Study on the Ratio of Pore-Pressure/Stress Changes During Fluid Injection and Its Implications for CO₂ Geologic Storage

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Abstract: The success of fluid injection into geological formations, which is the main operation during both carbon dioxide (CO₂) geologic storage and wastewater injection, is contingent on the geomechanical integrity of the site. A key task that allows us to evaluate the risk of geomechanical failure is the precise prediction of pore-pressure buildup and subsequent change in the state of stresses during and after the fluid injection. Contrary to traditional approaches, where total stresses are assumed to remain constant, recent studies have ascertained that total stresses in fact change in every direction as fluid extraction/injection disturbs the pore-pressure field and causes deformations. In this study, we conduct an in-depth investigation of the ratio of change in total stress to that in pore-pressure, $\Delta\sigma/\Delta P$, which has been denoted in the literature as the pore-pressure/stress coupling. We employ a numerical simulation method that couples single-phase fluid flow in porous media with poroelasticity to explore the spatiotemporal evolution of the $\Delta\sigma/\Delta P$ ratio for various conditions. These numerical experiments allow us to examine how different material properties and structural geometries would influence the evolution of $\Delta\sigma/\Delta P$ in both vertical and horizontal directions. These ratios of pore-pressure/stress changes exhibit different spatiotemporal evolutions depending on key factors that include the hydraulic boundary condition, Biot's coefficient, Poisson's ratio, and the hydraulic diffusivity of both the injection zone and caprock. On the basis of observations, we suggest firsthand guidelines for analytically determining the ratio of pore-pressure/stress changes, $\Delta\sigma/\Delta P$. Finally, we use examples and case studies to illustrate how the $\Delta\sigma/\Delta P$ ratio can be incorporated into an analytic calculation for determining a maximum sustainable pressure limit.

Keywords: Poroelasticity, pore-pressure/stress change ratio, induced seismicity, and CO₂ geologic storage

1. Introduction

Carbon Capture, Utilization, and Storage (CCUS) has been actively studied in the last two decades because of its role as a bridge in the transition from a fossil-fuel-dependent system to a renewable-energy-dependent one (Socolow and Pacala, 2006). Geologic carbon storage involves injecting carbon dioxide, which is captured from an emission source and transported to a sequestration site, into a geological formation that is typically deeper than 800 m (IPCC, 2005). Several challenges remain for the success of geologic carbon dioxide (CO₂) storage, such as managing field-wide pore-pressure buildup during CO₂ injection, enhancing the sweep efficiency of injected CO₂, monitoring CO₂ migration (Shakiba and Hosseini, 2016; Alfi and Hosseini, 2016; Hosseini and Alfi, 2015)), controlling any possible CO₂ leakage, and ensuring the geomechanical integrity of the storage site (Hosseini and Nicot, 2012; Kim and Santamarina, 2013; Kim and Santamarina, 2014; Stauffer et al., 2011). Two of these challenges—maximizing CO₂ injectivity and ensuring geomechanical integrity—may conflict with each other. Therefore, it is essential to have a reliable estimate of the initial in situ stress field and a valid prediction of stress paths during CO₂ injection to optimize the achievement of these two goals (Rutqvist et al., 2008).

Contrary to traditional approaches where total stresses are assumed to remain constant, recent studies report that total stresses change in response to changes in pore pressure. For example, many petroleum production fields reported that horizontal stresses, σ_h , decreased as pore pressure, P , declined during fluid extraction (Addis, 1997; Ferronato et al., 2008; Hillis, 2000; Hillis, 2001; Streit and Hillis, 2004). Stress and pore-pressure measurements from the sites reveal that both stress and pore pressure decreased with a certain ratio that ranges $0.34 \leq \Delta\sigma_h/\Delta P \leq 1.18$ (Altmann et al., 2010). Let's examine how stresses would evolve if the ratio $\Delta\sigma_h/\Delta P$ is

reflected during fluid extraction/injection. To simplify the analysis, a hypothetical reservoir under a normal-faulting stress regime (i.e., extensional stress regime) is considered here. During fluid extraction, the Mohr circle would expand rightward and so approach a failure criterion as pore pressure declines (Figure 1a and c, under isothermal conditions—no temperature change is considered). This rationale may explain a number of reported microseismic events during and after petroleum production (Segall and Fitzgerald, 1998). In contrast, the Mohr circle would shrink leftward and so maintain a certain distance from a failure criterion during fluid injection (compare Figure 1b and d, under isothermal conditions). Note that this analysis applies only to a reservoir under the normal-faulting stress regime. Stress paths for a reservoir under a reverse-faulting or a strike-slip stress regime would exhibit different trajectories (Rutqvist et al., 2008; Vilarrasa et al., 2013b).

It is worth noting that the preceding analysis considers change of pore-pressure disturbance in the horizontal stress only. This approach reflects many previous analyses that found vertical stress changes negligible. However, recent studies have ascertained that total stresses change in every direction as fluid extraction/injection disturbs the pore-pressure field and causes deformations (Altmann et al., 2010; Safari et al., 2013; Schoenball et al., 2010). If this is true, injecting CO₂ into a geologic formation would cause both vertical and horizontal stresses to increase as pore pressure builds up in a reservoir. In this case, we need to know the ratio of pore-pressure/stress changes in both directions to properly predict stress paths during fluid injection. These ratios then need to be incorporated for evaluating the maximum sustainable pressure limit that helps to avoid any geomechanical failures and thus undesirable induced seismic events. However, no previous study has investigated how the ratio of pore-

pressure/stress changes develops with injection time at different locations for various material and geometrical conditions.

In this manuscript, we present a brief review of theoretical background that elucidates stress changes coupled with pore-pressure disturbance based on linear poroelastic theory (Biot, 1962; Wang, 2000). We conduct an in-depth investigation of the ratio of change in total stress to change in pore pressure $\Delta\sigma/\Delta P$ (which has been described as pore-pressure/stress coupling in much of the literature). We employ numerical simulations that couple single-phase fluid flow in porous media with poroelasticity to explore spatiotemporal evolution of the $\Delta\sigma/\Delta P$ ratio for various conditions. Note that our main objective is to investigate large-scale geomechanical changes, not pore-pressure buildup itself; this simpler model facilitates focusing on the poroelastic effect (Rutqvist, 2012). These numerical experiments allow us to examine the effect of material properties and structural geometries on the evolution of $\Delta\sigma/\Delta P$ in both vertical and horizontal directions. On the basis of observations, we suggest firsthand guidelines for analytically determining the ratio of pore-pressure/stress changes, $\Delta\sigma/\Delta P$. Finally, we offer examples and case studies to illustrate how these $\Delta\sigma/\Delta P$ ratios can be incorporated into an analytic calculation for determining a maximum sustainable pressure limit to minimize the risk of undesirable induced seismic events during CO₂ injection at a storage site. All analytical computations and numerical simulations in this manuscript assume isothermal fluid-injection conditions. Poroelastic analyses for nonisothermal conditions can be found elsewhere (e.g., single-phase fluid flow (De Simone et al., 2013; Goodarzi et al., 2010; Kim and Hosseini, 2015; Kim and Hosseini, 2014; Neuzil, 2003); two-phase fluid flow (Preisig and Prévost, 2011; Vilarrasa et al., 2014; Vilarrasa et al., 2013b)).

2. Analytical Solution: Ratio of Pore-Pressure/Stress Changes

Here, we briefly show theoretical equations that demonstrate the correlation between changes in pore pressure and stress in porous media. A closed-form solution for this correlation, even if limited to a simple setting, can be very useful for many underground problems such as soil consolidation (Biot, 1941), hydraulic fracturing (Detournay et al., 1989), reverse water-level fluctuation (Verruijt, 1969), and ground upheaval (Selvadurai, 2009). The analytical derivation herein is described based on the work by Rudnicki (Rudnicki, 1986). For a saturated linear-elastic porous medium, change in the total stress tensor σ_{ij} is related to the displacement gradient $u_{i,j} = \partial u_i / \partial x_j$ and change in pore fluid pressure P :

$$\sigma_{ij} = G(u_{i,j} + u_{j,i}) + \lambda u_{k,k} \delta_{ij} - \alpha P \delta_{ij} \quad (1)$$

where λ and G are the Lamé parameters of linear elasticity, α is Biot's coefficient, and δ_{ij} is the Kronecker delta. (Note: Rudnicki's work follows a sign convention of continuum mechanics, i.e., tensile stress is positive.) Another constitutive equation relates change in the fluid mass content per unit volume m of a porous medium with the displacement and pore pressure:

$$m - m_0 = \alpha \rho_f [u_{k,k} + \alpha P / (\lambda_u - \lambda)] \quad (2)$$

where m_0 is the reference value of m , ρ_f is the mass density of pore fluid, and λ_u is the Lamé parameter for an undrained condition. Darcy's law describes mass flow rate q_i per unit area in the x_i direction as a function of intrinsic permeability k , fluid viscosity η , and the pressure gradient. In the absence of body force, it can be expressed as:

$$q_i = -\rho_f \frac{k}{\eta} \frac{\partial P}{\partial x_i} \quad (3)$$

The force equilibrium equation can be expressed in a compact notation as:

$$\frac{\partial \sigma_{ij}}{\partial x_i} + F_j = 0 \quad (4)$$

where F_j denotes a component of body force. As a last component to complete the set of equations, continuity is expressed with change in the fluid mass and a source of fluid mass Q :

$$\nabla \cdot q + \frac{\partial m}{\partial t} = Q(x, t) \quad (5)$$

Combining Darcy's law (Equation 3) with fluid mass conservation (Equation 5), the equilibrium equation (Equation 4), and two constitutive equations (Equations 1 and 2) yields the diffusion equation (Cleary, 1977):

$$\frac{\partial m}{\partial t} = c \nabla^2 m + \left\{ Q(x, t) + [\rho_f k(\lambda_u - \lambda) / \alpha \eta (\lambda_u + 2G)] F_{k,k} \right\} \quad (6)$$

Diffusivity c is defined using geomechanical and hydraulic properties of a porous medium (Rudnicki, 1986; Wang, 2000):

$$c = \frac{k(\lambda_u - \lambda)(\lambda + 2G)}{\alpha^2 \eta (\lambda_u + 2G)} = \frac{k}{\eta} \frac{2G(1-\nu)}{(1-2\nu)} \left[\frac{B(1+\nu)}{3\alpha(1-\nu) - 2B\alpha^2(1-2\nu)} \right] \quad (7)$$

where ν is Poisson's ratio under a drained condition, and B is Skempton's coefficient. If a fluid is injected at a point with a constant rate q into an infinite homogeneous poroelastic medium in the spherically symmetric domain, the solutions for Equation 6 are obtained as follows (Rudnicki, 1986):

$$\text{Change in the fluid mass: } m(x, t) = \frac{q}{4\pi cr} \operatorname{erfc}\left(\frac{1}{2} \xi\right) \quad (8)$$

$$\text{Displacement: } u_i(x, t) = \frac{q}{\rho_f c} \frac{x_i}{r} \left[\frac{\lambda_u - \lambda}{8\pi\alpha(\lambda_u + 2G)} \right] \left(\operatorname{erfc}\left(\frac{1}{2}\xi\right) + \frac{2}{\xi^2} g(\xi) \right)$$

$$\text{where } g(\xi) = \frac{1}{2\sqrt{\pi}} \int_0^\xi s^2 \exp\left(-\frac{1}{4}s^2\right) ds = \operatorname{erf}\left(\frac{1}{2}\xi\right) - \frac{\xi}{\sqrt{\pi}} \exp\left(-\frac{1}{4}\xi^2\right) \quad (9)$$

where radial distance is $r=(x_k x_k)^{1/2}$, Boltzmann variable is $\xi=r/(ct)^{1/2}$, and complementary error function is $\operatorname{erfc}(z)=1-\operatorname{erf}(z)$. Changes in pore pressure and stresses can be calculated using Equation 9 and constitutive equations (Altmann et al., 2010; Rudnicki, 1986):

$$P(x, t) = \frac{q}{\rho_f c} \frac{1}{4\pi r} \left[\frac{(\lambda_u - \lambda)(\lambda + 2G)}{\alpha^2(\lambda_u + 2G)} \right] \operatorname{erfc}\left(\frac{1}{2}\xi\right) \quad (10)$$

$$\sigma_{ij}(x, t) = -\frac{q}{\rho_f c} \frac{(\lambda_u - \lambda)G}{4\pi r \alpha(\lambda_u + 2G)} \left\{ \delta_{ij} \left[\operatorname{erfc}\left(\frac{1}{2}\xi\right) - \frac{2}{\xi^2} g(\xi) \right] + \frac{x_i x_j}{r^2} \left[\operatorname{erfc}\left(\frac{1}{2}\xi\right) + \frac{6}{\xi^2} g(\xi) \right] \right\} \quad (11)$$

Equations 10 and 11 directly indicate that changes in pore pressure and stresses vary as a function of distance from an injection point, elapsed time, injection rate, diffusivity, and other poroelastic properties. Furthermore, the ratio of change in stress and pore-pressure $\Delta\sigma/\Delta P$ can be expressed using these equations (note that the sign has changed; compression is now defined as positive):

$$\frac{\Delta\sigma_{ij}(x, t)}{\Delta P(x, t)} = \frac{\alpha(1-2\nu)\{\delta_{ij}[\operatorname{erfc}((1/2)\xi) - (2/\xi^2)g(\xi)] + (x_i x_j / r^2)[\operatorname{erfc}((1/2)\xi) + (6/\xi^2)g(\xi)]\}}{2(1-\nu)\operatorname{erfc}((1/2)\xi)} \quad (12)$$

Equation 12 implies that the ratio of change in stress and pore-pressure $\Delta\sigma/\Delta P$ evolves on a spatiotemporal scale. Moreover, it shows that two parameters, Biot's coefficient α and Poisson's ratio ν , determine the absolute value of ratio $\Delta\sigma/\Delta P$, whereas Boltzmann variable ξ affects how the $\Delta\sigma/\Delta P$ evolves before reaching its absolute value. For a homogeneous infinite medium, ratios

of stress and pore-pressure changes converge to $\Delta\sigma_{rad}/\Delta P = \alpha \cdot (1-2\nu)/(1-\nu)$ and $\Delta\sigma_{tan}/\Delta P = (\alpha/2) \cdot (1-2\nu)/(1-\nu)$, radial and tangential directions from the point source, respectively. These terminal values were defined as long-term limit solutions (Altmann et al., 2010). Refer to Safari et al. for a summary of static analytical solutions for other reservoir shapes (Safari et al., 2013).

3. Numerical Simulation

The analytical solution for the ratio of change in stress to change in pore pressure $\Delta\sigma/\Delta P$ (Equation 12) is valid for a point injection in homogeneous infinite isotropic poroelastic media (Altmann et al., 2010). In a real application, however, material properties between geologic formations—including a CO₂ storage aquifer and surrounding strata—are different. The analytic solution is for the spherical domain, but property contrasts and fluid injection over the entire thickness of the storage aquifer indicate that the cylindrical domain is more appropriate. Moreover, because structural geometry and boundary conditions also affect the evolution of $\Delta\sigma/\Delta P$ during fluid injection, we implemented numerical simulations to explore the spatiotemporal evolution of $\Delta\sigma/\Delta P$ for various conditions.

3.1 Simulation Method

We used the commercial software COMSOL to investigate the ratio of pore-pressure/stress changes during fluid injection into a storage aquifer. The single-phase fluid-flow condition was employed because it suffices to explore the poroelastic coupling between changes in pore pressure and stresses (Rutqvist, 2012), which is also the reason that only isothermal conditions are considered in this study. If the main purpose is to investigate pore-pressure buildup itself driven by CO₂ injection, two-phase fluid flow should be employed because the partial miscibility and capillarity alter the overpressure pattern (see example - (Okwen et al.,

2011)). The subsurface flow module in COMSOL contains predefined sets of equations for the application of Earth-science-related problems (COMSOL, 2012). In this module, two sets of constitutive equations for poroelasticity are combined with force equilibrium, mass continuity, and Darcy's law. Among the predefined sets of equations, the first constitutive equation relates stress tensor σ , strain tensor ε , and pore fluid pressure P :

$$\sigma = \bar{C}\varepsilon - \alpha P\vec{I} \quad (13)$$

Elasticity matrix $\bar{C}$ in Equation 13 refers to a drained condition, and $\vec{I}$ is an identity matrix. The second constitutive equation relates the increment in fluid content ζ to volumetric strain ε_{vol} :

$$P = M(\zeta - \alpha\varepsilon_{vol}) \quad (14)$$

where Biot's modulus M is the inverse of the storage coefficient S , which is a function of porosity φ , Biot's coefficient α , fluid bulk modulus K_f , and drained bulk modulus K_d :

$$S = \frac{\varphi}{K_f} + (\alpha - \varphi)\frac{1 - \alpha}{K_d} \quad (15)$$

The fluid equation comes from mass conservation:

$$\frac{\partial}{\partial t}(\rho_f \varphi) + \nabla \cdot (\rho_f \vec{u}) = Q \quad (16)$$

where Darcy's velocity $\vec{u}$ and the storage model are:

$$\vec{u} = -\frac{k}{\eta}(\nabla P + \rho_f g \nabla z) \quad (17)$$

$$\frac{\partial}{\partial t}(\rho_f \varphi) = \rho_f S \frac{\partial P}{\partial t} \quad (18)$$

where z is a vertical coordinate. These equations can be translated into the diffusion formulation:

$$\rho_f S \frac{\partial P}{\partial t} + \nabla \cdot \rho_f \left[-\frac{k}{\eta} (\nabla P + \rho_f g \nabla z) \right] = -\rho_f \alpha \frac{\partial \varepsilon_{vol}}{\partial t} \quad (19)$$

Lastly, solid deformation complies with force equilibrium:

$$\nabla \cdot \sigma + (\rho_f \varphi + \rho_d) \bar{g} = \bar{0} \quad (20)$$

where ρ_d denotes dry density of a porous medium. Equations 13–16 and 19–20 are coupled during the numerical simulation, and computation iterates among these equations at each time step using a finite-element method. The numerical simulation method was validated via comparing its results with those from analytical solutions described by Altmann et al. (2010). Figure 2 shows that the numerical simulation method in this study yields results that are identical to those from the analytical solution (Equation 12) for a homogeneous porous medium model, thus verifying the simulation method.

3.2 Simulation Model and Parameters

The main objective of this study is to examine spatiotemporal variation of the pore-pressure/stress change ratio $\Delta\sigma/\Delta P$ when the geometry is neither infinite nor homogeneous. To simulate linear fluid injection rather than point injection, which is more realistic, we built a simple simulation model (Figure 3) and conducted many numerical “experiments” for various conditions.

The left end of the model is an axis of symmetry. A constant fluid-injection rate is imposed on the left end of the injection zone during the numerical simulation while gravity is

turned off. Depth to the top of the injection zone, the only stratum in the model with a high permeability value, is 1000 m. Thickness of the injection zone is set to 100 m.

The right end of the injection zone is set either as a fluid outlet or closed boundary, in order to investigate the impact of boundary conditions. The top and bottom ends of the model are set as no-flow boundaries. In terms of mechanical boundary conditions, rollers are imposed on the left and right ends and at the bottom of the model (i.e., only translational displacement is allowed). The top surface is free to move. The vertical boundary is 2 km away from the top. The radial boundary is also set as 2 km away from the left end to investigate the deviation in the horizontal stress change from the analytical solution that assumes a thin, laterally extensive reservoir (i.e., a passive basin; Rutqvist, 2012).

Identical or different values of Poisson's ratio, ranging from 0.05 to 0.4, are assigned to the injection zone and confining layers for each realization to examine the ratio's influence. The upper caprock that overlies the injection zone is assigned a permeability of either $k_{cap}=1\text{nd}$ ($\approx 10^{-21}\text{m}^2$, almost impermeable) or $k_{cap}=1\mu\text{d}$ ($\approx 10^{-18}\text{m}^2$, somewhat permeable, but less permeable than the injection zone); the other layer below the injection zone is fixed with $k=1\text{nd}$. Permeability of the injection zone is given either $k_{IZ}=10\text{md}$ or 100md . Lastly, a hydraulic barrier (e.g., an impermeable fault) is inserted into the injection zone at several realizations to investigate the barrier's effect on the evolution of $\Delta\sigma/\Delta P$. Table 1 summarizes all input parameters applied for these various realizations.

4. Numerical Experiment: Results and Discussion

In this section, we present numerical simulation results that shed light on the influence of several factors—including material properties, boundary conditions, and the existence of

hydraulic barriers—on the ratio of pore-pressure/stress change $\Delta\sigma/\Delta P$. Focus is on two stress ratios: (1) the ratio of change in total radial stress to change in pore pressure $\Delta\sigma_r/\Delta P$, and (2) the ratio of change in total vertical stress to change in pore pressure $\Delta\sigma_z/\Delta P$ for the axisymmetric simulation model. Compression is positive for stresses, as it is in traditional geotechnical engineering. We also focus primarily on the $\Delta\sigma/\Delta P$ evolution along two lines of interest: (1) the *middle* line of the injection zone, and (2) the *interface* between the injection zone and upper caprock (Figure 3).

4.1 Hydraulic Flow Condition

The first numerical experiment result presented here is the effect of hydraulic boundary conditions. Figure 4 shows simulation results when the hydraulic boundary of the injection zone (right end) is open for flow. Ratio $\Delta\sigma_r/\Delta P$ increases with distance away from the injection well (Figure 4a and b). Note that stresses are transmitted via the deformation of rock skeleton, whereas pore pressure diffuses through pore space (Altmann et al., 2010). Because the propagation of stress does not depend on the intrinsic permeability of a porous medium, change in stress travels faster than change in pore pressure (Rutqvist, 2012). As a result, change in pressure diminishes toward zero faster than change in total stresses, which leads to the ascent in the ratio $\Delta\sigma_r/\Delta P$ away from the injection well. As time elapses, a broader area in the injection zone converges to $\Delta\sigma_r/\Delta P = \alpha \cdot (1-2\nu)/(1-\nu)$, designated as the long-term limit solution of the homogeneous infinite model (Figure 4a). We also observed that the asymptotic value of $\Delta\sigma_r/\Delta P$ is greater at the interface between the injection zone and the upper caprock (called the *interface* hereafter; line [b] in Figure 3) than it is along the middle of the injection zone (called the *middle* hereafter; line [a] in Figure 3). Because fluid flow into the caprock is hindered by the latter's low permeability, excess pore pressure at the *interface* causes more compression to be transmitted to the rock skeleton, which leads to a higher ratio of pore-pressure/stress change $\Delta\sigma/\Delta P$ at the *interface* than at the *middle*.

On the other hand, the other ratio, $\Delta\sigma_z/\Delta P$, decreases with distance away from the injection well; it even converts from positive (compressive) to negative (tensile) values (Figure 4c). Similar to radial stress, $\Delta\sigma_z/\Delta P$ is higher at the *interface* than at the *middle* (Figure 4c and d). Moreover, a broad area at the *interface* converges to the long-term limit solution of the homogeneous infinite model $\Delta\sigma_z/\Delta P \approx (\alpha/2) \cdot (1-2\nu)/(1-\nu)$, whereas the *middle* line converges to

$\Delta\sigma_z/\Delta P \approx 0$. Expansion of the pressurized injection zone is partly resisted by the rigidity of overlying caprock (Rutqvist et al., 2007), which also hinders infiltration of pressurized fluid into it. These mechanisms cause the vertical compression at the *interface* as well as in the lower part of the caprock (Segall and Fitzgerald, 1998; Vilarrasa et al., 2013a), suggesting that neglecting the vertical stress change is valid only for the inside of an injection zone. The spatiotemporal changes of both ratios, $\Delta\sigma_r/\Delta P$ and $\Delta\sigma_z/\Delta P$, become trivial beyond ~10 days of fluid injection and exhibit their rapid convergence to asymptote curves.

Next, we changed the permeability of the injection zone from $k_{IZ}=100\text{md}$ to $k_{IZ}=10\text{md}$ to examine its effect on $\Delta\sigma/\Delta P$. Asymptotic values do not seem to be affected by the permeability change of the injection zone. However, $\Delta\sigma/\Delta P$ converges more slowly to its asymptote curve as permeability descends (Figure 5).

We also investigated the effect of the hydraulic boundary condition of the injection zone. Asymptote curves become flat as the boundary condition changes from open to closed (compare Figures 4 and 6). Specifically, the entire area converges to the corresponding long-term limit solutions (i.e., $\Delta\sigma_r/\Delta P \approx \alpha \cdot (1-2\nu)/(1-\nu)$ at the *middle* and $\Delta\sigma_z/\Delta P \approx (\alpha/2) \cdot (1-2\nu)/(1-\nu)$ at the *interface*) when the hydraulic boundary closes. The no-flow condition permits pore-pressure buildup to accumulate at the boundary in a way similar to how stress incrementally accumulates. As a result, the entire length attains the same value of $\Delta\sigma/\Delta P$ after a certain period of time elapses (~10 days for this simulation model).

We observed that the asymptotic value of $\Delta\sigma_r/\Delta P$ is at its minimum whereas that of $\Delta\sigma_z/\Delta P$ is at its maximum near the injection well in all cases (Figures 4–6). In addition, the ratios

$\Delta\sigma_r/\Delta P$ and $\Delta\sigma_z/\Delta P$ along the *middle* of the injection zone are smaller than those at the *interface* between the injection zone and the upper caprock.

4.2 Permeability of Caprock

We conducted a second set of numerical experiments in which the permeability of caprock is changed from $k_{cap}=1\text{nd}$ (almost impermeable) to $k_{cap}=1\mu\text{d}$ (permeable to some extent) to investigate how caprock permeability influences the ratio $\Delta\sigma/\Delta P$. It was observed that both ratios $\Delta\sigma_r/\Delta P$ and $\Delta\sigma_z/\Delta P$ are barely affected at the *middle* by the change in caprock permeability (Figure 7a and c). However, the asymptote curves of these ratios at the *interface* shifted downward, closer to curves for the *middle* of the injection zone (Figure 7b and d). This result supports the previous rationale that the hindrance of fluid flow into the caprock contributes to yielding values of $\Delta\sigma/\Delta P$ higher at the *interface* compared with values inside the injection zone.

4.3 Property Contrast: Poisson's Ratio

In the previous simulations, two parameters—Poisson's ratio and Biot's coefficient, which mainly determine asymptotic values of $\Delta\sigma/\Delta P$ —were assigned identically to both injection zone and upper caprock. To find out what would happen if these parameters between the injection zone and upper caprock were different, we conducted two other numerical experiments: in *Case I*, Poisson's ratio was set at $\nu_{IZ}=0.15$ for the injection zone and $\nu_{cap}=0.3$ for the upper caprock; in *Case II*, these values were switched between the two layers. These results are compared with two reference cases: in *Reference I*, Poisson's ratio was set at $\nu=0.15$ for all layers; in *Reference II*, it was set at $\nu=0.30$ for all layers. (Note that Biot's coefficient α was set the same for all layers in this study.)

Case I. At the *middle*, both ratios $\Delta\sigma_r/\Delta P$ and $\Delta\sigma_z/\Delta P$ match well with those from *Reference I* (Figure 8a and c). At the *interface*, $\Delta\sigma_z/\Delta P$ again matches well with the ratio from *Reference I* (Figure 8d). However, $\Delta\sigma_r/\Delta P$ values lie between two curves from *References I* and *II* (Figure 8b).

Case II. At the *interface*, the ratio $\Delta\sigma_r/\Delta P$ again falls between the two curves from *References I* and *II* (Figure 8b), the same trend as observed in *Case I*. Other values, $\Delta\sigma_z/\Delta P$ at the *interface* and $\Delta\sigma_r/\Delta P$ and $\Delta\sigma_z/\Delta P$ at the *middle*, agree well with ratios from *Reference II* (Figures 8a, b, and d).

These numerical experiments suggest that the radial pore-pressure/stress change ratio $\Delta\sigma_r/\Delta P$ at the *interface* can be approximated to be an average of two reference cases, where Poisson's ratio from either the injection zone or the caprock is assigned identically to both layers. Aside from ratio $\Delta\sigma_r/\Delta P$ at the *interface*, other ratios follow the reference condition, where

Poisson's ratio of injection zone is set the same at both layers. Refer to Vilarrasa et al. for similar hydromechanical analyses for different material properties (Vilarrasa et al., 2013a).

4.4 Hydraulic Barrier

For the last set of numerical experiments, a hydraulic barrier was inserted into the injection zone at a different distance from the injection well. The hydraulic barrier ran vertically from top to bottom of the injection zone so no fluid could propagate beyond it. Numerical simulation results show that the asymptote curve of $\Delta\sigma_r/\Delta P$ moves upward the farther the hydraulic barrier is located from the injection well. The asymptote curve eventually converges to the curve of the condition where the right end of the injection zone is closed (Figures 6a and b, 9a and b). The opposite trend is observed for the other ratio, $\Delta\sigma_z/\Delta P$: the asymptote curve shifts downward as the hydraulic barrier is located farther away, and it converges again to the curve of the same condition as above (Figures 6c and d, 9c and d). This pattern occurs because a greater portion of compression is imparted to the vertical stress as the hydraulic barrier shortens the travel distance for pressurized fluid flow, resulting in smaller $\Delta\sigma_r/\Delta P$ and higher $\Delta\sigma_z/\Delta P$ values. This observation also supports the theory that stresses redistribute with different ratios if a structural anomaly such as the hydraulic barrier is present inside of the injection zone.

4.5 Suggestion: Evaluating a Reservoir Stress Path

It is often necessary to quickly determine whether a current injection rate needs to be lowered after a certain magnitude of pressure buildup. In this regard, we suggest a guideline that semianalytically determines the ratio of pore-pressure/stress changes, which can lead to a more precise evaluation of the reservoir stress path. In the radial direction, we suggest using $\Delta\sigma_r/\Delta P = \alpha \cdot (1-2\nu)/(1-\nu)$ for the inside of an injection zone as well as for the *interface* between the

injection zone and caprock to update the stress with a given estimate of pore-pressure buildup. In the vertical direction, we recommend adopting $\Delta\sigma_z/\Delta P=0$ for the inside of an injection zone and $\Delta\sigma_z/\Delta P=(\alpha/2)\cdot(1-2\nu)/(1-\nu)$ at the *interface* to update the stress.

If Poisson's ratio between the injection zone and upper caprock is noticeably different, we suggest using $\Delta\sigma/\Delta P$ of the reference condition, where Poisson's ratio of the injection zone is solely assigned to these layers, except $\Delta\sigma_r/\Delta P$ at the *interface*. The ratio $\Delta\sigma_r/\Delta P$ at the *interface* can be approximated to be an average of two reference cases, where Poisson's ratio from either the injection zone or the caprock is solely assigned to these layers.

If a structural geometry is complex (e.g., an impermeable fault exists in an injection zone), we recommend conducting numerical simulations that incorporate the poroelastic effect in advance to determine asymptotic values of $\Delta\sigma_r/\Delta P$ and $\Delta\sigma_z/\Delta P$, because these values could deviate significantly from the long-term limit solutions of the ideal geometry.

5. Implications for CO₂ Geological Storage: Maximum Sustainable Pressure Limit

The ratios of pore-pressure/stress change need to be reflected in updating stress fields during fluid injection. In this section, we discuss an analytical approach in which $\Delta\sigma/\Delta P$ is incorporated for determining the maximum sustainable pressure limit.

5.1 Failure Criterion and Effective Stress

Reactivation of preexisting fractures via shear slip (or induced seismicity) determines the maximum sustainable pressure limit because, in most cases, such reactivation occurs prior to shear failures of intact rock and/or tensile fractures (Rutqvist et al., 2007; Rutqvist et al., 2008). Assuming that preexisting fractures may exist at any point with an arbitrary orientation, the

potential of shear slip can be expressed as a function of the coefficient of internal cohesion S_0 and the angle of internal fracture friction ϕ based on the Coulomb failure criterion (Jaeger et al., 2007):

$$|\tau_{m2}| = (\sigma_{m2} - P_c) \sin \phi + S_0 \cos \phi \quad (21)$$

where $\tau_{m2} = (\sigma_1 - \sigma_3)/2$ denotes maximum shear stress, $\sigma_{m2} = (\sigma_1 + \sigma_3)/2$ represents mean stress in the two-dimensional principal stress plane, and P_c denotes critical pore-pressure required to trigger the shear slip (compression is defined positive). If we assume that cohesion is zero for preexisting fractures, Equation 21 can be expressed in terms of effective principal stresses σ_1' and σ_3' :

$$\sigma_1' = q_{slip} \sigma_3' \quad (22)$$

Slope q_{slip} in Equation 22 is a sole function of friction angle:

$$q_{slip} = [(\tan^2 \phi + 1)^{1/2} + \tan \phi]^2 \quad (23)$$

If we consider 30° for the friction angle, slope becomes $q_{slip} = 3$.

In traditional approaches, effective stress is assessed simply with the initial total stress σ_0 , pore-pressure $P = P_0 + \Delta P$, and Biot's coefficient as $\sigma' = \sigma_0 - \alpha(P_0 + \Delta P)$ (Guéguen and Boutéca, 2004). However, if we consider that the ratio of pore-pressure/stress change $\Delta\sigma/\Delta P$ persists during fluid injection, vertical and horizontal effective stresses σ'_v and σ'_h evolve with pore-pressure buildup as follows:

$$\sigma'_v = \sigma_{v0} + \Delta\sigma_v^P - \alpha P_f = \sigma_{v0} + \beta_v \Delta P - \alpha(P_0 + \Delta P) \quad (24)$$

$$\sigma_h' = \sigma_{h0} + \Delta\sigma_h^P - \alpha P_f = \sigma_{h0} + \beta_h \Delta P - \alpha(P_0 + \Delta P) \quad (25)$$

where $\beta_v = \Delta\sigma_v / \Delta P$ denotes the ratio of change in total vertical stress to change in pore pressure and $\beta_h = \Delta\sigma_h / \Delta P$ denotes the ratio of change in total horizontal stress to change in pore pressure. In the following section, we examine how the pore-pressure/stress coupling affects effective stresses and how the maximum sustainable pressure limit can be evaluated on the basis of Equations 24 and 25.

5.2 Maximum Pressure Limit

First, we investigate a hypothetical case in which a storage reservoir belongs to an extensional stress regime (i.e., a normal-faulting stress regime). If we consider the reservoir to be located 1 km below the surface, with an average density of porous media $\rho_t = 2650 \text{ kg/m}^3$, water density $\rho_w = 1000 \text{ kg/m}^3$, and initial total stress ratio $K = \sigma_{h0} / \sigma_{v0} = 0.7$, then the initial stress state is as follows: total vertical stress $\sigma_{v0} = 26 \text{ MPa}$, total horizontal stress $\sigma_{h0} = 18.2 \text{ MPa}$, and initial pore pressure $P_0 = 9.8 \text{ MPa}$. We evaluate maximum allowable increase in pore pressure ΔP_{max} before triggering the reactivation of preexisting fractures for the following four scenarios: (1) Total stresses remain constant (traditional approach). (2) Both horizontal and vertical stresses change with same ratio $\beta_h = \beta_v = 0.5$ (can be used as an analogy to a strike-slip faulting stress regime). (3) Only horizontal stress couples with pore-pressure buildup $\beta_h = 0.66$ (from $\alpha \cdot (1-2\nu) / (1-\nu)$ where $\alpha = 1$ and $\nu = 0.25$; prevalent method for a simplified-poroelastic analytical calculation (Chiaramonte et al., 2008; Vidal-Gilbert et al., 2010; Zoback and Zinke, 2002)). (4) Horizontal and vertical stresses increase with different ratios $\beta_h = 0.66$ and $\beta_v = 0.33$ (from $(\alpha/2) \cdot (1-2\nu) / (1-\nu)$; in accordance with this study).

Figure 10 illustrates anticipated stress paths in the σ'_v - σ'_h space and corresponding Mohr circles in the τ - σ' space for these four scenarios. The traditional approach (scenario 1) yields the maximum sustainable pressure limit $\Delta P_{max} \approx 4.4 \text{ MPa}$ (Figure 10a), while the limit value doubles to $\Delta P_{max} \approx 8.7 \text{ MPa}$ for scenario 2 (Figure 10b). The slope of the stress path $\Delta \sigma'_v / \Delta \sigma'_h$ is identical for these two scenarios. The maximum sustainable pressure limit ascends to $\Delta P_{max} \approx 15 \text{ MPa}$ in scenario 3 (Figure 10c). Noticeably, the stress regime transitions during the pore-pressure buildup in a way that horizontal stress surpasses vertical stress ($\sigma_h > \sigma_v$). This event occurs because only $\Delta \sigma_h / \Delta P$ is reflected; as a result, the stress path approaches the other failure criterion $\sigma'_h = q_{slip} \cdot \sigma'_v$ instead of $\sigma'_v = q_{slip} \cdot \sigma'_h$. Lastly, scenario 4 yields the maximum sustainable pressure limit $\Delta P_{max} \approx 22.5 \text{ MPa}$; vertical and horizontal stresses become comparable as they approach the shear slip line in this scenario (Figure 10d). Note also that Mohr circles shrink and shift leftward toward the failure criterion in scenarios 3 and 4 as pore pressure increases under an extensional stress regime.

Next, we examine an opposite case in which a storage reservoir belongs to a compressional stress regime (i.e., a reverse-faulting stress regime) with the initial total stress ratio $K = \sigma_{h0} / \sigma_{v0} = 1.5$; corresponding horizontal stress is $\sigma_{h0} = 39 \text{ MPa}$ (other values are the same as in the previous analysis). The stress path during pore-pressure buildup and the maximum sustainable pressure limit for each scenario is summarized in Figure 11. The stress regime does not transition for all of these scenarios; only the slope of stress path $\Delta \sigma'_v / \Delta \sigma'_h$ differs. Again, scenario 2 yields the maximum sustainable pressure limit, twice that of the traditional approach, $\Delta P_{max} \approx 19.2 \text{ MPa} = 2 \times 9.6 \text{ MPa}$ (Figure 11a and b), with an identical stress path gradient. Interestingly, scenario 3 results in the maximum sustainable pressure limit, smaller than that from the traditional approach, $\Delta P_{max} \approx 7.5 \text{ MPa} < 9.6 \text{ MPa}$ (Figure 11a and c). Scenario 4 yields the

maximum sustainable pressure limit $\Delta P_{max} \approx 11.4 \text{ MPa}$, which is slightly higher than that from the traditional approach by $\sim 2 \text{ MPa}$ (Figure 11d). Contrary to the extensional stress regime, Mohr circles enlarge in scenarios 3 and 4 as pore pressure increases (Figure 11c and d).

These examples illustrate that the discrepancy in the maximum sustainable pressure limit could be substantial, depending on the consideration of stress evolution. Therefore, we emphasize that initial stress state, material properties, and structural geometry conditions combine to incur site-specific ratios of pore-pressure/stress changes; thus, the maximum sustainable pressure limit should be determined accordingly.

5.3 Application

We applied the suggested guideline to the case study, where potential for a shear slip was numerically evaluated on the basis of sequential coupling between multiphase fluid flow and geomechanics (TOUGH-FLAC; (Rutqvist et al., 2007)). Rutqvist et al. (2007) simulated CO_2 injection into a storage aquifer (1.5 km depth) overlain by low-permeability caprock (Poisson's ratio is $\nu=0.25$ and Biot's coefficient is $\alpha=1$; other parameters are listed in Table 1 in (Rutqvist et al., 2007)). The numerical simulation yielded $\Delta P_{max}=13.3 \text{ MPa}$ for an extensional stress regime ($\sigma_{ho}/\sigma_{vo}=0.7$), whereas the traditional approach and simplified poroelastic analysis ($\beta_h=\alpha(1-2\nu)/(1-\nu)=0.67$ and $\beta_v=0$) yielded $\Delta P_{max}=3.3 \text{ MPa}$ and $\Delta P_{max}=48.3 \text{ MPa}$, respectively. The numerical simulation led to an observation that the traditional approach underestimates the pressure limit, whereas the simplified poroelastic analysis grossly overestimates the pressure limit for an extensional stress regime (Rutqvist et al., 2007). However, if we apply $\beta_h=0.66$ and $\beta_v=0.33$ for the *interface* between the injection zone and upper caprock, based on this study's observations when $\nu=0.25$ and $\alpha=1$, the maximum pressure limit is calculated as

$\Delta P_{max} \approx 13.5 \text{ MPa}$, which shows good agreement with the sequentially coupled numerical simulation result.

We also compared results for the reservoir in a compressional stress regime ($\sigma_{h0}/\sigma_{v0}=1.5$), with the other conditions the same. The sequentially coupled numerical simulation yielded $\Delta P_{max}=9.3 \text{ MPa}$, whereas the traditional approach and simplified poroelastic analysis resulted in $\Delta P_{max}=10.3 \text{ MPa}$ and $\Delta P_{max}=12.3 \text{ MPa}$, respectively (Rutqvist et al., 2007). If we apply $\beta_h=0.66$ and $\beta_v=0.33$, the maximum pressure limit is calculated as $\Delta P_{max} \approx 11.4 \text{ MPa}$. Even though discrepancies between the other analytical computations (traditional and simplified poroelastic) and the numerical simulation method are not significant for the compressional stress regime, the proposed guideline once again leads to a good match with the sequentially coupled numerical simulation.

6. Conclusions

Predicting an increase in pore pressure and ensuing changes in the state of stresses during and after fluid injection is critical for the success of CO_2 geologic storage. To examine effects of material properties, boundary conditions, and structural geometries, we conducted numerical experiments to investigate the spatiotemporal evolution of the ratio of change in total stress to change in pore pressure $\Delta\sigma/\Delta P$ during fluid injection under various conditions. Salient observations are as follows:

- The ratio of change in radial stress to that in pore pressure $\Delta\sigma_r/\Delta P$ escalates with distance away from the injection well. As the fluid injection persists, a broad area in the injection zone converges to $\Delta\sigma_r/\Delta P \approx \alpha \cdot (1-2\nu)/(1-\nu)$. Moreover, impermeable upper caprock causes the

asymptotic value of $\Delta\sigma_r/\Delta P$ at the *interface* between the injection zone and the caprock to be larger than that at the *middle* of the injection zone by 0.1~0.15.

- The 1:1 (horizontal:vertical) model size yields the identical result of $\Delta\sigma_r/\Delta P \approx \alpha \cdot (1-2\nu)/(1-\nu)$ inside the injection zone compared to a theoretical thin & laterally extensive reservoir condition.
- The ratio of change in vertical stress to that in pore pressure $\Delta\sigma_z/\Delta P$ not only decreases with distance away from the injection well but also converts from positive (compression) to negative (tension). A broad area at the *interface* converges to $\Delta\sigma_z/\Delta P \approx (\alpha/2) \cdot (1-2\nu)/(1-\nu)$, while the *middle* line converges to $\Delta\sigma_z/\Delta P \approx 0$. Therefore, regarding the vertical pore-pressure/stress change ratio as $\Delta\sigma_z/\Delta P = 0$ is valid only for the inside of the injection zone.
- The asymptote curves for $\Delta\sigma/\Delta P$ eventually become flat when the hydraulic boundary of the injection zone is closed.
- Two parameters, Biot's coefficient α and Poisson's ratio ν , determine asymptotic values of $\Delta\sigma/\Delta P$, whereas the Boltzmann variable $\xi = r/(c \cdot t)^{1/2}$ influences the spatiotemporal evolution of $\Delta\sigma/\Delta P$ en route to its asymptote curve.
- If Poisson's ratio is different between an injection zone (ν_{IZ}) and upper caprock (ν_{cap}), $\Delta\sigma_r/\Delta P$ at the *interface* falls between curves resulted from the two reference cases, where either ν_{IZ} or ν_{cap} is solely assigned to these layers. Other ratios follow curves from the reference case, where ν_{IZ} is solely assigned to both injection zone and caprock.
- If a hydraulic barrier, such as an impermeable fault, exists near the injection well, it alters how pore-pressure buildup imparts compression to the stress components. Numerical simulations help

better capture a complex structural geometry condition. In Section 4.5, we suggest a firsthand guideline to decide the pore-pressure/stress change ratios.

- We suggest incorporating the ratios of pore-pressure/stress changes into an analytic calculation when evaluating stress paths and maximum sustainable pressure limits. While the traditional approach and the simplified poroelastic analysis would underestimate or overestimate the pressure limit, respectively, accurate reflection of the pore-pressure/stress change ratios can lead to a more reliable evaluation of the maximum sustainable pressure limit.

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Figure Captions

Fig. 1 Examples of change in state of stresses during fluid extraction/injection. (a) and (b): traditional approach; (c) and (d): poroelastic approach. Note: This illustration is for normal-faulting stress regime ($\sigma_h < \sigma_H < \sigma_v$); ratio of pore-pressure/stress change is greater for horizontal stress ($\Delta\sigma_v/\Delta P < \Delta\sigma_h/\Delta P$). After Hillis (2001).

Fig. 2 Verification of the numerical simulation method: comparison between results from numerical simulation and analytical solution. (a) Ratio of change in radial stress to change in pore pressure $\Delta\sigma_r/\Delta P$, and (b) ratio of change in vertical stress to change in pore pressure $\Delta\sigma_z/\Delta P$. Note: Solid line represents numerical simulation results, and dashed line represents analytical solution. Injection point located 5 km deep from surface for axisymmetric reservoir model. Used material properties: injection rate $Q=20\text{kg/s}$, fluid density $\rho_f=1000\text{kg/m}^3$, porosity $\phi=0.167$, diffusivity $c=0.082\text{m}^2/\text{s}$, Lamé parameters $\lambda_u=13.4\text{GPa}$, $\lambda=8.3\text{GPa}$, $G=5.5\text{GPa}$, Biot's coefficient $\alpha=0.7$. Injection period=164 days (Altmann et al., 2010).

Fig. 3 Simulation model for numerical experiments in this study: geometry, lines of interest (center line of injection zone and *interface* between injection zone and upper caprock), and illustration of hydraulic barrier (activated at several realizations).

Fig. 4 Spatiotemporal evolution of pore-pressure/stress change ratios when hydraulic boundary of injection zone is open. (a) $\Delta\sigma_r/\Delta P$ at *middle* of injection zone, (b) $\Delta\sigma_r/\Delta P$ at *interface* between the injection zone and upper caprock, (c) $\Delta\sigma_z/\Delta P$ at *middle*, (d) $\Delta\sigma_z/\Delta P$ at *interface*, and (e) ΔP in the injection zone. Note: Blue line represents after time $t=1$ day, green line represents after $t=10$ days, and red line represents after $t=1$ year. $\nu=0.3$, $\phi=0.25$, $\alpha=1$ for all layers, permeability of injection zone is $k_{IZ}=100\text{md}$, and permeability of upper caprock is $k_{cap}=1\text{nd}$. Other parameters as listed in Table 1.

Fig. 5 Spatiotemporal evolution of pore-pressure/stress change ratios when permeability of injection zone changes to $k_{IZ}=10\text{md}$ for open-end boundary condition. (a) $\Delta\sigma_r/\Delta P$ at *middle*, (b) $\Delta\sigma_r/\Delta P$ at *interface*, (c) $\Delta\sigma_z/\Delta P$ at *middle*, (d) $\Delta\sigma_z/\Delta P$ at *interface*, and (e) ΔP in injection zone. $\nu=0.3$, $\phi=0.25$, $\alpha=1$ for all layers, and $k_{cap}=1\text{nd}$. Other parameters as listed in Table 1.

- Fig. 6** Spatiotemporal evolution of pore-pressure/stress change ratios when hydraulic boundary of injection zone is closed. (a) $\Delta\sigma_r/\Delta P$ at *middle*, (b) $\Delta\sigma_r/\Delta P$ at *interface*, (c) $\Delta\sigma_z/\Delta P$ at *middle*, (d) $\Delta\sigma_z/\Delta P$ at *interface*, and (e) ΔP in injection zone. $\nu=0.3$, $\phi=0.25$, $\alpha=1$ for all layers, $k_{IZ}=100\text{md}$, and $k_{cap}=1\text{nd}$. Other parameters as listed in Table 1.
- Fig. 7** Spatial evolution of pore-pressure/stress change ratios when permeability of caprock k_{cap} varies. (a) $\Delta\sigma_r/\Delta P$ at *middle*, (b) $\Delta\sigma_r/\Delta P$ at *interface*, (c) $\Delta\sigma_z/\Delta P$ at *middle*, and (d) $\Delta\sigma_z/\Delta P$ at *interface*. Note: Solid line represents when $k_{cap}=1\text{nd}$, and dashed line represents when $k_{cap}=1\mu\text{d}$. $\nu=0.3$, $\phi=0.25$, $\alpha=1$ for all layers, and $k_{IZ}=100\text{md}$. Other parameters as listed in Table 1. Total simulation time $t_{simul}=1$ year.
- Fig. 8** Spatial evolution of pore-pressure/stress change ratios when Poisson's ratio differs between injection zone and upper caprock. (a) $\Delta\sigma_r/\Delta P$ at *middle*, (b) $\Delta\sigma_r/\Delta P$ at *interface*, (c) $\Delta\sigma_z/\Delta P$ at *middle*, and (d) $\Delta\sigma_z/\Delta P$ at *interface*. Note: Black solid line represents *Case I* while red solid line represents *Case II*. Dot-dashed line represents *Reference I*, and dashed line represents *Reference II*. $\phi=0.25$, $\alpha=1$ for all layers, $k_{IZ}=100\text{md}$, and $k_{cap}=1\text{nd}$. Other parameters as listed in Table 1. Total simulation time $t_{simul}=1$ year.
- Fig. 9** Spatial evolution of pore-pressure/stress change ratios when hydraulic barrier exists in injection zone. (a) $\Delta\sigma_r/\Delta P$ at *middle*, (b) $\Delta\sigma_r/\Delta P$ at *interface*, (c) $\Delta\sigma_z/\Delta P$ at *middle*, and (d) $\Delta\sigma_z/\Delta P$ at *interface*. Note: Solid line represents when location of hydraulic barrier is 100 m away from injection well; dot-dashed line represents hydraulic barrier 500 m away; longer dashed line represents hydraulic barrier 1000 m away; and shorter dashed line represents long-term limit solution of homogeneous infinite model. $\nu=0.3$, $\phi=0.25$, $\alpha=1$ for all layers, $k_{IZ}=100\text{md}$, and $k_{cap}=1\text{nd}$. Other parameters as listed in Table 1. Total simulation time $t_{simul}=1$ year.
- Fig. 10** Stress paths in effective stress σ'_v - σ'_h space and corresponding Mohr circles with Coulomb failure criterion in the τ - σ' space for a storage reservoir of $K=\sigma_{h0}/\sigma_{v0}=0.7$. (a) Traditional approach, (b) when $\beta_h=\beta_v=0.5$, (c) when $\beta_h=0.66$, $\beta_v=0$, and (d) when $\beta_h=0.66$, $\beta_v=0.33$. Note: Mohr circle A represents initial stress state; B denotes stress state after pore pressure increases by $\Delta P=4.4\text{MPa}$, maximum limit for traditional

approach; and C describes stress state at moment of shear slip after considering ratios of pore-pressure/stress changes differently in each scenario.

Fig. 11 Stress paths in effective stress space and corresponding Mohr circles for a storage reservoir of $K=\sigma_{h0}/\sigma_{v0}=1.5$. (a) Traditional approach, (b) when $\beta_h=\beta_v=0.5$, (c) when $\beta_h=0.66$, $\beta_v=0$, and (d) when $\beta_h=0.66$, $\beta_v=0.33$. Note: Mohr circle A represents initial stress state; B denotes stress state after $\Delta P=9.6\text{MPa}$, maximum limit for traditional approach; and C describes stress state at moment of shear slip after considering ratios of pore-pressure/stress changes differently in each scenario.

Table 1 Input parameters for numerical simulations

Property	Symbol	Value	
		Injection zone	Confining layers
Young's modulus	E	30GPa	30GPa
Poisson's ratio	ν	0.05~0.4	0.05~0.4
Dry bulk density	ρ_d	2250kg/m ³	2250kg/m ³
Porosity	φ	0.1~0.4	0.1~0.4
Biot's coefficient	α	0.8~1	0.8~1
Bulk modulus of fluid	K_f	2.2GPa	2.2GPa
Density of fluid	ρ_f	1000kg/m ³	1000kg/m ³
Viscosity of fluid	η	0.001Pa·s	0.001Pa·s
Permeability	k	10md or 100md	1μd or 1nd
Injection rate	Q	1kg/s	
Radius of injection well	r_w	0.1m	
Thickness of injection zone	T_{IZ}	100m	
Depth to top of injection zone	D_{IZ}	1000m	
Simulation time	t_{simul}	365days (1year)	

(a) Fluid Extraction

(b) Fluid Injection

(c) Fluid Extraction – Pore pressure/stress coupling

(d) Fluid Injection – Pore pressure/stress coupling

Fig. 1 Examples of change in state of stresses during fluid extraction/injection. (a) and (b): traditional approach; (c) and (d): poroelastic approach. Note: This illustration is for normal-faulting stress regime ($\sigma_h < \sigma_H < \sigma_v$); ratio of pore-pressure/stress change is greater for horizontal stress ($\Delta\sigma_v/\Delta P < \Delta\sigma_h/\Delta P$). After Hillis (2001).

Fig. 2 Verification of numerical simulation method: comparison between results from numerical simulation and analytical solution. (a) Ratio of change in radial stress to change in pore pressure $\Delta\sigma_r/\Delta P$, and (b) ratio of change in vertical stress to change in pore pressure $\Delta\sigma_z/\Delta P$. Note: Solid line represents numerical simulation results, and dashed line represents analytical solution. Injection point located 5 km deep from surface for axisymmetric reservoir model. Used material properties: injection rate $Q=20\text{kg/s}$, fluid density $\rho_f=1000\text{kg/m}^3$, porosity $\phi=0.167$, diffusivity $c=0.082\text{m}^2/\text{s}$, Lamé parameters $\lambda_u=13.4\text{GPa}$, $\lambda=8.3\text{GPa}$, $G=5.5\text{GPa}$, Biot's coefficient $\alpha=0.7$. Injection period=164days (Altmann et al., 2010).

Fig. 3 Simulation model for numerical experiments in this study: geometry, lines of interest (center line of injection zone and *interface* between injection zone and upper caprock), and illustration of hydraulic barrier (activated at several realizations).

Fig. 4 Spatiotemporal evolution of pore-pressure/stress change ratios when hydraulic boundary of injection zone is open. (a) $\Delta\sigma_r/\Delta P$ at *middle* of injection zone, (b) $\Delta\sigma_r/\Delta P$ at *interface* between the injection zone and upper caprock, (c) $\Delta\sigma_z/\Delta P$ at *middle*, (d) $\Delta\sigma_z/\Delta P$ at *interface*, and (e) ΔP in the injection zone. Note: Blue line represents after time $t=1$ day, green line represents after $t=10$ days, and red line represents after $t=1$ year. $\nu=0.3$, $\phi=0.25$, $\alpha=1$ for all layers, permeability of injection zone is $k_{IZ}=100\text{md}$, and permeability of upper caprock is $k_{cap}=1\text{nd}$. Other parameters as listed in Table 1.

Fig. 5 Spatiotemporal evolution of pore-pressure/stress change ratios when permeability of injection zone changes to $k_{IZ}=10\text{md}$ for open-end boundary condition. (a) $\Delta\sigma_r/\Delta P$ at middle, (b) $\Delta\sigma_r/\Delta P$ at interface, (c) $\Delta\sigma_z/\Delta P$ at middle, (d) $\Delta\sigma_z/\Delta P$ at interface, and (e) ΔP in injection zone. $\nu=0.3$, $\phi=0.25$, $\alpha=1$ for all layers, and $k_{cap}=1\text{nd}$. Other parameters as listed in Table 1.

Fig. 6 Spatiotemporal evolution of pore-pressure/stress change ratios when hydraulic boundary of injection zone is closed. (a) $\Delta\sigma_r/\Delta P$ at *middle*, (b) $\Delta\sigma_r/\Delta P$ at *interface*, (c) $\Delta\sigma_z/\Delta P$ at *middle*, (d) $\Delta\sigma_z/\Delta P$ at *interface*, and (e) ΔP in injection zone. $\nu=0.3$, $\phi=0.25$, $\alpha=1$ for all layers, $k_{IZ}=100\text{md}$, and $k_{cap}=1\text{nd}$. Other parameters as listed in Table 1.

Fig. 7 Spatial evolution of pore-pressure/stress change ratios when permeability of caprock k_{cap} varies. (a) $\Delta\sigma_r/\Delta P$ at *middle*, (b) $\Delta\sigma_r/\Delta P$ at *interface*, (c) $\Delta\sigma_z/\Delta P$ at *middle*, and (d) $\Delta\sigma_z/\Delta P$ at *interface*. Note: Solid line represents when $k_{cap}=1\text{nd}$, and dashed line represents when $k_{cap}=1\mu\text{d}$. $\nu=0.3$, $\phi=0.25$, $\alpha=1$ for all layers, and $k_{IZ}=100\text{md}$. Other parameters as listed in Table 1. Total simulation time $t_{simul}=1$ year.

Fig. 8 Spatial evolution of pore-pressure/stress change ratios when Poisson's ratio differs between injection zone and upper caprock. (a) $\Delta\sigma_r/\Delta P$ at *middle*, (b) $\Delta\sigma_r/\Delta P$ at *interface*, (c) $\Delta\sigma_z/\Delta P$ at *middle*, and (d) $\Delta\sigma_z/\Delta P$ at *interface*. Note: Black solid line represents *Case I* while red solid line represents *Case II*. Dot-dashed line represents *Reference I*, and dashed line represents *Reference II*. $\phi=0.25$, $\alpha=1$ for all layers, $k_{IZ}=100\text{md}$, and $k_{cap}=1\text{nd}$. Other parameters as listed in Table 1. Total simulation time $t_{simul}=1$ year.

Fig. 9 Spatial evolution of pore-pressure/stress change ratios when hydraulic barrier exists in injection zone. (a) $\Delta\sigma_r/\Delta P$ at *middle*, (b) $\Delta\sigma_r/\Delta P$ at *interface*, (c) $\Delta\sigma_z/\Delta P$ at *middle*, and (d) $\Delta\sigma_z/\Delta P$ at *interface*. Note: Solid line represents when location of hydraulic barrier is 100 m away from injection well; dot-dashed line represents hydraulic barrier 500 m away; longer dashed line represents hydraulic barrier 1000 m away; and shorter dashed line represents long-term limit solution of homogeneous infinite model. $\nu=0.3$, $\phi=0.25$, $\alpha=1$ for all layers, $k_{IZ}=100\text{md}$, and $k_{cap}=1\text{nd}$. Other parameters as listed in Table 1. Total simulation time $t_{simul}=1$ year.

Fig. 10 Stress paths in effective stress σ'_v - σ'_h space and corresponding Mohr circles with Coulomb failure criterion in the τ - σ' space for a storage reservoir of $K=\sigma_{h0}/\sigma_{v0}=0.7$. (a) Traditional approach, (b) when $\beta_h=\beta_v=0.5$, (c) when $\beta_h=0.66$, $\beta_v=0$, and (d) when $\beta_h=0.66$, $\beta_v=0.33$. Note: Mohr circle A represents initial stress state; B denotes stress state after pore pressure increases by $\Delta P=4.4 \text{ MPa}$, maximum limit for traditional approach; and C describes stress state at moment of shear slip after considering ratios of pore-pressure/stress changes differently in each scenario.

Fig. 11 Stress paths in effective stress space and corresponding Mohr circles for a storage reservoir of $K = \sigma_{h0}/\sigma_{v0} = 1.5$. (a) Traditional approach, (b) when $\beta_h = \beta_v = 0.5$, (c) when $\beta_h = 0.66, \beta_v = 0$, and (d) when $\beta_h = 0.66, \beta_v = 0.33$. Note: Mohr circle A represents initial stress state; B denotes stress state after $\Delta P = 9.6 \text{ MPa}$, maximum limit for traditional approach; and C describes stress state at moment of shear slip after considering ratios of pore-pressure/stress changes differently in each scenario.