Impact of injection pressure during cold water reinjection on the state of stress in geothermal reservoirs

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Abstract

During cold water injection into geothermal reservoirs, pore pressure increases and the reservoir rock is brought closer to fracturing conditions. The fracturing may cause early cold water breakthrough into production wells. A 2-D reservoir simulator describing fully coupled fluid flow, thermal flow, and geomechanical behavior was used in this study. The objective of this work is to investigate the evolution of the stress state in liquid-dominated reservoirs and to establish how principal stress directions change during injection pressure increase. The paper describes simulated fracturing pressure changes due to cold-water injection. It also discusses how to predict orientation/re-orientation of hydraulic fracture propagating from an injector.

***Keywords**: numerical modelling, re-injection, state of stress.*

1 Introduction

The mechanical behavior of a body, i.e. the changes in its dimensions (its deformation), or in some cases its failure, depends on the external and internal forces distribution acting on the body. Considering an infinitesimal cube isolated from the body, it is held in equilibrium by forces imposed on its surfaces. The cube can be oriented in such a way that only forces normal to its surfaces are present. Under these conditions there are three pairs of independent forces since the cube is in equilibrium.

The physics of the geomechanical behavior of a geothermal reservoir, and its mathematical description, are rather complex due to the porous nature of the rock coupled with fluid flow (multiphase flow) through the pores. The strain concept is used to describe deformation of a material and it is directly related to displacement through strain/displacement relations. When modeling deformation of a poro-elastic medium we use the continuum mechanics (continuous medium) concept, which states that every infinitesimal sub-volume of the material is occupied by the medium consisting of solid skeleton and porous space, and its properties (porosity, permeability, etc.) either vary smoothly from one point to another or are the same everywhere.

One of the main ideas of the theory is that the stress in a saturated porous material is 'carried' partially by the pore fluid and partially by the solid matrix. This is the so-called total stress and it refers to the bulk volume of the rock. The part of the total stress carried by the solid rock matrix, is called effective stress, and it represents the actual state of stress in the solid rock grains.

Fluid injection into a reservoir, and production from the formation, perturbs the local in-situ stress state. The stress can either be altered by changes in pore pressure, or by temperature perturbations in non-isothermal flow.

During cold water injection into geothermal reservoirs, pore pressure increases. Suffciently accurate estimation of reservoir stresses becomes essential in many geothermal injection – production operations when a reservoir is brought closer to fracturing conditions. This is because induced stress changes may cause formation fracturing. The fracturing may cause early cold water breakthrough into production wells. In naturally fractured/stress sensitive reservoirs the state of stress changes cause opening or closing of existing fractures and permeability variations.

2 Formulation of the coupled model

A fully coupled fluid flow, thermal flow, and geomechanical behavior model incorporates the fluid flow equation with energy conservation and stress equilibrium equations. Energy balance law was assumed under the following assumptions (Rewis, 1999):

- the only energy transfer to the system is by convective and conductive heat transfer through the boundary, and mechanical work done by surface traction,
- kinetic energy changes are small compared to those of the internal energy,
- negligible viscous dissipation,
- instantaneous local thermal equilibrium between rock and fluid.

To determine stress variations in the system, the following governing equations from the theory of poro-thermo-elasticity are used. Computer code is used to solve the following system of equations (Chen *et al.*, 1995):

$$G \cdot \nabla^2 u_i + (G+L) \cdot \frac{\partial}{\partial i}(\nabla \cdot \mathbf{u}) + \alpha_B \cdot \frac{\partial P}{\partial i} + (2 \cdot G + L) \cdot \frac{\partial(\alpha_T \cdot T)}{\partial i} = 0 \qquad i = x, y \qquad (1)$$

$$\nabla \cdot \left(\frac{k}{\mu_f} \cdot \nabla P \right) = c_t \cdot \frac{\partial P}{\partial t} - \beta_t \cdot \frac{\partial T}{\partial t} - \alpha_B \cdot \frac{\partial}{\partial t}(\nabla \cdot \mathbf{u}) \qquad (2)$$

$$\nabla \cdot (\lambda \cdot \nabla T) - \nabla \cdot \left(\frac{\rho_f \cdot k \cdot C_f \cdot T}{\mu_f} \cdot \left(\nabla P + \frac{P}{\rho_f} \right) \right) = \frac{\partial}{\partial t}\left((1-\phi) \cdot \rho_s \cdot C_s \cdot T + \phi \cdot \rho_f \cdot C_f \cdot T \right) \qquad (3)$$

Where:

u – displacement vector, m,
G – shear modulus, Pa,
L – Lame's constant, Pa,
α_B – Biot's poroelastic coefficient,
P – pressure, Pa,
α_T – coefficient of thermal linear expansion, 1/K,
T – temperature, K,
k – permeability, m^2, mD
μ_f – viscosity of fluid, Pas,
c_t – total isothermal compressibility of reservoir, 1/Pa,
β_t – total isobaric compressibility of reservoir, 1/K,
t – time, s,
λ - thermal conductivity, W/mK,
C_f, C_s – heat capacity of fluid and solid, J/kgK
ρ_f, ρ_s – density of fluid and solid, kg/m^3,
ϕ - porosity, -.

The numerical simulator solves the system of P.D.E. given above in a two-dimensional domain, under a plain strain assumption using control-volume finite difference discretization (Rewis, 1999; Osorio et al., 1999).

3 Thermal stress during injection into geothermal reservoir

The response of a reservoir volume was analyzed to investigate the effects of temperature changes on stress perturbations during injection of cold water. The plane strain condition is assumed and also single-phase, slightly compressible fluid flows. No fluid or heat flow in the vertical direction is allowed. Following these assumptions pore pressure, temperature, displacement, and the stress field will not change in the vertical direction and the problem can be solved in 2D. Furthermore, the grid boundaries coincide with the directions of the initial principal horizontal stresses. Constant injection rate is specified at the well. Because of symmetry a quarter of the area is considered and no flow boundary conditions along left and bottom boundary. Constant pressure along right and top boundary is assumed (see Figure 4).

3.1 Numerical simulation

In the following, we analyze simulation results where we consider a square area of 1000 m by 1000 m, as shown in Figures 4-6. The orientation of the initial principal stresses coincides with the grid boundary. Because of symmetry a quarter of the area is considered with the injection well located in the corner. We assume an initial reservoir pressure of 15 MPa and an initial reservoir temperature of 80°C. The average porosity is assumed 13%. In the simulated cases, three different values of permeability are used: 250 mD, 500 mD and 1000 mD. Injected water temperature is assumed to equal 15°C.

Figures 1-3 show well pressure changes in time for the cases analyzed. Higher injection rate requires higher injection pressure, which results in faster and further growing fracture. Due to lower permeability of rock (250 mD), 140 m^3/hr injection flow rate causes fracturing of rock after 700 days of injection. In 1000 mD permeability rock, fracture is initiated after 1400 days at 350 m^3/hr water rate injection. Such rock fracturing may result in faster cold front movement towards the production well.

Water injection induced fracturing is often encountered in cases of tight/low permeability formations. This type of reservoir is the most stress sensitive reservoir, where permeability may be expected to be stress dependent.

Figures 4-6 show pressure, temperature and incremental horizontal stress after 1500 days of injection. As expected, the greatest temperature-change occurs in the near-well region. Cooling of the formation (by the cold injected water) results in tensile stress development, which overcomes the incremental compressive stresses resulting from the injection-induced fluid-pressure increase. The cooling effect can bring the reservoir closer to fracturing conditions. Analysis of the simulation runs suggests the possibility of local stress reorientation (which depends on the relative magnitude of the stress perturbations compared to the initial state of stress).

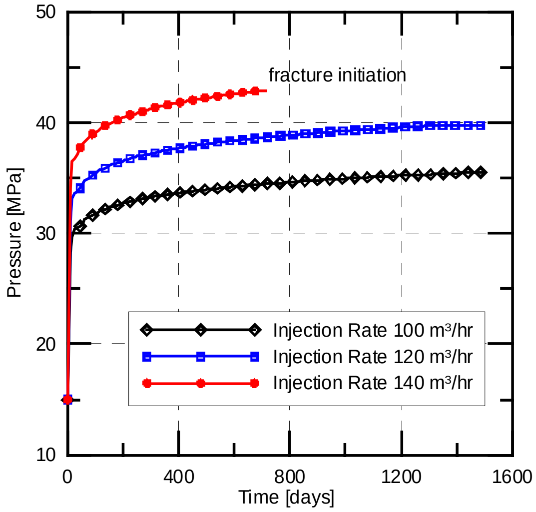

Figure 1: Simulated well pressure for three different injection rates and a rock permeability of 250 mD.

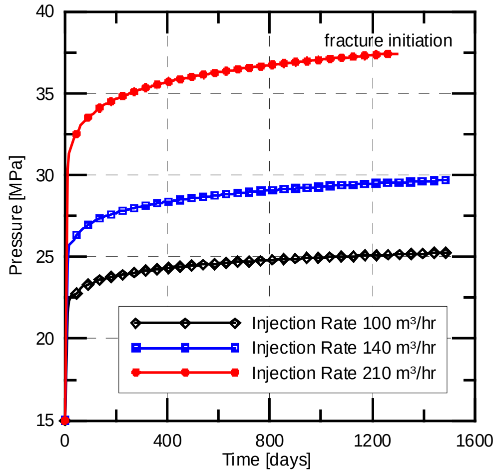

Figure 2: Simulated well pressure for three different injection rates and a rock permeability of 500 mD.

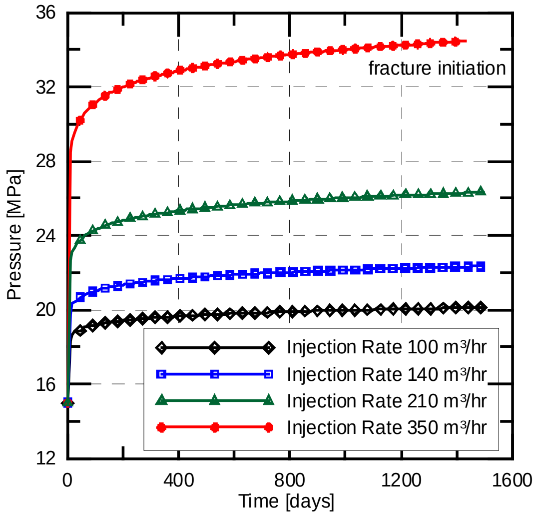

Figure 3: Simulated well pressure for three different injection rates and a rock permeability of 1000 mD.

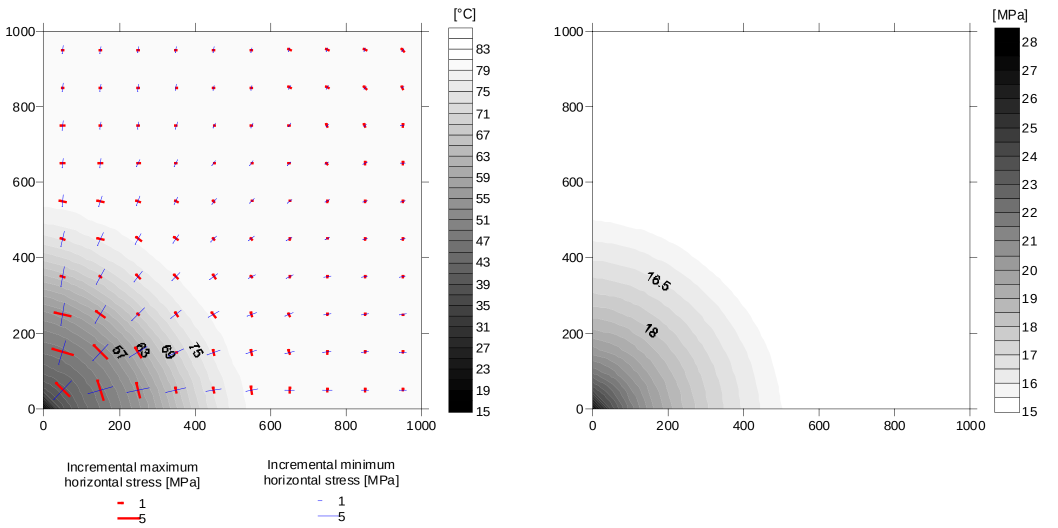

Figure 4: Pressure, temperature and incremental horizontal stress after 1500 days of injection for rock permeability of 250 mD and injection rate of 140 m^3/hr.

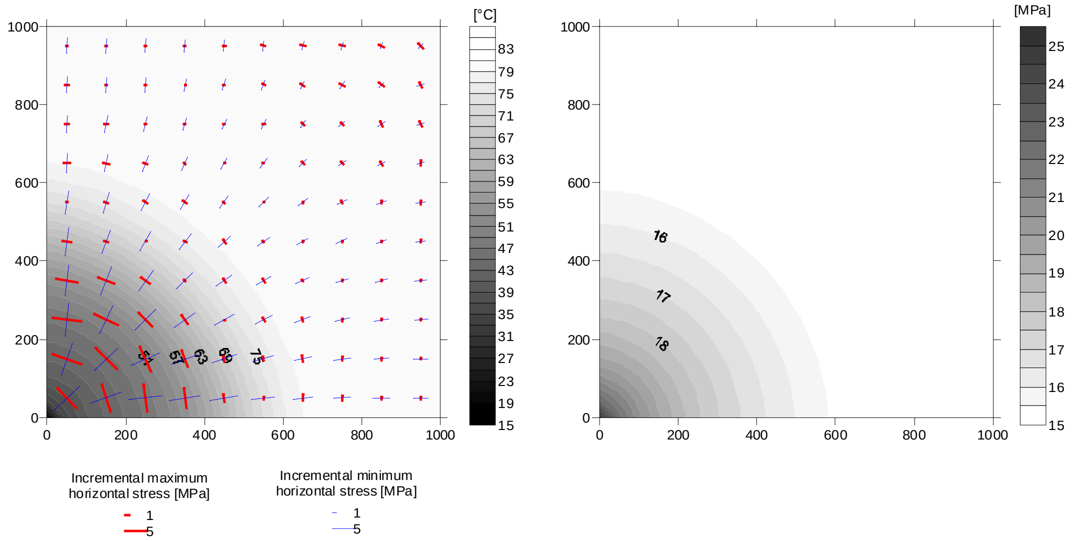

Figure 5: Pressure, temperature and incremental horizontal stress after 1500 days of injection for rock permeability of 500 mD and injection rate of 210 m^3/hr.

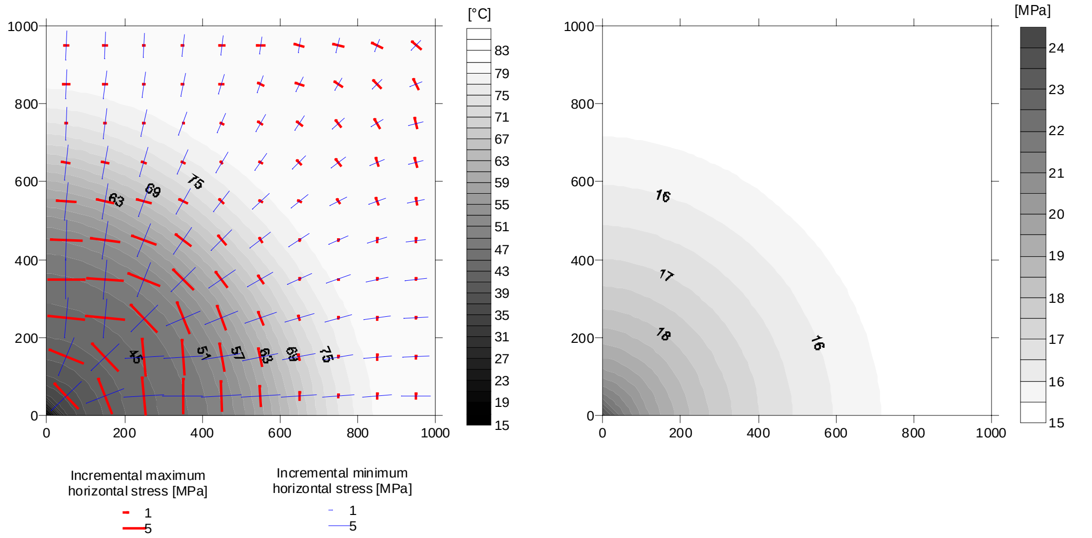

Figure 6: Pressure, temperature and incremental horizontal stress after 1500 days of injection for rock permeability of 1000 mD and injection rate of 350 m^3/hr.

4 Conclusions

Water injection induced fracturing is often encountered in cases of tight/low permeability formations. These types of reservoirs are the primary candidates for stress sensitive behaviour, where permeability is stress dependent.

A numerical model to determine the impact of injection on geomechanical behavior of a geothermal reservoir has been developed. Compared with the conventional isothermal or thermal reservoir simulators, description of the flow- and thermal-induced evolution/distribution of reservoir stresses is the unique feature of the simulator presented here. Simulation results show that the thermal-induced stresses overcome the incremental compressive stresses resulting from the injection-induced fluid-pressure increase. The thermal stresses alter the in-situ stress anisotropy in both magnitude and direction. The results also show that the magnitude of the tensile stresses resulting from cold-water injection increases, when injection pressure decreases, due to higher reservoir permeability, and as time of the injeciton increases.

Estimation of geothermal reservoir stresses enables to determine optimal injection rate to avoid rock fracturing (and early cold water breakthrough) in geothermal management. The analysis of geomechanical behaviour of geothermal reservoir presented in the paper can be used to predict hydraulic fracture propagation due to cold-water injection. A 3-D model extension could deliver more detailed information about mechanical behaviour of a rock.

5 References

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