

Effects of CO₂ Injection on the Petrophysical Properties of Reservoir Rocks: A Review

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ABSTRACT

Increasing carbon emissions pose a serious issue affecting the environment. Several methods have been proposed to reduce this phenomenon. Carbon capture and storage (CCS) and enhanced oil recovery EOR are among these methods, which typically involve injecting CO₂ into geological formations to store CO₂ or to enhance oil production. The effectiveness of these methods relies heavily on the interaction between CO₂, rock, and water. This review summarizes most of the important studies that focused on the alteration of mineralogy, porosity, permeability, and wettability of the host rock, employing different methods such as core flooding and static soaking. Despite extensive research on CO₂-water-rock interactions, significant uncertainties remain regarding the comparative effects of supercritical CO₂ and carbonated brine injection on petrophysical, geochemical, and geomechanical properties under representative reservoir conditions. This review addresses these gaps by synthesizing recent experimental findings and identifying key challenges and research needs related to injectivity, low-permeability formations, and long-term reservoir integrity. This review focuses on the effects of various factors, including the CO₂ phase during injection and the presence of impurities. An analytical comparison of the supercritical and dissolved CO₂ phases was also conducted, which revealed that supercritical CO₂ generally promotes stronger mineral dissolution, wettability alteration, and salt precipitation near the injection zone. In contrast, carbonated brine produces more uniform geochemical reactions and tends to preserve or improve permeability while maintaining water-wet conditions. This review provides a comprehensive understanding of the effect of CO₂ injection on the geochemical and petrophysical properties of various rock types, integrating recent discoveries and identifying knowledge gaps.

Keywords: CO₂ sequestration, CCS, CO₂-brine-rock interaction, Injection of carbonated water, Supercritical CO₂, Reservoir wettability.

1. INTRODUCTION

Mitigating the emission of CO₂ is a critical challenge that is associated with our living conditions in this era. One of the effective methods to mitigate human-induced CO₂

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emissions is Carbon Capture and Storage (CCS) (Shen et al., 2013; Menefee et al., 2018; Raza et al., 2022). However, it affects rock pore structure since it results in acid-generating processes (Vafaie et al., 2023). The feasibility of CO₂ injection mainly relies on the porosity and permeability of the storage formations. The dissolution-precipitation of minerals resulting from CO₂ interactions with host rock is equally significant (Sayegh et al., 1990; Saeedi et al., 2011).

The interactions among CO₂, brine, and rock are crucial to geological carbon storage (GCS) and EOR processes, and examining these interactions can enhance understanding of the long-term behavior of storage reservoirs. Due to the chemical reaction between the injected CO₂ and the fluid and rock, the rock and the Hydrocarbons will transform.

Injected CO₂ dissolves in formation water, resulting in the creation of dilute carbonic acid. The acid reaction with rock minerals would result in ion dissolution and precipitation and generate secondary mineral dissolution (Al-Yaseri et al., 2017). It was noted that the parameters that dramatically modify the rock's physical properties during CO₂-brine-rock interactions are the brine's composition and salinity, the reactive surface area of the pores, and the duration of contact. The research in (Md Yusof et al., 2022) aimed to determine the predominant factor and the extent of influence of each component. This study showed that the pronounced factor was brine salinity, followed by exposure duration. In geological storage, the injected CO₂ will experience varying outcomes when interacting with the formation rock and formation fluids. Part of the injected CO₂ occupies the pore space within the storage site, referred to as structural or stratified capture; part dissolves in water, referred to as dissolved capture; some is retained as residual CO₂ due to capillary forces, as shown in Fig. 1, and part may precipitate to form carbonate minerals, known as mineral trapping (Knauss et al., 2005).

Hence, injecting CO₂ into the reservoirs as an EOR mechanism or CCS alters the system's chemical composition, leading to the dissolution and precipitation of minerals, which, in turn, change the rock's physical properties. Therefore, a thorough comprehension of the system's geochemistry is crucial to ensure adequate, safe, and efficient CO₂ storage (Eyitayo et al., 2024) and an efficient EOR process. This review paper presents several important studies that investigated a wide range of injection conditions, including pressure, flow rate, and CO₂ purity, across different rock types.

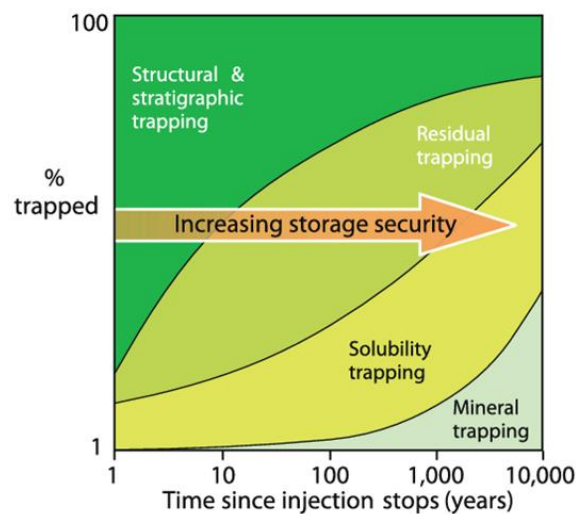


Figure 1. A diagram showing how the proportions of a CO₂ plume are trapped by residual, dissolution, and mineral trapping over time (IPCC, 2005).



The main focus was to highlight the differences in the injection of carbonated water and supercritical CO₂ into carbonate and sandstone rocks. This review proposes a simple yet comprehensive comparison to evaluate how each CO₂ phase affects fluid saturation distribution. The comparison focused on the physicochemical and petrophysical alterations induced by each fluid, including changes in porosity, permeability, and mineral dissolution behavior, and reservoir stability. The articles analyzed for this review have been obtained from the following databases: Scopus, Web of Science, ScienceDirect, and Google Scholar. A search of literature was conducted for papers published between the years 2010 and 2025 with key phrases like "CO₂-rock reaction", "carbonated fluid", "supercritical CO₂", "carbon sequestration", and "enhanced oil recovery". Papers that dealt with experiments related to CO₂-water-rock reactions and their effect on the aforementioned parameters have been considered.

2. METHODS OF CO₂ INJECTION AND ANALYSIS

Most experimental investigations on CO₂-water-rock interactions have relied on laboratory-scale setups designed to simulate reservoir conditions. Core flooding experiments are among the most common. Several studies have been conducted to investigate how different pressures affect CO₂-water-rock interaction (**Mohamed et al., 2010; Alemu et al., 2011; Yu et al., 2012; Tarokh et al., 2020**) with a pressure range of 10-30 MPa. Other researchers choose to study the effect of temperature (up to 200 °C) on CO₂-water-rock interaction (**Luquot and Gouze, 2009; Karaei et al., 2020; Seyyedi et al., 2020; Rigby et al., 2022**). Furthermore, Laboratory core flooding studies that significantly vary the flow rate typically operate over a wide experimental range from ≈ 0.01 mL/min⁻¹ (very low/pore-scale leakage tests) to over 10 mL/min⁻¹ (field-analog injection cycles), with many studies using increasing rates within 0.1–14 mL/min⁻¹ to investigate transition regimes between uniform dissolution and channel flow. Typical experimental examples include the study by (**Luquot and Gouze, 2009**) (conducted baseline low-rate percolation experiments at approximately 0.01 mL/min⁻¹), and the study by (**Giwelli et al., 2018**). (cyclic ScCO₂ injection at rates of 2–14 mL/min⁻¹). The study by (**Yang et al., 2020**) (pore-scale leakage test at low to moderate velocities). Researchers also use static or batch experiments to study CO₂-water-rock interactions by immersing rock samples in CO₂-saturated brine or by exposing them to CO₂ in controlled environments. These methods allow researchers to focus on the chemical effects of CO₂ without the effect of fluid flow. Recent findings include studies by (**Akbari et al., 2020**), who revealed changes in limestone porosity. (**Wang et al., 2022**) evaluated mineral stabilization in carbonate rocks under reservoir-like conditions, while (**Licbińska et al., 2024**) combined laboratory tests with geochemical modeling to analyze long-term rock interactions. (**Al-Jawad et al., 2025**) observed mineral transformations in limestone during batch-soaking experiments, reflecting conditions in carbonate reservoirs.

3. THE CO₂ PHASES UPON STORAGE

Since the interaction effects differ depending on CO₂ phase (**Al-Ameri et al., 2015; Peter et al., 2021**), it is important to understand how CO₂ phase changes with distance and time. For this reason, the study categorizes CO₂ phases into supercritical CO₂ and dissolved CO₂ (carbonated water). In order to have an understanding of how the reactions between carbon dioxide, brine, and rock differ according to location within the geological reservoir, it is

possible to define five zones around the wellbore that differ in terms of fluid-phase distribution and saturation. Chemical interactions differ in type and extent across various zones surrounding the wellbore, categorized by fluid-phase saturations —specifically the volumetric proportions of CO₂ and aqueous (brine) phases in the pores, as well as the concentrations of dissolved CO₂ and water molecules in both phases (Kim et al., 2013; Rohmer et al., 2016). As shown in Fig. 2, when the rock pore network is full of dry supercritical CO₂, A1 is the closest wellbore zone. A2 is a place where supercritical CO₂ (wet CO₂) is mixed with water. A3 shows the transition zone where the two fluid phases exist in different amounts, while A4 shows the brine around the CO₂ plume that is rich in CO₂. The A2 and A4 zones are affected by how well CO₂ and water can mix, which changes with temperature and pressure (Akbari et al., 2020).

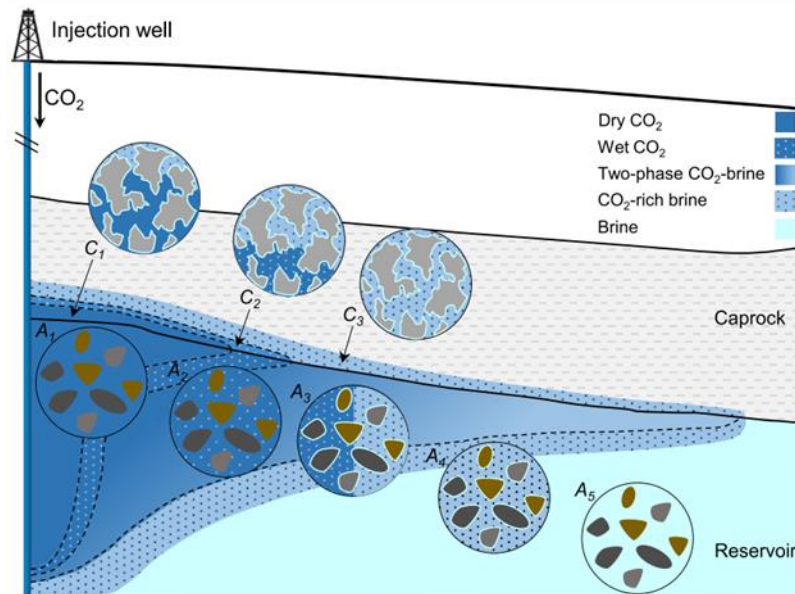


Figure 2. Schematic of a geological CO₂ storage site with zones formed around the injection well (Vafaie et al., 2023)

In zones A2 and A3, the CO₂ phase may have different amounts of dissolved water. At temperatures below 60 °C, the dissolved water content should not exceed 1 mol%. At 100 °C and above 10 MPa, the dissolved water content should be between 2 and 3 mol%. On the other hand, CO₂ dissolves in the water phase in areas A3 and A4. Its solubility depends strongly on pressure, usually between 2 and 3 mol% at pressures above 10 MPa and temperatures below 60 °C (Spycher et al., 2003). A5 is the uninvaded zone, the farthest from the injection well. Zone A5 is not affected by CO₂. However, the other zones that are in direct contact with CO₂ may experience different physicochemical effects.

3.1 Supercritical CO₂ (scCO₂)

The CO₂ must have a temperature ≥ 30.98 °C and a pressure ≥ 1070 psi to be in the supercritical state (Al-Ameri et al., 2015). The continuous injection of dry supercritical CO₂, which is minimally chemically reactive, extracts and desiccates the rock from the resident brine in the near-wellbore zone, potentially leading to salt precipitation with rapid loss of formation porosity and permeability (Mohamed et al., 2013; Andre et al., 2017; Tang et al., 2018). The capillary pressures between CO₂ and brine increase the formation damage. However, greater damage is observed in heterogeneous rocks than in homogeneous rocks



due to their elevated permeability, which triggers more pronounced precipitation reactions. CO₂ dissolves in brine, forming carbonic acid that dissolves carbonate minerals (**Mohamed et al., 2010**). The partitioning experiments conducted by (**Rempel et al., 2011**) indicate that trace elements are soluble in supercritical CO₂, with solubilities of 0.6 ppm for Fe and 39 ppm for Na. This serves as an initial assessment of mineral solubility in supercritical CO₂, although additional data is required. The interaction of CO₂ with mineral surfaces may lead to de-wetting, resulting in a decrease in capillary entry pressure, changes in the amounts of residually trapped CO₂ and relative permeability, and an increase in CO₂ penetration into low-permeability rock (**Farokhpoor et al., 2013**). Halite deposition transpires when the solubility threshold of approximately 26.5% by weight is surpassed (**Bacci, 2013**). Comparable issues are observed in injection wells used in gas storage operations, where dry natural gas is injected into saline aquifers (**Lorenz and Müller, 2003**). It was disclosed that ScCO₂ injection resulted in a slight increase in sandstone permeability far from the injection well. Mineral–fluid reactions involving supercritical CO₂ remain inadequately understood and should constitute a unified focus of research. Further experimental investigations are required to determine how hydrated supercritical CO₂ behaves and how it affects the transport properties of reservoirs and caprocks. The long-term effects of supercritical CO₂ on reservoir caprocks are particularly concerning. Firstly, **Table 1** presents the study of the effects of ScCO₂.

Table 1. The main findings from several studies on ScCO₂ effects on different types of rocks

Authors	Rock Type	Experimental Conditions	Quantitative Outcomes	Key Findings
(Chiquet et al., 2007)	Mica and Quartz	Exposure to CO ₂ under storage conditions	Contact angle/wettability alteration observed (exact values not reported)	CO ₂ altered the wettability of both minerals. Wettability change was more pronounced in mica. Altered wettability may reduce capillary sealing efficiency. Changes may facilitate capillary breakthrough.
(Al-Yaseri et al., 2017)	Sandstone	scCO ₂ injection into Berea and Bandera Grey sandstone; varying injection rates	Berea permeability increased by 11–23%; Bandera permeability showed no significant change	Permeability response depended on sandstone type. Berea sandstone exhibited moderate permeability enhancement. Bandera Grey sandstone showed negligible change. Injection rate had little effect on permeability.
(Pimienta et al., 2017)	Limestone and Sandstone	scCO ₂ injection into fluid-saturated rocks; exposure periods >4 h	Water saturation decreased by ~3%; calcium concentration increased; permeability and P-wave velocity	CO ₂ dissolution rapidly acidified pore fluids. Calcite dissolution increased with exposure time. Mechanical weakening was observed in some rocks. Rock response varied depending on mineral composition.



			decreased after prolonged exposure	
(Wang et al., 2019)	Sandstone	scCO ₂ injection into very low-permeability sandstone	Porosity remained nearly unchanged; permeability decreased (exact percentage not reported)	Permeability reduction was caused by fines migration. Clay dissolution and secondary mineral precipitation altered pore structure. Large pores decreased while medium-sized pores increased. Pore clogging reduced flow capacity.
(Zhou et al., 2020)	Shale	scCO ₂ and subCO ₂ exposure; permeability measurements over time	Greater permeability reduction under scCO ₂ ; inflection point observed after ~12 h	scCO ₂ caused greater permeability decline than subCO ₂ . Gas adsorption and swelling contributed to permeability reduction. Permeability evolution occurred in two stages. High stress sensitivity resulted in mechanical degradation.
(Kamali et al., 2021)	Carbonate, clay-rich, and mixed formations	scCO ₂ exposure in formations with different mineral compositions	Permeability increased by up to 400% in calcite-rich samples; permeability decreased in clay-rich samples	Mineral dissolution strongly influenced permeability evolution. Calcite-rich formations showed substantial permeability enhancement. Clay-rich formations experienced permeability reduction. Response depended on mineralogical composition.
(Medina et al., 2022)	Shale	scCO ₂ exposure; low-pressure gas adsorption and NMR analysis	Increased pore volume in 1–1000 nm range (carbonate-rich shale); increased pore volume mainly in 1–10 nm range (clay-rich shale)	Carbonate-rich shale showed pore enlargement over a broad pore-size range. Clay-rich shale exhibited changes mainly in small pores. Transport rates remained relatively stable in carbonate-rich shale. Clay-rich shale may act as an effective seal due to low permeability.
(Razali et al., 2022)	Carbonate	scCO ₂ injection; varying injection rates in rocks with different permeabilities	Recommended critical rates: 12 mL/min (10–100 mD), 10 mL/min (100–1000 mD), 8 mL/min (1000–10000 mD)	Excessive injection rates promoted fines migration and pore blockage. Higher differential pressure increased formation damage risk. Salt precipitation and scale formation impaired injectivity.



				Mineral reactions reduced porosity and permeability.
(Alchin et al., 2022)	Sandstone	scCO ₂ injection with brine displacement	Permeability decreased (exact percentage not reported)	Dry-out and salt precipitation reduced permeability. Injectivity impairment was observed. Salt precipitation had a stronger effect than fines migration. Reduced liquid saturation promoted formation damage.
(Wapperm et al., 2022)	Saline aquifers / depleted gas reservoirs	scCO ₂ injection under reservoir conditions	Quantitative changes not reported	Salt precipitation may reduce injectivity. Formation damage can occur due to porosity and permeability reduction. Joule-Thomson cooling may induce hydrate formation. Solid-phase formation can impair well performance.
(Tianshou Ma et al., 2024)	Shale	Shale samples exposed to scCO ₂ , brine, and scCO ₂ -brine mixture	Peak stress and elastic modulus decreased; Poisson's ratio increased (exact values not reported)	Mechanical properties deteriorated after exposure. Greatest strength reduction occurred in the scCO ₂ -brine system. Elastic modulus decreased after saturation. Poisson's ratio increased following immersion.
(Laskowski et al., 2025)	Sandstone	Exposure to supercritical CO ₂ (scCO ₂)	UCS decreased from 21.04 MPa to 12.67 MPa; Young's modulus decreased from 10.29 GPa to 4.27 GPa; porosity decreased by ~50% at core edges	Exposure to scCO ₂ significantly weakened the sandstone. Mechanical properties deteriorated substantially. Mineral dissolution altered rock composition. Reductions in UCS and porosity were linked to mineralogical changes.

3.2 Carbonated Water (CO₂ Dissolved in Brine)

Dissolving CO₂ in water produces an acidic solution called carbonate. When this water is injected, it causes an alteration in the rock's geochemical and petrophysical properties. Primarily, an enhancement in porosity and permeability, due to the dissolution of calcite and dolomite, can be traced by the increasing concentrations of dissolved Ca and Mg ions in water. Carbonated water injection is characterized by a uniform reaction, which causes less formation damage over the exposure duration. The calcium and magnesium ions released over time may cause secondary mineral precipitation. This can partially block pores and reduce their permeability (Akbari et al., 2020; Karaei et al., 2020). Many factors affect the



intensity of these alterations, such as injection pressure, temperature, and CO₂ concentration. Elevated CO₂ partial pressures and contact durations often increase dissolution; on the other hand, greater temperatures encourage reprecipitation (Error! Reference source not found. **Abe et al., 2021**). Studies showed that mineral interactions change surface charge and wettability, making carbonate surfaces more water-wet by altering surface roughness and chemistry (**Seyyedi et al., 2020**). Similar outcomes in basalt-CO₂ systems. The aqueous carbonation mechanisms are essential in mineral transformation following CO₂ exposure (**Ferreira et al., 2024**). Injecting carbonated water starts a dynamic balance between mineral dissolution and precipitation. This controls the changes in porosity, permeability, and wettability in carbonate reservoirs during CO₂ storage or enhanced oil recovery. In this paper, several studies have been proposed that investigate the injection of carbonated water in different types of rocks, as shown in Error! Reference source not found..

Table 2. The main findings from several studies on the effects of carbonated water on different types of rocks.

Authors	Rock Type	Experimental Conditions	Quantitative Outcomes	Key Findings
(Hoefner et al., 1988)	Carbonate limestone	Acid flooding/core flooding experiments	Acid breakthrough volume \approx 1.5 PV	Wormhole formation depended on mineral heterogeneity. Pressure-drop trends matched simulation results. Continuous injection after breakthrough caused limited wormhole growth. Results can assist acidizing optimization.
(Benoit Lamy-Chappuis et al., 2014)	Sandstone	CO ₂ -saturated brine injection into calcareous sandstone cores	Porosity increased 5–15%; permeability increased beyond classical model predictions	Rapid calcite dissolution occurred. Transport-limited dissolution-controlled reactions. Permeability increased disproportionately relative to porosity. Acid transport rate-controlled dissolution efficiency.
(Al-Yaseri et al., 2017)	Sandstone	Carbonated brine injection at different flow rates	Permeability increased (exact percentage not reported)	Permeability improvement depended on pore-throat size. Carbonated brine enhanced flow capacity. Flow rate had negligible influence. Mineral dissolution-controlled permeability evolution.
(Seyyedi and Sohrabi, 2017)	Carbonate reservoir rock	Pore-scale investigation of crude oil–CO ₂ compositional effects during carbonated	Improved oil recovery observed; exact $\Delta\phi$ and Δk not reported	Carbonated water injection enhanced oil recovery. Oil recovery was strongly influenced by crude oil–CO ₂ interactions. Mass transfer between CO ₂ and crude oil contributed to recovery mechanisms.



		water injection		Pore-scale observations demonstrated the effectiveness of carbonated water flooding in carbonate reservoirs.
(Wei Xiong et al., 2018)	Basalt	Dissolved CO ₂ exposure in fractured basalt cores	Carbonate precipitation observed (no quantitative values reported)	Aragonite was the dominant carbonate mineral formed. Mineralization occurred mainly along fractures. Carbonates gradually formed in connected pores. Dissolved CO ₂ penetrated into the basalt matrix.
(Seyyedi et al., 2020)	Carbonate limestone	CO ₂ -saturated brine injection	Porosity and permeability increased; microchannels formed (exact percentages not reported)	Heterogeneous dissolution altered pore structure. Intergranular porosity and medium pores increased. Micropore size decreased. Downstream rock-property changes remained limited.
(Foroutan et al., 2020)	Sandstone	CO ₂ -enriched brine injection	Porosity increases 3.6%; permeability increases 72.1%; Young's modulus decreased 53% and 48% for S1 and 16% and 11% for S2	Calcite and clay dissolution improved flow properties. Significant permeability enhancement was observed. Mechanical properties deteriorated. Rock response varied between samples.
Tarokh et al. (2020)	Sandstone	Liquid CO ₂ injection into heat-damaged Berea sandstone	Porosity increase ≈10%; permeability increases up to 100%; elastic property changes 2–12%; creep rate >2× higher	CO ₂ treatment improved porosity and permeability. Mechanical properties changed only slightly. Viscoelastic deformation increased significantly. Heat-damaged sandstone was highly sensitive to CO ₂ treatment.
(Karaei et al., 2020)	Carbonate, clay, and moderate carbonate	Carbonated brine injection; CO ₂ pressure <1–7 MPa; temperatures 27–100°C; confining pressure 5–15 MPa	Permeability increased from 4.29→7.62 mD (freshwater), 2.98→7.24 mD (seawater), and 2.32→5.69 mD (formation brine); density decreased from 1.1511→1.1261 g/cm ³	Higher CO ₂ pressure increased permeability. Higher confining pressure reduced permeability. Temperature reduced permeability and density. Freshwater produced higher permeability than seawater and formation brine.



(Vafaie et al., 2023b)	Carbonate limestone	CO ₂ -saturated water injection	Porosity increases up to 9.7%; permeability increases up to three orders of magnitude; dynamic Young's modulus decrease up to 39%	Mineral dissolution increased porosity and permeability. Dissolution patterns strongly controlled permeability evolution. Porosity–permeability relationship followed a power law (exponent = 24). Mechanical properties deteriorated after CO ₂ exposure.
(Okoli et al., 2024)	Basalt	Laboratory CO ₂ exposure experiments	Strength decreased with increasing exposure time (exact values not reported)	Dissolution increased basalt porosity. Mineralization enhanced CO ₂ storage potential. Permeability and reaction rates evolved. Mechanical strength progressively declined.
(Tale et al., 2025)	Carbonate limestone	CO ₂ -saturated brine injection	Porosity increased by ≈0.01% under brine injection; permeability doubled after CO ₂ -saturated brine injection	Calcite dissolution enhanced permeability. Quartz dissolved without noticeable precipitation. Brine alone had minimal impact. Carbonated brine significantly improved flow properties.

4. COMPARISON BETWEEN ScCO₂ AND CARBONATED BRINE INJECTED INTO SANDSTONE AND CARBONATE ROCKS

When injecting (ScCO₂) and carbonated brine into sandstone formations, they react differently. ScCO₂ injection primarily results in rapid acidification of the CO₂-brine interface and the dissolution of reactive minerals, such as feldspars, carbonates, and silicates, within the sandstone matrix (Noiriel et al., 2009; Alemu et al., 2011). Usually, such a process causes an expansion of the pores at the inlet, which leads to mineral precipitation downstream as the dissolved ions return to equilibrium (Iglauer, 2011).

On the other hand, injecting a carbonated brine into the aqueous phase results in more uniform reactions within the core. That is by evenly distributing the carbon dioxide and mitigating interference effects (Luquot and Gouze, 2009). The studies indicate that carbonated brine has fewer damaging effects on permeability and causes a more gradual alteration in porosity than ScCO₂ flooding. This is due to its reduced interfacial tension and a more stable flow regime (DePaolo and Zheng, 2013; Arif et al., 2017). Also, ScCO₂ helps move small particles and alters wettability, enhancing the feasibility of Co₂ applications (Arif et al., 2019). Carbonated brine, on the other hand, keeps or even improves water-wetness, which stabilizes two-phase flow (Iglauer et al., 2015). In summary, scCO₂ and rock interact to rapidly alter geochemistry and capillary architecture over a small area. But flooding with carbonated brine breaks down minerals more slowly and uniformly, causing less damage, as shown in Fig. 3.



A significant aspect of CO₂ injection into carbonate rocks is the comparatively high solubility of carbonates; low permeability does not affect the dissolution rate but rather localizes the dissolution process. If the permeability is low, dissolution will occur near the injection well. Injecting CO₂ into carbonates could be a problem in theory because (1) carbonates dissolve quickly, which leads to (2) the formation of dissolution cavities, and (3) CO₂ solutions are acidic, which makes the problem worse. Fluid accessibility to the reactive surface area is also a key parameter (Drexler et al., 2019). When supercritical carbon dioxide (ScCO₂) and carbonated brine are added to carbonate rocks, they alter the rock's porosity, permeability, and mineral stability through asymmetric, yet interconnected, chemical and physical interactions. When supercritical carbon dioxide is injected, the supercritical phase, which does not wet the rock matrix, comes into direct contact with the rock matrix. This creates sharp interfaces between carbon dioxide and brine, which favor the dissolution of calcite and dolomite in small areas near flow channels (Luquot and Gouze, 2009; Noiriél et al., 2009; Eytayo et al., 2024).

This process results in an uneven increase in rock porosity, which forms wormholes and possibly a decrease in mechanical strength (Karaei et al., 2020). On the other hand, carbonated brine injection produces a more balanced reaction front and slower mineral dissolution because the acidic solution diffuses more evenly across the pore network (Akbari et al., 2020; Abe et al., 2021). (Ferreira et al., 2024) assert that carbonated brine typically results in milder mineral transformations and more consistent permeability patterns, with secondary precipitation, such as calcite or gypsum, facilitating the attainment of dissolution equilibrium over time. Wettability studies show that carbonated carbon dioxide modifies carbonate surfaces, rendering them more hydrophilic and reducing the effectiveness of capillary trapping. On the other hand, carbonated brine maintains or even increases water humidity because it does not damage the surface or the chemical material to the same extent (Ibrahim et al., 2021). Injecting carbon dioxide into the reservoir results in reduced stability and increased variability in reservoir conditions, primarily affecting fluid saturation distribution, fluid properties, and reservoir behavior (Eytayo et al., 2025). On the other hand, adding carbonated brine to the reservoir improves control over geochemical changes and helps maintain reservoir strength. Storing carbon dioxide in carbonate deposits is safer and may even be better for the environment.

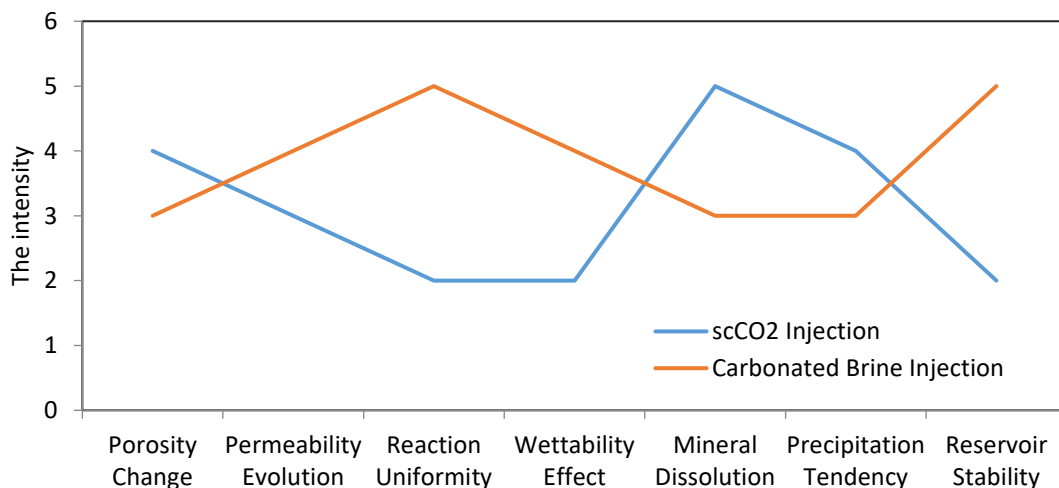


Figure 3 . A comparison between the intensity of the effect of scCO₂ and carbonated water on the properties of rock water and reservoir stability



In conclusion, variations in permeability response are primarily controlled by mineral composition and the balance between dissolution and precipitation processes. Carbonate-rich rocks often exhibit permeability enhancement due to calcite dissolution and wormhole development, whereas clay-rich formations may experience permeability reduction due to fines migration, pore blockage, and secondary mineral precipitation. This is beneficial for CCS. However, calcite-rich formation provides better permeability enhancement.

Porosity and Permeability: When ScCO_2 comes into contact with minerals, it dissolves them very quickly. This can make the material more porous, but it can also make the flow routes uneven and unstable. On the other hand, carbonated brine dissolves minerals slowly and evenly, which improves permeability in a more controlled manner **(Akbari et al., 2020; Abe et al., 2021)**.

Uniformity of Reaction: Since CO_2 is already dissolved in water, carbonated brine reacts more evenly throughout the rock. Reactions with ScCO_2 are less uniform and occur more commonly at the interface between CO_2 and water **(Shen et al., 2013; Ferreira et al., 2024)**.

Wettability: The presence of CO_2 alters the wettability. ScCO_2 makes the rock surface more CO_2 -wet (less water-wet), which can make it less effective at capturing CO_2 . Carbonated brine usually keeps the surface wetter **(Al-Khulaifi et al., 2019)**.

Mineral Dissolution and Precipitation: ScCO_2 dissolves the fastest-dissolving minerals; however, this can cause new minerals to redeposit, potentially blocking pores. Carbonated brine breaks down minerals more slowly, which keeps them from clogging **(Akbari et al., 2020)**.

Stability of the Reservoir: Carbonated brine better preserves the rock's integrity because it has a slower chemical impact on the rock. Rapid reactions and uneven stress can make certain areas weaker because of ScCO_2 **(Luquot and Gouze, 2013; Shen et al., 2013)**. **Fig. 3** indicates the effect intensity of the factors mentioned above

5. EFFECT OF IMPURITIES IN INJECTED CO_2 ON CO_2 -WATER-ROCK INTERACTION

When CO_2 is taken from industrial sources and stored underground, it often contains small amounts of other gases, such as SO_2 , H_2S , or N_2 . These pollutants can significantly alter how CO_2 interacts with formation water and rock minerals. Brine dissolves acidic gases like SO_2 and H_2S , forming strong acids that lower pH and make minerals like calcite, dolomite, and feldspar dissolve more readily **(Wigand et al., 2008)**. This may temporarily raise the fluid's porosity and ion concentrations, but over time, secondary minerals like gypsum, anhydrite, or clays may form and partially block the pores of cap rocks, making it less permeable **(Gaus, 2010)**. Conversely, non-reactive gases such as N_2 and O_2 generally dilute CO_2 and reduce its solubility, thereby limiting the intensity of these reactions **(Tian and Duan, 2011)**. Modelling studies suggest that the initial brine composition and contaminant concentration jointly influence reaction rates and the minerals most affected **(Shen et al., 2013)**. Impurities make the CO_2 -water-rock system more chemically complex.

At first, this makes dissolution easier, but it could also lead to the formation of new minerals that change the system's porosity, permeability, and long-term storage properties **(Carey et al., 2007; Gale, 2010)**. Error! Reference source not found. highlights the important studies that investigated the impurities.



Table 3. The main findings from several studies on the effect of impurities.

Authors	Impurity Type	Rock Type / System	Experimental Conditions	Quantitative Outcomes	Key Findings
(Tian and Duan, 2011)	H ₂ S and SO ₂	Mineral sequestration systems	Gas CO ₂ -injection experiments	Quantitative values not reported	<ul style="list-style-type: none"> • H₂S had little influence compared with pure CO₂ injection. • SO₂ strongly affected pH and mineral reactions. • SO₂ promoted the formation of acidic zones. • Sulfur was largely immobilized as sulfate minerals, particularly alunite.
(Wilke et al., 2012)	SO ₂ and O ₂	Carbonate-bearing systems	Supercritical CO ₂ containing 0.5 vol.% impurities	Gypsum precipitation >50 wt%; impurity concentration = 0.5 vol.%	<ul style="list-style-type: none"> • Impurities generated sulfuric and nitric acids. • Carbonate dissolution increased compared with pure CO₂. • Significant gypsum precipitation occurred. • Silicates released additional cations despite limited visible alteration.
(Boulouri nejad et al., 2013)	H ₂ S	Reservoir rock and caprock samples	CO ₂ and CO ₂ -H ₂ S injection	Reservoir permeability ↑ 10–30%; caprock permeability ↑ 3–10%; permeability decreased at 5000 ppm H ₂ S; little change at 100 ppm H ₂ S	<ul style="list-style-type: none"> • H₂S altered dissolution and precipitation reactions. • Kaolinite dissolution and precipitation were observed. • Anhydrite and pyrite formed only in the presence of H₂S. • High H₂S concentrations promoted salt precipitation and permeability reduction.
(Renard et al., 2014)	SO ₂ and O ₂	Carbonate and clay-bearing systems	Mixed-gas injection experiments	Quantitative values not reported	<ul style="list-style-type: none"> • Strong acidification resulted from SO₂ and O₂. • Calcite completely dissolved. • Dolomite partially dissolved. • Anhydrite, barite, hematite, and potassium beidellite formed during alteration.



6. CHALLENGES AND KNOWLEDGE GAPS

The first issue concerns the successful simulation of the field reservoir conditions in the laboratory setting. It is difficult to replicate such factors as high pressure, increased temperature, prolonged time periods, and geological heterogeneity at once in the field reservoir. As can be seen from recent studies on high-pressure flooding experiments carried out at 33 MPa and 140°C in low-permeability carbonate reservoirs, achieving stable reservoir conditions was quite difficult and required long-term comparisons (**Shuheng et al., 2025**).

The second topic for research concerns a better knowledge of the behavior of multiphase flows, which causes injectivity impairment due to CO₂ injection into the formation. The mechanisms of injectivity impairment, fine particle transport, and the blocking of pores are not yet well studied (**Keykhosravi et al., 2025**). As reported by (**Nguyen et al., 2024**), fine particle segregation and pore blocking can happen during the initial stage of CO₂ flooding; however, the process itself is still difficult to estimate. A further area of knowledge that is significant to mention is that of tight and low-permeability formations. As noted, data in the laboratory and field settings currently available are still relatively limited, thus limiting predictions regarding the petrophysical and geochemical impacts that may be expected during long-term operations in these reservoir types. A study by (**Al-Shajalee et al., 2021**) was conducted with nitrogen rather than CO₂. However, they both systematically demonstrate how prolonged gas–fluid flow degrades reservoir-modifying materials over time. This temporal dimension is the effect of extended exposure duration on reservoir performance.

Finally, an issue that needs to gain much attention relates to the mechanical stability of reservoirs in long-term operations. Studies of fluid injection in reservoirs mainly focus on the geophysical and petrophysical modifications of the reservoir, yet relatively little is known about the mechanical aspects of such operations. Recent research combining mechanics and geochemistry has shown that continuous injection of CO₂ into the reservoirs could weaken the reservoir matrices (**Eyitayo et al., 2025**), and thus, an investigation should be carried out. Such issues can enhance predictions of reservoir operations.

7. CONCLUSIONS

1. The effects of CO₂ injection on the geochemical, petrophysical, and geomechanical properties of reservoir rocks have been explored in this review, with specific attention to the comparison between supercritical CO₂ (scCO₂) and carbonated brine injection.
2. It is shown that the interactions among CO₂, water, and rock affect mineral dissolution/precipitation, wettability, porosity, permeability, and rock mechanics; however, the extent and type of effect strongly depend on the rock mineralogical composition and the parameters of CO₂ injection.
3. It should be mentioned that there are certain differences between the effects of scCO₂ injection and carbonated brine injection. Namely, scCO₂ injection is likely to result in increased mineral dissolution, increased wettability alteration, more significant salt precipitation, and local effects around the injection site.
4. Carbonated brine injection results in uniform geochemical reactions in the rock matrix and porosity/ permeability increase while keeping the water wetting state intact.
5. The presence of impurities such as hydrogen sulfide (H₂S), sulfur dioxide (SO₂), and oxygen (O₂) affects the reaction pathway and the stability of mineralogy, which could impact both efficiency and safety. With respect to carbon capture and storage (CCS) and



CO₂-enhanced oil recovery (CO₂-EOR) applications, such observations indicate the significance of characterizing the specific mineralogy and petrophysical properties of the reservoir before the process of injection.

6. There is still much work to be done, even if significant progress has been made. Further research should concentrate on recreating real field conditions, increasing knowledge about multiphase flows and injectivity reduction, studying the behavior of low-permeability rocks, and analyzing the geo-mechanical impact of CO₂ injection.

Credit Author Contribution Statement

Fatima Ibrahim Naef: Writing – original draft. Mohammed Saleh Al-Jawad: review & editing, Validation.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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تأثيرات حقن ثاني أكسيد الكربون على خصائص الصخور والمياه: مراجعة

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الخلاصة

يمثل تزايد انبعاثات الكربون مشكلة خطيرة تؤثر سلباً في البيئة. وقد طُرحت عدة تقنيات للحد من هذه الظاهرة، من أبرزها تقنيات احتجاز الكربون وتخزينه والاستخلاص المعزز للنفط، والتي تعتمد عادةً على حقن ثاني أكسيد الكربون في التكوينات الجيولوجية بهدف تخزينه أو تحسين إنتاج النفط. وتعتمد كفاءة هذه التقنيات بدرجة كبيرة على طبيعة التفاعلات المتبادلة بين ثاني أكسيد الكربون والصخور والمياه المكمّنية. تستعرض هذه المراجعة معظم الدراسات المهمة التي تناولت التغيرات الحاصلة في التركيب المعدني، والمسامية، والنفاذية، وقابلية البلل للصخور الخازنة، باستخدام أساليب تجريبية مختلفة مثل حقن اللباب الصخري والغمر الساكن المضغوط وعلى الرغم من كثرة الدراسات المتعلقة بتفاعلات CO_2 الماء-الصخر، ما تزال هناك حالات عدم يقين جوهرية فيما يتعلق بالتأثيرات المقارنة لحقن ثاني أكسيد الكربون في حالته **فوق الحرجة أو على هيئة محلول ملحي مكرين على الخصائص البتروفيزيائية والجيوكيميائية والجيوميكانيكية تحت ظروف مكمّنية ممثلة للواقع. وتعالج هذه المراجعة هذه الفجوات المعرفية من خلال تجميع وتحليل أحدث النتائج التجريبية، وتحديد أبرز التحديات والاحتياجات البحثية المتعلقة بقابلية الحقن، والتكوينات منخفضة النفاذية، وسلامة المكامن على المدى الطويل. كما تركز المراجعة على تأثير عدة عوامل، منها طور ثاني أكسيد الكربون أثناء الحقن ووجود الشوائب المصاحبة له. وقد أُجريت مقارنة تحليلية بين ثاني أكسيد الكربون في حالته فوق الحرجة وحالته المذابة، وأظهرت النتائج أن ثاني أكسيد الكربون فوق الحرج يعزز بصورة أكبر ذوبان المعادن، وتغير قابلية البلل، وترسب الأملاح بالقرب من منطقة الحقن. في المقابل، يؤدي المحلول الملحي المكرين إلى حدوث تفاعلات جيوكيميائية أكثر تجانساً، كما يميل إلى المحافظة على النفاذية أو تحسينها مع الإبقاء على ظروف البلل المائي للصخر. تتوفر هذه المراجعة فهماً شاملاً لتأثير حقن ثاني أكسيد الكربون في الخصائص الجيوكيميائية والبتروفيزيائية لمختلف أنواع الصخور الخازنة، من خلال دمج أحدث النتائج العلمية وتحديد الثغرات المعرفية التي ما تزال بحاجة إلى مزيد من البحث والدراسة.

الكلمات المفتاحية: تفاعلات ثاني أكسيد الكربون والماء والصخور، خزانات الكربونات والحجر الرملي، ثاني أكسيد الكربون فوق الحرج والماء الكربوني، تغيير المسامية والنفاذية.