

Accelerating The Dissolution of CO₂ in Aquifers

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Abstract

Assessments of aquifer storage capacity and security have generally assumed that reservoir engineering would be limited to site selection and placement of the injection wells. In previous work we have shown that it is possible to accelerate the dissolution of CO₂ in brines by active reservoir engineering achieved by pumping brines from regions where it is undersaturated into regions occupied by CO₂ [1]. Here we report 2- and 3-D reservoir simulations of aquifers with/without horizontal confinement and with/without inhomogeneity. For a horizontally confined reservoir geometry, we find that it is possible to dissolve essentially all injected CO₂ within 300 years at an energy cost that is less than 10% of the cost of compressing the CO₂ from atmospheric pressure to reservoir conditions. We anticipate that reservoir engineering to accelerating dissolution can simplify risk assessment and permitting of storage projects, and will expand the number and geographic extent of reservoirs which are acceptable for storage.

Keywords: CO₂, dissolution, aquifer, efficiency, risk mitigation.

Introduction and objectives

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.

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. 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 residual gas trapping, dissolution in the reservoir fluids or subsequent geochemical reactions. Storage security can be increased either by reducing the probability of leakage or by increasing the rate at which CO₂ is immobilized within the aquifer.

In a previous work we have shown that reservoir engineering methods can be used to accelerate the dissolution of CO₂ in brines reducing the time-scale in which leakage is possible, and thus reducing the risks of leakage and simplifying risk assessments.

In this paper we explore the feasibility of pumping brine from distant, undersaturated, regions in the aquifer to the CO₂ ‘bubble’ in order to accelerate mass transfer so accelerating dissolution. More specifically, our objective is to develop and test configurations for brine production and injection wells in simple reservoir geometries that

- maximize the rate of CO₂ dissolution, and or
- minimize the energy cost of dissolution.

Methodology

In earlier work we explored the possibility of accelerating dissolution in unconfined horizontal aquifers. In this paper we have studied the acceleration of dissolution in horizontal confined reservoirs for which higher dissolution rates can be achieved at lower energy cost. In addition, we have crudely optimized injection geometry using ensembles of reservoir simulations and have explored the effects of reservoir inhomogeneity.

In minimizing the energy cost of dissolution, we have defined a figure-of-merit as follows. For each case we compare a reference case with CO₂ injection but without any additional fluid pumping to an ‘engineering’ case with pumping. We then (i) assess the increase in CO₂ dissolution (engineering - reference) and (ii) assess the mechanical, *pressure × volume*, work done by the additional pumping fluids within the reservoir. The most important figure-of-merit is the ratio of additional work done to the mass of CO₂ dissolved due the engineering. For convenience, we normalize this by 300 kJ/kg which is approximately the energy required to compress CO₂ from STP to typical reservoir conditions [1]:

$$\varepsilon = \frac{\Delta \text{ pumping work (kJ)}}{\Delta \text{ CO}_2 \text{ dissolved (kg)}} \times \frac{1}{300(\text{kJ/kg})}$$

Injection of CO₂ and brines was simulated using three commercial reservoir simulators: GEM-GHG (a derivative of the GEM Compositional simulator which being developed for CO₂ storage applications by CMG); Schlumberger’s ECLIPSE-100 and CMG’s IMEX (both are Black-Oil reservoir simulators). In order to use a Black-Oil simulator for gas storage simulation one needs to represent brine and CO₂ by oil and gas, respectively. The CO₂ solubility in brine then can be represented by gas dissolution in oil using solution gas-oil ratio function [2]. For a two-component system, the ‘Black-Oil’ formulation does not introduce any additional approximations and is more numerically robust and faster.

Results

We have examined two idealized reservoir geometries: first, an infinite horizontal reservoir and second, a ‘top-hat’ geometry in which a cylindrically-symmetric vertical step serves as a barrier to horizontal migration of CO₂. In each case, the caprock that forms the upper boundary is assumed to be impermeable. The ‘top-hat’ geometry and reservoir properties are shown in Figure 1. The reservoir properties (including depth) for the ‘infinite horizontal’ case are identical to those shown in Figure 1 except for the absence of confining step.

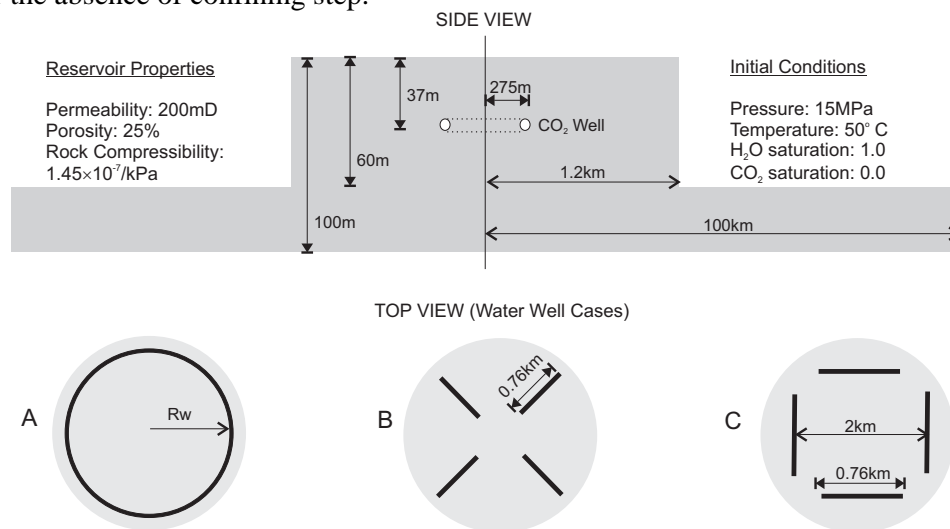


Figure 1 Schematic drawing of ‘top-hat’ reservoir geometry with three of alternate well configurations.

In all cases CO₂ is injected at a rate of ~1 megatons per year for 15 years. In the brine injection cases presented here we do not explicitly model brine production. In a real-world application one would produce brine at one or more wells distant from the injection site. For simplicity, we have chosen a reservoir with sufficiently large horizontal extent (100 km radius) that the increase in average pressure due to brine injection at the boundary can be neglected over the simulation period. We have verified that this approximation does not significantly affect the results with simulations that included explicit brine production and injection.

The effect of brine injection in the top-hat geometry is shown in Figure 2 for a case where the brine injection well is located near the ‘edge’ of the reservoir formed where the caprock meets the confining wall. With brine injection at 1 Mt/year, ~63% of the CO₂ is dissolved in 200 years forming a plume of saturated brine that moves outwards from the confining top-hat. In the absence of brine injection there is negligible CO₂ dissolution after initial injection during the same time period. The effect of brine injection on dissolution is evident in Figure 3: compare the solid lines labeled ‘1 Mt/yr’ and ‘0 Mt/yr’.

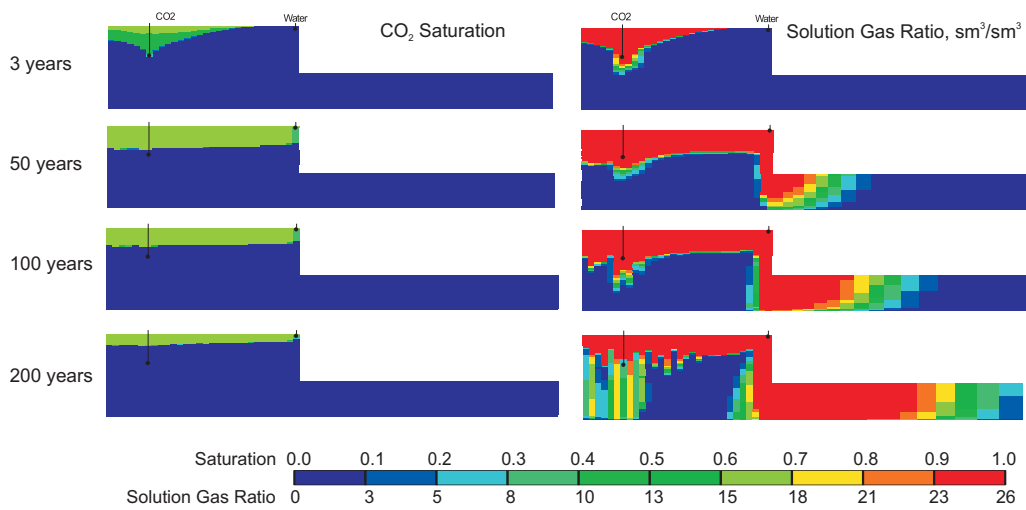


Figure 2 Gas saturation and dissolved gas fraction during brine injection.

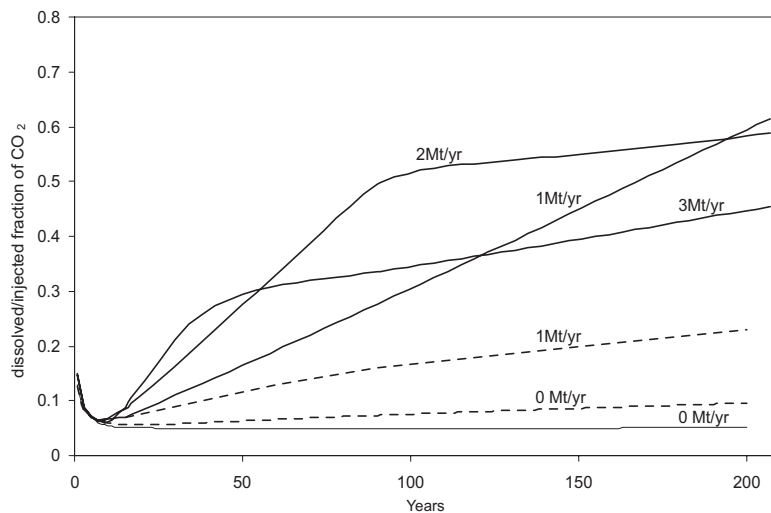


Figure 3 Dissolved fraction of CO₂ (dashed lines for horizontal reservoir, solid lines for ‘top-hat’ geometry) for different brine injection rates.

Brine injection is substantially more effective in accelerating dissolution in the confined geometry because buoyancy forces acting on the CO₂ bring it into closer contact with the injected brine. In the case of the ‘infinite horizontal’ reservoir brine injection pushes the CO₂ away from the injection point reducing the effectiveness of further injection. (Compare the 1 Mt/yr injection rates in the two cases shown in Fig. 3.). Note that, without brine injection dissolution is slightly higher in the ‘infinite horizontal’ case because the CO₂ continues to spread beneath the caprock after CO₂ injection ceases.

Optimizing injection well placement and injection rate. We systematically explored the effect of varying well location in the cylindrically symmetric case ‘top-hat’ and found that the optimal location for the injection well was at the top of the reservoir at the maximum radius as constrained by the horizontal step in the caprock. Figure 4 shows the effect of varying injection well radius on dissolved fraction after 200 years of simulation.

We also varied the injection rate as shown in Figure 5. For each injection rate, the fractional dissolution exhibited a bilinear behaviour. The rate of dissolution makes a sharp transition from relatively high dissolution rates to substantially lower dissolution rates with a transition time that occurs later for lower injection rates. The transition between high and low dissolution rates is associated with the moment when brine injection has reduced CO₂ saturation at the brine injection point to zero (Figure 5). It opens a CO₂-free path for undersaturated brine from the injection well to the bottom of the reservoir.

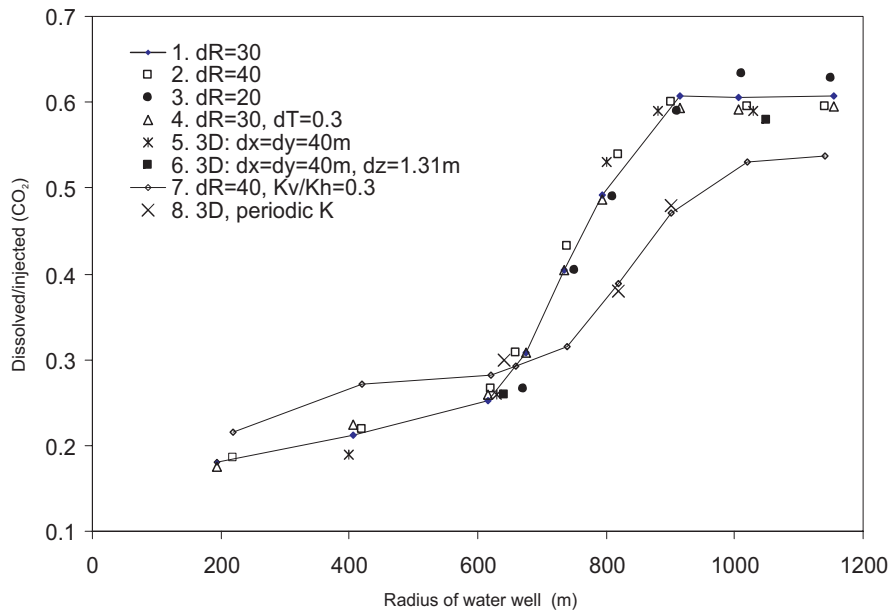


Figure 4 Dissolved fraction as a function of injection well radius and numerical tests. The first six data sets demonstrate that discretization errors are small: data sets 1-4 show 2D simulation with different grid size in radial direction ($dR=30, 40, 20$ with time step 1day and 30 meters with time step 0.3day), while data set 5-6 show 3D simulations using a cartesian grid. Data sets 7 and 8 explore the impacts of reservoir anisotropy and inhomogeneity as described in the text.

3D simulations with alternate well geometries and reservoir inhomogeneity. The cylindrically symmetric reservoir geometry and the circular injection wells are, of course, quite unrealistic. A real-world reservoir would have an uneven and tilted caprock as well as inhomogeneous reservoir properties; and, real-world injection wells would not be as long or symmetric as the wells explored here.

We have explored more the realistic injection well geometries shown as ‘B’ and ‘C’ in Figure 1. The ‘C’ geometry proves to be more effective in accelerating dissolution because it more nearly approximates the optimal large-radius well geometry. Using the ‘C’ geometry, ~43% of injected CO₂ was dissolved in 200 years as compared to ~63% in the optimal circular case with the same 1 Mt/yr injection rate.

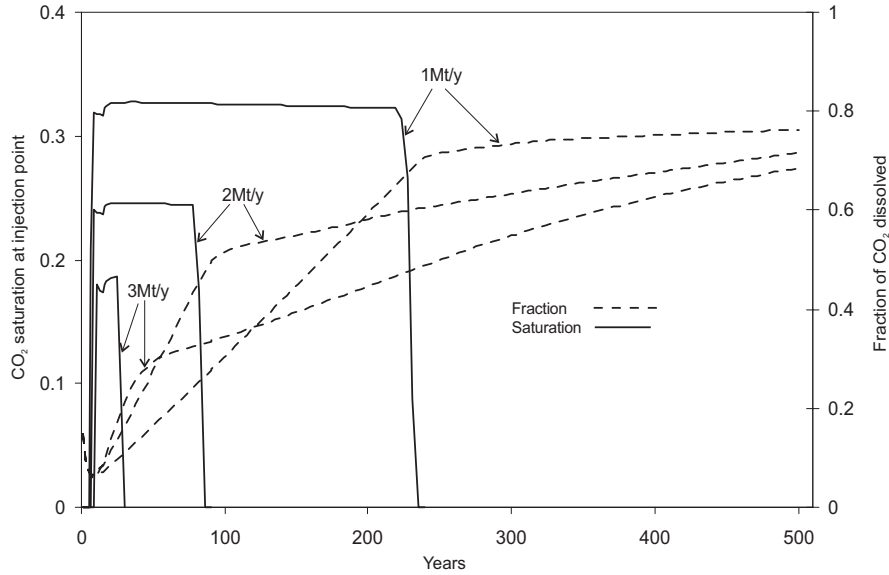


Figure 5 Dissolved fraction (dashed lines right axis) and gas saturation at the injection well location (solid lines left axis) for a 2D simulation with the maximum-radius injection well.

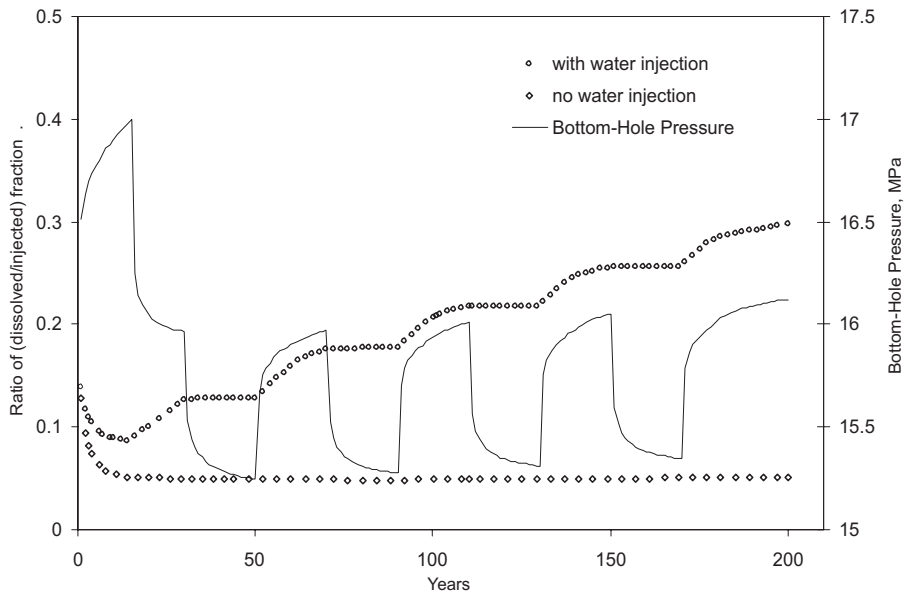


Figure 6 Cyclic brine injection. The result plotted is for a 500m-radius injection well. The corresponding result without cycling produces a lower fraction dissolved, ~0.2 after 200 years as compared to ~0.28 with cycling, but requires roughly twice the pumping energy.

Finally, we have explored the effect of reservoir anisotropy by making horizontal permeability three times the vertical permeability, $K_v = K_h/3$ (Fig. 4 data set '7'). Finally we explored the effects of reservoir inhomogeneity by introducing periodic perturbations in the horizontal permeability: $K_h = 200 \exp[(\gamma \cos(2\pi x) \cos(2\pi my) \cos(2\pi mz)]$ with $\gamma=0.2$, $l=m=1/120\text{m}$ and $n=1/5\text{m}$.

Cyclic brine injection. It was shown that cycling of water injection may enhance the dissolution as well as reducing the energy required for pumping. Figure 6 shows results from a case in which brine is injected on a ~20 year interval with the rate of 1 Mt/year. Cyclic injection increases the dissolution of CO₂ compared to the constant injection as well as reducing time-integrated power required for pumping brines. Figure 6 shows the dissolution efficiency with and without saline water injection and the bottom-hole pressure for the case with water injection. In this case the dimensionless efficiency ε of brine pumping was about 7%.

Conclusions

We demonstrate that pumping of brines within a reservoir can significantly accelerate the dissolution of CO₂ in an aquifer. For an infinite reservoir bounded by a horizontal caprock the brines injected push the CO₂ 'bubble' into undersaturated water-CO₂ area of reservoir, while for the a horizontally confined reservoir the undersaturated injected water mixes with the CO₂ 'bubble' trapped by the step.

Although we have not yet explored the effectiveness of using brine pumping to accelerate dissolution in a fully realistic reservoir, we have obtained broadly consistent results using several different reservoir and injection well geometries and when representations of reservoir anisotropy and inhomogeneity are included. The consistency of results suggests that similar engineering techniques could be applied to real-world reservoirs.

Assessments of the risk of leakage of CO₂ from a storage formation may need to consider leakage mechanisms and their likelihood of occurrence during the full time period over which mobile free-phase CO₂ remains in the reservoir. Accelerating CO₂ dissolution in brines reduces the time-scale in which leakage is possible. Once dissolved, risk assessments may well ignore the leakage pathways resulting from the very slow movement of CO₂-saturated brines. Developing cost-effective means to accelerate the rate of CO₂ dissolution in aquifers is therefore of first-order importance.

We speculate that similar methods might be used to (i) increase the volumetric storage efficiency; (ii) steer the 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 residual phase trapping of the liquid or supercritical phase; and, (v) decrease reservoir pressures (and pressure gradients) near the point of injection.

List of References

- [1] Keith D.W., Hassanzadeh H and Pooladi-Darvish M., 2005: Reservoir engineering to accelerate dissolution of stored CO₂ in brines. *Proceedings of 7th International Conference on Greenhouse Gas Control Technologies*, Pergamon.
- [2] Hassanzadeh H., Pooladi-Darvish M., Elsharkawy A.M., Keith D.W. and Leonenko Y., in press: Predicting Thermodynamic and Transport Properties of a CO₂-Water Mixture for Geological Storage *Fluid Phase Equilibria*.