Impact of Salt Precipitation on Porosity-Permeability Correlations: Implications for CO_2 Storage

Introduction

Carbon capture and storage (CCS) in subsurface porous media is considered a mature technology for mitigating global warming and keeping the global average temperature increase below 2 ^oC, as set by the Paris Agreement (Tamme, 2020). For successful underground CO_2 storage, three critical elements must be satisfied: injectivity, containment, and capacity. Among various proposed reservoir types, saline aquifers and depleted hydrocarbon reservoirs have attracted attention due to their proven capacity and containment. However, injectivity, which is crucial for long-term injection, may pose uncertainties in a CCS project design. One widely accepted challenge is salt precipitation, which can impair injectivity.

Continuous contact of dry-CO_2 with the existing brine in reservoir leads to water evaporation and thereby increasing in salt concentration. As the concentration exceeds the solubility limit, salt precipitates, reducing porosity and permeability and potentially impairing injectivity. Salt precipitation occurs on several parameters, such as reservoir properties (e.g., permeability, temperature, and pressure), brine composition, and operational conditions (e.g., injection rate, temperature and well configurations). Avoiding or mitigating salt precipitation is crucial to maintain sufficient injectivity. Thus, understanding the underlying mechanisms and interactions between different parameters is essential.

The effect of salt precipitation on injectivity impairment varies across different fields. For example, at Sleipner, CO_2 has been injected since 1996 without any reported injectivity issues, while significant salt precipitation has been recorded at Snøhvit (Pawar et al., 2015) and Aquastore (Talman et al., 2020), requiring treatments to improve injectivity. These variations underscore the necessity of accurately measuring porosity-permeability correlation as function of salt precipitation to predict injectivity impairment prior the commencement of underground CO_2 storage projects.

Understanding the extent to which salt precipitation can affect injectivity is crucial. The amount of salt precipitation and its impact on permeability reduction has shown a broad spectrum of values. Studies by Muller et al. (2009), Wang et al. (2009), Bacci et al. (2011), Ott et al. (2015), Tang et al. (2015), and Peysson et al. (2014) reported significant permeability reduction, up to several orders of magnitude, resulting from salt precipitation, even with minor porosity reductions. Cui et al. (2023) presented five equations correlating porosity and permeability for different rock types. Sokama-Neuyam and Ursin (2015) observed up to a 35% reduction in permeability in core flooding experiments. Despite a consensus on permeability reduction due to salt precipitation, Ott et al. (2015) reported increased permeability following salt precipitation. These conflicting findings highlight the complexity of the porosity-permeability relationship and the need for further investigation.

The porosity-permeability correlation is one of the uncertainties in evaluating the injectivity of CO_2 in saline aquifers. Proper experimental estimation of this correlation is a vital input for numerical studies. Therefore, this study focused on experimentally investigating the effect of salt precipitation on porosity and permeability reduction. The results showed that even a minor reduction in porosity could significantly reduce permeability. Additionally, different rock types with varying microscopic structures exhibit differences in porosity-permeability correlation. As the amount of salt precipitation increases, a longer time is required for full imbibition, highlighting the practical importance of understanding the effect of capillary forces during shut-in periods. This study aims to contribute to a more comprehensive understanding of the interplay between salt precipitation, porosity, and permeability, ultimately aiding in developing more effective CO_2 storage strategies.

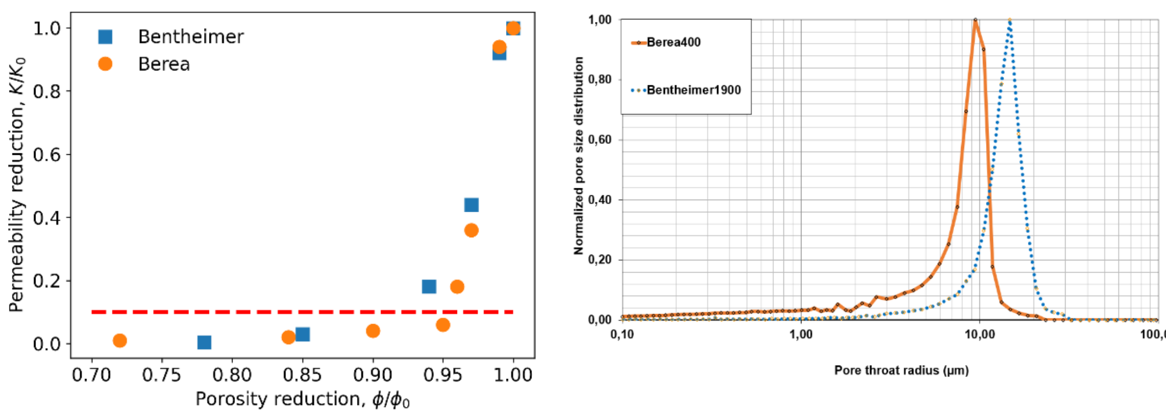
Experimental procedure

Core samples from Berea and Bentheimer sandstones were cut in to 3 cm lengths. The cores were dried at 60 °C, and then the air permeability was measured using a TinyPerm-II mini permeameter. After permeability measurements, the cores were vacuumed and saturated with a brine solution. To correlate the effect of salt precipitation on permeability and porosity reduction, each core sample from Berea and Bentheimer sandstones was saturated with brine solution of concentrations ranging from 3 to 24 wt.% NaCl. That is, six different core samples of Berea and Bentheimer cores were saturated with six different brine solutions with varying NaCl concentrations of 3%, 6%, 9%, 12%, 18%, and 24%. After the cores were saturated with the designated brine solution, the weight of each core was measured to calculate porosity. The cores were then dried again, and weight of the core and air permeability were measured. The increase in the weight of the core compared to the initial weight in the dry condition as well as the reduction in core permeability, are indications of salt precipitation in the core. The core plugs were then placed in a plate containing brine with 3 wt.% NaCl, to estimate the spontaneous imbibition rate, simulating the backflow of brine from the saline aquifer during the shut-in period. Again, the cores were dried to investigate further reduction of porosity and permeability due to the imbibition of 3 wt.% NaCl.

Results

Permeability reduction as a function of porosity reduction due to salt precipitations is illustrated in Figure 1-a. As shown, the general trend indicates that with decreasing porosity, permeability is dramatically reduced. However, the rate of decrease varies among different rock samples. In Berea sandstone, the permeability reduction is faster than in Bentheimer sandstone. We established a threshold for permeability reduction at 10%, below which permeability is considered dramatically low, significantly reducing injectivity. With reference to this threshold, Berea sandstone shows a 90% reduction in permeability with only a 5% reduction in porosity. In contrast, Bentheimer sandstone requires a 15% reduction in porosity for permeability to fall below the threshold.

To understand why a small reduction in porosity can have such a dramatic effect on permeability and consequently on injectivity, it is crucial to consider the microscopic structure of these rock samples. The microscopic structure consists of pore bodies and pore throats. After salt precipitation and during permeability measurement, some salt crystals may move from the pore bodies and become lodged in the pore throats. Rock samples with narrower pore throats have a higher chance of blockage. Referring to the pore size distribution of these two rock samples, illustrated in Figure 1-b, Bentheimer sandstone has larger pore throats, which aligns with our explanation of its slower permeability reduction compared to Berea sandstone. Additionally, the connectivity of the pore network in Bentheimer sandstone is better, allowing for more efficient fluid flow even after some degree of salt precipitation.



(a) (b)

Figure 1: (a) Porosity-permeability correlation in studied core samples, (b) Pore size distribution

Even though porosity-permeability correlations initially appear to show non-significant differences, we conducted a synthetic numerical comparison using the data obtained in Figure 1-a. A radial reservoir model was considered with a porosity of 0.2 and a permeability of 150 mD, and the brine salinity was set at 5%. The reservoir pressure and temperature were set to 21 MPa and 60°C, respectively. The simulation was run using TOUGH2. The only difference between two cases is effect of salt on porosity-permeability correlation. The injection pressure results are shown in Figure 2. As depicted, the injection pressures in both reservoirs remain nearly identical for the first 15 days. However, after this period, the Berea reservoir exhibits a significant increase in injection pressure, indicating injectivity impairment. This dramatic rise in injection pressure signifies the need for injectivity treatment to maintain effective CO_2 injection rates.

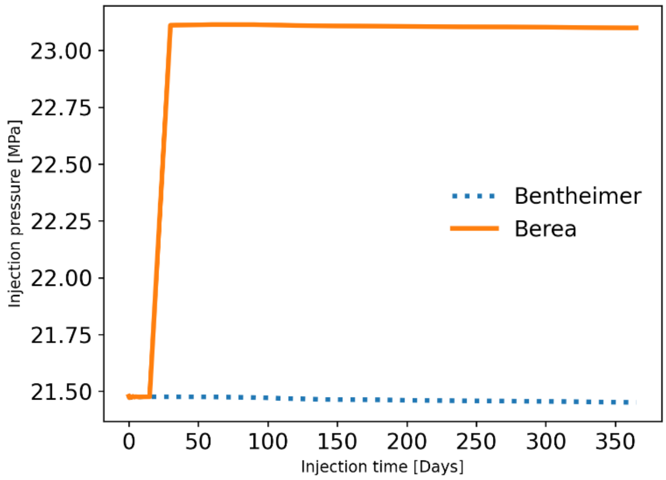


Figure 2: Comparison of injection pressure for two different reservoirs

The rate of imbibition after salt precipitation was also studied, focusing on capillary backflow during the shut-in period. This is a crucial aspect, as it determines how quickly brine can be imbibed back into dry-out region. During the shut-in period, additional salt can be transported to the dry-out region, causing further deterioration of the near-wellbore area, and leading to increased injectivity impairment when injection resumes. Our results (illustrated in Figure 3) show that as the amount of salt precipitation increases, the imbibition rate decreases in both rock samples. This decrease is attributed to the additional time required for salt dissolution. However, the impact of salt precipitation is more pronounced in Berea sandstone compared to Bentheimer sandstone. This difference is directly related to the microscopic structure and connectivity of the rock. Berea sandstone, with its less connected pore network and narrower pore throats, forces brine to pass through pore throats that are already blocked by salt, necessitating a longer dissolution process. In contrast, Bentheimer sandstone, with its larger and more connected pore network, allows brine to bypass blocked regions, maintaining a higher imbibition rate.

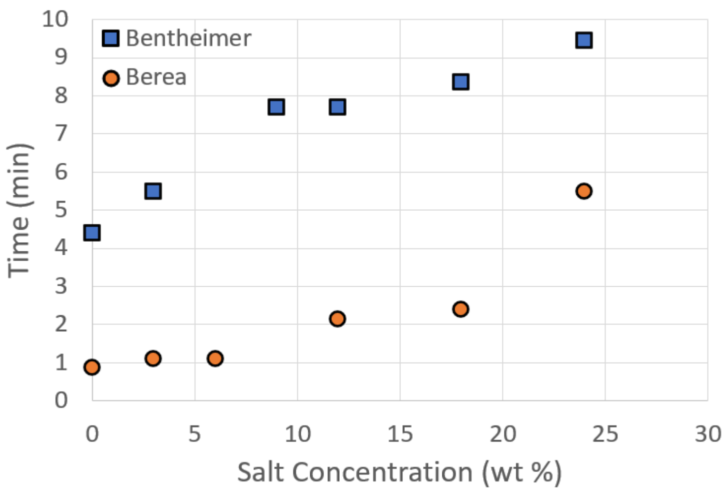


Figure 3: Comparison of rate imbibition at different salt concentration

Conclusions

Salt precipitation is a significant issue that can lead to injectivity impairment during CO_2 storage in saline aquifers. Focusing solely on the amount of salt precipitated is insufficient to evaluate the success of a storage project. Instead, considering the microscopic structure of the reservoir rock is crucial. The results demonstrate that even slight amounts of salt precipitation may have negligible effects on porosity but can dramatically impact injectivity.

Our study found that Berea sandstone, with its smaller pore radius, showed a more significant reduction in permeability compared to Bentheimer sandstone with the same amount of salt precipitation. These minor changes in the porosity-permeability correlation significantly impact the numerical evaluation of injectivity. This highlights that porosity-permeability correlation is among the uncertainties that should be experimentally evaluated accurately prior to any numerical modelling to gain a more realistic insight into injectivity impairment.

Overall, the study emphasizes that a detailed understanding of the rock's microscopic structure and petrophysical properties is essential for predicting and managing the impacts of salt precipitation on CO_2 injectivity. This approach can lead to more reliable and efficient CO_2 storage solutions, contributing to the broader goal of mitigating global warming through effective carbon sequestration.

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