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Impact of Supercritical CO_2 Injection on Formation Breakdown Pressure and Total Storage Capacity: Application for CO_2 Sequestration in Deep Saline Formation

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Abstract

Deep saline formations offer vast CO_2 storage potential, yet capacity estimates often overlook CO_2-specific geomechanical behavior. Laboratory studies demonstrate that supercritical CO_2 injection reduces formation breakdown pressure (P_b) by 8-32% compared to water-based measurements, potentially leading to premature fracturing and capacity overestimation. This study quantifies the impact of CO_2-induced P_b reduction on storage capacity and plume migration through numerical reservoir simulation. A two-phase CMG model (9,000 ft deep, 375 ft reservoir, 100 ft seal) with baseline P_b of 5,265 psi. Sensitivity analyses examined 10% to 25% P_b reductions reflecting experimental observations. Results demonstrate that 10% P_b reduction yielded 17% capacity loss (7,077 vs. 8,548 tons baseline), while 25% reduction caused 87% loss (1,125 tons). These findings establish that water-based P_b assumption systematically overestimate storage capacity, establishing that CO_2 specific geomechanical testing is essential for reliable forecasting.

Introduction

Deep saline formations offer storage capacities of 1,000-10,000 gigatons globally for CO_2 sequestration(Benson and Cole, 2008 ; Bachu, 2015), yet accurate capacity estimation remains constrained by formation P_b, which governs maximum sustainable injection pressure (Rutqvist, 2012). Current methodologies employ water-based hydraulic fracturing measurements (Zoback and Gorelick, 2012), neglecting CO_2 properties-lower viscosity, enhanced diffusivity, and reduced interfacial tension (Span and Wagner, 1996);(Bachu and Bennion, 2008), that fundamentally alter rock-fluid interactions. Recent experiments demonstrate CO_2 injection reduces P_b by 8-32% compared to water (Bennour et al., 2015; Amoah et al., 2024) through enhanced microfracture penetration and grain boundary weakening (Espinoza and Santamarina, 2010). Despite critical implications for injection pressure limits and storage volumes, systematic reservoir-scale studies quantifying capacity sensitivity to fluid-specific P_b reduction remain absent, undermining reliable project design and economic viability.

This study evaluates CO_2-induced P_b reduction impacts on plume migration and storage capacity through integrated numerical simulation. The model consists of cap rock (overburden layer) and reservoir rock. Through the high-resolution numerical simulation examine the variation in the storage capacity in the response of the reduction of P_b.

Methods

A reservoir-scale numerical model was constructed in CMG-GEM (CMG, 2023) to evaluate CO_2 storage under varying P_b constraints. The model represents a 9000-ft deep saline formation consisting of a 375-ft thick storage reservoir overlain by a 100-ft thick shale caprock. The computational domain was discretized using a structured Cartesian grid system with dimensions of 100 (x) × 100 (y) × 16 (z) cells (Figure 1).

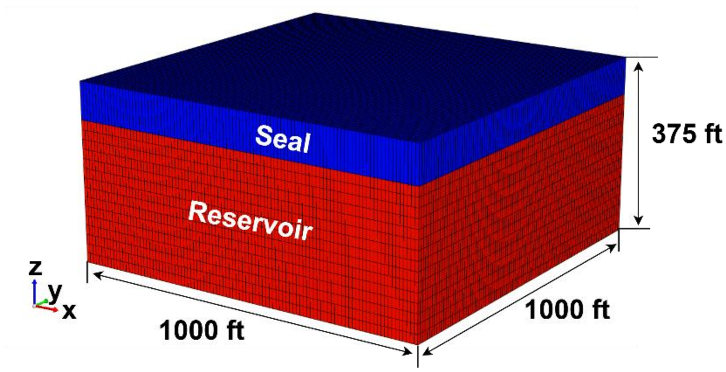

Figure 1. Reservoir model for numerical simulation. Seal layer is characterized by porosity = 5% and permeability = 2nD. Reservoir layer depicted porosity = 17% and permeability = 2mD

The horizontal grid is uniform, with each cell measuring 10 ft × 10 ft. Vertically, the 475-ft total thickness is divided into two geological units:

- Seal (Layer 1): A 100-ft thick shale acting as the primary seal.
- Reservoir (Layers 2–16): A 375-ft thick saline formation, subdivided into 15 sub-layers of uniform 25-ft thickness. The top of this reservoir is set at a true vertical depth (TVD) of 9,000 ft.

The model represents a homogeneous and isotropic system without geomechanical consideration. The storage formation was initialized as brine-saturated, with an initial water saturation (S_w) of 1.0. Capillary pressure was included in the simulation to prevent CO2 migration. The initial pore pressure was defined by a reference pressure of 4,000 psi at the seal. A pore pressure gradient of 0.433 psi/ft was applied within the brine-filled reservoir. In contrast, the underlying reservoir was assigned a higher initial gradient of 0.6 psi/ft, reflecting its distinct petrophysical properties.

A single vertical injection well is placed at the center (500ft, 500ft) of the model domain. The well is perforated across four reservoir layers from 12 through 15, defining the active injection interval. Injection is operated under combined rate and pressure constraints: the well is set to inject CO_2 at a surface rate of 100,000 scf/day, while respecting a maximum bottom-hole pressure (BHP) limit of 5,000 psi. This pressure limit is set slightly below the estimated formation breakdown pressure ($P_b \approx 5,265$ psi) to prevent unintended hydraulic fracturing and to reflect realistic operational and regulatory constraints for CO_2 injection.

Four P_b reduction scenarios were tested relative to the baseline (P_b = 5,265 psi): 10%, 15%, 20%, and 25% reductions, consistent with experimental CO_2 fracturing data (Blessed paper). CO_2 trapped mass were monitored over a 10-year shut-in period.

Results

The study of numerical simulations of CO_2 injection into the brine saturated formations, accounting for experimentally observed reductions in P_b, demonstrates profound impacts on plume dynamics, storage capacity and economic viability.

Sensitivity of storage capacity to P_b reduction

To evaluate the sensitivity of storage performance to CO_2-specific effects, four scenarios were modeled with P_b reductions of 10%, 15%, 20%, and 25%. These values were selected to represent the 8–32% P_b reductions reported in laboratory studies (Blessed et al. 2024) comparing water versus supercritical CO_2 injection behavior.

In each simulation, CO_2 injection proceeded until reservoir pressure approached the prescribed P_b limit, at which point injection was automatically terminated to avoid inducing mechanical failure in the caprock. Following shut-in, plume evolution specifically plumes radius and CO_2 trapped mass was monitored over a 10-year period (Figure 2).

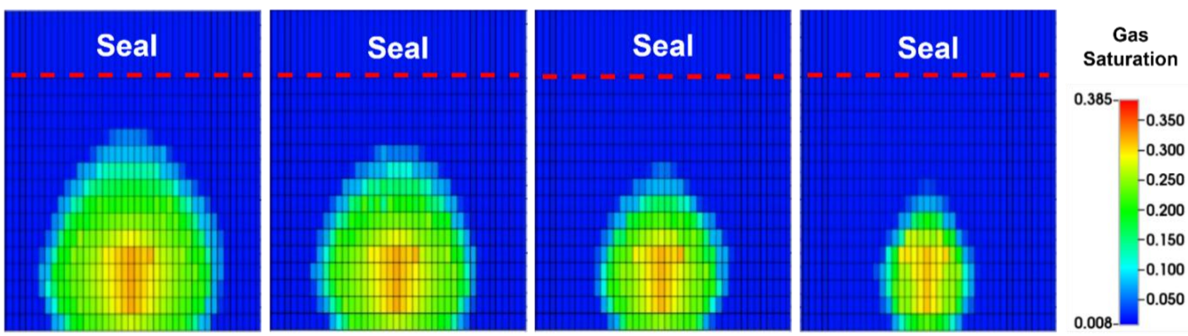

Figure 2. CO_2 plume migration after 10-year period; a) Plume migration after 10% P_b reduction; b) Plume migration after 15% P_b reduction; c) Plume migration after 20% P_b reduction; d) Plume migration after 25% P_b reduction

Results demonstrate that storage capacity exhibits pronounce non-linear sensitivity to P_b constraints. The baseline scenario (0% P_b reduction) permitted continuous injection accumulating 8,548 metric tons of CO_2 before reaching pressure limits. Introduction of even modest 10% P_b reduction decreased total injected mass to 7,077 tons, a 17% capacity loss relative to baseline. This sensitivity intensified dramatically with increasing P_b reduction severity: 20% reduction restricted injection to 2,733 tons (68% capacity loss), while

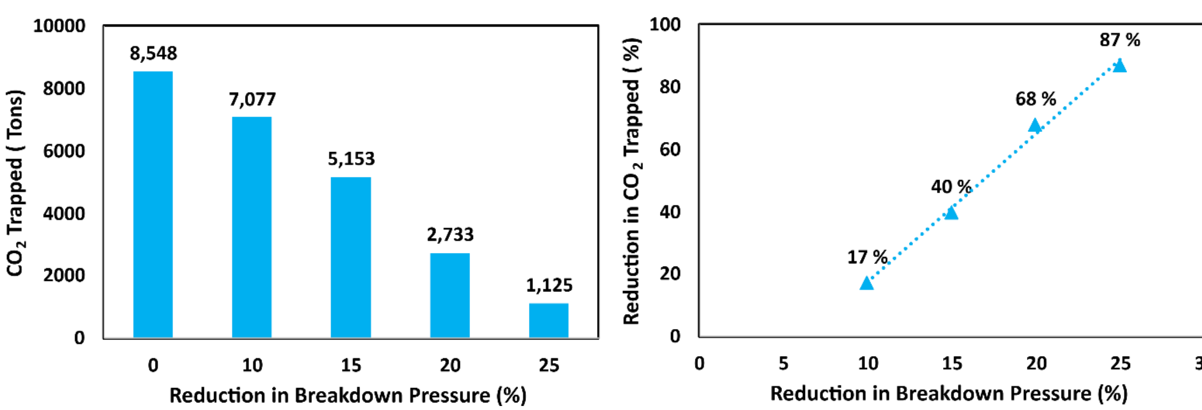

Figure 3. Impact of P_b on CO_2 storage capacity; a) CO_2 trapped as function of P_b reduction; b) CO_2 reduction as function of P_b reduction

maximum 25% reduction permitted only 1,125 tons, representing an 87% reduction in storage capacity compared to the base case (Figure 3).

Economic Implications and Project Viability Assessment

Translating the observed capacity sensitivities into economic terms reveals substantial financial implications that directly impact CCS project viability. Under the U.S. 45Q tax credit ($85/ton), the financial viability of CCS projects is highly sensitive to P_b fluctuations. While a baseline capacity of 8,548 tons generates $726,580 in credits, a modest 10% reduction in P_b drops revenue to $601,545-a 17% loss. More severe reductions lead to an economic collapse: a 20% reduction triggers a 68% revenue loss ($232,305 total), while a 25% reduction slashes revenue by 87%, resulting in a $630,955 shortfall compared to conventional water-based assumptions.

Discussion

Previous research established geomechanical constraints as critical factors in CO_2 storage capacity. (Rutqvist, 2012) comprehensively examined formation P_b limits and injection-induced fracturing risks using coupled hydromechanical models. However, these foundational studies employed water-based hydraulic properties without addressing fluid-specific behavior. (C.A. Amoah et al., 2024) demonstrated through laboratory experiments that CO_2 injection reduces P_b by 8-32% compared to water, establishing that traditional water-based minifrac tests are inadequate for CO_2 storage projects. This finding underscores a fundamental requirement: breakdown pressure characterization must employ the actual injection fluid CO_2 rather than water proxies. The distinct properties of CO_2 (lower viscosity, enhanced rock penetration, modified effective stress) alter fracture mechanics in ways that water-based testing cannot capture, leading to systematic overestimation of safe injection pressures and storage capacity when water measurements are inappropriately applied to CO_2 operations. This study uniquely bridges laboratory observations with reservoir-scale simulation to quantify how CO_2-specific P_b reductions impact storage capacity and project viability. Unlike prior work limited to either geomechanical theory or laboratory experiments, this investigation systematically evaluates capacity sensitivity (17-87% losses), and economic implications (45Q revenue losses of $125,000-$631,000 (CO2 Report, 2025)). The integration of geomechanical sensitivity analysis with economic assessment provides unprecedented quantitative evidence that conventional water-based capacity estimates overestimate storage potential by some number of factors, establishing CO_2-specific testing as an economic imperative for reliable project planning.

Conclusions

This study demonstrates that CO_2 injection can substantially reduce formation P_b, and that this effect has a critical influence on both CO_2 plume behavior and total storage capacity in deep saline formations. Numerical simulations show that even modest reductions in P_b lead to disproportionately large declines in injected CO_2 mass, plume radius, and long-term trapped volume. Across the 10–25% P_b reduction range examined, storage capacity decreased by 17% to 87% relative to the baseline scenario. Under U.S. 45Q tax credits ($85/ton), these capacity reductions translate to revenue losses from $125,000 to $631,000 at the simulation scale for individual well, potentially reaching tens to hundreds of millions annually for commercial-scale facilities.

These findings establish that conventional water-based P_b assumptions systematically overestimate storage capacity and underestimate project risk. Industry adoption of CO_2-specific geomechanical testing protocols is essential, requiring: (1) replacement of water-based measurements with CO_2-appropriate characterization methods; (2) implementation of conservative operational safety factors accounting for 20-30% P_b reduction. Accurate capacity forecasting incorporating CO_2-specific rock mechanics is critical for technically sound, economically viable, and environmentally secure carbon storage deployment.

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