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Effects of Injection Temperature on Injection Capacity of Geothermal Wells—Numerical Study

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Keywords
Injection capacity, permeability, fractured reservoir, numerical simulation, MINC model

ABSTRACT

An injection test on Sumikawa Well SD-1 was carried out to evaluate the effect of water temperature on the injection capacity. It was concluded that injecting low temperature water increases the permeability-thickness product and the injection flow rate owing to an increase in fracture aperture and a decrease in reservoir pressure around the injection well. To quantitatively evaluate reservoir pressure changes and the influence of injection temperature on the injection capacity during injection, we have conducted numerical studies using a two-dimensional cross-sectional model. Considering the relationship between porosity, permeability, and pressure/temperature, Garg's theory (1984) and a modified Kozeny-Carman relationship were applied to a double-porosity (MINC) model, where the fracture porosity and permeability should increase as a result of cooling in the reservoir. Consequently, it is suggested that the injection capacity tends to increase during injection due to an increase of permeability caused by an expansion in the fracture aperture, if the temperature of the injected water is significantly lower than that of the reservoir. Since the injected low temperature water tends to flow downward vertically through fractures because of gravity, rather than horizontally, the cooling of the reservoir also propagates in the vertical direction rather than in the horizontal direction. Accordingly, the vertical permeability increases with time leading to a well injection capacity increment during injection.

Introduction

In some geothermal fields, it is observed that injection capacity increases, when low temperature water is substituted for high temperature water (e.g. Uchiyama and Tan-no, 1982; Horne et al., 1987; Ariki, 1997). There are some studies on the changes in transmissivity due to fluid temperature. Grant (1982), Horne et al. (1987) and Kitao et al. (1990) described the injectivity changes during an injection test. Contreas (1990) conducted a laboratory experiment on permeability changes using geothermal sandstones at temperatures of 25°C to 270°C. Benson et al. (1987), Nakao et al. (1991, 1995), and Nakao and Ishido (1992, 1994, 1997) conducted numerical-simulation studies to evaluate the effect of injection temperature on injectivity. In another study, Ariki and Hatakeyama (1997, 1998) conducted a field experiment to evaluate the effect of water temperature on injection capacity. Nakao and Ishido (1997) applied numerical simulation to examine the downhole pressures observed at Yutsubo Well Y-2T. During injection testing of this well, the observed downhole pressures eventually began to decline despite sustained injection rate. Nakao and Ishido (1998) have carried out numerical simulation studies using a radial flow model, double porosity (MINC) model, and “a modified Kozeny-Carman relationship”. The modified Kozeny-Carman relationship is the equation which multiplies the term for expressing the drastic increase in permeability due to the opening and/or induced connections of existing fractures. Nakao and Ishido (1998) attributed the gradual pressure decline during cold water injection as a result of porosity increases due to cooling and pressure buildup.

To evaluate the effect of water temperature on injectivity, Ariki and Hatakeyama (1997, 1998) conducted a test program on the Sumikawa Well SD-1 in which both injection flow rates and temperatures were varied and flowing pressures were monitored downhole. Wellhead injection temperatures of both ~50°C and ~150°C were used in these tests. It was observed that the pressures measured downhole and the influence of flow rate on pressure are both less if lower temperature water is injected. Apparently, the transmissivity and the injection flow rate increase with decreasing injection temperature. It is concluded that injecting hotter water reduces the permeability thickness and the injection flow rate owing to decreases in fracture aperture and increases in reservoir pressure around the injection well.

In the results of existing research, the improvement of the vertical permeability and effect of the gravity have not suffi-
ciently been clarified on the phenomenon of the increase in injection capacity due to the downward flow of low temperature water. In this paper, in order to examine the improvement of the vertical permeability by the downward flow of the injected low temperature water and the effect of gravity, we have carried out numerical simulation studies using a two-dimensional cross-sectional model, Garg’s theory (1984) for thermo-elastic rocks, and the modified Kozeny-Carman relationship.

**Numerical Approach**

**Garg’s Theory (1984) and the Modified Kozeny-Carman Relationship**

Garg (1984) applied concepts from the Theory of Interacting Continua to develop constitutive relations for thermo-elastic fluid-saturated porous media. And Garg (1984) suggested the following Equation (1) for the relationships between porosity, pore pressure, and temperature:

\[
\frac{\partial f\rho}{\partial t} = \left( \frac{1 - f\rho_0}{K + \frac{4G}{3}} \right) \times \left[ \frac{\partial P}{\partial t} + 3 \frac{\partial T}{\partial t} \left( a_p K - a_g \left( K + \frac{4G}{3} \right) \right) \right]
\]

where
- \( f\rho_0 \) = local instantaneous porosity
- \( K \) = bulk modulus (Pa)
- \( G \) = shear modulus (Pa)
- \( a_p \) = linear thermal expansion coefficient for dry porous rock (°C⁻¹)
- \( a_g \) = linear thermal expansion coefficient for rock grain material (°C⁻¹)
- \( P \) = pressure (Pa)
- \( T \) = temperature (°C)

Pritchett (1995) suggested “the modified Kozeny-Carman relationship” shown in Equation (2) in order to express the drastic improvement of the permeability of the isolated crack expanding by the thermal contraction of the rock, and developing, and coupling the crack for the minute change of the porosity (Pritchett, 1999: personal communication).

\[
k = k_0 \left( \frac{\phi}{\phi_0} \right)^{e_3} \left[ \frac{1 - \phi_0}{1 - \phi} \right]^{e_2} \times \exp[e_1(\phi - \phi_0)]
\]

where
- \( \phi_0 \) = initial porosity
- \( k_0 \) = initial permeability
- \( e_3, e_2, e_1 \) = user-specified parameters

In the case of \( e_3=3, e_2=2, \) and \( e_1=0 \), Equation (2) becomes the Kozeny-Carman relationship between porosity and permeability. Nakao and Ishido (1998) explain the gradual pressure decline during cold water injection as a result of porosity increase due to cooling and pressure buildup. It is necessary to assume a porosity dependence of permeability much stronger than the Kozeny-Carman relationship (i.e., \( e_3=3,e_2=2, \) and \( e_1=900 \)) to adequately explain this behavior.

**Numerical Model Description**

We have conducted numerical simulation studies using a two-dimensional cross-sectional model that is similar to the model used by Cox and Bodvarsson (1985), to examine the improvement of the vertical permeability and the effect of the gravity during low temperature water injection. Garg’s theory (1984) and the modified Kozeny-Carman relationship were applied to a double-porosity (MINC) model from Nakao and Ishido (1997). We also examined the change in the pressure of the block containing the injection well, which is described as “the injection block”. The numerical model geometry and coordinate are shown in Figure 1. A MINC-type (Pruess and Narasimahan, 1985) fracture/matrix composite representation is employed for the whole model.

In order to examine the downward flow due to the effect of gravity in the case of low temperature thermal water (50°C) injection into a high temperature reservoir (250°C) with a predominantly vertical high permeability, we used the two different injection blocks shown in Figure 1. These are:

1. Injection into the top block of the model: “the upper injection”
2. Injection into the bottom block of the model: “the lower injection”
Table 1. Model parameters used for numerical simulation on thermal water injection.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Simulation period</td>
<td>Simulation term: 30 days (= 2.592 x 10^3 sec) time increment: max. 4 hours (= 1.44 x 10^4 sec)</td>
</tr>
<tr>
<td>Computed geometry</td>
<td>Two-dimensional Cartesian geometry</td>
</tr>
<tr>
<td></td>
<td>Horizontal length = 1,050 m (50m x 21 blocks) Vertical length = 1,050 m (50m x 21 blocks) Width = 50 m</td>
</tr>
<tr>
<td>Boundary condition</td>
<td>Top: Impermeable, insulated boundary</td>
</tr>
<tr>
<td></td>
<td>Bottom: Impermeable, insulated boundary</td>
</tr>
<tr>
<td></td>
<td>Side (left): Impermeable, insulated boundary</td>
</tr>
<tr>
<td></td>
<td>Side (right): Prescribed pressure boundary</td>
</tr>
<tr>
<td>Injection condition</td>
<td>Injection grid = (1,1) or (1,21)</td>
</tr>
<tr>
<td></td>
<td>Injection flow rate = 30 kg/sec</td>
</tr>
<tr>
<td></td>
<td>Injection temperature = -50°C (Internal energy = 214 kJ/kg)</td>
</tr>
<tr>
<td>Rock property</td>
<td>MINC model</td>
</tr>
<tr>
<td>Grain density</td>
<td>2,500 kg/m³</td>
</tr>
<tr>
<td>Porosity</td>
<td>5%</td>
</tr>
<tr>
<td>Specific heat</td>
<td>2.5 W/m·°C</td>
</tr>
<tr>
<td>Thermal conductivity</td>
<td>1.0 x 10^{-12} m²</td>
</tr>
<tr>
<td>Fracture permeability</td>
<td>- Horizontal permeability = 1.0 x 10^{-12} m²</td>
</tr>
<tr>
<td>- Vertical permeability</td>
<td>= 1.0 x 10^{-12} m²</td>
</tr>
<tr>
<td>Matrix permeability</td>
<td>= 1.0 x 10^{-12} m²</td>
</tr>
<tr>
<td>Fracture zone volume fraction</td>
<td>0.01</td>
</tr>
<tr>
<td>Fracture spacing</td>
<td>10 m</td>
</tr>
<tr>
<td>Number of shells</td>
<td>5</td>
</tr>
<tr>
<td>e-parameter in equation (2)</td>
<td>e3 = 3; e2 = 2; e1 = 1.0 x 10^0</td>
</tr>
<tr>
<td>Fracture</td>
<td>= 5.0 x 10^{10} Pa</td>
</tr>
<tr>
<td>Rock grain modulus</td>
<td>3.0 x 10^{10} Pa</td>
</tr>
<tr>
<td>Thermal expansion coefficient for dry porous rock = 1.5 x 10^{-5} °C^{-1}</td>
<td></td>
</tr>
<tr>
<td>Thermal expansion coefficient for rock grain material = 1.5 x 10^{-5} °C^{-1}</td>
<td></td>
</tr>
<tr>
<td>Initial condition</td>
<td>Temperature = 250 deg. C</td>
</tr>
<tr>
<td>Pressure</td>
<td>Upper boundary pressure is 55 bars and other blocks are hydrostatic pressure</td>
</tr>
</tbody>
</table>

1) Initial Condition and Boundary Condition
The initial temperature distribution is 250°C in the whole model, and the initial pressure distribution corresponds to a hydrostatic profile. One side boundary is employed at constant pressure. The other three boundaries (top, bottom, and other side) are impermeable and insulated.

2) Injection Condition, Rock Properties, and Parameters for MINC Model
The model parameters used for the study are listed in Tables 1 and 2. We employed Base Models and other models for sensitivity studies with the following parameters:

Table 2. Model parameters used for sensitivity study of numerical simulation.

<table>
<thead>
<tr>
<th>Model</th>
<th>Coordinate of injection block</th>
<th>Injection Temp. (deg C)</th>
<th>e1</th>
<th>e2</th>
<th>e3</th>
<th>Fracture spacing (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base model A</td>
<td>(01,21)</td>
<td>50</td>
<td>1000 2 3 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Base model B</td>
<td>(01,01)</td>
<td>50</td>
<td>1000 2 3 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>model 1A</td>
<td>(01,21)</td>
<td>150</td>
<td>1000 2 3 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>model 1B</td>
<td>(01,01)</td>
<td>150</td>
<td>1000 2 3 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>model 2A</td>
<td>(01,21)</td>
<td>250</td>
<td>1000 2 3 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>model 2B</td>
<td>(01,01)</td>
<td>250</td>
<td>1000 2 3 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>model 3A</td>
<td>(01,21)</td>
<td>50</td>
<td>0     0 0 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>model 3B</td>
<td>(01,01)</td>
<td>50</td>
<td>0     0 0 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>model 4A</td>
<td>(01,21)</td>
<td>150</td>
<td>0     0 0 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>model 4B</td>
<td>(01,01)</td>
<td>150</td>
<td>0     0 0 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>model 5A</td>
<td>(01,21)</td>
<td>250</td>
<td>0     0 0 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>model 5B</td>
<td>(01,01)</td>
<td>250</td>
<td>0     0 0 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>model 6A</td>
<td>(01,21)</td>
<td>50</td>
<td>0     2 3 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>model 6B</td>
<td>(01,01)</td>
<td>50</td>
<td>0     2 3 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>model 7A</td>
<td>(01,21)</td>
<td>50</td>
<td>1000 2 3 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>model 7B</td>
<td>(01,01)</td>
<td>50</td>
<td>1000 2 3 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>model 8A</td>
<td>(01,21)</td>
<td>50</td>
<td>1000 2 3 50</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>model 8B</td>
<td>(01,01)</td>
<td>50</td>
<td>1000 2 3 50</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

note: Bold values in figures show the different values from Base model.

1. Injection location
   - Upper injection; coordinate (1,21)
   - Lower injection; coordinate (1,1)

2. Injection temperature
   - ~50°C (internal energy = 214 kJ/kg)
   - ~150°C (internal energy = 653 kJ/kg)
   - ~250°C (internal energy = 1,086 kJ/kg)

3. Relationship between porosity and permeability - the effect of e3, e2 and e1
   - e3 = e2 = e1 = 0
   - e3 = 3, e2 = 2, e1 = 0
   - e3 = 3, e2 = 2, e1 = 1,000

4. Fracture spacing of MINC model
   - 1 m
   - 10 m
   - 50 m

5. Injection location
   - Upper injection = coordinate (1,21)
   - Lower injection = coordinate (1,1)

Injection flow rate = 30 kg/s
Vertical global permeability = 1 x 10^{-12} m² (Vertical fracture permeability = 1 x 10^{-10} m²)
Horizontal global permeability = 1 x 10^{-12} m² (Horizontal fracture permeability = 1 x 10^{-10} m²)
Rock bulk modulus = 5 x 10^{10} Pa
Rock shear modulus = 3 x 10^{10} Pa
Thermal expansion coefficient for dry porous rock = 1.5 x 10^{-5} °C^{-1}
Thermal expansion coefficient for rock grain materials = 1.5 x 10^{-5} °C^{-1}

Bulk and shear modulus were estimated from P wave and S wave velocities at 0% porosity using data from andesite samples from the Society of Exploration Geophysicists of Japan (1990)
The thermal expansion coefficient is set up for dry porous rock and rock grain material respectively, but we used the same value.

For our numerical simulation studies, we used the STAR general-purpose geothermal reservoir simulator (Pritchett, 1995). The modified Kozany-Carman relationship between porosity and permeability is employed for the fracture zone of MINC model.

**Results and Discussion**

**The Effect of Injection Location**

The changes in pressure and temperature of Base Models A and B are plotted in Figures 2 and 3, respectively. Figure 2 shows that the pressure increase of the upper injection block is smaller than that of the lower injection block. On the other hand, the temperature changes of both injection blocks are almost equal. However, the temperature change at late time of the upper injection is larger than that of the lower injection block. The temperature and mass-flux distributions, one month after the start of injection, are shown in Figures 4 and 5 respectively. (a) and (b) of the figures show the model of the upper injection and the lower injection, respectively. According to Figure 4, the temperature distribution of the upper injection shows a pattern of predominant downward flow, and that of the lower injection shows a pattern of predominant horizontal flow. The difference between the two temperature distributions occurs because the heat transfer is controlled by convection. It is demonstrated in the fluid flux of Figure 5, the difference exists due to the downward flow which is predomin-

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Figure 2. Temporal changes in pressure increase of injection block - Base model - (a)Upper injection and (b)Lower injection.

Figure 3. Temporal changes in temperature of injection block - Base model - (a)Upper injection and (b)Lower injection.

Figure 4. Temperature distribution at one month later - Base model - (a)Upper injection and (b)Lower injection.

Figure 5. Mass flux distribution at one month later - Base model - (a)Upper injection and (b)Lower injection.
Table 3. \( \Delta P, \rho g / \mu, \rho g / \mu \) and \( M_A \) in equation (4) of "injection block" at five days, fifteen days and thirty days later - Model 3, Model 4, Model 5 and Base model.

<table>
<thead>
<tr>
<th>Model</th>
<th>Injection Location</th>
<th>( \Delta P ) (Pa)</th>
<th>( \rho g / \mu ) (Pa s/m)</th>
<th>( \rho g / \mu ) (Pa s/m)</th>
<th>( \rho / \mu ) (Pa s/m)</th>
<th>( M_A ) (kg s/m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>e=0</td>
<td>model 3A</td>
<td>(01.21) → (01.20)</td>
<td>7250</td>
<td>-8467</td>
<td>-1217</td>
<td>5.8 \times 10^{-1}</td>
</tr>
<tr>
<td>e=0</td>
<td>model 4A</td>
<td>(01.21) → (02.21)</td>
<td>1222</td>
<td>1222</td>
<td>3.7 \times 10^{-1}</td>
<td>4.6 \times 10^{-1}</td>
</tr>
<tr>
<td>e=0</td>
<td>model 5A</td>
<td>(01.21) → (01.20)</td>
<td>1302</td>
<td>-8150</td>
<td>-790</td>
<td>8.8 \times 10^{-1}</td>
</tr>
<tr>
<td>e=10</td>
<td>model 3A</td>
<td>(01.21) → (01.20)</td>
<td>7052</td>
<td>-7850</td>
<td>-780</td>
<td>6.8 \times 10^{-1}</td>
</tr>
<tr>
<td>e=10</td>
<td>model 4A</td>
<td>(01.21) → (02.21)</td>
<td>802</td>
<td>802</td>
<td>7.5 \times 10^{-1}</td>
<td>5.3 \times 10^{-1}</td>
</tr>
<tr>
<td>e=10</td>
<td>model 5A</td>
<td>(01.21) → (01.20)</td>
<td>9258</td>
<td>-8600</td>
<td>928</td>
<td>5.3 \times 10^{-1}</td>
</tr>
<tr>
<td>e=20</td>
<td>model 3A</td>
<td>(01.21) → (01.20)</td>
<td>1370</td>
<td>-1238</td>
<td>5.2 \times 10^{-1}</td>
<td>5.1 \times 10^{-1}</td>
</tr>
<tr>
<td>e=20</td>
<td>model 4A</td>
<td>(01.21) → (02.21)</td>
<td>794</td>
<td>794</td>
<td>7.6 \times 10^{-1}</td>
<td>6.0 \times 10^{-1}</td>
</tr>
<tr>
<td>e=20</td>
<td>model 5A</td>
<td>(01.21) → (01.20)</td>
<td>970</td>
<td>970</td>
<td>8.0 \times 10^{-1}</td>
<td>6.6 \times 10^{-1}</td>
</tr>
<tr>
<td>e=30</td>
<td>model 3A</td>
<td>(01.21) → (01.20)</td>
<td>796</td>
<td>-8485</td>
<td>619</td>
<td>1.3 \times 10^{-1}</td>
</tr>
<tr>
<td>e=30</td>
<td>model 4A</td>
<td>(01.21) → (02.21)</td>
<td>324</td>
<td>324</td>
<td>1.2 \times 10^{-1}</td>
<td>3.8 \times 10^{-1}</td>
</tr>
<tr>
<td>e=30</td>
<td>model 5A</td>
<td>(01.21) → (01.20)</td>
<td>8832</td>
<td>-8479</td>
<td>353</td>
<td>1.2 \times 10^{-1}</td>
</tr>
</tbody>
</table>

*note: *) "—" means downflow.

The Effect of Injection Temperature

Figure 6 shows the temporal pressure changes of the injection block at injection temperatures of 50°C (Base Model), 150°C (Model 1) and 250°C (Model 2). (a) and (b) of the Figures show the model of upper injection and lower injection, respectively.

The pressures of the upper injection block in the case of the 50°C and 150°C thermal water injections decline with time after initial pressure buildup. Pressure decline is shown to be larger, as the injection temperature lowers. In case of lower injection, large pressure declining is not observed after initial pressure buildup at each injection temperature. The initial pressure buildup at 250°C, thermal water injection is a little larger than that at the other injection temperatures. The initial pressure buildup at 50°C and 150°C thermal water injection is almost the same magnitude, and there is a slight pressure decline afterwards in the case of 150°C thermal water injection.

Usually the low-temperature thermal water will cause temporal pressure increase, while flow resistance increases, because increased viscosity. In the present numerical simulation, however, the mobility ratio \( k / \mu \) increases with the improvement of permeability by thermal contraction of the rock with temperature lowering. Consequently, the pressure declines with time in the case of the upper injection. On the other hand, the pressure in the case of the lower injection does not decrease with time. Still, the pressure behavior in case of 250°C thermal water injection equal to initial temperature of geothermal reservoir shows the same behavior regardless of the injection location, since there are no effect from the downward flow by density difference and the permeability change. The difference recognized in Figure 6 (a) and (b) (overleaf) seems to be the effect of gravity when the low temperature water is injected into the high-temperature geothermal reservoir. That is to say, it is due to the difference as the vertical permeability, caused by the low-temperature thermal water injection, improves the downward flow. In Model A, the
vertical flow is more predominant than the lateral flow because of gravity effects from the improvement in permeability, and the pressure that initially increases tends to gradually decline. It is shown to be more significant as the injection temperature is lowered, since it is related to the improvement in permeability. In the meantime, such tendency is not observed in Model B in which the downward flow has not occurred.

The Effect of Parameters $e_3$, $e_2$, and $e_1$

In case of parameters $e_3=e_2=e_1=0$ (no permeability change)

In case of parameter $e_3=e_2=e_1=0$, no permeability changes with changes in temperature and pressure. The temporal pressure changes of the injection block at injection temperature of 50°C (Model 3), 150°C (Model 4), and 250°C (Model 5) are shown in Figure 7. (a) and (b) of the Figures show the model of the upper injection and the lower injection respectively. In the case of the upper injection, the initial pressure buildup is smaller as the injection temperature is lower. The temporal pressure changes after the initial pressure buildup increase after the early time slight declining in case of 50°C water injection. There is a decline tendency in the case of 150°C, and is almost constant in the case of 250°C. In the case of the upper injection under constant permeability, it is recognized that the magnitude of the pressure increase at the lower injection temperature, is relatively smaller than that at initial reservoir temperature injection. The case of the lower injection at injection temperatures 50°C and 150°C, the temporal pressure changes increase with time, and that of injection temperature 250°C becomes almost constant after the initial pressure buildup. The pressure increase magnitude at 50°C and 150°C is larger, as the injection temperature is lower. These effects are due to the increase of flow resistance that accompanies the increase in viscosity and fluid density with the lower temperature of injection water.

According to (a) and (b) in Figure 7, the pressure behavior of the injection block differed by the injection location, when water is injected at lower temperature from initial reservoir temperature with constant permeability. In the case of the same temperature water as the initial reservoir temperature 250°C, the pressures of the injection block show the identical behavior even if the injection location is different. The difference of pressure behavior between the upper injection and the lower injection is mainly considered due to the existence of the downward flow.

In the case of a variety of parameters $e_3$, $e_2$ and $e_1$ (permeability change)

We conducted numerical simulations under a variety of parameters $e_3$, $e_2$, and $e_1$.

Figure 8 shows the results in the case of injection temperature 50°C with the following parameters:
- $e_3=e_2=e_1=0$ (no permeability change)
The Kozeny-Carman relationship is given by:

\[ e_3 = 3, e_2 = 2, e_1 = 0 \] (Kozeny-Carman relationship)

\[ e_3 = 3, e_2 = 2, e_1 = 1.000 \] (modified Kozeny-Carman relationship)

Figures (a) and (b) show the model of the upper injection and the lower injection, respectively. The magnitude of the pressure increase of the upper injection for 30 days are lower than those of the lower injection under the same conditions of parameters \( e_3, e_2 \) and \( e_1 \). This is reasonable since the model in which the permeability greatly changes for the change in porosity, is lower in the magnitude of the pressure increase of the injection block. The change of the permeability greatly affects the pressure behavior.

As mentioned above, the behavior in which the pressure greatly declines with the continuation of the cold water injection, is considered to be easily observed under conditions where the downward flow is predominant and the permeability is greatly changed by the temperature.

**The Effect of Fracture Spacing for MINC Model**

The fracture spacing for MINC model is the parameter which causes large effects in pressure and temperature behavior (e.g., Pritchett and Garg, 1990; Ishido, 1993; Yano, 1995; Nakao and Ishido, 1998). Figure 9 shows the results of the fracture spacing 1m, 10m and 50m. (a) and (b) of the figures show the model of the upper injection and the lower injection. The magnitude of the pressure declining after the initial pressure buildup is recognized as being lower, as the fracture spacing is larger. Especially noteworthy is, the result of fracture spacing at 50 m in the case of the upper injection that shows that the pressure declines largely with time and lowers than the initial pressure. The permeability of the injection block after 30 days of injection in this model, is improved from \( 1.0 \times 10^{-12} \text{m}^2 \) initially to \( 1.06 \times 10^{-11} \text{m}^2 \), and it increases at about 11 fold compared to the initial permeability. The permeability of injection block after 30 days of injection in this model, however, is lower than that of the Base Model A \( 1.42 \times 10^{-11} \text{m}^2 \); Figure 10). This is due to the higher temperature of the injection block compared to that of Model A, since there are more inflows of the high temperature water in the vicinity.

On the other hand, in case of the lower injection, there is little change in pressure behavior.

These behaviors reflect the temperature lowering of the fracture zone in the MINC model. The MINC model consists of the fracture zone and rock matrix where the time constant is extremely different, and it is the model where fluid and heat mutually transfer between fracture zone and rock matrix. The fluid migration of the fracture zone is rapid, and the time constant is small. On the other hand, heat and fluid storability of the rock matrix are large, and the time constant is large (Ishido, 1999). This means that the temperature of the fracture zone changes in a short time and that the temperature of the rock matrix is difficult to change. The difference in behavior between a fracture type and a porous-type of reservoir increases, as the fracture spacing gets larger (Yano et al., 1995). The transport rate of heat from the rock matrix to the fracture zone decreases, as the fracture spacing is larger in the MINC model, and the lowering temperature of the fracture zone increases. As a result, the temperature decreases, as the fracture spacing is larger, and the pressure declined remarkably, since permeability increases.

**On Enhancement of Injection Capacity**

Transmissivity Improvement by Low-Temperature Injection

We have carried out numerical simulation studies using Garg's theory (1984) for thermo-elastic rocks and "modified Kozeny-Carman relationship" to evaluate the pressure behavior during cold water injection.
Substituting the parameters used for our numerical simulations into Equation (1), we have:

$$\frac{\partial \phi}{\partial t} = \frac{0.95}{9 \times 10^{10}} \left[ \frac{\partial P}{\partial t} - 1.8 \times 10^6 \frac{\partial T}{\partial t} \right]$$

(3)

Therefore, the porosity is controlled for the temporal temperature change, when temporal pressure change is smaller than $1.8 \times 10^6 \times$ temperature change (°C). The porosity depends temperature change, since the pressure change magnitudes are lower than $4 \times 10^5$ Pa and the temperature change magnitudes are within the range of 120°C and 150°C. The temporal changes in the permeability and the temperature of injection block and the adjacent blocks of Base Models A and B are shown in Figures 10 and 11, respectively. According to Figure 10, the magnitudes of permeability are, in ascending order: the lower injection block, the upper injection block, the adjacent block just under the upper injection block, the adjacent block just aside the lower injection block, the adjacent block just above the lower injection block, and the adjacent block just beside the upper injection block. Figure 10 shows that the correlation is reverse to Figure 11. As mentioned above, the effect of the temperature on permeability is large. Permeability of the predominant flow direction shows relative improvement, since the temperature is controlled by the convection at longer times in the Model. At longer times in Base Model A, it is recognized that the amount of permeability increase per unit time of the upper injection block decreases and the permeability of the adjacent block just beside the upper injection block decreases. As shown in Figure 5 (a), the effect is due to the inflow of the high temperature water in the vicinity of the local vortex around the injection block.

Next, we discuss Equation (2) for the relationship between permeability and porosity. There is some research which discusses the permeability reductions due to the porosity decreases by the scale of silica, etc. (e.g., Itoi et al., 1987; Verma and Pruess, 1988; Weir and White, 1996). We, however, used the modified Kozeny-Carman relationship (see, Equation (2)) in which permeability greatly changes even with minute changes in porosity. We explain the physical meaning of parameter $eI$ in the Equation (2). The parameter $eI$, is used so that the minute change of porosity greatly influences permeability. This parameter seems to be able to explain how permeability greatly changes in the fracture type reservoir by applying the percolation theory. Germanovich and Lowell (1992) examined the role of thermoelastic stresses in a hydrothermal upflow zone as a mechanism for focusing, and applied the percolation theory to address the possibility that thermoelastic stresses due to heating may affect fracture network connections. In our numerical simulations, parameter $eI$ of Equation (2) is used as a result of improving permeability and continuity of the fracture by injection of the low temperature thermal water. The fracture aperture increases by thermal contraction of the rock during low temperature water injection into a geothermal reservoir. In turn leads to drastic improvement in the permeability.

The Effect of Gravity

In order to evaluate the effect of downward flow of low temperature water on the pressure behavior, we examined the pressure behavior of the injection block of Models 3 to 5 which are injected at different temperatures (50°C, 150°C and 250°C) under constant permeability (see Figure. 7). The pressure increase in the case of the lower injection becomes larger with time as injection temperature is lowered which reflects the increase in fluid density and viscosity. In the case of the upper injection, the initial pressure buildup is smaller as the injection temperature is lower. And the temporal pressure changes after the initial pressure buildup change to a little increase after the early slight declines in the case of 50°C temperature thermal water injection, to a decline tendency in case of 150°C, and to almost constant state in case of 250°C respectively. This difference between the upper injection and the lower injection using low temperature thermal water seems to be the effect of gravity. The effect of gravity is examined based on the following equation:

$$M_A = -\frac{\rho k}{\mu} (\Delta P + \rho g)$$

(4)

where

- $M_A$: mass-flux (kg/s-m²)
- $\rho$: fluid density (kg/m³)
- $k$: permeability (m²)
- $\mu$: viscosity coefficient (Pa-s)
- $\Delta P$: pressure gradient (Pa/m)
- $g$: gravity acceleration (m/s²)
Table 3 shows the values of $\Delta P$, $\rho g$, $\rho^2 gk / \mu$ and $M_A$ after injection at: 5 days, 15 days and 30 days in Model 3, Model 4, Model 5 and Base Model. As shown in Table 3, when the water at injection temperatures of 50°C and 150°C (which is lower than the initial reservoir temperature) is injected, the downward flow becomes predominant in case of the upper injection and the horizontal flow becomes predominant in case of the lower injection with time. The gravity term $\rho^2 gk / \mu$ (Equation (4)) and mass-flux $M_A$ of the vertical direction remarkably increase in the Base Model A with improvement in permeability with time. Base Model A after the 30-day injection shows about a 10 fold increase in the gravity term and about a doubling in vertical mass flux in comparison with Model 3A in which permeability does not change. On the other hand, Base Model B after injection for 30 days shows about a 6 fold increase in the gravity term and about a factor of 0.4 times in vertical mass flux in comparison with Model 3B in which permeability does not change. All mass flux becomes the same equal magnitude, regardless of the injection location, in A and B of Model 5 that are injected at 250°C water equal to initial reservoir temperature.

When the low temperature water is injected into the shallow part of high temperature reservoir with strong vertical orientation of fractures as in Model A. These results show that the downward flow is predominated by the effect of the gravity. It improves vertical permeability with the temperature lowering by downward flow of low temperature water. Also, when downward flow becomes more predominant, it drastically promotes the pressure decline around the injection well.

### The Improvement of Injection Capacity

The injection capacity can be described as the $M(t)$ in the following equation:

$$
M(t) \propto (P_{well}(t) - P_{near}(t))
$$

where

- $M(t)$ = injection capacity (kg/s)
- $P_{well}(t)$ = downhole pressure at injection point (Pa)
- $P_{near}(t)$ = reservoir pressure around injection well at injection point (Pa)

In the present numerical simulation studies, we mainly discussed the pressure of the injection block. The pressure of the injection block almost corresponds to $P_{near}(t)$ in Equation (5). $M(t)$ seems to drastically improve with increases of permeability and lowering of $P_{near}(t)$. When $P_{well}(t)$ is at constant condition there at is an almost constant well head pressure.

Accordingly, the pressure increase around the injection well is suppressed by increase of mobility $\rho pk / \mu$. Increased permeability occurs with predominant of downward flow of low temperature water injected into high temperature geothermal reservoir with vertical orientation fractures. Injection capacity also improves. Behavior in which injection-capacity is enhanced by low temperature water injection when the permeability is greatly dependent on the temperature. Cold water flows downwards from the injection location. It is remarkable when the temperature of the flowing region is greatly reduced.

### Conclusions

Based on a field injection experiment, Ariki and Hatakeyama (1997, 1998) suggested that low temperature water injected into the reservoir flows through fractures down to a deep zone below the well, influences the permeability-thickness product and the injection flow rate. This occurs by increasing the fracture aperture (through thermal contraction) and reduces the reservoir pressure at the feedzone depth by gravity. Furthermore, the increase in storativity associated with the thermally-induced increase in fracture aperture will also promote reservoir pressure decline. These combination of effects enhance the injection-capacity during low temperature water injection, relative to the situation when hot water is injected.

The following conclusions are obtained from the present numerical simulation studies using a two-dimensional cross-sectional model, Garg's theory (1984) for thermo-elastic rocks, and “the modified Kozeny-Carman relationship”:

a. The behavior in which permeability increases with time in the case of low temperature water injection into a high temperature geothermal reservoir can be explained by applying the thermoelasticity of the porosity and the modified Kozeny-Carman relationship in which the permeability of rock greatly changes with minute changes in porosity.

b. The injection capacity of a geothermal reservoir with vertically orientated fractures, shows a tendency to be enhanced by the effect of the gravity, relative to that of the geothermal reservoir with horizontally orientation fractures when low temperature water is injected.

c. The injection capacity drastically improves when the low temperature water is injected into the shallow part of a geothermal reservoir with vertically orientated fractures.

Though it is a result that follows the two-dimensional cross-sectional model under limited conditions, it is suggested that the injection capacity is enhanced by the low temperature water injection. Still, it is necessary to verify the effect of the injection temperature on the injection capacity by a comparison between measured data and numerical calculations. This remains as a future problem to be solved.

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