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Experimental Investigation of the Impact of CO_2 on Interfacial Tension and Rock Properties in Application to CO_2 Storage in Saline Aquifers

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Abstract

This study experimentally investigates the effect of CO_2 storage on key rock-fluid interactions in sandstone reservoirs and saline aquifers using Berea sandstone as an analog for reservoir rock. The research focuses on the changes in interfacial tension (IFT) and rock properties as a result of CO_2 exposure —critical factors that influence the effectiveness of CO_2 trapping mechanisms and the long-term stability of geological carbon storage. These insights are essential for improving carbon capture, utilization, and storage (CCUS), and as well as modeling such processes, which are vital for project design and derisking for decarbonization.

All experiments were conducted under controlled reservoir conditions of 150°F and 1500 psi. IFT measurements were taken before and after CO_2 exposure over one month of storage period to capture the effects of CO_2 on rock-fluid interactions. In addition, routine core analysis (RCA) was performed before and after the storage tests to assess changes in fundamental rock properties, such as porosity and permeability, which are indicative of the reservoir's ability to retain injected CO_2.

To further understand the chemical and mineralogical transformations during CO_2 storage, fluid chemistry was monitored using inductively coupled plasma (ICP) analysis, allowing for the detection of changes in ion concentrations and dissolved minerals. X-ray diffraction (XRD) analysis was also conducted to track any alterations in rock mineralogy, shedding light on how prolonged CO_2 exposure influences mineral reactions and rock integrity.

This study provides valuable insights into how CO_2 storage impacts IFT and rock properties in Berea sandstone, serving as an analog for sandstone reservoirs and saline aquifers. These findings are critical for advancing the accuracy of predictive models that estimate CO_2 storage capacity, improving the understanding of reservoir behavior, and enhancing containment integrity in CCUS projects. Overall, this study contributes to developing more effective strategies for long-term geological storage of CO_2, utilizing the measured data to reduce uncertainty and support engineering efforts to mitigate climate change.

Introduction

Carbon capture, utilization, and storage (CCUS) represents a cornerstone technology in mitigating the effects of anthropogenic carbon dioxide (CO_2) emissions and combating climate change. Among various approaches to geological storage, saline aquifers and sandstone reservoirs have gained prominence due to their vast storage capacities and widespread availability. Successful implementation of CCUS relies on an intricate understanding of reservoir-scale processes, particularly the interaction of CO_2 with rock and brine systems under reservoir conditions. These interactions influence key properties such as interfacial tension (IFT), wettability, porosity, and permeability, which govern CO_2 migration, trapping, and long-term storage/containment.

This study focuses on experimentally investigating the impact of CO_2 storage on IFT and rock properties in Berea sandstone as an analog for sandstone reservoirs and saline aquifers. IFT is a critical parameter influencing capillary pressure, injectivity, and storage efficiency, while changes in rock properties such as porosity and permeability directly affect reservoir performance. Previous studies (Espinoza and Santamarina, 2010; Li et al., 2012) have highlighted the significance of IFT and mineral reactions in controlling the geomechanical and geochemical behavior of reservoirs under CO_2 exposure. However, a comprehensive analysis combining these aspects under high-pressure and high-temperature (HPHT) conditions remains limited. By conducting IFT measurements, routine core analysis (RCA), and chemical and mineralogical characterizations, this research aims to address these gaps and provide quantitative insights to derisk and optimize CCUS operations.

The subject experimental work performed under HPHT conditions (150°F and 1500 psi) involved IFT measurements using a high-precision Drop Shape Analyzer, core analysis for porosity and permeability, and fluid chemistry monitoring using Inductively Coupled Plasma (ICP) spectroscopy. Mineralogical changes were assessed using X-ray Diffraction (XRD) analysis, capturing the dynamic interplay of dissolution and precipitation processes during CO_2 exposure. When CO_2 is injected, it dissolves in the brine and the process can be more complex especially when hydrocarbons are present. There are many detailed studies for compositionally complex systems without the presence of flow (Venkatraman et al. 2017, Khan et al. 2023, Ratnakar et al. 2020, Dindoruk et al. 2021, and Ratnakar et al. 2024). Such dissolution can lead to the formation of carbonic acid, which reacts with carbonate minerals.

The findings of this study are critical for enhancing the accuracy of predictive models for CO_2 storage capacity, improving the understanding of reservoir behavior, and minimizing uncertainties in designing and executing CCUS projects.

Methodology

Several experiments were performed both before and after CO_2 storage to characterize its effects on rock-fluid and fluid-fluid interactions at reservoir conditions of 150°F and 1500 psi. The main tests performed in this study included interfacial tension (IFT) measurements between supercritical CO_2 and saturated brine, routine core analysis (RCA) to assess changes in porosity and permeability, inductively coupled plasma optical emission spectroscopy (ICP-OES) analysis for fluid chemistry, and X-ray Diffraction (XRD) analysis to evaluate mineralogical changes after CO_2 storage. These analyses were carried out pre-storage, and after one month of storage with CO_2. This approach allowed for the identification and quantification of the impacts of storage duration on the individual phases and their interactions.

Experimental Set up

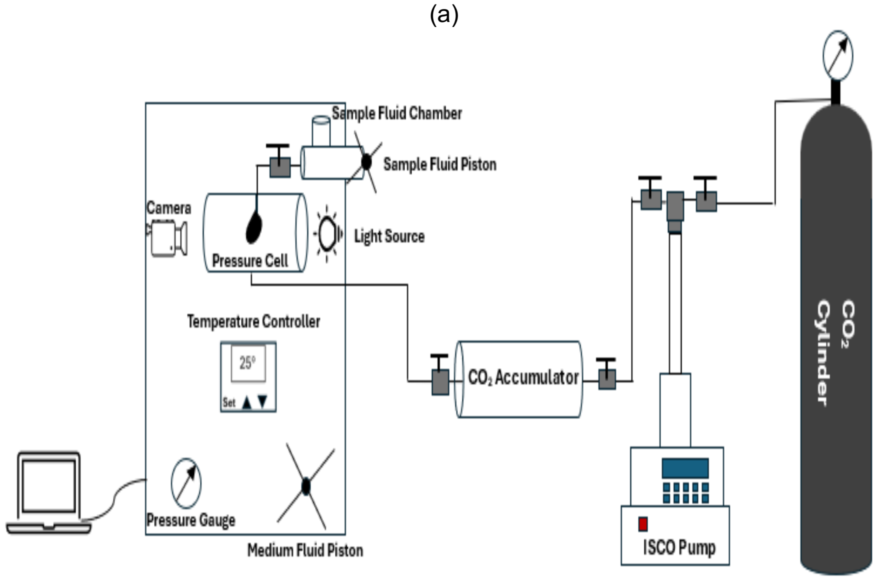
In this study, we conducted comprehensive experimental work, including exposure tests, RCA, IFT, ICP-OES, and XRD analyses. The schematic of the exposure test includes a CO_2 gas cylinder, an Isco pump, high-pressure high-temperature accumulators, a pressure gauge, and an oven. Detailed descriptions of the experimental set up, materials and procedures for the exposure test, RCA, ICP-OES and XRD can be found in the studies by Ahmed et al. (2024a; 2024b).

IFT

Measuring interfacial tension (IFT) is vital for understanding the behavior of CO_2 plumes in saline aquifers under reservoir conditions. To achieve this, we utilized a high-pressure, high-temperature (HPHT) Drop Shape Analyzer (DSA) from Krüss/Eurotechnica to perform precise IFT experiments between supercritical CO_2 and brine at 150°F (65°C) and 1500 psi. This state-of-the-art equipment is specifically designed for surface and interfacial characterization at extreme conditions, accommodating pressures up to 10,000 psi and temperatures as high as 356°F (180°C), as demonstrated in Figure 1.

The main components of the DSA are a HPHT cell, a sample fluid chamber, a sample fluid piston, a a camera, a light source, a temperature controller, a pressure gauge, and a heater, as shown in Figure 1a. Using the high-resolution camera, the integrated software applies the pendant drop method (PDM) to calculate real-time IFT values with high accuracy. Since the density of supercritical CO_2 is lower than that of brine, the experiments were conducted by suspending brine droplets within the surrounding CO_2 phase, enabling reliable IFT measurements.

(a)



(b)

Figure 1. HPHT DSA100 (a) and schematic of the DSA (b) (Paker et al., 2024).

Experimental Procedure

Interfacial tension (IFT) values are highly sensitive to the presence of impurities and to variations in pressure and temperature. Therefore, several precautions must be taken during the experimental procedure to minimize errors and ensure accurate results. These precautions include thoroughly cleaning all associated equipment prior to testing and allowing sufficient time for the system to reach thermal equilibrium. Such precautions are critical for preventing contamination and preserving the integrity of the measurements (Paker et al., 2025).

Results and Discussion

The interfacial tension (IFT) of the CO_2/brine system was measured before and after exposure to CO_2, as shown in Figure 2 and Figure 3, respectively. The IFT increased by approximately 10%, rising from 32.64 mN/m to 35.80 mN/m after CO_2 exposure. This increase aligns with the values reported in the literature, where IFT for CO_2/brine systems under similar conditions typically ranges between 30–38 mN/m (Li et al., 2012; Espinoza and Santamarina, 2010). The observed IFT change suggests a modification of interfacial properties due to chemical interactions and ion redistribution in the brine during exposure (Tale et al., 2025). These changes may influence CO_2 injectivity and storage efficiency by altering capillary pressure and wettability, which are critical for the migration and trapping of CO_2 in deep saline aquifers.

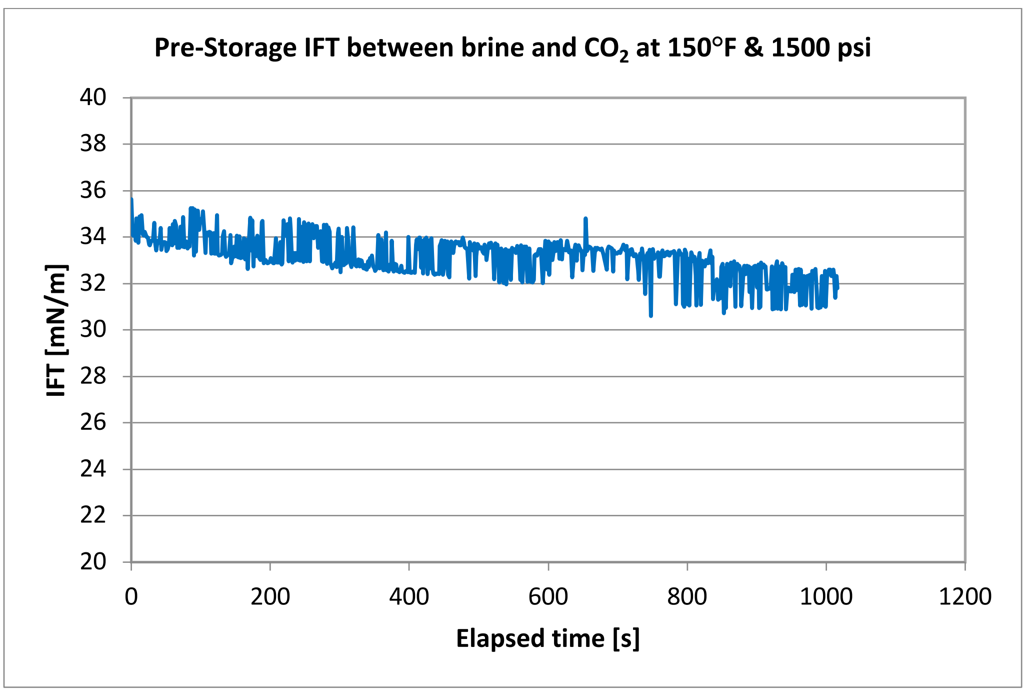


Figure 2. IFT Before CO_2 exposure.

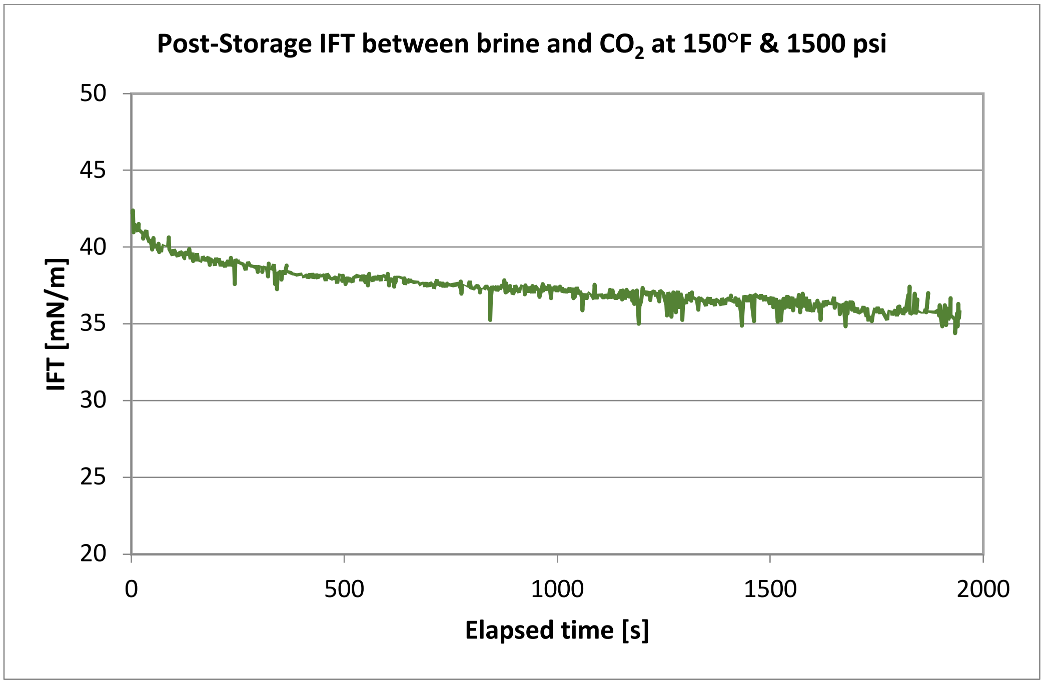
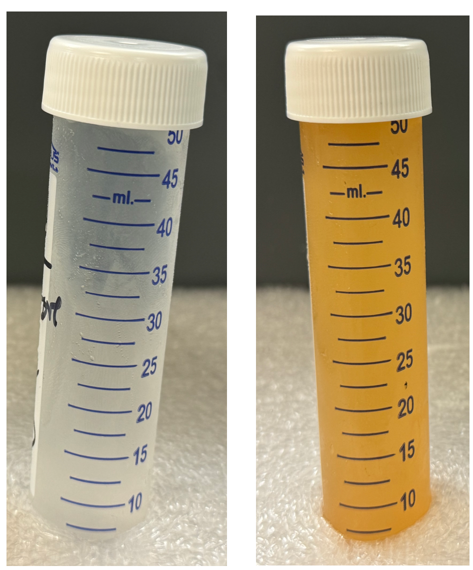


Figure 3. IFT After CO_2 exposure.

Visual observations revealed a distinct color change in the brine from colorless before CO_2 exposure to yellow afterward, as shown in Figure 4. This discoloration is likely due to changes in fluid chemistry caused by chemical reactions between the rock and CO_2-saturated brine under HPHT conditions. Specifically, the yellowing may result from the formation of iron oxides, hydroxides, or sulfur oxides, consistent with findings reported by Kaszuba et al. (2005) and Matter et al. (2007).



(a) (b)

Figure 4. Brine Before CO_2 Exposure (a) and After CO_2 Exposure (b).

Inductively Coupled Plasma (ICP) analysis confirmed significant increases in bicarbonate, sulfate, and magnesium ion concentrations, indicating intense mineral reactions. X-ray Diffraction (XRD) analysis revealed the dissolution of carbonates and pyrite, accompanied by halite precipitation. Quartz and K-feldspar remained unchanged, suggesting that these minerals were not reactive under the experimental conditions.

Routine Core Analysis (RCA) demonstrated slight reductions in porosity and permeability after the CO_2 exposure. These decreases suggest that mineral precipitation exceeded dissolution during the experiment, resulting in pore throat blockage. This observation aligns with the XRD results, which indicated the formation of halite and other precipitants that likely contributed to the reduction in such properties.

Conclusions

This study demonstrates the significant impact of CO_2 storage on interfacial tension and rock properties in sandstone reservoirs and saline aquifers. The observed increase within IFT after a month of CO_2 exposure approximately 10%, coupled with porosity and permeability reductions, underscores the influence of mineral reactions and ion redistribution on CO_2 trapping mechanisms. The results highlight the dual role of mineral dissolution and precipitation in altering reservoir properties, emphasizing the need for careful reservoir characterization and management (i.e., from well-count to injectivity and thus the storage as a whole) in CCUS applications. These findings provide valuable data for refining predictive models, enhancing storage efficiency, and ensuring long-term containment integrity in geological formations.

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