Dissolved CO_2 injection to eliminate the risk of CO_2 leakage in geologic carbon storage

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Abstract. Geologic carbon storage is usually viewed as injecting, or rather as storing, CO_2 in supercritical phase. This view is very demanding on the caprock, which must display: (1) high entry pressure to prevent an upward escape of CO_2 due to density effects; (2) low permeability to minimize the upwards displacement of the brine induced by the injected CO_2; and (3) high strength to ensure that the fluid pressure buildup does not lead to caprock failure. We analyze the possibility of injecting dissolved CO_2 and, possibly, other soluble gases for cases when the above requirements are not met. The approach consists of extracting saline water from one portion of the aquifer, reinjecting it in another portion of the aquifer and dissolving CO_2 downhole. Mixing at depth reduces the pressure required for brine and CO_2 injection at the surface. We find that dissolved CO_2 injection is feasible and eliminates the risk of CO_2 leakage because brine with dissolved CO_2 is denser than brine without dissolved CO_2 and thus, it sinks towards the bottom of the saline aquifer.

Keywords: CO_2 storage, dissolved CO_2, leakage, caprock, buoyancy.

1.1 Introduction

Geologic carbon storage is usually considered as injecting CO_2 in free phase under supercritical or liquid (cold) conditions, which will eventually become supercritical

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under pressure and temperature reservoir conditions (Vilarrasa et al., 2013). This injection scheme leads to a CO_2-rich phase which floats on resident brine. Thus, CO_2 remains in the upper portion of the saline formation, which may lead to leakage across the caprock. While the concept is robust and simple, its application is hindered by two sets of difficulties (Fig. 1.1):

1) Large volumes of CO_2, in the order of millions of tons per year, will have to be injected for industrial scale geologic carbon storage projects. Such injections will displace the resident brine, possibly polluting shallow drinking water aquifers (Birkholzer and Zhou, 2009; Birkholzer et al., 2012). Additionally, a large pressure buildup will be generated, which may reactivate fractures or faults, potentially inducing felt earthquakes (Zoback and Gorelick, 2012; Vilarrasa and Carrera, 2015),
2) Supercritical CO_2 is lighter than the resident brine, so it may leak upwards along sloping aquifers, across the caprock, through faults or wells (Lindeberg, 1997; Pruess, 2008; Nordbotten et al., 2009; Humez et al., 2011).

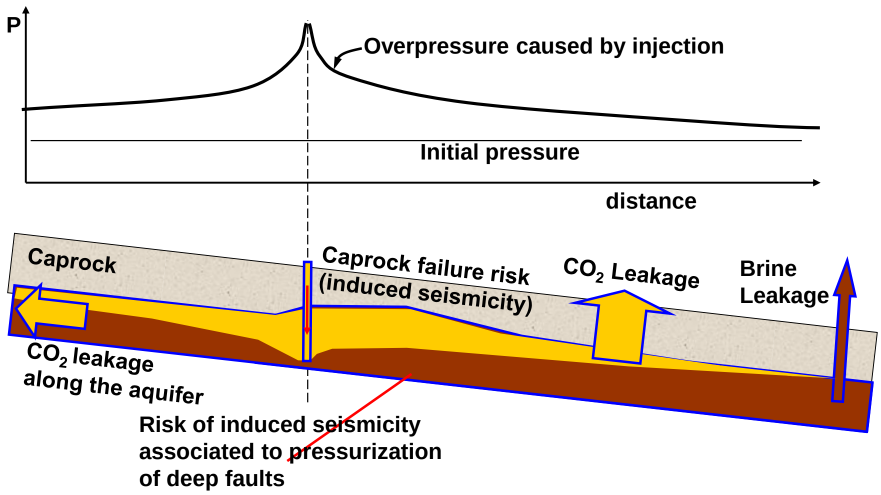

Fig. 1.1 Schematic representation of supercritical CO_2 storage and some of the difficulties it must overcome. Note that overpressure (above) can be large and extend over a large area, thus risking caprock sealing capacity and the occurrence of felt induced seismicity

These difficulties have motivated approaches for fluid pressure control. The main idea behind these approaches consists in pumping native brine from the storage formation where CO_2 will be injected. The pumped brine can be disposed of (e.g., in sites close to the sea), or desalinated (e.g., in water scarce regions) and the residual brine reinjected into a saline formation (Court et al., 2011; Bergmo et al., 2011). This concept includes approaches such as the "Active CO_2 Reservoir Management" (Buscheck et al., 2011, 2012) or the "Passive injection" strategy (Dempsey et al., 2014). These approaches increase CO_2 storage capacity and reduce the induced pressure buildup and associated risks. Nonetheless, the risk of leakage persists with these two storage strategies because the injected CO_2 is still buoyant and thus, stays at the top of the storage formation.

To overcome this issue, CO_2 can be injected dissolved into the brine. Dissolved CO_2 injection can be regarded as a special case of pressure control. By injecting CO_2 dissolved in the pumped brine, the risk of buoyant escape of CO_2 is eliminated. This is because the density of CO_2-rich brine is higher than that of resident brine and thus, the injected CO_2-rich brine will tend to sink towards the bottom of the storage formation (Fig. 1.2).

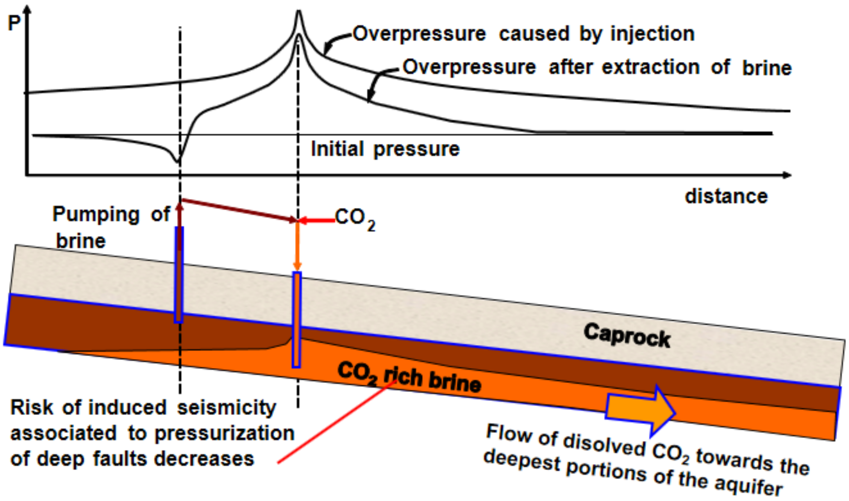

Fig. 1.2 Schematic representation of the dissolved CO_2 concept. Brine is pumped from the storage formation and reinjected after dissolving CO_2 in it. Note that both maximum pressure buildup and the area affected by overpressure are significantly reduced. Note also that the concept can be extended to other flue gases (Carrera et al, 2011)

It may be argued that CO_2 will dissolve naturally in the aquifer without the need of engineered actions. However, dissolving the whole CO_2 plume may require centuries. Actually, dissolution rates are slow for relatively low permeability media and only becomes quite fast in porous media with a high vertical permeability once convection develops under the CO_2 plume (Riaz et al., 2006, Hidalgo and Carrera, 2009, Pau et al., 2010; MacMinn et al., 2012; Elenius and Johannsen, 2012). Even though CO_2 dissolution can be accelerated by fluctuating the injection rate (Bolster et al., 2009) and/or by alternating CO_2 and brine injection either in the well or at some distance (Leonenko and Keith, 2008, Hassanzadeh et al., 2008; Zhang and Agarwal, 2012), some of the injected CO_2 will continue in free-phase.

The goal of this paper is to present the dynamics of a dipole system in which brine is pumped from one well and brine with dissolved CO_2 is injected in the other well. We aim to assess the feasibility of dissolved CO_2 injection as an effective storage strategy. We also investigate the effects of this storage approach on the rock geomechanical stability.

1.2 Dynamics of the Dipole System

The dynamics of a dipole system of dissolved CO_2 injection and brine pumping is non-trivial. The injected CO_2-rich brine is denser than the resident brine and, as a result, it tends to sink. However, this sinking tendency of CO_2-rich brine is counter-balanced by the high pressure at the injection well and by the drag generated by the pumping well. Consequently, part of the injected CO_2 may be pumped and returned to the surface, which reduces the efficiency of the system. The critical pumping rate, Q_c [L^3 T^{-1}], can be defined as the maximum flow rate that can be pumped with negligible CO_2 concentration (0.1% of saturation) (Pool et al., 2013).

To understand the system dynamics and thus, being able to optimize its design, we consider a homogeneous sloping aquifer of constant thickness b [L] and slope m [–] (Fig. 1.3). The dipole system consists of an injection-pumping well pair. A fully penetrating pumping well pumps brine from the storage formation at a constant flow rate, Q_p [L^3 T^{-1}]. The pumped brine, CO_2 and, possibly other gases, are injected separately at the injection well, which is located at a distance d [L] downslope, and mixed downhole. The resulting CO_2-saturated brine is denser than the native brine, leading to a safe storage in which the CO_2-saturated brine will sink to the bottom of the storage formation.

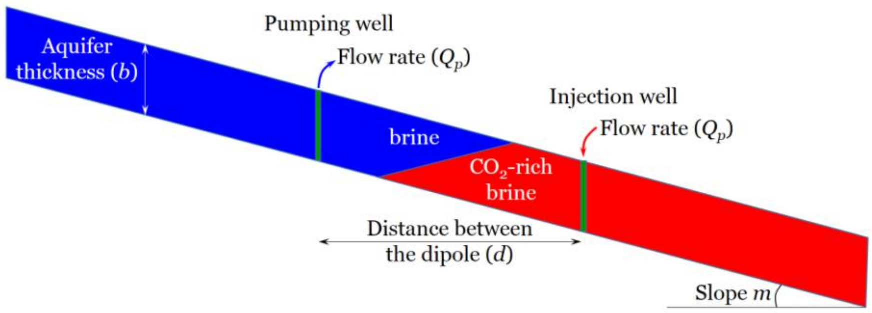

Fig. 1.3 Model set-up for the analysis of dissolved CO_2 injection in a dipole system in which brine is pumped and reinjected with CO_2 in the same saline formation through vertical wells in a sloping homogeneous aquifer

To illustrate the dynamics of the system, we show the case of a confined saline aquifer, with 20% slope, at a depth ranging from 1000 to 1800 m. The aquifer is assumed homogeneous and isotropic. The extent of the model is 4000 x 1000 x 50 m^3 and the distance between the fully penetrating injection-pumping well pair is

500 m. Water viscosity, μ [M L^{-1} T^{-1}], is assumed to be constant and equal to 0.4 mPa·s. The buoyancy factor is taken as ε=0.027 (ε=(ρ_s-ρ_b)/ ρ_b, where ρ_s [M L^{-3}] is the density of CO_2 saturated brine and ρ_b [M L^{-3}] is the density of resident brine).

Simulation results show that the movement of the injected CO_2-saturated brine plume is governed by two factors: (1) viscous forces induced by the pumping-injecting wells which produce a dipole flow field, and (2) buoyancy forces caused by the difference between the density of the injected CO_2-saturated brine and that of the resident brine. Buoyancy, f_b [M L^{-2} T^{-2}], is quantified by (Pool et al., 2013)

$$f_b = V'\Delta\rho m g \tag{1.1}$$

where V' [L^3 L^{-3}] is the dimensionless injected volume, which is given by $V' = Q_p t/(\pi d^2 b)$, t [T] is time, g is gravity [L T^{-2}] and $\Delta\rho$=ρ_s-ρ_b [M L^{-3}]. Viscous forces, f_v [M L^{-2} T^{-2}], are given by (Pool et al., 2013)

$$f_v = \frac{Q_p \mu}{2\pi d b k} \tag{1.2}$$

where k [L^2] is the intrinsic permeability. While buoyancy forces grow with the plume size because they depend on the injected volume V', viscous forces remain constant over time. This difference explains the time dependent role of density. During the initial stage (Fig. 1.4a), viscous forces mainly control flow and transport and thus, CO_2-saturated brine migrates radially from the injection well and towards the pumping well. Similar effects would be obtained assuming constant density. Once the CO_2-saturated brine plume reaches the pumping well, CO_2 concentration in the pumping well rises gradually until an equilibrium between upslope forces caused by the pumping well and downslope forces driven by buoyancy effects is attained (Fig. 1.4b). At this instant of time (t_d [T]), the CO_2 mass fraction at the pumping well reaches its maximum. Afterwards, density-driven flow leads to a growth of the plume downslope along the bottom of the aquifer because buoyancy forces increase and start to dominate over viscous forces. As a result, the extent and weight of the plume rise, pulling the plume downslope. This pull retreats the CO_2-saturated brine plume towards the injection well, which leads to a decrease in the CO_2 mass fraction at the pumping well (Fig. 1.4c). Finally, steady state is reached (Fig. 1.4d). It should be highlighted that the first arrival decreases with the pumping rate, but the peak time remains constant, which is surprising and requires further analysis.

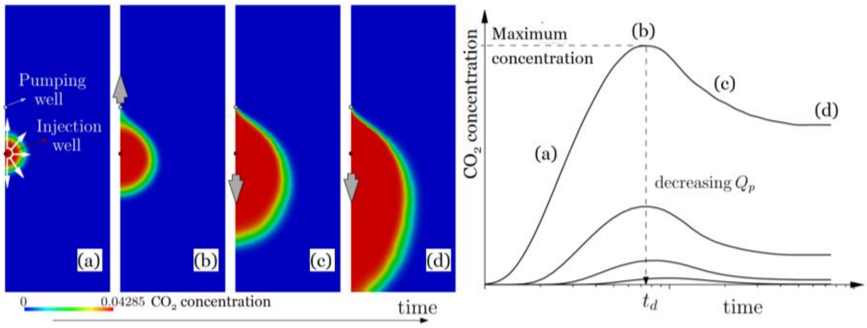

Fig. 1.4 The four stages (a-d) of dissolved CO_2 injection in a sloping aquifer: left, plan view of vertically averaged concentration; right, time evolution of CO_2 concentration at the pumping well (modified from Pool et al., 2013)

The first arrival time of the CO_2, which is controlled by the dipole nature of the flow field, can be computed by integrating the travel time along the flow line between the two wells, giving (Grove and Beetem, 1971)

$$t_0 = \frac{\pi \phi b d^2}{3Q_p} \tag{1.3}$$

where ϕ [L^3 L^{-3}] is porosity. This implies that the first arrival depends on the distance between the two wells, the aquifer thickness and the pumping rate. However, it is independent of the aquifer permeability. On the other hand, the time for which the CO_2 mass fraction at the pumping well peaks (t_d) is controlled by the balance between buoyancy and viscous forces. Since both are proportional to Q_p and inversely proportional to b, t_d becomes independent of both the flow rate and aquifer thickness. But t_d is affected by the aquifer slope and the aquifer permeability. On the one hand, an increase in the aquifer slope causes f_b to increase and thus, the time to balance viscous forces decreases. On the other hand, a decrease in permeability leads to an increase in f_v, which increases the time to reach equilibrium.

The response of the system is also affected by the well characteristics, i.e., vertical or horizontal, because pressure buildup evolution differs when injecting through horizontal and vertical wells. CO_2 injection induces a smaller overpressure when injecting through vertical than horizontal wells (Zhang and Agarwal, 2012; Vilarrasa, 2014). In contrast, it is the other way around for water injection (Zhang and Agarwal, 2012). For CO_2 injection through a vertical well, pressure buildup peaks at the beginning of injection, but subsequently drops (Vilarrasa et al., 2016). However, pressure builds up continuously when injecting CO_2 through a horizontal well, which induces a higher pressure buildup in the long term (Zhang and Agarwal, 2012). In contrast, water injection leads to higher pressure buildup when injecting through a vertical than a horizontal well. As a result, caprock and fault stability may be compromised. Even though caprock integrity is not a concern when injecting CO_2 dissolved in brine because it sinks, fault stability may be an issue because of potential felt induced seismicity (De Simone et al., 2017). Thus, horizontal wells are preferable for injection of CO_2-rich brine.

1.3 Conclusions

We have shown that dissolved CO_2 injection is feasible to store CO_2 in deep saline formations. This CO_2 storage concept displays a number of advantages over conventional supercritical CO_2 storage. First, it is easy to control and generates little overpressure, which reduces (virtually eliminates) induced seismicity risk. Second, since CO_2-rich brine is denser than native brine, CO_2 tends to sink towards the deepest portions of the storage formation, reducing (virtually eliminating) the risk of CO_2 leakage. Last but not least, for the same reason, there is no need for a caprock.

1.4 Acknowledgments

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