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Coupled hydromechanical modeling to study the integrity and safety of geological storage of CO_2

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Abstract

The present study provides a set of numerical tools for modeling the geomechanical aspects related to the safety of geological CO_2 storage, namely, caprock damage and fault reactivation due to reservoir pressure rise. Large scale finite element models are used to describe the injection process. The change of the effective stress field is investigated. Different cracking mechanisms are considered to examine the caprock integrity for high injection rates and different initial *in situ* stress conditions. Last, a special hydromechanical joint element is presented to model the response of the faults / fractures affected by the pressure build-up in the reservoir.

Keywords: CO_2 geological storage, safety study, hydromechanical modeling, rock fracture, fault modeling, risk analysis

1. Introduction

From a practical point of view, the safety study of a storage site consists, among others, in the evaluation of the sustainable injection pressure or flux, and the safety factor for a given injection rate. The objective of the present work is to study the effects of CO_2 injection in deep geological formations on its mechanical response in terms of safety storage risk assessment. Gas injection modifies the reservoir pressure, and the effective stress field in the reservoir and caprock formations. The most important process in hydromechanical behavior is a general reduction of effective stresses caused by the high-pressure injection of CO_2 around the injection well. An accurate evaluation of this stress field modification is a key issue for assessing any leakage risk related to geomechanical aspects. Two existing (and well-established) codes are used to model the hydromechanical impact of CO_2 injection on the effective stress field in the reservoir and its surrounding rocks. Two main risks are then studied in the present work, namely, the risk of caprock damage around the injection well and that of permeability increase of existing faults.

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2. Large scale hydromechanical modeling of local stress field modification

Coupled thermo–hydro–mechanical (THM) processes under multiphase flow conditions are prevalent in a number of underground applications such as nuclear waste disposal in geological media, geothermal energy extraction, enhanced recovery from oil and gas reservoirs, and underground storage of gas. Numerical modeling of CO_2 injection integrity and performance must also consider cross-coupling of geochemistry, geomechanics, flow, and transport. Therefore, a coupled THMC (including chemical processes) simulator is ideally required for the analysis of these problems. However, except for a few specialized and simplified approaches, there is (to the authors' knowledge) no single computer code that handles general coupled THMC processes – including multiphase and multicomponent fluid flow and reactive transport – in geological media.

In the present paper, the investigation is limited to hydromechanical effects of CO_2 injection on the stress field in isothermal conditions. The effects of chemical reactions between injected CO_2 and geological formations are not considered. Two existing numerical codes, each specialized to a few of the above processes, are coupled to potentially account for all processes in the hydromechanical response of CO_2 injection.

TOUGH2 [1; 2], a THC code, and Code_Aster [3], a THM code, are linked using sequential run and data transfer. The TOUGH2 code solves coupled problems of multiphase, multicomponent fluid flow in geological systems. A sequential coupling between TOUGH2 and FLAC3D is already used by Rutqvist et al. [4] to model hydromechanical aspects related to geological storage of CO_2.

Code_Aster is a general purpose thermo-mechanical finite element code developed by EDF and handles coupled thermo-hydro-mechanical couplings in porous media. However, the gas phase is limited to perfect gases and CO_2 in its supercritical state cannot be modeled by the THM routines of Code_Aster. A fully coupled HM code may obtain more accurate results, but such simulations are always time consuming. A sequential coupling of two codes enables us to perform large scale simulations in a reasonable time.

2.1. Coupling of TOUGH2 and Code_Aster

TOUGH2 and Code_Aster® are linked by using sequential runs and data transfer through nonlinear coupling functions. Figure 1 gives a schematic view of the sequential coupling. At step *n*, the total pore pressure in the whole geological medium is calculated from the liquid pressure P_l, liquid saturation S_l, gas pressure P_g and gas saturation S_g. The calculated pressure is transferred to the mechanical code that gives the effect on the effective stresses σ' and strain ε through the theory of fully saturated porous media [5]. These results are used to assess the changes in hydraulic properties (porosity ω, permeability k) through empirical nonlinear functions. The modified hydraulic properties are used as input parameters for step $n+1$. However, the stress-dependent effects are not taken into account for the analysis presented in this paper, where we focus on the tendency for fault reactivation at a regional scale. One can note that the thermo-mechanical coupling can also be implemented by following the same principle.

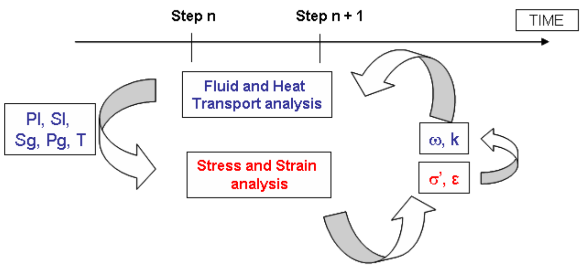


Figure 1: Schematic view of sequentially linking specialized codes respectively in fluid and heat transport analysis (TOUGH2) and stress and strain analysis (Code_Aster®)

2.2. Paris Basin hydromechanical model

2.2.1. General description

The present goal is to study the mechanical behavior of the interface between a reservoir and a caprock layer in the context of the multilayered system of the French Paris basin. The Paris basin is a multilayered system that consists of several layers of permeable brine-water formations (referred to as aquifers) interlaced with layers of low-permeability formations (referred to as caprock). Spatial variability of both hydraulic and geomechanical properties is not taken into account. Each layer is modeled as an idealized homogeneous horizontal layer.

The model is a 2D axisymmetric model and extends vertically from the ground surface to a depth of 2000 m, and horizontally around 100 km to simulate laterally infinite conditions. The cell dimensions vary from 0.3 m to 1000 m along the *r*-direction and from 1m to 250m along the *z*-direction. This leads to a total of 435x46 elements. On the bottom and lateral boundaries, flow and normal displacements are prescribed. The output of the hydraulic analysis, i.e., the total pore pressure is interpolated on the mechanical mesh. CO_2 is injected at the supercritical state at a mass rate of 320 kg / s corresponding to an annual rate of 10 Mt / y in the Dogger formation at a depth of 1500 m.

2.2.2. Hydromechanical properties

As hydromechanical properties of the reservoir rocks (Dogger formation) are poorly referenced, analyses performed on rock samples extracted from quarries of the Paris Basin are used to approximate the reservoir rock properties. The Lavoux limestone presents properties close to the Dogger formation [6]. The global transmissivity of the Dogger formation reaches a mean value of around 42 D.m with a global thickness of 150 m. The Van Genuchten's model [7] is used to describe relative permeability and capillary pressure.

The hydraulic and mechanical properties of the other layers are based on typical order of magnitudes that can be found in the Paris basin context [8; 9; 10]. Caprock formations are assumed to have identical hydromechanical properties and low permeable brine aquifer formations are assumed to have the same hydromechanical properties as well. Aquifer (two layers) and caprock formations differ by their porosity, intrinsic permeability and air entry pressure. Relative permeability and capillary pressure models [7] are assumed to be the same as the Lavoux limestone. The rock matrix is assumed to be elastic, i.e., governed by the Young's modulus E and Poisson's ratio ν. The model hypotheses are summarized in Tables 1 and 2.

Table 1: Hydromechanical properties for the Paris Basin case

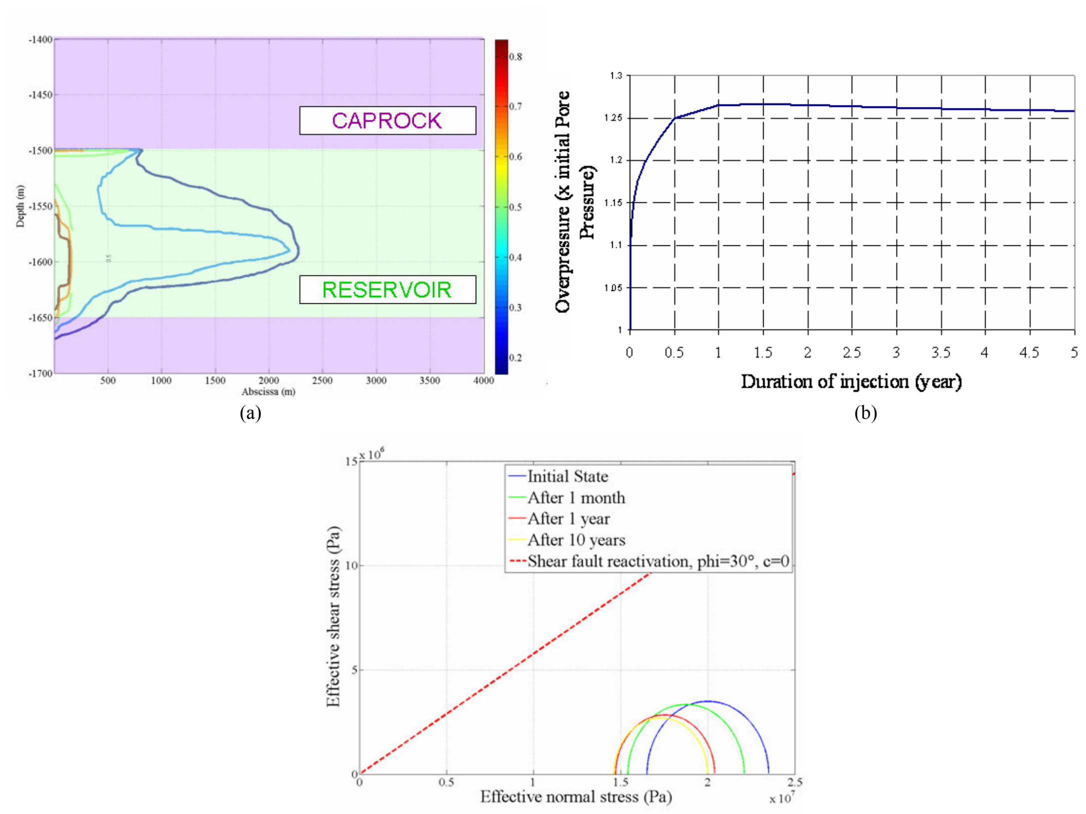
	Young's Modulus [GPa]	**Poisson's ratio**	**Intrinsic permeability [mD]**	**Porosity [%]**
Aquifer 1	20	0.3	800	15
Aquifer 2	20	0.3	90	15
Caprock	15	0.3	0.1	5
Basement	50	0.3	0.1	5

Table 2: Relative permeability and capillary pressure model

	Van Genuchten parameter m = 1-1/n	**Residual liquid saturation [%]**	**Residual gas saturation [%]**	**1/Air entry pressure [Pa^{-1}]**
Aquifer	0.600	20	0.05	5.4e-5
Caprock	0.600	20	0.05	1.e-6
Reservoir	0.600	20	0.05	5.4e-5

2.2.3. Hydraulic analysis output

The objective is to determine the maximum pressure at the interface to be used in a failure risk assessment procedure (see section below). Figure 2 illustrates the CO_2 saturation field and the corresponding overpressure and effective stress change on the reservoir – caprock interface after 10 years of injection.



(a) (b)

(c)

Figure 2: Gas saturation field (a), total overpressure (b) and effective stress change on the reservoir – caprock interface (c) after 10 years of injection at 10 Mt/y

3. Risk of caprock fracturing

3.1. Simplified hydro-mechanical modeling

The simulations in Section 2 showed a detailed analysis for a given storage site and injection scenario. In this section, a series of parametric studies are presented to investigate the effect of different parameters on the maximum sustainable injection pressure / rate. The maximum allowable injection pressure determined such that:

1. sufficient quantities of CO_2 are injected,
2. the integrity of caprock is preserved.

In this framework, the underground is considered as a saturated porous medium to simplify the simulations, the fluids being described by water properties. This hypothesis will enable us to perform an important number of large scale coupled hydromechanical simulations for covering a large range of parameters. The injection is simulated by a fluid flow on the injection tubing sides. However, the loading process is represented by an equivalent injection rate. The latter, r_e, is the equivalent amount of stored CO_2 in terms of volume considering that CO_2 stored in the geological formation has a density of 700 kg / m^3 [11]. The increasing rate is slow enough to generate at each time step a quasi-static situation in terms of stress state.

A typical example is studied to analyze the effect of gas injection on the effective stresses in the reservoir and caprock. The reservoir in which CO_2 is injected is located between 1,375 and 1,425 m. The host rock (i.e., reservoir) is sealed by a 100-m thick caprock. An isotropic elastic behavior is assumed. According to the symmetry of the problem, only one half of the domain is meshed to create an axisymmetric finite element model. Triangular quadratic elements are used with a particular mesh refinement around the injection well. The hydraulic and mechanical governing equations are totally coupled.

Let us consider that for all materials Poisson ratio $\nu = 0.25$ and initial density $\rho_{h0} = 2300$ kg/m^3. Table 3 shows other material properties. The hydraulic properties of water are considered for the pore fluid phase, namely, $\rho_{l0} = 1000$ kg / m^3, $\mu = 4.33\ 10^{-4}$ Pa.s and $K_w = 2$ GPa. A confinement coefficient k_0 characterizes the initial stress state; it is the ratio between the horizontal and vertical total stresses. The horizontal displacement is set to zero on the lateral boundaries and the vertical displacement is set to zero on the lower boundary. The initial vertical stress is set to zero on the upper boundary. The normal fluid flow is set to zero on the lateral boundaries except along the injection tubing where the loading is applied and it is set to zero on the lower boundary. The fluid pressure is set to zero on the upper boundary. The modeled geometry is wide enough to avoid the loading to influence the pore pressure on the lateral boundaries.

Table 3: Material properties: E is Young modulus, K_{int} the intrinsic permeability, ϕ^0 initial porosity

Layer name	Layer depth [m]	E [GPa]	K_{int} [m²]	ϕ^0	Biot's coefficient
Soil	0 - 100	1	10^{-13}	0.3	1.0
Layer 0	100 - 1275	20	10^{-15}	0.15	0.8
Caprock	1275 - 1375	20	10^{-17}	0.05	0.8
Hostrock	1375 - 1425	20	10^{-14}	0.15	0.8
Layer 1	1425 - 1525	20	10^{-17}	0.05	0.8
Layer 2	1525 - 2800	20	10^{-15}	0.15	0.8

3.2. Effective stress modification due to CO_2 injection and the study of caprock damage mechanisms

The stress field is significantly modified around the injection well. It is to be noted that the stress state in the horizontal plane is almost the same in any direction. The principal stress direction corresponds to the horizontal and vertical directions. As shown in Figure 3, the injection may lead to important modifications of horizontal, vertical and shear stresses in the studied zone. It is to be noted that in Figure 3, the different loading levels are characterized by a normalized injection rate $r = r_e / r_0$, where r_0 is the equivalent injection rate that induces the vertical effective tensile stress at the interface between caprock and hostrock. The stress state is significantly modified on the interface between caprock and hostrock.

The pore pressure increases more homogeneously in the hostrock than in the caprock or layer 1 because of high permeability of hostrock. It implies that the effective stress level is more homogeneous in the hostrock than in the caprock or layer 1. For the used material parameters, various fracture mechanisms may be considered depending on the initial conditions and injection rate level. A criterion is associated with each possible fracture mechanisms, namely,

- Shear stress induced mechanism (A). Coulomb criterion with zero cohesion

$$0 \le 1/2(\sigma'_h + \sigma'_v)\sin(\theta) + 1/2|\sigma'_h - \sigma'_v| - C_0 \cos(\theta) \quad (1)$$

where C_0 is the material cohesion set to zero, $\theta = 27°$ the friction angle, σ'_h the horizontal effective stress and σ'_v the vertical effective stress. A pore pressure rise does not necessarily generate a shear stress increase. Yet, the Mohr-Coulomb criterion may be activated because a pore pressure rise always generates a normal (to fault line) stress decrease.

- Vertical opened crack (B). Rankine criterion for the horizontal direction: $0 \le \sigma'_h$
- Horizontal opened crack (C). Rankine criterion for vertical direction: $0 \le \sigma'_v$

Criteria (B) and (C) may be activated by pore pressure rise.

For low confined grounds ($k_0 < 0.8$), the three criteria may be activated as shown in Figure 4, while for high confined grounds ($k_0 > 0.8$) only two criteria are activated, namely, the Mohr-Coulomb and the vertical Rankine criteria. For every ground confinement, as the injection rate increases, the first mechanism to be activated is due to shear stresses. However, it is difficult to say if it is problematic or not for the storage reliability because the activation of a Mohr-Coulomb criterion with zero cohesion means that existing cracks slide but do not necessarily mean that existing cracks start to grow. It may be assumed that the activation of this kind of mechanism modifies the material permeability. Two tension induced mechanisms are possible, namely, vertical or horizontal cracking of rocks. The growth of vertical cracks in opening mode is more problematic for the storage reliability because it generates flow paths towards the surface or the upper layers. It also appears that average confinement conditions mean lower fracture risk.

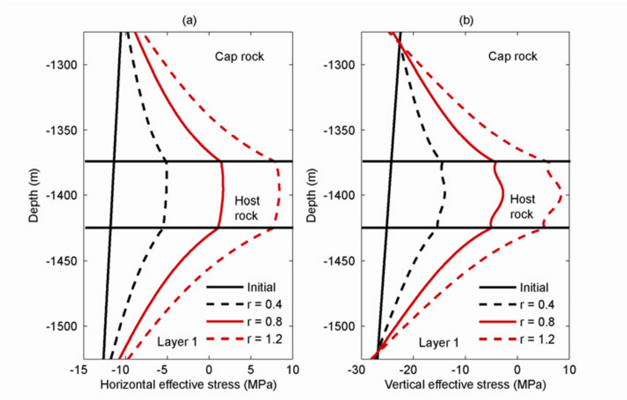


Figure 3: Horizontal effective stress (a) and vertical effective stress (b) along the vertical direction for different normalized injection rates with a confinement coefficient $k_0 = 0.7$ [12].

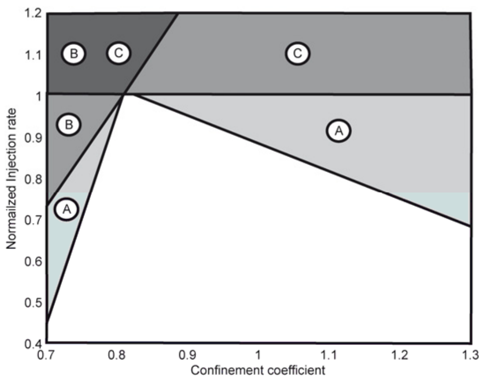


Figure 4: Maps of cracking mechanisms for different confinement conditions and injection rates [12]

4. Numerical modeling of the hydromechanical behavior of faults

Deep well injection weakens the strength of a fault. Hydromechanical response of fractures and faults affected by CO_2 injection determines their role concerning the storage integrity. The decrease of effective stress (soil mechanics convention) in the vicinity of a fault may lead to its failure. The motion of a fault (opening or sliding) may also increase its permeability.

The analysis of fluid flow in naturally fractured porous media is generally very difficult because of the complex nature of the phenomena. The problem to be solved is strongly nonlinear. The nonlinearity arises from the law of mechanical behavior of fracture or rock matrix and the flow law as well as the hydromechanical coupling. The transmittivity of the fractures is more sensitive to pressure changes because the fracture width depends on fluid pressure. The hydromechanical joint elements (two and three-dimensional) are implemented in the finite element code Gefdyn [13]. The approach consists in using a consistent formulation of flow in deformable rock masses through a variational formulation with particular attention to the continuity conditions between the fracture and the deformable porous matrix, as the rock deformations and the fluid are fully coupled. As a first order approximation, a fault is modeled as a distinct object using a hydromechanical joint element.

Several relationships have been proposed in the literature for the flow in fracture. To test the implementation of joint elements in Gefdyn, the formulation proposed by Cappa et al. [14] is followed and laminar flow proportional to the pressure gradient and the aperture of the fracture is assumed

$$\partial_t u_{rw} = -K_f \, grad(p) \tag{2}$$

where $\partial_t u_{rw}$ is the relative seepage velocity, p the pressure and

$$K_f = \frac{(e_{ini} + f[u_N])^3}{12\mu e_{ini}} = \frac{k_f (e_{ini} + f[u_N])^3}{12\rho g} \; with \; k_f = \frac{\rho g}{\mu e_{ini}} \tag{3}$$

where e_{ini} is the initial hydraulic aperture at the initial effective stress, f a factor reflecting the influence of the roughness of the fracture on the tortuosity of the flow, $[u_N]$ the normal displacement discontinuity between the two sides of the fracture, μ the fluid dynamic viscosity, ρ the fluid mass density and g the gravitational acceleration.

A hydraulic-pulse-test carried out in a shallow fracture unit (Fig. 4-a) [14] is considered as the reference to check the implemented joint elements. A two-dimensional model (10 m × 10 m) of a single fracture surrounded by a deformable rock mass is used. A plane strain 2D analysis neglecting the gravity effects on fluid flow and mechanical deformation is carried out. All boundaries are considered to be impermeable. A constant stress, set according to the weight of the overlying rock (10 m) is applied on the top and right boundaries. Zero vertical displacements are prescribed on the bottom boundary and zero horizontal displacements on the left boundary. Before the pulse test, the *in situ* fluid pressure is set to 39 kPa. At the injection point, the fluid pressure is increased to 125 kPa and then is returned to the initial starting level. The mechanical and hydraulic properties are shown on the table 4. Figure 4-b shows normal displacement-versus-pressure curve during the pulse injection. The comparison between obtained results and reference ones shows a good agreement.

Table 4: Mechanical and hydraulic properties of the model

Fracture		**Rock matrix**		**Fluid**	
Normal stiffness	40 GPa/m	Young's modulus	70 GPa	Mass density	1000 kg/m^3
Shear stiffness	4 GPa/m	Poisson's ratio	0.29	Bulk modulus	2 GPa
Hydraulic aperture	10^4 m	Mass density	2400 kg/m^3	Dynamic viscosity	10^{-3} Pa.s
f (roughness)	1	Permeability	0		

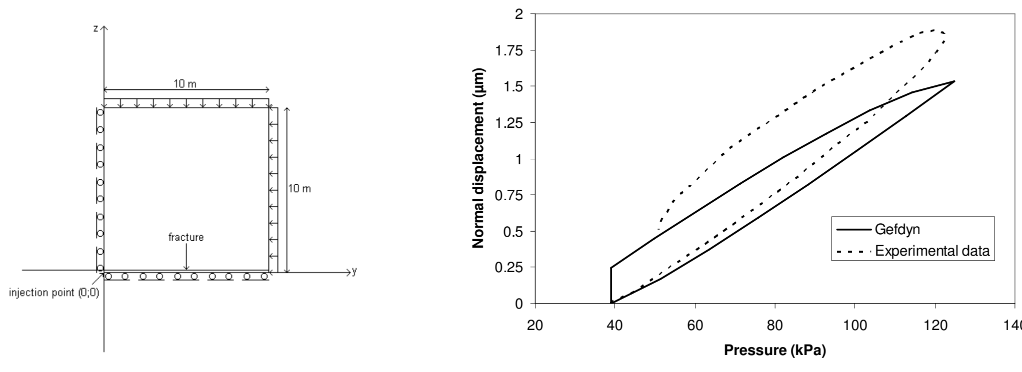


Figure 5: Geometry and boundary conditions of the pulse test (left) and normal displacement versus pressure at injection point (right)

5. Conclusions

This work is a general presentation of the mechanical changes induced by CO_2 injection in a representative geological reservoir. The analyses presented herein are simplified because of a lack of field data. Large scale coupled hydromechanical finite element calculations were performed to evaluate the change in effective stresses due to gas injection. In this context, a sequential approach is used. Two existing numerical codes, each specialized to a few of the involved processes, are linked using a sequential run and data transfer through nonlinear coupling functions. Results indicate that the most important process in hydromechanical behavior of the caprock is a general reduction of effective stresses, caused by the high-pressure injection of CO_2. The interface between the injection zone, i.e. hostrock, caprock and the lower parts of the caprock are the most critical regions of the analyzed model.

Different cracking mechanisms, namely, tensile cracking and shear sliding are examined for different initial *in situ* stress conditions and injection scenarios. Results show that the most likely damage mode and the injection pressure that may induce caprock damage strongly depend on the initial stress state of the site. A low horizontal stress increases the risk of tensile damage. Shear sliding damage becomes predominant when initial horizontal stresses increase.

A special hydromechanical joint element for modeling the response of faults is also presented. The incorporated approach consists in using a consistent formulation of flow in deformable rock masses through a variational formulation with particular attention to the continuity conditions between the fracture and the deformable porous matrix, as the rock deformations and the fluid are fully coupled. As a first order approximation, a fault is modeled as a distinct object using a hydromechanical joint element. The ability of the model to simulate the fault hydromechanical behavior is discussed through a comparison with a reference example.

6. Acknowledgements

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