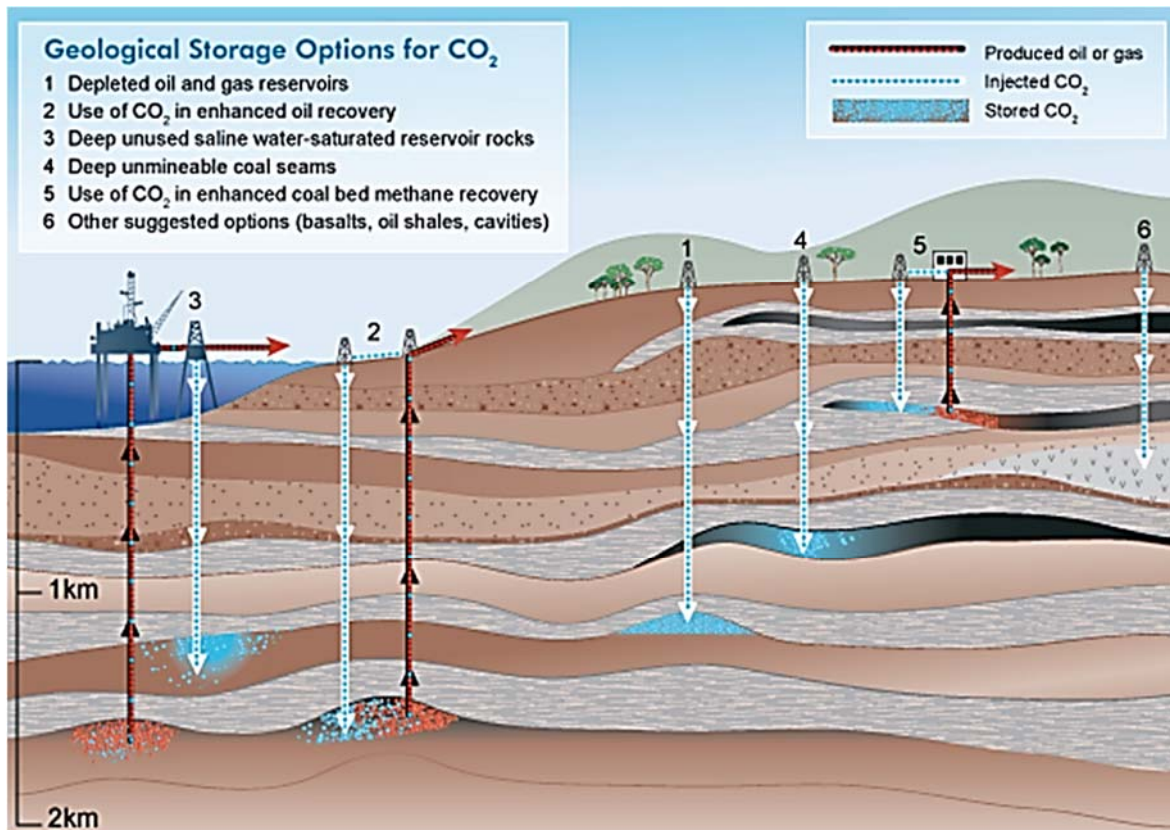


Figure 1: Some geological storage options for CO₂ [48].

It is revealed that all deep-seated (>1 km) saline aquifers (perhaps excepting aquifers found between deeply-buried old lava flows) [36] of the world are located within sedimentary basins. Such basins can host enormous quantities of CO₂ due to their large pore volume and high permeability that minimise the number of necessary injectors, and ease pressure dissipation [30]. Once supercritical CO₂ enters the storage reservoir, it displaces saline pore water and then begins to react with groundwater, gas and rocks in the formation [49,50], which eventually leads to precipitation of new minerals and/or dissolution of pre-existing minerals [51]. Formation and dissolution of minerals can affect the rock porosity and consequently change the capacity of the host reservoir [52].

The density of supercritical CO₂ in saline reservoirs is about 0.6-0.7 g/cm³, which is lower than the density of saline formation water, thus causing CO₂ to rise towards the caprock due to buoyancy force [53,54]. To assure long-term CO₂ storage, the host basin must be considerably large and the caprock must possess a good sealing capacity [55]. Fleury et al. [56] defined a caprock as a low- to very low-permeability formation above the CO₂ storage formation, in which no CO₂ migration should occur. This low-permeability caprock is essential to prevent CO₂ from migrating out of the storage reservoir, and minimising the CO₂ leakage. The presence of unrecognised fracturing or faulting is another critical factor that can result in loss of caprock integrity and in CO₂ leakage. However, further research is needed to explore the effect of pervious faults on the caprock integrity [57].

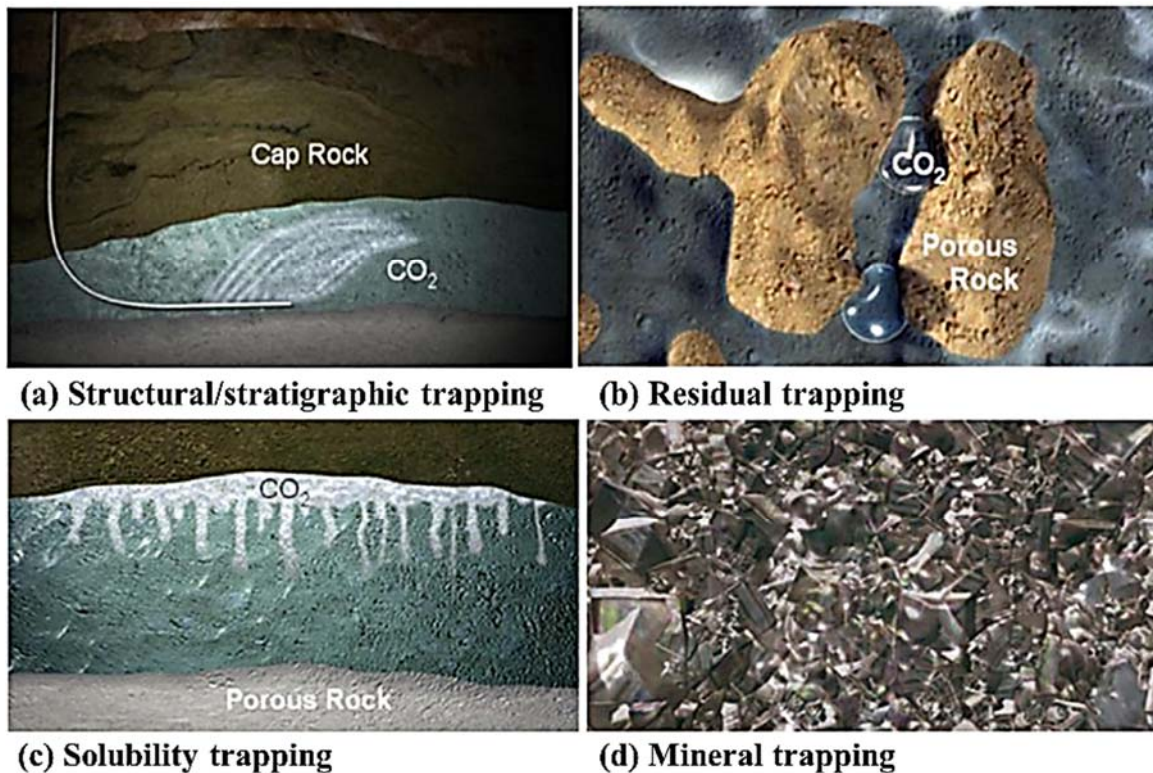


Figure 2: The four main CO₂ trapping mechanisms (reprinted with permission from Zhao et al. [58], Copyright 2017 Elsevier).

There are four main trapping mechanisms that can securely store CO₂, namely, structural/stratigraphic, residual, solubility, and mineral trapping, **Figure 2** [30,59].

(a) Structural/stratigraphic trapping: Once CO₂ is injected, it can rise up to the top of geological structures and remain below an impermeable top seal [60], where it is stored as a high-density free phase that is unable to enter the pore space of the caprock, except through slow diffusion or through faults, **Figure 2a** [61]. This is the most dominant trapping mechanism.

(b) Residual trapping: In this mechanism, the injected CO₂ initially displaces the fluid as it progresses through the porous rock. As CO₂ continues to move, the displaced fluid returns and disconnects and traps the remaining CO₂ within pore spaces, **Figure 2b** [59]. It is reported that the phenomenon does not happen within structural and stratigraphic traps, but only where water drainage occurs during CO₂ injection [62].

(c) Solubility trapping: In this mechanism, CO₂ dissolves in brine, reducing the volume of free-phase CO₂, **Figure 2c**. CO₂ dissolution increases the brine density and can induce a gravitation instability, which accelerates the transfer of injected CO₂ to CO₂-lean brine [63].

(d) Mineral trapping: In this mechanism, CO₂ is involved in geochemical reactions with saline water and minerals in host rock leading to the precipitation of carbonate phases that effectively lock up the CO₂ in immobile secondary phases for geological timescales, **Figure 2d** [64]. This process is slower than solubility trapping and takes place over a longer geologic timescale [65–67].

2.1.2 Depleted Oil and Gas Reservoirs

CO₂ storage in depleted oil and gas reservoirs is considered as one of the most effective storage options because of several advantages including: (a) depleted oil and gas reservoirs have been extensively studied before and during the hydrocarbon exploration stage, including the storage capacity, (b) surface and underground infrastructure, e.g., injection wells and pipelines, already exist and can be utilised for the storage process either without or with only minor modifications [33,45,68–71], and (c) the injection of gases such as CO₂ as an EOR technique has been widely known and employed within the oil and gas industry and, therefore, such experience can be used for the storage process [43]. In addition, oil and gas reservoirs are valuable hydrocarbon-containing analogues that can be used to demonstrate the effectiveness of caprock or seal over geological periods [72], since if this was not the case, the oil and gas in such reservoirs would have escaped long ago.

Storage in oil and gas reservoirs has many similarities to storage in saline aquifers, since the rock types are similar [73], and brine is present in both cases. On the other hand, oil and gas reservoirs can be potentially considered for EOR, which makes them economically more favourable than saline aquifers [74–76]. Since the global average factor for recovery in typical oilfields is approximately 40% [77], there is often a substantial amount of oil which is left in the reservoir. This is the main driver for deployment of EOR around the world. However, challenges of the technology deployment remain (mainly the dynamic nature of the downhole environment), although some of these uncertainties could have been considered and addressed during the early stages of a field's exploration and/or production.

Amongst existing options for EOR, including gas, thermal, chemical, or plasma-pulse injection methods, gas injection is the most commonly used technique. In the gas injection technique

(typically CO₂, nitrogen and natural gas), miscible gases are introduced into the reservoir to reduce the interfacial tension between oil and water and improve oil displacement, while maintaining reservoir pressure. CO₂ is considered as the most suitable option, since it can reduce the oil viscosity, and also is cheaper compared to liquefied natural gas [78]. Since the advent of CCS technology, more CO₂ for EOR is expected to be available from large point sources [5]. For example, it has been reported that the utilization of CO₂ for EOR has led to additional production of almost 250,000 barrels of oil per day in the United States [79].

The main requirements for deployment of CO₂-EOR projects are [80]: (i) additional characterisation of storage site by gathering key information on caprock integrity and abandoned wells, to determine the risk of leakage; (ii) additional measurements of fugitive and venting emissions from any surface processing facilities; (iii) enhanced monitoring and field surveillance to identify, and/or estimate leakage rates from sites to assess whether reservoir behaviour is as anticipated or not; and (iv) modifications to abandonment processes such as removal/retrofitting of any components of the well, to ensure such components can withstand effects of corrosion.

Nevertheless, in addition to the aforementioned requirements, governments need to consider legal issues and provide legislation that can cover storage site operation. These issues derive from different models of regulation for CO₂-EOR and CO₂ permanent storage, in which the former should be focused on resource recovery, and the latter on waste disposal [81]. For example, where recovery of hydrocarbon is prioritised, the effective decontamination of oil remaining in place after production ceases may cause legal issues. Such situation can be specific to jurisdiction, and may be particularly important where onshore mineral and storage rights are held privately (i.e., United States) [81].

The type and level of impurities in CO₂ streams is one of the important factors that needs to be critically characterised prior to a CO₂-EOR project. The impurities in the CO₂ stream depend on the point source of CO₂ and its corresponding capture technologies [82]. The acceptable impurities and their concentration are determined based on a combination of transport, storage, and economics-related parameters. Typically, the minimum acceptable purity of CO₂ streams is around 90%_{vol} [83]. Higher levels of impurities can shift the boundaries in the CO₂ phase diagram to higher pressures, implying higher operating pressures are needed to maintain the CO₂ in its dense phase. Moreover, it has been reported that non-condensable impurities often lead to a reduction in the CO₂ storage capacity by a degree greater than the molar fraction of the impurities in the CO₂ stream [84].

Corrosion is the main associated concern with impurities. Corrosive impurities (such as CO, NO₂, SO₂, H₂S, Cl) can significantly impact the transport and injection facilities; thus, it is essential to limit the level of impurities on a case-specific basis, and to establish viable mitigation strategies regarding the potential challenges [82]. It should be pointed out that although some impurities are flammable in nature (such as CO, H₂, H₂S, CH₄), the CO₂ stream would not be flammable due to relatively low concentrations of those impurities, and such safety concerns for flammability are usually not considered in the evaluation of safety procedures. The excessive concentration of O₂ in CO₂ streams is another factor that can affect efficiency of the CO₂-EOR process. The presence of O₂ can trigger microbial activity in the reservoir [82], and can eventually lead to operational issues such as injection blockage, and oil degradation and oil souring [85].

Environmental aspects of EOR are associated with production of large amounts of water which may contain radioactive substances and toxic heavy metals [86]. These substances can contaminate the sources of potable water if a proper waste management and disposal strategy

is not adopted. Although regulations already exist, governments must assure that the operators adhere to existing regulations where reinjection of brine (deep into the ground) for recovery is authorised (such as in the United States) [87].

The Weyburn-Midale CO₂ storage project in Canada is one of the examples in which the captured CO₂ is successfully and effectively used for EOR and storage in the Weyburn oilfield. In this project, not only is a considerable amount of additional oil recovered [88], but also the life cycle of the oilfield is extended for 20-25 years [89]. CO₂-EOR studies based on the Weyburn case history have been mainly focused on long-term monitoring [90,91], induced seismicity [92], core assessment of CO₂ impact on the reservoir [93], and interaction of formation waters, oil and minerals [94]. Cantucci et al. [51] developed a geochemical model for CO₂ storage in deep reservoirs using the Weyburn case history, and studied brine/oil geochemical equilibrium. They assessed reservoir evolution during CO₂ injection, and predicted precipitation and dissolution processes over 100 years post injection. They found that CO₂ and carbonate dissolution are the main chemical reactions in the reservoir, and this takes place within the first year of simulation. In addition, evolution of chemical features by time suggested that CO₂ can be safely stored by both mineral and solubility trapping.

Although the CO₂-EOR process has significantly increased oil recoveries, the following strategies can potentially lead to further improvement [95]: (i) increasing the amount of injected CO₂ compared to the typical range – such as conducted in the San Joaquin basin, where a recent numerical model was developed and used to prove that it was possible to recover 67% of the original oil in place (OOIP) by injecting 2.0 HCPV (hydrocarbon pore volume) of CO₂ [96]; (ii) utilising innovative flood design and well management to obtain a higher proportion of residual oil through strategies such as isolation of poorly swept reservoir intervals for CO₂ injection, altering injection and production well patterns, and deploying much closer well

spacing [97]; (iii) improving the mobility ratio by increasing the viscosity of water [98]; and (iv) minimising miscibility pressure using miscibility-enhancing agents [99].

2.1.3 Unmineable Coal Seams

Unmineable coal seams provide another option for storing anthropogenic CO₂. The presence of cleats within the coal matrix provide some permeability to the system. In addition, the coal matrix contains a very large number of micro-pores which makes it capable of adsorbing significant amounts of gases. The CO₂ trapping mechanism is based on the higher affinity of coal towards gaseous CO₂ than methane. Therefore, the injected CO₂ can replace previously adsorbed methane and be permanently stored, while enhancing methane production [30]. This provides the opportunity of storing large amounts of CO₂ while still improving the profitability and efficiency of commercial operations of coalbed methane (CBM) [100,101]. It should be noted that CO₂ accelerates CBM production, but the total amount of produced methane is not necessarily greater than that without CO₂ injection. IEAGHG [102] outlined the principal technical criteria that are required for successful application of enhanced coal bed methane (ECBM) recovery, including: (i) reservoir homogeneity; (ii) minimal faulting/folding; (iii) optimal depth range; (iv) concentrated coal geometry; and (v) adequate permeability.

The ECBM approach has been tested at two demonstration sites, namely, the Alberta Carbon Trunk Line (ACTL) project in Canada, and the San Juan Basin pilot project, USA, [100]. At the completion of the Alberta project tests, key lessons learned were: (a) continuous injection of CO₂ is possible even in tight reservoirs; (b) despite injectivity declines, injection can still proceed; (c) it is possible to predict significant enhanced CBM production; and (d) injected CO₂ remains within the reservoir while sweep efficiency is increased [103]. For the San Juan Basin pilot project, the key conclusions were: (a) there was an increase in methane recovery

over the estimated ultimate primary recovery; (b) given the prevailing gas prices at the time of implementation of the project (without considering any tax credit benefits), the pilot itself was uneconomic, although gas prices in the future may make it appear economically attractive; and (c) the injected CO₂ causes a reduction in coal permeability and correspondingly CO₂ injectivity, which in turn compromises any likely increment in methane recoveries and project economics. Another small-scale study on a CBM field is in the Central Appalachian Basin (Buchanan County, Virginia, USA) where several monitoring, verification and accounting (MVA) techniques are being used in improving the understanding of storage complexities [101,104]. In addition, the potential ECBM implementation and the major differences in production between close wells with the same stratigraphy (but different groundwater/bacterial presence) have been initially investigated (such as those in the Surat basin, Australia [105]). However, further exploration is required to fully characterise and depict those differences.

Although CO₂-EOR is an established approach in the oil industry, utilisation of CO₂ for ECBM is yet to be well understood. However, many of the uncertainties in ECBM recovery can be addressed based on the existing knowledge of the CO₂-EOR process. For example, for recoverable reserves in ECBM production, it may be important to consider existing technologies from the oil industry which can be utilised with slight modification. For the well integrity in ECBM production, existing well materials can be considered as a benchmark and used after appropriate improvements. Additionally, field management strategies, including risk assessment and monitoring, can be adopted from established processes and applied throughout project lifecycles.

2.1.4 Basalt Formations

Deep basalt formations, found within large igneous provinces, have been proposed as a potential option for CO₂ storage [106–108]. Basaltic rocks form approximately 8% of the continents and much of the ocean floor. Therefore, there is an enormous potential CO₂ storage capacity in basaltic rocks [109]. The key positive aspects of their potential for CO₂ storage are their high reactivity and abundance of divalent metal ions in such rock which can potentially fix CO₂ for geological timescales [110]. However, basalt flows have highly heterogeneous permeability and porosity (including that of matrix and fractures), and typically consist of a low-permeability centre, with high permeability zones at the upper and lower portions. Thus, the key parts of a basalt sequence for CO₂ storage are the rubbly zones between individual flows.

Injection of free-phase CO₂ into deeply-buried basalts (such as the CarbFix pilot project in Iceland) can displace water in pore spaces and fractures [111]. The reduction in the amount of water can hinder carbonation and hydration of the basalt. Therefore, injection of CO₂ with an optimum amount of water in the same reservoir may be a potential solution. Goldberg et al. [112] studied CO₂ injection in deep sea basalt and reported that it: (i) facilitates formation of stable carbonates in relatively short geologic time, and delays return of CO₂ to the atmosphere; (ii) provides enough depth that allows denser CO₂ liquid to sink; (iii) stops upward migration of acidified basement fluids through an impermeable sediment cover; and (iv) forms stable hydrate when CO₂ escapes to shallower depths containing water with lower temperatures. It is important to note that sparse and rare CO₂ leakage in a limited amount does not necessarily affect the sea bottom environments.

Due to the potential formation of secondary carbonate mineral and the possibility of long-term CO₂ trapping in basalts, it is important to consider changes in rock volume and to determine whether there is the probability of self-healing of fractures. Such issues were numerically explored by Van Pham et al. [110]. They reported that at 40°C, calcium was significantly consumed by oxide which could possibly be limited to the formation of siderite and ferromagnesium carbonates. However, at higher temperatures, 60-100°C, magnesite formed together with ankerite and siderite. They also found that both carbonation and hydration reactions resulted in an increase in the volume of solids and blockage of available pores, and consequently a reduction in the maximum amount of stored CO₂.

Alongside basalt mineral assemblages, there have been studies aimed at understanding the fundamentals of long-term CO₂ storage through mineral carbonation reactions that involve common magnesium silicates in serpentinites. CO₂ reacts with magnesium silicates in the form of serpentinites, which are both abundant and thermodynamically suitable rocks to form magnesium carbonates [113]. Andreani et al. [114] studied the carbonation process under optimal flow conditions and their study suggested that reduction in porosity and permeability is confined to diffusion-limited zones or reduced flow, although high flow rates result in armoring of mineral surfaces after initial dissolution.

The presence of fractures in the caprock layer of basalt formations has also been a source of uncertainty. There is a possibility for leakage through the fractures, which may imply that basalts appear unlikely to be suitable for CO₂ storage. On the other hand, the migrating CO₂ through the fractures can potentially undergo mineralisation before reaching the surface, and be stored within the formation [115]. Thus, comprehensive exploration is needed to characterise the kinetics of CO₂-basalt interactions.

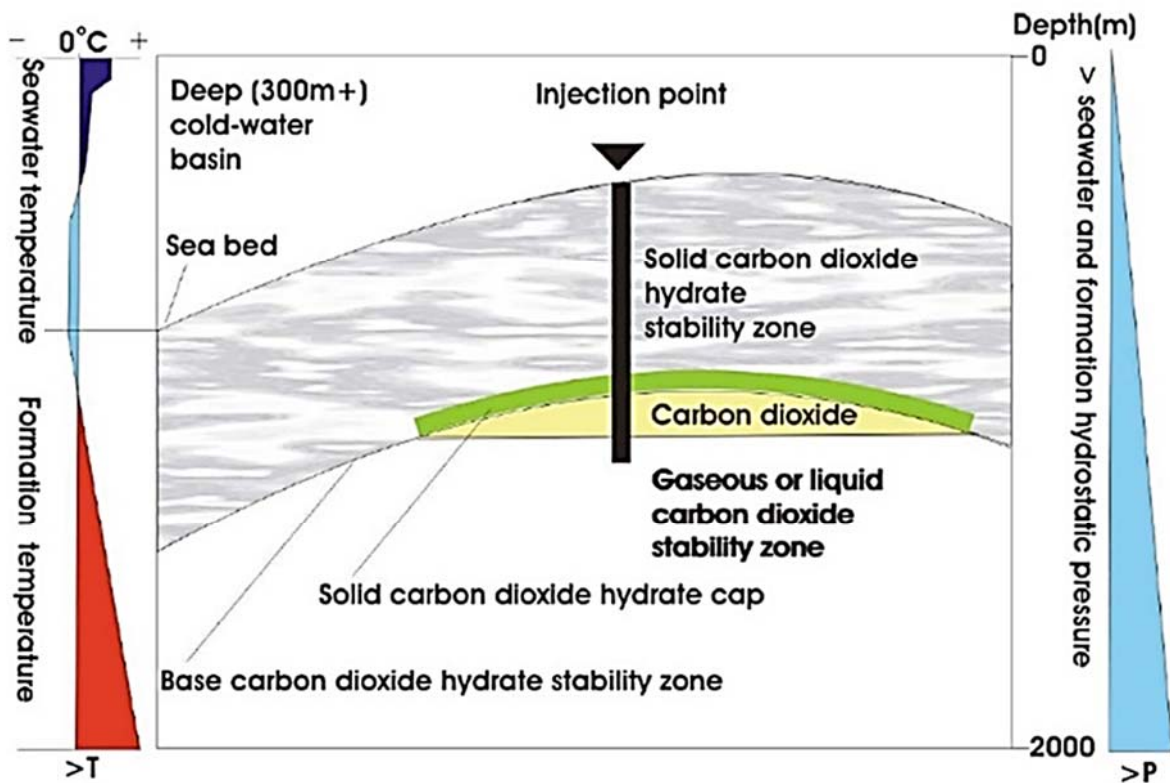


Figure 3: Schematic of hydrate storage and associated ‘cap’ of CO₂ hydrate (adapted with permission Rochelle et al. [116], Copyright 2017 Geological Society of London).

2.1.5 Hydrate Storage of CO₂ within the Subsurface Environment

Subsurface storage of CO₂ as hydrates is also a promising, novel option which aims to use CO₂ hydrate to trap CO₂ molecules in a lattice of water molecules [35]. CO₂ hydrate can rapidly form in the presence of water (that is abundant underground) and the appropriate pressure and temperature conditions [117]. In addition, its fast formation kinetics may potentially allow a degree of self-sealing in the unlikely event of fracture formation in the hydrate cap. Formation of CO₂ hydrates is applicable in both underground geological and oceanic storage. However,

since the hydrates are stable only at elevated pressures and temperatures below 10°C [116], its applicability is limited to a few environments, including shallower sediments that are beneath cold waters, and below thick permafrost, where there may not be large sources of CO₂ nearby.

The CO₂ hydrate storage mechanism is mainly based on the formation of an impermeable CO₂ hydrate cap over a large amount of buoyancy-driven migrating liquid CO₂, **Figure 3**. In this method, the liquid CO₂ is injected into deep-water or sub-permafrost sediments, beneath the CO₂ hydrate stability zone. Migration of the rising liquid CO₂ to the cooler hydrate stability zone leads to precipitation of CO₂ hydrates within rock pore spaces and formation of an impermeable layer of CO₂ hydrates, that blocks the upward migration beneath liquid CO₂ [116]. Alternatively, a hydrate storage strategy based on CO₂-EGR (enhanced gas recovery) was proposed by US DOE (Department of Energy). In this approach, the CO₂ is injected into methane hydrate-bearing sediments in order to release the methane from methane hydrates, and subsequently form CO₂ hydrates instead [37]. However, CO₂-EGR is a relatively new concept and its viability has not yet been fully explored. One of the main associated concerns with CO₂-EGR is the possibility of mixing of the injected CO₂ with existing methane which in turn may degrade the resources [118].

CO₂ hydrate storage is still at a relatively low technology readiness level (TRL), and the majority of the work has been focused on theoretical modelling [119,120] and lab-scale experiments [121–123]. Therefore, there are uncertainties that remain, particularly in respect to CO₂-EGR. Drilling through hydrate-bearing sediments can change local temperature and pressure, and may eventually destabilise the hydrate [124]. The key remaining issues that need to be addressed in order to advance the assessment of hydrate storage feasibility are the demonstration of hydrate cap formation, and understanding of the CO₂-methane hydrate exchange mechanism and its impact on methane production.

2.1.6 CO₂-based Enhanced Geothermal Systems

The thermal properties of dense-phase CO₂, like water, make it capable of transporting significant amounts of heat. However, it also possesses some superior physical properties, such as significantly lower viscosity, higher compressibility and expansivity [125–128]. Therefore, CO₂ can be applied for the extraction of heat from the subsurface, and used for geothermal power production. Owing to its low viscosity, CO₂ can effectively access the rock mass, and can be particularly utilised as a working fluid for enhanced geothermal systems (EGS) [34,128]. One of the drawbacks of using water as the heat transmission fluid in EGS is its inevitable loss during fluid circulation. Since water is considered a valuable commodity, its loss is associated with economic liability. On the other hand, the loss in CO₂-based EGS would offer the possibility of geological storage of CO₂ underground, and can be considered as an ancillary benefit [128].

For an effective and successful storage strategy based on CO₂-EGS, the CO₂-filled rock mass needs to remain separate from the surrounding water-filled rock mass, and the stored CO₂ should be isolated. The key mechanism that can ensure the aforementioned criteria is based on fast CO₂-water-rock reactions that result in precipitation of carbonate minerals at the interface between the CO₂-filled core of the EGS and the surrounding water-filled regions. In terms of geographical aspects, this approach would only be appropriate for countries which have subsurface formations with sufficiently high temperatures at economically-drillable depths. In addition, in densely populated countries, the synergic use of subsurface can be more challenging, and requires a high level of coordination [42].

In general, the technique is currently at a relatively low TRL, and the majority of conducted work has been mainly limited to theoretical modelling [129], and laboratory experiments [130].

The key barrier for further advance of this technology is associated with uncertainty in effectiveness of sealing around the CO₂-filled zone. In addition, the CO₂-rock interaction at elevated temperature is not clearly known, and further studies are required to characterise the effect of CO₂ on dissolution and precipitation, and consequently variation in fracture permeability and EGS operation.

2.2 Deep Ocean Storage

An alternative strategy for sequestration of anthropogenic CO₂ is to deliberately inject the CO₂ into deep ocean water. Oceans cover 70% of the earth's surface with an average depth of 3.8 km [131], and have absorbed almost a third of cumulative anthropogenic CO₂ emission from the atmosphere over the industrial period [132]. Mathematical models have shown that injected CO₂ could remain in the ocean for several hundred years [131]. These cold (ca. 1°C) and deep (ca. 4-5 km) waters move slowly, and can remain isolated from the atmosphere for millennial timescales.

The main proposed approaches for ocean storage are based on direct dissolution of CO₂ into the seawater. In the first approach, liquid CO₂ is directly discharged to the seafloor and forms rising droplet plumes. Alternatively, liquid CO₂ is injected into a column, where it can react with seawater, at a controlled rate, to form hydrate [131]. There is, however, opposition regarding deep ocean storage of CO₂ due to the potential local acidification of seawater around the CO₂ injection point [133,134], and correspondingly, possible negative impact on benthic organisms. In addition, it is not yet clear whether international regulations will allow ocean storage projects [24]. In 1996, the London Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter (also known as the London Convention) prohibited disposal of industrial wastes into the sea [135]. Therefore, if CO₂ is considered as an industrial

waste, disposing it beneath the sea is prohibited. However, there has not been agreement whether CO₂ is regarded as industrial waste or not, even though in 2006, there was an amendment to the London Protocol, in which CO₂ is included in the “reverse list” allowing it to be considered for storage below the seabed. In parallel, the Convention for the Protection of the Marine Environment of the North-East Atlantic (also known as the ‘OSPAR Convention’) pointed out that “CO₂ can be only stored in accordance with an authorisation or permit given by the Party’s competent authority” [136]. Thus, the uncertainties associated with the oceanic sequestration and its environmental aspects need to be evaluated and possible mitigation strategies should be specified.

The main key parameters that can be used to evaluate the efficiency of oceanic sequestration are injection depth, residence time (time-scale at which the stored CO₂ returns to atmosphere), and the distribution of CO₂ concentration. Xu et al. [137] studied the potential of storing CO₂ in the North Pacific by developing a regional ocean general circulation model with different parameters of sub-grid mesoscale mixing, and assuming a zero air-sea CO₂ exchange. Their results showed that the storage depth is one of the key parameters for isolating the stored CO₂ and minimising its return to the atmosphere. It was determined that to store CO₂ in the ocean over a few hundred years, an injection depth of over 1000 m is necessary. In addition, it was revealed that after 50 years of continuous CO₂ injection (at different locations and a maximum depth of 5750 m) more than 10% of dissolved CO₂ would return to the atmosphere, which can be considered as a source of leakage. Hill et al. [138] evaluated the storage efficiency by means of mean residence time for impulse injections based on several scenarios, using an ocean circulation model. It was found that the North Atlantic is more efficient for sequestration of CO₂ over timescales of several hundred years and longer, while the Pacific basin is more efficient for shorter timescales. It should be noted that this study was based on relatively small

magnitudes and the effect of air-sea CO₂ exchange was neglected; however, for large boundaries, the significance of this effect is unknown and needs to be investigated.

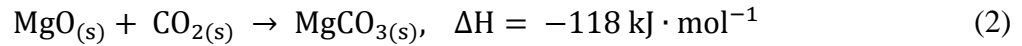
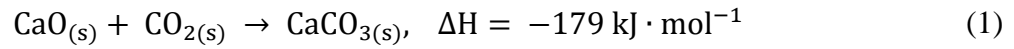
The distribution of CO₂ concentration after injection can be used to assess the sequestration site selection. The ideal site is referred to where the CO₂ is efficiently diluted and has the least negative impact on biota. Masuda et al. [139] studied the local distribution of CO₂ concentration as a function of injection rate and eddy activity distribution, by simulating CO₂ injection into several sites around Japan using an oceanic general circulation model. It was revealed that the maximum concentration of CO₂ can differ by a factor of 10 amongst sites, and this discrepancy is mainly attributed to the local distribution of eddy activity. Further, it was determined that no chronic impact on biota would be caused if injection rates are limited to 20 Mt/a.

According to aforementioned discussions, there are several improvements and uncertainties that need to be considered and addressed in future research in order to enhance the evaluation of oceanic sequestration, including: (i) improving the current numerical model by including an air-sea CO₂ exchange mechanism for better evaluation of storage efficiency; (ii) further investigating the determination and quantification of ocean site selection criteria; and (iii) further quantification and demonstration of the viability of transporting large amounts of CO₂ in the Pacific Ocean.

2.3 Mineral Carbonation

The concept of CO₂ mineral carbonation (mineralisation) as an alternative CO₂ sequestration strategy was first proposed by Seifritz [113]. In this method, the captured CO₂ is sequestered through the process of mineralisation where CO₂ is reacted with alkaline earth metal oxides or

hydroxides, such as calcium- and magnesium-rich minerals to produce stable carbonates, Eq. (1) and (2).



There are two methods of mineral carbonation: in-situ and ex-situ. The in-situ method involves the production of carbonates through the injection of CO₂ into a geologic formation, while the ex-situ method is carried out above ground in an industrial plant using previously mined or local rock [140,141]. In-situ mineral carbonation would typically be considered in basalts or ophiolite rocks which are enriched in magnesium, iron, and calcium silicates [140]. Major advantages for the in-situ mineral carbonation method stem from the fact that no extensive mining is needed as only a few boreholes are required for the process. On the other hand, there can be major uncertainties such as lack of geological characteristics or unknown caprock or seal potential. In addition, geochemical reactions may act to reduce reactivity, porosity, and permeability, which in turn can cause lining of the initially formed flow paths. Ex-situ mineral carbonation can be done through either direct (gas- and aqueous-based) or indirect processes. In the direct gas-based method, gaseous CO₂ is reacted with minerals to produce carbonates [142,143]. The gas-solid carbonation reaction typically takes place at temperatures below 650°C [113,144,145], and the main limiting factors are the reaction rate and rock storage capacity. In the direct aqueous-based method, CO₂ is reacted with minerals in the presence of an aqueous solution, usually taking place in a single step [142]. Sanna et al. [140], Olajire [146] and Bobicki et al. [142] reported that constraints like mineral dissolution, CO₂ dissolution, and product layer diffusion are the main factors that make direct mineral carbonation less viable for commercial deployment and development.

Matter and Kelemen [147] studied permanent CO₂ storage in geological reservoirs by mineral carbonation using natural analogues. Results from their study showed that the rate of mineralisation is high in host rocks rich in magnesium- and calcium-bearing minerals. Their results also showed that precipitation of carbonate minerals can clog pre-existing voids, although stress induced by rapid precipitation may also lead to fracturing and increased pore volume. The local environment may also be affected through mining, as certain types of calcium- and magnesium-rich mineral deposits may contain asbestiform phases and other health-depleting impurities [5].

Although magnesia (MgO) and lime (CaO) are the most naturally abundant alkali and alkaline earth metal oxides, they do not exist as binary oxides in nature and are usually bonded up as silicate, such as serpentine [18]. Cipolli et al. [148] and Bruni et al. [149] studied CO₂ interactions with serpentine from spring waters in Genova (Italy). After geochemical analysis of the high-pH waters from serpentinites and reaction path modelling for sequestration in aquifers containing serpentinites, Cipolli et al. [148] confirmed that the progressive reaction of ultramafic rocks with meteoric waters is affected by serpentinisation. This initially led to the formation of MgHCO₃ waters when the system is exposed to CO₂ and subsequently the formation of Na-HCO₃ and Ca-OH type waters upon further interaction with the host rock under highly reducing closed-system conditions. After simulating high-pressure CO₂ injection into deep aquifers by reaction path modelling, their results indicated that serpentinites have good capacity for CO₂ sequestration, mainly because of the formation of carbonate minerals. It should be noted that this process caused a reduction in porosity of the aquifer under closed system conditions. This suggests that such implications need to be carefully evaluated by further field and laboratory tests.

From a survey of spring waters in the Genova province using irreversible water-rock mass transfer, Bruni et al. [149] reported that many neutral Mg-HCO₃ and some high-pH Ca-OH waters were found to be associated with serpentinites. They explored the viability of using serpentinite dissolution and calcite precipitation under open- and closed-system conditions for long-term CO₂ sequestration. From their study, the interaction of these waters, which are of meteoric origin (as indicated by stable isotopes of water and dissolved N₂ and Ar), show a progressive evolution in chemistry of the aqueous phase from immature magnesium-rich, SO₄Cl facies of low salinity to intermediate Mg-HCO₃ facies and to some mature Ca-OH facies. Further, the high-pH Ca-OH water can absorb CO₂ and form calcite deposits, suggesting that the process can be utilised for the sequestration of anthropogenic CO₂.

On the other hand, the less attractive aspects of mineral carbonation are the potential environmental and human concerns. Mineral carbonation processes have the potential for terrain alteration through large-scale mining operations, and subsequent disposal of the reacted materials. In addition, certain types of calcium- and magnesium-rich mineral deposits may contain asbestiform phases and other health-depleting impurities [5].

According to the reviewed literature, future studies, that potentially help to evaluate the viability of CO₂ sequestration by mineral carbonation, can be focused on: (i) mineral carbonation with respect to mineral and CO₂ dissolution; (ii) product layer diffusion; (iii) the possibility of less terrain alteration; and (iv) handling mineral impurities in the sequestration process.

3 CO₂ Storage Site Evaluation Criteria

Before the deployment of storage technology, it is important to identify key storage site evaluation criteria that allow assessing whether the technology is credible, safe, reliable,

trustworthy, environmentally benign, and economically viable. This is especially important if the ethics management mechanisms are not established. The identification of key evaluation criteria and recommendations in the site evaluation process should provide clear inputs for costs-risks-investment business decisions [150]. Studies on site-selection and -evaluation criteria for CO₂ storage in geological formations have highlighted that the main criteria to be considered are geological, geothermal, geohazards, hydrodynamic, hydrocarbon potential and basin maturity, and economic, societal, and environmental issues [36,151–156].

3.1 Geological Factors

The most suitable CO₂ storage strategy has been currently attributed to sedimentary basins, where sedimentary rocks, containing appropriate porosity and permeability, are often located at or near to power stations and energy-intensive industries [157]. This implies the importance of the distance between point sources of CO₂ and storage sites, in order to minimise the cost of transportation. Thus, for point sources of CO₂ that are not located close to ideal sedimentary formations, the high cost of transportation can be avoided by selecting an alternative storage option.

The key geological parameters for storage site evaluation are aquifer properties such as reservoir volume/porosity/permeability, pressure and temperature, sweep efficiency (which is a function of heterogeneity of formation), caprock permeability, entry and fracture pressures, quantities of reactive minerals, thickness of formation for CO₂ injection, CO₂ solubility in saline water, potential for seismogenic faults, and stress regime. Injectivity is another factor that is used to evaluate both the economic and technical suitability of a storage site, and enhance the security of storage [152,153]. Injectivity itself is a function of several parameters such as

vertical and horizontal permeability, rock compressibility, effective thickness, reservoir heterogeneity, reservoir and fracture pressures, and depth of injection [152].

The Bunter Sandstone formation in the UK's southern North Sea is a specific case where detailed CO₂ containment studies were conducted on both reservoir storage capacity and caprock integrity. Heinemann et al. [72] numerically simulated the injection of CO₂ into the formation over a period of 30 years and at a rate of 1 Mt/a of CO₂ for each well. They reported that since there are few producing fields, information about reservoir and caprock is sparse, but can be evaluated through legacy borehole records which were targeting deeper horizons. They found that approximately 3.8-7.8 Gt of CO₂ can be stored in the reservoir, depending on the maximum safe pressure of injection, and the seal is capable of effectively retaining CO₂.

Geological site assessment can be further improved upon using systematic, yet generally accepted approaches that consider and focus on injection capacity and risks of containment. A possible way to achieve these improvements is to adopt experiences from the oil and gas industry, especially by utilising numerical models that can quantify the roles of dominant CO₂ trapping mechanisms for basins. In addition, there are only a few studies on geophysical and geochemical risk assessments that are prerequisites to induced seismicity and potential leakage and, thus, learn-by-doing methods [42] should also be considered in future studies.

3.2 Geothermal Gradient

With regard to the critical point of CO₂ (7.38 MPa and 31.1°C, equivalent to a hydrostatic head of 738 m) a slight variation in geothermal gradient by depth can cause CO₂ to enter supercritical conditions. Assuming the pressure distribution within a sedimentary basin is hydrostatic, the associated minimum threshold depth for injecting CO₂ in the supercritical state at a geothermal gradient of 30°C/km and surface temperature of 10°C is around 800 m [158,159], **Figure 4**.

Nevertheless, hydrodynamic and geothermal conditions are not always constant across all basins, and for the same basin, are not the same from place to place. The limiting factors for geothermal regime in any sedimentary basin may include: (i) basin type, age and tectonism; (ii) basement heat flow, (iii) thermal conductivity and heat production in the sedimentary succession, and (iv) temperature at the top of the sedimentary succession. For ECBM projects, the minimum depth can be <800 m only if CO₂ is adsorbed by coal. A pilot CO₂ storage experiment at depth <800 m is the Ketzin Project [160]. However, this project did not receive positive public acceptance due to concerns on the possibility of leakage [161].

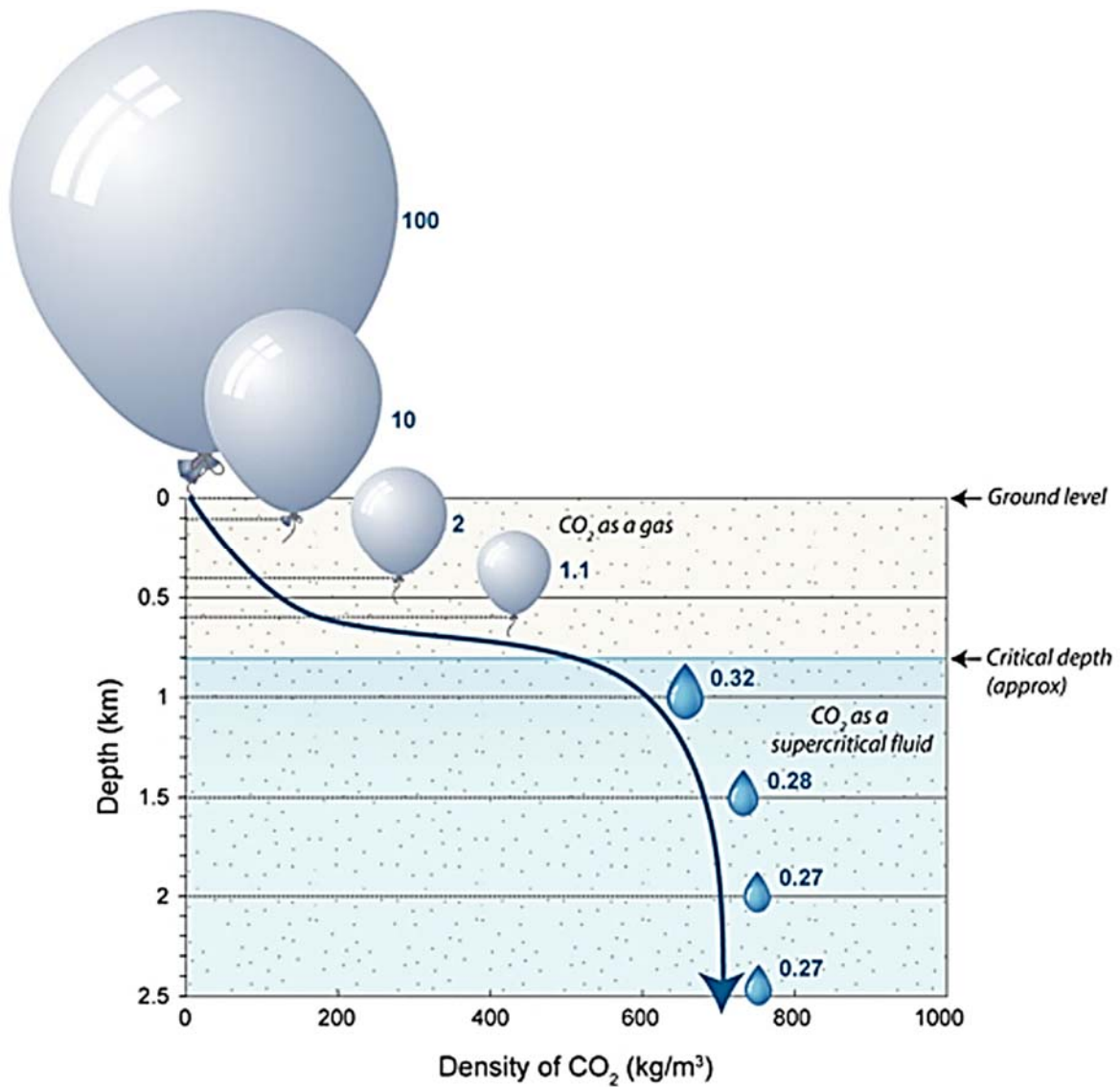


Figure 4: Relative volumes of CO₂ stored underground as a function of depth in storage reservoirs [162]. Note: Blue numbers in this figure represent relative volume of CO₂ at each depth.

3.3 Geohazards

Geohazards are attributed to the short- and long-term geological and environmental conditions that can potentially cause widespread damage to storage systems, and are necessary to be

appraised as part of storage site selection criteria. Accordingly, for effective CO₂ containment after injection, geologically hazardous areas should be avoided. For storage systems, the geohazards are mainly associated with seismicity, landslides and volcanic activity. In a study on the geo-database of caprock quality and the distributions of deep saline aquifers for geological CO₂ storage in Italy by Buttinelli et al. [57], it was highlighted that shallow and deep seismicity, magmatism, presence of degassing structures and anomalous thermal flux, are some geodynamical domains that can negatively affect storage systems. They identified the primary geological risks that are needed to account for selection of a potential injection structure, namely: (i) seismogenic sources and areas, as identified through geophysical and geological studies; (ii) historical and recent distribution of seismic events; and (iii) natural diffuse degassing structures. This study can be used as a benchmark for identification of local geohazards.

3.4 Hydrodynamic Factors

The hydrodynamic regime of formation water (including local pressure, salinity, and flow velocity) is very crucial for CO₂ storage, especially when injection is done in depleted oil and gas reservoirs [36], where the movement of CO₂ plume within the reservoir is influenced by hydrodynamic trapping. There is a close relationship between basin type and formation water flows. For example, in intracratonic and foreland basins which have undergone some uplift and erosion, the formation water flow is affected by lateral and vertical erosional rebound. This can make aquifers significantly under-pressured [163], as was seen in the Alberta basin in Canada [164]. Under-pressurised formations are the best for geological confinement and storage of CO₂ as they have a greater ability to cope with increasing pressure during injection operations.

The role of faults in hydrodynamic regime and their permeability structure are still to be evaluated as a consequence of sealing processes inside the fault bodies [165].

3.5 Hydrocarbon Potential and Basin Maturity

In basins with limited or no known resource potential (such as hydrocarbon reservoirs) [166], there are several reasons that may constrain CO₂ storage, namely because [36]: (i) most of the hydrocarbon resources are still undiscovered, thus there is concern about likelihood of contamination; (ii) being immature with respect to development means there are no depleted oil and gas reservoirs yet; and (iii) limited exploration means the geology and hydrogeology of basins are not understood. Certainly, since occurrence of energy reserves in such basins is not identified, it is not practical to proceed based on CO₂ storage in oil and gas formations (both for EOR and permanent storage). However, since there is still the possibility of having deep saline aquifers in such basins, storage may still be feasible only after evaluating detailed environmental and economic considerations [36]. For basins with relatively recent geological history and known hydrocarbon potentials that are still under exploration and production, contamination of hydrocarbons with CO₂-related impurities are the main source of concern that must be addressed before technology deployment. This also involves the early stages of primary production in CO₂-EOR. For basins which are either under development stage or for which limited exploration data exist, the lack of in-depth subsurface information is a limiting factor for storage site evaluation. Nevertheless, for all cases, 3D geophysical and geochemical modelling can improve the limited knowledge of such basins. On the other hand, CO₂ storage in mature basins is highly applicable for several reasons, including availability of ample data on the geothermal regime, hydrocarbon reserves, and coal beds [36].

The extent of basin development is another important factor that should be considered for site selection, given that many of the factors that make a reservoir suitable for an oil/gas reservoir also make it suitable for CO₂ storage. Strategic planning is also required to ensure that hydrocarbon extraction operations and CO₂ storage operations do not interfere with each other. For a well-explored basin with hydrocarbon potential, significant information exists on the rocks, reducing geological uncertainty. The presence of oil/gas may also allow for CO₂-EOR/EGR, and this may help reduce the cost of CO₂ storage. However, the presence of potentially thousands of hydrocarbon wells (some possibly several decades old), may increase uncertainties in long-term storage due to a greater potential for borehole-related CO₂ leakage.

3.6 Economic, Societal and Environmental Issues

Economic considerations in CO₂ geological storage usually revolve around existing or required infrastructure, and are dependent on ongoing climate change policy. In mature continental basins, the infrastructure such as pipelines, wells, and access roads may already be in place. In immature basins, infrastructure may be either missing or very limited [36]. In offshore basins, a major challenge is that CO₂ injection and storage may be very expensive, due to the necessity for construction of new infrastructure, including long pipeline routes. Therefore, a specific mandatory carbon tax might be considered, such as the one for features, events and processes (FEPs). However, it is important that the development of infrastructure and regulatory models for CO₂ storage should reflect expectations and attract government attention, while not compromising storage security and its impact on the environment. Achieving these key purposes is crucial for storage economics, since meeting technology deployment capable of substantially reducing anthropogenic CO₂ would greatly depend on decades of extensive investments.

Many suitable sedimentary basins for CO₂ storage are in developing countries (e.g., India and Nigeria). In the majority of developing countries, the top priority in development targets is to increase the living standards of their population, which may be rated higher than climate change and deployment of CCS [36,167]. This can imply that CO₂ storage in geological media may be economically more acceptable in developed countries such as those in North America and Europe [36]. In addition, the distribution of cities and natural resources, such as coal and oil/gas, are some aspects of environmental monitoring and ethics management that can affect the deployment of CO₂ storage. Development of storage projects in heavily-farmed areas can lead to challenges such as land access and right-of-way for facilities, which need to be considered during site characterisation activities. In addition, CO₂ storage can potentially influence the quality of natural resources such as oil and gas, metals and non-metals [152]. Therefore, it is important to consider preliminary regional planning on synergic and conflicting subjects of concern.

A substantial reduction in anthropogenic CO₂ can only be achieved if the majority of countries, including developing countries, participate in the implementation of CO₂ storage technology soon. Thus, it is important for stakeholders in the CCS industry to embark on technology transfer to build national capability. The awareness campaigns need to highlight the global importance of storage deployment for the local public. Furthermore, CO₂ storage should be promoted as an environmentally benign activity, and as a measure to address the environmental problems of communities.

In summary, the associated factors for assessment of storage site selection were discussed. A combination of these factors determines the feasibility of a potential storage site. Although the aforementioned principal factors need to be considered for evaluation of storage sites, there may be additional aspects which are specific to particular storage sites. These additional factors

can include (but are not limited to): (i) size and nature of site for potential future expansion; (ii) political aspects, such as the possibility of future regional development plans; and (iii) cultural heritage aspects, such as the existence of Native Title Claims where a person or a group may claim that they hold rights and interests in a given land or area according to traditional customs and laws.

4 CO₂ in the Reservoir

The candidate technology for development of CO₂ storage in the subsurface should potentially assure a minimum residence time of 1000 years and a leakage rate of less than 0.1% per year [5]. Therefore, one of the most important aspects of CO₂ storage is to have a clear understanding of the mid- to long-term behaviour of CO₂ in the reservoir. The CO₂ behaviour in the reservoir is a complex process (**Figure 5**) which depends on a variety of components within the reservoir system, including geochemistry, mineralogy, fractures, pore fluid dynamics, and variation in geochemical effects such as dissolution and precipitation of minerals [30,168], and can continue for thousands of years, until the stored CO₂ is immobilised as solid carbonate precipitates. There are several factors that influence containment of CO₂ within the reservoir, including CO₂-rock interaction, induced seismicity during the injection, and the potential risk of leakage that will be comprehensively discussed in this section. In addition, accurate estimation of reservoir storage capacity is one of the key prerequisite parameters for evaluating the suitability of a storage site, and will be covered in this section.

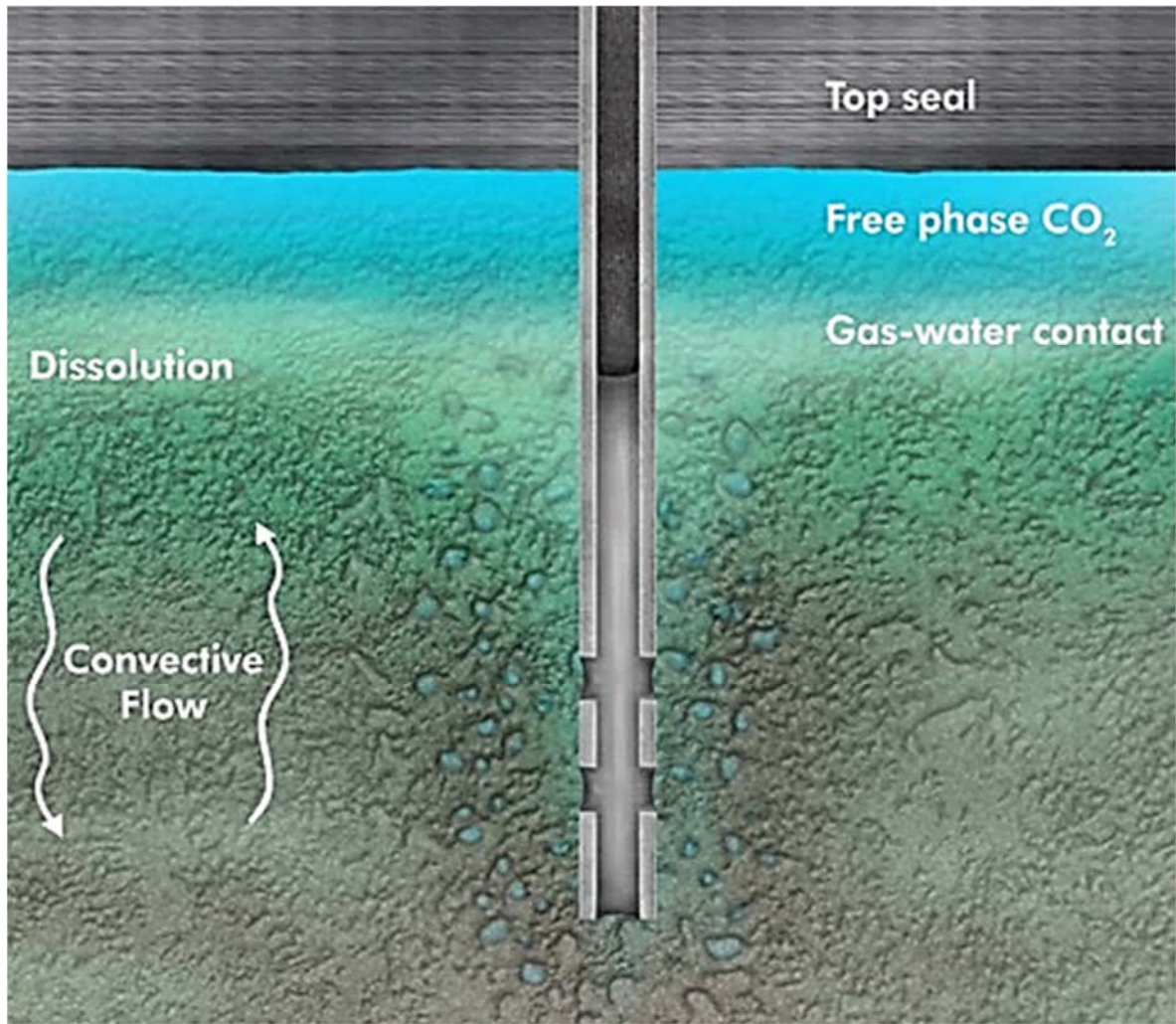


Figure 5: Post-injection dispersion of CO₂ in the reservoir [169].

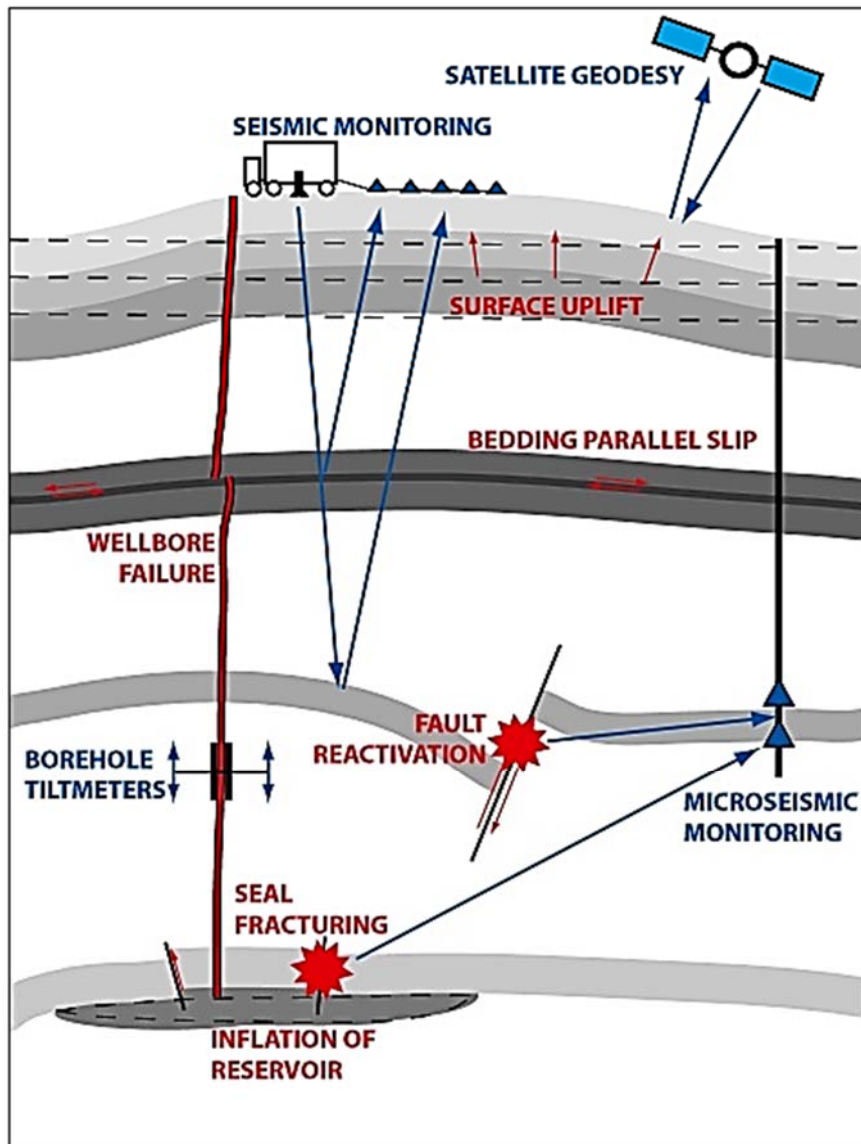


Figure 6: Schematic description of geomechanical deformation in CO₂ storage sites (in red text) with potential monitoring options (blue text), (reprinted with permission from Verdon et al. [176], Copyright 2017 Proceedings of the National Academy of Sciences).

4.1 CO₂ Natural Analogue

CO₂ analogue cases can be used to advance our understanding of the behaviour of CO₂ in reservoirs, and to further improve reservoir management strategies [165,170,171]. Much research has been conducted on different aspects of CO₂ analogues by means of CO₂ storage, including natural accumulations [172], gas migration along fault systems [173], CO₂ leakage [170], seal efficiency [165,174], and storage security in natural reservoirs [175]. In many natural analogues, where the CO₂ is ultimately generated from volcanic and mafic processes, and sometimes from the mantle [165,174], some seals have been capable of securely trapping CO₂ for up to several million years in sedimentary formations. Whilst the mode of formation of these CO₂ analogues may differ from that in a CO₂ storage project, many of their features are analogous to man-made storage schemes, which implies the feasibility of long-term CO₂ storage [171].

Pearce et al. [172] reported that natural CO₂ accumulations occur in many basins across Europe, suggesting that it is possible to identify the potential CO₂ leaks and to predict the long-term geomechanical and geochemical behaviour of a storage site, **Figure 6**. They found that although volcanic activity and seismically active areas allow CO₂-rich fluids to migrate to the surface, stratigraphic traps allow accumulation of CO₂ below limestone, evaporites, and mudstone caprocks. In areas where reactivation of fractures allows migration of CO₂-rich fluids, some degree of limited self-healing may occur through calcite precipitation. In addition, a comparative study between reservoir sandstone and equivalent formations nearby indicated that feldspar dissolution in reservoir sandstones can potentially increase the secondary porosity [172]. Annunziatellis et al. [173] studied gas migration along fault systems and through the vadose zone in the Latera caldera of central Italy, by integrating near-surface gas geochemistry

and structural geology surveys, to understand the migration behaviour of CO₂. Their results revealed the pattern of gas migration along high-permeability pathways within faults with discharge occurring typically from spatially restricted gas vents. However, the distribution, size and strength of vents seemed to be controlled by both the evolution and deformation style of the fault, which in turn is associated with rheology of lithological units cut by fault. It implies that the gas migration may be changed drastically along a strike.

Jeandel et al. [177] reported the lessons learned from natural and industrial analogues for storage of CO₂. Initially, they sampled gases from natural analogues in the Colorado Plateau and the French carbo-gaseous provinces from both leaking and well-confined sites. Furthermore, they performed a tracing study for two years on subsurface natural gas storage. It was pointed out that since in natural analogues, geochemical fingerprints depend on geological context and containment criteria, these analogues are sufficient tools for the detection of deeply-seated CO₂ toward the surface.

Quattrocchi et al. [170] conducted research on strategic CO₂ natural analogues from slightly anomalous leakage of CO₂, CH₄ and radon along the main activated faults of the strong L'Aquila earthquake (magnitude 6.3, Italy), using soil gas survey and groundwater sampling approaches. Their study also highlighted the implications for risk assessment monitoring tools and public acceptance of CO₂ and CH₄ underground storage. It was revealed that the geochemical measurements from soils can be successfully used for discrimination of activated seismogenic segments. In addition, it was highlighted that the geochemical anomalies are not deleterious to human health. Therefore, there is no associated concern with the CO₂-CH₄ explosion during the recurrence of strong earthquakes (such as L'Aquila), where gases are stored naturally in the subsurface at a depth of 1-2 km. A comprehensive natural CO₂ reservoir dataset, consisting of 76 CO₂ natural analogues around the world, was developed by Miocic et

al. [175]. Their analysis highlighted that the key controlling factors for successful retention of CO₂ are thick and multiple caprock, dense CO₂ phase, and a minimum reservoir depth of 1200 m. In addition, although the faults can securely isolate CO₂, it is important to fully characterise the sealing ability of faults during the storage site assessment.

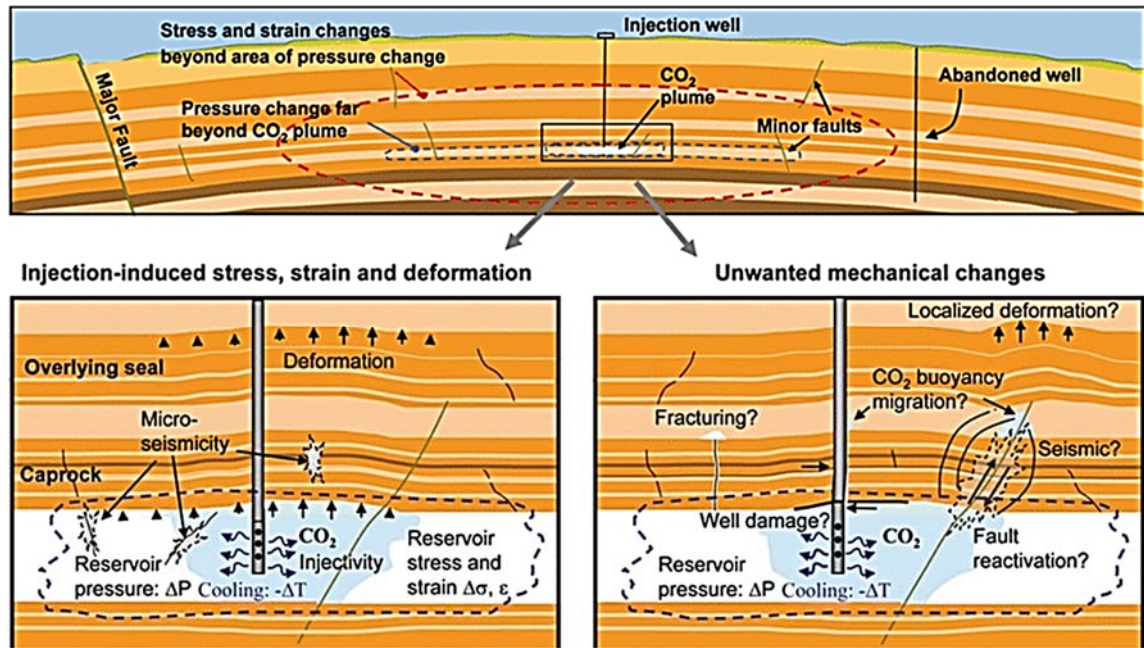


Figure 7: Some geomechanical processes and key technical issues with geological carbon storage in sedimentary formations (reprinted with permission from Rutqvist [178], Copyright 2017, Springer).

4.2 Induced Seismicity

Extensive injection experience in oil and gas operations has demonstrated that CO₂ injection procedures must be carefully monitored, otherwise undesirable side effects can be caused.

These include both short-term (such as induced seismicity) and long-term geomechanical effects (**Figure 7**), that in turn may affect the caprock integrity (as the seal) and, consequently efficiency of storage [179,180]. The CO₂ injection can potentially affect subsurface stress and lead to changes in in-situ fluid pressure and induced seismicity [181]. Fluid pressures are known to play a key role in seismicity, as pore pressures act against tectonic and gravitational forces. Thus, excessive increase in fluid pressures may cause rock failure, and consequently induced seismicity [182]. Induced seismicity is also associated with hydraulic fracturing when a rock is fractured purposely by injection of water at high pressures to increase permeability of reservoirs such as in enhanced geothermal activities or shale gas production, and the disposal of oilfield waste fluids.

Nevertheless, there may be some similarities in seismicity induced by CO₂ and by water [183–186]. It is reported that there were similar rates and magnitudes of induced seismicity between the two fluids; however, there is a difference when fluid is injected into low or high pressure. Verdon et al. [185] suggested that since the viscosity and bulk modulus of CO₂ are lower than water, induced seismicity is less likely to occur. Although from a geomechanical outlook, the key factor that leads to fault reactivation is change in the stress acting on the fault, which is influenced mainly by pore pressure changes caused by injection. Thus, it confirms that the increase in pore pressure across a reservoir is predominantly determined by pore volume occupied by the injected fluid.

The potential risk of induced seismicity caused by CO₂ injection has been outlined above. Accordingly, the following mitigation strategies can be considered [187]: (i) selection of sites with high porosity and permeability, (ii) estimating stress state of potential sites, (iii) selecting sites which are associated with no evidence of faulting, and (iv) selection of sites in regions with low rates of natural seismic activity.

4.3 Leakage Pathways

In an ideal storage site, CO₂ will be permanently confined to its host formation. However, in the unlikely event of migration and leakage, there are various potential modes in which CO₂ can escape from the storage formation. Leakage pathways for CO₂ can correspond to well leakage, diffusive loss, induced migration by capillary pressure, and escape through faults and fracture networks. However, it should be mentioned that there has been no report that proves noticeable leakage of CO₂ from any known storage sites.

4.3.1 Well Leakage and Abandoned Orphaned Wells

Leakage of buoyant CO₂ up the wells is possible when the integrity of the well plug or caprock-cement seal is compromised [29,188,189]. Therefore, the presence of high-quality well sealing (and eventual plugging) is a pre-requisite for both hydrocarbon exploration and production, and for CO₂ storage [190]. The American Petroleum Institute (API) standardised a procedure and cement composition for well plugging in 1952. Accordingly, the wells in the United States are classified in three categories: wells not plugged with cement, wells plugged before 1952, and wells plugged after 1952 [191]. The wells plugged after 1952 are associated with the least potential leakage due to modern technology and strict regulation. However, the possibility of cement degradation should be considered. Slightly acidic CO₂-rich brine can react with alkaline borehole cement, breaking down cement minerals, and forming carbonate minerals and silica. These reactions may be sufficient to block porosity, especially if the volume of secondary solids exceeds that of the original phases. However, if fluid flow were maintained (e.g., through a larger flow feature in a poorly-completed well), there is the possibility for dissolution of the carbonated cement. Factors such as extensive rains, temperature, cement type, rock composition, presence of aggressive impurities such as H₂S and brine concentration control the

degree of reaction, and hence degree of degradation [190,191], and consequently alter the lifespan of the cements. This issue can be escalated especially for old abandoned wells.

Connell et al. [192] studied the integrity of wellbore cement in CO₂ storage using core flooding experiments and simulations. Their experimental results showed that the degradation of cement occurs in two stages: the first stage is the precipitation of carbonates from various cement phases, and the second stage is erosion of cement as the calcium carbonate dissolves in formation water. It was revealed that considerable erosion can occur only when the water flow (which is under-saturated in carbonate and calcium ions) across cement dissipates the dissolved calcium carbonate. Thus, even if the bottom of a cement seal reacts initially, the reaction may soon stop if the borehole is well-sealed. On the other hand, if the seal is poor, the continuous fluid flow allows progressive reactions to increase the initial permeability. Thus, assuring the quality of the initial seal is crucial to long-term well-sealing performance. However, this is not usually the case for older infrastructure. Moreover, in some countries, there has been extensive experience in plugging CO₂-leaking wells, even though it is still important to evaluate and monitor wells depending on case-specific instances [193].

Upon completion of injection and well closure, most abandoned wells are plugged such that CO₂ escape is unlikely. However, abandoned wells are associated with high permeability, and there is a potential risk if the monitoring strategy is not properly deployed. The potential risk is more likely associated with abandoned orphaned wells that are no longer under jurisdiction of the operating company, and the liability is left to the state. In such events and processes, the current regulatory measures may not be adequately sufficient, which may impose a potential risk for security of storage [191,194]. Thus, adopting appropriate regulatory measures for abandoned orphaned wells is necessary and should be considered accordingly.

4.3.2 Diffusion

A gradient in CO₂ concentration can cause the CO₂ to migrate through and into the water-saturated pore spaces of rocks by molecular transport [25]. For an intact caprock, the CO₂ transport is limited to a very slow molecular diffusion. Therefore, a very small amount of CO₂ can enter the caprock, which in turn limits the reaction rate of mineralisation in the reservoir, and may potentially alter the porosity and permeability due to induced degradation. On the other hand, for the permeable host rock, the advection of flow is more dominant (at the presence of pressure gradient), meaning larger amounts of CO₂ can pass through, and consequently the impact of long-term reaction and mineral trapping is significant [195,196].

Wang and Peng [197] developed a numerical model to simulate the CO₂-brine interaction in the fracture network, and evaluated the caprock sealing efficiency based on deformation, gas diffusion, advection and sorption of CO₂. It was revealed that the diffusion process results in initial swelling and later shrinking of the shale matrix through sorption of CO₂ and alters the porosity/permeability of the fracture network. However, in their model geochemical reaction kinetics were not implemented, and should be considered to further improve the accuracy of the simulations. It should be highlighted that although diffusion is an important factor when the potential leakage in CO₂ storage systems is considered, the advection flow induced by temperature and pressure build-up during CO₂ injection can be a source of concern [198], especially for storage systems within fractured fields [170].

4.3.3 Capillary Leakage

Capillary leakage is another factor by which CO₂ can affect the sealing efficiency of caprock. Capillary leakage occurs when the pressure of accumulated CO₂ within brine-saturated caprock exceeds the capillary entry pressure, P_{c,CO_2} (pressure required for a fluid to enter the caprock

pores) [199]. Therefore, capillary entry pressure is the maximum permitted overpressure, and should be considered as a measure for sealing efficiency of the caprock. Capillary entry pressure is a function of brine/CO₂ interfacial tension, γ_{w,CO_2} , wettability of caprock (associated with contact angle, θ , of brine/CO₂/mineral system), and pore size, R_{pore} , within caprock, Eq. (3). Thus, any change in these parameters can alter the capillary pressure and may consequently affect the sealing efficiency.

$$P_{c,CO_2} = \frac{2\gamma_{w,CO_2} \cos \theta}{R_{pore}} \quad (3)$$

Caprocks undergo a change of wettability when exposed to CO₂ [200–202]. Li et al. [43], Li et al. [203] and Hildenbrand et al. [204] described the relationship between sealing capacity of caprock and interfacial tension, and reported that the interfacial tension between CO₂ and water is lower than that between oil and water and also much lower than that between methane and water. It implies that sealing efficiency of any given caprock should be lower with regard to CO₂ than the hydrocarbons.

4.3.4 Faults and Fracture Networks

Pre-existing fractures and faults can serve as either fast fluid conduits (that allow flow) or flow barriers [25], and need to be regarded as a potential source of leakage. Seismogenic sources can be used as reference for evaluating the fractures and faults in seismogenic country rocks [57]. It is reported that although the potential for seismic activity is higher in locations with pre-existing faults, the stress rate of rocks can be influenced by confining pressure around the rock, or pore pressure [205]. Excessive injection rate during the injection operation can cause a local pore pressure build-up. Consequently, pre-existing fractures can be reactivated and may cause the formation of small new cracks. In addition, reactions within the caprock and reservoir

system, such as mineral dissolution, may impact the sealing capacity of pre-existing faults and fractures. For example, the reactions can cause the dissolution of fracture-filling carbonate minerals, which in turn can potentially widen CO₂ flow paths, and increase the permeability. Therefore, downhole pressures and CO₂ injection rates should be carefully monitored during, and shortly after, active injection operations. It is also important to measure soil gas and CO₂ flux above and near CO₂ storage sites such as in the case of the Weyburn project [206].

It is worth noting that the anisotropic nature of fault rock permeability may cause a discrepancy in CO₂ migration in different orientations. In a study by Farrell et al. [207] the anisotropic permeability values were measured parallel to fault dips and were found to be up to 10 times greater than the permeability along fault strike. Therefore, it is important to take anisotropic permeability into consideration when CO₂ migration and leakage within faults and fracture networks are determined. In addition, the mechanism of permeability anisotropy by grain-scale deformation within the faulting is not well-quantified and needs to be highlighted.

4.4 CO₂-Brine-Rock Interaction

Once CO₂ dissolves in formation water, it forms a weak acidic solution and this initiates a cascade of geochemical reactions that may ultimately trap the CO₂ as solid carbonate minerals. Initially, CO₂ is trapped as dissolved species (such as CO₂(aq) and HCO₃⁻ ions). Dissolution of silicate minerals rich in Ca or Mg can release these elements into solution and, if the pH is high enough, can lead to the precipitation of secondary carbonate phases, trapping the CO₂ in secondary minerals. The involved reaction processes have many similarities to weathering reactions (though at different pressures and temperatures).

The extent of CO₂-water-rock reactions and proportion of free-phase CO₂ versus dissolved CO₂ versus mineralised CO₂ depend on the amounts of reactive minerals in the storage formation

and their rates of reaction, and will thus vary from site to site. However, also crucial is the extent to which CO₂ can mix with water and rock. In terms of injection operations, this could be enhanced by varying well injection to sweep the CO₂ plume through a large rock volume as much as possible. In terms of natural processes, the descent of plumes of CO₂-rich pore water (denser than CO₂-free pore water) would be aided by high vertical permeability and the absence of laterally-extensive permeability barriers.

CO₂-brine-rock interaction enables both mineral dissolution and generation of secondary minerals. In terms of rates of dissolution/corrosion, carbonate minerals dissolve/corrode faster than feldspar, with quartz being more resistant [208]. Since CO₂-brine-rock interaction affects the pore structure, it is possible that after interaction, permeability of the rock as well as displacement pressure could either increase or decrease, and this will have a consequent impact on CO₂ migration rates.

The dawsonite formation during storage and its potential role in trapping CO₂ in reservoirs has been controversial for more than a decade [209]. While natural occurrences in previously CO₂-charged reservoirs showed a lack of dawsonite, numerical studies revealed the possibility of large-scale storage in these reservoirs. In addition, Hellevang et al. [210] reported that based on thermodynamic calculations, dawsonite can be potentially formed at high CO₂ pressure during the injection, while it is not stable once the pressure decreases upon completion of injection. Although exact conditions for formation of dawsonite (CO₂ pressure, temperature, alkalinity, ionic strength) are highly uncertain, experience from natural occurrences, such as in the sequences of the Songliao and Hailaer basins in China, showed that dawsonite can be formed under CO₂ storage conditions. Despite the available aforementioned evidence on formation of dawsonite during CO₂ storage, its formation mechanism, including nucleation (retention time) and growth rate under storage reservoir conditions are not clearly known, and

should be addressed in future studies. On the other hand, the presence of SO₂ or H₂S as impurities in the CO₂ stream may also liberate and reduce iron from mineral grain coatings [211]. The presence of Fe²⁺ in solution can lead to iron-rich carbonate precipitation and enhance CO₂ mineral trapping. However, the presence of such impurities in the CO₂ stream can raise environmental concerns, and may not be acceptable for CO₂ transport processes [212].

Several studies have investigated CO₂-brine-rock interactions in the context of CO₂ storage, by focusing on flood characteristics and fluid-rock interactions of different formations, including South West Hub of Western Australia [213], Lower Tuscaloosa formation (United States) [214], the Zaosie anticline reservoir, central Poland [220]; [215], and the Weyburn site (Canada) [216]. Saeedi et al. [213] investigated sandstone samples for in-situ multiphase flow characteristics using laboratory measurements. The samples were obtained from the Triassic Lesueur Sandstone (Wonnerup Member) in the South West Hub of Western Australia which is currently being considered for CO₂ storage. The results showed that samples possess favourable characteristics in terms of residual capillary trapping. Although absolute gas permeability of the post-CO₂-flood samples is between 25-60%, this degree of permeability alteration did not significantly affect the petrophysical properties of rock. They proposed that the reduction in permeability can be attributed to formation damage by fines which originated from kaolinite particles occurring within the pore space of rock samples. Soong et al. [214] explored geochemical interactions in a static system for CO₂-brine-rock similar to saline aquifers with samples from the Lower Tuscaloosa formation, Jackson County, Mississippi, United States. After continuous exposure to CO₂ for six months, various analytical techniques were utilised to ascertain permeability values for the sandstone core samples before and after the exposure. Results show that the sandstone permeability decreased due to CO₂ exposure, suggesting that it can have implications for long-term reservoir behaviour. Tarkowski et al.

[215] also performed petrophysical analysis through CO₂-brine-rock interaction experiments using samples from the potential Zaosie anticline reservoir in central Poland. The objective of their study was to determine any induced changes in reservoir rock properties and sealing rocks. In-situ conditions were used to test the samples, and to characterise them by means of specific surface area, porosity, pore size and distribution. It was revealed that both rock matrix and cements were partially dissolved; however, reservoir rock properties did not change significantly, and it had a negligible effect on CO₂ storage.

Cantucci [216] performed geochemical modelling of water-rock interaction to evaluate effects of short- and medium-term disposal of CO₂ in deep geological formations, based on the Weyburn (Canada) site case. Results show that after 100 years of injection, CO₂ can be neutralised by solubility (as CO₂(aq)) and mineral trapping through precipitation of dawsonite. Liu et al. [26] also tested CO₂-brine-caprock interaction to assess the long-term security of stored CO₂ in deep geological reservoirs in the Eau Claire formation (United States). They carried out batch experiments of the caprock in brine at 200 °C and 300 bar to test the extent of fluid-rock reactions. The results showed minor dissolution of anhydrite and K-feldspar, and precipitation (pore-filling and pore-bridging) of clay minerals (smectite and/or illite) and siderite in the vicinity of pyrite.

The CO₂-brine-rock interaction in deep coal seams was numerically and experimentally studied by Wang et al. [217]. Their leachate chemistry analysis showed significant mobilisation of major elements because of dissolution of silicate and carbonate minerals in the coal measure strata. For lithic sandstone (after reaction with CO₂-brine and CO₂-free brine), the amounts of quartz, plagioclase, chlorite and illite increased considerably, whereas the amounts of biotite, kaolinite, illite/smectite decreased. However, calcareous mudstone (reacted with CO₂-brine and CO₂-free brine) showed major alteration of minerals after 12 days of treatment. In addition,

it was revealed that CO₂ was permanently trapped as dolomite and siderite. Although their geochemical simulation can indicate the dissolution and precipitation of mineral to some extent, the results did not agree well with experiments. It was suggested that a better prediction can be achieved by further implementing and improving the effect of fluid flow, geochemical reactions and geomechanics in the model.

4.5 CO₂ Storage Capacity Estimation

Estimation of the CO₂ storage capacity in potential geological formations is one of the main prerequisites that assures effective and safe implementation of CCS. Several authors have either outlined or deployed various methods for the estimation of storage capacity [16,57–59,62,218–224]. The strategies for estimation of capture capacity can be classified into static and dynamic approaches. The static methods use volumetric and compressibility-based algorithms. On the other hand, the dynamic methods are based on transient numerical or analytical models and are used for prediction of injected CO₂ behaviour within the formation over a desired time period [219,224] and can be used to predict and assess injectivity, wellbore pressure, and tracking of CO₂ saturation within the formations during and after the injection period [225–227].

Quantification of CO₂ storage capacity is mainly correlated with the type of geological formations and their associated trapping mechanisms that act over different timeframes, as well as the boundary conditions (open versus closed) [5,219,220,224]. In this section, the available methodologies for estimation of theoretical, G_t , and effective, G_e , storage capacities for different geological formations will be outlined. It should be noted that theoretical capacity provides a maximum upper limit to the storage estimation, while effective capacity (as a subset

of theoretical capacity) presents a more realistic measure by taking into account a range of technical cut-off limits [62].

4.5.1 Estimation of CO₂ Storage Capacity in Saline Aquifers

Estimation of storage capacity in saline aquifers is very complex due to the different physical and chemical trapping mechanisms, including structural and stratigraphic, solubility, residual, and mineral trapping that simultaneously occur at different rates and timescales [220]. However, to the best of our knowledge, the mineral trapping mechanism has not been taken into account by any storage capacity estimation approach, due to complexity of the process and poorly understood timeframes [219].

4.5.1.1 The CSLF method

The Carbon Sequestration Leadership Forum (CSLF) [228] provided individual models for estimation of the storage capacity of saline aquifers based on different trapping mechanisms, namely, structural and stratigraphic, solubility, and residual trappings. The CSLF method for structural and stratigraphic trap is a volumetric approach that assumes complete displacement of native formation water down to the spill point [224], and is calculated using Eq. (4):

$$G_e = G_t C_c = A H \varphi \rho_{CO_2} (1 - S_{wirr}) C_c \quad (4)$$

where A , H , φ , ρ_{CO_2} , S_{wirr} are trap area, average thickness, porosity, CO₂ density, and irreducible water saturation, respectively. C_c in Eq. (4) is a capacity coefficient associated with cumulative effects of trap heterogeneity, CO₂ buoyancy, and sweep efficiency. The term $(1 - S_{wirr}) C_c$ is equivalent to storage efficiency factor (E) and is provided by Cantucci et al. [224].

The CSLF method for solubility trapping is a time-dependent (dynamic) approach and needs to be accompanied by numerical simulations at the local- and site-scale for a given period of time [62] and can be calculated by Eq. (5) [228]:

$$G_e = G_t C = A H \varphi (\rho_{w_s} X_s^{CO_2} - \rho_{w_0} X_0^{CO_2}) C \quad (5)$$

where X^{CO_2} and ρ_w are the CO₂ content (mass fraction) in formation water and density of formation water, respectively, and the subscript 0 and s denote the initial and saturation (at the specified time) state. C is a coefficient that accounts for all factors that affect the spread and dissolution of CO₂ in the entire volume of the aquifer.

The CSLF method for residual trapping is a time-dependent approach and needs to be coupled with numerical simulations. The method is based on irreducible CO₂ saturation in the pore space after completion of the injection step, and is calculated using Eq. (6) [224,228]:

$$G_t = \Delta V_{trap} \rho_{CO_2} \varphi S_{CO_2,t} \quad (6)$$

where ΔV_{trap} and $S_{CO_2,t}$ are the volume of trap CO₂ and trap CO₂ saturation and can only be specified using numerical simulation at the local- and site-scale and for a given time [228].

4.5.1.2 The US-DOE method

The US-DOE (United States Department of Energy) method [219] is a volumetric and compressibility-based approach. It only includes the physical trapping mechanism, namely, structural and stratigraphic trapping, for estimation of effective storage capacity of saline aquifers, and is given by Eq. (7):

$$G_e = A H \rho_{CO_2} \varphi E_{saline} \quad (7)$$

where E_{saline} is storage efficiency factor that indicates the fraction of pore volume that will be eventually occupied by injected CO₂. The calculated values of E_{saline} for different cases are provided by Bachu [16,219].

4.5.1.3 The pressure-limit method

The pressure-limit approach estimates the effective storage capacity of saline aquifers based on the maximum possible amount of CO₂ that can be injected before reaching a maximum allowed pressure [224]. Zhou et al. [218] proposed a quick assessment method for estimation of saline storage capacity of closed and semi-closed boundary systems at early stages of site selection. This method assumes that the displaced native brine, by cumulative injected CO₂, occupies additional pore volume within the formation which in turn results in pore and brine compressibility and correspondingly transient (dynamic) pressure build-up, $\Delta p(t)$, that can be readily estimated [218], Eq. (8):

$$G_e(t) = A H \rho_{CO_2} \varphi \Delta p(t) (\beta_p + \beta_w) \quad (8)$$

where t is time, and β_p and β_w are pore and native brine compressibility, respectively.

Szulczewski et al. [229] developed a time-dependent estimated approach for both open and closed boundary systems, by taking into account CO₂ displacement to brine, residual and solubility trapping, Eq. (9):

$$G_e(t) = H W \rho_{CO_2} \sqrt{\frac{k Z T}{\mu_w} \frac{P_f - (P_0 - \rho_w g D)}{4 \tilde{P}_{max}}} \quad (9)$$

where k , Z , T , g , and μ_w are permeability, compressibility factor, temperature, gravitational acceleration, and brine viscosity, respectively, W and D are width of the well array and depth

to aquifer, P_f , P_0 , and \tilde{P}_{max} are fracture, initial, and maximum non-dimensional pressures, respectively. \tilde{P}_{max} is determined based on a numerical second-order finite-volume method.

4.5.1.4 The USGS method

United States Geological Survey (USGS) [230,231] developed an estimation method by considering both residual trapping in the open part of the aquifer and buoyant trapping, Eq. (10):

$$G_e = \rho_{CO_2} V_b E_b + \sum_{i=1}^3 [\rho_{CO_2} (A H \varphi - V_b) R_w R_{i,se} E_{i,r}] \quad (10)$$

where V_b is the buoyant trapping pore volume, R_w is the fraction of available area for storage, E_b and $E_{i,r}$ are buoyant and residual trapping storage efficiency, respectively, and $R_{i,se}$ is residual trapping storage-resources based on residual trapping injectivity classes ($i = 1-3$).

4.5.2 Estimation of CO₂ Storage Capacity in Depleted Oil and Gas Reservoirs

The estimation of storage capacity in oil and gas reservoirs is the most straightforward and almost the simplest compared to other formations, due to the well-known characteristics of oil and gas reservoirs derived from industry experience [228]. The storage capacity is associated with the reservoir characterisation (such as temperature, effective volume, and pressure), resources (such as original gas in place, OGIP, and original oil in place, OOIP, and recovery factor), and CO₂ properties at the reservoir [224].

4.5.2.1 The CSLF method

CSLF [228] developed two approaches for estimation of theoretical storage capacity. The first method is based on OGIP and OOIP, Eq. (11) and (12), respectively, at surface conditions and

is associated with the available storage volume that was previously occupied by gas and oil and can be replaced by CO₂.

$$G_t = \rho_{CO_2,r} R_f (1 - F_{IG}) OGIP \left[\frac{P_s Z_r T_r}{P_r Z_s T_s} \right] \quad (11)$$

$$G_t = \rho_{CO_2,r} \left[\frac{R_f OOIP}{B_f} - V_{iw} + V_{pw} \right] \quad (12)$$

where R_f is the recovery factor, F_{IG} is fraction of injected gas, $\rho_{CO_2,r}$ is CO₂ density at the reservoir, and subscripts s and r stand for reservoir and surface conditions, respectively. V_{iw} and V_{pw} are the volumes of injected and produced water, respectively, and B_f is the formation volume fraction that brings the volume of oil from standard to in-situ conditions.

The second method is based on the geometry (volume) of the reservoir, and is given by Eq. (13):

$$G_t = \rho_{CO_2,r} [A H \varphi R_f (1 - S_w) - V_{iw} + V_{pw}] \quad (13)$$

where S_w is water saturation.

One of the main assumptions to derive Eq. (11) - (13) is that the evacuated pores during the production of the recoverable hydrocarbons should be filled with the injected CO₂ [232]. However, if the reservoirs are underlain by aquifers, water can invade the pores during the production of hydrocarbons. In this event, the pores occupied with water may not all be available for the injected CO₂, and the storage capacity can decrease. Correspondingly, an effective storage capacity can be calculated using Eq. (14) [228]:

$$G_e = C_e G_t \quad (14)$$

where C_e is a capacity coefficient that accounts for cumulative effects of CO₂ mobility, CO₂ buoyancy on oil and water, reservoir heterogeneity, water saturation, and aquifer strength.

4.5.2.2 The US-DOE method

The US-DOE [219] proposed a volumetric algorithm for the estimation of storage capacity, based on the standard industry approach for calculation of OGIP and OOIP [219,233], given by Eq. (15):

$$G_e = \rho_{CO_2, std} A H \varphi B (1 - S_w) E_{oil/gas} \quad (15)$$

where B is the initial oil or (and) gas formation volume factor, and $E_{oil/gas}$ is storage efficiency factor that indicates the fraction of total pores associated with produced oil and gas, that can be occupied by injected CO₂. $E_{oil/gas}$ can be calculated from local CO₂-EOR experience, or alternatively from reservoir simulation as standard volume of CO₂ per volume of OOIP [219].

4.5.2.3 The Zhao-Liao method

Zhao and Liao [221] proposed a model for estimation of CO₂ storage capacity of highly water-saturated oil fields, by considering two new terms in the CSLF method for CO₂ solubility trapping in oil and water [228], Eq. (16):

$$G_e = \rho_{CO_2, r} A H \varphi S_{CO_2} \quad (16)$$

where S_{CO_2} is the sequestration factor and indicates CO₂ solubility in oil and water, CO₂ sweep efficiency, CO₂ displacement, CO₂ recovery factor of oil and water, and can be specified using the local CO₂-EOR experience, or reservoir simulations (such as the stream tube simulation method).

4.5.2.4 The IEA-GHG method

IEA Greenhouse Gas R&D program (IEA-GHG) provided a model for estimation of storage capacity of gas reservoirs by assuming the reservoir can be refilled with CO₂ until the formation returns to its original reservoir pressure (pre-production pressure), Eq. (17) [102].

$$G_e = \rho_{CO_2,r} UPR_{g,std} B E_{gas} \quad (17)$$

In Eq. (17) $UPR_{g,std}$ is the ultimately recoverable reserves of gas at standard pressure and temperature.

4.5.3 Estimation of CO₂ Storage Capacity in Unmineable Coal Seams

The estimation of storage capacity in unmineable coal seams involves the displacement of coal bed methane (CBM), and assumes that since the coal has a higher affinity towards gaseous CO₂ than CH₄, the CH₄ in coal will be replaced by injected CO₂ [219,224].

4.5.3.1 The CSLF method

In the CSLF method [228], the estimated storage capacity is determined based on the initial gas in place, IGIP and reservoir gas deliverability ($C'R_f$), Eq. (18):

$$G_e = \rho_{CO_2,std} R_f IGIP C' \quad (18)$$

where C' is the completion factor.

4.5.3.2 The US-DOE method

The US-DOE [219] provided a volumetric algorithm for estimation of storage capacity, Eq. (19):

$$G_e = A H \rho_{CO_2, std} C_{CO_2} E_{coal} \quad (19)$$

where C_{CO_2} is the maximum adsorbed volume of CO₂ at standard conditions (Langmuir isotherm volume constant), and E_{coal} is storage capacity factor. E_{coal} is a function of available volume for CO₂ storage and displacement, and indicates the total fraction of bulk coal that accommodates the injected CO₂ [219,224].

4.5.3.3 The ZLH method

The Zhao-Liao-He (ZLH) method [222] was developed from a model for estimation of storage capacity of the coal bed in the presence of water. The model is based on the CO₂ adsorption in the coal bed, CO₂ displacement to formation water, and CO₂ solubility in water, Eq. (20):

$$G_t = 10^{-7} (A H \rho_{coal, b} g_{cs} R_f C_{ER} \rho_{CO_2, std}) + [A H \varphi (1 - S_w)(1 - R_w)C_{CO_2, w}] \quad (20)$$

$$+ [A H \varphi S_w R_w \rho_{CO_2}]$$

where C_{ER} is the replacement coefficient of CH₄ by CO₂ in the coal bed, R_w is the recovery factor of reservoir water, g_{cs} is coal bed gas content, and $C_{CO_2, w}$ is the CO₂ solubility coefficient in water.

4.5.4 Assessment of Estimation Approaches

National Energy Technology Laboratory (NETL) [234] conducted a comprehensive comparative study by applying CSLF [228], US-DOE [219], Zhou et al. [218], Szulczewski et al. [229], and USGS [230] methods on 13 saline formation data sets in the identical conditions. It was reported that the lowest and largest storage capacity estimation methods were presented by Zhou et al. [218] and USGS [230], respectively. Cantucci et al. [224] developed a case study (Italian case study) to assess the estimation approaches by applying CSLF [228], Eq. (4), US-

DOE [219], and Zhou et al. [218] methods on a potential reservoir in Po Plain (Northern Italy). In this study, the effect of residual and solubility trapping was rather small, and not considered in the calculations. The largest and lowest storage capacities were obtained by CSLF and Zhou et al. [218] methods, respectively. Although the difference between storage efficiency factor obtained from CSLF and US-DOE methods was relatively small, there was a considerable discrepancy with the Zhao et al. [218] model. However, as it was pointed out by Goodman et al. [219], the uncertainty in estimation of storage capacity arises from variability and characterisation of aquifers and is much more significant than uncertainty in selection of estimation method. Therefore, estimation and evaluation of specific geologic formation characteristics, rather than utilisation of arbitrary and constant values, is critical and needs to be taken into account. In addition, although the volumetric approaches are helpful for identification of the prospective CO₂ storage in pre-feasibility studies, further numerical modelling is needed to advance the characterisation, and assess the dynamics of CO₂ storage based on operational and regulatory factors.

On the other hand, it was noticed that no methodology has been developed to account for the mineral trapping mechanism for estimation of CO₂ storage capacity. The significance of mineralisation on overall storage capacity in comparison with other trapping mechanisms is not well-understood. Thus, considering the mineralisation trapping may lead to a more accurate determination of long-term storage capacity.

5 Major World CO₂ Storage Projects

This section provides an overview of current and past major large-scale CO₂ projects worldwide, **Table 2**. In most of these projects CO₂ has been stored in saline aquifers or used for EOR. In addition, other CO₂ storage projects worldwide which are in planning, under

construction, or have operated for only a shorter period are provided in the supplementary material, **Table S1**.

The most important factor that assures the success of storage projects depends on the security of containment. Accordingly, it is necessary to continually improve site selection and characterisation, technical operation parameters, monitoring and verification tools and quantitative risk assessments. Addressing these factors holistically will form the basis for appropriate technical regulations and the enactment of positive public perception to enable unhindered deployment of large-scale CO₂ storage operation.

5.1 In Salah Project

The In Salah storage project (**Figure 8**), is located in Algeria, and is jointly operated by a consortium of British Petroleum, Statoil and Sonatrach. This project is a fully operational world-pioneering onshore gas field which receives CO₂ from the In Salah oil field [235]. This formation is a depleted oil and gas reservoir, found at 1800 m [236], 1850 m [237], 1900 m [238,239] in the subsurface (**Figure 9**). The project has been operated since 2004 [236,238]. It is estimated that total capacity of the formation is about 17 Mt of CO₂ [89,237], and a total of 4 Mt has already been injected between 2004 and 2011 [240]. During the injection, almost 4000 t of CO₂ per day [30] was injected into the 20-m-thick methane-producing Carboniferous sandstone Krechba formation via three wells [237,238,241]. The injection cost approximately \$6/t of CO₂, and the total cost of storage was estimated around US\$2.7 billion [242–245].

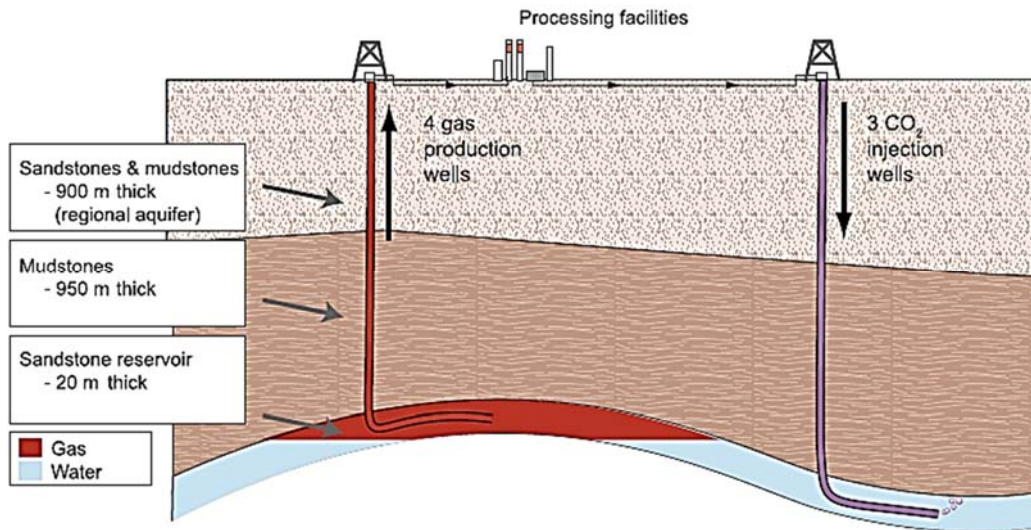


Figure 8: CO₂ storage in the Krechba formation, In Salah Gas Project [5].

The project site has been carefully monitored using satellite InSAR (Interferometric Synthetic Aperture Radar), and time-lapse seismic and micro-seismic data. All collected monitoring data have been used in refining and updating the geological, flow dynamic and geomechanical models of the storage project. The injection was suspended in June 2011 over fears about the integrity of the caprock [236,246]. Although, there was CO₂ migration from reservoir into the overburden, no CO₂ leakage into the atmosphere was envisaged [240]. In addition, Verdon [185] noted that CO₂ injection caused substantial induced seismic activity. Since then, injection strategies for the future have been reviewed, and comprehensive site monitoring strategies outlined through an intensified research and development program. Although the reviewed site monitoring strategies are yet to be fully disclosed in the open literature, the new scheme should include a detailed and improved microseismic monitoring array that provides real-time and intensive geomechanical response surveillance that would allow operators to quickly adjust injection parameters to ensure safe operation of the project [242]. Such monitoring strategies

should equally improve understanding of geological and geomechanical characterisation of reservoir and overburden [235]. Experience from the In Salah project can be relevant in understanding injectivity of CO₂ in other settings around the world where storage is either ongoing or intended in clastic reservoirs with low permeability.

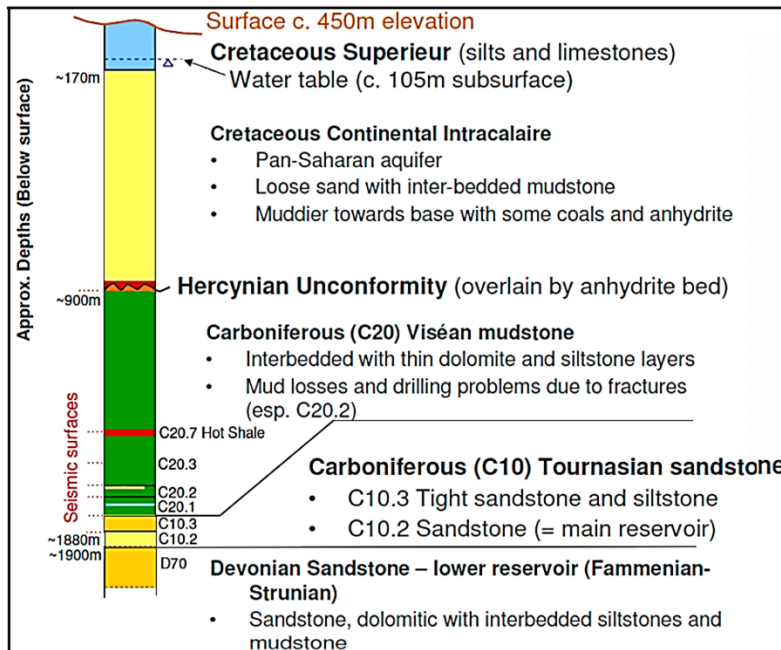


Figure 9: Krechba Stratigraphic Column, In Salah Gas Project (reprinted with permission from Pamukcu et al. [236], Copyright 2017, Elsevier).

5.2 Ketzin Project

The Ketzin storage project is located in Ketzin, Germany, was led by The Helmholtz Centre Potsdam GFZ German Research Centre for Geosciences and Ketzin Partners, started in 2008 and was completed in 2009. The project, which operated for a relatively short period when compared to other projects reviewed here, was sought to store CO₂ in the subsurface so that it could be monitored to provide information relevant for future policy and environmental

regulations. This project was known as the first onshore CO₂ storage project in Europe. A continental Triassic siliciclastic unit called the Stuttgart formation (**Figure 10**), which is characterised by sandstones, was used as the CO₂ reservoir [89,247–251]. The source of CO₂ for the project was a hydrogen production and oxyfuel pilot plant (*Schwarze Pumpe*). The CO₂ was transported by a pipeline and stored in a saline sandstone formation aquifer at approximately 630 m in the subsurface. By the end of the project, a total of 67,271 t of CO₂ was successfully stored in the reservoir. Even though CO₂ was stored at a relatively low depth in the Ketzin project reservoir, experience from monitoring of CO₂ flow behaviour in the subsurface did not suggest detectable leakage throughout the period of injection.

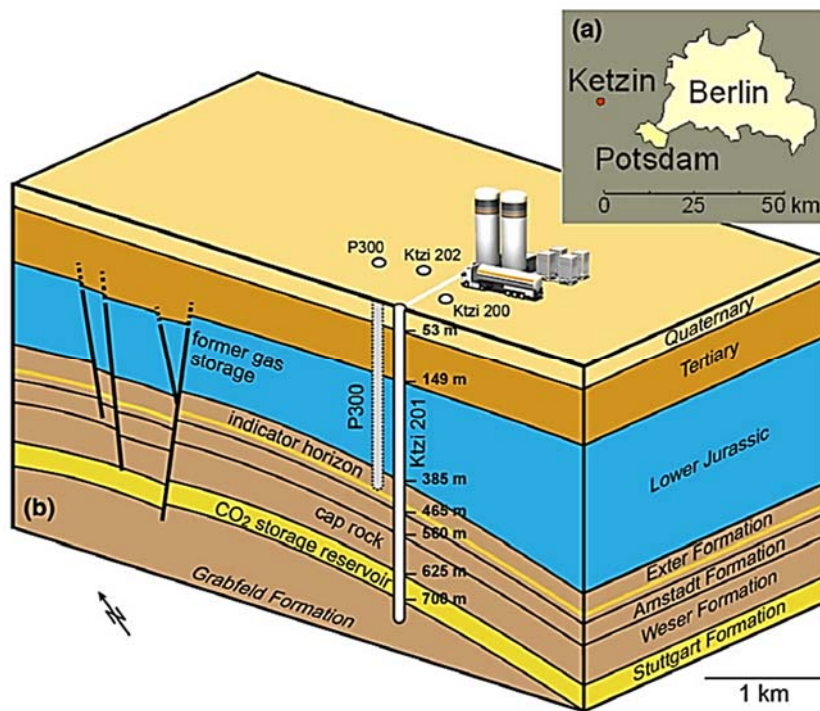


Figure 10: (a) Location of the Ketzin CO₂ project; (b) schematic block diagram of the Ketzin CO₂ target reservoir and other structural features (reprinted with permission from Martens et al. [252], Copyright 2017, Springer).

5.3 Sleipner Project

The Sleipner storage project, located in the mid-central North Sea (**Figure 11**), is operated by Statoil. This project is the first commercial-scale CO₂ injection project in the world [253–255]. The project was conceived by the need to evade Norwegian carbon tax, that would be payable if CO₂ had vented [256,257]. Injection began in 1996 and uses a North Sea Norwegian saline aquifer found between 800-1000 m below the sea floor. The storage formation is of the late Cenozoic age and called the Utsira formation [258–261]. The Utsira formation is a 200 to 250 m thick massive sandstone, with 15.5 Mt of injected CO₂ since the project started until June 2015 [89]. The source of Sleipner's CO₂ is the captured CO₂ through scrubbing from the natural gas processing field located at Sleipner West [256,262,263]. The stored CO₂ is prevented from escaping to the surface by a 200-300 m thick layer of shale called the Nordland shales, which acts as caprock [36,258,264]. Mackenzie et al. [265] reported the occurrence of a 50 m deep confined wedge of sandstone, which is found closer to the lower seal of the Utsira formation, that provides additional capacity for storage in the reservoir.

Although there is no evidence of leakage at the sea bottom, as 3D seismic monitoring has confirmed (**Figure 12**), the CO₂ plume has risen through eight thin shale rock layers within the aquifer and reached the caprock in less than three years since the start of injection and storage. However, the shales are very efficient in enhancing mixing and consequently CO₂ dissolution. These will hopefully address major challenges and improve risk management in the lifecycle of CO₂ storage projects in all stages and elements.

Nevertheless, while it is true that extensive experience on storage has been gained from CO₂ storage projects like Sleipner, given the natural heterogeneity of geologic formations that vary

from place to place, more far-reaching experience is needed to attain maturity in areas such as site selection, CO₂ flood engineering and reservoir management, workflow integration, monitoring and remediation and regulatory development.

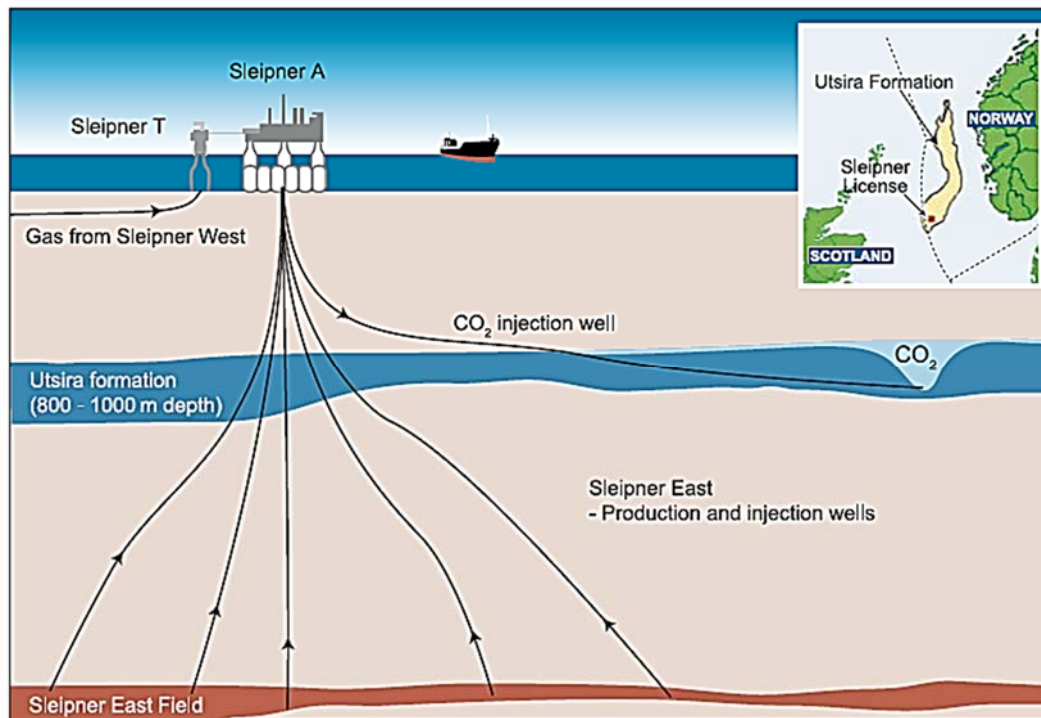
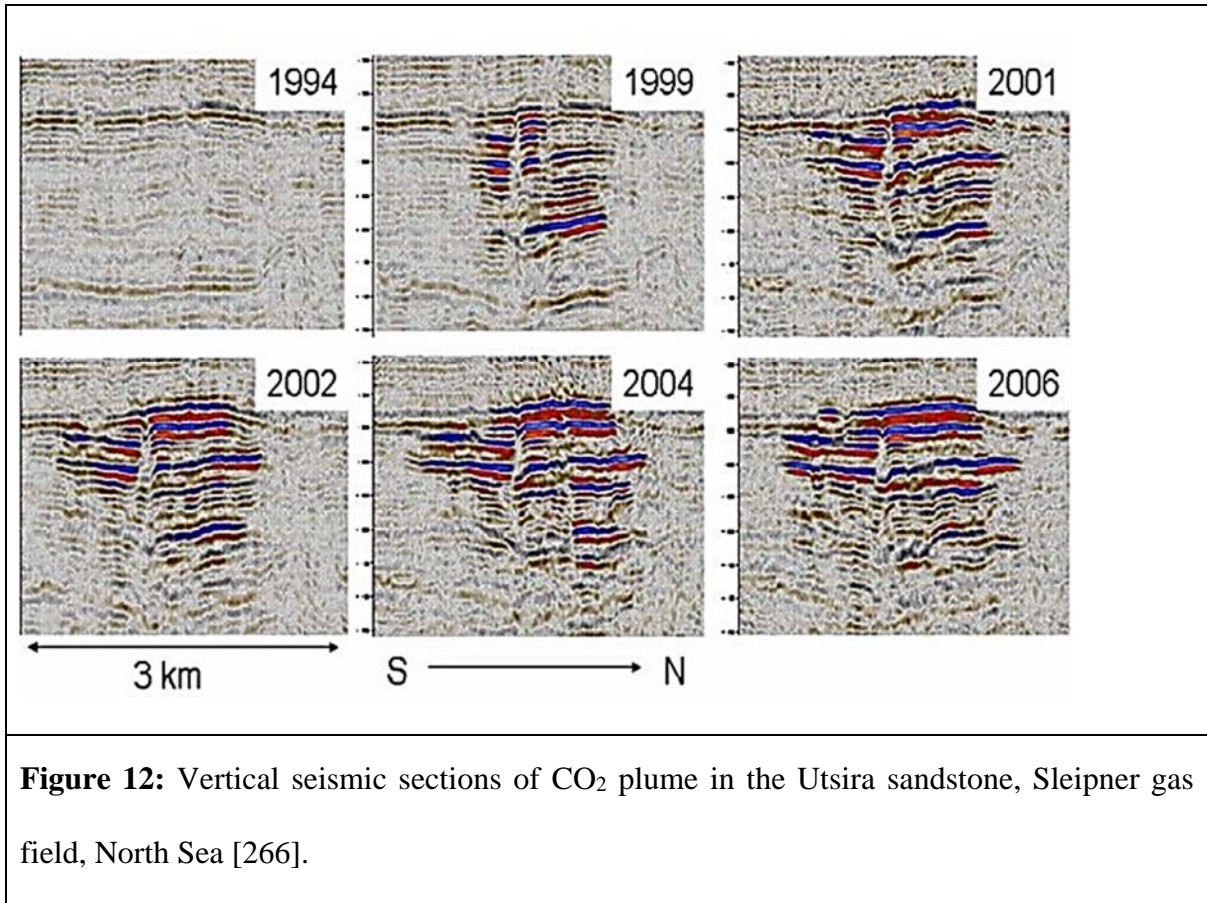


Figure 11: A simplified diagram of the Sleipner CO₂ storage project, with an inset depicting the extent of the Utsira formation [5].



5.4 Weyburn – Midale Project

The Weyburn-Midale storage project, located in south central Saskatchewan (Canada), is operated by Cenovus Energy [267], Apache Canada [268], and collectively managed by Petroleum Technology Research Centre (PTRC) [269,270]. The motivation for the project was to increase oil production (CO₂-EOR) [271] and further research and development in the area [272]. Before the commencement of the Alberta Carbon Trunk Line (ACTL) as the world's largest storage project which was expected to commence injection in 2018 [273], the Weyburn-Midale project, which started in 2000, had been the world's largest storage project [274]. The injection of CO₂ is taking place at rates of about 3000 to 5000 t/d [89] which optimises EOR and increases production [271]. The project is expected to have a lifespan of about 20 to 25

years [30]. It has been estimated that the total amount of CO₂ to be stored in the field by 2025 to 2030 is 20 Mt [36,275]. The operating cost is currently about US\$20/t of CO₂ [89].

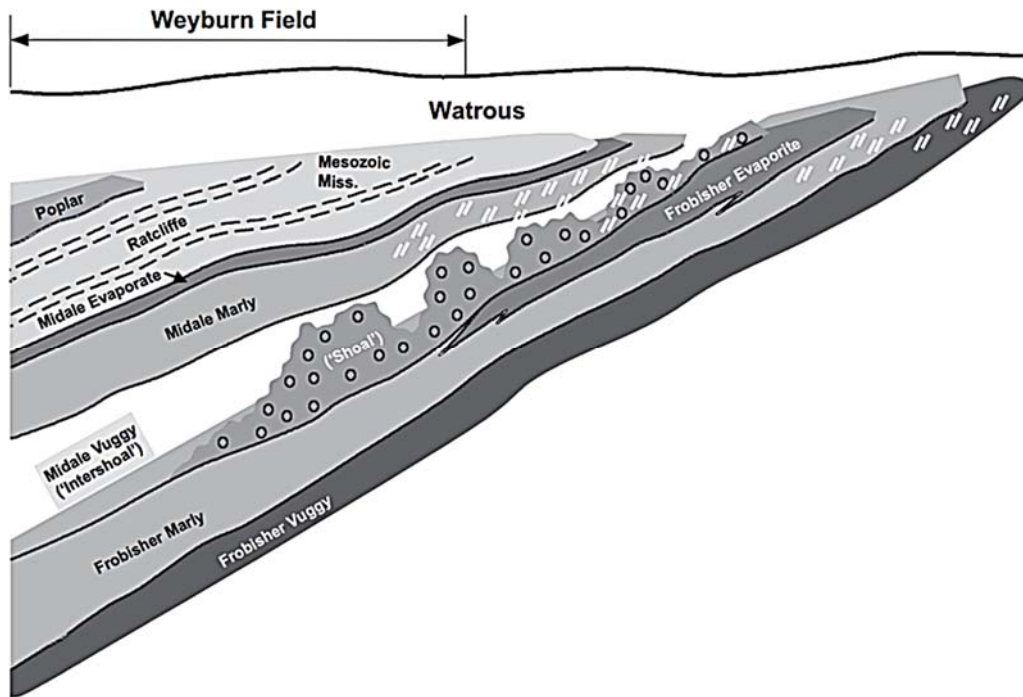


Figure 13: Schematic NE-SW cross section through the Weyburn field with underlying geologic formations (adapted with permission from Riding and Rochelle [276], Copyright 2017, Geological Society of London).

There are two different aquifers in the Midale carbonate reservoir (**Figure 13**) of the Weyburn project field, namely the vuggy and marly beds [30,216,277,278]. The vuggy beds have suitable reservoir properties in the lower regions, while the upper regions are limestone dominated and characterised by a relatively low permeability but high porosity [30]. The marly beds are a dolostone unit, characterised by low permeability and high porosity. Both aquifer formations are sealed by an anhydrite caprock [275], implying that both vuggy and marly beds

can store more fluid or gas than they can transmit. Other information on the geology of the Weyburn area is provided by Wegelin [279] and Rah [280].

In 2011, there was an unsubstantiated claim by a farmer that Weyburn was leaking CO₂ at the surface, from evidence of gas bubbles, dead animals and algal blooms found around a pond in a farm (Kerr farm) near the injection site. This created a controversy in the media but investigations using gas monitoring, CO₂ isotopic analysis and other techniques revealed that there was no leakage of CO₂ from Weyburn [206,281,282].

5.5 Snøhvit Project

The Snøhvit project, located in offshore Norway, is operated by Statoil ASA and partners [283] which comprise Petoro AS, GDF Suez E&P Norge AS, Total E&P Norge AS, Hess Norge, and Norsk Hydro. Like the Sleipner project, the motivation for CO₂ storage in the Snøhvit project is carbon tax exemption from the Norwegian government [256,284]. Snøhvit started in late 2007, and is the first offshore field where oil is produced without the use of offshore installations. The Snøhvit project sources its CO₂ from an LNG processing project. The CO₂ is captured by a scrubbing approach [285], transported via pipeline from onshore to offshore (**Figure 14**), and stored in the saline Tubaen sandstone formation reservoirs at 2600 m deep with a thickness of 45 to 75 m [89]. The total storage capacity of sandstone reservoir formation is estimated around 31 to 40 Mt, and about 0.7 Mt of CO₂ has been safely stored per year.

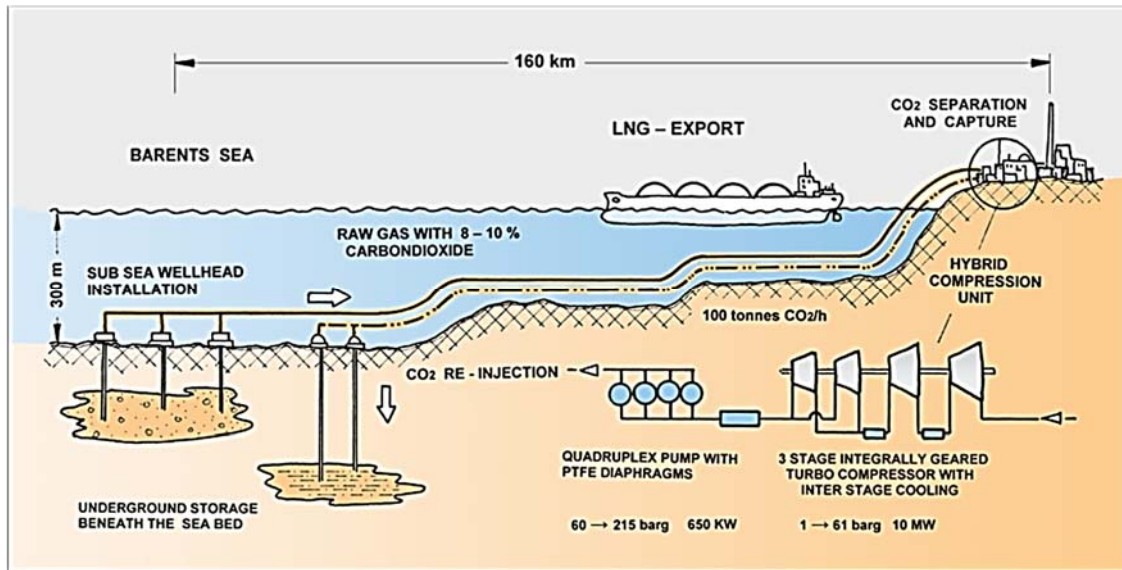


Figure 14: Schematic of the Snøhvit storage project showing fluid transport [286].

However, in early 2010 Statoil reported that the storage capacity is lower than that initially expected for Snøhvit, and the possibility of increasing the capacity by drilling new holes or increasing porosity/permeability of the formation by fracturing techniques has been considered. A program has also been set up to monitor and investigate the behaviour of stored CO₂ within the reservoirs of Snøhvit [89]. It is reported that injection of CO₂ ended in April 2011 but injection continued at normal levels in a fall-back reservoir [235].

5.6 Alberta Carbon Trunk Line Project

The Alberta Carbon Trunk Line (ACTL) project (CO₂-EOR) is in the industrial heartland of Alberta, Canada (**Figure 15**), and is operated by Enhance Energy Inc. It is currently the world's largest CCS project, consisting of a 240-km pipeline and infrastructure capable of collecting, compressing, and storing up to 14.6 Mt of CO₂ per year at maximum operational capacity. The CO₂ for the ACTL project is sourced from the North West Sturgeon Refinery and Agrium

Fertiliser Plant (Alberta, Canada) [274], and the injection was expected to begin in 2018 [273]. The total storage capacity is around 2 Gt of CO₂, and the total cost of the project is estimated at US\$1.2 billion [89].



Figure 15: Alberta Carbon Trunk Line Project location (reprinted with permission from Heal and Kemp [287], Copyright 2017, Elsevier).

5.7 Otway Basin Project

The Otway Basin Pilot Project (OBPP) is located in Australia, and is managed by the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) [288]. OBPP is considered as the largest geosequestration onshore project, and started in 2008 [30,289,290]. The CO₂ for the OBPP is sourced from a natural CO₂-rich gas deposit (Buttress gas well) [290], and injected into a 2000 m deep depleted gas reservoir (Waarre formation) (**Figure 16**) at a rate of 65445 t/a [291].

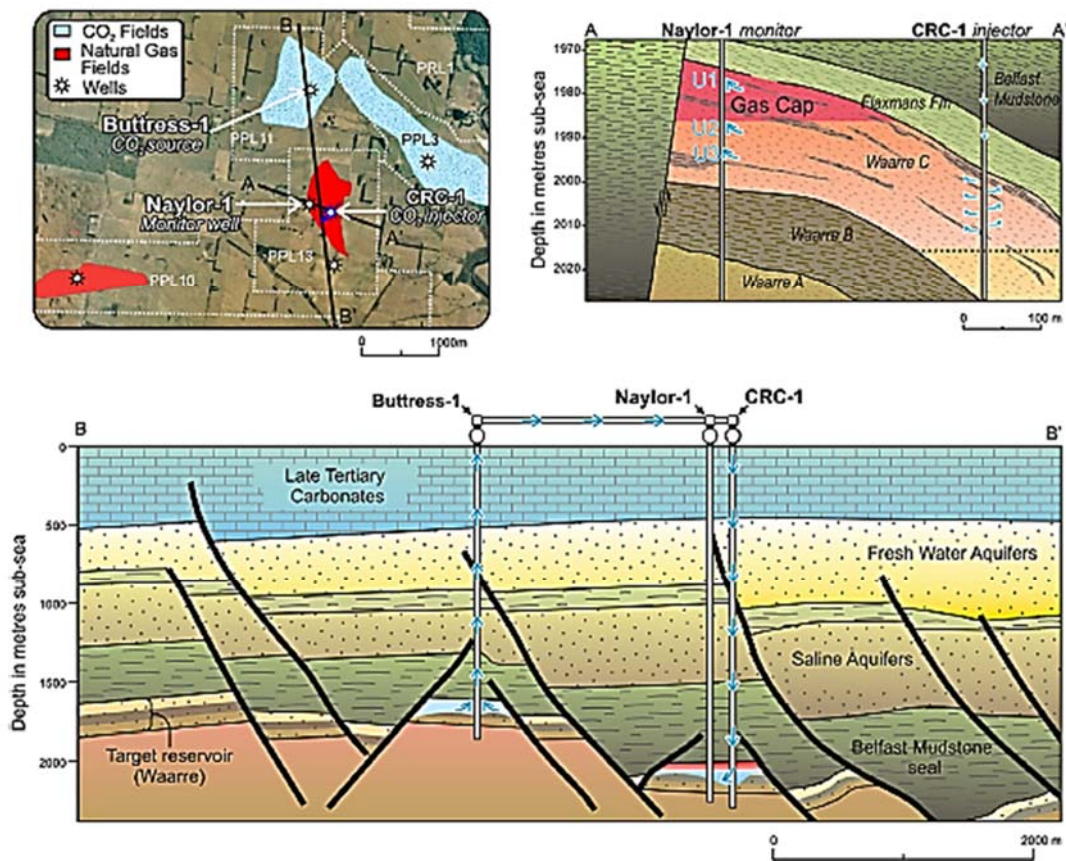


Figure 16: (AA') Cross section of the CO₂ injection well (CRC-1) within the Otway Project. (BB') The Buttress gas well which is the source for the experiment and the CRC-1 injection well (reprinted with permission from Dance [292], Copyright 2017, Elsevier). Note: the dark

coloured lines show faults within the subsurface. Faults (if pervious) are cracks in the earth's crust which could be vents for leakage.

Adverse environmental impacts of the OBPP on soils between 2007-2012 were explored by Schacht and Jenkins [293]. Prior and during storage of CO₂ into the Waarre formation, gas concentrations including CO₂, CH₄, N₂, and O₂ were measured for leakage detection. Fixed gas relationships and isotopic studies showed that CO₂ found in the soil was of biogenic origin, and also there was no deep subsurface source of CO₂. Therefore, the results showed that injected CO₂ has no noticeable impact on the local ecosystem in and around the Otway Project site. Monitoring and investigations are still being carried out within the OBPP, especially to understand geomechanical processes, CO₂ plume migration, caprock integrity and the possibility of fault reactivation [30]. In addition, preliminary probabilistic studies of seismic hazards of the CO₂CRC Otway Project revealed that the potential induced seismicity associated with CO₂ injection and storage is very low [294].

5.8 Boundary Dam Project

The Boundary Dam storage project is located in Estevan (Saskatchewan, Canada), and is managed by SaskPower. This is the world's first commercial-scale post-combustion capture (lignite firing) and storage project, (**Figure 17**), capable of injecting 1 Mt of CO₂ per year, which shows the synergic nature of the CCS value chain. The 90% captured CO₂ is utilised for EOR in the Weyburn field in southern Saskatchewan, which requires only a 66 km pipeline (built by Cenovus Energy), while the remaining CO₂ is used for the Aquistore Project (managed by the PTRC), where CO₂ is stored in a 3.4 km deep brine-sandstone formation.

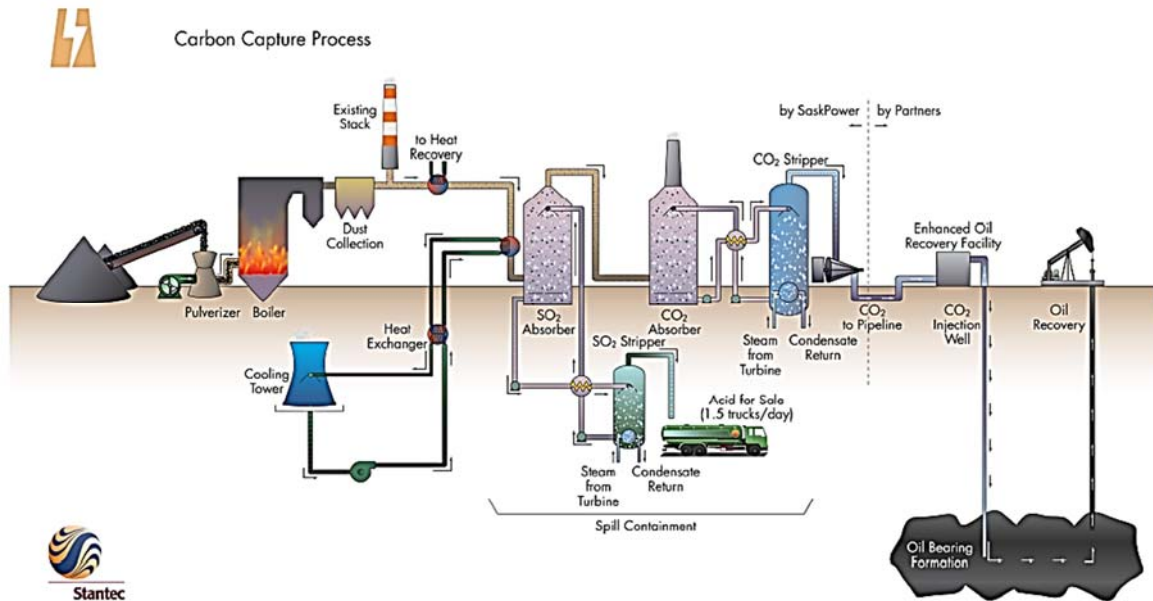


Figure 17: The Boundary Dam Project process illustration [295].

The deepest units within the Williston Basin, the Winnipeg and Deadwood formations, were chosen as the target zone for CO₂ injection. These two geological formations possess greater storage capacity for CO₂ than any oil reservoir in western Canada. The storage complex suitability was investigated using high-resolution 3D seismic images, and data obtained from injection and observation wells. The obtained data show there are no significant faults in the storage site, and no adverse effect by knolls on the surface of the underlying basement formation. In addition, it was revealed that there is a continuous regional sealing formation in the area [270].

5.9 Cranfield Project

The Cranfield storage project is located in the Cranfield oilfield in Natchez (Mississippi, USA), and is operated by the Southeast Regional Carbon Sequestration Partnership (SECARB),

Department of Energy (DOE), National Energy Technology Laboratory (NETL), Southern States Energy Board (SSEB), Texas Bureau of Economic Geology, Denbury Resources, Advanced Resources International (ARI), Electric Power Research Institute (EPRI), and the University of Alabama (began in 2009). In this project, 1.5 Mt per year of CO₂, sourced from the Jackson Dome (Mississippi), was injected into saline Tuscaloosa sandstone formation occurring down-dip of the Cranfield oilfield [89]. The Tuscaloosa formation is a 15 m thick heterogeneous sandstone of fluvial sedimentology at a depth of 3000 m in the subsurface (Figure 18), and is widely spread across the region.

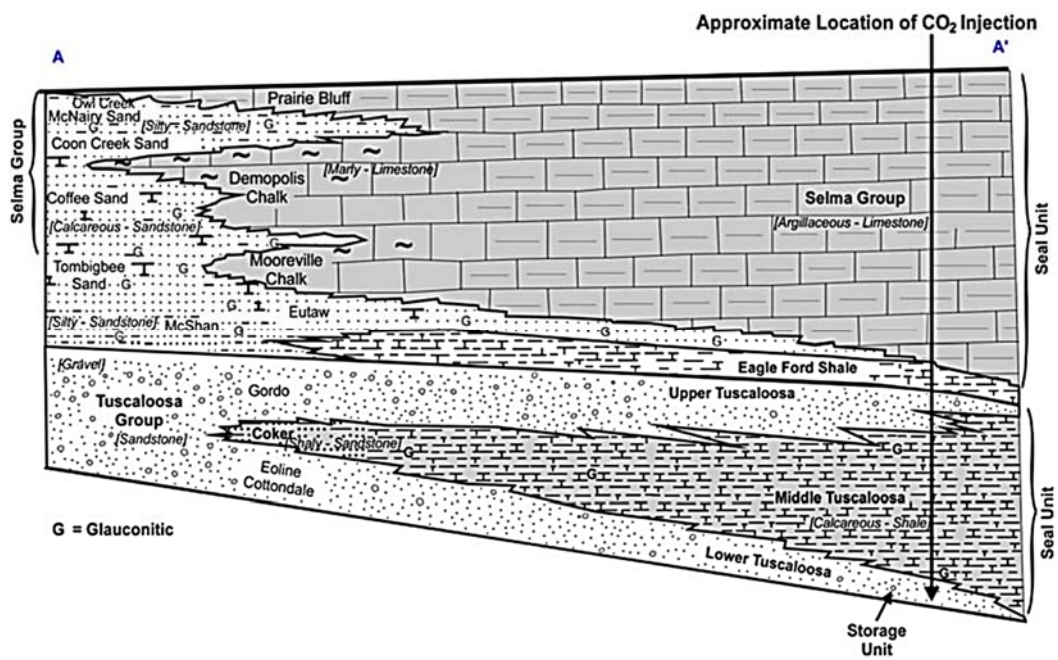


Figure 18: Cross section (AA') of lithofacies within the Cranfield Project with approximate location of CO₂ injection. (reprinted with permission from Griffith et al. [296], Copyright 2017, Springer).

The estimated total cost of storage is US\$93 million, and 4.7 Mt of CO₂ was stored until August 2013 [89,297–299]. Anderson et al. [300] investigated CO₂ leakage at the Cranfield project site, between 2009 and 2014, by extensive geochemical monitoring of process-based soil gas ratios, light hydrocarbon concentrations, stable and radioactive isotopes for CO₂ and CH₄, noble gases, and perfluorocarbon concentrations. Their results suggested that although some gases were detected, their origin cannot be correlated to the subsurface CO₂ reservoirs, and no associated leakage is recorded.

5.10 Frio Brine Pilot Project

The Frio Brine Pilot Project (2004-2006) is located in the Texas Gulf Coast (United States), and was operated by DOE and NETL, under the leadership of the Texas Bureau of Economic Geology. CO₂ for the project was sourced from the South Liberty oilfield near Houston [301]. The CO₂ injection in the Frio sandstone formation was conducted in two phases: a 10-day injection in 2004 (1600 t of CO₂ at a depth of 1500 m), and a 5-day injection in 2006 (250 t of CO₂ at a depth of 1600 m) [302].

Prior to implementation of the project, CO₂ storage experience in the United States was limited to hydrocarbon formations [302]. The main objectives of this project were to demonstrate CO₂ injection into brine formation without causing adverse health and environmental effects, to explore subsurface behaviour of injected CO₂, and to develop required experience for the large-scale injection demonstrations in high-permeability, high-volume sandstone [302,303]. On successful completion of the project in 2006, it was suggested that leakage-monitoring above the storage zone should be conducted as an alternative or as a complement to near-surface or surface monitoring [304]. A major success of the project was the ease of on-site analysis using

downhole sampling techniques to detect injection tracers and changes in water chemistry, for instantaneous measurements.

5.11 Citronelle Project

The Citronelle storage project, is located at the Citronelle oilfield in Bucks County (Alabama, United States), and is managed by SECARB, Denbury Resources and Southern Energy. The project started in 2011, and stored 0.15 Mt of CO₂ within Paluxy formation (thickness of 335 m), in a saline aquifer (southern flank of the Citronelle Dome), at a depth of 3000 to 3400 m. The CO₂ is sourced from the Plant Barry power station in Mobile (Alabama, USA), and transported via a 19 km long pipeline to the storage site [305]. Total storage cost is estimated at US\$111 million [89,306,307].

Although no soil gas baseline survey was reported for the Citronelle Project, Chen and Liu [308] performed geophysical sensing for CO₂ storage using a Derivative of Refractive Microtremor (DoReMi) method to determine changes in geologic formation and migration of CO₂ before and during injection through seismic measurements. The project is currently under post-injection process phase and no evidence of leakage is reported so far [309].

5.12 Decatur Project

The Decatur storage project (November 2011 - September 2015) is located in Decatur, Illinois Basin (United States), and was operated by Archer Daniels Midland, the Midwest Geological Sequestration Consortium (with Illinois State Geological Survey as leader), Schlumberger Carbon Services, and Richland Community College. The Mount Simon sandstone formation (**Figure 19**) was selected as the target formation due to its optimum saline sink and the presence of overlying Eau Claire shale which was expected to provide efficient sealing. The project

aimed at assessment of the storage potential of the Mount Simon sandstone formation, and the integrity of the overlying Eau Claire shale as a seal. The total cost of the project was US\$208 million, and CO₂ was sourced from an ethanol production plant in Decatur, and transported via a 1.9 km pipeline. After a year of operation, 317,000 t of CO₂ at the rate of 1100 t/d was injected into the formation using a single injection well. [89,247,310]. It was revealed that additional storage of 3-4.5 Mt of CO₂ in the same saline aquifer would be feasible in a follow-up project [247].

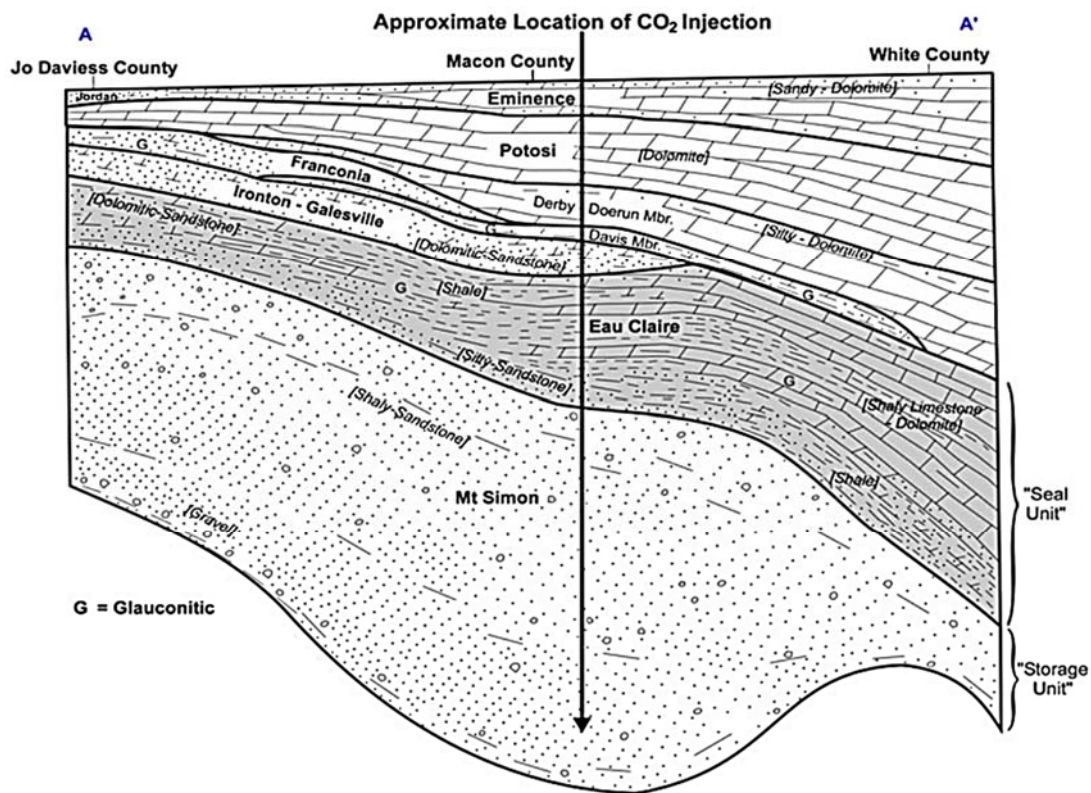


Figure 19: Cross section (AA') of lithofacies within the Decatur Project with approximate location of CO₂ injection showing the Mt. Simon formation as storage unit and the overlying

Eau Claire formation as seal unit (reprinted with permission from Griffith et al. [296], Copyright 2017, Springer).

Streibel et al. [247] performed a comparative study of the Decatur and Ketzin projects, as examples of successful onshore CO₂ storage, by considering project characteristics, monitoring approaches, pressure build-up, and public perception. Both projects aimed to demonstrate CO₂ storage in saline aquifers, but in different fluvial depositional systems, reservoir temperature and pressure conditions, injection rate, and particularly amount of stored CO₂ which was approximately 15 (by volume) times higher in the Decatur project. The results showed that: (i) the Decatur storage reservoir is thick, but the CO₂ plume is relatively thin, making geophysical detection challenging; (ii) The Ketzin storage reservoir is much thinner, with a thick CO₂ plume, which eases geophysical detection; (iii) geomechanical conditions at Decatur, in combination with the injection rate and pressure, induced microseismic activity, while no such activities were detected at Ketzin; (iv) the induced microseismic activity at Decatur was along pre-existing planes of weakness and could not be detected by geophysical tools; and (v) the project developers recognised the need to monitor the shallow groundwater and soil flux, but they also suggested that subsurface sampling/pressure monitoring and cased-hole logging would be necessary in the case of seal or well failure.

5.13 Northern Reef Trend Project

The Northern Reef Trend project is located within the Michigan Basin, (Michigan, United States), and is operated by the Midwest Regional Carbon Sequestration Partnership (MRCSP), DTE Energy, Core Energy, and Battelle. The CO₂ is sourced from a natural gas processing plant, transported via a 24-km pipeline, and stored in a depleted carbonate reservoir within the

Northern Reef Trend. This formation is characterised by a series of highly compartmentalised reservoirs at about 1800 m in the subsurface where geologic history indicates an ancient coral reef environment. The project started in 2013, and it is planned that in 3 to 5 years of operation about 1 Mt of CO₂ will be injected in the oil field which has undergone waterflooding in recent years and is almost at the end of its productive life. The MRCSP is also tracking and monitoring the behaviour of injected CO₂ to quantify how much CO₂ is retained in the formation after the removal of oil. The total cost of the project is US\$23 million [89,311].

5.14 Port Arthur Project

The Port Arthur project (January 2013 - September 2015) is located in Port Arthur (Texas, United States), and was operated by Air Products and Chemicals, Denbury Onshore, Bureau of Economic Geology at the University of Texas at Austin, and Valero Energy Corporation. The CO₂ was sourced from the existing steam methane reformers in the Valero Refinery in Port Arthur, and transported via a 19-km pipeline to Denbury's Green pipeline for further transportation over more than 100 km for EOR in the Oyster Bayou and West Hastings oilfields. By May 2013, over 222,000 t of CO₂ was injected into the formation, resulting in an additional recovery of 1.6 to 3.1 million barrels of domestic oil annually. The total cost of the project is US\$431 million [89,312]. To the best of our knowledge, there is no known study on CO₂ monitoring in the Port Arthur project, and it is very likely that a monitoring program will be proposed to confirm that CO₂ is safely stored.

5.15 Zama Project

The Zama storage project is located near Zama City (Alberta, Canada), and is operated by PCOR (Plains CO₂ Reduction Partnership) and Apache Canada. The project started in 2006 and aims at demonstration of commercial acid gas injection for hydrocarbon recovery, in order

to reduce the cost of CO₂ purification. The CO₂ stream contains almost 70% CO₂ and 30% H₂S and is sourced from a gas processing plant [89]. The Zama project is estimated to operate for 18 years and to store 1.3 Mt of CO₂ and 0.5 Mt of H₂S. Since 2006, 80,000 t of H₂S has been stored, which enabled the recovery of more than 35,000 barrels of oil. The storage reservoir of the Zama oilfield, the Keg River formation saline aquifer, is of Middle Devonian, and is at a depth of approximately 1500 m. [89,313].

The co-injection of CO₂ and H₂S (acid gas) into geologic formations for permanent storage is both environmentally and economically beneficial. Bennion and Bachu [314] studied the effect of CO₂ and H₂S at in-situ reservoir conditions on permeability of inter-crystalline sandstone from the Wabamun Lake area (Alberta, Canada). It was revealed that interaction of H₂S-saturated brines-rock is more aggressive than CO₂-saturated brines-rock interaction. Moreover, it is important to note that co-injection of gas mixtures, particularly CO₂-H₂S, has been demonstrated to be safe, and viable for storage to a considerable extent. However, it is also essential to further explore the effect of acid gas injection and its implications on the physical reservoir quality of target formations using both experimental studies for short-term effects and numerical models for long-term prediction.

5.16 Ordos Project

The Ordos storage project is located in Inner Mongolia (China), and is managed by the Shenhua Group. This project began in 2010 at pilot scale, and will be operated at full scale by 2020. The CO₂ is sourced from a coal liquefaction plant, which is currently emitting 3.6 Mt of CO₂ per year, transported via a 200-km onshore pipeline system, and is injected into a saline aquifer. It is reported that by 2014, up to 150,000 t of CO₂ was stored within the Ordos formation. The total estimated cost of the project is US\$1.46 billion [89,315]. A system for monitoring of

ground, above-ground and under-ground was developed [316], and the vertical seismic profile (VSP) was used to track CO₂ migration. The results showed that the injected CO₂ remained within 450 m from the injection well, and no incidence of CO₂ leakage was observed. However, continuous monitoring is suggested to track CO₂ plume movement over a more extended period.

Table 2: Major world CO₂ storage projects (large-scale projects either operated previously or currently operating), [30,89].

Name	Location	CO₂ Source	CO₂ Sink	Status	Other important information
In Salah	Tamanrasset, Algeria	Oil and gas	Oil and gas reservoir	2004-2011	CO ₂ injection stopped for fear about caprock integrity even though storage complex was not compromised.
Ketzin	Brandenburg, Germany	Hydrogen production and oxyfuel plant	Saline aquifer	2008-2009	First European onshore CO ₂ storage project, motivated by need for information for the future CCS policies in the EU.
Sleipner	Offshore, Norway	Natural gas	Saline aquifer	since 1996	World's first commercial-scale CO ₂ injection project, motivated by the Norwegian carbon tax policy.
Weyburn -Midale	Saskatchewan, Canada	Coal gasification	Oil and gas reservoir	since 2000	World's largest CCS project. In addition to EOR, the project was motivated by need for R&D in the area. In 2011, there were allegations that stored CO ₂ was leaking near injection site, but later investigations did not confirm it.

Snohvit	Offshore, Norway	LNG processing	Saline aquifer	since 2007	Motivated by the carbon tax in Norway. The first offshore field where oil is produced without the use of offshore installations.
Alberta Carbon Trunk Line	Alberta, Canada	Refinery and fertiliser plant	Oil and gas reservoir	from 2018	When in operation, the world's largest CCS project intended to generate over one billion barrels of oil, with value of ~\$15 billion in royalties.
Otway Basin	Victoria, Australia	Natural CO ₂ - rich gas	Oil and gas reservoir	since 2008	Motivated by the signing of the Kyoto Protocol in 2007, the largest geosequestration onshore project in Australia, aimed at demonstrating transport and geological storage of CO ₂ , testing the regulatory and scientific CO ₂ storage concepts, and evaluating response of public through engaging with stakeholders.
Boundary Dam	Saskatchewan, Canada	Post- combustion lignite-fired plant	Saline aquifer	since 2014	World's first commercial-scale CCS project employing post-combustion capture from lignite-fired plant, motivated by EOR, but also aims to sell CO ₂ , fly ash and sulphuric acid for industrial uses. A major turning point was signing the MoU between SaskPower and UKCCSRC for a 3-year

research initiative aimed at improving performance and reducing costs of CCS operations.

Cranfield	Mississippi, USA	Natural source	Oil and gas reservoir	since 2009	First amongst the SECARB commercial-scale projects which reached and exceeded the injection target with > 3 Mt of CO ₂ injected and monitored since the start of the project.
Frio Brine Pilot Project	Texas, USA	Oil processing	Saline aquifer	2004-2006	First demonstration on CO ₂ storage in saline aquifer in the United States.
Citronelle	Alabama, USA	Power station	Saline aquifer	since 2011	Feedstock is provided from the first and largest fully integrated commercial prototype coal-fired source in the USA.
Decatur	Illinois, USA	Ethanol production plant	Saline aquifer	since 2011	Motivated by the need to appraise storage potential of the Mount Simon sandstone formation and the integrity of overlying Eau Claire shale as the seal. Two major milestones reached: establishment of the storage facility; and the public launch of the National Sequestration Education Center.

Northern Reef Trend	Michigan, USA	Natural gas processing	Oil and gas reservoir	since 2013	Uses existing EOR infrastructure to transport CO ₂ 16 km from capture to storage site.
Port Arthur	Texas, USA	Steam methane reformers	Oil and gas reservoir	since 2013	Captured CO ₂ is dried and purified to 97% at the Port Arthur facility, transported 19 km via pipeline to Denbury's Green, and further piped 100 km and used for EOR.
Zama	Alberta, Canada	Gas processing	Oil and gas reservoir	since 2006	Motivated by the need to explore and to demonstrate the effectiveness of injecting mixture of CO ₂ and H ₂ S for EOR, while the costs of CO ₂ separation from H ₂ S are avoided.
Ordos	Ordos, Inner Mongolia, China	Coal liquefaction	Saline aquifer	since 2010 at pilot scale, from 2020 full scale	Managed by China's largest coal mining company. The coal liquefaction plant where CO ₂ is sourced for this project is located on a large deposit of coal tar.

6 General Conclusions and Future Outlook for CO₂ Storage

This work presents a review of state-of-the-art developments in carbon dioxide storage. It discusses critical issues that have been solved as well as challenges that require further attention for CO₂ sequestration, storage site evaluation criteria, behaviour of CO₂ in the reservoir, and methodologies for estimating CO₂ storage capacity. In addition, the major world CO₂ storage projects, including their states of developments were highlighted. Based on our review, it can be concluded that:

a) Although CO₂ storage, as an emerging technology, is faced with technical challenges which are improving by ongoing research, there are also associated problems with public acceptability of the technology, implying that dispelling of misconceptions on CCS has not yet reached a significant maturity level.

b) Although it has been demonstrated that CO₂ can be sequestered by means of mineral carbonation and deep ocean storage, the underground geological storage of CO₂ is still the most viable choice due to economic factors, their wide geographical distribution, and environmental concerns.

c) Even though some researchers suggested that CO₂ storage in saline aquifers is preferable (due to relative abundance and availability of huge storage volumes) over oil and gas reservoirs, they often neglect the costs associated with deployment of storage in saline aquifers. Oil and gas reservoirs usually have existing infrastructure that can support storage activities with minor modifications. In addition, they have been comprehensively characterised during exploration and production stages, and could utilise CO₂ for both storage and EOR. Therefore, storage in oil and gas reservoirs can be a better alternative over saline aquifers.

d) Since geologic systems are often associated with uncertainties due to their heterogeneity, appropriate site evaluation is crucial for the development of all future storage projects. In addition, continuous monitoring for the existing projects must be undertaken.

e) CO₂ transportation over long distances from sources to storage sites can incur considerable costs, and is not economically favourable. Therefore, the storage site should be ideally as close as possible to CO₂ sources. In addition, where the point sources of CO₂ are located far from ideal sedimentary formations, the high cost of transportation may be minimised by choosing an alternative storage option. Alternatively, single pipe facilities can be developed for a cluster of CO₂ producers.

f) Complex behaviour of injected CO₂ within fluvial depositional structures may potentially lead to undesirable events, such as induced seismicity and leakage, if appropriate reservoir management strategies are not adopted. Thus, detailed geomechanical and geochemical assessments of sites are essential.

g) Although monitoring experience from the majority of projects suggested that CO₂ storage can be effectively and securely achieved, issues like induced seismicity can still pose threats to storage projects if such potentials are not well investigated.

Although high-quality knowledge has already been attained covering many aspects of CO₂ storage, the following challenges remain:

a) Despite the technically proven feasibility of CO₂ storage, low levels of public awareness have greatly affected the pace of technology deployment. Ethical implications of CO₂ storage development need further evaluation, and more effective ethic mechanisms should be adopted to promote public embracing of the technology. Development of scientist-policymaker-public

communication strategies is essential to transfer and highlight the necessity of CO₂ storage to society.

b) It is important to establish cost curves involved in the whole sequestration chain such as in the geographical relationship between CO₂ sources and storage sinks. This will play a key role in decision making, especially during large-scale CCS deployment.

c) Detailed regional assessments are the key factor to establish how well an emission source would match suitable storage options, and what storage volumes are required. On a case-by-case basis, it is always important to assess risks associated with storage such as CO₂ leakage and induced seismicity, as well as public acceptance of the technology.

d) Although legal and regulatory frameworks for facilitating CO₂ storage implementation exist, it is important to make inter-subjective comparisons between frameworks for different countries or regions such as United States-Canada and the European Union, Australia, and Asia.

e) For further deployment of alternative storage options, such as serpentinite and basaltic formations, it is necessary to enhance our understanding in order to distinguish potential uncertainties and explore the corresponding mitigation strategies. This can include the understanding of CO₂ migration in the presence of potential faults or excessive pressure build-up and the effect of CO₂-rock interaction to facilitate or impede the migration, using both experimental and, particularly, numerical approaches.

f) Helping industry in terms of long-term stability or financial instruments is essential to enable timely deployment of large-scale commercial CO₂ storage projects considering that CCS is a short- to medium-term climate change mitigation strategy.

g) There are currently limited data defining reservoir system strength variation in relation to reactions of rock minerals by CO₂-enriched brine. Therefore, further research is required to focus on grain-size parameters of the reservoir formations to assess the effect of supercritical CO₂ and how it alters reservoir quality, such as porosity and permeability, and its corresponding effects on CO₂ migration. It is also important to take into consideration the effects of impurities such as NO₂, SO₂ and H₂S in such studies.

h) Numerical models capable of describing changes in reservoirs over longer periods of injection and storage could also be utilised to understand long-term effects of CO₂ and impurities on physical reservoir quality. In addition, such numerical models can be potentially coupled with volumetric approaches to further depict the dynamic aspects of storage capacity estimation during and after the injection period.

i) Models, with higher performance capacity than existing ones, are required for building and calibrating 3D pre-injection and 4D post-injection reservoir geomechanical simulations in order to have a better assessment of fault and caprock integrity, especially in deep saline aquifers and depleted oil and gas formations. These models should take into consideration critical pore pressure for fault activation.

j) There is a necessity in demonstrating stability of borehole seals in the longer term, as their failure will govern CO₂ leakage regardless of the quality of any caprock. It is also required to demonstrate the ability of remediation in the unlikely event of well leakage.

Abbreviations

ACTL	Alberta Carbon Trunk Line
API	American Petroleum Institute
ARI	Advanced Resources International
CAS	Chinese Academy of Sciences
CBM	Coal Bed Methane
CCS	Carbon Capture and Storage
CCSU	Carbon Capture Storage and Utilisation
CO2CRC	The Cooperative Research Centre for Greenhouse Gas Technologies
CSLF	The Carbon Sequestration Leadership Forum
DOE	Department of Energy
DoReMi	Derivative of Refractive Microtremor
ECBM	Enhanced Coal Bed Methane recovery
EGS	Enhanced Geothermal System
EOR	Enhanced Oil Recovery
EPRI	Electric Power Research Institute
FEP	Features, Events and Processes
GHG	Greenhouse Gas
HCPV	Hydrocarbon Pore Volume
IMO	International Maritime Organisation
InSAR	Interferometric Synthetic Aperture Radar
IPCC	Intergovernmental Panel on Climate Change
LNG	Liquefied Natural Gas
MIT	Massachusetts Institute of Technology
MoU	Memorandum of Understanding
MRCSP	Midwest Regional Carbon Sequestration Partnership

MVA	Monitoring, Verification and Accounting
NETL	National Energy Technology Laboratory
OBPP	Otway Basin Pilot Project
OGCM	Ocean General Circulation Model
OGIP	Original Gas in Place
OoIP	Original Oil in Place
OSPAR	Oslo Paris
PCOR	Plains CO ₂ Reduction Partnership
PFTs	Perfluorocarbon tracer compounds
PTRC	Petroleum Technology Research Centre
SECARB	Southeast Regional Carbon Sequestration Partnership
SEM	Scanning Electron Microscope
SSEB	Southern States Energy Board
SWP	The Southwest Regional Partnership
TRL	Technology Readiness Level
UKCCSRC	UK Carbon Capture and Storage Research Centre
US-DOE	United States Department of Energy
USGS	United States Geological Survey
VSP	Vertical Seismic Profile
XRD	X-Ray Diffraction

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A Review of Developments in Carbon Dioxide Storage

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Table s1: Other CO₂ storage projects and their operational status (projects currently under construction, in planning (as of 2015), or operational within a shorter time period) [1].

Project Name	Location	Operator(s)	Feedstock	Capture Process	CO₂ Sink	Status
Peterhead	Aberdeenshire, UK	Shell and SSE	Gas	Post-combustion	Depleted gas wells	Planning
White Rose	North Yorkshire, UK	Capture Power	Coal	Oxyfuel combustion	Saline aquifer	Planning
Kevin Dome	Montana, USA	Big Sky	Natural source		Saline aquifer	Planning
Wasatch Plateau	Utah, USA	SWP	Natural source		Saline aquifer	Planning
Bell Creek	Montana, USA	PCOR	Gas processing		EOR	Planning
Fort Nelson	British Columbia, Canada	Spectra Energy	Gas processing		Saline aquifer	Planning
Quest	Alberta, Canada	Shell	Steam-methane reforming		Saline aquifer	Planning
ULCOS Florange	Lorraine, France	ArcelorMittal	Steel production		Saline aquifer	Planning
Gorgon	Western Australia, Australia	Chevron	Gas processing		Saline aquifer	Under construction
Yulin	NW Shaanxi, China	Shenhua & Dow Chemicals	Coal-to-chemicals		Saline aquifer	Planning
ESI CCS Project (also known as Abu Dhabi CCS project)	Abu Dhabi, UAE	Masdar and ESI	Steel industry		EOR	Planning
Tomakomai	Hokkaido, Japan	JCCS	Hydrogen production	Post-combustion	Saline aquifer	Planning
Pikes Peak	Saskatchewan, Canada	Husky Energy	Coal	Post-combustion	EOR	Planning

Big Bend Station	Florida, USA	Siemens	Coal	Post-combustion	Vented	Planning
E. W. Brown	Kentucky, USA	University of Kentucky	Coal	Post-combustion	N/A	Under construction
ECO2 Burger	Ohio, USA	Powerspan	Coal	Post-combustion	Vented	Operated 2008-2010
Pleasant Prairie	Wisconsin, USA	Alstom	Coal	Post-combustion	Vented	Operated 2008-2009
AEP Mountaineer	West Virginia, USA	AEP	Coal	Post-combustion	Saline aquifer	Operated 2009-2011
Karlshamn	Blekinge, Sweden	E.ON	Oil	Post-combustion	Vented	Operated 2009-2010
Compostilla	A Coruña, Spain	ENDESA	Coal	Oxyfuel combustion	Saline aquifer	Operated 2009-2012
Puertollano	Ciudad Real, Spain	ELCOGAS	Coal	Pre-combustion	Recycled	Operated 2010-2011
Lacq	Aquitaine, France	Total	Oil	Oxyfuel combustion	Depleted gas	Operated 2010-2013
Buggenum	Limburg, Netherlands	Vattenfall	Coal	Pre-combustion	Vented	Operated 2011-2013
Ferrybridge CCSPilot100+	West Yorkshire, UK	SSE	Coal	Post-combustion	Vented	Operated 2012-2013
Aberthaw	Wales, UK	RWE	Coal	Post-combustion	N/A	Operational 2013-2014
Jilin	Jilin, China	PetroChina	Natural gas processing	Post-combustion	EOR	Operational since 2009

Shidongkou	Shanghai, China	Huaneng	Coal	Post-combustion	Commercial use	Operational 2011
Brindisi	Brindisi, Italy	Enel & Eni	Coal	Post-combustion	EOR	Operational 2011
Wilhelmshaven	Lower Saxony, Germany	E.ON	Coal	Post-combustion	Vented	Operational 2012
Mongstad	Hordaland, Norway	Statoil	Gas	Post-combustion	Saline aquifer	Operational 2012
Callide-A Oxy Fuel	Queensland, Australia	CS Energy	Coal	Oxyfuel combustion	Saline aquifer	Operational 2012
Jingbian	Shaanxi, China	Yanchang	Chemicals	N/A	EOR	Operational 2013
Boryeong Station	South Chungcheong, South Korea	KEPCO	Coal	Post-combustion	N/A	Operational 2013
Polk	Florida, USA	Tampa Electric	Coal	Pre-combustion	Saline aquifer	Operational 2014
Kemper County	Mississippi, USA	Southern	Coal	Pre-combustion	EOR	Under construction
WA Parish Petra Nova	Texas, USA	NRG Energy	Coal	Post-combustion	EOR	Under construction
HECA	California, USA	SCS	Petroleum coke	Pre-combustion	EOR	Planning
TCEP	Texas, USA	Summit Power	Coal	Pre combustion	EOR	Planning
Bow City	Alberta, Canada	BCPL	Coal	Post-combustion	EOR	Planning
ROAD	North Sea, Netherlands	E.ON	Coal	Post-combustion	Depleted oil or gas wells	Planning

Magnum	Eemshaven, Netherlands	Nuon	Various	Pre-combustion	Depleted oil or gas wells	Planning
Captain	Stirlingshire, UK	Summit Power	Coal	Post-combustion	Saline aquifer	Planning
Killingholme	North Lincolnshire, UK	C.GEN	Coal	Pre-combustion	Saline aquifer	Planning
Don Valley Power Project	South Yorkshire, UK	2Co Energy	Coal	Pre-combustion	Saline aquifer	Planning
Longyearbyen	Svalbard, Norway	Unis CO ₂	Coal	Post-combustion	Saline aquifer	Planning
Daqing	Heilongjiang, China	Alstom & Datang	Coal	Oxyfuel combustion	EOR	Planning
Dongguan	Guangdong, China	Dongguan Taiyangzhou Power	Coal	Pre-combustion	EOR	Planning
Shengli oilfield	Shandong, China	Sinopec	Coal	Post-combustion	EOR	Planning
GreenGen	Bohai Rim, China	GreenGen	Coal	Pre-combustion	EOR	Planning
Lianyungang	Jiangsu, China	Lianyungang Clean Energy	Coal	Pre-combustion	Saline aquifer or EOR	Planning
Korea CCS	To be decided: South Gyeongsang (Samcheonpo) or South Chungcheong (Taean), South Korea	KCRC	Coal	Oxyfuel	Saline aquifer	Planning
Taweelah	Abu Dhabi, UAE	Masdar	Gas	Post-combustion	EOR	Planning

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