

Review

Site and Formation Selection for CO₂ Geological Sequestration: Research Progress and Case Analyses

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Abstract

Carbon Capture and Storage (CCS) is a key technology for achieving carbon neutrality goals. Relevant foreign research began in the 1970s, but overall it remains in the exploration and demonstration stage. Clarifying the geological parameters and characteristics of reservoir–caprock systems in CCS projects is of great significance to the effectiveness and safety of long-term storage. By reviewing 15 typical global CCS projects, this paper identifies that ideal reservoirs are gently structured sandstones with few faults (characterized by high porosity, high permeability, and large scale, which are conducive to CO₂ diffusion) or basalts (which can react with CO₂ for mineralization, enabling permanent storage). Caprocks are mainly composed of thick mudstone and shale; composite caprocks consisting of multi-layer low-permeability formations and tight interlayers within reservoirs have stronger sealing performance. Additionally, they should be far from faults, and sufficient caprock thickness is required to reduce leakage risks. Meanwhile, this paper points out the challenges faced by CCS technology, such as complex site selection, limitations in long-term monitoring, difficulties in designing injection parameters, and challenges in large-scale deployment. It proposes suggestions including establishing a quantitative site selection system, building a comprehensive monitoring network, and strengthening collaborative optimization of parameters, so as to provide a basis for safe site selection and assessment.

Keywords: CO₂ geological sequestration; site and formation selection; reservoir–caprock assemblage; basalt mineralization sequestration; CO₂ leakage



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1. Introduction

Since the Industrial Revolution, massive emissions of greenhouse gases such as CO₂ have led to a continuous rise in global temperatures. Compared with the pre-Industrial Revolution period, the global average temperature has risen by 1.1 °C [1], resulting in a rise in sea levels, increased extreme high temperatures, and more arid climates [2]. As a major global economy, China's CO₂ emissions reached 12.6 Gt in 2023, accounting for 31% of the world's total, which is equivalent to the sum of emissions from the United States, India, and the 27 EU countries [3,4]. To address global climate change and environmental pollution, China clearly put forward the major strategic decision of “carbon peaking and carbon neutrality” in September 2020, striving to reach the peak before 2030 and achieve neutrality before 2060 [5]. The “dual carbon” goals are on an ambitious timeline and entail significant tasks; as such, developing carbon emission reduction technologies to support

in-depth energy and industrial structure adjustment is an urgent need. Carbon Capture and Storage (CCS) is widely recognized as an important measure for promoting carbon reduction and a key technology for achieving the “dual carbon” goals [6].

During the geological sequestration process, CO₂ is injected into the target formation through the wellbore. Under the formation's temperature and pressure conditions, CO₂ usually exists in a supercritical state, with a viscosity close to that of gas and a density similar to liquid [7]. This characteristic causes CO₂ to gradually migrate to the interface between the target formation and the caprock when it diffuses away from the injection wellbore to the deep formation. If the caprock is improperly selected, high permeability may lead to CO₂ leakage along the caprock [8]; when injection parameters are excessively high or there are faults in the formation, CO₂ may leak along the faults, resulting in reduced sequestration efficiency [9]. Therefore, finding the appropriate matching relationship between reservoir and caprock, sequestration temperature and pressure conditions has a significant impact on the sequestration effect.

This paper aims to systematically sort out the current status of site and formation selection for Carbon Capture and Storage (CCS) projects worldwide, and comprehensively analyze the reservoir–caprock petrophysical parameters, temperature–pressure conditions, burial depth, formation water salinity, rock types, and geological characteristics of different projects in various countries. On this basis, it conducts in-depth discussions on geological issues faced by typical projects, such as sudden increase in formation pressure, rock salt precipitation, and caprock integrity. Through comprehensive comparative analysis of key geological parameters of reservoir–caprock, it provides references for subsequent site and formation selection in CO₂ geological sequestration. Meanwhile, it summarizes various challenges in the development of CCS technology, including the complexity and uncertainty of sequestration site selection, difficulties in injection and site parameter design, limitations of long-term sequestration monitoring, and high difficulty in large-scale layout and full industrial chain development, and puts forward targeted development suggestions and optimization paths.

2. The History of Global CO₂ Geological Sequestration Development

As one of the current key technologies for mitigating global warming, CO₂ geological sequestration technology (CCS) has gone through three main stages: preliminary exploration in the 1970s, technological formation in the 1990s, and rapid development up to the present day. Early CO₂ sequestration projects mostly aimed to enhance recovery efficiency; as our understanding of climate change deepened, CO₂ sequestration technology gradually moved from theoretical exploration to commercial application, resulting in diversified sequestration techniques such as deep saline aquifer, mineralization, and depleted oil reservoir sequestration [10].

CCS research was initiated in the 1960s, initially focusing on the mechanisms and theoretical feasibility of geological sequestration. Later, the United States and Canada attempted to study CO₂'s role in enhanced oil recovery [11]; this period was dominated by laboratory simulations and small-scale pilot projects. In 1972, Chevron successfully implemented the world's first commercial CO₂-enhanced oil recovery project, SACROC, at the Kelly Snyder Oilfield in Texas, USA, marking the beginning of early CO₂ sequestration technology practice. To date, this project has been operating successfully for more than 30 years [12], with a total injected CO₂ volume exceeding 150 million tons [13].

At the beginning of the 1990s, the theories and technologies of CO₂ sequestration gradually matured [11] and CO₂-EOR (CO₂-enhanced oil recovery) technology was widely applied; various sequestration methods such as terrestrial and marine sequestration and CO₂-enhanced coalbed methane recovery were gradually promoted. In 1996, Statoil (Nor-

wegian National Oil Company) launched the world's first CO₂ saline aquifer sequestration project at the Sleipner Oilfield in the North Sea [14], with a cumulative sequestration volume exceeding 20 million tons, thus verifying the feasibility of geological sequestration. In 2000, the Canadian Weyburn Project successfully captured and sequestered CO₂ generated from the coal chemical industry, with a total sequestration volume exceeding 18 million tons [15]; in addition, projects such as Algeria's In Salah Project and Australia's Gorgon Project were successively implemented, further verifying the reliability of CO₂ geological sequestration technology. During this stage, the mechanisms, safety, and leakage risks of CO₂ sequestration gradually became more understood.

Since 2010, CO₂ sequestration technology has been in a state of rapid development. The change in CO₂ sequestration capacity over the past 15 years is shown in Figure 1. As of 2024, the total number of global CCS projects in operation, under construction, and in planning has reached 628, as shown in Table 1, representing a year-on-year increase of 60.2%. It has a total sequestration capacity of 416 Mtpa [10], with a year-on-year increase of 14.9%, as detailed in Figure 2. Different from the previous two stages, where traditional developed countries dominated entirely, emerging economies have played an important role in theoretical research and engineering practice during this period. For example, China has implemented the world's first low-porosity and -permeability coal-based CCS demonstration project—the Shenhua CCS Project [16]. In recent times, CCS technologies have been fully applied and researched. As an example, CO₂ mineralization sequestration in basalt has been investigated, which utilizes minerals such as olivine, pyroxene, and feldspar present in volcanic rocks to undergo chemical reactions with CO₂, thereby achieving permanent carbon sequestration [17]. Iceland's CarbFix is the world's most successful basalt sequestration project. Monitoring results show that the cumulative injection volume of the CarbFix Project reached 82,600 tons from 2014 to 2022, with a mineralization rate of 95% within two years. In 2013, the Wallula Project injected 977 tons of CO₂, with a mineralization rate exceeding 60%, verifying the feasibility of CO₂ mineralization sequestration in basalt [18].

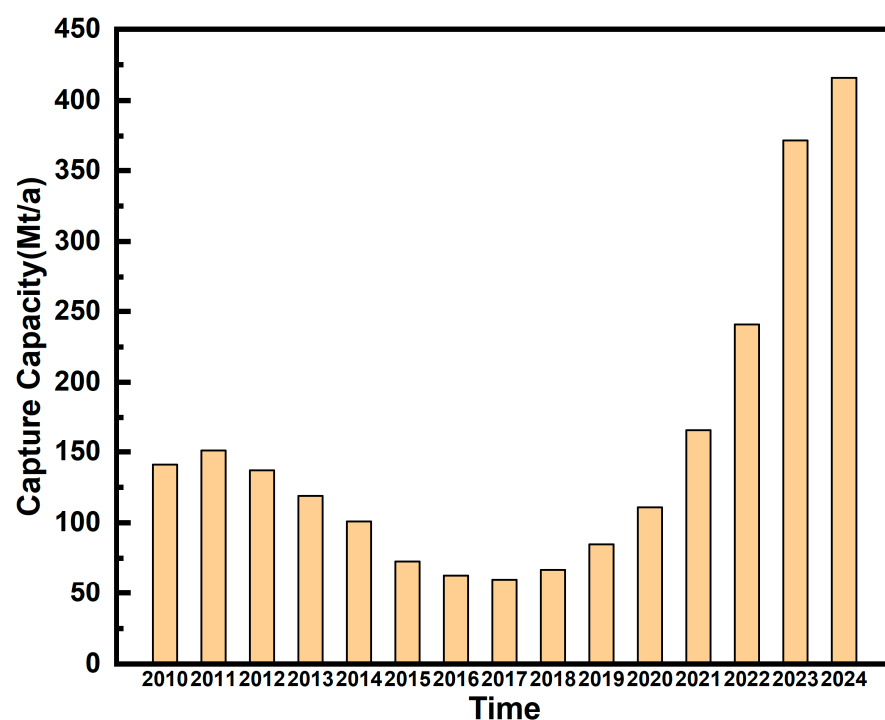


Figure 1. This is a graph of changes in capture capacity of CCS projects, which depicts changes in CO₂ storage capacity over the past 15 years.

Table 1. This is the 2024 Summary Table of CCS Projects (Operational, Under-Construction, and Planned) by Region. Globally, the total number of operational, under-construction, and planned CCS projects amounts to 628 [10].

Area	In Operation	Under Construction	Late-Stage Development	Early-Stage Development	Total
Americas	27	18	146	145	337
Europe	5	10	75	105	195
Asia	17	14	21	25	77
Oceania	1	2	5	9	17
Africa	0	0	0	3	3
Total	50	44	247	287	628

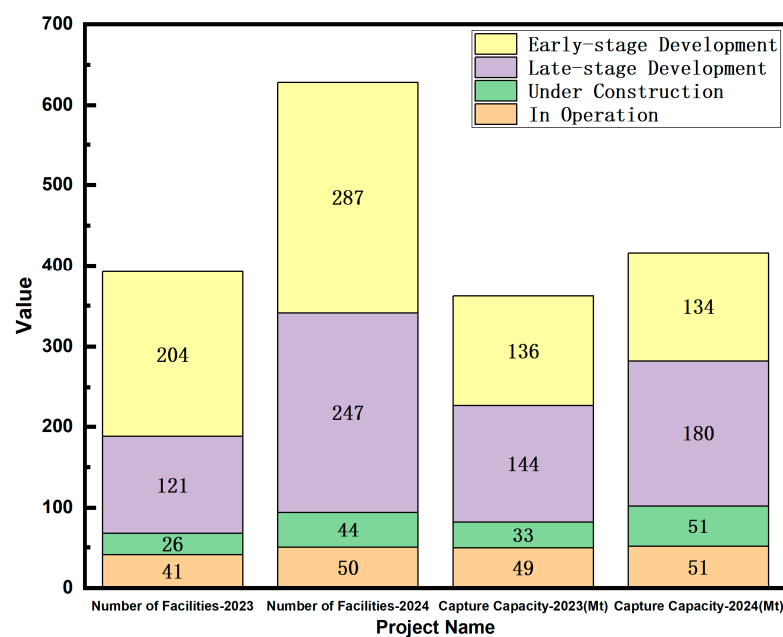


Figure 2. This is a schematic diagram of the number of CCS projects and their capture capacity from 2023 to 2024, in which the number of projects has a year-on-year growth of 60.2%, and the storage capacity has a year-on-year growth of 14.9%.

3. Projects in Europe and Africa

3.1. Norway Sleipner Project

Sleipner is located in the Norwegian North Sea, with the injection site in a large anticline structure with no developed faults [19]. Since 1996, the CO₂ separated from the Sleipner gas field has been injected into the Utsira sandstone reservoir. This reservoir is 800–1000 m below sea level, with a thickness of approximately 250 m, extending about 450 km from north to south and covering an area of 26,000 km², with a sequestration potential of 16 billion tons [20]. The Utsira Formation is mainly composed of unconsolidated fine-grained sandstone, with a small amount of medium- and coarse-grained sandstone. Its average porosity is 37%, its permeability ranges from 1 to 8 D (with an average of 5 D), its average temperature and pressure are 37 °C and 10.3 MPa, respectively, and its formation salinity is 3.5×10^4 mg/L [21]. In terms of reservoir site selection, this project has the following advantages: Firstly, the Utsira sandstone is characterized by thin interbeds separating thick sandstone units, with marine turbidite deposits, stable sand bodies, a large scale, and high sequestration potential [21]. Secondly, the Utsira sandstone reservoir has relatively high porosity and permeability parameters [22]. Thirdly, the reservoir is an

anticline structure that dips southward, with no obvious fault development [23], facilitating CO₂ migration and increasing the contact area between the CO₂ plume and water [24]. The Sleipner caprock is divided into two parts: the main part is the Nordland Shale with a thickness of 200–300 m [25], and the other is the thin shale layers alternating with sandstone [26]. The Nordland Shale is mainly composed of clay minerals and some silt minerals. It has a large thickness and low porosity and permeability [27], and plays a major sealing role in the sequestration system; the dense nature of the thin shale layers enables them to serve as natural barriers in the reservoir, which can significantly prevent upward CO₂ migration [28].

Permeability, hydraulic conductivity, caprock sealing ability, and pressure-bearing conditions should be considered when selecting caprock. The first two jointly affect injectability and long-term sealing capacity [24]; the latter can prevent upward CO₂ migration and reduce caprock breakthrough risk [22], while a relatively high pressure-bearing capacity can avoid caprock fracture leakage due to CO₂ injection [23]. The Nordland caprock is mainly composed of gray clayey silt or silty clay, which is dense with poorly developed bedding and poor permeability and hydraulic conductivity. Combined with a caprock thickness exceeding 200 m, the above-mentioned characteristics can achieve a good sealing effect [21]. The seepage characteristics of the Sleipner reservoir and caprock make it an ideal sequestration site: the relatively high porosity and permeability of the reservoir facilitate CO₂ entry and diffusion, while the dense caprock can effectively seal and prevent its upward migration. When it comes to leakage issues, fault impacts should also be considered. It is generally believed that the CO₂ leakage rate is at a constant value along faults [29]; however, it is affected by the Joule–Thomson cooling effect [30]. If this effect is significant during the CO₂ leakage and expansion process, this may affect fault permeability due to hydrate formation and residual water freezing [31].

During the sequestration period, to further assess leakage conditions, the project adopted a series of measures to track the migration of CO₂, such as time-lapse gravity monitoring, microseismic monitoring and 4D seismic monitoring; monitoring data show that CO₂ has been safely sequestered over more than two decades of operation, with no significant leakage detected. Additionally, some scholars have also studied the sealing effect of the Sleipner caprock; through conducting laboratory experiments, establishing sequestration models and risk assessment models, the experimental and calculation results indicate that the caprock will not have reactions unfavorable to CO₂ sequestration [32,33]. In conclusion, with 20 million tons of CO₂ injected, no gas leakage has been monitored in the Sleipner project.

3.2. The Norwegian Snøhvit Project

Snøhvit is located in the Hammerfest Basin of the Barents Sea, Norway. From 2008 to 2011, a cumulative total of 1.1 million tons of CO₂ was injected into the fault block of the Tubåen Reservoir, which is approximately 100 m below the Snøhvit gas field [34]. The Tubåen Reservoir has a burial depth of 2600 m, and its thickness gradually increases from 45 m to 130 m from east to west. The reservoir is dominated by sandstone with good vertical compartmentalization [21], a porosity ranging from 1% to 16%, and a permeability of 130–880 mD [35]. The reservoir temperature and pressure are 98 °C and 28.5 MPa, respectively, with a formation salinity of 1.6×10^5 mg/L [36].

Similarly to Sleipner, the caprock of Snøhvit can also be considered to consist of two parts. First is the marine shale Nordmela Formation that directly overlies the Tubåen Reservoir (Figure 3) [21], with a thickness of 60–100 m, an average porosity of 13%, and an average permeability of 1–23 mD [36]. Second is the 1–3 m thick thin shale layers in the reservoir; these ultra-low-permeability thin shale layers divide the reservoir into multiple

discontinuous flow units, reduce vertical permeability, and effectively control the vertical CO₂ migration within the reservoir units [37–39].

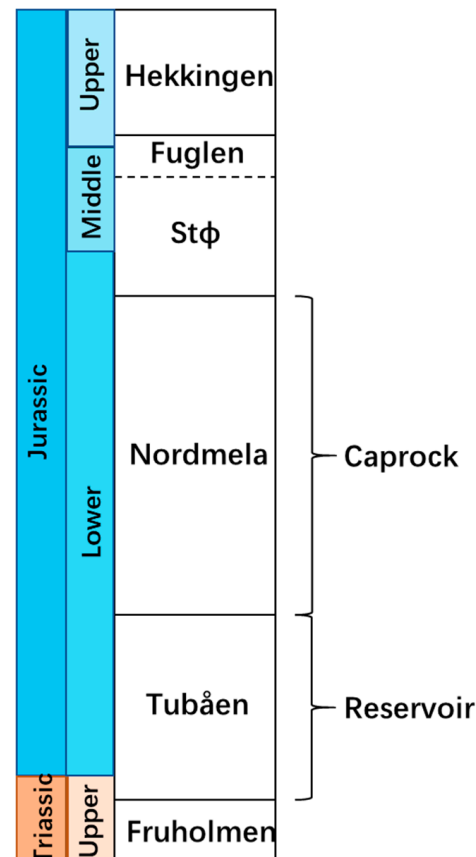


Figure 3. This is the stratigraphic map of the Snøhvit Project, in which the Nordmela Formation (shale) overlies the Tubåen.

A sudden increase in reservoir pressure caused by CO₂ injection is a key challenge in geological sequestration. Excessive CO₂ may activate faults, trigger seismic activities, and even damage caprock integrity. To address the issue of sudden pressure increase, a variety of pressure management strategies are applied in engineering practice: controlling the injection rate to avoid excessive pressure gradients around the wellbore and reduce the risk of pressure breakthrough; adopting intermittent injection to reduce pressure buildup near the wellbore—numerical simulations show that with 48 h each for injection and shutdown periods, the pressure buildup within 10 m of the wellbore can be alleviated by approximately 10% [30]; and deploying multiple injection wells and production wells to proactively regulate the reservoir pressure distribution. The Snøhvit project encountered severe pressure issues in the Tubåen reservoir during the initial injection phase (see Figure 4). Within 6 months of injection, the bottom-hole pressure quickly approached the fracture pressure (39 MPa). The corresponding pressure management strategy was to redirect CO₂ injection to the backup reservoir, and monitor plume dynamics and assess caprock conditions through 4D seismic monitoring [40]. To date, the caprock of this project has effectively prevented CO₂ leakage.

3.3. German Ketzin Project

The Ketzin Project is located in a sub-basin of the Permian–Mesozoic basin system in northeastern Germany. This basin has an anticlinal structure, with a fault zone developed at the top. The target reservoir is the Stuttgart Formation, an Upper Triassic sandstone saline

aquifer located approximately 650 m below the surface [41] (see Figure 5). The Stuttgart Formation has an average thickness of 80 m and is mainly composed of sandstone and shale, with some pores filled with gypsum. Affected by paleorivers, it exhibits heterogeneity in the geological section, with significant differences in porosity and permeability. The effective porosity of the reservoir ranges from 2% to 26%, and the permeability ranges from 0.02 to 2700 mD. The initial reservoir temperature and pressure are 33 °C and 6.2 MPa [42].

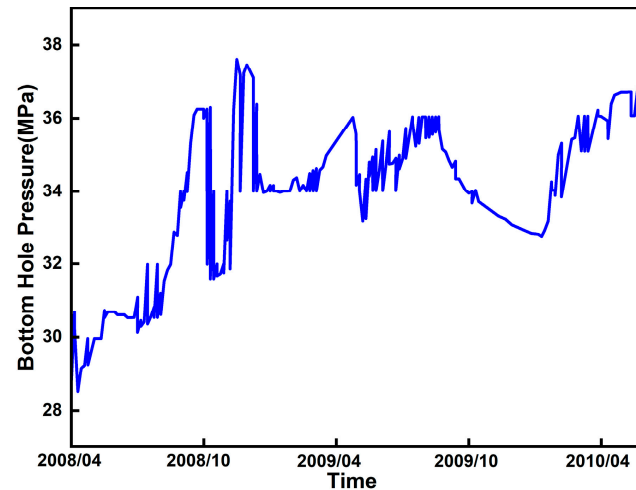


Figure 4. This is the diagram of bottom-hole pressure variation in Well F2H, where the maximum pressure is nearly 38 MPa, approaching the fracture pressure.

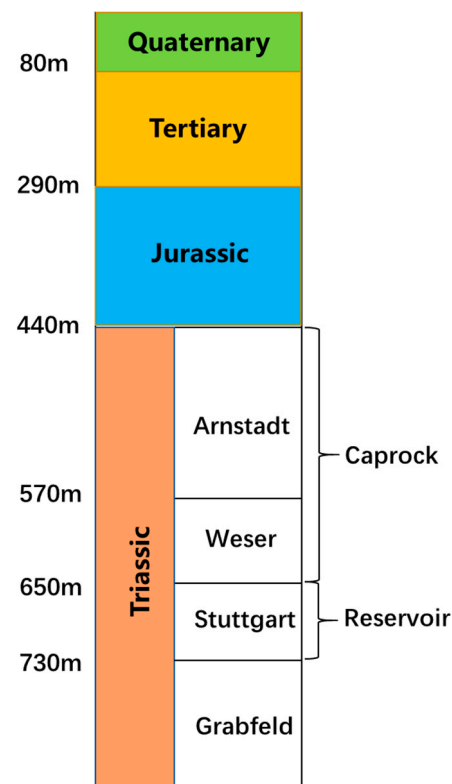


Figure 5. This is the stratigraphic map of the Ketzin Project, which shows the Stuttgart reservoir, located approximately 650 m below the surface.

The upper part of the Stuttgart Formation is overlain by the 80 m thick Weser caprock, the lower part of which is mudstone and the upper part a 10–20 m thick anhydrite layer [42]. Above the Weser caprock, there is also an approximately 130 m thick layer composed of

mudstone and carbonate rock (Arnstadt Formation), providing a second leakage barrier for the sequestration body [43].

Unlike other projects with a burial depth exceeding 800 m, this project's relatively shallow burial depth makes it unable to meet the supercritical CO₂ conditions. Even after corresponding measures are taken, the reservoir pressure rises to 7.4–7.8 MPa and the temperature ranges from 31 °C to 35 °C, basically reaching supercritical CO₂ conditions (33 °C and 7.38 MPa) [44]; however, the CO₂ flowing in the reservoir may still undergo phase changes. Therefore, to ensure sequestration and diffusion efficiency, the injection layer selected for this project has good storage and seepage capabilities. In terms of sequestration safety, the project adopts a classic multi-barrier reservoir–caprock combination, i.e., interbedding high-permeability zones and low-permeability mudstones in the sandstone formation. The resulting vertical heterogeneity effectively restricts vertical CO₂ migration. In addition, the sequestration area is an anticlinal structure, and no faults are found around the injection point, forming a natural trap [45].

Since CO₂ injection can alter the stress state of the reservoir and caprock, thereby affecting sequestration safety, it is necessary to predict geomechanical properties, sealing performance, and leakage risks. Amélie Ouellet established a 3D static geomechanical model for the Ketzin sequestration site to predict potential leakage and assess caprock stability. The results show that during the CO₂ injection process, faults were not activated and the caprock remained stable [42]. Combined with on-site monitoring measures such as 3D/4D seismic monitoring, crosswell seismic monitoring, and electrical resistivity tomography, it was verified that the caprock integrity remained undamaged [46].

3.4. Iceland CarbFix Project

The target formation is olivine tholeiitic basalt composed of interbedded lava flows and pyroclastic rocks [47], with a depth ranging from 400 to 800 m. The 200 m thick top section of the reservoir is composed of relatively unaltered lava flows, where a groundwater system is developed [48]. At a depth of 500 m, the reservoir temperature is approximately 30 °C, rising to 55 °C at 700 m. The average porosity is 8.76%, and the pH value ranges from 8.4 to 9.4 [49]. Due to structural joints and lava sequence directionality, the vertical permeability (1700 mD) is significantly higher than the horizontal permeability (300 mD) [50]. The caprock above the reservoir is a low-permeability pyroclastic rock formation, which seals the target saline aquifer [49].

The reservoir's characteristics—namely its significantly higher vertical than horizontal permeability—lengthen the CO₂ fluid flow path, as has been verified through tracer monitoring prior to formal injection. In the pre-injection test, water was taken from Well HN-01, saturated with dissolved CO₂ (see Figure 6 for the two CO₂ injection methods), after which a tracer was added and injected into the formation through Well HN-02; the tracer was only detected again at Well HN-04: a small portion (~3%) arrived within a few days after injection, while the majority (~97%) appeared much later [51]. The initial 3% migrated through small-volume horizontal fractures at the top of the reservoir, and the remaining 97% migrated slowly through pores; finally, the tracer was detected at a depth of 750 m in Well HN-04 [52]. Both scenarios are shown in Figure 7. The structure of this reservoir can therefore effectively extend the contact time between CO₂ and formation rocks, promoting CO₂ mineralization sequestration [49].

Currently, most CCS projects inject CO₂ into sandstone reservoirs, while a small number inject into basalt reservoirs. The selection of whether to use sandstone or basalt for reservoirs must be comprehensively determined based on the project's core objectives, rock properties, and geological conditions. Sandstone reservoirs are widely distributed and have enormous sequestration potential, but they mainly rely on structural sequestration. Their

mineralization rate is extremely slow, and they depend on structural traps and caprock sealing in the short term. In contrast, basalt reservoirs primarily rely on mineralization sequestration, which features a fast mineralization rate and enables permanent carbon sequestration—no long-term leakage risk monitoring is required. However, their sequestration capacity is limited by the distribution of basalt [17]. Therefore, sandstone reservoirs are preferred for areas with widely distributed sedimentary basins and high-quality caprocks, or for scenarios requiring large-scale sequestration and equipped with infrastructure. Meanwhile, basalt reservoirs are preferred for scenarios where there are widely distributed basalt formations with well-developed fractures, along with extremely high safety requirements at the injection site (e.g., densely populated areas, ecologically sensitive areas), sufficient water sources (for dissolving CO_2), and either small sequestration scales or scales achievable through multi-well clusters [53].

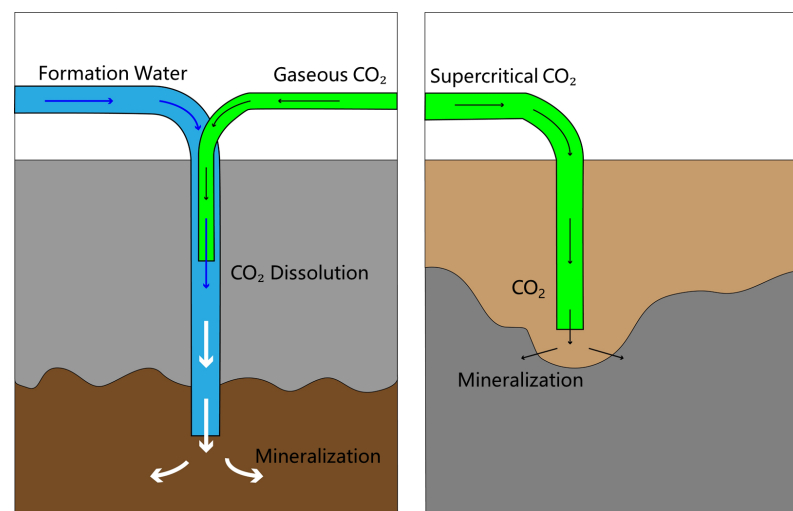


Figure 6. This shows the two CO_2 injection methods, and the Carbfix project employs the method of saturated dissolution of gaseous CO_2 in water.

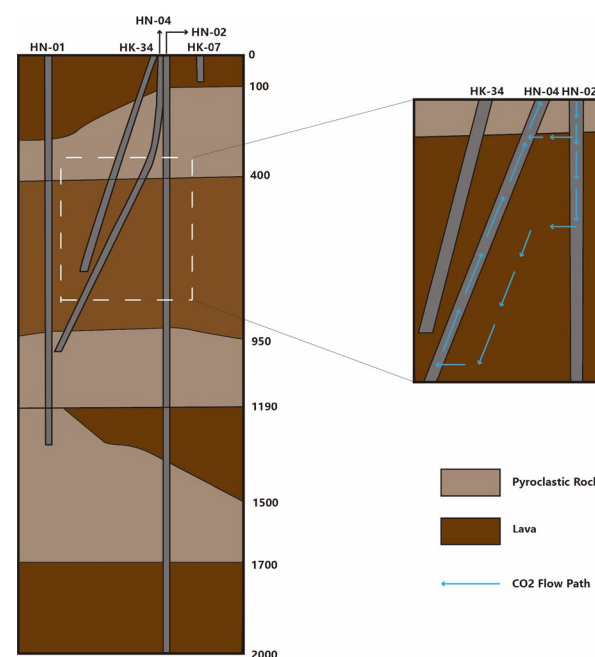


Figure 7. This shows the two flow pathways of CO_2 : the initial 3% of CO_2 migrates through small-volume horizontal fractures at the top of the reservoir, while the remaining 97% migrates slowly through pores. Finally, the tracer was detected in the deep layer at a depth of 750 m in Well HN-04.

3.5. Algerian in Salah Project

From 2004 to 2011, 4 million tons of CO₂ separated from natural gas was injected into the Tournaisian, a Carboniferous sandstone formation, through three wells: KB-501, KB-502, and KB-503 [54,55]. The Tournaisian Formation is approximately 20 m thick and located around 1900 m below the surface, with an average porosity of 17%, a permeability of 10–100 mD [21], and a temperature and pressure of 90 °C and 17.9 MPa, respectively [56].

The Tournaisian Formation is overlain by a mudstone caprock with a length of approximately 1–1.5 km and a thickness of around 900 m [56] (see Figure 8). The caprock consists of two parts: the main part is Carboniferous Viséan mudstone with a thickness of about 700 m, and below it lies Hot Shale with a thickness of approximately 200 m [57]. Similarly to the above-mentioned projects, In Salah does not rely on a single caprock for sealing; instead, the caprock and the thin-layer barriers in the reservoir work together to form a composite sealing system, enhancing sequestration safety. Even if there are geological defects in the caprock, the underlying 1–5 m thick thin mudstone layers can still block vertical CO₂ migration and prevent leakage [58,59].

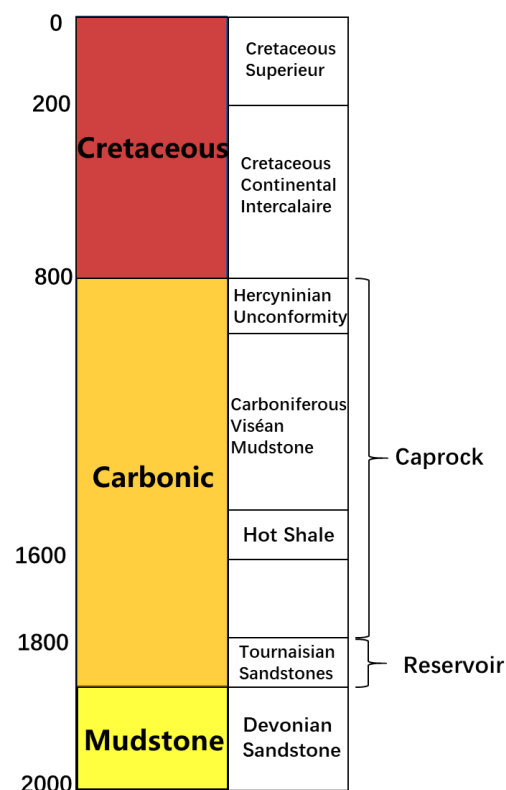


Figure 8. This is the stratigraphic map of the In Salah Project, where the Tournaisian Formation (reservoir) is overlain by a mudstone caprock with a length of approximately 1–1.5 km and a thickness of approximately 900 m.

A series of folds have formed in the Tournaisian Formation under tectonic compression. Although the matrix permeability is low, faults and fractures are relatively well developed [21]. In the context of CO₂ storage, faults and fractures have always been regarded as the main leakage pathways. Compared with the surrounding matrix reservoir, both have high permeability, which allows CO₂ to migrate quickly through the caprock to adjacent aquifers. The local pressure increase caused by CO₂ injection can also lead to fractures near the wellbore. If the injection area intersects with a fault with high permeability, and the fluid pressure induced by injection migrates upward through the caprock, it will increase the risk of vertical leakage to the surface [60]. Therefore, to ensure the safety and

effectiveness of the reservoir, the project established a coupling model based on logging data, seismic data, and InSAR data [46] to predict the deformation and pressure changes in the caprock during CO₂ injection. Although there is clear evidence that the CO₂ injection in this project has induced the upward propagation of natural fractures into the upper caprock, this caprock is sufficiently thick to effectively prevent CO₂ migration [61]. After the project ceased operation, no CO₂ leakage was confirmed through groundwater, soil, and surface gas sampling.

4. Asia–Pacific Region

4.1. Australian Gorgon Project

The Gorgon Project is located on Barrow Island, which is in the offshore Carnarvon Basin along the northwest coast of Australia. This project captures CO₂ separated from nearby gas fields and injects it into the Dupuy Formation, which is approximately 2300 m below the surface, at a rate of 4 million tons per year [62]. The Dupuy Formation is a Late Jurassic clastic formation mainly composed of sandstone and siltstone, with a thickness ranging from 200 to 500 m. Its average porosity and permeability are 20% and 25 mD, respectively, with a salinity of 7×10^3 mg/L, and the temperature and pressure are 70 °C and 20.2 MPa, respectively [63].

The Dupuy Formation can be divided into four main parts from bottom to top: the Basal Dupuy, Lower Dupuy, Upper Massive Sand, and Upper Dupuy. Overlying this formation is the Cretaceous Barrow Formation shale caprock [63] (see Figure 9 for details). The Basal Dupuy, Lower Dupuy, and Upper Massive Sand are basically composed of silt and fine and medium sand, with good sequestration potential and thus serving as the main bodies in this regard. The Upper Dupuy contains lenticular structures and has poor sequestration potential, acting as the first barrier for CO₂ sequestration. The second barrier is the Barrow Formation shale, which is widely distributed over the Dupuy Formation as a caprock [64].

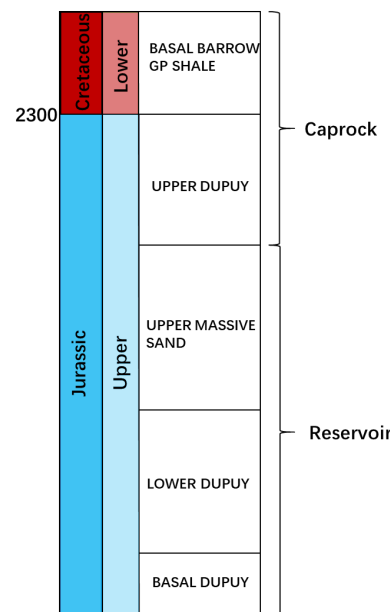


Figure 9. This is the stratigraphic map of the Gorgon Project. The Dupuy Formation can be divided into 4 main parts from bottom to top: Basal Dupuy, Lower Dupuy, Upper Massive Sand, and Upper Dupuy. The Dupuy Formation is overlain by the Cretaceous Barrow Formation (shale caprock).

In the reservoir, stable and gentle formations result in an absence of large-scale structural traps. However, under the influence of buoyancy, supercritical CO₂ in the formation

will migrate horizontally and vertically in the form of plumes [65]. Therefore, in the Upper Dupuy, there is a 100 m thick siltstone “Waste Zone”, which, together with the Barrow Formation shale caprock, jointly prevents vertical CO₂ migration [66]. The Dupuy Formation contains lenticular structures, which are composed of rock layers that are thick in the middle, thin at the edges and sealed by impermeable rock layers. This structure can form natural geological barriers to hinder lateral CO₂ plume migration. In addition, the impermeable layers at the edges of the lenticular structures can increase CO₂ migration resistance via a capillary effect, restricting the plume front’s advancement. Together, these two structures form a CO₂ trapping mechanism, enabling effective sequestration [64].

4.2. Chinese Shenhua Project

The Shenhua CCS Project is located in the Ordos Basin. This area has a gentle structure, weak geological deformation influence, long-term stability, and no developed faults, making it a typical cratonic basin [67]. From 2011 to 2015, 300,000 tons of CO₂ was injected into multiple saline aquifers at a depth of approximately 1690–2450 m (Figure 10) through one injection well (INJW) [21]. These aquifers are distributed in the bottom of the Lower Triassic Liujiagou, Permian Shiqianfeng, and Permian Shihezi Formations, as well as the Permian Shanxi and Ordovician Majiagou Formations [68]. Among these, the thicknesses of the Liujiagou, Shiqianfeng, Shihezi, Shanxi, and Majiagou Formations are 123 m, 291 m, 242 m, 135 m, and 86 m, respectively. Except for the Ordovician Majiagou Formation, which is dolomite, all the other formations are sandstone, with a porosity ranging from 5% to 12.9% and permeability ranging from 0.1 to 6.58 mD [69].

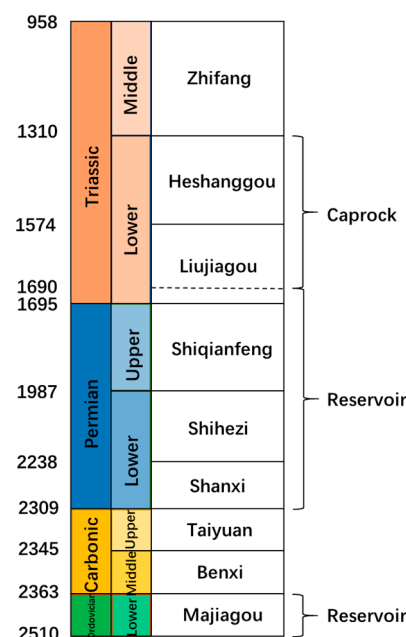


Figure 10. This is the stratigraphic map of the Shenhua Project, where multiple sets of saline aquifers are developed.

Potential sequestration formations require porosity, permeability, and a depth exceeding 800 m. Additionally, a suitable impermeable layer must exist above these formations to prevent CO₂ from rising upward. Based on formation characteristics, the Shenhua CCS Project has identified the following local reservoir–caprock combinations [70]: ① Bottom of the Liujiagou Formation: in the interval of 1690–1695 m, the medium-coarse sandstone with fine gravel serves as the regional reservoir, and the 5–15 m thick mudstone and silty mudstone serve as the regional caprock; ② Shiqianfeng Formation: located in the interval of 1695–1987 m, the bottom of this formation uses feldspathic quartz sandstone as the

regional reservoir (with a porosity of 2~7% and permeability of 0.02~0.28 mD), and the upper part consists of 30–140 m thick interbedded mudstone and silty mudstone with argillaceous siltstone, which serves as the regional caprock; ③ Shihezi Formation: located in the interval of 1987–2238 m, the bottom of this formation uses a set of yellow-green thick-bedded medium-coarse sandstone with gravel as the reservoir (with a porosity of 2~8.5% and permeability of 0.1~0.38 mD), and the upper part consists of 80–150 m thick gray-green and yellow-green mudstone, which serves as the caprock; ④ Shanxi Formation: located in the interval of 2238–2309 m, a well-developed sandstone reservoir is present at the bottom of this formation (with a porosity of 1~9% and permeability of 0.1~0.4 mD), and it is overlain by dark mudstone that acts as the caprock; ⑤ Majiagou Formation: located at a depth of 2363–2510 m underground, the light gray to gray-white calcareous dolomite at the bottom serves as the reservoir, and the top consists of a combination of ferruginous aluminous mudstone, dark mudstone, and argillaceous siltstone, which acts as the caprock. To further ensure sequestration safety, a caprock approximately 700 m thick is selected above these 5 sets of formations, covering the top of the Liujiagou Formation and the Heshanggou Formation. Among them, the bottom of the Heshanggou Formation is mainly composed of mudstone [68], with an average porosity and permeability of 2.99% and 0.25 mD, respectively; the top of the Liujiagou Formation is composed of light reddish-brown fine sandstone and reddish-brown mudstone, with an average porosity and permeability of 11.40% and 4.5 mD [71].

Caprock integrity is one of the key factors for evaluating the long-term containment performance of CO₂. To prevent stored CO₂ from leaking into groundwater sources or the atmosphere, it is essential to inspect and identify potential leakage pathways. Yan W conducted chemical analysis using field-obtained rock and fluid samples from the Shenhua Project, and determined the concentrations of common ions and salinity via ion chromatography. Preliminary analysis indicates that the integrity of the regional caprock is sufficient for the sequestration process of this project [72]. Based on on-site injection data and monitoring well data, with a cumulative injection of 300,000 tons of CO₂, no leakage or adverse phenomena have been observed, and the caprock integrity has been proven to be sound [73].

4.3. Chinese Enping 15-1 Project

There is a naturally well-sealed saline aquifer approximately 3 km away from the Enping 15-1 Platform, which enables long-term CO₂ sequestration. This saline aquifer is located 800–900 m below the seabed, with a thickness of approximately 50 m, an average porosity and permeability of 26% and 2997 mD, respectively, and an initial temperature and pressure of 52.4 °C and 8 MPa. The caprock above it has a thickness of 180 m and a vertical permeability of 0.0004 mD [74].

Therefore, the reason why this reservoir–caprock combination can effectively sequester CO₂ lies in three key characteristics: first, a large reservoir thickness; second, good regional connectivity, which prevents the formation of local high pressure; and third, an overlying, thick low-permeability argillaceous caprock with good sealing performance [74].

4.4. Japanese Tomakomai Project

In this project, CO₂ is injected into two reservoirs. Among them, the shallow Moebetsu Formation is a Pleistocene saline aquifer, located approximately 1000 m below the seabed. It is mainly composed of sandstone, with a thickness of about 200 m, a pressure of 10.67 MPa, a temperature of 44.8 °C, a porosity of 20–40%, and a permeability of 9–25 mD, overlaid by a 200 m thick Moebetsu mudstone caprock. The deep Takinoue Formation is a Miocene saline aquifer, located approximately 2400 m below the seabed, with a thickness of about

600 m and a salinity of 1.8×10^4 mg/L. This reservoir is mainly composed of volcanic and pyroclastic rocks, with a porosity of 3–19%, a permeability of 0.01 mD–2.6 D, a temperature of 91 °C, and a pressure of 34.37 MPa. It is overlaid by a Miocene Series mudstone caprock with a thickness of approximately 1100 m (see Figure 11) [75].

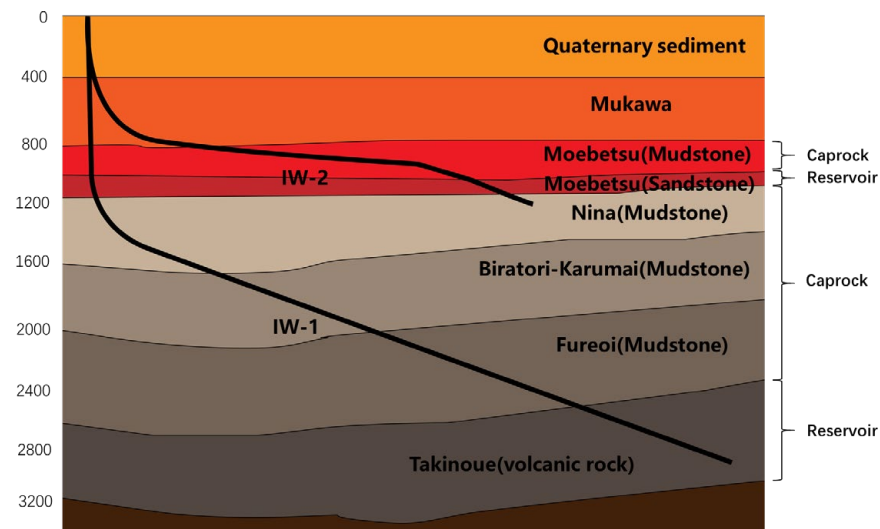


Figure 11. This is the geological cross-section schematic diagram of the Tomakomai Project, and the project injects CO₂ into two reservoirs.

The porosity and permeability of the Takinoue Formation are significantly lower than those of the Moebetsu Formation, and its heterogeneity is also higher [76]. However, during the project site selection process, based on existing adjacent well and 2D seismic data, it was determined that this formation has a large volume and enormous storage capacity. These conditions help alleviate the problem of sharp reservoir pressure increase caused by CO₂ injection into the reservoir; as such, the Takinoue Formation was selected as the main sequestration formation [77]. Nevertheless, in the actual injection tests, the bottom-hole pressure changes in the two formations are shown in Figures 12 and 13; it can be seen that its low porosity and low permeability characteristics restricted the injection process, and the actual injection rate was much lower than planned [78].

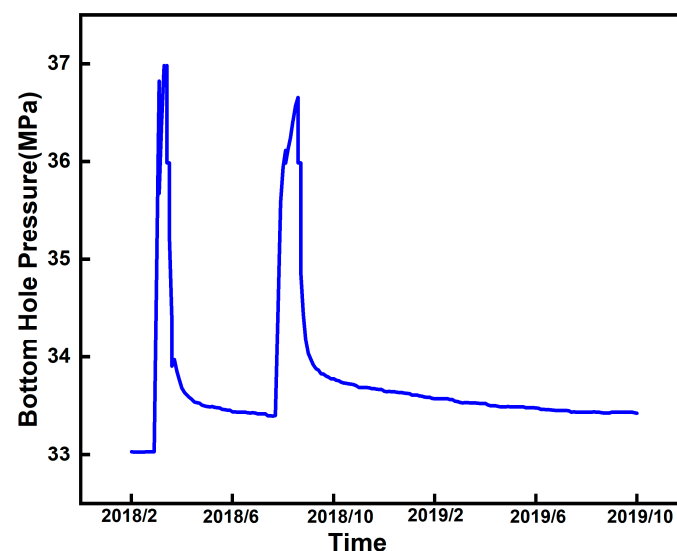


Figure 12. This is the schematic diagram of bottom-hole pressure for Well IW-1, with a pressure increase of nearly 4 MPa.

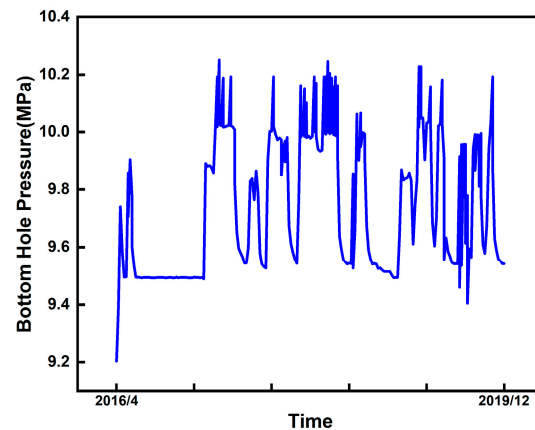


Figure 13. This is the schematic diagram of bottom-hole pressure for Well IW-2, with a pressure increase of less than 1.3 MPa.

4.5. Japanese Nagaoka Project

The project is located in the Nagaoka Oil and Gas Field in southern Niigata Prefecture. The target reservoir Haizume has a depth of approximately 1100 m, a thickness of 60 m, a temperature of 48 °C, and a pressure of 10.8 MPa, with the injected CO₂ in a supercritical state [79]. Based on well test and logging data, the reservoir is divided into five zones (see Figure 14), among which Zone-2 is composed of alternating sandstone, siltstone and conglomerate [80], with a thickness of 12 m, a porosity of 22.5%, and a permeability of 7 mD. It serves as the main CO₂ sequestration layer, with the overlying low-permeability Pleistocene shallow marine formation acting as the caprock [50,81].

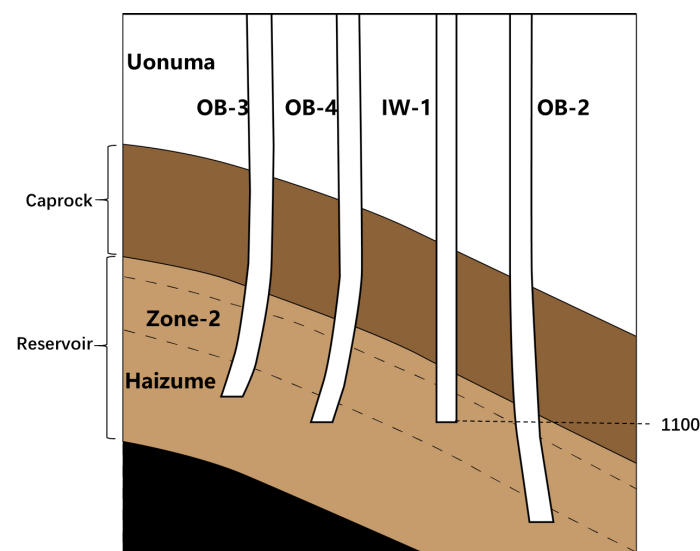


Figure 14. This is the schematic diagram of the Nagaoka Project, where the reservoir is divided into 5 regions.

The geological structure of this project has formed various trapping methods to control CO₂ migration. Physical Trapping [82]: The shale and clay rock layers above the storage reservoir play a role in physical sealing, preventing upward CO₂ migration. Cores collected from injection wells have confirmed their blocking effect on the vertical migration of injected CO₂. Dissolution Trapping: During the lifecycle of injection operations, approximately 29% of CO₂ dissolves in formation water. Mineral Trapping: Over a long time scale, dissolved CO₂ undergoes chemical reactions with rock minerals and is converted into carbonate minerals. Residual Gas Trapping: When CO₂ migrates in the reservoir, formation

water flows back into saturated zones and continuous CO₂ is separated by formation water. Due to capillary pressure, once non-wetting CO₂ is separated from the continuous phase it is trapped in pores [83] (see Figure 15).

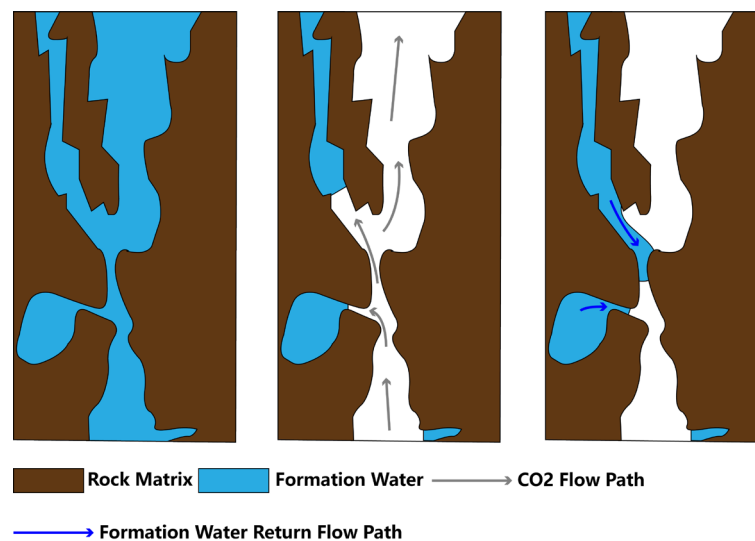


Figure 15. This is a schematic diagram of residual gas trapping. When CO₂ migrates in the reservoir, formation water flows back to the CO₂-saturated zone, and the continuous CO₂ is separated by the formation water. Once non-wetting CO₂ separates from the continuous phase, it is trapped by pores due to capillary pressure.

5. Projects in the Americas

5.1. Canadian Quest Project

The Quest Project is located in the Western Canadian Sedimentary Basin. CO₂ generated from oil sand decarbonization is injected into the saline aquifer in the middle-lower part of the basin through three wells: IW-5-35, IW-8-19 and IW-7-11 [84]. The reservoir has a depth of approximately 2000 m and a thickness of 350 m [85], and is composed of several intervals with different lithologies. In order from deep to shallow, they are the basal Cambrian sandstone, lower marine sand, middle Cambrian shale, and two salt beds [86]. The CO₂ injection point is located in the basal Cambrian sandstone; this layer is locally interbedded with thin mudstone layers, with an average thickness of approximately 41 m, an average porosity and permeability of 17% and 1000 mD, respectively, and an average temperature of 60 °C. The low porosity and permeability of the middle Cambrian shale and Lower and Upper Lotsberg serve as reservoir sealing barriers. The aforementioned formations and the Winnipegosis salt body overlying the reservoir complex jointly constitute the caprock's main body; the entire sequence has a thickness of approximately 300 m [87].

To clarify the direct and indirect impacts of CO₂ migration behavior on the caprock, the project has deployed multiple types of microseismic monitoring facilities, including downhole geophone strings, seismic surface nodes, and distributed acoustic sensors. As of 2022, a total of 656 microseismic events have been monitored [85]. Meanwhile, each of the project's three injection sites is equipped with one deep monitoring well and one shallow groundwater monitoring well. Through comprehensive analysis of microseismic monitoring data and underground sampling data, it can be confirmed that no geological events affecting CO₂ sequestration safety have occurred in the project area [88], and the caprock integrity has been effectively guaranteed.

Deep saline aquifers provide great potential for CCS projects; however, they face a key issue in practical operation, namely halite precipitation. When dry CO₂ is injected into the formation, water in the natural brine evaporates into the CO₂, causing halite to precipitate

from the formation water. This clogs the pore spaces in the near-wellbore area, leading to a decreased CO₂ injection rate [89]. This phenomenon has been observed in multiple CCS projects. In Snøhvit [34] and In Salah [90], for example, reservoir damage caused by halite precipitation was recorded. The Quest Project uses the injection index to represent changes in injection capacity (see Equation (1), where Q_m is the mass injection rate, P_{bh} is the bottom-hole pressure, and P_r is the reservoir pressure). Injection rate monitoring was conducted for Well IW-7-11 in August 2015, and a gradual decrease was observed (see Figure 16). Downhole video imaging logging was performed on this well in April 2018, revealing salt scale covering the perforation holes and thus indicating halite precipitation as a potential cause of the decreased injection rate in this well [88]. Currently, in engineering practice, fresh water [91] or methyl ethylene glycol (MEG) [34] is mostly used for cleaning before injection to dissolve halite precipitation near injection wells. Moreover, pre-injection fresh water cleaning before CO₂ injection can reduce pore blockage and alleviate a certain degree of pressure buildup. This method cannot prevent precipitation from occurring, but it can force it away from the injection point and expand its distribution range, thus reducing injection obstruction. Another method is to saturate and dissolve CO₂ in water before injection, which can directly avoid brine evaporation and thereby prevent halite precipitation [92]. The project carried out flushing and restoration work in July and August 2020, and the injection capacity was quickly improved (Figure 17).

$$I = \frac{Q_m}{(P_{bh} - P_r)} \quad (1)$$

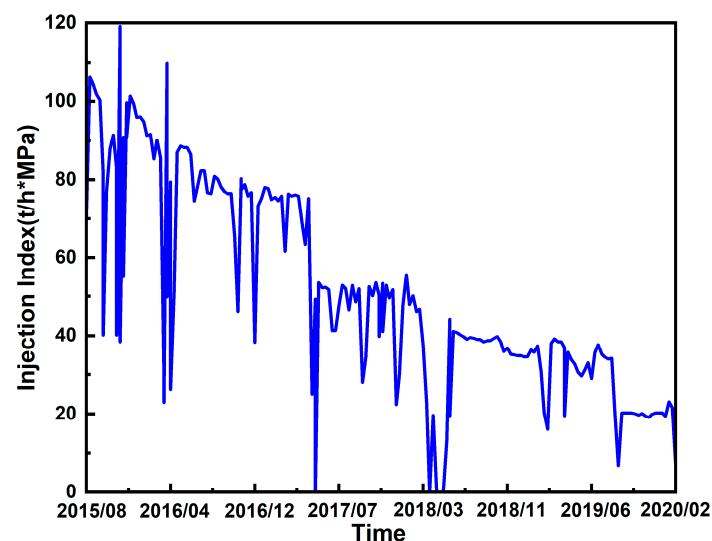


Figure 16. This is the change in injection rate for Well IW7-11, and a gradual decrease in injection rate is observed.

5.2. American Decatur Project

The Illinois Basin, where the Decatur Project is located, is a typical cratonic basin with little geological activity and a stable structure. It has sedimentary rock layers up to several thousand meters deep, including thick mud shale, making it an ideal CCS sequestration site [93]. The injection interval of this project is the Cambrian Mount Simone Sandstone Formation at a depth of 1691–2150 m, with a thickness of approximately 459 m and an average porosity and permeability of 20% and 185 mD, respectively [94]. There is a low-permeability (less than 1 mD) thin layer at a depth of 2092–2094 m [95]. The reservoir is overlaid by a 151 m thick Eau Claire Formation as the caprock. The lower part of this formation is composed of 60 m thick black marine shale and silty mudstone, while the upper part is composed of low-permeability siltstone and carbonate rocks, with a porosity

of 3–4% and permeability of less than 0.001 mD. Its physical properties are significantly lower than those of the reservoir, and it has good sealing performance [94,95].

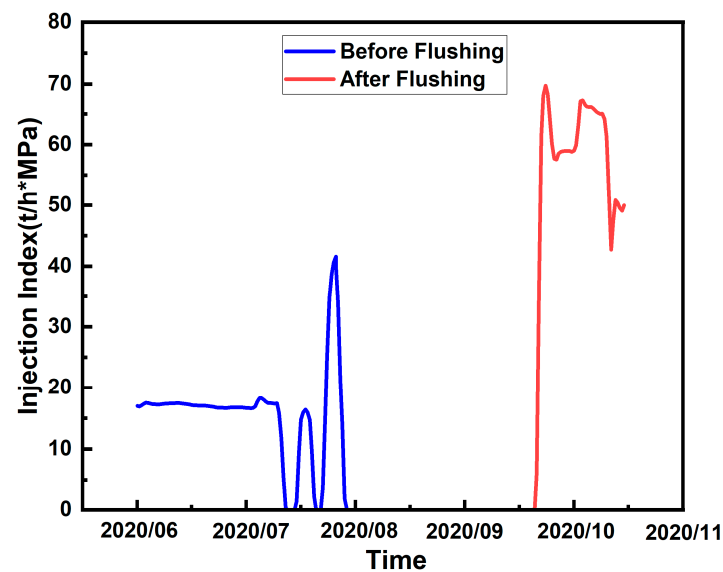


Figure 17. This is a diagram of changes in injection rate before and after freshwater flushing, from which it can be seen that the injection capacity recovered rapidly after flushing.

The sedimentary system of the Mount Simone Sandstone is mainly a continental braided river-alluvial fan system, with aeolian-playa and interdune environments developed locally. In the injection interval, sand bodies are distributed in an interconnected manner. Although the sedimentary extent of individual sand bodies varies, larger flow units can be formed through sand–sand contact relationships, indicating that the reservoir has good connectivity and can effectively promote CO₂ plume diffusion [96].

Similarly to the Quest Project, the Decatur Project has also detected a large number of microseismic events. Scholars' hypocenter depth relocation shows that the seismic activities occurred 400 m above the caprock Eau Claire Shale. Thus, it is concluded that the seismic activities monitored so far do not pose a threat to the sealing integrity of the caprock [97].

5.3. American Wallula Project

In this project, the basaltic formation for injection is composed of multiple continuous lava flow units, contains a regional aquifer [98], and has sufficient porosity and lateral connectivity. Fluid flow within this formation can extend to several kilometers, making it suitable as a target formation for CO₂ injection and sequestration [99]. Seismic exploration results show that there are no fault structures or fracture zones in this area, providing relatively stable geological conditions for sequestration activities [98]. Above the reservoir, there are low-permeability sedimentary layers and basaltic caprocks, which can prevent CO₂ migration and provide sufficient time for mineralization reactions [50].

The injection interval is an interlayer with a thickness of approximately 20 m within the 828–887 m depth range of the Grande Ronde Formation [100], with a temperature of 40 °C, porosity between 10% and 15%, and permeability decreasing from 100 mD to 40 mD as depth increases, giving an average of 70 mD. The caprock has a porosity no greater than 0.5% and extremely low permeability, ranging between 10^{−6} and 10^{−2} mD [101].

5.4. Brazilian Pre-Salt Project

The Pre-Salt reservoir is composed of lacustrine carbonate rocks [102], with a depth of over 5000 m. It is overlaid by an Aptian evaporite layer approximately 2000 m thick, covering the entire Santos Basin [103]. The structural traps of the Pre-Salt reservoir are

mainly attributed to this thick salt caprock. The sparse distribution of faults in the reservoir significantly reduces CO₂ leakage risk; the continuous distribution and high plasticity of the salt rock endow it with a strong self-healing ability, which can inhibit fracture development in the long term [104]. Comprehensively, the structural trapping mechanism and geochemical sequestration of the Pre-Salt Project jointly constitute dual guarantees for safe, long-term CO₂ sequestration [105].

5.5. American SACROC Project

The SACROC project is located in the Kelly Snyder Oilfield, Texas, USA, and is the world's first commercial project for CO₂ flooding. Initially designed for oil production, the project saw a rapid early pressure decline, which forced the operators to adopt pressure maintenance measures such as water injection. When the water spread outside the oilfield, water injection could no longer provide sufficient energy [106]. Therefore, starting from 1972, the SACROC project adopted the method of alternating CO₂ and water injection into depleted oil and gas reservoirs to enhance oil recovery, with a CO₂ injection rate of 7 million tons per year [107].

The Cisco and Canyon formations are the oil-producing layers of the project, and also the target layers for CO₂ injection. They are Pennsylvanian carbonate rocks and part of the Horseshoe Atoll reef complex. Due to large-scale fluctuations in sea level, karstification, clastic flow, vuggy, and microfractures are present in the formation [108]. Measurements show that the reservoir porosity ranges from 4.0% to 20.0%, and the permeability varies even more significantly, showing strong heterogeneity. Its average physical properties are as follows: burial depth of 2042 m, thickness of 79 m, porosity of 7.6%, and permeability of 19.4 millidarcies (mD) [12].

Overlying the SACROC reservoir is a 150 m thick Wolfcampian shale. This thick, organic-rich black shale layer, due to its tight and low-permeability (0.05 mD) characteristics, has become a regional and highly effective cap rock. It not only successfully trapped a large amount of oil and gas in the carbonate reservoir but also provided a reliable sequestration barrier for the CO₂ injected later, ensuring that CO₂ is safely stored deep underground and preventing it from leaking into shallow aquifers or the atmosphere. Despite 50 years of CO₂ injection with a cumulative injection volume of 150 million tons, no signs of CO₂ leakage have been found through surface calcium deposition, changes in the chemical properties of shallow groundwater, abnormal surface CO₂ gas concentrations, or long-term changes in surface vegetation [12].

Tables 2 and 3 summarize the site and reservoir selection parameters and characteristics of typical CCS projects worldwide.

Table 2. Summary of reservoir geological parameters.

Project	Temperature (°C)	Pressure (MPa)	Depth (m)	Thickness (m)	Porosity (%)	Permeability (mD)	Salinity (mg/L)	Lithology	Geological Characteristics
Sleipner	37	10.3	800–1000	250	37	1000–8000	3.5×10^4	Sandstone	Large-scale anticline structure; faults are not developed
Snøhvit	98	28.5	2600	45–130	1–16	130–880	1.6×10^5	Sandstone	Fault-block structure; faults are developed
Carbfix	30–55	/	400–800	400	8.76	Vertical: 1700 Horizontal: 300	/	Basalt	Vertical permeability is significantly higher than horizontal permeability
Ketzin	33	6.2	630–650	20–100	2–26	0.02–2700	/	Sandstone, Shale	Anticlinal basin; fault zone is developed at the top
In Salah	90	17.9	1900	20	17	10–100	/	Sandstone	Anticline, folds are formed, faults are developed
Gorgon	100	22	2300	200–500	20	25	7×10^3	Sandstone, Siltstone	Anticline
Shenhua	/	/	1690–2450	877	5–12.9	0.1–6.58	/	Sandstone, Dolomite	Cratonic Basin, gentle structure, monoclinical structure, faults are not developed
Enping 15-1	52.4	8	800–900	50	26	2997	/	/	Good regional connectivity, injection will not form local high pressure
Tomakomai	Shallow Layer: 44.8 Deep Layer: 91	Shallow Layer: 10.67 Deep Layer: 34.37	Shallow Layer: 1000 Deep Layer: 2400	Shallow Layer: 200 Deep Layer: 600	Shallow Layer: 20–40 Deep Layer: 3–19	Shallow Layer: 9–25 Deep Layer: 0.01 mD–2.6 D	Deep Layer: 1.8×10^4	Shallow Layer: Sandstone Deep Layer: Pyroclastic Rock	Deep Takinoue Formation with poor physical properties, not conducive to injection
Nagaoka	48	10.8	1100	60 (Zone-2)	22.5	7	/	Sandstone, Siltstone, Conglomerate	/
Quest	60	/	2000	350	17	1000	/	Sandstone, Shale, Salt Rock	Sedimentary Basin
Decatur	/	/	1691–2150	459	20	185	/	Sandstone	Cratonic Basin, few geological activities, stable structure
Wallula	40	/	828–887	20	10–15	40–100, average 70	/	/	Regional aquifers exist in basalt, providing a suitable environment for sequestration
Pre-Salt	/	/	Over 5000	/	/	/	/	Lacustrine Carbonate	Faults are sparsely distributed in the reservoir
SACROC	/	/	2042	79	7.6	19.4	/	carbonatite	Develop karstification, clastic flow, vuggy and microfractures

Table 3. Summary of caprock geological parameters.

Project	Depth (m)	Thickness (m)	Porosity (%)	Permeability (mD)	Lithology	Characteristics
Sleipner	/	200–300	/	/	Clay Minerals, Partial Silt Minerals	There are thin shale layers in the reservoir
Snøhvit	/	60–100	13	1–23	Shale	There are thin shale layers in the reservoir
Ketzin	440–650	Weser: 80, Arnstadt: 130	/	/	Anhydrite Layer, Mudstone, Carbonate Rock	Two composite strata
Carbfix	/	/	/	/	Pyroclastic Rock	/
In Salah	800–1800	900	/	/	Mudstone	There are 1–5 m thick thin shale layers in the reservoir
Gorgon	2000	/	/	/	Shale, Sandstone	There are geological lenses
Shenhua	1310–1690	700	Heshanggou Formation: 2.99, Liujiagou Formation: 11.4	Heshanggou Formation: 0.25, Liujiagou Formation: 4.5	Mudstone, Sandstone, Feldspar Rock	/
Enping 15-1	/	180	/	0.0004	Argillaceous	/
Tomakomai	/	Shallow Layer: 200 Deep Layer: 1100	/	/	Mudstone	/
Nagaoka	/	/	/	/	Argillaceous Shale	Pleistocene Neritic facies
Quest	/	300	/	/	/	/
Decatur	1539	151	3–4	Less than 0.001	Shale, Silty Mudstone, Siltstone, Carbonate Rock	/
Wallula	/	/	Not exceeding 0.5	10^{-6} – 10^{-2}	Low-Permeability Sedimentary Rock and Basalt	/
Pre-Salt	/	2000	/	/	Evaporite	The continuity and high-plasticity characteristics of salt rock enable it to inhibit fracture development
SACROC	/	150	/	<0.05	Shale	/

6. Global Development Recommendations for CO₂ Geological Sequestration Technology

6.1. Engineering Challenges Faced by CCS Technology Development

As a key supporting technology for achieving global carbon neutrality goals, CCS technology has been applied in demonstration projects in some countries and industries. However, from the perspective of global large-scale deployment, it still faces multiple systematic engineering challenges, such as site and formation selection, engineering parameter design, long-term monitoring, and difficulties in large-scale development and full industrial chain advancement. These intertwined issues severely restrict its transition from the “demonstration phase” to the “commercial popularization phase”.

(1) Complexity and Uncertainty in Sequestration Site Selection

A qualified sequestration site must meet multiple criteria, including high porosity and permeability of the reservoir, caprock integrity, geological structural stability, and sufficient burial depth. However, existing exploration technologies can only identify faults and large fractures within the reservoir range, thus ignoring the impact of micro-fractures on CO₂ leakage. Currently, the determination of reservoir porosity and permeability parameters can only be conducted through laboratory experiments on core samples, while well logging only targets the wellbore profile, making it impossible to measure the physical parameters of the entire reservoir. Therefore, to ensure the safety and effectiveness of site selection, it is necessary to obtain underground data using multiple technical means such as seismic exploration, well logging, and sampling analysis [109]. Even so, accurate characterization of formations thousands of meters below the surface remains impossible, resulting in inherent risks in sequestration potential assessment, injection capacity prediction, and long-term safety analysis.

(2) Limitations of Long-Term Sequestration Monitoring

After successful CO₂ injection into the ground, it is necessary to ensure its safe storage in the reservoir over time scales of hundreds or even thousands of years in the future. Any potential formation defects may weaken the sealing performance of the caprock and even pose threats to the local ecological environment. Leakage is a gradually worsening process, and early detection of micro-leakage is extremely challenging. Therefore, it is essential to establish a multi-level and multi-dimensional comprehensive monitoring system. Specifically, optimized technology combinations and monitoring plans must be designed based on the specific conditions of the site, and a sound monitoring index system must be established to achieve efficient, economical, and reliable long-term monitoring.

(3) Difficulties in Injection and Site Parameter Design

The CO₂ injection process is a critical link in CCS technology, so the success of this process is directly related to sequestration effectiveness and long-term safety [110]. From an engineering perspective, factors affecting CO₂ injection and long-term sequestration effects include site parameters and injection parameters—namely, the number, distribution pattern, and spacing of injection/monitoring wells, as well as injection temperature, pressure, displacement, and method. Appropriate well layout can significantly affect the uniformity of CO₂ distribution in the reservoir and monitoring effects, while reasonable injection parameters can ensure that CO₂ exists in a supercritical state in the wellbore and formation, enhancing plume mobility and sequestration capacity, and preventing CO₂ from breaking through the caprock or activating faults. However, CCS technology still faces issues such as the risk of wellbore integrity failure, challenges in CO₂ distribution uniformity, and insufficient scientific basis for parameter regulation. The existing engineering design and

injection parameter system have not yet fully solved the problems of sealing performance, plume control, and long-term stability under complex geological conditions.

(4) Difficulties in Large-Scale Layout and Full Industrial Chain Development

Existing CCS projects are still mainly pilot projects, with a lack of large-scale demonstration experience and high costs. Onshore sequestration projects are few in number and small in scale, and the long-term sequestration effects of deep saline aquifers and depleted oil and gas reservoirs still require verification by more million-ton-level projects. Offshore sequestration projects need to integrate full-chain technologies of CO₂ capture, compression, transportation, and injection. Although coastal industrial zones have high emission intensity, they lack shared transportation pipelines, and a cross-enterprise and cross-industry carbon transportation infrastructure sharing mechanism has not yet been established. The capture, transportation, and sequestration segments belong to different industries, with inconsistent technical standards and business models, leading to difficulties in integrating the entire industrial chain [111].

6.2. Development Recommendations for CCS Technology

To address the aforementioned challenges and ensure the safety and effectiveness of CO₂ geological sequestration, a series of measures must be implemented throughout the whole project lifecycle.

(1) Establish a Multi-Level, Quantitative Site Selection Evaluation System and Clarify Quantitative Thresholds for Key Geological Parameters

From a macro perspective, it is recommended to develop a detailed multi-scale evaluation system to achieve a gradual focus from regional-level assessment, basin-level screening, target-level optimization, to site-level detailed investigation. This evaluation system should cover multiple modules including geological conditions, sequestration potential, socio-economic factors, and environmental risks. It should also adopt methods such as the Analytic Hierarchy Process (AHP) and GIS technology [104] to conduct quantitative weighting and spatial overlay analysis on various indicators, and generate site selection zoning maps to provide intuitive basis for decision-making. From a micro perspective, clarify the quantitative thresholds of key geological parameters such as reservoir–caprock thickness, porosity, permeability, burial depth, and maximum pressure limit. Develop differentiated standards by combining the aforementioned multi-scale evaluation system with regional geological characteristics.

(2) Build a Comprehensive and Multi-Dimensional Monitoring System to Effectively Identify and Assess CO₂ Leakage Risks

CO₂ monitoring technologies include migration monitoring and leakage monitoring. Migration monitoring refers to tracking the range of CO₂ migration (including horizontal and vertical directions). It mainly uses methods such as Vertical Seismic Profile (VSP) and downhole temperature and pressure testing, which is of great significance for understanding the evolution of CO₂ plumes. Leakage monitoring refers to monitoring whether CO₂ leaks through methods such as shallow groundwater monitoring, isotope monitoring, and atmospheric eddy covariance method, so as to effectively evaluate the safety of CCS projects [112]. There are many CO₂ monitoring technologies, each with different applicable conditions, advantages and disadvantages. The deployment of monitoring methods needs to be combined with the environmental conditions and requirements of the sequestration project to build a comprehensive three-dimensional monitoring system, which can effectively identify and assess the risks of CO₂ leakage. Table 4 below lists the commonly used monitoring measures in some projects.

Table 4. This is a summary of commonly used detection measures in typical projects. It is categorized by three monitoring locations (deep layers, surface, and atmosphere) and two monitoring contents (migration and leakage).

Projects	Monitoring Methods	Spatial Location	Content Classification
Sleipner	3D/4D Seismic	Deep	Migration
	Gravity Monitoring	Deep	Migration
Weuburn	VSP	Deep	Migration
	Microseismic	Deep	Migration
	Soil Flux	Surface	Leakage
	Groundwater Sampling	Surface	Leakage
In Salah	InSAR	Surface	Leakage
	Time-lapse Seismic	Deep	Migration
	Ssotope Tracer	Surface	Leakage
	Soil Gas Analysis	Surface	Leakage
Ketzin	Cross-Hole Resistivity	Deep	Leakage
	Downhole Temperature and Pressure	Deep	Leakage
	Microorganism	Surface	Leakage
Tomakomai	Permanent Subsea Cable	Surface	Leakage
	Ocean-Bottom Seismometer	Deep	Migration
Shenhua	Atmospheric Eddy Covariance Monitoring	Atmosphere	Leakage
	SF ₆ Tracer	Surface	Leakage
	Radar Deformation Monitoring	Surface	Leakage

(3) Strengthen the Collaborative Optimization of Engineering Parameters for CCS Projects

From an engineering perspective, the design parameters that affect CO₂ injection and long-term sequestration effects can be divided into three categories: wellsite layout, wellbore design, and injection parameters. In terms of wellsite layout, the collaborative layout of injection wells and monitoring wells is the most important parameter. Its rationality directly affects CO₂ plume migration control, formation pressure field balance, and multi-dimensional risk monitoring; parameters such as wellsite scope and distance do not affect injection and monitoring effects, but they will impact engineering feasibility and social acceptability. In terms of wellbore design, integrity-related parameters (wellbore, cement materials, and wellbore structure) are key parameters to prevent CO₂ leakage along the wellbore; parameters such as well completion method and wellbore depth support sealing performance and injection efficiency, and need to be considered collaboratively with wellbore integrity parameters. In terms of injection parameters, injection pressure and injection rate directly affect the safety of the entire injection process. In summary, to achieve the core objectives of safe sequestration, efficient injection, and controllable costs, it is urgent to strengthen the collaborative optimization of design parameters.

6.3. Development Prospects for CCS Technology

In the field of CCS technology, China has made a certain amount of progress in theoretical research and engineering practice; however, further focus on site and reservoir selection methods is necessary, especially from the perspective of the coupling of multiple physical fields during long-term sequestration. Emphasis should be placed on aspects such

as CO₂–rock–water interactions, geostress fields, dynamic temperature field evolution, and fault activation. Taking these as constraint conditions, a new method for CO₂ geological sequestration site and reservoir selection should be developed. Future research should strengthen the following aspects:

- (1) The coupling process of physical geostress–temperature–formation properties should be studied, considering the multi-scale effects of mineral dissolution, precipitation, pore pressure evolution, and changes in rock mass mechanical properties. In this way, multi-field coupling models suitable for different geological sequestration scenarios can be established.
- (2) Through the integration of long-term laboratory physical simulation and field monitoring data, the temporal variation laws of formation porosity, permeability and mechanical strength during the long-term sequestration process should be quantified, improving the parameter calibration method for the site and formation selection model.
- (3) A risk assessment algorithm based on the multi-field coupling model should be developed to accurately identify potential risk areas (e.g., structurally active zones) during the site and reservoir screening phase. In this way, theoretical support could be provided for safety assessment, risk prediction, and sequestration site emergency prevention and control.

7. Conclusions

By systematically reviewing the site and formation selection practices of 15 typical global CCS projects (including Norway's Sleipner, Germany's Ketzin, Iceland's Carbfix, China's Shenhua and Enping 15-1, the U.S.'s Decatur, and Australia's Gorgon), this paper conducts a quantitative comparative analysis focusing on the key geological parameters of reservoir–caprock assemblages, and clarifies the core parameter thresholds and adaptation rules for the safe and efficient implementation of CO₂ geological sequestration.

From the perspective of reservoirs, ① Sandstone or basalt formations with gentle structures and underdeveloped faults are ideal sites for CO₂ sequestration. The Sleipner project, relying on a large fault-free anticline structure, has successfully sequestered over 20 million tons of CO₂, becoming a benchmark for large-scale sequestration. Although the Shenhua project uses low-permeability sandstone, it still achieves the safe sequestration of 300,000 tons of CO₂ due to the gentle structure of the craton basin and the absence of developed faults. ② Reservoirs need to have relatively high porosity and permeability to ensure CO₂ diffusion into the deep part of the formation. For high-porosity and high-permeability reservoirs, such as the Utsira Sandstone of the Sleipner project (porosity 37%, permeability 1–8 D), no sudden pressure increase has been observed after the cumulative injection of 20 million tons of CO₂. For low-porosity and low-permeability reservoirs, such as the sandstone of the Shiqianfeng Formation in China's Shenhua project (porosity 2–7%, permeability 0.02–0.28 mD), multiple sets of reservoir–caprock combinations are required to make up for insufficient seepage capacity. For the deep Takinoue Formation of the Tomakomai project (porosity 3–19%, permeability 0.01 mD–2.6 D), the actual injection rate is much lower than the designed value due to relatively low porosity and permeability, which intuitively reflects the key role of high porosity and permeability in improving diffusion efficiency. ③ Formations with stable and large-scale sand bodies have great sequestration potential, and the formation pressure rises slowly after injection. The Utsira Sandstone of the Sleipner project extends 450 km from north to south, with a sequestration potential of 1.6 billion tons; during more than 20 years of injection, the formation pressure has remained stable, and no leakage has been monitored. ④ Formations with good vertical compartmentalization and lower vertical permeability of the reservoir than horizontal permeability are conducive to the lateral migration of CO₂ plumes. Low-permeability

interlayers have developed in the reservoirs of projects such as Snøhvit, Shenhua, and Gorgon, dividing the reservoir into multiple independent flow units, significantly reducing vertical permeability and effectively controlling the upward movement of plumes.

Regarding caprocks, ① The lithology of caprocks is mainly dominated by thick mudstone and shale. Moreover, composite caprocks composed of multiple low-permeability formations and tight interbeds within the reservoir can significantly improve the sealing performance of the formation. For example, the caprock of the Enping 15-1 project (180 m thick, vertical permeability 0.0004 mD) and the Eau Claire caprock of the U.S. Decatur project (151 m thick, permeability < 0.001 mD) collectively reflect the quantitative range for effective sealing: “caprock thickness $\geq$ 50 m, permeability < 0.01 mD”. The Ketzin project, on the other hand, forms a composite barrier through the Weser caprock (80 m thick mudstone) and the Arnstadt caprock (130 m thick mudstone and carbonate rock), ensuring sequestration safety. ② Site selection should avoid the intersection of injection areas with high-permeability faults, and a sufficiently thick caprock can reduce leakage risks. The In Salah project established a coupling model based on logging and seismic data, clearly avoiding high-permeability fractures and fault zones in the injection area. Although injection-induced fractures were monitored to propagate upward, the 900 m thick mudstone caprock effectively prevented CO₂ leakage.

Meanwhile, the key parameters provided in this paper also offer quantitative references for engineering practice. The reservoir burial depth mostly exceeds 800 m (e.g., 800–900 m for Enping 15-1 and 2600 m for Snøhvit) to meet the supercritical temperature and pressure conditions of CO₂ (temperature $\geq$ 31 °C, pressure $\geq$ 7.38 MPa); during the injection process, intermittent injection (simulations show that 48 h each for injection and shutdown can alleviate 10% of pressure accumulation) can significantly alleviate pressure accumulation near the wellbore and avoid fault activation. In summary, through the quantitative comparison of key geological parameters of typical global projects, this paper reveals the ideal sequestration model of “gentle structure + large-scale reservoir with high porosity-permeability and low lateral heterogeneity + multi-layer ultra-thick composite caprock with low permeability”, and further clarifies the selection and response measures for different geological conditions (e.g., sandstone/basalt) and different sequestration challenges (pressure management, halite precipitation). In the future, it is necessary to further strengthen the research on the theory of formation multi-physical field coupling, consider the impacts of long-term sequestration on the formation stress field, temperature field, and physical-chemical properties, etc., and provide a scientific basis for avoiding high-risk areas in site and formation selection as well as for safety assessment.

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