Multiscale Challenges and Opportunities in CO_2 Storage: Lessons from Arabian Clastic Systems

Introduction

Geological CO_2 storage in clastic reservoirs is a central pillar of global decarbonization strategies. The abundance of hydrocarbon accumulations across the Arabian Plate, translates into numerous clastic reservoirs which exhibit favourable properties for CO_2 storage, including moderate to good porosities, permeabilities ranging from tens to hundreds of millidarcies, and regional continuity extending over hundreds of kilometres, commonly overlain by thick mudstone or evaporite seals. These attributes provide significant storage potential and strong intrinsic containment potential (Vahrenkamp et al., 2021).

However, past experience from both hydrocarbon and CCS projects demonstrates that CO_2 storage performance is not solely governed by reservoir properties. Instead, it is controlled by multiple factors including reservoir architecture, lateral connectivity, permeability magnitude, and vertical heterogeneity, which govern injectivity, plume geometry, pressure dissipation, and long-term migration of the CO_2 plume. Thermo-Hydro-Mechanical-Chemical (THMC) processes also play a role in determining the fluid–rock interactions and dynamic reservoir properties. Simplified representations of these interactions can lead to significant uncertainty in injectivity forecasts, plume migration, and containment assessment (Lua et al., 2025).

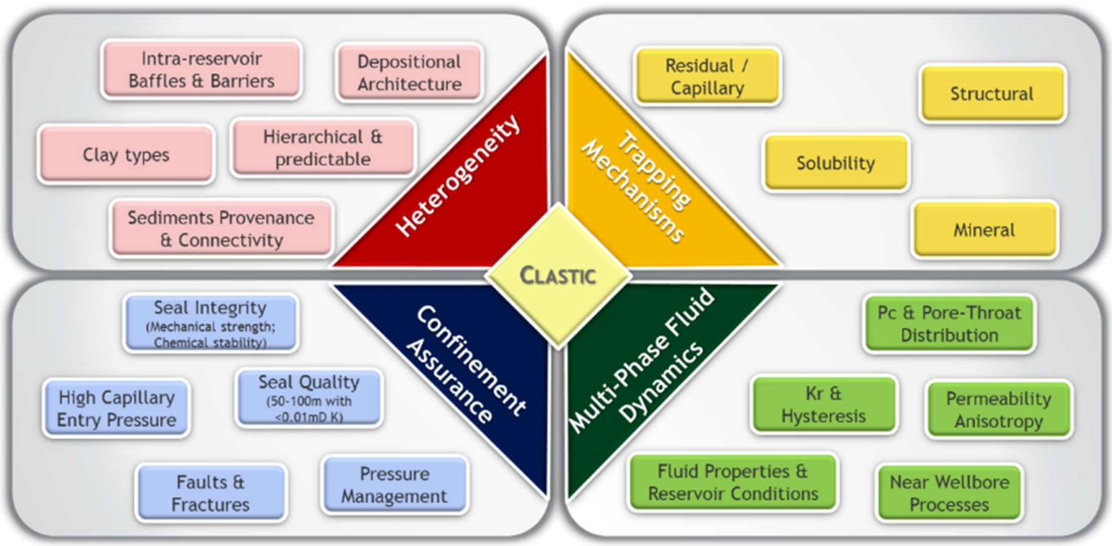

Figure 1. Main factors controlling CO_2 storage in clastic reservoirs.

To address these challenges, Saudi Aramco has implemented a systematic approach to site-maturation for clastic reservoirs, integrating geological characterization, dynamic modelling, and risk assessment. This paper synthesizes key lessons from these studies using a selection of case studies and compares and contrasts their relevance to clastic CO_2 storage projects globally (Figure 1).

Multiscale Reservoir Heterogeneity

Clastic reservoir heterogeneity spans from pore to kilometre-scale (Morad et al., 2010; Figure 2) and is governed by depositional processes and sediment provenance, which influences grain-size distribution, clay mineral content, vertical variations, connectivity contrasts and petrophysical properties. Moreover, reservoir heterogeneity may evolve dynamically during CO_2 injection as pressure builds, resulting in varied effects including stress redistribution, geochemical reactions, salt precipitation, and thermal effects which can modify porosity–permeability relationships, particularly in proximity to the wellbore.

The examples from this study are referenced from detailed CO_2 storage screening and reservoir evaluations, across different depositional settings including fluvial, deltaic, shoreface, and turbidite systems. Across these diverse settings, reservoir connectivity, permeability, and vertical heterogeneity consistently emerge as first-order controls influencing capacity, injectivity and containment. The key insights under each of these themes are summarized below;

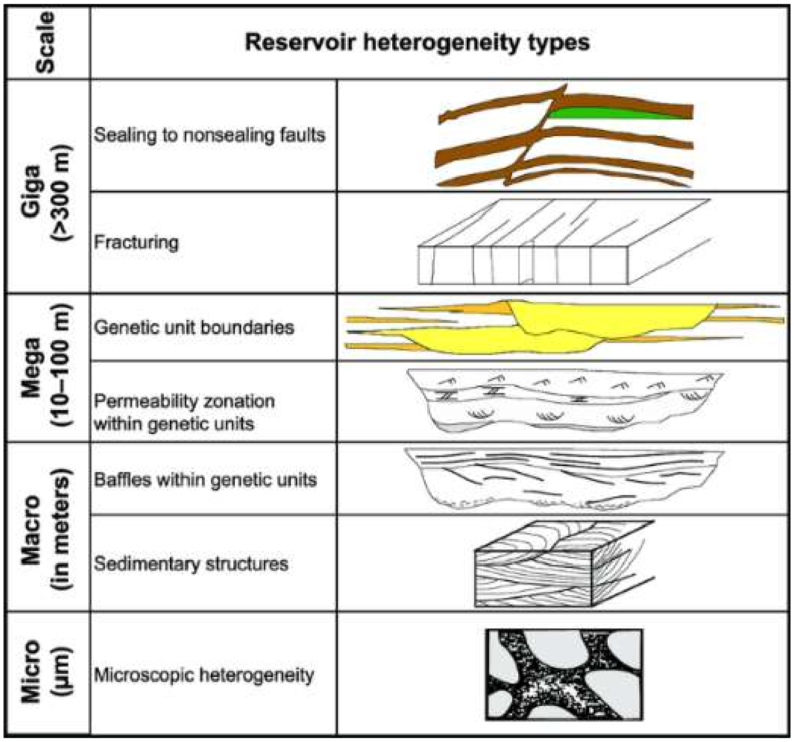

Figure 2. Reservoir heterogeneity in sandstone bodies, from micrometre to hundred-meter scales (modified from Morad et al., 2010).

- **Connectivity:** Reservoir connectivity represents one of the largest uncertainties. Sand-rich bodies that appear laterally continuous at seismic scale may be hydraulically compartmentalized stratigraphically (mud drapes, shale lenses, facies pinch-outs, or diagenetic barriers etc.) below seismic resolution. Depositional architectures such as discontinuous channels, bar complexes and stacked turbidite lobes introduce variability in sandbody thickness and lateral extent, directly influencing effective storage capacity and pressure communication. Structural overprinting can alter connectivity and the presence of faults and fractures can either increase transmissibility or create barriers, depending on factors such as clay content, cementation, stress state, and juxtaposition. Modelling results show that subtle alterations in connectivity can have a significant impact on plume geometry and pressure dissipation.
- **Permeability magnitude:** While permeability alone does not define suitability, it strongly conditions injectivity, pressure build-up, and plume migration. Low-permeability sandstones exhibit injectivity limitations and rapid pressure build up, whereas high-permeability reservoirs allow high injection rates but may promote rapid lateral plume migration. Moderate-permeability reservoirs typically provide a balance between injectivity and plume control. Facies-dependent diagenetic effects complicate permeability upscaling, reinforcing the need for probabilistic scenarios.
- **Vertical heterogeneity:** Vertical heterogeneity exerts a disproportionate control on CO_2 migration and trapping. Stacking patterns, fining-upward successions, flooding surfaces, and heterolithic intervals all create vertical permeability contrasts that promote stratified plume migration. Shale laminae and siltstone interbeds, which are often below seismic resolution, act as vertical baffles, enhancing residual and capillary trapping while limiting upward CO_2 migration. Simulation results indicate that vertical heterogeneity plays a major role in determining plume geometry and column height, often exceeding the influence of the structural closure. Injection-induced pressure changes

and geochemical reactions, such as clay swelling or salt precipitation, may dynamically modify vertical permeability and must be represented in dynamic models.

Thermo-Hydro-Mechanical-Chemical (THMC) Processes

Effective CO_2 storage requires a comprehensive understanding of complex Thermo-Hydro-Mechanical-Chemical (THMC) processes, which occur in conjunction with multi-scale reservoir heterogeneity. These processes encompass various mechanisms, including trapping mechanisms, dynamic changes in reservoir properties, interactions between fluids and rocks, and geochemical reactions. Aramco's in-house screening workflow and detailed analyses have shown that the storage capacity, injectivity, and containment are primarily controlled by the interplay between reservoir properties, fluid characteristics, and in-situ conditions. The THMC processes involved in CO_2 storage include;

- Dynamic pore-scale properties, including capillary pressure, relative permeability, hysteresis, and wettability, play a crucial role in controlling CO_2 movement and storage. The geometry and mineralogy of pore throats determine capillary entry pressures, which in turn affect the mobility and geometry of CO_2 plumes. This can lead to a stratified advance of the plume in the presence of sub-seismic heterogeneity. After injection, the re-imbibition of brine and the resulting relative permeability hysteresis lead to the immobilization of CO_2 through residual trapping. This process is heavily influenced by the pore structure, saturation history, and evolving wettability of the rock, particularly in clay-rich sandstones.
- The behaviour of CO_2 is further modified by fluid properties and in-situ conditions. For example, changes in pressure and temperature affect the density and viscosity of CO_2, which in turn impact its buoyancy and lateral spreading. The salinity of the brine influences interfacial tension and solubility, while thermal effects alter fluid properties, stress conditions, and mineral reactions. These factors collectively govern the injectivity, plume dynamics, and trapping efficiency.

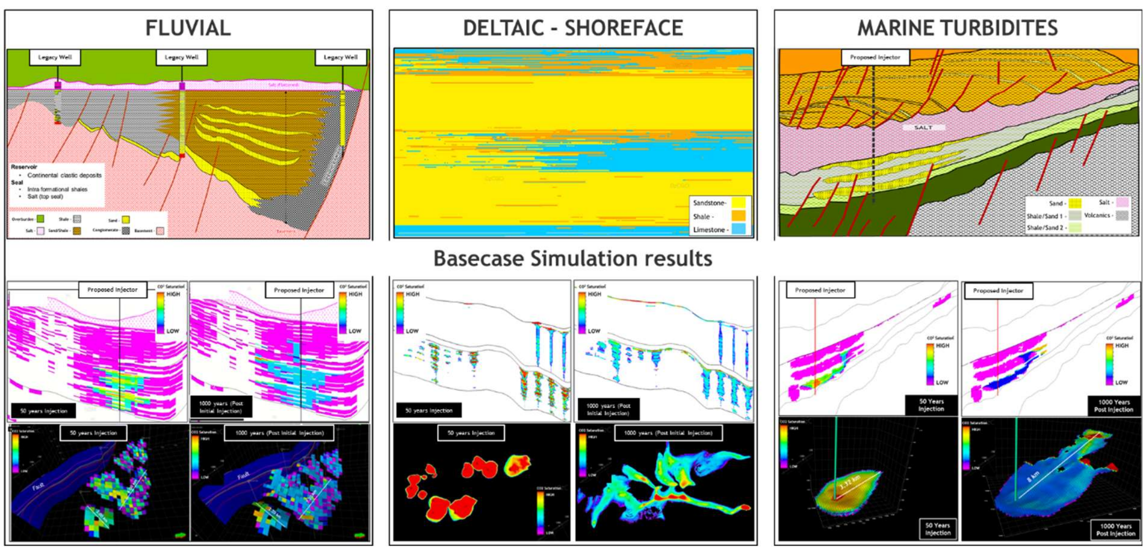

Figure 3 Modelling example of CO_2 plume behaviour in various clastic depositional environments. (A) Fluvial, (B) Deltaic – Shoreface, (C) Marine Turbidites. Showing impact on heterogeneities and THMC processes.

CO_2 Confinement Assurance

The long-term containment of CO_2 depends on what geological barriers are present (e.g., geomechanical stability, structural geometry, geochemical self-sealing etc.). Screening and detailed studies indicate that caprock properties, seal integrity, and operational strategies that control the long-term confinement of CO_2 are:

- Caprock properties, which depend on thickness, lateral continuity, mineralogy, clay content and fabric. Sub-seismic heterogeneities, such as laminations and microfractures, can impact capillary entry pressure and CO_2 migration.
- Caprock integrity, encompasses geomechanical stability and microscopic containment. Pressure increases can trigger fractures and fault reactivation, while thermal and geochemical processes alter mechanical properties. Integrated geomechanical and capillary analyses are essential to assess seal performance and integrity.
- Operational strategies, complement geological and mechanical barriers. Controlled injection rates, phased development, and pressure relief measures maintain pressures below fracture thresholds, ensuring long-term containment.

Characterization, Modelling, and Risk-Informed Assessment

Sparse well control, incomplete core, low-resolution seismic, and a lack of dynamic testing restrict the characterization of fine-scale heterogeneity and reservoir connectivity.

Modelling workflows must honour reservoir architecture through static models, while explicitly accounting for sub-grid variability in capillary behaviour and reaction kinetics. Dynamic simulation platforms should integrate multiphase flow with geomechanical and geochemical processes to simulate CO_2–brine displacement, trapping evolution, pressure propagation, and stress–permeability feedbacks.

Sensitivity analyses spanning injection strategies, petrophysical realizations, fault properties, and operational constraints define outcome envelopes ranging from best to worst-case scenarios. Probabilistic frameworks further propagate uncertainty to generate statistical predictions of plume migration, storage efficiency, and containment risk. Collectively, this integrated approach provides a robust, risk-informed foundation for site selection.

Conclusions

The tectonic and depositional setting of the Arabian Plate, provides multiple gigatons of potential for secure CO_2 storage within clastic reservoirs. Saudi Aramco's studies have identified the following crucial elements that impact storage performance in clastic reservoirs:

- Storage performance is primarily controlled by reservoir connectivity, permeability and vertical heterogeneity.
- Multiphase flow and trapping behaviour are governed by dynamic reservoir properties and fluid–rock interactions.
- Long-term containment depends on caprock quality, geomechanical integrity, and effective pressure management.
- Integrated, probabilistic workflows are essential for uncertainty quantification and risk-informed decision making.

These lessons are directly transferable to clastic CO_2 storage projects worldwide and confirm that such systems are technically viable when supported by comprehensive characterization, simulation, and risk analysis.

Keywords: CO_2 storage; clastic reservoirs; heterogeneity; multiphase flow; trapping mechanisms; confinement assurance; geomechanics; uncertainty and risk assessment

References

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