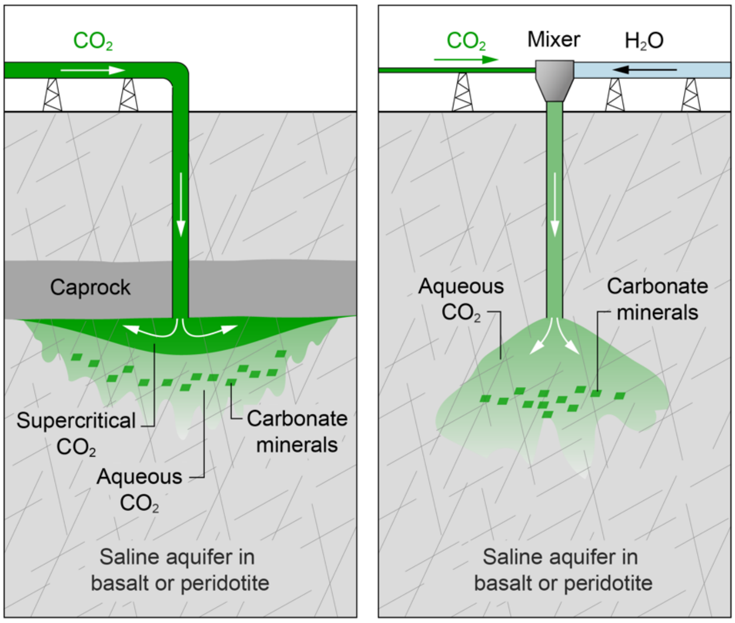
Geological storage of CO_2 by in-situ mineralization in basalt and peridotite formations

Containment, safety and environmental compatibility of current worldwide implementation sites



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Executive summary (English)

Switzerland is aiming to achieve net-zero greenhouse gas emissions by 2050. Reaching this target will require the permanent, safe and environmentally compatible storage of both hard-to-abate CO_2 emissions and CO_2 generated by negative emission technologies. Globally, the most promising storage approach is injection of CO_2 into geological formations, which offer high storage capacities, isolation from the biosphere and atmosphere, and an established record of storage security, safety and environmental compatibility. While geological storage options within Switzerland are still under assessment, Swiss emitters may wish to make use of proven geological storage sites abroad, either by exporting their captured CO_2 or by procuring atmospheric carbon removals achieved by direct air capture and coupled storage facilities.

Within this context, the Swiss Federal Office for the Environment (FOEN) is mandated to evaluate the permanence, safety and environmental compatibility of any injection facility that intends to store CO_2 on behalf of Swiss industries. Internationally recognized recommendations and extensive operational experience exist for evaluating CO_2 storage in depleted oil and gas reservoirs and in deep saline sedimentary aquifers. By contrast, the emerging technology of in-situ CO_2 mineralization in basaltic (mafic) and serpentinized peridotite (ultramafic) formations is not yet explicitly addressed in these recommendations, and practical experience with this approach remains limited. To date, only one such project has progressed from the pilot stage to commercial-scale CO_2 injection.

To fill this gap in evaluation criteria, the present scientific report provides FOEN with geological and regulatory background information to support its assessments of current and future in-situ CO_2 mineralization facilities worldwide. Information has been synthesized from the scientific literature, conference presentations and online interviews with operators of active mineralization projects. The in-situ mineralization technology is explained for readers without geological training, and its advantages, disadvantages and risks are compared to those of conventional CO_2 geological storage. Six implementation sites that have injected, or intend to inject, CO_2 underground are reviewed: four in basalt formations (CarbFix, Iceland; Wallula, USA; Jizan, Saudi Arabia; Elementeita/Cella, Kenya) and two in serpentinized peridotites (Chalk, Oman; Fujairah, UAE). Key findings are summarized in Figures 1 and 2 and Tables 3–5. The features of in-situ mineralization relevant to FOEN's mandate are examined in detail, and recommendations are made as to how FOEN may best evaluate individual projects.

This report concurs with the prevailing opinion in the geological sciences that the reviewed projects convincingly prove the efficacy of in-situ CO_2 mineralization in basaltic and serpentinized peridotite rocks, and that this technology can provide permanent, safe and environmentally compatible storage of CO_2. In-situ mineralization entails injecting CO_2 either pre-dissolved in water or as a free, supercritical phase. Over months to years, carbonate minerals form through spontaneous reactions between injected CO_2 and the basalt and peridotite rocks, thereby permanently immobilizing the CO_2. Prior to complete mineralization, however, the accompanying dissolved or free CO_2 remains mobile and could, in principle, leak from the target reservoir and potentially contaminate overlying aquifers. The fate of CO_2 in these fluid forms must therefore be evaluated and monitored throughout the operational lifetime of the injection campaign (likely many decades in commercial operations) and for some additional years until mineralization is complete. Major hurdles with large-scale injection of pre-dissolved CO_2 will be (i) sourcing the huge amounts of water required (20–32 times the mass of CO_2 injected); (ii) managing reservoir pore pressure, and (iii) mitigating the risk of induced earthquakes. Injection of free-phase CO_2 circumvents the water-supply constraint and enables higher CO_2 injection rates, but it necessitates the presence of an impermeable caprock to ensure containment, a feature that is uncommon in basaltic and serpentinized peridotite settings. A persistent challenge for both injection strategies is the development of reliable methods to verify complete (i.e., 100%) mineralization of CO_2 at the reservoir scale.

Although much of the literature portrays in-situ mineralization as fundamentally different from conventional CO_2 storage in sealed sedimentary aquifers, this report emphasizes the similarities between the two approaches. Because carbonation reactions are not instantaneous and the time required for complete mineralization is not yet fully known, target aquifers for secure in-situ mineralization must exhibit the same formation-scale containment properties as sediment-hosted aquifers that are suitable to store aqueous CO_2 or for both aqueous and supercritical CO_2 (depending on the chosen injection mode). Consequently, for the purpose of evaluating storage security, safety and environmental compatibility, in-situ mineralization should not be viewed as an entirely separate category of CO_2 storage but as a variant of long-term storage in sedimentary aquifers. The two approaches target different host rocks and different long-term states of stored CO_2, but their reservoirs must have equivalent hydrogeological properties.

In line with the above reasoning, this report concludes that the existing EU, ISO and US-DOE guidance documents for CO_2 storage in depleted oil/gas reservoirs and in sedimentary basins are both suitable and sufficient to evaluate and monitor the fate of dissolved CO_2 and free-phase CO_2 in in-situ mineralization sites. It is recommended that FOEN base its future evaluations of the permanency, safety and environmental compatibility of in-situ CO_2 mineralization facilities on these established documents, supported by reviews from technical experts. Each geological site will, however, possess unique characteristics requiring specific expert evaluation by FOEN.

Zusammenfassung (Deutsch)

Die Schweiz strebt bis 2050 eine Netto-Null-Bilanz in Bezug auf Treibhausgasemissionen an. Um dieses Ziel zu erreichen, müssen schwer reduzierbare CO_2-Emissionen und CO_2, welches durch Negativemissionstechnologien entsteht, dauerhaft, sicher und umweltverträglich gespeichert werden. Weltweit ist die Injektion von CO_2 in geologische Formationen im Untergrund der vielversprechendste Ansatz für die Speicherung. Sie bietet hohe Speicherkapazitäten, eine Isolierung von der Biosphäre und der Atmosphäre und ist nachgewiesenermassen einschlusswirksam, sicher und umweltverträglich. Während Optionen für die geologische Speicherung innerhalb der Schweiz geprüft werden, könnten Schweizer Emittenten bewährte geologische Speicherstätten in anderen Ländern nutzen, entweder durch den Export ihres CO_2 oder durch den Erwerb von Kohlenstoffentfernungen, die durch gekoppelte Abscheidungs- und Speicheranlagen erzeugt werden.

In diesem Zusammenhang hat das Schweizer Bundesamt für Umwelt (BAFU) den Auftrag, die Einschlusswirksamkeit, Sicherheit und Umweltverträglichkeit jeder Injektionsanlagen zu bewerten, die CO_2 für die Schweizer Industrie speichern soll. Für die Bewertung der CO_2-Speicherung in erschöpften Öl- und Gaslagerstätten sowie in tiefen salinen Sedimentaquiferen gibt es international anerkannte Empfehlungen und umfangreiche Betriebserfahrungen. Im Gegensatz dazu wird die sich entwickelnde Technologie der In-situ-Mineralisierung von CO_2 in basaltischen (mafischen) und serpentinisierten Peridotit-Formationen (ultramafischen) in diesen Empfehlungen noch nicht ausdrücklich behandelt, und die praktischen Erfahrungen mit diesem Ansatz sind nach wie vor begrenzt. Bislang hat nur ein einziges Projekt den Sprung von der Pilotphase zur CO_2-Injektion im kommerziellen Massstab geschafft.

Um diese Lücke in den Bewertungskriterien zu schliessen, liefert der vorliegende wissenschaftliche Bericht dem BAFU geologische und regulatorische Hintergrundinformationen zur Unterstützung seiner Bewertungen aktueller und künftiger Anlagen zur In-situ-Mineralisierung von CO_2 weltweit. Die Informationen wurden aus wissenschaftlicher Literatur, Konferenzvorträgen und Online-Interviews mit Betreibern aktiver Mineralisierungsprojekte zusammengetragen. Die In-situ-Mineralisierungstechnologie wird für Leser ohne geologische Vorkenntnisse erläutert, und ihre Vor- und Nachteile sowie Risiken werden mit denen der konventionellen geologischen CO_2-Speicherung verglichen. Sechs Standorte, an denen CO_2 unterirdisch injiziert wurde oder injiziert werden soll, werden diskutiert: vier in Basaltformationen (CarbFix, Island; Wallula, USA; Jizan, Saudi-Arabien; Elementeita/Cella, Kenia) und zwei in serpentinisierten Peridotiten (Chalk, Oman; Fujairah, Vereinigte Arabische Emirate). Die wichtigsten Ergebnisse sind in den Abbildungen 1 und 2 sowie in den Tabellen 3–5 zusammengefasst. Die für den Auftrag des BAFU relevanten Merkmale der In-situ-Mineralisierung werden eingehend untersucht, und es werden Empfehlungen abgegeben, wie das BAFU einzelne Projekte am besten bewerten kann.

Dieser Bericht steht im Einklang mit der in den Geowissenschaften vorherrschenden Meinung, dass die untersuchten Projekte die Wirksamkeit der In-situ-CO_2-Mineralisierung in basaltischen und serpentinisierten Peridotitgesteinen überzeugend belegen und dass diese Technologie eine dauerhafte, sichere und umweltverträgliche Speicherung von CO_2 ermöglichen kann. Bei der In-situ-Mineralisierung wird CO_2 entweder vorab in Wasser gelöst oder als freie, überkritische Phase injiziert. Über Monate bis Jahre hinweg bilden sich durch spontane Reaktionen zwischen dem injizierten CO_2 und den Basalt- und Peridotitgesteinen Karbonatmineralien, wodurch das CO_2 dauerhaft immobilisiert wird. Vor der vollständigen Mineralisierung bleibt das begleitende gelöste resp. freie CO_2 jedoch mobil und könnte grundsätzlich aus dem Zielreservoir austreten und möglicherweise darüber liegende Grundwasserleiter kontaminieren. Das Verhalten des CO_2 in diesen flüssigen Formen muss daher während der gesamten Betriebsdauer der Injektionskampagne (wahrscheinlich viele Jahrzehnte im kommerziellen Betrieb) und für einige weitere Jahre bis zum Abschluss der Mineralisierung bewertet und überwacht werden. Die grössten Hürden bei der grosstechnischen Injektion von vorab gelöstem CO_2 sind (i) die Beschaffung der erforderlichen riesigen Wassermengen (das 20- bis 32-fache der injizierten CO_2-Masse), (ii) die Steuerung des Porendrucks im Reservoir und (iii) die Minderung des Risikos induzierter Erdbeben. Die Injektion von CO_2 in der freien Phase umgeht die Einschränkungen der Wasserversorgung und ermöglicht höhere CO_2-Injektionsraten, erfordert jedoch das Vorhandensein einer undurchlässigen Deckschicht, um die Eindämmung zu gewährleisten, was in basaltischen und serpentinisierten Peridotit Formationen selten der Fall ist. Eine anhaltende Herausforderung für beide Injektionsstrategien ist die Entwicklung zuverlässiger Methoden zur Überprüfung der vollständigen (d. h. 100-prozentigen) Mineralisierung von CO_2 auf Reservoir-Massstab.

Obwohl in der Literatur die In-situ-Mineralisierung häufig als grundlegend anders als die konventionelle CO_2-Speicherung in versiegelten sedimentären Aquiferen dargestellt wird, betont dieser Bericht die Ähnlichkeiten zwischen den beiden Ansätzen. Da Karbonatisierungsreaktionen nicht sofort ablaufen und die für eine vollständige Mineralisierung erforderliche Zeit noch nicht abschliessend bekannt ist, müssen Ziel-Aquifere für eine sichere In-situ-Mineralisierung dieselben Rückhalteeigenschaften auf Formations-ebene aufweisen wie sedimentäre Aquifere, die für die Speicherung von wässrigem und/oder überkritischem CO_2 (je nach gewähltem Injektionsmodus) geeignet sind. Folglich sollte die In-situ-Mineralisierung zum Zwecke der Bewertung der Speichersicherheit, der Sicherheit und der Umweltverträglichkeit nicht als eine völlig eigenständige Kategorie der CO_2-Speicherung betrachtet werden, sondern als eine Variante der Langzeitspeicherung in sedimentären Aquiferen. Die beiden Ansätze zielen auf unterschiedliche Wirtsgesteine und unterschiedliche Langzeitzustände des gespeicherten CO_2 ab, aber ihre Reservoirs müssen äquivalente hydrogeologische Eigenschaften aufweisen.

In Übereinstimmung mit der oben genannten Argumentation kommt dieser Bericht zu dem Schluss, dass die bestehenden Leitfäden der EU, der ISO und des US-DOE für die CO_2-Speicherung in erschöpften Öl-/Gaslagerstätten und in Sedimentbecken sowohl geeignet als auch ausreichend sind, um das Verhalten von gelöstem und freiphasigem CO_2 in In-situ-Mineralisierungsspeichern zu bewerten und zu überwachen. Es wird empfohlen, dass das BAFU seine künftigen Bewertungen der Einschlusswirksamkeit, Sicherheit und Umweltverträglichkeit von CO_2-Mineralisierungsanlagen auf diese etablierten Dokumente basiert und sich zudem auf Gutachten von technischen Experten stützt. Jeder geologische Standort weist jedoch einzigartige Merkmale auf, die eine spezifische fachliche Bewertung durch das BAFU erfordern.

1. Introduction

1.1. Need for permanent storage of Swiss CO_2 emissions

Achieving Switzerland's climate target of net-zero greenhouse gas emissions by 2050 includes developing means to store domestic hard-to-abate CO_2 emissions and CO_2 captured from the atmosphere in a permanent, safe and environmentally sustainable manner (Fedlex, 2022). Internationally, injection of CO_2 into porous and permeable geological formations is regarded as the most promising approach to this challenge, owing to their high storage capacity, their isolation from the biosphere and atmosphere, and their verified performance record of storage security, safety and environmental compatibility (IPCC, 2006). Accordingly, the long term climate strategy of the Federal Government of Switzerland encourages geological storage of domestic CO_2 emissions where possible within Swiss territory (Bundesrat, 2022; BFE, 2025). By 2050, the hard-to-abate emissions in Switzerland are likely to amount to 3 million tonnes of CO_2 (Mt CO_2) per year. The vision of the Federal Government is that 1–2.5 Mt CO_2 of this annual total could be stored in 5 geological sites (BFE, 2025).

From both the scientific and industrial exploration perspectives, the capacity for geological CO_2 storage within Switzerland is not yet well defined. An initial appraisal based on the geological literature applied standard international assessment methodologies to estimate the theoretical capacity of deep saline sedimentary aquifers under the Swiss central plateau (Chevalier et al., 2010). Subsequent scientific investigation of the most promising of these aquifers assessed its prospective (unproven) storage resources at approximately 50 Mt CO_2 (Diamond et al., 2019). Other candidate aquifers have yet to be investigated in comparable detail. Regarding the potential for in-situ mineralization in Switzerland, formations of metamorphic rocks with suitable basaltic and ultramafic compositions are abundant in the Alps, but their structural and hydrogeological features are viewed as unsuitable for in-situ CO_2 mineralization (Ladner et al., 2023). A literature study of further geological, technical, economic and other aspects concluded that such storage of CO_2 in Switzerland is infeasible in the near term and possibly unsuitable in the long term (Martin et al., 2025). To date, no standard industrial geological exploration (i.e., involving seismic surveys, drilling and injection tests) has been conducted in Switzerland specifically to identify and verify the suitability of a CO_2 storage site. Future exploration may or may not succeed in this task, but it will likely require decades to execute. In the meantime, and perhaps for the long term, Switzerland will need to cooperate with other countries that possess favourable onshore or offshore geological settings and that have established secure, safe and environmentally sustainable CO_2 storage sites. Such cooperation could involve the export of Swiss CO_2 and also procurement of carbon removals generated abroad by geological storage, using carbon market mechanisms operating under the Paris Agreement (FOEN, 2025a).

1.2. Need for a report on implementation sites for in-situ CO_2 mineralization

The Swiss Federal Office for the Environment (FOEN) is tasked with scrutinizing the efficacy, safety and environmental compatibility of any injection facilities that receive CO_2 from Switzerland for permanent storage abroad or that store air-captured CO_2 on behalf of Swiss entities, in accordance with legislation governing disposal of waste (Epiney et al., 2024; FOEN 2025b). While this mandate derives from the legal definition of captured CO_2 as a waste substance, the need for such environmental oversight may persist even if CO_2 export is handled under a specific legislation in the future.

Environmental compatibility is also obligatory for any projects certified by FOEN under the revised (post-2024) Federal Act on the Reduction of CO_2 Emissions (Fedlex, 2011). This includes the issuance of CO_2 certificates ("attestations") in accordance with Section 5 of the CO_2 Ordinance (Fedlex, 2025). For foreign projects, a formal bilateral agreement with the host country is required, specifying the conditions needed to ensure environmental compatibility in accord with Article 6 of the Paris Agreement, and with the London Protocol if CO_2 exported from Switzerland is stored offshore (FOEN, 2025c).

Globally, the predominant geological methods of storage entail injecting CO_2 into either previously exploited natural gas and oil reservoirs or into deep, saline aquifer formations in sedimentary basins. More than 50 such projects are currently in successful commercial operation in numerous countries (Global CCS Institute, 2024), and approximately 200 Mt CO_2 has already been stored (IEA, 2025a). Detailed information on the site characteristics, injection procedures and monitoring protocols of the projects are published in the scientific and technical literature. In addition, best-practice guidelines for operational safety and environmental sustainability are well established, tested and governed by regulatory standards (e.g., EC 2024a, 2024b; ISO 2017). The information accessible in the best-practice guideline documents is sufficient to enable FOEN to remotely assess and validate projects implementing these conventional methods of CO_2 storage.

Another geological storage method under development, known as “in-situ CO_2 mineralization”, involves injecting CO_2 into certain chemically reactive rock formations (basalt and peridotite, explained below), such that the CO_2 is permanently immobilized in the form of solid carbonate minerals. Worldwide, only one site is so far operational at a commercial scale, situated at Hellisheidi in Iceland (originally named CarbFix2), where almost 0.1 Mt CO_2 has been injected. Switzerland has gained initial experience with CO_2 export and storage at this well documented site through the DemoUpCARMA and DemoUpStorage demonstration projects (Becattini and Mazzotti, 2023). However, additional sites for in-situ CO_2 mineralization are being developed in other countries, for which FOEN currently has insufficient expertise and documentation to thoroughly assess their effectiveness, operations and environmental compatibility. At present, best-practice regulations are being modified to cover all the variants of this evolving technology, but an internationally accepted standard is still outstanding. Given this state of affairs, this report commissioned by FOEN provides a scientific review of the security (CO_2 containment), safety and environmental compatibility of in-situ mineralization projects to support ongoing and future assessments by FOEN.

1.3. Scope, information sources and organization of this report

This report reviews in-situ mineralization projects that have actually injected CO_2 in practice, or are currently in the drilling phase with the intention to inject. At the time of writing this report, only six such projects are known to us, situated in USA, Saudi Arabia, Kenya, Oman, the United Arab Emirates (UAE), as well as the above-mentioned CarbFix2 project in Iceland. Many countries have undertaken desktop screening studies to assess whether their geological formations are potentially suitable for in-situ CO_2 mineralization. These screening studies are not reviewed here, as they remain too preliminary to allow meaningful assessment of CO_2 containment, safety and environmental compatibility at specific sites.

The thematic scope of this report encompasses (1) geological, physical and geochemical processes involved in the implementation of the in-situ mineralization technology; (2) environmental impacts (e.g., water sources), risks and risk mitigation strategies (e.g., for seismicity, contamination of aquifers and CO_2 leakage); (3) energy requirements for injection; (4) applicability of existing best-practice recommendations for CO_2 storage in saline sedimentary aquifers; and (5) criteria to evaluate in-situ mineralization projects with respect to their containment, safety and environmental compatibility. Methods to estimate storage capacities at given sites are not discussed herein, as they do not bear on the key topics of containment, safety and environmental compatibility. Site permitting is touched on in passing, but other operational, economic, legal, political or social aspects of the implementation of this technology are not addressed. Some of the latter aspects are reviewed by Nath et al. (2024).

The information reported herein is drawn from the scientific literature (which is currently scant for some of the active injection projects), scientific conference presentations and online interviews with team members of several of the active injection projects. Although these information sources are limited, they provide insight into the current state of the art of in-situ CO_2 mineralization and they enable a preliminary evaluation of the security, safety and environmental issues associated with each project.

This report is organized as follows. Principles of CO_2 storage by in-situ mineralization are first introduced, then the current status of international regulations regarding safety and environmental issues is presented. These chapters provide a context in which the chosen reservoirs and injection approaches of the individual projects are subsequently discussed. A comparison is then made of the advantages and disadvantages of the in-situ mineralization method versus the well-established storage in oil/gas reservoirs or saline sedimentary aquifers. Open questions regarding the in-situ mineralization technology are also presented. Finally, recommendations are proposed of how FOEN could best evaluate individual in-situ mineralization projects in the future.

2. Principles of CO_2 storage by in-situ mineralization

Storage of CO_2 in the geological subsurface by inducing the precipitation of carbonate minerals is termed **in-situ CO_2 mineralization** or **in-situ mineral carbonation** or **in-situ mineral trapping**. The same carbonation reactions with the same rock reactants (or other natural or manufactured materials) can also be induced artificially in industrial reactors at the surface of the Earth. In that case, the CO_2 storage approach is termed **ex-situ CO_2 mineralization** or **ex-situ mineral carbonation**.

The in-situ mineralization technology is still very much under development. The one operating commercial-scale project (CarbFix2, Iceland) is highly successful, not only owing to the ingenuity of its development team but also to the many inherently advantageous features of its site. It is located in an area that has been producing geothermal energy for decades, hence its subsurface is well explored and scientifically well understood. Its rocks are particularly reactive to CO_2, and the reaction rates are enhanced by the high temperatures caused by nearby active volcanism. The operational context is also advantageous, providing a mature multi-well geothermal infrastructure, abundant geothermal power, and abundant spent geothermal water for injection. This combination of features cannot be readily replicated elsewhere. Consequently, pilot projects attempting to implement in-situ mineralization in other countries are experimenting with different approaches tailored to their local geological, infrastructure and water-supply conditions. For example, some projects inject or plan to inject CO_2 pre-dissolved in water whereas others inject only free-phase CO_2 or alternations of water and free CO_2. This means that the geology, infrastructure and approach of each of the ongoing projects reviewed in this report is unique. No standardized recipe or set of recipes for reliable, full-scale in-situ mineralization in different countries has emerged as yet.

Despite the diversity of in-situ mineralization projects, they are all subject to the same general geological and subsurface engineering principles. A basic understanding of these principles aids understanding of the variants of the technology and of how their implementation sites can be evaluated in terms of storage permanency, safety and environmental impacts. The present Chapter provides an introduction to the key principles and terminology relevant to the in-situ approach, written primarily for readers who have scientific training but are not geologists. The specifics of each ongoing project are presented and assessed in terms of these principles and terminology in a subsequent chapter.

2.1. Advantages of and geological constraints on in-situ CO_2 mineralization

Observations from nature and laboratory experiments have shown that **aqueous CO_2** (CO_2 dissolved in water) may react chemically with certain rocks in the geological subsurface and form minerals of the carbonate group (e.g., calcite, $CaCO_3$). Carbonate minerals contain CO_2 in the form of CO_3^{2-} oxyanions (negatively charged), which are fixed to divalent cations (positively charged, e.g. Ca^{2+}) by strong ionic bonds within the atomic lattices of the minerals.

Hundreds of carbonate minerals are known to exist, involving dozens of chemical elements. However, only 3 elements, **Ca, Mg and Fe**, are sufficiently abundant in common rocks to sequester CO_2 in the form of carbonate minerals in amounts large enough to meet CO_2 storage aims. The common rocks in question are basalt and peridotite (described in detail below) and other closely related rocks. In principle, rarer rocks rich in Fe- or Mn-oxides would also be suitable for in-situ mineralization, but they have high commercial value as ores for steel manufacture and hence are not targeted for CO_2 storage. The sedimentary rocks used for conventional CO_2 sequestration typically contain only small amounts of Ca, Mg and Fe that are not already locked in carbonate minerals, such that CO_2 mineralization provides only a minor, long-term contribution to the total CO_2 stored.

Inducing carbonate-forming reactions by injecting CO_2 into basalt and peridotite formations is an attractive storage option for three main reasons:

(1) The technology copies naturally occurring processes that have long been studied in the geological sciences.

(2) The product carbonate minerals are known to be thermodynamically stable over geological timescales and hence any mineralized CO_2 is permanently stored. It follows that once all the injected CO_2 at a given site is mineralized, further costly monitoring of CO_2 containment is unnecessary.

(3) The technology makes use of rock types that are different from those used in conventional geological CO_2 storage in saline sedimentary aquifers. Hence, it opens up new onshore and offshore geological settings, which may enable more countries to undertake geological storage and which significantly increases the rock volume potentially available globally for CO_2 storage.

2.2. Target rocks for in-situ CO_2 mineralization

To aid understanding of the basalt and peridotite raw materials currently targeted for in-situ carbonation, it is helpful to distinguish the terms rock, mineral, mineraloid and crystal. **Rocks** are natural aggregates of solid grains, typically of one or more minerals. Each **mineral** consists of a specific set of chemical elements bonded together in a rigid, three-dimensional crystalline lattice structure. Individual grains of minerals are termed **crystals**. Some rocks contain non-crystalline solids, such as volcanic glass or coal. Volcanic glass contains a variable assortment of chemical elements in an unordered (amorphous) structure, for which it is technically termed a **mineraloid**. The amorphous nature of mineraloids makes them less stable and hence more chemically reactive than the crystalline minerals. Minerals and mineraloids are the solid thermodynamic phases that participate in carbonation reactions. A given mineral in a rock usually occurs as a vast number of separate crystals (typically ~ 1 mm in diameter), each with identical elemental composition and lattice structure. To facilitate discussion of the huge variety of rocks in the Earth, each scientific rock name denotes an aggregate of a characteristic set of minerals occurring as crystals in characteristic sizes, shapes and spatial distributions.

2.2.1 Basalt

The volcanic rock **basalt** is a major target for CO_2 mineralization owing to its global occurrence and its high contents of the potentially carbonate-forming elements Ca, Mg and Fe (Table 1). Basalt is found in many countries worldwide and it also makes up the top ~2 km of the seafloor beneath the world's oceans. Basalt contains crystals of the silicate minerals **olivine** ($(Mg,Fe)_2SiO_4$), **plagioclase-feldspar** ($(Na,Ca)Al_2Si_2O_8$), and a member of the **pyroxene** group, the **clinopyroxene** species **augite** ($Ca(Mg,Fe)Si_2O_6$). In addition, basalt may contain **volcanic glass** (Table 2). Basalts with the same overall chemical composition may vary from purely crystalline through all intermediate mixtures to purely glass. Basalt is one of numerous dark coloured, Mg- and Fe-rich rocks that are collectively called **mafic** (a term composed from letters in the adjectives magnesian and ferric).

Some basalts contain abundant pore spaces inherited from the formation of gas bubbles during solidification of the parent lava. These pores are usually connected to each other, such that the rock matrix is intimately permeable to water and CO_2. Thus, in nature, all the pore spaces in basalt, and indeed all the pore spaces in all other rocks in the Earth's crust, are filled (saturated) with some kind of fluid phase, typically saline water. Other basalts have been so rapidly chilled and fragmented during their eruption into seawater, lake water or under glaciers, that they consist dominantly of fine glass shards, for which these variably permeable rocks are termed **hyaloclastite**. Still other basalts are massive and crystalline with very low porosities and with impermeable rock matrices. In these cases, infiltration and reaction of CO_2 can occur only along fractures in the basalt.

Table 1. Examples of typical chemical compositions of unaltered basalt and peridotite, expressed as element oxides in mass%.

	SiO_2	TiO_2	Al_2O_3	FeO	Fe_2O_3	MgO	CaO	Na_2O	K_2O
Basalt	50.2	1.3	15.7	8.7	1.8	7.84	11.7	2.5	0.1
Peridotite	44.5	0.1	2.8	1.2	7.4	41.3	2.5	0.2	0.04

Table 2. Typical contents of main reactive minerals and glass in basalt and serpentinized peridotite, expressed as volume fractions (vol.%).

	Olivine	Clino-pyroxene	Plagioclase feldspar	Volcanic glass	Ortho-pyroxene	Serpentine
Basalt	0–15	20–35	50–65	0–100	0-10	0
Peridotite	50–100	0–20	<10	0	0–35	0–100

As high rock-matrix permeability is often a primary feature of basalts, many of them have been infiltrated during their geological past by warm, solute-bearing groundwaters. Chemical reactions with such groundwaters have often replaced some or all of the original volcanic minerals and glass by other minerals through a process termed **secondary alteration**. The resulting **alteration minerals**, also termed **hydrothermal alteration minerals** or **metamorphic minerals**, are mostly silicates, including zeolites, clays, chlorite, epidote, albite, quartz and amphibole. Importantly, various carbonate minerals may also form during such natural alteration and should not be confused with those formed by purposefully injecting CO_2.

Owing to their above-mentioned mineralogical and geological complexity, basalt target rocks are variously described in the literature on in-situ CO_2 mineralization as “basalt” or “altered basalt” or “mafic rocks”.

2.2.2. Peridotite

The second main target rock for CO_2 mineralization is **peridotite**, which makes up the Earth’s mantle. Past tectonic processes have occasionally thrust blocks of mantle peridotite into the crust of the Earth, and in some localities around the world, subsequent tectonic uplift and erosion has now exposed peridotite at the Earth’s surface, both on land (most famously in Oman/UAE) and occasionally on the seafloor.

Peridotite is composed dominantly of crystals of the minerals olivine and a Ca-free member of the pyroxene group, the **orthopyroxene** species **enstatite** ($(Mg,Fe)SiO_3$). Minor clinopyroxene may also be present (Table 2). As reflected in its mineral content, peridotite contains much less Ca, Al, Si and Fe than basalt, but much more Mg (Table 1). Peridotite is one of the extremely dark coloured, Mg-rich rocks collectively termed **ultramafic**.

Like the primary minerals in basalt, the primary Mg-rich olivine and Mg-rich pyroxene minerals in peridotite are not stable over long periods in the presence of water at temperatures below about 400 °C. Although the rock matrix of peridotite is impermeable, peridotite bodies are typically fractured due to deformation that accompanied their tectonic emplacement. Groundwater or seawater continually circulates through such fracture networks in the upper part of Earth’s crust, such that most known occurrences of peridotite have undergone a history of slow reaction with water along their way to the

Earth's surface. During this hydration process, part or all of the original olivine and orthopyroxene crystals have been converted to the minerals of the **serpentine** group ($Mg_3Si_2O_5(OH)_4$), accompanied by minor magnetite (Fe_3O_4) and brucite ($Mg(OH)_2$). The intensity of this secondary mineral alteration typically varies from place to place, even within the same peridotite body, producing variably altered rocks termed **serpentinized peridotite**.

The serpentine mineral group comprises three main structural variants named **lizardite**, **chrysotile** and **antigorite**. A peculiarity of all these minerals is that they have much larger molar volumes than their olivine and orthopyroxene precursors. Consequently, the fractures through which water penetrates into peridotite often become clogged by the volume expansion that accompanies serpentinization. In cases where essentially all the original olivine and pyroxene have been hydrated by repeated fracturing and chemical reaction events, the resulting rock is termed **serpentinite**. The chemical composition of serpentinites is virtually the same as that of the precursor peridotite, with the addition of 12–16 wt.% H_2O bound within the lattices of the serpentine crystals.

Owing to their above-mentioned mineralogical and geological complexity, peridotite target rocks are variously described in the literature on in-situ CO_2 mineralization as "peridotite" or "altered peridotite" or "serpentinized peridotite" or "serpentinite" or "ultramafic" rocks.

2.3. Reservoir properties and responses to fluid injection

Onshore basalt and its mineralogically altered equivalents occur worldwide in many localities in the subsurface as layered formations from a few meters to hundreds of meters thick and from several kilometers to thousands of kilometers in lateral extent. Relevant onshore peridotite bodies may be as small as a few km^3, or as large as the 5–7 km thick, 550 x 70 km mass of serpentinized peridotite in Oman–UAE.

Whereas the rock matrix of basalts can be both porous and permeable, the rock matrix of peridotites and serpentinized peridotites is normally non-porous and impermeable. However, both kinds of rock formations are commonly dissected by fracture networks that render the formations permeable to water and CO_2, irrespective of the rock matrix properties. If the porosity and permeability of a formation are large enough to allow fluids to be injected and extracted through wells equipped with pumps, then the formation can be referred to as an **aquifer**. As mentioned above, all porous rocks deeper than a few tens of meters are saturated with one or more fluid phases (water, oil, gas). The fluids may be stagnant or naturally flowing under regional-scale hydraulic gradients (flow rates are often in the order of 0.1 to a few metres per year). Onshore aquifers at depths of less than ~200 m typically contain fresh water. Deep natural aquifers (including those in sedimentary rocks) are typically saturated in salty water, hence they are referred to as **saline aquifers**, regardless of the type of rock in which they reside. Host rocks can be distinguished where necessary by the terms sedimentary aquifer, sandstone aquifer, limestone aquifer, basalt aquifer, peridotite aquifer, and so on. Thus, the term "saline aquifer" does not apply uniquely to sedimentary formations.

If an aquifer is exploited or intended to be exploited for any energy-related purpose (e.g., extraction of natural gas, oil, heat, or injection of wastewater, CO_2 or H_2) it is termed a **reservoir**. The total porosity of a reservoir (the sum of the porosities of the rock matrix and any fractures) determines how much fluid it can store. For commercially efficient storage of water or CO_2, the total porosity of the reservoir typically needs to be greater than 10 vol.%, and the total permeability (the sum of the permeabilities of the rock-matrix and any fractures) needs to be greater than approximately 10^{-14} m^2 (equivalent to 10 millidarcy, symbolized md or mD). The actual values of porosities and permeabilities of reservoirs vary greatly and often unpredictably from one formation to another and even within individual formations. Rock-matrix and fracture porosities are usually determined by analysing drill core or wellbore images, or from geophysical signals obtained by lowering measurement instruments into wells ("geophysical logging" or “wireline logging”). Reservoir permeabilities are determined by fluid injection or production tests through wells.

The measurable fluid pressure in shallow aquifers is often equal to the weight of a water column that extends to the Earth’s surface, attesting to the connectivity of pore spaces throughout thick stacks of rocks. This **hydrostatic pressure** rises at the rate of approximately 10 MPa per km of depth, depending on the salinity and temperature of the pore waters. With increasing depth, the hydraulic connection to the Earth’s surface diminishes as pores begin to close owing to the increasing pressure exerted by the rock overburden. Thus, fluid pressures in very deep aquifers exceed the hydrostatic gradient, approaching the **lithostatic pressure** (rock overburden pressure). The lithostatic pressure gradient varies from ~22 to 30 MPa/km, according to the densities of the overlying rock types.

Injection of aqueous CO_2 (i.e., CO_2 pre-dissolved in water) or free-phase CO_2 into a basalt or serpentinized peridotite aquifer, with the intent of driving carbonation reactions, must be conducted at pressures that exceed the natural fluid pressure at the base of the injection well. Pre-existing (“native”) groundwater must be pushed away from the injection well to make space for the free-phase CO_2 or the aqueous CO_2 solution. The actual pressure needed to achieve injection depends not just on the static fluid pressure in the reservoir but also on the permeability of the reservoir (low permeability requires higher pressures). This pressure is typically site-specific and can be derived by hydraulic testing through a well. The volumetric rate of fluid injection (Q) divided by the excess pressure ($P_{\text{well bottom}} - P_{\text{reservoir}}$) required to achieve that rate is defined as the **injectivity index** (I):

$$I = Q / (P_{\text{well bottom}} - P_{\text{reservoir}}) \quad [\text{m}^3\ \text{s}^{-1}\ \text{MPa}^{-1}] \tag{1}$$

where $P_{\text{well bottom}}$ is the bottom-hole flowing pressure in the injection well. Upon prolonged injection, the added mass of fluid raises the backpressure in the reservoir, often leading to reductions in injectivity.

The injectivity of wells can often be increased by **hydraulic stimulation** of the surrounding rocks. Injecting water at elevated pressures can cause narrow, pre-existing fractures to widen, thereby enhancing their permeability. Injecting water at even higher pressures can induce new fractures to form in rocks that have low matrix permeability, via the process known as **hydrofracturing** (also informally termed “hydrofracking”). For example, injection tests in serpentinized peridotite have shown that these rocks may have critically low natural permeability at depths greater than a few hundred meters, owing to the almost complete sealing of fractures by serpentine. However, as serpentine is a weak, platy mineral, the sealed fractures can be readily re-fractured and opened to fluid flow. The pressure required for this stimulation is determined by raising the injection pressure step-wise and monitoring the resulting changes in reservoir pressure and injectivity. This approach is used in the ongoing Fujairah (UAE) project to achieve a useful level of permeability without generating perceptible seismicity (Section 5.6.5). Fractures in basalt that are sealed by other hydrothermal alteration minerals may be much more difficult to open and may require higher injection pressures.

In a reservoir formation that is under elevated tectonic stress in addition to simple overburden stress (a common situation), raising the internal fluid pressure by injecting large amounts of fluid may cause pre-existing, stressed faults to slip and possibly release seismic energy as **induced earthquakes**. One a-priori aid to detect faults is to conduct surface seismic surveys over large areas around the planned injection point. However, steep faults are often hard to detect and it is difficult to distinguish a potentially leaky fault from one that is impermeable because it is sealed by a filling of clay or finely ground rock. The local history of natural seismicity can indicate the locations and activity of faults, and regional studies of the orientations of tectonic stresses relative to those of known faults can help identify the risks of both natural and induced earthquakes (see Section 2.8 for details of seismic risks and mitigation strategies).

A further consequence of the increase in reservoir fluid pressure due to prolonged injection is that the storage capacity of fluid in the reservoir can be exceeded and either native groundwater or the injected fluid may be expelled from the reservoir through fractures or faults into overlying rock formations, including perhaps into other overlying aquifers. To avoid such fluid **leakage**, the stress state, fluid capacity and hydrogeology of the reservoir and its surroundings need to be well understood prior to beginning injection by conducting thorough site characterisations and numerical simulations of the reservoir response. This allows leakage risks to be assessed and potential sites to be discarded or accepted for implementation. For sites that pass these feasibility tests, injection rates can be carefully planned so that the reservoir fluid pressure is maintained below the danger threshold. This operational strategy is termed **pressure management**, and it has been developed by commercial companies over many decades for enhanced oil recovery, refilling of seasonal gas reservoirs, wastewater disposal and conventional CO_2 storage. The success of this approach for conventional CO_2 storage is demonstrated by its 30-year record: to date, no fluid leakage has occurred for geological (subsurface integrity) reasons at the more than 50 full-scale commercial sites implementing that technology (IEAGHG, 2025a).

2.4. CO_2 injection approaches for in-situ mineralization

2.4.1 Constraints on CO_2 injection modes

Considering the properties and possible responses of the target reservoirs, several principles guide the choice of CO_2 injection approaches for in-situ mineralization projects. The first is that **carbonation reactions will occur only if CO_2 is dissolved in water**. The aim is therefore to force CO_2-bearing water into contact with as high a volume of reactive rock as possible, in order to generate as much new carbonate as possible. Thus far, two main injection modes have been employed to achieve this aim, depending on the geological architecture of the storage site, as described in the following.

In principle, the desired aqueous form of CO_2 can be generated within the reservoir by injecting dry, free-phase CO_2 at a rate low enough that it dissolves completely into the native groundwater. Dissolution of CO_2 increases the density of the groundwater slightly (typically by a few percent), but even this small difference is significant for the dynamics of fluid flow in the reservoir. Over periods of decades, CO_2-enriched groundwater tends to sink to the bottom of the reservoir, displacing the native CO_2-poorer groundwater towards the top. An advantage of this **negative buoyancy** for CO_2 storage is that the **CO_2-enriched groundwater has no spontaneous tendency rise through the overlying rock column and potentially leak into shallower aquifers or even to the Earth's surface**.

While the above approach is feasible, in practice the injection rates required to achieve immediate total dissolution are too slow to be useful for commercial storage. Deep groundwaters have a certain maximum capacity to dissolve CO_2, expressed as the **solubility of CO_2**, the value of which depends directly on pressure, inversely on salinity, and variably on temperature (solubility decreases with temperature up to approximately 175 °C, but thereafter the solubility rises with temperature; Diamond and Akinfiev, 2003; Akinfiev and Diamond, 2010). Commercially viable injection rates for free CO_2 are much higher than the rate at which CO_2 can dissolve into the groundwater within the surrounding pore network. At such high injection rates, the solubility is quickly exceeded around the injection well and bubbles of excess free CO_2 will coexist with the CO_2-saturated water. Whereas groundwater in physical contact with a free CO_2 bubble reaches saturation within minutes inside individual rock pores, the diffusion of CO_2 away from the interface is very slow, owing to the narrow and tortuous flow paths in typical pore networks. This means that even in an aquifer with steadily flowing groundwater, **free-phase CO_2 may persist for decades to millennia, before it is completely consumed by dissolution into a very large mass of groundwater**.

2.4.2 CO_2 injection into reservoirs sealed by an impermeable caprock

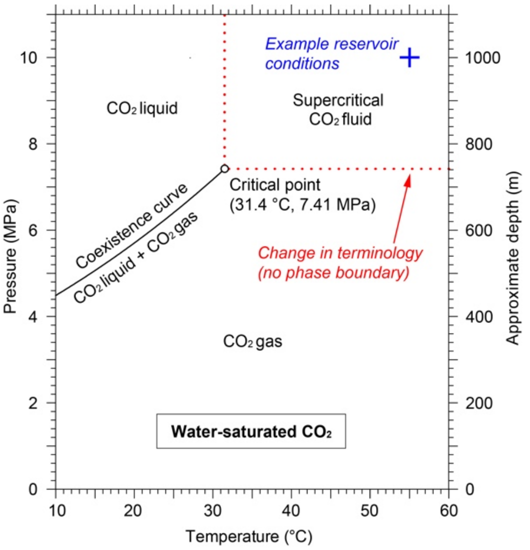
A free CO_2 phase within the reservoir is typically in the **supercritical state** (see box below for a definition of the supercritical state) rather than the gas or liquid states. It is also usually saturated with respect to the native groundwater (i.e., it contains dissolved H_2O and is thus “wet”). Both wet and dry supercritical CO_2 have much lower densities than the surrounding native groundwater (e.g., 0.3–0.8 g/cm^3 for dry CO_2 compared to 1–1.05 g/cm^3 for groundwaters). This density contrast imparts high buoyancy to the CO_2 phase and therefore its individual bubbles tend to coalesce and migrate upwards through the reservoir as a plume, displacing the groundwater. Consequently, if a storage campaign is designed to inject supercritical CO_2 at a high rate, then a laterally extensive layer of **impermeable caprock** (also termed a **seal** or an **aquitard** or a **confining layer**) must be present above the reservoir, to stop the plume from escaping and rising through the rock column towards the Earth’s surface (Figure 1A). Since the caprock is a feature of the local stratigraphy, this mechanism of confining free CO_2 within the reservoir is termed **stratigraphic trapping**. Along the migration route of the CO_2 plume, droplets of supercritical CO_2 are retained within the pore network by capillary forces, providing another CO_2 trapping mechanism termed **residual trapping**.

Suitable caprocks (claystones and salt layers) occur often in sedimentary rock sequences, but less commonly above basalt or peridotite formations. Nevertheless, sites do exist where caprocks are present above or within basalt sequences, e.g., where thick, unfractured and impermeable basalt layers act as caprocks for underlying basalt layers that have good reservoir properties. In these cases, large amounts of supercritical CO_2 can be injected and trapped within the reservoir, with the required dissolution of CO_2 into the groundwater proceeding over long periods thereafter (Figure 1A). This procedure constitutes the first of the two main injection modes applied thus far for in-situ mineralization. Examples of its use are the reviewed injection projects at Wallula and Elementeita (Chapter 5). The latter plans to alternate injections of free CO_2 and water to promote their mutual dissolution in the reservoir.

Definition of “supercritical fluid state”

The diagram on the right displays equilibrium phase relations of water-saturated CO_2 (water is stable everywhere in the diagram). CO_2 liquid and CO_2 gas are stable together at elevated pressures along the phase boundary labelled “coexistence curve”. Below 20 °C on this curve, the two phases differ strongly in all their thermodynamic properties, including density. At progressively higher temperatures on the curve, the differences between the two phases steadily decrease until at 31.4 °C and 7.41 MPa the differences vanish completely. At all conditions beyond this critical point (field bordered by red dots, open to higher pressures and temperatures) it makes no sense to use the words liquid or gas, as only one fluid phase is stable. To distinguish this state, it is termed “supercritical fluid” (in which “super” means “beyond” and “critical” refers to the “critical point”). Thus, the red dotted lines mark changes in terminology, not physical phase boundaries.

This phase behaviour is by no means unique to CO_2. All volatile substances and their mixtures exhibit critical behaviour, but the temperature and pressure conditions of their critical points vary (e.g., the critical point of H_2O is at 374 °C and 22.1 MPa; the critical point of CH_4 is at –82 °C and 4.6 MPa).



Most geological formations suitable for CO_2 storage, including reservoirs tested thus far for in-situ mineralization, are at temperature and pressure conditions within the supercritical field (e.g., blue cross at ~1 km depth and 55 °C).

The term “supercritical CO_2“ is often informally abbreviated to “scCO_2”, “sCO_2” or “$CO_{2,sc}$”.

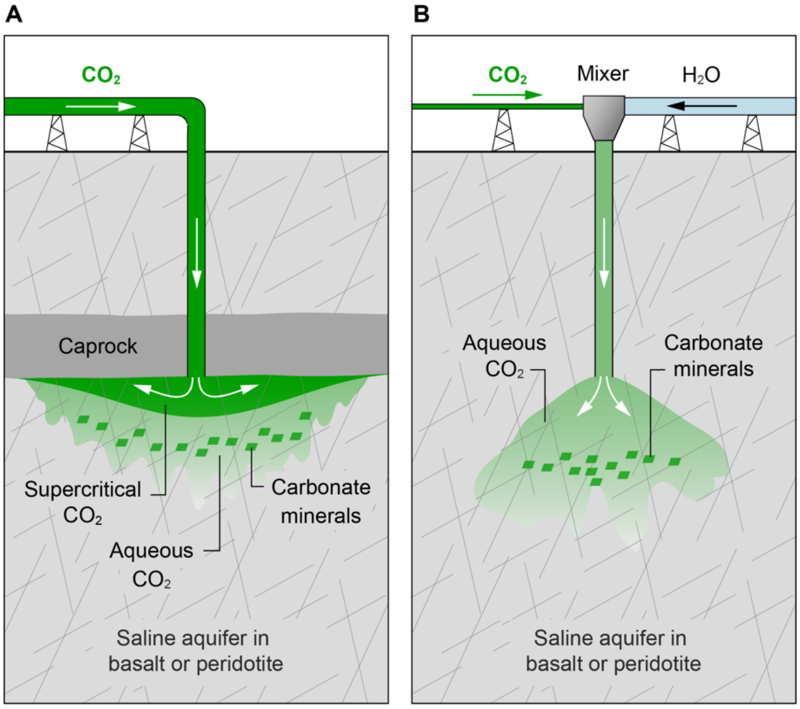


Figure 1. Schematic illustrations (not to scale) of the two main injection modes used in in-situ mineralization projects, differing by whether an impermeable caprock is present above the reservoir or not. (**A**) *Reservoir with a caprock:* supercritical CO_2 is injected through a well directly into the deep reservoir, where it forms a buoyant plume that it stratigraphically trapped by the caprock. Along the base of the plume, CO_2 slowly dissolves into the groundwater where it reacts chemically with the rock and precipitates CO_2-bearing minerals (carbonates). Example projects are Wallula (USA) and Elementeita (Kenya). (**B**) *Reservoir without a caprock:* CO_2 is pre-dissolved in large quantities of water and then injected into the deep reservoir. The aqueous CO_2 reacts chemically with the rock and precipitates carbonate minerals. Example projects are CarbFix2 (Iceland), Jizan (Saudi Arabia), Chalk (Oman) and Fujairah (UAE). Figure inspired by a diagram in Snaebjörnsdottir et al. (2020).

2.4.3 CO_2 injection into reservoirs without an impermeable caprock

The rarity of adequate caprocks associated with basalts and peridotites means that many in-situ mineralization projects must ensure, through their injection design, that no buoyant plume of supercritical CO_2 will form in the subsurface. At these sites CO_2 is injected pre-dissolved in water, at a concentration that maintains the aqueous solution in a single phase (undersaturated) state and guarantees its negative buoyancy in the reservoir. To attain this pre-dissolved state, the separate CO_2 and water feed streams at the Earth's surface are either mixed prior to pumping into the well (Figure 2B), or they are pumped into the well separately but simultaneously, such that they mix during their downward travel. In both cases, mixing must occur according to a pre-determined mass ratio that allows the CO_2 to dissolve completely into the water before it reaches the deep injection interval of the well. The requisite ratio is calculated to be slightly lower than the thermodynamic solubility of CO_2 in the saline groundwater under the pressure and temperature within the reservoir. This injection procedure is the second main mode of introducing reactive aqueous CO_2 into basalt or peridotite reservoirs. Examples of its use are the projects CarbFix2 (Iceland), Jizan (Saudi Arabia), Chalk (Oman) and Fujairah (UAE), which are reviewed in detail in Chapter 5.

The great advantage of direct injection of pre-dissolved aqueous CO_2 is that its negative buoyancy ensures that CO_2 is contained within the reservoir from the outset by the mechanism termed **solubility trapping**. By adopting this injection mode, the more common basalt and peridotite reservoirs that are unsealed by caprocks become amenable to the in-situ mineralization technology. In addition, the fact that CO_2 is already in the reactive aqueous state upon injection means that the slow step of dissolving CO_2 from a supercritical CO_2 plume into the groundwater is bypassed, leading to somewhat faster reaction of the CO_2 with the reservoir rock and hence faster mineralization. However, this mode also brings several disadvantages:

(1) As aqueous CO_2 solubility is only 3–5 wt.% at the pressures, temperatures and salinities of typical reservoirs, the mass of CO_2 that can be injected through one well per year is much less than that attainable by injecting dense supercritical CO_2 under a caprock.

(2) Large amounts of water are needed to dissolve the CO_2 prior to its entry into the reservoir. **Approximately 20 to 32 times more water is required than the mass of CO_2 stored.** For example, injecting just 100,000 t CO_2/yr requires between 2.0 and 3.2 Mt H_2O to act as the solvent. A constant supply of this water must be available in the vicinity of the site at a reasonable cost, which may compete with alternative uses of the water (e.g., for agriculture). Sites near a coast may take advantage of seawater for this purpose, though its high salinity reduces the solubility of CO_2 compared to freshwater, and seawater corrodes surface infrastructure and well casings, raising maintenance costs. Seawater has been tested in the CO2SeaStone and other pilot projects in Iceland (Sections 2.9 and 5.1.6) and in the Fujairah project in Oman (Section 5.6.6). For inland projects, extraction of saline groundwater from another reservoir above or below the target storage reservoir may be an option to obtain the required solvent water for injection. This is the method planned for the Elementeita injection pilot in Kenya (Section 5.4.6). Alternatively, it may be possible to pump the required water out of a second distant well (production well) drilled into the storage reservoir itself. This is the method used in the CarbFix2 operation in Iceland (Section 5.1.6) and in the Jizan pilot project in Saudi Arabia (Section 5.3.1). However, the method may be counter-productive in the long term. The drop in groundwater pressure at the base of the production well induces a hydraulic gradient that attracts flow of the CO_2-bearing water from the injection well, potentially leading to a short circuit and unwanted extraction of some of the injected CO_2.

(3) Injecting large amounts of incompressible water into a reservoir over long periods raises the reservoir pressure much more than injecting free CO_2, which is highly compressible. As outlined in Section 2.3, this in turn raises the risks of trigging slip on naturally stressed faults and thereby inducing felt earthquakes, and also of causing leakage of the injected solution from the reservoir via flow through faults. If leakage occurs upwards into the overlying rocks, the associated reduction in pressure at shallow depths may induce degassing of the aqueous solution and exsolution of a mobile, free CO_2 phase.

2.5. Stability of carbonate minerals formed by in-situ CO_2 mineralization

Given that only carbonate minerals incorporating Ca, Mg and Fe cations are relevant to CO_2 storage (Section 2.1), the thermodynamically stable carbonate species of interest are **calcite** ($CaCO_3$), **dolomite** ($CaMg(CO_3)_2$), **ankerite** ($Ca(Mg,Fe)(CO_3)_2$), and Mg–Fe carbonates ($(Mg,Fe)CO_3$). The latter can be expressed as mixtures (solid-solutions) of the endmembers **magnesite** ($MgCO_3$) and **siderite** ($FeCO_3$).

Siderite is prone to decomposition in surficial, air-saturated water, whereby Fe^{2+} in its structure is oxidized to Fe^{3+}, releasing the bound CO_2. However, siderite is completely stable in contact with water that contains no molecular oxygen, which is typical of groundwaters in the pores of rocks at depths below 200 m. In contrast, calcite, dolomite and magnesite are chemically stable over millions of years in both the surficial and deep crustal environments, as attested to by the abundance of limestone and other carbonate rocks at the Earth's surface. In Switzerland, for example, the entire Jura mountain chain and a significant fraction of the Alps are composed of carbonate rocks. Calcite does dissolve very slightly in surface water and in groundwaters (e.g., locally forming caves), but the amount of CO_2 released by this process is absolutely negligible compared to the amount of CO_2 retained in the rocks.

Although dolomite is perfectly stable from a thermodynamic standpoint, its formation by abiotic carbonation of basalt or serpentinized peridotite is kinetically inhibited, resulting in almost no formation of dolomite by in-situ mineralization below approximately 100 °C. Magnesite also normally fails to nucleate and grow from aqueous solution at temperatures below 80 °C. Consequently, in-situ CO_2 mineralization projects that have targeted rocks at low temperatures have found that the initial reaction products are calcite and other metastable carbonates, such as nesquehonite ($MgCO_3 \cdot 3H_2O$), hydromagnesite ($Mg_5(CO_3)_4(OH)_2 \cdot 4H_2O$) or aragonite (which has the same $CaCO_3$ formula as calcite but a different crystal lattice structure), or even amorphous carbonates. The hydrated carbonates such as hydromagnesite fix CO_2 over timescales of tens of thousands of years, as observed in natural wetlands. In the longer term, these highly metastable carbonates transform to calcite and magnesite.

2.6. Carbonation reactions

2.6.1. Reaction stoichiometries

To provide an understanding of the key carbonation processes involved in the in-situ mineralization technology, simplified chemical reactions are presented below. They describe the formation of example carbonates from the main minerals in basalt and serpentinized peridotite upon reaction with aqueous CO_2. As mentioned above, metastable precursor minerals may form at low temperatures in nature instead of the stable carbonate and silicate products shown in the reactions. In the following equations, arrows pointing to the right denote spontaneous reactions that are thermodynamically favoured. The description here refers only to the stoichiometry of the reactions (*relative* proportions of reactants and products), whereas their rates are discussed in the subsequent section. Note that, in the geological environment, the abundance ratio of reactants does not match the stoichiometric ratio. This means that if the least abundant reactant is entirely consumed and the reaction stops, one or more of the other reactants remains present in excess in the reservoir.

Regardless of which CO_2 injection mode is employed (Figure 1 and Section 2.5), as soon as CO_2 dissolves in water it forms a certain amount of carbonic acid (H_2CO_3, Eq. 2). Some of this acid spontaneously dissociates to bicarbonate and protons (symbolized as H^+ but actually present as hydronium ions in solution, H_3O^+), thereby generating acidity (Eq. 3):

$$\underset{\text{Mutual dissolution before injection or in reservoir}}{CO_2 + H_2O} \rightarrow \underset{\text{Dissolved carbonic acid}}{H_2CO_{3(aq)}} \tag{2}$$

$$\underset{\text{Dissolved carbonic acid}}{H_2CO_{3(aq)}} \rightarrow \underset{\text{Protons}}{H^+_{(aq)}} + \underset{\text{Aqueous bicarbonate}}{HCO^-_{3(aq)}} \tag{3}$$

Thus, the carbonic acid solution entering the reservoir rock initially has a pH of 3.5–4.5, according to the exact CO_2/H_2O ratio at the fluid pressure and temperature in the injection interval of the well. This acidity is sufficient to rapidly dissolve any pre-existing ("native") carbonate minerals near the injection well (e.g., calcite, Eq. 4), which is obviously counterproductive for storing CO_2:

$$\underset{\text{Protons}}{H^+_{(aq)}} + \underset{\substack{\text{Crystalline}\\ \text{calcite}}}{CaCO_3} \rightarrow \underset{\text{Dissolved aq. species}}{Ca^{2+}_{(aq)} + HCO^-_{3(aq)}} \tag{4}$$

Once the amount of injected carbonic acid exceeds that consumed by dissolution of any pre-existing carbonate minerals, the injected fluid retains its low pH because the other rock-forming minerals react only slowly. The native groundwaters in chemical equilibrium with deep-seated basalts or serpentinized peridotites typically have basic pH values above 7 (i.e., up to 10 in basalts and up to 11 in peridotites, depending on temperature). As the injected acid is far from being in chemical equilibrium with the reservoir rock, the released protons undergo spontaneous hydrolysis reactions with the main constituent minerals, such as clinopyroxene (Eq. 5). The result is that the critical cations that form carbonate minerals – Ca, Mg and Fe – are leached from the rock-forming minerals and transferred to the aqueous solution (Eq. 5):

$$\underset{\text{Clinopyroxene}}{Ca(Mg_{0.8}Fe_{0.2})Si_2O_6} + \underset{\text{Protons}}{4H^+_{(aq)}} \rightarrow \underset{\text{Dissolved aq. species}}{Ca^{2+}_{(aq)} + 0.8Mg^{2+}_{(aq)} + 0.2Fe^{2+}_{(aq)} + 2SiO_{2(aq)} + 2H_2O} \tag{5}$$

The consumption of protons shows that reaction 5 tends to neutralize pH or even drive it to alkaline values, since the amounts of reactant minerals in the reservoir rocks are inexhaustible in practice (i.e., they are present in excess). As pH rises, some of the bicarbonate ion in turn dissociates to the aqueous carbonate ion (Eq. 6):

$$\underset{\text{Aqueous bicarbonate}}{HCO_3^-{}_{(aq)}} \rightarrow \underset{\text{Proton}}{H^+_{(aq)}} + \underset{\text{Aqueous carbonate ion}}{CO_3^{2-}{}_{(aq)}} \tag{6}$$

The cations released from the reactant mineral (Eq. 5) typically remain in solution for some time and may be swept away from the reaction site owing to the hydraulic gradient imposed by the injection pressure, or to the natural movement of the groundwater in the reservoir. However, as soon as the local concentrations of dissolved cations and bicarbonate/carbonate ions rise to critical levels of supersaturation, they combine to precipitate crystalline carbonate minerals. Equations 7 and 8 show examples of the formation of calcite and magnesite–siderite mixed minerals, accompanied by release of protons. Aqueous silica released via reaction 4 may also precipitate as amorphous silica (or at higher temperatures as cryptocrystalline chalcedony, SiO_2) independently of the carbonation reactions (Eq. 9).

$$\underset{\text{Dissolved aq. species}}{Ca^{2+}_{(aq)} + HCO_3^-{}_{(aq)}} \rightarrow \underset{\text{Proton}}{H^+_{(aq)}} + \underset{\text{Crystalline calcite}}{CaCO_3} \tag{7}$$

$$\underset{\text{Dissolved aq. species}}{Mg^{2+}_{(aq)} + Fe^{2+}_{(aq)} + 2HCO_3^-{}_{(aq)}} \rightarrow \underset{\text{Proton}}{2H^+_{(aq)}} + \underset{\text{Crystalline magnesite–siderite solid solution}}{(Mg,Fe)CO_3} \tag{8}$$

$$\underset{\text{Dissolved aq. species}}{SiO_{2(aq)}} \rightarrow \underset{\text{Solid amorphous silica}}{SiO_2} \tag{9}$$

Thus, Eqs. 2–9 show the chain of individual reactions that lead to in-situ carbonation of clinopyroxene. The overall reaction can be summarized as in Eq. 10, where the intermediate reactions are omitted and the symbol $CO_{2(aq)}$ represents all the dissolved species of CO_2 (excess H_2O molecules do not need to be considered). Analogous net reactions for carbonation of the other main minerals and glass in basalt are given in Eqs. 11–13. In the case of plagioclase and glass reactants, which contain insoluble aluminium (Eqs. 12 and 13), a clay mineral (e.g., kaolinite or a more complicated smectite mineral) may form as the product. As smectites lock Ca, Mg and Fe strongly within their crystal lattices, aluminium-rich rocks tend to have less free cations available for carbonation.

$$\underset{\text{Clinopyroxene}}{Ca(Mg_{0.8}Fe_{0.2})Si_2O_6} + \underset{\text{Dissolved}}{2CO_{2(aq)}} \rightarrow \underset{\substack{\text{Crystalline}\\ \text{calcite}}}{CaCO_3} + \underset{\substack{\text{Crystalline}\\ \text{magnesite–siderite}}}{(Mg_{0.8}Fe_{0.2})CO_3} + \underset{\substack{\text{Solid}\\ \text{amorph. silica}}}{2SiO_2} \tag{10}$$

$$\underset{\text{Olivine}}{(Mg_{0.9}Fe_{0.1})_2SiO_4} + \underset{\text{Dissolved}}{2CO_{2(aq)}} \rightarrow \underset{\substack{\text{Crystalline}\\ \text{magnesite–siderite}}}{2(Mg_{0.9}Fe_{0.1})CO_3} + \underset{\substack{\text{Solid}\\ \text{amorph. silica}}}{SiO_2} \tag{11}$$

$$\underset{\substack{\text{Plagioclase}\\ \text{feldspar}}}{CaAl_2Si_2O_8} + \underset{\text{Dissolved}}{CO_{2(aq)}} + 2H_2O \rightarrow \underset{\substack{\text{Crystalline}\\ \text{calcite}}}{CaCO_3} + \underset{\substack{\text{Crystalline}\\ \text{kaolinite}}}{Al_2Si_2O_5(OH)_4} \tag{12}$$

$$\underset{\text{Amorphous basaltic glass}}{Si_{0.55}Al_{0.2}Mg_{0.13}Fe_{0.08}Ca_{0.14}O_{1.76}} + \underset{\text{Dissolved}}{0.35CO_{2(aq)}} + 0.2H_2O \rightarrow \underset{\text{Crystalline calcite}}{0.14CaCO_3} + \underset{\text{Crystalline magnesite–siderite}}{0.21(Mg_{0.62}Fe_{0.38})CO_3} + \underset{\text{Solid amorph. silica}}{0.35SiO_2} + \underset{\text{Crystalline kaolinite}}{0.1Al_2Si_2O_5(OH)_4} \tag{13}$$

Equations 14 and 15 show the carbonation of orthopyroxene and serpentine, which along with olivine and clinopyroxene make up the bulk of serpentinized peridotites.

$$\underset{\text{Orthopyroxene}}{(Mg_{0.8}Fe_{0.2})SiO_3} + \underset{\text{Dissolved}}{CO_{2(aq)}} \rightarrow \underset{\text{Crystalline magnesite–siderite}}{(Mg_{0.8}Fe_{0.2})CO_3} + \underset{\text{Solid amorph. silica}}{SiO_2} \tag{14}$$

$$\underset{\text{Serpentine}}{Mg_3Si_2O_5(OH)_4} + \underset{\text{Dissolved}}{3CO_{2(aq)}} \rightarrow \underset{\text{Crystalline Magnesite}}{3MgCO_3} + \underset{\text{Solid amorph. silica}}{2SiO_2} + 2H_2O \tag{15}$$

An obvious method to confirm that the above reactions actually occur in in-situ mineralization reservoirs is to examine drill cores extracted from the expected regions of carbonate precipitation. Unfortunately, flow paths in the reservoirs cannot be predicted yet with the spatial precision required to ensure success of sampling by drilling and coring, which by nature is a costly operation. Consequently, carbonate minerals formed by CO_2 injection have been identified at only one site to date, from the wall of the injection well at the Wallula project (Lahiri et al., 2023; Section 5.2.8; note that, in the famous photographs on the internet showing basalt cores retrieved from the CarbFix site in Iceland, the calcite that fills pores in those images is of natural origin, having formed long before the CO_2 injection campaign began). Given this practical difficulty in recovering the reaction products, other indirect methods are used to verify that carbonate has precipitated, as described further below.

Recent experimental work suggests that reactions similar to those above can also occur when H_2O condenses from wet supercritical CO_2 and forms ultra-thin layers of CO_2-bearing water on mineral surfaces (e.g., Schaef et al., 2013; Abdolhosseini Qomi et al., 2022). Some mineral carbonation may therefore occur in the region of the reservoir occupied by the CO_2 plume, but the quantitative effect of this mechanism in commercial-scale storage projects is yet be demonstrated.

2.6.2 Reaction kinetics

The foregoing section breaks down the chemical reactions leading to in-situ mineralization into several steps. Among these, the dissolution of CO_2 into water (Eq. 2), the dissolution of pre-existing carbonate minerals (e.g., Eq. 4) and the precipitation of calcite (e.g. Eqs. 8 and 9) all run quickly (within minutes to hours) in laboratory experiments that are initially far from equilibrium. In the reservoir environment, reactions involving large quantities of dissolved reactants may take much longer, owing to the complex geometries of the pore network that retard mass transport (Section 2.4) and to the variability of saturation states. Nevertheless, the reactions enumerated above are likely to be the fastest in the overall chain of reaction steps. Magnesite precipitation is kinetically hindered at temperatures below approximately 80 °C (Saldi et al., 2009), and so other metastable hydrated Mg-carbonates take its place as reaction products. By comparison, dissolution of the Ca-, Mg- and Fe-bearing silicate minerals and glass that make up the bulk of the reservoir rocks (e.g. Eq. 6) is very slow. Thus, dissolution of the minerals that provide the key aqueous cations for carbonation is often the rate-limiting step in in-situ mineralization (Gíslason et al., 2010).

Laboratory experiments, many performed specifically to better understand in-situ mineralization, have quantified the dissolution rates of volcanic glass and of the most important rock-forming minerals in basalt and serpentinized peridotite, including their dependency on solution composition, saturation state, temperature, pH and normalized reactive surface area exposed to the pore fluid (e.g., Heřmanská et al., 2022, 2023; Oelkers and Addassi, 2025). The rates are consistent with experiments in which powdered rock samples are induced to react with water at the pH values typical of carbonic acid. The results show that glassy and crystalline basalts dissolve at up to 100 times faster than altered basalts at ambient temperatures, and up to 1000 times faster at elevated temperature (120 °C) (Delerce et al 2023a, 2023b). The mineral dissolution rates are readily integrated into reactive-transport simulations, but their application to reliably predict processes in real reservoirs is complicated by (i) the natural variability of reactive mineral surface areas and their evolution during reaction with $CO_{2(aq)}$, and (ii) the detailed dynamics and local composition of the moving pore fluid. Similar complications apply to predicting mineral precipitation rates. Consequently, emphasis is currently placed on empirical field observations of short-term carbonation rates in the reservoirs, with which the numerical simulations can be later calibrated to predict the long-term behaviour of the site.

Mineral carbonation rates within the reservoirs have been determined empirically by co-injecting non-reactive and non-adsorbing chemical tracers dissolved in the CO_2-bearing water at known concentrations. These are mostly chemical substances that do not occur in natural geological environments (e.g. fluorescein, SF_6, $SFCF_3$), or which are present in nature only in tiny concentrations (e.g., bromide). After waiting for a certain incubation time (e.g., months) to allow carbonation reactions to occur in the reservoir, the fluid is sampled either in an observation well or by pumping back into the injection well. Any observed reduction in the tracer concentrations is ascribed to mixing between the injected solution and the native groundwater in the reservoir. Once corrected for such mixing, any observed drops in aqueous CO_2, Ca and Mg concentrations compared to the initial values are interpreted to indicate carbonate precipitation, even though the precipitated minerals themselves can rarely be observed. Based on these changes in ion concentrations, the fraction of mineralized CO_2 can be calculated by mass balance.

In addition to analysing the concentration of the main aqueous solutes in the reservoir fluid, such as aqueous CO_2, Ca and Mg, isotopes of these elements can also be used to monitor the progress of carbonation reactions. For example, since the industrially-sourced CO_2 that is supplied for injection typically has a very different origin from any native CO_2 already in the reservoir, the stable isotope signature of carbon ($\delta^{13}C$) in solution can be used to trace the concentration of injected CO_2 versus total CO_2. The behaviour of all these tracers is well known in the Earth sciences through decades of research including hydrological groundwater testing.

Table 3 lists the empirical carbonation rates determined with the above technique in the in-situ mineralization projects reviewed in Chapter 5 below. In the one high-temperature, high-tonnage project conducted to date (CarbFix2), 60% of the injected CO_2 was mineralized within just 4 months, as expected from the reservoir temperature above 250 °C. All the other sites have tested low-temperature reservoirs at 20–45 °C. The three sites in basalts yielded variable carbonation rates, despite their similar temperatures, presumably reflecting differences in properties of the specific reservoir rocks (e.g., content of glass and alteration minerals, surface areas of reactive minerals, tortuosity of flow paths and rate of fluid migration). Nevertheless, all three prove that a large fraction of the injected CO_2 is mineralized within two years. Two rates are shown in Table 3 for the low-temperature CarbFix site, reflecting results obtained by using different tracers (Section 2.6.2).

The only site tested thus far in serpentinized peridotite (Chalk, Oman) suggests significantly faster reactions at only 35 °C, with almost 90% of the injected CO_2 mineralized within just 1.5 months (Table 3). Note, however, that a total of only 44 $kgCO_2$ was injected in that project, making the observations susceptible to processes that may compete with carbonate precipitation, such as CO_2 reduction by hydrogen or CO_2 accumulation in labile biomass blooms near the injection well (Section 5.5.11). The applicability of the derived carbonation rate to storage of higher tonnages has not yet been verified.

While the carbonation rates in Table 3 are positive demonstrations of in-situ mineralization, it is still not clear how much time is required to achieve 100% carbonation of the injected CO_2, particularly when commercial quantities of CO_2 are injected. The reaction rates may not be linear in time and hence extrapolations to completion may not be reliable.

Table 3. Rates of in-situ CO_2 mineralization estimated from tests using geochemical tracers in storage reservoirs.

Project	Reservoir rock	Reservoir temperature	Mineralized fraction of injected CO_2	Time to attain mineralized fraction	Reference
High temperature projects					
CarbFix2 (Iceland)	Glassy basalt	> 250 °C	60%	4 months	Clark et al., 2020
Low temperature projects					
CarbFix (Iceland)	Glassy basalt	20–33 °C	95%*	24 months	Matter et al., 2016
			72% ± 5%*	24 months	Pogge von Strandmann et al., 2019
Wallula (USA)	Basalt	36 °C	60%	24 months	McGrail et al., 2017
Jizan (Saudi Arabia)	Altered basalt	45 °C	70%	10 months	Oelkers et al. 2025
Chalk (Oman)	Serpentinized peridotite	35 °C	88%*	1.5 months*	Matter et al. 2025b

* The two different carbonation rates for the same site and same injection test arise from use of different tracers (Section 2.6.2).

** Only 44 kg of CO_2 were injected in the Chalk project and the results may have been affected by CO_2 removal processes other than carbonation (Section 2.6.2). The applicability of the reported rate to larger scale CO_2 injection is yet to be demonstrated.

2.6.3. Pore clogging and mineral passivation

Owing to the high molar volume of carbonate minerals, the solid products of all the carbonation reactions in Section 2.6.1 fill more volume than the reactants. Hence, as increasing amounts of new carbonate form, the pore spaces in the rock matrix and in the fractures are expected to become clogged, reducing permeability. At the beginning of the CarbFix project (Section 5.1), it was anticipated that such clogging around the base of the injection well would severely reduce injectivity and shorten the useful lifetime of the injection site. However, it is an interesting fact that this potential issue has not be encountered during the first 10 years of CarbFix injections or during any other of the much shorter in-situ mineralization projects. At least in the short term (decades), the new carbonate minerals apparently precipitate at some distance downstream from the site where the volcanic glass or silicate minerals in the host rocks first dissolve and release their Ca, Mg and Fe cations. This behaviour is in accord with the delayed kinetics of the mineral dissolution reactions (Section 2.6.2), which additionally neutralize the carbonic acid and facilitate the precipitation of carbonate minerals. Nevertheless, over the long term and at high CO_2 injection rates, zones of clogging are likely to develop, which may block off unreacted compartments of the reservoir from contact with the injected CO_2 solution. Clogging is therefore still considered to be a potential limiting factor in realizing the theoretical capacity of storage sites.

Another expected phenomenon, based on observations of mineral carbonation experiments (Béarat et al. 2006; Daval et al., 2011), is that carbonation reactions tend to armour (passivate) the unreacted substrate rock at the micrometer scale. This lowers the amount of rock that can actually react with dissolved CO_2. Not only newly formed carbonate minerals that may armour the substrate, but also amorphous silica produced by the dissolution of olivine and other silicates (Eqs. 10–15) may coat the reactant minerals, hindering or ceasing further dissolution and liberation of cations for carbonation. Over many decades or more of operation, the reactivity and hence the capacity of the local reservoir to mineralize CO_2 may dwindle to sub-viable levels due to this process. Similarly, precipitation of other alteration minerals, such as silicates and Fe-oxides, may coat and seal the surfaces of primary minerals and prevent their reaction with CO_2.

2.7. Safety of in-situ mineralization 1: Toxic substances

A standard procedure in geological drilling operations is to treat injection wells with strong acids, such as HCl, prior to beginning injection tests. This is done to remove any ground-up rock particles or drilling mud in the wellbore, which may clog the natural rock pores and artificially lower injectivity. The added acids react quickly and are thus quantitatively neutralized. Their product residues are normally flushed from the well after a given reaction period of some hours, then disposed of following normal safety and environmental procedures. Acidization of wells for in-situ mineralization is no different from that carried out in wells drilled for fresh water resources or for oil and gas production or for geothermal energy. Thus, while the acids themselves are dangerous, obeying their standardized handing procedures ensures no safety risk.

As mentioned in Section 2.5, mechanical stimulation of fracture networks via hydrofracturing may be required to permit injection of CO_2-bearing water into serpentinized peridotite reservoirs. To our knowledge, no additional chemical substances have been co-injected for this operation in in-situ mineralization operations, except for inert chemical tracers used to track the progress of carbonation reactions. In the shale-gas industry by contrast, hard mm–cm size particles (fracking proppants) are routinely and legally co-injected with water during hydrofracturing, so that the freshly opened fractures cannot close once the injection pressure is released. Sand is the most common proppant but resin-coated materials are also used. Whether this method will be employed in the future for in-situ mineralization in peridotite reservoirs remains to be seen, but in any case, it would be subject to safety and environmental approval by the relevant permitting authority.

The main carbonate minerals formed in the reservoir via in-situ mineralization are non-toxic, as are the other main non-carbonate products of the carbonation reactions (e.g., amorphous silica and kaolinite, Eqs. 10–15). Their environmentally benign nature is underscored by the fact that all of the mentioned minerals, except for the Fe-carbonates, have been safely used for many decades by the food industry as additives in small concentrations in processed foods.

As documented for CO_2 injection into sediment-hosted saline aquifers (e.g., Kharaka et al., 2006), the carbonic acid injected into basalt and serpentinized peridotite reservoirs may dissolve certain chemical species that are weakly attached via adsorption to exposed mineral surfaces. Some of these, such as As, Pb, Sb, Co, Cu, Zn, Cr and Ni (and various organics more likely found in oil and gas reservoirs), are potentially toxic to living organisms. The listed elements may also be present within basalts and peridotites as strongly bonded components of the main rock-forming minerals and of minor sulfide and oxide minerals. The solubility of sulphides containing As, Pb, Sb, Cu, Zn and Ni may be moderate in carbonic acid, but the only Cr-bearing oxide, chromite, is entirely insoluble. Regardless of whether the reservoir is reduced or oxidized, in the long term the pH is buffered to neutrality or higher by the excess silicate and carbonate minerals. Therefore, any mobilized toxic elements are likely to reprecipitate harmlessly within the reservoir once the pH swings to higher values (as described in Section 2.6.1). Experiments on low temperature carbonation of peridotites indicate that potentially toxic transition

metals can be incorporated to some extent into the newly formed carbonates and Fe-(hydr)oxides, limiting their mobility (Hamilton et al., 2020).
Separately from the naturally occurring toxic chemical species in reservoirs, in situ mineralization projects may also purposefully inject toxic gas components that are present within their CO_2-dominated feedstock. For example, the Carbix2 project in Iceland co-injected large quantities of highly toxic H_2S and verified that it is immobilized in the reservoir by precipitation as the sulfide mineral pyrite, FeS_2 (Clark et al., 2020 and Section 5.1).

In all of the above cases, escape of toxic substances from the reservoir is only possible if the reservoir fluid leaks (Section 2.5). Routine monitoring for leakage includes chemical analysis of groundwaters for the contaminants discussed above as well as for anomalous concentrations of CO_2.

2.8. Safety of in-situ mineralization 2: Earthquake risks

The risk from earthquakes is a topic that planners must always consider when developing CO_2 storage in deep geological formations. The assessment of this risk follows a staged workflow: (i) regional screening to avoid active faults and high-hazard areas; (ii) site characterization based on 3-D seismic surveys, well data and measured stress/pore-pressure relationships; (iii) prospective risk/hazard analysis (including earthquakes); and (iv) design of injection procedures and monitoring measures to maintain the system well below failure conditions. This methodology is specified in the EU (2009) regulatory guidance document for CO_2 storage projects. The EU CCS Directive recommends that site selection should account for “geological characteristics, for example seismicity,” and only proceeds where risks (including CO_2 leakage following earthquakes) are acceptably low (EC 2024a).

The only in-situ CO_2 mineralization site where seismicity has been monitored over a long period (10 years) is Hellisheidi, Iceland. There, for decades before the start of the CO_2 mineralization project, geothermal fluid had been routinely re-injected into the reservoir following extraction of its heat. When CO_2 was added to the spent geothermal fluid and co-injected in dissolved form during the CarbFix projects, no increase in seismicity was observed (Hjörleifsdóttir et al., 2020).

In the absence of other detailed empirical observations of seismicity associated with in-situ CO_2 mineralization projects, the following sections provide background information on the sources of earthquake risks, on the correlations found between seismicity and water injections in other types of subsurface projects (wastewater disposal and geothermal), and on relevant approaches to risk assessment and monitoring.

2.8.1. Sources of earthquake risks

Earthquakes (seismic events) are typically a response to sudden physical displacement (slip) of rocks along fault planes that are under strong unbalanced stresses. The stress state on the fault is controlled by numerous geological phenomena, but in areas without ongoing magmatism it is dominated by the movements of tectonic plates.

The **seismic risk** associated with in-situ mineralization activities arises from three different sources:

1) **Natural seismicity**: The natural predisposition of the region of the injection site and reservoir to be affected by seismic events
2) **Triggered seismicity**: The possibility of triggering an earthquake on a nearby fault that was already close to failure due to natural tectonic stresses, but the human activity provides the final impetus by changing stress or pore pressure conditions.
3) **Induced seismicity**: The possibility of human actions perturbing local stress or pore pressure conditions strongly enough to cause fault rupture where none was naturally imminent.

The risk of induced or triggered seismicity is inherent to all fluid injection into the subsurface (e.g., Ellsworth, 2013, Keranen et al., 2014, Weingarten et al., 2015). The primary factor is the potential for injection-driven pressure perturbations to interact with pre-existing faults. Injection elevates pore pressure and induces poroelastic stress changes, reducing the effective normal stress (stress oriented perpendicular to the fault plane) that normally counteracts movement on critically stressed faults. Modelling of coupled fluid flow and geomechanics has shown that pressure diffusion over spatial and temporal scales can affect distant fault networks, necessitating integrated simulations for accurate risk assessment. Beyond mechanical effects, CO_2 can also chemically alter fault zones by reacting with the minerals present in the faults, modifying their frictional strength and permeability (White and Foxall, 2016). Laboratory and field studies suggest that mineral precipitation along faults could alter slip behaviour, whereas CO_2-induced mineral dissolution may promote localized stress concentrations and microcracking, potentially enhancing permeability but also sustaining the seismic hazard (Lisabeth et al., 2017).

The distinction, especially between triggered and induced seismicity, is hard to make in practice. Fault systems are under complex and largely unknown natural stress states, and with the present understanding of seismology, it is generally not known if a given fault is close to failure. Consequently, if an earthquake occurs on a nearby fault during underground human activity, it is unclear whether that fault would have slipped soon anyway without human activity. Moreover, to make the distinction, it would be necessary to quantify the exact stress change caused by the human action, which is often tiny compared to total tectonic stresses but still enough to trigger fault slip. The magnitude range for both induced and triggered events spans from imperceptible microseismicity to damaging earthquakes, and while they may both occur close to a project site, their proximity does not prove causation. Perhaps the main distinction between induced and triggered seismicity is that, whereas both can happen immediately after human activity starts, triggered events might also occur days to years later. Given the practical difficulties in distinguishing between triggered and induced events, in the following they are lumped together as “anthropogenic seismicity”.

2.8.2. Earthquake risks and consequences related to CO_2 storage

For any CO_2-injection project, three scenarios related to fault reactivation and seismicity are of primary concern: (i) property damage due to ground shaking; (ii) public nuisance due to ground tremors; and (iii) contamination of drinking water. The three scenarios result in different categories of potential damage: harm to property, impacts on public well-being, or degradation of drinking water quality. The first scenario—property damage—is a common concern for natural and anthropogenic seismicity. The second scenario reflects the fact that even non-damaging earthquakes can be disturbing to nearby communities. We adopt the commonly used term “nuisance” for this type of impact, although the term can be misleading, implying that it is trivial. In reality, the consequences can be significant, as public opposition may lead to project shutdowns (Deichmann and Giardini, 2009) or foster scepticism towards geologic carbon storage as a safe technology (Singleton et al., 2009). The third scenario stems from the understanding that slip along a fault zone can change its permeability, potentially creating or reopening pathways for fluid leakage (e.g. Zoback and Gorelick, 2012). This latter scenario is generally considered less worrying where pre-dissolved aqueous CO_2 is injected, but it is of concern in the in-situ mineralization projects where free-phase supercritical CO_2 is injected (e.g., Wallula and Cella; Sections 5.2 and 5.4 below).

2.8.3. Insight from seismicity related to CO_2 storage in sedimentary aquifers

Field experience with CO_2 injection has grown in recent years, with new demonstration and commercial-scale projects coming online. Nevertheless, documented seismicity directly linked to CO_2 injection remains sparse, typically limited to microseismic signals and rare felt events (Evans et al., 2012; Foulger et al., 2018). Scrutiny of five commercial-size CO_2 injection plants either for enhanced oil recovery (EOR; Section 3.3) or in saline sedimentary aquifers (Aneth, Codgell, Weyburn, Decatur, In Salah) revealed that hydromechanical behaviour is highly site- and operation-specific (White and Foxall, 2016).

2.8.4. Insight from seismicity related to wastewater disposal projects

The largest earthquakes (> M 3) related to fluid injection have been recorded in operations where wastewater is disposed of in geological formations. Lessons drawn from the literature reveal clear patterns in how wastewater injection systematically triggers felt seismicity. A prominent case study in Oklahoma demonstrates that rising injection volumes reliably correlate with increases in both the frequency and magnitude of induced earthquakes—and that these relationships can be quantified via predictive models, such as a power-law relation linking monthly injection volumes to event rates ($R^2 \approx 0.77$), enabling the derivation of "sustainable injection" thresholds to reduce seismic risks.

Comparable behaviour is seen broadly across U.S. midcontinent regions: increasing injection into deep disposal formations—especially when fluid reaches basement-hosting faults—elevates pore pressure, lubricates pre-existing fractures, and heightens the chances of felt earthquakes. The largest and most consequential events underscore this hazard: the 2011 M 5.7 earthquake in Prague, Oklahoma (the strongest injection-induced earthquake to date in the USA) caused significant structural damage and was preceded by a swarm of smaller injection-related earthquakes. Similarly, the 2011 M 5.3 earthquake in Trinidad, Colorado was linked to long-term injection, demonstrating that even relatively lower-volume operations can eventually generate damaging seismicity if critically stressed faults are activated, particularly where fluids have been emplaced into crystalline basement or the deepest sedimentary units (Ellsworth, 2013; Keranen et al., 2014; McGarr et al., 2015).

In response, the implementation of "**traffic-light**" regulatory systems has become a common mitigation strategy. In Oklahoma and elsewhere, these systems assign green/yellow/red statuses based on seismic thresholds, resulting in real-world success in reducing felt events when injection rates are curtailed or wells shut down after exceeding thresholds. Moreover, recent physics-based forecasting frameworks underscore that pore-pressure diffusion dominates the stress changes driving seismicity, while poroelastic effects play a minor role—thus highlighting the importance of managing injection rates and the spatial distribution of injectors to mitigate felt seismic hazard while optimizing fluid disposal.

2.8.5. Insight from seismicity related to geothermal projects

Experience from geothermal projects that re-inject the produced water offer contrasting insights. Here just a few of the most well-known and well-studied cases are mentioned. The Geysers, California, USA is an example of large-scale re-injection of treated municipal wastewater. Since the late 1990s and early 2000s, seismicity rates have increased, including numerous felt M 3–4+ events with clear temporal links to injection operations and volumes (Majer and Peterson, 2007). In the Upper Rhine Graben, Germany, re-injection at geothermal power plants has been accompanied by persistent induced seismicity; several felt events were reported near Landau (ML 2.7, 2.4 in 2009) and Insheim (ML ~2.2–2.4 in 2010), prompting enhanced monitoring and hazard assessments (Sisi et al.,2025). In the Taupo Volcanic Zone in the North Island, New Zealand, induced seismicity was observed in a number of geothermal fields, with felt events notably at Rotokawa (M 3.3), Kawerau (M 3.2), Mokai (M 3.2), Ngatamariki (M 2.7) and Wairakei (M 2.5). A clear correlation with reinjection wells could be observed for some of those fields (Sherburn et al., 2015). In Hengill, Iceland, the geothermal wastewater reinjection in 2011 produced a marked seismicity increase that was felt in nearby Hveragerði (Aradottir et al., 2020), and geodetic data showed injection-related deformation concurrent with the seismicity. Subsequent adaptive management (rate/pressure control and well configuration) reduced the occurrence of $M \geq 2$ events substantially.

In general, induced seismicity is prevalent in geothermal projects targeting crystalline or metamorphic rocks, or sedimentary rocks that are close to the underlying crystalline basement (e.g. St Gallen, M3.5 in 2011) (Evans et al., 2012), where the reservoir rocks have low matrix porosity at depths greater than 2.5 km, as well as in tectonically active areas. Among the best documented cases where EGS activity produced felt seismicity is Basel, Switzerland (December 2006). An EGS injection test beneath the city induced a sequence of thousands of earthquakes during a few days of stimulation; the largest widely reported event had an $M_L/M_W \approx 3.4–3.2$ and was felt by residents, causing minor non-structural damage and causing the project to be abandoned (e.g., Baisch et al., 2009, Giardini, 2009, Kraft et al., 2009). This case become a classic example of rapid fault reactivation by pressurization and of the importance of site characterization, traffic-light protocols, and public risk management.

Pohang, South Korea (Nov 2017) is also a well-studied case of EGS inducing seismicity. Hydraulic stimulation at a deep geothermal site preceded a damaging seismic sequence that culminated in a Mw 5.5 earthquake (Grigoli et al. 2018). The event caused injuries and structural damage and was judged very likely to have been induced or triggered by the stimulation operations. Pohang is the largest and most consequential example of stimulation-related seismic hazard and prompted national investigations, compensation programs, and wide reassessments of EGS risk management.

St. Gallen, Switzerland (2013), although not a classic EGS stimulation, is also an example of anthropogenic earthquake associated with deep geothermal exploitation. During stimulation and related well-control responses, a sequence of induced earthquakes included a felt event of $M_L \approx 3.5$ with shaking observed in nearby towns (Diehl et al., 2017). Investigations point to stimulation plus subsequent operational responses (including a gas kick and remedial pumping) that ultimately triggered slip on a nearby fault. The case emphasized operational controls and the need for robust well and hazard protocols during unplanned events.

Other EGS sites targeting granitic basement rocks or tight sandstones are Fenton Hill (New Mexico, USA), Fjällbacka (Sweden), Soultz-sous-Forêts (France) Paralana and Habanero (Australia), and Rosemanowes (UK). They have produced extensive microseismicity used to map stimulation but generally only rarely produced felt events (approximate M_L below 2, Evans et al.,2012; Buijze et al., 2020). Reviews of global induced seismicity in geothermal projects (e.g. Evans et al.,2012; Buijze et al., 2020, Kivi et al., 2023) catalogue the range of outcomes and the contributing factors. Injection-induced pore-pressure increase near critically stressed faults, poro-elastic stress transfer from stimulated zones to nearby faults, pre-existing, optimally oriented faults close to injection wells, and/or operational complications (e.g., unexpected pressure responses, or gas kicks) are all triggering causes. Overall, these patterns emphasize that while most injection operations are aseismic, felt seismicity systematically clusters in projects with high injection rates, elevated pressures, or hydraulic connectivity to critically stressed basement faults.

Operational parameters, such as the differential injection pressure ΔP (Eq. 1) play a role in inducing or triggering seismicity. Most felt earthquakes have occurred at $\Delta P > 5$ MPa, in systems targeting crystalline rock. However, seismicity has also been induced during circulation at low ΔP (< 1.5 MPa), for example at the above-mentioned Insheim site in the Upper Rhine Graben. In hydrothermal systems, the relationship between ΔP and induced earthquake magnitudes is not straightforward. At the Geysers, for instance, injection does not require applied pressure because the reservoir is underpressured and water can enter under gravity alone. However, the effective pressure change at reservoir depth may be considerably larger when accounting for the water column. In this case, the pressure relative to the original reservoir state can reach around 7 MPa, corresponding to an excess pressure of roughly 3.5 MPa (Martínez-Garzón et al., 2014).

Even if a general correlation between injected volume and the maximum magnitude of seismicity holds for waste water injections (McGarr et al., 2014), this correlation does not seem to be representative of hydrothermal systems (Buijze et al., 2020). The temperature contrast between injected and in-situ waters plays a role too. In the cases of hydrothermal systems, where reservoir waters can be much hotter than injected fluids, ΔT appears to be directly proportional to the magnitude of the induced events. In summary, the likelihood of felt seismicity depends strongly on how operational parameters interact with in-situ stress, fault orientation, and the mechanical and hydrogeological properties of the reservoir and surrounding rocks. Such events are more probable when stress changes reach critically stressed faults, often in the crystalline basement. Larger pressure and temperature changes, acting over wider areas, further increase the chance of fault reactivation.

While these geothermal cases and wastewater injection cases differ in purpose and chemistry from in-situ CO_2 mineralization projects, they highlight the complex interplay between reservoir properties, injection strategy, and induced seismicity potential. In conclusion, globally only a small fraction of fluid-injection projects generates felt earthquakes, but the likelihood of such events differs between wastewater disposal and geothermal reinjection. In the US, most Class II disposal wells (EPA, 2018) are aseismic, yet a concentrated subset of high-rate wells accounts for nearly all felt events: nationwide analyses show that while < 1% of all wells are linked to felt seismicity, as many as 61 % of wells injecting > 48,000 m^3/month and 76% of those injecting >160,000 m^3/month were spatiotemporally associated with nearby earthquakes (Weingarten et al., 2015). The Weingarten et al. (2015) report concluded that, at the scale of their study, a well's cumulative injected volume, monthly wellhead pressure, depth, and proximity to crystalline basement do not strongly correlate with earthquake association, and that injection rate is the key parameter. Enhanced Geothermal Systems (EGS) more frequently experience felt seismicity, though damaging events remain rare (Buijze et al., 2020).

The lessons learnt through the numerous studies conducted on geothermal projects allow to better understand, manage, and minimize the risk of anthropogenic seismicity. A thorough site selection and fault mapping (including high-resolution seismic imaging and stress field assessment) is a key element to avoid injecting near critically stressed faults. Moreover, a robust real-time seismic monitoring and traffic-light systems with pre-defined thresholds and rapid operational responses (halt, reduce, or modify injection) have to be in place. The limits of traffic-light systems, thresholds and decision rules must be conservative and context-specific. Adaptive operational strategies (controlled injection volumes/rates, stepped stimulation, pressure management) informed by microseismic monitoring and forecasting models must also be in force. Finally, post-event investigations and independent reviews to learn from occurrences and update regulations are part of normal best practice.

2.8.6. Seismic risk assessment

It follows from the above literature review, that the risk of seismic events—whether natural or anthropogenic—must be evaluated prior to all CO_2 injections. The natural earthquake risk is assessed via Probabilistic Seismic Risk Analysis (PSRA) to estimate shaking levels with specified annual probabilities at the site and critical infrastructure (wells, compressors, monitoring stations). PSRA produces hazard curves (ground motion vs. annual exceedance probability), which are then compared to structural design codes (e.g., the European - Eurocodes and the American Society of Civil Engineers - ASCE 7) to ensure that wells, surface facilities, and monitoring stations can withstand shaking up to a target probability level (e.g., "no significant damage at 1/500 yr"). PSRA thus informs engineering design acceptance criteria: if the hazard exceeds the tolerance, redesign or relocation is required before proceeding. PSRA also informs project go/no-go and siting decisions. If it shows a high probability of damaging ground motions, operators may decide not to proceed with an injection project at that site.

Regulators can require that PSRA be performed as part of the Environmental Impact Statement. Thus, a site with unacceptably high seismic risk may not be granted a permit. PSRA are also inputs for traffic-light system levels. Traffic-light protocols typically define thresholds in terms of magnitude or local ground shaking intensity (e.g., ML ≥ 2.0 = “orange”, ML ≥ 2.7 = “red” at a CO_2 storage site). The choice of these thresholds is informed by PSRA and fragility functions (the probability of exceeding/attaining a given damage state for a given intensity level of ground motions). The fragility of infrastructure near the injections (probability of damage given shaking) is then mapped to magnitude levels expected to generate those shaking intensities at given distances. Traffic light “red” is often set at the level where the probability of infrastructure damage or unacceptable nuisance to the public becomes significant.

PSRA is standard in CCS project studies (e.g., at Otway project in Australia; Stirling et al., 2011). A useful approach to assess anthropogenic seismicity risk is to adapt the PSRA and, as certain regions are subject to both natural and induced events, a unified assessment framework is also desirable. PSRA involves coupling the probability of an event occurring with its societal consequences (M > 4.0), which in the case of anthropogenic seismicity includes nuisance caused by any felt ground motion (ca. M > 2) as well as building and infrastructure damage. Therefore, the smaller magnitude events need to be a key focus of an expanded risk assessment and management workflow.

Fault and stress mapping, slip tendency analyses and geomechanical modelling are typical key elements in hazard assessment. Thorough site characterization within the predictable CO_2 plume footprint can help identify and avoid critically oriented faults close to injection zones. 3D (and often 4D) seismic survey, combined with geological and well log data, are commonly used to detect faults and estimate the maximum magnitude that may be expected. However, there are limitations to fault detectability, especially in strike-slip faults and faults confined in crystalline rocks. The most common way to obtain information faults that escape detection during the pre-injection phase is to carefully monitor micro-seismicity and its relation to pressure evolution.

2.8.7. Seismic risk management

Monitoring to detect any earthquake-related impact remains a necessary measure. This implies that (micro-) seismicity has to be monitored possibly before, during and after injections and that management measures have to be put in place. Neglecting these aspects could have the fatal consequence of being unable to respond to the population in the event of even minor incidents, and effectively undermine confidence in the CO_2 storage technology being developed.

Monitoring via a dense local network (downhole + surface) provides a low magnitude of completeness to track background natural seismicity and any changes during operations. This baseline is essential to characterize and locate events correctly, even if it is unfortunately expensive. Costs can be reduced by installing dual-purpose arrays, i.e., using the same array for both active and passive seismic monitoring (e.g., Aquistore; White et al., 2014), or through the employment of Fiber Optics technology. Ambient noise interferometry techniques can be useful to reduce uncertainties in crustal velocity models and derive information on focal mechanisms (e.g. Shapiro et al., 2007; Goetz-Allmann and Wiemer, 2013).

From a risk management perspective, a key issue is whether warning signs can be detected before hazardous seismicity develops. Operators predefine operational thresholds (traffic-light systems), in terms of background seismicity rate and actions, such that if a natural or man-made seismic event perturbs the field, they can pause, inspect, and adapt injection protocols. However, if the largest earthquakes occur early in a sequence with little warning, measures like traffic-light systems or injection-rate control may have limited effect. As a result, it is important to include damage mitigation strategies within the project design to ensure practical consequences will be low even if felt earthquakes cannot be prevented.

For CO_2 storage in aquifers sealed by caprocks, the injection depth, and the potential for the pressure front to reach deeper formations are key operational considerations (White and Foxall, 2016). Learning from the case-history of projects like Weyburn (Canada) and In Salah (Algeria), seismicity may be partly mitigated by ongoing fluid extraction, which serves to offset pressure increase due to CO_2 injections.

Pilot-scale injection into basalt formations, such as at the Wallula in-situ mineralization project (Section 5.2), has operated under pressure limits similar to those assumed for sedimentary storage capacity modelling (McGrail et al., 2014; Jahediesfanjani et al., 2017).

Last but not least, the aspect of community vulnerability has to be carefully addressed. For anthropogenic seismicity, the effects of felt but non-damaging ground motions have paramount relevance. In the context of enhanced geothermal systems, the US DOE has developed protocols for assessment of vibration levels in the form of acceptability criteria, Community perception of seismicity risk is strongly influenced by outreach efforts and perceived local benefits. A community's general familiarity with carbon storage technology is an important factor in the perception of its riskiness.

2.9. Energy requirements for in-situ mineralization

The energy requirements for in-situ mineralization are primarily linked to CO_2 and water compression. At sites where supercritical CO_2 is injected below a caprock, energy consumption is expected to be similar to that in conventional CO_2 storage operations, i.e., 60–106 kWh/t CO_2 stored (IEA (2004). The range in consumption reflects differences in storage depth, injectivity and CO_2 transport conditions, including whether CO_2 is delivered in gaseous or liquid form. No data are available for the one pilot site (Wallula) that has used this injection mode to date.

At sites where CO_2 is pre-dissolved in water and then injected into the target reservoir, the main energy demand arises from pumping the water. Reported values of electricity consumption are on the order of ~100 kWh per tonne of CO_2 stored at the CarbFix2 (Iceland) site, reflecting the need for 20–32 tonnes of water to dissolve each tonne of CO_2 (Section 2.4.3). The energy required to inject CO_2 pre-dissolved in water depends only mildly on the injection depth (Sigfússon et al., 2015). As the depth of the target reservoir increases, the required degree of compression increases but the mass of water needed to dissolve a given mass of CO_2 decreases, owing to the strong sensitivity of CO_2 solubility to pressure (Diamond and Akinfiev, 2003). As a result, the electrical energy required to inject CO_2 in dissolved form remains fairly constant with depth at ~100 kWh/t CO_2 stored. In the DemoUpCARMA, DemoUpStorage and CO2SeaStone pilot projects (Becattini, in prep.), CO_2 was co-injected with seawater, with mixing occurring at depth in the well. In these operations, average electricity consumption during periods of continuous injection was about 150 kWh/t CO_2. This value is higher than those reported by Sigfússon et al. (2015), in part because the solubility of CO_2 is lower in seawater than in typical low-salinity surface or shallow groundwaters, but it is consistent with the small-scale, pilot-stage nature of the projects.

At in-situ mineralization sites in serpentinized peridotites (Sections 5.5 and 5.6) the energy demand can be significantly higher (up to ~200–225 kWh/t CO_2 stored) due to higher injection pressures and the need for water recirculation (Planet A, 2022).

It is important to note that, when considering the overall energy requirements of geological storage of CO_2 – involving capturing, transporting, and injecting CO_2 into the subsurface – the injection step generally represents the smallest contribution to the total energy consumption and hence to the overall environmental impact of the CO_2 value chain. The actual size of the contribution depends on factors such as the CO_2 source, the distance between source and storage site, and the transport mode. However, as a general rule, the subordinate energy consumption of CO_2 injection holds true regardless of the storage method, whether conventional injection of supercritical CO_2 or in-situ mineralization (Burger et al., 2024).

3. Comparison of in-situ mineralization with other CO_2 storage approaches

In addition to in-situ mineralization, four other approaches to geological storage of CO_2 have been developed, verified and commercially implemented at an industrial scale. These are described in the following sections, and then the two most important of them (CO_2 storage in depleted oil and natural gas reservoirs and in deep saline sedimentary aquifers) are compared to the in-situ mineralization technology.

Which, if any, of these approaches can be implemented in a geographical area of interest depends on the specifics of the local geology (a property termed **geological endowment**). Thus, it cannot be assumed that a given geographical location will be favourable for subsurface CO_2 storage. The potential can be estimated based on existing local geological knowledge (screening surveys have already been conducted for CO_2 storage in many areas worldwide) but the potential can only be verified by exploration campaigns involving drilling and hydraulic testing.

3.1. CO_2 storage in depleted oil and gas reservoirs

Sandstone and carbonate sedimentary rocks often contain high volumes of connected pores (up to 30%), through which oil and natural gas (dominantly methane) can migrate over geological time. Both of these fluids are less dense than the saline groundwater in the pores of the sedimentary rocks, hence their buoyancy drives them upwards through permeable strata. If the oil and gas enter an aquifer that is covered by impermeable caprocks, their migration is confined to the aquifer until they perhaps encounter a permeable fault or stratigraphic structure that leads to a higher aquifer. Alternatively, if the aquifer and its caprock have been previously folded or faulted into a dome-like structure (Fig. 2A), then the two buoyant fluids become permanently immobilized in what is termed an oil or gas **trap**. Physically trapped accumulations of this type, the oldest of which formed more than 500 million years ago, are the main global source of commercially exploited oil and natural gas. Extraction through production wells typically takes decades and during this time groundwater along the margins of the trap structure steadily seeps in to fill the vacated pore space. The water-filled trap is termed a **depleted natural gas (or oil) reservoir**.

For several reasons, depleted oil and gas reservoirs are the prime choice for geological CO_2 storage. First, by virtue of having stored buoyant fluids over millions of years, nature has proven that the reservoirs act as permanent containers without significant leakage pathways. Numerous reservoirs are known where the gas is dominantly CO_2 rather than methane (e.g. at Montmiral in France, where 98% of the gas is CO_2 – now being extracted for the food industry– and where this gas has been trapped for 35 million years; Pauwels et al., 2007). These are thus perfect analogues of a storage site for anthropogenic CO_2. Second, by virtue of having been exploited by petroleum companies, the reservoirs are very well explored and understood from geological and reservoir engineering perspectives. This understanding is based on extensive characterization through drilling, seismic surveys, and decades of pumping tests. Third, by virtue of having produced oil or gas for sale over many decades, the safety of surface operations has been demonstrated and the sites are already connected to pipelines that could potentially supply them with waste CO_2 for storage. Thus, the major costs of developing a CO_2 storage site have already been financed, and normally only surface infrastructure investments are required to re-purpose them. Normal injection pressures allow the groundwater that has intruded into the trap during hydrocarbon exploitation to be forced back into the deeper regions of the aquifer. Finally, depleted natural oil and gas reservoirs sustain injection of high-density supercritical CO_2, which maximizes the amount of CO_2 that can be stored in the available pore space.

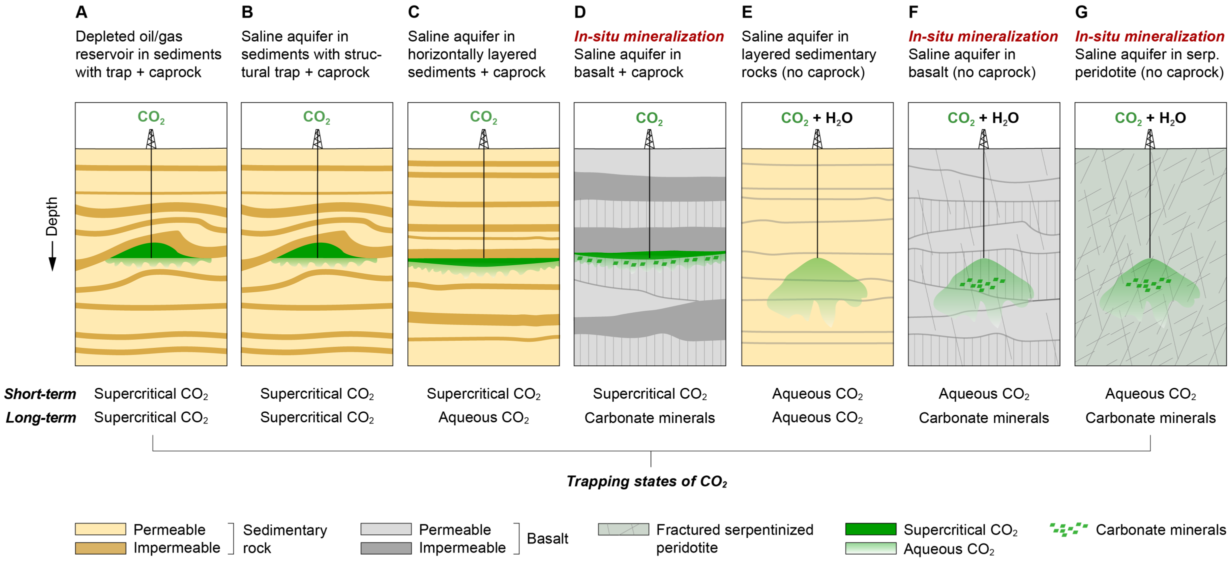


Figure 2. Schematic cross-sections comparing the spectrum of current approaches for permanent geological storage of CO_2. Not shown are approaches that simultaneously extract hydrocarbons: enhanced oil recovery (EOR), and enhanced methane recovery from deep coal beds (ECBMR); see text. "Short-term" trapping states of CO_2 refer to multi-decade to century time-scales, including 30–50 year CO_2 injection periods typical of commercial storage.

(**A**) Injection of supercritical CO_2 into a depleted oil or natural gas reservoir formed by a dome fold in a porous, saline sedimentary aquifer sealed by a caprock. Buoyant supercritical CO_2 is physically trapped by the caprock.

(**B**) Injection of supercritical CO_2 into a hydrocarbon-free dome fold within a saline sedimentary aquifer. Buoyant supercritical CO_2 is trapped by a caprock.

(**C**) Injection of supercritical CO_2 into a sequence of horizontally layered sedimentary rocks. Buoyant supercritical CO_2 is trapped in a saline aquifer below an impermeable caprock.

(**D**) *In-situ mineralization.* Injection of supercritical CO_2 into a saline aquifer in basalts. Buoyant supercritical CO_2 is trapped within a laterally extensive, horizontal layer by an impermeable basalt caprock (e.g., Wallula project).

(E) Proposed injection of CO_2 pre-dissolved in water into a saline aquifer within sedimentary rocks. No caprock is required for containment, as the aqueous solution has negative buoyancy.

(**F**) *In-situ mineralization.* Injection of CO_2 pre-dissolved in water into a saline aquifer within porous or fractured basalts. No caprock is required for containment, as the aqueous solution has negative buoyancy.

(**G**) *In-situ mineralization.* Injection of CO_2 pre-dissolved in water into a fractured saline aquifer within non-porous, serpentinized peridotite. No caprock is required for containment, as the aqueous solution has negative buoyancy. *Approach D shares the same short-term trapping state of CO_2 (supercritical) as conventional approaches A–C. Similarly, approaches E–G share the same short-term trapping state (aqueous CO_2) as the long-term trapping state in conventional approach C. Therefore, the criteria to evaluate containment, safety and environmental compatibility of CO_2 storage in conventional approaches can be applied to the in-situ mineralization approaches D, F, G.*

While depleted oil and gas reservoirs are eminently suitable for CO_2 storage, they occur only in certain geographical areas (for example, no volumetrically significant examples have been discovered in Switzerland) and there is competition for their post-exploitation use. Hundreds of depleted reservoirs are now used worldwide for strategic storage of natural gas that has been imported from elsewhere. The reservoirs are filled in summer when prices are low and then the gas is produced again for sale and consumption in winter, the cycle being repeated over many decades. However, once the demand for methane is replaced in the future by demand for carbon-free energy sources, the reservoirs are likely to be used to store hydrogen or compressed air. Whereas the reservoirs can be re-used indefinitely for these commercially valuable and strategic purposes, filling them with waste CO_2 just once would preclude any future re-use for alternative applications.

3.2. CO_2 storage in saline sedimentary aquifers

Deep saline aquifers in sedimentary rocks are being used worldwide to store supercritical CO_2 in two variants. Some of the implemented sites have the same geological features as depleted oil or natural gas reservoirs, including a layer of porous reservoir rock and an overlying impermeable caprock, both folded or faulted into a dome-shaped trap (Fig. 2B, Table 4). The only geological difference with respect to depleted oil/gas reservoirs is that the traps in the saline sedimentary aquifers did not happen to enclose hydrocarbon source rocks or lie along the migration path of hydrocarbons in the distant geological past, and so they were never filled with oil or gas. Operational differences with respect to depleted oil/gas reservoirs include the need to hydraulically test the integrity of the caprock before permanent containment of supercritical CO_2 can be guaranteed, and the need to carry out subsurface exploration, drilling of wells and installation of surface pipelines.

In the second variant, saline sedimentary aquifers are being used globally for permanent CO_2 storage even if they contain no structural traps (Fig. 2C; e.g., Aquistore in Saskatchewan). Predictive reservoir simulations, calibrated by post-injection monitoring, have shown that reservoirs with large lateral extents (hundreds of km) and with equally extensive caprocks can trap free CO_2 plumes over long enough times (centuries to millennia) for the injected supercritical CO_2 to dissolve completely into the native groundwater, resulting in permanent non-buoyant storage.

In principle, the latter type of sealed sedimentary aquifer without a structural trap (Fig. 2C) would also permanently trap CO_2 that is injected in pre-dissolved aqueous form. This approach has not yet been implemented solely for CO_2 storage because it would allow only a small amount to be stored compared to the high tonnages achievable by injecting supercritical CO_2 into the same reservoir. However, it has been proposed as a means to add value to normal saltwater disposal operations in sealed sedimentary aquifers through co-injection (Xiong et al., 2023).

Finally, in regions where porous sedimentary aquifers lack caprocks, injection of aqueous CO_2 may offer a viable option for storing a relatively small amount of CO_2 (Fig. 2E). This has been suggested for aquifers in Japan that are located close to industrial CO_2 emitters (Suekane et al., 2008).

3.3. CO_2 storage during enhanced oil recovery

Since the 1970s, CO_2 has been commercially injected into petroleum reservoirs to lower the viscosity of heavy oil and thereby facilitate its production by pumping through wells. The process is termed Enhanced Oil Recovery (EOR) or Enhanced Hydrocarbon Recovery (EHR). Commonly, each injection of CO_2 is alternated with an injection of incompressible water, which forces the CO_2 deep into the formation (similar alternation is foreseen for an ongoing in-situ mineralization project in Kenya, as described in Section 4.4). Approximately 55–65% of the injected CO_2 is co-produced with the oil and is re-used in the next EOR cycle, but the remainder stays permanently sequestered within the reservoir. Although around 35 Mt CO_2 are incidentally stored in this way each year (IEA, 2021), most of the injected CO_2 is sourced from nearby wells that commercially produce natural gas, in which CO_2 is a common natural component. Thus, the impact of EOR on storage of independently generated, hard-to-abate industrial emissions is limited. More importantly, EOR is inherently linked to high net CO_2 emissions if the produced oil is burned as an energy source without associated CO_2 capture and storage (IEAGHG, 2016).

3.4. CO_2 storage during enhanced coal-bed methane recovery

Another commercial storage technology termed Enhanced Coal-Bed Methane Recovery (ECBMR) entails injecting CO_2 into coal seams that lie too deep to ever be economically mined as fuel resources. Coal particles are porous and they have huge surface areas that are naturally coated in physically adsorbed methane (natural gas). Injected CO_2 displaces the methane and itself becomes more strongly adsorbed on the particle surfaces. The desorbed methane can be produced and sold, rendering the process commercially profitable. Since the amount of CO_2 adsorbed compensates for the amount of CO_2 generated by burning the produced methane, the process cannot be used to store independently generated hard-to-abate industrial emissions. However, if the CO_2 produced by combustion is captured and re-injected, ECBMR could in principle enable net-zero use of methane as an energy source.

3.5. Comparison of CO_2 storage capacities

Table 4 compares the major features of CO_2 storage in sedimentary aquifers and depleted oil/gas reservoirs with those of in-situ mineralization. In principle, all these approaches can be executed safely and can result in permanent storage of CO_2. However, they differ greatly in their currently proven storage capacities, as follows.

The proven storage capacity of all worldwide depleted natural gas reservoirs is high at around 390 Gt CO2 (Ladbrook et al., 2009; Table 4), which is 10 times greater than the current ~40 Gt annual global emissions of anthropogenic CO_2. This capacity may not be realized in practice, because CO_2 storage is in competition with other potential uses of the reservoirs (Section 2.9.4).

By comparison, the storage capacity of saline sedimentary aquifers is likely to be giant. The estimated potential capacities vary between 8000 and 55,000 Gt CO2 (Global CCS Institute, 2019; Table 4), which is 200 to 1375 times higher than the annual global anthropogenic emissions. Accordingly, much effort is being devoted worldwide to develop aquifer storage sites. Saline aquifers may also face competition from other uses, such as geothermal energy extraction, though the high temperature areas favoured for geothermal energy are considered less favourable for CO_2 storage as this lowers the density and hence mass of CO_2 that can be stored at a given depth. Heat storage in saline aquifers is usually conducted at shallower depths than CO_2 storage, therefore competition with this use is likely to be limited. Aside from these considerations, there are many other technical, economic, legal, social and political reasons why the giant potential storage capacities may not be practically achievable in the future (Giddans et al., 2025).

The theoretical storage potential of global basalts and peridotites via in-situ mineralization is estimated to be even higher than that of saline aquifers in sedimentary rocks. However, many workers have pointed out the difficulties of making accurate estimates (e.g. Cao et al., 2024), hence the numbers are to be taken as only indicative at this stage. Continental flood basalts in the Columbia River Basin of north-western USA have an estimated storage potential of 10–100 Gt CO2 (McGrail et al., 2006). Storing CO_2 in the comparable formations in India, Brazil, Siberia and elsewhere would bring the total up to at least 300 Gt CO2. Whereas the total capacity in on- and offshore Iceland alone is estimated at 7000 Gt CO2 (Snæbjörnsdóttir and Gíslason, 2016), and similarly active volcanic areas are present in other onshore locations around the world, gigantic volumes of the same rocks are also present below the world’s ocean floors. These include volcanically old and hence cool regions (e.g., Rosenqvist et al., 2024) or young, anomalously hot regions along mid-ocean ridges. Along these ridges, tectonic plate spreading is continually generating vast amounts of porous, permeable and glassy basalts in areas of high heat flow (up to 400 mW m^{-2} on the ridges compared to ~50 mW m^{-2} on the continents). The global system of mid-ocean ridges is 65,000 km long and its anomalously hot zones are around 5 km wide. The depth to these volcanic ridges is on average 2.5 km, but this lies within the feasibility of drilling

Table 4. Comparison of current methods of geological CO$_2$ storage. Colours indicate some relative advantages and disadvantages. Note that the short-term trapping state of CO$_2$ in in-situ mineralization (dissolved CO$_2$) is the same as the long-term trapping state in sedimentary-aquifer storage (**bold**).

Feature	CO$_2$ storage in depleted oil/gas reservoirs	Sediment-hosted aquifer CO$_2$ storage	In-situ CO$_2$ mineralization in reactive saline aquifers
Reservoir rock	Sandstone, dolostone, limestone	Sandstone, dolostone, limestone	Basalt or serpentinized peridotite
Reservoir hydrogeology	Saline aquifer	Saline aquifer	Natural saline aquifer or artificially induced aquifer
Potential CO$_2$ storage capacity worldwide	High: 390 Gt (but other uses are in competition – see text)	Giant: 8000–55,000 Gt	Giant: 30–300 Gt in continental flood basalts; >100,000 Gt in mid-ocean ridge basalts; >100,000 Gt in peridotites
Short-term (decades) trapping state of CO$_2$	Supercritical CO$_2$	Supercritical CO$_2$	**CO$_2$ dissolved in groundwate**r
Main long-term (centuries) trapping state of CO$_2$	Supercritical CO$_2$	**CO$_2$ dissolved in groundwater**	Solid carbonate mineral
State of injected CO$_2$	Supercritical CO$_2$	Supercritical CO$_2$	CO$_2$ dissolved in water or supercritical CO$_2$
Water mass required for injection	None	None	20–32 times more water than CO$_2$
Amount of CO$_2$ per tonne of injected fluid	100 wt.%	100 wt.%	3-5 wt.%
Min. depth of injection	800 m to ensure CO$_2$ is in dense supercritical state	800 m to ensure CO$_2$ is in dense supercritical state	500 m to attain acceptably high solubility during injection
Max. depth of injection	Approx. 3 km, depending on drilling costs and site permeability	Approx. 3 km, depending on drilling costs and reservoir permeability	Approx. 3 km, depending on drilling costs and reservoir permeability
Caprock	Implicit	Extensive caprock required	Not required
Structural trap	Implicit	Site-dependent	Not required
Threat* of upward leakage of CO$_2$ in gas state	Leaky wells; caprock damaged during injection	Site-dependent (presence of gas-permeable faults; integrity of caprock)	Transient decompression during fault slip or lateral outflow from aquifer
Threat *of upward leakage of CO$_2$ in aqueous state	Strong over-pressurisation of aquifer upon injection	Strong over-pressurisation of aquifer upon injection	Strong over-pressurisation of aquifer upon injection
Threat* of hydrofracturing	Negligible	Negligible	Hydrofracturing performed purposefully to inject CO$_{2(aq)}$ into serpentinized fractures
Threat* of induced or triggered seismicity	Site-dependent; (presence of stressed faults)	Site-dependent (presence of stressed faults)	Site-dependent (presence of stressed faults); Purposeful hydrofracturing;
Threat* of contaminating overlying freshwater aquifers	Upward leakage of supercritical CO$_2$ through permeable faults or wells	Upward leakage of supercritical CO$_2$ through permeable faults or wells	Strong over-pressurisation of aquifer upon injection or during fault slip

* The risks of these threats being realized have been demonstrated to be very low if the site characterization has followed the EU Directive (EU, 2009) and technical guidelines (EC 204a, 204b; ISO 2017).

technology as demonstrated by the hundreds of research boreholes already successfully drilled into the ocean crust. Thus, the total storage capacity of basalts is well above 100,000 Gt CO$_2$ (Kelemen et al., 2019). The problems with accessing the deep seafloor for CO$_2$ storage would be its high cost compared to the other onshore approaches described above and the challenge of verifying containment within the basalts and mitigating any leakage to the ocean. Estimated capacities for CO_2 mineralization in peridotite are also above 100,000 Gt CO2 (Kelemen et al., 2019).

3.6. Hydrogeological equivalence of reservoirs for in-situ mineralization and for conventional CO_2 storage in sedimentary aquifers

The literature on in-situ mineralization focuses on mineralization reactions and their rates. The reader may therefore gain the impression that in-situ mineralization is an entirely alternative approach to the well-established storage of CO_2 in depleted oil/gas reservoirs or in saline aquifers within sedimentary host rocks (e.g., Snæbjörnsdóttir et al., 2020; Matter et al., 2025b). It is true that the primary, *long-term* storage state of CO_2 differs between the approaches (Fig. 2, Table 4), but the *short-term* (multi-decade) behaviour of CO_2 in in-situ mineralization sites is the same (Fig. 2). In-situ mineralization sites where aqueous (dissolved) CO_2 is injected (Fig. 2E–G) share the same short-term trapping state (aqueous CO_2) as the long-term trapping state in horizontally-layered sedimentary aquifers, with or without caprocks (Fig. 2C and E). Similarly, in-situ mineralization sites where supercritical CO_2 is injected into basalts sealed by caprocks (Fig. 2D, e.g., Wallula and Elementeita) share the same long-term state of CO_2 (free-phase supercritical CO_2) as in conventional depleted oil/gas reservoirs and in caprock-sealed traps in saline sedimentary aquifers (Fig. 2A and B).

All of the field and experimental studies of in-situ mineralization reaction kinetics have shown that precipitation of carbonate minerals takes time; mineralization is not quantitatively instantaneous upon injection of aqueous CO_2. In order to guarantee CO_2 containment, the target basalt and serpentinized peridotite aquifers must therefore be capable of securely trapping CO_2-bearing water or supercritical CO_2 instantaneously and at least until all (100%) of the injected CO_2 is locked within carbonate minerals.

Exactly how long it takes to mineralize all of the injected CO_2 has not yet been demonstrated in any of the field projects or experimental studies. Linear extrapolation of the rates in Table 3 for basalt reservoirs implies periods between 7 months in glassy basalts at high temperature (250 °C) and perhaps 2–3 years in altered basalts at low temperatures (20–45 °C). However, there are various reasons why linear extrapolation may underestimate the time needed to attain complete mineralization, e.g., reduction of permeability due to clogging (Section 2.6.3), passivation of the reactive surfaces of minerals (Section 2.6.3), and competition for cations from precipitating clay minerals (Section 2.6.1). This implies that up to several years may be required for completion of the carbonation reactions following just one short injection period (Section 2.6.2, Table 3). If CO_2 is injected continuously over a period of several decades (e.g., 30–50 years), as is typically envisaged for commercial storage sites, then the aquifer must securely retain dissolved CO_2 for at least a few years longer than this period.

The above arguments lead to a key conclusion for the present report, which is set in a box below for emphasis:

> Because carbonation reactions are not instantaneous and the time required for complete mineralization is not yet known, target aquifers for secure in-situ mineralization must exhibit the same formation-scale containment properties as sediment-hosted aquifers that are suitable to store aqueous CO_2 or both aqueous and supercritical CO_2 (depending on the chosen injection mode). Consequently, for the purpose of evaluating storage security, safety and environmental compatibility, in-situ mineralization should not be viewed as an entirely separate category of CO_2 storage but as a variant of long-term storage in sedimentary aquifers. The two approaches target different host rocks and different long-term states of stored CO_2, but their reservoirs must have equivalent hydrogeological properties.

4. Evaluation criteria for in-situ CO_2 mineralization

4.1. Basis for evaluation criteria

As outlined in Section 1.2, FOEN is mandated to evaluate foreign in-situ mineralization projects to which Swiss entities intend to export CO_2 from Switzerland or intend to procure attestations for geological storage of CO_2 captured by negative-emissions technologies. Accordingly, the focus of FOEN is on CO_2 containment, safety and environmental compatibility. To our knowledge, no generalized, best practice document exists for these topics specifically as they apply to in-situ mineralization. However, the preceding section has shown that assessment and monitoring of in-situ mineralization sites must unavoidably be based on the same criteria as already long applied to conventional storage projects in sedimentary aquifers (including depleted oil and gas reservoirs), in which aqueous CO_2 or supercritical CO_2 are the long-term trapping states. Several international guidelines for such aquifers are available and their suitability for in-situ mineralization is discussed in the following.

International guidelines typically include the need and methods to estimate long-term storage capacity of CO_2 in the supercritical and aqueous states, as this relates directly to the risks summarized in the chapters above. Although methods to estimate the storage capacity achievable by CO_2 mineralization are not yet fully developed or standardized, this will not hinder FOEN in executing its mandate. This report takes the view that, since all evidence points to carbonate minerals being permanently stable in the reservoir environment, as long as a candidate storage reservoir for in-situ mineralization satisfies the criteria for permanency, safety and environmental compatibility of CO_2 storage in the fluid states, and provided the normal industry requirements of site closure and long-term monitoring are adequately financed and executed, the question of how much CO_2 is eventually mineralized versus remaining dissolved in aqueous solution is immaterial. For this reason, methods to estimate how much carbonate can be precipitated in given in-situ mineralization sites is not treated in detail in the present report. Estimation of carbonation capacity is of course relevant for other aims, such as optimal site selection for implementation of in-situ mineralization, design of injection plans and number of wells for a given site, and assessment of the contribution of specific in-situ mineralization sites to national and global goals to mitigate climate change.

4.2. International guidelines

In 2006 the Intergovernmental Panel on Climate Change (IPCC, 2006) issued guidelines for greenhouse gas inventories, including a review of the scientific principles and assessment methodology for geological storage. As this document preceded the first in-situ mineralization tests in Icelandic basalts in 2012 (Section 5.1), it discusses in-situ mineralization primarily in relation to long-term mineral carbonation reactions in sedimentary aquifers. In-situ carbonation of basalts is touched upon only in passing. This authoritative guideline became the basis for and is compatible with later, more specific international regulations on geological storage of CO_2 (Dixon et al., 2015). For example, since 2011, geological storage has been considered a legitimate Clean Development Mechanism (CDM) under the Kyoto Protocol of the United Nations Framework Convention on Climate Change (UNFCCC, 2011b).

In 2009, the EU released a legally non-binding Directive to guide the permanent, safe and environmentally sound development, operation and monitoring of CO_2 storage sites in sediment-hosted aquifers and depleted oil/gas reservoirs within the EU (EU, 2009). In-situ mineralization in basalts and serpentinized peridotites was not mentioned in that Directive.

In 2017 the International Organization for Standardization (ISO) released document ISO 27914 on "Carbon dioxide capture, transportation and geological storage" (ISO, 2017). This document was written by Technical Committee ISO/TC 265, which consists of representatives from 18 countries including

Canada, USA and Norway (which so far have the most practical experience in Carbon Capture and Storage, CCS) and also Switzerland. Ten further countries participated as observers, and the document was written in liaison with numerous other international CCS organizations (IEAGHG, IEA, GCCSI, CSLF, WRI, EIGA, and CO2GEONET). This comprehensive document makes no mention of the in-situ mineralization approach other than explicitly stating that the document does not address CO_2 storage in basalts (or in other rock types: coal, shales and salt).

In 2024 the European Commission published a series of guidance documents to improve understanding of the 2009 EU Directive and provide more detailed indications of how it can be implemented (EC 2024a, 2024b). These newer guides mention in-situ mineralization with regard to storage capacity and monitoring of containment of the aqueous CO_2, but do not introduce new measures that are specific to this approach. That treatment is consistent with our conclusion in Section 3.6, that in-situ mineralization is to be viewed as a hydrogeological equivalent of conventional CO_2 storage.

The present report uses criteria from all of the above guidance documents to evaluate the permanent containment, safety and environmental compatibility of the ongoing in-situ mineralization projects in countries outside the EU. The EU Directive states that it does not apply to projects intending to inject less than 100,000 tonnes of CO_2 (a relatively small amount) for the purposes of research, development or testing of new processes. Most of the projects evaluated in this report fall within this excepted class, but application of the storage-site criteria nevertheless identifies to what extent the pilot projects are aiming to comply with the international storage standards.

In line with the mandate of FOEN to assess environmental safety, the EU Directive (EU, 2009) states that the **minimum conditions for an acceptable CO_2 storage site are that there is no significant risk of leakage, and no significant health or environmental impacts are likely to occur.** Accordingly, storage site operators are obliged to provide permitting authorities proof of permanency of CO_2 storage, safety and environmental compatibility. The following sections summarize the basis for these proofs and their evaluation criteria. Caprock criteria are included, as they are relevant to in-situ mineralization projects injecting supercritical CO_2 (e.g., Wallula and Elementeita; Chapter 5).

4.3. Criteria to demonstrate permanent CO_2 containment

Proof that a given in-situ mineralization site provides permanent CO_2 containment (also termed **storage security**) derives from two sources: (1) monitoring of **conformance** of the behaviour of injected CO_2 in the reservoir with its predicted (model) behaviour, and (2) long-term instrumental **monitoring** for leakage. For full-scale storage sites, proof of containment is additionally required to meet compliance with regulations for site closure and transfer of site liability.

As a testimony to the comprehensiveness of the containment criteria recommended in the international best-practice documents, the performance record of conventional CO_2 storage sites since they were first implemented some 30 years ago is reiterated here from Section 2.3: none of the more than 50 commercially operated sites that have been selected, implemented and operated in accordance with the best-practice principles has ever been found to leak CO_2 for a geological (subsurface integrity) reason (IEAGHG, 2025a). At one site (Decatur, Illinois), a damaged section of an observation well was found to have leaked a small amount of free-phase CO_2 above the main caprock at 1500 m depth, but this was detected by routine monitoring and the damage was readily repaired (EPA, 2024). As the leakage occurred into rocks that were sealed above by multiple secondary caprocks, it posed no environmental threat. This event is in line with the long-held opinion in the CO_2 storage industry, that potentially poorly sealed wells constitute the highest-risk component of the technology.

4.3.1. Monitoring of conformance

Given the geometric and hydrogeological complexities of subsurface reservoirs, predicting the behaviour of injected CO_2 (whether in the aqueous or pure state) is a challenging scientific task. A large amount of time, effort and funds are invested in this endeavour at each storage site. During initial site selection and characterization, sufficient information needs to be assembled to construct a static, three-dimensional (3D), digital model of the geological **storage complex**. The complex is the 3D extent of the storage reservoir that will be accessed by the injected CO_2, including any internal faults and fracture systems, and where necessary, one or more caprocks of ≥ 20 m thickness. The overall stratigraphy and structural geology of the site needs to be specified, including rock units above and below the reservoir, based on field observations, seismic surveys and examinations of drill cores. In the digital model, the relevant reservoir and caprock units need to be assigned full quantitative hydrogeologic properties (distribution of accessible porosity, distribution of permeability, poroelastic moduli, stress state, maximum fracturing pressure, initial fluid pressure, reservoir temperature distribution, heat capacities, heat conductivities, chemical composition of native groundwater, rate and direction of groundwater flow, etc.). Input for these properties comes from analyses of drill cores through the storage complex, and from downhole geophysical logging, hydrotests and stress tests.

Once the static geological model has been constructed, numerical reactive-transport simulations of the planned CO_2 injections are conducted at the reservoir scale. These dynamic simulations track the physical migration of the injected fluid, its chemical and physical interaction with native groundwater and reservoir rock, and the evolution of pressure, temperature and stress, all as a function of time and space. Available benchmarked industry and academic simulation codes are capable of fully coupling thermal, hydraulic and chemical (THC) processes on the one hand, or coupling thermal, hydraulic and mechanical processes on the other (but not yet all four aspects, which are coupled in nature). Both thermodynamic and kinetic aspects of mineral–fluid reactions are treated quantitatively. The codes permit simulations within large spatial domains (several km^3) discretized into millions of cells. The simulation results predict the movement, location, state and trapping mechanisms of the injected CO_2-bearing fluid within the storage complex (i.e., how much CO_2 is in the aqueous or mineral carbonate states) at high temporal and spatial resolution for periods of up to thousands of years. As is always the case with such models, the accuracy of their predictions depends on the quality of the numerous input parameters listed above (many of which are uncertain in practice), and on the realism and completeness of the processes accounted for in the models.

The match between the model predictions and reality is typically tested in preliminary pilot injection projects involving small amounts of CO_2. The results allow mismatches to be investigated and the models refined. Regulatory authorities examine the results of pilot tests prior to granting a permit to operate a storage site.

Once injection for long-term storage begins, the conformance test consists of monitoring as many features of the stored CO_2 as possible and repeatedly comparing them to the predictions of the reactive-transport reservoir simulations. Monitoring can involve tracking the migration of the injected fluid using 4D geophysical surveys (seismic reflection, electrical resistivity) and observation wells along the flow path. The evolution of pressure, temperature, reservoir fluid composition and stress can be monitored by instruments placed in injection and observation wells and via surveillance of seismicity recorded on the surface or in shallow wells.

Deviations of the observations from the predicted processes in the reservoir need to be reported, investigated and explained, typically by updating and analysing the THC reservoir models, and may trigger corrective measures according to a pre-planned scheme, such as lowering injection rates.

4.3.2. Monitoring for leakage

Leakage is defined as any escape of CO_2 from the defined storage complex. As part of the permitting process prior to starting injection for storage, operators are required to define all possible site-specific leakage paths and their associated hazards and risks. In principle, leakage may occur in the aqueous or decompressed gaseous state by fluid ascent along the outside of improperly cemented wells (whether operating or abandoned), by upward expulsion into shallow freshwater aquifers, and eventually by seepage into surficial soils, water bodies (lakes, rivers, seawater), and the atmosphere. Before injection starts, operators are required to measure baseline concentrations of CO_2 in the listed situations, including shallow aquifers, soils and surficial water bodies, and install long-term CO_2-detection devices. Based on a monitoring plan, concentration measurements must be made at suitable intervals and reported to the regulatory authority. Deviations from the baseline concentration that indicate leakage are the prompt to activate pre-planned mitigation steps, such as reducing reservoir pressure or stopping CO_2 injection altogether. Kolahchian et al. (2024) outline a possible framework for monitoring, measurement and verification (MMV) of in-situ mineralization in peridotites.

In practice, it is often difficult to prove that a minor deviation of a CO_2 concentration baseline in surface or near-surface monitoring sites is due to leakage from an underlying storage reservoir. For various reasons, the surface and shallow sub-surface environments are prone to natural fluctuations of CO_2 contents at several time scales. Depending on its source, the CO_2 feedstock being injected may have an isotopic composition ($\delta^{18}O$, $\delta^{13}C$, $\delta^{14}C$) that differs strongly from that of natural CO_2 in the monitoring environment, allowing for clear identification of leakage. Another possibility for unambiguous monitoring is to analyse repeatedly for the artificial tracers that are often co-injected with the CO_2 during early pilot- and development stages of the storage site (Section 2.6.2). However, in large-scale commercial storage operations, co-injection of tracers may not be feasible for cost reasons.

4.3.3. Duration of post-closure monitoring

For the reasons given in Section 2.1, it is widely accepted that once all injected CO_2 becomes fixed as carbonate minerals, an in-situ mineralization site no longer needs to be monitored to assure conformance or detect leakage. Yet, as stated in Section 2.6.2, it is still not clear how long it takes to achieve 100% mineralization, and we are not aware of any proposals in the literature of field methods that could be used to verify 100% mineralization at a given site. In addition to the use of co-injected geochemical tracers (Section 4.3.2), an obvious methodology is to sample the reservoir fluid via wells, determine the concentrations of solutes and calculate the saturation states of all potential carbonate minerals. If these calculations indicate that the minerals are saturated, then it could be argued that chemical equilibrium has been achieved in the reservoir and hence all the CO_2 that can be mineralized has been mineralized. In practice, this methodology may not account for mineral metastability (Section 2.6.2), which will stabilize higher residual aqueous CO_2 concentrations than those at full equilibrium, and it may fail to yield solute concentrations that are representative of the entire storage zone within the reservoir.

Until mineralization is complete, all in-situ mineralization reservoirs will contain elevated concentrations of residual aqueous CO_2. In projects that inject supercritical CO_2 under a caprock, the reservoirs may also contain residual free-phase CO_2 that has not yet dissolved into the groundwater. The questions therefore arise as to how long the sites need to be monitored after injection has ceased and if in practice this period will last beyond the closure and decommissioning of the site.

Whereas aqueous (dissolved) CO_2 is viewed as a permanent and secure state of storage by the guidance documents (e.g., ISO, 2017), none of the reviewed documents waives the need to monitor for conformance and leakage once this end-state has been achieved. The minimum duration is typically set to the duration of the injection programme, but local regulators may choose to require monitoring beyond the cessation of injection. If the groundwater in an in-situ mineralization reservoir is naturally stagnant, and if the pressure gradients induced by CO_2 injection have decayed or stabilized, then post-closure monitoring is likely to be unnecessary. In contrast, if the groundwater is found to be naturally migrating due to regional hydraulic-head gradients, then it can be concluded that discharge must be occurring somewhere in the system to explain the flow (e.g., discharge into another confined or unconfined aquifer). This raises the possibility that the aqueous CO_2 may eventually escape the defined storage reservoir. In this case, an evaluation of the flow rates versus the likely mineralization rates may determine if there is need for long-term monitoring.

In in-situ projects that inject supercritical CO_2, the duration of post-closure monitoring should follow the regulations for conventional CO_2 storage, in line with Section 3.6. However, there is no universally accepted regulation for this case, and the recommended duration of monitoring to ensure CO_2 containment varies somewhat between the international guidance documents:

- The Intergovernmental Panel on Climate Change (IPPC, 2006) argued that post-closure monitoring is necessary only until it can be demonstrated that any plume of supercritical CO_2 has ceased to migrate within the reservoir, in conformance with the forecasts of reservoir simulations. Once the CO_2 plume in an in-situ mineralization reservoir is demonstrated to be immobile, and if the groundwater in the reservoir is stagnant, then monitoring could cease.

- The US Environmental Protection Agency (EPA) implements a Class VI Well Rule for geologic sequestration (EPA, 2018), requiring post-injection site care (PISC) for a period of 50 years, unless a shorter period is approved based on site-specific data showing that the free-phase CO_2 plume has stabilized and is not expected to migrate.

- The European Union Directive (EU 2009) states that monitoring should continue until the site is deemed permanently safe, typically interpreted as 20–50 years after injection ceases.

- ISO 27914 (ISO, 2017) explicitly does not address the post-closure period and it leaves post-closure requirements to regulators.

In practice, the international guidance documents are treated literally as guidance only, and monitoring regulations for conventional CO_2 storage sites are set by local legal jurisdictions. The required duration of monitoring thus varies enormously. For example, the Province of Alberta in Canada requires post-closure monitoring for 10 years, whereas the State of California in USA requires monitoring for 100 years (IEA, 2022). Presumably, the application of these regulations to in-situ mineralization sites will also vary between jurisdictions. In Switzerland, containment of CO_2 in any geological storage site, regardless of the trapping mechanism, must be verified annually for an undefined period into the future (Fedlex, 2025).

The multi-decade periods that may be required for post-closure monitoring of conventional CO_2 storage sites has meant that the long-term responsibility for monitoring and the long-term liability for sites cannot be borne by the original commercial operators but must be transferred to the state. The technical and legal conditions for this transfer are part of the initial permitting process prior to commencing injection. Even if very long-term monitoring is not required for in-situ mineralization sites, a similar transfer of liability is necessary. As an example, the legal requirements of monitoring and transfer of liability at the commercial-scale CarbFix in-situ mineralization site are published in the permit for that project (EAI, 2024).

4.4. Criteria to demonstrate safety

Safety refers to avoidance of risks that could cause accidents, injuries or illness to the project staff and to human populations in the vicinity of the CO_2 storage site. This includes on-site risks during surface operations (about which we authors are not qualified to make expert comments), risks associated with transport of CO_2 to the injection site, the risk of inducing strong earthquakes during CO_2 injection (Section 2.8), and risks related to CO_2 leakage from the defined storage complex, e.g., asphyxiation or hypercapnia in humans and animals.

Proof of compliance with industry regulations that govern operational safety must to be provided to the regulator by the operator of the storage site, just as in any other industrial operation. Proof that no unsafe leakage is occurring is provided by the same leakage monitoring programme as described in Section 4.3.2.

4.5. Criteria to demonstrate environmental compatibility

Proof of environmental compatibility is based on two sources:

(1) Reports from the site operator to the regulator that demonstrate careful handling of environmentally sensitive materials, responsible use of water resources to co-inject with CO_2 and responsible disposal of waste water. Permitting authorities also typically require operations to conform to limits on noise and atmospheric emissions (injection sites usually have a small surface footprint of approximately 5000 m^2, which is easily monitored). At the outset of a storage project the operator is further obliged to submit plans to the regulator of how the site will be decommissioned at the end of its injection lifetime, including details of how wells will be plugged and abandoned, and how any changes made to the landscape will be rehabilitated.

(2) Assessments of environmental risks due to CO_2 leakage in either the gaseous or aqueous states (e.g., acidification and toxic-metal contamination of shallow freshwater aquifers, effects on the biosphere including animals; accumulation of CO_2 gas in depressions on the surface topography) and their possible impact, likelihood, degree of acceptability, and contingent corrective measures (e.g., ceasing injection of CO_2, plugging wells). These assessments include establishing pre-injection CO_2 concentration baselines in the local environment, using the same site-specific monitoring programmes as described in Section 4.3.2.

Any active CO_2 injection site could also cause additional environmental perturbations at the Earth's surface, similar to many other industrial activities. During the construction phase, these may include generating dust, noise, light, and traffic pollution. During operation of the sites, surface perturbations may include increased noise, traffic, risks of water contamination, soil erosion, disruption to local biodiversity, and aesthetic changes to the landscape and other social impacts. Assessments of such impacts are routine (e.g. an example is given by Nyaga et al., 2024 for the DAC plant at the Cella CO_2 mineralization site in Kenya) and are not dealt with in this report.

5. Implementation sites for in-situ CO_2 mineralization

The following sections summarize the aims, geological context, reservoir characteristics, and status of CO_2 injection operations at six sites that have already implemented or intend to implement in-situ CO_2 mineralization.

5.1. Basalt site 1: CarbFix2, Iceland

5.1.1 Sources of information

Information on this project was obtained exclusively from the cited literature.

5.1.2. Project overview

In 2012, the Carbfix company in Iceland began an extensive research and development project named "Carbfix", injecting 230 t CO2 into basalts in the first pilot study of in-situ mineralization worldwide (Gíslason et al., 2018). Following this successful demonstration, the approach was upscaled in 2014 to industrial-scale storage of CO_2 and H_2S in project "CarbFix2", with local Icelandic funding plus contributions from the EU and US-DOE (Gunnarsson et al., 2018; Clark et al., 2020). Since then, more than 84,000 t CO2 have been stored. CarbFix2 officially ended in 2021 but injection at the CarbFix2 site and at three other sites is being conducted by the CarbFix company and its partners. It is notable that the costs of the upscaled operation are significantly offset by co-injecting H_2S, the disposal of which would otherwise be much more expensive (Gunnarsson et al., 2018).

The CO_2 derives principally from the Hellisheidi geothermal power plant (30 km ESE of Reykjavík centre), which produces large volumes of natural, CO_2- and H_2S-bearing thermal water. Annual emissions of CO_2 from the plant are approximately 42,000 t. The CO_2 and H_2S are captured within the cooled wastewater from the surface power plant and then piped to one of the reinjection sites. All the reinjection sites are located in uninhabited areas free of vegetation, about 18 km from the urban perimeter of Reykjavík (Fig. 3).

In 2017, CarbFix2 began injecting CO_2 directly captured from air (Climeworks DAC) as a small-scale pilot, and in 2021 the first commercial DAC plant was installed, in partnership with Climeworks. In 2024 the even larger Mammoth DAC plant was commissioned, again with Climeworks, aiming to inject 36,000 t CO_2 / y. Since 2023, Carbfix Co. has been using the same approach as at Hellisheidi to inject CO_2 emitted from the Nesjavellir geothermal power plant (situated 11 km to the NE of Hellisheidi) into basalts at 900 m depth (project GECO).

The Carbfix company was founded in Reykjavík in 2007 by Reykjavík Energy (a major geothermal energy provider) in collaboration with scientists from the University of Iceland, the CNRS in France, and Columbia University in USA. Environmental and safety regulation of the project is handled by the Environment Agency of Iceland (also written as Icelandic Environment Agency).

5.1.3. Geological setting

The island of Iceland is entirely volcanic in origin, being situated where the mid-Atlantic volcanic ridge (a tectonic plate boundary) rises above sea level. Hence, volcanism and its associated seismicity are active in many parts of the island. The Carbfix injection sites are located between two active volcanoes and their associated NE–SW-trending dyke swarms.

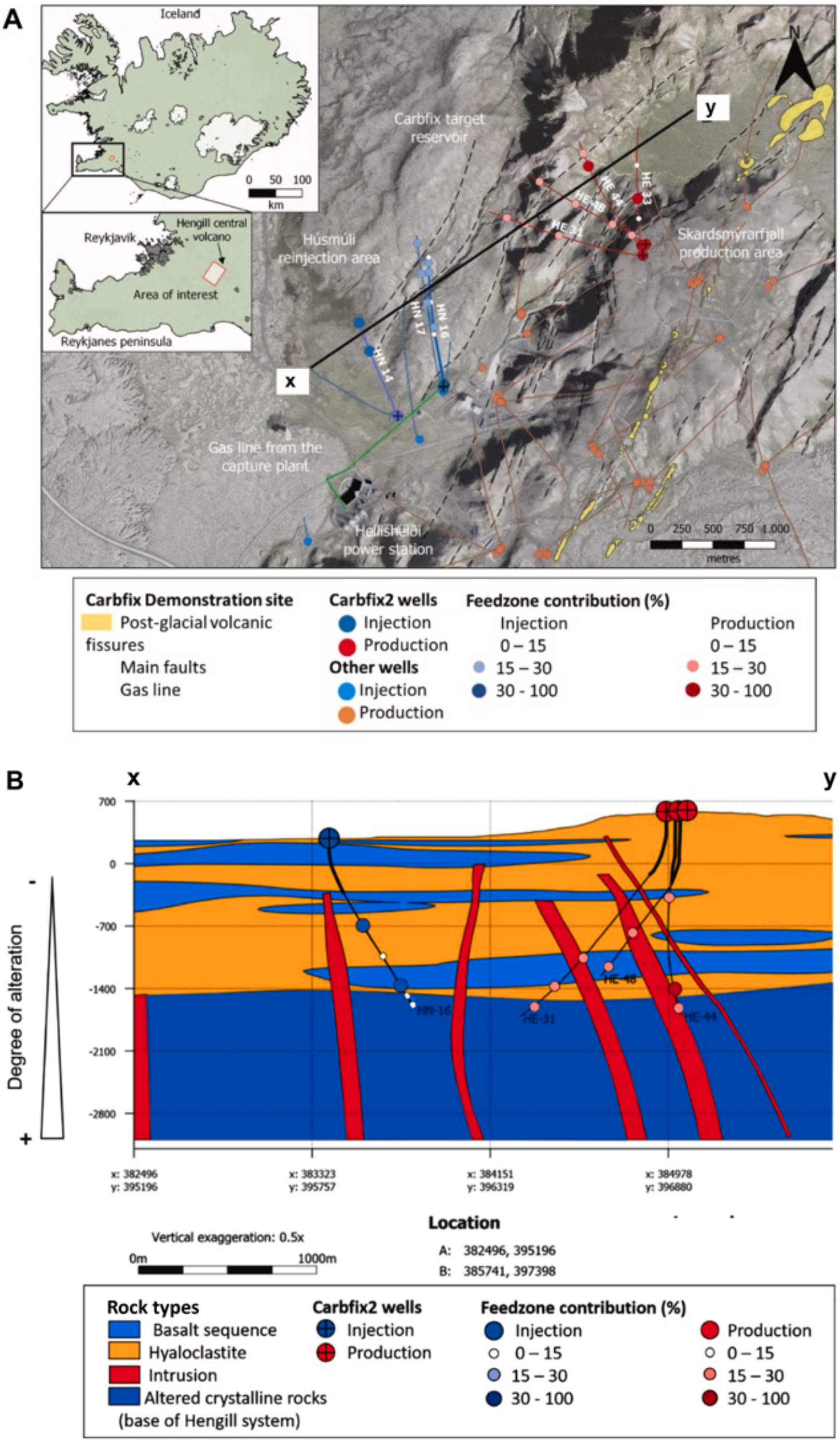


Figure 3. **(A)** Location of CarbFix2 injection sites in a barren basalt lava field, 20 km east of Reykjavík. The source of the CO_2 for injection is the Hellisheidi geothermal power plant (bottom centre of Fig.). The original CarbFix pilot site was located 2 km SW of the power plant. **(B)** Vertical cross-section along the line x–y in panel A, showing injection and production wells. The target aquifer for CO_2 injection is the stack of lavas (basalt and glassy hyaloclastite) between 700 and 1400 m depth. Modified (labels adjusted) after Ratouis et al. (2022).

5.1.4. Site characterization

Many features of the gas injection site had already been characterized during the previous history of exploration and production of geothermal water for energy extraction. Over 100 wells are present, reaching depths from 100 to 3300 m. Their scientific investigation and practical use to pump hot water provided detailed understanding of the basalt reservoir.

All these wells, including the injection and monitoring wells for the CarbFix projects, intersect a sequence of layered basaltic lavas (Fig. 3B), each up to several hundred meters thick, which accumulated during repeated eruptions of volcanoes in the distant Icelandic highlands. Within the targeted reservoir depth of 400–800 m, some layers consist of intact, glassy basaltic lava and others are accumulations of compacted fragments of basalt and glass (hyaloclastites). Their mean rock-matrix porosities are 8.5% and their permeabilities are very high and variable between 3×10^{-13} m^2 and 1.7×10^{-12} m^2 (Sigfússen et al., 2015). Regional-scale extensional faults with vertical offsets of up to 300 m cross-cut the lava sequence and their bordering damage zones significantly enhance permeability. Similarly, fracture-damage zones caused by the intrusion of crystalline basaltic dykes (red in Fig. 3B) provide additional high permeability zones at depths greater than 800 m.

Owing to the typically high volcanic geothermal gradients in the area (~100 °C/km), the deeper rocks are hydrothermally altered to secondary silicate minerals such as chlorite and epidote, but also including native calcite and pyrite (FeS_2) – the two minerals envisioned to fix the injected CO_2 and H_2S via in-situ mineralization.

5.1.5. Injection procedure

The original CarbFix pilot project pioneered the injection of 250 t CO2 pre-dissolved in water into the lava reservoir at 540 m depth, where the temperature was only 35 °C (Sigfússon et al., 2015). Water and CO_2 were piped separately into the well and allowed to mix completely before entering the basalts. Based on solubility calculations, the composition of the final injected mixture (3.5 wt.% CO_2) was chosen such that the solution remained in the single-phase state (undersaturated with respect to the free CO_2 phase) within the reservoir. Addition of non-reactive, non-sorbing chemical tracers to the injected mixture allowed the amount of CO_2 mineralization to be estimated (Matter et al., 2016). This led to the conclusion that **95% of the injected CO_2 was mineralized in the form of calcite within two years** (Matter et al., 2016).

The upscaled CarbFix2 operation is copying the CarbFix approach, including the use of a tracer to track containment of the gases, but it is injecting into a much deeper and hotter region of the reservoir, at 1900–2200 m depth and at 220–260 °C (Gunnarsson et al., 2018). This deep region of the reservoir is the source of the geothermal water for the Hellisheidi power plant, and its production wells are located within 2 km horizontal distance from the CarbFix2 injection wells. Pumping of the thermal water to the surface through the production wells has lowered the reservoir fluid pressure and hence established a hydraulic gradient across the 2 km flow path between the base of the production wells and the CarbFix injection wells. The principle is that mineralization of the injected aqueous CO_2–H_2S solution will occur as the solution slowly migrates towards the geothermal production wells in response to the induced hydraulic gradient (Fig. 4). Since the injected solution is slightly acidic, it is expected to leach the key carbonate-forming cations from the fast-reacting glass in the basalt. Further downstream, once the acidity is neutralized by the water–glass reactions, carbonate minerals should precipitate (e.g., Eq. 13 in Section 2.6.1).

The injected aqueous CO_2 solution is cooler and hence much denser than the native reservoir water, and even when it has entered deep into the reservoir and heated up to the ambient temperature, the injected solution remains significantly denser because it contains more dissolved CO_2 than the native water (Section 2.6). Consequently, the injected solution possesses negative buoyancy and therefore it will not rise through the reservoir as it flows towards the low-pressure zone at the base of the production wells. The lack of an impermeable caprock on the reservoir is of no concern for CO_2 containment.

State-of-the-art numerical simulations of the long-term injection project (using code TOUGH2; Ratouis et al., 2022) are able to quantitatively reproduce a wide variety of observations by considering only thermal-hydraulic phenomena (not chemical processes) and they confirm the conceptual model shown in Figure 4. These simulations provide the basis for conformance of the site and aid in predicting its behaviour into the future.

An advantage of the CarbFix2 well configuration, by which the injected fluid is at least partially recovered through the production wells (Fig. 4; a so-called “doublet” well coupling), is that build-up of fluid pressure in the reservoir is minimized and can be actively managed, thereby avoiding overpressurization and associated fracturing or seismicity.

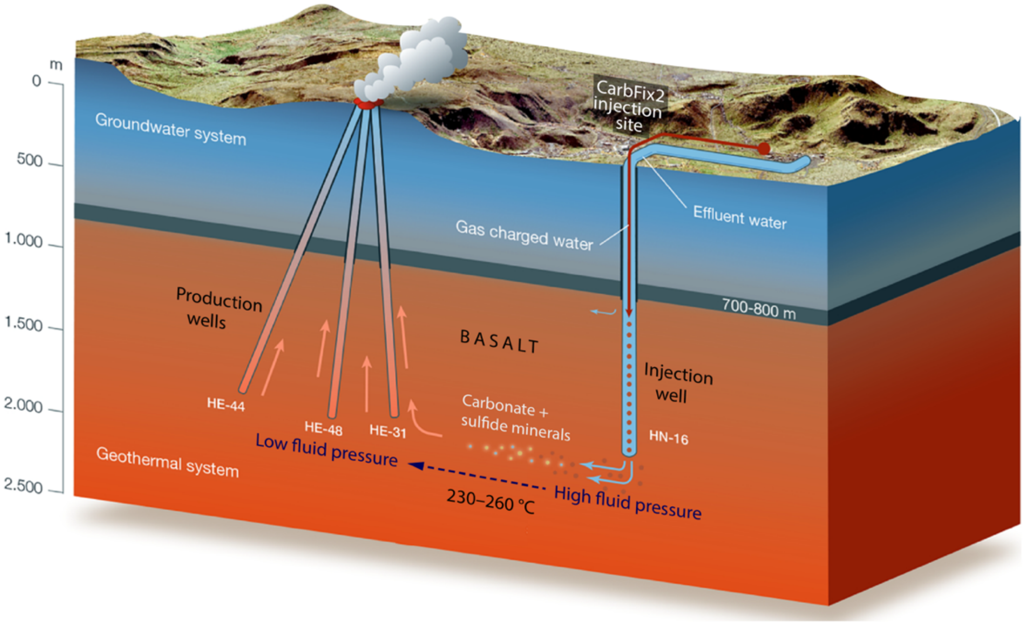


Figure 4. Simplified conceptual model of the deep basalt reservoir of the CarbFix2 in-situ mineralization project. Injection of CO_2 pre-dissolved in water under high pressure creates a hydraulic flow gradient towards the low fluid pressure region at the base of the geothermal production wells. Migration of the aqueous CO_2 solution in response to this gradient allows the fluid to react with the basalt at ~250 °C and precipitate carbonate and pyrite along the flow path. Water pumped up the production wells is analysed to monitor the efficiency of the carbonation reactions. Modified (labels added) after Gunnarsson et al. (2018).

5.1.6. Source of water for injection

The H_2O : CO_2 mass ratio in the injected solution is 28 : 1, implying a huge consumption of water for a relatively small amount of sequestered CO_2. The water is mostly condensate from the Hellisheidi power plant’s steam turbines and is pumped at elevated pressure, already containing the dissolved CO_2, via pipeline to the injection wells. There, additional effluent water is admixed at depth within the injection well. Consequently, the CarbFix2 in-situ mineralization project is self-sufficient regarding water and hence it does not compete with usable freshwater resources on Iceland. An ongoing Carbfix project named “SeaStone” is currently testing the use of seawater as an alternative solvent for co-injection with CO_2.

5.1.7. Project maturity

The Carbfix-operated successor project to CarbFix2 is globally the only commercial-scale in-situ mineralization site operating at present, and its approach has reached a high level of scientific and technical maturity. Currently, about 34% of the CO_2 emitted from the geothermal power plant, i.e., 12,000 t CO2, is being injected per year. Operations are now being scaled up even further in readiness for a new project named “Silverstone”, such that 95% of the CO_2 emitted by the Hellisheiði power plant (up to 40,000 t CO_2 / yr) can be geologically stored via in-situ mineralization.

In 2023, the Carbfix company began injecting CO_2 from the Nesjavellir Geothermal Power Plant in SW-Iceland as a part of the Europe Horizon 2020 funded GECO project. The same approach is used as at the Hellisheiði Geothermal Power Plant, but with optimized capturing efficiency of the scrubbing tower. The gases are dissolved in condensate from the plant‘s turbines and injected into the basaltic subsurface below 900 m.

5.1.8. Proof of CO_2 containment

In the CarbFix2 operation, co-injection of a non-reactive, non-sorbing tracer that is stable even at the high temperatures of the reservoir (1-naphthalenesulfonate) has allowed the breakthrough of the injected solution to be monitored by chemically analysing fluid sampled at the wellheads of the production wells. Monitoring for breakthrough of dissolved cations and any remaining CO_2 or H_2S in the solution (and their possible reaction products CH_4 and SO_2) is also carried out in the same way. Time-series concentration analyses of the tracer taken over a two-year interval (Fig. 5A) have tracked the dispersion and mixing of the injected CO_2 solution with the native reservoir water between the injection and production wells. This time-series allows the analogous time-series behaviour of the injected CO_2 to be calculated for the hypothetical case in which no mineralization occurs (Fig. 5B, green curves). Comparison of this hypothetical behaviour with the observed time-series of CO_2 concentrations (Fig. 5B, blue symbols) reveals the mass of CO_2 that has been lost from the solution along its flow path through the deep reservoir. Control analyses of CH_4 (Fig. 5B, purple symbols) show that the loss of $CO_{2(aq)}$ was not due to chemical reduction. **These results are the principal proof that CO_2 is being stored permanently in the CarbFix2 basalt reservoir.**

Additional geochemical observations, such as similar time-series analyses of dissolved Ca, Mg and other solutes (Clark et al., 2020), and the calculated thermodynamic saturation states of candidate carbonate minerals (Clark et al., 2020) suggest that the lost $CO_{2(aq)}$ precipitated initially as siderite while pH values were still low and CO_2 contents high, then passed through dolomite and perhaps ankerite before calcite became the dominant carbonate to precipitate once elevated pH values were attained and CO_2 concentrations fell due to the progress of reaction. Taking account of the temperature differences, these results from CarbFix2 are consistent with those gained in the original CarbFix project, and demonstrate that the geochemical signatures arising from injection of CO_2-bearing water are reproducible. In the CarbFix project, the occurrence of calcite crystals on a damaged downhole (submersible) pump in the monitoring well was also taken as evidence that calcite precipitated in the reservoir. However, there are other ways to explain the presence of such calcite in this situation (e.g., Wanner et al., 2017).

Using the above methods, it is estimated that **over 60% of the CO_2 injected in the CarbFix2 project is mineralized in the form of calcite within 4 months** (Clark et al., 2020). Thus, in-situ mineralization in basalt at CarbFix2 seems to occur faster than in the CarbFix pilot project, as expected from the accelerated reaction rates caused by the much higher temperatures in the CarbFix2 reservoir.

The above estimate of mineralized CO_2 is referenced to a 4 month period, as this is the minimum travel time that the CO_2-bearing solution takes to migrate from the injection well to the nearest production well, where the monitoring was conducted (4.3 months to reach well HE-31, 5.4 months to reach well HE-48, and 9 months to reach well HE-44 – see Fig. 4; Gunnarsson et al., 2018). As only 60% of the injected CO_2 was mineralized, most of the residual 40% remains in dissolved form within the reservoir. **Some of this residual 40% passes through the production well and is released to the atmosphere upon degassing of the reservoir fluid at the wellhead.** This is visible in Fig. 5, where we have highlighted two areas (yellow boxes): “Area 1” (between the green curve and blue dots) indicates the time-integrated amount of $CO_{2(aq)}$ that has precipitated as calcite, whereas “Area 2” (between the blue dots and the dashed line showing the pre-injection concentration) indicates the amount of injected $CO_{2(aq)}$ that has passed through the reservoir, up the production wells and presumably allowed to degas into the atmosphere. Exactly what fraction of the non-mineralized “residual 40%” of CO_2 is thus released into the atmosphere versus remaining in the reservoir is not clear to us. However, this observation underscores the fact that a well-doublet geometry is prone to re-extraction of some of the injected CO_2.

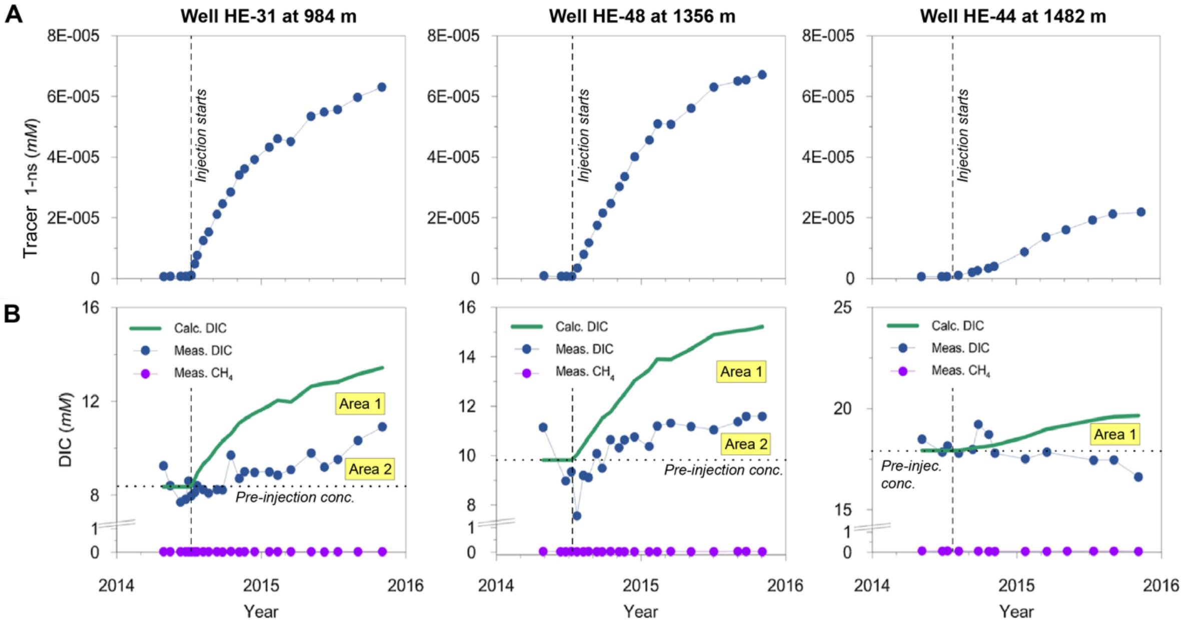


Figure 5. Principal proof for permanent, in-situ mineralization of CO_2 in the CarbFix2 project, based on chemical analyses at the wellheads of three production wells (HE-31, HE-48 and HE-44) over a two-year period. **(A)** Time-series analyses of a non-reactive, non-sorbing, temperature-resistant tracer (1-naphthalenesulfonate) that had been co-injected with the CO_2-bearing solution. These data track the breakthrough of the injected fluid into the production wells, and enable quantification of the dispersion and mixing of the injected fluid as it migrates through the basalt reservoir. **(B)** Chemical analyses of the concentration of $CO_{2(aq)}$ (expressed as total Dissolved Organic Carbon, DIC) in samples taken in a time series over ~1.5 years at the wellheads of the three production wells. Green curve: hypothetical behaviour assuming no carbonate precipitation has occurred in the reservoir (based on the tracer behaviour in panel A). Blue dots: observed concentrations. The differences in behaviour of the three sampled wells are ascribed to their differing distances from the injection well (cf. Fig. 4: fluid travel times to the injection wells are 130 days to HE-31, 163 days to HE-48 and 272 days to HE-44). The purple dots show methane concentrations, ruling out any loss of $CO_{2(aq)}$ by chemical reduction. Between the green curve and blue dots, “Area 1” (labelled for this report) indicates the amount of $CO_{2(aq)}$ that has been lost from the injected fluid. Between the blue dots and the pre-injection concentration (dashed line), “Area 2” indicates the amount of $CO_{2(aq)}$ that has passed through the production well and degassed to the atmosphere at the wellhead. Modified (labels and guidelines added) after Gunnarsson et al. (2018).

5.1.9. Safety

The CarbFix2 operations are subject to stringent regulations, building directly on Iceland’s long experience with producing geothermal waters for electricity generation. No surface operational issues, ground movements or felt seismicity have been reported. The lack of felt seismicity is notable and confirms the well-doublet geometry as a viable, long-term means to avoid over-pressurizing the reservoir.

In contrast, prior to the CarbFix projects, up to 2 cm of surface ground movements and simultaneous seismicity, including two M4 events, were caused by re-injection of wastewater into the same reservoir as that used for CarbFix2. However, these phenomena lasted only for the first few months of re-injection (Juncu et al., 2020).

5.1.10. Environmental compatibility

The permit for the project was issued by the regulator, the Environment Agency of Iceland and is published online (EAI, 2024), thereby providing transparency for the public. No deviations from the regulations have been reported from the CarbFix and CarbFix2 projects.

As noted above at the end of Section 5.1.8, a fraction of the injected CO_2 is re-extracted inadvertently via the production wells and is degassed into the atmosphere.

The site of the CarbFix2 storage reservoir was carefully chosen to lie between, not within, zones of active volcanism. Nevertheless, active and dormant volcanoes lie just a few kilometers to the west and east, and therefore the site could be affected in the future by volcanic eruptions. Entry of magma into the storage reservoir may release CO_2 along the margins of the intrusion, regardless of whether the CO_2 is initially present in carbonate minerals or dissolved in the groundwater. If the site becomes buried by erupted lavas, the resulting increase in overburden pressure on the storage reservoir would raise the solubility limit of CO_2 and hence enhance the long-term stability of CO_2 stored in the aqueous state. Carbonate minerals would remain unaffected by such burial. Although the temperature of the storage reservoir may rise by some tens of degrees, this is unlikely to cause a problematic increase in fluid pressure, as the additional overburden would tend to counteract the thermally induced fluid expansion. Volcanic eruptions are typically preceded by ground deformation and uplift, and the eruptions themselves often rupture local faults, generating earthquakes. Both processes could cause leakage of any dissolved CO_2 persisting in the aqueous state, but any CO_2 sequestered in carbonate minerals would remain stably stored.

5.1.11. Evaluation

The CarbFix projects are the flagship demonstrators for in-situ mineralization as a means to store CO_2 in geological formations. The science and engineering know-how now being applied to the commercial-scale operations is based on decades of early experience with extraction of geothermal waters, on the successful CarbFix pilot project, and on the past 11 years of successful operation of the CarbFix2 injection site. The Carbfix company has recently documented its in-situ mineralization methodology (Carbfix, 2022) and its compliance with ISO best practice (ISO, 2017) has been certified by Det Norske Veritas (DNV), an independent, international verifier.

Throughout this history of development achieved by the Carbfix company, scientific collaborators have published a wealth of relevant research findings in international peer-reviewed scientific journals. Notable among these are results of site characterization and predictive simulations of CO_2 injection and reservoir behaviour, which were published before the injection campaigns began (e.g. Gíslason et al., 2010). This practice exposes the scientific basis of the project to pre- and post-injection scrutiny and verification by interested parties who are completely independent of the project. Regardless of whether the predictions are confirmed or refuted by the post-injection monitoring programme, this practice enhances the transparency and credibility of the project management. Likewise, the publication of the certification document concerning methodology (Carbfix, 2022) and of the permit for operating the storage sites (EAI, 2024) ensures transparency.

Overall, the cited 60% mineralization of the injected CO_2 within 4 months has proven with hard scientific data that in-situ carbonation of basalts is a viable storage option. However, it should not be overlooked that the residual 40% of the injected CO_2 remains in dissolved aqueous form within the reservoir over some longer – as yet undetermined – period, and that some of this residuum is being inadvertently pumped out of the production wells and released to the atmosphere. However, it is reasonable to assume that **injection into a similar reservoir without production wells would guarantee complete and permanent containment of CO_2 in its combined mineral and dissolved forms.**

The energetic and economic efficiency of the coupled Hellisheidi power plant and CarbFix2 in-situ mineralization project is impressive. By the time the Silverstone gas-capture installation is complete (enabling 95% of the power plant's gas emissions to be captured), Hellisheidi will be supplying electricity and urban heating water for consumers in Reykjavík, electricity to CarbFix2 pumps to sequester its CO_2 emissions, and electricity and hot water to drive the Mammoth direct air capture plant, for which CarbFix2 will sequester an additional 36,000 t CO_2 per year. The latter fraction of the total stored CO_2 will then allow CarbFix2 to be considered a negative emissions technology.

5.2. Basalt site 2: Wallula, USA

5.2.1. Sources of information

Information on this project was obtained exclusively from the cited literature.

5.2.2. Project overview

From 2009 to 2015, the US Pacific Northwest National Laboratory PNNL (McGrail et al., 2017) conducted a CO_2 injection pilot in basalts at the Wallula locality (46°06'06.55"N 118°55'05.86"W), situated 20 km southeast of Pasco in south-eastern Washington State, USA. Partial funding came from the Big Sky Carbon Sequestration Partnership of the US Department of Energy, and the State of Washington acted as project regulator. The aim was to test injectivity and containment of the basalts for CO_2 in three thermodynamic states: supercritical, aqueous and solid carbonate minerals. The site is located on the property of a paper mill directly beside the Columbia River in an irrigated agricultural area of an otherwise semi-arid region.

5.2.3. Geological setting

The target basalts for CO_2 storage belong to the Columbia River Basalt Group, a 5 km thick stack of hundreds of individual lava layers (lava "flows") that extends over 200,000 km^2 of the states of Washington, Oregon and Idaho (an area 5 times greater than that of Switzerland). Such huge occurrences of areally blanketing basalts are termed continental flood basalts. The volcanism responsible for the basalts lasted from 17 to 6 million years ago and is entirely extinct. Heat flow in the region (60 mW/m^2) has now decayed to within the typical continental range, and the mean geothermal gradient in the region is 41 °C/km. Note that the five currently active volcanoes in the west of Washington State (including Mount St. Helens) are caused by geological processes that are entirely unrelated to those that formed the Columbia River basalts. Individual lava flows in the Columbia River Basalts are stratiform (sheet-like) and subhorizontal, with thicknesses of 30–60 m and lateral extents from tens to hundreds of km (Fig. 6). Owing to variations in the eruption rates and surface topography during lava emplacement, the flows vary in their reservoir properties, some being highly porous and permeable while others are massive, non-porous and impermeable. Comparably large continental flood basalts to those in the Columbia River Group occur in India (Deccan Traps), Brazil (Paraná-Etendeka) and Siberia (Siberian Traps), hence there is international interest in their suitability for CO_2 storage.

Figure 6. Typical outcrop of stacked lava flows belonging to the Columbia River Basalt Group along the Grande Ronde River in Washington State, USA (from Self et al., 2014). The Wallula project injected supercritical CO_2 into basalt layers of this type at 830-890 m depth below surface.

5.2.4. Site characterization

Only one well was drilled into the reservoir rocks. Well cuttings and geophysical logging at 830–890 m depth identified a 60 m thick set of porous lava flows showing strong syn-eruption fragmentation (brecciation) and fracturing. Hydrotests showed these flows to be highly permeable and therefore they were designated as the target reservoir. Overlying these is the intact and massive, regionally extensive Umantum basalt layer, which has very low rock-matrix porosities and permeabilities (≤ 1e-19 m^2), and which thus serves as a sealing caprock for the CO_2 reservoir (McGrail et al., 2014). Both the reservoir lavas and caprock lavas are mineralogically dominated by plagioclase, augite and volcanic glass, with minor native calcite and quartz partially filling pores (Polites et al., 2022). Prior to injection the temperature in the reservoir was 36 °C and the fluid pressure was near hydrostatic at 7.7 MPa.

5.2.5. Injection procedure

In 2013 a total of 977 t CO_2 were injected in the dry, supercritical state through the single well at depths of 830–890 m (average rate of ~0.5 kg/s; 40 Mt/day; Depp et al. 2022; White et al., 2020). Note that the original literature stating this tonnage (McGrail et al., 2017) uses the petroleum industry abbreviation “MT” for “metric tons”, which is not to be confused with the S.I. abbreviation “Mt” for “millions of tonnes”. Seven months after injection, the concentrations of the aqueous cations Ca, Mg, Fe and Mn in the groundwater of the reservoir had increased strongly, indicating that dissolution of supercritical CO_2 into the groundwater had caused acidification that resulted in leaching of the carbonate-forming cations from the basalt. This behaviour was as expected from pre-injection laboratory experiments carried out on Columbia River basalts (McGrail et al., 2006; Schaef et al., 2010, 2011).

5.2.6. Source of water for injection

As CO_2 was injected in the dry, supercritical state, no water was required for co-injection. Modest amounts of local on-site water from the paper factory (“Boise system water) was used for drilling and hydrotesting.

5.2.7. Project maturity

The pilot project was completed in 2015 and is considered by the operator to be a success. No long-term monitoring of the CO_2 reservoir has continued beyond 2015, and there is no mention in the reviewed literature that surface monitoring for leakage might be continuing. Upscaling of the results of the Wallula project is currently being undertaken by at least two projects: (1) the Oregon Basalt CarbonSAFE Phase II project at Hermiston, Oregon (HERO CarbonSAFE) is planning to establish a storage site to inject 50 Mt CO_2 over 30 years beneath the Hermiston natural-gas-fired power station (McLaughlin et al., 2024); and (2) The Columbia River Basalt Technical Assistance Program (CaRBTAP) is undertaking research and development to support implementation of in-situ mineralization in the Columbia River Basalts (Carbon Solutions, 2025).

5.2.8. Proof of CO_2 containment

In 2011, prior to injecting CO_2, a long-term hydrotest was conducted from the injection well, confirming that the designated caprock lavas preclude hydraulic connectivity with the overlying basalt aquifers. This conclusion is supported by contrasting groundwater compositions in the reservoir versus overlying aquifers above the caprock. This proof of the sealing function of the caprock enabled the project regulator to issue an injection permit for the Wallula project.

In 2015, two years after CO_2 injection, the injection interval of the well was surveyed again by geophysical logging and numerous small “sidewall” cores were drilled from the immediately adjacent reservoir rock. Examination of these cores revealed newly formed carbonate minerals: aragonite ($CaCO_3$), ankerite ($Ca(Fe,Mg,Mn)(CO_3)_2$) and siderite ($FeCO_3$), with chemical and stable carbon and oxygen isotopic compositions distinct from the known native (pre-existing) carbonate minerals (Lahiri et al., 2023). Fluid sampling was repeated, revealing increased concentrations of TIC, Ca, Fe, Mg, and Mn by 1.5 to 3 orders of magnitude, consistent with the expected dissolution of basalt due to the acidification of the reservoir groundwater by injection of CO_2. Hydrotests were also repeated. Based on a comparison of the pre-and post-injection observations, it is estimated that **60% of the injected CO_2 was mineralized as carbonates within 2 years after injection** (McGrail et al., 2017). This mineralization rate equates to 293 t CO_2 / yr, similar to that was expected based on laboratory experiments, strengthening confidence in the predicted mineralization rates (Polites et al., 2022; Cao et al., 2024). These observations were taken as confirmation that a large portion of the injected CO_2 was successfully mineralized (McGrail et al., 2017; Polites et al., 2022; Lahiri et al., 2023). However, regardless of the mineralization rates and fraction of mineralized CO_2, the containment of the site is guaranteed by the demonstrated sealing property of the caprock at Wallula.

5.2.9. Safety

No safety-relevant operational incidents were reported. Seismicity was monitored but no events ≥ M 2 were reported. The Wallula injection site was decommissioned in 2015 and the one drilled well was permanently plugged, all in compliance with Washington State well regulation and abandonment procedures.

5.2.10. Environmental compatibility

Aqueous trace metals were tracked over time in the injection interval of the well, revealing increasing concentrations of Ni, Co, and Zn, though Ni and Co remained below 1 and 0.1 $\mu g/g_{H2O}$, respectively. These concentrations are not problematic as long as no leakage of the groundwater occurs, as expected from with the evidence above regarding CO_2 containment. It was demonstrated at this site that at least some of the potentially toxic metals are incorporated into the newly formed carbonate minerals, limiting their concentration in the fluid (Polites et al., 2022).

5.2.11. Evaluation

The Wallula injection pilot has been conducted in compliance with the local governmental regulator by applying a comprehensive, science-based methodology incorporating state-of-the-art field and laboratory tests. Numerical simulations were conducted to interpret hydrotests (White et al., 2022), but to our knowledge no reservoir-scale numerical simulations have been performed. As all evidence on the performance of the site comes from one well, input data are presumably insufficient to usefully constrain such large-scale models. With the exception of the latter, the study is fully in accordance with international best practice (cf. Section 4.2). The site investigations have been performed by experienced reservoir geologists and geochemists from a world-renowned research institute (Pacific Northwest National Laboratory). Numerous scientific publications (some peer-reviewed) document various aspects of the injection procedures and results, lending credibility to the project. Wallula has thus contributed important advances to the in-situ mineralization technology in basalts.

5.3. Basalt site 3: Jizan, Saudi Arabia

5.3.1. Sources of information

Information on this project was obtained from the cited literature, from an oral conference presentation (Oelkers et al., 2025) and from a 1-hour online interview with Dr. Hussain Hoteit, Professor of Energy Resources and Petroleum Engineering at the King Abdullah University of Science and Technology (KAUST), Saudi Arabia, who is a member of the site characterization and injection team for the project.

5.3.2. Project overview

Saudi Arabia intends to reduce its inland CO_2 emissions from currently 600 Mt/yr to 230 Mt/yr by 2030. To this end a national geological storage programme is underway, with ongoing large-scale CO_2 injection into depleted oil and gas reservoirs in eastern Saudi Arabia (Vahrenkamp et al., 2021). The long-term focus of this programme is on storing Saudi emissions, rather than accepting CO_2 for storage from other countries.

On the southwestern Red Sea coast of Saudi Arabia, the Jizan Economic City (Fig. 7A, inset) is emitting large amounts of CO_2 from its petroleum refining, power generation and desalination facilities. As the city lies more than 1000 km from the eastern CO_2 storage fields, a search has been made for local geological sites in which the captured emissions can be sequestered. In 2018, an in-situ CO_2 mineralization pilot project was launched, sited 40 km north of Jizan Economic City (Fig. 7A). A site was selected in 2022 in a desertic area crossed by wadi courses with very sparse vegetation. Small-scale farms, industrial installations and some settlements are also present nearby. Laboratory CO_2 mineralization experiments on the reservoir basalts showed traces of calcite forming after 60 days at 40 °C (Oelkers et al., 2022), thereby justifying a field injection pilot.

The pilot project is operated by Saudi Aramco, the state-owned Saudi Arabian Oil Company. In Saudi Arabia, the entire subsurface deeper than 300 m below surface is owned by the national government. The site has been investigated scientifically by researchers at the King Abdullah University of Science and Technology (KAUST), in collaboration with former members of the Carbfix site-characterization team (Oelkers, Gíslason).

5.3.3. Geological setting

The Jizan site is located within one of the many large occurrences of basalt lavas in western Saudi Arabia (locally termed Harrats). The target reservoir basalts belong to the Jizan Group (Fig. 7A), which formed between 30 and 21 million years ago. Other basalts as young as 10,000 years (labelled

"Quaternary effusive volcanism" in Fig. 7A) cut through and locally overlie the Jizan Group (Fig. 7B). Owing to this recent volcanic activity, heat flow in the area is anomalously high (< 210 mW/m^2) and hot springs occur in the greater region with discharge temperatures of 46–79 °C (Lashin and Al Arifi, 2012). The injection site is situated on outcrops of basalt lava flows that continue to 1 to 2.5 km depth. Over a very large surrounding area towards the coast, the same basalts are present in the subsurface, buried by thin layers of alluvial sediments (too permeable to serve as caprocks). The Jizan Group basalts are locally cut by large extensional faults that run N–S, parallel to the coast (Fig. 7B).

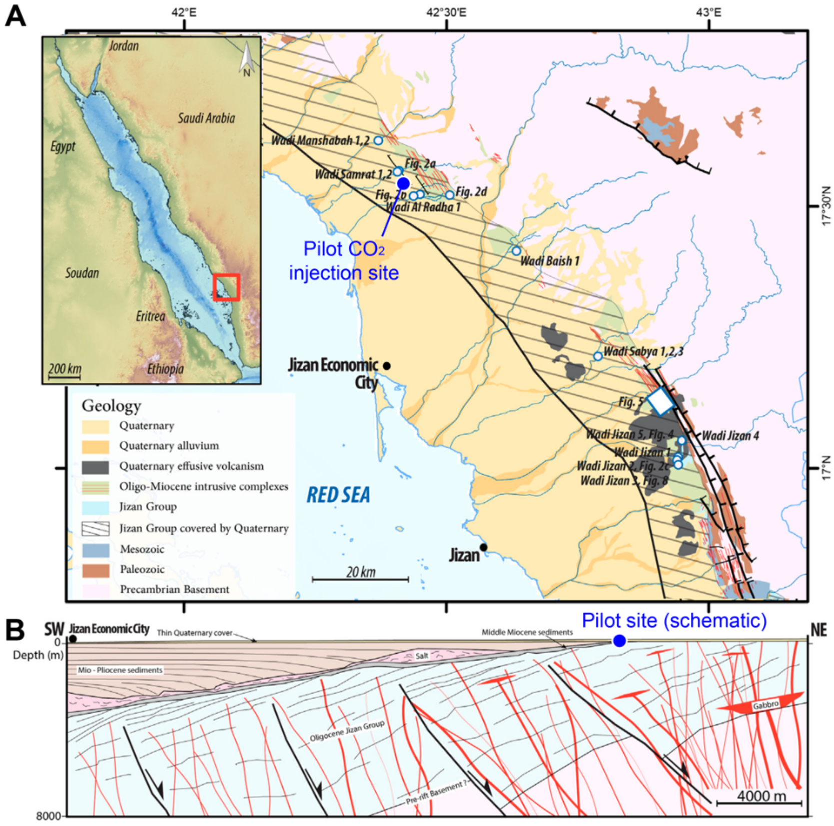


Figure 7. Location and geological setting of the Jizan in-situ mineralization pilot project. **(A)** The reservoir basalts into which CO_2 was injected belong to the SW-dipping Jizan Group. These are locally overlain by 10,000 year-old "Quaternary effusive" basalts. **(B)** Vertical cross-section from Jizan Econo-mic City to the NE. Jizan Group basalts are cut by Quaternary basalt feeder dikes (red) and inferred faults. The basaltic dikes induced hydrothermal alteration and clogging of the rock-matrix pores in the older Jizan Group basalts. Location of pilot site is projected into the cross-section. Modified (labels added) after Fedorik et al. (2023).

5.3.4. Site characterization

To characterize the site, five vertical wells were drilled to depths of 120–1000 m (Menegoni et al. (2025). Cuttings from the wells and samples from outcrops nearby were analysed for their petrophysical and geochemical properties. The target basalts have low rock-matrix porosity and permeability, owing to devitrification and recrystallization accompanying hydrothermal alteration (Section 2.5) during the young Quaternary volcanism. The minerals formed during this alteration include the refractory silicates albite, chlorite, epidote and also the carbonate calcite. Fortunately, the target basalts are densely fractured, providing sufficient porosity, permeability and injectivity to constitute an aquifer.

The dimensions and spatial frequency of fractures and the stress state of the networks were characterized by surface and aerial mapping, as well as by various borehole geophysical logging methods including flowmeters. The bulk hydraulic properties and stress thresholds of the basalt reservoir were calculated from these observations (Fedorik et al., 2023; Menegoni et al., 2025). No impermeable caprock is present at the pilot site. The reservoir temperature at the ~650 m injection depth is 45 °C.

The groundwater in the reservoir is moderately saline (5000-6000 mg/L TDS) and is thus non-potable and unsuitable for agricultural purposes. Based on the various data collected, the subsurface behaviour of the injected aqueous CO_2 was simulated using the well-known reactive-transport software TOUGHreact (Xu et al., 2014), which couples thermal, hydraulic and chemical processes, including full thermodynamics and kinetics for mineral–fluid reactions. To date, no publications are available on the results of these simulations or on whether the executed CO_2 tests conform with the model predictions.

5.3.5. Injection procedure

In 2023, an aqueous solution of CO_2 was pumped through an injection well into the reservoir at 650 m depth. The $CO_2 : H_2O$ ratio was pre-set in the solution such that the CO_2 remains in the undersaturated, dissolved state within the reservoir at 45 °C and 6.5 MPa hydrostatic pressure. Considering the salinity, this implies a $CO_2 : H_2O$ mass ratio of 0.042 or an $H_2O : CO_2$ mass ratio of 23.6 (this study). A total of 131 t CO_2 was injected over a period of 30 days, at an average rate of 2.5 L/s (max. 5 L/s). Three non-reactive and non-adsorbing chemical tracers were co-injected with the aqueous CO_2. This injection phase was followed by a 1-year period of monitoring, involving geochemical analyses of formation water in the injection well and in an observation/production well situated 120 m from the injector.

5.3.6. Source of water for injection

Initially the plan was to use seawater for co-injection, but environmental regulations did not permit this owing to the risk of contaminating local shallow freshwater resources. Therefore, during CO_2 injection through the injection well, groundwater in the storage reservoir was simultaneously extracted by pumping through the observation/production well situated at a distance of 130 m (Fig. 8A). The produced water was continuously pumped through a pressurized surface pipe to the injector wellhead, to be mixed with CO_2 and reinjected into the storage reservoir. This installation, known as a closed-system well doublet, enables management of fluid pressure within the reservoir (Section 3.6) and, by recycling the groundwater, it minimizes the amount of water needed to inject the CO_2.

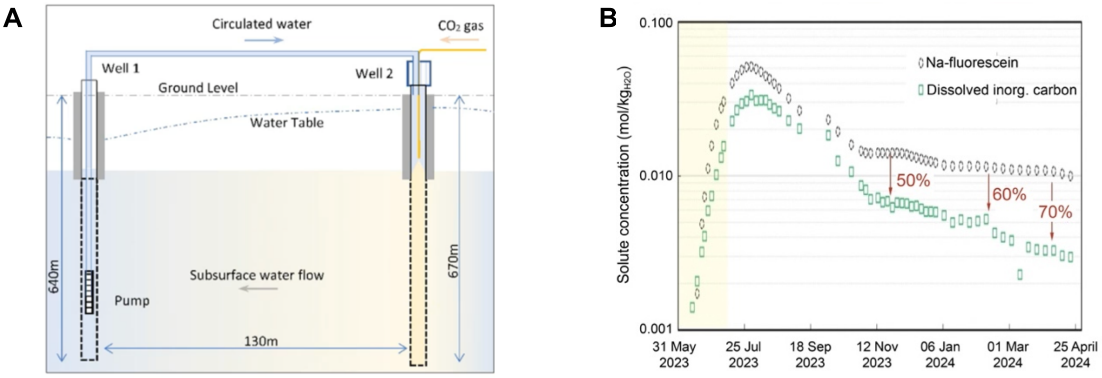


Figure 8. A) Well-doublet injection scheme at the Jizan site in which groundwater from the reservoir is extracted from Well 1 and reinjected together with CO_2 into the reservoir through Well 2. The two fluids mix completely within the well before entering the reservoir. The inert, non-adsorbing tracer Na-fluorescein was co-injected with the same concentration as CO_2. After Ahmed et al. (submitted). **(B)** Analyses of dissolved inorganic carbon (DIC; sum of all dissolved species of CO_2) and of Na-fluorescein in water extracted from Well 1 as a function of monitoring time. Note that *y*-axis is logarithmic. Injection of CO_2 began on 31 May 2023 and continued for one month (pale yellow region). Groundwater flow carried the injected solution towards well 1, consistent with the rise of DIC sampled at well 1 (peak in late July, 2023). Decay of DIC thereafter is due to dispersion of flow. The evolution of Na-fluoroscein concentrations tracks the migration of injected H_2O through the reservoir. The deficit in aqueous CO_2 (DIC) with respect to Na-fluoroscein points to removal of CO_2 from the solution by precipitation of carbonate minerals.

5.3.7. Project maturity

Monitoring was completed in 2024, after which the injection project was concluded. It is considered by the operator to be a success. Based on this result, upscaling studies are now underway towards developing a large storage facility. The costs of sequestering CO_2 in the Jizan basalts is estimated at 25 $US/t (Oelkers et al., 2025).

5.3.8. Proof of CO_2 containment

Analyses of the co-injected tracers in water samples from the production well (e.g., Fig. 8B) showed a consistently increasing deficit of CO_2 in the solution, indicating that **70% of the injected CO_2 had been mineralized within 10 months**. During this period, carbonate minerals were seen to have precipitated in the downhole pump within the production well. These findings, supported by thermodynamic mineral-saturation indices calculated from the fluid analyses, indicate that the CO_2 missing in the observation well had been removed from solution by precipitation of the carbonate minerals calcite, ankerite and siderite along the flow path in the reservoir. This is good proof that a large fraction of the injected CO_2 was permanently contained by the pilot project.

5.3.9. Safety

No operational issues relevant to human safety have been reported. As is standard in exploration for oil and natural gas, a precautionary gas collection tank was installed on the injection wellhead for the duration of the injection test to collect any natural gas or CO_2 that by accident migrates up the injection well.

We are not aware if seismicity was monitored during the pilot project, but the shallow depth of injection (600 m) reduces the risk of strong seismicity (Section 2.8.5). No CO_2 leakage has been reported that could potentially harm humans or animals in the vicinity.

5.3.10. Environmental compatibility

Fluid sampling in the production well showed that certain heavy and potentially toxic metals were leached from the reservoir rocks by the injected water–CO_2 mixture owing to its acidity. A subsequent reduction in concentrations showed that these metals were immobilized within precipitating minerals, simultaneously with acid neutralization by reaction with the rocks (Oelkers et al., 2025).

5.3.11. Evaluation

The Jizan injection pilot has been conducted with a comprehensive, state-of-the-art, science-based methodology incorporating field, laboratory and simulation results in accordance with international best practice (cf. Section 4.2). The site investigations have been performed by experienced reservoir geologists and engineers, in collaboration with scientists who first developed the in-situ technique in the Carbfix project in Iceland (Section 5.1). Several peer-reviewed scientific publications document aspects of the Jizan project, and more publications are in preparation, lending the project much credibility.

Whereas the proof of CO_2 containment at Jizan is compelling, we note that solute monitoring in the water extraction well (Fig. 8A) implies that a significant fraction of the injected CO_2 (up to 30%) was indeed pumped out of the production well (see also discussion regarding similar behaviour at Carbfix2 in Section 5.1.8) and presumably re-injected through the injection well. Moreover, the observed precipitation of carbonate minerals in the downhole production pump proves that carbonatesupersaturated water was being removed from the reservoir in the closed-system, well doublet. This demonstrates that the amount of CO_2 that can be sequestered in the chosen approach is limited by the rate of carbonate mineral precipitation between the two wells of the doublet versus the rate of groundwater flow.

5.4. Basalt site 4: Elementeita, Kenya

5.4.1. Sources of information

Specific information on this project was obtained exclusively from a 1-hour online interview in March 2025 with Dr. Claire Nelson, a geologist/geochemist and a co-founder and Chief Technology Officer for the Cella project. No documentation of the project is available at present but Cella intends to publish scientific papers on their findings in due course. A review of the CO_2 storage potential of basalts in Kenya was also consulted (Okoko and Olaka, 2021)

5.4.2. Project overview

The company Cella (based in New York, USA, https://www.cellamineralstorage.com) is conducting a scientific test injection pilot in Kenya. For this first and only project by Cella, the stated aims are to demonstrate a "novel injection method" and to assess the storage capacity of the reservoir by injecting 200 t CO2.

The test site is located on the southern shore of the saline Lake Elementeita (also written Elementaita), 115 km NW of Nairobi in western central Kenya (Fig. 9). The immediate surroundings of the site are known as the Elementeita Badlands, a semi-arid area devoid of human activities but with scenic value. Sparse farms and an urban settlement are located at Kikopey Township (also written Kekopey), 3.5 km to the ENE.

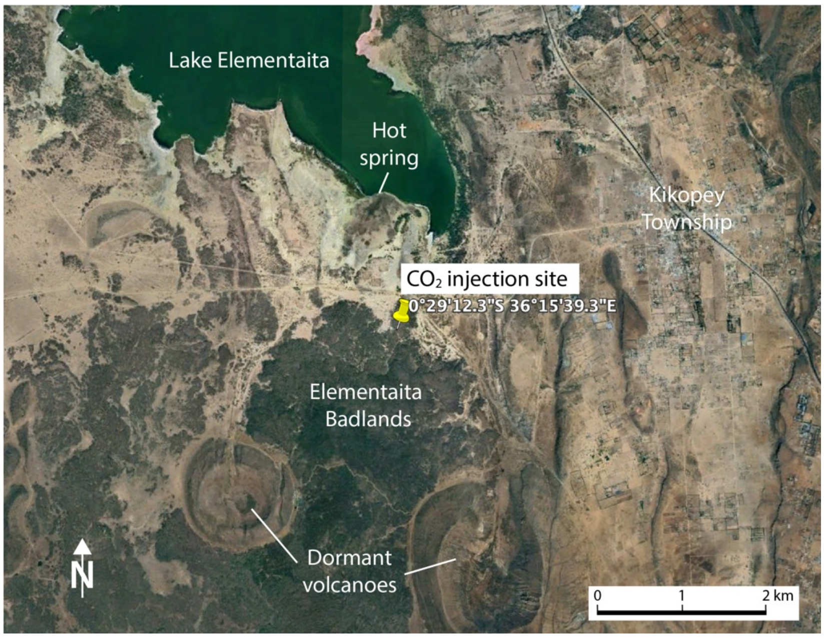


Figure 9. Location of the Cella CO_2 injection pilot project at Lake Elementeita, Kenya. Map constructed from *Google Maps*.

The site is owned by an independent power producing company with a permit for geothermal exploration, including drilling. The site hosts a solar power plant and a direct air-capture (DAC) facility for CO_2 (Octavia Carbon Co.) which will provide CO_2 for storage in the future. However, for the initial proof-of-concept injection test, Cella will buy CO_2 from outside sources. There are currently no plans to attract imports of foreign CO_2 for storage at the site.

5.4.3. Geological setting

The test site lies within the Central Kenya Volcanic Rift zone, characterized by young basalts (~4–0.01 million years old), other related volcanic rocks, and intervolcanic paleo-lake sediments (Okoko and Olaka, 2021). The local topography includes intact cones of dormant volcanoes (Fig. 9). Just 20 km to the south is the currently active volcano Ol Doinyno Eburru. Owing to the recent volcanic activity, the geothermal gradient is elevated (~70–75 °C/km), as manifested at the surface by a hot spring situated on the edge of Lake Elementeita just 1.5 km north of the injection site (Fig. 9). Geothermal energy resources are being explored and produced in the greater area.

5.4.4. Site characterization

By March 2025, drilling of the first injection well was underway and had reached approx. 700 m depth. Drill hole cuttings have revealed a horizontally layered rock sequence beginning at the surface with basalts, underlain by other types of volcanic rocks (trachydacite and trachyandesite, which are relatively poor in Ca, Mg and Fe and hence unfavourable for CO_2 mineralization), then a layer of lake sediments at 700 m depth, underlain by further basalts possibly up to 100 m thick. The plan is to inject CO_2 into the lower basalt layer at 800 m depth, where the temperature is estimated at ~75 °C. This basalt is expected to behave as a porous and fractured aquifer with good reactivity for CO_2 mineralization, while the overlying lake sediments are expected to serve as an impermeable caprock to trap the buoyant, free-phase CO_2. The hydraulic properties and chemical reactivity of both units are yet to be tested.

5.4.5. Injection procedure

The intention is to inject supercritical CO_2 and water separately as pure phases in multiple, alternating steps (WAG: "Water Alternating Gas"), as routinely done in enhanced oil recovery operations (Section 3.3). This injection mode is expected to bring three advantages: (1) it should allow more CO_2 to be injected per well than in an operation injecting only aqueous CO_2; (2) the repeated, sequential mixing of CO_2 and H_2O should increase the rate at which the supercritical CO_2 dissolves into the water, from where it can react with the basalt to precipitate carbonate minerals; and (3) the shunting of CO_2 by incompressible water should enable greater lateral penetration into the reservoir than could be achieved by injecting compressible CO_2 alone, thereby accessing greater pore surface areas where the carbonation reaction occurs. This WAG procedure constitutes the "novel injection approach" announced by Cella. The envisaged radius of influence of the injected 200 t CO2 is estimated to be 400 m.

5.4.6. Source of water for injection

Water for drilling and injection is obtained from a shallow aquifer on-site. This groundwater is alkaline with high chloride and fluoride contents and hence not directly usable for drinking or agricultural irrigation. There is the option of re-injecting waste water into the shallow alkaline aquifer.

5.4.7. Project maturity

The project is designed as a small scale, proof-of-concept field injectivity test and it is currently in an early stage of site characterization. The viability of the defined reservoir for containing CO_2, whether in the supercritical, aqueous or mineralized states, has not yet been demonstrated.

5.4.8. Proof of CO_2 containment

The project has not yet advanced to the point of injecting CO_2, hence proof of containment is outstanding. Cella plans to use stable isotopes (e.g., of Ca) to evaluate the extent of $CaCO_3$ precipitation, similarly to one of the methods applied at Carbfix (Pogge von Strandmann et al., 2019).

5.4.9. Safety

The drilling operation is being run by an experienced geothermal exploration company (Kenya has a large and well established geothermal energy industry, currently with an installed capacity of 860 MWe – almost as much as the operating Gösgen nuclear power plant in Switzerland). We have no information regarding the extent to which the operation complies with normal industry safety standards, although there are presumably no concerns. Human populations are distant and there is no apparent conflict with land use.

5.4.10. Environmental compatibility

Water use for the CO_2 injection pilot will be high but a source of otherwise unusable water is present (Section 5.4.6) for the relatively small volume required for the small-scale test injection.

5.4.11. Evaluation

In the absence of publications and quantitative data on the Cella site, only a cursory evaluation is possible. Without data on the properties of the caprock and the lateral extent and hydrogeology of the reservoir and the caprock, it is too early to evaluate containment of CO_2. The elevated reservoir temperature (~75 °C) is favourable in that it is likely to accelerate mineralization reactions, but owing to its effect on reducing the density and viscosity of CO_2, it will accelerate migration of the supercritical CO_2 plumes. The Cella site is close to active volcanoes, and therefore it could be affected at some time in the future by volcanic eruptions. The possible consequences are likely to be the same as given in Section 5.1 above for the Carbfix site in Iceland.

5.5. Serpentinized peridotite site 1: Chalk, Oman

5.5.1. Sources of information

Information on this project was obtained from (i) the cited literature, (ii) a 1-hour online interview in March 2025 with James Woolner, project manager for the operator company 44.01, (iii) a 1-hour online interview in May 2025 with Dr. Juerg Matter, a geoscientist and Scientific Officer for 44.01, (iv) a public lecture held at the November 2024 Swiss Geoscience Meeting by Matter, and (v) an oral presentation at the 2025 Goldschmidt Conference in Prague. Both Woolner and Matter have been involved in the site characterization and injection tests at the Chalk site, Oman.

5.5.2. Project overview

In 2023 the company 44.01, founded in Oman, injected 0.044 t CO2 (44 $kgCO_2$) from an industrial ammonia plant into serpentinized peridotites at a remote locality (approx. 37° 59' 12.1" N, 15° 25' 56.5" E) in the southern Hajar mountain range of Oman. The site is situated in Wadi Lawayni, 57 km almost due west from the township of Tiwi on the coast of Oman (Fig. 10). The area is a rocky, mountainous desert with scant vegetation and no population settlements. The aim of the project, named Chalk, was to test the rate at which CO_2 reacts with the reservoir rocks. The site was chosen to take advantage of four existing research boreholes that had been drilled into serpentinized peridotites in 2016–2019 and that had been kept open for groundwater sampling and hydraulic testing. However, the site is very far from any supply of industrial CO_2 or water and hence no possible upscaling was foreseen at this location, regardless of the outcome of the injection test. The regulator for the project was the Ministry of Energy and Minerals.

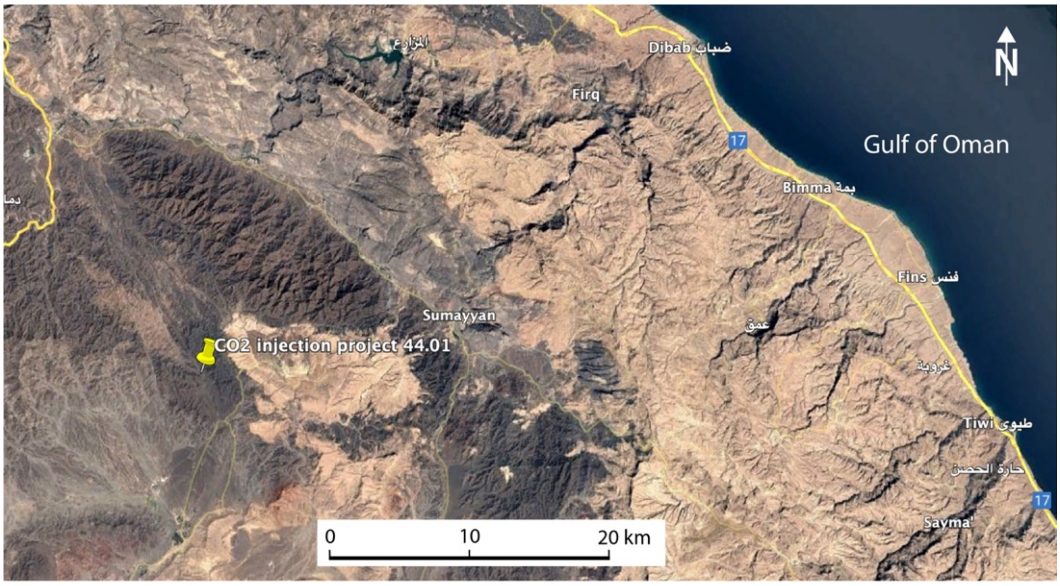


Figure 10. Location of the Chalk in-situ mineralization pilot project in serpentinized peridotites in the Sultanate of Oman. The site (yellow pin) is situated within the desertic, uninhabited southern Hajar Mountains, approx. 60 km west of the coastal township of Tiwi.

5.5.3. Geological setting

The site is surrounded by vast quantities of serpentinized peridotite and a related olivine-rich rock known as dunite. These rocks belong a giant sheet of oceanic mantle that was thrust from the floor of the Gulf of Oman onto the Arabian tectonic plate about 90 Ma ago as part of the Semail ophiolite.

5.5.4. Site characterization

The existing boreholes at the site had already been investigated and characterized in the context of the Oman Drilling Project, including wireline geophysical logging, petrologic and mineralogic studies of drill core and cuttings, and extensive hydraulic tests, which characterized the water injectivity of the fractured peridotite (e.g., Lods et al., 2020). The reservoir for the CO_2 injection test was chosen between 150 and 400 m depth in a strongly serpentinized peridotite, in which the permeability is below 2×10^{-15} m^2. No low-permeability caprock is present. The native reservoir fluid was at 35 °C and it is highly reducing and alkaline (pH = 11), which promotes precipitation of carbonate (Section 2.6.1). In addition to these parameters, baseline chemical analyses of $CO_{2(aq)}$, $Ca^{2+}_{(aq)}$, $Mg^{2+}_{(aq)}$, $SiO_{2(aq)}$ and $\delta^{13}C$, were made for later comparison with the post-injection fluid. The serpentinized peridotites contain no native carbonate minerals below about 100 m depth.

5.5.5. Injection procedure

The small amount of CO_2 was co-injected with water and with a known concentration of bromide (Br^-), an inert, non-adsorbing tracer. The chosen H_2O : CO_2 mass ratio (184 : 1, or 0.54 wt.% CO_2) ensured that the two fluids mixed completely within the injection well before the single-phase aqueous solution entered the reservoir at depths between 150 and 400 m. With this composition the injected fluid had a pH of 4.1, whereas the native reservoir fluid had a pH of ~11. After leaving the injected fluid to react with the reservoir rock for 45 days, fluid was pumped back into the injection well and re-sampled. Analyses of the recovered fluid for bromide (Fig. 12A) showed that 38% of the injected fluid was recovered after 240 hours of pumping. Analyses of the other key dissolved solutes, $CO_{2(aq)}$, $Ca^{2+}_{(aq)}$, $Mg^{2+}_{(aq)}$, $SiO_{2(aq)}$ and $\delta^{13}C$, were repeated on each aliquot of recovered fluid to enable the precipitation of carbonate to be quantitatively tracked.

5.5.6. Source of water for injection

Some 8200 liters of industrial wastewater were trucked into the remote project site for co-injection with CO_2.

5.5.7. Project maturity

The project was successful in its stated aims of injecting aqueous CO_2 and demonstrating significant mineralization within months, and the site was then decommissioned.

5.5.8. Proof of CO_2 containment

Mass balance calculations using the solute compositions measured before and after injection indicated that **88% of the injected CO_2 had been mineralized after 45 days** (Matter et al., 2025). To our knowledge, this is the first and to date the only field-based estimate of the rate of in-situ mineralization in serpentinized peridotites. However, it should be borne in mind that this result is based on an injection of only 44 kgCO_2. Its validity for a high-tonnage injection has yet to be determined.

The derived rate is surprisingly rapid. In recognition of its importance for proof of CO_2 containment, we explain in the following the calculation method originally developed by Matter et al. (2016) for Carbfix and later followed by 44.01. We then use the time-series diagrams of chemical analyses presented by Matter et al. (2025) to inspect the reported 88% mineralization result.

Analyses of the bromide tracer recovered during backpumping show an almost exponentially decreasing concentration with time (Fig. 12A). This behaviour reflects the radial dispersion, mixing and dilution of the injected fluid during its 45-day incubation period. For each recovered aliquot of mixed fluid, the mass balance of injected fluid and native reservoir fluid components can be expressed as:

$$w_{tr}^{mix} = X_{in}^{mix} w_{tr}^{in} + (1 - X_{in}^{mix}) w_{tr}^{na} \tag{16}$$

where w_{tr}^{in} is the measured mass concentration of bromide tracer in the injected fluid, w_{tr}^{na} is the measured mass concentration of tracer in the native reservoir fluid as measured before the injection test, and w_{tr}^{mix} is the mass concentration of tracer in the mixture. Rearranging Eq. 16 yields the mass fraction of injected fluid in the mixture sampled by each aliquot of pumped fluid (X_{in}^{mix}):

$$X_{in}^{mix} = \frac{(w_{tr}^{mix} - w_{tr}^{na})}{(w_{tr}^{in} - w_{tr}^{na})} \tag{17}$$

Knowledge of X_{in}^{mix} via Eq. 17 allows hypothetical concentrations to be calculated for the other measured aqueous solutes that are sensitive to the precipitation of carbonate minerals (e.g., $Ca^{2+}_{(aq)}$, $Mg^{2+}_{(aq)}$ and $CO_{2(aq)}$ – see Eq. 7), assuming that no carbonate precipitation occurred. For example, the hypothetical amount of $CO_{2(aq)}$ expected in each aliquot of recovered fluid in the absence of mineral precipitation ($w_{CO2}^{mix\_hypo}$) is given by:

$$w_{CO2}^{mix\_hypo} = X_{in}^{mix} w_{CO2}^{in} + (1 - X_{in}^{mix}) w_{CO2}^{na} \tag{18}$$

where w_{CO2}^{in} is the measured concentration of $CO_{2(aq)}$ in the injected fluid, and w_{CO2}^{na} is the measured mass concentration of tracer in the native reservoir fluid as measured during the baseline survey before the injection test. Figure 11B (in which $CO_{2(aq)}$ is labelled as Dissolved Inorganic Carbon, DIC) shows the difference between the measured concentration of $CO_{2(aq)}$ in the recovered fluid (blue symbols) and that expected in the hypothetical mixture assuming no precipitation (orange symbols). When integrated over the duration of the data collection, this difference is equal to the net loss of CO_2 from solution that actually occurred in the reservoir.

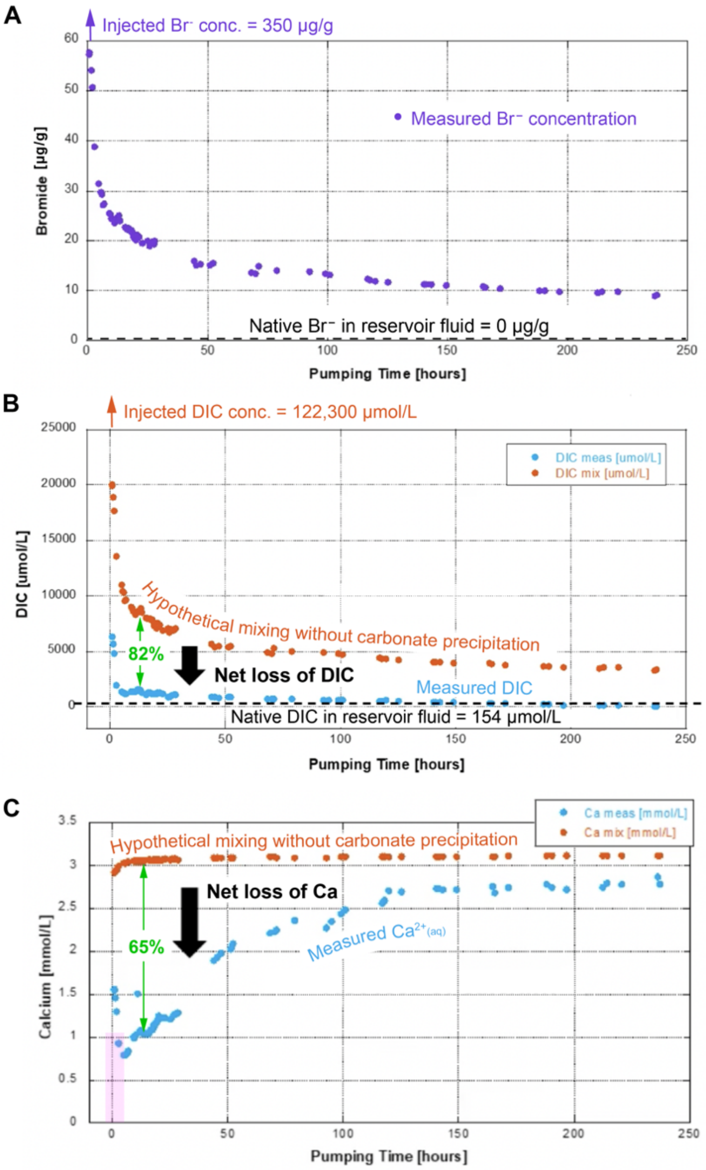


Figure 11. Estimation of amount of injected CO_2 precipitated as carbonate minerals in the Chalk project (Oman) after a reaction time of 45 days. Graphs show 240 h of pumping (*x*-axes) to recover samples of the mixture between injected fluid (traced with bromide) and native reservoir fluid. See text for further explanations. **(A)** Concentrations of bromide tracer vs. recovery time. **(B)** Behaviour of Dissolved Organic Carbon (DIC, equivalent to total $CO_{2(aq)}$) vs. recovery time. The labelled 82% loss of DIC (green) was calculated by the authors of the present report for comparison only (see text). **(C)** Behaviour of dissolved calcium, the cation in precipitated calcite ($CaCO_3$). The labelled 65% loss of Ca (green) was calculated by the authors of the present report for comparison only (see text). Graphs modified (labels added) after Matter et al. (2025).

Our estimated net loss of 82% for one example aliquot (marked green in Fig. 11B) nicely confirms the more accurate estimate of 88% by Matter et al. (2025). Our calculated example of 65% net loss of Ca from approximately the same aliquot of recovered fluid is not necessarily inconsistent with the value of 88% CO_2 mineralization, as the deficit in Ca may have been filled by co-precipitation of another cation, e.g. Mg within the calcite (so-called "high-Mg calcite"). However, all other carbonates except dolomite (e.g., magnesite and hydromagnesite) were calculated to be thermodynamically undersaturated during the entire backpumping operation (Matter et al., 2025). Whereas dolomite forms as a product of weathering of the serpentinized peridotite at near-surface conditions (over millennia), it is widely viewed as being kinetically inhibited in low-temperature abiotic environments. The details of the carbonation process in the Chalk project thus remain unresolved.

5.5.9. Safety

No issues were reported.

5.5.10. Environmental compatibility

No details are available, but given the fact that the drilling of wells had already been completed before 44.01 began its project, any environmental impacts of the CO_2 injection are likely to have been negligible.

5.5.11. Evaluation

This pilot project demonstrated that (1) aqueous CO_2 can be successfully injected into serpentinized peridotites at depth, and (2) carbonate minerals form from the injected CO_2 within a period of months. As only a very small amount of CO_2 was injected (44 kg; Matter et al., 2025), it is conceivable that other processes, in addition to or instead of dissolution of serpentinized peridotite, may have contributed to lowering the CO_2 content in the backpumped fluid. Scenarios that occur to us include precipitation of carbonate from cations already dissolved in the alkaline groundwater (rather than being first dissolved upon CO_2 injection), microbially mediated precipitation of dolomite, or microbially mediated methanation of the injected CO_2 (the reservoir fluid should contain molecular hydrogen, but neither H_2 nor CH_4 were included in the analyses to our knowledge; microbially-mediated methanation this is known to operate within weeks to months in sandstone aquifers; Trias et al., 2017; Hellerschmidt et al., 2024). It is also known from the CarbFix site in Iceland that injection of CO_2 may induce biomass blooms, which incorporate CO_2 and could thereby confuse the results of tracer tests (Daval, 2018). At any rate, the details of the CO_2 drawdown and hence of the inferred mineralization remain to be clarified. Similarly, the applicability of the derived reaction rate to higher tonnages of CO_2 remains to be verified. The long-term fate of the CO_2 remaining in solution was not addressed in this project.

5.6. Serpentinized peridotite site 2: Fujairah, UAE

5.6.1. Sources of information

Information on this project was obtained from the cited literature and from the same sources as given for the Chalk project above (Section 5.5): (i) a 1-hour online interview in March 2025 with James Woolner, project manager for the company named 44.01, (ii) a 1-hour online interview in May 2025 with Dr. Juerg Matter, a geoscientist and Scientific Officer for 44.01, and (ii) a public lecture held in at the Nov. 2024 Swiss Geoscience Meeting by Matter. Both Woolner and Matter have been involved in the site characterization and injection tests at Fujairah, Oman.

5.6.2. Project overview

Since 2023 the company 44.01 has built on its experience in the Chalk project (see above) and injected 70 t CO2 into serpentinized peridotites at its in-situ mineralization site in Fujairah, on the eastern (Gulf of Oman) coast of the United Arab Emirates (UAE). The ongoing project is a partnership with the Abu Dhabi National Oil Company (ADNOC), the Abu Dhabi Future Energy Company (Masdar) and the Fujairah Natural Resources Corporation. A permit for the injection was issued to ADNOC by the local regulator – the Fujairah National Resource Corporation (FNRC).

The Fujairah site is situated in a desert of rocky outcrops with rugged topographic relief (Fig. 12), close to Fujairah City. The serpentinized peridotites host a shallow freshwater aquifer but apart from this these rocks have no other use than CO_2 storage, hence the outcrops are devoid of settlements. A few farms and industrial installations are present in the wadi valleys between the peridotite outcrops.

The aim of the initial 10 t CO2 pilot was to demonstrate the safety and efficiency of the 44.01 injection procedure in the UAE, and to assess the potential to scale-up operations at the site in 2025. The CO_2 was obtained from a local industrial source, and is planned to be supplemented by an on-site DAC plant in the near future.

Figure 12. Site of the CO_2 injection project of the company 44.01 near Fujairah, eastern coast of UAE. The visible mountains are serpentinized peridotite. Solar panels (foreground) provide electricity for the operation. Image from 44.01 website.

5.6.3. Geological setting

The targeted serpentinized peridotites belong to the Oman–UAE ophiolite (also known as the Semail or Semail ophiolite). The rocks in Fujairah are essentially identical to those tested in the 44.01 Chalk project in Oman, described above (Section 5.5).

5.6.4. Site characterization

Drilling of two wells to 900 m depth and characterization of the site were carried out from 2021 to 2023. Rock cores were extracted and the wells were logged using various wireline tools that enabled detailed fracture analysis. Stress, mechanical and hydraulic tests were also performed, allowing identification of hydraulically active fractures. The results showed that highly fractured serpentinized peridotites are present everywhere in the subsurface below a thin superficial layer of alluvial gravels. A surface transient electromagnetic resistivity (TEM) survey over an area of 700 x 300 m combined with the interpretations of downhole hydrotests revealed vertical layering of porosity and permeability in the peridotites down to 1000 m depth. The upper 100 m are affected by intense fracturing associated with weathering and they are therefore highly permeable, hosting a shallow freshwater aquifer. Below this layer, low resistivity was detected down to 400 m, indicating abundant electrically conductive groundwater, and hydrotesting confirmed groundwater circulation through a fracture network with very high permeability of 10^{-8} to 10^{-5} m^2. At greater depths, higher resistivity was detected and ascribed to low fracture porosity and to the virtual absence of electrically conductive groundwater. Throughout the reservoir the rock matrix permeability is negligible (10^{-21} to 10^{-18} m^2).

Injectivity tests were performed through perforated intervals at 610, 680 and 780 m depth over a wide range of rates. Maximum injectivity was determined at 13 kg/s for a wellhead pressure of 8.3 MPa at 780 m depth (injectivity index = 1.1 kg/(s MPa). The observed variation of injection rates with time showed that fracture permeability varied strongly with distance from the injection well. Injection pressure also varied with time, revealing that the fracture permeability is stress-dependent.

To avoid contaminating the shallow aquifer with CO_2, the reservoir for the project was defined in the large interval 650–900 m depth, where temperatures are reported to be between 60 and 90 °C. With a mean soil temperature of around 30 °C, the latter temperature implies a geothermal gradient of at least 60 °C/km, which is unusually high for the geological setting. The site is within a few km of the coast but a hydraulic connection between the CO_2 reservoir and the seafloor is excluded by the great depth of the deep reservoir and by its low permeability.

5.6.5. Injection procedure

Most CO_2 injection pilot projects elsewhere have measured the injectivity index (Section 2.5) of the selected reservoir under the constraint that no fracturing damage be caused to the reservoir or caprock. In the Fujairah and Chalk (Oman) projects, which do not have designated caprocks, it was found that the fractures in the deep reservoir are largely sealed by weak serpentine minerals and hence stimulation of the permeability was required to achieve useful injection rates. The stimulation was carried out by purposefully hydrofracturing ("hydrofracking"; Section 2.5) the reservoir under low excess injection pressure. The magnitudes of the earthquakes caused by this hydrofracturing were measured by seismic monitoring at $M_L \leq -2$, well below the level at which humans can feel shaking at the Earth's surface.

Pure CO_2 was co-injected with seawater in a pre-calculated ratio such that the CO_2 completely dissolved into the seawater during migration of the fluids down the injection well. The aqueous solution of CO_2 then entered reservoir where it remained in this state during later mineralization reactions.

5.6.6. Source of water for injection

Seawater from the nearby Gulf of Oman was initially used as the solvent to inject dissolved CO_2 into the reservoir. Because the solubility of CO_2 in seawater is significantly lower than that in fresh water, very high water/CO_2 mass ratios were required for the injection. Later in the injection operation, locally sourced industrial wastewater was used as the solvent.

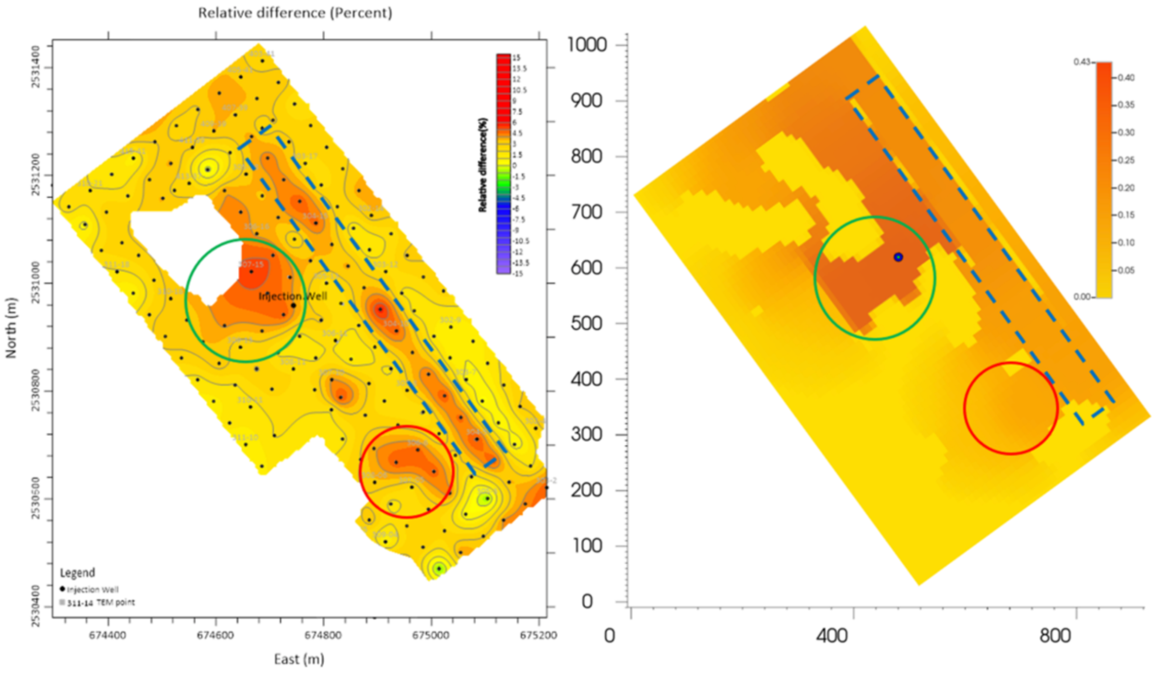
5.6.7. Project maturity

Having successfully demonstrated good injectivity and CO_2 storage in the serpentinized peridotites, 44.01 is upscaling its infrastructure in the UAE to carry out the next injection test with 300 t CO2. The company has secured $37 million in funding and it aims to develop a full-scale storage site in UAE to accommodate 20,000 t CO2 per year, based on current estimates of reservoir storage capacity. At present, industrial sources of CO_2 at or near Fujairah are insufficient to meet the planned injection rate. The company is therefore open for contracts to store waste CO_2 from suppliers further afield, including international sources. The company’s business plan also includes a new storage site near industrial point sources of CO_2 emissions at the large port of Sohar in northern Oman.

5.6.8. Proof of CO_2 containment

A second well sited 15 m from the injection well was used as an observation well to monitor CO_2 mineralization at Fujairah by sampling groundwater from the injection depth intervals. Recovery of non-adsorbing, non-reactive aqueous tracers that had been co-injected with the CO_2 solution, along with changes in pH, total dissolved organic carbon and ^{14}C isotope signature, showed that CO_2 had been lost from the injected fluid during its migration to the observation well. Mass balance calculations quantifying the amount of mineralized CO_2 (as in Section 5.5.8) have not been published yet.

Based on the FMI and sonic data, a digital model of the fracture network (DFN) was created and flow through the network was simulated by the coupled thermal–hydraulic computer code CMG–GEM (Mahzari et al., 2025). Input parameters were varied until the hydrotests could be reproduced. This calibrated model was then used in conjunction with the TEM map of the reservoir (Fig. 13) to track the migration of the injected CO_2-bearing water. Coupled thermal-hydraulic-chemical processes were modelled on the same DFN with a different simulator (PFLOTRAN + DfnWorks; results not yet published). By quantitatively considering rock dissolution rates, carbonate mineral precipitation rates and fluid flow rates, the simulation showed that leaching of potential carbonate-forming cations (Ca^{2+}, Mg^{2+} and Fe^{2+}) by the acidified water occurs close to the injection well, whereas carbonate mineral precipitation occurs at some radial distance from the well. A conclusion is that this spatially displaced precipitation minimizes pore clogging and reduction of injectivity near to the injection well.



(a) (b)

Figure 13. Maps (axes show 1 km x 1 km) of Transient Electromagnetic (TEM) monitoring of the migration of 150 m^3 of injected CO_2-bearing water through the Fujairah serpentinized peridotite reservoir at 1000 m depth. **(A)** Relative difference (%) between electrical resistivity after and before injection. Reddish areas (low resistivity) mark high concentrations of injected solution migrating away from the injection well along fracture networks. **(B)** Results of fracture-flow simulation showing volume fraction of water in the fracture network. The calculations are based site characterization data exclusive of TEM, demonstrating good agreement between observations and model predictions (compare blue dashed rectangles and green and red circles in panel a and panel b). From Kolahchian et al. (2024).

The simulations predicted CO_2 mineralization in the form of calcite and magnesite, but to our knowledge no direct observations of solid carbonates were made. The possibility of drilling a well to directly verify CO_2 mineralization deep in the reservoir (e.g., by extracting rock cores) is viewed as impractical. Too little is known about the detailed migration paths and hydrodynamic dispersion of the injected CO_2-bearing solution to guarantee successful siting of such a verification well.

5.6.9. Safety

The project operator 44.01 has stated that it is following the EU Directive (EU, 2009) with regard to safety, and its compliance is monitored by the project regulator based on weekly activity reports submitted by 44.01.

5.6.10. Environmental compatibility

No environmental concerns have been noted by the operator 44.01.

5.6.11. Evaluation

Only two extended conference abstracts (without peer review) have been published to date on the Fujairah project. While these provide a certain amount of information, they do not provide sufficient data for an in-depth evaluation of the efficacy of CO_2 storage at the sites. However, it is clear that the 44.01 team is scientifically highly competent: several of their team members played central roles in developing the Carbfix project in Iceland and also in the 44.01 pilot injections in Oman. The development of electromagnetic surveying to monitor the migration of the injected CO_2-bearing solution is a novel and promising methodology for serpentinized peridotite reservoirs.

The extended abstract authored by members of the company 44.01 (Kolahchian et al., 2024) is an excellent proposal for an appropriate monitoring, measuring, reporting and verification (MMRV) programme for in-situ mineralization of serpentinized peridotites. The recommendations largely overlap with the Guidance Documents of the 2009 EU Directive (EC 2024a, b) and ISO Document 27914 (ISO, 2017) for CO_2 storage in sedimentary reservoirs, but includes features unique to serpentinized peridotites. However, it is not clear if this entire suggested programme has actually been executed at Fujairah. This will presumably become clear as more detailed descriptions of Fujairah are published. In line with other workers (e.g. McCail et al.,), 44.01 has stated that no long-term monitoring will be required once all the injected CO_2 is fixed in stable carbonate minerals.

5.7. Comparison of implementation sites for in-situ mineralization

Table 5 compares the main features of the six in-situ mineralization projects evaluated above. Each of the basalt-hosted sites has different geological features, and the modes of injection also differ somewhat. This diversity underscores the site-specific nature of the in-situ mineralization technology. Accordingly, evaluations of this technology for containment, safety and environmental compatibility must be made on a site-by-site basis, not by a global applicable method.

Table 5. Comparison of past or ongoing CO_2 storage projects aimed at in-situ mineralization.

Feature	CarbFix2 Iceland	Wallula USA	Jizan Saudi Arabia	Elementeita Kenya	Chalk Oman	Fujairah UAE
Reservoir rock	Glassy basalt	Basalt	Altered basalt	Basalt	Serpentinized peridotite	Serpentinized peridotite
Caprock	None	Layers of impermeable basalt	None	Possibly present; to be tested	None	None
Structural trap	None	None	None	None	None	None
Tonnage of CO_2 injected	>84,000	977	131	*No injection yet*	0.044	>70
State of injected CO_2	Pre-dissolved in water	Supercritical	Pre-dissolved in water	Supercritical alternating with water	Pre-dissolved in water	Pre-dissolved in water
Depth of CO_2 injection	1900–2200 m	830–890 m	350 m	800 m	150–400 m	650–900 m
Containment						
Proof of CO_2 containment	Convincing	Convincing	Convincing	*No injection yet*	Positive but only 44 kgCO_2 injected	*No information*
State of contained CO_2	Aqueous + carbonate minerals	Supercritical + aqueous + carbonate minerals	Aqueous + carbonate minerals	*No injection yet*	Aqueous + carbonate minerals	Aqueous + carbonate minerals
Fraction of injected CO_2 fixed in carbonate minerals	60% in 4 months	60% within 2 years	70% in 10 months (based on tracer concs.)	60% within 2 years (based on tracer concs.)	88% in 1.5 months	*No test performed*
Risk of upward leakage of CO_2 in aqueous state	Only if aquifer becomes strongly over-pressured upon injection	Only if aquifer becomes strongly over-pressured upon injection	Extremely low; only if caprock is damaged during injection	Site not yet fully characterized	Only if aquifer becomes strongly over-pressured upon injection	Only if aquifer becomes strongly over-pressured upon injection
Risk of hydrofracturing	Moderate; may be part of injection procedure	Extremely low	Extremely low	Likely to be extremely low	Purposefully conducted to enable CO_2 injection	Purposefully conducted to enable CO_2 injection
Safety						
Felt induced seismicity	None in 10 yr	None	*No information*	*No injection so far*	*No information*	*No information*
Environmental compatibility						
Risk of contamination	Extremely low	Only if CO_2 leaks into higher aquifers	Extremely low	Extremely low	Extremely low (toxic metals)	Extremely low (toxic metals)
Water : CO_2 injection mass ratio	28 : 1 (2.35 Mt water injected)	None	24 : 1 (3100 t water injected)	*No injection yet*	186 : 1 (82 t water injected)	*No information*
Source of water for injection	Spent thermal groundwater	No water used	Groundwater from storage reservoir	*No injection yet*	Industrial wastewater	First seawater, then industrial wastewater

6. Open problems

6.1. Duration of reservoir permeability and reactivity

Neither the one commercial-scale in-situ mineralization operation (CarbFix2) nor the pilot projects executed thus far have encountered the anticipated reduction in injectivity due to pore clogging by precipitation of carbonate minerals. This is presumably due to sluggishness of the carbonation reactions, such that precipitation occurs only when the CO_2-bearing solution has been forced well away from the injection site and dispersed in the reservoir, as well as to the short (~ 1 decade) duration of observations (Section 2.6.3). However, this process is still widely considered to be a potentially limiting factor on achieving the theoretical storage capacities in the long-term, once large amounts of CO_2 are injected over long periods in full-scale storage projects (e.g., Gíslason et al., 2010). Longer observation periods are required to know how problematic this phenomenon will be.

Similarly, passivation of reactive mineral surfaces (Section 2.6.3) and competition with clay minerals for carbonate-forming cations (Section 2.6.1) are also likely to reduce the practically realizable storage capacity via carbonation of basalts and serpentinized peridotites.

The extent to which the efficacy of in-situ mineralization projects will be impacted by the above processes is still an open question. If they turn out to be serious as suspected, it could result in injection wells being prematurely abandoned and new, costly wells being drilled elsewhere in the pristine reservoir where carbonation has not yet occurred.

6.2. Use of reservoir groundwater for CO_2 injection

The operators of the Jizan project (Section 5.3) emphasize the advantages of sourcing groundwater from the reservoir to co-inject with CO_2, thereby avoiding the need to obtain large amounts of water from elsewhere and enabling management of reservoir pressure. However, we note that the injected CO_2-enriched water may migrate preferentially to the production well, owing to the low entry pressure of the well during pumping. Any injected CO_2 that is extracted from the reservoir in this way would have to be reinjected. With time, this need to recycle a fraction of each injected aliquot will limit the total amount of new waste CO_2 that can be injected.

This problem of unintentionally recycling injected CO_2 could perhaps be mitigated in a full-scale storage site if the reservoir properties are favourable. If groundwater flow rates in the reservoir are very low, a closed-system doublet installation would be more sustainable if the production well were placed at greater distance from the injection well, thereby allowing more mineralization to occur before the water is extracted. Nevertheless, the need to extract water from the same aquifer as the storage target may, in the long term, lead to dwindling capacity to inject new deliveries of CO_2 versus recycling the CO_2 that has already been injected one or more times at the same site. If the storage site has a high rate of groundwater flow, then the water extraction well would be better sited upstream of the injection well, such that the preferential migration of injected solution to the production well—due to its low entry pressure— is counteracted by the natural flowing pressure in the reservoir. The injected CO_2 solution would then migrate downstream, away from the production well. However, a relatively high flow rate of the reservoir groundwater implies that a discharge for that water is present at some distance along the flow path; otherwise, no water movement could occur. That opens the potential for long-term leakage site of CO_2-bearing water, but any CO_2 already locked in carbonate minerals would remain permanently stored in the aquifer.

For injection sites near the coast, seawater is an inexhaustible source of water, but several projects have found it to be technically too difficult to use over long periods. The high salinity of seawater causes corrosion of surface installations, pumps and well casings, and their regular replacement can be prohibitively expensive. The high salinity also significantly lowers the capacity of water to dissolve CO_2 for injection, thereby putting higher demands on water pumping volumes and on the consequent management of reservoir fluid pressure.

6.3. Estimates of CO_2 storage capacity

Most of the operators of the reviewed injection sites have made estimates of the ultimate storage capacity of their reservoirs. However, most of these workers have emphasized the high uncertainty associated with their estimates, and they point out the present lack of internationally accepted, rigorous and reliable methods to predict storage capacities (e.g. Cao et al., 2024). This issue is a focus of on-going research and development. The current uncertainty has consequences for national and global CO_2 storage programmes and for potential clients wishing to invest in specific sites or enter contracts to store their waste CO_2. However, as pointed out in Section 4.1, this uncertainty is not a significant factor when evaluating of the permanency, safety and environmental compatibility of CO_2 storage in new in-situ mineralization sites.

6.4. Verification of completion of CO_2 mineralization

As pointed out in Sections 2.6.2 and 4.3.3, methods to prove 100% mineralization of the injected CO_2 have not yet been devised and demonstrated. We view this as is a critical gap in knowledge of the in-situ mineralization technology, which has not been explicitly addressed in the literature that we have reviewed. Proof of completion of the mineralization reactions is required to establish when a site can be closed and its liability transferred from the operator to a state entity in perpetuity. In view of the high costs of long-term monitoring and of remediation in the event of detected CO_2 leakage, development of reliable methods to establish complete mineralization will significantly improve the acceptability of new in-situ mineralization sites for regulators, governments and the public.

6.5. Guidance documents tailored to in-situ mineralization

The success of the in-situ mineralization technology is already sufficient to encourage its implementation at many more sites worldwide. As pointed out in Section 4.2, no internationally accepted guidance documents exist yet, which are specifically adapted to this approach to CO_2 storage. We understand that operators of existing projects are lobbying to have such guidelines formulated along the lines of the EC (2024b) and ISO (2017) documents. Until such documents exist, operators, regulators and the public will be uncertain as to how to best handle the many technical and legal facets of the technology.

7. Recommendations to FOEN to evaluate in-situ mineralization projects in the future

7.1. Acquisition of site documentation

As the details of the required proofs of permanent CO_2 containment, safety and environmental compatibility are site-specific, we recommend that FOEN acquires the relevant documentation from each specific project under evaluation, both from the operator and the regulatory agencies. This documentation should include the provisions for plugging and abandoning wells, for site rehabilitation at the end of the lifetime of the injection project, and the stipulations for post-closure monitoring and transfer to liability. As mentioned in Section 4.4.3, the local regulator determines the duration of monitoring, if any, beyond the cessation of injection.

In principle, the local permitting authorities for the sites in question should have already assessed these proofs and regulations and could perhaps provide their reviews. An excellent example is the certification document of the in-situ mineralization methodology developed by the Carbfix company (Carbfix, 2022). Ideally, such exchange of information would be guaranteed within any bi-national agreement governing export of Swiss CO_2 to a country offering geological CO_2 storage. Much information may also be available in scientific or technical publications, in line with best-practice principles. Alternatively, the documents could be obtained directly from the operating company, as long as they have already been vetted and approved by a competent permitting authority.

7.2. Expert opinions

Owing to the complexity and multidisciplinary nature of characterizing and operating an in-situ mineralization site, we recommend that FOEN's evaluation of the site documents should include assessments by at least the following technical experts:

(1) an expert in reservoir geology (ideally a geologist with experience in the oil and gas industry or in aquifer CCS);

(2) an expert in surface- and subsurface technical operations related to deep wells (ideally a well-completions or production engineer);

(3) an expert on induced seismicity associated with water injections and on natural seismic risks (ideally a seismologist);

(4) an expert on surface and near-surface environmental incompatibilities and their detection and monitoring methods (ideally an environmental scientist).

If the necessary expertise is not available within FOEN, then external experts could perhaps be co-opted for topics 1 and 2 from the Swiss Geological Survey at Swisstopo, for topic 3 from the Swiss Seismological Service at ETHZ, and for topic 4 from the Swiss Federal Office of Aquatic Science and Technology (EAWAG).

FOEN will be interested in evaluating other aspects of the in-situ mineralization projects as well, such as economic, social and political, but these are outside the scope of this report.

7.3. Basis for FOEN evaluations

Assuming the evaluations required by FOEN fall within the same scope as the present report, the above experts may base their evaluations on the contents of this report plus the criteria given in the various international best-practice documents listed in Chapter 4.

8. Comparison with 2025 IEAGHG review on in-situ mineralization

During final editing of the present report, a new IEAGHG review of in-situ mineralization became available to us (IEAGHG, 2025b). Rather than integrating the findings of that review within the various sections above, a brief comparison of the two studies is provided below, such that the IEAGHG review serves as an independent check on comprehensiveness and conclusions of the present report.

The IEAGHG report is authoritative, having been written by 12 authors and reviewed by 15 international experts from industry, academia and research organisations. It uses standard geological and reservoir engineering terminology and thus much of the report is aimed at readers already knowledgeable in the field of geological storage. However, chapters on non-geological topics are understandable for all.

As in the present report, the IEAGHG study does not provide a recipe to evaluate the permanency, safety, environmental compatibility and storage capacity of potential in-situ mineralization sites. Instead, it reviews a large body of literature and summarizes the state of knowledge on the same topics covered in the present report, providing more details on costs and regulations, and including additional topics such as legal barriers, revenue streams, CO_2 transport, and economic opportunities of in-situ mineralization.

Crucially, the conclusions drawn by the IEAGHG review are fully in line with those of the current report. In particular, the perspective on site evaluation criteria developed in Section 3.6 above ("Hydrogeological equivalence of reservoirs for in-situ mineralization and for conventional CO_2 storage in sedimentary reservoirs") is also compatible with the IEAGHG review, although the latter does not formulate this perspective explicitly.

The IEAGHG review is rich in information and broad in scope, and as such it is recommended reading for any expert that FOEN may request to assess future in-situ mineralization projects.

9. Conclusions

The above review of scientific and technical literature, and of oral presentations and interviews with operators of injection projects, leads to the following conclusions regarding in-situ mineralization as a means of achieving geological CO_2 storage:

- The reviewed implementation projects have convincingly demonstrated that the in-situ mineralization approach applied to basaltic and serpentinized peridotite aquifers can lead to permanent, safe and environmentally compatible storage of CO_2. Abundant scientific studies have proven that carbonate minerals are the most stable form in which to store CO_2 permanently.

- Sites near active volcanism have advantages owing their naturally high reservoir temperatures, which enhance CO_2 mineralization rates. Burial by future volcanic eruptions is unlikely to cause escape of the CO_2 stored in dissolved aqueous or carbonate mineral forms.

- In-situ mineralization can be implemented by either of two main injection modes, or by a combination thereof. One main mode entails injection of buoyant supercritical CO_2 into a reservoir that is sealed above by an impermeable caprock, essentially copying the conventional CO_2 storage approach for sedimentary formations. The caprock precludes escape of the free-phase CO_2 while it slowly dissolves into the underlying groundwater. Once in the aqueous state the CO_2 reacts with the rock and liberates Mg, Ca and Fe, which in turn combine with the injected CO_2 to form stable carbonate minerals. Unfortunately, suitable caprocks are not often associated with basalt and peridotite formations, and therefore this approach is unlikely to have widespread applicability. The second main mode is to inject CO_2 that is already pre-dissolved in water, for which no caprock is necessary to guarantee containment, as CO_2-bearing water has negative buoyancy. Reaction of aqueous CO_2 with the reservoir rock leads to CO_2 trapping as carbonate minerals in the same way as the first approach.

- All of the field demonstrations that have employed injection of aqueous CO_2, including the one upscaled storage project (CarbFix2, Iceland), have required huge amounts of water to be injected simultaneously with the CO_2 (typically 20–32 times more water than CO_2). This sets high demands on local water supplies, with potential conflicts of use that may limit the amount of CO_2 that can ultimately be stored underground. In ideal aquifers with appreciable groundwater flow rates, a technically and environmentally sustainable approach is to extract the water necessary for injection from the storage reservoir itself. This brings the added advantage of enabling fluid pressure management in the reservoir. Alternatively, water for co-injection may be drawn from overlying or underlying aquifers. However, for hydrogeological reasons, these strategies may not be feasible in practice at many or even at most storage sites.

- The history of conventional CO_2 storage in sedimentary aquifers has demonstrated that injection of compressible supercritical CO_2 only rarely generates felt earthquakes. The highest recorded magnitude is 4.5. Similar behaviour is expected for in-situ mineralization projects that inject supercritical CO_2 below a caprock. In-situ mineralization sites that have injected aqueous CO_2 have not caused increased local seismicity to date. Nevertheless, as water is incompressible, a higher risk of generating felt earthquakes is expected for this mode of injection, consistent with experience in wastewater disposal and geothermal operations. Seismic responses to fluid injection are highly site-dependent, but well-established methodologies exist to evaluate risks and to monitor and mitigate seismicity. Earthquake risk is therefore not viewed as an impediment to widespread implementation of the in-situ mineralization technology.

- The longest-running injection programme worldwide has been operating for only 11 years (CarbFix2), hence the longer-term behaviour of in-situ mineralization sites has not yet been tested. Numerous issues could possibly arise over extended periods, such as:

(i) Clogging of reservoir porosity and permeability by the carbonate minerals (carbonation reactions induce strong increases in solid volume), passivation of reactive mineral surfaces, competition with clay minerals for carbonate-forming cations, and consumption of CO_2 by labile biomass blooms near the injection wells;

(ii) Increase in reservoir fluid pressure due to injection of large amounts of incompressible water could activate local faults or hydrofracturing, leading to CO_2 leakage and/or felt earthquakes;

(iii) Development of hydrodynamic short-circuits and unintentional re-extraction of injected CO_2 in projects where the water for co-injection is sourced from the storage reservoir itself.

Any of these issues could lead to lower effective storage capacities than initially expected. In some cases, drilling new injection wells in other areas of the reservoirs may circumvent these limitations. Failure to achieve the originally planned storage capacity does not affect the integrity of the site or permanency of its CO_2 storage, provided any leakage is definitively remedied prior to decommissioning.

- The time required for *complete* (~100%) mineralization of CO_2 injected into basaltic and serpentinized peridotite reservoirs has not yet been demonstrated. Completion of the reactions will likely take several years following cessation of injection. Therefore, any proposed reservoirs of this type must be capable of effectively trapping the injected aqueous or free-phase CO_2 over the lifetime of the injection programme (e.g., several or many decades) plus at least several years more until all the injected CO_2 is finally mineralized. Reliable methods to verify complete mineralization of the injected CO_2 at the reservoir scale are not yet developed. Until they become available, regulations for conventional CO_2 storage in the local legal jurisdiction will likely determine the duration of post-closure monitoring of in-situ mineralization.

- Most of the implemented projects have encountered difficulties in forecasting the total storage capacity of their specific sites. This is largely due to uncertainties in predicting the naturally complex distribution of reservoir permeability and the dispersion of the injected CO_2-bearing solution. This aspect of reservoir simulation is a current focus of research in the in-situ mineralization sector. The present inability to forecast storage capacity does not affect the permanency, safety or environmental compatibility of the sites.

- Energy consumption for in-situ mineralization involving injection of supercritical CO_2 is likely similar to that of conventional CO_2 storage (60–106 kWh/t CO_2 stored). When aqueous CO_2 is injected, energy consumption varies from 100 to 225 kWh/t CO_2 stored, depending on the injection pressure, whether seawater or freshwater is used, and whether recirculation wells are involved. As is true for conventional storage, the injection step in in-situ mineralization projects requires far less energy than the CO_2 capture and transport steps.

- No international best-practice guidelines exist yet that specifically address the in-situ mineralization technology. This lack is currently being addressed in the in-situ mineralization sector.

- In lieu of specifically tailored guidelines, evaluations of in-situ mineralization projects by FOEN should be based on the criteria provided in best-practice documents designed for conventional CO_2 storage in saline sedimentary aquifers. This is recommended despite mineralization playing only a minor role in those aquifers owing to their unfavourable chemical compositions. The guidelines for conventional storage are suitable because the long-term state of CO_2 stored in sedimentary aquifers (dissolved, aqueous form and perhaps also as free supercritical CO_2) is the same as the short-term state of CO_2 injected into basalt and peridotite reservoirs for in-situ mineralization.

- Each proposed site for in-situ mineralization will have unique geological characteristics that require site-specific evaluation by FOEN. The complexity of the technology is such that dependable evaluations will require reviews by experts in geological reservoirs, seismicity, environmental impacts, and injection operations in wells and on the surface.

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11. Index of terms