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Modelling Thermal Recovery of a High Temperature Geothermal Well

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ABSTRACT

In some geothermal projects, due to lack of suitable re-injection wells, temporary reinjection of cold fluids into high temperature wells might be required. Apart from a risk of permanent damage to the well, the main concern in this case is the time required for the well to obtain its natural state. In this study, we will model a period of cold reinjection into a well with high production capacity using Tough2 code via Petrasim interface and simulate the cooling and the thermal recovery of the well profile. We will start with building the conceptual model in two dimensions; obtain the natural state temperature distribution. Then we will simulate different injection periods, covering three months, six months, and one year and evaluate the results.

1. Introduction

The field is a high temperature liquid dominated field with bottom-hole temperatures reaching 270°C. It is not under exploitation yet and we do not have much data to calibrate it against. Therefore, we will build a two-dimensional model for now and study a conceptual model. This will also enable us to run different scenarios with fast convergence of calculations.

Using a two-dimensional model would bring with it some limitations. Taking into account the purpose of our study, which is the thermal recovery of a geothermal well, the biggest limitation would be the lack of convective heat transfer in a two dimensional X-Y section model.

We will apply an optimistic approach, and start the production of the "recovering well" with full flow rate as soon as the reinjection ends. This would hasten the recovery of the well as it would draw hot fluids near the wellbore, and might cover up for the lack of convective heat transfer.

2. Model Geometry

Our model is 14000 km long, 11000 km wide and 500 meters thick. It is a two-dimensional section at depth of around 950 meters below sea level. The model consist of three wells, SA-1, SA-2 and SA-3. SA-2 is one of the best production clusters in the field. However, it will be used for re-injection purposes since the reinjection clusters of the power plant are not ready.

We are using polygonal meshing for the model. Maximum cell area is defined as 1.0E6 m^2. Minimum refinement area of the meshes are set to 30°. This is the maximum allowable angle between surface normal at neighboring mesh vertices. In addition, we introduce a further refinement near wells and set the maximum area near wells to 100 m^2.

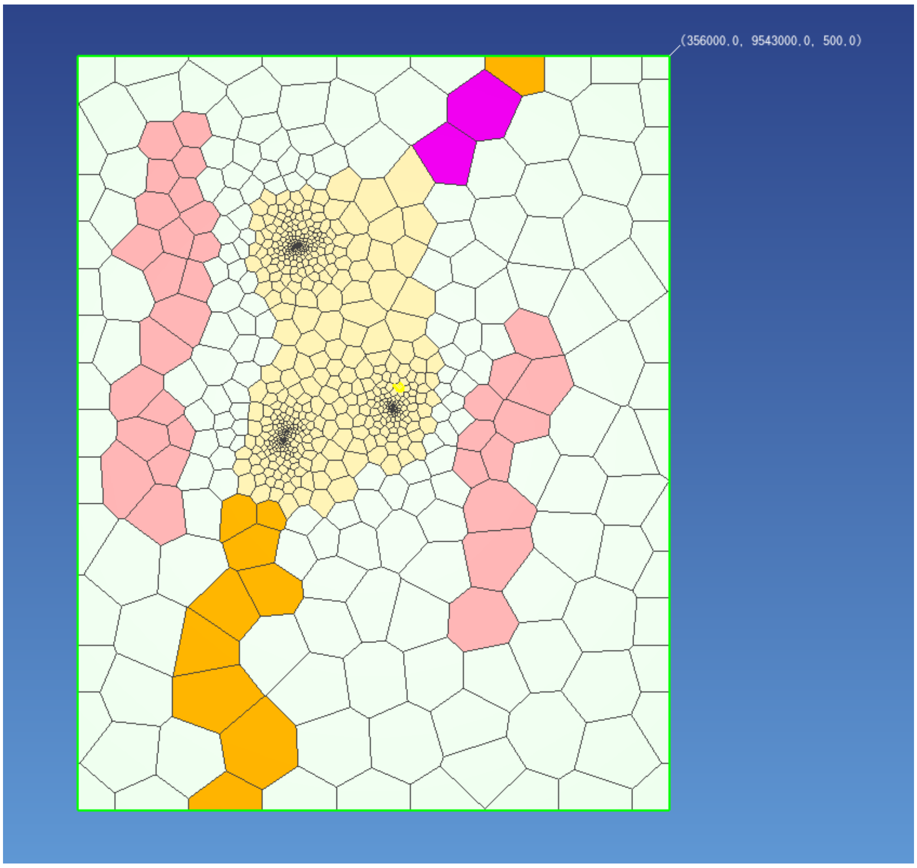

Figure 1 Model Geometry and Permeability Distribution

The yellow zone in the middle is the high permeability reservoir zone. The red cells are low permeability zones representing the lateral boundaries of the system. The dark orange represents the faults carrying the fluid up to the reservoir. The purple cells are outflow pathways, which have high permeability.

3. Initial and Boundary Conditions

According to the well testing conducted in the area, and other geophysical surveys, the heat source to the system is assumed to be from south-west, while the outflow of the system is at northeast. Since our model is two-dimensional at this point, we will apply these boundaries at the same depth. These boundary conditions are represented by a fixed state for the heat source and an infinite volume for the outflow zone.

The pressure value at the inflow boundary is 129 bar while it is 127 bar at the outflow boundary. This will create a flow towards north east, and develop a temperature distribution according to the permeability values assigned to the model as shown in Figure 1.

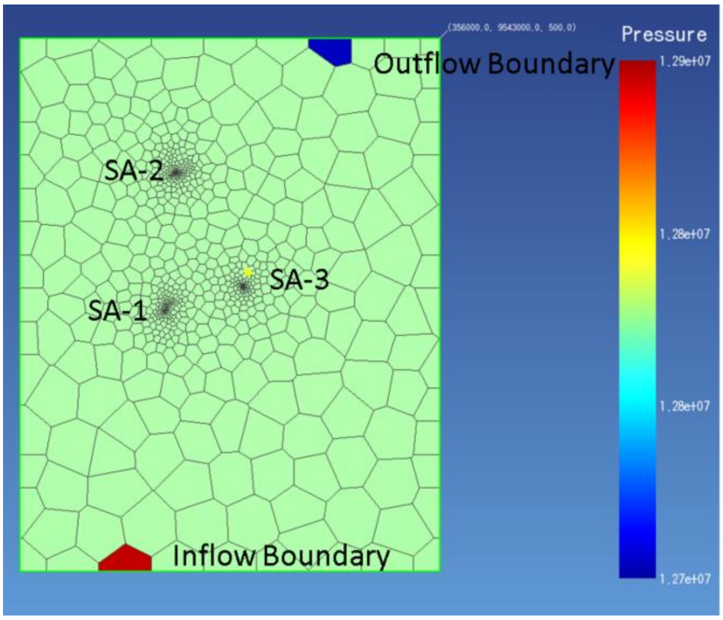

Figure 2 Boundary Conditions

4. Natural State

Initially, we ran the model for 1.5 million years. We saw that satisfactory results were reached at around year 634195. Therefore, we re-ran the model until this year in order to be able to load the results of the run as the initial conditions for the second step of our model. The temperature distribution of the natural state is as follows;

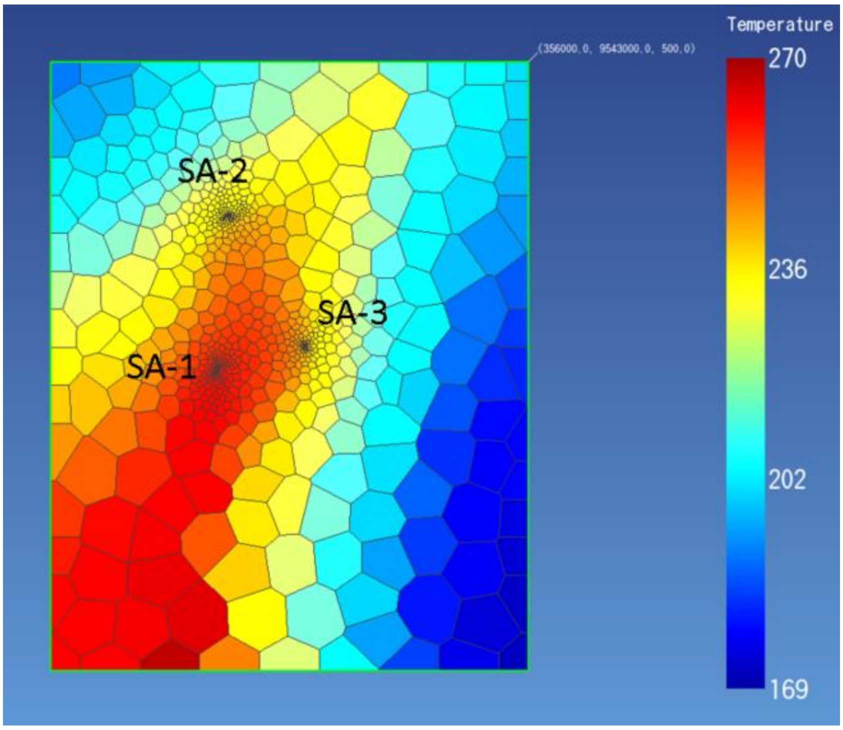

Figure 3 Natural State Temperature Distribution

5. Re-injection Scenarios

We will simulate the cold injection to well SA-2 with 500 kg/s cold water at 450 kJ/kg enthalpy at 100 °C. Three different durations of cold injection will be modelled; 3 months, 6 months and 1 year. The wells SA-1 and SA-3 produces 250 kg/s of mass each during the reinjection periods. The results from each scenario are used as the initial condition for the final steps, which is the thermal recovery.

6. Thermal Recovery of SA-2 and Evaluation of Results

After injecting cold fluid to SA-2 for different durations, we used the results of each scenario as the initial conditions for our final models. The final simulation is made by stopping the injection to SA-2, and starting its production with 250 kg/s, which is the same flow rate as the other two wells in the model. We moved the new reinjection area to the northeast section of the field in order to maintain the pressure in the field. Below are the results for each scenario.

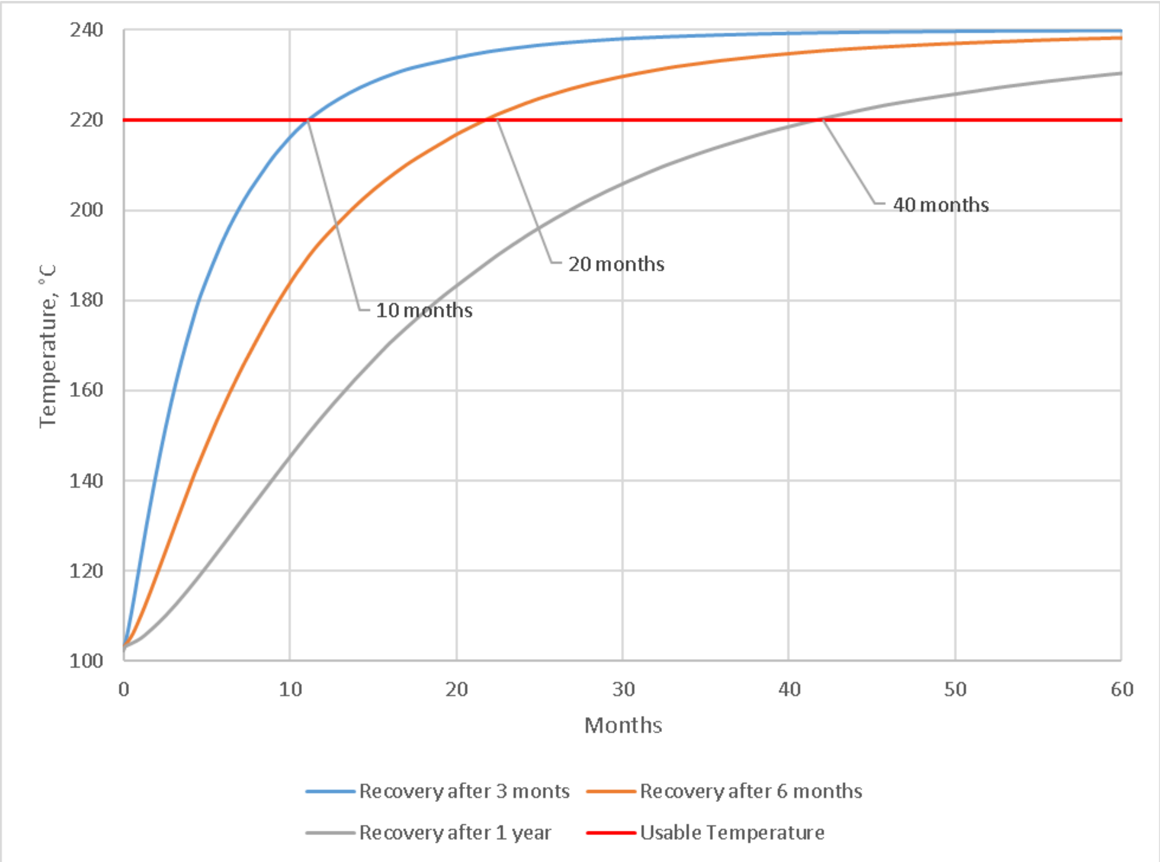

Figure 4 Temperature Recovery Period of Each Scenario

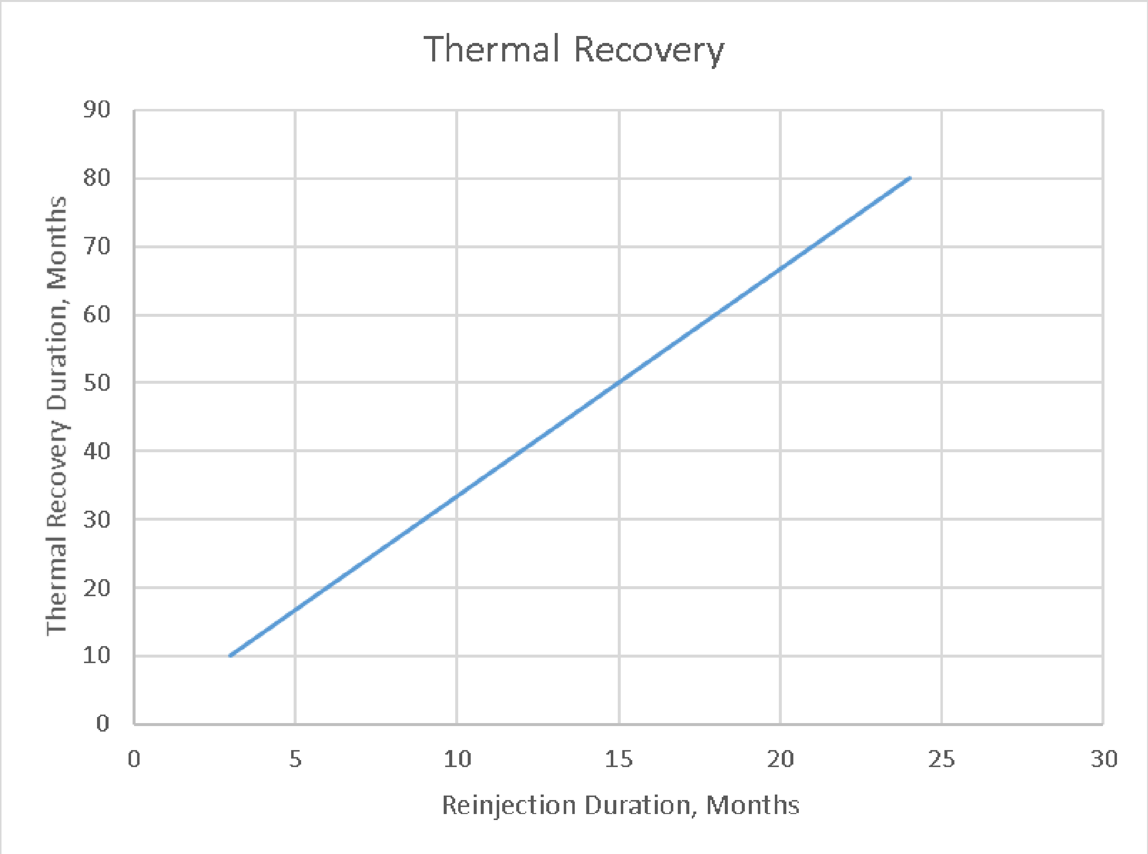

Figure 5 Reinjection Duration vs. Thermal Recovery Period

Conclusion

We have developed a two-dimensional model, representing the bottom of a liquid dominated reservoir and studied the thermal recovery period of a production well after various durations of cold reinjection. With a model as such, we are neglecting the effects of convective heat transfer. Therefore, even though the individual thermal recovery durations calculated by the model may not be reliable, the model shows that the thermal recovery is most likely to take longer than the reinjection period. We have calculated a recovery period of 10 months for only 3 months of reinjection. Moreover, this is a result of immediate production of the well, which is an optimistic approach. The duration for the thermal recovery doubles as the reinjection length doubles. This means, an increase of only 6 months in the reinjection period, may result in an increase of 20 months in the thermal recovery of a well.

REFERENCES

TOUGH Workshop. Lawrence Berkeley Laboratory Berkeley, California, pp. 37–43. Pruess, K., Oldenburg, C., Moridis, G., 1999. TOUGH2 User's Guide, Version 2.0. Berkeley, California: Lawrence Berkeley National Laboratory, Earth Sciences Division. [1]