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STOCHASTIC ANALYSIS OF FACTORS AFFECTING THE LEAKAGE OF CO_2 FROM INJECTED GEOLOGICAL BASINS

Ana González-Nicolás, Brent Cody and Domenico Baù

Colorado State University
Department of Civil and Environmental Engineering
Fort Collins, CO 80523-1372 USA
e-mail: anagna@engr.colostate.edu

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1 INTRODUCTION

The Earth is experiencing global warming as a consequence of increased greenhouse gas (GHG) concentrations[1]. Carbon dioxide (CO_2) is the most important GHG produced by human activities[1]. In the last decade, Carbon Capture and Sequestration (CCS) had been advanced as a promising technology for reducing CO_2 emissions in the atmosphere. Deep saline aquifers are possible sites for long-term CO_2 storage[2,3,4]. CCS in deep saline aquifers involves gravity override since the supercritical CO_2 injected is less dense and less viscous than brine. If the injected CO_2 finds a potential pathway that leads back to the surface, it may affect adversely shallow groundwater resources or even land surface. Characteristics of the cap rock overlying the injected formations are decisive elements for the effectiveness and safety of CCS systems. Permeability, spatial distribution of potential carbon escape pathways, and increase of pore pressure in the injected formations may directly influence CO_2 leakage. Also, additional leakage pathways may be created during the CO_2 injection process due to fracturing of the cap rock associated with increased pore pressure and the ensuing effective stress reduction.

Therefore, assessing the risk of leakage of CO_2 given the uncertainty on these parameters is vital prior to the implementation of this technology. In this work, we investigate the effect of uncertain parameters such as: porosity and permeability of injected aquifers, cap rock permeability, and the location, size and permeability of CO_2 leakage pathways through the sealing layers. A statistical probability distribution function is prescribed for each of these parameters representing their typical range of variability. Three injection scenarios are considered, which differ from one another depending on CO_2 injection rates and time schedules. A semi-analytical model, CO2FLOW[5], based on previous works[6,7,8,9,10], is used to simulate the injection of CO_2 into a hypothetical deep saline aquifer overlain by a sequence of aquitards and aquifers. A stochastic simulation approach is applied to study the influence of the uncertain parameters on: (i) the mass of CO_2 that migrates into overlying formations, in relation to the total mass of injected CO_2; and (ii) the maximum fluid overpressure produced by carbon injection.

2 METHODOLOGY

2.1 Geological setting

The analysis is applied to the hypothetical geological system described in Figure 1, consisting of a deep saline aquifer overlain by three aquifers and four aquitards. The enumeration of the aquifers starts at the deepest from L1 to L4. Supercritical CO_2 is injected within aquifer L1 from a single well. Aquifer L1 has a thickness of 100 m, whereas the other three overlying aquifers are each 350-m thick. The bottom of aquifer L1 is 1500-m deep. The four aquifers are separated by 50-m thick aquitards, which are assumed impermeable except where there is a leaky pathway. When the plume of CO_2 reaches a leaky pathway, it can escape to the upper aquifer. Initially all formations are saturated with brine under hydrostatic pressure conditions. Three main scenarios having differing CO_2 injection rates and durations are simulated: 100 kg/s over 20 years (Scenario S1), 50 kg/s over 40 years (Scenario S2) and 33.33 kg/s over 60 years (Scenario S3). The final injected mass of CO_2 of the three scenarios is the same: 63,072,000 t. 24 leaky pathways are assigned, which form a square regular grid with the injection well positioned at its center. The N-S and E-W distances between pathways are 1 km. A reference case is considered with the hydro-geomechanical parameters provided in Table 1. Parameters of this table remain unchanged (deterministic) unless the parameter of interest is considered uncertain.

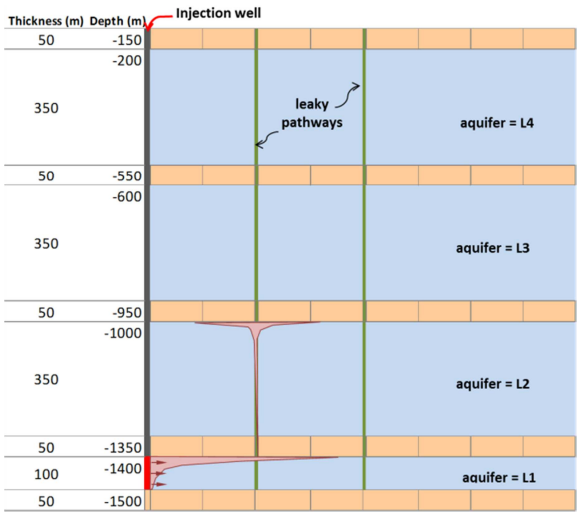

Figure 1: Hypothetical geological setting used in this study

Parameter	Symbol	Value
Aquifer permeability (m^2)	k	1E-13
Aquifer porosity (/)	ϕ	0.15
Pathways permeability* (m^2)	k_{lp}	1E-13
Radius pathways (m)	r	0.20
Number of pathways (/)	n_{lp}	24
Brine density (kg/m^3)	ρ_b	1000
CO_2 density (kg/m^3)	ρ_c	600
Brine viscosity (Pa·s)	μ_b	4.5E-4
CO_2 viscosity (Pa·s)	μ_c	4.6E-5
Brine residual saturation (/)	$s_{r,b}$	0.3
System compressibility (m^2/N)	C	4.6E-10

*Unless otherwise specified, k_{lp} is assumed to be equal along a leaky pathway, ie continuous.

Table 1: Hydro-geomechanical parameters

2.2 Description of the model

The algorithm used in this study is CO2FLOW[5] a semi-analytical model based on previous works[6,7,8,9,10]. CO2FLOW structures the domain as a horizontal stack of aquifer/aquitard layers perforated by injection wells and leaky pathways. The algorithm estimates fluid flux and mass transferred for both CO_2 and brine across each aquitard at each potential pathway location (i.e. leaky well) at each time step, as well as pressure difference.

Aquifers are horizontally level, homogenous, and isotropic. Aquitards are impermeable, except where perforated by leaky pathways. Therefore leaky pathways are the only locations in the domain where fluid is able to transfer between aquifers. The algorithm is a vertical integrated solution that assumes sharp interface between the displaced brine and the advancing front of CO_2. Further details about the assumptions underlain by the algorithm can be found in[6].

The multi-phase pressure equation (Equation (4)[6]) is both non-linear and discontinuous. Time stepping is required because of the discontinuous nature of the pressure equation. At each time step, a set of linear equations is solved to calculate pressures in each layer and pressure gradients across each leaky pathway. The linearization of the pressure solution is accomplished by using Green's functions. Pressure gradients, as well as CO_2 plume locations and leaky well relative permeabilities, are used to calculate leakage fluxes. The time step is then advanced and the process is repeated until a prescribed injection duration is completed. The analytical form of the algorithm allows for reducing the computational effort and performing a complete simulation in 1-2 CPU minutes, making possible the application of this solution within a stochastic simulation (or Monte Carlo) approach.

2.3 Stochastic analysis

In the stochastic analysis presented here, the uncertain parameters of interest are: permeability and porosity of injected aquifers; permeability of the leaky pathways; and cap rock discontinuity as represented by the location, size and permeability of cap rock discontinuities. The prescribed statistical distributions of these uncertain parameters are given in Table 2. To characterize the permeability of leaky pathways three different distributions are considered that share the same expected value. When studying the uncertainty on cap rock discontinuity, 100 leaky pathways (with k_{lp}=1E-13 m^2) are used. Their positions are assigned randomly with a minimum radial distance of 500 m from the injection well. Table 3 shows how cap rock discontinuity is accounted for in these simulations. Leakage area is defined as the ratio between the total area of the 100 leaky pathways and the area of a hypothetical domain of 10 km x 10 km.

Parameter	Distribution	Expected value	Standard deviation	Minimum value	Maximum value	Realizations
Aquifer permeability (m^2)	Log-normal	1E-13	0.5	-	-	1000
Aquifer porosity (/)	Uniform	-	-	0.05	0.35	1000
Pathways permeability (m^2)	Case 1: Log-normal	1E-13	1	-	-	1000
	Case 2: Bi-modal	1E-13	-	1E-15*	1E-11*	1000
	Case 3: Bi-modal	1E-13	-	1E-16*	1E-10*	1000
Pathway continuity	Log-normal	1E-13	1	-	-	1000

*50% chance for bi-modal distributions

Table 2: Distribution of uncertain parameters

Case	Leaky pathways	Pathway Radius (m)	Leakage Area (%)	Realizations
A1	100	1.0	0.0003	500
A2	100	4.0	0.005	500
A3	100	5.6	0.01	500

Table 3: Area of leakage depending on the cap rock discontinuity

3 RESULTS

Results from stochastic flow simulations are presented in terms of sample cumulative distribution functions (CDF's), which can be used to estimate: *(i)* probability of fracturing that may undermine the sealing properties of the cap rock; and *(ii)* probability of leaked mass to be exceeding predefined threshold values. In these analyses, overpressure is defined as the difference between the final and initial pore pressures in proximity of the injection well, whereas the percentage of leaked CO_2 leakage is defined as the ratio between the mass of CO_2 that escapes from aquifer L1 into overlying aquifers and the total amount of injected CO_2.

3.1 Permeability of the aquifer

The permeability of the aquifer is expected to have a significant influence on the fluid overpressure, with low permeability values producing large overpressures. Figure 2a shows the CDF's of the pore overpressure in proximity of the injection well obtained by assuming uncertain aquifer permeability (Table 2). Its range varies between 8 bar and 400 bar, with the largest variability observed for the largest injection rate (Scenario S1). In Figure 2a, the red line represents the maximum admissible overpressure around the injection wells calculated as[11]:

$$\Delta p_{max} = \sigma' \cdot \frac{\upsilon}{1-\upsilon} \tag{1}$$

where: υ is the Poisson ratio and σ' is the estimated effective vertical stress at the cap rock depth. Assuming a Poisson ratio of 0.25, Δp_{max} is estimated to be equal to 62 bars. This value is considered as the overpressure threshold beyond which the cap rock is likely to fissure. Figure 2a reveals that, in Scenario S1, there is only a 65% probability of not exceeding Δp_{max}. For scenarios S2 and S3, this probability increases to about 85% and 92%, respectively. Smaller overpressures are obtained when injecting with lower flow rates (Scenario S3).

Uncertainty on formation permeability has also a significant influence on CO_2 mass leakage. In general, high permeability values correspond to reduced mass leakage (results not shown here) since low fluid overpressures are obtained, and consequently more CO_2 tends to remain in aquifer L1. Figure 2b shows that leakage of CO_2 is typically less likely at lower injection rates, although different injection rates produce similar leakage values for larger permeability values. In practice, the comparison of the results obtained in these scenarios indicates that S3 would be the most convenient scenario in terms of safety of the CCS system.

3.2 Porosity of the aquifer

Uncertainty on formation porosity has a slight effect on the maximum pore overpressure at the injection well. Figure 3a shows that the greatest variability in overpressure is found in scenario S1. In general, larger porosities results in larger values of overpressure since the propagation of the overpressure pulse depends on porosity (Equation (4)[6]) and the same amount of CO_2 occupies a smaller region of the aquifer, hence retarding the attenuation of this pulse.

Uncertainty on formation porosity has also some effect on the variability of CO_2 mass leakage. Smaller porosities are expected to result in larger leakage rates. Indeed, the shape of the

plume depends on porosity (Equation (3)[6]) and lower porosities result in faster plume propagation and a higher likelihood of encountering leaky pathways. However, Figure 3b shows that the variability of CO_2 mass leakage is relatively contained (about one order of magnitude), with lower leakage obtained with lower injection rates (scenario S3). Comparison of Figures 2 and 3 shows that uncertainty in porosity has a much lower influence on pore overpressure and CO_2 mass leakage than the uncertainty in formation permeability.

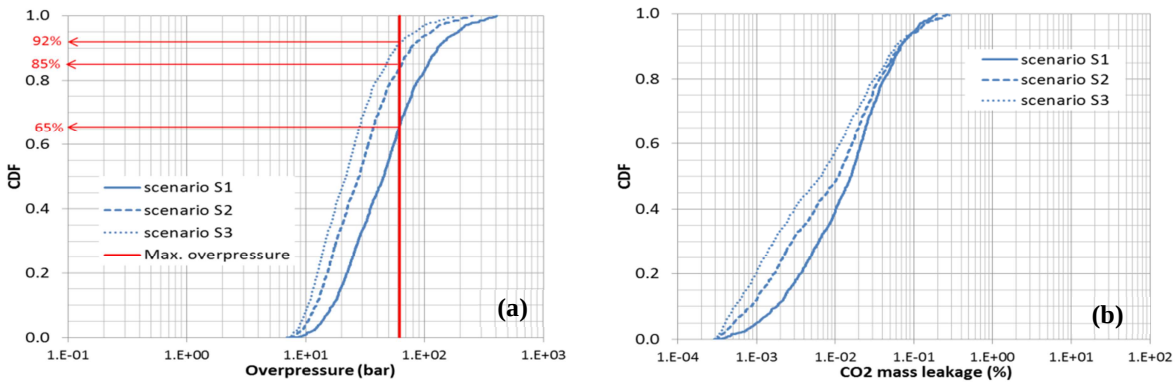

Figure 2: CDF of the (a) pore overpressure with maximum overpressure allowed in red, and (b) CO_2 mass leakage (%) for the uncertainty coming from aquifer permeability

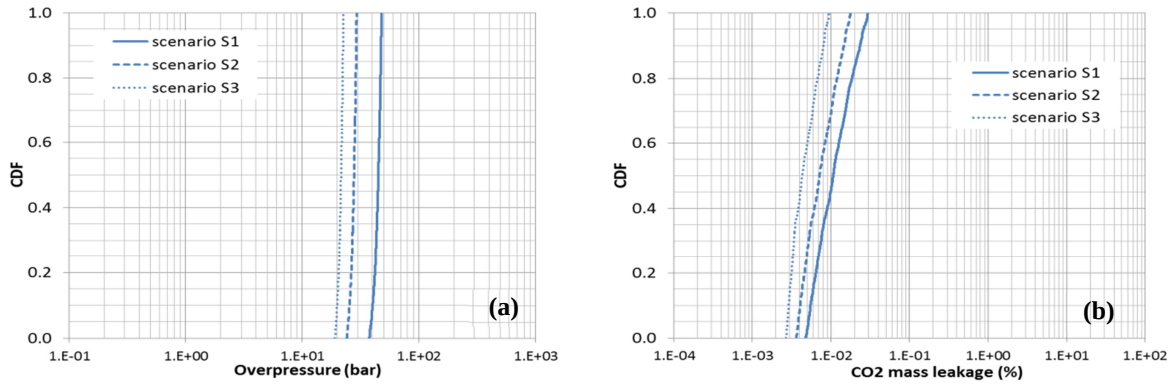

Figure 3: CDF of the (a) pore overpressure and (b) CO_2 mass leakage (%) for the uncertainty coming from aquifer porosity

3.3 Pathway permeability

Stochastic simulation results indicate the pore overpressure nearby the injection well to be fairly insensitive to uncertainty on pathway permeability and are consequently not presented here. In fact, this result can be easily explained by noting that, for the geological setting investigated here (Section 2.1), overpressure is depending upon local conditions around the injection well, such as injection rate and formation permeability, far more than it is on conditions in regions of the domain "away" from the well. Figure 4 display the CDF's of CO_2 mass leakage

according to the assumed statistical distributions of pathway permeability k_{lp}. In this case, only results for scenario S3 are shown since, as previously indicated, it appears to be the most convenient from a safety standpoint. Although all k_{lp} distributions have the same expected value, the CDF's for CO_2 mass leakage are significantly different. In Figure 4, it may be observed that for Case 1 (Table 2, log-normal k_{lp}) the probability of CO_2 leakage is typically the smallest except for values of k_{lp} sampled from the upper tail of its distribution. In Cases 2 and 3, k_{lp} is sampled from bi-modal distributions (Table 2) characterized by two equally likely values, 1E-11 - 1E-15 m^2 in Case 2, and 1E-10 - 1E-16 m^2 in Case 3. The CDF profiles in Figure 4 emphasize that CO_2 leakage is probabilistically larger in Case 3, which is characterized by leakage pathways of larger permeability.

The impact of k_{lp} on the amount of CO_2 leakage and also on plume distribution in overlying aquifers is described in Figure 5, which compares the partitioning of the mass of CO_2 leaked out from aquifer L1 among the upper formations L2, L3, and L4. Two deterministic cases characterized by different k_{lp} values, 1E-12 and 1E-13 m^2, are considered. Escape of CO_2 into shallower formations is more pronounced as the permeability of leaky pathways is increased (solid bars in Figure 5). In addition, scenario S1, which has the largest injection rate, exhibits the greatest amount of CO_2 leakage from aquifer L1.

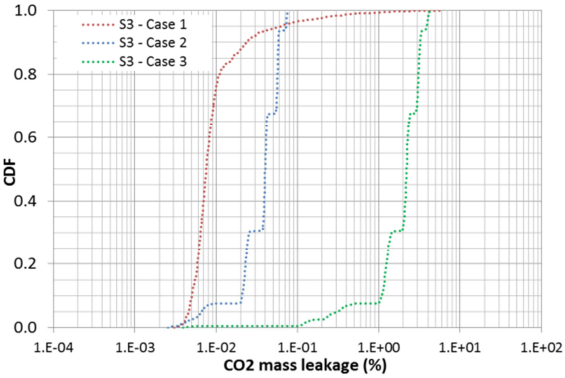

Figure 4: CDF of CO_2 mass leakage (%) for the uncertainty coming from pathway permeability

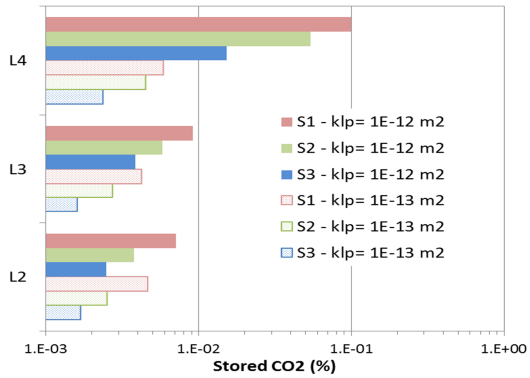

Figure 5: Comparison of distribution of stored CO_2 for different pathways permeabilities and scenarios

3.4 Leaky pathway continuity and cap rock discontinuity

Abandoned wells may constitute escape pathways for injected CO_2 when the sealing cement along its casing is deteriorated. If the deterioration is uniform along the well, then the well may be modeled as a continuous vertical pathway, characterized by a single relatively high value of k_{lp} across all aquitards. Conversely if the cement conditions are irregular along the well casing, then the well represents a discontinuous leaky pathway, with high values of k_{lp} prescribed only in some of the aquitards.

The analysis of the uncertainty on the vertical continuity of these leaky pathways shows that it has little effect on fluid overpressure in the vicinity of the injection well. Therefore these results are not presented here. Moreover, overpressure CDF's from continuous and discontinuous

pathways overlap. On the other hand, the results shown in Figure 6 indicate that CO_2 mass leakage is very sensitive to uncertainty on pathway continuity. Figure 6 shows that leakage of CO_2 is typically less likely for discontinuous pathways and the greatest variability is found for continuous pathways (about three orders of magnitude). Continuous pathways present greater leakage of CO_2 because continuous vertical pathways facilitate the upward escape of CO_2 into overlying aquifers. Instead, leakage through a discontinuous pathway is controlled by segments of the leaky well with lowest permeability, which prevents CO_2 escape and force the carbon plume to travel along a more tortuous pathway in order to leak into shallower layers.

Similar to leakage pathway permeability (Section 3.3), uncertainty on location of cap rock discontinuities slightly affects the pore overpressure CDF's as long as these are located away from the injection well. The percentage of leaky area on the cap rock is expected to affect the fluid overpressure, with larger values producing slightly lower fluid overpressure.

Uncertainty on discontinuity location of the cap rock affects the variation of CO_2 mass leakage (see Figure 7). However its impact on the CDF is less significant if compared with aquifer permeability or pathway permeability. Generally, if discontinuities are closer to the injection well greater leakage is expected. Hence, if no minimum radial distance is set (500 m), larger leakages should be expected. Figure 7 shows that CO_2 mass leakage is less likely with smaller permeable areas of the cap rock (cases A1 and A2).

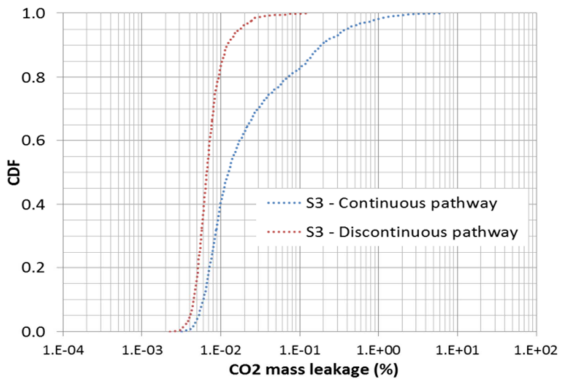

Figure 6: CDF of CO_2 mass leakage (%) for the uncertainty coming from pathway continuity

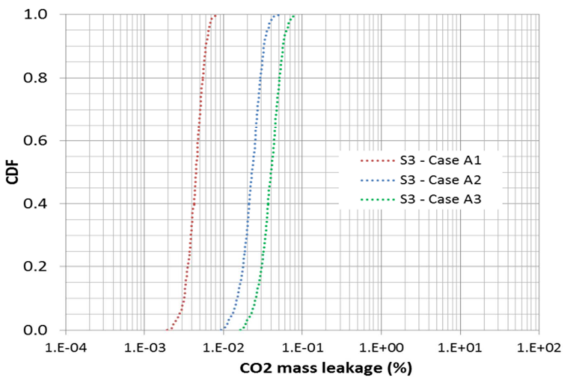

Figure 7: CDF of CO_2 mass leakage (%) for the uncertainty coming from cap rock discontinuity

4 CONCLUSIONS

In this work, the variability of CO_2 mass leaked and fluid overpressure in proximity of injection wells were analyzed stochastically based upon the uncertainty on: permeability and porosity of injected aquifers, permeability pathways, continuity pathways, and cap rock discontinuity. For the three injection scenarios considered here, it was observed that lower injection rates reduce the probability and the intensity of CO_2 mass leakage into overlying formations due the smaller fluid overpressures produced in the injected aquifer. Therefore, injection of CO_2 at low rates and protracted for a longer period of time would be most convenient policy for the safety of the CCS system.

Among the investigated uncertain parameters, the most influential on both CO_2 leakage and fluid overpressure was the aquifer permeability. Fluid overpressure in proximity of injection wells seemed unaffected by uncertainty from the permeability of leakage pathway located far away. On the other hand, the CO_2 leakage was very sensitive to this uncertainty and to the type of statistical distribution used to characterize it.

Porosity and discontinuity of the cap rock also affected CO_2 mass leakage, although comparatively less than aquifer permeability or pathway permeability. Finally, uncertainty on pathway continuity had no effect on fluid overpressure variability. However, mass CO_2 leakage was observed to be very sensitive to uncertainty from pathway continuity.

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