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MODELING OF GEOMECHANICAL PROCESSES DURING INJECTION IN A MULTILAYERED RESERVOIR-CAPROCK SYSTEM AND IMPLICATIONS ON SITE CHARACTERIZATION

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INTRODUCTION

In this paper we present results of a numerical simulation of the potential for fault reactivation and hydraulic fracturing associated with CO_2 injection in a multilayered reservoir-caprock system, and discuss its implications on site characterization. The numerical simulation is performed using the coupled processes simulator TOUGH-FLAC (Rutqvist et al. 2002, Rutqvist and Tsang, 2003), and is an extension of earlier numerical studies of a single caprock system (Rutqvist and Tsang., 2002).

In this study, CO_2 is injected for 30 years in a 200 meter thick permeable saline water formation located at 1600 meters depth (Figure 1). The injection formation is overlaid by several layers of caprocks, which are intersected by a permeable fault zone allowing upward migration of the CO_2 within the multilayered system (see Table 1 for material properties). The potential for fault slip or fracturing are calculated, based on the time-dependent evolution and local distribution of fluid pressure and the three-dimensional stress field, including important poro-elastic stresses.

The numerical results are discussed with respect to the site-characterization strategy that would be recommended for evaluation of maximum sustainable injection pressure at an industrial CO_2 injection site.

SIMULATION RESULTS

Figures 2 and 3 present the main hydrological and geomechanical results. Figure 2a shows that CO_2 spreads within the storage formation, both upward and laterally, as significant flow is allowed through the permeable fault zones. At the end of the 30-year injection period, the downhole pressure has increased by 9 MPa to 25 MPa, which is well below the lithostatic stress at depth of the injection formation. (The lithostatic stress is about 35 MPa at the injection level, based on the weight of the overlying rock mass). Effective stress decreases as fluid pressure increases within the CO_2 storage zone (Figure 2b). By comparing contours for pressure and effective stresses in Figures 2a and b, it can be observed that the decrease in vertical effective stresses is approximately equal to the increase in fluid pressure, whereas the decrease in horizontal effective stress is much smaller. This difference in the magnitude of change in vertical and horizontal effective stresses is a result of injection induced poro-elastic stresses, which tend to provide additional confining (total) stresses in the horizontal direction.

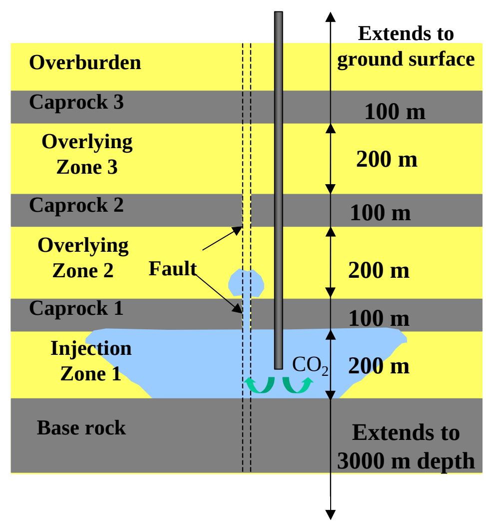
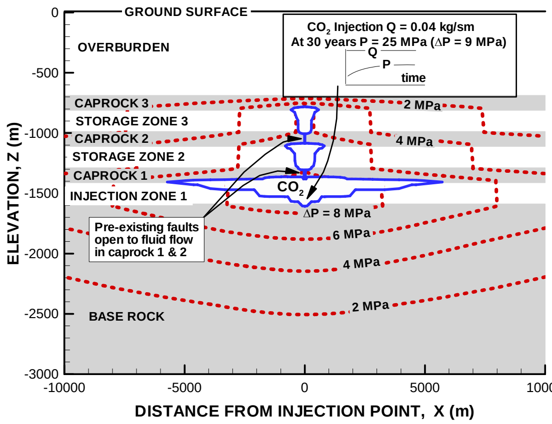


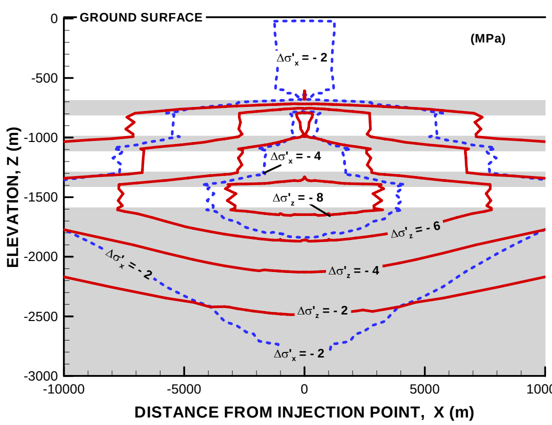
Figure 1. Model geometry for simulation of CO2 injection into a multilayered reservoir-caprock system.

Table 1. Rock properties

Property	Inject. Zone	Caps	Fault
Young's modulus, E (GPa)	5	5	2.5
Poisson's ratio, ν (-)	0.25	0.25	0.25
Saturated density, ρ_s (kg/m^3)	2260	2260	2260
Flow porosity, ϕ (-)	0.1	0.01	0.1
Permeability, k, (m^2)	1×10^{-13}	1×10^{-19}	1×10^{-14}
Residual CO_2 saturation (-)	0.05	0.05	0.05
Residual liquid saturation (-)	0.3	0.3	0.3
van Genuchten, P_0 (kPa)	19.9	621	0.9
van Genuchten, m (-)	0.457	0.457	0.457



(a)



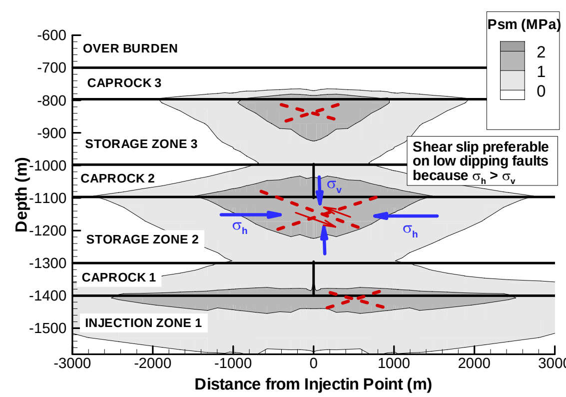
(b)

Figure 2. Simulated hydraulic and mechanical responses after 30 years of CO2 injection. (a) Spread of CO2-rich fluid and changes in fluid pressure. (b) Fluid pressure induced changes in vertical and horizontal effective stresses.

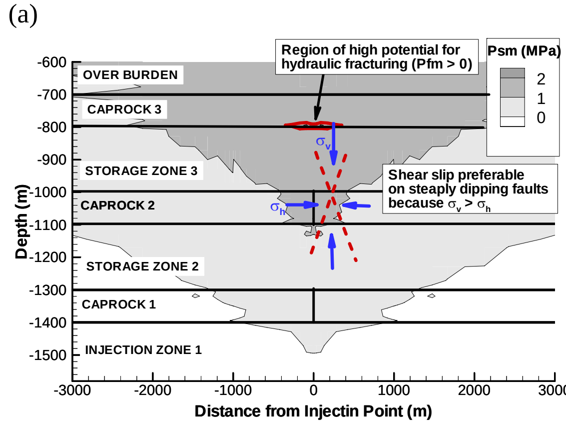
Figure 3 presents the potential for fault slip and hydraulic fracturing for two different anisotropic stress regimes—extensional stress regime and compressional stress regime. The results in Figure 3 are presented in terms of pressure margins to onset of shear slip or fracturing. These pressure margins are evaluated using failure criteria for fracturing and shear-slip adopting conservative rock mass strength parameters. Specifically, the pressure margin for fault-slip was calculated for arbitrarily oriented fractures, having zero cohesion and a static friction angle of 30°. A positive pressure margin implies that the local fluid pressure is above the critical pressure for onset of hydraulic fracturing of shear slip. In Figure 3, dark contours indicate areas of the highest potential for onset of shear slip.

The results in Figure 3 illustrate a complex distribution shear-slip potential and its dependency on the stress regime. An isotropic stress regime is most favorable for avoiding shear slip during injection (not shown). In the case of a compressional stress regime (Figure 3a), the shear slip is most likely to be initiated in subhorizontal fractures at the interface between the permeable formation layers and an overlying caprock. In the case of an extensional stress regime (Figure 3b), the shear slip is likely to occur in subvertical fractures in the upper aquifer and in the overburden rock. In addition, a high potential for hydraulic fracturing occurs in the case of an extensional stress regime at the lower parts of Caprock 3 (Figure 3b).

In this simulation the major vertical fault zone was open to fluid flow through Caprock 1 and 2, whereas it was sealed within Caprock 3. The results in Figure 3 indicates that this fault zone is much more likely to be reactivated to breach the seal of Caprock 3 in the case of an extensional stress regime, whereas it is unlikely in the case of a compressional stress regime.



(a)



(b)

Figure 3. Calculated pressure margin for shear slip under (a) compressional stress regime with $\sigma_{hi} = 1.5\sigma_{vi}$ and (b) extensional stress regime with $\sigma_{hi} = 0.7\sigma_{vi}$.(The one and only location for hydraulic fracturing is also indicated in (b).

IMPLICATIONS FOR SITE CHARACTERIZATION

The numerical results indicate that the coupled HM processes are quite complex and heterogeneous within the multilayered system and depend on the local evolution of fluid pressure and three-dimensional. Because of this complexity, a site-specific, coupled numerical analysis may be necessary for an accurate estimate of the maximum sustainable injection pressure at an industrial CO_2-injection site. Such coupled numerical modeling is associated with large data and model uncertainties, including uncertainties in location, orientation, and mechanical properties of pre-existing faults. Thus, the success and usefulness of such coupled numerical analysis is highly dependent on a comprehensive and accurate site characterization.

Our analysis shows that for evaluation of the maximum sustainable CO_2-injection pressure, it is essential to have a good estimate of the three-dimensional *in situ* stress. Thus it is not sufficient to determine estimate the lithostatic stress; the minimum principal stress is also an important parameter to characterize. Furthermore, the evolution of principal stresses (stress path) during injection should be evaluated and, if possible, monitored. Existing techniques for in situ stress measurements, e.g. hydraulic mini-frac tests, may be utilized for this purpose.

To be able to predict the evolution of stresses by coupled numerical modeling it is essential to have good estimates of the in situ mechanical and coupled hydraulic-mechanical properties. Mechanical properties of both the caprock and injection aquifer are required. If the deformation modulus of the cap rock and injection aquifer are very different, large vertical variation in poro-elastic stresses will occur, which in turn will increases shear stresses at the aquifer-caprock interfaces.

It might also be possible to estimate the evolution of the stress field by coupled hydraulic-mechanical back-analyzes against measured large-scale deformations monitored with tilt-meters during the injection. This would be possible if injection induced stresses are approximately proportional to the injection-induced deformations.

CONCLUSIONS

We have conducted a simulation study of hydromechanical processes during CO_2 injection into a faulted multilayer system. In this study, we focused on how the initial stress regime affects the potential for inducing irreversible mechanical changes in the system. The following general conclusions can be made related to the site characterization of industrial CO2 injection sites:

- The three-dimensional in situ stress field should be carefully characterized and monitored (if possible).
- Potential for fault reactivation and fracturing should be analyzed for the entire region affected by mechanical stress changes, which is generally more extensive than the region affected by fluid pressure (e.g in the overburden).
- The maximum sustainable injection pressure should be estimated using a site-specific coupled reservoir-geomechanical model that accounts for local evolutions of fluid pressure and the three-dimensional stress field.
- The mechanical and coupled hydrological-mechanical properties of various formations, including permeable formations and caprocks should be characterized.

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