CO_2 sequestration in oil/gas reservoirs, saline aquifers and coal beds

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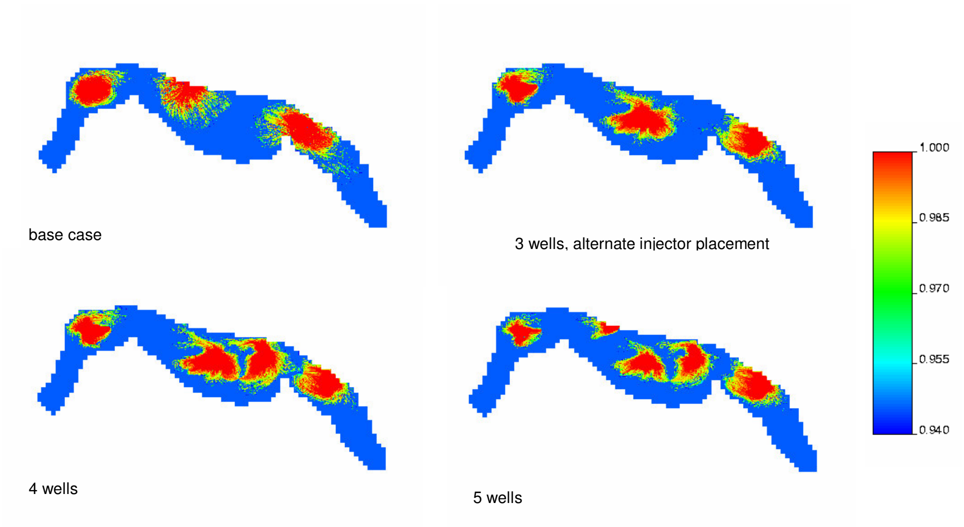
Description: Current projections of worldwide energy use indicate that fossil fuels will play a significant role for an extended period, if for no other reasons than the fact that time scales for changing energy systems are long and the investments required very large. Capture and storage of a portion of the carbon dioxide (CO_2) released as a result of combustion of fossil fuels offers one approach to limiting carbon emissions. Injection of CO_2 into geologic formations is being considered as one way to reduce emissions of CO_2 to the atmosphere associated with energy use. Possible settings for geologic sequestration include reservoir rocks that are currently producing oil or gas, deep formations that contain brine, and deep coal beds that will not be mined in the future. In our research program, we consider a variety of technical issues that must be addressed if geologic sequestration is to be conducted at a scale large enough to have significant impact on CO_2 emissions to the atmosphere. We consider all three geologic settings with an aim of elucidating the central physics of sequestration and translating this understanding into fast, practical tools for flow prediction in the subsurface.

Oil and gas reservoirs: Oil and gas reservoirs have considerable appeal as storage locations for CO_2. They have known geological seals and, as long as the seals were not damaged during oil or gas production, should be able to hold injected CO_2 indefinitely. Also, thanks to prior experience in gas injection operations for Enhanced Oil Recovery (EOR) or Enhanced Gas Recovery (EGR), existing oil and gas fields are likely to be the first places approved by the regulatory structure for sequestration at a large scale. An added benefit is that EOR and EGR offer the opportunity for recovery of some of the costs of CO_2 storage.

CO_2 sequestration processes in oil and gas reservoirs are inherently compositional (Fig. 1), that is, the fluid flow strongly depends on component transfer between the various phases present in the reservoir. A detailed representation of the rock permeability is also crucial to accurate modeling of sequestration processes, as the more mobile phases will preferentially flow through high permeability paths. High resolution computational grids are required to represent the permeability variations. High resolution simulation for compositional displacement processes is extremely challenging and generally too computationally expensive to perform with current conventional simulation tools. We consider compositional streamline simulation as a promising alternative to conventional simulation approaches due to the low CPU requirement allowing for fast and accurate development of CO_2 injection strategies aiming to co-optimize storage and recovery as illustrated below. Conventional simulation approaches are not suitable optimization problems at field scale within a reasonable time frame.



base case

3 wells, alternate injector placement

4 wells

5 wells

Figure 1: CO_2 distribution in a condensate reservoir for varying injection schemes.

Saline Aquifers: The goal of CO_2 sequestration is to store CO_2 for centuries or thousands of years if not indefinitely. Our objective is to determine the time and length scales that characterize the sequestration of CO_2 in saline aquifers (Fig. 2). Accurate description of the physical mechanisms that control the behavior in these complex processes is necessary. Construction of mathematical and high fidelity numerical models that accurately capture the relevant time and length scales is essential.

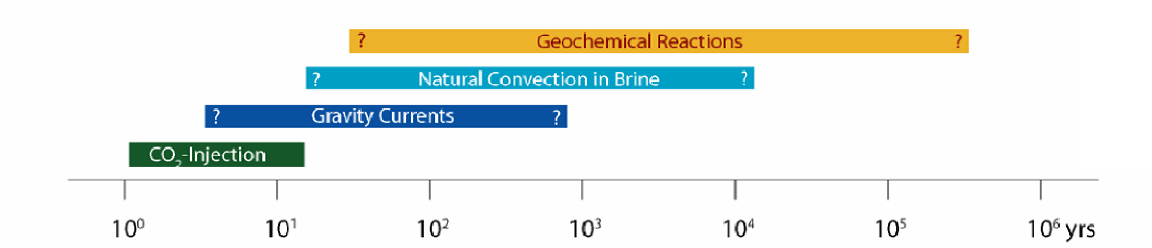


Figure 2: Time scales for CO_2 storage in saline aquifers.

Injection Period (~10^1 yrs): During the injection phase, flow rates near the injection well are high. Advection and gravity segregation are the dominant transport mechanisms. Movement of low viscosity CO_2 will be dominated by heterogeneity, and an appropriate representation of heterogeneity is important. Additional effects include capillarity and viscous fingering. Structural trapping and CO_2 immobilized as residual gas are the most important sequestration mechanisms in this phase.

Post Injection Period (10^2 to 10^6 yrs): After injection has ended, buoyancy and capillary forces will dominate over viscous forces (Fig. 3). Dissolution and precipitation reactions are likely to become more important as time proceeds. Important physical/chemical processes in the post-injection period are:

- Residual trapping associated with updip buoyancy-driven CO_2 migration
- Dissolution of CO_2 in the brine
- Downward buoyancy driven fingering

- Precipitation and dissolution of carbonate and silicate minerals

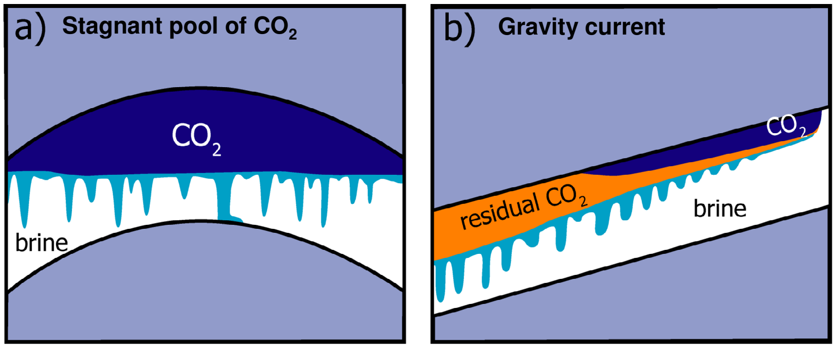


Figure 3: Potential trapping mechanisms of CO_2 injected into an aquifer.

Coal beds: Methane recovery from coalbeds has grown in importance as an energy source in recent years and now accounts for about 10 % of U.S. natural gas production. Coalbeds have large internal surface area and strong affinity for gases such as methane (CH_4) and carbon dioxide (CO_2). Gas is present both as a bulk phase in the pore space and on the solid in an adsorbed state at liquid-like density.

Effective methods to release fully methane from tight coalbed resources have yet to be developed. Injection of CO_2, so-called enhanced coalbed methane recovery (ECBM), is a means to increase the ultimate recovery as well as sequester greenhouse gases. Interestingly, most coals adsorb substantially more CO_2 than CH_4 at the same pressure. The mechanisms of gas adsorption, desorption, and transport through coal beds, however, are not yet elucidated to the same level of detail as mechanisms of gas injection into hydrocarbon reservoirs or saline aquifers. In this portion of our study, methane/carbon dioxide/nitrogen flow and adsorption behavior within coal is investigated from a laboratory and simulation perspective.

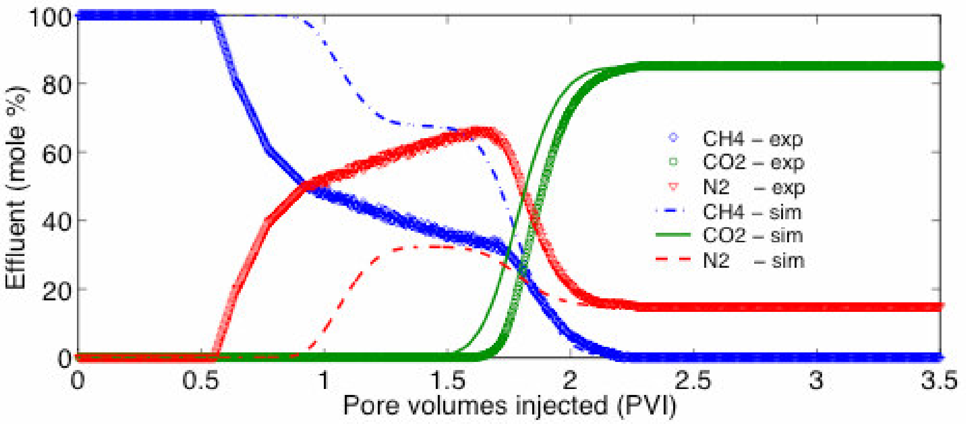


Figure 4: Effluent composition from experiment and simulation of an ECBM process.

The interplay of gas sorption and transport in coal yields a rich set of dynamical behavior (Fig. 4). Injection of mixtures with a large fraction of carbon dioxide reduces the initial recovery rate but increases breakthrough time as well as decreases the total amount of injectant needed to sweep out the coalbed. The experimental program verifies that coalbeds are useful to separate chromatographically N_2 and CO_2 while at the same time coalbed methane is recovered.

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