Earth Systems, Resources, and Sustainability, Online First, 2026

Scilight Earth Systems, Resources, and Sustainability

Journal Homepage: https://www.sciltp.com/journals/esrs

Review

Formation-Specific CO_2 Trapping in Geological Storage: A Review of Classical Mechanisms and Supporting Retention Processes

Muhammad Hammad Rasool[1,2,*], Numair Ahmed Siddiqui[2], Maqsood Ahmad[2], Nisar Ahmed[2], Muhammad Mubashir[2], Opeyemi Lawal[2], Muhammad Shakil[2] and Arnob Deb[2]

[1] Department of Oil and Gas Engineering, Faculty of Chemical Engineering, Universiti Teknologi MARA, 40450 Shah Alam, Selangor, Malaysia

[2] Geoscience Department, Universiti Teknologi PETRONAS, Bandar Seri Iskandar, 32610, Perak, Malaysia

[*] Correspondence: hammadrasool44b@gmail.com

ABSTRACT

The long-term security of geological CO_2 storage depends on trapping mechanisms and the geological and hydrodynamic controls governing their effectiveness. Although classical mechanisms are well established, their interactions with formation-specific controls remain insufficiently integrated into comparative assessments. This review examines structural, residual, solubility, mineral and adsorption trapping, and evaluates capillary entry pressure, regional groundwater flow, and geological heterogeneity as controls on CO_2 migration and immobilization. Experimental, numerical, and field evidence published between 1979 and 2026 is synthesized across seven settings: onshore and offshore saline aquifers, depleted hydrocarbon reservoirs, basalts, ultramafic formations, organic-rich shales, and coal seams. Quantitative comparisons of residual saturation, capillary breakthrough pressure, adsorption parameters, and mineralization performance reveal how pore architecture, wettability, permeability contrasts, fluid transport, and mineral reactivity alter retention. Structural trapping depends on seal integrity and capillary thresholds, whereas residual trapping reflects pore-scale displacement and saturation hysteresis. Groundwater flow and reservoir heterogeneity influence plume migration, CO_2–brine contact, and access to reactive minerals, thereby governing dissolution and carbonation. In coal and shale, adsorption retains CO_2 directly, although swelling and restricted pore accessibility can limit injectivity. An evidence-informed five-dimensional framework compares mechanism clarity, time to effectiveness, permanence potential, enhancement potential, and monitoring transparency. It identifies formation-specific trade-offs and verification uncertainties, providing a basis for interpreting geological CO_2 retention and monitoring priorities under representative geological conditions and available field evidence.

ARTICLE INFO

History:

Received 23 September 2026
Revised 16 November 2026
Accepted 23 November 2026
Published: 27 November 2026

Keywords:

CO_2 trapping mechanism;
CO_2 storage;
in situ mineralization;
decarbonization

Citation:

Rasool, M.H.; Siddiqui, N.A.; Ahmad, M.; et al. Formation-Specific CO_2 Trapping in Geological Storage: A Review of Classical Mechanisms and Supporting Retention Processes. *Earth Systems, Resources, and Sustainability*. Online First, 2026. https://doi.org/10.53941/esrs.2027.100001

Copyright: © 2026 by the authors. This is an open access article under the terms and conditions of the Creative Commons Attribution (CC BY) license (https://creativecommons.org/licenses/by/4.0/).
Publisher's Note: Scilight stays neutral with regard to jurisdictional claims in published maps and institutional affiliations.

Research Highlights

- Critically reviews CO_2 trapping mechanisms across seven geological environments.
- Evaluates structural, residual, solubility, mineral, adsorptive and supporting trapping processes.
- Introduces a five-dimensional framework for comparing trapping effectiveness.
- Identifies formation-specific limitations, enhancement opportunities, and monitoring gaps.

1. Introduction

To achieve mid-century net zero emissions, a robust strategy to reduce legacy carbon emissions is required in addition to a rapid shift to renewable energy sources [1–3]. Carbon capture and storage (CCS) remains one of the most scientifically sound and technologically feasible options in the portfolio of climate mitigation solutions for the permanent sequestration of anthropogenic CO_2 [4–6]. However, the long-term success of CCS depends on one important principle: the long-term containment of injected CO_2 within the storage complex.

Current research in CO_2 storage within the scientific and engineering communities recognizes and classifies trapping into five primary mechanisms: structural, residual, solubility, mineral, and adsorptive trapping, with the latter being particularly relevant to organic matter-rich formations such as coal seams and shales [7–10]. These mechanisms provide a useful conceptual framework; however, they may oversimplify the complex, formation-specific interactions among fluid behaviour, rock properties, and temporal evolution. In practice, each geological formation; whether a saline aquifer, depleted hydrocarbon reservoir, basalt formation, shale layer, or coal seam, exhibits unique physical, chemical, and flow properties that govern how CO_2 is trapped [11].

More importantly, the relative contribution, time to effectiveness [12], permanence [13], and detectability [14] of individual trapping mechanism vary substantially among geological formations and evolve throughout the operational and post-closure phases of a storage site. For instance, mineralization or mineral trapping may be the most secure form of trapping, but its onset can take decades or centuries, limiting its immediate contribution to short-term monitoring, reporting, and verification (MRV) programs [15, 16]. Conversely, structural trapping offers rapid containment following injection but may be susceptible to leakage pathways associated with faults, fractures, or caprock breaches [17]. In addition, formation-dependent retention mechanisms, particularly adsorptive trapping in organic-rich formations [18] and supporting controls, such as hydrodynamic effects [19], remain comparatively less emphasized in conventional CCS assessment frameworks.

The understanding of CO_2 storage mechanisms across a wide range of geological formations has been substantially advanced through extensive research. Previous reviews have examined geological CO_2 storage at different levels. For example, Rasool and Ahmad proposed a multi-heuristic screening framework for evaluating the suitability of different formations for CO_2 sequestration [20]. In a related study, Rasool and Ahmad introduced a reactivity-based scale for assessing the mineralization potential of different basalt formations [21]. Kim et al. provided a comprehensive review of mineral trapping mechanisms [22], while Bashir et al. examined the broader spectrum of CO_2 storage pathways and associated challenges [23]. Similarly, a range of previous studies conducted by individual researchers or research groups have investigated the behaviour of CO_2 trapping in saline aquifers [7], in other formations such as depleted oil and gas reservoirs [24], shale formations [18], coal bed methane (CBM) reservoirs [25], sandstone formations [26], basalts [27], ultramafic formations [28] and carbonate systems [29]. Despite these advances, a critical knowledge gap remains in understanding how the effectiveness and relative contribution of established CO_2 trapping mechanisms vary across geological settings and how formation-specific characteristics regulate long-term storage performance.

Existing reviews commonly discuss structural, residual, solubility, and mineral trapping individually, while the interactions between these classical mechanisms and supporting retention processes and controls, including adsorption, hydrodynamic effects, capillary entry pressure, and geological heterogeneity, remain fragmented across different formation types. Thus, the novelty of this review lies in integrating the five classical CO_2 trapping mechanisms with supporting retention processes and geological controls, including regional groundwater flow, capillary

entry pressure, and facies heterogeneity, to explain why the dominant retention pathways differ across seven geological settings and how these differences affect trapping timescales, permanence, enhancement potential, and field verification.

This perspective review develops a formation-specific framework for evaluating geological CO_2 trapping behaviour and long-term storage performance. It distinguishes the five classical trapping mechanisms, namely structural, residual, solubility, adsorption, and mineral trapping, from additional retention processes and geological controls, including hydrodynamic effects, capillary entry pressure, and geological heterogeneity. These mechanisms and controlling factors are evaluated across saline aquifers, depleted oil and gas reservoirs, basaltic and ultramafic formations, shales, coal seams, and offshore deep saline systems to determine how geological context governs relative contributions. A five-dimensional (5D) evaluation framework is proposed to systematically compare storage formations based on trapping performance, limitations, monitoring requirements, and long-term storage feasibility. By linking fundamental trapping processes with geological context and practical storage considerations, this review provides an integrated basis for site evaluation, monitoring design, and improved assessment of long-term geological CO_2 storage performance.

To provide the broader context of the CCS value chain, an integrated overview of carbon capture, conditioning, transport, and subsurface storage processes is presented in Figure 1.

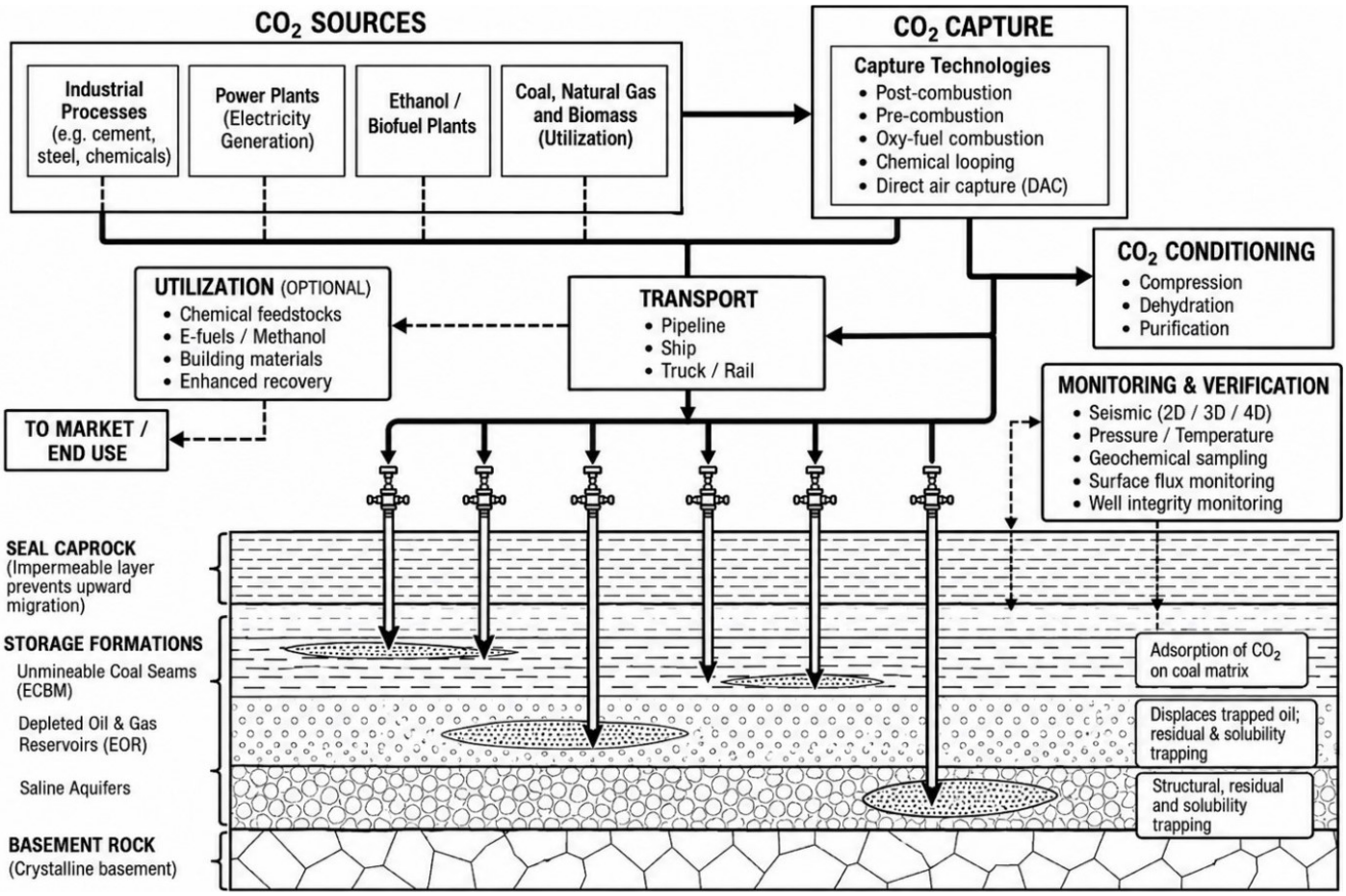

Figure 1. Integrated overview of carbon capture, conditioning, transport, and subsurface storage processes.

2. Literature Search Strategy and Review Structure

The literature included in this narrative review spans 1979–2026, from foundational studies on carbonate–aquifer geochemistry to recent investigations of CO_2 trapping in geological formations. The search combined general terms such as "geological CO_2 storage" and "carbon sequestration" with terms for classical trapping mechanisms and supporting retention processes and controls, including "structural trapping", "residual trapping", "solubility trapping", "mineral trapping", "CO_2 adsorption", "regional groundwater flow", "capillary entry pressure", and "reservoir heterogeneity." Formation-specific terms included "saline aquifer", "depleted oil and gas reservoir", "basalt", "shale", "coal seam", and "ultramafic rock" from three platforms such as SCOPUS, Web of Science and Google Scholar.

Studies were selected for their relevance to the mechanisms that retain CO_2, the geological and operating conditions that control their effectiveness, or the methods used to verify retention. The review drew on field observations, laboratory experiments, and numerical studies. Studies focused solely on CO_2 capture, transport, or *ex situ* mineralization were outside the scope of the trapping synthesis. Findings were interpreted in the context of formation type, study scale, and reported conditions, particularly where laboratory results or model predictions were used to explain field behaviour. The selected evidence was synthesized first by trapping mechanism and then across seven geological settings. This comparison informed the five-dimensional framework, which evaluates the clarity of the dominant retention mechanism, its time to effectiveness, permanence potential, enhancement potential, and monitoring transparency.

This review implements a narrative review approach with critical synthesis to systematically examine and compare the classical and supporting mechanisms governing CO_2 trapping in subsurface geological environments. In addition to the mechanism-by-mechanism treatment, the review extends the investigation by evaluating how each trapping mechanism performs across seven major geological settings such as saline aquifers, depleted oil and gas reservoirs, basaltic formations, shales, coal seams, offshore deep saline systems, and ultramafic complexes. This enables the identification of dynamic interdependencies between formation properties and trapping performance, thereby revealing constraints and trade-offs that are often overlooked in siloed assessments.

To support this comparative evaluation, a five-dimensional framework is developed to assess each formation across key performance criteria: (i) clarity of the dominant trapping mechanism, (ii) time to effectiveness, (iii) permanence potential, (iv) enhancement feasibility, and (v) monitoring transparency. The scoring system is informed by a synthesis of peer-reviewed field studies, laboratory experiments, and geochemical modelling insights.

3. Overview of CO_2 Trapping Mechanisms

CO_2 trapping mechanisms refer to the physical, chemical, and thermodynamic processes that keep injected carbon dioxide stored within subsurface formations [10, 30]. These mechanisms act at different rates and vary in effectiveness depending on the geological and hydrological conditions of the storage formation [31, 32]. Geological CO_2 retention includes five classical trapping mechanisms: structural, residual, solubility, and mineral trapping where adsorption provides an additional direct retention mechanism and can dominate in coal seams and some organic-rich shales. Regional groundwater flow, capillary entry pressure, and facies heterogeneity influence where CO_2 migrates and where these retention mechanisms operate. Capillary entry pressure is the threshold that must be exceeded for CO_2 to invade a brine-filled pore or sealing unit. During brine imbibition, capillary forces can also disconnect the CO_2 phase through snap-off, leaving isolated ganglia that contribute to residual trapping. These roles are treated separately because resistance to phase invasion and residual immobilization occur at different stages of displacement.

This section first explains the main classical trapping mechanisms and then discusses the other processes that can affect how well they work with time. The classification shown in Figure 2 provides the basis for the subsequent discussion.

3.1. CO_2 Trapping and Retention Mechanisms

Classical trapping mechanisms describe the main ways injected CO_2 is kept within geological formations. These include structural, residual, solubility, and mineral trapping, and each works through different physical or chemical processes and over different timescales. Their contribution to safe CO_2 storage depends on reservoir properties, fluid–rock interactions, and the geological setting. The following subsections explain how each mechanism works and the main factors that control it.

3.1.1. Structural Trapping

Structural trapping is one of the first mechanisms that keeps injected CO_2 within a storage formation. It works by trapping buoyant CO_2 beneath a low-permeability geological seal, as shown in Figure 3 [10, 33]. After injection, supercritical CO_2 is less dense than formation brine and therefore tends to move upward through permeable rocks. This movement continues until the CO_2 reaches a low-permeability caprock, such as shale, mudstone, or evaporite [34, 35]. If the geological structure provides a closed trap, such as an anticline, fault block, or stratigraphic wedge, the CO_2 collects beneath the seal. This is similar to the way oil and gas are naturally trapped underground and the concept has been widely applied in CO_2 storage related modelling studies [17].

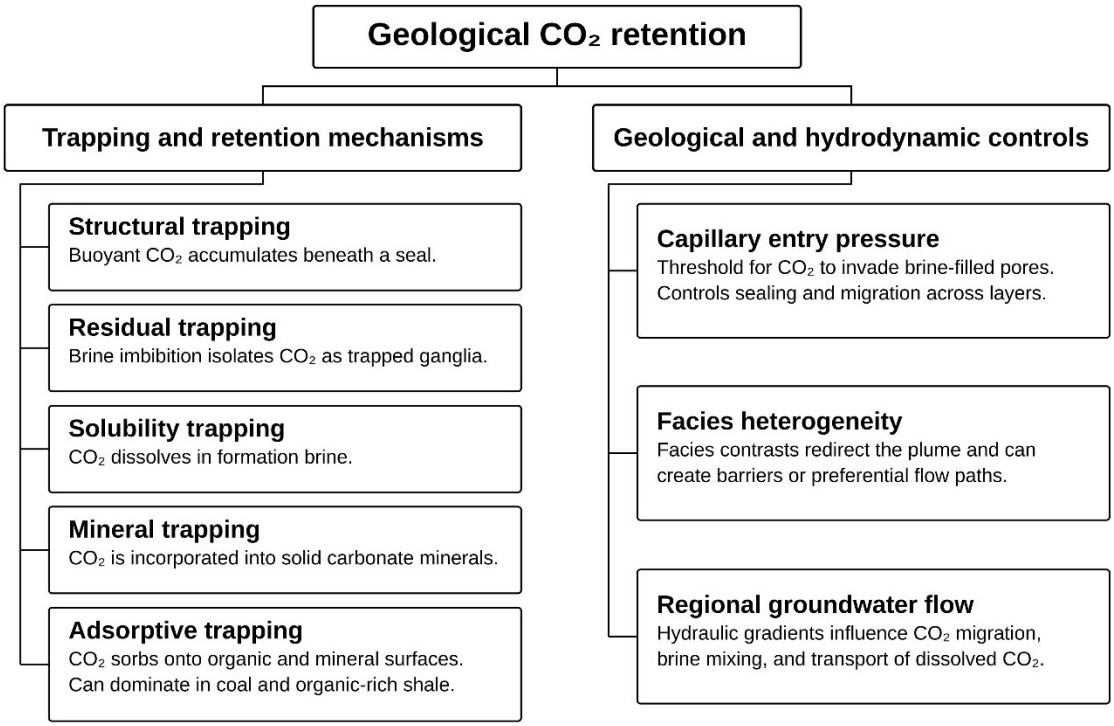

Figure 2. Different types of classical and supporting CO_2 subsurface trapping mechanisms.

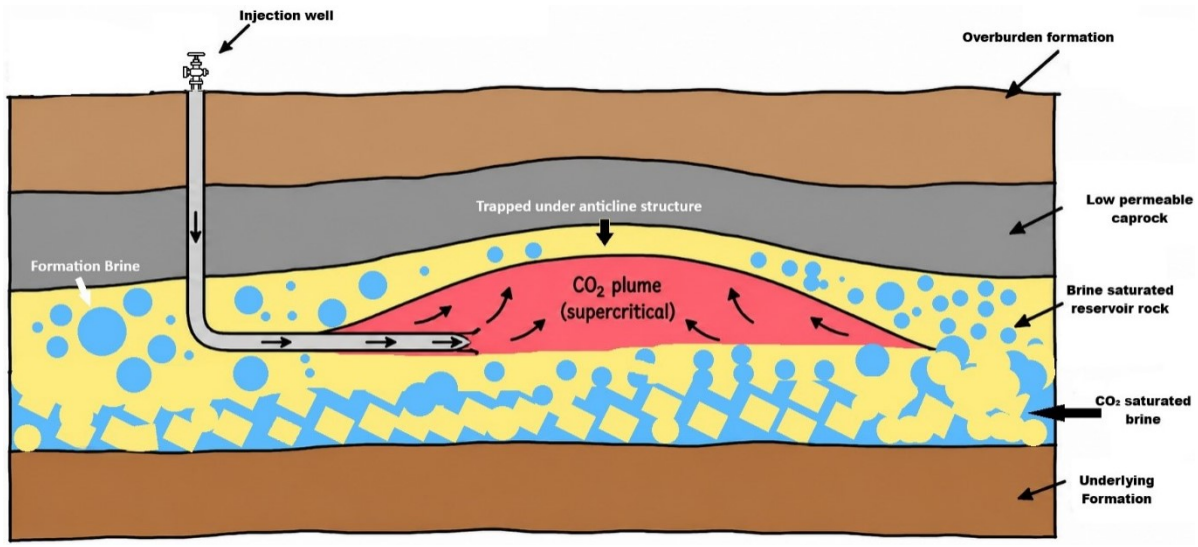

Figure 3. Conceptual illustration of structural trapping of CO_2 beneath a caprock in a saline aquifer (schematic, not to scale).

However, structural trapping does not guarantee permanent storage on its own because the CO_2 remains physically trapped without being chemically changed [36]. Its long-term performance therefore depends greatly on the condition of the caprock and the presence of faults or fractures that could allow CO_2 to escape [37, 38]. A caprock that is initially stable may also be affected if injection raises the pressure beyond its fracture limit. This may cause new fractures, reopen existing faults, or allow CO_2 to pass through the caprock. In formations with existing fractures or small leakage pathways, the chance of CO_2 migration may increase if other trapping mechanisms do not provide additional retention [39]. In coupled hydromechanical simulations, Zhang et al. found that sustained pore-pressure diffusion could drive fault reactivation and that the extent of slip depended on the permeability of the fault damage zone [40].

Structural trapping depends on the capillary sealing capacity, lateral continuity, and mechanical integrity of the caprock. Free-phase CO_2 can enter an intact, brine-wet seal when the local CO_2–brine pressure difference exceeds its capillary entry pressure. Once entry occurs, further migration depends on seal permeability and thickness, as well as the connectivity of the avail-

able flow paths [36]. Faults can restrict flow across a low-permeability fault core while transmitting fluids along connected fractures in the surrounding damage zone. Their transmissibility depends on fault-rock composition, the juxtaposition of reservoir and sealing units, and fracture aperture and connectivity [41]. During injection, increasing pore pressure can reduce the effective normal stress across faults and fractures, promoting fracture opening or slip on favourably oriented faults. Cooling near the injection well can further alter local stresses. The effect on containment depends on whether these changes create or improve a connected pathway through the sealing sequence. At In Salah, monitoring data were consistent with hydraulic fracturing in part of the lower caprock and possible interaction with pre-existing fractures, while the available evidence indicated that CO_2 remained within the overall confinement zone [42].

The effectiveness of structural trapping also varies with the type of storage formation. It is most effective in depleted oil and gas reservoirs and saline aquifers that have clearly defined structures and continuous sealing rocks [43, 44]. In comparison, basalt formations, organic-rich shales, and ultramafic rocks may not have the closed geological structures needed for this type of trapping, making other trapping processes more important. Structural traps can be monitored using methods such as 4D seismic imaging and pressure analysis, although these methods may not always detect very small leaks, gradual fault movement, or slow CO_2 migration through pathways that are difficult to identify.

3.1.2. Residual Trapping

Residual trapping, also called capillary trapping, occurs when small amounts of CO_2 become trapped within the pore spaces of the reservoir rock, as shown in Figure 4 [45, 46]. It develops when brine re-enters CO_2-swept pores during imbibition and disconnects the CO_2 phase into isolated ganglia. In brine-wet rock, brine films can thicken in narrow throats and sever the CO_2 connecting adjacent pore bodies, a process known as snap-off. The tendency for snap-off depends on the distribution of pore-body-to-throat size ratios, pore connectivity, and the advancing brine contact angle. Narrow throats connecting wider pore bodies can favour snap-off, whereas wettability closer to neutral can suppress it. CO_2–brine interfacial tension sets the magnitude of capillary forces and, together with flow velocity and brine viscosity, governs the balance between capillary and viscous forces during imbibition [47]. This dependence on displacement history is reflected in relative permeability hysteresis. At the same CO_2 saturation, the imbibition curve can show lower CO_2 relative permeability than the drainage curve because a portion of the CO_2 is disconnected and contributes little or nothing to flow [48]. In Berea sandstone at 70 °C and 9 MPa pore pressure, CO_2 occupied 85% of the pore volume at the end of drainage and 35% remained after brine imbibition [49]. Across four sandstone cores, Krevor et al. reported maximum residual CO_2 saturations of 21–33% of pore volume [50]. These results show why reservoir models should use rock-specific relationships between initial and residual CO_2 saturation rather than a single trapping fraction.

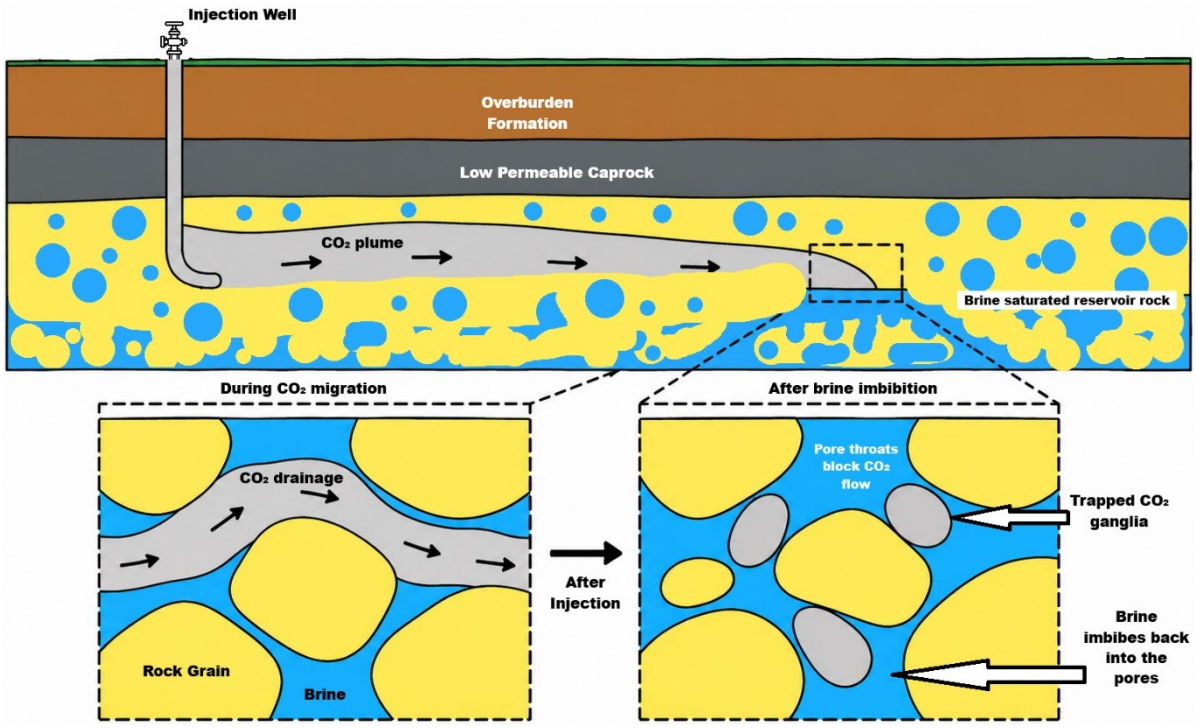

Figure 4. Illustration of residual trapping governed by drainage–imbibition hysteresis during CO_2 injection and post-injection phases. Capillary forces isolate CO_2 as immobile ganglia within pore throats, limiting remobilization (schematic, not to scale).

Residual trapping is a particularly robust and early acting mechanism, typically becoming effective within weeks to months after injection. Unlike structural trapping, residual immobilization does not require structural closure, although overall storage security still depends on adequate containment of the storage complex. This form of trapping is governed by the hysteresis in the relative permeability-saturation curves between drainage (CO_2 displacing brine) and imbibition (brine re-entering CO_2 zones) and is thus highly sensitive to pore-scale rock properties, fluid-rock wettability, and interfacial tension. Water-wet formations with fine pore structures, high capillary entry pressures, and favourable wettability conditions promote stronger residual trapping [51].

Despite its advantages, residual trapping is not universally unfailing. Its effectiveness contrasts sharply across formations due to differences in pore geometry, rock mineralogy, and fluid distribution dynamics. For instance, residual trapping is limited in highly fractured or vuggy formations where capillary continuity is disrupted. Regional groundwater flow can redirect the free-phase CO_2 plume and promote dissolution under favourable conditions, but it does not directly immobilize free-phase CO_2 [52]. Its influence on plume migration depends on the magnitude and direction of the hydraulic gradient. Using pore-scale imaging and modelling, Moghadasi et al. showed that pressure depletion can remobilize residually trapped CO_2 when disconnected CO_2 clusters reconnect and form a continuous flow path [53]. Additionally, modelling and validating residual trapping at the field scale remains challenging. *In situ* quantification often demands sophisticated tracer tests, core-flooding experiments, or time lapse seismic surveys, which have its own limitations in spatial resolution and interpretability [54].

From a risk perspective, residual trapping helps reduce the chance that CO_2 will move again if the caprock is damaged or reservoir pressure changes. For this reason, it is often included in simulation models as an additional safeguard against leakage, especially where structural trapping is limited. However, its effectiveness is not the same in every formation. It should be assessed based on local geological variations, reservoir history, and changes in fluid saturation over time [55].

3.1.3. Solubility Trapping

Solubility trapping refers to the process by which injected CO_2 dissolves into the formation brine, converting from a free-phase supercritical fluid into an aqueous-phase species that cannot migrate under buoyant forces as shown in Figure 5 [56].

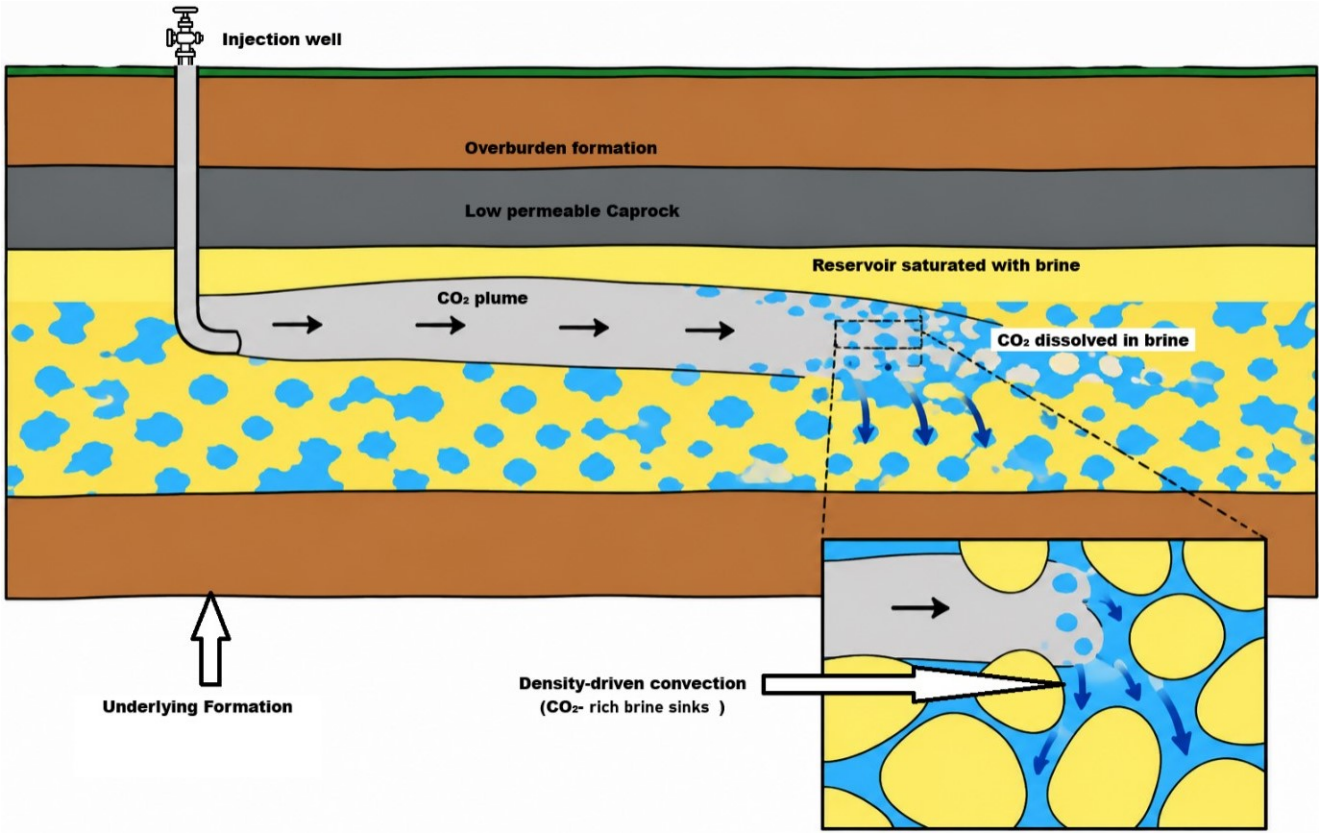

Figure 5. Schematic of solubility trapping illustrating CO_2 dissolution into formation brine and subsequent density-driven convection. Dissolved CO_2 forms carbonic species, enhancing stability and reducing plume mobility over time (schematic, not to scale).

At reservoir conditions, the equilibrium molality of molecular CO_2 dissolved in brine depends on the fugacity of CO_2 in the CO_2-rich phase and its activity in the aqueous phase [57, 58].

$$\gamma_{CO_2(aq)} \frac{m_{CO_2(aq)}}{m^\circ} = K_{diss}(T,P) \frac{f_{CO_2}}{f^\circ}, \qquad f_{CO_2} = \phi_{CO_2}\, y_{CO_2}\, P \tag{1}$$

Here, m and γ refer to the molality and aqueous activity coefficient of molecular CO_2 dissolved in brine. The dissolution equilibrium constant is dimensionless and depends on temperature T and pressure P. The reference molality m° is 1 mol kg^{-1}, and the reference fugacity f° is 1 bar. In the CO_2-rich phase, φ is the CO_2 fugacity coefficient, which accounts for non-ideal behaviour, and y is the CO_2 mole fraction. At fixed temperature, pressure, and CO_2 fugacity, increasing brine salinity generally reduces the equilibrium molality of dissolved CO_2 through the salting-out effect [57]. Equations (2a)–(2c) describe how dissolved inorganic carbon is distributed among aqueous species.

Dissolution and Acid–Base Reactions go by Equations (2a)–(2c).

$$CO_2(aq) + H_2O \rightleftharpoons H_2CO_3 \tag{2a}$$

$$H_2CO_3 \rightleftharpoons H^+ + HCO_3^- \tag{2b}$$

$$HCO_3^- \rightleftharpoons H^+ + CO_3^{2-}. \tag{2c}$$

These reactions form bicarbonate species, which are pH-sensitive and buffered by brine alkalinity. This transformation from molecular CO_2 to aqueous ions increases the chemical stability and reduces the mobility of CO_2 in the formation. Prominently, as CO_2 dissolves, the local brine density increases, initiating density-driven convection, which enhances further dissolution through downward fingering of CO_2-rich brine [59].

The amount of CO_2 that dissolves in formation water depends on temperature, pressure, brine composition, and how long the CO_2 remains in contact with the water [60, 61]. Higher pressures in deeper formations allow more CO_2 to dissolve. Dissolved CO_2 may also react with ions such as Ca^{2+} and Mg^{2+} and later contribute to mineral trapping. However, dissolution can be slow in low-permeability or layered formations because fluid movement and mixing are limited. In such settings, it may take decades for large amounts of CO_2 to dissolve, making its contribution to long-term storage difficult to measure directly [62].

A limitation of solubility trapping is that dissolved CO_2 is difficult to detect directly with geophysical methods. Unlike free CO_2, it does not produce strong seismic or resistivity changes. Its presence is therefore usually assessed through fluid and geochemical measurements or estimated using numerical models. Although dissolved CO_2 can return to a free phase if pressure or temperature changes, conditions in deep saline formations generally favour it remaining dissolved. For this reason, solubility trapping is often treated as a long-term form of CO_2 storage at depths greater than about 800–1000 m. It also reduces the amount of mobile CO_2, limits upward movement, and supports chemical reactions that may eventually lead to mineral trapping [63].

In summary, solubility trapping serves as an important intermediate mechanism that enhances the thermodynamic stability of stored CO_2 [9, 64]. The equilibrium extent of dissolution depends on CO_2 fugacity, brine composition, and aqueous carbonate speciation, while the rate of dissolution depends on CO_2–brine contact and mixing. Although it is difficult to confirm directly in the field, it contributes to long-term CO_2 storage and should be considered when planning a safe storage site.

3.1.4. Mineral Trapping

Mineral trapping is widely regarded as the most permanent and thermodynamically secure mechanism for CO_2 sequestration as shown in Figure 6 [65]. It involves the transformation of dissolved CO_2 into solid carbonate minerals through geochemical reactions with reactive components of the reservoir rock [66, 67]. Once CO_2 dissolves in formation brine, the resulting carbonate species (HCO_3^-, CO_3^{2-}) can interact with metal cations such as calcium, magnesium, or iron released from silicate or carbonate minerals, precipitating as solid phases like calcite ($CaCO_3$) magnesite ($MgCO_3$) or siderite ($FeCO_3$) [68].

The general form of the mineralization reaction is represented by Equations (3a)–(3c)

$$CO_2(aq) + H_2O + Ca^{2+} \rightarrow CaCO_3(s) + 2H^+ \tag{3a}$$

$$CO_2(aq) + H_2O + Mg^{2+} \rightarrow MgCO_3(s) + 2H^+ \tag{3b}$$

$$CO_2(aq) + H_2O + Fe^{2+} \rightarrow FeCO_3(s) + 2H^+. \tag{3c}$$

When CO_2 dissolves in formation brine, it initially lowers the pH and can accelerate the dissolution of reactive minerals, releasing Ca^{2+}, Mg^{2+}, and Fe^{2+}. The rate of cation release depends on mineral composition, temperature, and the reactive surface area in contact with the brine. As fluid–rock reactions consume acidity and buffer the pH, a greater fraction of dissolved inorganic carbon occurs as carbonate ions. Carbonate minerals can precipitate when the activities of carbonate ions and the relevant cations are high enough for the brine to become supersaturated with respect to a particular mineral phase. Even under supersaturated conditions, slow nucleation or crystal growth can delay precipitation, while competing reactions can consume cations that would otherwise be available for carbonation. The overall mineralization rate therefore depends on how quickly the rock supplies cations and buffers acidity, how long the CO_2-rich brine remains in contact with reactive surfaces, and how rapidly carbonate minerals precipitate. The precipitated carbonates provide durable storage where they remain stable under the expected reservoir conditions [22, 69, 70].

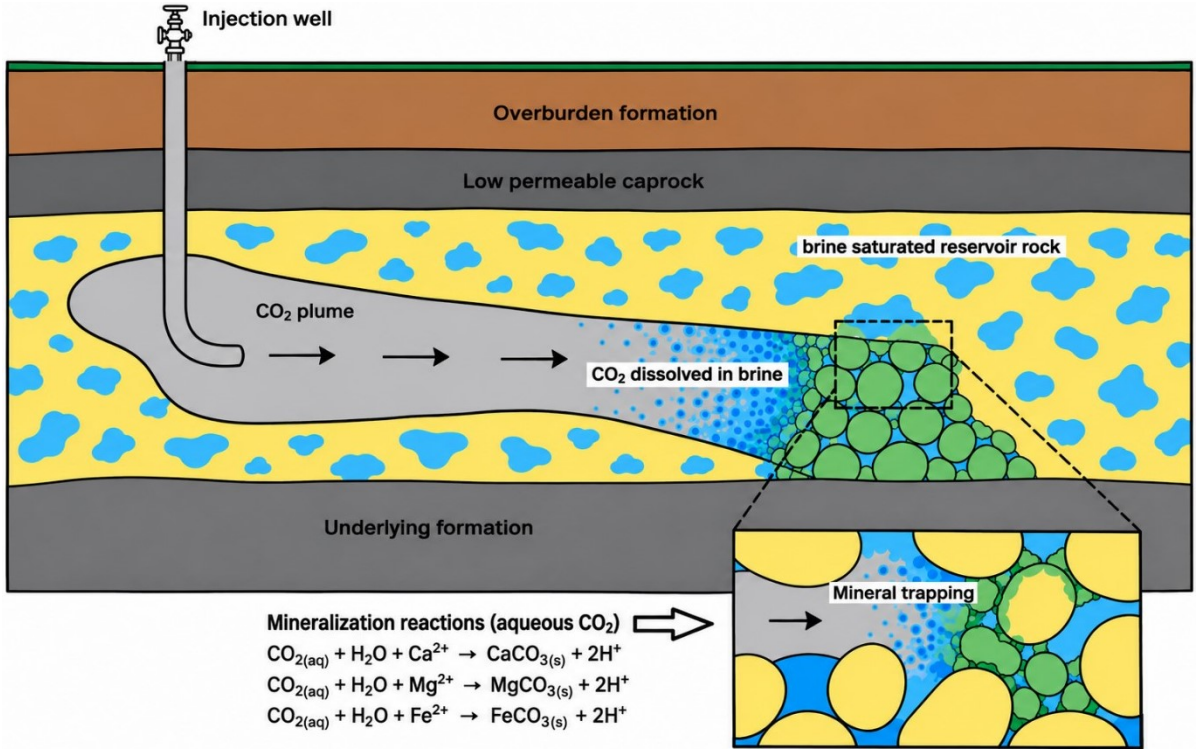

Figure 6. Illustration of mineral trapping driven by fluid–rock interactions and carbonate precipitation reactions in porous media. CO_2 is converted into stable mineral phases (e.g., $CaCO_3$, $MgCO_3$, $FeCO_3$), providing permanent sequestration (schematic, not to scale).

Mineral trapping works well in basaltic formations, ultramafic rocks, and feldspathic sandstones. Basalts, for instance, are rich in calcium and magnesium bearing silicates, and field experiments such as CarbFix in Iceland have demonstrated near complete carbonation within 2 years under favourable geochemical and hydrological conditions [71]. In contrast, carbonate reservoirs may not gain much from mineral trapping due to buffering effects that suppress CO_2 reactivity or because pre-existing carbonate saturation limits further precipitation [72, 73].

Despite its promise, mineral trapping remains difficult to verify using conventional monitoring tools. In the early stages, mineral formation may cause only small changes in seismic and resistivity measurements. For this reason, methods such as geochemical modelling, isotope analysis, and core samples are often used to check whether mineralization has occurred. Mineral precipitation may also reduce porosity and permeability or block pore spaces if it develops near injection zones or along flow paths [74].

In summary, mineral trapping converts dissolved inorganic carbon into solid carbonates. The durability of this retention depends on the stability of the precipitated phases under the expected reservoir conditions. As such, it should be seen as a long-term mechanism, best suited for formations rich in reactive silicates and those capable of maintaining extended fluid–rock contact time.

3.1.5. Adsorptive Trapping

Adsorptive trapping is a formation-specific process that supports the main trapping mechanisms by providing another way to hold CO_2 on solid surfaces, where organic-rich material is present. As shown in Figure 7, CO_2 is adsorbed physically on mineral surfaces or organic matter within the reservoir rock. Unlike solubility trapping, where CO_2 dissolves in formation brine, or mineral trapping, where CO_2 reacts to form solid minerals through precipitation, adsorption mainly depends on intermolecular forces such as van der Waals forces. These intermolecular forces hold CO_2 molecules on internal surfaces within microporous structures. Its importance therefore depends strongly on the composition and surface properties of the formation. Adsorption becomes especially important in low-permeability, clay-rich, or carbon-rich formations such as shales, coal seams, and tight mudrocks, illustrated in Figure 7 [65]. This process is specifically important in low-permeability formations that contain high amounts of clay, organic matter, or carbon-rich material [75, 76].

CO_2 adsorption in coal and shale depends on the composition of the solid matrix, the distribution of accessible pore sizes, and competition from water and other gases. In coal, rank and maceral composition influence the abundance and surface chemistry of micropores. In shale, kerogen type and thermal maturity affect organic porosity, while clay minerals provide additional adsorption surfaces [77, 78]. Moisture can occupy adsorption sites and block access to narrow pores, reducing the surface area available to CO_2 and CH_4. In binary adsorption experiments on marine shales at 60 °C and pressures up to 11 MPa, Wei et al. reported CO_2/CH_4 selectivity factors of 1.14–2.66.

Moisture reduced uptake of both gases, with a larger reduction for CH_4 [79]. The results show that preferential CO_2 adsorption can persist even as moisture lowers the amount of CO_2 retained, so dry, pure-gas isotherms can overestimate uptake under moist reservoir conditions. CO_2 adsorption can also swell the coal matrix and narrow cleats, while swelling in shale can alter pore and fracture apertures. These changes affect how much of the adsorptive matrix remains accessible during injection [80].

The adsorption process can be described using isotherm models, most commonly the Langmuir isotherm Equation (4) [78]:

$$q = \frac{q_{\max} \cdot b \cdot P}{1 + b \cdot P} \tag{4}$$

where:

q = amount of CO_2 adsorbed per unit mass of rock (mol/kg),

$q_{\max}$ = maximum adsorption capacity,

b = Langmuir affinity constant (related to the strength of adsorption),

P = partial pressure of CO_2.

This equation shows that adsorption increases as pressure rises but eventually reaches a maximum saturation level. CO_2 is adsorbed more strongly than methane. This property is used in enhanced coalbed methane recovery (CO_2-ECBM), where injected CO_2 replaces methane that is adsorbed on coal surfaces.

However, adsorptive trapping also has some limitations and challenges. In coal seams, CO_2 adsorption can cause the coal matrix to swell. This swelling may block the cleat system, which decrease its permeability and lowers CO_2 injection rates over time. Similarly, in shales formation, organic matter and very small pores are not evenly distributed. This causes variations in CO_2 adsorption and makes its behaviour more difficult to predict accurately. CO_2 may also be released from the surface if the reservoir pressure falls below a critical threshold. This could allow some of the previously adsorbed CO_2 to move again during later stages of storage [81, 82]. Another challenge is measuring adsorptive trapping under field conditions Unlike structural or residual trapping; adsorption does not make a clear change in seismic or resistivity signals. Field-scale validation mainly relies on laboratory adsorption isotherms, core analysis, and indirect production data, specifically in CO_2-enhanced coalbed methane (ECBM) applications [83].

Despite these limitations, adsorptive trapping is still useful in specific geological formations, especially where structural or solubility trapping is less effective. Its rapid adsorption, low leakage risk, and suitability for gas-rich, low-permeability formations make adsorptive trapping an important part of overall CO_2 storage, especially in unconventional reservoirs.

In summary, adsorptive trapping can hold CO_2 in fine-grained and organic-rich formations. Although the process is reversible, it can still provide CO_2 storage under suitable conditions [84]. It is most suitable for low-permeability formations where other trapping mechanisms are less effective. However, its long-term reliability depends on controlling matrix swelling, maintaining reservoir pressure, and keeping a stable balance between CO_2 adsorption and desorption.

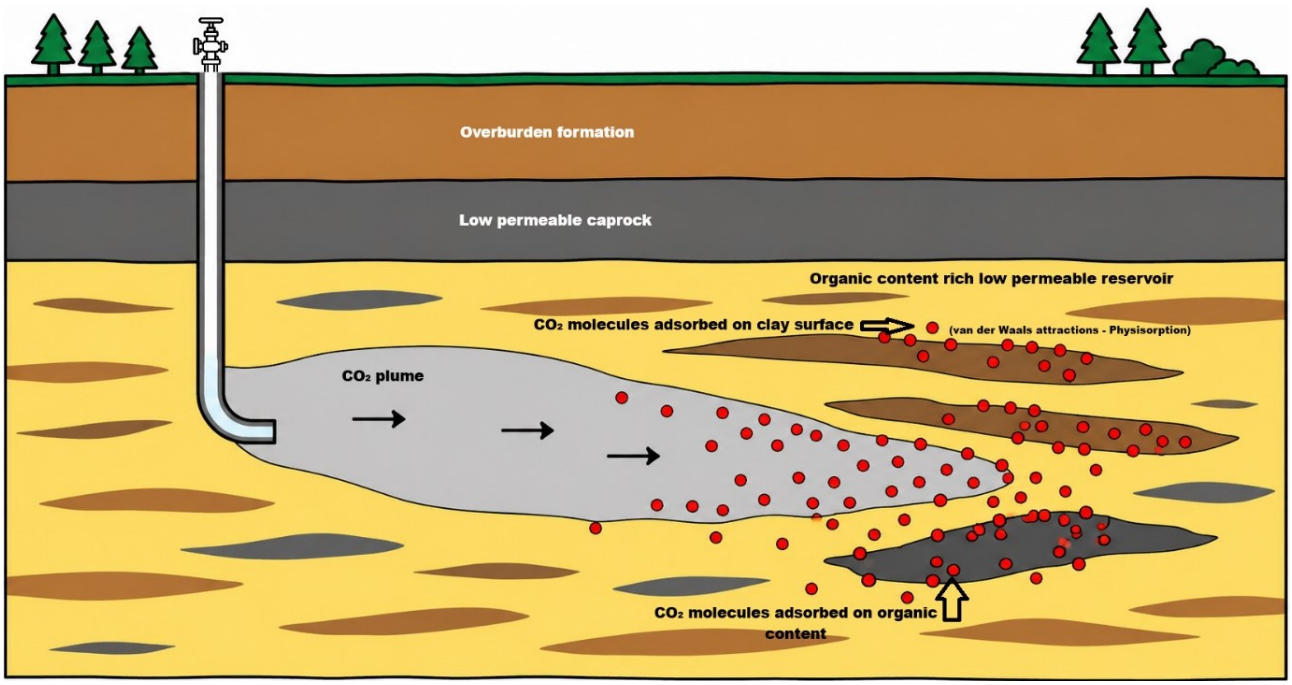

Figure 7. Schematic of adsorptive trapping showing CO_2 retention on mineral and organic surfaces within low permeability formations. CO_2 molecules are immobilized through physisorption in microporous structures, reducing mobility (schematic, not to scale).

3.2. Geological and Hydrodynamic Controls (Supporting Mechanisms)

Besides the main trapping mechanisms, CO_2 can also be retained through many formation-specific processes and geological conditions that help strengthen, control, or support its long-term storage in the subsurface. These processes include hydrodynamic effects, capillary entry pressure and geological heterogeneity, which affect how CO_2 moves underground, how well it is contained and how it interacts with formation fluids and rocks. The following subsections examine how these supporting processes help to improve CO_2 storage security across different geological settings.

3.2.1. Hydrodynamic Trapping

Hydrodynamic trapping supports the main trapping mechanisms by controlling how far CO_2 moves, how long it remains underground, and how much it is diluted by regional groundwater flow, as shown in Figure 8 [19]. Instead of directly trapping CO_2, slow subsurface flow gradually moves the CO_2 plume over long distances and time periods. This increases contact with formation brine and reservoir rock, which can promote residual, solubility, and eventually mineral trapping [52]. This process is especially important in deep, large saline aquifers, including offshore basins, where groundwater moves slowly and regional flow paths can extend for tens to hundreds of kilometers [85].

The main idea of hydrodynamic trapping is that, under certain flow conditions, buoyant CO_2 does not rise directly upward. This can happen when the direction of CO_2 movement is flatter than the slope of the regional aquifer or when opposing hydraulic pressure gradients restrict its upward migration. This allows the CO_2 plume to move almost horizontally, becoming thinner and more spread out as it travels. Over time, some of the CO_2 plume can become trapped through residual and solubility trapping and may eventually form minerals. Therefore, hydrodynamic trapping mainly helps other trapping mechanisms develop rather than providing permanent storage by itself [52].

Where brine and a separate CO_2-rich phase coexist, the Darcy flux of each phase is described by the multiphase form of Darcy's law Equation (5) [86].

$$\mathbf{u}_\alpha = -\frac{k_{r,\alpha}}{\mu_\alpha}\,\mathbf{K}\left(\nabla p_\alpha - \rho_\alpha \mathbf{g}\right), \qquad \alpha \in \{b, c\} \tag{5}$$

The subscripts b and c denote the brine and CO_2-rich phases, respectively. In Equation (5), $\mathbf{u}_\alpha$ is the Darcy flux of phase α, $\mathbf{K}$ is the intrinsic permeability tensor, and $k_{(r,\alpha)}$, μ_α, p_α, and ρ_α are the relative permeability, dynamic viscosity, pressure, and density of that phase. The vector $\mathbf{g}$ denotes gravitational acceleration and points downward. Capillary pressure is the difference between the CO_2-rich phase pressure and the brine pressure. The density contrast between the two phases produces an upward buoyant force on the less dense CO_2-rich phase, while regional hydraulic gradients can redirect plume migration. Relative permeability controls how readily each phase flows and varies with saturation and displacement history. Dissolved CO_2 is advected with the brine, while diffusion and hydrodynamic dispersion contribute to its redistribution.

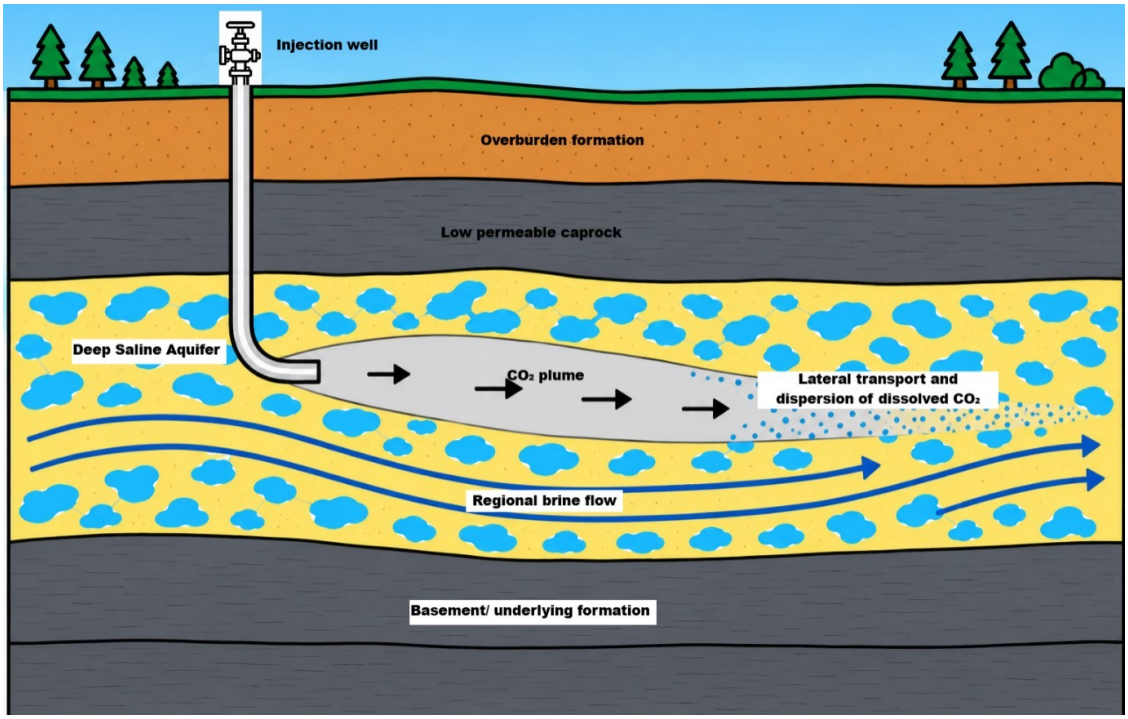

Figure 8. Schematic of hydrodynamic trapping illustrating long-distance lateral migration and dilution of CO_2 under regional groundwater flow. Progressive dispersion reduces plume thickness and facilitates transition to residual, solubility, and mineral trapping over time (schematic, not to scale).

Hydrodynamic trapping is useful for large-scale CO_2 storage because it allows the CO_2 to spread through a larger part of the formation, rather than remaining only near the injection well. In high-capacity reservoirs where groundwater flow is well understood, hydrodynamic trapping provides a natural buffer by allowing the CO_2 plume to spread and gradually become partly trapped by other mechanisms. This is specifically useful in multi-well injection projects because it can help control pressure build-up and reduce interactions between CO_2 plumes from different wells [10, 32].

However, hydrodynamic trapping is difficult to predict and monitor accurately. Because CO_2 migration occurs over very large distances and long time periods, it is hard to track the plume directly using conventional seismic surveys or well-logging tools. Also, if the storage site is not well contained by geological barriers or structural features, the CO_2 plume may gradually move outside the intended storage area, especially over very long periods of time. Regulations often require CO_2 to remain within a defined storage area. This makes it difficult to rely only on hydrodynamic trapping for long-term containment.

Another limitation is that hydrodynamic trapping does not completely stop CO_2 from moving. Instead, it mainly slows its migration and reduces the chance of leakage by spreading the plume over a larger area. Therefore, hydrodynamic trapping needs to work together with other mechanisms, such as residual or solubility trapping, to provide secure CO_2 containment. In addition, numerical models of regional groundwater flow and CO_2 migration can be strongly affected by uncertain parameters. These parameters include permeability anisotropy, boundary conditions, and small stratigraphic traps that can change or redirect the flow path.

Therefore, hydrodynamic trapping plays an important supporting role in CO_2 storage, especially in deep saline aquifers that are widely connected across large areas. Although hydrodynamic trapping does not directly immobilize CO_2, it helps spread the plume over a wider area and gives other trapping mechanisms more time to become effective. However, because hydrodynamic effects are difficult to predict and monitor, they should be considered a supporting process that helps other trapping mechanisms work more effectively, instead of a separate mechanism for permanently immobilizing CO_2.

3.2.2. Capillary Entry Pressure Controls

Capillary entry pressure helps support structural trapping by restricting CO_2 movement through low-permeability rocks and sealing boundaries. As shown in Figure 9, free-phase CO_2 can enter a brine-saturated pore or fracture when the local CO_2 pressure exceeds the local brine pressure by more than the capillary entry pressure [87]. This control is specifically important where different rock types meet, such as permeable injection zones that are sealed by tight mudstones, cemented layers, or fractures with high capillary sealing capacity. This is also very important for caprock performance because a high enough capillary entry pressure prevents CO_2 from entering the overlying seal, helping maintain long-term structural containment [30, 87].

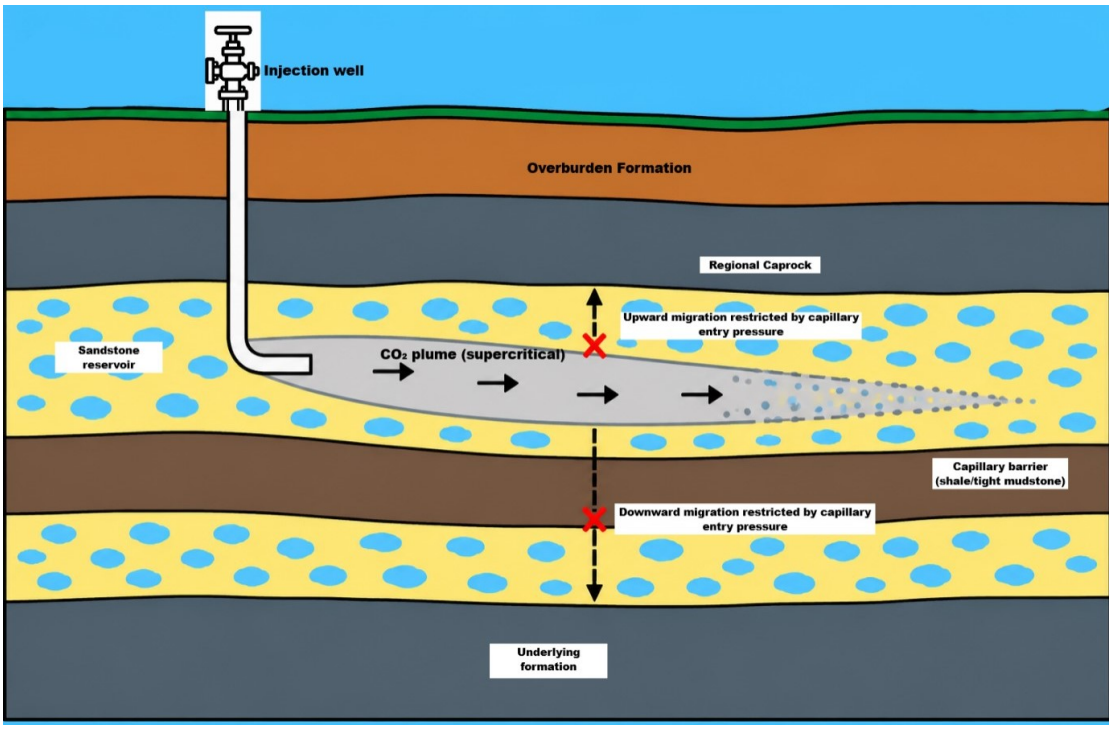

Figure 9. Illustration of capillary entry pressure control on CO_2 migration across permeability contrasts in subsurface formations. The threshold pressure, governed by pore throat size, wettability, and interfacial tension, limits phase invasion into tighter units (schematic, not to scale).

The physical basis for this mechanism lies in the Young–Laplace equation, which defines the capillary entry pressure (P_c) (see Equation (6)) required for a non-wetting phase (CO_2) to enter a pore [87].

$$P_c = 2\gamma \cos\theta / r \tag{6}$$

where:

γ = interfacial tension between CO_2 and brine,
θ = contact angle (wettability),
r = effective pore throat radius.

In water-wet rocks, brine coats the mineral surfaces, while CO_2 behaves as the non-wetting phase. Therefore, CO_2 needs enough capillary entry pressure to push the brine out of small pores. This can naturally trap CO_2 at boundaries between different rock types, such as where permeable sandstone is in contact with tight shale. Even small geological features, such as mud drapes, thin layered beds, or cemented zones, can act as capillary barriers. These features can slow or block the upward and sideways movement of the CO_2 plume and create local areas of containment. In fractured formations, capillary pressure can stop CO_2 from entering narrow fracture networks unless the injection pressure becomes high enough to overcome the critical entry pressure [88, 89].

The main advantage of capillary entry pressure is that it can resist CO_2 movement without requiring a closed geological structure or any chemical reaction. This makes capillary entry pressure an important safety mechanism for CO_2 storage, specifically in formations that contain multiple layers or separate compartments. However, this mechanism can be easily affected by changes in interfacial properties, mineral composition, pore size distribution, and especially rock wettability. Changes in temperature, pressure, salinity, or chemical reactions can change these properties and change the capillary entry pressure. This may allow CO_2 to break through the barrier [90].

Another limitation is that capillary entry pressure works only up to a certain limit. Once this pressure threshold is exceeded, the barrier can be breached and CO_2 may move into the next geological layer. Therefore, if the injection pressure reaches or exceeds this limit, the sealing barrier may fail suddenly and permanently. Predicting this behaviour requires detailed information about pore-throat sizes and interfacial properties, but such data are rarely available at the field scale. Free-phase CO_2 can enter a brine-saturated seal when the local CO_2 pressure exceeds the brine pressure by more than the capillary entry pressure [87]. Breakthrough occurs when CO_2 migrates through a connected pathway across the seal. Mechanical failure, such as fracture opening or fault reactivation, depends on the local stress state and injection-induced changes in pore pressure [36].

Even so, capillary entry pressure remains an important supporting control because it helps many sealing formations, specifically caprocks, prevent CO_2 migration. It also helps create internal barriers within heterogeneous reservoirs, which can limit CO_2 movement and support containment related to stratigraphic layers and different rock facies. Its role is specifically important in formations with multiple layers, where upward CO_2 movement is restricted by several capillary-sealed barriers rather than by a single caprock.

In summary, capillary entry pressure is an important pore-scale mechanism that prevents both upward and sideways CO_2 movement, improving overall containment. Although capillary entry pressure works passively and is difficult to measure directly, it can greatly improve the long-term security of CO_2 storage, specifically in layered, heterogeneous, and fractured geological formations. However, its reliability depends strongly on keeping suitable interfacial properties throughout the entire storage period.

3.2.3. Facies- and Heterogeneity-Driven Controls

Facies patterns and reservoir heterogeneity influence how CO_2 moves through the formation and can improve the effectiveness of the main trapping mechanisms. As shown in Figure 10, geological breaks, different rock layers, and internal reservoir complexity can disturb the CO_2 plume and change its movement, causing it to slow down or follow different flow paths. Changes in permeability, porosity, and capillary entry pressure across the reservoir can create internal barriers and isolated zones. These features promote localized accumulation and compartmentalization. These features can keep the CO_2 plume in the reservoir for longer and increase its contact with formation fluids and rocks. By changing the pathways through which CO_2 moves, they can strengthen structural and residual trapping and also provide more time for solubility trapping and, over longer periods, mineral trapping [91].

These geological controls are specifically important in fluvial, deltaic, and turbidite reservoirs, where sandstone layers are mixed with mudstones, siltstones, or cemented zones. This creates strong vertical and lateral variations within the reservoir. CO_2 usually moves through high-permeability zones, but when it reaches lower-permeability rock layers, its movement can slow down, stop temporarily, or be redirected along a different path. These internal barriers can divide the CO_2 into separate zones, keep it in the reservoir for longer, and give residual, solubility, and even mineral trapping more time to occur within these confined zones [92].

Facies architecture and reservoir heterogeneity are not separate trapping mechanisms. Instead, they influence the shape, timing, and development of the main CO_2 trapping mechanisms. For example, a continuous shale layer can block upward CO_2 movement for many years, giving more time for CO_2 to dissolve and accumulate in the zone below. Similarly, a tight diagenetic barrier can increase capillary trapping below it while forcing CO_2 to spread sideways along its flanks [93, 94].

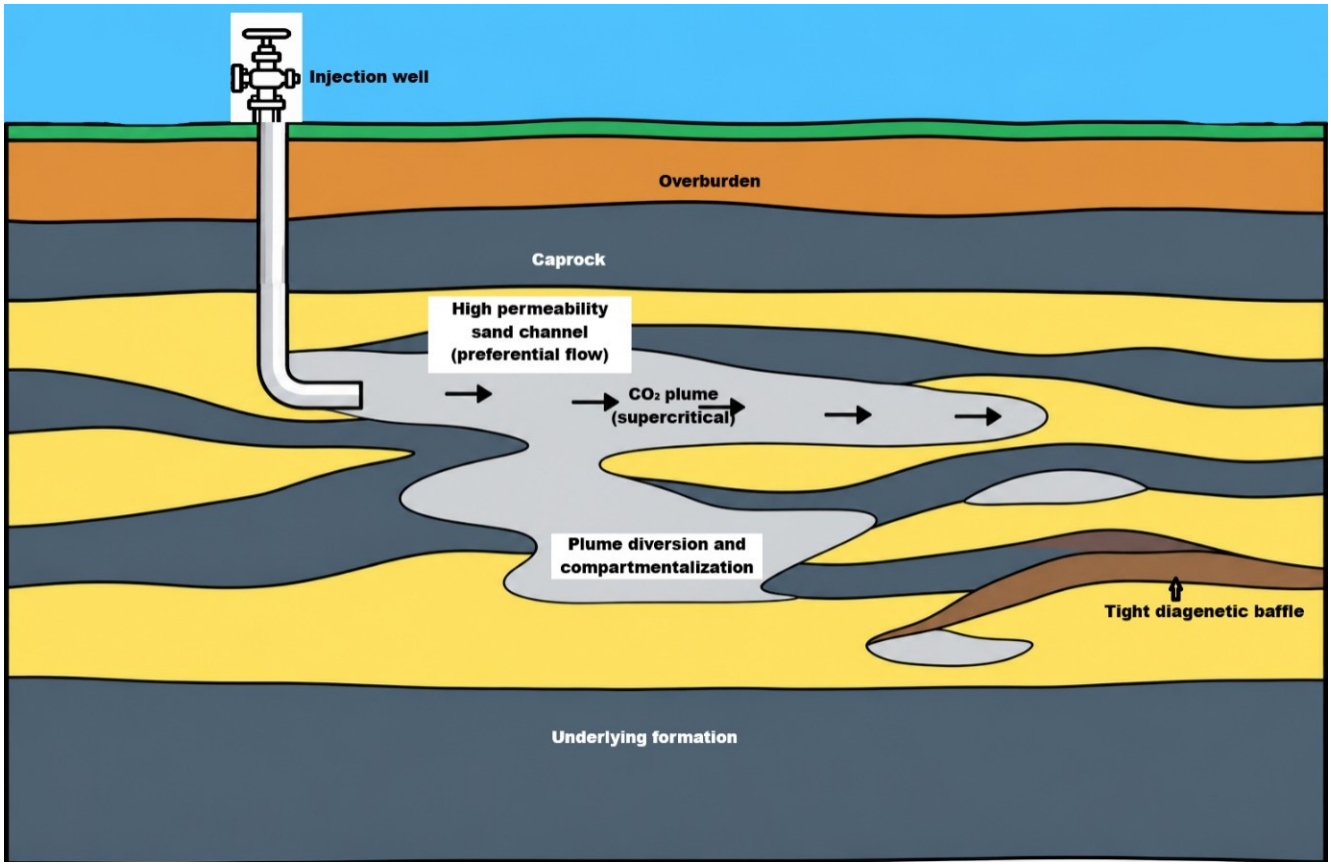

Figure 10. Conceptual illustration of CO_2 injection, migration in facies- and heterogeneity-driven trapping. Reservoir heterogeneity promotes plume diversion, compartmentalization, and enhanced CO_2 storage through multiple trapping mechanisms (schematic, not to scale).

One major advantage of heterogeneity-related trapping is that it is common in real reservoirs. Completely uniform formations are rare, while geological variations are usually present. However, the main weakness of heterogeneity-related trapping is that it is difficult to predict. Small-scale geological features, especially those smaller than a meter, may not be clearly detected by seismic data or well logs. As a result, their effect can be underestimated or completely missed in static reservoir models. To properly represent their effects, detailed geological models, outcrop analogue studies, and sometimes stochastic simulations are needed to account for uncertainty in their spatial distribution [93, 95].

Moreover, the efficacy of facies-based trapping is non-permanent: unlike residual or mineral trapping, CO_2 retained behind a heterogeneity trap may eventually leak or bypass if the pressure gradient changes or if connected pathways develop over time. Therefore, this process should be viewed as temporary but still useful. It can slow CO_2 migration, help distribute pressure more safely, and provide enough time for other trapping mechanisms to become effective.

In summary, facies architecture and reservoir heterogeneity play an important role in controlling CO_2 storage behaviour, even though their effects are often underestimated. By changing the shape of the CO_2 plume and the pathways it follows, facies architecture and reservoir heterogeneity can indirectly improve the effectiveness of other trapping mechanisms. However, they also make CO_2 behaviour more difficult to model and predict. In geologically complex formations, such as deltaic, estuarine, or channelized systems, these controls can strongly influence how far the CO_2 plume spreads, how easily CO_2 can be injected, and how well it remains contained over the long term.

As summarized in Table 1, five principal CO_2 trapping mechanisms contribute to geological storage: structural, residual, solubility, mineral, and adsorption trapping.

Taken together, studies in Table 2 show why formation-specific assessments must distinguish how much CO_2 a rock can retain, how readily CO_2 can reach the relevant pores or mineral surfaces, and how long retention takes to develop. The overlap in residual saturation between the sandstone and limestone samples illustrates the importance of pore structure and saturation history,

while the increase in breakthrough pressure with effective stress within each caprock material shows that sealing thresholds depend on the stress conditions under which they are measured. For adsorption, the Langmuir capacity indicates the upper limit of the fitted isotherm, but uptake at reservoir pressure also depends on the half-saturation pressure and the fraction of the sorptive matrix accessible to injected CO_2. Similarly, the high mineralized fractions at CarbFix and Samail demonstrate rapid conversion under the respective pilot conditions, while formation-scale performance also depends on sustained injectivity and the volume of reactive rock contacted. These distinctions provide the basis for the formation-by-formation comparison in Section 4, where the importance of each trapping mechanism is evaluated alongside the geological and operational conditions that govern its contribution.

Table 1. Summary of CO_2 subsurface trapping mechanisms.

Classical Trapping Mechanism	Supporting Mechanism/Control	Supporting Role	Key Limitations/Controls
Structural trapping [38]	Capillary entry pressure [47]	Prevents CO_2 penetration into sealing units e.g. sealing fault or caprock	Wettability, pore-throat size, interfacial tension, pressure
	Facies/heterogeneity [95]	Creates barriers and compartments that restrict migration	Barrier continuity, fault connectivity, facies architecture
Residual trapping [48]	Capillary entry pressure/ capillary contrasts [47]	Controls pore invasion, displacement, and residual immobilization	Wettability, pore structure, capillary hysteresis
	Facies/heterogeneity [95]	Alters flow paths and local residual saturation	Permeability contrasts, connectivity, spatial variability
	Hydrodynamic effects [52]	Promotes plume redistribution and brine imbibition	Groundwater velocity and flow direction
Solubility trapping [96]	Hydrodynamic effects [52]	Enhances CO_2–brine contact, mixing, and dissolved-CO_2 transport	Flow rate, mixing, salinity, pressure and temperature
	Facies/heterogeneity [95]	Controls plume spreading, residence time, and fluid contact	Reservoir connectivity and permeability distribution
Mineral trapping [73]	Hydrodynamic effects [52]	Transports dissolved CO_2 toward reactive minerals	Fluid transport and reaction timescale
	Facies/heterogeneity [95]	Controls fluid–rock contact and access to reactive minerals	Mineral distribution, reactivity, flow pathways
Adsorption trapping [78]	-	Provides additional surface-based CO_2 retention	Surface area, mineralogy/organic content, pressure and temperature

Table 2. Quantitative synthesis of representative experimental measurements and reported CO_2 trapping parameters across geological formations.

Parameter	Rock or Setting	Reported Value and Conditions
Residual CO_2 saturation **[50]**	Four sandstone cores	Maximum observed residual saturations of 21–33% of pore volume at 50 °C and 9 MPa.
Residual CO_2 saturation **[97]**	Indiana limestone	Supercritical CO_2 residual endpoint of 23.7% of pore volume at 50 °C and 9 MPa.
CO_2 breakthrough pressure **[98]**	Sandy Opalinus Clay	Breakthrough pressures of 2.0, 3.0, and 4.0 MPa at effective mean stresses of 8.0, 8.5, and 9.0 MPa, respectively. Stepwise liquid-CO_2 coreflooding on water-saturated samples.
CO_2 breakthrough pressure **[98]**	Clayey Maquoketa Shale	Breakthrough pressures of 10.0, 10.5, and 11.0 MPa at effective mean stresses of 15, 20, and 25 MPa, respectively. Stepwise liquid-CO_2 coreflooding on water-saturated samples.
CO_2 Langmuir parameters **[99]**	Lignite, bituminous coal, and anthracite	Fitted Langmuir volume V_1 (cm^3/g) and pressure P_1 (MPa) for pure CO_2 were 35.84 and 2.61 for lignite, 35.36 and 4.36 for bituminous coal, and 35.97 and 2.38 for anthracite.
CO_2 Langmuir parameters **[78]**	Barnett, Eagle Ford, Marcellus, and Montney shales	At 40 °C, fitted V_L ranged from 33.1 to 153.0 scf/ton, and P_L ranged from 263.2 to 475.1 psia.
Mineralized fraction **[71, 100]**	CarbFix basalt and Samail peridotite pilots	CarbFix estimated more than 95% within two years. Samail estimated approximately 88% within 45 days.

4. Formation by Formation Analysis of Trapping Mechanisms

Based on trapping mechanisms discussed earlier, a formation-by-formation analysis of the trapping mechanisms is carried out in subsequent sections.

4.1. Onshore Saline Aquifers

Saline aquifers is broadly focused geological formation and most expansively studied by the researchers for large-scale CO_2 because of their global distribution, saturation with non-potable brine, and high pore volume [101, 102]. These formations support several CO_2 trapping mechanisms across different spatial and temporal scales specifically structural, residual, solubility, and, in certain mineralogies, mineral trapping. Despite their promising theoretical capacity, practical CO_2 storage in saline aquifers relies mainly on local heterogeneities, kinetic constraints, and uncertainties in monitoring [7].

Structural trapping is typically dominant at the early phase of storage in most deep saline aquifers. While injecting into structurally closed systems notably anticlines or fault blocks sealed by laterally extensive evaporite or shale caprocks, buoyant CO_2 accumulates beneath the seal in the same way oil and gas are naturally trapped. Because structural trapping depends heavily on caprock integrity, fault architecture, and injection-induced overpressure, its reliability in saline aquifers can vary significantly. Long-term containment can be threatened by small-scale discontinuities, undetected faults, or limited seal capacity. In consequence, in stratigraphically open systems or aquifers lacking classical closures, structural trapping takes a back seat and needs support from alternative mechanisms [103].

Residual or capillary trapping appears as a critical mechanism when the CO_2 injection is shut in or at the time of advancing plume slows because of pressure depletion or lithological barriers. Throughout this stage, re-

entering brine displaces mobile CO_2, fragmenting it into disconnected ganglia that turn out to be immobilized by capillary forces within porous area. This method is effective in water-wet, fine-grained formations with favourable pore throat distributions. In the case of heterogeneous aquifers with anisotropic permeability or large-scale heterogeneities, residual trapping effectiveness may differ spatially and can be very path dependent. Furthermore, the precise quantification of residually trapped CO_2 in the field remains a challenge attributable to its subtle geophysical footprint and dependence on indirect monitoring approaches [104].

Mineral trapping, thermodynamically permanent mechanism, plays a relatively minor role in maximum saline aquifers because of their common mineralogical composition. Quartz-rich sandstones dominated in many saline aquifers with limited quantities of reactive silicate minerals for instance feldspars or mafic constituents. In such surroundings, the precipitation of carbonate minerals is kinetically slow and may necessitate decades to centuries to become significant. However, saline aquifers with volcanic or arkosic provenance may hold sufficient calcium, magnesium, or iron-bearing minerals to facilitate long-term mineralization, if accompanied by reactive fluid additives or planned enhancements [102]. Capillary entry pressure and geological heterogeneity have an influence on CO_2 containment and migration in saline aquifers. Capillary barriers created by interbedded siltstones or mudstone drapes can locally obstruct vertical migration, while internal lithological heterogeneities such as crossbedding, grain size disparity, or diagenetic cementation may compartmentalize the CO_2 plume and delay breakthrough. In laterally extensive aquifers with regional flow systems, hydrodynamic trapping may happen as CO_2 migrates slowly because of natural groundwater gradients. However, this mechanism is hard to monitor and naturally discouraged by regulatory frameworks that highlight containment within predefined storage complexes [103].

4.2. Depleted Oil and Gas Reservoirs

Depleted oil and gas reservoirs are main candidates for geological carbon storage as they have proven containment capacity, well characterized subsurface data, and existing infrastructure. These kinds of formations have already held buoyant hydrocarbons for geological spans, which serves as indirect evidence of caprock integrity and structural trap reliability. In addition, comprehensive production histories, pressure–volume–temperature (PVT) data, and existing wells significantly diminish the uncertainties linked with reservoir behaviour. But, the same attributes that form these formations appealing can also present unique risks and constraints that differentiate them from unproduced systems such as saline aquifers [105].

Structural trapping is a dominant mechanism in depleted reservoirs, utilizing the identical geological closure that initially trapped the hydrocarbons in most scenarios, the CO_2 plume acts similarly to hydrocarbons, accumulating beneath sealing caprocks and along fault-bound sections. Though, depletion-induced changes in pressure, stress, and rock fabric may compromise the very seals that once confirmed hydrocarbon entrapment. Caprock fatigue, fracture dilation, or pressure differentials are responsible for long-term production that can make the system more vulnerable to leakage or fault reactivation during CO_2 injection occurs. In addition, the old wellbores some poorly cemented or abandoned decades ago creates the risk of vertical leakage pathways that are not naturally encountered in virgin formations [106].

Residual trapping is another major mechanism in depleted reservoirs, frequently enhanced by the hysteresis effect from previous hydrocarbon production. Since brine re-entered the reservoir during secondary or tertiary recovery, it changed the saturation history, often increasing the rocks water-wetness and creating favourable conditions for residual CO_2 trapping. Compared to fresh formations, depleted reservoirs often attain higher capillary trapping efficiency because of a combination of prior saturation paths and fluid-flow-induced micro-scale heterogeneities. However, the distribution of residual saturation is often highly uneven, especially within complex or compartmentalized reservoirs. This variability means that detailed modelling is a must if accurate estimates is preferred [107, 108].

Solubility trapping in depleted reservoirs is a complex mechanism because of the coexistence of residual hydrocarbons, brine, and CO_2. CO_2 can dissolve not only in brine but also hydrocarbon phases. In the case of oil-bearing reservoirs, this mechanism leads to CO_2 enriched oil swelling, viscosity reduction, and even miscible or near-miscible displacement, depending on reservoir pressure and oil composition. These interactions are advantageous for CO_2 enhanced oil recovery (EOR), but they complicate long-term storage goals, specially where CO_2 acts as a displacing agent. The dissolution dynamics are simpler in gas-depleted fields, but the partitioning of CO_2 between brine and residual gas introduces additional thermodynamic modelling complication [109].

Mineral trapping is heavily governed by the lithology of these reservoirs. Many oil and gas reservoirs find their host environments within carbonate or siliciclastic rocks. In carbonate reservoirs, mineral trapping is driven by the dissolution-reprecipitation cycle of calcite or dolomite, which can either enhance or compromise reservoir porosity. Feldspar-bearing sandstones facilitate centuries-long CO_2 sequestration through gradual albite or anorthite mineralization, a method that slows down considerably in diagenetically altered or heavily cemented reservoirs due to constrained reactive surface areas.

Supporting mechanisms also play a critical role. Capillary entry pressure maintains its relevance, especially at the transition zone between reservoir units and caprock seals. Facies driven trapping is commonly observed within deltaic or turbiditic reservoirs, where interbedded shales and lateral permeability variations can obstruct plume migration to enhance containment. Although depleted fields rarely focus hydrodynamic trapping on account of their

compartmentalized flow regimes, this mechanism can still occur in expansive, basin-connected systems.

Despite having these advantages, depleted reservoirs introduce engineering and regulatory complications. Legacy wells frequently represent the weakest link in the containment system, particularly when they lack modern well integrity standards. Undetected leakage pathways can form by CO_2-cement interactions, annular flow, or pressure communication along micro-annuli. Lastly, regulators may put stricter MRV (Monitoring, Reporting, and Verification) requirements on such sites owing to these known risks.

4.3. Basaltic Formations

Basaltic formations provide a distinct CO_2 storage environment when compared to sedimentary basins. These volcanic rocks, basically composed of calcium and magnesium rich silicates such as olivine, pyroxene, and plagioclase feldspar, provide a highly reactive geochemical matrix that assists mineral trapping as the dominant sequestration mechanism. Unlike structural or residual mechanisms that depend on physical containment, basalt formations exploit their geochemical reactivity to convert dissolved CO_2 into stable carbonate minerals such as calcite, magnesite, and siderite, thus attaining long-term retention through carbonate precipitation [110].

The trapping of basalts is heavily governed by their mineralogical composition, porosity structure, and hydrological connectivity. Fresh, glassy basalts are reactive, while weathered or altered flows may be not as much of effective. The vesicular nature of many basalt flows delivers initial pore space, but this porosity is often discontinuous and can be poorly connected, resulting in low matrix permeability. Therefore, CO_2 injection occurs into fractured zones or flow-top breccias, which serve as primary conduits for fluid movement. Dual-porosity system forms when flow occurs in fractures, but reactions primarily occur in the matrix, demanding sufficient residence time for mineralization to proceed [111].

Mineral trapping in basalts occurs through a sequence of reactions starting with CO_2 dissolution into water, leading to acidic fluid-rock interaction that releases divalent cations (Ca^{2+}, Mg^{2+}, Fe^{2+}) from silicate breakdown. These ions then precipitate with dissolved carbonate species to form solid minerals. Full details of all possible reactions can be reviewed in our previous work [21].

At the CarbFix pilot site in Iceland, Matter et al. estimated that more than 95% of the CO_2 injected during the monitored experiment mineralized within two years. The estimate was derived from tracer and dissolved inorganic carbon mass balances along the flow path between the injection and monitoring wells. The percentage is relative to the CO_2 injected during the pilot. A carbon inventory for the wider project would also need to account for subsequent injections and quantify carbon remaining in other forms. In the pilot, CO_2 was injected fully dissolved in water into reactive basalt. The reported timescale therefore reflects the injection method and the local conditions governing fluid flow, mineral dissolution, and carbonate precipitation [71].

In basaltic systems, initial-stage solubility and residual trapping are often restrained by temporary period and limited spatial extents. Solubility trapping occurs through CO_2 dissolution in formation water, although elevated salinity can reduce CO_2 solubility through the salting-out effect. The resulting decrease in pH promotes basalt dissolution and the release of divalent cations (Ca^{2+}, Mg^{2+}, and Fe^{2+}), facilitating subsequent carbonate mineralization. Residual trapping is less effective because of the fracture dominated flow regime, which restricts the pore scale capillary forces required to immobilize disconnected CO_2. Besides, structural trapping is not often reliable in basalt formations because of the pervasive presence of interconnected fractures, lava tubes, and irregular flow geometries that reduce the chance of creating large, continuous caprock seals.

Fluid management is one of the biggest operational tasks in basalt-based CO_2 storage. Injecting supercritical or free-phase CO_2 into fractured basalt can cause rapid migration and bypass reactive surfaces. Accordingly, high reactivity requires that the CO_2 be dissolved in water or brine prior to injection. Although pre-dissolved CO_2 mineralization demands high water volumes and precise injection control, field-scale deployment should mitigate pressure build-up, fracture reactivation, and seismicity risks [112].

The lack of geophysical difference between newly formed carbonates and the host rock complicates the monitoring and verification of basalt carbonation. Most field validation depends on geochemical tracers, fluid sampling, and core recovery, combined with reactive transport modelling to quantify the extent of carbonation. Furthermore, advanced techniques such as X-ray diffraction, stable isotope analysis, and micro-CT imaging are often required to validate *in situ* mineral formation.

Concisely, basaltic formations provide one of the most geochemically secure and potentially durable pathways for CO_2 sequestration through rapid mineral trapping. But, their fractured nature, inadequate injectivity, and operational complexity require careful site selection and engineering. Even though conventional plume-based injection methods fail to align with basaltic systems, these formations offer a viable mechanism for permanent carbon storage when managed through tailored geochemical and hydraulic controls.

4.4. Shale Formations

Shale can serve as a caprock or, in selected settings, as a conditional CO_2 storage reservoir. As a caprock, its low matrix permeability and high capillary entry pressure can restrict upward migration of free-phase CO_2, provided that the seal is laterally continuous and lacks transmissive pathways across it [36]. As a storage reservoir, an organic-rich shale can retain CO_2 by adsorption on kerogen and mineral surfaces, but low matrix permeability limits the volume of rock that injected CO_2 can reach. Natural or induced fractures can improve injectivity and increase contact with the shale matrix, while fractures con-

nected to faults or overlying units can provide pathways for migration. A decline in reservoir pressure can also promote desorption and remobilization of CO_2. The suitability of shale as a primary storage reservoir therefore depends on whether it can sustain injection at practical rates, provide access to enough sorptive pore space, and retain CO_2 over the expected pressure history [36].

CO_2 molecules in shale formations are captured through physical adsorption onto the surfaces of clays, kerogen, and microporous minerals, a method referred as adsorptive trapping. This process is controlled by physisorption and is captured by Langmuir-type isotherms. Shales often show high specific surface areas and nanoscale porosity, particularly in organic-rich zones such as black shales or source rocks, allowing substantial CO_2 uptake per unit volume. Adsorbed CO_2 is retained via weak van der Waals interactions, exhibiting its retention pressure-dependent and reversible upon environmental shifts. This trapping is advantageous for both low rate and long-term injection scenarios because it does not require a transition to the aqueous or mineral phase [18].

Capillary entry pressure trapping also plays a vital role in shales, where shale acts as a vertical or lateral seal. Unless injection pressures exceed a specific threshold, the non-wetting CO_2 phase fails to penetrate shales as they possess small pore throats and strong water-wet character. Shales primarily act as barriers to vertical fluid migration, keeping underlying fluids confined even when CO_2 pools at the seal's base. Consequently, it becomes invaluable in multi-layered storage systems, offering extra security even if they aren't the primary storage target. Despite these benefits, both residual and solubility trapping mechanisms are often minimal in shale formations. Due to their extremely low permeability, the fluid mobility is restricted, which decreases the effectiveness of capillary driven CO_2 disconnection and aqueous phase mixing. Unless artificially fractured, the flow of both brine and CO_2 is extremely constrained, thereby restricting the interaction duration between CO_2 and reactive surfaces essential for substantial dissolution or mineralization [71].

To enhance the injectivity if hydraulic fracturing is applied in formations, the CO_2 may migrate through a system of induced or natural fractures, increasing surface area for adsorption but also introducing challenges in plume control and pressure management. Fracture networks are often heterogeneous, poorly connected, and anisotropic, making prediction of CO_2 movement complex. Furthermore, high injection pressures essential to fracture or stimulate shale formations may exceed caprock if not tightly managed. This raises the risks of induced micro seismicity or unintended leakage into neighbouring strata [113, 114].

Tracking adsorptive CO_2 storage in shales presents another layer of complexities. In contrast to free-phase CO_2 or vast variations in saturation, adsorption does not create strong seismic or resistivity contrasts. Field-scale quantification of stored CO_2 is inferred from laboratory-derived isotherms, core analyses, or production data in enhanced gas recovery operations. Developing techniques such as NMR, infrared spectroscopy, or sorption-desorption cycles may offer extra insight, but routine field deployment remains limited.

In terms of long-term security, shales are providing a relatively stable chemical environment, exclusively if pressure is managed below desorption thresholds. However, the adsorbed CO_2 remains in a metastable state, susceptible to pressure drops, thermal fluctuations, or chemical change of adsorption sites. Furthermore, swelling effects predominantly in clay-rich shales may decrease fracture permeability and impair injectivity over time, creating complications in sustained operations.

4.5. Coal Seams

Coal seams that are unmineable are characterized as a unique class of CO_2 storage formations where the dominant trapping mechanism is adsorption onto organic-rich surfaces. Coal's microporous structure generates huge surface areas with a natural preference for CO_2 over gases such as methane and nitrogen. This selective affinity drives CO_2-enhanced coalbed methane (ECBM) recovery. Then, injected CO_2 pushes out the adsorbed methane and securely takes its place. Though, this method offers the double benefit of carbon storage and energy recovery, the geomechanically and operational constraints linked with coal seams limit their viability as reliable , large-scale CO_2 storage reservoirs [115].

Injected CO_2 moves through the cleat network and diffuses into the coal matrix, where it is generally adsorbed preferentially over CH_4. As the local CO_2 concentration rises, competitive adsorption promotes CH_4 desorption. The released CH_4 must then diffuse back to the cleats and flow toward a production well. CO_2 uptake can swell the coal matrix, narrowing the cleats and reducing permeability. At the same time, rising pore pressure can reduce the effective stress acting across the cleats and favour opening, while CH_4 desorption can contribute to matrix shrinkage. The net permeability change depends on the balance among these effects and can vary as the CO_2 front advances [77]. At the Allison Unit pilot in the San Juan Basin, pressure falloff tests at four CO_2 injection wells indicated near-well coal permeability below 1 mD after CO_2 exposure [116]. This illustrates a practical limitation of enhanced coalbed methane recovery. A coal seam can have a high affinity for CO_2, yet a decline in cleat permeability can restrict both continued injection and the flow of displaced CH_4 to production wells [117].

Other trapping mechanisms like solubility trapping are minimal but not negligible. CO_2 can dissolve into formation water within cleat networks, but the volume of mobile water is limited in most coal seams at shallow to intermediate depths. Localized residual trapping can occur within cleat-bound pore networks, though its overall magnitude is constrained by the absence of an intergranular pore framework. Moreover, mineral trapping remains largely non-existent or exceptionally sluggish as coal mineralogy features low concentrations of reactive silicates and is dominated by unreactive components such as quartz.

The mechanical response of coal to CO_2 injection makes long-term storage reliability difficult. Beyond permeability degradation, high injection pressures can influence fracture slip, bedding-plane separation, or induced micro seismicity. Also, coal's inherent heterogeneity and layered composition result in anisotropic mechanical behaviour, which predominantly complicates accurate reservoir-scale forecasting. In contrast to conventional reservoirs featuring containment boundaries, coal seams frequently feature abandoned mine workings, structural faults, or surface outcrop pathways. Unless adequately isolated, these anomalies heighten the hazard of lateral fluid migration or premature surface breakthrough [118].

Tracking CO_2 storage in coal seams introduces a distinct set of hurdles. Standard seismic or resistivity techniques are hardly suitable for detecting adsorbed phase CO_2. Consequently, assessing sorption dynamics and storage efficiency needs indirect approaches, including gas compositional tracking, pressure-transient analysis, tracer deployment, and production performance monitoring. Though laboratory core sorption data are routinely scaled up for field models, unknowns regarding cleat connectivity, stress regimes, and saturation history create impactful variance in predictive results.

Nonetheless, coal seams offer fast CO_2 immobilization through adsorption and offer cost-offsetting methane recovery, which may also improve project economics. Their use as storage sites is best suited to low-injectivity, low-volume scenarios, especially in regions with unmineable coalbeds or mature CBM infrastructure. Maximizing safety and operational performance requires accurate pressure management, fracture control, and comprehensive reservoir pre-screening governed by geomechanical behaviour.

4.6. Offshore and Deep Saline Formations

Onshore and offshore deep saline aquifers are considered separately in this review because, although they share the same basic trapping physics, differences in geological setting, operating conditions, accessibility, monitoring, and infrastructure can lead to different storage and deployment considerations.

Offshore saline aquifers vary in lithology, burial depth, geothermal regime, permeability, structural setting, and basin-scale groundwater flow. These differences influence injectivity, pressure propagation, plume migration, and the relative contributions of individual trapping mechanisms. At Sleipner, the Utsira Sand supported sustained CO_2 injection and time-lapse seismic imaging of the plume. At Snøhvit, pressure buildup in the compartmentalized Tubåen Formation constrained injection. Water depth, distance from shore, and access to wells and infrastructure also influence monitoring and deployment. The offshore cases discussed here therefore illustrate site-specific outcomes across a range of reservoir and operating conditions [96].

Offshore and deep saline formations are increasingly prioritized in national and international carbon storage strategies due to their large volumetric capacity, inherent isolation from populated areas, and proximity to major industrial emission clusters. These formations, often located at depths exceeding 800 to 1000 m below the seabed, are typically composed of thick, laterally extensive sandstone or carbonate aquifers sealed by marine shales, evaporites, or low permeability caprocks. Their size and isolation provide an opportunity for gigatonne-scale injection, yet their operational complexity, monitoring limitations, and regulatory scrutiny demand sophisticated site assessment and risk mitigation strategies [119, 120].

In deep saline offshore systems, structural trapping is often the primary mechanism for initial plume stabilization. Anticlines, fault-bound closures, or stratigraphic traps many identified from oil and gas exploration data can provide favourable geometries for containing buoyant CO_2. However, the structural behaviour of offshore formations under injection pressure is not always well constrained. Subtle tectonic stresses, fault reactivation potential, and long-range hydraulic connectivity introduce uncertainties in containment reliability. In offshore formations, total vertical stress reflects the combined weight of the water column and overlying sediments, while effective stress also depends on formation pore pressure. Injection-induced increases in pore pressure can reduce the effective normal stress on existing faults and promote slip, depending on fault orientation and frictional strength. Injection pressure limits should therefore be based on the site-specific stress state and the margin between operating bottom-hole pressure and the pressure at which fractures may initiate or reopen [36].

Residual trapping plays a crucial secondary role in offshore formations, particularly in high-quality sandstone reservoirs where water-wet conditions, fine-grained pore structures, and favourable capillary pressure distributions exist. The saline brine imbibes into the CO_2-swept region post-injection, immobilizing portions of the CO_2 plume in pore spaces through capillary snap-off. This residual trapping mechanism can be especially effective in heterogeneous or laminated offshore reservoirs, where internal baffles or facies transitions promote discontinuous plume growth and increase the surface area for capillary disconnection [48].

Solubility trapping is significantly enhanced in deep saline offshore systems due to the high pressures and moderate temperatures that elevate CO_2 solubility in brine. CO_2 solubility in brine generally increases with pressure under relevant storage conditions, although the relationship also depends on temperature, salinity, and phase behaviour. Over time, dissolved CO_2 can migrate downward via density-driven convection, further stabilizing the storage system. However, tracking the progress of solubility trapping offshore remains a formidable challenge due to the inaccessibility of formation fluids and the lack of reactive geophysical signatures [121].

Mineral trapping is also more promising in offshore volcanic margin settings or in formations with feldspathic or mafic provenance, where reactive silicates can re-

lease divalent cations such as Ca^{2+}, Mg^{2+}, and Fe^{2+}. In deep marine environments with relatively stable thermal regimes and long residence times, these reactions may progress more rapidly than in their onshore counterparts. Nonetheless, most offshore reservoirs are quartz-dominated and thus exhibit relatively low *in situ* carbonation potential without chemical or thermal enhancement. The long timescales required for significant mineral precipitation make this mechanism relevant primarily for multi-century permanence projections rather than immediate risk mitigation [122].

One often-overlooked supporting control in offshore storage is hydrodynamic trapping, which involves the lateral migration of dissolved or mobile CO_2 under the influence of regional groundwater flow or basin-scale pressure gradients. Given the vast spatial extent of offshore aquifers, hydrodynamic trapping can help dilute and distribute CO_2 plumes across kilometers of formation, minimizing local pressure build-up. However, it also raises regulatory and liability issues, as the CO_2 may migrate beyond the defined storage complex, complicating long-term monitoring and ownership accountability [85].

The offshore setting introduces unique challenges for monitoring, verification, and leak detection. Conventional seismic monitoring is complicated by the water column, seabed noise, and complex acquisition logistics. Surface deformation techniques such as InSAR are not applicable, and borehole monitoring wells are expensive to drill and maintain. As such, offshore MRV programs often rely on 4D seismic surveys, seabed geochemistry, and fiber-optic sensing systems, many of which are still under refinement for commercial deployment. These limitations underscore the importance of designing storage projects around predictable and verifiable trapping behaviour, rather than relying on post-injection diagnostics [96].

From an operational standpoint, offshore storage benefits from reduced surface footprint, political feasibility, and access to depleted offshore hydrocarbon infrastructure for retrofitting. However, it demands higher capital investment, rigorous marine permitting, and robust risk communication frameworks to maintain public and environmental trust. Despite these hurdles, projects such as Northern Lights (Norway) and Gorgon (Australia) have demonstrated the feasibility of offshore CO_2 storage at scale, paving the way for future deployments in similar geologic settings.

4.7. Ultramafic and Serpentinized Formations

Ultramafic and serpentinized formations present a unique mineralogical opportunity for permanent CO_2 sequestration through rapid and long-term retention through carbonate precipitation mechanisms [123]. Ultramafic and serpentinized formations are considered separately from basalts because their Mg-rich mineralogy, carbonation pathways, reaction kinetics, and fracture-controlled fluid accessibility result in distinctly different CO_2 mineralization behaviour. These formations, typically composed of olivine-rich peridotites, pyroxenes, and serpentine group minerals, are highly reactive with acidic, CO_2-rich fluids and can convert gaseous or dissolved CO_2 into solid carbonate phases such as magnesite ($MgCO_3$), siderite ($FeCO_3$), and dolomite ($CaMg(CO_3)_2$). Unlike most sedimentary rocks where mineral trapping is a slow, geologic-timescale process, ultramafic formations offer kinetically favourable pathways for *in situ* carbonation within years to decades under suitable conditions [28].

The fundamental advantage of ultramafic systems lies in their abundance of divalent cation sources particularly magnesium and iron which are liberated upon weathering or hydrothermal alteration. In serpentinized peridotites, the partially altered mineral matrix provides an ideal combination of reactive surface area, fluid accessibility, and natural fracture systems that facilitate enhanced permeability. The carbonation reactions in these rocks are exothermic and self-reinforcing. Serpentinization is the hydration of ultramafic minerals such as olivine and pyroxene, producing serpentine and, depending on the reaction conditions, minerals such as brucite and magnetite. Carbonation occurs when CO_2-bearing fluids react with minerals to precipitate solid carbonates. Pre-existing serpentinization changes the mineral assemblage available for carbonation by consuming some of the original olivine and pyroxene and forming secondary phases that can also supply Mg. It also changes the pathways through which CO_2-bearing fluids reach those minerals. Secondary minerals can fill pores and fractures, reducing connected porosity and permeability, while connected fractures formed during alteration can increase fluid access to reactive surfaces. The effect of prior serpentinization on carbonation therefore depends on both the minerals present and the connectivity of the pathways that deliver CO_2-bearing fluids [28, 124]. Equation (7) illustrates the net carbonation reaction for forsterite. For example, carbonation of forsterite (Mg_2SiO_4), a common ultramafic mineral:

$$\mathrm{Mg_2SiO_4 + 2CO_2 \rightarrow 2MgCO_3 + SiO_2} \tag{7}$$

Carbonate precipitation can fill pores and narrow fractures, reducing permeability and limiting further access of CO_2-bearing fluids to reactive minerals. Where mineral growth generates sufficient stress, it can also initiate or extend fractures, creating new flow paths and exposing fresh mineral surfaces. The net effect on permeability depends on where precipitation occurs, the local stress state, and whether the resulting fractures are connected. Carbonation can therefore reduce permeability locally, while its effect on reservoir-scale containment depends on how the fracture network evolves [28].

However, ultramafic systems come with practical challenges. Most suitable outcrops are in tectonically active regions or ophiolitic belts (e.g., Oman, Albania, New Caledonia), often far from industrial CO_2 sources. Their accessibility and depth vary widely from shallow near-surface exposures to deeply buried mantle-derived units affecting the feasibility of injection infrastructure and fluid delivery. Additionally, while the natural permeability of fractured peridotite can be high, heterogeneity and anisotropy in fracture

networks complicate plume control and pressure management [70, 125].

Unlike conventional saline aquifers, solubility and residual trapping mechanisms are typically short-lived in ultramafic formations. CO_2 injected into these systems either reacts rapidly or migrates through fractures if not retained. Because of this, there is a strong preference for pre-dissolving CO_2 in water prior to injection to ensure intimate fluid–rock contact and to mitigate gas phase mobility. This "carbon mineralization in aqueous phase" strategy is central to several pilot projects targeting ultramafics, such as those in Oman, where fractured mafic and ultramafic zones are tested for reactive transport behaviour [100].

Monitoring in ultramafic systems focuses on core sampling, fluid chemistry evolution, and mineralogical transformation through tools like XRD, SEM-EDS, and stable isotope geochemistry. Geophysical techniques are less effective due to subtle contrasts between altered and unaltered rock. However, volumetric strain mapping, thermal anomalies from exothermic reactions, and microseismicity tracking can provide indirect validation of carbonation progress. Over time, as carbonate minerals fill fractures and micropores, seismic velocity and resistivity may increase slightly, providing signals for integrated reservoir models [126, 127].

Natural hydrogen generation during serpentinization is associated with the oxidation of ferrous iron in ultramafic rocks, and laboratory experiments show that hydrogen yields depend on mineralogy, temperature, and reaction conditions. Experiments introducing CO_2 into actively serpentinizing systems also show that CO_2 can alter the reaction pathway. The Samail pilot demonstrated *in situ* CO_2 mineralization. Integrated operation would require separate field evidence of sustained hydrogen generation and recovery alongside verified CO_2 mineralization [128].

Table 3 summarizes the dominant CO_2 trapping mechanisms, supporting retention processes, and key geological characteristics across different storage formations.

The field cases in Table 4 show that formations differ in both the amount of CO_2 that can be delivered to the reservoir and the fraction that can be retained by a particular mechanism. Decatur and Sleipner demonstrate sustained injection into permeable saline sandstones, while the K12-B pilot illustrates how large permeability contrasts can occur within a depleted reservoir. In coal and shale, the storage contribution of adsorption depends on how much of the sorptive matrix the injected CO_2 can reach and how much remains after pressure declines. The Allison Unit illustrates the effect of near-well permeability loss, while the Chattanooga test shows why injected mass and retained mass must be tracked separately. The CarbFix and Samail pilots demonstrate that substantial mineralization can occur on short timescales under favourable conditions. Their mineralized fractions describe the conversion of CO_2 delivered during each pilot, while storage at larger scale also depends on whether injection can be sustained and whether flow reaches enough reactive rock. These differences explain why injectivity, storage capacity, and trapping efficiency need to be evaluated separately when comparing formations.

Table 3. Primary and Secondary CO_2 Storage mechanism across various formations.

Formation Type	Dominant Classical Mechanism(s)	Supporting Retention Processes / Controls	Geologic Advantage	Key Limitation	Monitoring Challenge
Saline Aquifers [96]	Structural, residual, solubility; mineral (long term)	Hydrodynamic effects; capillary entry pressure; heterogeneity	Large pore volume and widespread occurrence	Pressure buildup, seal integrity, variable reservoir quality	Separating mobile, residual, and dissolved CO_2
Depleted Oil & Gas Reservoirs [24]	Structural, residual, solubility	Capillary entry pressure; heterogeneity	Existing characterization and proven trapping structures	Legacy wells and pressure-management constraints	Distinguishing injected CO_2 from remaining reservoir fluids
Basaltic Formations [129]	Mineral, solubility	Heterogeneity; hydrodynamic effects	Highly reactive Ca–Mg–Fe-bearing minerals	Fracture-controlled injectivity and possible mineral clogging	Quantifying *in situ* mineral carbonation

Table 3. *(Continued)*.

Formation Type	Dominant Classical Mechanism(s)	Supporting Retention Processes / Controls	Geologic Advantage	Key Limitation	Monitoring Challenge
Ultramafic & Serpentinized Formations [100]	Mineral	Heterogeneity; hydrodynamic effects	High Mg content and carbonation potential	Low permeability and limited access to reactive minerals	Quantifying reaction extent and carbonate formation
Shale Formations [78]	Adsorption; structural trapping where applicable	Capillary entry pressure; heterogeneity	Strong sealing capacity and high internal surface area	Very low permeability and limited injectivity	Quantifying adsorbed versus free/dissolved CO_2
Coal Seams [77]	Adsorption	Heterogeneity	High CO_2 adsorption affinity	Swelling and permeability reduction	Quantifying adsorbed CO_2 and its spatial distribution
Offshore Deep Saline Systems [119]	Structural, residual, solubility; mineral (long term)	Hydrodynamic effects; capillary entry pressure; heterogeneity	Large storage capacity and regional-scale formations	High operational cost and pressure management	Offshore access and tracking dispersed/dissolved CO_2

Table note: *Shale formations are primarily investigated for CO_2-enhanced oil recovery (CO_2-EOR) in unconventional reservoirs, with adsorption providing formation-dependent CO_2 retention. Low matrix permeability and limited injectivity constrain their potential for dedicated geological CO_2 storage*.

Table 4. Comparative overview of CO_2 injection performance, trapping characteristics, and reservoir properties across selected geological storage projects.

Geological Setting	Representative Field Case	Reported Evidence	What the Evidence Shows
Onshore saline aquifer [130]	Illinois Basin–Decatur, USA	Approximately 1000 t CO_2/day and 999,215 t injected over three years. The lowermost Mt. Simon Sandstone averaged about 200 mD at the site.	The permeable lower interval supported sustained injection at demonstration scale. The cumulative mass describes project throughput.
Depleted gas reservoir [131]	K12-B, Dutch North Sea	Up to 20,000 t CO_2/year. Reported permeability was 300–500 mD in aeolian sands and 5–30 mD in lower-permeability facies.	The pilot demonstrated reinjection into a depleted field with strong facies contrasts. The operating rate reflects the pilot configuration and does not establish a formation-wide injectivity limit.

Table 4. *(Continued)*.

Geological Setting	Representative Field Case	Reported Evidence	What the Evidence Shows
Basalt [71]	CarbFix pilot, Iceland	More than 95% of the injected CO_2 was estimated to mineralize in less than two years.	The tracer-based estimate demonstrates rapid conversion under the pilot conditions, where CO_2 was injected dissolved in water.
Organic-rich shale [132]	Chattanooga Shale, USA	463 t CO_2 injected into a legacy horizontal gas well during a huff-and-puff test.	The test demonstrated that CO_2 could be placed in the shale through the existing well. Quantifying long-term retention requires accounting for CO_2 recovered during flowback and tracking the remaining inventory.
Coal seam [116]	Allison Unit, San Juan Basin, USA	Pressure falloff tests indicated near-injector permeability of less than 1 mD after CO_2 exposure.	The result illustrates how permeability loss near injection wells can limit access to the coal matrix even where adsorption is favourable.
Offshore saline aquifer [133]	Sleipner, Norwegian North Sea	Approximately 1 million t CO_2/year injected into the Utsira Sand, with reported permeability of 1–3 $\times 10^{-12}$ m^2.	The injection rate is field evidence from Sleipner. The capacity estimate covers the wider Utsira–Skade system and has a different spatial basis.
Ultramafic formation [100]	Samail ophiolite peridotite pilot, Oman	Approximately 88% of injected CO_2 was estimated to mineralize within 45 days.	The mass balance shows rapid mineralization under the pilot conditions. Sustained injection and conversion over a larger rock volume remain separate questions.

5. Toward an Integrated 5D CO_2 Trapping Framework

The complexity of CO_2 trapping in subsurface formations requires a paradigm shift from mechanism-specific assessments toward a holistic, multi-dimensional framework. The Integrated *5D Trapping Evaluation Framework* proposed here offers a systematized, comparative lens that spans five key parameters: (i) dominant mechanism clarity, (ii) time to effectiveness, (iii) permanence potential, (iv) enhancement potential, and (v) monitoring transparency (Figure 11). Each dimension captures a distinct facet of CO_2 retention efficacy, enabling a comprehensive evaluation of storage site performance beyond conventional volumetric or injectivity metrics.

This framework is useful as global CO_2 storage initiatives diversify across geological from mature hydrocarbon basins to untested ultramafic complexes. Current models often overgeneralize trapping effectiveness without accounting for formation-specific controls such as mineralogy, flow regime, geochemical reactivity, and operational feasibility. By applying this five-dimensional rubric, we can not only diagnose the strengths and vulnerabilities of each trapping system but also inform risk assessments, moni-

toring design, and enhancement strategies across varied geologic regimes.

For each geological setting, the five dimensions were scored separately using the rubric and the evidence synthesized in Section 4. Each score represents the rubric category that best describes the dominant retention process under representative formation and injection conditions. The evidence was interpreted in relation to the scale and conditions of each study, because a result observed in a laboratory experiment or a field pilot may apply only to the conditions tested. For example, basalt was assigned a permanence score of 5 because carbonate precipitation can provide durable CO_2 retention where the precipitated minerals remain stable under expected reservoir conditions. It received a monitoring transparency score of 2 because the amount of CO_2 converted to carbonate is generally inferred from tracers, fluid chemistry, or modelling and is difficult to quantify across the reservoir. The two scores therefore reflect different properties of the same retention process. The scores are ordinal judgements. Their applicability to an individual site depends on how closely its geology, injection conditions, and monitoring capabilities match the evidence used in the assessment. The scores are indicative, rubric-based assessments of representative formation conditions and may vary with site-specific geology, injection design, and the strength of the available evidence.

The rubric criteria are tabulated in Table 5.

5.1. Evidence and Rationale for the 5D Scores

The six geological categories were compared using the five criteria defined in Section 5. Field observations, laboratory measurements, and numerical simulations were interpreted at the scale and under the conditions of each study. Where direct measurements were limited, the scores represent indicative judgements based on the expected behaviour of the dominant retention process. Basaltic and ultramafic formations were grouped for the 5D comparison because both rely on carbonate mineralization in representative reactive settings. Their mineralogy, fluid pathways, and reaction kinetics are discussed separately in Sections 4.3 and 4.7.

Dominant mechanism clarity. Onshore and offshore saline aquifers and depleted oil and gas reservoirs were assigned a score of 4 because structural or stratigraphic containment is well supported in characterized storage intervals. Field observations from Decatur, Sleipner, Otway, and K12-B show how plume migration can be interpreted in relation to reservoir geometry and sealing units, although the relative contributions of residual trapping and dissolution vary with site conditions. Basaltic and ultramafic formations received a score of 5 because independent field studies provide convergent evidence for carbonate formation from injected CO_2. This includes tracer and geochemical evidence at CarbFix, isotopic evidence from recovered carbonates at Wallula, and a tracer-corrected carbon balance at Samail. The score applies to reactive intervals reached by the injected fluid. Coal seams received a score of 4 because preferential CO_2 adsorption is well established, while organic-rich shale received a score of 3 because the contribution of adsorption is more sensitive to the accessible pore network, mineral and organic composition, moisture, and gas competition [71, 77, 79, 100, 130, 131, 133–136].



Figure 11. Integrated 5D trapping framework incorporating dominant mechanism clarity, time to effectiveness, permanence potential, enhancement potential, and monitoring transparency for comparative evaluation of geological CO_2 storage formations.

Table 5. Scoring criteria of integrated 5D trapping framework.

Parameter	Score 1	Score 2	Score 3	Score 4	Score 5
Dominant mechanism clarity	Available evidence is insufficient to identify the dominant retention mechanism.	A plausible mechanism has been proposed, but evidence of its dominance is limited.	The mechanism is established, but its contribution varies substantially with site conditions.	The dominant mechanism is well supported under representative formation and injection conditions.	Independent lines of evidence consistently confirm the dominant mechanism under relevant conditions.
Time to effectiveness	The mechanism is expected to make little contribution during injection or the assessed post-injection period.	A material contribution is delayed by substantial limits on fluid access, transport, or reaction.	A material contribution builds progressively as transport or reaction proceeds.	The mechanism makes a material contribution during the early operational period.	The mechanism makes a material contribution promptly after injection begins at the scale assessed.
Permanence potential	Retention is weak, with substantial potential for remobilization or leakage under expected conditions.	Retention is sensitive to plausible changes in pressure, fluid composition, or operating conditions that can remobilize CO_2.	Long-term retention is plausible but depends strongly on maintaining specified reservoir, seal, or well conditions.	Long-term retention is expected, with limited remobilization under representative reservoir conditions.	Very high long-term retention is expected where CO_2 is incorporated into mineral phases that remain stable under anticipated reservoir conditions.
Enhancement potential	Available evidence indicates that practical enhancement options are severely constrained.	A plausible intervention has been proposed or tested in the laboratory, with uncertain field feasibility or benefit.	Formation-specific modelling or a field pilot supports a benefit under stated conditions, with limited evidence of transferability.	Field studies demonstrate a measurable benefit and support applying the intervention at comparable sites.	Multiple field projects demonstrate sustained benefits across a range of sites or operating conditions.
Monitoring transparency	Available monitoring methods provide little practical constraint on the defined target.	Indirect measurements constrain the target, with substantial uncertainty.	Established methods track the target, with limited sensitivity or spatial or temporal resolution.	Established methods reliably track the target at the scale needed for the assessment.	Multiple validated methods independently constrain or quantify the target with high spatial and temporal resolution.

Scores represent the expected behaviour of the dominant trapping or retention process under representative formation conditions rather than overall project performance, which may also be constrained by injectivity, capacity, infrastructure, and site-specific geology.

Time to effectiveness. Onshore saline aquifers scored 3 because, under the representative conditions assessed, structural or stratigraphic trapping makes a material contribution progressively as CO_2 migrates through heterogeneous intervals and accumulates beneath effective barriers. Offshore saline aquifers scored 4 because, in the assessed configuration, the plume reaches effective barriers, and structural or stratigraphic trapping makes a material contribution during the early operational period. This assessment concerns early plume containment. Residual trapping and dissolution can continue to develop as brine re-enters swept pores and mixes with CO_2. Depleted oil and gas reservoirs also received a score of 4 because structural trapping can make a material contribution during early operations as CO_2 accumulates within the existing reservoir closure. Basaltic and ultramafic formations received a score of 3 because mineral trapping develops as CO_2-bearing water reaches reactive minerals and carbonate precipitation progresses. At Hellisheiði, reactive transport simulations predicted complete mineralization within 10 years for a 1200-tonne injection scenario and approximately 80% after 100 years for a 400,000-tonne scenario. At Samail, a field pilot estimated approximately 88% mineralization within 45 days. These results illustrate the influence of injection design and the volume of reactive rock contacted on the time needed for substantial mineralization. Coal and organic-rich shale also received a score of 3. In both settings, formation-scale adsorption develops as CO_2 moves through cleats or fractures and diffuses into the matrix. Connectivity, matrix access, and swelling can govern the rate at which the sorptive volume is contacted [50, 100, 116, 133, 134, 136–138].

Permanence potential. Basaltic and ultramafic formations received a score of 5 where injected carbon is incorporated into carbonate phases that remain stable along the anticipated geochemical trajectory. Onshore and offshore saline aquifers received a score of 4 under representative conditions with a competent seal and managed reservoir pressure. Residual immobilization and dissolution can further reduce the mobile CO_2 inventory. Depleted reservoirs received a score of 3 under the representative conditions assessed here, where long-term containment depends more strongly on legacy-well integrity and the response of the reservoir and seal to depletion and repressurization. Coal and organic-rich shale received a score of 2 because adsorption remains pressure dependent, and depressurization or changes in gas composition can promote desorption and remobilization [73, 77, 100, 136, 137, 139].

Enhancement potential. Onshore saline aquifers received an enhancement potential score of 4 because field testing at Quest demonstrated that halite remediation could restore CO_2 injectivity, while offshore saline aquifers scored 3 because the benefit of brine extraction for pressure management was supported by simulations of the Bunter Sandstone. Depleted reservoirs received a score of 4 based on reinjection through a converted production well at K12-B and modelling of how well design and reservoir pressure affect CO_2 delivery in a depleted gas field. Basaltic and ultramafic formations also received a score of 3 because injecting CO_2 dissolved in water has been demonstrated in reactive rock at CarbFix and Samail. Its broader application depends on water supply, fluid access, and the ability to sustain injection. Coal and organic-rich shale received a score of 2 because measures to improve access to sorptive surfaces face persistent field constraints. Coal swelling can reduce cleat permeability, while shale stimulation can improve fracture access without establishing how much of the surrounding matrix participates in retention. These scores distinguish evidence of improved delivery or pressure management from evidence of an increase in the trapped fraction [100, 116, 131, 140–144].

Monitoring transparency. Onshore saline aquifers received a monitoring transparency score of 3 because time-lapse seismic surveys can track the free-phase CO_2 plume, as demonstrated at the Ketzin CO_2 Storage Pilot Site [145]. At the Illinois Basin–Decatur Project, weak seismic contrast and limited survey repeatability reduced plume resolution. Offshore deep saline aquifers received a score of 2 where limited access to monitoring wells and insufficient seismic resolution constrain plume extent and containment mainly through indirect observations. The Sleipner CO_2 Storage Project demonstrates that clearer plume imaging is possible under favourable seismic conditions. Depleted reservoirs also received a score of 4 because downhole and tracer measurements tracked migration in characterized fields with suitable well access, as demonstrated at Otway and K12-B. Basaltic and ultramafic formations received a score of 2 because the mineralized inventory is inferred from tracers, fluid chemistry, and mineral samples, with uncertainty in its spatial distribution. Coal seams received a score of 2 because pressure and production data provide indirect constraints on retention. Organic-rich shale received a score of 1 because available pressure and flowback data provide little practical constraint on the amount of CO_2 retained by adsorption at formation scale. Reliable free-phase plume imaging does not establish the same level of confidence in the dissolved, residual, adsorbed, or mineralized inventory [71, 116, 131, 132, 146–148].

The 5D scores are ordinal judgements based on how closely the available evidence matches each rubric descriptor under representative formation and injection conditions. The strength of that evidence varies across formations and criteria. Field observations establish performance under the conditions tested, while laboratory experiments and numerical models inform projections where formation-scale observations are limited. Time-to-effectiveness scores are therefore indicative and depend on when the dominant mechanism is expected to make a material contribution at the scale assessed. Enhancement scores reflect the specific benefit demonstrated, such as improved CO_2 delivery, pressure management, or increased retention. Monitoring scores apply to the stated target, such as the free-phase plume or the inven-

tory retained by a particular mechanism. Individual scores may change as site conditions are better characterized or new evidence becomes available. Where reported, the unweighted total is a descriptive summary of the five scores. Its interpretation is limited to the assumptions and evidence used in this comparison.

The scoring is provided in Table 6 and Figure 12.

Table 6. Comparison of geological formations based on mechanism clarity, time to effectiveness, permanence potential, enhancement potential, and monitoring transparency. Scores represent the expected behaviour of dominant trapping or retention processes under representative formation conditions and should not be interpreted as an overall ranking of storage-site suitability.

Formation	Mechanism Clarity	Time to Effectiveness	Permanence Potential	Enhancement Potential	Monitoring Transparency
Onshore Saline Aquifers	4	3	4	4	3
Depleted Oil & Gas Reservoirs	4	4	3	4	4
Basalt and ultramafic Formations	5	3	5	3	2
Shale Formations	3	3	2	2	1
Coal Seams	4	3	2	2	2
Offshore Deep Saline Aquifers	4	4	4	3	2

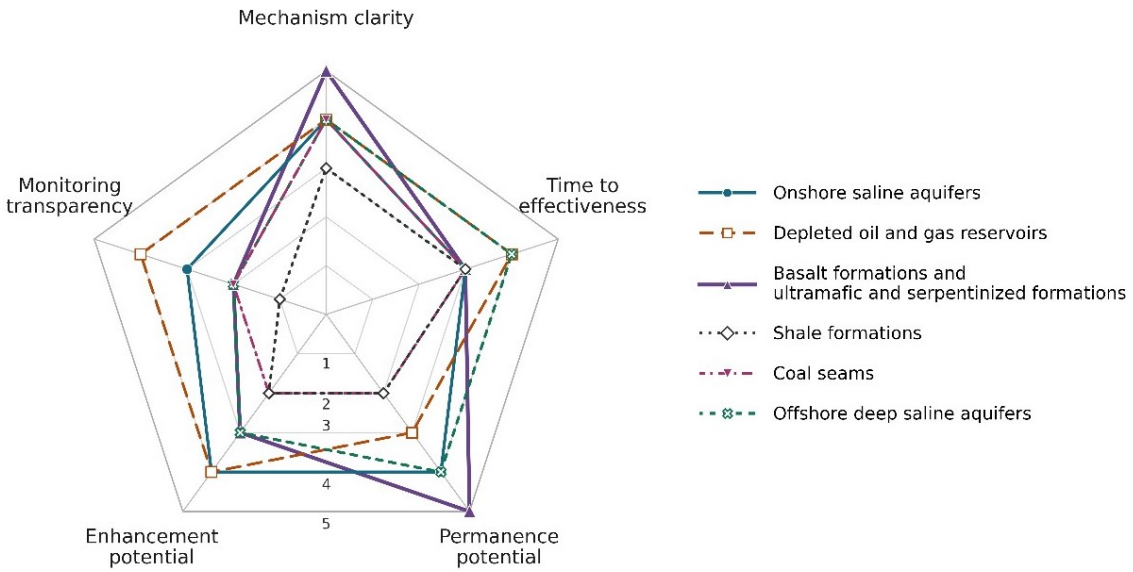

Figure 12. Radar chart comparing different geological storage formations based on key performance indicators including mechanism clarity, time to effectiveness, permanence, enhancement potential, and monitoring transparency. The comparison highlights the relative strengths and limitations of each formation for effective and long-term CO_2 storage. The basaltic and ultramafic are shown under a same profile.

6. Critical Challenges and Future Directions for CO_2 Trapping Mechanisms Related Studies

Despite the maturity of conceptual models describing CO_2 trapping, significant scientific, engineering, and policy-related challenges remain unresolved. These limitations are particularly pronounced when mechanisms are examined within the context of specific geological formations, where heterogeneity, kinetics, and monitoring constraints undermine the generalizations often assumed in storage simulations and policymaking.

6.1. Critical Challenges

i. Most studies still consider structural, residual, solubility, and mineral trapping separately, even though these mechanisms often occur together and change with time. In saline aquifers, for example, structural trapping can initially contain the CO_2 plume, giving more time for dissolution and later mineralization. This transition between mechanisms is not always represented well in current models.

ii. Trapping can also vary considerably within the same reservoir. Changes in permeability, porosity, facies distribution, and wettability affect how CO_2 moves and how effectively it becomes trapped. These variations make predictions particularly difficult in heterogeneous formations, while low injectivity adds another challenge in shale and coal seams.

iii. Mineral trapping provides very stable long-term storage, but mineralization can be slow under natural reservoir conditions. Basalts and ultramafic rocks are more reactive because of their silicate mineralogy, although reaction rates still depend strongly on fluid–rock contact and reservoir conditions. Improving these rates at field scale remains an important challenge.

iv. Some trapping processes are much easier to monitor than others. Free-phase CO_2 can often be followed using seismic methods, whereas dissolved CO_2 and newly formed carbonate minerals are much harder to detect directly. Their presence is therefore commonly inferred from geochemical measurements, modelling, or indirect geophysical changes, which introduces uncertainty into long-term verification.

v. There are also limitations in current monitoring, reporting, and verification (MRV) approaches. Monitoring has traditionally focused strongly on plume movement, containment, and leakage, while directly quantifying the amount of CO_2 held by residual, solubility, or mineral trapping remains more difficult. Better methods are therefore needed to determine how much CO_2 is retained by each mechanism over time.

6.2. Future Research Directions

To address these multifaceted challenges, future efforts must pivot toward integrative, dynamic, and site-specific strategies that acknowledge the complexity of subsurface systems:

i. Future models should better connect fluid flow, geochemical reactions, and rock mechanics from the pore scale to the reservoir scale. This would help show how trapping mechanisms change with time and how reservoir heterogeneity affects their performance.

ii. More work is needed on methods to accelerate mineral trapping, particularly in basaltic and ultramafic formations. Catalysts, nanofluids, and chelating agents could be investigated for improving carbonation rates under reservoir conditions.

iii. Technologies such as Distributed Acoustic Sensing (DAS), reactive tracers, and data-driven analysis of geochemical measurements could improve the monitoring of trapping processes that are difficult to observe directly.

iv. Each storage site should be assessed according to the trapping mechanisms expected to operate there, when they become effective, how permanent they are likely to be, and how easily they can be monitored. This would provide a more realistic basis for comparing potential storage sites.

v. More field-scale evidence is needed, particularly for offshore, basaltic, and other less extensively tested storage settings. Long-term monitoring would help establish how trapping mechanisms change during and after CO_2 injection.

vi. Reactive transport and geomechanical models should be coupled to examine possible changes in fractures, caprock properties, permeability, mineral precipitation, and coal swelling during CO_2 storage.

vii. Monitoring, reporting, and verification (MRV) approaches should better account for CO_2 retained through residual, solubility, and mineral trapping rather than focusing mainly on free-phase plume containment and leakage.

7. Conclusions

This review demonstrates that geological CO_2 trapping is strongly formation-specific and cannot be adequately represented by a single mechanism-based hierarchy. The main conclusions are:

i. Structural, residual, solubility, mineral and adsorptive trapping represent the five classical trapping mechanisms. However, their relative contributions vary with geological setting and evolve over time.

ii. Structural and residual trapping generally provide early containment. Whereas solubility and mineral trapping immobilize CO_2 and strengthen long-term storage security.

iii. Hydrodynamic effects, capillary entry pressure, and geological heterogeneity controls complement the classical mechanisms, and their significance depends strongly on formation characteristics.

iv. No single trapping portfolio is ideal across all formations. Saline aquifers and depleted reservoirs rely on multiple interacting mechanisms, mineral trapping is particularly important in basaltic and ultramafic systems, and adsorption becomes significant in coal and shale formations.

v. The proposed 5D framework provides a structured comparison of geological settings based on mechanism clarity, time to effectiveness, permanence potential, enhancement potential, and monitoring transparency.

Author Contributions

M.H.R.: Conceptualization, Methodology, Investigation, Literature review, Formal analysis, Visualization, Writing—original draft, Writing—review & editing. N.A.S.: Supervision, Validation, Writing—review & editing. M.A.: Supervision, Validation, Writing—review & editing. N.A.: Validation, Writing—review & editing. M.M.: Writing—review & editing, Visualization. O.L.: Writing—review & editing, Visualization. M.S.: Writing—review & editing, Visualization. A.D.: Writing—review & editing, Visualization. All authors have read and agreed to the published version of the manuscript.

Funding

The work is funded by the Research Grant: YUTP-FRG (015LC0-529).

Institutional Review Board Statement

Not applicable.

Informed Consent Statement

Not applicable.

Data Availability Statement

Data is available upon request.

Acknowledgement

The authors gratefully acknowledge the researchers whose contributions have shaped our understanding of geological CO_2 storage, and hope that the visual illustrations presented here will make this evolving field more accessible to future generations of researchers.

Conflicts of Interest

The authors declare no conflict of interests.

Use of AI and AI-Assisted Technologies

Generative AI tool (ChatGPT 5.5) was used solely to assist with language editing and improving the clarity and readability of the manuscript. The authors reviewed and verified all AI-assisted text and take full responsibility for the content of the manuscript.

References

1. Renné, D.S. Progress, opportunities and challenges of achieving net-zero emissions and 100% renewables. *Sol. Compass* **2022**, *1*, 100007.
2. Morris, J.; Chen, Y.-H.H.; Gurgel, A.; et al. Net zero emissions of greenhouse gases by 2050: Achievable and at What Cost? *Clim. Chang. Econ.* **2023**, *14*, 2340002.
3. Deutch, J. Is net zero carbon 2050 possible? *Joule* **2020**, *4*, 2237–2240.
4. Greig, C.; Uden, S. The value of CCUS in transitions to net-zero emissions. *Electr. J.* **2021**, *34*, 107004.
5. Nathanael, A.J.; Kannaiyan, K.; Kunhiraman, A.K.; et al. Global opportunities and challenges on net-zero CO_2 emissions towards a sustainable future. *React. Chem. Eng.* **2021**, *6*, 2226–2247.
6. Suleman, H.; Nasir, R. CCUS: The road to net-zero. *Energies* **2023**, *16*, 4260.
7. Shukla Potdar, R.; Vishal, V. Trapping mechanism of CO_2 storage in deep saline aquifers: Brief review. In *Geologic Carbon Sequestration: Understanding Reservoir Behavior*; Vishal, V., Singh, T.N., Eds.; Springer: Cham, Switzerland, 2016; pp. 47–58.
8. Zhang, L.; Li, X.; Ren, B.; et al. CO_2 storage potential and trapping mechanisms in the H-59 block of Jilin oilfield China. *Int. J. Greenh. Gas Control* **2016**, *49*, 267–280.
9. Abba, M.K.; Abbas, A.J.; Nasr, G.G.; et al. Solubility trapping as a potential secondary mechanism for CO_2 sequestration during enhanced gas recovery by CO_2 injection in conventional natural gas reservoirs: An experimental approach. *J. Nat. Gas Sci. Eng.* **2019**, *71*, 103002.
10. Al Hameli, F.; Belhaj, H.; Al Dhuhoori, M. CO_2 sequestration overview in geological formations: Trapping mechanisms matrix assessment. *Energies* **2022**, *15*, 7805.
11. Ajayi, T.; Gomes, J.S.; Bera, A. A review of CO_2 storage in geological formations emphasizing modeling, monitoring and capacity estimation approaches. *Pet. Sci.* **2019**, *16*, 1028–1063.
12. Baines, S.J.; Worden, R.H. The long-term fate of CO_2 in the subsurface: Natural analogues for CO_2 storage. In *Geological Storage of Carbon Dioxide*; Baines, S.J., Worden, R.H., Eds.; Geological Society: London, UK, 2004; Volume 233, pp. 59–85.
13. Ambrose, W.A.; Lakshminarasimhan, S.; Holtz, M.H.; et al. Geologic factors controlling CO_2 storage capacity and permanence: Case studies based on experience with heterogeneity in oil and gas reservoirs applied to CO_2 storage. *Environ. Geol.* **2008**, *54*, 1619–1633.
14. Bourg, I.C.; Beckingham, L.E.; DePaolo, D.J. The nanoscale basis of CO_2 trapping for geologic storage. *Environ. Sci. Technol.* **2015**, *49*, 10265–10284.
15. Sun, L.; Liu, Y.; Cheng, Z.; et al. Review on multiscale CO_2 mineralization and geological storage: Mechanisms, characterization, modeling, applications and perspectives. *Energy Fuels* **2023**, *37*, 14512–14537.
16. Zhang, C.; Wang, Y.; Kou, Z.; et al. Recent research advances in enhanced CO_2 mineralization and geologic CO_2 storage. *Adv.*

Geo-Energy Res. **2023**, *10*, 141–145.

17. Iglauer, S. Optimum storage depths for structural CO_2 trapping. *Int. J. Greenh. Gas Control* **2018**, *77*, 82–87.
18. Hameli, F.A.; Belhaj, H.; AlDhuhoori, M.; et al. Emerging advances in CO_2 storativity and trappability within shale reservoirs. *Energy Sci. Eng.* **2024**, *12*, 3950–3966.
19. Bachu, S.; Gunter, W.D.; Perkins, E.H. Aquifer disposal of CO_2: Hydrodynamic and mineral trapping. *Energy Convers. Manag.* **1994**, *35*, 269–279.
20. Rasool, M.H.; Ahmad, M.; Ayoub, M. Selecting geological formations for CO_2 storage: A comparative rating system. *Sustainability* **2023**, *15*, 6599.
21. Rasool, M.H.; Ahmad, M. Reactivity of basaltic minerals for CO_2 sequestration via in situ mineralization: a review. *Minerals* **2023**, *13*, 1154.
22. Kim, K.; Kim, D.; Na, Y.; et al. A review of carbon mineralization mechanism during geological CO_2 storage. *Heliyon* **2023**, *9*, e23135.
23. Bashir, A.; Ali, M.; Patil, S.; et al. Comprehensive review of CO_2 geological storage: Exploring principles, mechanisms, and prospects. *Earth-Sci. Rev.* **2024**, *249*, 104672.
24. Wei, B.; Wang, B.; Li, X.; et al. CO_2 storage in depleted oil and gas reservoirs: A review. *Adv. Geo-Energy Res.* **2023**, *9*, 76–93.
25. White, C.M.; Smith, D.H.; Jones, K.L.; et al. Sequestration of carbon dioxide in coal with enhanced coalbed methane recovery: A review. *Energy Fuels* **2005**, *19*, 659–724.
26. Gholami, R.; Raza, A. CO_2 sequestration in sandstone reservoirs: How does reactive flow alter trapping mechanisms? *Fuel* **2022**, *324*, 124781.
27. Goldberg, D.S.; Takahashi, T.; Slagle, A.L. Carbon dioxide sequestration in deep-sea basalt. *Proc. Natl. Acad. Sci. USA* **2008**, *105*, 9920–9925.
28. Nisbet, H.; Buscarnera, G.; Carey, J.W.; et al. Carbon mineralization in fractured mafic and ultramafic rocks: A review. *Rev. Geophys.* **2024**, *62*, e2023RG000815.
29. Teng, Y.; Wang, P.; Xie, H.; et al. Capillary trapping characteristics of CO_2 sequestration in fractured carbonate rock and sandstone using MRI. *J. Nat. Gas Sci. Eng.* **2022**, *108*, 104809.
30. Raza, A.; Rezaee, R.; Bing, C.H.; et al. Carbon dioxide storage in subsurface geologic medium: A review on capillary trapping mechanism. *Egypt. J. Pet.* **2016**, *25*, 367–373.
31. Peter, A.; Yang, D.; Eshiet, K.I.-I.I.; et al. A review of the studies on CO_2–brine–rock interaction in geological storage process. *Geosciences* **2022**, *12*, 168.
32. Zhang, D.; Song, J. Mechanisms for geological carbon sequestration. *Procedia IUTAM* **2014**, *10*, 319–327.
33. Fentaw, J.W.; Emadi, H.; Hussain, A.; et al. Geochemistry in geological CO_2 sequestration: A comprehensive review. *Energies* **2024**, *17*, 5000.
34. Wang, S.; Jin, K.; Zhao, W.; et al. Mechanism, modeling and challenges of geological storage of supercritical carbon dioxide. *Energies* **2025**, *18*, 4338.
35. Rigby, S.P.; Alsayah, A.; Seely, R. Impact of exposure to supercritical carbon dioxide on reservoir caprocks and inter-layers during sequestration. *Energies* **2022**, *15*, 7538.
36. Rutqvist, J. The Geomechanics of CO_2 storage in deep sedimentary formations. *Geotech. Geol. Eng.* **2012**, *30*, 525–551.
37. Shukla, R.; Ranjith, P.; Haque, A.; et al. A review of studies on CO_2 sequestration and caprock integrity. *Fuel* **2010**, *89*, 2651–2664.
38. Song, J.; Zhang, D. Comprehensive review of caprock-sealing mechanisms for geologic carbon sequestration. *Environ. Sci. Technol.* **2013**, *47*, 9–22.
39. Osmond, J.L.; Mulrooney, M.J.; Holden, N.; et al. Structural traps and seals for expanding CO_2 storage in the northern Horda platform, North Sea. *AAPG Bull.* **2022**, *106*, 1711–1752.
40. Zhang, Y.; Li, Q.; Li, X.; et al. Reactivation of rate-and-state faults induced by CO_2 injection: Effects of pore pressure diffusion and fluid pressurization. *J. Rock Mech. Geotech. Eng.* **2026**, *18*, 954–970.
41. Nicol, A.; Seebeck, H.; Field, B.; et al. Fault permeability and CO_2 storage. *Energy Procedia* **2017**, *114*, 3229–3236.
42. White, J.A.; Chiaramonte, L.; Ezzedine, S.; et al. Geomechanical behavior of the reservoir and caprock system at the In Salah CO_2 storage project. *Proc. Natl. Acad. Sci. USA* **2014**, *111*, 8747–8752.
43. Shah, M.S.; Zendehboudi, S.; Duan, X.; et al. Geological and technical foundations of offshore CO_2 storage in depleted reservoirs. *ACS Omega* **2026**, *11*, 17013–17078.
44. Freifeld, B.M.; Oldenburg, C.M.; Jordan, P.; et al. *Well Integrity for Natural Gas Storage in Depleted Reservoirs and Aquifers*. Technical Report LBNL-1006165; Lawrence Berkeley National Laboratory: Berkeley, CA, USA, 2016.
45. Jammernegg, B. CO_2-Brine Primary Displacement Mechanisms: Salt Precipitation as a Result of Supercritical Gas Injection. Ph.D. Thesis, Montanuniversität Leoben, Leoben, Austria, 2025.
46. Ngouangna, E.N.; Dzulkarnain, I.B.; Jaafar, M.Z.; et al. The effects of brine on CCUS-EOR and challenges faced during CO_2 projects: A review involving storage mechanisms with future prospects. *ACS Omega* **2026**, *11*, 111–142.
47. Iglauer, S.; Pentland, C.; Busch, A. CO_2 wettability of seal and reservoir rocks and the implications for carbon geo-sequestration. *Water Resour. Res.* **2015**, *51*, 729–774.
48. Akbarabadi, M.; Piri, M. Relative permeability hysteresis and capillary trapping characteristics of supercritical CO_2/brine systems: An experimental study at reservoir conditions. *Adv. Water Resour.* **2013**, *52*, 190–206.
49. Pentland, C.H.; El-Maghraby, R.; Iglauer, S.; et al. Measurements of the capillary trapping of super-critical carbon dioxide in Berea sandstone. *Geophys. Res. Lett.* **2011**, *38*, L06401.
50. Krevor, S.C.M.; Pini, R.; Zuo, L.; et al. Relative permeability and trapping of CO_2 and water in sandstone rocks at reservoir conditions. *Water Resour. Res.* **2012**, *48*, W02532.
51. Niu, B.; Al-Menhali, A.; Krevor, S.C. The impact of reservoir conditions on the residual trapping of carbon dioxide in Berea sandstone. *Water Resour. Res.* **2015**, *51*, 2009–2029.
52. Heinemann, N.; Stewart, R.J.; Wilkinson, M.; et al. Hydrodynamics in subsurface CO_2 storage: Tilted contacts and increased storage security. *Int. J. Greenh. Gas Control* **2016**, *54*, 322–329.
53. Moghadasi, R.; Foroughi, S.; Goodarzi, S.; et al. Trapping and remobilization during geological CO_2 storage: A pore-scale imaging and modeling study. *Adv. Water Resour.* **2025**, *205*, 105092.
54. Suekane, T.; Nobuso, T.; Hirai, S.; et al. Geological storage of carbon dioxide by residual gas and solubility trapping. *Int. J. Greenh. Gas Control* **2008**, *2*, 58–64.
55. Soroush, M.; Wessel-Berg, D.; Torsaeter, O.; et al. Investigating residual trapping in CO_2 storage in saline aquifers–application of a 2D glass model, and image analysis. *Energy Sci. Eng.* **2014**, *2*, 149–163.
56. Meng, Q.; Jiang, X. Numerical analyses of the solubility trapping of CO_2 storage in geological formations. *Appl. Energy* **2014**, *130*, 581–591.
57. Duan, Z.; Sun, R.; Zhu, C.; et al. An improved model for the calculation of CO_2 solubility in aqueous solutions containing Na^+, K^+, Ca^{2+}, Mg^{2+}, Cl^-, and SO_4^{2-}. *Mar. Chem.* **2006**, *98*, 131–139.
58. Spycher, N.; Pruess, K. A phase-partitioning model for CO_2–brine mixtures at elevated temperatures and pressures: Application to CO_2-enhanced geothermal systems. *Transp. Porous Media* **2010**, *82*, 173–196.
59. Iding, M.; Blunt, M.J. Enhanced solubility trapping of CO_2 in fractured reservoirs. *Energy Procedia* **2011**, *4*, 4961–4968.

60. Burnside, N.; Naylor, M. Review and implications of relative permeability of CO_2/brine systems and residual trapping of CO_2. *Int. J. Greenh. Gas Control* **2014**, *23*, 1–11.
61. Nghiem, L.; Shrivastava, V.; Kohse, B.; et al. Simulation and optimization of trapping processes for CO_2 storage in saline aquifers. *J. Can. Pet. Technol.* **2010**, *49*, 15–22.
62. Rochelle, C.A.; Czernichowski-Lauriol, I.; Milodowski, A.E. The impact of chemical reactions on CO_2 storage in geological formations: A brief review. In *Geological Storage of Carbon Dioxide*; Baines, S.J., Worden, R.H., Eds.; Geological Society: London, UK, 2004; Volume 233, pp. 87–106.
63. Leslie, R.; Cavanagh, A.J.; Haszeldine, R.S.; et al. Quantification of solubility trapping in natural and engineered CO_2 reservoirs. *Pet. Geosci.* **2021**, *27*, petgeo2020-120.
64. Chen, Z.; Zhou, Y.; Li, H. A review of phase behavior mechanisms of CO_2 EOR and storage in subsurface formations. *Ind. Eng. Chem. Res.* **2022**, *61*, 10298–10318.
65. Golding, S.; Uysal, I.; Boreham, C.; et al. Adsorption and mineral trapping dominate CO_2 storage in coal systems. *Energy Procedia* **2011**, *4*, 3131–3138.
66. Siqueira, T.A.; Iglesias, R.S.; Ketzer, J.M. Carbon dioxide injection in carbonate reservoirs–a review of CO_2-water-rock interaction studies. *Greenh. Gases Sci. Technol.* **2017**, *7*, 802–816.
67. Hanshaw, B.B.; Back, W. Major geochemical processes in the evolution of carbonate—Aquifer systems. *J. Hydrol.* **1979**, *43*, 287–312.
68. Pearce, J.; Raza, S.; Baublys, K.; et al. Unconventional CO_2 storage: CO_2 mineral trapping predicted in characterized shales, sandstones, and coal seam interburden. *SPE J.* **2022**, *27*, 3218–3239.
69. Rasool, M.H.; Ahmad, M.; Siddiqui, N.A. Revisiting basalt reactivity for in situ CO_2 mineralization: A condition-dependent reactivity framework. *Environ. Earth Sci. Proc.* **2026**, *43*, 6.
70. Kelemen, P.; Benson, S.M.; Pilorgé, H.; et al. An overview of the status and challenges of CO_2 storage in minerals and geological formations. *Front. Clim.* **2019**, *1*, 9.
71. Matter, J.M.; Stute, M.; Snæbjörnsdóttir, S.Ó.; et al. Rapid carbon mineralization for permanent disposal of anthropogenic carbon dioxide emissions. *Science* **2016**, *352*, 1312–1314.
72. Snæbjörnsdóttir, S.Ó.; Sigfússon, B.; Marieni, C.; et al. Carbfix: CO_2 mineral storage in basaltic rocks. In *The Impacts of Volcanism on Sedimentary Basins and Their Energy Resources*; Geological Society of London: London, UK, 2022; pp. 7–8.
73. Snæbjörnsdóttir, S.Ó.; Sigfússon, B.; Marieni, C.; et al. Carbon dioxide storage through mineral carbonation. *Nat. Rev. Earth Environ.* **2020**, *1*, 90–102.
74. Clark, D.E. Mineral Storage of Carbon in Basaltic Rocks at Elevated Temperatures: A Field and Experimental Study. Ph.D. Thesis, University of Iceland, Reykjavík, Iceland, 2019.
75. Wang, K.; Wang, G.; Ren, T.; et al. Methane and CO_2 sorption hysteresis on coal: A critical review. *Int. J. Coal Geol.* **2014**, *132*, 60–80.
76. Garnier, C.; Finqueneisel, G.; Zimny, T.; et al. Selection of coals of different maturities for CO_2 Storage by modelling of CH_4 and CO_2 adsorption isotherms. *Int. J. Coal Geol.* **2011**, *87*, 80–86.
77. Busch, A.; Gensterblum, Y. CBM and CO_2-ECBM related sorption processes in coal: A review. *Int. J. Coal Geol.* **2011**, *87*, 49–71.
78. Heller, R.; Zoback, M. Adsorption of methane and carbon dioxide on gas shale and pure mineral samples. *J. Unconv. Oil Gas Resour.* **2014**, *8*, 14–24.
79. Wei, S.; Ji, X.; Zhang, T.; et al. Moisture dependence of binary CH_4 and CO_2 adsorption equilibrium on marine shales: Experimental and modelling study. *Sep. Purif. Technol.* **2026**, *380*, 135095.
80. Lin, S.; Chang, X.; Wang, K.; et al. Swelling damage characteristics induced by CO_2 adsorption in shale: Experimental and modeling approaches. *J. Rock Mech. Geotech. Eng.* **2025**, *17*, 5526–5541.
81. Romanov, V.N.; Ackman, T.E.; Soong, Y.; et al. CO_2 storage in shallow underground and surface coal mines: Challenges and opportunities. *Environ. Sci. Technol.* **2009**, *43*, 561–564.
82. Liu, S.; Sun, B.; Xu, J.; et al. Study on competitive adsorption and displacing properties of CO_2 enhanced shale gas recovery: Advances and challenges. *Geofluids* **2020**, *2020*, 6657995.
83. Mastalerz, M.; He, L.; Melnichenko, Y.B.; et al. Porosity of coal and shale: Insights from gas adsorption and SANS/USANS techniques. *Energy Fuels* **2012**, *26*, 5109–5120.
84. Rasool, M.H.; Abdulkareem, F.A.; Meester, R.J.C.; et al. Enhancing shale oil recovery through CO_2 injection and sequestration techniques. In *Reference Module in Earth Systems and Environmental Sciences*; Elsevier: Amsterdam, The Netherlands, 2026.
85. Larkin, R.G. Hydrodynamic trapping of CO_2 geosequestered in saline aquifers. In Proceedings of the SPE Improved Oil Recovery Symposium, Tulsa, OK, USA, 24–28 April 2010; Paper SPE-128205-MS; SPE: Tulsa, OK, USA, 2010.
86. Pruess, K.; Müller, N. Formation dry-out from CO_2 injection into saline aquifers: 1. Effects of solids precipitation and their mitigation. *Water Resour. Res.* **2009**, *45*, W03402.
87. Zhou, Y.; Hatzignatiou, D.G.; Helland, J.O. On the estimation of CO_2 capillary entry pressure: Implications on geological CO_2 storage. *Int. J. Greenh. Gas Control* **2017**, *63*, 26–36.
88. Gershenzon, N.I.; Ritzi, R.W.; Dominic, D.F.; et al. Capillary trapping of CO_2 in heterogeneous reservoirs during the injection period. *Int. J. Greenh. Gas Control* **2017**, *59*, 13–23.
89. Ide, S.T.; Jessen, K.; Orr, F.M. Jr. Storage of CO_2 in saline aquifers: Effects of gravity, viscous, and capillary forces on amount and timing of trapping. *Int. J. Greenh. Gas Control* **2007**, *1*, 481–491.
90. Li, B.; Tchelepi, H.A.; Benson, S.M. The influence of capillary entry-pressure representation on CO_2 solubility trapping. *Energy Procedia* **2013**, *37*, 3808–3815.
91. Larson, R.C. The Effect of Microscale Heterogeneity on the Transport of Carbon Dioxide in Geologic Carbon Sequestration. Master's Thesis, The University of Texas at Austin, Austin, TX, USA, 2024.
92. Darraj, N.; Manoorkar, S.; Spurin, C.; et al. Pore-scale investigation of heterogeneity effects on saturation and trapping for geological CO_2 storage in dolomites. In Proceedings of the SPE Europe Energy Conference and Exhibition, Vienna, Austria, 10–12 June 2025; Paper SPE-225555-MS; SPE: Vienna, Austria, 2025.
93. Illangasekare, T.H. Validation of models simulating capillary and dissolution trapping during injection and post-injection of CO_2 in heterogeneous geological formations using data from intermediate scale test systems. Presented at the Carbon Storage R&D Project Review Meeting, Pittsburgh, PA, USA, 20–22 August 2013; DOE Project DE-FE0004630.
94. Harris, C.; Jackson, S.J.; Benham, G.P.; et al. The impact of heterogeneity on the capillary trapping of CO_2 in the Captain Sandstone. *Int. J. Greenh. Gas Control* **2021**, *112*, 103511.
95. Krishnamurthy, P.G.; DiCarlo, D.; Meckel, T. Geologic heterogeneity controls on trapping and migration of CO_2. *Geophys. Res. Lett.* **2022**, *49*, e2022GL099104.
96. Ringrose, P.S.; Furre, A.-K.; Gilfillan, S.M.V.; et al. Storage of carbon dioxide in saline aquifers: Physicochemical processes, key constraints, and scale-up potential. *Annu. Rev. Chem. Biomol. Eng.* **2021**, *12*, 471–494.
97. El-Maghraby, R.M.; Blunt, M.J. Residual CO_2 trapping in Indiana limestone. *Environ. Sci. Technol.* **2013**, *47*, 227–233.
98. Kim, H.; Vilarrasa, V.; Makhnenko, R.Y. Laboratory-scale assessment of CO_2 sealing potential of heterogeneous caprock. *Water Resour. Res.* **2025**, *61*, e2025WR040339.
99. Li, M.; Long, Y.; Guo, L.; et al. An experimental study on CO_2 displacing CH_4 effects of different rank coals. *Geofluids* **2022**, *2022*, 6822908.
100. Matter, J.M.; Speer, J.; Day, C.; et al. Rapid mineralisation of carbon

dioxide in peridotites. *Commun. Earth Environ.* **2025**, *6*, 590.

101. Eyitayo, S.; Arbad, N.; Okere, C.; et al. Advancing geological storage of carbon dioxide (CO_2) with emerging technologies for climate change mitigation. *Int. J. Environ. Sci. Technol.* **2025**, *22*, 5023–5056.
102. Uliasz-Misiak, B.; Misiak, J. Underground gas storage in saline aquifers: Geological aspects. *Energies* **2024**, *17*, 1666.
103. Cui, G.; Hu, Z.; Wang, Y.; et al. Migration characteristics and local capillary trapping mechanism after the CO_2 leakage out of saline aquifers. *Fuel* **2024**, *356*, 129347.
104. Li, X.; Yue, G. CO_2 trapping mechanism in deep saline aquifers under the control of composite geological factors: A numerical case study in China. *J. Supercrit. Fluids* **2025**, *221*, 106547.
105. Zhou, X.; Wu, Y.-S.; Chen, H.; et al. Review of Carbon dioxide utilization and sequestration in depleted oil reservoirs. *Renew. Sustain. Energy Rev.* **2024**, *202*, 114646.
106. Amer, M.; Mabrouk, W.M.; Eid, A.M.; et al. 3D seismic modeling of the Amal oil field to evaluate CO_2 storage potential in depleted reservoirs, Southern Gulf of Suez. *Sci. Rep.* **2025**, *15*, 18334.
107. Mouallem, J.; Raza, A.; Mahmoud, M.; et al. Impact of petrophysical properties on CO_2 residual trapping in limestone formations. *Fuel* **2025**, *396*, 135327.
108. Lawal, U.-K.; Khan, H.J.; Alajmei, S.; et al. Evaluating CO_2 residuals in water aquifers and depleted oil reservoirs via X-ray coreflooding experiments. *Energy Fuels* **2024**, *38*, 17761–17769.
109. AlRassas, A.M.; Al-Alimi, D.; Zosseder, K.; et al. AI-driven predictive framework for CO_2 sequestration and enhanced oil recovery: Insights from a depleted oil reservoir. *J. Clean. Prod.* **2025**, *519*, 146054.
110. Zhao, R.; Zhong, Z.; Yu, Y.; et al. Numerical simulation of CO_2 storage by basalts in Xingouzui formation, Jianghan Basin, China. *Int. J. Greenh. Gas Control* **2024**, *134*, 104133.
111. Boruah, A. Basalt: A viable host rock for CO_2 sequestration and mineralization. In *CO_2 Geosequestration: Capturing Carbon for a Sustainable Future: Carbon Dioxide Storage in Geological Media*; Springer: Cham, Switzerland, 2025; pp. 95–107.
112. Otabir, P.N.; Khanal, A.; Nath, F. Geochemical impacts of CO_2 mineralization in carbonate and basalt formations: A critical review on challenges and future outlook. *Energy Fuels* **2025**, *39*, 1226–1251.
113. Han, L.; Shi, X.; Ni, H.; et al. Review of CO_2 fracturing and carbon storage in shale reservoirs. *Energy Fuels* **2024**, *38*, 15913–15934.
114. Zheng, S.; Sang, S.; Wang, M.; et al. Experimental investigations of CO_2 adsorption behavior in shales: Implication for CO_2 geological storage. *Front. Earth Sci.* **2023**, *10*, 1098035.
115. Zhang, G.; Ranjith, P.; Fu, X.; et al. Pore-fracture alteration of different rank coals: Implications for CO_2 sequestration in coal. *Fuel* **2021**, *289*, 119801.
116. Reeves, S.; Taillefert, A.; Pekot, L.; et al. *The Allison Unit CO_2–ECBM Pilot: A Reservoir Modeling Study*. Topical Report; Advanced Resources International: Houston, TX, USA, 2003.
117. Niu, Q.; Cao, L.; Sang, S.; et al. Anisotropic adsorption swelling and permeability characteristics with injecting CO_2 in coal. *Energy Fuels* **2018**, *32*, 1979–1991.
118. Viete, D.; Ranjith, P.G. The mechanical behaviour of coal with respect to CO_2 sequestration in deep coal seams. *Fuel* **2007**, *86*, 2667–2671.
119. Qin, J.; Zhong, Q.; Tang, Y.; et al. CO_2 storage potential assessment of offshore saline aquifers in China. *Fuel* **2023**, *341*, 127681.
120. Donda, F.; Volpi, V.; Persoglia, S.; et al. CO_2 storage potential of deep saline aquifers: The case of Italy. *Int. J. Greenh. Gas Control* **2011**, *5*, 327–335.
121. Lee, H.; Seo, J.; Lee, Y.; et al. Regional CO_2 solubility trapping potential of a deep saline aquifer in Pohang basin, Korea. *Geosci. J.* **2016**, *20*, 561–568.
122. Johnson, J.W.; Nitao, J.J.; Knauss, K.G. Reactive transport modelling of CO_2 storage in saline aquifers to elucidate fundamental processes, trapping mechanisms and sequestration partitioning. In *Geological Storage of Carbon Dioxide*; Baines, S.J., Worden, R.H., Eds.; Geological Society: London, UK, 2004; Volume 233, pp. 107–128.
123. Power, I.M.; Wilson, S.; Dipple, G.M. Serpentinite carbonation for CO_2 sequestration. *Elements* **2013**, *9*, 115–121.
124. Cutts, J.A.; Steinthorsdottir, K.; Turvey, C.; et al. Deducing mineralogy of serpentinized and carbonated ultramafic rocks using physical properties with implications for carbon sequestration and subduction zone dynamics. *Geochem. Geophys. Geosyst.* **2021**, *22*, e2021GC009989.
125. Goff, F.; Lackner, K.S. Carbon dioxide sequestering using ultramafic rocks. *Environ. Geosci.* **1998**, *5*, 89–101.
126. Martin, A.; Becattini, V.; Marieni, C.; et al. Potential and challenges of underground CO_2 storage via in-situ mineralization in Switzerland. *Swiss J. Geosci.* **2025**, *118*, 1.
127. Rush, G.E.; O'Connor, W.K.; Dahlin, D.C.; et al. Laboratory tests of mafic, ultra-mafic, and sedimentary rock types for in-situ applications for carbon dioxide sequestration. In Proceedings of the 29th International Technical Conference on Coal Utilization & Fuel Systems, Clearwater, FL, USA, 18–22 April 2004; Report DOE/ARC-2004-038: Albany Research Center (ARC), U.S. Department of Energy (DOE): Albany, OR, USA, 2004.
128. Ellison, E.T.; Templeton, A.S.; Zeigler, S.D.; et al. Low-temperature hydrogen formation during aqueous alteration of serpentinized peridotite in the samail ophiolite. *J. Geophys. Res. Solid Earth* **2021**, *126*, e2021JB021981.
129. Schaef, H.T.; McGrail, B.P.; Owen, A.T. Carbonate mineralization of volcanic province basalts. *Int. J. Greenh. Gas Control* **2010**, *4*, 249–261.
130. Bauer, R.A.; Will, R.; Greenberg, S.E.; et al. Illinois basin–decatur project. In *Geophysics and Geosequestration*; Davis, T.L., Landrø, M., Wilson, M., Eds.; Cambridge University Press: Cambridge, UK, 2019; pp. 339–370.
131. Vandeweijer, V.; van der Meer, B.; Hofstee, C.; et al. Monitoring the CO_2 injection site: K12-B. *Energy Procedia* **2011**, *4*, 5471–5478.
132. Louk, K.; Ripepi, N.; Luxbacher, K.; et al. Monitoring CO_2 storage and enhanced gas recovery in unconventional shale reservoirs: Results from the Morgan County, Tennessee injection test. *J. Nat. Gas Sci. Eng.* **2017**, *45*, 11–25.
133. Boait, F.C.; White, N.J.; Bickle, M.J.; et al. Spatial and temporal evolution of injected CO_2 at the Sleipner Field, North Sea. *J. Geophys. Res. Solid Earth* **2012**, *117*, B03309.
134. Jenkins, C.R.; Cook, P.J.; Ennis-King, J.; et al. Safe storage and effective monitoring of CO_2 in depleted gas fields. *Proc. Natl. Acad. Sci. USA* **2012**, *109*, E35–E41.
135. McGrail, B.P.; Schaef, H.T.; Spane, F.A.; et al. Field validation of supercritical CO_2 reactivity with basalts. *Environ. Sci. Technol. Lett.* **2017**, *4*, 6–10.
136. Chang, X.; Lin, S.; Yang, C.; et al. A critical review of $ScCO_2$-enhanced gas recovery and geologic storage in shale reservoirs. *Gas Sci. Eng.* **2024**, *125*, 205317.
137. Bachu, S. CO_2 storage in geological media: Role, means, status and barriers to deployment. *Prog. Energy Combust. Sci.* **2008**, *34*, 254–273.
138. Aradóttir, E.S.P.; Sonnenthal, E.L.; Björnsson, G.; et al. Multidimensional reactive transport modeling of CO_2 mineral sequestration in basalts at the Hellisheidi geothermal field, Iceland. *Int. J. Greenh. Gas Control* **2012**, *9*, 24–40.
139. IEAGHG. *Criteria for Depleted Reservoirs to be Developed for CO_2 Storage*. Technical Report 2022-01; IEA Greenhouse Gas R&D Programme: Cheltenham, UK, 2022
140. Buscheck, T.A.; Sun, Y.; Chen, M.; et al. Active CO_2 reservoir management for carbon storage: Analysis of operational strategies to

relieve pressure buildup and improve injectivity. *Int. J. Greenh. Gas Control* **2012**, *6*, 230–245.

141. Tillero, E. Machine learning-based modelling for geologic CO_2 storage in deep saline aquifers. Case study of bunter sandstone in Southern North Sea. *Int. J. Greenh. Gas Control* **2024**, *133*, 104077.
142. An, Y.; Kwon, S. Evaluation of CO_2 injectivity and geological storage scenarios using nodal analysis and tubing injectivity index in a depleted gas field in Malaysia. *Energies* **2025**, *18*, 5983.
143. Gunnarsson, I.; Aradóttir, E.S.; Oelkers, E.H.; et al. The rapid and cost-effective capture and subsurface mineral storage of carbon and sulfur at the CarbFix2 site. *Int. J. Greenh. Gas Control* **2018**, *79*, 117–126.
144. Smith, N.; Boone, P.; Oguntimehin, A.; et al. Quest CCS facility: Halite damage and injectivity remediation in CO_2 injection wells. *Int. J. Greenh. Gas Control* **2022**, *119*, 103718.
145. Ivanova, A.; Kashubin, A.; Juhojuntti, N.; et al. Monitoring and volumetric estimation of injected CO_2 using 4D seismic, petrophysical data, core measurements and well logging: A case study at Ketzin, Germany. *Geophys. Prospect.* **2012**, *60*, 957–973.
146. Jenkins, C.; Barraclough, P.; Correa, J.; et al. Field tests of geological storage of CO_2 at the Otway International Test Centre, Australia: Trapping and monitoring the migrating plumes. *Geoenergy* **2024**, *2*, geoenergy2023-035.
147. Chadwick, R.A.; Marchant, B.P.; Williams, G.A. CO_2 storage monitoring: Leakage detection and measurement in subsurface volumes from 3D seismic data at Sleipner. *Energy Procedia* **2014**, *63*, 4224–4239.
148. Bukar, I.; Bell, R.; Muggeridge, A.H.; et al. Carbon dioxide migration along faults at the illinois basin—decatur project revealed using time shift analysis of seismic monitoring data. *Geophys. Res. Lett.* **2025**, *52*, e2024GL110049.