Impact of cold fluid injection on caprock integrity

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Abstract. In Brazilian pre-salt fields, the extracted carbon dioxide is reinjected into the reservoirs to enhance oil recovery and reduce greenhouse gas emissions. The injection of cold CO_2 can alter the mechanical and hydraulic properties of the subsurface, inducing variations in formation stresses. Stress variations can be significant enough to generate undesirable fracture propagation, damage the caprock, and activate natural fractures or geological faults. Consequently, this can lead to seismicity, leaks, and contamination of shallower aquifers and the release of CO_2 into the atmosphere. This study investigates the thermo-hydro-mechanical effects of cold fluid injection on caprock integrity. A fully coupled thermo-hydro-mechanical (THM) finite element model is employed to simulate the behavior of the rock formation. The proposed model considers poroelasticity, fluid flow, and convection/diffusion heat transfer within the permeable rock formation under single-phase fluid flow conditions. The research examines temperature diffusion, pore-pressure buildup, and stress variation under isothermal or non-isothermal injection scenarios. In the isothermal scenario, the results indicate that fluid injection leads to reservoir expansion due to the pressurization process. However, in the non-isothermal scenario, the thermally disturbed region throughout the reservoir results in compaction rather than expansion, despite the injection. The immediate temperature induces a significant increase in deviatoric stresses within the reservoir and on the caprock, reaching critical levels that cause plastic deformations and compromise caprock integrity. This study provides valuable insights into the complex process of cold fluid injection, emphasizing the importance of considering hydraulic, mechanical, and thermal coupling in evaluating caprock integrity.

Keywords: Thermo-hydro-mechanics, cold fluid injection, waterflooding, caprock integrity.

1 Introduction

The Pre-salt fields, located mainly in the Campos and Santos basins, have joined to energy transition and decarbonization trends. The Pre-salt reservoirs are complex and mostly composed of highly heterogeneous carbonate formations containing karsts, vugs, and fractures at multiple scales [1,2]. They can be simplistically divided by an upper interval comprising microbial carbonates and a lower interval composed of cemented shell debris (coquinas) [2,3]. The study of these formations is challenging, mainly due to several interacting physical processes, the heterogeneity in porosity, permeability, and complexity of the fracture system characteristics with variable intensity and persistence in a wide range of orientation, separation, aperture, and scales [4,5]. In these reservoirs, enhanced oil recovery is being used through the alternating reinjection of water and CO_2 (WAG) as working fluid to reduce greenhouse gas emissions [6,7]. WAG emerges as a useful solution to continue significant hydrocarbon production while promoting an adequate destination for the CO_2 content produced [8]. Using water alternating CO_2 injection has led to higher recovery rates than injecting water or CO_2 alone [3]. One of the most important environmental concerns in the use of these transitional technologies is the possible leakage and contamination of subsurface or surface resources during injection and storage [9,10]. Potential leakage pathways include fracturing of the cap rock [11], migration along fractures and geological faults [12], diffusion through the cap rock, and migration along abandoned wells or old assets drilled for oil and gas exploration and production purposes [13,14]. Significant cooling of the reservoir and cap rock by injection of cold fluid and dispersed volume enhances tensile and shear rupture stresses, jeopardizing containment integrity. This process creates a cooled zone around the well, which may compromise the integrity of both the reservoir and the saline caprock due to the combined effect of temperature and pore pressure changes propagating through to surroundings. These changes are not exclusively mechanical; they result from the simultaneous action of different physical processes: thermal, hydraulic, and mechanical (THM) processes. In the case of injection into previously depleted reservoirs, in-situ stresses are impacted by the reduction and subsequent increase in reservoir pressure [15]. Increased pore pressure during the reinjection process can lead to fracturing conditions. In such cases, the propagation of undesired fractures and their interaction with natural fractures can cause loss of integrity of the cap layers or activation of geological faults [16], generating environmental damage due to seismicity problems and leakage to shallower aquifer layers. Therefore, understanding reservoir geomechanics is crucial for ensuring its integrity over the years [17]. Fluid injection into the reservoir affects the stresses and pore pressure, consequently impacting the entire rock system.

This work investigates the thermo-hydro-mechanical effect of cold fluid injection on caprock integrity. A fully coupled thermo-hydro-mechanical (THM) finite element model simulates the rock formation behavior. The proposed model considers poroelasticity, fluid flow, and convection/diffusion heat transfer within the permeable rock formation under single-phase fluid flow conditions. The temperature diffusion, pore-pressure buildup, and stress variation under isothermal or non-isothermal injection scenarios are investigated. The results show reservoir expansion in the isothermal scenario due to fluid injection, which is expected in the pressurization process. In the non-isothermal scenario, the thermally disturbed region throughout the reservoir resulted in compaction rather than expansion, even though it was subjected to injection. The instantaneous drop in temperature induces a significant increase in deviatoric stresses within the reservoir and on the caprock, reaching critical levels that cause plastic deformations and compromise caprock integrity. Finally, the study adds valuable insight to understand the complex cold fluid injection process better, considering hydraulic, mechanical, and thermal coupling.

2 Mathematical and numerical models

2.1 Thermo-hydro-mechanical formulation

The injection of cold fluid in the deep confined pre-salt formation induces a coupled thermo-hydro-mechanical process that may impact the caprock integrity. Temperature changes induce thermal strains, which in turn cause changes in the effective stresses. Furthermore, temperature variation can alter hydraulic properties and trigger phase changes within the fluid (e.g., liquid to gas). Conversely, variations in pore pressure influence the thermal process through the convective heat transfer and impact the effective stresses. Therefore, to assess caprock integrity, momentum balance, mass conservation, and energy balance must be solved simultaneously. The stress equilibrium can be formulated as,

$$\nabla \cdot \sigma + f = 0 \tag{1}$$

where σ is the total stress tensor, and f is the body force vector per unit volume. The total stress can be defined as.

$$\sigma = \sigma' - \alpha p \boldsymbol{I} \tag{2}$$

where σ' is the effective stress, α is the Biot coefficient, p is the pore pressure, and $\boldsymbol{I}$ can be defined as $[1 \quad 1 \quad 1 \quad 0 \quad 0 \quad 0]^T$. Biot coefficient can be estimated as,

$$\alpha = 1 - \frac{K_s}{K_g} \tag{3}$$

where K_s and K_g are the bulk moduli of the rock matrix and grains, respectively. The volumetric thermal expansion of the rock formation can be estimated as,

$$\varepsilon_T = -\beta_r \Delta T \boldsymbol{I} \tag{4}$$

where ε_T is the thermal expansivity tensor, β_r is the volumetric thermal expansion coefficient, and ΔT is the temperature increment. The thermoelastic stress-strain relationship can be defined as:

$$\sigma' = \boldsymbol{D}\varepsilon + K_s \varepsilon_T \tag{5}$$

where $\boldsymbol{D}$ is the elastic tensor. For small strain conditions, the strain tensor can be formulated in terms of displacement vector $\boldsymbol{u}$**,** as follows:

$$\varepsilon = \frac{1}{2}\left[(\nabla \boldsymbol{u}) + (\boldsymbol{u}^T)\right] \tag{6}$$

Combining equations (2)-(6) in equation (1), we have the partial differential equation governing the thermo-hydro-mechanical model equation:

$$\nabla \cdot [\boldsymbol{D}\nabla \boldsymbol{u} - \beta_r K_s \Delta T \boldsymbol{I} - \alpha p \boldsymbol{I}] + f = 0 \tag{7}$$

Mass conservation of fluid can be expressed as:

$$\frac{\partial}{\partial t}\left(\phi \rho_f\right) + \nabla \cdot \left(\phi \rho_f v_f\right) = Q \tag{8}$$

where t is time, ϕ is the porosity of the porous media, ρ_f is the mass density of the pore fluid, v_f is the flow velocity vector, Q is a source of fluid mass. Darcy's velocity vector v_f and the storage model is,

$$\phi v_f = \frac{\kappa}{\mu}\left(\nabla p + \rho_f g\right) \tag{9}$$

$$\frac{\partial}{\partial t}\left(\phi \rho_f\right) = \rho_f S \frac{\partial p}{\partial t} \tag{10}$$

where κ is the intrinsic permeability, μ is fluid viscosity, p is pore fluid pressure, and g is gravity. The storage coefficient S is a function of porosity, Biot's coefficient α, fluid bulk-modulus K_f, and bulk moduli of the rock matrix K_s:

$$S = \frac{\phi}{K_f} + (\alpha - \phi)\frac{1-\alpha}{K_s} \tag{11}$$

Combining equations (9) and (10) in equation (8), the diffusion formulation is:

$$\rho_f S \frac{\partial p}{\partial t} + \nabla \cdot \rho_f \left[\frac{\kappa}{\mu}\left(\nabla p + \rho_f g\right)\right] = \rho_f \alpha \frac{\partial \varepsilon_{vol}}{\partial t} \tag{12}$$

where ε_{vol} represents the volumetric strains.

The convective heat transfer in porous media consists of both heat conduction and heat advection with thermodynamic properties volumetrically averaged to account for solid and pore fluid, as follows:

$$(\rho c)_m \frac{\partial T}{\partial t} - \phi \beta_p T \frac{\partial p}{\partial t} - \beta_r K_s T \frac{\partial}{\partial t}(\nabla \cdot \boldsymbol{u}) - \rho_f c_f v_r \nabla T + \nabla \cdot (\boldsymbol{\lambda_m} \nabla T) + \boldsymbol{Q}^T = 0 \tag{13}$$

where

$$\begin{aligned} (\rho c)_m &= \phi \rho_f c_f + (1-\phi)\rho_r c_r \\ \lambda_{\boldsymbol{m}} &= \phi_f \lambda_{\boldsymbol{f}} + (1-\phi)\lambda_{\boldsymbol{r}} \end{aligned} \tag{14}$$

where c_f and c_r are the specific heat and $\boldsymbol{\lambda_f}$ and $\boldsymbol{\lambda_r}$ are thermal conductivities of the fluid and the rock matrix, T is temperature, β_p is the pore compressibility of the fluid, v_r is the relative velocity of the fluid with respect to that of the rock matrix, and $\boldsymbol{Q}^T$ is the heat source.

3 Simulation model

We developed a conceptual model of the pre-salt reservoir to investigate the impact of temperature and flow changes on the mechanical behavior of the reservoir, caprock, and underburden. As illustrated in Figure 1, the model considers a water depth of 2137 m, the last 300 m of the caprock, the reservoir thickness of 100 m, and the first 300 m of the underburden. The caprock and underburden are assumed to be impermeable layers without hydraulic contribution. Initial effective stresses in the caprock and underburden are $\sigma_v = 95$ MPa and $\sigma_h = 80$ MPa, while the permeable reservoir has an initial pore pressure of $P_0 = 60$ MPa and effective stresses of $\sigma_v = 35$ MPa and $\sigma_h = 20$ MPa. The rock formation is assumed to be thermally homogeneous with an initial temperature of 75ºC. We conducted numerical simulations using the finite element software Abaqus® for two different operations: (1) isothermal fluid injection and (2) non-isothermal cold fluid injection. An axisymmetric model composed of quadrilateral elements with linear interpolation schemes was used for pore pressure, temperature, and displacement fields. The reservoir was subjected to the injection at a constant rate of 4000 m³/day over a period of 30 years for the isothermal condition. For the non-isothermal condition, a cold fluid at 10ºC is injected with the same injection rate and period. Tables 1 e 2 summarize all parameter values used during the numerical simulations for the rock and for the fluid, respectively.

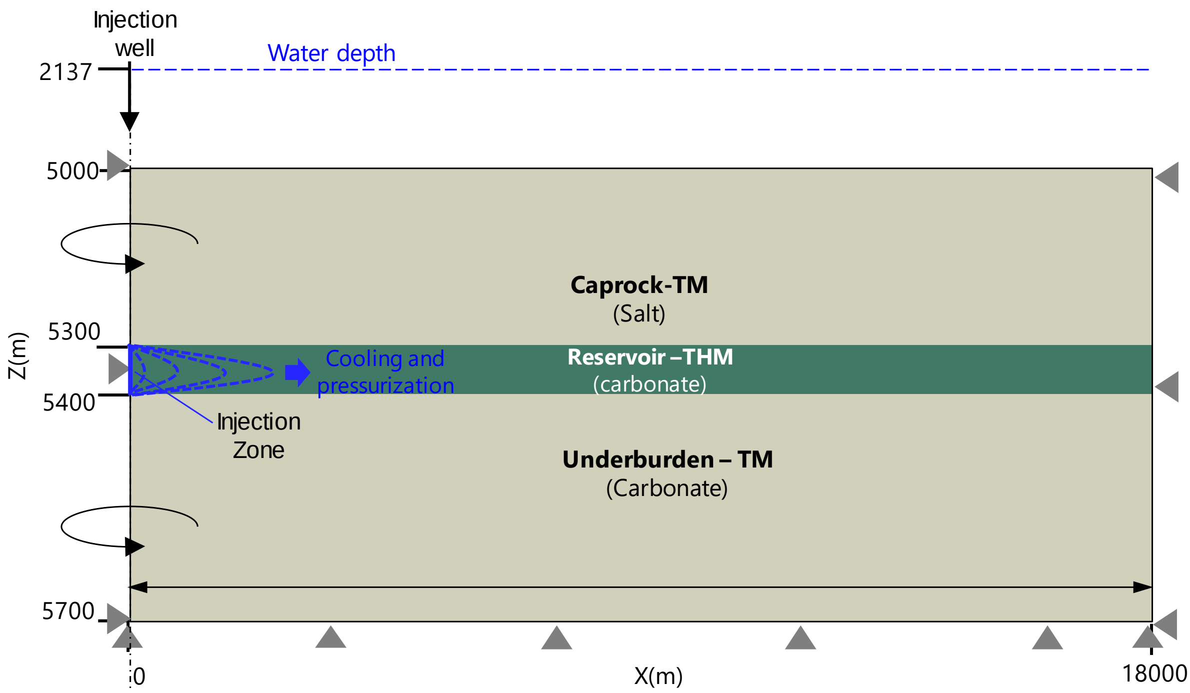

Figure 1. Simplified model of Pre-salt reservoir and surroundings

Figure 2 presents the vertical displacement and temperature profiles along the well (segment A-A') after 30 year for isothermal and non-isothermal conditions. Comparing the vertical displacements under isothermal and non-isothermal conditions (Figure 2a), we observe that the cold fluid injection increases the vertical displacements in all layers (caprock, reservoir, underburden). Under isothermal conditions, both the top and bottom of the reservoir exhibit predominantly upward displacements. In contrast, under non-isothermal conditions, the top and the area above the reservoir show subsidence, while the bottom and the area below the reservoir exhibit heaving.

Table 1. Input parameters for the rock formation

Properties	Units	Caprock	Reservoir	Underburden
Young's modulus, *E*	GPa	35	50	50
Poisson's coefficient, υ	-	0.36	0.25	0.25
Biot coefficient, α	-	-	1	-
Saturated density, ρ	kg/m3	2160	2630	2630
Porosity, ϕ	%	-	10	-
Conductivity, λ_r	W/(m °C)	5.5	2.5	2.5
Permeability, k	mD	0	1000	0
Specific heat, cp	J/(kg °C)	943.5	892.4	892.4
Thermal expansion of rock, α_r	[1/°C]	3.50E-05	1.00E-05	1.00E-05
Friction angle, f	°	34.65	11.08	11.08
Cohesion, *c*	MPa	0	11	11

Table 2. Input parameters for the injected fluid

	Properties	Units	values
Fluid properties	specific heat, c_f	J/(kg °C)	4191
	viscosity, μ	cP	1.307
	Bulk modulus of fluid, K_f	GPa	0.588
	Density, ρ_f	kg/m^3	999
	Conductivity, λ_f	W/(m °C)	0.578
	Thermal expansion, α_f	[1/°C]	8.83E-05

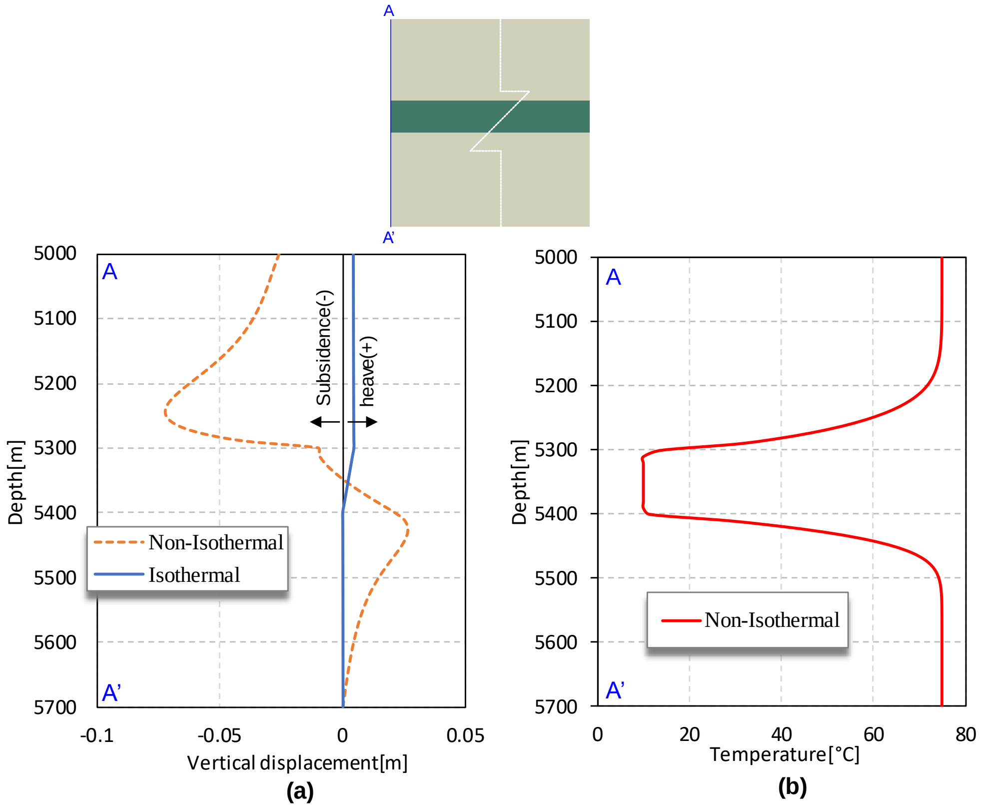

Figure 2. Numerical results after 30 years for isothermal and non-isothermal conditions: vertical displacement profile (a) and temperature along the well (segment A-A') (b).

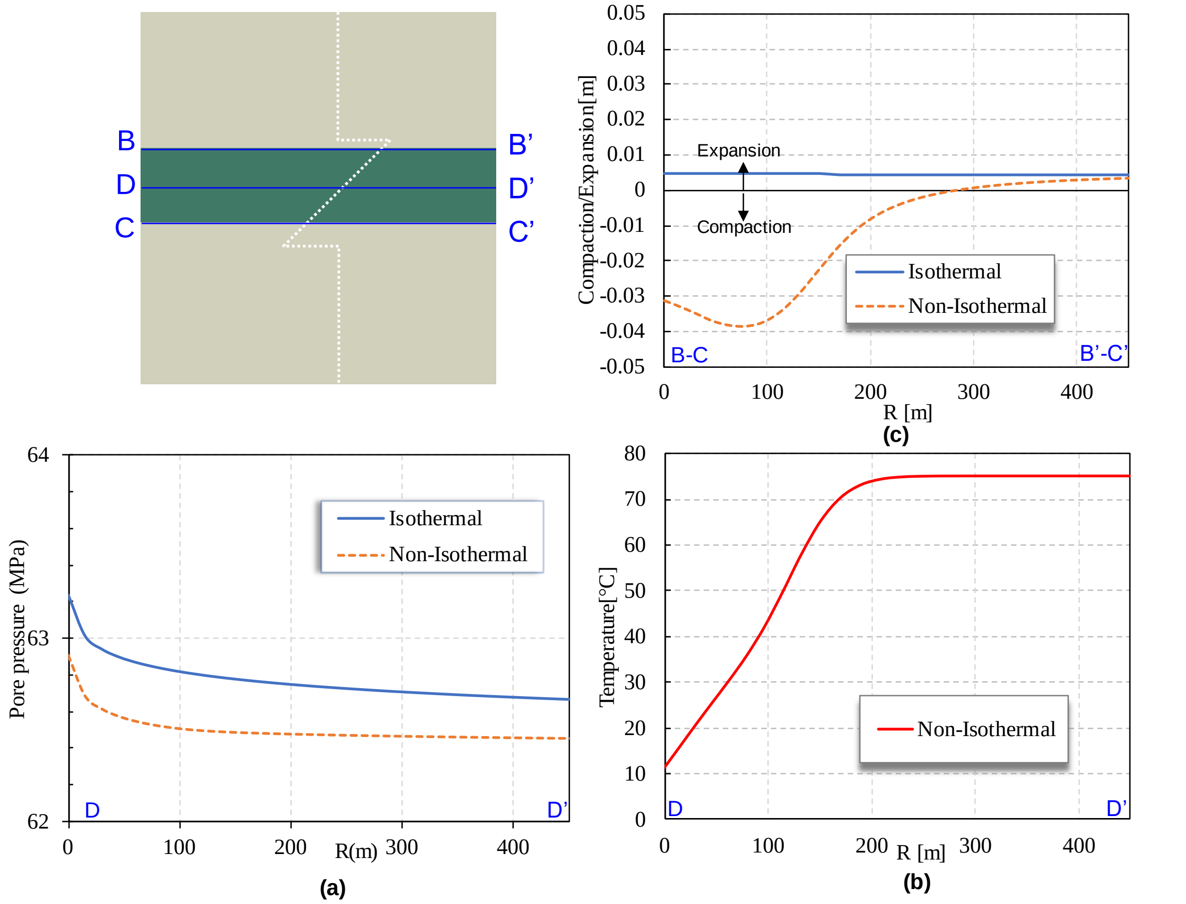

Figure 3. Reservoir compaction (a), pore pressure (b), and temperature (c) along the segment D-D' at 30 years.

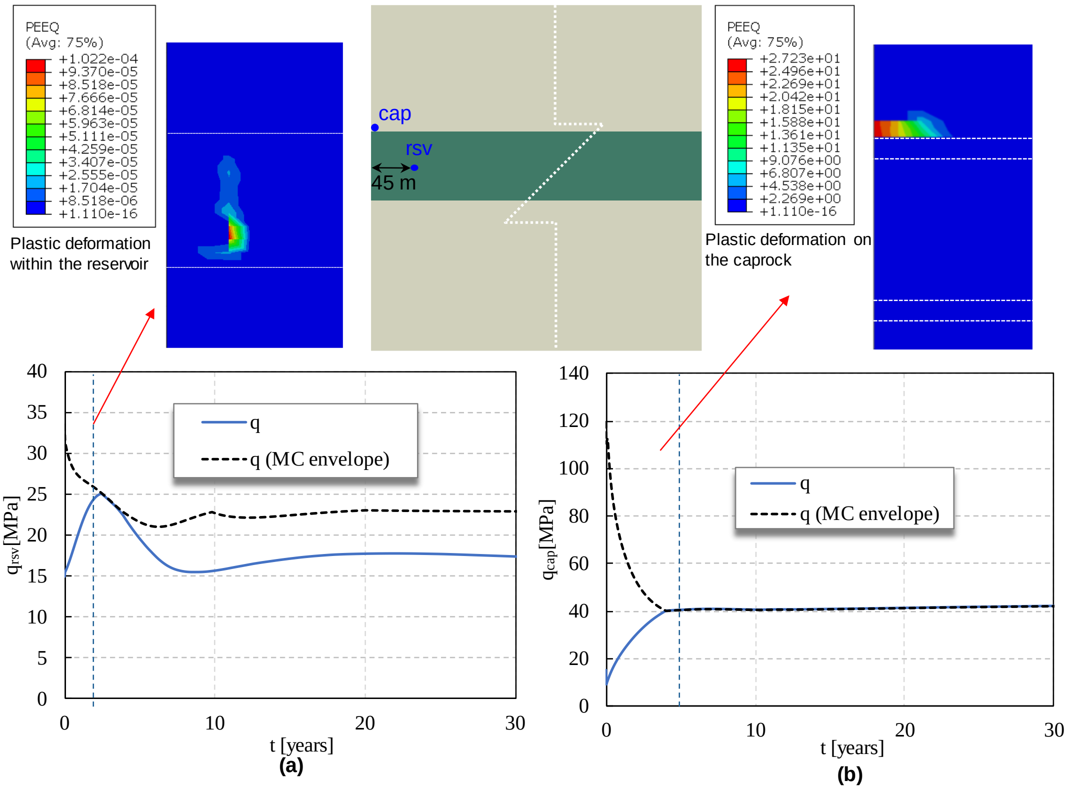

Figure 4. Deviatoric stress evolution and critical deviatoric stress for non-isothermal conditions: (a) within the reservoir at point (rsv), and (b) on the caprock at point (cap).

Figure 3 illustrates the compaction/expansion of the reservoir, pore pressure and temperature after 30 years under isothermal and non-isothermal conditions. In Figure 3a, reservoir compaction/expansion is calculated as the difference between the vertical displacements of the bottom and top of the reservoir (segments B-B' and C-C', respectively). Under non-isothermal conditions, compaction within the reservoir indicates that thermal behavior dominates the coupling mechanisms in the thermally disturbed region. Outside this region, the reservoir undergoes subtle expansion due to the low-pressure buildup from injection. For the isothermal conditions, as shown in Figure 3a, the reservoir exhibits uniform subtle expansion due to increased pore pressure. This expansion is low enough to maintain the integrity of the reservoir and caprock over the 30 years of fluid injection. In contrast, the higher compaction in the cooled region results in greater perturbation of deviatoric stresses in the caprock and reservoir, reaching the critical deviatoric stress level (according to Mohr-Coulomb Yield envelope) and generating plastic deformations, as shown in Figure 4. Pore pressure along the segment D-D' is lower under non-isothermal conditions (Figure 3b) due to volumetric contraction by thermal strains, generating additional traction stresses. Finally, temperature propagation extends 100 m vertically (Figure 2b) and 200 m horizontally (Figure 3c) after 30 years of fluid injection.

4 Conclusions

This work investigates the effect of cold fluid injection on caprock integrity using a fully coupled thermo-hydro-mechanical (THM) finite element model. We conducted numerical simulations for two different operations: (1) isothermal fluid injection and (2) non-isothermal cold fluid injection. The results show that in the isothermal scenario, reservoir expansion occurs due to pore pressure increments from fluid injection, which is expected during the pressurization process. In the non-isothermal scenario, the cooled region throughout the reservoir results in compaction rather than expansion despite the injection. In this case, thermal behavior dominates the coupling mechanisms within the thermally disturbed region. Outside this region, the reservoir undergoes subtle expansion due to the low-pressure buildup from injection. The instantaneous drop in temperature induces a significant increase in deviatoric stresses within the reservoir and on the caprock, reaching critical levels and causing plastic deformations, thereby compromising the containment integrity of the reservoir. This study provides valuable insights into the complex cold fluid injection process by considering hydraulic, mechanical, and thermal coupling.

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