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Effect of CO_2 injection temperature on caprock stability

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Abstract

Deep saline aquifers are promising candidates for long-term CO_2 storage, provided they don't leak. However, injection of CO_2 causes pressure buildup and affects the geomechanical stresses in the caprock. If CO_2 is injected at a temperature different from the temperature in the aquifer, additional stresses develop due to thermal expansion/contraction. Our work addresses the question whether these stresses are capable of fracturing the caprock and causing leakage. Using a fully coupled thermo-poromechanical model we simulate 10 years of continuous injection of CO_2 at different temperatures. We use the geomechanical parameters for aquifer on Krechba (In Salah, Algeria) including recently published data on initial in situ stresses. We found that when CO_2 is injected at temperature 40-50ºC the stresses in the caprock become tensile and even overcome the tensile strength causing fracturing of the caprock. After initiation the fractures begin to propagate, driven by high fluid pressure in the reservoir. We estimate the fracture length to be 50 m within the first 10 years of propagation.

Keywords: CO_2 sequestration; fully-coupled modeling; In Salah; thermal stress; fracture propagation

1. Introduction

Deep saline aquifers are promising candidates for CO_2 storage because they are widespread and have large capacity. Currently one of the main concerns related to CO_2 sequestration in aquifers is to elaborate operation conditions providing safe storage for long term perspective. A target aquifer for CO_2 injection is bound from above by geological formation with low permeability – a caprock. Presumably caprock prevents injected CO_2 from migration to shallow aquifers and leakage. However, injection of CO_2 changes the geomechanical stresses in the caprock and may lead to its failure. Simulation of the CO_2 injection in

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the aquifers helps to elaborate the optimal operation conditions, when substantial amount of CO_2 is injected without losing the caprock integrity.

Modeling CO_2 injection in an aquifer involves simultaneous consideration of fluid flow and geomechanics. Therefore these two processes have to be coupled in simulations. Often it is achieved by means of so-called explicit (iterative) coupling [1]: once the fluid flow equations are solved for pressure and temperature on a certain time step, these variables are fed to geomechanical model to find strains and stresses. Recently Preisig and Prevost offered a fully coupled model for simulation of CO_2 injection operations, which solves fluid and solid equations simultaneously [2]. They tested the model against iterative coupling, and showed that it gives substantially better predictions, unless the number of explicit iterations is very high [3].

Often when modeling the injection, the temperature of injected CO_2 is assumed to be equal to that of the formation [4]. However, usually it is not true: e.g. for the injection site in Nagaoka, Japan the well head temperature of CO_2 is 32ºC [5] and "approximately 30ºC" for Nisku in Canada [6], while the ambient temperature in the aquifer is noticeably higher. Calculations show that at typical injection rates the CO_2 temperature at the well bottom remains noticeably lower than the ambient temperature of the reservoir [7, 8]. When cold CO_2 is injected in the aquifer, it causes significant thermal stresses around the injection well, so that aquifer and even caprock can fracture [6, 8, 9]. If fractures propagate in the vertical direction, they can serve as paths for CO_2 leakage.

Here we study the development of stresses in the caprock caused by CO_2 injection at different temperatures. We use the fully-coupled thermo-poromechanical simulations method [2]. We use parameter of Krechba field (In Salah, Algeria) as an example. Our calculations are based on the recently published field data for in situ stresses [10]. We used the results of our simulations (pressure and stresses) in the analytical model [11] to predict the rate of fracture propagation driven by fluid outflow from the aquifer.

2. Model and method

2.1. Model geometry and injection parameters

To study the effects related to injection temperature we use the parameters of CO_2 injection operation ongoing at In Salah Algeria. Following ref. [3] we consider a two dimensional region of 5000 m width and 1820 m depth, which consists of three layers: narrow sandstone aquifer (20m), stiff caprock (900m) and soft shallow overburden (900m). The mechanical properties are based on [4] of the layers are summarized in Table 1. The materials are considered linear elastic.

Table 1. Mechanical properties of the injection site

Layer	Overburden	Caprock	Aquifer
Depth	0-900 m	900-1800 m	1800-1820 m
Young's modulus	1.5 GPa	20 GPa	6 GPa
Poisson's ratio	0.2	0.15	0.2
Porosity	0.1	0.01	0.17
Permeability	10^{-4} mD	10^{-4} mD	50 mD

The surface temperature is 30ºC, the temperature gradient is 30ºC/km, the initial temperature in the reservoir is 90ºC, the initial fluid pressure is 18.2 MPa. There are no published data on injection temperature for In Salah, so we make three simulation runs the temperature of CO_2 injection is 90ºC, 50ºC and 40ºC. The amount of CO_2 injected in the well was assumed to be 12 MMScfd, which is in between the values used in [4] and [3]. The thermal properties of the system are used following [3] and summarized in Table 2. The properties of CO_2 at the values of temperature under consideration are calculated based on the equation of state by Span and Wagner [12]. For the brine we used the properties of water at 90ºC and 27.9 MPa: density 10^3 kg/m3, viscosity $3{\cdot}10^4$ Pa·s and compressibility $4.1{\cdot}10^{-10}$ Pa^{-1}. The change in relative permeability due to partial saturation of one phase is modeled according to van Genuchten-Mualem model [13]. The residual saturations of CO_2 and brine are 0.15 and 0.25, respectively, exponential parameter, responsible for the shape of the retention curve, m = 0.5.

Table 2. Thermal and fluid flow properties

Linear thermal expansion coefficient of rock	$1.2{\cdot}10^{-5}$ $ºC^{-1}$
Isotropic thermal conductivity of saturated rock	2.5 W/m/ºC
Specific heat capacity of rock	10^3 J/kg/ ºC
Specific heat capacity of fluids	$4.2{\cdot}10^3$ J/kg/ ºC

2.2. Geomechanical and stress data

While in the absence of field data the previous work from our group gave estimates for the initial stresses based on K_0 lateral stress coefficients, in the current simulations we assign initial stresses based on the measured values reported by Morris et al. [10] for KB-502 CO_2 injection well: σ_V = –44.5 MPa, σ_{Hmax} = –49.9 MPa, σ_{Hmin} = –30.8 MPa, with the pre-injection fluid pressure of 19.2 MPa. We use the solid mechanics sign convention for the stresses: compressive stresses are negative and tensile stresses are positive. The minimum horizontal stress is reported to be acting parallel to the well [14].

We calculate then the lateral stress coefficients and assume them to be constant throughout the all layers. From the value of vertical stress we calculated the solid density to be 2400 kg/m^3. Once we know the lateral stress coefficients K and solid density, we can calculate the initial effective stresses for our system at any depth. In order to take into account the change of K with the depth, one needs to measure the in situ stresses at a number of various depths; these data is not currently available.

2.3. Modeling techniques

For the simulations of the CO_2 injection we solve the pressure equation, balance of momentum (stress) equation, saturation equation and heat equation by means of the fully coupled method [2, 3]. We use a 2D mesh representing the whole 5000m × 1820m region and consisting of 2975 4-node elements. Boundary conditions are specified as follows: on all boundaries except the top surface normal displacements are fixed. On the right side of the mesh we used the pressure boundary conditions to allow the fluid outflow. Temperature is fixed to the initial values at the top and bottom, but not on the sides. CO_2 is injected through a horizontal well, perpendicular to the considered plane. Below, when presenting the results only a 40x40m region around the injection well is displayed.

Numerical simulations of fully-coupled thermo-poromechanical problems were completed using the DynaFlow finite elements code [15]. We do not include the fracture propagation in our simulations explicitly, but use the physical parameters (pressure, stresses) obtained from simulations to predict the fracture behavior using an analytical model [11]. More details can be found in [16].

3. Results and discussion

We simulated continuous injection of CO_2 in the aquifer within 10 years, within this time the pressure in the aquifer increased by 11 MPa. In three different runs we used different values of the injection temperature: 90ºC (which is equal to the temperature in the aquifer), 50ºC and 40ºC. Figure 1 shows the temperature profiles around the injection well and the component of effective stress perpendicular to the displayed plane. We see the strong correlation between the stresses in the caprock and the temperature diffusion in it. While for the case when CO_2 is injected at 90ºC the stresses remain compressive, for injection at lower temperatures, the stresses become tensile.

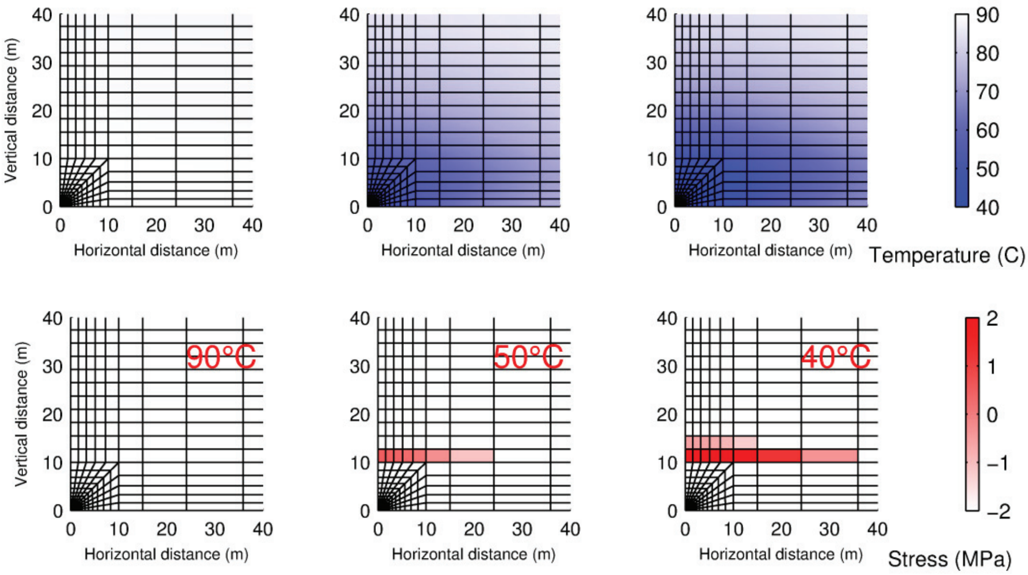

Fig. 1. (top) Temperature profiles in the aquifer and caprock around the injection well after 10 years of continuous injection of CO2 at 90ºC, 50ºC and 40ºC (bottom) corresponding effective horizontal stresses. Horizontal injection well is perpendicular to the displayed plane and is in the origin of the coordinate system.

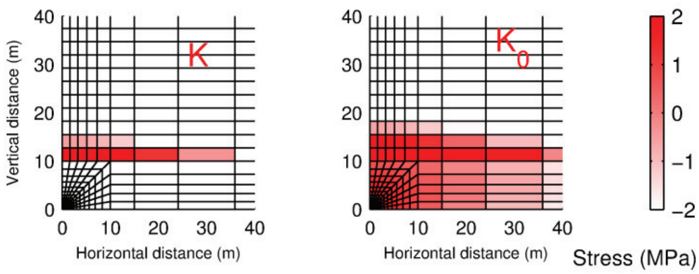

Fig. 2. Effective horizontal stress after 10 years of continuous injection (left) calculated based on initial stress values from in situ measurements; (b) calculated based on K_0 values of lateral stress coefficients

The stresses after injection depend strongly on the initial values. In the work by [3] due to the absence of field data, the initial stresses were calculated based on the K_0 lateral stress coefficients. Here the field data from [10] were used for calculations of lateral stress coefficient. Figure 2 shows that initial stresses can dramatically change the predictions for stresses induced by CO_2 injection.

When the effective stress in the caprock overcomes the tensile strength (typical values for shale is 0.2 to 2.0 MPa [17]), the caprock fractures. The fluid from the aquifer enters the fracture and causes its propagation. The action of cohesion forces can be neglected in comparison to the values of stresses and fluid pressures, so the fracture will be propagating when the fluid pressure exceeds the total stress in the caprock. While the fluid pressure drives the fracture propagation, it also limits the rate of the propagation. When aquifer has relatively low permeability (50 mD in our case), the fluid outflow from an aquifer is slow and therefore it is a rate-determining process for the fracture propagation. Assuming elliptical shape of the fracture and using the GdK relation between the width and the height of the fracture [18], estimates predict the vertical propagation of the fracture for ~50 m within 10 years after its appearance [11].

4. Conclusion

Using fully-coupled method we simulate the continuous injection of carbon dioxide at different temperatures. We used the geomechanical parameters for the aquifer on Krechba field (In Salah, Algeria), including the measured in situ stresses, reported recently [10]. We showed that when CO_2 is injected at temperatures 40-50ºC the stresses in the caprock near the injection well to become tensile in less than 10 years, while when CO_2 is injected 90ºC (ambient temperature in the aquifer) at the same rate the stresses remain compressive. This result agrees with the recent study from Goodarzi et al. [6]

Our simulations show, that the stresses can even overcome the tensile strength of the caprock, so the caprock will fracture. Due to the increased pressure in the reservoir, the fractures will propagate. Using the analytical model for propagation of fracture driven by fluid outflow from a low-permeability aquifer [11] we estimated the length of fractures after 10 years from initiation to be ~50m. It could be a concern in the long-term perspective.

We also showed that use of field data for initial in situ stresses instead of stresses calculated based on K_0 lateral stress coefficients, changes the predictions for resulting stresses dramatically. However, we had stresses data only for a single depth and therefore we assumed constant values of lateral stress coefficients for all the depths.

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