PROCEEDINGS, 43rd Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 12-14, 2018
SGP-TR-213

Development of Numerical Methods for Estimating Fluid Flow Path in Fractured Geothermal Reservoir

Fuad Ikhwanda, Anna Suzuki, Toshiyuki Hashida

Tohoku University, Graduate School of Engineering, 6-6-11-707, Aza-Aoba, Aramaki, Aobaku, Sendai 980-8579, Japan

ikhwanda.fuad@rift.mech.tohoku.ac.jp

Keywords: tracer analysis; fracture surface area; field application

ABSTRACT

Reinjection is crucial for sustainable geothermal developments. In order to predict thermal performances due to cold water injection, a method has been developed to estimate effective heat transfer areas. Tracer response curves at production wells are analyzed to determine flow rate and pore volume at each flow path, and effective heat transfer areas are optimized by short-term thermal response curves from the same production wells. This study accounted for water leakage from the flow path into surrounding rocks in the estimation method. The estimation method was validated by comparing with numerical simulation results. The estimation results show good accuracies of the effective heat transfer areas in the numerical simulation. This method was applied to data from the Balcova geothermal field. The estimated heat transfer areas were reasonable.

1. INTRODUCTION

Inter-well flow tests have been conducted to obtain important information of reservoir characteristics. These data are interpreted to build reservoir models. Current commercial reservoir simulators are based on distributed parameter models. The distributed parameter models require flow and rock properties on each calculation cell in advance. Some of the models describe fractures implicitly by using porous blocks, while the others express fracture explicitly by using both fracture and porous blocks separately with fine grids. In practical, the model consisting of fractures explicitly is expected to reproduce more realistic tracer response and thermal response curves. However, it needs huge computational cost to develop the numerical models. There is also high uncertainty in determining the required parameters. Therefore, a simplified approach is needed at an early stage of development.

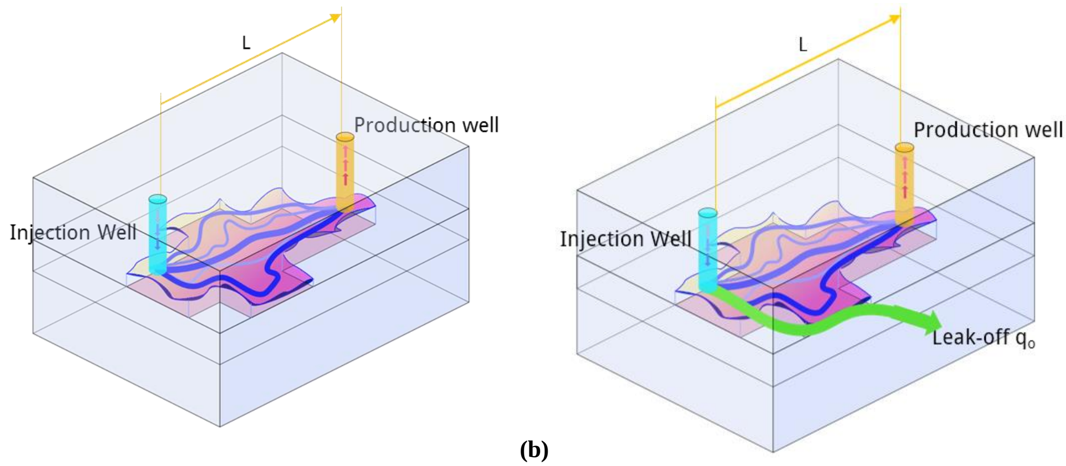
The simplified approach is expected to have less uncertainty than the distributed parameter models. Robinson and Tester (1984) and Robinson et al. (1988) used analytical solutions for heat exchangers with one-dimensional flow in the “fracture” and no flow in the “matrix”. They matched temperature histories of two EGS projects by adjusting surface areas in the single fracture. Their models assumed the fracture thickness is perfectly uniform in the entire area. The assumption of the single fracture with one-dimensional flow normally oversimplifies complex reservoir structures. On the other hand, a model accounting for several flow paths has been developed to interpret tracer recovery and been used successfully in various geothermal fields in Iceland and worldwide (Arason and Björnsson, 1994; Axelsson et al., 1995). The model can estimate properties of all flow paths, such as the pore-space volume and the dispersivity. However, parameters in the flow path model are not unique for multi-channel flow. Based on the flow path model, Shook and Suzuki (2017) proposed a method to determine flow properties for several flow paths uniquely, by using tracer and thermal response data between a pair of an injection and a production wells. Their method allows estimation of effective heat transfer areas for multi-channel flow.

The model proposed by Shook and Suzuki (2017) assumed that all of water and tracers were recovered at the production well. However, in real geothermal fields, injected water may flow into the surrounding rocks and not recovered. Thus, this study extended the previous method in order to use it for the case where water leaks off into the surrounding rocks. The method was applied to a set of field data obtained from the Balcova geothermal field in Turkey.

2. METHOD

Shook and Suzuki (2017) proposed a flow path model to estimate effective heat transfer area. The model directly calculates thermal interactions between injected cold water and surrounding rocks by using available tracer and temperature responses. The concept of the flow path model is shown in Figure 1(a). We assume that there are several flow paths between a well pair. We do not have to know the actual structure of fracture nor the number of flow paths connecting between the injection and the production wells. The cold water and the tracer are injected into an injection well. The tracer concentration and the temperature decline are observed at a production well. The tracer breakthrough curve is used to obtain the flow properties of each path.

The previous study (Shook and Suzuki, 2017) assumed that all of water and tracers are recovered at the production well. This study furtherly developed the flow path model by considering the leakage of the fluid and the tracers. The schematic of fluid leak-off is shown in Figure 1(b).



(a) **(b)**

Figure 1: Schematics of the flow path model in a reservoir (a) without leakage and (b) with leakage.

First, we need to calculate the recovery rate r, which is given by

$$r = \frac{m_{tracer\ recovered}}{m_{tracer\ injected}} = \frac{q'}{q_I} \tag{1}$$

where q' is flow rate of recovered fluid. The temperature of the production fluid with leakage is derived in the following form:

$$T_w = T_I - (T_I - T_J)erfc\left[\frac{1}{(\rho C_p)_w}\frac{A}{2q'}\sqrt{K_R(\rho C_p)_R}\frac{1}{\left(t-\frac{(\rho C_p)_T}{(\rho C_p)_w}\frac{V_p}{\phi q'}\right)^{1/2}}\right] \tag{2}$$

The above heat transfer equation describes thermal response in a single path. However, actual flow fields may consist of several flow paths between wells. Although some tracer response curves may clearly have several peaks indicating the number of flow paths, the others may not show countable peaks. Therefore, instead of counting the number of peaks, we virtually divided the tracer response curve into several partitions and assumed each partition as a single flow path. The most suitable number of partition may depend on each simulation. By using the partition of tracer response curves, pore volume and flow rate of each virtual flow path were obtained. We assumed that the flow rate of each virtual flow path is proportional to the ratio of mass of tracers recovered in respective path.

Each flow path will have different contribution into the thermal breakdown at the production zone. The accumulative thermal breakdown of the reservoir weighted by the flow rate can be written by:

$$T_w(t) = \frac{1}{q_{tot}}\sum_{j=1}^{N_{path}} q_j w_{wj} T_w(t, A_j, q_j, V_{pj}) \tag{3}$$

where t is time, A is the heat transfer area, q is the flow rate, and V_p is the pore volume. Index j is used to note the j-th flow channel. All parameters except the heat transfer area are known from the tracer response. If we could obtain a short-time thermal breakdown curve, the heat transfer area can be estimated by curve-fitting with the solution of heat transfer equation (Eq. 3). We have to match the curve with the observed temperature by using an optimization algorithm. In this research, the L-BFGS-B method from the python *scipy* package is used to minimize the objective function (OBJ) as follows:

$$OBJ = \sum_{t=0}^{N_t} \frac{|data(t) - T_w(t, A_j)|}{data(t)} \tag{4}$$

Combination of areas in the flow paths, which give the lowest OBJ value, is selected, and the sum of the areas is determined to be the estimated heat transfer area.

3. VALIDATION OF THE FLOW PATH MODEL

3.1 Synthetic model

We validated the flow path model accounting for the leakage of injected water. Synthetic results were obtained from a numerical simulator, TOUGH2 (Pruess et al., 1999). The model consists of a fracture area surrounded by rock masses, as shown in Figure 2. The fracture zone includes six paths with different permeability. The model was made as simple as possible to reduce the uncertainty. Assuming the symmetry around the fracture zone, we built a half-model with a layer of the fracture zone and 15 layers of rock masses. The thickness of the fracture layer was 0.01 m. Total thickness of the model was 640.11 m. We set fine grid mesh near the fracture layer, while the mesh on far side from the fracture layer is thicker. A production well and a reinjection well were placed at each end of the fracture zone with vertical length of 60 m. Both wells had open-section on the entire length of the model. The well pair was placed 53 m apart. The area between the wells was divided into 19 columns. We assumed that the fluid mainly flows in one-dimensional direction between the wells. The simulation condition is listed in Table 1.

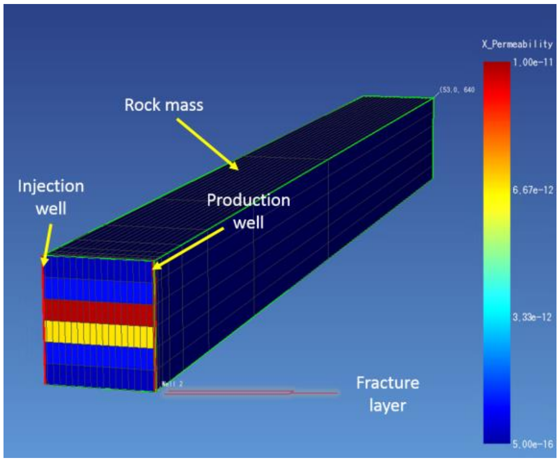


Figure 2: Numerical model of a fracture zone with six flow paths distributed vertically.

Table 1: Simulation properties of the synthetic model.

Parameter	Value
Number of layer	6
Injection temperature	25 °C
Initial temperature	200°C
Porosity	0.5
Well distance	53 m
Surface area	3180 m^2
Water injection rate	1 kg/s
Tracer injection rate	0.1 kg/s (1 hour)

3.2 Effect of leakage

We obtained tracer and temperature data with and without leakage, as shown in Figure 3 and Figure 4, respectively. Both tracer response curves with and without leakage include several peaks during the observation. It is considered that there are several flow paths represented by each peak. The travel time of tracer particles depend on the flow velocity. Major fluid path gave the highest peak of the tracer response curve. In the case of no leakage (Figure 3(a)), the recovery rate in Eq. (1) was 1.0, which was obtained from the tracer response curve. In contrast, the recovery rate was 0.85 in the case with leakage (Figure 3(b)).

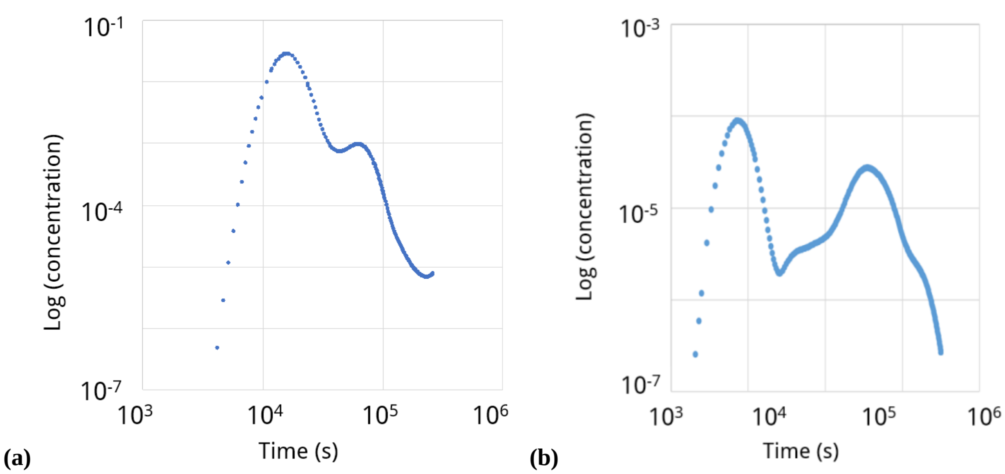


Figure 3: Tracer response curves simulated from the TOUGH2 (a) without leakage and (b) with leakage.

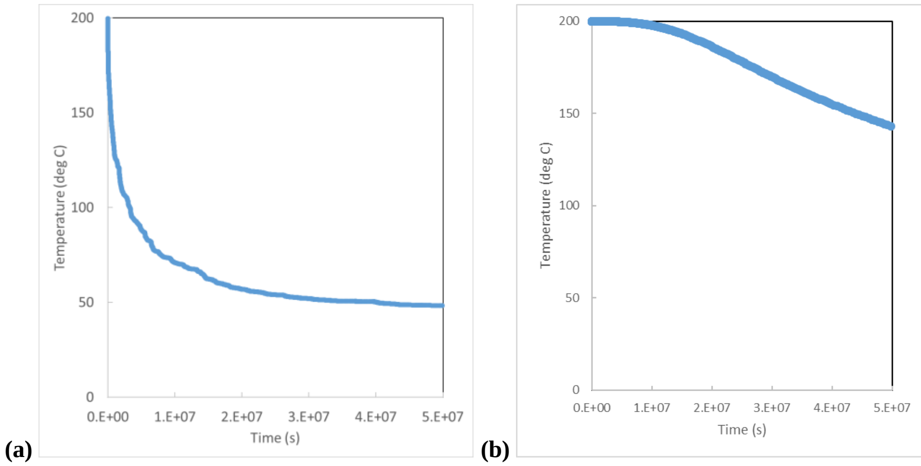


Figure 4: Thermal breakdown curves simulated from the TOUGH2 (a) without leakage and (b) with leakage.

We analyzed the response data based on the proposed estimation method. Because the actual number of flow path was unknown, we varied the number of virtual partition from 1 to 10. Figure 5 shows the flow rate and the pore volume for each flow path with different number of partitions. The single column describes the value for each flow path. Flow rate and pore volume of each channel in the partition is depicted by different colors.

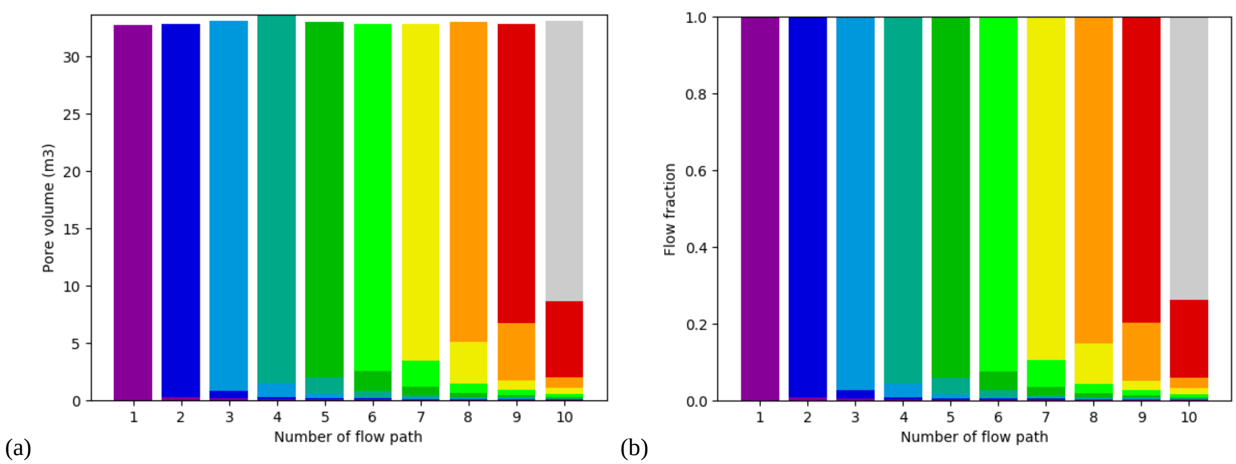


Figure 5: Flow rate and pore volume calculated from tracer response curves. The tracer was simulated by the TOUGH2 without leakage.

First, we analyzed the simulation result for the case without leakage. Temperature result shown in Figure 4(a) was used the data to estimate heat transfer area for each number of flow paths. The heat transfer area estimation and the value of objective function (OBJ) for each number of flow paths are shown in Figure 6. Lower value of OBJ means better fitting with the temperature data. The result shows that the value of OBJ with nine flow paths was the lowest among the models with different numbers of flow paths, which can be considered to provide the best estimation for the heat transfer area. Figure 7 shows the thermal breakdown curve-fitting result between model with nine flow paths and the temperature data. The fitted curve revealed a good agreement with the temperature result obtained from the TOUGH2.

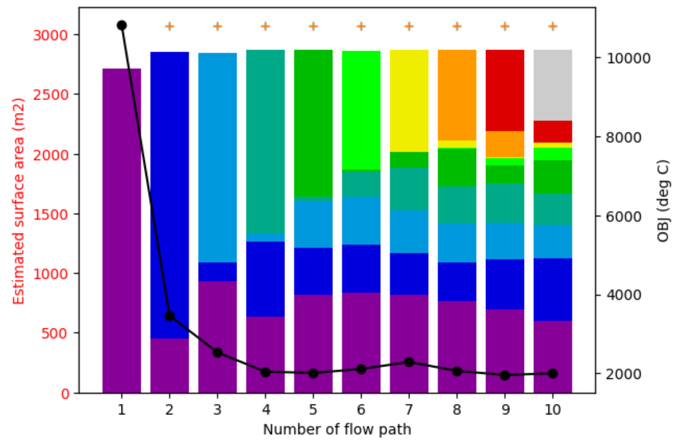


Figure 6: Estimated results for effective heat transfer area for the simulation without leakage. The total length of bars is the estimation of the accumulated surface area. Color difference describes each surface area for each flow path. The plots of "+" describes the exact surface area of fracture zone set in the numerical simulation. The black line plots the minimum value of the objective function.

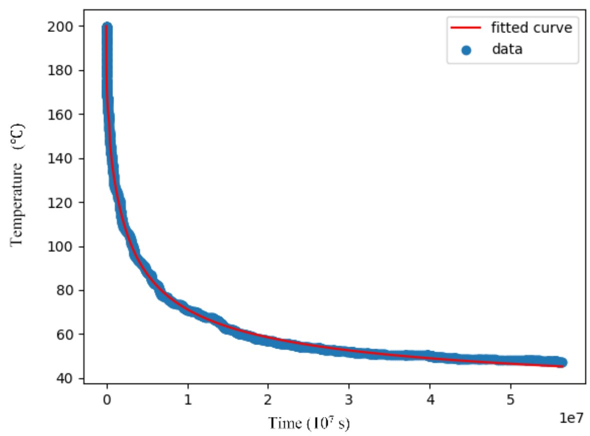


Figure 7: The best-fit curve with the thermal breakdown data.

The best estimation of heat transfer area is 2873 m^2 in the model without fluid leakage. The exact answer of the area was 3113.4 m^2. Estimation errors slightly occurs. It may be caused by the difference between the constants used in the synthetic model and the estimation method. TOUGH2 utilizes steam table to determine water properties, such as density and heat capacity. The values are described as functions of temperature. While, the temperature is changing regularly as the simulation time progressed. On the other hand, our developed surface estimation method utilizes fixed density and fixed heat capacity of water regardless of temperature changes. Thus, the estimation value is slightly deviated from the reference model. In addition, the heat transfer area of reference model is assumed to be a perfect rectangular shape. However, some paths was assigned to rock with low permeability, it might have less effect on the heat transfer. Thus, by these considerations, we can conclude that the estimation results are sufficiently good for future production prediction.

Next, we analyzed the temperature results for the case with leakage as shown in Figure 4(b). The estimated surface area and the value of objective function (OBJ) for each number of flow paths are shown in Figure 8. The results shows model with 8 flow paths is the best estimation with has lowest OBJ value. The corresponding best estimation of heat transfer area is 3667 m^2 for model with leakage. The exact answer of the area was 3113.4m^2 Estimation for the case with leakage is considered as good. Figure 9 confirmed the curve fitting between thermal breakdown of synthetic model and estimation of fluid leak-off model.

We considered that there is heat transfer occurred in the surrounding layers due to high porosity and permeability outside the fracture. It is causing rapid temperature decline at production zone and underestimation of volume fracture zone. Therefore, the heat transfer area gave a rather optimistic temperature forecast at the later part of production. However, the estimation of early thermal breakdown and heat transfer area are considered to be sufficiently close.

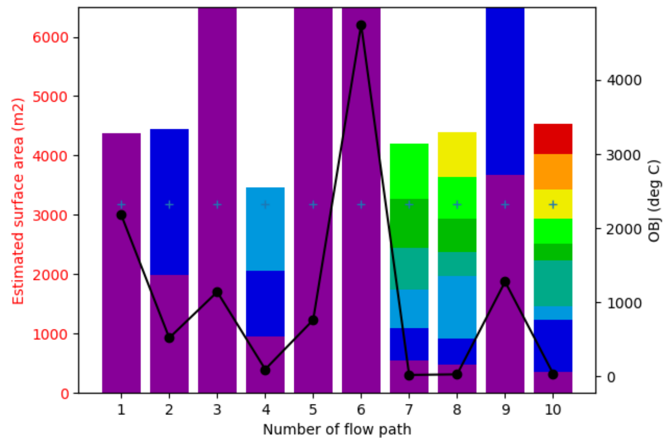


Figure 8: Estimated results for effective heat transfer area for the simulation with leakage. The total length of bars is the estimation of the accumulated surface area. Color difference describes each surface area for each flow path. The plots of "+" describes the exact surface area of fracture zone set in the numerical simulation. The black line plots the minimum value of the objective function.

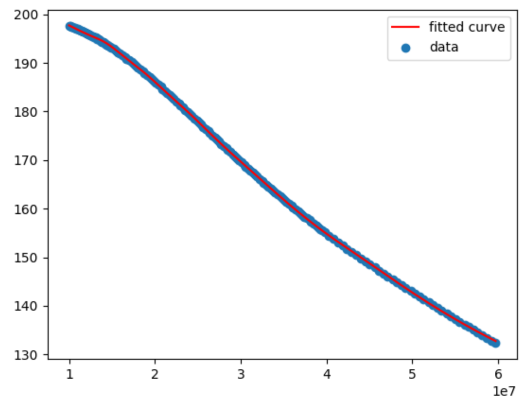


Figure 9: The best-fit curve with the thermal breakdown data.

3.3 Effect of length of temperature data

If estimation of heat transfer area can be done at an early stage of reservoir exploration, we can predict the future productivity of the reservoir and optimize the injection strategy. On the other hand, longer temperature data can reduce the uncertainty of evaluation and increase the estimation accuracy. Thus, we evaluated the effect of the amount of data on the estimation of heat transfer area. The amount of data used for fitting is described by the factor of thermal breakdown data, ξ, as:

$$\xi = \frac{T_{init} - T_{end}}{T_{init} - T_{inj}} \tag{5}$$

where T_{init} is initial temperature of the reservoir, T_{inj} is the injection temperature, T_{end} is the newest observed temperature at the time of simulation.

In order to evaluate the effect of the factor ξ on estimating heat transfer area, five estimations with ξ of 0.2, 0.4, 0.6, 0.8, and 1.0 were conducted and compared. We used the tracer and thermal response data obtained from the TOUGH2 model with full fluid recovery, which are shown in Figure 3(a) and Figure 4(a). The estimated heat transfer area and the final iteration of OBJ functions for each number of flow path are shown in Figure 10. The estimation errors was reduced by increasing the factor of temperature data ξ. When data factor was 0.6, the estimation error was the lowest. The increase of error with ξ more than 0.6 may be caused by the simulation errors mentioned in section 3.2. In general, estimation errors of model with temperature data factor larger than 0.4 are below 10%, as shown in Figure 11. We conclude that the estimated surface area is sufficiently close to the exact answer.

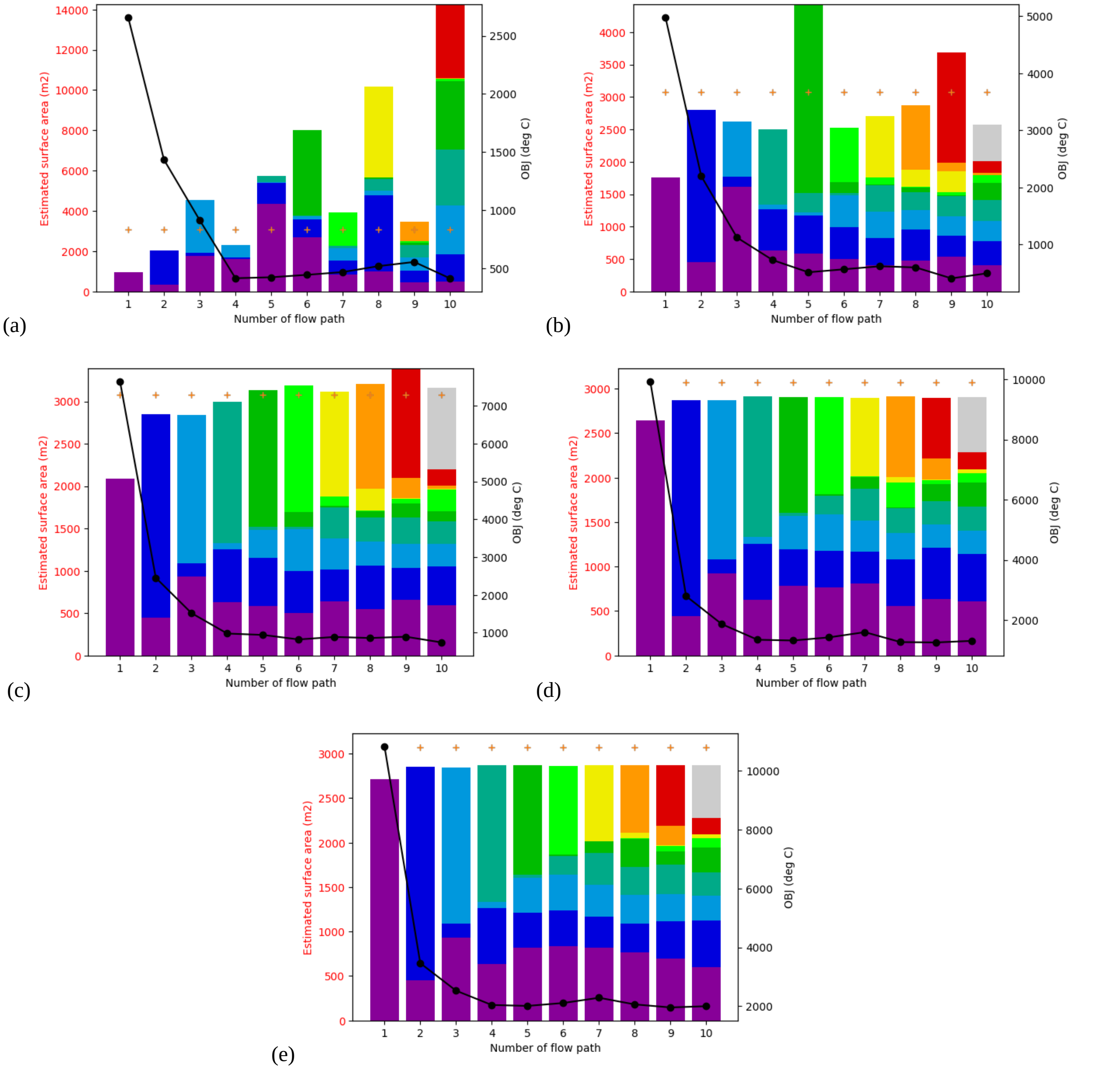


Figure 10: Estimated results for effective heat transfer area with factor of data (a) ξ =0.2, (b) ξ =0.4, (c) ξ =0.6, (d) ξ =0.8 and (e) ξ =1.0. The total length of bars is the estimation of the accumulated surface area. Color difference describes each surface area for each flow path. The plots of "+" describes the exact surface area of fracture zone set in the numerical simulation. The black line plots the minimum value of the objective function.

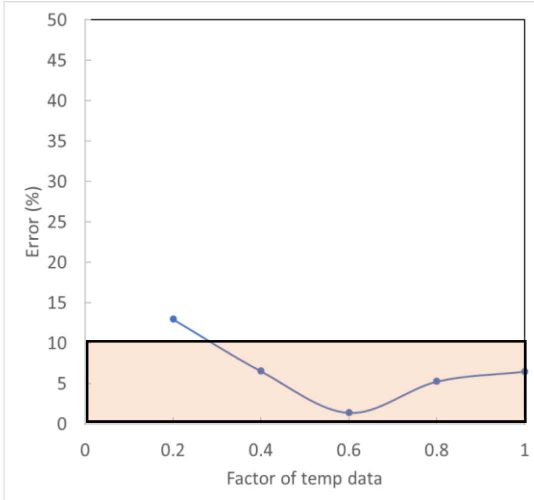


Figure 11: Effect of length of temperature data.

4. APPLICATION TO FIELD DATA

4.1 Balcova geothermal field

Balcova geothermal field is located on the shore of the Aegean Sea in Turkey and provides the largest geothermal district heating system in the country. The geothermal fluid is mainly used for public heating of municipal houses and greenhouses. The field view of Balcova field (Aksoy et al., 2008) is shown in Figure 12. A major 2-km long fracture, shown as the bold dashed line, in the reservoir is considered as the main region of fluid flow. Arkan & Palaktuna (2005) provided estimated reservoir properties as listed in Table 4.

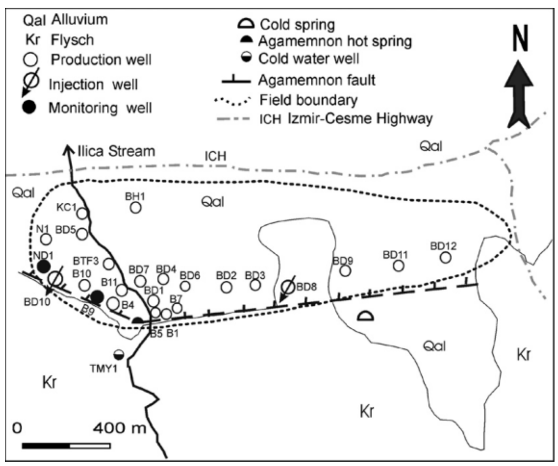


Figure 12: Field view of Balcova geothermal field.

Table 2: Properties of Balcova geothermal reservoir

Parameter	Most likely	Min	Max
Porosity	-	0.002	0.070
Rock specific heat (J/kg)	0.92	0.80	1.08
Rock density (kg/m^3)	2750	2600	2850
Rock temperature (°C)	135	100	145
Area (m^2)	9.00E+5	5.00E+5	2.00E+6
Thickness (mm)	0.35	0.25	1.00
Fluid density (kg/m^3)	930.6	921.7	958.1
Utilized temperature (°C)	80	-	-
Fluid specific heat (J/kg)	4.18	-	-

Based on the field observation (Arkan & Palaktuna, 2005), the reservoir porosity is not uniform. Porosity at the fracture zone should be 1.0. While the rock porosity is quite low (range between 0.002 and 0.07). Therefore, in our model, we assigned a function for determining fracture porosity of each flow path as follows:

$$\phi_{frac-i} = \frac{\phi_{frac-max} - \phi_{frac-min}}{1-(N+1)}(1-N) + 1 \tag{6}$$

where ϕ is the porosity, and N is the index of the flow channel. We have to note that, fracture porosity is defined as the volume occupied by the fracture inside the volume of rock by considering the wavy nature of fracture surface. The flow paths were indexed in respect of ease of flow. Fracture porosity of the first flow path was set to 1.0. The second path and the third path have more obstacles for fluid to flow, as their respective fracture porosity is getting smaller. The minimum porosity measured from the field rock, which is 0.002, was assigned to the *N*-th path.

There are available field data of tracer response curves and thermal breakdown of the reservoir. In 2003, flow testing was carried out in the Balcova geothermal field. Cold water of 60℃ was injected to well B9 and recovered at several production wells. Figure 13 plots the tracer response curves observed in the Balcova geothermal field. Recovery rate of the reservoir is decided by interpretation of tracer response curve. The temperature profiles of cold-water injection were obtained from Aksoy et al. (2008). Initial temperature observed at well B4 is 114 ℃. Large portion of injected fluid was recovered in well B4. We used the data obtained at well B4 as the major connection to the injection well.

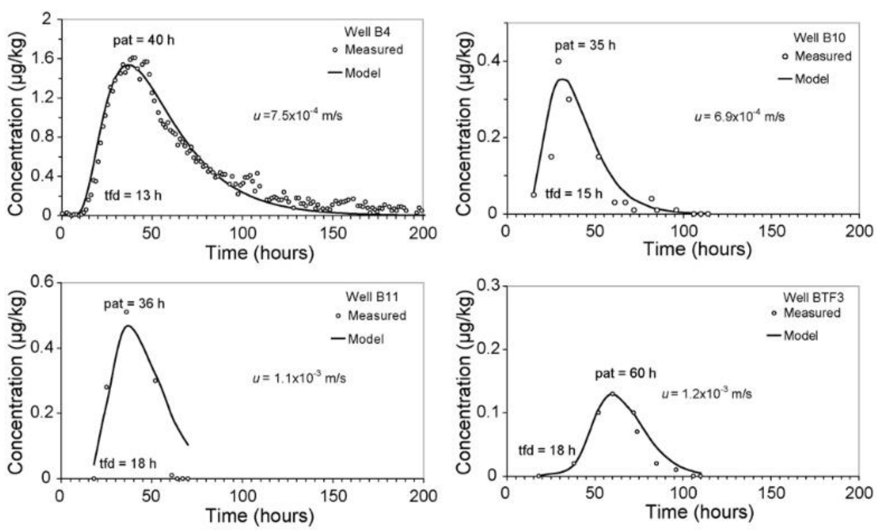
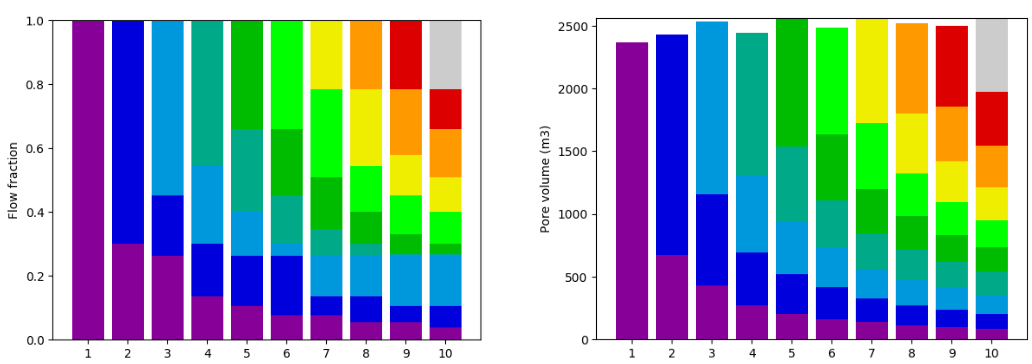


Figure 13: Tracer response curve injection at well B9 (Aksoy et al., 2008)

4.2 Estimation of effective heat transfer area in the Balcova field

We analyzed the tracer response of Balcova field data as shown in Figure 13 (Aksoy, et al., 2008). Because the number of flow path was unknown, we did simulations for the number of partitions from 1 to 10. Figure 14 shows the flow rate and the pore volume for each flow path with different numbers of flow paths. The single column describes the value for each flow path. The different colors in the column depicts the fractions of the flow rate and the pore volume for each flow channel.



(a) (b)

Figure 14: Flow rate and pore volume calculated from tracer response curves. The tracer was simulated by the TOUGH2 without leakage.

Temperature profiles of Balcova field, from Aksoy (2008), is used to estimate surface area for each number of flow paths. The estimated surface area and the value of objective function (OBJ) for each number of flow paths are shown in Figure 15. The low OBJ value means better fitting between the thermal breakdown calculation and the temperature data. The results show that model with six flow paths has the lowest value of OBJ. Therefore, we decided the estimated value model with six flow paths as the best estimation of surface area. Figure 16 shows the curve-fitting result of temperature data in the case of six flow paths. The fitted curve has a good agreement with Balcova field data. Estimated thermal breakdown curve has several different slopes over time. We consider that the cold-water passed through different flow path inside the reservoir. The impact of the cold water, which flowed in the fastest flow path, is depicted as first slope of the curve. In contrast, the last slope of the curve depicts the impact of cold water injection ran through the longest or the slowest flow path.

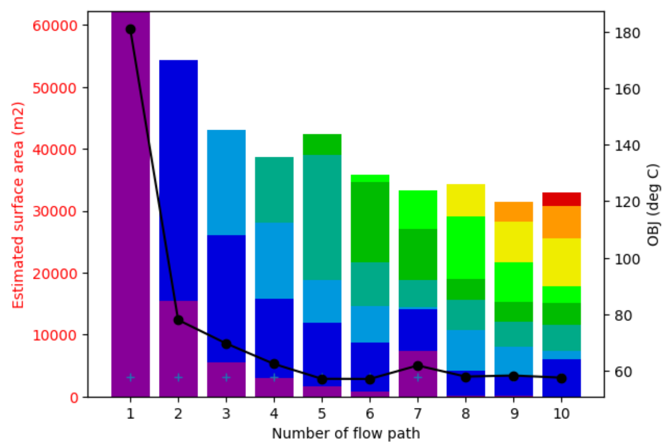


Figure 15: Estimated results of heat transfer area in the Balcova reservoir.

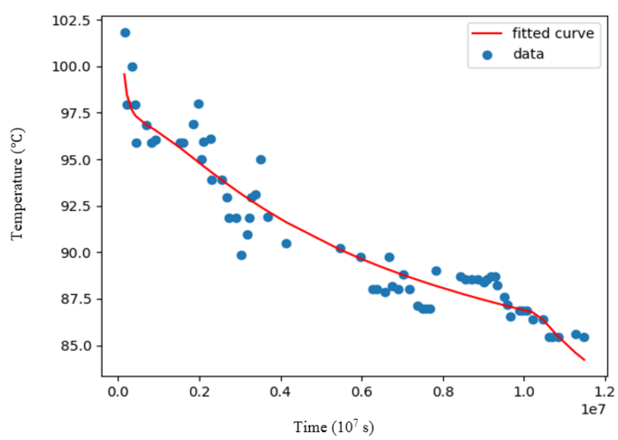


Figure 16: Curve fitting to thermal breakdown.

Furthermore, we did an interpretation of the simulation results as the exact shape of fracture model. The distance between well B4 and B9 was 114.3 m. Well B4 has a depth of 125 m, while well B9 injected water and tracer at 48-m deep. The exact distance between two well tips was 137.8 m. Let us assume the heat transfer area is simply a rectangular. The estimated surface area of the Balcova geothermal field is 35751.45 m^2. The area is a summation of the top and bottom wall of fracture. Area of single wall was the half from the estimation value. Thus, the width of fracture area can be calculated as below,

$$\mathrm{L} = \frac{1}{2}\frac{35751.45}{137.8} = 129.7\ m \qquad (7)$$

Because the one side of the rectangular was 137.8m from the distance between the wells, this value is reasonable. The dimension of heat transfer area can be fitted on reference map in Figure 12. Thus, the corresponding thermal breakdown solutions also fitted with the field data.

5. CONCLUSION

We have proposed a simplified approach of reservoir characterization by a flow path model. This approach can reduce computational cost and reduce uncertainty of distributed parameter models. We improved an ability of the model based on Shook and Suzuki (2017) by considering fluid leak-off from a reservoir during a flow test. The estimation method has been validated by using synthetic results of tracer and temperature data simulated from a numerical simulation. The results show a good agreement with thermal breakdown curve and a good accuracy of estimation of heat transfer area.

Application to real field data has been conducted. We estimated heat transfer area estimation of Balcova geothermal field in Turkey. Based on available field data, the estimated reservoir dimension was reasonable with the actual structure of the reservoir. In a next step, based on the successful estimation of the heat transfer area of a reservoir, we can build a future production plan for achieving sustainability of geothermal fluid production. The optimum reinjection conditions of the reservoir should be studied based on the developed flow path model.

ACKNOWLEDGEMENTS

This work was supported by the Japan Society for the Promotion of Science, under JSPS KAKENHI Grant Number JP17K19084, whose support is gratefully acknowledged."

REFERENCES

Aksoy, N., Serpen, U. & Filiz, Ș.: Management of the Balcova-Narlidere geothermal reservoir, Turkey. *Geothermics* **37,** (2008), 444-466.

Arason, P. and Bjornsson, G.: ICEBOX, 2nd edtion, *Orkustofnun*, Reykjavik, (1994).

Arkan, S. and Parlaktuna, M.: Resource Assessment of Balçova Geothermal Field. *Proc. World Geotherm. Congr. Anatalya, Turkey.* (2005), 24-29.

Axelsson, G., Bjomsson, G., Fldvenz, O.G., Kristmannsddttir, G. & Svemsddttir, G.: Injection experiments in low-temperature geothermal areas in Iceland. Proceedings of the World Geothermal Congress 1995, Florence, Italy, (1995)

Pruess, K., Oldenburg, C., & Moridis, G.: TOUGH2 User's Guide, Version 2.0. Earth Sciences Division, Lawrence Berkeley National Laboratory. University of California, Berkeley, CA. (1999).

Robinson, B. A. and Tester, J. W.: Dispersed fluid flow in fractured reservoirs: An analysis of tracer-determined residence time distributions. *J. Geophys. Res.* **89,** (1984), 10374-10384.

Robinson, B.A., Tester, J.W. & Brown, L.F.: Reservoir Sizing Using Inert and Chemically Reacting Tracers. United States: N. p., 1984. Web.

Shook, G. M. and Suzuki, A. Use of tracers and temperature to estimate fracture surface area for EGS reservoirs. *Geothermics* **67,** (2017), 40-47.