https://doi.org/10.29227/IM-2025-01-02-049 *Received: 30 Oct 2024, Accepted: 01 May 2025, Published: 01 Sep 2025*

Evaluating CO_2 storage strategies in saline aquifer: A simulation study on pressure, rate, and duration

LE Nguyen Hai Nam[1,2*], **CAO Minh Huy**[1,2]

[1] Faculty of Geology and Petroleum Engineering, Ho Chi Minh City University of Technology, Ho Chi Minh City, Vietnam
[2] Vietnam National University Ho Chi Minh City, Linh Xuan Ward, Ho Chi Minh City, Vietnam
[*] *Corresponding email: lnhnam@hcmut.edu.vn*

Abstract: *Carbon capture and storage (CCS) is a crucial strategy in reducing global CO_2 emissions, with previous studies indicating it could contribute up to 20% of the necessary reductions by 2050. This paper presents a two-dimensional simulation model developed using CMG-GEM to evaluate CO_2 storage potential in a saline aquifer. Seven scenarios were explored: varying injection pressures (15,000, 20,000, and 25,000 kPa), injection rates (5,000, 10,000, and 20,000 m^3/day), and injection periods (1, 10, and 20 years). The model incorporated four CO_2 trapping mechanisms: structural, residual gas, solubility, and mineral trapping. Results show higher pressures, increased injection rates, and extended injection periods generally improved CO_2 storage. The optimal conditions were an injection pressure of 20,000 kPa, a rate of 10,000 m^3/day, and a 20-year injection period, which struck the best balance between storage efficiency and operational feasibility. Over the 100-year simulation, the 20-year injection period achieved the highest CO_2 mineralization. While structural and residual trapping was dominant early on, mineral trapping became increasingly important in the long term, highlighting the effectiveness of these mechanisms for CO_2 sequestration in saline aquifers.*

Keywords: *CO_2 sequestration; CMG-GEM; CO_2 trapping mechanism*

1. Introduction

Climate change is one of the most urgent global challenges, primarily driven by the rise in greenhouse gases (GHGs) in the atmosphere, with carbon dioxide (CO_2) accounting for 76% of global emissions, mainly from fossil fuel combustion in energy production, transportation, and industry [1]. Carbon Capture and Storage (CCS) has emerged as a crucial approach to mitigate these emissions, involving the capture, transport, and underground storage of CO_2 in geological formations like saline aquifers, depleted oil and gas fields, or coal beds [2] [3]. On a global scale, significant efforts have been made to advance carbon capture and storage (CCS) technologies to mitigate CO_2 emissions and combat climate change. A notable initiative led by the United States government, in collaboration with fifteen partner organizations, explored CO_2 sequestration potential in southern Kansas. This study involved acquiring and reprocessing extensive 3D seismic data across multiple oil fields to simulate CO_2-enhanced oil recovery (EOR) and underground storage. The research demonstrated substantial CO_2 storage capacities in the Arbuckle saline aquifer, ranging from 8.8 to 75.5 billion metric tons, and projected up to 4 billion metric tons of long-term storage over 150 years [4]. Additionally, localized assessments, such as those in the Wellington Field, highlighted promising industrial-scale CO_2 disposal capacities, with dual benefits of reducing emissions and enhancing oil recovery. Among these options, deep saline aquifers show significant potential due to their extensive availability, large storage capacity, and ability to store CO_2 over long periods securely [3]. However, the efficiency of CO_2 storage in these aquifers relies heavily on well-operating parameters such as injection pressure, rate, and duration, which influence how CO_2 is injected and trapped underground[5–8]. Excessive pressure may cause reservoir damage, while insufficient rates can lead to ineffective trapping and early CO_2 breakthrough. A thorough understanding of these parameters is critical to optimizing storage efficiency and ensuring the secure, long-term containment of CO_2. Previous studies have explored CO_2 storage in saline

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aquifers, highlighting the importance of geological uncertainties and the dual benefits of enhanced oil recovery and CO_2 sequestration[7, 9]. Nonetheless, the specific effects of well-operating parameters on CO_2 trapping efficiency remain less understood[3, 10, 11].

This research addresses this gap by providing a detailed analysis and practical guidelines for designing effective and safe CCS operations. It investigates the impact of injection parameters on CO_2 trapping in saline aquifers through simulation modeling, offering insights into optimal conditions for maximizing CO_2 storage and minimizing associated risks.

2. Methodology

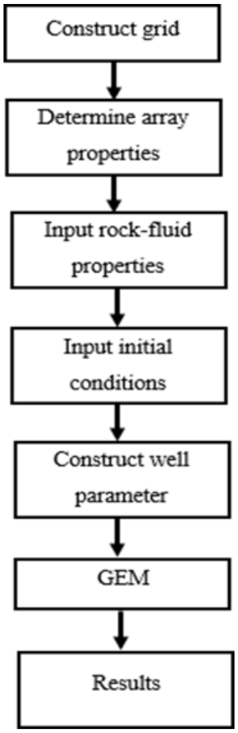

Fig. 1. Workflow of CO_2 storage model construction

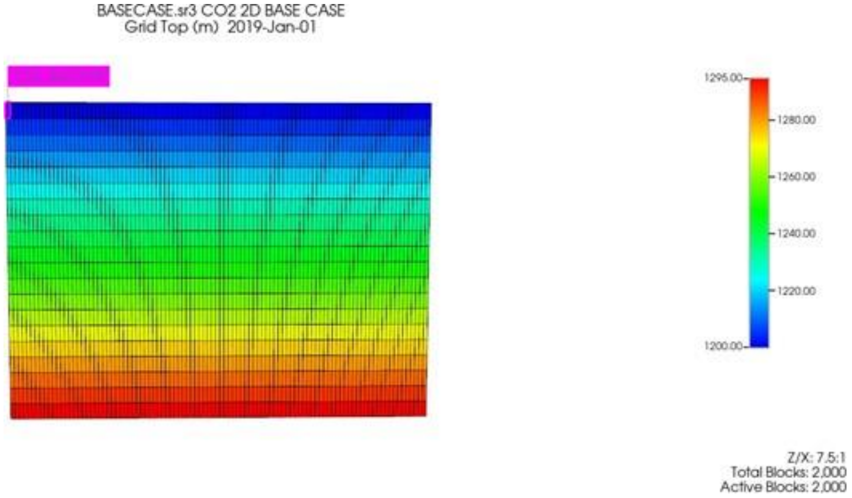

Fig. 2. Grid construction of CO_2 storage model

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2.1 Model Setup and Simulation

This research utilizes a CMG-GEM reservoir simulator to model CO_2 sequestration in a deep saline aquifer, chosen for its capability to simulate complex fluid dynamics and phase transitions within subsurface reservoirs. The model is structured as a two-dimensional Cartesian grid, comprising 100 grid blocks along the x-axis, 1 block along the y-axis, and 20 layers along the z-axis, creating 2,000 grid cells. This configuration represents a vertical cross-section of the reservoir, designed to simulate underground CO_2 over 100 years of monitoring.

Based on synthetic geological data (shown in Table 1), the model parameters include a reservoir depth of 1,200 meters, a reservoir pressure of 11,800 kPa, and a temperature of 167°F. The rock and fluid properties, such as permeability (100 mD) and porosity (18%), are derived from core sample analysis. The injection well is located at the grid coordinates (1, 1) and is perforated across all 20 layers, enabling CO_2 to be uniformly injected along the vertical profile of the aquifer.

Tab. 1. Synthetic reservoir properties

Properties	Unit	Value
Grid		100 x 1 x 20
Temperature	°F	167
Reservoir Pressure	kPa	11800
Rock compresibility	1/kPa	5.8e-7
Porosity	-	0.18
Grid top	m	1200
Thickness of each layer	m	5
Permeability	mD	100

2.2 Relative Permeability Curves

To accurately model the interactions between CO_2, water, and rock within the reservoir, relative permeability curves for two-phase flows (water-oil and liquid-gas) are generated based on previously published data. These curves are crucial for simulating CO_2 movement and trapping mechanisms in porous media. Stone's Model is utilized to develop relative permeability curves for three-phase interactions, providing a more detailed representation of the behavior between CO_2, water, and rock.

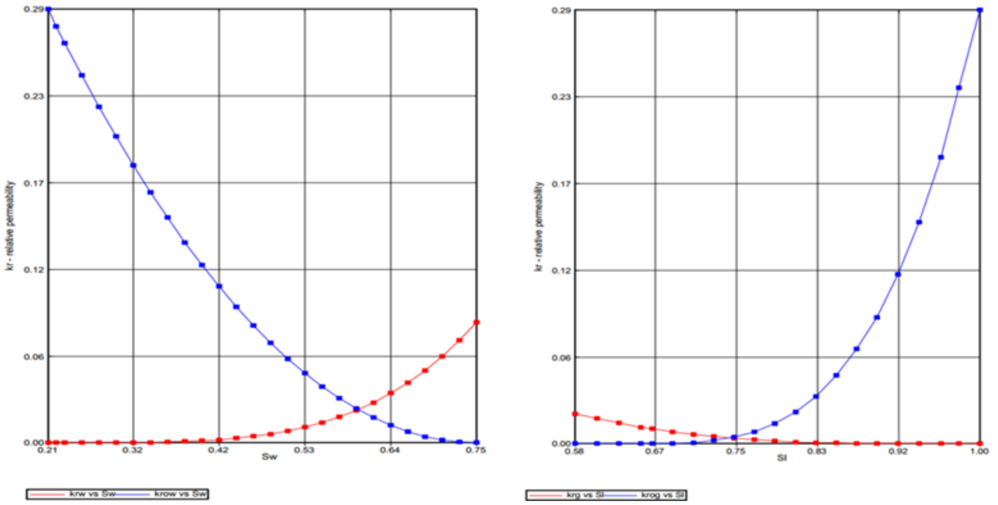

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Fig. 3. Generated relative permeability curves of water-oil (left) and gas-liquid (right)

2.3 Initial Conditions

Tab. 2. Initial condition of reservoir

Properties	Unit	Value
Reference depth	m	1200
Water – Gas contact	m	1150

The initial conditions are configured to represent the reservoir's natural state before CO_2 injection. The reservoir is initially saturated with formation water, with a water-gas contact depth of 1,150 meters. Pressure calculations reference a depth of 1,200 meters, and the formation water salinity is set at 35,000 ppm. These baseline conditions are maintained constant throughout the simulation, allowing for the isolation of effects resulting from changes in well-operating parameters.

2.4 Injection Scenarios

The simulation was conducted under multiple injection scenarios, adjusting key parameters such as injection pressure, rate, and duration. This approach aims to assess how each parameter influences CO_2 trapping efficiency. Table 3 provides a summary of the parameter values across different simulation runs.

- Injection Pressure: 15,000 kPa, 20,000 kPa, 25,000 kPa
- Injection Rate: 5,000 m^3/day, 10,000 m^3/day, 20,000 m^3/day
- Injection Duration: 1 year, 10 years, 20 year

Tab. 3. Scenarios of CO_2 storage process

No.	Injection Pressure (kPa)	Injection rate (m^3/day)	Years of injection
1	15000	10000	1
2	20000	10000	1
3	25000	10000	1
4	20000	10000	10
5	20000	10000	20
6	20000	5000	1
7	20000	20000	1

3. Results and discussion

This section presents the simulation outcomes across various well-operating parameters, analyzing their effects on the CO_2 trapping capacity within the saline aquifer. Detailed graphs, tables, and figures are included to illustrate trends and enable comparisons across the different scenarios. Each subsection focuses on a specific parameter—such as injection pressure, rate, or duration—and provides an in-depth explanation of the results to support the main findings. This analysis highlights how varying operational conditions influence storage efficiency and informs best practices for maximizing CO_2 sequestration in deep saline aquifers.

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3.1 Effects of Injection Pressure

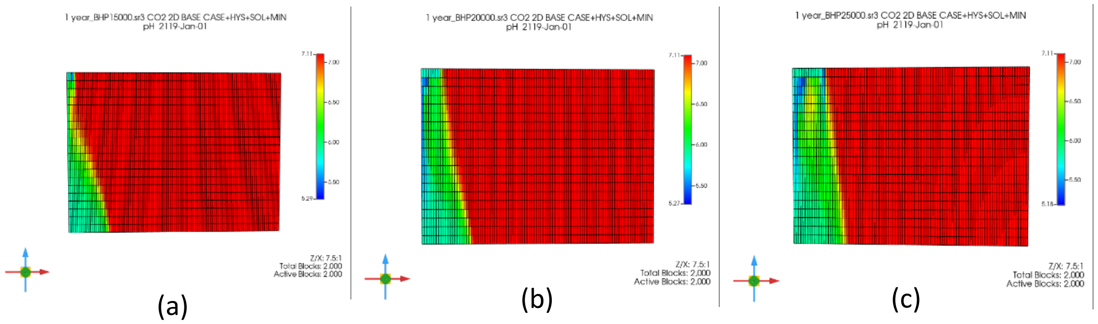
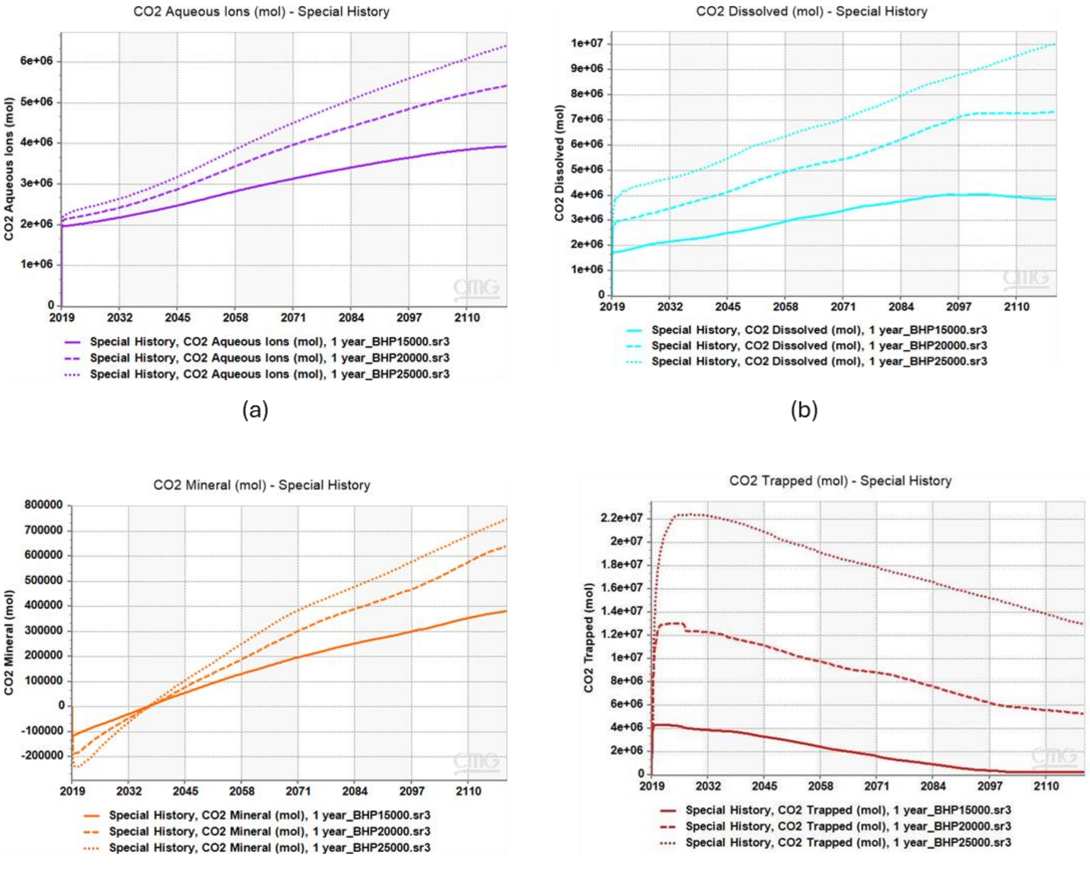


Fig. 4. pH after 100 years with various injection pressure (a) 15000 kPa; (b) 20000 kPa; (c) 25000 kPa



(a) (b)

(c) (d)

Fig. 5. CO_2 trapped in the reservoir with various injection pressures (a) aqueous trapping; (b) dissolved trapping; (c) mineral trapping, and (d) residual trapping

Fig. 4 illustrates the pH distribution in the saline aquifer after 100 years under different injection pressures: (a) 15,000 kPa, (b) 20,000 kPa, and (c) 25,000 kPa. These plots demonstrate how varying injection pressures influence the pH profile over time, with higher pressures resulting in more extensive

CO_2 diffusion and, thus, a broader area of lower pH values. This suggests that increasing the injection pressure enhances CO_2 penetration into the reservoir, impacting the surrounding pH and potentially affecting storage stability and trapping mechanisms. Fig. 5 depicts the CO_2 trapping efficiency, which increases markedly with higher injection pressures. At 15,000 kPa, the cumulative CO_2 trapped in the aquifer is less than that observed at higher pressures. The greatest trapping efficiency is achieved at 25,000 kPa, where the total CO_2 trapped—through mineralization, dissolution, and residual trapping—is significantly higher than at 15,000 kPa. However, while higher pressures improve CO_2 trapping, they also increase the risk of caprock fracturing, potentially compromising the storage security over time. This improvement in CO_2 trapping at elevated pressures is mainly due to the increased CO_2 mobility within the aquifer. Higher pressures enhance CO_2 solubility in formation water, which improves solubility trapping and reduces the buoyancy forces on injected CO_2, allowing for more uniform displacement of formation water. Despite these advantages, operational considerations include the potential risk of caprock failure and increased energy costs associated with high pressures. The optimal injection pressure for maximizing CO_2 storage while safeguarding reservoir integrity appears around 20,000 kPa, where trapping efficiency approaches its peak without compromising the reservoir's stability.

3.2 Effects of Injection Rate

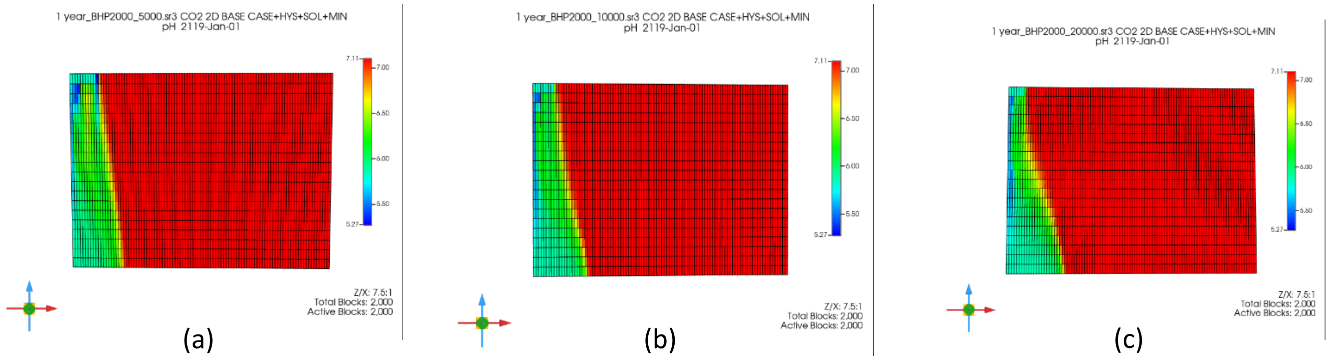
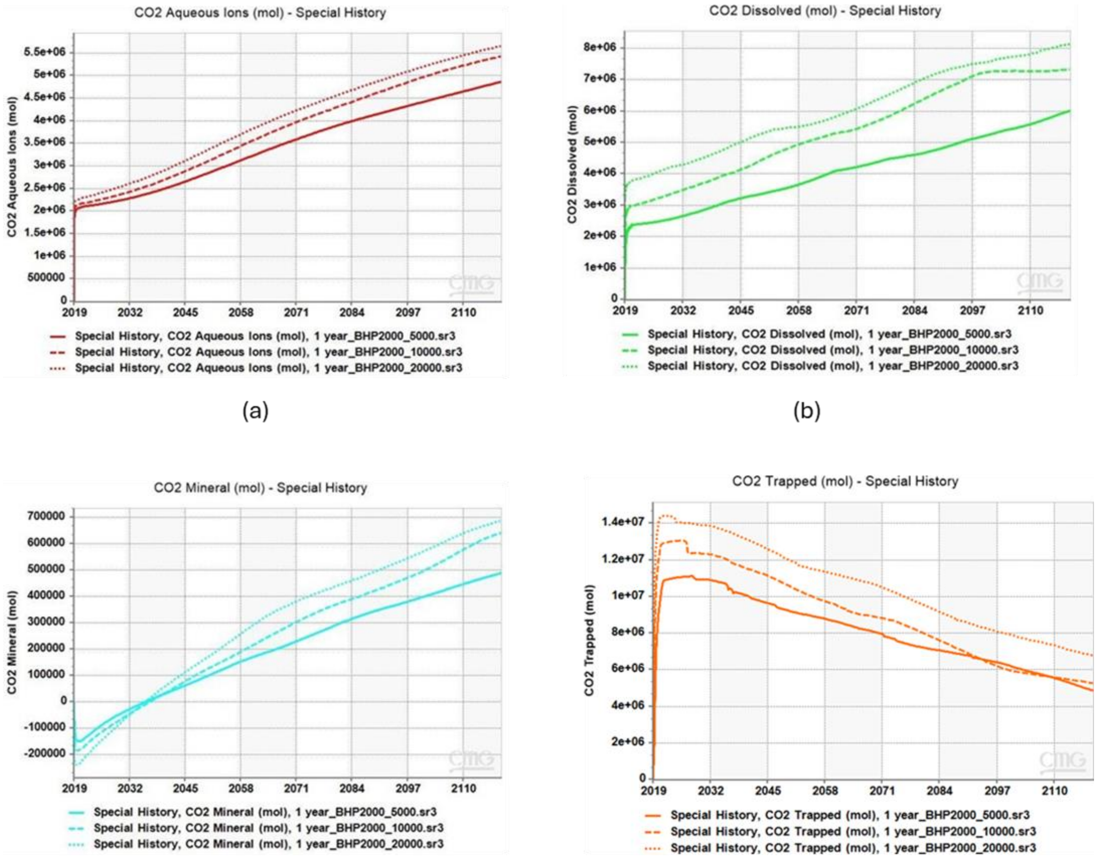


Fig. 6. pH after 100 years with various injection rate (a) 5000 m^3/day; (b) 10000 m^3/ day; (c) 20000 m^3/day



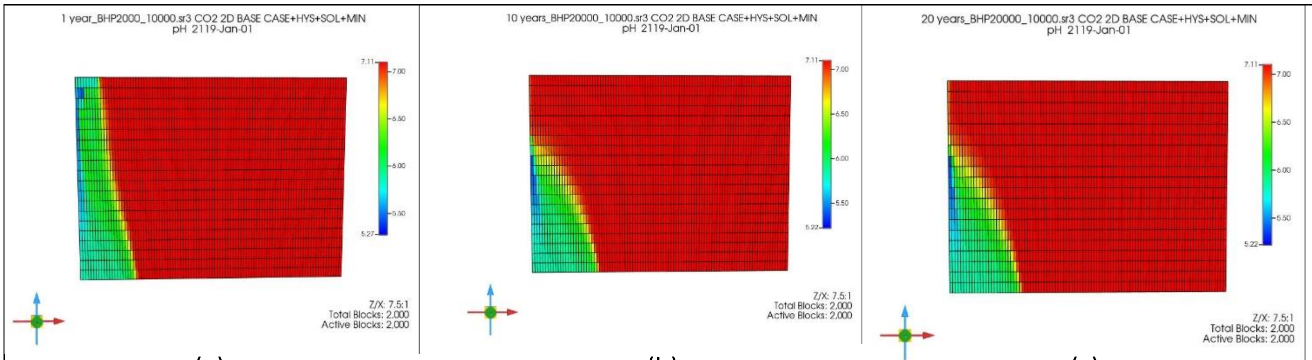
(a) (b)

(c) (d)

Fig. 7. CO_2 trapped in reservoir with various injection rate a) aqueous trapping b) dissolved trapping c) mineral trapping and (d) residual trapping

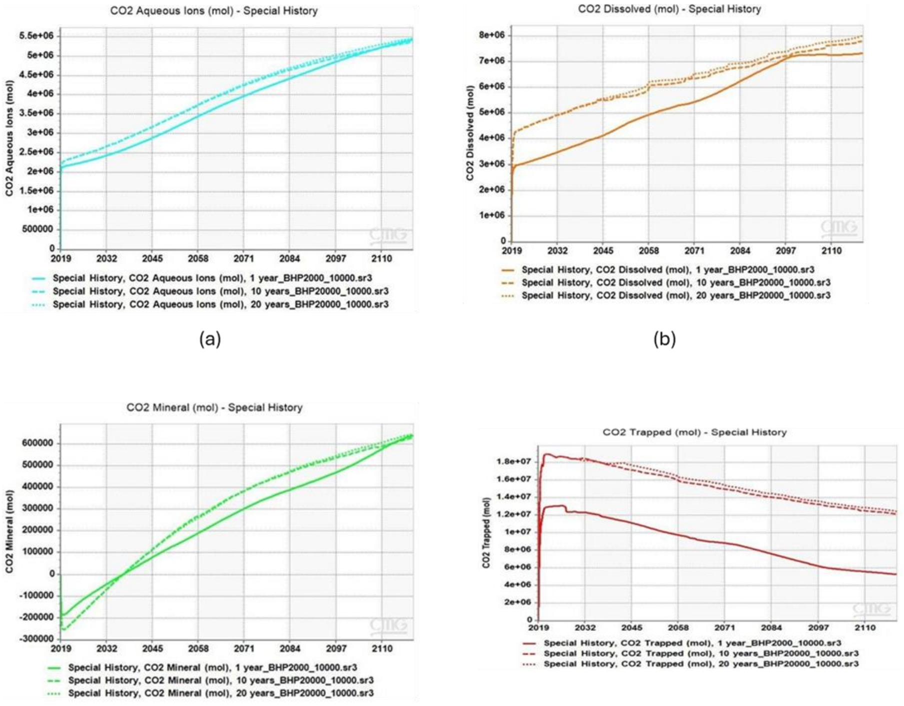
Fig. 6 shows the pH distribution in the saline aquifer after 100 years under different CO_2 injection rates: (a) 5,000 m³/day, (b) 10,000 m³/day, and (c) 20,000 m³/day. The varying injection rates influence the extent of CO_2 diffusion and the resulting pH reduction in the reservoir. Fig. 6 (c) shows that higher injection rates result in a broader spread of lower pH values, indicating increased CO_2 penetration and acidification within the aquifer. Increasing injection rates allows a larger volume of CO_2 to enter the reservoir in a shorter time, initially enhancing trapping efficiency. However, at high rates, such as 20,000 m³/day, the accelerated injection results in premature CO_2 breakthrough, diminishing the effectiveness of residual and solubility trapping mechanisms. The rapid movement of CO_2 through the reservoir reduces its contact time with formation water, limiting opportunities for long-term mineralization. These findings suggest that an injection rate of 10,000 m³/day achieves an optimal balance, maximizing CO_2 trapping efficiency while minimizing risks associated with early CO_2 migration and potential over-pressurization.

3.3 Effects of Injection Duration



(a) (b) (c)

Fig. 8. pH after 100 years with various injection period (a) 1 year (b) 10 years (c) 20 years



(a) (b)

(c) (d)

Fig. 9. CO_2 trapped in reservoir with various injection period a) aqueous trapping b) dissolved trapping c) mineral trapping and (d) residual trapping

Tab. 4. Summarization of CO_2 trapped after 100 years simulation of various scenarios

No.	Injection Pressure (kPa)	Injection rate (m^3/day)	Years of injection	CO_2 trapped after 100 years (mol)
1	15000	10000	1	2.31e+05
2	20000	10000	1	5.27e+06
3	25000	10000	1	1.30e+07
4	20000	10000	10	1.22e+07
5	20000	10000	20	1.25e+07
6	20000	5000	1	4.88e+06
7	20000	20000	1	6.78e+06

Figure 8 shows the pH distribution in the saline aquifer after 100 years under different CO_2 injection durations: (a) 1 year, (b) 10 years, and (c) 20 years. The varying injection periods influence the spread and depth of CO_2 penetration, as evidenced by the areas of reduced pH. Longer injection durations, as seen in Fig. 8 (c) with 20 years, result in a broader and deeper area of acidification, indicating greater CO_2 diffusion within the aquifer. This suggests that extending the injection period enhances CO_2 dispersion, impacting the geochemical environment of the reservoir over a larger area. Extending the injection period enhances CO_2 trapping across all mechanisms—residual trapping, solubility trapping, and mineralization. However, after approximately 10 years, the efficiency of additional CO_2 trapping decreases as the aquifer's pore space becomes saturated and the CO_2 plume reaches its maximal spread. From an operational perspective, prolonging the injection beyond 10 years may not be economically viable unless additional storage capacity is accessible. A 10-year injection period appears to provide an optimal balance, achieving substantial CO_2 trapping while reducing the risks associated with over-pressurizing the aquifer.

4. Conclusion

The simulation results indicate that CO_2 trapping efficiency in deep saline aquifers is significantly influenced by well-operating parameters, with optimal sequestration achieved at an injection pressure of 20,000 kPa, an injection rate of 10,000 m^3/day, and an injection duration of 10 years. These conditions effectively balance maximizing CO_2 storage capacity and maintaining reservoir integrity, thus minimizing operational risks

However, while these optimal conditions highlight technical feasibility, their practical implementation faces several operational challenges. One major consideration is the economic feasibility of maintaining high injection pressures and rates over extended periods, as this can significantly increase operational costs, including those for well infrastructure, compression, and monitoring systems. Moreover, the long-term financial sustainability of such operations may depend on carbon credit policies, government incentives, and market stability, which can vary by region.

Another critical concern is the risk of caprock integrity loss, which could lead to CO_2 leakage and compromise the safety and effectiveness of the storage site. High injection pressures, if not carefully monitored, can induce stress on the caprock, potentially causing fractures or reactivating existing faults. To address this, continuous monitoring and predictive modeling of geomechanical responses are essential to ensure the storage site remains secure. This study underscores the importance of balancing injection parameters to enhance solubility, residual, and mineral trapping mechanisms, all of which contribute to long-term CO_2 storage stability.

Acknowledgements

This research is funded by Vietnam National University HoChiMinh City (VNU-HCM) under grant number: DM2024-20-02. The support of Computer Modelling Group (CMG) in providing the software license for use in this research is highly appreciated.

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