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Injectivity Evaluation for Offshore CO_2 Sequestration in Marine Sediments

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Abstract

Global and regional climate change caused by greenhouse gases emissions has stimulated interest in developing various technologies (such as carbon dioxide (CO_2) geologic sequestration in brine reservoirs) to reduce the concentrations of CO_2 in the atmosphere. This study develops a statistical framework to identify gravitational CO_2 trapping processes and to quantitatively evaluate both CO_2 injectivity (or storage capacity) and leakage potential from marine sediments which exhibit heterogeneous permeability and variable thicknesses. We focus on sets of geostatistically-based heterogeneous models populated with fluid flow parameters from several reservoir sites in the U.S. Gulf of Mexico (GOM). A computationally efficient uncertainty quantification study was conducted with results suggesting that permeability heterogeneity and anisotropy, seawater depth, and sediment thickness can all significantly impact CO_2 flow and trapping. Large permeability/porosity heterogeneity can enhance gravitational, capillary, and dissolution trapping, which acts to deter CO_2 upward migration and subsequent leakage onto the seafloor. When log permeability variance is 5, self-sealing with heterogeneity-enhanced gravitation trapping can be achieved even when water depth is 1.2 km. This extends the previously identified self-sealing condition that water depth be greater than 2.7 km. Our results have yielded valuable insight into the conditions under which safe storage of CO_2 can be achieved in offshore environments. The developed statistical framework is general and can be adapted to study other offshore sites worldwide.

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Keywords: gravitational trapping; offshore sediment; CO_2 sequestration; injectivity; leakage potential; sediment heterogeneity; uncertainty quantification; Gulf of Mexico.

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1. Introduction

Global and regional climate change caused by greenhouse gas emissions has stimulated interest in developing various technologies to reduce the concentrations of carbon dioxide in the atmosphere [1-3]. Several approaches have been proposed for long-term storage and disposal of captured anthropogenic CO_2, including injection into geologic formations (such as into depleted oil and gas reservoirs [4-8], coalbeds [9], and saline aquifers [10-12]), deep ocean storage [13-14], and storage via chemical transformations (e.g., to make fertilizer, dry ice, and plastics, and even to carbonate soda [15-16]). Compared to geologic and ocean storage, however, the market demand for chemical transformations of the captured CO_2 is relatively limited – at around 200 million tons per year – or about 175 times smaller than the amount of CO_2 emitted globally from energy use in 2013 [15]. This study proposes CO_2 offshore storage in marine sediments, an option currently being explored [17-19]. It combines the benefits of geologic storage, deep-oceanic storage, and chemical transformation, and adds huge capacity to onshore geological carbon sequestration.

Studies suggest that the offshore storage can reduce monitoring expenses and lead to enhanced storage security [18-19]. By injecting CO_2 into sediments beneath the seafloor under suitable temperature and pressure conditions, CO_2 could be trapped through ‘self-sealing’ gravitational or hydrate-formation mechanisms [19]. Under gravitational trapping, an impermeable caprock above the CO_2 reservoir to prevent upward fluid migration is no longer required; when hydrates are formed, CO_2 becomes immobilized. Moreover, offshore locations are away from population centers. As a result, such operations avoid the perception of storage beneath a populated area, reduce the difficulty of establishing surface and mineral rights at candidate sites, and decrease the risk of contaminating underground sources of drinking water [20-21]. Notwithstanding high capital costs (e.g. drilling rigs), the overall economics of offshore storage may be more favorable than onshore storage. For example, storage can be combined with enhanced oil recovery (EOR) in depleted off-shore oil and gas fields, which have infrastructure in place including injection wells and pipelines. In many offshore settings, due to the great reservoir depths, high formation pressure is expected even after primary and secondary recoveries, thus ensuring the miscibility requirement for EOR [22-25]. However, off-shore storage has its own challenges. Based on experience gained in producing off-shore reservoirs, two main challenges have been identified: (1) storage security is compromised when the emplaced CO_2 in sub-seafloor sediments leaks into the overlying water column; (2) storage capacity and injectivity may not be guaranteed at all off-shore locations, because suitable reservoirs with sufficient areal extent, thickness, porosity, and permeability are needed.

Several offshore carbon geologic sequestration projects have been conducted, including the European Union’s CO_2ReMoVe project [26], Norway’s SUCCESS [27], the United Kingdom’s QICS [28-29], and the Australian Government’s National Low Emission Coal Initiative (NLECI) and National CO_2 Infrastructure Plan (NCIP) [30]. The ongoing Sleipner project has been injecting supercritical CO_2 into the Utsira Formation which lies 1 km beneath the seafloor in the central North Sea. Since 1996, about 15 Mt of CO_2 has been sequestered in this semi-consolidated sandstone formation overlain by low permeability caprocks [28]. These studies are located mainly in the shallow seas (seawater depth less than 1 km) and the injected CO_2 could not be trapped through ‘self-sealing’ storage [19].

Permeability in sedimentary deposits always exhibits spatial heterogeneity and anisotropy that reflect the original depositional and also post-depositional processes. Experimental, numerical, and field studies on geological storage suggest that reservoir permeability heterogeneity can enhance capillary and dissolution trapping while potentially helping to deter CO_2 migration and leakage [31-35]. Simulation results also suggest that models incorporating permeability heterogeneity can more accurately assess the various CO_2 trapping mechanisms [36-38]. While CO_2 ‘self-sealing’ storage can be very attractive, more detailed studies of CO_2 interaction with formation water and heterogeneous sediments under variable temperature and pressure conditions are needed for understanding mechanisms of CO_2 trapping processes in the deep-sea sediments and for quantitatively evaluating the CO_2 injectivity and possible leakage rates to sea.

This study is to develop a statistical framework for CO_2 accounting in the deep-sea sediments and quantifying CO_2 trapped in different processes such as solubility trapping, capillary trapping, heterogeneity trapping, gravitational and hydrate-formation trapping. The statistical framework starts from characterizing marine sediment heterogeneity and defining the associated independent parameters (which are statistically independent from output variables, but have a large impact on modeling results). The independent parameters can be classified into: sea depth, marine sediment thickness, permeability mean, variance and integral scale, and porosity. In most of the offshore sites such as in the sites of the Gulf of Mexico (GOM), the exact values of the independent parameters are not well-known, but we may obtain enough information to characterize or define the uncertainty distributions of these independent parameters. These distributions are used to sample the uncertain parameters and conduct geostatistical-based Monte Carlo (MC) simulations to quantitative evaluate both the storage capacity and leakage probability of marine sediments exhibiting variable permeability, variance, porosity and thicknesses. We focus on a set of synthetic models with reservoir fluid flow characteristics selected based on four sites in the GOM basin where sediments with sufficient thickness and permeability exist (Figure 1). As a result of historical exploration for development of petroleum and other resources, extensive subsurface characterization data exist in these sites, thus uncertainty in reservoir parameters can also be relatively well constrained [39-42]. Within a computationally efficient statistical framework, this study also aims to assess the uncertainty in the estimated storage capacity and leakage probability for the synthetic reservoirs. Results then yield insights into the conditions under which safe and permanent storage of CO_2 can be achieved in offshore environments. In the following sections, the characteristics of the four GOM sites are first summarized, followed by a description of the uncertainty methodology used to evaluate CO_2 storage and leakage into the sea.

2. Characteristics of Four GOM Sites

In the GOM basin, several investigations into marine sediments and reservoir properties (e.g. permeability, porosity, and temperature) at four sites have been conducted [43]. Figure 1 shows the locations of the four sites: Alminos Canyon, Bullwinkle, Ursa Basin, and Eugene Island. In the Alminos Canyon site, the unconsolidated and consolidated Oligocene sediments, mainly consisting of fine grained sand and immature Frio sand, have a high porosity (from 0.28 to 0.34) and a large permeability (from 100 to 3000 mD) [44-45]. In the Bullwinkle site, sediments mainly contain interconnected sheet and channel sands. The sheet sand has an average porosity and permeability of 0.33 and 2400 mD, respectively. In some individual sand layers porosities can reach 0.35 and permeability is up to 3300 mD [46-47].

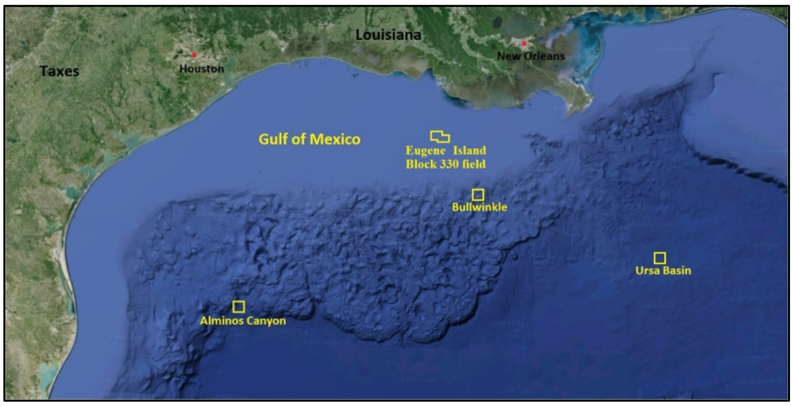

Fig. 1. The location of the four offshore sites in the Gulf of Mexico.

In the Ursa Basin, in-situ permeability of Ursa Siltstone is estimated at around 1 mD. The vertical permeabilities in this site were measured using the transient pulse decay technique [48], which are about one to two orders of magnitude less than the corresponding horizontal permeabilities. Long et al.[44] studied the consolidation and fluid overpressure near the seafloor in the Ursa Basin. There, porosity is up to 42% (a few samples even up to 80%) and the permeability is approximately 5 mD. More petrophysical properties of turbidite sand in this site can be found in reports [49-50]. In the Eugene Island site, offshore Louisiana, thick sequence of shale was covered by increasingly sand-rich sediments. Laboratory determination of in-situ permeability on core samples yield a mixture permeability ranging from 0.2 to 8000 mD and the porosity ranges from 0.16 to 0.35 [51-53]. Based on measured porosities in these four sites, permeability-porosity relationships have also been developed as:

$$ø = a + b \, log_{10}k, \tag{1}$$

where $ø$ is porosity and k is permeability; a and b are also site-specific constants. By using the permeability and porosity data collected the four sites (Figure 2), we estimated the two constants: $a = 0.145$ and $b = 0.062$.

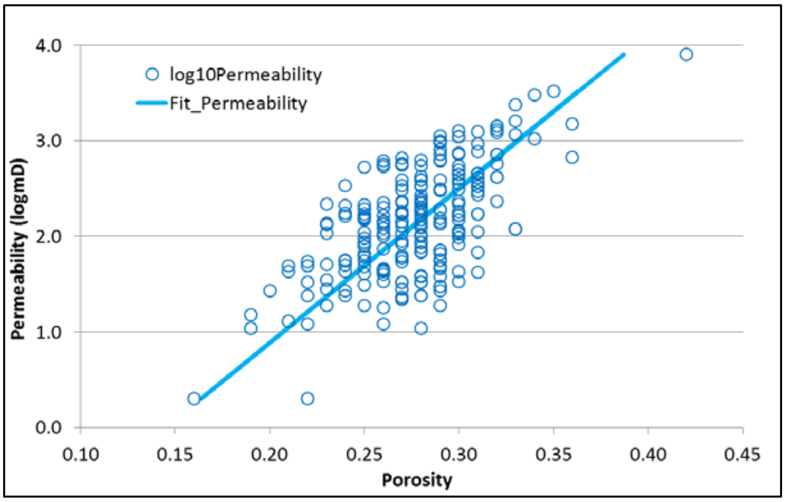

Figure 2: Measured permeability/porosity and the fitted curve for permeability/porosity distributions in the Gulf of Mexico

The geothermal features of northwestern GOM continental slope were studied by Milkov and Sassen [46], where approximation relations between depth-temperature and depth-geothermal gradient are provided. Both sea bottom temperature (T, ºC) and geothermal gradient (G, ºC/km) are correlated with seawater depth. By using equations derived by Milkov and Sassen [46], we can calculate temperatures at the sea bottom and in the sediments based on the sampled seawater depth. With the parameter information available for the four Gulf sites, we summarize the ranges and distributions of the uncertain parameters for simulating the heterogeneity of the marine sediments and shallow reservoirs in Table 1. The vertical spatial integral scale of log permeability is obtained from logging data, while the statistical anisotropy between horizontal and vertical integral scales is assumed to be 100. The anisotropy of horizontal and vertical permeability is varied to quantify the impact of the anisotropy factor on the CO_2 leakage from the sediments to the sea bottom. Having been limited by the available data, we assume that the ranges of the log permeability variance and horizontal integral scale are (0.01, 4) and (0.5, 5), respectively. The relative permeability functions for CO_2-brine multiphase flow simulations were calculated on the basis of the van Genutchten model to define the related coefficients [54-56]. Table 1 also lists the ranges of seawater depth, CO_2 injection rate, sea-bottom temperature, and geothermal gradient. The latter two parameters are correlated to seawater depth.

Table 1. Summarized uncertain parameters (independent parameters) and distributions.

	Uncertain parameters	Min.	Max.	Base case	**Distribution**
Sediment Property	Sediment thickness (km)	0.005	0.9	500	Uniform
	Mean permeability (D)	0.001	8	1.0	Log uniform
	Anisotropy factor	0.01	0.5	0.1	Uniform
	Log permeability variance	0.01	4.0	0.0	Uniform
	Integral scale (km)	0.5	5.0	1.0	Uniform
	Porosity	0.1	0.42	0.2	Correlated to perm
Physical Parameter	Sea depth (km)	0.1	4.4	2.5	Uniform
	CO_2 injection rate (kg/s)	0.002	2.0	0.3	Uniform
	Sea-bottom temperature (ºC)	2	20	2	Correlated to depth
	Temperature grad (ºC/km)	5	50	20	Correlated to depth

3. Monte Carlo Simulations of offshore CO2 sequestration

Given uncertainty of several key reservoir parameters, it is essential to conduct a set of Monte Carlo (MC) simulations to understand the uncertainty of the key properties impacting CO_2 storage/leakage in the marine sediments in the GOM. The uncertainty parameters (as listed in Table 1) considered in this work are: reservoir thickness, permeability, permeability anisotropy (horizontal to vertical permeability ratio), log permeability variance and integral scale, sea depth, and CO_2 injection rate. The sea depth is varied from 100 m to 4.4 km. A joint probability density function (PDF) is thus developed between water depth and the bottom water temperature and geothermal gradient based on the equations of Milkov and Sassen [46]. The seawater density is around 1.03 g/cm3 in the GOM. Other uncertainty factors, such as background fluid flow, will be considered and discussed in future work. Based on the MC simulation results, we conduct correlation analysis with PSUADE [57]. The computed correlation matrix of the sampled parameters is shown in Figure 3, in which permeability (rKmean) and porosity (rPor) are correlated, and pressure (Ptop) and temperature (Ttop) at the top of the sediments are correlated with seawater depth (Depth). Other parameters are independent to each other. Figure 4 shows the correlations between the sampled parameters and the output variables.

These MC simulations also incorporate permeability and porosity heterogeneity into the model, and results are analyzed to identify the conditions (i.e., water depth, sediment thickness, mean permeability and porosity, log permeability variance and integral scale, permeability anisotropy factor, and injection rate) under which the injected CO_2 can be trapped by gravitational trapping.

4. Global sensitivity analysis

A global sensitivity analysis technique, based on multivariate adaptive regression spline (MARS) with normalized indices, was applied to investigating sensitivities of the output variable (CO_2 leakage) to variation of the uncertain input parameters [57]. The MARS technique is based on computing a variance of conditional expectation (*VCE*) of the output variable.

The sensitivity of output variables to a number of input parameters is quantified and ranked from 0 to 100 to represent the relative importance of each input parameter to the prediction of output variables. Using the computationally efficient MARS response surface functions, the suite of *VCE* is then evaluated to generate prediction envelop of output variables given the uncertain input parameters [57-59].

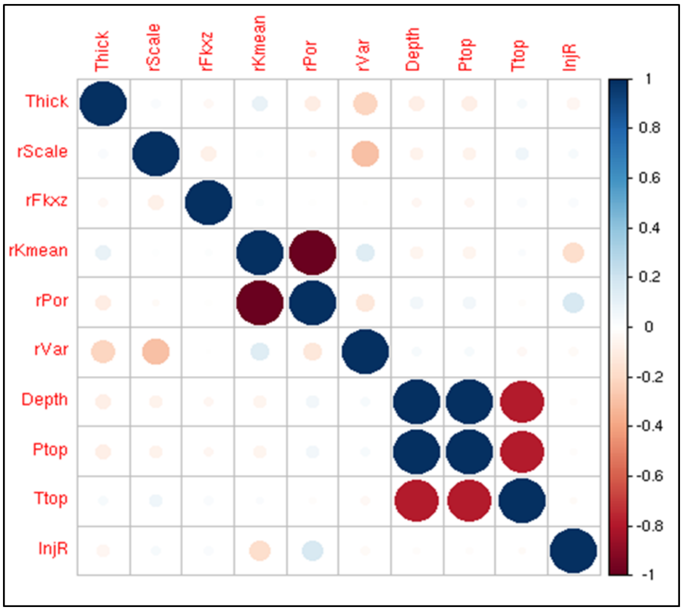

Fig. 3. The correlation matrix of among sampled parameters.

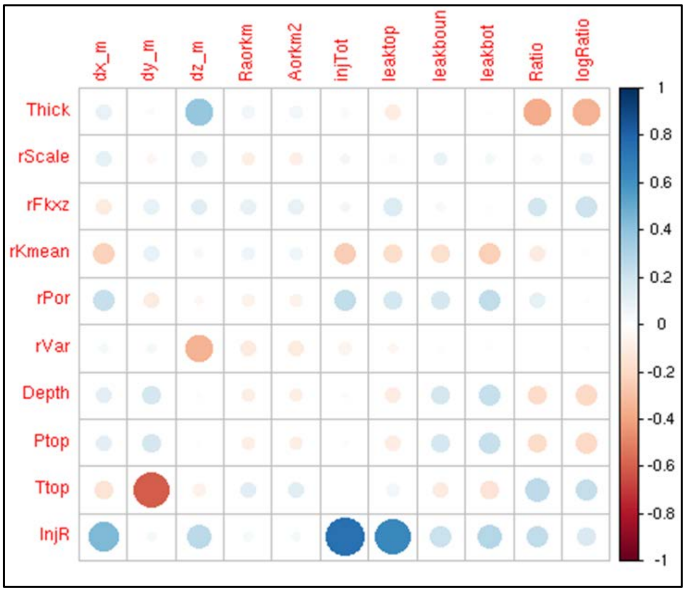

Fig. 4. The correlation matrix between the sampled parameters and the output variables.

The sensitivity analysis suggests that, for predicting CO_2 leakage out of the sediments into the sea in the GOM, permeability anisotropy factor, injection rate, water depth, sediment thickness, permeability variance, mean permeability, and seafloor temperature are the most sensitive parameters (Figure 5), which are also ranked from the most sensitive to less sensitive. Although porosity is positively correlated with horizontal permeability, CO_2 leakage is not as sensitive to this parameter compared to mean horizontal permeability. Interestingly, for the assumed statistical anisotropy ratio (100), log permeability horizontal integral scale has the least impact on CO_2 leakage.

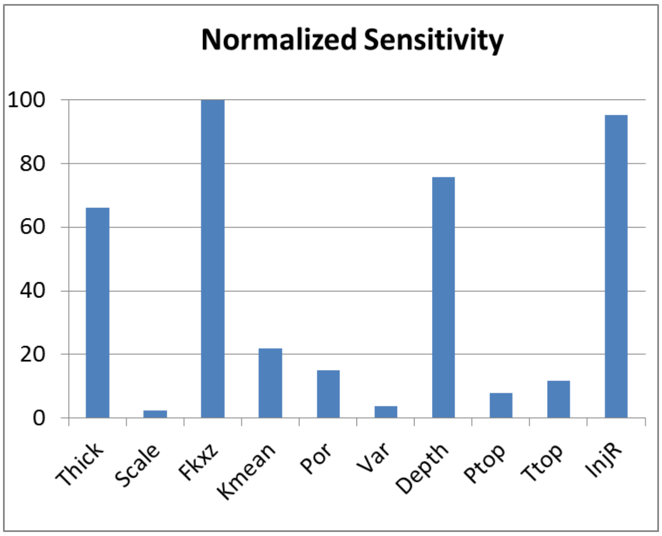

Fig. 5. The computed sensitivity index of the output variable (percent CO_2 leakage) to uncertain input parameter varied in the global sensitivity analysis.

5. Gravitational and heterogeneity trapping

A base case cross sectional model (thickness = 500 m, horizontal length = 5 km, and lateral length = 1m) was studied to obtain an initial understanding of CO_2 flow and trapping in marine sediments. The sediments are assumed to be heterogeneous with a horizontal mean permeability of 1D and a variance of 1. The heterogeneous horizontal permeability distributions are generated with Sequential Gaussian Simulation with a horizontal log permeability integral scale of 1.0 km. Porosity in this model is computed from horizontal permeability with Equation (1). The remaining parameters are listed in Table 1. The top of the reservoir model lies at the seafloor. A uniform CO_2 injection rate (0.3 kg/s) is assigned at the bottom-center of the model for 10 years. After injection ceases, CO_2 migration is simulated until the total simulation time 200 years.

Figure 6 shows simulated permeability field and the liquid-phase CO_2 pressure distribution at 20 years. The combined effect of reservoir fluid pressure and temperature causes the injected liquid CO_2 to have a density slightly greater than that of seawater (1.03 g/cm3) at the center of the CO_2 plume and near the topmost layers of the model (Figure 7). Near the bottom layers, due to increasing temperature with depth (base case geothermal gradient = 20 ^{o}C/km), the injected CO_2 has a density close to that of seawater. When CO_2 moves upwards by pressure difference, it becomes denser and confined by the higher-density CO_2 at the top layers. Thus, negative buoyancy of liquid CO_2 at the topmost layers prevents the liquid-phase plume from leaking onto the seafloor and all of the injected CO_2 sinks to the bottom layers. In this case, liquid CO_2 plume does not reach the upper boundary: at the end of 200 years, computed CO_2 leakage from the top of the sediments is 0 and the injected CO_2 is considered to be successfully trapped in the marine sediments. Results suggest that permeability heterogeneity, in particular, the presence of low-permeability layers, can additionally enhance storage security by deterring upwards migration. The model was further run to 1000 years and the liquid CO_2 plume has reached a steady state after 200 years, i.e., plume shape and size do not change anymore. For this case, CO_2 is safely sequestered by both gravitation and heterogeneity.

To refine the understanding of the key parameters and their potential interactions that can impact gravitational trapping, three additional sets of MC simulations (300 realizations total) were conducted sampling only sediment thickness, using an injection rate of 0.2, 0.02, and 0.002 kg/s, respectively. The other parameters are the same as those of the base case. The relative CO_2 leakage rate (normalized by by the injection rates) is computed and plotted against sediment thicknesses, for the increasing injection rate (Figure 8). When injection rate is 0.2 kg/s, gravitational trapping is accomplished, approximately, at a sediment thickness > 400 m; when injection rate is 0.02 kg/s, sediment thickness > 210 m; and when injection rate is 0.002 kg/s, sediment thickness > 90 m. Clearly, with all other conditions being equal, safe storage in these settings is influenced by both the injection rate and the thickness of the sediment. With increasing injection rate, thicker sediment is required to help deter CO_2 upward migration and leakage onto the seafloor.

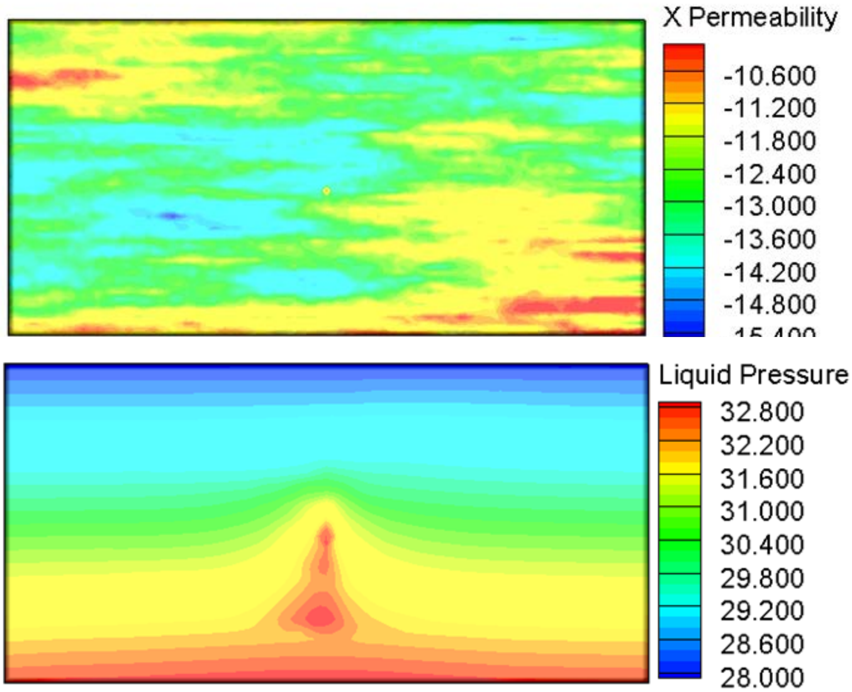

Fig. 6. Horizontal permeability (logm2) field (upper) and the simulated CO_2 liquid pressure (MPa) (lower), in a vertical cross section (from MC run 22).

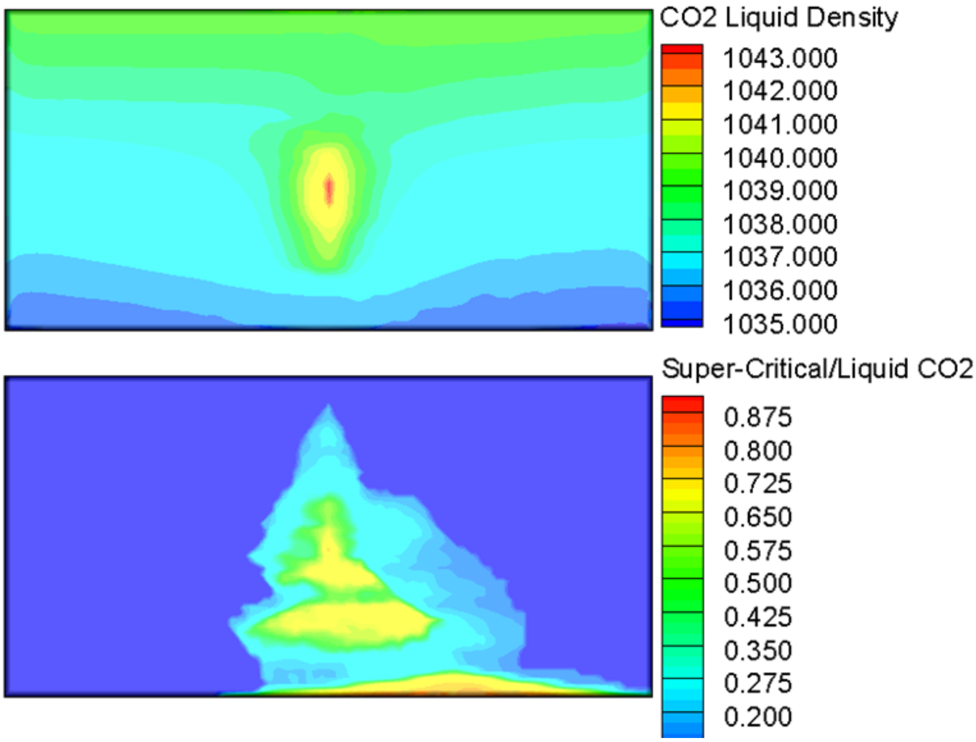

Fig. 7. The simulated CO_2 liquid density (upper) and CO_2 saturation (lower) in a vertical cross section (from MC run 22).

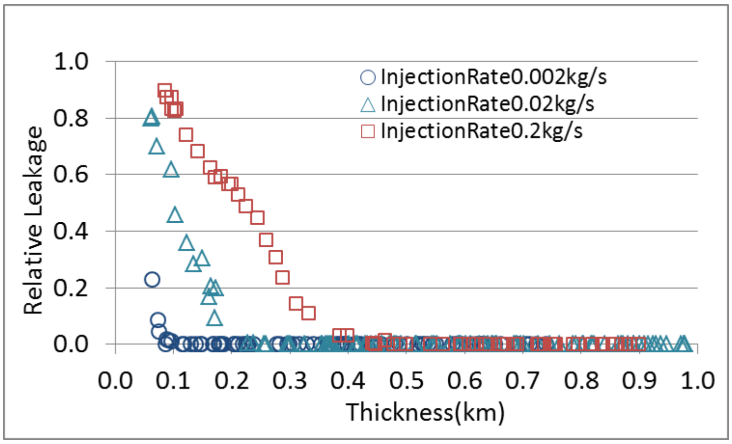

Fig. 8. The impact of the injection rates and the sediment thickness on the relative leakage to the seafloor

6. Summary and discussion

This study develops a statistical framework to simulate gravitational CO_2 trapping processes and to quantitatively evaluate both CO_2 injectivity (or storage capacity) and its leakage potential from marine sediments which exhibit heterogeneous permeability and variable thicknesses. The conducted numerical investigations indicate that the injected CO_2 can be gravitationally trapped in offshore marine sediments of the GOM with suitable temperature and pressures at the seafloors.

A selected suite of uncertain reservoir and environmental input parameters is defined, with results suggesting that safe storage could be accommodated in deep water GOM sediments with large thickness, high mean permeability and porosity, and with relatively low injection rate. Results also suggest that permeability heterogeneity with the presence of low-permeability layers, in particular, can additionally enhance storage security by deterring upwards migration. Our results have yielded valuable insights into the conditions under which safe and permanent storage of CO_2 can be achieved in offshore sediments. The developed uncertainty quantification framework is general and can be adapted to studying other offshore sites worldwide.

This study did not evaluate the impact of other mechanisms (such as geomechanical stress and deformation due to injection) and uncertainty factors (such as background fluid flow and geochemical self-sealing) on CO_2 injectivity (or storage capacity) and its leakage potential from marine sediments. The effects and their interaction with CO_2 fluid flow and trapping processes will be considered and discussed in future work.

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