

Article

Techno-Economic Investigation of CO₂ Injection Schemes for Geological Carbon Storage in Saline Aquifers

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Abstract

Deep saline aquifers are among the most promising formations for large-scale carbon capture and storage (CCS); however, reservoir pressure buildup, limited CO₂ dissolution, plume migration, and salt precipitation can reduce storage efficiency and injectivity. This study evaluates the technical and economic performance of engineered CO₂ injection strategies, including intermittent CO₂ injection (ICI), water-alternating-CO₂ (WA-CO₂), carbonated water injection (CWI), and carbonated water-alternating-CO₂ (CWA-CO₂), under low- (180 mD) and high-permeability (1000 mD) saline aquifers and injection rates ranging from 0.01 to 0.5 MTPA. Laboratory-derived relative permeability and CO₂ diffusivity data were incorporated into three-dimensional compositional reservoir simulations, while the most promising strategy was validated using the Sleipner benchmark model. Techno-economic performance was assessed through Monte Carlo uncertainty and sensitivity analyses. The results show that injection strategy, rate, and reservoir permeability strongly influence trapping efficiency and pressure evolution. ICI increased dissolution trapping by up to 20%, enhanced residual trapping by approximately 40%, and reduced average reservoir pressure by up to 10%, although its extended operating period reduced its economic attractiveness. Among the evaluated alternatives, WA-CO₂ provided the best balance between technical and economic performance by enhancing dissolution trapping, improving pressure management and plume control, and maintaining storage costs within 3.6–3.7% of the continuous injection base case. Field-scale validation using the Sleipner model demonstrated improved long-term trapping efficiency and reduced mobile CO₂ and plume extent. Monte Carlo analysis (20,000 realizations) confirmed the economic robustness of the evaluated strategies under the assumed policy framework, identifying Section 45Q tax credit and discount rate as the dominant economic drivers. These findings demonstrate that properly designed WA-CO₂ schemes can significantly improve the technical and economic performance of geological CO₂ storage.



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1. Introduction

Carbon dioxide (CO₂) is one of the primary greenhouse gases responsible for global warming and climate change. Increasing atmospheric CO₂ concentrations have been associated with a wide range of environmental impacts, including more frequent extreme weather events, reduced agricultural productivity, and biodiversity decline. Although global emission rates have fluctuated since 2000, CO₂ emissions remain a major environ-

mental challenge, with fossil fuel combustion and industrial activities accounting for more than 70% of total anthropogenic emissions [1].

Fossil fuels currently provide approximately 81% of global energy demand and are projected to remain the dominant energy source through at least 2040 [2]. This continued reliance contributes significantly to rising CO₂ emissions and their associated environmental consequences. As a result, the petroleum industry faces the challenge of maintaining energy production while minimizing its carbon footprint. One technology that addresses both objectives is CO₂-enhanced oil recovery (CO₂-EOR), which has been applied since the 1930s. Beyond improving hydrocarbon recovery during secondary and tertiary production stages, CO₂-EOR also provides an opportunity for subsurface CO₂ storage, thereby reducing atmospheric emissions [3,4].

Deep saline aquifers are widely recognized as one of the most promising geological formations for large-scale Carbon Capture and Storage (CCS) due to their extensive availability and large storage potential [5,6]. Unlike CO₂-enhanced oil recovery (CO₂-EOR) operations, the long-term containment of CO₂ in saline aquifers relies on several trapping mechanisms that limit upward plume migration. These include structural trapping, residual trapping, dissolution trapping, and mineral trapping, with the latter two generally considered the most secure forms of long-term storage. Because mineral trapping occurs over relatively long timescales, this study focuses on dissolution trapping, the second most reliable storage mechanism.

Dissolution trapping enhances storage security by transferring CO₂ from the mobile gas phase into the aqueous phase, thereby reducing buoyancy-driven migration and leakage risk. Once dissolved in brine, CO₂ reacts to form carbonic acid, bicarbonate, and carbonate species [7–9]. The process is further enhanced by density-driven convection, whereby CO₂-enriched brine becomes denser than the surrounding fluid and sinks, promoting vertical mixing and accelerating dissolution. In addition to natural convective processes, previous numerical studies have shown that engineered injection and mixing strategies can significantly improve dissolution efficiency and increase the amount of securely trapped CO₂ [10,11].

Although the storage capacity of a saline aquifer is primarily governed by its available pore volume and geological characteristics, the achievable injection rate is constrained by pressure limitations that ensure safe and sustainable operations and storage. CO₂ injection inevitably increases pore pressure within the storage formation [12]. The resulting pressure increase reduces the effective stress acting on the rock matrix while simultaneously increasing the circumferential (hoop) stress around the wellbore. If reservoir pressure approaches the fracture pressure, these stress changes may induce either shear failure or tensile fracturing of the reservoir or caprock [13,14]. Consequently, pressure management is a critical aspect of CO₂ storage design because it governs injectivity, limits the risk of geomechanical failure, and helps maintain long-term storage integrity.

Another important operational challenge is salt precipitation, which occurs when water evaporates in the near-wellbore region during CO₂ injection into highly saline formations [15–17]. Salt accumulation within pore spaces can impair injectivity by reducing permeability and restricting fluid flow. Previous studies have suggested that engineered injection schemes can mitigate this phenomenon by enhancing fluid redistribution and mixing, thereby reducing salt accumulation near the injection well. Although the present study does not explicitly model geochemical reactions, salt precipitation, or the associated permeability alterations, the investigated injection strategies, together with experimental evidence reported in the literature, suggest that they may simultaneously improve dissolution trapping, moderate pressure buildup, and alleviate dry-out effects from a reservoir engineering perspective. The coupled effects of geochemistry, salt precipitation, and ge-

omechanical changes on injectivity and long-term storage performance will be addressed in future work.

Current Status of Injection Schemes in Large Field-Scale CO₂ Projects

Continuous CO₂ injection remains the most widely adopted strategy for geological storage in deep saline aquifers because of its operational simplicity and compatibility with existing injection infrastructure. However, experience from large-scale commercial projects, including Gorgon (Australia) and Sleipner (Norway), has demonstrated that continuous injection is frequently accompanied by reservoir pressure buildup, which may reduce injectivity, limit storage capacity, and constrain long-term operational flexibility [18,19]. Elevated pore pressure may also increase geomechanical risks and necessitate pressure-management measures. Consequently, many CCS projects employ active pressure management through brine production from wells located outside the CO₂ plume, with the produced brine commonly disposed of or reinjected into shallower geological formations.

Several alternative operational strategies have been proposed to overcome these limitations while simultaneously improving storage performance. At the Gorgon project, for example, a dissolved-water CO₂ injection concept was evaluated with the objective of reducing capital and operating costs by eliminating the need for a dehydration unit [20,21]. The concept relied on maintaining water dissolved within the dense-phase CO₂ stream under reservoir conditions, but practical implementation proved unsuccessful because the complete range of operating conditions was not adequately considered during the engineering design. In contrast, the Sleipner project successfully operates with water-saturated CO₂ by employing corrosion-resistant alloys (CRAs) and appropriate corrosion mitigation practices [19]. These field experiences demonstrate that both operational design and material selection play critical roles in determining the technical feasibility, cost, and long-term reliability of large-scale CO₂ storage.

Beyond continuous injection, numerous studies—primarily within the oil and gas industry—have investigated engineered injection strategies aimed at enhancing dissolution trapping while mitigating operational challenges associated with geological CO₂ storage [22–30]. These approaches include Water-Alternating-Gas (WAG), carbonated water injection (CWI), carbonated water-alternating-gas (CWAG), and foam-assisted injection. Originally developed for enhanced oil recovery (EOR), WAG has demonstrated significant potential for reducing CO₂ mobility, delaying plume migration, and enhancing both residual and dissolution trapping compared with continuous injection [22,23]. Among these approaches, CWI has received particular attention because dissolving CO₂ into the injected water simultaneously improves sweep efficiency, enhances injectivity, reduces residual oil saturation, promotes CO₂ dissolution, alters reservoir wettability, and delays free-gas breakthrough, thereby reducing buoyancy-driven migration and the associated leakage risk [4,24,25,29–33].

Despite these advances, several important knowledge gaps remain. Most of the studies published in the literature [22–33] have evaluated only a single engineered injection strategy, synthetic numerical models, and assessed technical performance without considering economic viability. Furthermore, the combined influence of reservoir permeability, injection rate, pressure evolution, plume migration, experimentally derived transport properties, and long-term storage economics have rarely been investigated within a unified framework. As a result, the relative effectiveness of alternative injection strategies under realistic field conditions remains insufficiently understood, limiting their practical application in commercial CCS projects.

The performance of geological CO₂ storage is also strongly influenced by uncertainties in reservoir properties, including permeability, geological heterogeneity, structural architec-

ture, and flow connectivity [31–33]. These uncertainties affect pressure propagation, CO₂ migration pathways, dissolution rates, and trapping efficiency, highlighting the need for robust optimization methodologies supported by advanced compositional reservoir simulators capable of evaluating multiple operational scenarios before field implementation.

Motivated by these technical and economic challenges, this study develops an integrated modeling and optimization framework for field-scale CO₂ storage in deep saline aquifers. Laboratory-derived transport and flow properties are incorporated into three-dimensional compositional reservoir simulations to systematically evaluate continuous injection together with several engineered injection strategies over a range of representative reservoir conditions. The methodology is subsequently extended through validation using the heterogeneous Sleipner benchmark model and complemented by a comprehensive techno-economic assessment incorporating Monte Carlo uncertainty quantification and sensitivity analysis. Although the initial numerical investigations employ simplified homogeneous reservoir models and therefore do not explicitly represent all geological heterogeneity, geomechanical effects, or geochemical reactions, they provide a computationally efficient screening framework for identifying the most promising operational strategies prior to detailed site-specific studies. Consequently, the proposed workflow establishes a practical decision-support methodology that improves understanding of the coupled technical and economic performance of alternative injection strategies while providing guidance for the design and optimization of future large-scale CCS projects.

2. Methodology

Continuous CO₂ injection, while widely adopted for geological storage, presents several technical challenges. These include salt precipitation in highly saline formations, which can impair injectivity; a strong reliance on structural trapping in low-dip reservoirs, which may increase leakage risks; and rapid pressure buildup in closed or semi-closed systems where reservoir boundaries are located near the injection well. To overcome these limitations and improve storage performance, strategies that promote mixing between CO₂ and brine have been proposed. Enhanced mixing accelerates CO₂ dissolution, thereby increasing storage security, reducing buoyancy-driven migration, and mitigating pressure buildup. Furthermore, the use of injection water with salinity comparable to that of the formation brine, or the implementation of near-wellbore pre-flush treatments, may help reduce salt precipitation and maintain injectivity.

The overall methodology adopted in this study is illustrated in Figure 1. The investigation begins with a simplified homogeneous reservoir model, in which a series of three-dimensional numerical simulations are performed under controlled conditions to evaluate the influence of key operational parameters. The simulations were conducted using the commercial reservoir simulator developed by the Computer Modeling Group (CMG) [34], which models coupled multiphase flow, mass transport, and geochemical processes.

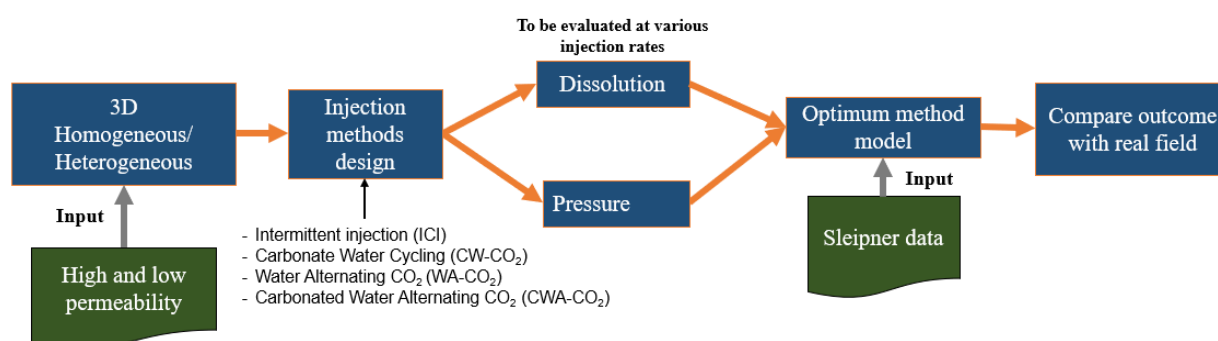


Figure 1. Workflow description.

The injection schemes examined in this work are adapted from techniques widely used in enhanced oil recovery (EOR) operations, particularly water-alternating-gas (WAG) injection. Continuous CO₂ injection is used as the reference case against which all alternative strategies are compared. Performance is evaluated using several key indicators, including the fraction of injected CO₂ dissolved in brine, the reduction in mobile free-phase CO₂, and average reservoir pressure buildup.

The alternative injection strategies considered include intermittent CO₂ injection (ICI), carbonated water injection (CWI), water-alternating-CO₂ injection (WA-CO₂) with different cycle ratios, and carbonated water-alternating-CO₂ injection (CWA-CO₂). A detailed description of the design and operating principles of each injection scheme is provided in the following section.

Finally, the most effective injection approach identified through the simulation study is applied to a field-scale model—such as Sleipner—to validate its performance and demonstrate its advantages over conventional continuous CO₂ injection under realistic conditions.

2.1. Injection Scheme Design

This study evaluates a series of engineered injection schemes adapted from enhanced oil recovery (EOR) practices to improve CO₂ storage performance. The operating conditions considered for each scheme are summarized in Table 1. Continuous CO₂ injection is used as the base case and serves as the reference scenario for all comparisons.

Table 1. Injection schemes operating conditions for the model simulations.

Scheme	Case	Conditions
Continuous CO ₂ injection	Base	-
Intermittent CO ₂ injection (ICI)	1	- Every 1 month
	2	- Every 6 months
	3	- Every 12 months
Water Alternating CO ₂ (WA-CO ₂)	4	30:120
	5	30:30
	6	120:30
Carbonated Water Injection (CWI)	7	20:1
	8	50:1
	9	150:1
Carbonated Water Alternating CO ₂ (CWA-CO ₂)	10	30:120
	11	30:30
	12	120:30

Intermittent CO₂ injection (ICI) is investigated to assess the potential benefits of periodically suspending CO₂ injection, thereby allowing additional time for pressure dissipation and CO₂ dissolution. Three different shut-in periods are evaluated to quantify the impact of interruption frequency on storage performance. Carbonated water injection (CWI) is examined at various CO₂-to-water mass ratios (Figure 2b1,b2) to determine its effectiveness in enhancing dissolution trapping and reducing the volume of mobile CO₂. Water-alternating-CO₂ (WA-CO₂) and carbonated water-alternating-CO₂ (CWA-CO₂) schemes are also analyzed using different CO₂/brine injection cycle durations (Figure 2a1,a2) to evaluate the influence of alternating injection patterns on trapping efficiency and reservoir pressure management.

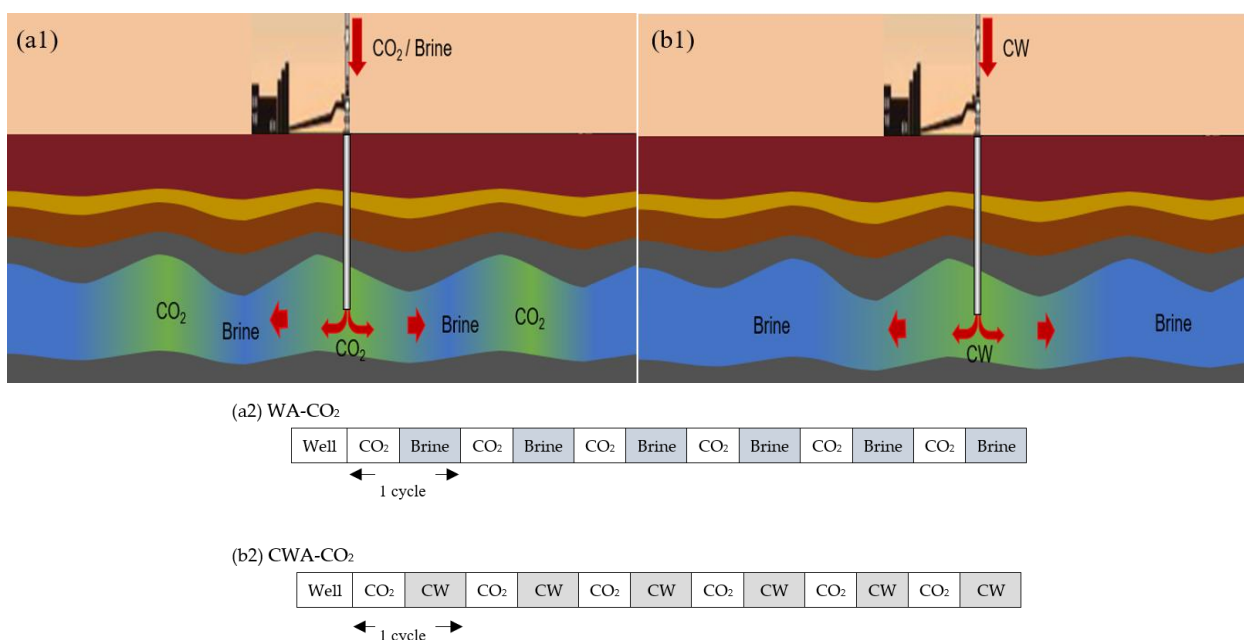


Figure 2. (a1,a2) Water alternating CO₂ injection scheme diagram. (b1,b2) Carbonated water injection scheme diagram.

In addition, all schemes involving water injection are assessed under a closed-loop configuration in which brine is produced ahead of the advancing CO₂ plume and subsequently reinjected with CO₂ into the reservoir. This approach is intended to enhance fluid mixing, moderate pressure buildup, and limit the lateral expansion of the CO₂ plume. For all simulated cases, the injected brine is assumed to have the same salinity as the native formation water, while the injected CO₂ is assumed to be pure (100% CO₂).

2.2. Experimental Data Adaptation

The incorporation of experimental observations into numerical simulations is essential for improving the accuracy and reliability of reservoir-scale CO₂ storage models. Laboratory measurements provide fundamental information on the petrophysical and transport properties governing CO₂ migration and trapping in saline aquifers and are therefore critical for model calibration and validation. In this study, experimental data were used to characterize key processes, including relative permeability behavior [35,36] and CO₂ diffusivity under elevated pressure and temperature conditions [37]. To minimize uncertainty associated with parameter transfer, the numerical model was designed to closely match the pressure, temperature, salinity, and permeability conditions of the selected experimental datasets. A comparison between the laboratory conditions and the reservoir simulation conditions is presented in Table 2.

Table 2. Comparison of laboratory experimental conditions and reservoir simulation conditions used for model calibration and validation.

Parameters	Relative Permeability [35,36]		CO ₂ Diffusivity [37]	Reservoir Model
Pressure (psi)	-	-	1400	1400
Temperature (°F)	-	-	140	140
Salinity (ppm NaCl)	-	-	100,000	100,000
Permeability (mD)	180 (Berea)	1000 (Utsira)	-	180/1000
Scale	Core	Core	Laboratory cell	Reservoir

The relative permeability curves adopted for the low-permeability reservoir were obtained from laboratory measurements on Berea sandstone [35], whereas those used for the high-permeability reservoir were derived from experimental data for the Utsira Formation [36]. In addition, the experimentally measured bulk CO₂ diffusion coefficient ($2.03 \times 10^{-9} \text{ m}^2/\text{s}$) at 1400 psi, 140 °F, and 100,000 ppm NaCl—conditions representative of the numerical model—was incorporated into the compositional simulation to improve the representation of dissolution trapping [37]. Because the investigated formations are highly permeable (180 and 1000 mD), the porous-medium diffusion coefficient was assumed to be approximately equal to the bulk CO₂ diffusivity. In reality, when there is spatial movement, the dispersion concept will also be part of the mixing process which is scale dependent. In addition, selected grid types and the grid size will also have an impact on various mechanisms [37].

Although the relative permeability and diffusivity measurements were obtained under laboratory conditions, these properties are routinely used as constitutive relationships in reservoir-scale compositional simulators. The objective is not to reproduce core-scale behavior directly, but rather to represent the average multiphase flow characteristics of the reservoir. Nevertheless, uncertainties associated with laboratory-to-field upscaling, spatial heterogeneity, and parameter transfer may influence the quantitative predictions. Therefore, the simulation results should be interpreted primarily as a comparative assessment of alternative injection strategies rather than as absolute field-performance forecasts.

Overall, the integration of experimentally derived parameters provides an experimentally grounded and physically consistent framework for evaluating injection strategies and assessing the long-term performance and security of geological CO₂ storage in deep saline aquifers.

2.3. Numerical Model Design

The performance of the proposed injection schemes was first evaluated using a three-dimensional homogeneous reservoir model under controlled conditions. A series of simulations was conducted using the commercial reservoir simulator developed by the Computer Modeling Group (CMG), which accounts for coupled multiphase flow, transport, and geochemical interactions relevant to geological CO₂ storage.

The compositional model consisted of 100,000 grid blocks arranged in a Cartesian grid with 100 cells in the I direction, 100 cells in the J direction, and 10 layers in the K (vertical) direction, as shown in Figure 3a. Individual grid-block dimensions were 140 ft × 140 ft × 30 ft in the X, Y, and Z directions, respectively. These dimensions were selected based on a grid-sensitivity analysis reported by Benavides et al. [38], ensuring an appropriate balance between numerical accuracy and computational efficiency. The resulting model covers an area of approximately 4500 acres.

Although the model size is smaller than that of a typical commercial-scale storage project, it is sufficiently large to capture the dominant mechanisms governing CO₂ migration, pressure propagation, and trapping efficiency. To address potential scale effects, the most promising injection strategy identified during the screening stage is subsequently applied to a field-scale model representative of a well-documented CCS project, such as Sleipner.

Because the primary objective of this study is to evaluate trapping performance and injectivity, the influence of overlying and underlying sealing formations is not explicitly considered. In addition to conventional injection configurations, a brine-cycling strategy is investigated. As illustrated in Figure 3b, the model includes a water-production well located within a quarter five-spot pattern. Two producer–injector spacings, 4950 ft and 9700 ft, are evaluated to identify the minimum separation distance required

to avoid premature breakthrough while minimizing CO₂ production and maximizing pressure-management efficiency.

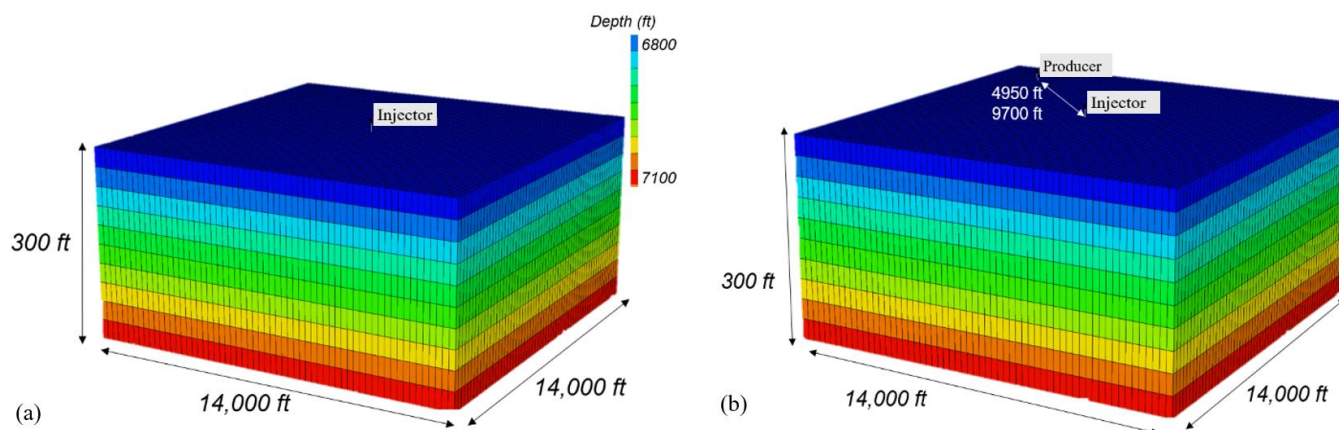


Figure 3. Dimensions of reservoir model with injection well centered (a) single injection well, (b) Cycling model where a water producing well is located diagonally at 4950 and 9700 ft from the injection well.

To compute the amount of CO₂ trapped by the different trapping mechanisms in terms of total CO₂ injected, we compared the quantity of CO₂ (in moles) trapped per mechanism relative to total CO₂ injected (in moles).

$$\text{Structural Trapping Percentage or free CO}_2 \text{ (STP)} = \frac{\text{Free CO}_2 \text{ (moles)}}{\text{Cum. CO}_2 \text{ Injected (moles)}} \times 100 \quad (1)$$

$$\text{Residual Trapping Percentage (RTP)} = \frac{\text{Residual CO}_2 \text{ (moles)}}{\text{Cum. CO}_2 \text{ Injected (moles)}} \times 100 \quad (2)$$

$$\text{Dissolved Trapping Percentage (DTP)} = \frac{\text{Dissolved CO}_2 \text{ (moles)}}{\text{Cum. Injected CO}_2 \text{ (moles)}} \times 100 \quad (3)$$

The reservoir fluid system consists of two phases: a supercritical CO₂ phase and an aqueous saline phase. For simplicity, only sodium chloride (NaCl) brine was considered, with a salinity of 100,000 ppm. This value is representative of deep saline aquifers used for CCS, whose reported salinities typically range from 35,000 to 205,000 ppm [39–44]. To minimize uncertainty associated with transport properties, the initial reservoir conditions were selected to match the experimental conditions used for CO₂ diffusivity measurements [36]. The initial reservoir pressure and temperature were set to 1400 psi and 140 °F, respectively. Although geothermal temperature gradients exist in deep formations, a uniform reservoir temperature was assumed throughout the simulations. Under these conditions, CO₂ remains in the supercritical state.

The thermophysical properties of CO₂ were modeled using the Peng–Robinson equation of state to calculate density and the Jossi–Stiel–Thodos correlation to estimate viscosity. Fluid properties at the reference conditions of 1400 psi and 140 °F were calculated using the correlations proposed by Ratnakar et al. [44] and are summarized in Table 3.

Table 3. Summary of the fluid (CO₂ and formation brine) properties at 1400 psi and 140 °F used in this study.

Fluid	Density (lb/ft ³)	Viscosity (cp)
CO ₂	16.83	0.0226
Brine	65.23	0.5500

Boundary conditions were selected to represent an extensive saline aquifer. Infinite-acting aquifer boundaries were imposed at the lateral reservoir edges to maintain constant far-field pressure during and after injection, thereby simulating pressure support from a laterally extensive formation. CO₂ dissolution into the aqueous phase was modeled using Henry's law to describe equilibrium solubility throughout the reservoir.

The present study focuses on multiphase fluid flow, pressure evolution, and CO₂ trapping mechanisms and therefore does not include coupled geomechanical deformation. Reservoir porosity and permeability were assumed to remain constant throughout the simulations, and stress-dependent variations in rock properties were neglected. Consequently, fracture initiation, fracture propagation, and stress-induced permeability changes were not explicitly modeled. This assumption is commonly adopted in reservoir-scale screening studies, where the primary objective is to compare the relative performance of different injection strategies rather than perform a detailed geomechanical assessment.

To ensure that all simulated scenarios remained within safe operating conditions, reservoir pressure was continuously monitored at the top and bottom reservoir layers, as well as through the reservoir-average pressure, and compared with an estimated fracture pressure limit. The fracture pressure was calculated using

$$P_f = P_o + G_f \times H \quad (4)$$

where (P_f) is the fracture pressure, (P_o) is the initial reservoir pressure, (G_f) is the fracture pressure gradient, and (H) is the reservoir depth. A representative fracture gradient of 0.75 psi/ft, consistent with reported values for the Utsira Formation [45], and a reservoir depth of 3100 ft were used, resulting in an estimated fracture pressure of 3725 psi. Since the model does not include stress-dependent permeability or porosity, it is assumed that the pressure-induced reduction in effective stress is insufficient to initiate mechanical failure or compromise reservoir integrity.

Two geological models were developed, representing low and high horizontal permeability scenarios, both with homogeneous petrophysical properties. The low-permeability case corresponds to Berea sandstone, characterized by an average permeability of 180 mD and porosity of 20%. The high-permeability case represents the Utsira Formation, with an average permeability of 1000 mD and porosity of 30% [45,46]. The vertical-to-horizontal permeability ratio (k_v/k_h) was set to 0.1.

The effective storage capacities for the low- and high-permeability cases, calculated using Equation (5), are 53 Mt and 80 Mt, respectively. The targeted injection rate is 0.5 MTPA to match the range of field injection rates. However, smaller rate scenarios (0.01, 0.1, 0.3 MTPA) are investigated with a 10-year injection period followed by 100 years of monitoring.

$$CO_2 \text{ free mass} = Area \times h \times NTG \times \phi \times (1 - s_{wir}) \times \rho_{CO_2} \times C \quad (5)$$

where $Area$ is the surface area, h is the reservoir thickness, NTG is the net-to-gross ratio, ϕ is porosity, s_{wir} is the irreducible water saturation, ρ_{CO_2} is the CO₂ density at reservoir conditions, and C is the capacity coefficient, which accounts for heterogeneity and typically ranges from 0.5% to 5% [47].

To enhance mixing efficiency, CO₂ injection is performed through the bottom three layers, corresponding to 90 ft of perforations. Table 4 summarizes the average petrophysical parameters used for the homogeneous models.

Hysteresis modeling is essential for accurately simulating multiphase flow behavior and trapping mechanisms of CO₂ during continuous or alternative injection schemes in CCS applications [38]. Hysteresis accounts for the path-dependent nature of fluid displace-

ment by defining distinct relative permeability and capillary pressure curves for drainage (CO_2 injection) and imbibition (water reinjection). Residual gas trapping—a key short-term sequestration mechanism—is incorporated using Land’s trapping model, which dynamically updates residual saturations based on saturation history. The relative permeability curves used in this study are derived from experimental core data, representing Berea sandstone for the low-permeability case and Utsira sandstone for the high-permeability case (see Figure 4).

Table 4. Model properties description.

Model Parameters	Reference Value	Units
Grid dimension	$100 \times 100 \times 10$	block
Aquifer size	$14,000 \times 14,000 \times 300$	ft
Top aquifer	3100	ft
Sand Thickness	300	ft
Sand Porosity	0.3–0.2	
Sand k_H	180–1000	mD
k_V/k_H	0.1	
k_r	$n_{\text{CO}_2} = 2\text{--}2.8, n_w = 3, 2.8$	
$S_{r\text{CO}_2}$	0.3, 0.35	v/v
Salinity	100,000	ppm
Pressure	1400	psi
Temperature	140	$^\circ\text{F}$

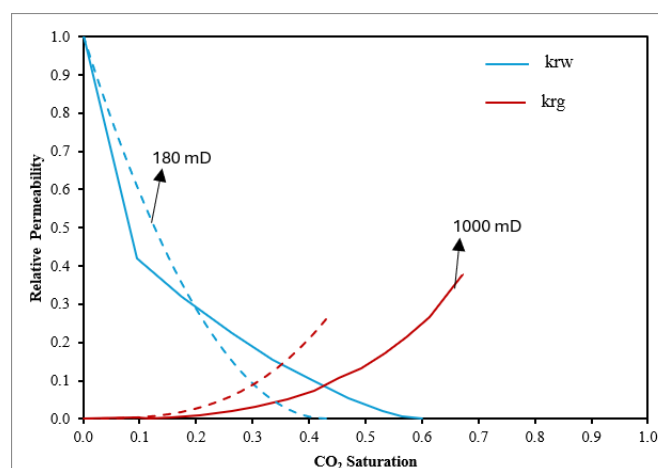


Figure 4. Relative permeability curves for low permeability (dashed lines) [35] and high permeability (solid lines) reservoir rocks [36].

Solubility modeling complements hysteresis by describing the dissolution of CO_2 into brine, a dominant mechanism for long-term storage security. CO_2 solubility is computed using an equation of state (EoS), specifically the Peng–Robinson model. Diffusivity strongly influences the dissolution process, as demonstrated by Oyagha et al. [37], who experimentally measured CO_2 bulk diffusivity in brine under high-temperature, high-pressure, and high-salinity conditions. At the reservoir conditions relevant to this study, the diffusivity coefficient is $2.03 \times 10^{-9} \text{ m}^2/\text{s}$. Henry’s law is employed to model phase equilibrium, while diffusivity-driven mass transport is used to predict the extent of CO_2 dissolution in the reservoir brine.

By integrating both hysteresis and solubility effects into a compositional reservoir simulator, this framework enables a comprehensive evaluation of injection scheme performance and supports the optimization of CO_2 storage efficiency in saline aquifers.

3. Results and Discussions

The base case, consisting of continuous CO₂ injection, was first simulated to establish a reference scenario against which all proposed injection schemes could be compared. Figure 5a,b present the evolution of the major trapping mechanisms—structural trapping (STP), residual trapping (RTP), and dissolution trapping (DTP)—normalized by the total amount of injected CO₂ and calculated using Equations (1)–(3). Results are shown for both low- and high-permeability reservoirs at an injection rate of 0.5 MTPA.

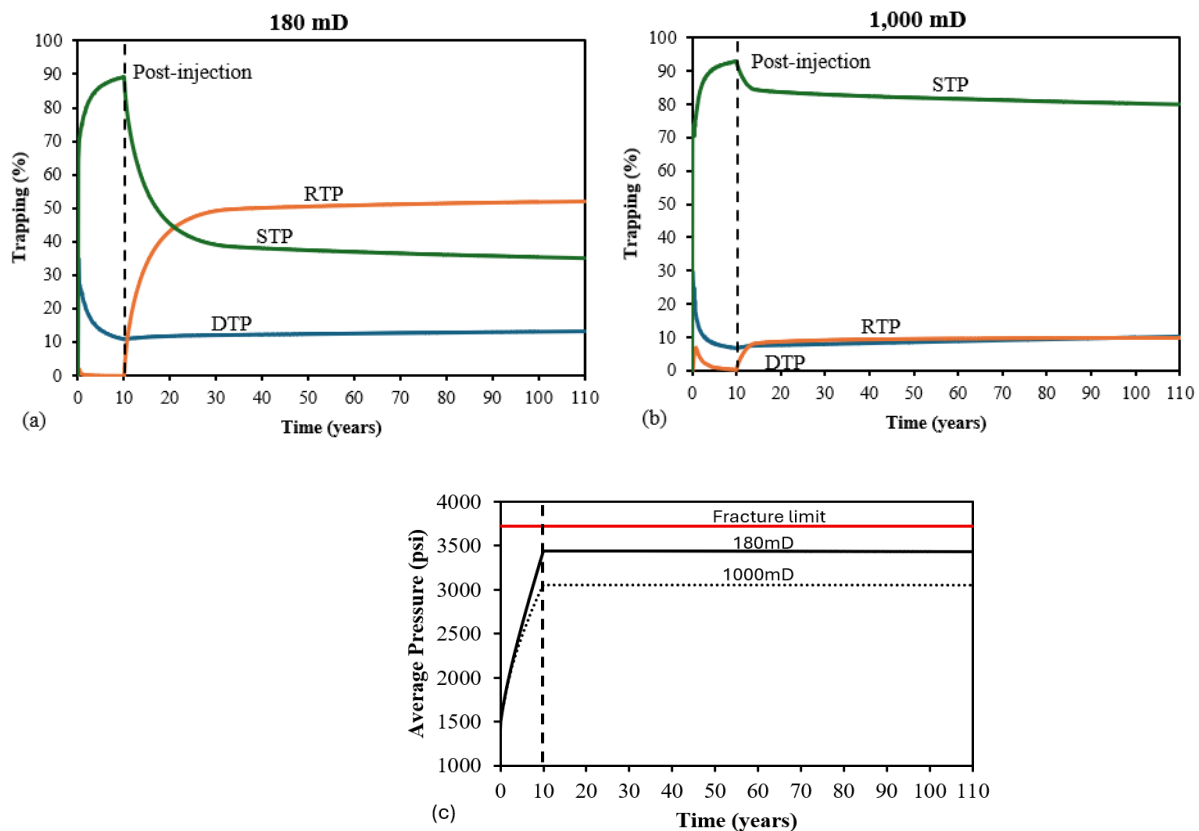


Figure 5. Trapping mechanisms distribution profile of base case (continuous CO₂ injection) and 0.5 MTPA, (a) low permeability reservoir (180 mD) and (b) high permeability reservoir (1000 mD). (c) Average reservoir pressure profile at both permeability scenarios. The red solid line represents the reservoir fracture limit.

A notable observation is that, under continuous CO₂ injection, a substantial fraction of the injected CO₂ remains as a free-phase plume trapped structurally within the reservoir, especially in high-permeability systems. In homogeneous formations with little or no structural dip, such as Berea sandstone analogs, this condition may increase the short-term risk associated with plume migration and potential leakage pathways. Over time, however, dissolution trapping progressively becomes the dominant storage mechanism. The exact timing depends strongly on reservoir permeability [37].

It should be noted that these results correspond to a simplified homogeneous reservoir without structural dip, developed to isolate the influence of the proposed injection strategies. Consequently, the conclusion that structural trapping dominates applies specifically to this class of reservoirs and should not be directly generalized to field-scale storage formations with complex geological architecture. In reservoirs exhibiting structural dip, heterogeneity, stratification, or anisotropy, plume migration and the relative contribution of the trapping mechanisms may differ substantially.

To illustrate this effect, Figure 6a summarizes the influence of structural dip reported by Benavides et al. [38], demonstrating that increasing reservoir inclination promotes plume migration and significantly alters the balance between structural, residual, and dissolution trapping in heterogeneous systems. Likewise, Figure 6b reproduces results from Pham et al. [48], showing that geological heterogeneity and internal vertical flow barriers strongly influence plume evolution and trapping behavior in the Utsira Formation. These published studies provide a sensitivity assessment of structural complexity and support the applicability limits of the present homogeneous model. Although the simplified model cannot reproduce all geological features of field-scale reservoirs, it provides valuable first-order insights into the governing physical processes and enables a systematic comparison of alternative injection strategies. The performance of the proposed schemes under fully heterogeneous and dipping reservoir conditions will be investigated in future work.

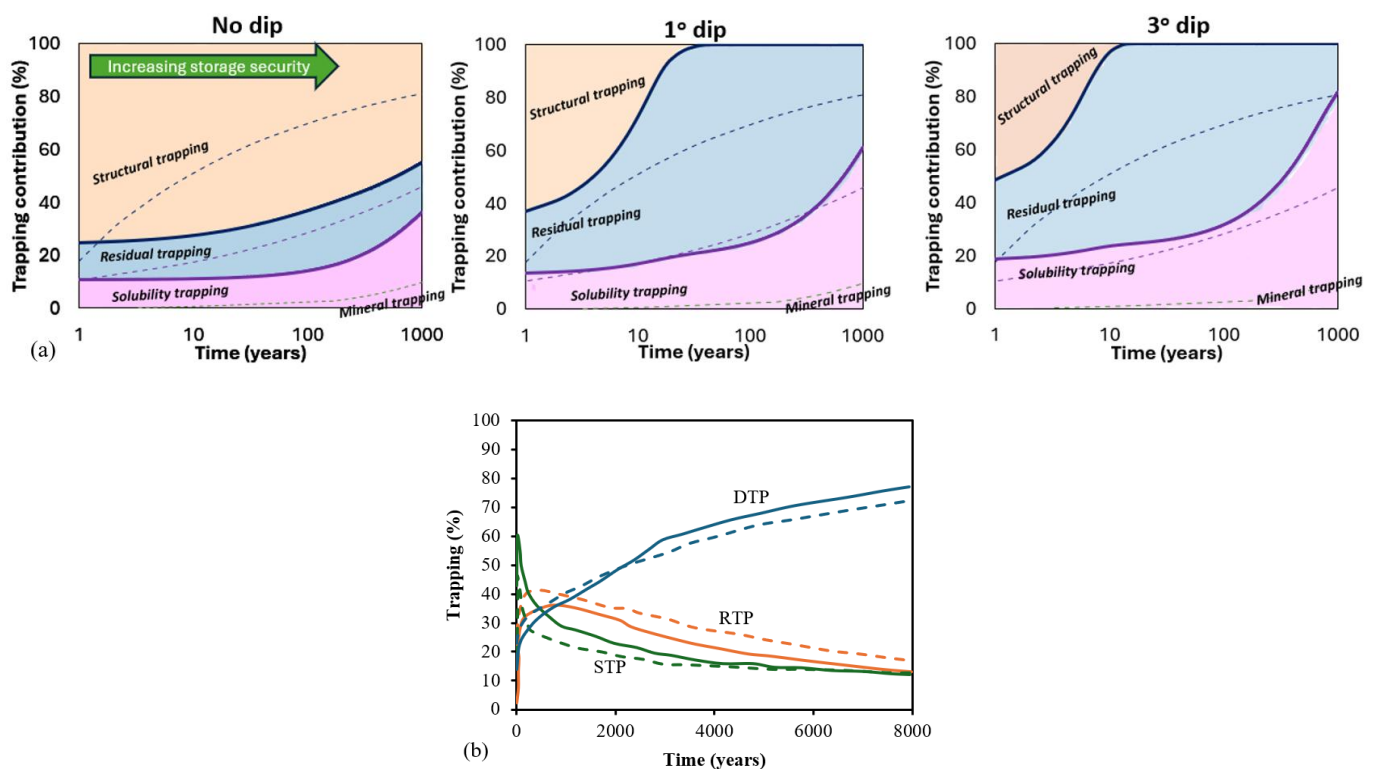


Figure 6. Comparison of CO₂ trapping mechanisms under different geological settings: (a) influence of structural dip on structural, residual, and dissolution trapping in heterogeneous reservoirs [37]; and (b) forecasted evolution of CO₂ trapping in the Utsira Formation for two reservoir configurations: a heterogeneous formation (solid curves) and a sandstone formation containing internal vertical flow barriers (dashed curves) [48].

Pressure buildup represents another critical design consideration, as excessive reservoir pressure can increase the risk of fracture initiation within the storage formation or its overlying confining units, potentially compromising storage integrity. Figure 5c illustrates the evolution of the average reservoir pressure for the base case. As expected, the low-permeability reservoir exhibits substantially greater pressure buildup than the high-permeability reservoir due to its lower transmissibility and reduced capacity to dissipate pressure. Nevertheless, in both cases the final average reservoir pressure remains below the estimated fracture pressure, indicating that the selected injection conditions maintain safe operating limits throughout the simulation period.

Finally, both the trapping behavior and pressure response are highly dependent on injection rate. To illustrate this effect, Appendix A presents the corresponding trapping profiles obtained at a lower injection rate of 0.01 Mtpa.

These results are used to compare and contrast the injection schemes. In the following section, the results of the sensitivity analysis will be discussed.

3.1. Sensitivity Analysis

Given the large number of simulation cases evaluated in this study, only one injection strategy is discussed in detail to illustrate the analysis methodology. The remaining cases are interpreted using the same approach, and a comprehensive comparison of all scenarios is subsequently presented to highlight their relative performance and key differences.

Intermittent CO₂ injection (ICI) was evaluated using three shut-in intervals—1, 6, and 12 months—while maintaining a total injection duration sufficient to achieve the target storage masses. Figure 7 compares the trapping behavior of Cases 1–3 with that of the continuous injection base case at an injection rate of 0.5 MTPA. The impact of intermittent operation is clearly visible during the injection period, as the reservoir is allowed to partially re-equilibrate during each shut-in cycle. Consequently, periods without injection promote additional fluid redistribution, pressure dissipation, and CO₂–brine interaction.

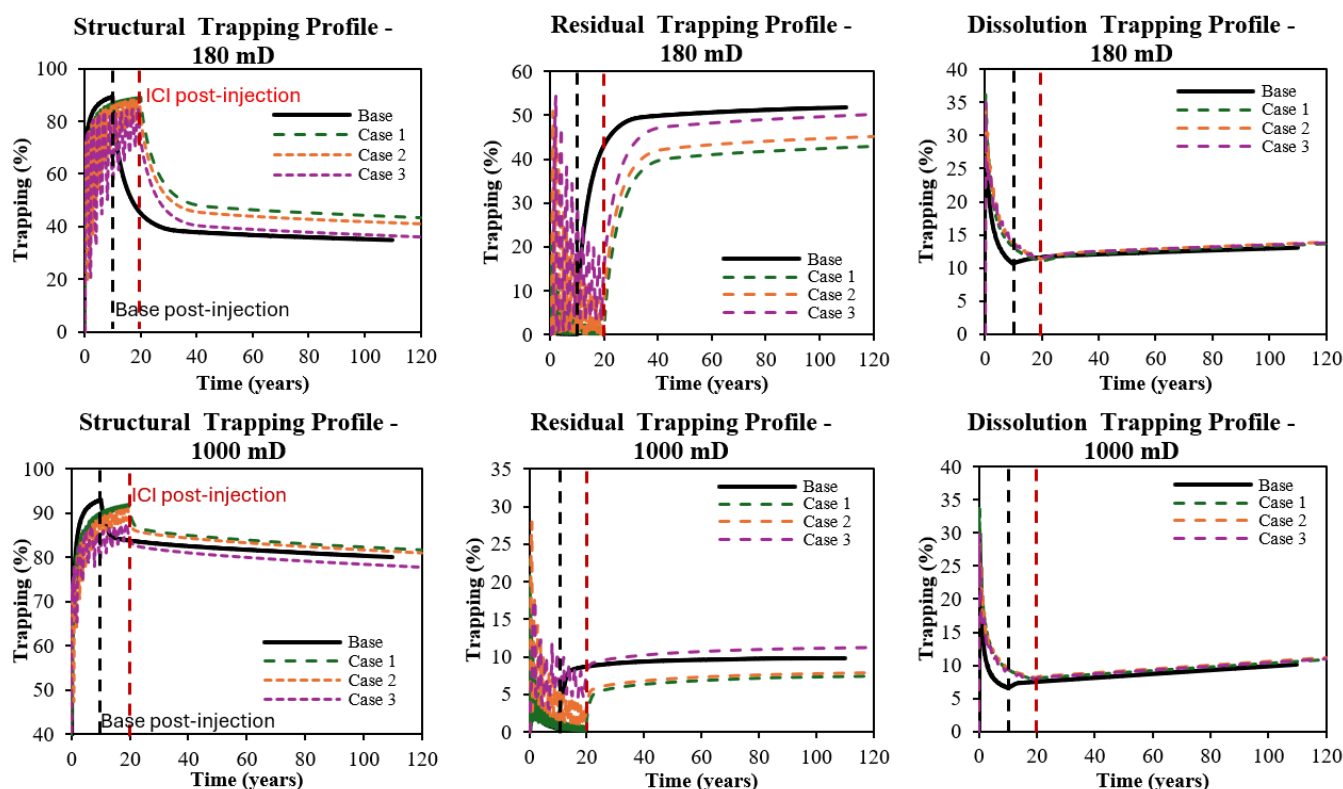


Figure 7. Distribution of CO₂ trapping mechanisms for the intermittent CO₂ injection (ICI) schemes (Cases 1–3). The top row shows the response for the low-permeability reservoir (180 mD), while the bottom row corresponds to the high-permeability reservoir (1000 mD).

This effect is particularly evident in Case 3, which employs a 12-month shut-in interval. Compared with continuous injection, the volume of free-phase CO₂ is reduced because a greater fraction of the injected CO₂ becomes immobilized through dissolution and capillary trapping processes during the non-injection periods. To quantify these differences, the relative change in each trapping mechanism was calculated with respect to the base case

using post-injection results. The percentage changes for all scenarios (Cases 1–12) are summarized in Section 3.4.

The results demonstrate that intermittent CO₂ injection can substantially enhance storage performance compared with continuous injection. Depending on the duration of the shut-in period, dissolution trapping increases by up to 20%, while the volume of mobile free-phase CO₂ decreases by approximately 15% during the injection period. The most pronounced improvement is observed in residual trapping, which increases by up to an order of magnitude relative to the base case. These results indicate that periodic injection interruptions provide additional time for CO₂ to redistribute, dissolve into the resident brine, and become immobilized within the pore space, thereby improving both storage security and the overall trapping efficiency of the sequestration process.

The evolution of CO₂ trapping can be divided into three distinct stages: the injection period, the post-injection period, and the long-term equilibrium stage. The relative contribution of each trapping mechanism varies throughout these stages. The present study focuses primarily on the injection period, as it is the phase most directly influenced by the operational conditions imposed by the proposed injection schemes.

During the early stages of injection, a portion of the injected CO₂ dissolves into the formation brine. However, because of ongoing plume migration and reservoir dynamics, part of this dissolved CO₂ subsequently transitions into other trapping forms, primarily residual and structural trapping. Analysis of the simulation results indicates that the rate at which dissolved CO₂ leaves the aqueous phase follows a power-law relationship that varies according to both the injection strategy and reservoir permeability (Figure 8).

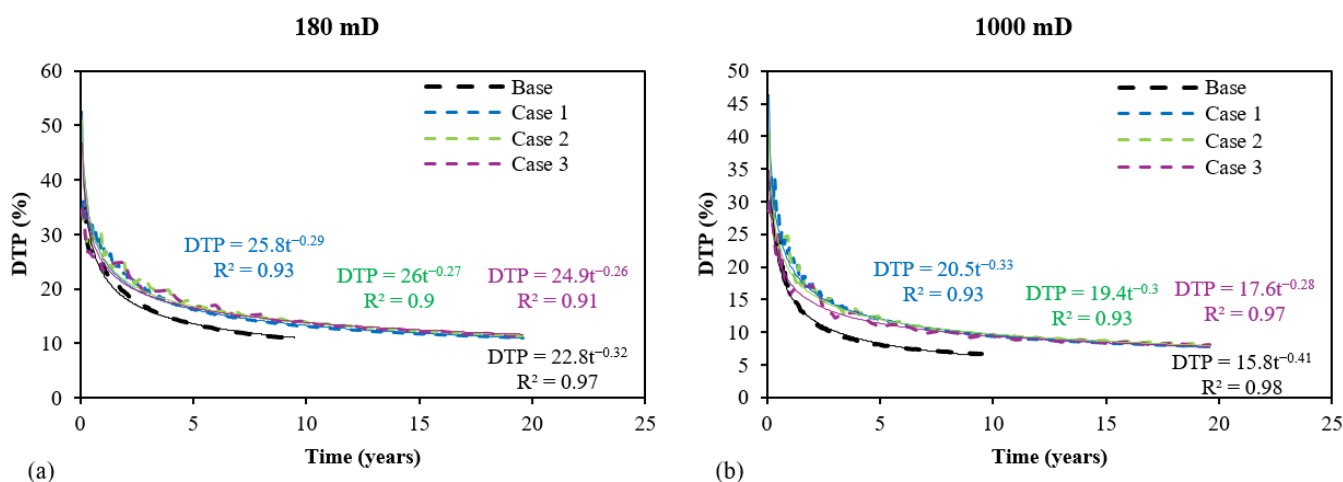


Figure 8. Dissolution trapping profile during injection from ICI scheme at 0.5 MTPA, (a) 180 mD and (b) 1000 mD.

The proposed injection schemes significantly influence this behavior. For example, intermittent CO₂ injection (ICI) exhibits a lower dissolved-CO₂ escape rate than continuous injection, indicating that a greater fraction of CO₂ remains dissolved within the brine. Similar trends are observed for the other engineered injection strategies. Among the evaluated cases, ICI and WA-CO₂ display the lowest escape rates, suggesting a stronger capacity to promote and preserve early-stage dissolution trapping. A summary of the calculated escape rates or decay exponent for all injection schemes is provided in Table 5.

Pressure behavior should be evaluated using two complementary metrics: the reservoir-wide average pressure and the pressure at the top reservoir layer. These indicators provide insight into both the overall pressure buildup within the storage formation and localized pressure responses near the upper portion of the reservoir, where containment integrity is of particular interest. In general, the pressure at the top of the reservoir

is the more conservative indicator because it is closest to the caprock and therefore more directly related to the risk of caprock failure. However, because the present numerical model represents a homogeneous reservoir and does not explicitly simulate a caprock with a defined fracture-pressure limit, the reservoir-wide average pressure is adopted as the primary metric for evaluating pressure evolution. Figure 9 compares the pressure response of Cases 1–3 with that of the continuous injection base case, enabling a direct assessment of the effectiveness of intermittent injection in managing reservoir pressure.

Table 5. Dissolved CO₂ withdrawal during injection.

Case	Decay Exponent	
	1000 mD	180 mD
Base	0.406	0.323
1	0.330	0.290
2	0.300	0.270
3	0.275	0.260
4	0.289	0.256
5	0.329	0.289
6	0.342	0.301
7	0.359	0.298
8	0.361	0.299
9	0.372	0.300
10	0.368	0.302
11	0.372	0.303
12	0.373	0.306

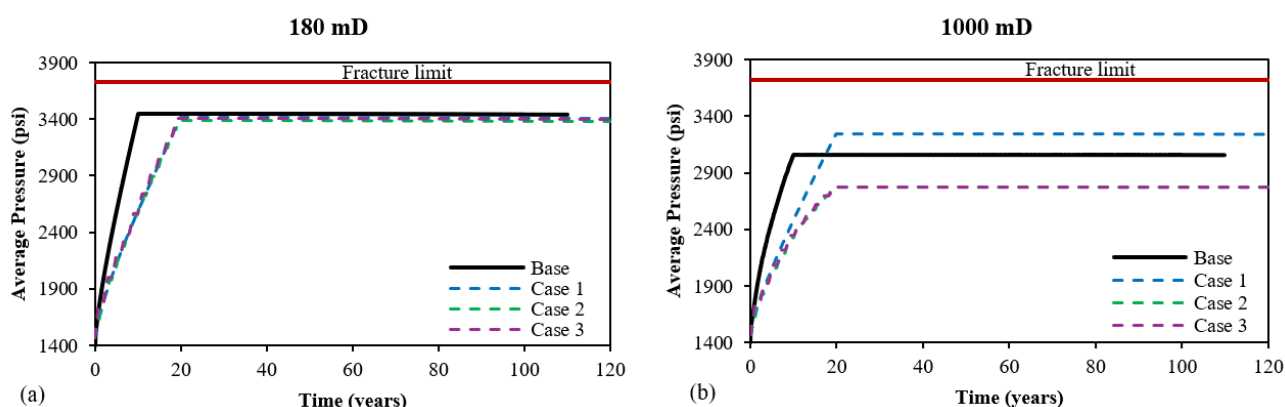


Figure 9. Average pressure profile of Cases 1–3 and the base case, (a) low permeability case (180 mD) and (b) high permeability case (1000 mD). The red solid line represents the reservoir fracture limit.

For the high-permeability (Darcy-scale) reservoir, the intermittent CO₂ injection (ICI) strategy reduces both average reservoir pressure and top-layer pressure by up to 15% in Case 2 and 3. This reduction indicates an increased pressure-management capacity, potentially allowing additional CO₂ to be injected while maintaining pressures below fracture limits. The effect becomes more pronounced as the duration of the shut-in period increases, highlighting the benefit of extended pressure-relief intervals.

In low-permeability formations, the ICI scenarios exhibit similar pressure trends among Cases 1–3, all of which maintain lower pressures than the continuous injection base case throughout most of the simulation period. Although the reductions are less pronounced than those observed in high-permeability systems, the final reservoir pressures remain consistently below those of the base case. These results suggest that intermittent injection can effectively moderate pressure buildup across a wide range of reservoir conditions.

It should be emphasized that the results presented correspond to a relatively high injection rate of 0.5 Mtpa. The magnitude of the pressure reductions and the overall pressure response vary with injection rate. A quantitative comparison of pressure changes for all cases and injection rates is provided in Appendix B.

3.2. Injection Rate

Injection rate plays a critical role in determining CO₂ trapping performance and storage efficiency. To evaluate its impact, five injection rates—0.01, 0.05, 0.1, 0.3, and 0.5 Mtpa—were simulated for both high- and low-permeability reservoirs (1000 mD and 180 mD, respectively). Figure 10a presents the relationship between injection rate and dissolution trapping, normalized by the total injected CO₂, at the end of the injection period for the continuous injection base case.

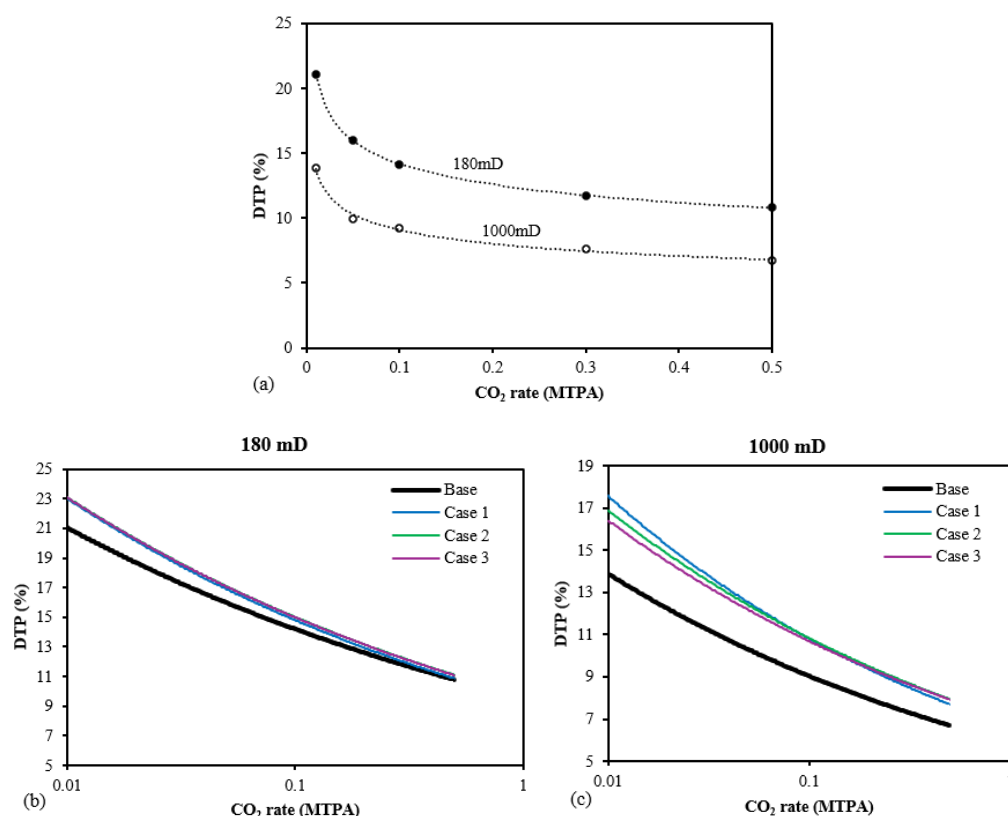


Figure 10. Dissolution trapping as a function of injection rate, (a) base case, (b) ICI at 180 mD, and (c) ICI at 1000 mD.

The results demonstrate that the amount of CO₂ injected strongly influences dissolution trapping efficiency. As injection rate increases, the balance between free-phase migration and CO₂ dissolution changes, affecting the overall contribution of dissolution trapping to long-term storage security. These findings highlight the importance of identifying an optimal injection rate that maximizes storage performance while maintaining economic viability and operational feasibility.

To investigate how engineered injection schemes influence this behavior, the same range of injection rates was applied to all proposed scenarios. Figure 10b,c compare the resulting dissolution trapping performance as a function of injection rate. The results show that all evaluated injection schemes enhance dissolution trapping relative to the continuous injection base case. However, the magnitude of the improvement depends on the injection rate, indicating a strong interaction between operational strategy and injection intensity. A

detailed quantitative assessment of the percentage increase in dissolution trapping relative to the base case for all scenarios is provided in Appendix B.

3.3. Cycling Schemes

For brine-assisted injection schemes such as water-alternating- CO_2 (WA- CO_2), carbonated water injection (CWI), and carbonated water-alternating- CO_2 (CWA- CO_2), the introduction of an incompressible fluid may potentially increase reservoir pressure buildup. To mitigate this effect, a closed-loop brine-cycling configuration is proposed, in which formation water is produced and subsequently reinjected into the reservoir, only during the CO_2 injection period. In addition to pressure management, this approach addresses issues related to brine sourcing, water compatibility, and plume control.

The use of a production well located ahead of the advancing CO_2 plume can also help regulate plume areal extent, preventing migration toward high-risk areas. A key design consideration is the spacing between the injection and production wells. The producer must be positioned sufficiently far from the injector to avoid premature CO_2 breakthrough during the operational period. The minimum well spacing required depends on several factors, including injection rate, cumulative CO_2 storage target, pressure drawdown, reservoir permeability, and geological heterogeneity.

In the proposed closed-loop system, the volumes of produced and reinjected brine are balanced to maintain reservoir fluid mass. However, the total volume of injected CO_2 remains constant across all scenarios to ensure achievement of the storage target of 5 Mt. To evaluate the influence of well spacing on system performance, a sensitivity analysis was conducted using two producer–injector distances, 4950 ft and 9700 ft, for Cases 4–12, which include the WA- CO_2 , CWI, and CWA- CO_2 injection schemes.

Evolution of the CO_2 concentration profile along the flow path from the injection well to the producer well show no CO_2 breakthrough at both producer–injector spacings in any of the simulated cases during CO_2 injection period. Figure 11 shows the evolution of CO_2 plume at Case 4 which is the highest water injection/production setting. The absence of breakthrough is primarily attributed to the relatively low brine production rates adopted to maintain the closed-loop operating strategy and the length of the injection period. Depending on the injection scheme, production rates ranged from approximately 40 to 150 bbl/day, resulting in a pressure drawdown below 40 psi on average. Consequently, the effect on average reservoir pressure and plume migration was limited.

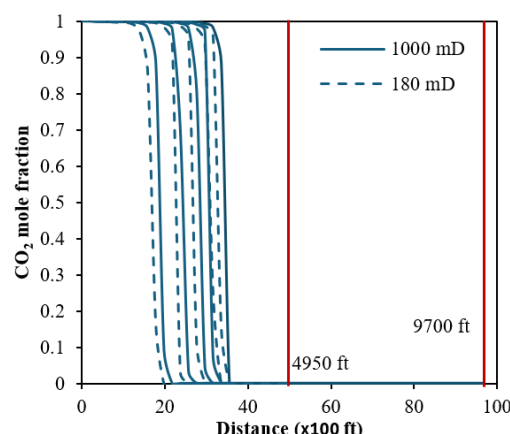


Figure 11. Evolution of the CO_2 migration (mole fraction) along the flow path from the injection well to the production well for Case 4, comparing low-permeability reservoir (dashed lines) and high-permeability reservoir (solid lines). Profiles are shown at 5-year intervals, with 50 years corresponding to the end of the injection and production period. The solid red lines represent the locations of the producer well at 9700 and 4950 ft.

Although higher brine production rates could further reduce reservoir pressure, enhance CO₂–brine mixing, thus improve dissolution trapping, such operating conditions fall outside the scope of the proposed closed-loop strategy. The objective of the present design is to balance injected and produced brine volumes, thereby minimizing the need for additional brine handling and disposal while maintaining operational simplicity.

Figure 12 presents the percentage change in average reservoir pressure relative to the continuous injection base case for all evaluated scenarios. In the 180 mD reservoir, water cycling consistently provides more effective pressure management than the corresponding non-cycling configurations. The greatest pressure reductions are observed in Cases 4 and 5, where pressure decreases by up to 5.1% with water cycling compared with 3.4% without cycling. For the remaining cases (6–12), pressure variations remain within approximately $\pm 1\%$ of the base case, indicating that these injection schemes have only a minor influence on reservoir pressure. Nevertheless, water cycling generally reduces or eliminates the small pressure increases observed in the non-cycling scenarios, demonstrating its effectiveness in low-permeability formations where limited transmissibility restricts natural pressure dissipation.

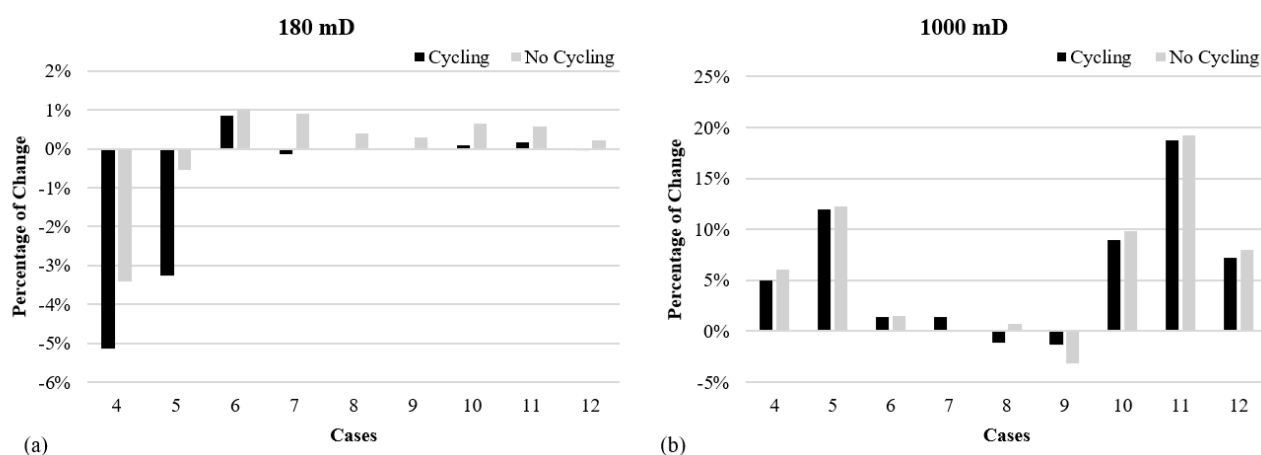


Figure 12. Percentage change in average reservoir pressure relative to the continuous injection (Base) case, comparing brine-cycling and non-cycling injection schemes for (a) the low-permeability reservoir (180 mD) and (b) the high-permeability reservoir (1000 mD).

The pressure response differs in the 1000 mD reservoir, where higher permeability promotes efficient pressure redistribution. Consequently, water cycling provides only modest additional pressure relief. Most cases exhibit slight pressure increases relative to the base case, with the largest increases occurring in Cases 5 and 11 (approximately 12–19%), whereas Cases 6–9 remain close to the base case. Among these, Case 9 produces the lowest pressure response, reducing average reservoir pressure by 3.2% without cycling and 1.3% with cycling.

Overall, these results demonstrate that the effectiveness of water cycling is strongly dependent on reservoir permeability. In low-permeability formations, periodic brine production and reinjection effectively alleviate pressure buildup, whereas in high-permeability reservoirs, where pressure naturally dissipates more efficiently, the principal benefit of water cycling shifts from pressure management toward improving CO₂ plume control and trapping efficiency.

Figure 13 compares the relative changes in dissolution and structural trapping with respect to the continuous injection base case for the water-cycling scenarios. The results demonstrate that reservoir permeability strongly influences the effectiveness of water cycling.

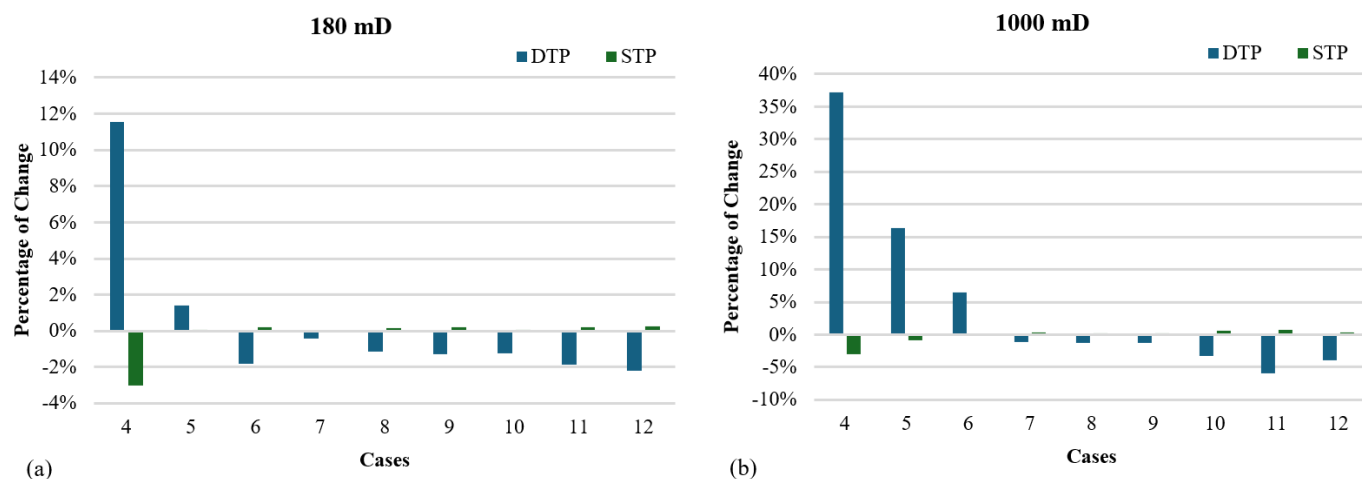


Figure 13. Percentage of dissolved and free CO₂ change for the cycling cases, (a) the low-permeability reservoir (180 mD) and (b) the high-permeability reservoir (1000 mD).

For the 180 mD reservoir, Cases 4 and 5 are the only operating strategies that improve dissolution trapping, increasing the dissolved CO₂ fraction by approximately 11.6% and 1.4%, respectively. Among these, Case 4 provides the greatest improvement, accompanied by a 3.0% reduction in structural trapping, indicating that a portion of the mobile CO₂ beneath the caprock has been converted into dissolved CO₂. The remaining cases produce only modest reductions in dissolution trapping (0.4–2.2%) together with negligible changes in structural trapping (less than 0.25%), suggesting that their trapping behavior remains similar to that of the base case.

A different trend is observed in the 1000 mD reservoir, where greater hydraulic connectivity promotes convective mixing and mass transfer. Water cycling substantially enhances dissolution trapping in Cases 4–6, with relative increases of approximately 37.3%, 16.3%, and 6.5%, respectively. These improvements are accompanied by corresponding reductions in structural trapping, reaching nearly 3.0% in Case 4, confirming that a larger fraction of the injected CO₂ is transferred from the free-gas phase into the aqueous phase. In contrast, Cases 7–12 exhibit small reductions in dissolution trapping (1.1–5.9%) and only marginal increases in structural trapping (less than 0.8%), indicating limited improvement over continuous injection.

Overall, the results show that Case 4 consistently provides the greatest enhancement in storage performance for both permeability scenarios. However, the underlying mechanisms differ between reservoirs. In the 180 mD formation, the low transmissibility limits convective mixing, resulting in only modest improvements in dissolution trapping. Conversely, the 1000 mD reservoir benefits from enhanced fluid communication, which significantly accelerates CO₂ dissolution and reduces the amount of structurally trapped free-phase CO₂. These findings indicate that the effectiveness of water cycling is highly permeability dependent and that its primary benefit shifts from modest trapping enhancement in low-permeability formations to substantially increased dissolution trapping in high-permeability reservoirs.

3.4. Overall Interpretation

Figure 14 compares the relative changes in dissolution trapping, structural trapping, and average reservoir pressure with respect to the continuous injection base case for the non-cycling scenarios. The results reveal that the effectiveness of the engineered injection strategies is strongly controlled by reservoir permeability.

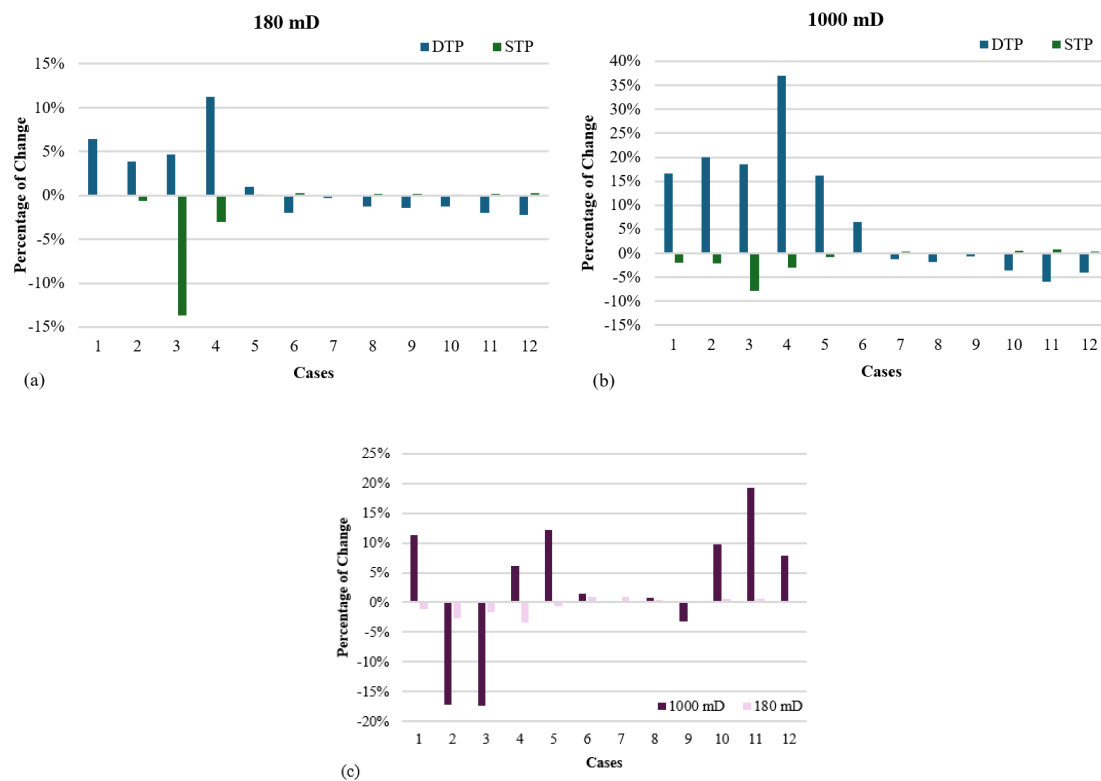


Figure 14. Percentage change in dissolved and free-phase CO_2 relative to the continuous injection (Base) at (a) high-permeability and (b) low-permeability settings, (c) percentage change in the average reservoir pressure for both permeability conditions relative to the base case.

For the 180 mD reservoir, Cases 1–4 consistently improve storage performance by simultaneously increasing dissolution trapping (3.9–11.2%) and reducing average reservoir pressure (1.2–3.4%). Among these, Case 4 provides the greatest overall benefit, increasing dissolution trapping by approximately 11.2% while reducing average pressure by 3.4%. Cases 2 and 3 also achieve notable pressure reductions (approximately 2.6–1.6%) while maintaining moderate improvements in dissolution trapping. Structural trapping changes remain relatively small, except for Case 3, which exhibits a pronounced reduction, indicating that a larger fraction of the injected CO_2 has transitioned from the free-gas phase into dissolved CO_2 . In contrast, Cases 6–12 slightly reduce dissolution trapping (0.3–2.2%) and generally produce small pressure increases (0.2–1.0%), indicating limited improvement over continuous injection.

The response differs markedly in the 1000 mD reservoir. The higher permeability promotes greater fluid communication and convective mixing, leading to substantially larger improvements in dissolution trapping for Cases 1–5, ranging from 16% to 37%. Case 4 again provides the greatest enhancement, increasing dissolution trapping by approximately 37%, followed by Cases 2 (20%), 3 (19%), 1 (17%), and 5 (16%). These increases are accompanied by corresponding reductions in structural trapping, confirming that a larger fraction of the injected CO_2 dissolves into the resident brine rather than remaining as mobile free gas. From a pressure-management perspective, however, the injection strategies exhibit different behaviors. Cases 2 and 3 are the only configurations that reduce average reservoir pressure (approximately 17%), whereas Cases 1, 4, 5, 10, 11, and 12 increase pressure relative to the base case. Among the latter, Case 11 produces the largest pressure increase (approximately 19%) while also exhibiting the greatest reduction in dissolution trapping, making it the least favorable operating strategy.

Overall, Case 4 consistently maximizes dissolution trapping for both permeability scenarios and therefore provides the greatest enhancement in storage efficiency. How-

ever, its pressure response is permeability dependent. In the 180 mD reservoir, Case 4 simultaneously improves dissolution trapping and reduces reservoir pressure, making it the most favorable overall configuration. In contrast, in the 1000 mD reservoir, although Case 4 achieves the highest dissolution trapping, it also increases average pressure by approximately 6% relative to the base case. Conversely, Cases 2 and 3 provide the best compromise between enhanced dissolution trapping and pressure management in the high-permeability reservoir by simultaneously increasing dissolution trapping by nearly 20% while reducing reservoir pressure by approximately 17%. These results demonstrate that the optimal injection strategy depends on reservoir permeability and on the relative importance assigned to maximizing dissolution trapping or minimizing reservoir pressure.

The residual between the no cycling and cycling approach on dissolution trapping is minimal, but cycling shows a potential improvement on dissolution trapping, as shown in Figure 15. Promoting the flow towards the producer well (increasing the pressure drawdown) might increase the dissolution trapping.

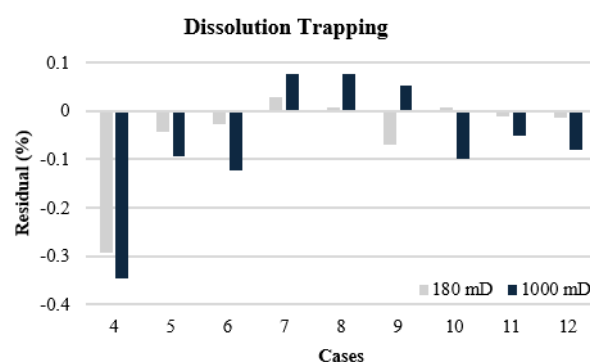


Figure 15. Residual between dissolution trapping percentage of no cycling and cycling schemes at both permeability settings.

3.5. Economic Evaluation and Uncertainty Analysis

The economic viability of CO₂ storage in deep saline aquifers is largely governed by government incentives, such as the U.S. Section 45Q tax credit, which provides \$85 per ton of permanently stored CO₂ (\$85 t⁻¹ CO₂) [49], together with the costs associated with CO₂ capture, compression, transportation, injection, and long-term monitoring. Although saline aquifers provide enormous theoretical storage capacity, large-scale deployment remains economically challenging because of the substantial capital and operational investments required. Consequently, project profitability depends strongly on policy incentives, as permanently stored CO₂ currently has limited direct commercial value.

The objective of this economic assessment is to compare the storage cost and profitability of the proposed injection strategies relative to the continuous CO₂ injection base case. All scenarios were designed to store a fixed target of 5 Mt of CO₂, allowing a direct comparison of the influence of injection duration and operational requirements. Capital expenditures (CAPEX) include drilling, surface facilities, and CO₂ transportation, while operational expenditures (OPEX) account for injection and water-management activities. A constant CO₂ tax credit of \$85 per ton was assumed for all cases. Since the post-injection monitoring period (100 years) is identical for every scenario, differences in profitability arise primarily from the injection-phase operating costs. The economic assumptions and corresponding data sources are summarized in Table 6.

Table 6. Economic assumptions.

Parameters	Value	Units	Reference
CO ₂ tax credit	85	\$/ton	[49]
Transportation	3.22	\$/ton	[50]
Permit cost	1.12	M\$	[51]
Injection well cost	3	M\$/well	[52]
CO ₂ facility capital cost	0.012	\$M/well	[11]
OPEX CO ₂ storage	3.6	M\$/year	[51]
Production well cost	2.9	\$M/well	[52]
Production facility capital cost	0.027	\$M/well	[11]
Water injection capital cost	0.011	M\$/well	[11]
Water recycle OPEX	0.3	\$/STB	[11]
Water injection OPEX	1	\$/STB	[11]

To account for uncertainty in the principal economic variables, a Monte Carlo analysis consisting of 20,000 realizations was performed. Probability distributions were assigned to the CO₂ tax credit, transportation cost, CAPEX, OPEX, discount rate, and long-term monitoring cost. Figure 16 summarizes the resulting net present value (NPV) distributions. Under the assumed uncertainty ranges, all evaluated injection schemes maintained a 100% probability of positive NPV, demonstrating strong economic robustness.

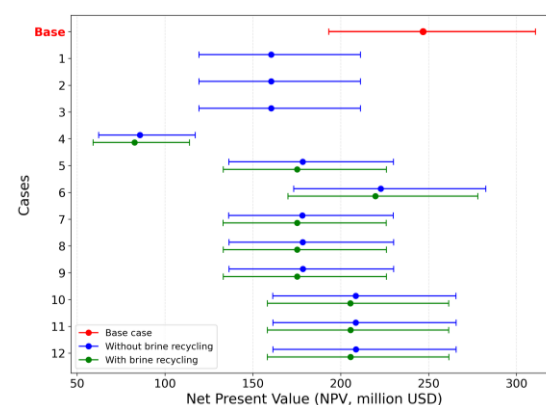


Figure 16. Comparison of the P10, P50, and P90 net present value (NPV) for each injection scheme obtained from the Monte Carlo economic analysis. The left endpoint represents the P10 value, the marker denotes the P50 (median) NPV, and the right endpoint corresponds to the P90 value. Blue symbols indicate the non-recycling injection schemes, whereas green symbols represent the brine-recycling schemes. The base case is highlighted in red and serves as the reference scenario.

For the non-recycling scenarios, the continuous injection base case produced the highest median NPV (P50) of approximately \$247 million, with a median storage cost of \$17.70 per ton of CO₂. The injection schemes (Cases 5–12) exhibited lower NPVs because of their longer project durations and additional water-management costs, although storage costs remained close to those of the base case, ranging between \$17.7 and \$18.4 per ton. Among these configurations, Case 6 achieved the highest median NPV (approximately \$220 million) while maintaining a storage cost only 3.6% higher than the base case. Cases 10–12 produced comparable economic performance, whereas Cases 5, 7, 8, and 9 yielded lower NPVs primarily because of their extended operating periods. As expected, Case 4, which requires the greatest brine injection volume and the longest operational duration, resulted in the lowest median NPV (approximately \$83 million) and the highest storage cost (approximately \$18.4 per ton), illustrating the economic penalty associated with prolonged operations despite its favorable technical performance.

A similar Monte Carlo analysis was performed for the brine-recycling configurations. The economic ranking remained essentially unchanged, with all cases maintaining a 100% probability of positive NPV. Although continuous CO₂ injection remained the most profitable option, the optimized recycling configurations—particularly Case 6—preserved strong economic performance while providing significant technical advantages, including enhanced dissolution trapping, improved pressure management, and greater long-term storage security. Compared with the base case, Case 6 reduced the median NPV by approximately 11% while increasing storage cost by only 3.6%, representing a favorable trade-off between economic performance and storage efficiency. These results indicate that incorporating brine recycling introduces only a modest economic penalty while substantially improving reservoir performance.

To identify the economic variables that most strongly influence project profitability, a Spearman rank sensitivity analysis was performed for both the base case and Case 6 (Appendix C). The Spearman correlation coefficient (ρ) measures the strength and direction of the monotonic relationship between an uncertain input parameter and the net present value (NPV), whereas the p -value indicates the statistical significance of that relationship. The results show that the CO₂ tax credit is the dominant economic driver, exhibiting a very strong positive correlation with NPV ($\rho = 0.93$ for the base case and $\rho = 0.90$ for Case 6; $p < 0.001$). The discount rate is the second most influential parameter ($\rho = -0.35$ and -0.41 , respectively; $p < 0.001$), highlighting the importance of financing conditions for long-term CCS investments. The stronger influence observed for Case 6 reflects its longer project duration, which increases the sensitivity of discounted cash flows to financing assumptions.

The remaining economic variables have comparatively minor effects on profitability. CO₂ transportation cost and CO₂ storage OPEX exhibit weak but statistically significant negative correlations with NPV ($\rho \approx -0.06$), whereas injection-well CAPEX has only a marginal influence ($|\rho| < 0.02$). Other parameters—including permitting costs, facility CAPEX, monitoring costs, and water-management infrastructure—show negligible correlations ($|\rho| < 0.01$), with several not reaching statistical significance ($p > 0.05$). Consequently, uncertainties associated with these variables contribute little to the overall economic uncertainty within the investigated ranges. The relative ranking of the economic drivers remains virtually unchanged between the base case and Case 6, indicating that project profitability is governed primarily by carbon-pricing policies and financing conditions rather than by individual capital or operating cost components. The slight positive correlation observed for the CO₂ injection facility CAPEX ($\rho \approx 0.014$) is considered economically insignificant and is attributed to Monte Carlo sampling variability rather than a meaningful economic trend.

3.6. Model Validation

To validate the proposed modeling framework and assess its applicability to field-scale CO₂ sequestration, the Sleipner storage project in the North Sea was selected as the benchmark case. As one of the world's longest-running and most extensively monitored CCS projects, Sleipner provides an ideal platform for model validation because of its comprehensive operational history, extensive monitoring dataset, and well-characterized geological setting within the Utsira Formation. The validation was performed using the publicly available CO2DataShare benchmark Sleipner reservoir model [53]. The grid configuration and key reservoir properties adopted in this study are presented in Figure 17 and summarized in Table 7, including porosity, permeability, formation thickness (787.2 ft), brine salinity (35,000 ppm NaCl) [39], and an initial reservoir pressure of 1450 psi. Incorporating these field-based parameters enables the simulations to closely reproduce the physical behavior of the Sleipner system, thereby increasing confidence in the predictive capability and field applicability of the proposed modeling framework.

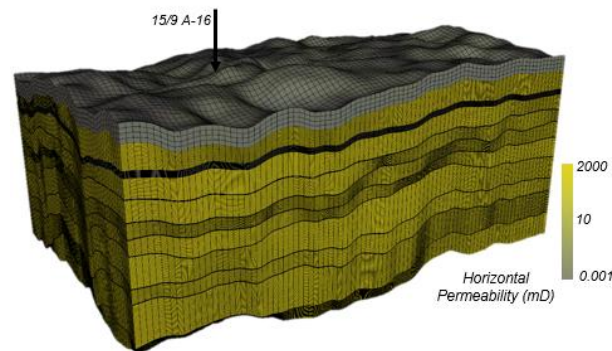


Figure 17. The Sleipner simulation grid with separate layers identified and the two penetrating wells 15/9-A-16 and 15/9-13 [53].

Table 7. Sleipner Model properties description.

Reservoir Properties	Value	Reference
Reservoir area (acres)	4665	[53]
Grid block (x,y,z)	$64 \times 118 \times 253$	[53]
k_v/k_h	0.1	[54]
Sand porosity (%)	36	[46]
Sand horizontal permeability (mD)	1000	[36,55]
Shale porosity (%)	34	[56]
Shale horizontal permeability (mD)	0.001	[57]
Pressure (psi)	1450	[58]
Temperature (°F)	90	[58]

Although intermittent CO₂ injection (ICI) demonstrated strong technical performance during the sensitivity analysis, its relatively high operational cost reduces its economic attractiveness. Carbonated water injection (CWI) offers both technical and economic advantages; however, the co-injection of water and CO₂ generates acidic conditions that may accelerate corrosion of surface and subsurface equipment. The additional costs associated with corrosion-resistant materials, specialized tubing, and infrastructure modifications were not considered in the economic assessment and would likely reduce the overall economic competitiveness of this approach. Consequently, the WA–CO₂ scheme with a 120:30 CO₂/brine injection-day ratio was selected for field-scale evaluation, as it provides a favorable balance between technical performance, operational simplicity, and economic feasibility. To ensure consistency with the previous sensitivity analysis, both the injection duration and total injected CO₂ mass were maintained.

The field-scale results demonstrate a substantial improvement in storage performance relative to continuous CO₂ injection. Dissolution and residual trapping increase significantly, resulting in an overall enhancement in trapping efficiency of up to 15% at the end of the injection period and 32% after 100 years of post-injection monitoring. These improvements are achieved with only a modest increase in storage cost of approximately 10%. One of the principal benefits of the WA–CO₂ strategy is its ability to accelerate CO₂ immobilization, thereby reducing the volume of mobile free-phase CO₂ and lowering the associated leakage risk.

As shown in Figure 18a,b, the WA–CO₂ scheme produces only a minor increase in reservoir pressure (approximately 1.1%) while enhancing dissolution and residual trapping by up to 18% and 12%, respectively, during the post-injection period. Correspondingly, the volume of free-phase CO₂ decreases by as much as 6% compared with the continuous injection case. Furthermore, quantitative and qualitative analyses of plume evolution (Appendix D) indicate a reduction of approximately 15% in plume areal extent, despite the highly lami-

nated and heterogeneous nature of the Utsira Formation. These results suggest that the WA-CO₂ strategy effectively limits plume migration while improving long-term storage security, making it a promising alternative for large-scale CO₂ sequestration projects.

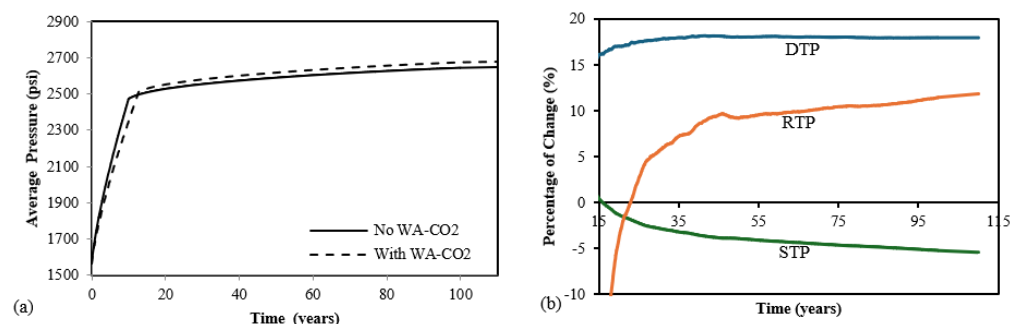


Figure 18. Comparison of continuous CO₂ injection and the WA-CO₂ injection scheme in the Utsira Formation: (a) average reservoir pressure evolution and (b) temporal changes in dissolution, residual, and structural trapping, expressed as percentage differences relative to the continuous injection case during the post-injection period.

4. Conclusions

This study developed and validated an integrated workflow to evaluate engineered injection strategies for geological CO₂ storage in deep saline aquifers by coupling calibrated compositional reservoir simulations using experimental data with techno-economic analysis. The effects of injection strategy, injection rate, reservoir permeability, and brine management on CO₂ trapping mechanisms, reservoir pressure, plume migration, and project economics were systematically investigated under representative reservoir conditions.

Continuous CO₂ injection, used as the reference scenario, was found to be dominated by structural trapping, particularly in high-permeability formations, resulting in a relatively large volume of mobile free-phase CO₂ during the injection period. In contrast, low-permeability reservoirs promoted greater residual trapping because lower flow velocities reduced the capillary number, allowing capillary forces to immobilize a larger fraction of the injected CO₂. Dissolution trapping became increasingly important during the post-injection period, with high-permeability formations exhibiting greater long-term dissolution due to enhanced convective mixing.

Injection rate was identified as one of the primary controls on storage performance. Lower injection rates consistently promoted dissolution trapping and reduced pressure buildup, whereas higher injection rates increased reservoir pressurization and the volume of mobile CO₂. All engineered injection strategies improved at least one aspect of storage performance relative to continuous injection. Intermittent CO₂ injection effectively enhanced dissolution and residual trapping while reducing reservoir pressure, particularly in low-permeability formations. Water-assisted injection strategies further improved storage performance by enhancing pressure management and plume control. The results also demonstrate that the effectiveness of these strategies is strongly permeability dependent, emphasizing that the optimal injection design should be tailored to the hydraulic characteristics of the storage formation. Among the evaluated configurations, Case 4 consistently provided the largest improvement in dissolution trapping, while Cases 2 and 3 offered the best compromise between enhanced trapping efficiency and pressure management in high-permeability reservoirs.

The techno-economic assessment indicates that WA-CO₂ provides the most balanced solution among the evaluated strategies by simultaneously improving trapping efficiency, limiting plume migration, reducing reservoir pressure, and maintaining competitive storage costs. Although intermittent CO₂ injection exhibited excellent technical performance, its

longer operational period reduced its overall economic attractiveness. Under the assumed Section 45Q tax credit of $\$85 \text{ t}^{-1} \text{ CO}_2$, all evaluated strategies remained economically viable. Monte Carlo uncertainty analysis and Spearman sensitivity analysis further demonstrated that the economic ranking of the injection strategies is robust within the investigated uncertainty ranges, with carbon price and discount rate identified as the dominant economic drivers. These economic conclusions are conditional on the adopted policy framework, and future investigations should evaluate alternative carbon-pricing scenarios and project break-even conditions.

Finally, validation using the Sleipner benchmark demonstrated that the proposed screening workflow can be successfully transferred from simplified, homogeneous models to a representative-scale reservoir. The selected WA- CO_2 configuration improved long-term trapping efficiency, reduced free-phase CO_2 saturation and plume extent, and enhanced storage security with only a modest increase in storage cost. Overall, this study provides a practical first-order decision-support framework for screening engineered injection strategies and demonstrates that properly designed WA- CO_2 systems represent a promising approach for improving the technical performance, operational safety, and economic viability of future large-scale geological CO_2 storage projects. Future work should extend the proposed methodology by incorporating fully heterogeneous reservoirs, coupled geomechanical and geochemical processes, and site-specific geological characterization to further refine injection strategy optimization.

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Appendix A

Trapping profile at 0.01 MTPA and continuous injection (base case).

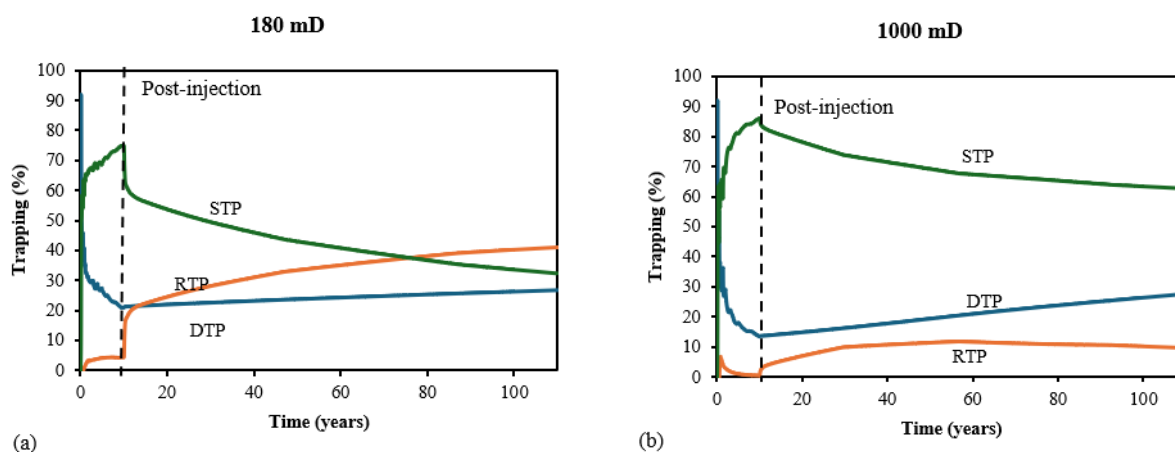


Figure A1. Trapping profile at a continuous injection (base case, 0.01 MTPA), (a) 180 mD, and (b) 1000 mD.

Appendix B

Percentage of change with respect to the base case at various injection rates.

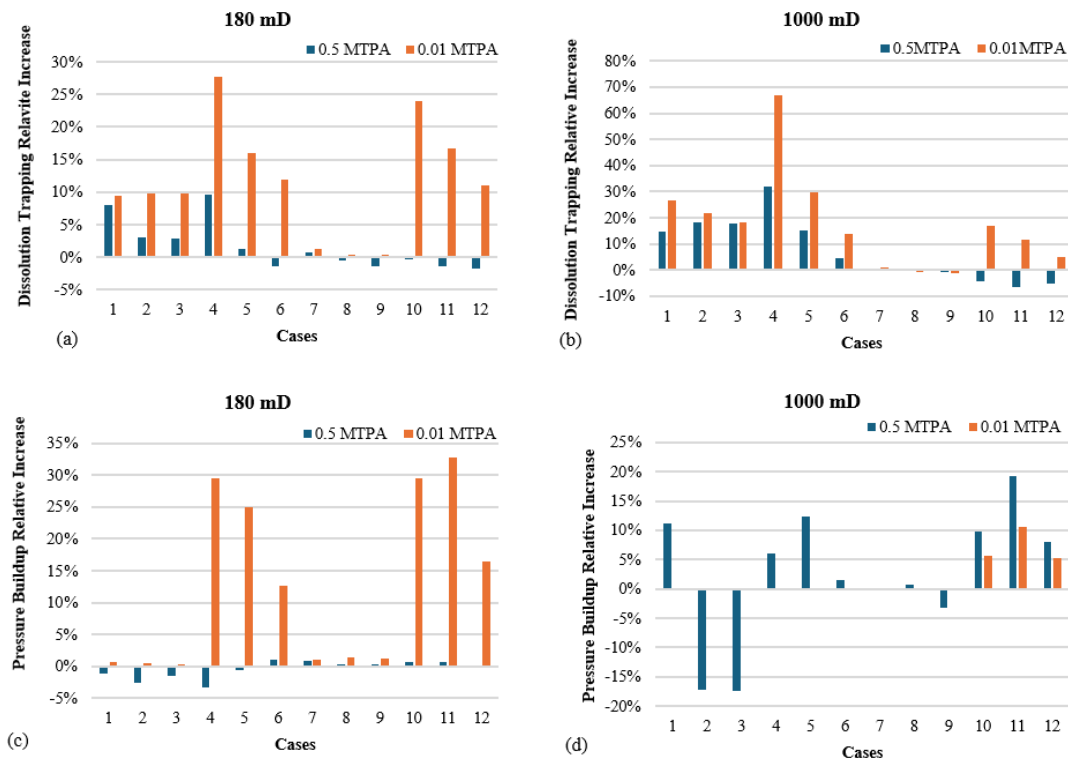


Figure A2. Comparison of percentage of change between high and low injection rate, (a) Dissolution trapping at 180 mD, (b) Dissolution trapping at 1000 mD, (c) Pressure buildup at 180 mD and (d) Pressure buildup at 1000 mD.

Appendix C

Spearman rank correlation sensitivity analysis of the net present value (NPV) for the Base case and Case 6.

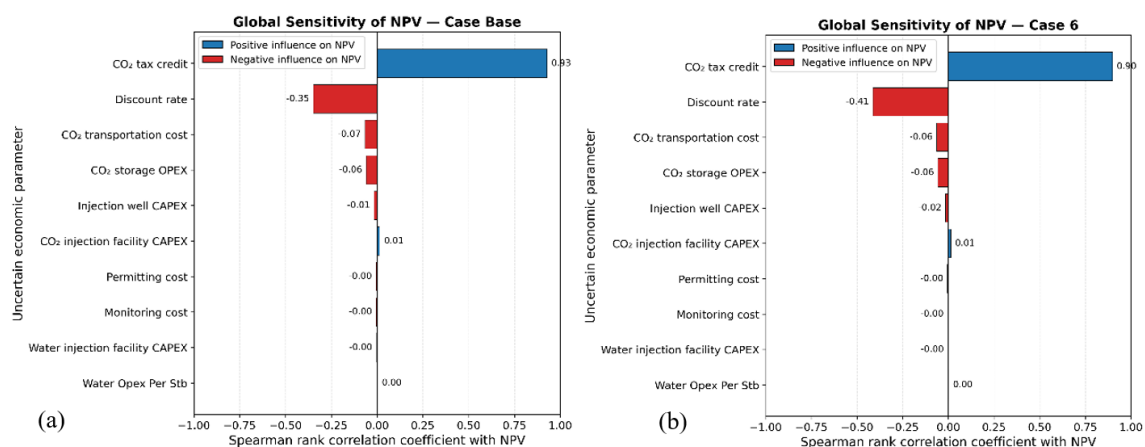


Figure A3. Spearman rank correlation sensitivity analysis of the net present value (NPV) for the (a) Base case and (b) Case 6. The horizontal bars represent the Spearman rank correlation coefficient (ρ), which quantifies the relative influence of each uncertain economic parameter on project NPV. Positive values indicate that increasing the parameter increases NPV, whereas negative values indicate that increasing the parameter decreases NPV. Larger absolute values of ρ correspond to greater parameter sensitivity.

Appendix D

Comparison of post-injection CO₂ plume extent between the WA-CO₂ injection scheme and continuous CO₂ injection in the Utsira Formation model.

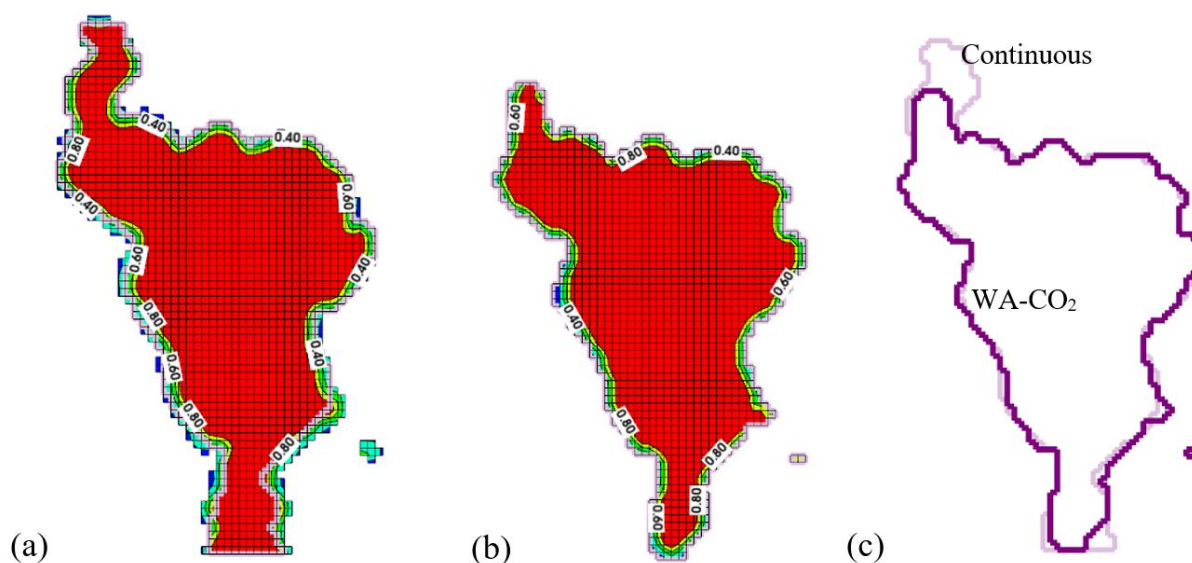


Figure A4. Qualitative comparison of CO₂ plume areal extension after 100 years post-injection (CO₂ mole fraction top view) at (a) continuous CO₂ injection, (b) WA-CO₂ injection scheme. (c) Area comparison as overlapping polygons.

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