Reservoir engineering to accelerate dissolution of stored CO₂ in brines

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Abstract
It is possible to engineer CO₂ storage in aquifers by accelerating the dissolution of CO₂ in brines in order to reduce the long term risk of leakage. Such reservoir engineering includes (i) optimizing the geometry of injection wells to maximize the rate at which buoyancy-driven flow of CO₂ and brines drives dissolution, or (ii) use of wells and pumps to transport CO₂ or brines within the reservoir in order to increase contact between CO₂ and undersaturated brines accelerating the rate of dissolution and residual gas trapping. Using a commercial multiphase reservoir-simulator and an idealized reservoir geometry we investigate the effect of pumping undersaturated brines from distant points in the reservoir to the ‘bubble’ of free-phase CO₂ confined under a caprock. Brine pumping can increase the rate of dissolution by more a factor of ten and can dissolve more than 80% of the injected CO₂ in 100 years. The energy required for pumping can be small compared to the energy cost of CO₂ capture and compression. The lifetime CO₂ emissions from running the brine pump can, for example, be less than 1% of amount of CO₂ in storage. Such reservoir engineering techniques might be used to increase storage efficiencies and could decrease the risk of leakage at comparatively low cost.

Introduction
Deep aquifers are a particularly important class of geologic storage system because of their ubiquity and large capacity. Two important uncertainties in assessing CO₂ storage in aquifers are storage efficiency and security, where efficiency denotes the fraction of total aquifer capacity that can be accessed for storage; and, security refers to the possibility that stored CO₂ will escape the aquifer system by migrating upwards through natural or artificial weaknesses in the capping formation.

The CO₂ injected into a saline reservoir is ~10-30% less dense than the resident brines. Driven by density contrasts CO₂ will flow horizontally (in a horizontal aquifer) spreading under the caprock, and flowing upwards through any high permeability zone or artificial penetration. The free-phase CO₂ (gas or supercritical fluid) slowly dissolves in the brines or is trapped as residual gas. Once dissolved, the resulting CO₂-rich brines are slightly denser than undersaturated brines making them negatively buoyant, and thus greatly reducing or eliminating the possibility of leakage. Dissolved CO₂ can eventually be transported out of the injection site by basin-scale circulations, but the rate of such transport is sufficiently slow that it can be ignored in assessing the risk of leakage. Moreover, dissolved CO₂ may be further immobilized by geochemical reactions.

Residual gas trapping occurs when bubbles of CO₂ are isolated within individual pores during two-phase flow. Residually trapped gas is not mobile and so will not contribute to buoyancy-driven upward migration of free-phase CO₂, the trapped gas will gradually dissolve as undersaturated brine flows through the pores.

As a framework for assessing storage security, we adopt the view that the only relevant risk of leakage arises from mobile free-phase CO₂, that is, CO₂ that remains in the gas (or supercritical fluid) phase and which is not immobilized by residual gas trapping. Assessment of storage performance thus depends on two factors: (i) the likelihood that free-phase CO₂ will leak out of the storage formation or alternatively the timescale over which significant leakage is expected to occur, and (ii) the rate at which free-phase CO₂ is immobilized by dissolution in the reservoir fluids or residual gas trapping. When more gas is immobilized security of storage is increased.

Assessments of storage capacity and security have generally assumed that reservoir engineering would be limited to site selection and placement of the injection well(s). More active reservoir engineering may increase storage capacity by increasing filling efficiency and may increase security by increasing the rate at which CO₂ is immobilized by dissolution or residual gas trapping. We examine the pumping of brines from distant points in the reservoir to the ‘bubble’ of free-phase CO₂ confined under a caprock in order to accelerate dissolution and residual gas trapping. The final section of the paper identifies some of the key uncertainties in our results and speculates about their implications.
Methods
We used the GEM (2003) simulator from Computer Modeling Group. GEM is a general equation-of-state based compositional reservoir simulator for modeling the flow of multi-phase, multi-component fluids. The model geometry is a three-dimensional element of symmetry of a CO₂ injection site with horizontal dimensions of 20×20 km. The distance of boundaries from the injection well is selected so that results are not much affected by the boundary. Furthermore, a boundary well is completed around the boundary and pressure in that well is fixed at the initial formation pressure to crudely simulate the natural aquifer outflow. Figure 1 shows the top view of the three dimensional model used in the simulations. The aquifer properties are taken from Nisku aquifer in Alberta basin and are given in Table 1. Corey type relative permeability is used for gas-water phases and capillary forces are neglected.

In all cases CO₂ is injected into the aquifer at a rate of 0.5 Mt/year (0.125 Mt/yr for modeled element of symmetry) using a vertical well with open completion throughout the thickness of the reservoir. The CO₂ injection rate was chose based on preliminary simulation that showed that, for this reservoir, ~0.5 Mt/yr was near the maximum injection rate that could be sustained for a single well over a 30 yr period without exceeding 90% of the reservoir fracture pressure.

In base case with brine pumping, brine is injected using two 460 m-long horizontal wells in the top layer of the aquifer at a rate of 200 m³/day (100 m³/day per well) from the beginning of gas injection. In all cases, brine is produced at the same rate with which it is injected using a single vertical production well located 11.8 km from the injection well. After the gas injection stopped at 30 years, the water injection was continued for a total of 200 years.

The square model domain was discretized in a 30×30 horizontal grid with 10 vertical layers. The horizontal grid spacing was non-uniform (Fig 1), with resolution increasing near the injection wells. We assessed errors due to numerical discretization by doubling the horizontal resolution to 60×60×10 from the baseline of 30×30×10. The data shown in Figure 2 demonstrates that the discretization errors are relatively small.

Results
Figure 3 shows the rate of dissolution with and without water injection. The injected CO₂ is less dense than the formation brine, so it rises to the top of the aquifer where it spreads under the capping formation. When water is injected near the top of the gas cap it flows through the gas accelerating dissolution and driving the gas outwards away from the injection well. For the 200 m³/day case, the amount of CO₂ in the dissolved phase increases from 20% (with no pumping) to 77% after 200 years of simulation. Vertical cross sections of gas saturation for both cases of with and without water injection are shown in Figure 4. The required pumping work is shown in Figure 5.

Figure 3 shows the effect of water injection rate on the dissolution of CO₂. Pumping rates of 400 m³/ day can achieve 97% dissolution in 100 years, although the energy costs of rises rapidly as pumping rates are increased beyond 300 m³/day (Fig 5).

The energy and financial cost of brine pumping
There is no doubt that brine pumping can accelerate dissolution, the crucial question is, at what cost? We construct a rough estimate of the energy and financial costs of brine pumping based on the time-integrated total pumping work. Our objective is to place these costs in perspective by comparing them to the cost of CO₂ capture and storage, in particular, the cost of capture which generally dominates total costs.

First consider energy costs. The total mechanical pumping work for a 100 year 200 m³/day case is roughly 0.3 PJ including pump inefficiencies and pressure drops in the injection tubing (1 PJ = 10¹⁵ Joules). (Here, and throughout this section, calculations for the full system, a factor of four times larger than the element of symmetry that was modeled explicitly.) One way to put this in perspective, is to compare it to the mechanical energy requirement for CO₂ compression that is embedded in CO₂ capture costs. The energy requirement to compress the 15 Mt of injected CO₂ from atmospheric pressure to reservoir pressure is about 5.3 PJ, so the energy cost of running the brine pump is ~5.5% of the energy cost of CO₂ compression. We can also compare the energy cost of brine pumping with the energy generated by a power plant that produced the CO₂. A coal
fired plant with CO₂ 95% capture operating at 33% efficiency produces ~57 PJ electricity for every 15 Mt of CO₂, so the energy cost of brine pumping is ~0.5% of the energy generated by the power plant.

Financial costs are harder to estimate. First, consider the costs of well drilling and completion. The cost of drilling and completing the necessary wells is of order $0.5 million US (Joshi, 2003), an insignificant cost compared to the cost of CO₂ capture which would be of order $500 million (equivalent to a capture cost of 33$/tCO₂). The costs of operating the pumps will dominate the cost of wells. Given a cost for CO₂-neutral electricity of 6 c/kWh, for example, the undiscounted cost of electricity to operate the pump would be $4.7 million. While we have not done a detailed cost analysis, it seems plausible that electricity costs will be a significant fraction of total cost of pumping including capital, operations and maintenance. Assuming this is correct, the discounted cost of brine pumping will be less than 1% of the total net present costs of CO₂ capture.

**Discussion**

The results described here are preliminary. More realistic analysis might include (i) use of a more realistic reservoir geometry including the effects of reservoir heterogeneity, (ii) optimization of the dissolution achieved for a given input of pumping energy by better choice of injection and production wells, and (iii) a full engineering-economic cost analysis. Nevertheless, the results presented here strongly suggest that active pumping of brines within a reservoir can significantly accelerate the immobilization of CO₂ by dissolution (and perhaps residual gas trapping) at comparatively low cost.

In this paper, we focused on increasing the rate of dissolution. Methods similar to those explored here, might be used to (i) increase the volumetric storage efficiency; (ii) steer large-scale movement of the free-phase CO₂ ‘bubble’, for example, to direct it away from a spill point or a known weakness in the caprock; (iii) accelerate the development of density driven convection within the brine; and, (iv) decrease reservoir pressures (and pressure gradients) near the point of injection.

Active reservoir engineering might play an important role in geologic storage for two distinct reasons. First, such engineering can reduce the actual risk of CO₂ leakage. Second, by shortening the timescale over which free-phase CO₂ remains in the reservoir, such methods might facilitate risk analysis and reduce regulatory and other uncertainties related to storing mobile CO₂ underground for long durations.

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**References**


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Table 1: The Aquifer properties used in simulations
Figure Captions

Figure 1: Top view of the aquifer used in the simulations which showing the modeled element of symmetry. CO₂ injection is a center. Brine injection is near center in two horizontal wells shown schematically.

Figure 2: Comparison between results of 30×30×10 and 60×60×10 grid block systems for gas injection well bottom-hole pressure, water injection well bottom-hole pressure, aquifer average pressure, and fraction of the injected gas dissolved in the formation water with 200 m³/day of water injection.

Figure 3: Effect of water injection rate on the dissolution of the injected gas into the aquifer.

Figure 4: Vertical cross sections at year 50. The without brine pumping on the right, with pumping on the left. Top row is gas saturation, bottom row is CO₂ content of brines (mole fraction).

Figure 5: Power requirements for brine pumping with various water injection rates.

Figure 1

Figure 2

Figure 3

Figure 4

Figure 5