Coupled Hydraulic and Mechanics Finite Element Modeling of CO2 Injection into a Layered Isotropic Media Using FEHM

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Abstract. CO2 injection into the hydrocarbon reservoir affects the subsurface mechanics and hydraulic condition. The injection has to be performed in a way that there will be no reservoir and/or top seal failure. In such case, a simulation of the injected fluid propagation needs to be performed to see its possible impact to the top seal and existing major faults. We use finite element method to perform this injection simulation. In this research, we use open source software Finite Element Heat and Mass Transfer Code (FEHM) to simulate CO2 injection processes into reservoir. Subsurface geological model was constructed in a dimension of 3000 m (easting) x 3000 m (northing) x 2000 m (vertical). Vertically, it consists of four layers which represent upper layer (400 m), top seal (200 m), reservoir (900 m), and basement (500m). The grid around the reservoir rocks is refined to give more detail results. The open hole injection is set at 850 - 890 m depth, 1500 m easting and 1500 m northing. The material is assumed to be isotropic. The initial pressure and temperature increase as a function of depth with a pressure gradient of 0.00981 MPa/m and a temperature gradient of 0.025 degrees C/m. A vertical fault is modelled at 600 m eastern to the injection well. Injection process is carried out with 6 kg/s of CO2 injection with simulation time for ten years to see its impact to the fault. A vertical fault is reactivated at 10 years.

1. Introduction

Increased CO2 emissions lead to climate change. Thus, demanding a way to reducing the impact of CO2 emissions. Geologic Carbon Sequestration or better known as Carbon Capture and Storage (CCS) is one of the technologies to reduce the impact of CO2 emissions by injecting CO2 emissions into hydrocarbon reservoir [1].

Geomechanical analysis in CCS has been discussed in several studies, especially in term of injection pressure [2]. Injection pressure is very influential in affecting the in-situ stress condition of the reservoir. Furthermore, in some cases, a large injection rate might cause a reactivation of existing faults [3].
The reservoir rock should be below an impermeable or caprock layer to trap the injected CO2. The stress perturbation due to injection on caprock is very crucial [4]. It is because the changes of in-situ stress in caprock and reservoir rocks due to injection might cause seal failure or fault reactivation.

The potential of failure and leakage on reservoir rock and caprock can be approximated in several ways; one of the possibilities is through numerical modeling. Modeling in this research is performed using Finite Element Method, in which we can simulate CO2 injection into hydrocarbon reservoir and estimate the possibility of rock failure as well as fluid leakage. The parameters required in this simulation are the rate of injection and in-situ stress parameters before injection, during injection and after injection. Using those parameters, we infer the stability of the reservoir.

2. Methodology
We used Finite Element Heat and Mass (FEHM) program [5] for simulating the CO2 injection. The reservoir is represented in 1268 orthogonal grid with dimension of 3000m (easting) x 3000m (northing) x 2000m (depth). As shown in Figure 1, the grid consists of 4 layers with isotropic physical parameters, i.e. the upper rock layer (0-400m), the caprock layer (400-600m), the reservoir (600-1500m), the bedrock / basement (1500-2000m). The input physical parameters, i.e. permeability, density, porosity, young modulus, and poisson ratio, for each zone are presented in Table 1.

Table 1. Physical parameters of Model.

| Zone | Permeability b (md) | Density a (kg/m³) | Porosity b (%) | Young Modulus b (GPa) | Poisson Ratio b |
|------|---------------------|------------------|---------------|-----------------------|---------------|
| 1    | 100                 | 2009             | 8             | 20                    | 0.25          |
| 2    | 30                  | 2273             | 5             | 30                    | 0.35          |
| 3    | 50                  | 2417             | 20            | 20                    | 0.3           |
| 4    | 50                  | 2495             | 5             | 40                    | 0.2           |

Table 2. Initial in-situ stress condition applied in this study.

| Pressure (MPa/m) |
|------------------|
| Shmin            | 0.01771          |
| SHmax            | 0.03473          |
We used static boundary condition. In which, there is no displacement at the outer boundary of the model (Zmin, Ymin, Ymax, Xmin, Xmax).

Figure 1. (a) 3D view of the reservoir model; injection point is located at 1500m (easting), 1500m (northing), and the fault is located 600 m east from the well. (b) The vertical view of the reservoir model with the open hole zone (850m-890m).

Figure 2. (a) A graph of the in-situ principal stress and pore pressure in the reservoir model prior to injection. (b) Calculated Mohr diagram before injection at a depth of 873 m [11]
The subsurface in-situ stress condition at depth of 873 m is plotted in Figure 2a, i.e. overburden stress \( S_v = 10.4960 \text{ MPa} \), minimum horizontal stress \( S_{\text{min}} = 6.8021 \text{ MPa} \) and maximum horizontal stress \( S_{\text{max}} = 21.6722 \text{ MPa} \). From which we evaluate the failure sensitivity to pore pressure changes due to injection using Mohr diagram. The injection simulation is conducted up to 10 years with an injection rate of 6 kg/s. The simulation is set in order to be able to evaluate the effect of injection rate on the reservoir stress condition and on the existing fault. The fault is set to be at a distance of 600 m from the point of injection (see Fig. 1), assuming a friction coefficient of \( \mu = 0.8 \).

3. Results and Discussion

The results of the modeling of 6 kg/s of CO2 injection for 1 year is shown in Figure 3. It is shown that the fluid has spread both horizontally and vertically. This injection causes a slight decrease of \( S_v \), \( S_{\text{min}} \), and \( S_{\text{max}} \), and increases the pore pressure in the reservoir. Figure 3b is the zoom in of the pore pressure perturbation in the vicinity of the open hole section. It can be seen that the pore pressure in the open hole section immediately increase following the injection fluid propagation. The injection continuously increases the pore pressure. The pore pressure increases results in decreasing \( S_v \), \( S_{\text{min}} \) and \( S_{\text{max}} \) around the open hole zone.

Based on Rubianto [8], \( S_{\text{max}} \) oriented N65E or NE-SW direction in the Strike-slip regime, \( S_{\text{max}} \) is 21.67 MPa at a depth of 873 m. After 1 year of injection, we get the value of \( S_v \) of 7.9834 MPa, \( S_{\text{min}} \) of 4.6784 MPa and \( S_{\text{max}} \) of 19.5485 MPa. The additional pore pressure is observed at 0.932 MPa, which causes Mohr circle shift to the left, assuming friction coefficient of (0.8), as shown Figure 4. It can be concluded that injection rate of 6 kg/s for a 10 years cause the fault to be in a stable condition.

The results are presented in figure 4. It can be seen that, according to Mohr diagram, the pore pressure increase of 0.07 MPa. Horizontal 873 m depth slices (Figure 5) were made to image the radial fluid movement as a function of time from injection point to the reservoir rock. It can be seen that after 4 hours the fluid starts to affect the fault (an increase of 0.02 MPa pore pressure to the fault), and after 10-years an increase of 0.07 MPa to the fault.

A graph of pore pressure and stress condition after 10 years injection (Figure 6). We can se that there is a intersection between the pore pressure graph and stress graph. it means that the pore pressure decrease significantly comparing to stress. We can interpret this as the pore pressure will propagate diffusional and the stress propagates through granular structure [12].
Figure 4. A graph of Mohr diagram at 873 m depth Mohr diagram after 10-years injection.

Figure 5. A map of pore pressure perturbation at the 873 m depth slice. The red line indicates the fault zone at different time period. The pore pressure is shown as a function of time: (a) before injection, (b) after 10 minutes, (c) after 6 hours, (d) after 1 day, (e) after 4 days, (f) after 30 days, (g) after 6 months, (h) after 1 year, and (i) after 10 years.
Figure 6. A graph of pore pressure and stress condition after 10 years injection. We can see that there is an intersection between the pore pressure graph and stress graph. It means that the pore pressure decrease significantly comparing to stress.

4. Conclusions

We conclude that our modelling could represent the in-situ stress perturbation caused by injection. According to our results, we show that an injection of 6 kg/s CO2 into the layered isotropic media representing the Gundih CCS subsurface would increase the pore fluid pressure after 10 year of injection. Furthermore, after 10-year of injection was conducted the fault will not be in the failure condition. It means that it safe if we are going to use the 6 kg/s injection in Gundih area. The simulation could also be applied to other CCS and geo-reservoir field. Furthermore, an integrated geosciences study is proposed to better validate the results obtained in this study [13].

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