Modelling Reservoir Behaviour during Stimulation Tests at Habanero #1

Baotang Shen *
CSIRO Exploration and Mining
PO Box 883, Kenmore, QLD 4069, Australia
baotang.shen@csiro.au

This study was to characterise the underground heat-exchange reservoir at Habanero #1 well operated by Geodynamics Ltd. Several three-dimensional coupled mechanical/fluid 3DEC models have been studied to understand the rock mass reaction to the stimulation tests that were conducted in November-December, 2003. The microseismic monitoring results by Tohoku University and the falloff test results on 12 December 2003 were used to estimate some key input parameters for the numerical modelling. The seismic results were also used as benchmarks for model verification tests. Different fracture orientations, rock mechanical properties and fluid properties were used in this study to investigate the effect of varying these parameters on rock mass response to fluid injection. The study provided an improved understanding of the fracture system that was activated during the stimulation tests.

Background

A program is being undertaken by Geodynamics Ltd to develop the Hot Fractured Rock (HFR) geothermal energy resource in the Cooper Basin. Habanero #1 was the first well drilled in this program and it reached a depth of over 4,400 m with a bottom hole temperature of over 240°C. Following the completion of the drilling, stimulation of the reservoir was conducted during November-December 2003 by injecting high pressure water into the fractured granite to activate the fractures and hence increase the permeability of the heat exchange reservoir. The response of the reservoir to injection has been monitored by Tohoku University using advanced microseismic monitoring systems. The location and timing of the seismicity associated with fracture movement were then mapped.

Understanding the characteristics of the heat exchange reservoir is the key for the design of ongoing operations. Because of the depth to the granite, there are very limited measurement techniques available that can be used to characterize the reservoir, apart from pressure and injection rate monitoring and microseismic monitoring. Numerical modelling hence becomes an important tool for this purpose.

The aim of the modelling is to provide interpretation and understanding of the reservoir behaviour during the stimulation tests, which will provide guidelines for future circulation tests.

Numerical models

The numerical models use a three-dimensional distinct element code, 3DEC, that can simulate coupled geomechanical-fluid processes and is especially suited to simulating coupled fluid flow and deformation in fractured rock masses (Itasca, 2003). 3DEC has the following main features:

- It simulates the joints/fractures explicitly.
- The fluid flow in the rock mass is considered to occur only in the rock fractures.
- The coupled process between fluid flow and rock fracture deformation is simulated.

In the granitic rock mass targeted for the HFR stimulation and circulation operations, fluid flow is believed to occur mostly in the fractures. Intact rock porosity and permeability is low and rock matrix flow is assumed to be insignificant. In this case, 3DEC is considered to be suitable and hence was chosen for this study.

Based on the seismic monitoring data, two different fracture patterns have been interpreted by different research teams. One interpretation showed that there are four shallow dipping major fractures, see Figure 1 (Wyborn, 2004, personal communication), whereas the other considered there is only one large fracture. The first interpretation has been used in this study.

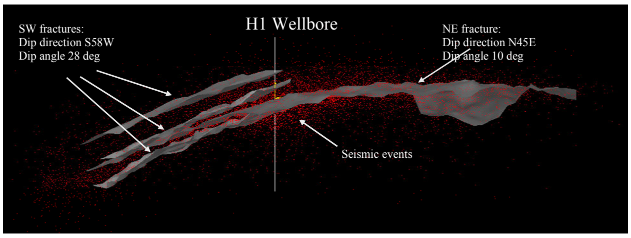

Figure 1. The major fractures delineated from the seismic monitoring data (based on one of the two interpretations). Fractures are shown in three dimensions with a viewing direction from SE to NW.

The four fractures considered may be large scale distinct fractures or they may represent fracture zones with some thickness (say, less than 150m). The limited accuracy on the location of the seismic events, and the fact that seismicity can occur both on and off the major fracture planes, does not permit a definitive location of the fracture planes.

The granite section of the Habanero #1 well was logged for natural fractures. There are three dominant fracture sets:

Set 1 – dip = 28°, dip direction = 238°

Set 2 – dip = 75°, dip direction = 230°

Set 3 – dip = 35°, dip direction = 155°

These fracture sets are considered to be smaller scale fractures intersecting the four major fractures in the reservoir, as shown in Figure 1.

The 3DEC model was constructed with an overall dimension of 4000m (E-W) x 4000m (N-S) x 1800m (depth), see Figure 2.

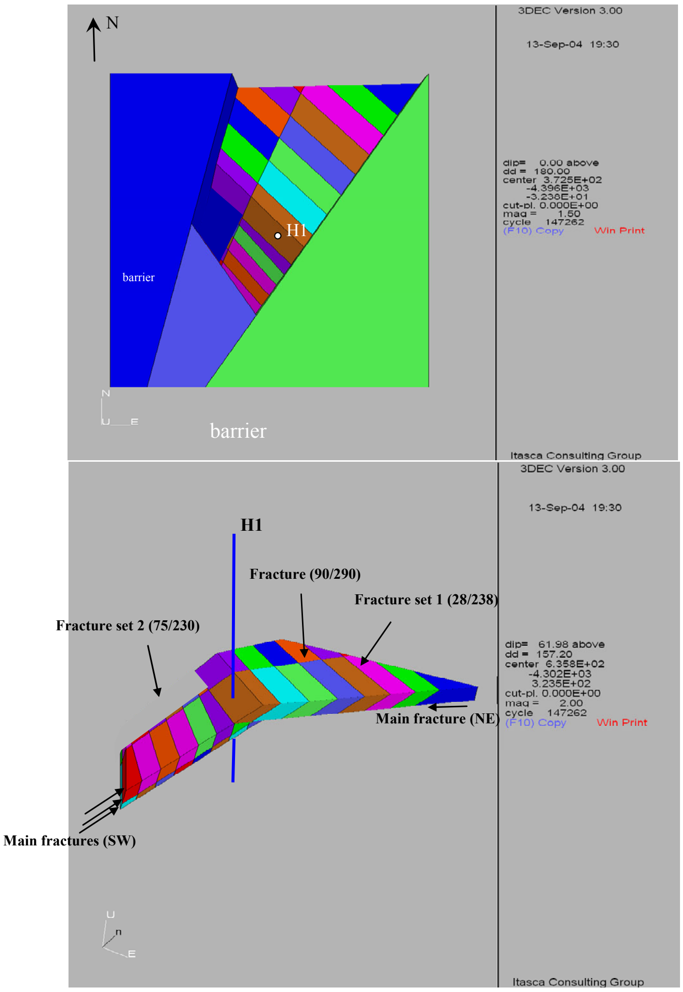

Figure 2. 3DEC model. Top figure – plan view of a 3DEC model (one block was hidden to show the detailed zone). Bottom figure – view of the detailed zone only.

A detailed region is defined as shown in the lower picture of Figure 2. This region is approximately the zone where seismic events have been detected during stimulation operations. The main sub-horizontal fractures delineated in Figure 1 define the upper and lower border of the detailed region. Note that in this model, the north-east trending sub-horizontal fracture in Figure 1 is considered to be a fracture zone with a thickness of approximately 150m, bounded by two 10° dipping fractures at the top and bottom.

The model shown in Figure 2 also includes two fracture sets with spacing of 150m. The 28/238 fracture set is included in the north-east part of the model, and the 75/230 fracture set is in the south-west part. One vertical fracture (90/290) is also included in the model to simulate a hydraulic barrier observed in the microseismic data. All the fracture sets are confined to the detailed region of the model.

The numerical modelling requires detailed mechanical and fluid properties of the rock mass and fluid to be specified. Due to the lack of directly measured data, most of the properties used were estimated based on existing knowledge and past studies for granitic rock (Barton, 1986; Evans, 2004; Choi, 2004, Hillis et al., 1997; Jeffrey, 2004; Shen, 2004). The values of the properties used in this study are listed below:

- Young's modulus = 65GPa
- Poisson's ratio = 0.25
- Friction angle = 33°
- Cohesion = 0
- Dilation = 5°
- Maximum aperture = 93 μm
- Residual aperture = 50 μm
- Fluid density = 990 kg/m^3
- Dynamic viscosity = 0.15×10^{-3} Pa sec
- Bulk modulus = 8×10^{5} Pa
- Pore pressure at a depth of 4250m = 74MPa
  Wellbore storage = 2×10^{-8} m^3/Pa
- In-situ stress at a depth of 4250m:
- σ_H = 149MPa (N85E)
- σ_h = 112MPa (N5W)
- σ_v = 98MPa

Model results

Several models with different fracture geometries and input parameters were used in this study. The model which produced the best match to the measurement data is discussed in this section. The best-fit model is judged by matching the numerical results with the following data:

- Falloff test data on 12 Dec 2003.
- Seismic results interpreted by Tohoku University

Matching the falloff test data

The injection-falloff test is a hydraulic test conducted by injecting into the reservoir at a constant rate which produces an associated increase in pressure. The injection is then stopped and the well is shut in with the pressure decline after shut in monitored. This is a standard test method to measure permeability of the reservoir. Longer injection and falloff periods result in measurement of permeability deeper into the reservoir.

An injection-falloff test was conducted on 12 December, 2003 after the completion of stimulation at Habanero #1. At that time, seismic activities in the reservoir had all ceased which indicated that fracture slip was no longer occurring. The bottom-hole pressure was increased from the in-situ pore pressure (74MPa) to 84.5MPa within about 2 hours by injecting water. Then the well was shut in and pressure dropped back to 74.5MPa within 3 hours. The measured pressure variation is shown in Figure 3.

To match the injection-falloff test results, three key input parameters in the numerical model were adjusted: They are:

- Bulk modulus of the fluid
- Fracture maximum aperture.
- Wellbore storage.

The fluid bulk modulus was found to affect the slope of the pressure build-up curve and the falloff curve; the maximum fracture aperture affects the magnitude of the peak pressure; and the wellbore storage affects the slope of the falloff curve.

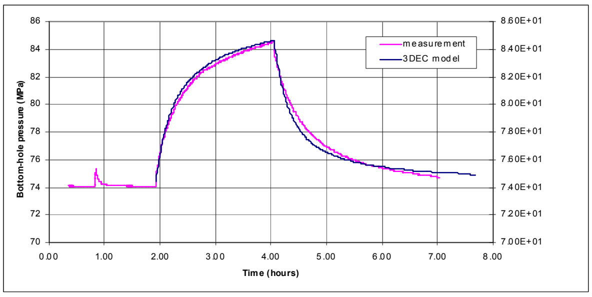

Figure 3. Matching of the numerical results with the measurement data for the falloff test.

The best match was obtained with an apparent fluid bulk modulus of 8×10^5 Pa for the reservoir, maximum fracture aperture of 93 μm and wellbore storage of 2×10^{-8} m^3/Pa, see Figure 3.

The resultant fluid bulk modulus for the reservoir is much lower than that of water at room temperature. The low bulk modulus required for the match is thought to be a result of the 3DEC model neglecting fluid storage in the rock matrix. The maximum fracture hydraulic aperture of 93 μm is equivalent to a permeability-height product (i.e. kh) of 200 md·m to the south-west of the borehole with three parallel main fractures. This agrees with the finding by Evens (2004) that "the far-field kh is 100 md·m or more".

The wellbore storage of 2×10^{-8} m^3/Pa is based on a wellbore volume of 41 m^3 and fluid bulk modulus of 2.0GPa. The 3DEC models did not include the wellbore therefore the effect of wellbore storage had to be considered as a separate effect.

Matching the seismicity monitoring data

The numerical model as shown in Figure 2 was used to investigate the fracture activation during stimulation process. The actual injection operation was done in 4 stages as shown in Figure 4. The 1st stage was the fracture initiation stage, and the 2nd-4th stage are actual fracture stimulation.

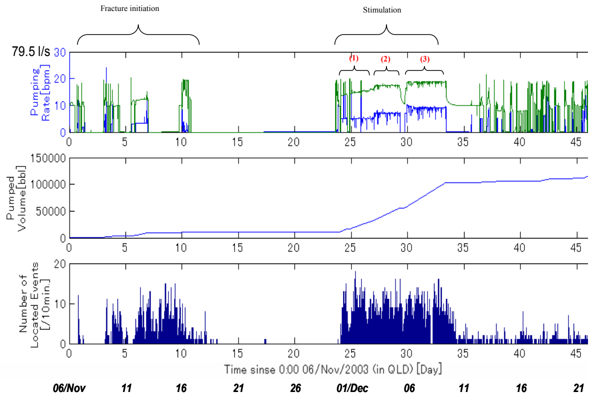

Figure 4. Summary of injection record (after Davidson, 2004).

After completion of the 4 stages of initiation and stimulation in the numerical model, the model results were extracted and processed. The modelled evolution process of fracture sliding was compared with that of microseismic events after initiation stage and stimulation stage as shown in Figure 5 and Figure 6. In the figures, the black dot points indicate the locations of the seismic events obtained from the microseismic monitoring. The red dot points represent the centre of a fracture element which has exceeded its shear strength (i.e. is sliding). Both the measured and predicted results are the cumulative results.

In the fracture initiation stage (Figure 5), the modelled fracture sliding in general matched well the microseismic records. The model results however did not match the isolated cluster of seismic events in the southern side of the wellbore. The run-away seismic cluster could be caused by localised stress concentration or highly conductive fractures in the rock mass. The model did not include any of these special features.

In the stimulation stages (Figure 6), the modelled fracture sliding matched reasonably well with the seismic records, both in the horizontal plan view and the cross section view.

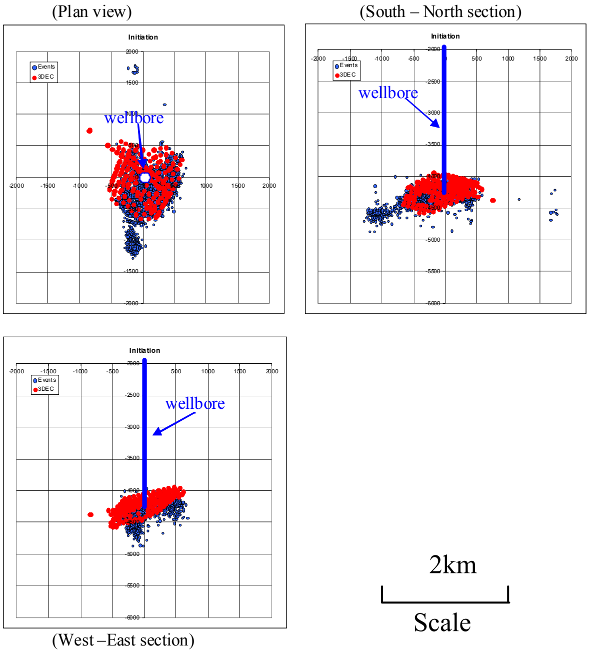

Figure 5. Comparison of the predicted fracture sliding and microseismic monitoring events during fracture initiation.

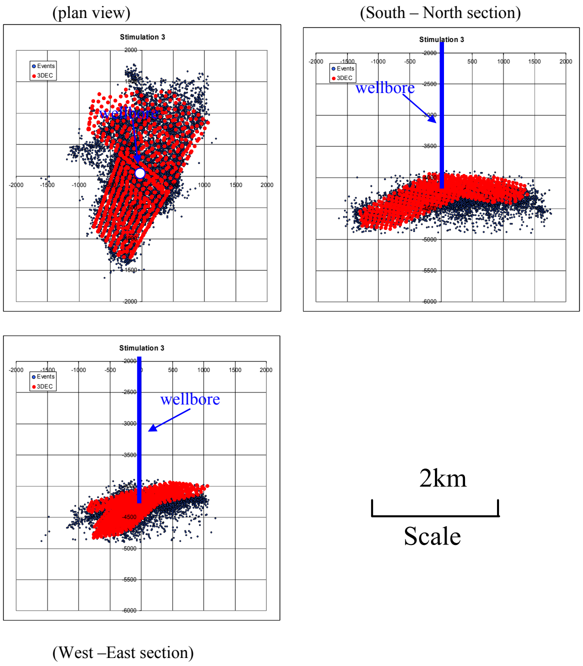

Figure 6. Comparison of the predicted fracture sliding and microseismic monitoring events during stimulation phase 3.

Because the main fractures in the 3DEC model were bounded by the border of the seismic events (except in the northern part where the main fractures extend to the model boundary), it is not surprising that the final locations of modelled fracture sliding matched well with that of the seismic events. However, a good match has also been obtained during the different stages and it is likely that the model is accurately calibrated (although it is possible that other combinations of fracture geometry and input parameters would produce similar matches.)

Injection pressure

The model-predicted time history of bottom-hole pressure of all phases is shown in Figure 7. In general, the predicted injection pressure shows the same trend as that recorded during the actual stimulation tests (see Figure 4). As the injection flow rate increases from 5 bpm (barrel per minute) to 9 bpm, the injection pressure increases accordingly.

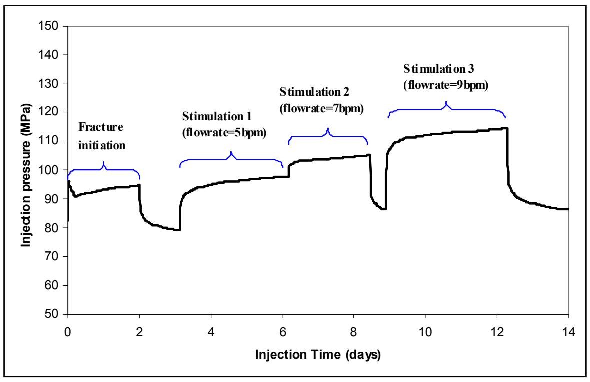

Figure 7. Predicted injection pressure at the wellbore using the 3DEC model.

The predicted magnitude of the injection pressure at the bottom of the wellbore, however, is higher than that calculated using the measured surface pump pressure (with consideration of pressure loss). At the later stage of the injection (stimulation stages 2 and 3), the predicted bottom-hole pressure is actually higher than the overburden stress. Two factors in the numerical model may have contributed to this: (1) The model has fixed boundaries on the top and bottom at a distance of 900m from the injection section. The fixed boundaries may have restricted the opening displacement of sub-horizontal fractures and hence resulted in higher fluid pressure. (2) The current 3DEC version only allows a single maximum fracture aperture defined for both shear and open joints. The maximum aperture of 93µm used in the model may not be suitable for open joints although it is reasonable for shear joints.

Figure 8 shows the predicted fluid pressure distribution in the main fractures when the injection flow rate is 9 bpm at the end of the stimulation tests. The fluid pressure in the immediate vicinity of the injection hole is over 100MPa. Fracture in this area would be opened by such pressure. The pressure dropped below 100MPa at about 50m away from the injection hole, implying fracture shearing rather than opening takes place beyond this distance. Measured pressures were, however, close to or below the fracturing opening pressure for all injection periods.

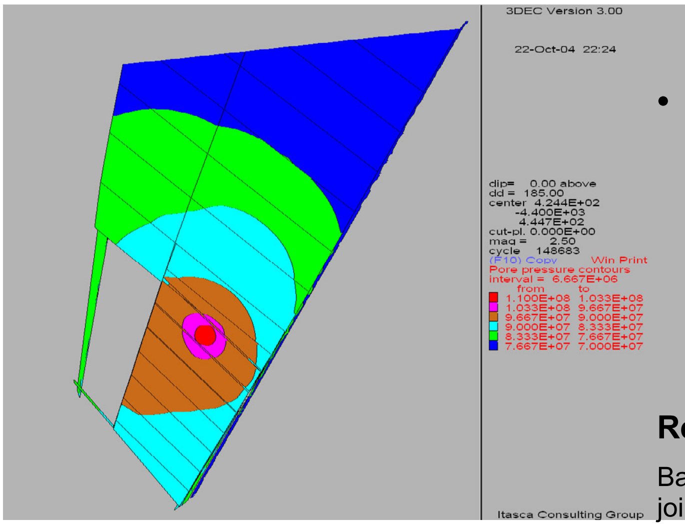

Figure 8. Fluid pressure distribution in the sub-horizontal main fractures at the end of the stimulation test.

Discussion and Conclusions

The study was the first step toward characterisation of the underground heat-exchange reservoir in the vicinity of the Habanero #1 well. The modelling results improved our understanding of the fracture system that has been activated during the stimulation tests. The key findings from this study are:

- To the south-west of the wellbore, the observed seismicity was likely due to fracture sliding along three large parallel fractures with a favourable dip (about 25° - 30°). These fractures were predicted to slide during the early stage of the stimulation tests, agreeing well with the seismic monitoring results.
- To the north and north-east of the wellbore, the observed seismicity was possibly caused by the shear movement in many relatively small fractures in a fracture set with a probable dip (dip/dip direction=28/238). The apparent main fracture with a dip of 10°, delineated from the seismic data, is unlikely to have any major contribution to the seismicity and it was predicted to remain inactive during stimulation tests. This apparent fracture may not exist in the form of a single explicit fracture.
- The fracture permeability in the stimulated zone in south-west is estimated to be around 200md·m (i.e. fracture aperture = 93μm) after stimulation.
- Fracture sets (35/155 and 75/230) which were observed from the borehole log were predicted to remain inactive during stimulation tests. They are unlikely to have contributed to the observed seismicity, although they may have some effect on fluid flow.
- The in-situ stresses inferred from back-analysis of the borehole breakout data are believed to be correct at Habanero #1 site (Shen, 2004). With the horizontal stresses being the major and intermediate principal stresses, the most favourable fracture orientation for sliding is about 28°. This agrees well with observation, particularly in the south-west of the wellbore.

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