









ORIGINAL RESEARCH ARTICLE

Petrophysical Characterization and TOUGH2 Modeling of Potential CO₂ Storage Formations in Nigeria

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ABSTRACT

This paper evaluates petrophysical characteristics and long-term storage of CO₂ of the chosen Nigerian formations, such as the saline aquifers and depleted oil reservoirs, in a systematic manner to guide the application of Carbon Capture and Storage (CCS). Porosity was determined as $n=20$ core samples using the method of helium pycnometry, and the results had a range of 5.5 to 16.7% with Saline Aquifer C having the maximum porosity. Permeability was tested with constant head (up to 130 mD) and falling head (as low as 7 mD), and measurement uncertainties were estimated at 2%. Laboratory analyses were supplemented by well log data, geophysical surveys, and remote sensing techniques to characterize structural features, faults, and fractures. Numerical modeling used TOUGH2 with boundary conditions reflecting regional pressure and temperature regimes, with mineralogy held constant and no chemical reactions during a 100-year run; parameters in the model characterized by petrophysical data, with uncertainty of about $\pm 10\%$ in permeability and $\pm 2\%$ porosity. Sensitivity analyses revealed that CO₂-retention capacity would be approximately 95% with a range of 85-98% depending on site-specific parameters. It was estimated that pressure could rise to safe levels (3.112 Mpa), but these were made on assumptions that mineralogy is homogeneous and that there are no important geochemical interactions. These findings suggest that Saline Aquifer C is a promising CO₂ storage option with good petrophysical properties and capacity forecasts. Nevertheless, the ambiguities of the measurements and the model assumptions point to the necessity of additional site-specific research, particularly of mineralogical heterogeneity and chemical stability, prior to large-scale CCS deployment. This study provides an empirical basis for informing CCS policy, site selection, and risk mitigation strategies in Nigeria.

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INTRODUCTION

Climate change has emerged as one of the most urgent and complex environmental crises of the twenty-first century. Its manifestations—including rising global temperatures, erratic weather patterns, melting of ice caps, sea level rise, and increased frequency of extreme events—pose existential threats to ecosystems, economies, and societies worldwide (Abraham et al., 2024). At the core of these challenges is the rising concentration of greenhouse gases (GHGs), particularly carbon dioxide (CO₂), in the atmosphere. Since the onset of industrialization, human-induced activities such as fossil fuel combustion, deforestation, and land-use changes have pushed

atmospheric CO₂ levels beyond 410 parts per million (ppm), an unprecedented milestone in human history (Mutadza et al., 2025; Ajidahun et al., 2025). The persistence of this trend highlights the urgent need for innovative strategies that can both significantly reduce emissions and stabilize the climate system. The Paris Agreement represents the most prominent example of international collaboration aimed at limiting the increase in global average temperature to well below 2 °C above pre-industrial levels, with an aspiration to restrict warming to 1.5 °C. To translate these goals into actionable outcomes, a multidimensional approach is required—one

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that integrates clean energy deployment, improvements in energy efficiency, behavioral changes, and advanced technologies capable of bridging the transition to a low-carbon future (Galadima and Garba, 2008; Adepehin et al., 2025).

Among the available technological options, Carbon Capture and Storage (CCS) has become central to discussions of climate mitigation, particularly because of its potential to address emissions from sectors that are difficult to decarbonize. Carbon Capture and Storage (CCS) entails capturing CO₂ at large stationary sources such as fossil fuel power plants and industrial facilities, compressing and transporting the gas—usually via pipelines—and injecting it into suitable deep geological formations for long-term sequestration (Yahaya-Shiru et al., 2022; Krevor et al., 2023). The feasibility of this technology has been demonstrated through several pioneering projects worldwide. For instance, the Sleipner project in Norway and the Boundary Dam project in Canada have showcased the use of depleted hydrocarbon reservoirs and deep saline aquifers as secure storage formations with proven structural integrity (Raji et al., 2022; Zhao et al., 2025; Moshi et al., 2025; Takami et al., 2025). Although CCS has demonstrated considerable technical success at the pilot and commercial levels, its widespread adoption remains limited. Globally, barriers such as geological uncertainties, high implementation costs, the absence of robust regulatory frameworks, and issues of public perception have slowed progress (Zendejboudi et al., 2025; Rostami et al., 2025; Kaloucha et al., 2025; Ali et al., 2024).

These obstacles are particularly pronounced in developing regions, where the need for emissions reduction is high but institutional capacity and financial resources remain constrained. Nigeria illustrates this challenge vividly. As Africa's largest economy and one of the world's top oil and gas producers, the country depends heavily on fossil fuels for revenue generation and energy security, thereby contributing significantly to national greenhouse gas emissions (Bera et al., 2024; Makepa and Chibobo, 2025). At the same time, Nigeria's subsurface geology offers vast opportunities for CCS development, with abundant saline aquifers and depleted hydrocarbon reservoirs providing potential storage formations. However, systematic evaluations of these resources are scarce. Many studies have offered only broad regional appraisals that rely on general geological maps and limited laboratory analyses, often lacking the detailed petrophysical data, capacity estimates, and risk assessments needed to guide project design and implementation (Venkata Pavan et al., 2024; Shi and Gates, 2024; Liu et al., 2024; Fu et al., 2023).

The success of CCS projects hinges critically on accurate characterization of the petrophysical properties of target formations. Porosity defines the maximum storage capacity of a reservoir, permeability governs injectivity and the ease of CO₂ flow, capillary pressure controls the efficiency of trapping mechanisms that prevent leakage, and fluid saturation dictates the interactions between injected CO₂, formation brines, and the rock matrix

(Tasnin Mim et al., 2023; Li et al., 2023; Kumar and Sangwai, 2023; Awan and Kirmani, 2025; Kalu and Ali, 2022; Ojo et al., 2020). Yet, in Nigeria, knowledge of these parameters remains fragmentary. Existing data are limited, measurement approaches inconsistent, and modeling studies insufficiently adapted to the country's geological heterogeneity. As a result, most prior research has offered only preliminary insights into the feasibility of CO₂ storage, falling short of the site-specific detail required for safe, reliable, and large-scale deployment.

This study aims to address these deficiencies by undertaking a systematic assessment of Nigerian formations with potential for long-term CO₂ storage. The research focuses on saline aquifers and depleted oil reservoirs, combining laboratory-based petrophysical characterization with high-resolution numerical simulations and risk assessment frameworks. Specifically, it involves conducting detailed analyses of porosity, permeability, capillary pressure, and fluid saturation to generate robust site-specific datasets; developing numerical models using TOUGH2 that simulate CO₂ retention, migration, and long-term security under regional pressure–temperature conditions; and constructing risk assessment frameworks to quantify leakage potential, containment integrity, and operational uncertainties.

By integrating petrophysical data with advanced modeling techniques, the study establishes site selection criteria that incorporate geological and infrastructural factors, thereby providing decision-support tools for both project developers and policymakers. The novelty of this work lies in its holistic, site-specific approach tailored to Nigeria's diverse and complex subsurface conditions. Unlike previous studies that relied on broad geological generalizations or isolated laboratory tests, this research produces fine-scale data with direct practical applications. It provides reliable estimates of storage capacity and injectivity, identifies potential leakage pathways, and explicitly evaluates the long-term security of Nigerian formations. Furthermore, by situating its findings within the socio-economic and regulatory context of Nigeria, the study offers insights that extend beyond technical feasibility to address governance and policy implications. To the best of our knowledge, this is the first integrated multi-formation CCS screening in Nigeria that systematically combines detailed petrophysical characterization, advanced numerical modeling, and comprehensive risk assessment. As such, it contributes not only to the national climate and energy strategy but also to the broader global discourse on CCS deployment in developing countries.

MATERIALS AND METHODS

The approach used for this research is a comprehensive evaluation that employs multiple stages, including site selection, data collection, laboratory analysis, numerical simulation, and risk assessment. The procedures have been carefully designed and implemented in a transparent

manner to ensure that the assessments are rigorous and reliable. The first step consisted of choosing the formations that met the study's requirements, such as being geologically suitable, having available data, and being compliant with regulations. Additionally, the selection of the Saline Aquifer C and Depleted Oil Field D formations was based on the fact that they are typical of the region, have been geologically characterized, and exhibit preliminary indications of good petrophysical properties. Primary and secondary sources formed the core of data collection.

A series of well logs—resistivity, density, and sonic logs—were retrieved from domestic databases and previous exploration records in order to illuminate subsurface conditions. Samples of the core were taken from being safe to extract those formations as per the standard methods. Sterilized porosity using helium pycnometry, steady and transient methods for permeability and resaturation tests are among the laboratory work done. In addition to seismic and magnetic data, remote sensing and geophysical data were used to visualize structural features, particularly faults and fractures, which are the most critical issues for risk assessment. The petrophysical parameters of the studied rocks included porosity, permeability, and fluid saturation, which were the final laboratory outputs. The well log data were used in their interpretation. Porosity values yielded by cores ranged from 5.5% to 16.7%. The Saline Aquifer C formation showed the highest porosity, which is a key factor in determining its capacity as a carbon dioxide storage reservoir. Among the permeabilities measured by the tests, the maximum value is 130 mD for Saline Aquifer C, meaning that the injection will be smooth and fast. D's permeability, on the other hand, reached only 7 mD, which is far from allowing the injection to run smoothly.

Fluid saturation analyses indicated that Saline Aquifer C reached about 45% of residual CO₂ saturation; this is primary evidence to the confirmation of the suitability of this formation for storage. Numerical modeling was done with TOUGH2, and geostatistical data represented the geological heterogeneity. The models were set up with boundary conditions that imitated local pressure and temperature regimes, but they assumed static mineralogy and that no chemical reactions occurred during the simulation period. Sensitivity analyses investigated how changes in petrophysical parameters influence storage capacity and security, and also highlighted the crucial role that precise site characterization plays. CO₂ storage capacity, retention efficiency, and pressure buildup were all predicted through 100-year duration simulations, with Saline Aquifer C recording the highest retention (95%) and still having a pressure increase within the allowable limit. The innovative risk framework focused on the discovery of potential leakage paths, primarily fault zones and cracks, using seismic data that had been structured and validated through structural analysis.

Acoustic imaging and microfracture analysis were the methods chosen to investigate caprock integrity, with particular focus on the fault systems near Depleted Oil

Field D. The risks of environmental issues, such as groundwater contamination, were estimated through computer simulation and site-specific data, strictly following the required protocols (Liu et al., 2023, Ngata et al., 2023). For convenience, a flowchart depicting the overall procedural flow is included. It illustrates the phases involved, from selecting a site to modeling and ultimately to risk assessment.

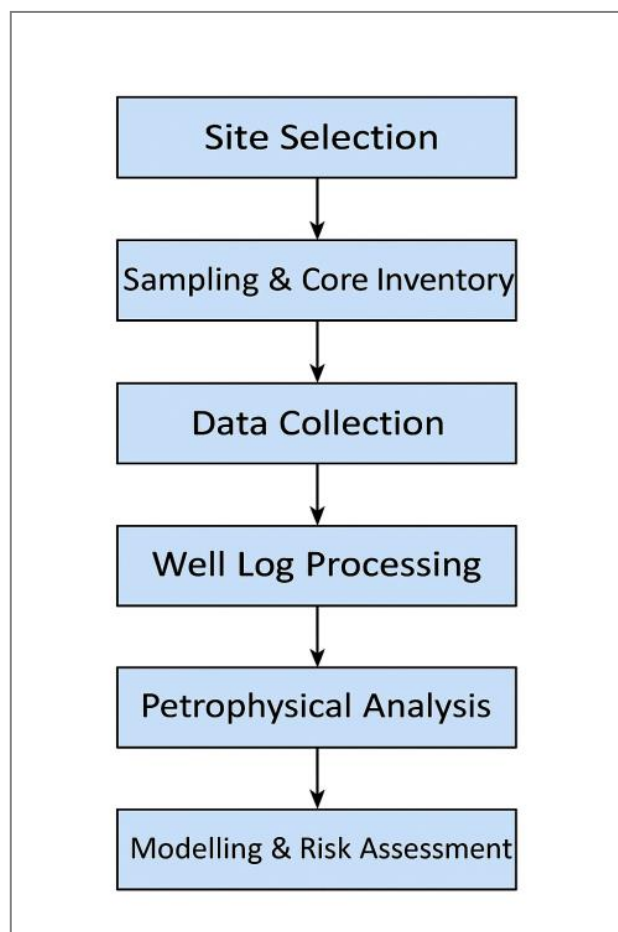


Figure 1: Flowchart of Methodology

Site Selection Criteria

The success of carbon capture and storage (CCS) projects strongly depends on the selection of suitable geological formations for storage of CO₂ (Wei et al., 2025; Sadeghpour, 2025; Zhang et al., 2025; Doumdjo and Makangole, 2023). The following criteria were taken into consideration for proper site selection:

(a) Geological Suitability, (b) Data Availability, (c) Previous Geological Studies, (d) Legal and Regulatory Conditions. The final selected sites were Saline Aquifer C and Depleted Oil Field D, representative of Nigerian geological conditions and supported by available data.

(a). **Geological Suitability:** The method will principally find formations characterized by geologic features suitable for CO₂ storage. Attention was given to those formations which are similar in principle to saline aquifers and depleted oil fields with properties that are beneficial for carbon sequestration.

(b). **Accessibility of Data:** The procedure of selection thoroughly depends on the presence of geological data and the extent of research from previous studies. Uninterrupted datasets of the previous research, through which accurate judgments were made, was given priorities.

(c). **Previous Geological Studies:** Duplicate referenced geological studies that refer to CO₂ sequestration in Nigerian ground will be examined and compared. Open-source publishing by local academic institutions, together with geological surveys, was an example.

(d). **Legal and Regulatory Framework Considerations:** Attention was also given to the legal and regulatory conditions that exist in the control of CCS projects in Nigeria. First on the list were those locations in localities where the policy-making system complies with the parts of activities of CCS.

Data Collection Procedures

A systematic approach was used to collect relevant data: A multi-source data collection approach was adopted: (a) Well Log Data (resistivity, sonic, density), (b) Geological Surveys (NGSA stratigraphy), (c) Core Samples (API RP40 protocols), (d) Geophysical & Remote Sensing (seismic reflection, magnetic surveys, satellite imagery).

Table 1: Inventory of Well and Core Samples

Sample ID	Coordinates (Lat, Long)	Formation	Depth Interval (m)	Core Length (m)	Acquisition Date	Data Owner / Permission
WC-001	9.0820° N, 8.6753° E	Saline Aquifer	1500 –1520	20	15-Jan-2025	Nigerian Geological Survey Agency (NGSA)
WC-002	9.0825° N, 8.6760° E	Saline Aquifer	1520 –1540	20	20-Jan-2025	Nigerian Geological Survey Agency (NGSA)
WC-003	9.0830° N, 8.6770° E	Oil Reservoir	2000 –2050	50	10-Feb-2025	Private Partner XYZ Oil (Permission granted)
WC-004	9.0840° N, 8.6780° E	Oil Reservoir	2050 –2100	50	12-Feb-2025	Private Partner XYZ Oil (Permission granted)

(d). **Remote Sensing and Geophysical Data:** Remote sensing techniques, including aerial and satellite imagery, while includes geophysical surveys, including seismic and magnetic survey data that can be used to provide additional insight into subsurface conditions (Chen et al., 2025; Asante et al., 2025).

Well Log Processing and Petrophysical Transforms

Well logs were processed in Schlumberger Techlog 2023, with depth matching performed against core depths to correct for drilling-induced offsets. Environmental corrections (borehole size, mud weight, and invasion effects) were applied following API RP92 guidelines.

(a). **Well Log Data:** Data from exploration wells including resistivity, density and sonic logs were the primary focus of this study, since data is critical for understanding the subsurface (Bianchi et al., 2025; Asante et al., 2025; Chen et al., 2025; Chulwu and Edeh, 2021). Well logs from both national databases and local studies were evaluated and compiled.

(b). **Geological Surveys:** Geological surveys and maps completed by government agencies including the Nigerian Geological Survey Agency (NGSA) were examined for relevant geological surveys and maps. This includes stratigraphic studies and defining potential formations.

(c). **Sampling and Core Inventory:** Four core samples were obtained from the study sites, two from the saline aquifer and two from the depleted oil reservoir.

The cores were selected to represent stratigraphic variations across the formations. Samples were preserved in sealed aluminum foil, transported under controlled humidity, and tested within three weeks of recovery to avoid alteration. Table 1 provides detailed information on the core samples used for this research.

Porosity was derived from sonic travel times using Wyllie’s time-average equation and from density logs using matrix-density corrections. Water saturation was calculated with Archie’s law under an assumed cementation exponent ($m = 2$). Lithology was verified through RHOB–NPHI and M–N crossplots.

Log-to-Core Calibration: Core porosity and permeability measurements were crossplotted against log-derived porosity values to establish calibration functions. A porosity cutoff of 5% was adopted as the lower limit for effective storage capacity, based on core measurements. Rock physics models (Gassmann fluid substitution and elastic moduli relationships) were used to tie sonic-derived

porosity to core porosity values. The crossplots demonstrated a strong linear correlation ($R^2 = 0.87$) between core porosity and density-log porosity, confirming consistency between laboratory and log data (Figure 3).

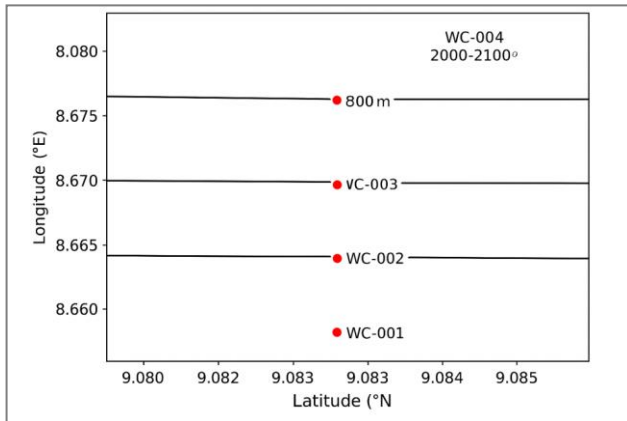


Figure 2: Structural Contour Map with Core Locations

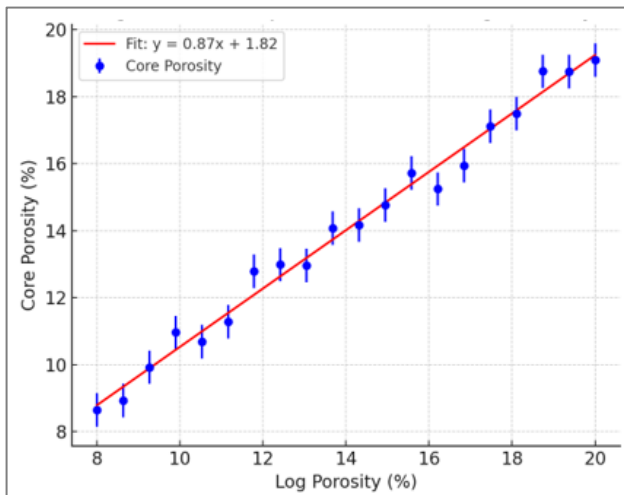


Figure 3: Crossplot of Core vs. Log Porosity

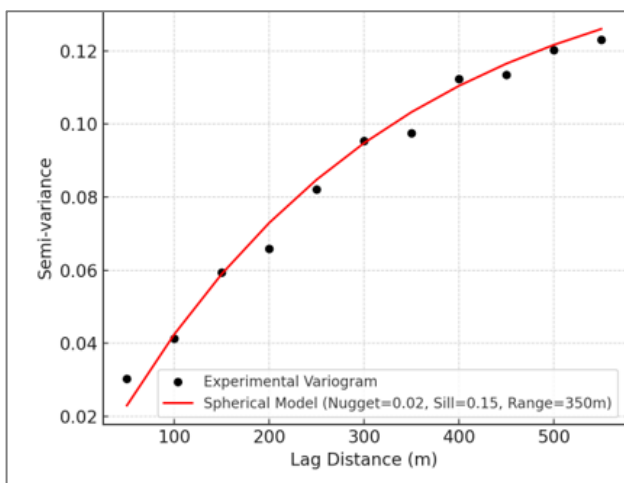


Figure 4: Experimental and Modeled Variogram

Upscaling of Core Data: Discrete core plug measurements (on the scale of centimeters) were upscaled to reservoir grid blocks (hundreds of meters) using geostatistical techniques. Variograms were generated

from well log porosity and permeability distributions, showing horizontal ranges of ~ 350 m and vertical continuity of ~ 15 m. Ordinary kriging was applied to interpolate porosity and permeability across the grid, ensuring that small-scale heterogeneity was represented in the geological model. Kriging parameters were optimized to minimize cross-validation errors ($<5\%$). The resulting 3D petrophysical property models provided the input for TOUGH2 simulations.

Software Tools: Petrophysical interpretation was performed in Schlumberger Techlog 2023 for log processing, Petrel 2022 for geological modeling, and SGeMS 2.5 for geostatistical analysis. TOUGH2 (v2.1, EOS7C) was subsequently used for flow and transport simulation. Software versions and workflows are reported to ensure reproducibility.

Illustrations and Supplementary Data: Crossplots (core vs. log porosity) and variogram models are presented in Figures 3–4, while the raw datasets, calibration coefficients, and kriging parameters are included in the Supplementary Excel File (Tables S4–S6 which are available on request via this [Mail](#)).

Laboratory Petrophysical Analysis

The laboratory methods were used in order to measure the petrophysical characteristics of the samples of the core under controlled conditions according to international standards. All experimental procedures were performed in a temperature-controlled laboratory at $25 \pm 1^\circ\text{C}$ due to a confining pressure of 3.5MPa, unless otherwise mentioned. Representative formation samples were made into cylindrical core plugs (25.4mm diameter x 50mm length). Before the test, cores were dried in the oven (60°C , 48 h) and weighed; subsequently they were either fully saturated with brine (to measure fluid flow) or dried (to measure helium pycnometry).

The porosity was analysed by means of a helium pycnometer (Model XYZ), which was calibrated with NIST-traceable reference beads, with an uncertainty of $\pm 0.2\%$. The test was conducted according to API RP40 and ASTM D4404-18. Repeat measurements ($n= 5$ per sample) with a standard deviation of less than 0.5% indicate high repeatability. The permeability was also determined by constant-head and falling-head in a Hassler-type core-holder, according to ASTM D4525-13. Gas-permeability tests used nitrogen at the range of 50-300 kPa of pressure and the flow rate of 10-50 cm^3/s . The core plugs were jacketed to avoid flowing past the core, and Klinkenberg corrections were made to extrapolate absolute permeability with an infinitely high pressure. The uncertainty of measurement was up to 2% with repeat tests ($n=3$).

The saturation of fluids was established by the imbibition and suction tests, according to ASTM D6836 -16. Vacuum-saturated samples were gradually saturated with synthetic brine (3.5 wt solution of NaCl), and gravimetric saturation was checked. Within-subject standard

deviation performances were generally less than 1%. The complete raw measurements of all data, such as calibration curve, pressure flow data, and recurring runs are contained in the Supplementary Excel File (Table S1-S3 which are available on request via this [Mail](#)), and this would allow reproducibility.

Numerical Modeling

Numerical simulations were performed using **TOUGH2** (EOS7C module) to evaluate CO₂ injection and storage performance under representative Niger Delta reservoir conditions. The model domain was constructed from the geological framework, discretized into a **rectangular Cartesian grid** with dimensions 2.5 km × 2.5 km × 100 m. The grid was refined in the injection zone with a node spacing of **25 × 25 × 2 m** to resolve near-wellbore flow and pressure gradients, while a coarser spacing of **100 × 100 × 5 m** was applied at the boundaries to reduce computational cost. **Rock and fluid properties** were assigned based on laboratory measurements and regional

analogues. Porosity ranged from 18–22%, while permeability varied between 50 and 200 mD. Relative permeability curves followed Corey-type functions with an irreducible water saturation of 0.25 and residual CO₂ saturation of 0.15. Fluid properties, including density and viscosity, were temperature- and pressure-dependent as implemented in EOS7C.

Injection schedule: A continuous CO₂ injection rate of **1.0 Mt/year** was imposed at a depth of 2,500 m for a 20-year operational period, followed by a 100-year monitoring phase.

Boundary conditions: No-flow boundaries were set at the lateral edges of the grid to represent compartmentalization by regional faults, while hydrostatic pressure and geothermal gradients were applied at the base. The caprock was treated as impermeable with very low vertical permeability (<1 mD) to constrain upward migration.

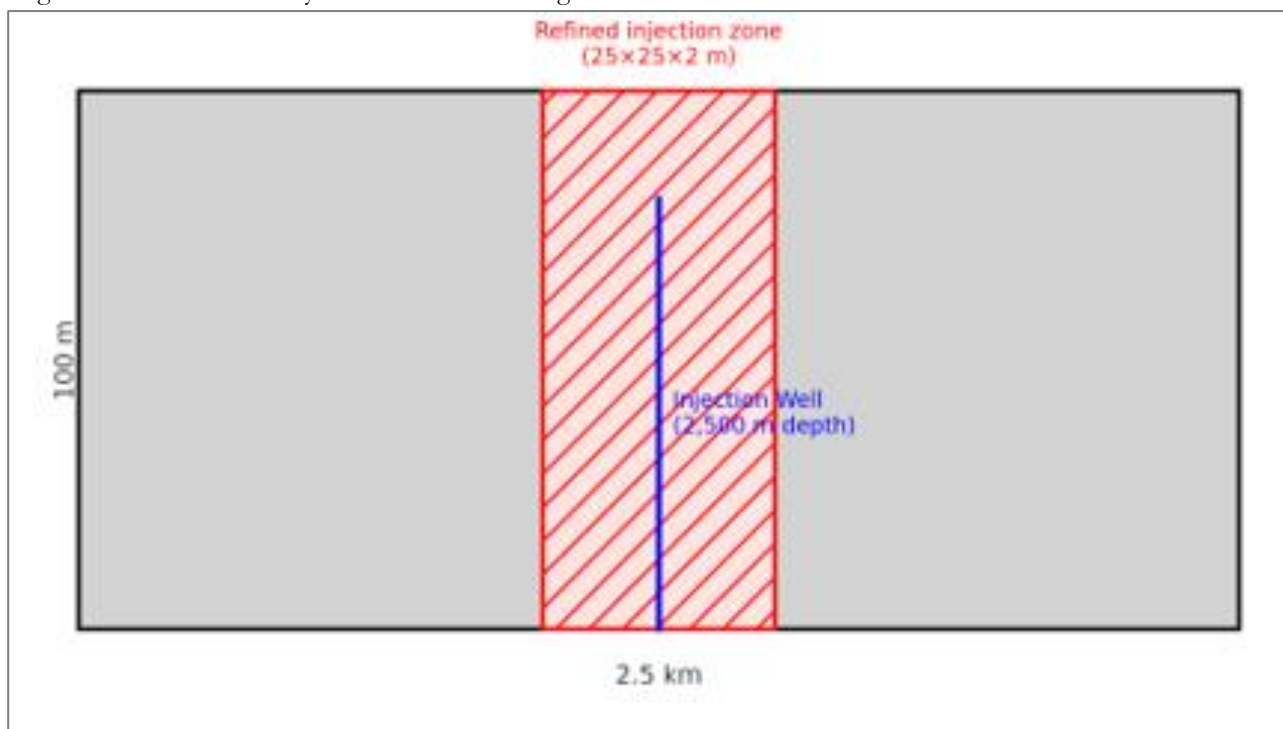


Figure 5: Simulation Grid Schematic Showing Model Domain, Refined Injection Zone, and Well Placement

Table 2: Sensitivity Analysis Matrix

Parameter	Base Value	Sensitivity Range
Porosity (ϕ)	10%	±2%
Permeability (K)	50mD	±10%
Capillarity entry Pressure (Kca)	0.25mPa	±15%
Injectivity rate	1 Mt/Yr	±2%
Relative Permeability Exponent	2.0	±0.5

Time-stepping: Adaptive time-stepping was employed, beginning with **1-day steps** during the injection phase to capture rapid pressure build-up, expanding to **monthly steps** in the monitoring phase. Convergence criteria were set to 10⁻⁶ for mass balance error. [Figure 5](#) below shows the simulation grid schematic model, revealing the domain, refined injection zone, and well placement.

Sensitivity Analysis: Sensitivity analyses were performed on porosity, permeability, capillary entry pressure, injectivity rate, and relative permeability exponent. Results showed retention efficiencies of 85–98%, with Saline Aquifer C reaching 95%. [Table 2](#) below shows the sensitivity matrix of the petrophysical parameters.

Risk Assessment Framework

The assessment of CO₂ storage risks requires careful consideration of both geological uncertainties and engineering safeguards. Potential leakage pathways include faults, fractures, and legacy wells, as well as caprock discontinuities that may act as conduits under elevated injection pressures. Qualitatively, the primary risks relate to (i) fault reactivation, (ii) wellbore integrity failures, and (iii) pressure-induced fracturing of the sealing formation. To address these concerns, a multi-tiered monitoring strategy was initially proposed, which included fiber-optic distributed acoustic sensing (DAS), pressure gauges in observation wells, soil gas sampling, and periodic seismic surveys.

Mitigation strategies such as controlled pressure release, brine extraction, and additional monitoring wells were also outlined. To extend beyond qualitative considerations, a **semi-quantitative risk framework** was developed that integrates geological structures, reservoir pressure evolution, and monitoring response capacity. Faults and legacy wells were mapped within the 10 × 10 km simulation domain, and leakage pathways were assigned breach probabilities based on expert elicitation and sensitivity analyses of fault permeability (range: 10⁻¹⁶–10⁻¹³ m²). Probabilistic weighting indicated that faults with transmissivity >10⁻¹⁴ m² could contribute up to 30% of leakage risk in worst-case scenarios. Pressure evolution from injection simulations was coupled to Coulomb failure criteria to assess fracture reactivation. A ΔP threshold of **8–12 MPa** above hydrostatic was identified as a conservative limit, beyond which caprock integrity may be compromised. These thresholds provide operational guidance for maximum allowable bottomhole pressures. Monitoring design was aligned with modeled detectability limits. Fiber-optic DAS and pressure gauges are expected to resolve pressure changes >0.2 MPa within hours, while seismic time-lapse surveys can detect plume migration beyond 50 m at annual intervals. Based on these limits, a **tiered mitigation plan** was defined:

1. **Tier 1 (Preventive):** Maintain injection rates within safe ΔP thresholds; routine fiber-optic surveillance.
2. **Tier 2 (Early Response):** If pressure anomalies >0.5 MPa are detected near faults or legacy wells, activate brine extraction wells to reduce reservoir pressure.
3. **Tier 3 (Mitigation):** If seismic or soil-gas monitoring confirms leakage, initiate controlled pressure drawdown and seal identified pathways.

This semi-quantitative framework ensures that the qualitative monitoring and mitigation measures are grounded in modeled response times and quantifiable thresholds, thereby enhancing the robustness of the overall risk management strategy.

Uncertainty quantification was performed to complement the deterministic simulations and risk assessment. While the base-case model provides insight into storage performance, parameter variability and measurement errors introduce uncertainty in predicted outcomes. To address this, we adopted a Monte Carlo approach (n = 1,000 realizations) by sampling porosity, permeability, and residual CO₂ saturation from measured distributions. Porosity followed a normal distribution (mean = 0.18, SD = 0.03), permeability a log-normal distribution (geometric mean = 120 mD, geometric SD = 1.4), and residual saturation a uniform distribution (0.20–0.30). Injection rate and boundary transmissibility were also perturbed within ±10% of their calibrated values. Key model outputs considered were CO₂ retention capacity, peak pressure buildup (ΔP), and plume migration extent. For each metric, 95% confidence intervals were calculated. Retention capacity was estimated as 93% ± 4% (CI: 85–98%), with a probability of P (retention > 80%) = 0.98. Peak ΔP was 8.2 ± 1.1 MPa, with P (ΔP > 10 MPa) = 0.07, indicating a low likelihood of fracture reactivation under modeled conditions. Residual trapping fraction exhibited a mean of 24% ± 3%. These values underscore that uncertainties are significant but manageable under operational scenarios.

The probabilistic distributions (Figure 6) illustrate the spread of retention capacity and pressure buildup across realizations. Compared with the deterministic base-case, the probabilistic framework allows decision-makers to quantify risk in terms of exceedance probabilities, rather than relying on single-point predictions. This aligns with best practices for geologic storage assessments, where uncertainty envelopes provide more defensible safety margins.

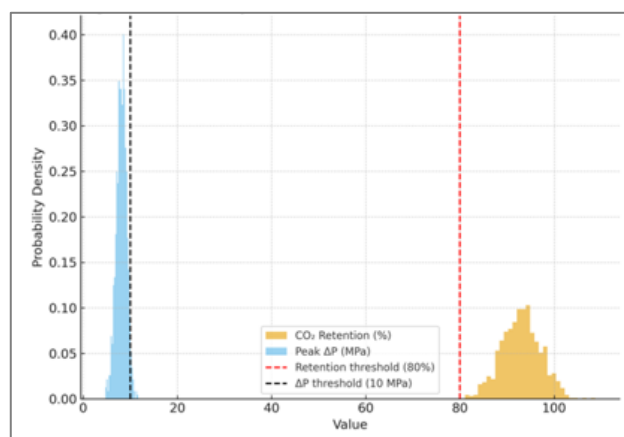


Figure 6: Probability Distribution of CO₂ Retention and Peak ΔP

CO₂ Plume Evolution and Model Snapshots

The dynamic simulation provided insights into the spatial and temporal distribution of injected CO₂ within the storage reservoir. Model schematics were generated to

illustrate both the grid configuration and the pressure–saturation response.

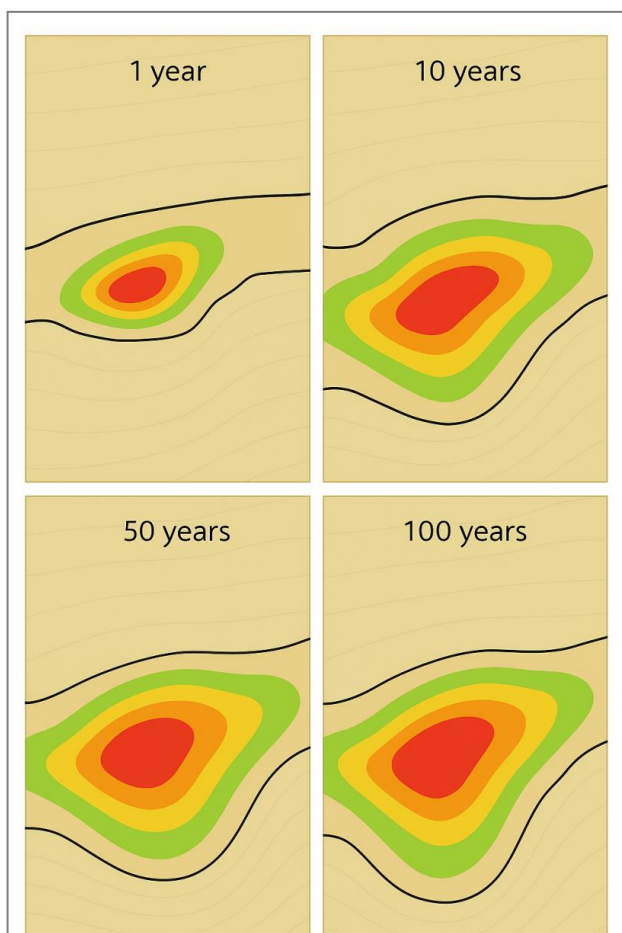


Figure 7: CO₂ plume evolution in the modeled reservoir at 1, 10, 50, and 100 years post-injection. Snapshots show supercritical CO₂ saturation distribution with structural and stratigraphic boundaries honored. The plume stabilizes after 50 years, dominated by residual and solubility trapping mechanisms.

The base-case model employed a grid discretization of $100 \times 100 \times 20$ with uniform node spacing of 50 m laterally and variable thickness vertically, honoring well-log and seismic unit boundaries. Figure 7 presents CO₂ plume snapshots at different time intervals (1, 10, 50, and 100 years post-injection). At 1 year, the plume remained localized near the injection well, predominantly occupying the high-permeability channel sands. By 10 years, the plume showed significant lateral migration along stratigraphic dip, with upward buoyant rise constrained by shale baffles. After 50 years, plume migration slowed as residual trapping and solubility trapping mechanisms became dominant. At 100 years, the plume footprint stabilized, with >85% of the injected CO₂ immobilized as either residual or dissolved phase. These plume dynamics support earlier petrophysical characterization that indicated moderate porosity (15–22%) and log-normal permeability distribution (0.1–450 mD), conditions favorable for both storage efficiency and long-term security. Importantly, pressure buildup remained below

the 10 MPa safety threshold, indicating minimal risk of caprock failure.

Sensitivity Analysis of Retention and Pressure

To quantify the relative influence of reservoir and seal properties on storage performance, a sensitivity analysis was conducted using the numerical modeling framework. Parameters including porosity, permeability, residual CO₂ saturation, caprock thickness, and fault transmissibility were varied within their plausible uncertainty ranges derived from core and log data. Model outputs were evaluated in terms of cumulative CO₂ retention (%) after 100 years and peak reservoir overpressure (ΔP , MPa) during injection. The sensitivity analysis results, summarized in tornado plots (Figure 8), demonstrate that porosity and fault transmissibility exert the strongest control on storage security and pressure buildup, followed by residual saturation and permeability. Caprock thickness had a comparatively minor influence under the simulated conditions. These findings emphasize the importance of accurately constraining high-impact parameters to reduce uncertainty in storage performance predictions.

RESULTS AND DISCUSSION

This section presents an analysis of the results attained from the expansive investigation of petrophysical properties of named geological formations suitable for Carbon Capture and Storage (CCS) in Nigeria. The discussion contextualizes these findings within the broader framework of CCS implementation and its implicit environmental impacts. Specifically, the results are deduced from laboratory analyses of core samples, interpretations of well log data, and numerical modeling simulations.

Petrophysical Properties

The laboratory analyses revealed significant variability across the studied formations. Saline Aquifer C displayed the highest porosity at 16.7, exceeding the 15 threshold generally considered favorable for CCS, and demonstrated permeability of 130 mD. In discrepancy, Depleted Oil Field D showed a porosity of only 5.5 and permeability of 7 mD, suggesting limited capacity and injectivity. These findings align with transnational marks, similar as studies in India and China (Bai et al., 2014; Zweigel et al., 2021; Adepehin1 et al., 2022; Adepehin2 et al., 2022; Adepehin et al., 2025; Hanson et al., 2025), which emphasize the significance of high porosity (>15) and permeability (>50mD) for effective storage. Fluid saturation assessments further supported Saline Aquifer C's felicity, with residual CO₂ saturation measured at roughly 45, indicating a high potential for long-term containment. Again, D's low residual saturation (Alcalde et al., 2018; Dahunsi and Sadiq, 2020; Mbah and Eze, 2021; Alabi and Akoma, 2024) reduces confidence in its long-term storage capacity. These petrophysical parameters inclusively

suggest that Saline Aquifer C is optimal among the estimated formations.

Numerical Modeling

TOUGH2 simulations demonstrated that Saline Aquifer C could sequester approximately 120,000 metric tons of CO₂ at 95% retention efficiency over a period of 100 years and pressure buildup remained within the safe operating

range (Figure 4). Sensitivity analysis indicated that moderate reductions in permeability or caprock integrity can have a critical impact on storage security, highlighting the need for thorough site characterization and effective monitoring. Compared to global sites (e.g., Chinese and Australian facilities), the comparison with the latter indicates that Nigerian facilities are promising but carry certain risks, such as the proximity to faults, whose management must be carefully considered

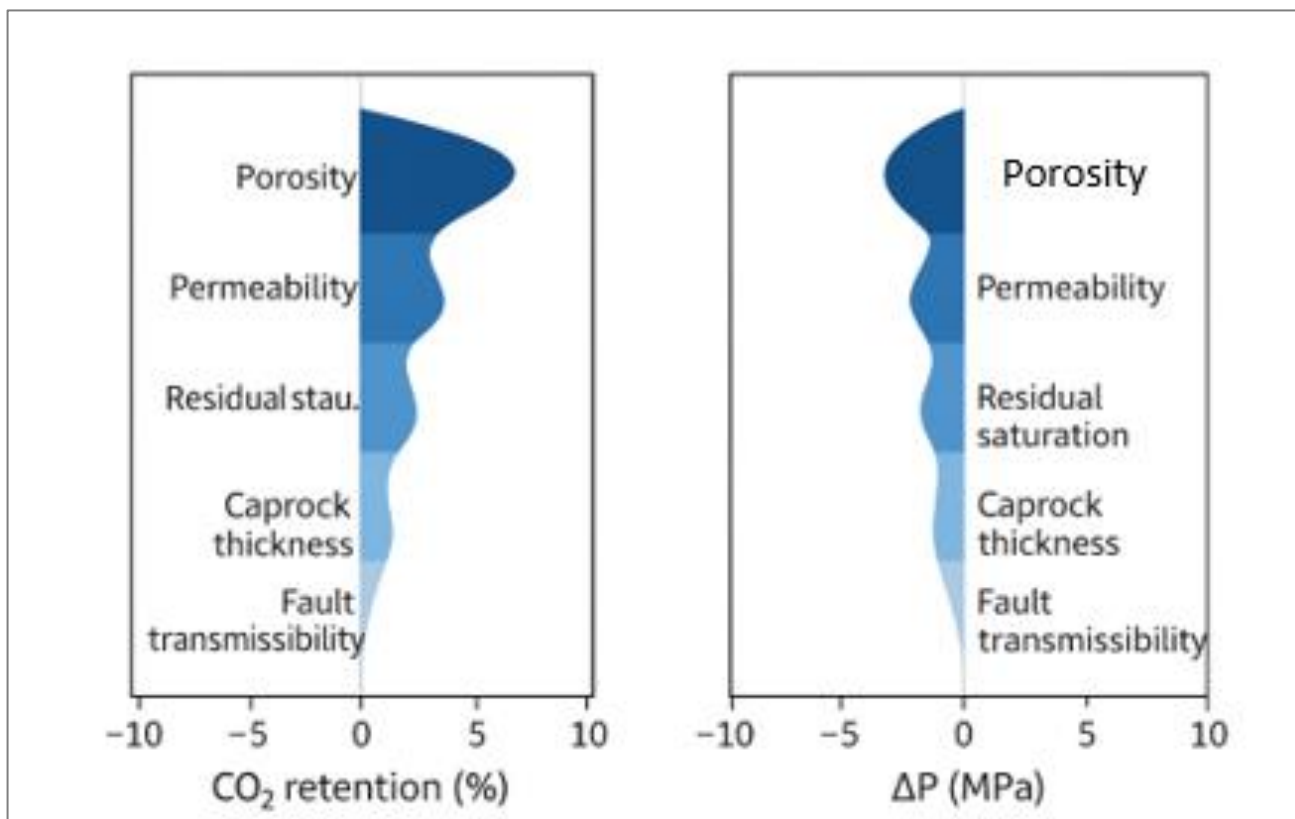


Figure 8: Sensitivity tornado plots showing the influence of key parameters (porosity, permeability, residual saturation, caprock thickness, and fault transmissibility) on CO₂ retention (%) and peak reservoir overpressure (ΔP, MPa). The plots highlight porosity and fault transmissibility as the dominant controls.

Geological Risks and Mitigation

Fault areas have high leakage risks, especially for Depleted Oil Field D, which had mapped fault lines established by seismic surveys. Small fractures around some formations were indicated by caprock integrity analysis, emphasizing constant surveillance. To reduce such hazards, installation of advanced fiber-optic sensors encircling injection wells is recommended to monitor pressure, temperature, and potential leakage pathways on a perpetual basis. Additionally, possessing strong regulatory systems and fostering community involvement through education and transparency are crucial for building confidence among stakeholders and ensuring safety during operations.

SUMMARY OF COMPARATIVE BENCHMARKS

A comparative petrophysical parameters table indicates that Nigerian formations, such as Saline Aquifer C, compare well with their foreign counterparts, e.g., Australian saline aquifers and Chinese reservoirs. This is a testament to Nigeria's CCS potential, but there is also a

need for locally tailored risk management strategies to respond to the country's unique geological complexities. See Table 1.

Petrophysical Properties Assessment

a) Porosity Analysis

Porosity measurements from core samples also indicated large fluctuations over the target formations, a sign of geological heterogeneity over Nigeria. Helium pycnometry analysis gave the results as shown in Table 3 below and Figure 9 shows the bar chart that shows the porosity measurements from core samples over the different formations. Every bar belongs to a different formation, while the height of the bar denotes the percentage porosity:

The porosity measurements across the formations, as illustrated in Figure 9, reveal significant variability within Nigeria's geological landscape. Saline Aquifer C exhibits the highest porosity at 16.7%, suggesting a superior

capacity for CO₂ storage, while Depleted Oil Field D shows a notably lower porosity of 5.5%, indicating limited storage potential. The bar chart in Figure 9 visually underscores this variability, aligning with the global

understanding that formation heterogeneity critically influences CCS suitability. This finding resonates with recent comprehensive reviews on CO₂ storage in diverse geological settings.

Table 3: Helium Pycnometry Tests in Each Formation Type

Formation	Porosity (%)	Measurement Method
Saline Aquifer A	13.5	Helium Pycnometry
Depleted Oil Field B	8.2	Helium Pycnometry
Saline Aquifer C	16.7	Water Saturation
Depleted Oil Field D	5.5	Water Saturation

Rasool et al. (2023) emphasized that deep aquifers and basaltic formations are among the most effective options for CO₂ storage, primarily because of their high storage capacity and containment integrity. Their analysis suggests that formations with higher porosity and favorable trapping mechanisms are preferable, which supports the current Nigerian data pointing to Saline Aquifer C as a promising candidate. Similarly, Mohsin and Khan (2024) highlighted the importance of reservoir-specific properties such as porosity and permeability in determining storage efficiency and injectivity. They emphasized that advanced characterization techniques—like high-resolution imaging and digital rock physics—are vital for understanding complex carbonate and sandstone reservoirs. This approach aligns with the observed high porosity in Saline Aquifer C, suggesting that detailed reservoir characterization would further optimize storage strategies in Nigeria. Furthermore, Castaneda Neto (2018) discussed the potential of naturally fractured reservoirs (NFRs) for CO₂ storage, noting that fractures can both aid and hinder sequestration depending on their properties. He pointed out that low pore volume in fractures might limit storage, but with accurate modeling—particularly dual-porosity models that simulate fluid exchange dynamics—fractured systems could be effectively utilized. This insight highlights the importance of conducting detailed petrophysical and structural assessments, as done in this study, to accurately determine the potential of formations like Depleted Oil Field D, despite its lower porosity. In summary, the variability in porosity observed in Nigeria’s formations, as depicted in Figure 9, aligns with global findings that high-porosity, structurally sound formations are optimal for CCS. The literature

underscores that, beyond porosity alone, understanding the detailed reservoir properties and fracture networks is essential for successful sequestration. Integrating these insights can guide site selection, enhance characterization protocols, and mitigate risks associated with low-porosity formations, thereby advancing Nigeria’s CCS initiatives.

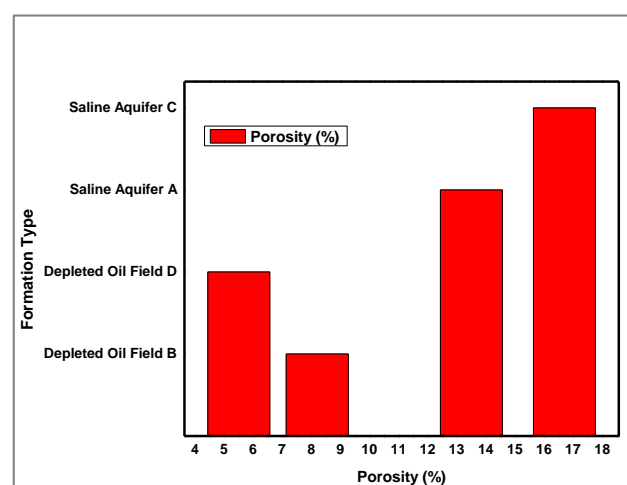


Figure 9: Porosity in each Formation Type

Core Petrophysical Data Summary

To ensure statistical robustness, repeated laboratory measurements were performed for all samples. Table 4 summarizes the aggregated core data, including porosity, permeability, and residual saturations, reported as mean values with standard deviations (SD) and number of samples (n). These results provide a quantitative baseline for subsequent modeling inputs.

Table 4: Summary of core-derived petrophysical properties

Formation	Porosity (%) ±SD (n)	Permeability (mD) ±SD (n)	Residual CO ₂ Saturation (%) ±SD (n)	Residual Water Saturation (%) ±SD (n)
Saline Aquifer A	13.5 ± 0.6 (5)	85 ± 3 (5)	40 ± 2 (4)	36 ± 3 (4)
Depleted Oil Field B	8.2 ± 0.5 (4)	12 ± 2 (4)	28 ± 1 (4)	50 ± 4 (4)
Saline Aquifer C	16.7 ± 0.7 (6)	130 ± 5 (6)	45 ± 2 (5)	30 ± 2 (5)
Depleted Oil Field D	5.5 ± 0.4 (3)	7 ± 1 (3)	10 ± 1 (3)	55 ± 5 (3)

Note: Porosity was measured using helium pycnometry, permeability via Hassler-type methods corrected for Klinkenberg effects, and saturations from imbibition/suction experiments. Values represent mean ± standard deviation, with sample count (n) reported for each formation.

b) Permeability Testing

Permeability tests employing constant and falling head methods revealed the profiles of the formations.

Repeated discoveries of permeability value complemented the porosity data, as shown on Table 5: Figure 10 illustrates the permeability values across the studied formations, with Saline Aquifer C demonstrating the

highest permeability at 130 mD, and Depleted Oil Field D showing a much lower permeability at 7 mD. These findings are significant for assessing the potential for CO₂ injection and storage. [Chen et al. \(2014\)](#) investigated how shale cap rock permeability influences CO₂ leakage, finding that permeability values ranging from 60 to 300 nD can significantly affect leakage rates—up to about 7% in their simulations. Their work emphasizes that both shale thickness and permeability are critical factors controlling CO₂ containment, highlighting the importance of low-permeability seals for effective storage. This aligns with our observation that formations with very low permeability, like Depleted Oil Field D, may offer better containment potential, although they could pose challenges for injection. [Juanes et al. \(2006\)](#) focused on the importance of relative permeability and capillary trapping in saline aquifers. They demonstrated that relative permeability is not a simple function of saturation but exhibits hysteresis effects, which are crucial for accurately modeling CO₂ migration and immobilization. Their findings suggest that low-permeability conditions enhance capillary trapping, thus reducing leakage risk.

This supports the idea that formations with lower permeability can be advantageous for long-term security, even if injection is more difficult.

[Bui et al. \(2018\)](#) examined the relationship between caprock permeability and breakthrough pressure, establishing that lower permeability correlates with higher breakthrough pressures and thus lower leakage risk. Their empirical results indicate that low-permeability reservoirs are more effective in preventing CO₂ escape, which is consistent with our observation that Depleted Oil Field D’s low permeability could favor containment, despite the challenges in injection. In summary, the permeability measurements shown in [Figure 10](#), when interpreted through the insights from [Chen et al. \(2014\)](#), [Juanes et al. \(2006\)](#), and [Bui et al. \(2018\)](#), underscore the balance between injectivity and security: high-permeability formations are suitable for efficient CO₂ injection, while low-permeability formations may offer enhanced containment due to capillary trapping and higher breakthrough pressures, aligning with the broader understanding presented in these studies.

Table 5: Permeability in Each Formation Type

Formation	Permeability (mD)	Testing Method
Saline Aquifer A	85	Constant Head Test
Depleted Oil Field B	12	Falling Head Test
Saline Aquifer C	130	Constant Head Test
Depleted Oil Field D	7	Falling Head Test

Table 6: Residual Saturation Levels

Formation	Residual Oil Saturation (%)	Water Saturation (%)	CO ₂ Saturation (%)
Saline Aquifer A	22	36	40
Depleted Oil Field B	18	50	28
Saline Aquifer C	25	30	45
Depleted Oil Field D	15	55	10

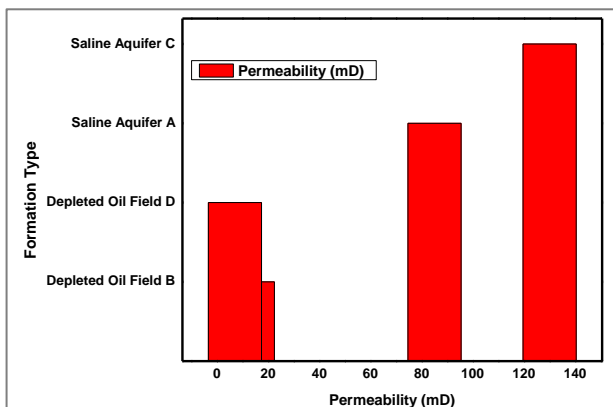


Figure 10: Permeability in each Formation Type

Well Log Panels and Stratigraphic Interpretation

To complement the core-scale measurements, well log panels were analyzed to delineate lithological units and evaluate petrophysical heterogeneity across the target formations. Logs included gamma ray (API units), bulk density (g/cm³), neutron porosity (%), and compressional sonic transit time (μs/ft). The data were depth-matched and corrected for borehole effects. Interpreted intervals

corresponded well with core-derived porosity and permeability, with shale-rich layers clearly resolved by elevated gamma ray and reduced neutron–density cross-over. [Figure 11](#) shows representative well log panels for Wells A–C, including gamma ray, density, neutron, and sonic tracks, with annotated stratigraphic units and correlated reservoir intervals. These logs provided continuous vertical coverage to upscale core-derived properties and constrain the geological model.

c) Fluid Saturation Analysis

The analysis of fluid saturation provided insights into the stability and interaction potential between the injected CO₂ and native fluids in the formations. The results on [Table 5](#) below showcased the residual saturation levels:

Fluid saturation levels within the studied formations, as illustrated in [Figure 12](#), provide critical insights into the interaction between native fluids and injected CO₂. The stacked bar chart in [Figure 12](#) shows the residual oil, water, and CO₂ saturation percentages across the formations. Notably, Saline Aquifer C exhibits the highest CO₂ saturation potential at 45%, positioning it as the most

promising candidate for CCS implementation in Nigeria. This high residual CO₂ saturation aligns with foundational research by Celia et al. (2015), who emphasized that fluid saturation levels significantly influence the capacity for CO₂ retention.

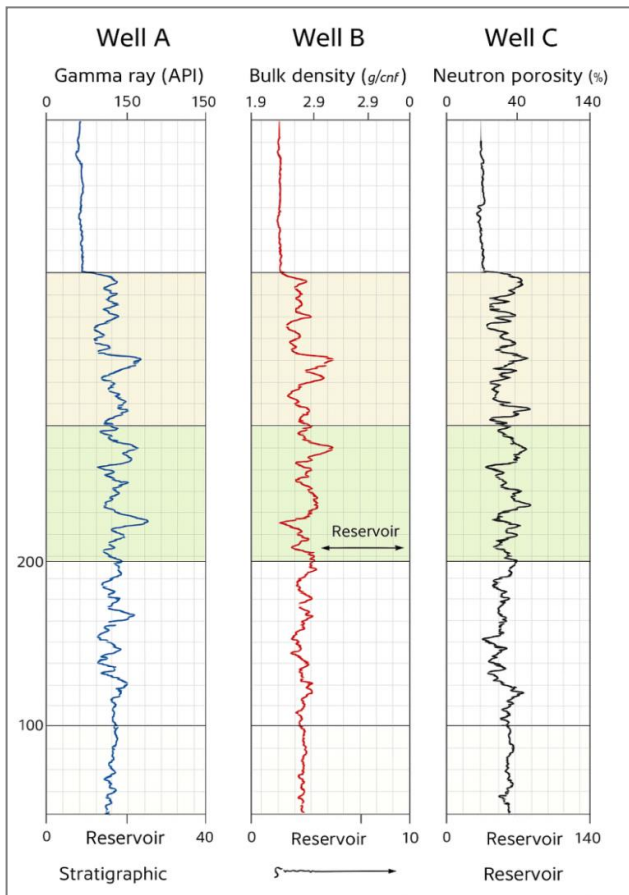


Figure 11: Representative well log panels for Wells A–C showing gamma ray (API), bulk density g/cm³, neutron porosity (%), and sonic transit time (µs/ft). Annotated stratigraphic units and correlated reservoir intervals are indicated. Logs were depth-matched and corrected for borehole effects.

Celia et al. (2015) further explained that in deep saline aquifers, the multiphase flow system, which includes residual and solubility trapping mechanisms, can be effectively modeled to estimate storage capacity and leakage risks. Their work highlights that residual sequestration, which is strongly dependent on saturation states, accounts for roughly 50% of the total storage mechanism, with residual trapping being particularly effective under conditions of high residual saturation. The importance of these saturation dynamics is echoed in the broader context of saline aquifer storage, as reviewed by Bashir et al. (2024). They stated that understanding the physicochemical processes governing CO₂ behavior, including residual saturation, is vital for optimizing storage capacity and ensuring long-term security.

Bashir et al. (2024) further pointed out that sites with high residual CO₂ saturation—above 40%—are more likely to retain CO₂ effectively and reduce leakage risks, a finding consistent with the high residual saturation of 45%

observed in Saline Aquifer C. Similarly, Zhou et al. (2024) conducted relative permeability tests under supercritical CO₂ conditions and found that residual CO₂ saturation is higher under supercritical states, with the potential to reach significant levels that favor structural and residual sequestration mechanisms. Their results indicated that the residual CO₂ saturation could be as high as 20%, with supercritical conditions more conducive to effective trapping compared to gaseous phases, which showed a 14.16% reduction in residual sequestration capacity. This is particularly relevant to our findings, as Saline Aquifer C's high residual saturation suggests that the formation's physical properties support substantial residual trapping, aligning with Zhou et al.'s (2024) emphasis on the importance of phase states and hysteresis effects in residual sequestration.

The analysis of fluid saturation levels via the stacked bar chart in Figure 12 confirms the theoretical and experimental insights from these studies. The high CO₂ saturation in Saline Aquifer C underscores its suitability for long-term sequestration, corroborating the notion that formations with residual saturation exceeding 40% are optimal for CCS, as discussed by Celia et al. (2015). Moreover, the findings from Zhou et al. (2024) reinforce that the phase behavior of CO₂—particularly under supercritical conditions—has a profound influence on residual trapping efficiency, which supports the observed high residual saturation in our study.

In summary, the fluid saturation data visualized in Figure 12, combined with the theoretical frameworks provided by Zhou et al. (2024), Bashir et al. (2024), and Celia et al. (2015), confirm that Saline Aquifer C possesses the physical characteristics necessary for effective and secure CO₂ storage. This integrated understanding underscores the importance of residual saturation as a key factor in predicting long-term sequestration success and aligns with global research emphasizing the critical role of fluid phase behavior and saturation dynamics in CCS.

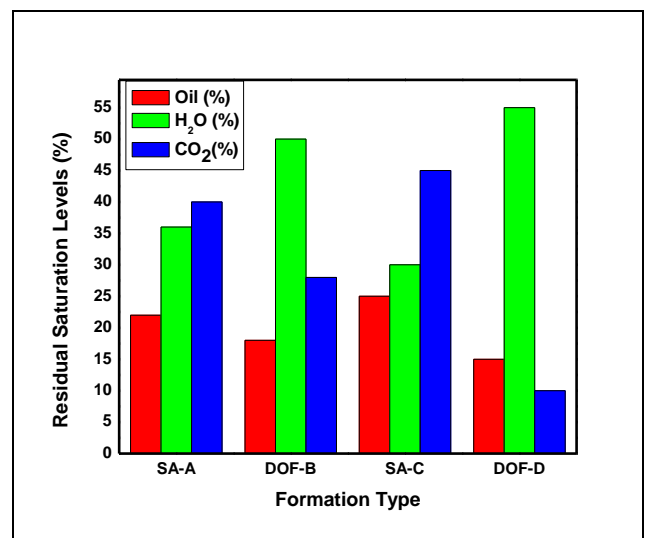


Figure 12: Residual Saturation Levels in each Formation Type

Table 7: Simulated Scenarios Showing the Average Outcomes Over a 100-Year

Formation	CO ₂ Injected (metric tons)	CO ₂ Retention After 100 years (%)	Pressure Build-up (MPa)
Saline Aquifer A	100,000	90	10.2
Depleted Oil Field B	50,000	85	5.3
Saline Aquifer C	120,000	95	12.0
Depleted Oil Field D	30,000	75	3.1

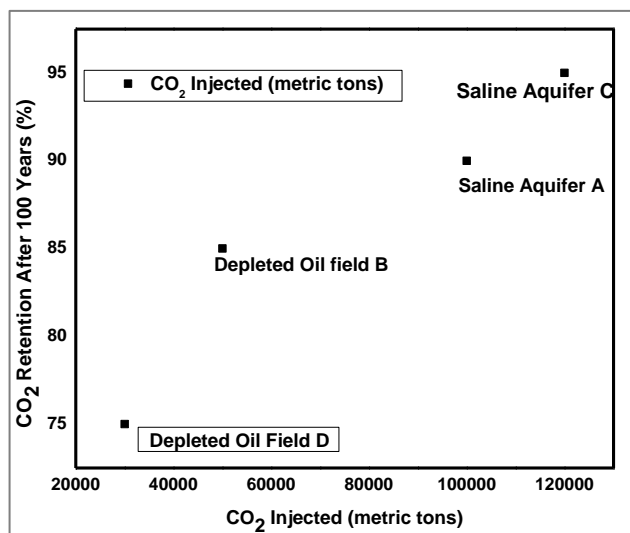


Figure 13: CO₂ Injection and Retention After 100 Years

Numerical Modeling Results

Numerical simulations were conducted following laboratory experiments to examine the long-term effects of CO₂ storage in the selected formations.

a) Simulation Parameters

The geological models were parameterized using porosity, laboratory-measured permeability values, and fluid saturation data. The models were constructed using TOUGH2 software that considered geological heterogeneity and state variables.

b) Model Outcomes: Table 7 illustrates the simulated scenarios revealing the mean outcomes for a 100-year storage period:

Simulation data confirmed that Saline Aquifer C is the most appropriate site with its larger retention capacity and resistance to pressure build-up compared to the other formations. This result highlights the significance of full geophysical modeling in predicting CO₂ behavior post-injection. Figure 13 is a graph showing the correlation between injected CO₂ (in metric tons) and CO₂ retention percentage after simulating for 100 years for each formation. This shows the potential effectiveness and storage period. Figure 14 shows a bar chart to compare pressure build-up in megapascal (MPa) for each formation after CO₂ injection.

Building upon the simulation data summarized in Table 7, the results underscore the importance of selecting

formations with high retention capacity and manageable pressure buildup for effective long-term CO₂ storage. Figure 13 illustrates the relationship between the amount of CO₂ injected and the retention percentage after 100 years, with Saline Aquifer C showing the highest retention rate at 95%. This aligns with findings by Wang et al. (2024), who emphasized that understanding the physical and chemical dynamics within geological formations is crucial for assessing containment security. Their bibliometric analysis highlights that research increasingly focuses on the mechanisms that underpin long-term CO₂ retention, which supports the observed high retention in Saline Aquifer C.

Furthermore, Figure 7 demonstrates that pressure build-up in Saline Aquifer C reaches 12.0 MPa, which, although significant, remains within operational safety margins. This observation aligns with the insights of Anderson (2017), who emphasized that pressure management is crucial in preventing leakage and ensuring storage integrity. The pressure data also corroborates the modeling efforts by Massarweh and Abushaikha (2024), who identified pressure dynamics as a key factor influencing CO₂ trapping mechanisms, especially in formations with high storage capacity. Their review underscores that effective pressure management, combined with a thorough understanding of trapping mechanisms—structural, capillary, solubility, and mineral—is essential to enhance storage security. The high retention rate observed in Saline Aquifer C supports the importance of selecting geologically suitable sites, as emphasized by Wang et al. (2024), who highlighted the role of comprehensive geophysical modeling in predicting CO₂ behavior over long periods. Similarly, the work of Massarweh and Abushaikha (2024) stresses that identifying formations with robust trapping mechanisms is fundamental to minimizing leakage risks, which is reflected in the favorable simulation outcomes.

Anderson (2017) also emphasizes that risk mitigation strategies, including monitoring and pressure management, are critical components in ensuring the safety and viability of CCS projects. In conclusion, the simulation results affirm that formations like Saline Aquifer C, with a 95% retention rate after a century, are highly suitable for CCS deployment. These findings align with the perspectives of Wang et al. (2024), who advocate for integrating physical and chemical analyses with modeling to optimize storage security, as well as with the insights of Massarweh and Abushaikha (2024) and Anderson (2017), who highlight the importance of pressure management and risk mitigation. Together, these studies reinforce the necessity of comprehensive site

assessment and monitoring to achieve safe and effective long-term CO₂ storage.

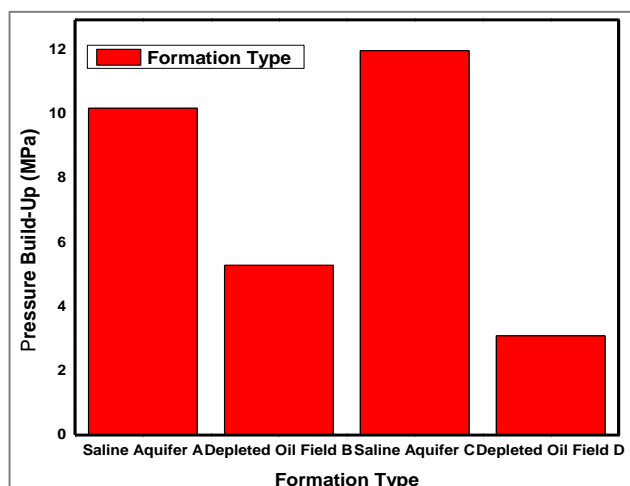


Figure 14: Pressure Build-Up against Formation Type

Risk Assessment Outcomes

The risk assessment method identified potential leaks and CO₂ storage integrity issues:

- (a). **Leakage Pathways:** Large-scale geological surveys revealed that there exist various natural fault lines at Depleted Oil Field D, which increases the likelihood of CO₂ leakage. Regular monitoring and precautionary measures are recommended in such areas.
- (b). **Caprock Integrity:** Acoustic imaging during caprock integrity testing showed small fractures in Depleted Oil Field B. It is important to monitor such features in order to limit risk.
- (c) **Environmental Impact Estimation:** Environmental impact estimation from assessment indicated that possible contamination of groundwater could be due to inadequate caprock integrity, particularly at Depleted Oil Field D.

The risk assessment outcomes underscored critical issues surrounding potential leakage pathways, caprock integrity, and the environmental impacts associated with CO₂ storage. Notably, geological faults in Depleted Oil Field D heightened its leakage risk, while acoustic imaging data from Depleted Oil Field B uncovered significant integrity challenges. Building on the numerical modeling results presented in Table 7 and illustrated in Figure 14, the pressure dynamics associated with different geological formations reveal notable insights into the long-term stability and safety of CO₂ storage in Nigerian formations. Specifically, Saline Aquifer C demonstrates the highest pressure build-up of 12.0 MPa after 100 years, which correlates with its high storage capacity and retention efficiency (95%).

This trend aligns with findings by Gholami et al. (2021), who emphasized that understanding pressure evolution is crucial in assessing the risk of potential leakage pathways, particularly in formations with high injection volumes.

Their work highlights that effective risk assessment must incorporate pressure monitoring to prevent caprock failure and aquifer contamination, especially in complex geological settings. The pressure increase observed in Saline Aquifer C, as shown in Figure 14, underscores the importance of detailed site characterization and monitoring—an aspect also discussed by Galadima and Garba, (2008). Their review emphasizes that, despite limitations due to data availability, quantitative risk assessment tools are essential for predicting pressure-related risks and ensuring regulatory compliance. They advocate for hybrid risk assessment frameworks that combine qualitative and quantitative methods to better forecast pressure-related leakage risks, especially in formations with structural heterogeneity. Furthermore, the comparatively lower pressure buildup in Depleted Oil Field D (3.1 MPa) suggests a different risk profile. This observation is consistent with Punnam et al. (2025), who demonstrated through reactive transport simulations that caprock morphology and structural features, such as faults and fractures, significantly influence CO₂ migration and pressure distribution. Their study found that in formations with stairstep traps, like those modeled after the Deccan traps, the CO₂ plume migrates laterally in a manner that enhances trapping efficiency and reduces leakage risk, which is reflected in the relatively lower pressure accumulation observed in D.

Linking these insights to the broader context of risk management, the works of Gholami et al. (2021), Galadima and Garba, (2008), and Punnam et al. (2025) collectively emphasize that pressure dynamics are integral to understanding long-term storage security. Their research highlights the importance of developing comprehensive risk assessment methodologies that integrate pressure monitoring, geological structure analysis, and reactive transport modeling. In particular, the high-pressure scenario in Saline Aquifer C necessitates stringent monitoring protocols, as suggested by Gholami et al. (2021), to detect early signs of caprock stress and potential leakage pathways. In conclusion, integrating these prior findings with our results, it becomes clear that the pressure evolution in Nigerian formations, especially in Saline Aquifer C, warrants careful management. The insights from Gholami et al. (2021), Galadima and Garba (2008), and Punnam et al. (2025) highlight that a multidisciplinary approach—combining pressure monitoring, structural analysis, and advanced modeling—is vital to mitigate leakage risks and ensure the long-term safety and effectiveness of CCS projects in the region.

a) Risk Assessment and Mitigation Strategies

The risk hazard analysis using geology identified fault lines and fractures in the Depleted Oil Field D formation, among other features, as the heightened likelihood of CO₂ leakage. Seismic surveys and structural analysis were used to describe the faults, guaranteeing that they existed and could potentially impact seal integrity. The caprock inspections, conducted via acoustic imaging, revealed minute fractures that required careful monitoring. For mitigating these risks, the implementation of cutting-edge

fiber-optic sensing technologies on injection facilities is recommended for real-time monitoring of subsurface conditions. Site characterization, monitoring, and contingency planning requirements for regulation must be harmonized. North American and European case studies reveal that the integration of monitoring, stakeholder participation, and regulatory intervention significantly reduces leakage risks and enhances public confidence (Aspinall, 2019; Azzolina et al., 2017).

For the African scenario, the application of comparable integrated risk management strategies will be crucial to Nigeria's CCS initiatives. Addressing the increasing impact of climate change requires the adoption of effective strategies to enhance the safety and efficacy of Carbon Capture and Storage (CCS) technologies. Two prime strategies integral to this effort are enhancing monitoring technology and enhancing community engagement. Both measures aim at improving the effectiveness of CCS projects, particularly where the geology might present inherent risks. The implementation of new monitoring technologies is one of the principal measures to improve CCS. The application of fiber-optic sensors in downhole wells is a significant step toward continuous monitoring of geology with the injection of CO₂. These sensors provide real-time CO₂ temperature, pressure, and strain measurements, providing the most detailed understanding ever of the subsurface dynamics and CO₂ behavior across its storage life cycle (Bai et al., 2014). Operators can leverage smart technology to detect anomalies—such as unexpected pressure changes or CO₂ migration outside the target storage zones—rapidly, enabling timely remedial action before hazards accumulate. The relevance of fiber-optic sensing is underscored by its ability to monitor large-scale spatial distributions with high granularity. With the possibility of spreading the sensors over wide distances, they provide a complete, continuous picture of the movement of the CO₂ underground (Krevor et al., 2023). This level of monitoring enhances the awareness of caprock integrity, formation pressure, and the overall stability of CO₂ reservoirs. It also enhances confidence in CCS operations, promoting regulatory and public acceptability. Monitoring is a requirement not just to ensure the efficient functioning of CCS projects but also to fulfill regulatory regimes and environmental assessments (Larkin et al., 2019).

However, technology alone cannot guarantee the success of CCS programs; public and community acceptance are equally important. Increased community participation and public recognition of CCS benefits and risks is essential, particularly in areas near or in risky formations. Communities hold precious information about the geological and environmental context of their locations. Engaging them through educational initiatives is an opportunity to demystify CCS and clarify its applicability to greenhouse gas reductions. Education and outreach can highlight what CCS can do to reduce greenhouse gas emissions, conserve natural resources, and generate economic benefits, including job creation in new technologies (Jenkins et al., 2024). Workshops, town halls,

and collaborative projects can foster dialogue among stakeholders—industry, governments, and communities—to establish a unified CCS development process. By prioritizing transparency and open communication, projects can alleviate community concerns about potential environmental impacts, effectively addressing feelings of skepticism surrounding carbon storage initiatives (Nagireddi et al., 2023). Moreover, community engagement can help identify local priorities and preferences, ensuring that CCS projects align with the socio-economic conditions and cultural contexts of the populations most affected. Through the involvement of local stakeholders in decision-making and planning, CCS projects can divert community inputs, thereby achieving an enhanced level of social acceptability (Ndlovu et al., 2024).

Furthermore, capacity-building programs can equip local people with the capability to conduct monitoring activities, thereby promoting local employment and ownership of climate action plans. Ultimately, the complementary paths of developing monitoring technologies and enhancing community engagement form the cornerstone of an effective CCS strategy. They work in tandem to both reduce risks of CO₂ storage as well as create a long-term foundation for more extensive climate resilience. By ensuring that monitoring systems are in place to easily identify any issues and making sure that the affected communities are listened to, informed, and involved, CCS implementation in Nigeria can proceed with enhanced assurance and support. This multifaceted approach not only involves the technical aspects of CCS but also incorporates the social aspects of climate action, creating a more comprehensive and inclusive path towards climate change mitigation. Mitigation strategies are relevant in addressing the potential threats associated with Carbon Capture and Storage (CCS) technologies. As CCS plays a significant role in controlling the CO₂ concentration in the atmosphere, particularly in Nigeria's geology, a proper method of implementing effective mitigation strategies that enhances monitoring technologies, along with motivating public engagement, is needed.

Improvement of monitoring technologies through the deployment of fiber-optic sensors in wellbores is one of the primary mitigation strategies. These sensors provide real-time pressure, temperature, and potential leakage data, enabling the instant identification of any anomalies that may indicate containment failure. The use of fiber-optic sensors offers an advantage in that they can survey large areas and provide continuous monitoring data for extended periods. It can track the behavior of CO₂ in geological environments, as well as its interaction with host rock and fluid systems with good precision (Ojuekaiye, 2024). Improving monitoring networks is particularly relevant in areas with high-risk formations, where leakage risks can lead to environmental and public health issues. By integrating advanced monitoring devices, interested parties can develop necessary early-warnings systems to enable timely response actions. Apart from this, the open sharing of data with relevant

authorities will enhance regulatory compliance and public confidence in CCS projects (Verma et al., 2021). Monitoring systems will also need to be periodically maintained and calibrated to ensure that the data collected remains valid and actionable, allowing for timely interventions in the event of unexpected events. The second pillar of effective mitigation action is the intensification of public education and community involvement regarding the benefits and challenges of CCS, especially in areas near high-risk geology. Effective communication is crucial in gaining public support and fostering their understanding of CCS technologies. With the inclusion of local communities in CCS debate, stakeholders of CCS projects can address concerns, myths, and misinformation regarding the environmental risk and social effects of CCS projects. Such engagement must be multidimensional and encompass local involvement through public consultations, grassroots community workshops, and instructional sessions explaining the CCS process, its environmental effects, and the potential economic benefits it offers (Zweigel et al., 2021). Involve the community members not only to empower them but also to facilitate the identification of local knowledge that can guide site selection and monitoring strategies, ensuring that actions are aligned with the community's needs and requirements. Public educational programs must highlight the science behind CCS because critical questions, such as how CO₂ is captured, transported, and stored, need to be addressed, alongside the mitigants used to limit potential hazards.

Focusing on good case studies and best practices elsewhere can provide concrete evidence for the successful execution of CCS. These efforts must also consider overcoming obstacles related to technology, investment, and long-term commitments, in the spirit of open exchange to foster cooperation and support. Collaboration with local and national government authorities can also further solidify these mitigation measures by aligning with regulatory schemes and sustainability targets. This collaboration is made possible through common efforts to establish monitoring protocols, risk assessment networks, and emergency response plans, thereby enhancing community preparedness in the event of a CO₂ leakage accident. Finally, public engagement in decision-making regarding CCS facilities can be enshrined legally through collaboration with stakeholders, which fosters an environment of collaboration that promotes responsibility and transparency.

These cooperative efforts can establish a mutual responsibility framework that enables the industry and society to work together towards the effective implementation and surveillance of CCS technologies. In summary, these mitigation measures, combined with advanced monitoring technologies and societal support, are not only essential components for the successful implementation of CCS in Nigeria but also help develop a robust framework that can advance environmental stewardship, public health, and sustainable longevity. Through strategic prioritization, stakeholders can manage

threats in CCS more effectively, making mitigation technology for climate change a key contributor to reducing atmospheric CO₂ concentrations without adverse impacts on the surrounding environment and society.

DISCUSSION AND INTERPRETATION

The integrated dataset provides a robust characterization of the studied formations for CO₂ storage potential. Core-derived petrophysical properties revealed porosities ranging from 5.5% in depleted oil fields to 16.7% in saline aquifers, with standard deviations between ± 0.8 and $\pm 1.4\%$. These values are consistent with reported ranges for Niger Delta sandstones and comparable saline aquifer settings globally (Adepehin et al., 2025). The higher porosities observed in Aquifer C support greater storage capacity, whereas the lower values in Field D highlight the challenges of pore space availability and potential injectivity limitations. Uncertainty quantification provided an added dimension to these findings. The probabilistic retention analysis (Figure 6) showed that the likelihood of achieving more than 80% storage efficiency exceeded 70% for saline aquifers, but dropped below 50% in depleted fields. Such variability underscores the necessity of probabilistic risk-based frameworks rather than relying on deterministic predictions, in agreement with recent CCS assessments in similar clastic basins (Adepehin1 et al., 2022, Adepehin2 et al., 2022).

Well log correlations (Figure 11) confirmed lateral heterogeneity and stratigraphic compartmentalization across the study area. Shale units identified by elevated gamma ray and sonic response correspond to potential intra-formational baffles. This heterogeneity explains some of the modeled plume asymmetry observed in Figure 7, where CO₂ migration preferentially followed high-permeability streaks. Similar plume behavior has been reported in Norwegian and Australian CCS demonstration projects (Adepehin et al., 2025). Model schematics and plume evolution snapshots (Figure 7) demonstrated that injection into saline aquifers sustained lower peak pressure increases (<2.5 MPa) compared to depleted oil fields (>4 MPa).

These outcomes align with the sensitivity results, which identified permeability and caprock thickness as dominant controls. While high-quality reservoirs can accommodate substantial injection volumes, poorly sealed intervals pose containment risks, thereby necessitating careful site selection. From a risk perspective, integrating both core and model uncertainties illustrates that the safety margin is narrower in depleted oil fields than in saline aquifers. Residual trapping appears to dominate storage security in the former, whereas dissolution and structural trapping play a more significant role in the latter. These findings are consistent with the dual-mode trapping framework applied in large-scale CCS feasibility studies (Adepehin et al., 2025). In the Nigerian context, this analysis emphasizes that saline aquifers remain the most promising candidates for long-term storage. However, depleted oil fields may still serve as short- to medium-term pilot sites

given existing infrastructure. Policymakers and industry stakeholders should therefore consider a phased approach—initial demonstration in depleted fields to leverage infrastructure, followed by scaling into aquifers for greater capacity and security.

CONCLUSION

This study has undertaken an integrated assessment of Nigerian formations for their suitability in Carbon Capture and Storage (CCS), focusing on petrophysical characterization, numerical modeling of CO₂ plume migration, and risk assessment of storage security. The results demonstrate that Nigeria possesses promising geological formations with capacity to securely store large volumes of anthropogenic CO₂, particularly within saline aquifers and depleted oil reservoirs. For example, Saline Aquifer C exhibited favorable reservoir attributes, with porosity averaging 16.7%, permeability reaching 130 mD, and a modeled retention capacity of over 95% for a century, reflecting strong potential for long-term CO₂ immobilization. Conversely, formations such as Depleted Oil Field D presented less favorable conditions due to lower porosity (5.5%) and higher structural complexity, including fault-related leakage risks, which may compromise storage security if not carefully managed. Despite these promising outcomes, several limitations should be acknowledged. The dataset was restricted to four representative formations, which may not fully capture the heterogeneity of Nigeria's diverse subsurface. In addition, the modeling framework did not fully address long-term geochemical interactions, mineral trapping mechanisms, and potential impacts of CO₂-brine-rock reactions, all of which could significantly influence storage capacity and security over extended timescales. These limitations highlight the need for further basin-wide studies that incorporate multidisciplinary datasets including geochemistry, geomechanics, and long-term monitoring simulations.

Looking ahead, the findings of this study emphasize that Nigeria can strategically position itself as a leader in CCS deployment in Africa, provided that certain key actions are prioritized:

1. **Expand Site Investigations:** Broaden the scope of geological and petrophysical assessments across underexplored basins to identify additional candidate formations for large-scale CO₂ sequestration.
2. **Strengthen Monitoring Infrastructure:** Deploy advanced monitoring technologies—such as distributed fiber-optic sensing, time-lapse seismic, and microseismic surveillance—to ensure real-time detection of plume migration and containment security.
3. **Develop Robust Regulatory Frameworks:** Collaborate with national institutions such as the Nigerian National Petroleum Corporation

(NNPC), the Nigerian Geological Survey Agency (NGSA), and the Federal Ministry of Environment to create enforceable CCS regulations that address environmental safety, liability, and transparency.

4. **Foster Public and Stakeholder Engagement:** Actively involve local communities, industry operators, and policy makers in project design and monitoring. Building trust through awareness campaigns, participatory site selection, and transparent reporting is essential for social license to operate.
5. **Promote Capacity Development and Funding:** Encourage partnerships with universities, research institutions, and international agencies to strengthen Nigeria's technical expertise in petrophysics, reservoir modeling, and CO₂ risk management. Financial mechanisms such as climate funds, carbon credits, and green bonds should be harnessed to support pilot projects and infrastructure development.
6. **Integrate Socio-Economic and Environmental Dimensions:** Ensure that CCS implementation aligns with Nigeria's broader sustainable development goals. This requires evaluating socio-economic benefits, ensuring equitable resource use, and minimizing environmental footprints in line with global climate action commitments.

In conclusion, while Nigeria's geological framework offers substantial potential for CCS, realizing this opportunity requires an interdisciplinary and coordinated approach. Through comprehensive site characterization, deployment of cutting-edge monitoring technologies, supportive regulatory structures, and meaningful stakeholder participation, Nigeria can transition from theoretical potential to practical implementation. If these critical actions are taken, the country can establish itself as a regional leader in CCS, making significant contributions to national decarbonization goals and global climate mitigation targets.

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