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Synergistic CO_2 Co-Injection in Geothermal Systems: A Pathway to Localized Carbon Storage and Sustainable Energy

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ABSTRACT

This study investigates the synergistic integration of subsurface water injection systems with localized CO_2 sequestration to address challenges in sustainable energy production and carbon emissions reduction. By co-injecting CO_2 into geothermal and other subsurface water injection systems, the approach offers a dual benefit: enhancing local carbon storage while improving geothermal energy production. This method circumvents the need for costly CO_2 transport to centralized storage sites, making it particularly advantageous for small-scale emitters. The study focuses on CO_2–rock–brine interactions under reservoir pressure–temperature conditions, assessing mineral trapping efficiency, reservoir capacity, and the influence of thermo-hydro-chemical processes to evaluate the feasibility and risks of co-injection, including potential impacts on injectivity, mineral dissolution, and gas plume formation. The study includes a global assessment of geothermal doublet projects to estimate the potential CO_2 storage capacity in these fields over the next decade. A comparative life cycle assessment (LCA) is conducted to quantify the environmental and economic benefits of co-injection relative to conventional CCS approaches. By leveraging the global expansion of geothermal energy, this research aims to develop a scalable, localized, and cost-effective strategy (for both CO_2 management and enhanced geothermal energy production) encouraging future deployment of integrated geothermal–CCS systems and contributing to the broader goal of achieving net-negative emissions.

1 INTRODUCTION

Geothermal energy stands at the forefront of sustainable energy solutions, offering reliable, low-carbon power generation and long-term operational stability. Its ability to provide baseload energy makes it a critical component of the global energy transition (Loschetter et al., 2025). However, the urgent need to reduce greenhouse gas emissions has intensified the search for integrated approaches that simultaneously address energy production and carbon management (Loschetter et al., 2025; Cong et al., 2024). Traditional carbon capture and storage (CCS) strategies often rely on centralized storage sites (e.g. Prevost et al., 2022; Nick et al. 2025), which can be economically and logistically prohibitive for small- and medium-scale CO_2 emitters. These limitations have spurred interest in leveraging existing geothermal infrastructure for localized CO_2 sequestration, creating synergistic systems that enhance both energy recovery and carbon storage (Tai et al., 2025).

The integration of geothermal energy production with subsurface CO_2 storage has emerged as a promising strategy to address the dual challenges of sustainable energy supply and greenhouse gas mitigation. Conventional geothermal systems rely on water injection to maintain reservoir pressure and prolong heat extraction, but the co-injection of CO_2 with water introduces unique opportunities for enhanced geothermal recovery and distributed carbon storage. Recent advances have demonstrated that co-injecting CO_2 with water into geothermal doublet systems can provide dual benefits: increasing the efficiency of geothermal heat extraction and enabling in situ carbon storage (Tai et al., 2025; Loschetter et al., 2025). In these systems, CO_2 is dissolved in the injection water and introduced into the geothermal reservoir, where it can be trapped through a combination of solubility, residual, and mineral trapping mechanisms. This approach not only circumvents the need for long-distance CO_2 transport but also leverages the favorable pressure–temperature conditions of geothermal reservoirs to promote mineralization and long-term storage security. Such synergies make co-injection particularly attractive for regions with expanding geothermal capacity and dispersed industrial emissions (e.g. Willems and Nick, 2019).

The effectiveness of this strategy depends on a complex interplay between thermo-hydro-chemical processes, including CO_2–rock–brine interactions, mineral dissolution and precipitation, and changes in reservoir injectivity and capacity. Numerical modeling and field studies have highlighted the importance of optimizing operational

parameters (such as injection rates, CO_2 concentration, and well spacing) to maximize storage capacity and delay CO_2 breakthrough at production wells. Advanced simulation techniques have been developed to capture phase transitions and compositional flow in these systems, while life cycle assessments suggest that integrating CO_2 co-injection with geothermal operations can yield significant environmental and economic advantages over conventional CCS approaches (Salimi and Wolf, 2012; Nick et al., 2015).

Previous studies have extensively explored thermo-hydraulic performance, scaling risks, and optimization strategies for water-based injection in fractured and porous reservoirs (e.g. Salimzadeh et al., 2018; Marty et al., 2020; Crooijmans et al., 2016). These works have provided critical insights into reservoir behavior under long-term operation and informed best practices for geothermal energy extraction. However, despite these advances, the co-injection of CO_2 remains underexplored, particularly regarding its implications for mineral trapping efficiency, injectivity, and thermal breakthrough under realistic reservoir conditions. Addressing these knowledge gaps is essential for supporting the broad deployment of integrated geothermal-CCS systems.

Beyond technical feasibility, the global context underscores the urgency of this research. Geothermal energy is projected to expand significantly over the next decade, driven by its role in providing stable renewable power and supporting district heating networks (e.g. Willems and Nick 2019). At the same time, distributed industrial emitters (such as small manufacturing facilities and regional power plants) face increasing pressure to reduce emissions but lack cost-effective storage options (Loschetter et al., 2025). Co-injection strategies offer a localized solution that aligns with these trends, reducing reliance on centralized infrastructure and enabling flexible and site-specific deployment. By harnessing the synergies between geothermal energy production and localized CO_2 storage, this approach offers a scalable, cost-effective pathway toward net-zero emissions, supporting the broader transition to sustainable energy systems. Recent pilot projects, such as the GECO initiative in the Kızıldere geothermal field, demonstrate that re-injecting captured CO_2 dissolved in water can reduce emissions and enhance reservoir performance without adverse environmental impacts (Akin et al., 2025).

This study aims to evaluate the feasibility and benefits of integrating CO_2 co-injection with geothermal and other subsurface water injection systems as a localized carbon management strategy. In addition, a comparative life cycle analysis (LCA) is conducted to quantify the environmental and economic advantages of this approach over conventional CCS. Ultimately, the study seeks to propose a scalable pathway for simultaneous CO_2 sequestration and geothermal energy production, supporting the transition toward net-zero emissions.

2 METHODOLOGY

2.1 Carbonated water injection

The amount of CO_2 that can be stored during the lifetime of a geothermal facility depends on factors such as brine composition and pressure & temperature conditions. As an example, Innargi's recent announcement of delivering 110 MW of geothermal heat to Aarhus' district heating, leads to approximately 1400 m3/h (assuming 80 °C and 10 °C as production and reinjection temperatures, respectively) of geothermal brine to be produced and reinjected back into the reservoir. Considering the solubility of CO_2 in highly saline brine at 100 bar and 10 °C (e.g., 0.38 mol CO_2/kgw in 6 M NaCl), 5 Mt CO_2 could be stored throughout 20 years of operation. As a worst-case scenario, if at the production conditions (e.g., 20 bar and 80 °C) the brine is already saturated with respect to CO_2, the storage capacity decreases approximately by 20%. Higher capacities can be accommodated at higher reinjection pressures (Figure 1).

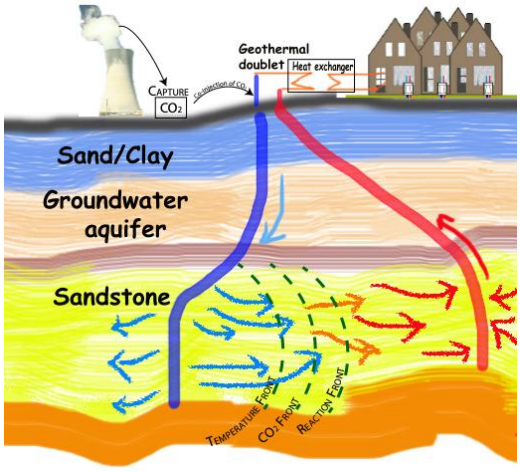


Figure 1. Co-injection of the cooled produced water and captured CO_2 into the reservoir (as carbonated water) is possible for deep geothermal exploitation methods (e.g., doublet system) and triggers complex thermo-hydro-bio-chemical processes. This enables safely storing CO_2 from nearby (small) emitters to help achieving the "net- zero" emissions target.

2.2 Reactive reservoir simulations involving CO_2

Reactive reservoir simulations were conducted using a fully coupled thermo-hydro-chemical (THC) modeling framework to evaluate the performance of mixed CO_2–water injection in geothermal doublet systems. The model solves mass and energy conservation equations for multiphase flow, incorporating CO_2 dissolution in brine, heat transport, and mineral reactions (calcite, feldspar) to assess solubility, residual, and mineral trapping mechanisms. Key assumptions include: (i) homogeneous and heterogeneous reservoir properties with permeability and porosity representative of sandstone formations; (ii) initial brine salinity of 6 M NaCl; (iii) injection at 10 °C and 100 bar and production at 80 °C and 20 bar; (iv) complete CO_2 solubility at injection conditions; and (v) negligible induced seismicity and infrastructure degradation over the 20-year operational period. Simulations explored variations in injection rate, CO_2 concentration, and well spacing to optimize storage capacity and delay thermal and CO_2 breakthrough at production wells.

2.3 LCIA comparison

The environmental performance of an integrated Direct Air Capture (DAC) and geothermal doublet system was evaluated using Life Cycle Assessment (LCA) in accordance with ISO 14040/44 standards. The functional unit was defined as one hour of operation, delivering 8,780 kWh of geothermal heat while capturing and storing 338 kg of atmospheric CO_2. System boundaries included DAC operation, sorbent use, CO_2 purification, pumps, heat exchangers, auxiliary electricity, and permanent storage, excluding infrastructure end-of-life and induced seismicity. Process modeling was performed in Aspen Plus V14 to generate mass and energy balances for DAC and geothermal loops, assuming complete CO_2 solubility at injection conditions. Foreground data were derived from Aspen outputs and literature for sorbent consumption, while background data were sourced from ecoinvent 3.10 in SimaPro 9. Impact assessment employed IMPACT 2002+ v2.15 to quantify midpoint and endpoint indicators, and net CO_2 abatement was calculated as captured CO_2 minus life-cycle emissions, normalized per kWh of heat for comparison with published geothermal LCAs. The main assumptions underlying the Aspen Plus V14 simulations and the SimaPro/ecoinvent 3.10 life-cycle modelling are listed in Table 1. These include DAC capture rates, CO_2–water equilibrium constraints, geothermal flow and pump duties, electricity inputs, and the LCA boundary definition.

Table1. Summary of key assumptions used in LCA

Category	Assumption	Value / Description	Source / Basis
DAC unit	CO_2 capture rate	338 kg CO_2/h	Aspen Plus V14 simulation
	Air CO_2 concentration	420 ppm	Ambient baseline
	Air flow rate	5.26×10^5 m^3/h	To satisfy 338 kg/h capture at 85% efficiency
	Capture efficiency	0.85	Assumed single-pass effectiveness
	DAC thermal duty	235 kW_{th}	Based on 2.5 GJ/tCO_2 regeneration duty
	DAC electricity (fans/blowers)	50 kW_e	From pressure drop & blower efficiency assumptions
	Sorbent make-up	0.16 kg/h	3–5 year life averaged over runtime
CO_2 handling	Compression	None	CO_2 fed at ~1 bar directly to membrane contactor; no compressor used
	Controls electricity	0.5 kWh/h	Placeholder for actuators/valves instrumentation
CO_2 dissolution	Contactor type	Hollow-fiber membrane contactor	Foreground modeled in SimaPro
	Water-side ΔP	0.3 bar	Vendor-typical; determines power adder
	Membrane ΔP hydraulic power	1.7 kW_e	ΔP·Q/η at 150,000 kg/h flow, η=0.75

	CO_2 solubility behaviour	Complete dissolution; zero free gas allowed	Enforced via Aspen Plus V14 flash equilibrium steps
Geothermal doublet	Water circulation rate	150,000 kg/h	Pump suction setpoint in Aspen model, assumed pure water
	Injection/production pressures	High-pressure loop (~100 bar mixing)	Aspen V14 model constraints
	Pump duties (base)	440 kW_e + 112 kW_e + 574 kW_e = 1.13 MW_e	Extracted from Aspen Plus V14
	Auxiliary electricity	+5% of pumping power	Operational allowance (controls, instrumentation)
	Water make-up	0 kg/h	No bleed; closed-loop assumption
Thermal output	Heat delivered	8,780 kWh/h	From Aspen production well temperature and flow
LCA system	Software	SimaPro 9	—
	Database	ecoinvent 3.10 (cut-off)	Applied for electricity, chemicals, materials
	LCIA method	IMPACT 2002+ (v2.15)	Used for midpoint and endpoint indicators
	Functional Unit	1 hour of integrated DAC-geothermal operation	Produces 8,780 kWh heat + stores 338 kg CO_2
	Boundary	Cradle-to-gate + permanent CO_2 storage	Excludes DAC unit EoL; excludes induced seismicity
CO_2 storage	Storage mechanism	CO_2 dissolved in brine; mineral trapping potential	Modelled via thermodynamic equilibrium in Aspen
	Fugitive CO_2	0 kg/h	No venting; enforced in process simulation

3 RESULTS

3.1 Reactive transport and life-time

Simulation results indicate that CO_2 co-injection significantly influences reservoir behavior over the operational lifetime. Initially, dissolved CO_2 remains uniformly distributed near the injection well, enhancing pressure support and heat extraction. Over time, reactive transport processes lead to mineral dissolution (primarily calcite) and secondary precipitation, which slightly alters porosity but does not compromise injectivity under modeled conditions. Thermal breakthrough occurs after approximately 18–20 years, consistent with conventional water injection scenarios, while CO_2 breakthrough at the production well is delayed beyond the modeled period due to strong chemical trapping. Mineral trapping contributes progressively, accounting for up to 15–20% of stored CO_2 after two decades, ensuring long-term storage security. These results confirm that optimized co-injection can achieve dual benefits (sustained geothermal performance and permanent CO_2 sequestration) without adverse impacts on reservoir integrity. Adding more complexity in the mineral composition could result in secondary mineral precipitation and increase the CO_2 mineral trapping. Studies show that the presence of reactive minerals such as anorthite, smectite, and chlorite increases the formation of stable carbonate minerals, thereby improving long-term storage security. For example, higher concentrations of anorthite and chlorite facilitate the precipitation of carbonates like calcite, siderite, and magnesite, leading to a greater proportion of CO_2 being permanently immobilized in the solid phase. These findings highlight the

importance of reservoir mineralogy in optimizing CO_2 sequestration strategies and ensuring storage effectiveness (Wang et al., 2016; Kim et al., 2023). As shown in Figure 2, including simplified mineral reactions alters the predicted geothermal-brine temperature and the resulting energy produced at the production well over time relative to the non-reactive scenario.

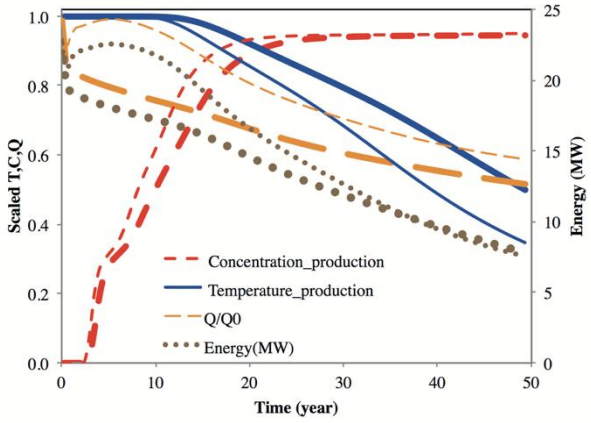


Figure 2. Temperature and CO_2 concentration measured at the production well together with produced energy and discharge for a heterogeneous aquifer with and without reactive minerals. The thicker lines represent the results of the system without reaction (from Nick et al., 2015).

3.2 LCIA comparison

Life Cycle Impact Assessment results demonstrate that the integrated DAC–geothermal system achieves substantial climate benefits while maintaining non-climate impacts within the range of conventional geothermal heat plants. As shown in Table 2, total damage per hour of operation is 643 mPt, corresponding to 0.0732 mPt/kWh, with human health, ecosystem quality, and resource use impacts comparable to baseline geothermal systems. Climate damage is strongly negative (−338 mPt/h), reflecting net CO_2 removal. Normalized per kWh, the system delivers approximately −0.38 kg CO_2-eq, significantly outperforming conventional geothermal heat (≈ 5–14 g CO_2-eq/kWh) and far below fossil-based heat (~ 236 g CO_2-eq/kWh for natural gas) (Table 3). While DAC introduces additional upstream burdens from electricity and sorbent use, these are outweighed by the permanent geological storage of captured CO_2. Overall, the combined system offers net-negative emissions and competitive environmental performance, positioning it as a scalable solution for climate mitigation and sustainable heat supply.

Table 2. LCIA Results (Per Hour and Per kWh)

Damage Category	Total (mPt/h)	Per kWh (mPt/kWh)
Total damage	643.00	0.0732
Human health	483.00	0.0550
Ecosystem quality	78.80	0.0090
Climate damage	-338.00	-0.0385
Resources	420.00	0.0478

Table 3. Climate Change Comparison with Literature

Case Study	System Type	GWP (gCO_2-eq/kWh)	Reference
DAC + geothermal doublet (this study)	Heat + CO_2 removal	-380	This work
Rittershoffen (France)	Deep EGS – heat only	5.9	Douziech et al. 2021
Upper Rhine Valley EGS (industrial heat)	EGS - heat	5.8–14	Pratiwi et al. 2018

Southern German DH plant	Deep geothermal district heating	83	Uhrmann et al. 2025
Industrial steam (Germany)	Geothermal + heat pump	171	Uhrmann et al. 2025
Low-T distribution (Iceland)	Geothermal network only	0.7	Egilsson 2025
General geothermal DH range	Mixed systems	14–202	IPCC 2011

3.3 Global capacity of CO_2 co-injection

We assume a capacity of 4.6 Mt of CO_2 storage for every 100 MW of geothermal (direct heat) doublet system. Based on this assumption, the current global installed capacity of deep geothermal systems for direct heat use (approximately 40 GWth in 2022) could theoretically store around 1,800 Mt (1.8 Gt) of CO_2. Looking ahead, forecasts by the IEA and industry indicate that geothermal heat use will grow around three times by 2050, driven by district heating and industrial applications. If installed capacity reaches 120–140 GWth by 2050, the potential CO_2 storage could rise to 5,500–6,400 Mt (5.5–6.4 Gt).

It is important to emphasize that these calculations represent rough estimates based on simplified assumptions. Actual storage capacity will depend on a range of factors, including reservoir pressure and temperature conditions, fluid and rock composition, mineralization potential, and operational strategies. Therefore, more detailed analyses and site-specific evaluations are required to validate these projections and optimize co-injection designs for different geological settings.

4 DISCUSSION

Many countries are undertaking great efforts toward decarbonization and the development of robust and reliable energy systems based on renewable resources. Transitioning from fossil-based to cleaner energy systems will not occur instantaneously but will extend over decades. Throughout this transition, CO_2 Capture and Storage (CCS) remains indispensable for achieving net-zero targets, while in the long run, integrating CCS with renewable energy production offers a pathway to negative emissions (Bonto et al., 2022).

However, deploying CCS at scale is challenging due to limited infrastructure and the high cost of transporting and conditioning CO_2 streams, which often excludes smaller emitters from centralized storage networks (Yoo et al., 2013). Localized sinks near emission sources are therefore critical to enable cost-effective carbon management. Geothermal energy production, increasingly popular in Europe and often located near urban centers, provides a unique opportunity for such integration (Marks-Bielska et al., 2020).

In geothermal systems, hot brine is produced for district heating or power generation (Barbier, 2002). At reservoir conditions, geothermal fluids typically contain dissolved gases such as CH_4, CO_2, N_2, and H_2S, with concentrations varying by field (Laier, 2023). Danish geothermal formation fluid samples show gas-liquid ratios up to 0.2, with CO_2 molar fractions reaching 25% in some cases. To prevent degassing, facilities may operate above bubble-point pressure. After heat extraction, the cooled brine is reinjected, and at typical reinjection conditions, fluids are often undersaturated with respect to CO_2, creating an opportunity for CO_2 dissolution and storage.

Co-injecting CO_2 with reinjected brine offers multiple operational benefits. Acidification from dissolved CO_2 can mitigate injectivity loss caused by salt precipitation, fines migration, and biofilm formation (Tranter, 2020; Brehme et al., 2018). Additionally, high CO_2 concentrations inhibit microbial growth (Bonto et al., 2022), reducing scaling and corrosion risks (Debs-Louka et al., 1999). These effects can improve near-wellbore permeability and reduce pumping energy requirements.

Nevertheless, risks must be managed. Upon reheating, CO_2 may exsolve, forming a gas phase that could migrate upward or remain trapped in pore space. While this enhances storage capacity, it introduces leakage concerns that require monitoring. Furthermore, early CO_2 breakthrough at production wells could increase corrosion and maintenance costs, particularly in heterogeneous reservoirs where preferential flow paths accelerate migration. To mitigate this, well design strategies (such as placing production wells deeper or using horizontal completions) can delay breakthrough and simultaneously improve thermal performance.

Overall, integrating CO_2 co-injection with geothermal systems represents a technically feasible and environmentally advantageous approach, but its success depends on site-specific reservoir characterization, optimized operational strategies, and robust monitoring frameworks. Future research should focus on quantifying mineral trapping under complex geochemical conditions, assessing long-term integrity under cyclic injection, and developing predictive models for heterogeneous formations.

5 CONCLUSION

CO_2 co-injection in geothermal systems offers a practical and scalable solution for achieving dual objectives: sustainable heat supply and localized carbon storage. Our simulations confirm that optimized co-injection maintains geothermal performance while securely storing CO_2 through solubility and mineral trapping, with minimal operational risks when properly managed. Life Cycle Assessment demonstrates that coupling DAC with geothermal operations delivers net-negative emissions (≈ −0.38 kg CO_2-eq/kWh for pure water assumption and ≈ −0.26 kg CO_2-eq/kWh for high-saline brine), outperforming conventional geothermal and fossil-based heat systems. Assuming a co-injection of CO_2 and cold water for 20 years, this approach could provide substantial global storage capacity, estimated at around 1.8 gigatons (Gt) for the current installed geothermal heat capacity and up to 5.5 Gt by 2050, supporting large-scale decarbonization efforts. Overall, CO_2 co-injection in geothermal systems represents a cost-effective, climate-positive pathway toward net-zero and negative-emission energy systems.

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