Optimization of Reinjection Allocation in Geothermal Fields Using Capacitance-Resistance Models

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Keywords: Capacitance resistance model, reinjection allocation, optimization

ABSTRACT
Reinjection of produced geothermal water for pressure support is a common practice in geothermal field management. The goal of optimization for this type of problem is usually to find one or more combinations of geothermal reinjection well locations and rates that will maximize the production and the pressure support at minimum cost. A simple capacitance-resistance model (CRM) that characterizes the connectivity between reinjection and production wells can determine an injection scheme that maximizes the sustainability of the geothermal reservoir asset. A CRM model is developed for a geothermal reservoir located in West Anatolia, Turkey. It has been demonstrated that this simple dynamic model provides an excellent match to historic data. The developed model is then used together with a nonlinear optimization algorithm to study several hypothetical scenarios.

1. INTRODUCTION
Geothermal reinjection involves injecting energy-depleted fluid back into the geothermal reservoir. It is an integral part of sustainable geothermal projects. Reasons for reinjection include remediation of production induced pressure drawdown, mitigation of subsidence, as well as waste-water disposal for environmental reasons. Reinjection is either applied peripheral to production area in high permeable systems or inside or near the reservoir production zone in somewhat limited permeability reservoirs. Cooling of production wells is one of the problems associated with reinjection that can be prevented or minimized through careful testing and reservoir management practices. Typically, tracer testing combined with reservoir simulation modeling is used predict reinjection induced cooling. Formal optimization strategies normally evaluate hundreds or even thousands of scenarios in the course of searching for the optimal solution to a given management question. This process is extremely time-consuming when numeric simulators of the subsurface are used to predict the efficacy of a scenario. One solution is to use a mathematical proxy or surrogate such as trained artificial neural networks (ANNs) to stand in for the simulator during the course of searches directed by some optimization technique (Akin, 2008).

Capacitance-resistance modeling of petroleum reservoirs has been used successfully to analyze transient behavior of petroleum reservoirs in the past (Albertoni and Lake, 2003; Nguyen et al., 2011; Sayarpour et al., 2007; Sayarpour, 2008; Weber et al., 2009; Yousef et al., 2006). The capacitance-resistance model derived from a continuity equation is an input-output model concentrated on describing the relationships between injectors and producers by modeling total fluid production from the reservoir. Typically, only observed injection rates and total production rates are required to history match the model and obtain a representation of these relationships. As opposed to numerical simulation models based on finite difference techniques, the capacitance-resistance model does not attempt to divide the reservoir into smaller parts resulting in fewer parameters that are necessary to specify the model.

In this study, use of capacitance resistance models is proposed for reinjection allocation in a geothermal reservoir where several potential reinjection well locations have been already identified. First capacitance resistance models are introduced. Then a field example is used to demonstrate the uses and advantages of the proposed methodology. Finally, the capacitance resistance model is used to optimize reinjection using several scenarios.

2. MODEL
The foundation of the capacitance resistive models relies on the material balance equation that includes total compressibility effect for a given reservoir control volume. The control volume represented as the drainage volume between an injector-producer pair is shown in Figure 1. The governing equation of the total fluid production for the control volume can be obtained as (Yousef et al., 2006);

\[ q_{ij}(t) = \dot{f}_j I_i(t) - \tau_{ij} \frac{dq_{ij}(t)}{dt} - J_{ij} \tau_{ij} \frac{dp_{ij}(t)}{dt} \]  

(1)

In this equation \( q_{ij}(t) \) represents the part of total production in producer \( j \) that is supported by injector \( i \) at time \( t \). \( \tau \) represents the time constant associated with the drainage volume between the injector \( i \) and producer \( j \). \( J_{ij} \) is the productivity index associated by the partial production \( q_{ij}(t) \). Assuming that part of the total field injection may either be lost from the reservoir (not contributing to total fluid production) or be supplemented by injection outside of the control volume (as an aquifer may drive production), one may modify the total injection rate \( f \) by the factor \( f \) which leads to the effective injection rate, \( \dot{f}(t) \), in the material balance. Integrating this equation over discrete time period \( \Delta t \), it is possible to obtain \( q_{ij}(t) \), if injection rates are constant and bottom-hole pressures in all wells are linearly changing.
Fig. 1. Schematic representation of the drainage volume between an injector and a producer used by the model.

\[
q_{jk} = q_{j(k-1)} e^{-\Delta t/\tau_{ij}} \left( 1 - e^{-\Delta t/\tau_{ij}} \right) f_{ij} l_{ik} - q_{j(k-1)} \left( \frac{p_{w}^{i,k} - p_{w}^{(k-1)}}{\Delta t } \right)
\]

(2)

Where \( f_{ij} \) is connectivity or gain between injector \( i \) and producer \( j \). Physically, the connectivity \( f_{ij} \) represents the steady-state fraction of water injected in injector \( i \) that contributes to production of water in producer \( j \). It is then possible to obtain an expression for the total production in producer \( j \) by summing up this equation over the injector index \( i \).

\[
q_{jk} = \sum_{i=1}^{n_{i}} q_{ijk} = \sum_{i=1}^{n_{i}} \left[ q_{ij(k-1)} e^{-\Delta t/\tau_{ij}} \left( 1 - e^{-\Delta t/\tau_{ij}} \right) f_{ij} l_{ik} - q_{j(k-1)} \left( \frac{p_{w}^{i,k} - p_{w}^{(k-1)}}{\Delta t } \right) \right]
\]

(3)

In the absence of bottom-hole pressure data and if it is assumed that the flowing bottom-hole pressure is constant the following equation can be obtained.

\[
q_{jk} = \sum_{i=1}^{n_{i}} q_{ijk} = \sum_{i=1}^{n_{i}} \left[ q_{ij(k-1)} e^{-\Delta t/\tau_{ij}} \left( 1 - e^{-\Delta t/\tau_{ij}} \right) f_{ij} l_{ik} \right]
\]

(4)

The objective function is as follows:

\[
\text{min } z = \sum_{k=1}^{n_{k}} \sum_{j=1}^{n_{p}} \left( q_{jk}^{\text{obs}} - q_{jk}^{\text{mod}} \right)^{2}
\]

(5)

In this equation \( q_{jk}^{\text{mod}} \) is the calculated production rate of producer \( j \) at the time step \( k \). This equation needs to be solved by a minimization algorithm subject to the material balance constraint that requires solving for all parameters (the connectivity and the time constants) for all producers \( (n_{p}) \) at the same time for a total number of \( n_{h} \) historic time periods.

\[
\sum_{j=1}^{n_{p}} f_{ij} \leq 1 \text{ for all } i
\]

(6)

\[
f_{ij}, \tau_{j} \leq 1 \text{ for all } i \text{ and } j
\]

(7)

The time constant parameter \( \tau_{j} \) reflects the sensitivity of a producer to the changing injection rates at different injectors. For a small pore volume and compressibility or a large productivity index, time constant is small. Any change in the injection rates will affect the flow rates at producers. On the other hand, for large total compressibility or very low permeability, time constant will be large. In this case producers are not significantly affected by injection changes at the injectors.

This model attempts to simulate a dynamic system with parameters that are not time dependent. This will create a problem if the geothermal reservoir parameters (i.e. permeability) are changing via chemical reactions such as dissolution and deposition. One other drawback of the model is temporary or permanent shut-in periods since the model considers every measured rate, regardless of its magnitude, as a physical result of injection elsewhere in the reservoir. If a production well is shut in, calculated connectivity of the corresponding well will be less than what it should be. In other words, water is not injected to the reservoir that would otherwise account for the zero production in given time periods. A similar effect occurs when unusually large or small productions are observed. A small production may reflect partial production due to, for example, mechanical problems. Whatever the reason, the presence of outliers in the measured rate data can strongly influence the resulting model fits.

RESULTS & DISCUSSIONS

The advantages and the disadvantages of the proposed model are evaluated using data from a field located in Buyuk Menderes Graben, Turkey. The field was discovered in 1967 and nine wells were drilled between 1982 and 1986. After that 5 additional production and 4 additional injection wells were drilled till 2008. The static bottom-hole temperatures of these wells change between 203°C and 232°C. There are two reservoirs in the field. The deepest reservoir is composed of Paleozic aged metamorphics mainly composed of fractured gneiss, karstic marble and schist, whereas the shallow reservoir is composed of Miocene to Pliocene aged sandstones and conglomerates. Pressure falloff and buildup tests provided a range of permeability-thickness from a moderate 34,000 mD-feet in the vicinity of Well #8 to high level of 58,200 mD-feet in the vicinity of Well #9. Since the reservoir thickness is relatively large (>600 m), this translates into a relatively low bulk permeability with localized high permeability corresponding to fractures. The reservoir is well connected and all of the participating production (Wells #5, #6, #8, #10, #11, #14, #17, and #19), injection (Wells #3, #8, #9, #22, #24, #25, and #26) and monitoring wells (Well #7) are completed in the same reservoir (Fig. 2).
Fig. 2. Production and reinjection well locations.

The proposed methodology described in the previous section has been applied to production and injection data using an Excel spreadsheet. The data used to demonstrate the use of CRM model consisted of field injection and production data between March 2009 and August 2010. The nonlinear Generalized Reduced Gradient algorithm optimization function in Excel was used and the results summarized in Table 1 and shown in Figure 3 through Figure 10 were obtained. In all wells a pretty good match was obtained. The CRM model slightly underestimated the production observed in Well #6 (Fig. 4) and Well #14 (Fig. 8). The time constants inferred from the optimization results show that the highest permeability is around Well #14 followed by wells #8, #6, #11, #5, #10, #17, and #19 (Table 1). As discussed in the preceding section, when the time constant of a producer is small any change in the injection rates will affect the flow rate at producers. When the gains calculated by the model are analyzed, it was found that 77.5% of the re-injected water into Well #3 travelled towards Well #6. Although other production wells are located somewhat closer compared to Well #6 (see Fig. 2) it looks like the east - west trending fault is the controlling factor. Similarly Well #8 mainly fed Well #11, #6 and #5 more than the other injectors possibly through a north – south fault system. The largest gain (0.992) was observed between Well #14 and Well #26 through the major fault passing across the field in east - west direction. Most of the re-injected water that is coming from injectors located in east to south east of the field flowed towards Well #14. Well #8 was used as an injector for 4 months and changed to a producer later on. That’s why the corresponding gain is taken as zero. Well #17 and Well #19 seem to receive little or no support from the injectors suggesting that either the test time is not long enough to see the injectors effect or due to high production of Well #14 these wells are getting limited support. Nevertheless, the estimated gains obtained from CRM are consistent with the geology of the field.

Table 1. Injector – producer connectivity (f_{ij}) results.

<table>
<thead>
<tr>
<th>Producer / Injector</th>
<th>5</th>
<th>6</th>
<th>8</th>
<th>10</th>
<th>11</th>
<th>14</th>
<th>17</th>
<th>19</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \tau_j ) (hours)</td>
<td>44747.77</td>
<td>1977.1</td>
<td>1311.2</td>
<td>133927</td>
<td>11908</td>
<td>323.32</td>
<td>278365</td>
<td>628504</td>
</tr>
<tr>
<td>3</td>
<td>0.000</td>
<td>0.775</td>
<td>0.080</td>
<td>0.000</td>
<td>0.000</td>
<td>0.145</td>
<td>0.000</td>
<td>0.000</td>
</tr>
<tr>
<td>8</td>
<td>0.269</td>
<td>0.302</td>
<td>0.120</td>
<td>0.000</td>
<td>0.410</td>
<td>0.000</td>
<td>0.001</td>
<td>0.000</td>
</tr>
<tr>
<td>9</td>
<td>0.004</td>
<td>0.464</td>
<td>0.053</td>
<td>0.000</td>
<td>0.002</td>
<td>0.001</td>
<td>0.000</td>
<td>0.000</td>
</tr>
<tr>
<td>22</td>
<td>0.002</td>
<td>0.055</td>
<td>0.037</td>
<td>0.000</td>
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<td>24</td>
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<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
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<tr>
<td>25</td>
<td>0.056</td>
<td>0.464</td>
<td>0.074</td>
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<td>0.000</td>
<td>0.000</td>
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</tr>
<tr>
<td>26</td>
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<td>0.000</td>
<td>0.000</td>
<td>0.003</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
</tr>
</tbody>
</table>

Figure 3. CRM fit for Well #5.
Figure 4. CRM fit for Well #6.

Figure 5. CRM fit for Well #8.

Figure 6. CRM fit for Well #10.

Figure 7. CRM fit for Well #11.
Model verification and reinjection allocation scenarios

The developed CRM is compared to actual data (i.e. the data that has not been used during model calibration) consisting of 3 years of production and injection data. The injection data is used in CRM together with the time constants and the gains to calculate the production in individual production wells. An excellent agreement has been observed both in well and field production (Fig. 11). Thus, it can be concluded that the characteristics of this geothermal reservoir can be inferred from analyzing production and injection data only.

Several scenarios were generated to optimize reinjection allocation in this field. Scenarios were developed in such a way that physical limits of the injection and production wells were considered. In the first scenario, Well #8 and Well #8 were stopped and the reinjection was equally distributed among the wells located in east and south east reinjection wells (Well #23, Well #24, Well #25, and Well #26). In the second scenario, injection from east and south east of the field was considered (no injection from Well #3, Well #8, and Well #9). The third scenario was a variant of 2nd scenario such that same wells were used for reinjection but Well #25 and Well #26 received the majority of reinjection. In the final scenario, the reinjection in east and south east wells (Well #23, Well #24, Well #25, and Well #26) was reduced (%25) and this amount was distributed equally to Well #3, Well #8, and Well #9. The best result was obtained with Scenario 2 followed by Scenario 1 and Scenario 3. In general, it was observed that increasing the reinjection of high gain injection-production well pairs has a beneficial effect on production. This is probably related to the geology of the field such that the injection wells that are located in the lower half of the field where the east—west trending faults control the flow support the production wells more than the others. On the other hand, increasing reinjection from wells that are somewhat closer to the middle of the field has a negative effect on production.
CONCLUSIONS
A simple capacitance-resistance model (CRM) that characterizes the connectivity between reinjection and production wells has been developed for a geothermal reservoir located in West Anatolia, Turkey. It has been shown that this simple dynamic model provides an excellent match to historic data. Several hypothetical scenarios to determine an injection scheme that maximizes the sustainability of the geothermal reservoir asset showed that injection from wells that are located at the lower half of the field where east–west trending faults are located is better compared to injection from the center of the field.

REFERENCES


