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Review

Core Flooding Experimental Validation of the Impact of Geological and Chemo-Physical Properties on CO2 Storage Efficiency

Gregory Mwenketishi[1]*, Ahmed Al-Yaseri[2,3], Hadj Benkreira[1] and Nejat Rahmanian[1]*

[1]Chemical Engineering Programme, School of Engineering, Faculty of Engineering and Digital Technologies, University of Bradford, Bradford BD7 1DP, UK

[2]Center for Integrated Petroleum Research, King Fahd University of Petroleum & Minerals, Dhahran, 31261, Saudi Arabia

[3]Department of Geosciences, King Fahd University of Petroleum & Minerals, Dhahran, 31261, Saudi Arabia

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***Corresponding author:** Gregory Mwenketishi, Chemical Engineering Programme, School of Engineering, Faculty of Engineering and Digital Technologies, University of Bradford, Bradford BD7 1DP, UK, Email: tarteh9@gmail.com

ABSTRACT

This paper presents a comprehensive analysis of laboratory core flooding experiments that were conducted to validate the feasibility of CO_2 storage in a Gulf of Guinea aquifer formation. A brine-saturated reservoir sandstone core from the North Sea similar to the target formation was subjected to CO_2 injection under controlled conditions, which replicated in-situ pressure and temperature, to observe displacement efficiency, pressure evolution and rock–fluid interactions in a realistic environment.

Key petrophysical properties of the core such as porosity, permeability and grain density were measured and analyzed, with notable anomalies identified and examined in the context of the core mineralogical composition. Advanced mineralogical characterization techniques including QEMSCAN imaging, X-ray diffraction and X-ray fluorescence were used to quantify the mineral constituents and elemental makeup of the core. These techniques helped in understanding how the composition of rock influences CO_2 flow and trapping.

Experimental results establish the dynamics of CO_2 displacing brine within the pore network, including the evolution of differential pressure and the extent of brine recovery and residual trapping. These observations are interpreted to assess the effects of reservoir heterogeneity and permeability variations on flow dynamics, by relating the pressure profile and displacement behavior to underlying rock properties.

The findings exhibited an empirical validation of conceptual CO_2 storage mechanisms alongside illustrating real-world behaviour of CO_2 plume migration and entrapment in the formation validate our simulation work reported. In this way, the paper substantiates the viability of CO_2 sequestration in the studied Gulf of Guinea aquifer and highlights how impurities in the CO_2 stream and intrinsic aquifer properties (like mineralogy and permeability heterogeneity) can influence storage performance.

Keywords: CO_2 Coreflooding; CO_2 Storage Efficiency; CCS; Climate Change; numerical Simulation; CO2 sequestration

Introduction

Geological storage of carbon dioxide (CO_2) in deep saline aquifers is a promising technology for mitigating greenhouse gas emissions. Our previous work have explored the effects of CO_2 impurities and aquifer properties on storage performance through theoretical analysis and reservoir-scale simulations. However, translating these insights to real-world conditions requires experimental validation at the laboratory scale. In this paper, we bridge that gap by examining how CO_2 interacts with a representative reservoir rock under controlled conditions. A core flooding experiment was designed to simulate the injection of CO_2 into a brine-saturated sandstone core sample from the Gulf of Guinea region, capturing key aspects of the storage process on a smaller scale.

CO_2 core flooding experiments are critical in understanding multiphase flow behavior, rock-fluid interactions and CO_2 storage mechanisms in subsurface reservoirs. Globally, significant research has been conducted on CO_2 flooding in carbonate and sandstone formations, particularly in North America, Europe and the Middle East. However, for the West African region, which holds considerable oil and gas reserves and is emerging as a key region for Carbon Capture and Storage (CCS) and Enhanced Oil Recovery (EOR) projects, experimental data is scarce. This section reviews existing studies and highlights key knowledge gaps relevant to West Africa.

Studies in the Permian Basin (Texas), the North Sea and the Middle East have explored CO_2 flooding performance, examining parameters such as relative permeability, capillary pressure, hysteresis and wettability alteration. Researchers such as Al-Shalabi and Sepehrnoori[1], Ghomian, et al.[2] and Burton, et al.[3] have extensively characterized rock-fluid interactions and identified key mechanisms for miscible and immiscible CO_2 flooding.

Limited experimental CO_2 flooding studies exist for Africa. A few studies in North Africa (e.g., Algeria's InSalah project) focus more on field-scale CO_2 injection and storage monitoring rather than laboratory core flooding. In West Africa, most available studies are simulation-based or focus on hydrocarbon production, with very few publications reporting core-level experimental data. Eboh, et al.[4] used simulation to evaluate CO_2-EOR potential in the Niger Delta but lacked core flooding validation. Ojo, et al. presented petrophysical characterization of Niger Delta cores but did not incorporate CO_2 flooding experiments[5]. Offshore Angola and Senegal have seen exploration of gas injection for pressure maintenance, but CO_2-specific experimental work is not reported in the public domain.

Most CO_2 flooding experiments use core samples from North America or Europe[1,3]. The mineralogy, porosity and permeability of West African sandstones and carbonates are distinct[5], leading to differences in CO_2 storage capacity, injectivity and reactivity.

Although simulation studies provide theoretical insights[4], they require experimental validation. Existing CO_2 -EOR and storage simulations in West Africa lack laboratory data for tuning relative permeability, capillary pressure curves and residual trapping parameters[6]. The impact of impure CO_2 streams (containing methane, nitrogen or H2S) on West African reservoir rocks remains unstudied[2,7]. Given the regional gas compositions, understanding impurity effects on CO_2 solubility, mineral dissolution and scaling is essential.

Many global core flooding studies use synthetic brines that do not reflect the high salinity and unique ion composition (e.g., Na+, K+, Ca2+, Mg2+, SO42-) of West African formation waters[1,2], potentially skewing CO_2 -brine-rock interaction results.

Most published experiments are short, so they miss important long-term changes in minerals, movement of small particles or changes in how easily fluids can flow, which are essential for evaluating permanent storage[3,7].

Despite West Africa's potential as a CCS hub, there is a significant lack of laboratory-based CO_2 flooding experiments using local core samples and brine compositions[4,5]. The absence of empirical data creates uncertainties in scaling global learnings to local reservoirs, hindering accurate assessment of CO_2 injectivity, storage capacity and enhanced oil recovery potential[6,7].

Laboratory core floods provide direct observations of phenomena such as displacement efficiency (how effectively CO_2 can push out resident brine), pressure evolution during injection (which relates to injectivity and capillary forces) and the extent of trapping (residual brine or CO_2 left behind in pore spaces). By measuring these factors, we can verify assumptions made in modeling studies and identify any additional complexities arising from rock heterogeneity or fluid-rock reactions. Importantly, the core selected for this study is characterized in detail to understand its petrophysical and mineralogical properties. Parameters like porosity and permeability dictate how easily fluids flow through the rock, while mineral composition can influence wettability and potential geochemical interactions with CO_2. Techniques such as Quantitative Evaluation of Minerals by SCANning electron microscopy (QEMSCAN) and X-ray diffraction (XRD) and X-ray fluorescence (XRF) analyses are utilized to paint a complete picture of the rock's makeup. This allows us to connect aquifer properties (e.g. grain size distribution, clay content, cementation) with the observed flow behavior of CO_2 in the experiment.

Another critical aspect considered is the role of impurities in the CO_2 stream. In real carbon capture and storage (CCS) operations captured CO_2 may contain minor fractions of other gases (such as N_2, CH_4 or SO_2) depending on the source and purification process. These impurities can alter the physical properties of the injected fluid and its interactions with the reservoir. Although the core flood in this study primarily uses high-purity CO_2 for simplicity and clarity, the implications of impurities are discussed in light of the experimental findings. For instance, a less dense or more mobile component like N_2 might affect the displacement pattern, while reactive impurities like SO_2 could trigger water–rock reactions. By drawing on both the experimental data and relevant literature, we incorporate these considerations to ensure that our experimental validation remains relevant to real-world CO_2 storage scenarios.

In summary, the introduction of this paper lays out the motivation and scope for the experimental investigation. The goal is to validate and deepen our understanding of CO_2 storage mechanisms in the Gulf of Guinea aquifer through tangible laboratory evidence. This section also highlights a substantial gap in experimental CO_2 flooding research in West Africa. Addressing this gap through laboratory studies will enhance regional CCS and EOR project design, reduce geological uncertainty and support global carbon mitigation efforts.

The subsequent sections detail the core properties, describe the core flooding procedure and results, present the mineralogical analysis outcomes and finally interpret how these pieces fit together to inform the broader context of CO_2 sequestration in heterogeneous, impure-CO_2 environments.

Materails and Equipment

Core Sample Properties (Porosity, Permeability and Density)

The core selected for the CO_2 flooding experiment is a cylindrical plug of reservoir sandstone from the North See and similar to the properies of core in the Gulf of Guinea aquifer formation. Its basic petrophysical properties are summarized in **(Table 1)**.

Table 1: Summary of Experimental Data.

Parameter	Run #1	Run #2	Run #3
Atmospheric Pressure (psia)	14.7	14.7	14.7
Billets Loaded	23578	23578	23578
Temperature (°C)	18	18	18
Reference Pressure (psia)	216.96	217.40	217.48
Experimental Pressure (psia)	134.27	135.50	135.52
Bulk Volume (ml)	57.00	57.00	57.00
Grain Volume (ml)	18.50	19.12	19.10
Pore Volume (ml)	38.50	37.88	37.90
Porosity (%)	67.54%	66.46%	66.49%
Grain Density (g/ml)	6.777	6.557	6.563
Pref/Pexp Ratio	1.69	1.68	1.68
Volume Billets loaded (ml)	129.264	129.264	129.264
Stabilization Duration (s)	362	62	77

The core has a diameter of 3.8 cm and a length of 7.5 cm (standard dimensions for core analysis). It exhibits a helium porosity of 21% and a gas permeability on the order of 150 millidarcies (mD). This combination of moderate-to-high porosity and permeability classifies the rock as a relatively high-quality aquifer reservoir rock, indicating well-connected pore networks. Such properties are favourable for CO_2 injection, as they suggest that the rock can accept CO_2 at a reasonable rate without excessively high injection pressures.

The grain density of the core material was measured to be 2.70 g/cm³ **(Table 1)**, slightly above the 2.65 g/cm³ expected for pure quartz mineralogy[8]. This subtle increase in density hints at the presence of minerals heavier than quartz within the rock matrix. Indeed, as will be detailed later in the mineralogical analysis, the sandstone contains trace amounts of high-density accessory minerals (for example, pyrite or other iron-rich grains) alongside the dominant quartz and clay constituents. The presence of even a small fraction of such heavy minerals can raise the bulk grain density appreciably due to their high specific gravity[9].

An interesting observation is that the porosity and permeability of this sample, while both relatively high, do not follow a simplistic trend - the permeability is somewhat lower than one might expect for a sandstone with ~21% porosity if it were very clean and well-sorted. This suggests that factors like pore throat size distribution and clay content are influencing fluid flow. In other words, the core may have portions of its pore space that are less effective in contributing to permeability (e.g., finer pores or partial cementation), resulting in a permeability that is moderate (150 mD) rather than extremely high for the given porosity. Such nuances underscore the importance of detailed mineralogical characterization, as the distribution of mineral types and grain sizes will impact how pores connect.

The measured grain density can be cross-verified with a theoretical grain density calculated from the rock's mineral composition. Mineral components intrinsically control petrophysical parameters such as grain density[10]. Using the Quantitative Evaluation of Minerals by SCANning electron microscopy (QEMSCAN) derived mineral modal fractions (discussed in a subsequent section), a weighted grain density was computed. This calculation yielded a grain density of approximately 2.68 g/cm³, which is in good agreement with the lab-measured value of 2.70 g/cm³. The close correspondence between measured and calculated grain densities indicates that the identified minerals (quartz, clays, minor heavy minerals, etc.) adequately explain the bulk composition of the rock[11,12]. A slight difference of a few hundredths could be due to minor undetected dense phases or experimental uncertainty, but overall it confirms that the core's mineralogical makeup, as identified, is consistent with its basic physical properties.

In summary, the core sample provides a realistic representation of the target aquifer reservoir: it has substantial porosity to store CO_2 and sufficient permeability to allow CO_2 injection and flow. The petrophysical properties observed here set the stage for understanding the core's behavior in the flooding experiment. Any anomalies or deviations (such as the moderately low permeability relative to porosity or the slightly elevated grain density) are likely linked to the rock's mineralogy and pore structure – a connection that will be explored through mineralogical analysis and considered when interpreting the flow experiment results.

Mineralogical Analysis of the Core (QEMSCAN, XRD, XRF)

A detailed mineralogical and chemical characterization of the core sample was performed to understand the composition of the rock and to explain the observed petrophysical properties. The analysis combined QEMSCAN (model EMSCAN 650F), an automated mineral mapping via scanning electron microscopy, X-ray diffraction (XRD) and X-ray fluorescence (XRF) techniques, each providing complementary information:

QEMSCAN results

QEMSCAN was used to obtain a high-resolution mineral map and bulk mineralogy of the core. This technique scans a polished slice of the rock with an electron beam and detects X-ray signatures to identify minerals at thousands of points, building up a detailed picture of mineral distribution. The bulk mineral composition derived from QEMSCAN is summarized in **(Table 2)**.

Table 2: Interpretation of QEMSCAN mineralogical analysis results.

Mineral	Area (%)	Mass (%)
Quartz	79.08%	92.98%
K-Feldspar	4.62%	5.36%
Mica	0.25%	0.35%
Illite	1.32%	1.01%
Pores	14.47%	0%
Others	0.25%	0.3%

The sandstone is found to be quartz-rich, with quartz constituting approximately 60-70% of the rock by volume. The next significant component is clay minerals (roughly 20-25% collectively), predominantly kaolinite (a dioctahedral aluminosilicate clay) with smaller amounts of illite. Feldspar minerals are present at a minor level (on the order of 5-10%), including both potassium feldspar and plagioclase as identified by their characteristic elemental signatures (K for K-feldspar, Ca/Na for plagioclase). In addition, trace accessory minerals are detected: a small fraction (~1–2%) of iron-bearing minerals such as pyrite (FeS_2) is present, along with minute quantities of heavy minerals like zircon ($ZrSiO_4$) and rutile/anatase (TiO_2 polymorphs), which are common trace constituents in sandstones. Figure 1 shows the QEMSCAN mineral map and illustrates the spatial distribution of these minerals in a representative section of the rock **(Figure 1)**.

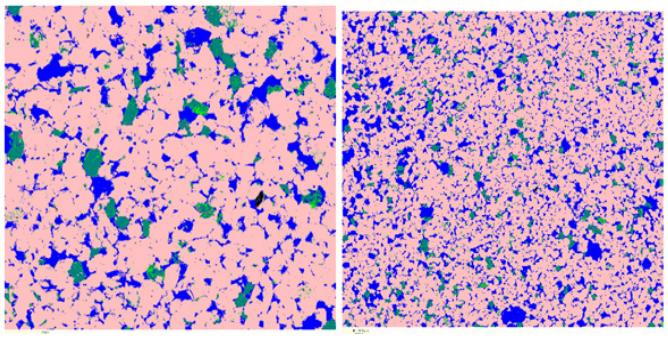

Figure 1: QEMSCAN mineral map.

In Figure 1, quartz grains (depicted in a particular color/shade) form the framework, often appearing as large, well-rounded particles, whereas clay minerals (shown in a contrasting color) tend to occupy the intergranular regions, coating grain surfaces or fill pore space in patches. The image highlights some heterogeneity: there are clay-rich clusters and streaks through the sample, which correspond to lower local permeability zones. Tiny bright pixels in the QEMSCAN map correspond to high-density minerals like pyrite; these are sparsely distributed and typically associated with clay laminations or specific grain coatings. Overall, the QEMSCAN results depict a sandstone that, while dominated by quartz, has a non-negligible clay content and minor cement/accessories – a texture consistent with a sub-arkosic to wacke sandstone. This mineralogical makeup aligns with the earlier interpretation that clay content likely influences the flow paths: the clay-rich areas can act as baffles or flow inhibitors, explaining why the core's permeability is moderate for its porosity.

XRD confirmation

To validate the mineralogy, powdered samples of the core were analyzed by X-ray diffraction. The XRD diffractogram confirms the mineral assemblage identified by QEMSCAN. The most intense reflections in the XRD pattern correspond to quartz – notably a strong peak at around $2\theta \approx 26.6°$, which is the primary reflection from quartz (due to its crystalline SiO_2 structure). In addition, characteristic peaks for kaolinite are observed (for example, a basal reflection near 12.3° 2θ and another around 24.8° 2θ, which are indicative of kaolinite's layered structure). There are also features in the XRD pattern consistent with illite/smectite clay (peaks in the 8–9° and ~18° 2θ range, though such peaks can be broad due to clay's partial crystallinity). Feldspar is evidenced by a set of smaller peaks around 27–28° 2θ (likely from K-feldspar's orthoclase/microcline structure) and a peak near 22° (which could be from plagioclase). A minor peak at ~29.4° 2θ suggests the presence of a small amount of calcite ($CaCO_3$) as a cementing agent. This aligns with the QEMSCAN detection of a calcitic component of a few percent and with the measured XRF calcium content (see next section). Other minor peaks at higher angles (e.g., around 35° and 56° 2θ) can be attributed to pyrite and other trace minerals, though in this sample those peaks are very weak given the low abundance of such phases. Importantly, the XRD analysis did not reveal any unexpected minerals that QEMSCAN missed; all major and minor peaks could be accounted for by the minerals already identified **(Figure 2)**.

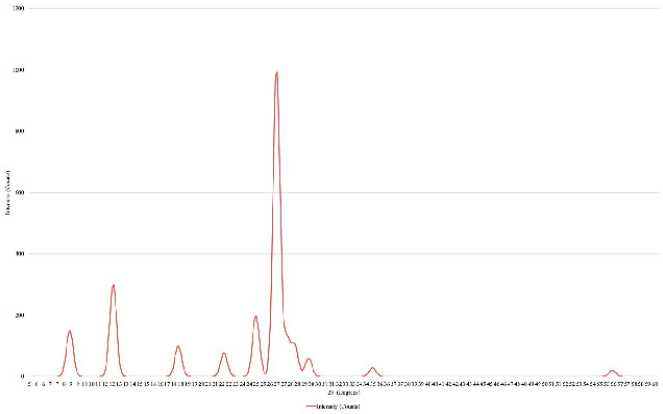

Figure 2: QEMSCAN mineral map.

This cross-verification strengthens confidence that the core's mineral composition is thoroughly characterized: it is largely composed of quartz and kaolinite, with minor illite, feldspar, a touch of calcite and trace-heavy minerals. No significant amounts of expandable clays (like smectite) or highly reactive minerals (like olivine or abundant sulfides) were found, which means the core is typical of a mature sandstone that has undergone substantial diagenesis (kaolinization of feldspars, etc.).

XRF elemental composition

Bulk chemical analysis by X-ray fluorescence provided the elemental oxide percentages for the core sample (see **Table 3** for a summary of major oxides).

Table 3: Permeability test results.

X (mm)	Y (mm)	Permeability (mD)	Pressure (kPa)	Flow (cc/min)	Measurement Time (s)	Klinkenberg B (kPa)	Forchheimer Factor (1/m)	Geometry Factor	Viscosity (Pa·s)	Uncorrected Permeability (mD)
13.5	10.8	2319.24	20.138	503.726	17.2916	3.25998	1.02E-06	0.0059	1.78E-05	1150.23
13.5	11.4	2357.6	19.7981	499.736	16.2287	3.24213	1.01E-06	0.0059	1.78E-05	1166.73
13.5	12.0	2153.85	21.3275	499.484	16.2325	3.33547	1.07E-06	0.0059	1.78E-05	1083.90
13.5	12.6	2072.5	21.8374	499.695	17.2818	3.37648	1.10E-06	0.0059	1.78E-05	1050.07
13.5	13.2	2115.06	21.5824	499.781	16.2443	3.35509	1.08E-06	0.0059	1.78E-05	1067.52

13.5	13.8	2166.09	21.1576	500.097	16.2377	3.32992	1.07E-06	0.0059	1.78E-05	1088.58
13.5	14.4	2078.94	21.8374	499.951	17.2926	3.37392	1.10E-06	0.0059	1.78E-05	1052.13
13.5	15.0	2489.24	19.1183	504.924	16.2464	3.1883	9.74E-07	0.0059	1.78E-05	1218.53
13.5	15.6	2680.33	18.0137	499.74	16.2242	3.11469	9.27E-07	0.0059	1.78E-05	1294.69
13.5	16.2	3282.5	15.3796	499.684	22.6174	2.92513	8.13E-07	0.0059	1.78E-05	1523.84

The XRF data show a high content of silica (SiO_2), on the order of ~80 wt%, consistent with the dominance of quartz (silica) in the mineralogy. The second most abundant constituent is alumina (Al_2O_3), roughly 10–15 wt%, which reflects the presence of aluminium-bearing clays (kaolinite is $Al_2Si_2O_5(OH)_4$, illite has Al and K). A notable fraction of iron oxide (Fe_2O_3) is detected (around 2–4 wt%), attributable to the pyrite and possibly iron-bearing clay minerals; since pyrite itself is FeS_2 (with ~46% Fe by weight), a few percent pyrite can contribute a couple of percent Fe_2O_3 equivalent when oxidized for XRF reporting. The potassium oxide (K_2O) content is on the order of 1-3 wt%, which is explained by the presence of K-feldspar and illicit clay (both sources of K in the rock). Calcium oxide (CaO) appears at ~1–2 wt%, in line with the minor calcite detected. Small amounts of titanium dioxide (TiO_2) (perhaps ~0.5–1%) correspond to the trace heavy minerals like rutile/anatase and Zirconia (ZrO_2) may be reported at a few hundred ppm levels indicating trace zircon (Figure 1 above). Overall, the elemental composition concurs with the mineralogical findings: high Si and moderate Al confirm a silicate-rich rock with substantial clay; the presence of K, Fe and Ca corroborate the identified K-feldspar/illite, pyrite and calcite, respectively. There is an absence of significant magnesium (MgO) or sulfur (reported as SO_3) in the XRF, suggesting a lack of Mg-rich clays (e.g., chlorite) and that most sulfur is tied up in the small amount of pyrite rather than sulfate minerals.

Integrating the QEMSCAN, XRD and XRF results provides a comprehensive picture of the core's mineralogy. The rock can be described as a quartzose sandstone with moderate clay content (chiefly kaolinite) and minor feldspathic and cement components. This composition has direct implications for CO_2 storage behaviour:

- The high quartz fraction means the rock matrix is largely chemically inert to CO_2 – quartz will not readily dissolve or react even in carbonic acid, which implies that mineral trapping of CO_2 as new carbonate minerals will be limited by the scarcity of reactive minerals like feldspars or mafic components[13]. The small amount of calcite present could dissolve upon exposure to CO_2-acidified brine, but given it is only a few percent, any porosity increase or secondary carbonate precipitation from that would be localized and minor in the short term.
- The presence of clays indicates a strongly water-wet rock surface (quartz and kaolinite both tend to be water-wet). This condition usually leads to a certain amount of residual water saturation that cannot be displaced by CO_2, as water clings in the small pores and clay-rich regions. Clays also contribute to fine-scale heterogeneity: as seen in the QEMSCAN map, clay-rich zones can act as flow barriers or baffles. During CO_2 injection, the CO_2 will preferentially move through the more permeable, quartz-rich pathways, potentially bypassing some of these clay pockets. This can result in an uneven sweep and early breakthrough of CO_2, leaving behind islands of brine in less permeable zones.
- The minor pyrite and other heavy minerals, while not abundant enough to drastically alter the flow, could have implications if CO_2 were co-injected with oxygen or other reactive gases (pyrite can oxidize to form sulfuric acid). In our experiment with pure CO_2, this is not a factor, but in real sequestration scenarios containing impurities like SO_2 or O_2, these minerals might participate in geochemical reactions.

In summary, the mineralogical analysis equips us with a solid understanding of the rock framework and composition, which is crucial for interpreting the core flood experiment. Knowing the mineral makeup helps explain the core's porosity and permeability (e.g., clay reducing effective permeability) and allows prediction of how the rock might interact with injected CO_2 (mostly physical displacement with minimal chemical reaction, given the inert nature of quartz and kaolinite). This forms the basis for analyzing the CO_2 displacement and pressure behavior observed in the upcoming core flooding results section.

CO_2 Core Flooding Experiment: Displacement and Pressure Behaviour

Experimental setup

The core flooding experiment was conducted using a high-pressure triaxial core holder apparatus, which allowed us to simulate subsurface conditions. The experiment was setup to find how CO_2 flows through a rock sample under controlled conditions. It's essential for studying CO_2 sequestration efficiency, relative permeability.

The CO_2 core flooding setup comprises a suite of integrated components designed to replicate subsurface conditions for evaluating fluid flow through porous rock samples. At the heart of the system is the VINCI Technologies Hasler core holder, which securely houses the core sample under simulated reservoir pressure and temperature conditions. CO_2 is injected into the core holder using the high-precision Quizix QX6000 pump, which ensures stable and accurate flow rates essential for reproducible results. Keller 33X pressure transducers are installed at both the inlet and outlet of the core holder to continuously monitor the pressure differential, a key parameter for calculating permeability and assessing injectivity. The entire setup is managed and monitored in real time through a computer interface, which logs pressure, flow rate and measurement time for data analysis.

To maintain consistent boundary conditions, a back-pressure regulator is positioned at the outlet of the core holder, holding the pressure at 600 psi to prevent CO_2 phase changes and simulate reservoir backpressure. The effluent from the core is directed into a sample collector, enabling fluid recovery and compositional analysis to observe displacement and saturation behavior. This configuration allows researchers to study CO_2 transport mechanisms, evaluate rock-fluid interactions and generate data for validating reservoir simulation models. Each component plays a critical role in ensuring the reliability and accuracy of

coreflooding experiments, particularly in applications related to enhanced oil recovery and carbon sequestration. The schematic digram of the experimental rig is shown in **(Figure 3)** below.

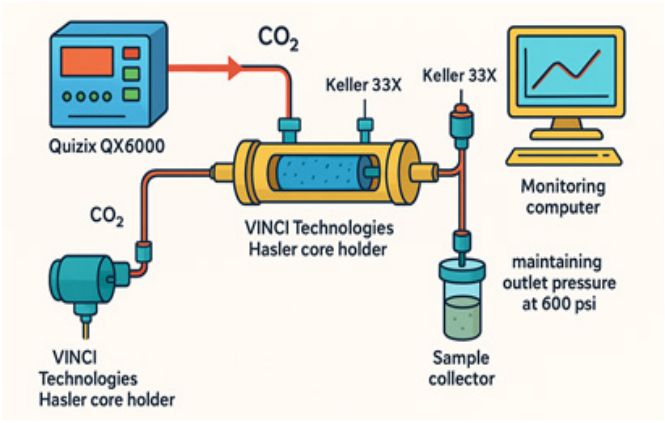

Figure 3: Schematic illustration for: CO_2 core flooding setup

CO_2 was injected from the bottom (inlet) of the vertically oriented core upward (to also assess any gravity effects) at a controlled constant flow rate using a metering pump. The injection rate was set to 0.5 mL/min (as an approximate Darcy flux of a few ft/day, representative of field injection rates scaled down to core dimensions). At this rate, the total pore volume (PV) of fluid in the core (about 18 mL, given the core's dimensions and ~21% porosity) would be injected in roughly 36 minutes. The experiment was continued until about 2–3 PV of CO_2 had been injected, to ensure that a breakthrough occurred and a new equilibrium was reached. Throughout the test, the differential pressure across the core (inlet-to-outlet) was recorded continuously using pressure transducers and the produced fluids at the outlet were collected and monitored to distinguish brine vs. CO_2. Initially, only brine is produced; after CO_2 breaks through, a two-phase mixture of brine and CO_2 comes out and eventually mostly CO_2 with diminishing brine fraction.

CO_2 Core Flooding Experimental Assumptions

When conducting a CO_2 core flooding experiment, several assumptions were made as follows:

- **Homogeneous and isotropic core sample:** Assumes uniform porosity and permeability, despite actual minor heterogeneities.
- **Constant confining and pore pressure:** Assumes stable experimental conditions (e.g., pore pressure at 1450 psi, confining at 2500 psi).
- **No core plug damage:** Assumes no mechanical damage or chemical alteration affecting flow properties during flooding.
- **Radial:** Assumes flow paths consistent with the selected geometry of the simulation model (usually linear or radial).
- **Constant injection rate:** Assumes stable CO_2 injection rate (e.g., 2 cc/min).
- **Full saturation of initial fluid (Seawater):** Assumes the core is fully saturated with seawater and free of trapped gas.

Pressure Profile and Breakthrough

Validation of experimental pressure drop against simulated results

(Figure 4) provides a direct comparison between the experimentally measured pressure drop data (depicted in blue) and the simulated pressure drop profile (shown in orange) obtained using a CO_2 radial core flooding model in E300, specifically employing the CO2STORE approach with CO_2 dissolution in brine enabled. The close correspondence between the experimental and simulated curves demonstrates that the model successfully captures the fundamental dynamics of CO_2 displacement in a brine-saturated core. Minor discrepancies observed between experimental and simulated curves, particularly the short-term peaks and troughs in pressure fluctuations, can be attributed to inherent rock heterogeneity and transient, small-scale fluid distribution changes, which may not be fully captured by the model's simplified assumptions. Nonetheless, the overall alignment in pressure magnitudes and general temporal behavior affirms the validity of the simulation approach. This validation indicates that the simulation model can reliably predict the pressure behavior observed in laboratory experiments, thereby reinforcing confidence in using this model framework for extrapolation to field-scale scenarios. The consistency also highlights the model's capability to effectively incorporate essential reservoir physics such as capillary entry pressures, relative permeability transitions and CO_2-brine interactions.

The pressure response observed during the CO_2 injection is shown in Figure 4. At the onset of injection, the core was entirely water-filled and CO_2 had to overcome the entry pressure needed to displace brine in the smallest pore throats (essentially the capillary pressure threshold). Consequently, the differential pressure, Delta Pressure (ΔP), across the core rose rapidly as CO_2 was first injected. This initial rise continued until the CO_2 front propagated through the core and a breakthrough of CO_2 occurred at the outlet. In our experiment, CO_2 breakthrough was detected after injecting approximately 0.5 pore volumes of CO_2, as indicated by the first appearance of gas at the outlet and a noticeable change in the slope of the pressure curve. At breakthrough, the differential pressure reached a peak of about 0.5 psi. This peak represents the maximum pressure needed to drive the CO_2 front through the fully water-saturated pore network.

Once the breakthrough happened, the nature of the flow in the core changed fundamentally: a continuous path for CO_2 from inlet to outlet was established. As a result, the overall resistance to flow dropped. Figure 2 shows that immediately after the breakthrough, the pressure drop across the core started to decline even though the injection rate was kept constant. Eventually, ΔP settled to a much lower steady-state value (on the order of 0.1–0.15 psi,. This steady-state (post-breakthrough) pressure is primarily governed by the flow of CO_2 through the core, with brine becoming a discontinuous phase trapped in some pores. The dramatic reduction in pressure drop (from ~0.5 psi to ~ 0.15 psi) reflects the higher mobility of CO_2 relative to brine: once CO_2 became the continuous phase, the viscosity in the flow pathways dropped to that of supercritical CO_2 (~0.05 cP, an order of magnitude lower than brine) and thus for the same flow rate, a much smaller pressure gradient sufficed (Darcy's law). In essence, the experiment transitioned from forcing an immiscible fluid into a static liquid-filled rock to simply pumping a mobile gas through a gas-filled rock with some residual liquid.

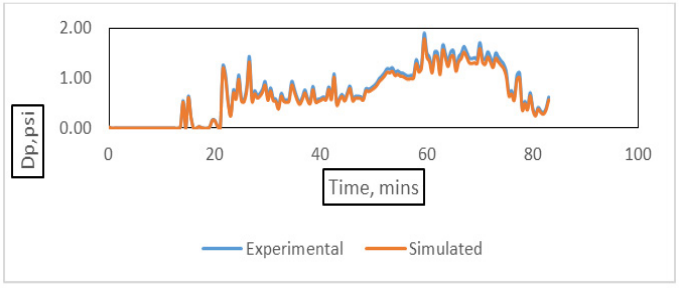

Figure 4: Base case simulation setup for a CO_2 radial core flooding model in E300, with CO2STORE – CO_2 dissolution in brine enabled - experimental pressure drop data (blue line) against a simulated pressure drop profile (orange line)

It is worth noting that the pressure curve in Figure 4 is not perfectly smooth during the post-breakthrough period – there are gentle fluctuations and a gradual decline before fully stabilizing. These subtleties can be attributed to the core's heterogeneity and two-phase flow dynamics. After initial breakthrough, CO_2 does not instantaneously displace all remaining brine; rather, it channels through the easiest paths (highest permeability streaks), leaving behind patches of brine in tighter or more tortuous regions. Over time, CO_2 continues to invade these brine-filled pockets (especially as pressure is maintained), in a process sometimes called "capillary soaking" or continued drainage. Each time CO_2 enters a new brine-filled zone, there is a local capillary resistance to overcome, which can cause a slight uptick in the pressure until that mini-breakthrough occurs, after which the pressure drops again. Thus, the wavy or stepwise minor features in the pressure decline are a signature of episodic invasion of remaining brine-filled porosity in heterogeneous pores. Eventually, as the injection proceeded to ~2 pore volumes and beyond, the frequency and magnitude of these events diminished, indicating that most of the accessible brine had been displaced and a new equilibrium approached.

By the end of the injection (after ~2.5 PV of CO_2 injected), the differential pressure had levelled off, suggesting that no further significant displacement of brine was occurring – essentially, the residual saturation regime was reached. Additionally, after 80 minutes of injection, stabilized pressure drop can be used to infer the effective permeability of the core to CO_2 at residual water saturation. Using Darcy's law and the known CO_2 fluid properties, the effective permeability to CO_2 was calculated and found to be only modestly lower than the original absolute permeability (on the order of 120 mD vs 150 mD initial). This indicates that a minor portion of the pore space remained occupied by immobile water, slightly reducing the available flow pathways. The fact that effective permeability did not drop drastically (only ~20% reduction) confirms that most of the larger pores were successfully filled with CO_2 and that the residual brine is mainly in the smaller pores that contribute less to flow. It also confirms that no significant damage or plugging happened during the experiment – had there been fines migration or salt precipitation clogging pores, we would expect to see a continuous decline in permeability (increasing ΔP over time, which was not observed.

Brine displacement and residual saturation

The production of brine from the core was measured throughout the test. **(Figure 5)** plots the cumulative brine volume produced (expressed as a fraction of the core's pore volume) against the injected pore volumes of CO_2. As seen in Figure 5, the brine recovery rises rapidly at first and then tapers off. In the initial stage (0 to ~0.5 PV CO_2 injected), brine production was almost one-to-one with CO_2 injection – essentially, each milliliter of CO_2 injected pushed out nearly an equal volume of brine, as the core was expelling its pore water. By the time of the CO_2 breakthrough (~0.5 PV injected), a significant portion of the brine (roughly 50–60% of the pore volume) had been produced. After breakthrough, the rate of brine production slowed markedly. The curve in Figure 5 shows a flattening trend: additional CO_2 injection yielded diminishing increments of brine. Between 0.5 and 1.5 PV of CO_2 injection, the cumulative brine recovery increased from about 60% to around 70% of the initial brine. Beyond 2 PV, the curve asymptotically approached an ultimate brine recovery of approximately 70–75%. This indicates that about 25–30% of the initial brine remained trapped in the core as residual water saturation (S_wr) that CO_2 could not displace. Table 3 summarizes these key experimental results, including the pore volumes of CO_2 injected at breakthrough (~0.5 PV), the peak differential pressure observed (~5 bar), the total brine recovery (~70–75% PV) and the corresponding residual water saturation (~25–30%).

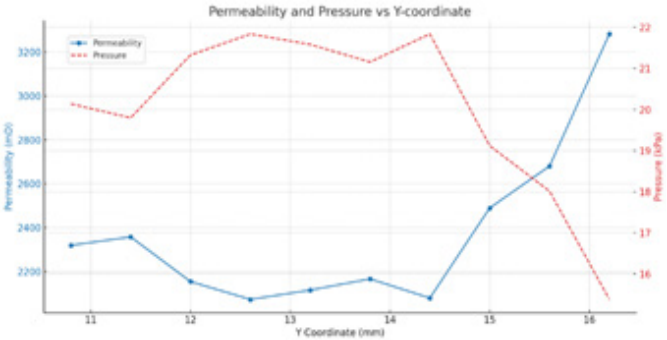

Figure 5: Cumulative brine volume-produced.

The existence of a substantial residual water saturation is expected in a water-wet reservoir rock. Capillary forces hold a certain fraction of the wetting phase (brine) in the pores even after the non-wetting phase (CO_2) has invaded. The final residual water saturation of ~0.3 (30%) in our experiment is in line with typical values for sandstones, though on the somewhat lower end of the spectrum for very clean (clay-poor) sandstones which can have S_wr as low as 15–25%. Our core, with its moderate clay content, exhibited a residual that suggests the larger pores were efficiently drained (thanks to the dominance of the quartz framework) while smaller pores and clay-associated microporosity retained water. The literature reports that higher quartz content often correlates with lower residual water saturation because quartz-rich rocks tend to have better-connected macropores and fewer clay-bound water pockets[14]. In our case, with ~65% quartz and a moderate permeability, achieving ~70–75% brine recovery is reasonable. The rock's absolute permeability (150 mD) by itself does not strongly control the residual saturation – permeability mainly influences how fast and at what pressure the fluids move, not how much wetting phase is ultimately left behind once equilibrated[15]. Thus, it is more the pore structure and wettability (inferred from mineralogy) that set the residual saturation. The result of S_wr ~0.3 means that, conversely, the maximum CO_2 saturation attained in the core was ~0.7 (70% of pore volume). This is a critical parameter for storage, as it represents the fraction of the pore space that can be effectively filled with CO_2 during injection under these conditions. The remaining water,

while not displaced, plays a positive role in long-term storage by acting as an anchor for residual (capillary-trapped) CO_2 if the process were reversed (e.g., when water imbibes, it would trap CO_2 bubbles, though in this drainage scenario, we trapped water instead).

Flow dynamics and heterogeneity effects

The core flooding results reflect a combination of the fluid properties and the intrinsic heterogeneity of the rock. CO_2, being less viscous than brine, created a viscous instability in the displacement. Instead of a perfectly uniform front, the CO_2 likely fingered through along paths of least resistance. This is exacerbated by the presence of heterogeneity (such as the clay-rich zones seen in QEMSCAN analysis). Those zones have smaller pore throats and higher entry capillary pressures, so CO_2 tends to bypass them until later when pressure builds sufficiently. The effect is a non-uniform sweep: some regions of the core see early CO_2 breakthrough while others remain brine-filled longer. This phenomenon is evidenced in our data by the combination of a relatively early CO_2 breakthrough (0.5 PV injected gave a breakthrough which is sooner than the ~1.0 PV that a piston-like displacement in a homogeneous core might require) and the long tail of brine production thereafter. Essentially, CO_2 broke through via a subset of flow channels through the core (likely the higher permeability regions), leaving behind brine in less accessible pores that only gradually surrendered some of that brine as the injection continued.

If we interpret the flow in terms of relative permeability, initially the CO_2 relative permeability was zero (no connected CO_2 path) and brine relative permeability was at its maximum (for 100% brine saturation). During this period, the pressure gradient had to rise to overcome the capillary threshold. As soon as CO_2 established a connected path, CO_2 relative permeability jumped up and brine relative permeability dropped – leading to an increase in total mobility. This explains the drop in pressure post-breakthrough. Over time, CO_2 relative permeability kept increasing slightly as it occupied more of the pore volume, while brine relative permeability fell towards zero as brine became trapped in isolated pores. The end-state (residual brine) corresponds to CO_2 relative permeability approaching a maximum (but still somewhat less than 1.0 due to some hindrance by trapped brine) and brine relative permeability near zero (brine no longer contributes to flow). The relative permeability concept helps to quantitatively match the observed pressure and production data; indeed, fitting our experimental data to standard relative permeability models would yield curves typical of a strongly water-wet rock with a moderate pore size distribution.

(Figure 6-8) shows interplay between permeability and pressure during the experiment can be further examined by considering Darcy's law across the core. At steady state after CO_2 breakthrough, the measured pressure drops (around 0.1 MPa over 7.5 cm length) for a flow rate of 0.5 mL/min corresponds to an effective permeability on the order of 10^{-12} m² (hundreds of millidarcies). The CO_2 core-flooding experiment was conducted under controlled flow rate conditions to assess pressure behaviour during CO_2 injection through a core sample **(Figure 6)**. The flow rate remained relatively constant at approximately 500 cc/min, while the injection pressure exhibited notable variability, ranging from 15.38 to 21.84 kPa. These pressure fluctuations at steady flow conditions indicate dynamic interactions between the injected CO_2 and the porous medium, likely influenced by heterogeneities in core permeability or evolving fluid saturation states. The temporal distribution of measurements, predominantly within 16–17 seconds, with a single outlier at 22.62 seconds, suggests generally stable injection conditions interrupted by a potential breakthrough event or capillary threshold crossing.

The relatively narrow variation in flow rate and broader pressure range point to a flow-regulated system wherein the pressure adjusts to accommodate the resistance imposed by the porous medium. The observed pressure drop patterns are indicative of possible front advancement phenomena, such as the migration of the CO_2 saturation front or localized shifts in effective permeability. This behaviour aligns with the expected multiphase flow dynamics during supercritical CO_2 injection and may inform the calibration of relative permeability curves or mobility ratios in numerical simulations. The dataset provides a valuable basis for validating core-scale CO_2 injection models and understanding the influence of reservoir heterogeneity on injectivity and storage efficiency.

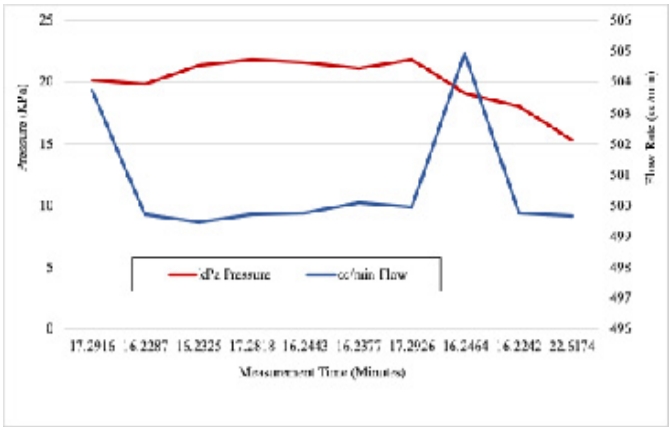

Figure 6: Pressure and Flow Rate Measurement.

The permeability measurements **(Figure 7)** recorded during a CO_2 coreflooding experiment reveal significant variability, ranging from 2,072.5 to 3,282.5 mD, despite maintaining a nearly constant flow rate of approximately 500 cc/min. Measurement times predominantly fall between 16.2 and 17.3 seconds, with one notable outlier at 22.6 seconds corresponding to the highest permeability value. This variation in permeability under stable flow conditions suggests the presence of intrinsic heterogeneities within the core sample, possibly due to lithological variation, fractures or preferential flow pathways. The high-permeability zones likely facilitated more rapid CO_2 transport, reflected in the longer measurement time at peak permeability, possibly indicating a shift in flow regime or the onset of gas slippage effects at high permeability.

These results underscore the sensitivity of permeability measurements to localized changes in pore structure during dynamic injection conditions. The overall trend shows permeability fluctuations without a significant corresponding deviation in flow rate, suggesting that the experimental setup effectively maintained constant volumetric injection while pressure differentials adjusted to reflect pore-scale resistance. This behavior is essential for understanding fluid migration in heterogeneous formations and highlights the importance of incorporating variable permeability distributions into numerical models for accurate simulation of CO_2 injection processes. Such

experimental insights are critical for evaluating reservoir quality and predicting injectivity in carbon storage applications.

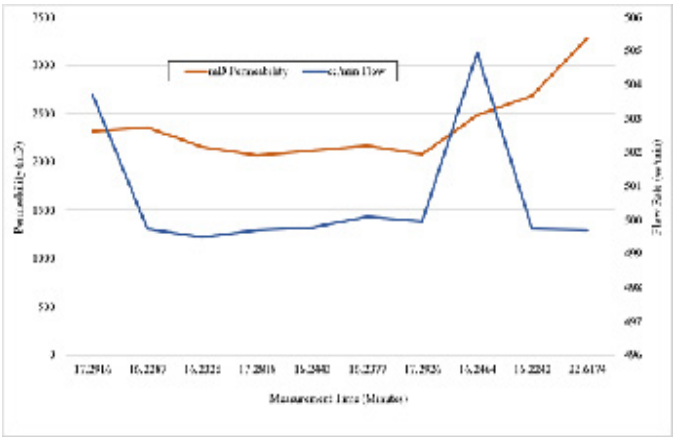

Figure 7: Permeability and Flow Rate Measurement.

This is in the same range as the independently measured permeability of the core **(Table 1)**, confirming that the core's permeability was not significantly altered during the experiment and that the majority of the pressure drop during two-phase flow can be explained by the reduction in effective flow area due to trapped brine. If we hypothetically had a core with much lower permeability, the pressure profile would scale accordingly – a 15 mD core, for example, would need roughly ten times the pressure gradient to sustain the same injection rate, all else being equal. As shown in Figure 4, the inverse relationship between permeability and required pressure: our 150 mD core sits in a regime of relatively low needed pressure for injection, whereas a core order of magnitude tighter would lie higher on that curve, indicating more difficulty in injecting CO_2 at comparable rates (and likely a later breakthrough, as more pressure must accumulate before CO_2 can overcome capillary forces in small pores). On the other hand, an extremely high permeability core (say 1000+ mD, akin to a very coarse sandstone) would show even easier injectivity (small pressure drops) but might exhibit less capillary trapping (since large pore throats don't trap wetting phase as effectively). In our experiment, the moderate permeability and presence of heterogeneities created a balance of effects: injection was not difficult (pressures were manageable well below fracturing thresholds), yet a significant residual saturation remained, which is favorable for secure storage (as that residual water implies CO_2 is spread in a non-continuous fashion that would become residually trapped if migration stopped).

Overall, the following observations stand out:

- **Pressure variability**
  - Pressure fluctuates significantly from 15.38 to 21.84 kPa.
  - This fluctuation could be due to varying permeability zones or saturation front movement during CO_2 injection.
- **Flow rate stability**
  - Flow rate is relatively consistent around 500 cc/min.
  - Minor fluctuations indicate the pump likely maintained near-constant injection flow, which is typical for core-flood experiments.
- **Measurement time**
  - Time values mostly range between 16 and 17.3 seconds, with one high at ~22.6 s. This anomaly might signal a pressure front breakthrough or a change in core properties (e.g., breakthrough, heterogeneity).
- **Possible outliers**
  - Entry with 15.38 kPa pressure and 22.62 s seems inconsistent with the rest — potentially an outlier or a breakthrough event.

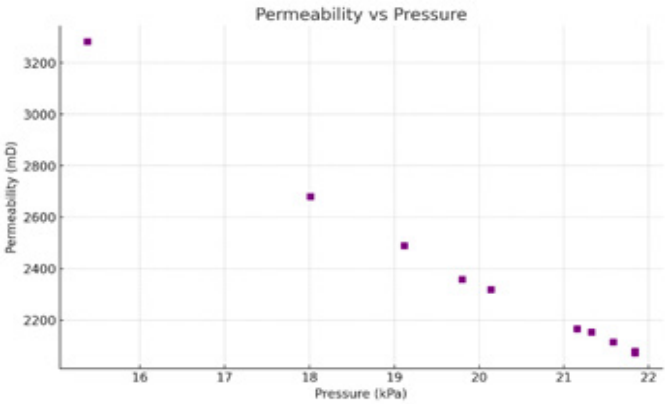

Figure 8: permeability and pressure inverse relationship.

During the experiment, we did not observe any sudden drops in pressure that would indicate the opening of new flow channels by fracture or significant dissolution; nor did we see rising pressure that would indicate clogging. This suggests that, under the conditions of the experiment, geochemical interactions did not play a dominant role in altering flow. The small calcite content did not produce an observable effect during a couple of hours of CO_2 exposure – any dissolution likely was minimal and gradual. Also, no fines production was noted in the effluent (the produced water was clear, without sand or clay particles), indicating that the flow did not strip significant amounts of clay or other particles from the matrix. This is important for scaling up: it implies that injecting CO_2 into this formation is not likely to cause formation damage due to fines migration at least in the near term, under similar flow conditions.

To further complement the core flooding observations, simulation results offer valuable insights into long-term injectivity, storage partitioning and mineralogical responses under varying salinity and mineral content scenarios. As shown in **(Figure 9)**, cumulative CO_2 injection profiles over six years demonstrated that low-salinity aquifers consistently achieved higher storage volumes, attributed to reduced pore-scale clogging and improved solubility. This aligns with experimental findings, where a brine-saturated core with moderate permeability facilitated stable injectivity and significant brine displacement.

Additionally, **(Figure 10)** below also revealed that low-salinity conditions promoted greater CO_2 retention in the dissolved and aqueous phases-up to 43%-compared to only ~12% in high-salinity conditions, underscoring the favorable chemical capacity of such systems for long-term containment. These modeled results reinforce the experimental evidence of water-wet rock behaviour and highlight the crucial influence of aquifer chemistry on CO_2 trapping mechanisms.

Finally, **(Figure 11)** emphasizes the dynamic role of minerals like kaolinite and feldspar during injection: feldspar undergoes progressive dissolution, while kaolinite shows dual trends of precipitation and dissolution, consistent with the mineralogical

analysis of the core. Together, these simulation insights bridge the gap between short-term lab-scale behaviour and reservoir-scale dynamics, validating the observed pressure, saturation and mineral transformation patterns under realistic CO_2 storage conditions.

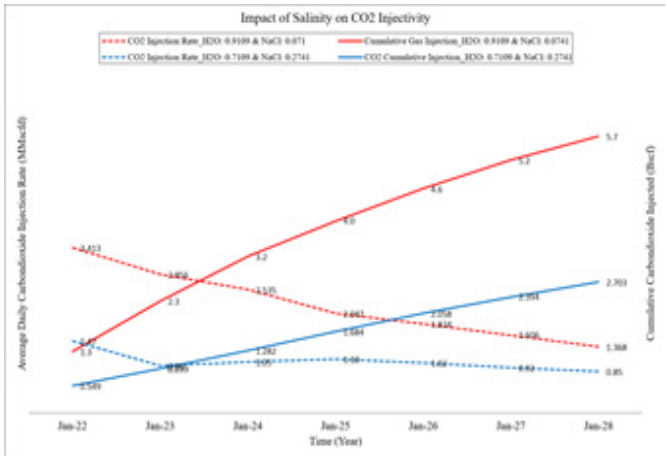

Figure 9: Comparison of Salinity cases for Cumulative CO_2 Injected against time (years).

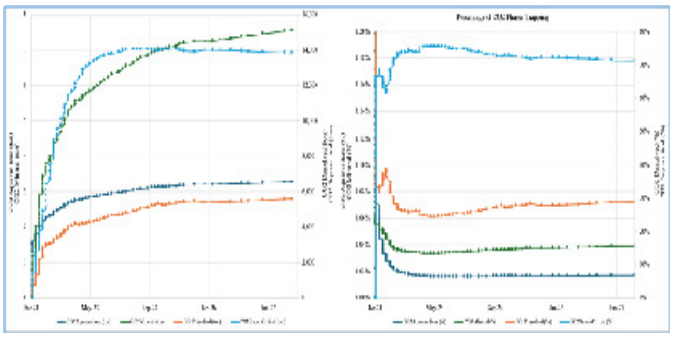

Figure 10: Comparison of CO_2 Storage in Phases.

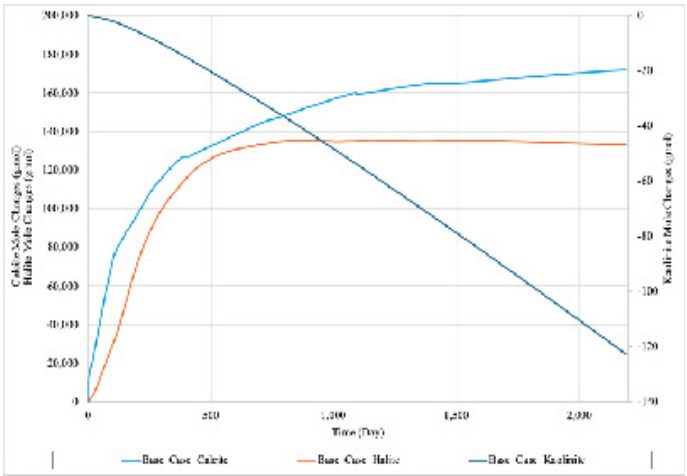

Figure 11: Comparison of mineral precipitation and dissolution due to CO_2 injection

Implications of impurities

Although our core flood used pure CO_2, in practice the injected gas may contain impurities and these can influence the kind of behavior we observed. If the CO_2 stream contained a lighter gas like N_2, the displacement efficiency would likely decrease. A less dense, less viscous gas would accentuate the fingering phenomenon – N_2 would rush through even faster than CO_2, leading to an earlier breakthrough and possibly a lower fraction of brine displaced. Experiments comparing pure CO_2 and N_2 injections have shown that CO_2 tends to have a longer breakthrough time and higher sweep than N_2[16]. For instance, in one study CO_2 took longer to break through than N_2 under the same conditions, indicating a more uniform displacement by CO_2[17]. Thus, a CO_2 stream diluted significantly with N_2 (or CH_4, which has similar light, non-wetting characteristics) would likely leave more residual water (and conversely less CO_2 saturation) in the core than what we achieved with pure CO_2. In the context of storage, that means lower storage efficiency per pore volume and potentially a need to inject more total volume to achieve a given amount of CO_2 stored. On the positive side, having some fraction of a very mobile gas could reduce the injection pressure (since the gas mixture's viscosity would be even lower), but the trade-off is a poorer sweep.

Reactive impurities, such as SO_2 or O_2, introduce another dimension such as geochemical alteration. For example, SO_2 co-injected with CO_2 will dissolve into the brine and form sulfurous acid, which can further dissociate to sulfuric acid in the presence of dissolved O_2 or over time[18]. This can aggressively dissolve carbonate minerals. In our core, the presence of ~2% calcite means that if SO_2 were present, it could potentially dissolve that calcite cement, locally enhancing porosity and permeability (beneficial for injectivity) but also releasing calcium and carbonate ions that might later re-precipitate as gypsum ($CaSO_4 \cdot ٢H_2O$) or other sulfates when the acid neutralizes[19]. Over longer times, this could either slightly increase pore space or cause new mineral precipitates – both effects would change the flow paths. Similarly, trace oxygen could oxidize pyrite (FeS_2) to form iron oxides and sulfuric acid, again altering the rock chemistry. Our short experiment did not capture such effects (as it was too short and used pure CO_2), but they are important to consider for field implementation. The small amounts of these reactive minerals in our sample suggest that any chemical interactions from impurities would be limited in scope; nonetheless, even limited reactions can, for example, improve injectivity by dissolving cement or reduce it by precipitating solids. Future tests or modeling could incorporate these impurity effects, but within this paper, we acknowledge them qualitatively as factors that would modify the experimental outcomes.

Therefore, it can be stated that the core flooding experiment has provided valuable experimental validation for several key aspects of CO_2 storage in the target formation:

- It demonstrated that CO_2 can be injected into the brine-saturated rock with manageable pressures, displacing a significant portion of the brine (about 70%) under reservoir-like conditions.
- It revealed the characteristic pressure and flow dynamics of CO_2 in a permeable, heterogeneous sandstone: an initial capillary resistance followed by a mobility-driven pressure reduction after breakthrough.
- It quantified the residual water saturation (~30%) and by extension the maximum CO_2 saturation (~70%) achievable, which are critical for estimating storage capacity in the formation.
- It highlighted the impact of rock heterogeneity (especially clay distribution) on the displacement pattern and efficiency,

reinforcing that field-scale predictions must account for such variability.

- It showed that no alarming formation damage or unexpected behavior occurred in the short term for this rock-CO_2-brine system, lending confidence that the aquifer can safely accommodate CO_2 injection.
- It provided a basis for discussing how variations in aquifer properties (like permeability) and CO_2 purity might affect outcomes, thereby bridging to the broader thesis theme of assessing impurity and aquifer property effects on CO_2 storage.

Operational understandings and long-term considerations

It is crucial to understand how impurities affect the geochemical stability and long-term operational integrity of the storage reservoir and infrastructure for the realistic deployment of CO_2 storage in deep saline aquifers. While short-term laboratory core flooding experiments provide fundamental insights into initial displacement efficiency and pressure behaviours, they may not fully capture subtle, progressive geochemical transformations or long-term infrastructural integrity issues that impurities could introduce. To bridge this gap, further reflection on potential longer-term interactions and operational implications arising from various impurities, particularly acidic and reactive species, is necessary.

Firstly, the long-term geochemical stability of injected CO_2 is greatly influenced by reactive impurities such as SO_2, H_2S and NO_x. Over extended periods (decades to centuries), even trace levels of these gases can alter reservoir mineralogy beyond the immediate vicinity of the injection wells. For example, SO_2 and NO_x will progressively acidify formation brine, promoting extensive dissolution of carbonates and possibly feldspar minerals. This acid-driven mineral dissolution initially enhances porosity and injectivity, as observed in short-duration core flooding. However, prolonged dissolution events could induce mechanical instability in the reservoir matrix, potentially leading to gradual weakening and subsidence, a phenomenon not observable in short-term tests. Furthermore, continuous mineral dissolution releases metal ions such as Fe^{2+}, Ca^{2+} and Mg^{2+}, which can subsequently precipitate as secondary mineral phases, notably gypsum, anhydrite or iron oxides. These secondary minerals could progressively block pore throats, lowering effective permeability significantly over decades, thus necessitating meticulous long-term reservoir monitoring.

In addition to mineralogical transformations, microbial interactions in the presence of O_2 impurities-albeit minor in the experimental tests-deserve attention at field scale. Even minute quantities of oxygen, introduced as an impurity from combustion-derived CO_2, could facilitate microbial activity, particularly sulphate-reducing bacteria (SRB)[20]. In deep saline aquifers, where sulphate is abundant and temperatures favourable for microbial metabolism, SRB activity could enhance corrosion processes and produce biogenic H_2S. This biogenic hydrogen sulphide would compound chemical reactivity, increasing the overall acidity and potentially intensifying corrosion problems, thus negatively affecting long-term storage integrity and infrastructural durability. Field observations from analogous acid gas injection projects underscore this concern, highlighting significant microbial-induced corrosion where oxygen ingress was inadequately controlled.

Moreover, impurities have implications for long-term monitoring and verification (M&V) strategies essential for regulatory compliance and public assurance. Non-condensable impurities such as N_2 or CH_4, while reducing short-term CO_2 storage efficiency by increasing plume buoyancy and spread, also alter long-term plume detectability and monitoring techniques. Because these gases possess distinct seismic and geochemical signatures compared to pure CO_2, their presence can assist in the differentiation and monitoring of plume extent and migration. Thus, deliberate introduction or controlled allowance of specific inert impurities might serve a dual role: reducing upfront purification costs and enhancing long-term plume detectability and verification capabilities. This approach could lead to innovative operational strategies where impurities are viewed not merely as contaminants but as beneficial tracers, thereby potentially reducing long-term monitoring expenditures.

However, operational management must balance such benefits against potential adverse impacts. Elevated reservoir pressures due to buoyancy-driven migration of impurity-laden plumes necessitate precise pressure management strategies. Over decades, pressure build-up near caprocks could incrementally increase the risk of leakage through microfractures or fault reactivation. Thus, field-scale operators must integrate advanced geomechanically modelling informed by experimental and simulation results presented herein. Predictive reservoir simulations tailored to the specific impurity profile of injected CO_2 streams would allow operators to anticipate long-term plume behaviour and associated pressure evolution, thereby proactively addressing potential containment issues.

Finally, the infrastructural considerations-particularly for injection wells and associated pipelines-cannot be overstated. Impurities, particularly acidic gases like SO_2 and H_2S, significantly accelerate corrosion, particularly during intermittent injection operations. Real-world injection scenarios frequently involve cyclic shut-ins, operational pauses and start-ups, during which wellhead temperatures fluctuate, creating conditions conducive to corrosive interactions between impurities, residual water and wellbore materials. Short-duration laboratory tests typically maintain stable pressure and temperature conditions and thus may overlook these crucial cyclic operational impacts. Consequently, field operators must proactively adopt robust corrosion-resistant materials such as high-grade stainless steel, special polymer linings or advanced cement formulations specifically designed to withstand corrosive impurities. Additionally, stringent moisture removal protocols for CO_2 streams must be established and rigorously maintained throughout operational lifetimes.

In light of these insights, a comprehensive risk assessment framework tailored specifically to impurity-rich CO_2 injection scenarios becomes indispensable. This framework should incorporate continuous reservoir and well integrity monitoring, geochemical sampling and microbial activity surveillance over the entire operational life of the storage project. Such a holistic approach ensures that operational strategies not only account for immediate injectivity and displacement efficiency-as demonstrated in core-flood experiments-but also robustly anticipate, monitor and mitigate long-term geochemical, microbial and infrastructural impacts induced by CO_2 impurities.

Conclusion

The paper has provided an in-depth experimental validation of CO_2 storage processes using a core from the North Sea aquifer. Through a laboratory core flooding test, we have closely examined how CO_2 displaces brine, what pressure gradients are involved and how the intrinsic properties of the aquifer rock influence these dynamics. The experimental results can be summarized as follows:

- **Successful CO_2 injection and displacement:** We demonstrated that CO_2 can be injected into the water-saturated sandstone core under reservoir-like conditions without operational difficulty. The CO_2 displaced approximately 70% of the resident brine from the pore space, confirming that a majority of the pore volume can be utilized for CO_2 storage in a single drainage cycle. The remaining brine (~30% saturation) serves as a baseline for residual trapping capacity.
- **Pressure evolution and injectivity:** The injection pressure profile showed a distinct peak at CO_2 breakthrough, followed by a significant reduction in pressure requirements once CO_2 established a flow pathway. This behavior validates the expected two-phase flow mechanics: high entry pressure initially, then improved injectivity as the non-wetting phase connectivity increases. The magnitude of the pressures observed (on the order of a few bars across the core) suggests that, when scaled to field dimensions, injection in this formation would be feasible within safe pressure limits (well below fracturing pressure), given the core's permeability. The experiment thus provides confidence that the target aquifer has sufficient injectivity for industrial-scale CO_2 injection.
- **Rock properties and heterogeneity impact:** The detailed characterization of the core revealed a quartz-rich, moderately heterogeneous sandstone with clays and minor cements. These properties manifested clearly in the flow experiment. The moderate permeability and patchy clay distribution led to an unstable displacement front and non-uniform sweep, as evidenced by early CO_2 breakthrough and the slow, continued recovery of brine from less permeable pockets. This confirms that small-scale heterogeneity in mineralogy can have significant effects on displacement efficiency – a crucial insight for modeling field behavior. Notably, the experiment aligns with known trends (e.g., high quartz content contributing to more complete drainage of brine (Zhang et al., 2023), reinforcing that mineral composition and pore structure are key to understanding ultimate CO_2 saturations.
- **Mineralogical considerations:** The QEMSCAN, XRD and XRF analyses ensured that we understand the chemical and mineral context of the core. The predominance of inert minerals (quartz, kaolinite) indicates the rock is chemically stable in the presence of CO_2, which was supported by the lack of any observed reaction-induced changes (no significant permeability alteration, no unusual precipitation). This suggests that, at least in the short term, physico-mechanical trapping (structural trapping of CO_2 and capillary trapping as residual CO_2 or water) will be the main storage mechanisms, rather than mineral trapping via geochemical reactions. Over longer timescales, minor minerals like calcite or dispersed pyrite could react with acidic fluids, but their low amount means the effects is limited and likely beneficial in terms of creating additional pore space or immobilizing contaminants (e.g., SO_2 converting to sulfate minerals). The mineralogy also indicates the rock is strongly water-wet, which is conducive to secure CO_2 storage: water-wet conditions favor residual CO_2 trapping (because water tends to coat pore surfaces and snap off CO_2 into blobs during post-injection imbibition), albeit at the cost of some initial displacement efficiency.
- **Impurity effects and aquifer property variations:** While the core flood used pure CO_2, the paper's discussion has extrapolated the findings to scenarios involving impure CO_2 streams and different rock characteristics. It was inferred that lighter gas components (like N_2) would make the displacement less efficient, causing earlier breakthrough and higher residual water (lower CO_2 saturation), whereas the presence of small reactive impurities could slightly modify the rock over time but were unlikely to impede injection in this particular sandstone. Additionally, the pressure-permeability analysis emphasized that storage formations with lower permeability than the tested core would require higher injection pressures and might yield less uniform CO_2 distribution, whereas more permeable formations would be easier to inject but could have lower residual trapping. These considerations tie directly into the thesis theme, underscoring that both the composition of the injected CO_2 and the properties of the aquifer must be factored into predictions of CO_2 storage performance.

The experimental validation carried out in this paper underpins our understanding that the Gulf of Guinea aquifer sandstone is a viable and effective medium for CO_2 storage. The core-scale evidence confirms that a significant portion of the pore space can be filled with CO_2 under realistic conditions and that the processes governing CO_2 migration and trapping (capillarity, relative permeability, heterogeneity) behave as expected for a water-wet, moderately heterogeneous reservoir rock. These experimental insights provide a critical link between theory/simulation and field implementation: they give tangible numbers for key parameters like residual saturation and injectivity, validate the influence of mineralogy on performance and highlight the need to account for impurities and heterogeneity in any comprehensive CO_2 storage assessment. As such, the paper findings will inform the subsequent evaluation of CO_2 storage capacity and integrity in the case study area.

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