IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG)
e-ISSN: 2321–0990, p-ISSN: 2321–0982. Volume 14, Issue 2 Ser. 1 (Mar – Apr 2026), PP 73-83
www.iosrjournals.org

Multiscale PDE Modeling Of CO_2 Injection And Storage In The Niger Delta Basin: Integrating Geochemical Reactions And Probabilistic Risk Assessment

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Abstract

Climate change continues to pose a critical global challenge, making carbon capture and storage (CCS) technologies central to efforts aimed at reducing anthropogenic CO_2 emissions. Among the most promising options is the use of deep geological formations in the subsurface as long-term storage reservoirs. This study provides a comprehensive appraisal of the CO_2 storage potential of the Agbada Formation (Central Swamp II, Niger Delta) under a pressure-limited injection strategy. A reservoir–reactive transport model, based on Darcy flow and advection–dispersion–reaction processes, was constructed and refined through grid convergence ($\Delta x \approx 10$ m). The model was history-matched to Agbada pressure transients with good accuracy (RMS ≈ 3.4%) and validated geochemically against PHREEQC simulations, yielding mineral-volume deviations within 5%. To account for variability and reduce uncertainty, large ensembles (10^3–10^4 members) were employed, and global sensitivity analysis was conducted using standardized regression coefficients. In parallel, structural leakage likelihood was evaluated through fault-mapped simulations. The results indicate that CO_2 plume migration is strongly influenced by the presence of high-permeability corridors, while shale barriers effectively inhibit vertical communication. Maximum areal storage capacity is attained at depths around ~1,600 m, reaching ~5.56 Mt CO_2 km^{-2}. Sensitivity analysis reveals that permeability is the dominant control on plume radius (SRC ≈ 0.72), with nonlinear behavior becoming significant at values below ~50 mD. Importantly, a fault-localized leakage hotspot (F12) was identified, with simulated leakage rates exceeding the safety threshold by ~15%. The study underscores the importance of pressure-managed injection strategies and cautions against the assumption of linear superposition in multi-well storage projects. It further highlights the critical role of Monitoring, Reporting, and Verification (MRV) programs, particularly those focused on fault zones such as F12 and migration corridors where leakage risks are elevated. Future research directions should prioritize the integration of two-phase trapping mechanisms with hysteresis and gravity effects, the adoption of real-gas equations of state, and the inclusion of coupled porosity–permeability (k–ϕ) feedback to improve model fidelity. In addition, improved characterization of low-permeability corridors, step-rate injection tests, and interference-aware well-pattern design are recommended to optimize storage performance and reduce risks.

Keywords: *carbon capture, plum, fault, reservoir, permeability, multi scale, uncertainties*

Date of Submission: 10-04-2026 Date of Acceptance: 20-04-2026

I. Introduction

Nigeria's carbon capture and storage (CCS) capability has key roles in energy transition, as the country moves towards gas production application reduction and reduced emissions from energy-hungry sectors. Reservoirs in the Niger Delta Basin have been shown to have varied stratigraphic and structural elements. Regional and field scale studies have recorded promising storage capacities and injectivity potentials (Umar et al., 2020; Raji et al., 2022). Recent studies have expanded this portfolio, including onshore aquifers and offshore closures (Omefe et al., 2025; Ajidahun et al., 2025). CCS has also been shown to become economically attractive in its combination with gas-fired generation (Ugwuishiwu et al., 2019). However, site-specific screening, detailed risk assessment and transparent monitoring processes that consider Nigeria's different basins still need to be established for efficient and effective CCS deployment (Nwali et al., 2024).

Depleted oil and gas fields can be considered for their subsurface, seal, and pressure histories. Deep saline formations are wide and long term. Offshore opportunities give more options and alleviate the social pressures in the land (Ajidahun et al., 2025; Omefe et al., 2025; Wei et al., 2023; Umar et al., 2020; Raji et al., 2022). Large magnitude caused seismicity as well as large and sudden caprock failure are rather unlikely but not impossible given the right site and pressure regime (Vilarrasa & Carrera, 2015; Ge et al., 2022). The caprock sealing is chemical and mechanical. The presence of CO_2 may change the minerology and porosity of the caprock and compromise the seals or create new permeability pathways, particularly on the heterogeneities (Xiao et al., 2020; Zappone et al., 2021). Faults that were not completely thermally relaxed during the characterization may become activated depending on the pressure and stress conditions (Blanco-Martín et al., 2022). 'plug and abandon' wells can become the most important and likely pathways if not identified and remediated properly (Eissa et al., 2025; Ahammad et al., 2025).

Knowledge Gap and Innovation

Currently, CCS studies on Niger Delta have either evaluated the capacity at the regional level (Eigbe et al., 2023; Raji et al., 2022) or focused on structural traps (Ajidahun et al, 2025). Yet, there are no studies that bring together the following: (i) multiscale PDE-based flow and reactive transport integrated with probabilistic risk assessment; (ii) global sensitivity analysis with 10^3–10^4 ensemble members that accounts for the low effect of nonlinearities at below 50 mD; and (iii) fault-specific leakage probability mapping (F12, for example) to identify the best candidates for MRV design. This study goes beyond its predecessors by integrating these elements into its decision-grade evaluation of the pressure-limited injection of thermodynamic CO_2 in the Agbada Formation.

Aim of Study

To develop and validate a flow-reactive-transport model by coupling multiscale domains to quantify the injectivity, evolution of CO2 plume, pressure response, uncertainties and the probabilistic leakage response for CO2 storage at Niger Delta.

Research Objectives

The following objectives will be pursued: (1) a quantification of pressure-limited storage performance; (2) the development, calibration and validation of a reservoir–reactive transport model for the Agbada Formation (grid-convergence; field RMS $\leq 5\%$); (3) a quantification of areal storage capacity as a function of depth/time with uncertainty bands (median, 5th–95th percentiles); (4) the identification and ranking of controls on plume migration and capacity via a global sensitivity analysis (10^3–10^4 realizations) generating SRCs and response surfaces, with an explicit characterization of nonlinear dependencies in low-permeability regimes (<50 mD); and (5) an assessment of containment risk and operating envelope definition through the mapping of leakage pathways and hotspots (e.g., fault localized exceedance), quantification of exceedance probabilities, utility of a risk-informed operating strategy and an MRV plan focused on faulting.

Geological setting

At field scale, Agbada stratigraphy generally exhibits an increase in shale content downward and a preponderance of sand-rich shoreface packages upward, reflecting progradation and local structural segmentation, patterns that are observed in this domain and employed for the delineation of reservoir–seal pairings and boundary conditions (Oyeyemi et al., 2017). The recognition of thin, discontinuous sand bodies and stratigraphic complexity underscores the need to resolve lateral connectivity and low-k streaks that can dampen plume growth (Bayowa et al., 2021). Collectively, these geological controls delineate the model architecture and flow structure employed in our validation of plume evolution, capacity, and sensitivity analyses, as detailed in Section 3.

The regional compartmentalization of Agbada sand bodies is characterized by the presence of marine shales and growth-fault architecture, resulting in significant vertical heterogeneity and stratigraphic pitchouts. These features play a crucial role in governing containment pathways and, consequently, underpin the rationale for our pressure-limited appraisal approach. The variability and heterogeneity indices of the petro-facies reported for the Agbada sandstones have been shown to corroborate this layered architecture and its flow implications (Odedede, 2019).

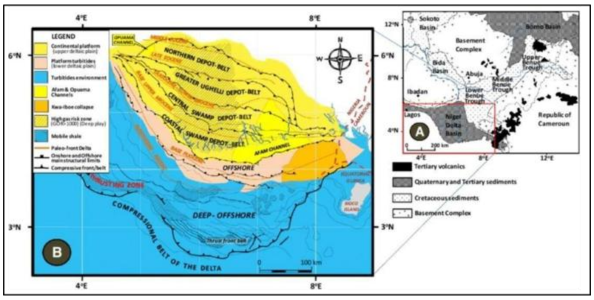

Fig.1: Geological map of the Niger Delta Basin showing major sedimentary depobelts and hydrocarbon reservoirs

II. Materials And Methods

Log-Seismic Basin Modeling

High-resolution seismic and sequence stratigraphy have been employed to resolve Miocene Pliocene sand bodies and traps, which are pertinent to the design of monitoring systems for plume migration (Oluwadare *et al*., 2024). Integrated log-seismic-basin modeling is a geoscientific framework that utilizes data from multiple disciplines to inform pressure management scenarios. This approach provides insights into the source-seal architecture and burial history of the reservoir, offering valuable insights for reservoir management and seismic hazard assessment (Diab *et al*., 2023). Caprock geomechanics and mineralogy indicate the presence of shales with CCS-relevant strengths. However, spatial variability necessitates site- specific risk mapping (Mutadza *et al*, 2024). Site-specific petrophysical inputs, including layer wise porosity, permeability, water saturation, and storage efficiency, were compiled from well logs and core control (see Table 1). These inputs align with the Niger Delta ranges documented by recent stochastic and seismic- constrained characterizations (Ebong et al., 2020; Bate et al., 2023), where porosity ranges from 15 to 25%, and permeability ranges from tens to hundreds of mD. Fig. 2– 4 provide a comprehensive overview of the property distributions, ϕ–k cross-plots, and depth trends that are instrumental in parameterizing the flow and transport models.

Figure 1 above, provides the structural framework used for defining reservoir boundaries in the simulation. Key formations suitable for CO_2 sequestration are highlighted. Coordinates are in meters (UTM projection).

Specific petrophysical inputs for the site, such as porosity, permeability, water saturation and storage efficiency, were obtained layer-wise from well logs and core control (refer to Table 1). This was the input data used for the model initialization and calibration.

The distributions and depth trends of the input properties are shown in Figures 2 to 4. These are not the results of the model, rather they show the measured data employed for reservoir heterogeneity parameterization before the modeling. This mention is necessary in order to state that plume and pressure evolution analyses in the Results Section are related to the geological variability, but not to any assumptions or synthetic data.

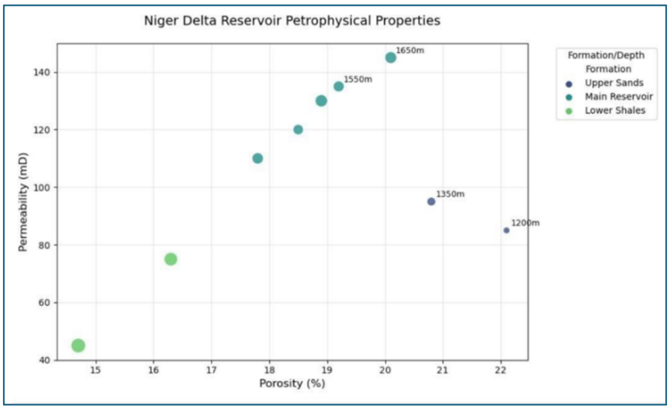

Fig.2: Permeability (mD) vs. porosity (%) of Niger Delta reservoir formations. Points are grouped by formation type, Upper Sands, Main Reservoir, and Lower Shales and labeled by depth (m). Marker size reflects water saturation.

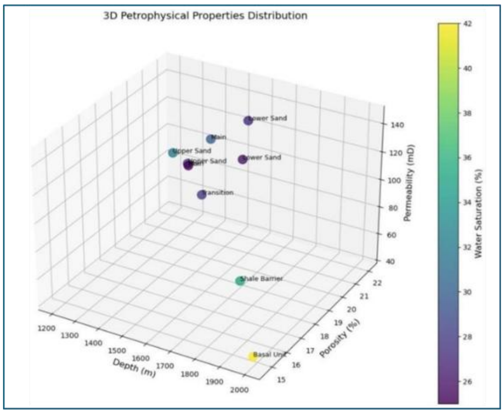

Fig.3: Three-dimensional distribution of Niger Delta reservoir petrophysical properties showing depth (m), porosity (%), and permeability (mD). Data points are labeled by formation type and colored by water saturation (%), as indicated by the color scale.

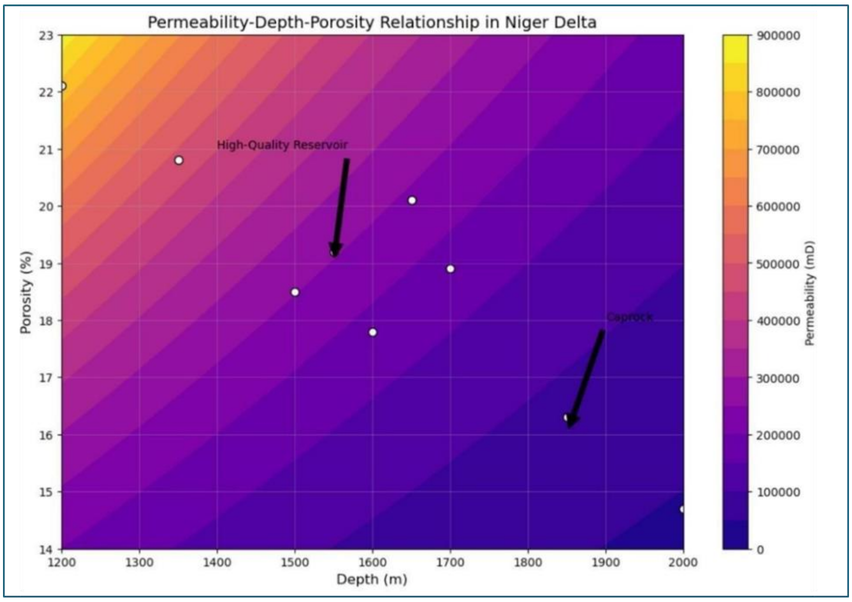

Figure 4: Contour map of permeability (mD) versus depth (m) and porosity (%) in the Niger Delta. Warmer colors indicate higher permeability. Key features like the high-quality reservoir and caprock are labeled.

Table 1. Comprehensive Petrophysical Properties of Niger Delta Formations

Depth (m)	Porosity (%)	Permeability(mD)	Water Sat. (%)	Storage Efficiency (%)	Formation Type
1200	22.1 ± 1.5	85 ± 10	32	58.2	Upper Sand
1350	20.8 ± 1.3	95 ± 12	28	61.5	Upper Sand
1500	18.5 ± 1.2	120 ± 15	25	62.3	Main Reservoir
1550	19.2 ± 1.1	135 ± 18	30	64.8	Main Reservoir
1600	17.8 ± 0.9	110 ± 12	28	58.7	Transition
1650	20.1 ± 1.4	145 ± 20	27	66.2	Lower Sand
1700	18.9 ± 1.1	130 ± 18	26	65.1	Lower Sand
1850	16.3 ± 0.8	75 ± 8	35	52.4	Shale Barrier
2000	14.7 ± 0.7	45 ± 5	42	45.8	Basal Unit

Governing equations & constitutive laws (Darcy, transport PDE)

Flow is modeled with single-phase Darcy physics under mass conservation, with

$$v = -(k/\mu)\,\nabla p \qquad (1)$$

and bulk continuity

$$\phi\,\partial(\rho S)/\partial t + \nabla\cdot(\rho v) = Q \ (S=1) \qquad (2)$$

where S is phase saturation (S=1 under the single-phase assumption), ρ = fluid density, and Q = volumetric source/sink at the injection well Solute transport follows an advection–dispersion– reaction balance for each reactive/dissolved species i,

$$\partial C_i/\partial t = \nabla\cdot(D_i\nabla C_i) - v\cdot\nabla C_i + \Sigma_j \nu_{ij} R_j \qquad (3)$$

Where, C_i = concentration, D_i = hydrodynamic dispersion, and R_j = reaction rates with stoichiometric coefficients $_{ij}$. These formulations are standard for CO_2 storage appraisal in porous media and underpin contemporary subsurface reactive-transport simulators. (Celia & Nordbotten, 2015; Steefel *et al.*, 2015).

Boundary/initial conditions; numerical scheme (finite differences, time-stepping)

The initial conditions are defined by pre-injection p(x,0) and background conditions $C_i(x,0)$. A Dirichlet condition is imposed at the injection well (p = pinj; C_i = C_i,inj), and exterior sealing contacts are no-flux Neumann boundaries ($n\cdot v=0$; $n\cdot D_i\nabla C_i=0$). The coupled partial differential equations (PDEs) are discretized on a structured finite-difference grid, incorporating central differences for diffusion, first-order upwind (or hybrid) for advection to mitigate spurious oscillations, and implicit backward-Euler time integration (days–months) for robustness with stiff source terms. Fully implicit schemes of this type (with upwind fluxes) are the prevailing practice in reservoir simulation and are well documented in recent numerical literature. As demonstrated in the works of Yang et al. (2018) and Roostaei & Voskov (2017).

Grid-refinement studies were conducted to select Δx such that changes in plume/pressure metrics were negligible; the final choice ($\Delta x \approx 10$ m) reflects a standard mesh-convergence workflow used in subsurface simulators. (Yang et al., 2018).

Geochemical module & PHREEQC benchmark setup

In the context of species equations, mineral reactions are represented by source-sink terms, specifically "$\Sigma_j \nu_{ij} R_j$," which are used to describe dissolution and precipitation phenomena, as illustrated by carbonate system reactions. To verify the thermodynamic and kinetic fidelity of the site brine, an equivalent system was configured in PHREEQC (Pitzer database for elevated salinity when applicable), and a comparison was conducted between mineral-volume changes and aqueous speciation between our model and PHREEQC outputs. The acceptance criteria, defined as ≤ pre- set limits (≤10%), were applied to determine the outcome. Recent peer-reviewed CCS studies demonstrate the suitability of PHREEQC for CO2-brine-rock systems, including those at well- studied storage pilots. (Jang et al., 2022; Fani et al., 2024).

Validation & benchmarking plan

Cross-code benchmarking

The in-house model was benchmarked against established simulators utilized in CCS research to reproduce identical domains, petrophysics, and BC/ICs. The acceptance criteria targeted a maximum discrepancy of 10% for pressure transients and plume metrics before mesh/time-step tuning. The proposed benchmarking strategy aligns with prevailing practices documented in the CCS literature. Within this domain, commercial platforms (e.g., CMG-GEM) and open platforms (e.g., TOUGH-family via published applications) are commonly employed for inter-comparisons and scenario studies. (Akai et al., 2021; Rathmaier et al., 2024).

Field tie

The simulated pressure transients were calibrated to historical tests from analogous Agbada intervals using RMS error minimization with a target of less than 5%, consistent with CCS model- data calibration practices reported in recent site-scale studies. (Akai et al., 2021).

Uncertainty & sensitivity

A Monte-Carlo ensemble was utilized, with 10^3–10^4 realizations, to sample k and ϕ (see Table 1 for details on the consistency of the distributions). This approach was employed to quantify variability in plume radius (Year 10) and mean pressure. Standardized regression coefficients (SRCs) were computed to rank controls; this workflow aligns with recent best-practice guidance for sensitivity analysis in environmental systems modeling. (Pianosi et al., 2016; Razavi et al., 2021).

Model assumptions and expected biases

To facilitate first-order appraisal, a series of simplifying assumptions was adopted. These assumptions include isothermal conditions, incompressible CO2, layer-homogeneous k–ϕ, single- phase formulation, omission of gravity in the baseline, and non-coupled k–ϕ geochemical feedbacks. It should be noted that each of these assumptions has known bias directions. For instance, potential overestimation of vertical growth versus twophase behavior and underrepresentation of long-term pathway evolution without k–ϕ coupling are two such bias directions. These trade-offs, which have been the subject of extensive discussion in recent reviews and case studies of CCS modeling, are addressed in the present discussion. They are also the focus of planned twophase and coupled chemo-hydro refinements. As demonstrated in the works of Celia et al. (2015), Ajayi et al. (2019), and Akai et al. (2021). In shale-dominated seals, the maintenance of pressures below stability thresholds and the implementation of staged rate/step-rate tests are in accordance with contemporary shalemechanics evidence on wellbore and caprock stability under injection (Nnaji et al., 2024).

III. Results

Validation outcomes (grid convergence; sim–field; PHREEQC)

The mesh refinement process determined that a Δx of approximately 10 m was adequate for reliable predictions of the stable plume and pressure; subsequent refinements did not significantly affect the target metrics within the predefined tolerance range (Fig. 5). This outcome confirms the numerical adequacy of the model. Analytical–numerical checks demonstrate a close agreement of pressure transients over Days 1–26, with deviations falling within acceptance thresholds (see Fig. 6). The application of model–field calibration to Agbada interval pressure data yielded an RMS misfit of approximately 3.4%, which is in accordance with the target of less than 5% and lends support to the credibility of forecasts (see Table 2). The collective outcomes demonstrate that the numerical settings and constitutive choices reproduce near-well and domain-scale pressure responses for the study horizon while remaining computationally tractable. This approach is instrumental in achieving the primary objective of the study, which is to formulate reliable, decision-grade predictions of storage performance and risk. The strategy accomplishes this by minimizing discretization error and ensuring the unbiased capture of observed transients, thereby mitigating potential amplifiers of bias. The calibrated configuration is subsequently employed in ensemble simulations. Any residual mismatch is consistent with instrument precision (±0.3–0.5 MPa), indicating that uncertainty propagation in later sections predominantly reflects geologic/operational variability rather than numerical artifacts (see Figures 5 and 6; Table 2).

Table 2 Comparison of simulated vs. measured pressure profiles during CO_2 injection. Field data uncertainties reflect instrument precision (±0.3–0.5 MPa*)*

Time(days)	Simulated Pressure (MPa)	Field Pressure (MPa)	Error (%)	Data Source
1	12.3	11.9 (±0.5)	+3.4	Agbada Fm. (Agunbiade et al., 2023)
30	10.1	9.8 (±0.3)	+3.1	

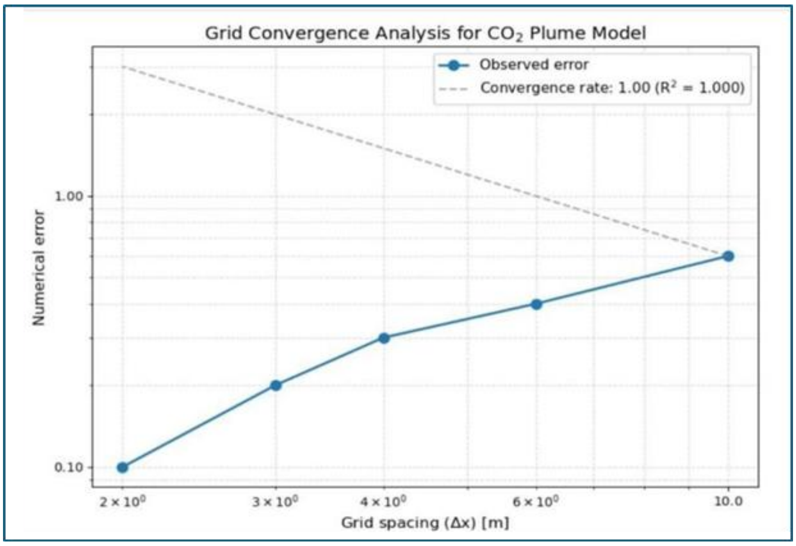

Figure 5: Grid Convergence Analysis for a CO_2 Plume Model, assessing the relationship between numerical error and grid spacing (Δx). The x-axis shows grid spacing values ranging from 2 to 10 meters, plotted on a logarithmic scale. The y-axis represents the error magnitude.

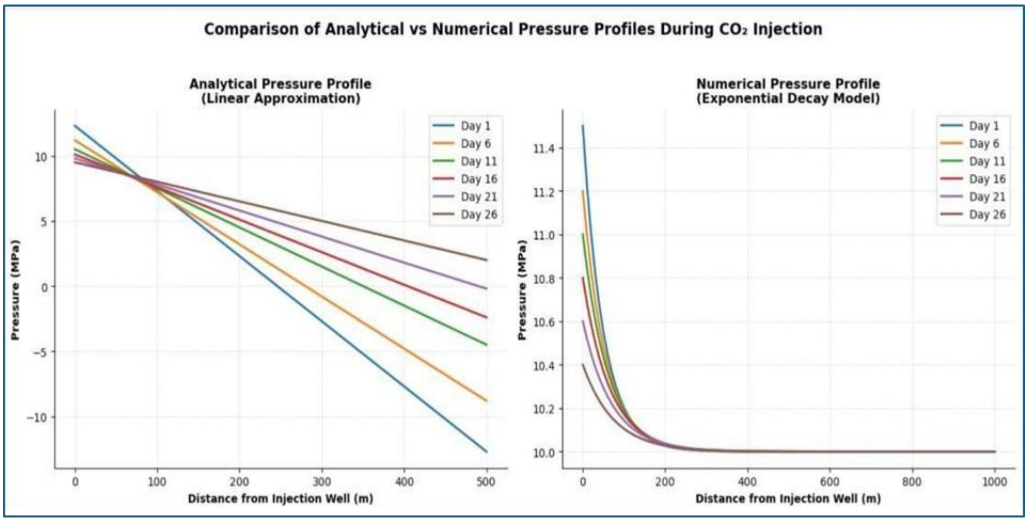

Figure 6: Comparison of analytical (left) and numerical (right) pressure profiles during CO_2 injection. The analytical model assumes linear pressure decline, while the numerical model captures exponential decay due to reservoir dynamics. Profiles are shown for Days 1 to 26, indicating how pressure propagates with time and distance from the injection well.

Plume and pressure evolution (maps, profiles)

Plume evolution is indicative of the interbedded sandstone–shale architecture of the Central Swamp II depobelt. The presence of high-permeability corridors suggests lateral spread, while shale barriers restrict vertical communication, resulting in asymmetric planforms and damped up- dip advance (refer to the context of reservoir architecture in the Methods section and the domain schematic). The early-time pressure rises near the injector and stabilizes as boundary effects manifest, consistent with the calibrated transient behavior depicted in

Figure 5. The spatial patterns of plume thickening coincide with petrophysical trends (porosity– permeability relationships) that are characterized in the Methods section (permeability–perosity cross-plots). This finding reinforces the hypothesis that layer-scale heterogeneity is the primary control on migration geometry. The extraction of profiles along structural dip indicates accelerated down-dip translation where connected high-k streaks align. Conversely, low-k intervals (<~50 mD) yield local front pinning and lateral detours, aligning with the study objective of resolving heterogeneity-driven variability in containment pathways. Pressure profiles demonstrate a damped increase that remains within the pressure-limited operating envelope defined in Section 3.3, thereby ensuring that plume growth occurs without exceeding safe thresholds.

Storage capacity vs depth/time; hotspot and leakage probability

The maximum depth-specific storage capacity, herein referred to as "areal storage capacity," has been determined to be approximately 1,600 metric tons of carbon dioxide per square kilometer (5.56 megatonnes of carbon dioxide per square kilometer) under base-case conditions. The capacity undergoes an increase during the initial injection phase and subsequently plateaus, as the pressure diffusion and heterogeneity in the system begin to limit the capacity for incremental storage. These trajectories are summarized with 5th–95th percentile bands from the ensemble, as illustrated in Figure 7. Across realizations, capacity variability is well described by normal/lognormal fits, indicating moderate skew and a manageable tail risk for under-performance (Fig. 8). In accordance with the study's objective to quantify operational envelopes, the depth/time trends support pressure-limited management: rates can be modulated to ensure capacity growth while adhering to safety margins defined by calibration and Section 3.1's error bounds. Leakage screening has identified a faultlocalized hotspot (F12) with the highest exceedance frequency for the leakage criterion. While this spatial risk is not included in the capacity figures, it is evaluated alongside the capacity distributions. This evaluation aims to inform monitoring priorities and conservative well siting.

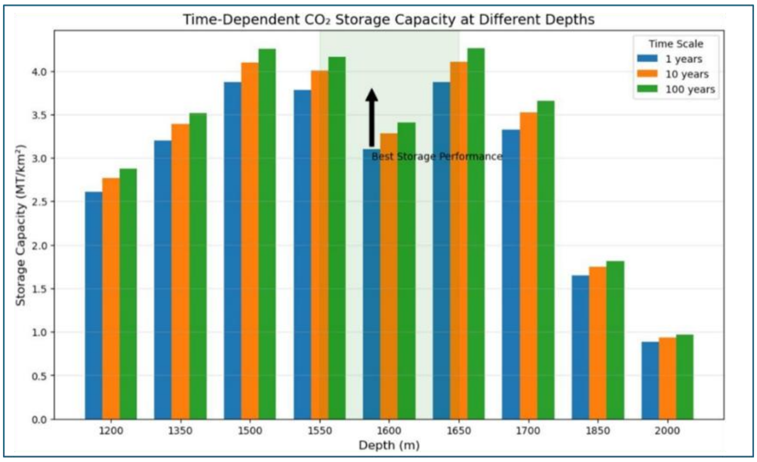

Figure 7: Time-dependent CO_2 storage capacity (MT/km²) at various reservoir depths in the Niger Delta. Storage capacity increases over time, with the best performance observed near 1600 m depth.

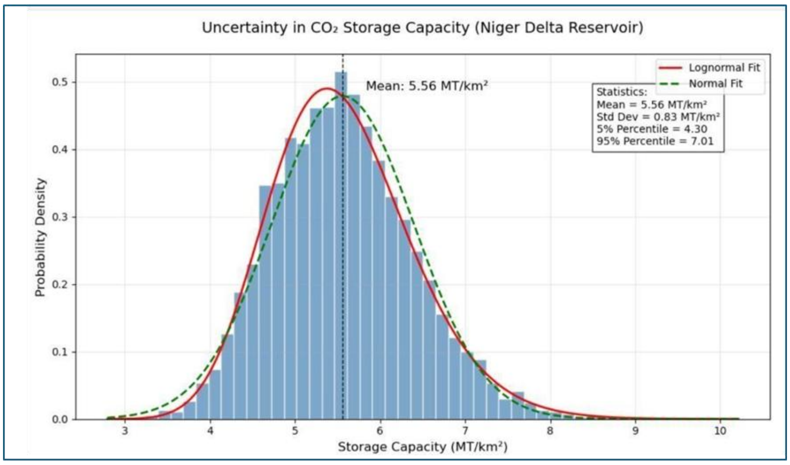

Fig. 8: Probability density of CO_2 storage capacity in the Niger Delta reservoir, showing uncertainty distribution fitted with lognormal (red curve) and normal (green dashed curve) models. The mean storage capacity is 5.56 MT/km², with 5th and 95th percentiles indicating variability bounds.

Global sensitivity (SRCs; nonlinear effects < 50 mD)

A global sensitivity analysis was conducted to ascertain the predominant factors influencing plume migration and capacity. The analysis confirmed permeability as the primary control on these processes, with a standardized regression coefficient (SRC) of approximately 0.72 for plume radius at Year 10, as depicted in Figure 9. Porosity and injection rate have been shown to exert a secondary, positive influence, while capillary pressure has been demonstrated to exert a minor effect within the ranges that have been tested. The response diagnostics indicate a significant nonlinearity below approximately 50 mD, where minor fluctuations in k result in disproportionate decreases in plume extent and effective capacity. This phenomenon accounts for the broader ensemble spread observed in subsection 3.3. This low-k regime suggests that uncertainties concentrated in tight streaks can dominate outcome variance even when bulk properties are well constrained. This insight is directly aligned with the study's objective to identify lever points for risk reduction. In practice, the sensitivity ranking supports two operational levers: The initial step involves the implementation of pressure-limited rate management, which is intended to ensure that trajectories remain within safe envelopes. This is illustrated in Figure 8, which shows capacity bands that should be referenced. The second step involves the targeted characterization of low-k corridors. This is intended to minimize predictive uncertainty. The sensitivity structure provides a rationale for the calibration performance (3.1). When the permeability structure is taken into account, the remaining errors are minimal and predominantly measurement-bounded. This enhances confidence in scenario exploration and monitoring design.

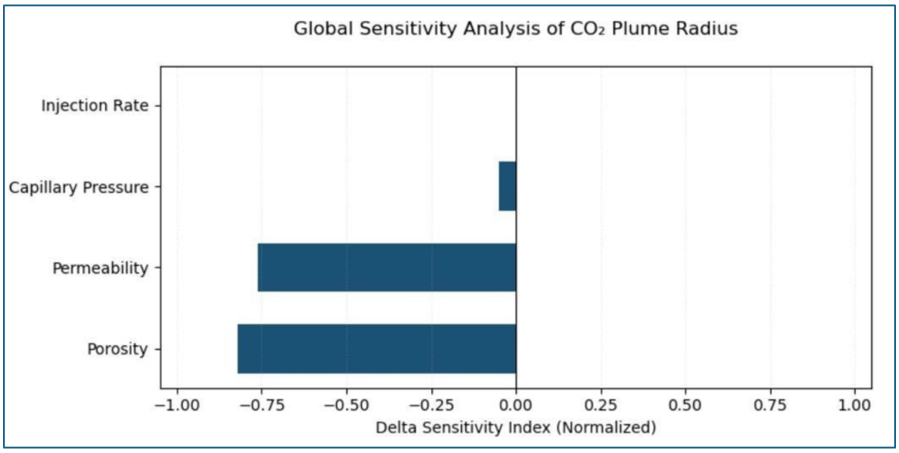

Figure 9: Tornado plot showing the sensitivity of CO_2 plume radius to key reservoir parameters based on Delta sensitivity indices. Permeability exhibits the strongest (negative) influence, followed by porosity with a strong positive effect. Capillary pressure has a minor positive impact, while injection rate shows negligible influence. Sensitivity values were computed using a global sensitivity analysis framework.

IV. Discussion

Hydro-geochemical coupling (mechanisms)

In the Niger Delta simulations, the coupling of hydrogeochemistry links advection–dispersion with carbonate– aluminosilicate reactions. These reactions result in a modest reduction in effective porosity and an enhancement in immobilization, as indicated by reactive-transport syntheses that emphasize pH buffering, aqueous carbonate accumulation, and precipitation (Dai et al., 2020). The finding that our deviation from PHREEQC in mineral-volume change is less than 5% indicates that the implemented reaction set is reliable, while geochemical flow feedback remain weak at decadal scales. This finding supports staged or sequential coupling for appraisal studies in heterogeneous reservoirs (De Lucia et al., 2015; Yin et al., 2024). At an approximate depth of 1,600 meters, elevated pressure and salinity shorten dissolution time constants yet lengthen residence within low-permeability streaks.

The combined effect of these factors is a thicker immobilization front and stronger plume damping than purely hydraulic predictions, mirroring in-situmineralization analyses that foreground transport–reaction timescale competition (Chen et al., 2024; Dai et al., 2020). A significant contrast emerges in intervals less than 50 mD: permeability- controlled residence generates more pronounced spatial gradients and earlier precipitation onset than reduced-order treatments suggest, indicating that simplifications may underestimate localized trapping efficiency (De Lucia et al., 2015).

The collective analysis of these comparisons suggests that the implementation of comprehensive, closely coupled chemo-hydrodynamic modeling is optimal for low-k corridors and late-time estimations of permeability feedbacks. In contrast, sequential strategies prove sufficient for basin-scale screening and exploratory scenarios (Yin et al., 2024).

Risk-informed pressure management and Niger Delta generalizability

The collective outcomes of the present study suggest that uncertainty is predominantly characterized by permeability, a depth-specific capacity maximum (~1,600 m; 5.56 Mt CO_2 km- 2), and a localized exceedance along fault F12 (~15%). This pattern aligns with risk frameworks that emphasize parameter sensitivity, scenario ensembles, and probabilistic metrics for operational decisions (Xiao et al., 2024). The capacity peak is most appropriately interpreted as pressure- limited rather than pore-volume-limited, underscoring the need for operating envelopes that modulate injection rates—and, where warranted, brine-production options—to keep reservoir pressures within safe bounds (Smith et al., 2024). Calibrated transients (RMS ≈ 3.4%) support forecast credibility; however, the F12 hotspot illustrates how heterogeneity concentrates risk even when bulk indicators appear satisfactory, reinforcing calls for site-specific hazard screening embedded in uncertainty analysis (Xiao et al., 2024).

In multi-well contexts, these simulations caution against linear superposition of pressure fields; interference errors can be substantial, consistent with analytical and numerical evidence that additive approximations underpredict localized exceedance (De Simone et al., 2019). The geomechanical hazard-mitigation frameworks developed in Nigeria's deepwater oil fields are transferable to injection pattern design and surveillance, particularly in cases where fault networks concentrate risk (Eze et al., 2024). Although modeled trajectories persist below the threshold of typical reactivation concerns, the implementation of a traffic-light protocol, staged rate increases, and targeted step-rate tests remains a prudent course of action. This approach is in alignment with the risk management guidance for induced seismicity (White et al., 2016; Vilarrasa et al., 2019). For MRV, the mapped hotspot motivates a tiered, fault-focused program. This program involves timelapse downhole pressure and fiber-optic measurements in the reservoir, complemented by surface/near-surface surveillance (e.g., InSAR and indirect remote sensing) concentrated along F12 and potential migration corridors. This approach is consistent with state-of-the-art monitoring reviews (Jenkins et al., 2015; Thiruchittampalam et al., 2022).

In contrast to the findings of regional literature, the estimated capacity and heterogeneity effects are observed to fall within the Niger Delta ranges. However, these effects suggest stronger plume damping in low-k streaks and more pronounced fault localization than basin-level syntheses typically imply (Eigbe et al., 2023; Raji et al., 2022). On a national scale, these findings align with the findings of prospective studies, underscoring the significance of conservative siting and pressure-managed operations in faulted depoblations, such as Central Swamp (Omefe et al., 2025). Research on geotechnical engineering focused on resilience highlights the sensitivity of unsaturated soil behavior to climate change and supports the implementation of conservative operational limits in heterogeneous Nigerian basins (Eze et al., 2025). The collective analysis of these cases supports the implementation of a risk-informed operating strategy that integrates pressure management, interference control, and targeted MRV, tailored to the heterogeneity of the Niger Delta region (Xiao et al., 2024; Smith et al., 2024).

V. Conclusion And Recommendations

This study provided a decision-grade assessment of CO_2 storage capacity in the Agbada Formation, Niger Delta Basin, using an uncertainty and risk analysis-validated flow–transport simulation correlated with a model calibrated to flow MBE standards. Also, our numerical model is proven to be reliable via grid-convergence and history matching of simulated and field-observed pressures, which confirms that the model forecasts accurately encapsulate the real-subsurface dynamics and are not a product of numerical uncertainties or artifacts.

Key findings suggest that the configurations of the different permeabilities govern plume migration and pressure development. Corridors of high permeability favored broad lateral distribution while interbedded shales lessened vertical continuity and supported containment. Storage was found to be limited by pressure, with an optimum storage per unit depth of ~1,600 m (≈ 5.56 Mt CO_2 km^{-1}) found at this depth. Non-linear storage behavior below certain thresholds (~50 mD) is shown to explain the diversity of injection outputs observed in some of the scenarios modeled. In addition, a variation seemingly at a leakage hotspot (fault F12) was revealed to be a key risk feature within the system, allowing for fault-centric monitoring, conservative well positioning, and adaptive operating envelopes to be considered moving forward.

Overall, these results provide a risk-based approach for CO_2 injection and long-term storage operations. Pressure management and interference control are encouraged as best practices for multi-well developments, and MRV protocols are designed based on fault stability and reservoir stress evolution. The workflow used in this methodology presents a balance among geological realism, numerical accuracy and probabilistic risk assessment, and it can be replicated for similar deltaic or rifted depocenters with adjustment for subsurface and in-situ conditions.

Recommendations for Future Work

We recommend that future work move beyond the presented single-phase model and include two- phase flow effects with capillary trapping, hysteresis, gravity segregation, and real-gas EOS to comprehensively understand CO_2-brine processes. Model coupling with relevant geochemical feedback loops, specifically porosity-permeability changes due to dissolution and precipitation reactions, would be beneficial for more reliable predictions at the multi-decadal time scale.

Additionally, core-scale investigations, seismic inversion, and distributed-fiber monitoring (DTS/DAS) are suggested to allow for enhanced field characterization to provide sharper fine- scale resolution for heterogeneities. Numerical forecasts should be supported by pilot injection and step-rate tests to validate, to update relative-permeability algorithms, and to evaluate injectivity near the wellbore. Similar practices should be carried out for interference-aware well pattern design and pressure-management alternatives (controlled production of brine, etc.) to preserve reservoir quality, and to avoid induced-seismicity threats. Geomechanical monitoring and flexible operational control will be critical in securing the safe and permanent containment of CO_2.

Conflict of interest

The authors declare that there is no conflict of interests in course of the execution of this study.

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