Numerical simulation of CO_2 injection into Lower Tuscaloosa CO_2 storage reservoir in Mississippi, USA with experimentally validated modeling parameters

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Introduction

Carbon capture and storage (CCS), which captures CO_2 from CO_2 emission sources like power plants and oil refinery plants and stores captured CO_2 in deep "CO_2 receivers" like saline aquifers and depleted oil reservoirs, is a promising strategy to reduce the emissions of CO_2 to the atmosphere (Liu et al. 2017). After CO_2 is injected into deep saline aquifers, CO_2 gets dissolved into, and reduces the pH of brine, which triggers mineral dissolution (Bacon et al. 2014). Dissolution of minerals causes increase of certain ions in solution (e.g., Na^+, Ca^{2+}, SiO_4^{4-}, etc.), which induces secondary precipitation of silica, silicates and carbonates (Miller et al., 2016). There is a need to understand if mineral dissolution and precipitation induced by chemical interaction between rock minerals and dissolved CO_2 impact reservoir permeability and containment effectiveness of CO_2 storage sites. In this paper, a reservoir-scale model is developed with key modeling parameters (i.e., equilibrium constants, rate constants and the exponent in permeability-porosity correlation) validated by experimental data and core-scale numerical simulation. The reservoir-scale model can be used to study the impact of mineral dissolution and precipitation on permeability evolution of CO_2 storage reservoir and caprock. We demonstrate an application of this model using geophysical and geochemical information from Plant Daniel CO_2 Storage Test Site in Mississippi, USA.

Model development

A 3-D TOUGHREACT model was developed to simulate injection of CO_2 into the CO_2 storage formation at Plant Daniel CO_2 Storage Test Site. The storage formation is a sandstone formation with an average depth of 3,100 m, an average permeability of 2190 mD and an average porosity of 26.8%. TOUGHREACT (Xu et al. 2005) is an advanced version of widely used subsurface multi-phase flow simulator TOUGH2 (Pruess et al. 2012), with chemical reaction modules added to TOUGH2. The model was constructed with four vertically stacked horizontal layers and the domain dimensions were 100, 000 m×100,000 m×188.5 m. Very large horizontal domain dimensions were chosen to minimize domain boundary effect on simulation results. The bottom two layers (Layers 1 and 2) belonged to the CO_2 storage formation and had a combined thickness of 36.5 m. The top two layers (Layers 3 and 4) belonged to the caprock and had a combined thickness of 152 m (Soong et al. 2016). Key minerals that are considered in dissolution/precipitation processes in TOUGHREACT include chlorite, microcline, illite, kaolinite, Na-feldspar, calcite, dolomite, iron hydroxide, gypsum, siderite, quartz, amorphous silica and montmorillonite. Mineral dissolution and precipitation cause porosity change of the formation, and permeability change is correlated with porosity change by an exponential relationship ($Perm_t = Perm_0 \times (Por_t/Por_0)^n$).
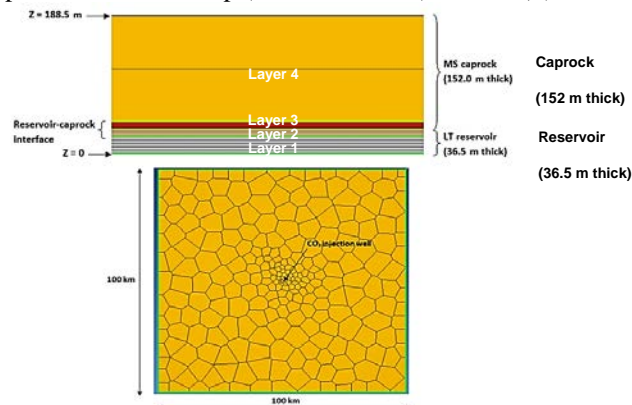

Fig. 1: Schematic of the TOUGHREACT reservoir-scale model

Results and discussion

From t=0 to t=1000 years, reservoir-scale porosity change of the CO_2 storage formation is negligible (Figure 2). Permeability changes at the location next to the CO_2 injector show a maximum permeability increase of 1.0 % for the CO_2 storage formation and a maximum permeability increase of 1.1 % for the caprock. Permeability changes at the location 5 km from the CO_2 injector show a maximum permeability increase of 3.2 % for the CO_2 storage formation and a maximum permeability decrease of 0.9 % for the caprock (Figure 3). Permeability change in the CO_2 storage formation next to the CO_2 injector is smaller than that 5 km away from the CO_2 injector, because water is quickly replaced by injected CO_2 and only residual water is left close to the CO_2 injector at t=0.2 year. Due to short of water supply, mineral dissolution and precipitation processes are suppressed and porosity and permeability changes become small. In summary, mineral dissolution and precipitation reactions have small to negligible effect on porosity and permeability of both CO_2 storage formation and caprock during a 1000-year simulation period. Because of negligible change of caprock permeability, most CO_2 injected into the storage formation is expected to be contained in the storage formation in the 1000-year simulation period, which ensures safe containment of CO_2 in the subsurface.
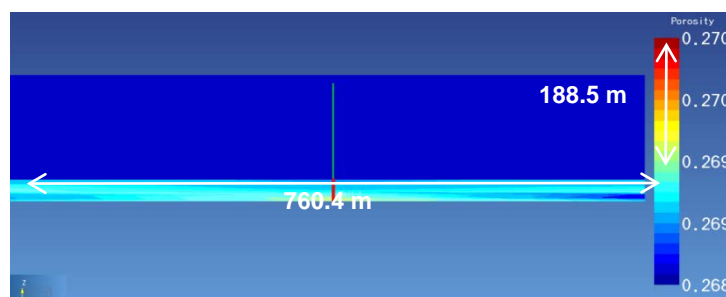

Fig. 2: Porosity profile of CO_2 storage formation at t=1000 years (30 years of CO_2 injection + 970 years of post CO_2 injection). Initial porosity of the CO_2 storage formation is 0.268. Initial porosity of the caprock is 0.087 and is beyond the range of the legend
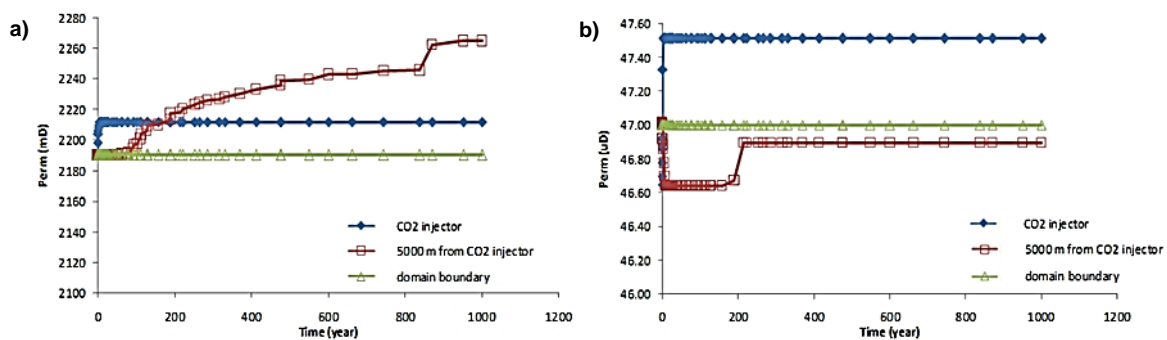

Fig. 3: Permeability evolution at three locations of CO_2 storage formation (a) and caprock (b) from t=0 to t=1000 years

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