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A TRACER-BASED MODEL FOR HEAT TRANSFER IN A HOT DRY ROCK RESERVOIR

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ABSTRACT

A model for heat transfer in a Hot Dry Rock (HDR) geothermal reservoir is developed which predicts produced fluid thermal performance based on the tracer-determined residence time distribution and an estimated value of fracture porosity. The tracer response is modeled as flow through several paths of highly fractured rock. Fracture porosity is used to convert fluid volumes to rock volumes, which is necessary to model the heat sweep. The produced fluid response is the mixing cup average of the individual path temperatures. The model adequately represents the measured thermal response of an HDR reservoir operated at the Fenton Hill NM HDR geothermal site in the late 1970's. Application to the current Fenton Hill reservoir predicts a rapid initial thermal drawdown of about 50°C, followed by a very slow thermal decline thereafter. The model is most sensitive to fracture porosity, and less so to the flow path geometry used to match the tracer response.

INTRODUCTION

One of the primary goals of HDR geothermal reservoir modeling is to estimate the energy capacity of the underground fracture system. As the region of rock defined by the primary fluid flow paths is cooled, a thermal front progresses from the injection to the production wellbore. The thermal front is defined as the region over which the fluid temperature increases from its inlet value to the outlet value. When the thermal front reaches the production well, the produced fluid temperature begins to drop, and the temperature of the energy source declines.

In the small prototype reservoirs tested to date, less than one year has been required to observe production fluid temperature changes, making an energy extraction experiment a feasible technique for determining reservoir size. However, for commercial-sized systems requiring at least 5 years before thermal drawdown and 20 years before abandonment, reservoir modeling is required to predict the time of onset of thermal drawdown and subsequent rate of produced fluid temperature decline.

Several heat transfer models have been proposed to predict produced fluid thermal drawdown in HDR reservoirs. Models have been based on a single, or perhaps a few, widely spaced parallel fractures having uniform fracture spacing, aperture size, and flow distribution (Carslaw and Jaeger, 1973, Gringarten et al., 1975, Bodvarsson and Tsang, 1982, and Zyvolski, 1983). Another approach has considered the reservoir to be a packed bed of spheres (Kuo et al., 1977, Hunsbedt et al., 1978, and Iregui et al., 1978). The characteristic size of the rock through which fluid flows, and the nature of the flow passages, have a strong influence on the thermal and hydrodynamic performance of the HDR reservoir.

Typically, the length scale of the rock in the direction of fluid flow is much larger than its length scale in the direction normal to fluid flow. Thus, temperature gradients in the rock in the direction of fluid flow are negligibly small compared with those normal to it. If the length scale of the rock normal to fluid flow is small, there is negligible internal thermal resistance in the rock. Under this condition, at any location along the fluid-flow path, heat is transferred to the fluid at a temperature equal to the rock initial temperature until all of the accessible heat in the rock (referenced to the water inlet temperature) is extracted. When this occurs, the rock local temperature rapidly falls to the fluid inlet temperature (denoting the location of the thermal front) and the process repeats itself at a small distance downstream from that location.

Conversely, if the rock is thick in the direction normal to fluid flow, large temperature gradients in this direction cause a gradual decrease of rock temperature over time at any location along the flow path. Compared with the sharp thermal front that exists for the limiting case of thin rock, the thermal front for this case is smeared over space and time.

Figure 1 shows the behavior of the fluid temperature at fixed values of time as a function of position for the limiting cases of thin and thick rock, and for intermediate cases. The sharp thermal front for the case of thin rock is in stark contrast to the smeared thermal front for the thick rock. Consider two reservoirs having equal volumes; one consisting of a single layer of thick rock and the other of a number of layers of thin rock. The useful energy content of the reservoir composed of thin rock is greater than that for one having the thick rock since for thin rock all of the rock volume contributes to heat transfer in the fullest possible way.

Of course, to predict thermal behavior, the models described above require specific reservoir parameters such as surface area, fracture spacing, or rock volume. These parameters are usually difficult to determine. The current study examines a new approach to heat transfer modeling which incorporates tracer and other information into a model to predict reservoir thermal capacity.

MODEL DEVELOPMENT

The proposed model assumes multiple flow paths, each of which behaves as a highly fractured bed of rock. The flow paths have different sizes and flow rates adjusted to match the observed tracer response. The assumption of highly fractured rock or small length scales in the direction normal to fluid flow implies very efficient extraction of energy from an individual path. However, by splitting the flow into paths of different sizes and flow rates, the model captures the nonuniformity of flow through fractured rock commonly observed in tracer experiments in HDR systems. We call this heat transfer process volumetric heat extraction with channeling. Figure 2 represents the idealized energy extraction model of several flows paths of highly fractured rock connected in parallel.

To establish the limits of applicability of the volumetric energy extraction assumption, we must compare the time for thermal diffusion within a rock block with that required to sweep heat from the flow path. Consider flow of a fluid through a highly fractured bed of rock, each rock having a characteristic length scale of R which is half of the rock thickness. We write an energy balance at the interface between the rock and fluid by equating the rate of heat conducted from the rock to the rate of heat convected in the fluid in the direction of flow

$$k_r \left.\frac{\partial T_r}{\partial r}\right|_{\text{interface}} + (\rho c)_f \,\bar{u} b\, \frac{\partial T_f}{\partial y} = 0 \qquad (1)$$

Energy storage in the fluid is neglected because the fluid volume is much smaller than the rock volume. Nondimensionalizing the length scales and rearranging, we get

$$\frac{-\left.\partial T_r/\partial (r/R)\right|_{\text{interface}}}{\partial T_f/\partial (y/L)} = \frac{(\rho c)_f R \bar{u} b}{k_r L} \qquad (2)$$

Recognizing that $\bar{u}\, b = (Q/A_{ht})\, L$, we obtain

$$-\frac{\left.\partial T_r/\partial (r/R)\right|_{\text{interface}}}{\partial T_f/\partial (y/L)} = \frac{(\dot{m}c)_f}{K} = Bi_m \qquad (3)$$

where K is the internal thermal conductance in the rock, $k_r A_{ht}/R$. Eqn. (3) is the ratio of the characteristic time for heat to conduct (or diffuse) through a rock thickness R, to the characteristic time for a mass of fluid to convect heat from rock area A_{ht}. If the internal thermal conductance of the rock is large compared with the fluid capacity rate $(\dot{m}c)_f$, the ratio from Eqn. (3) is small and the rock temperature is spatially uniform in the direction normal to fluid flow for all values of time; i.e., $\partial T_r/\partial(r/R)\big|_{\text{interface}}$ is negligible.

Traditionally, this ratio is referred to as the Number of Transfer Units (or NTU) in heat-exchanger theory. Since Eqn. (3) characterizes the ability of the rock to transfer heat as a lumped thermal mass, we may alternatively consider it as a modified Biot number (Bi_m) where the usual convective conductance in the expression for Biot number has been replaced by the fluid capacity rate. For HDR reservoirs, a value for Bi_m of 0.01 and smaller produces a thermal front that spans less than 20 percent of the distance in the direction of fluid flow. For Q/A_{ht} of 5×10^{-9} m/s which is typical for HDR reservoirs, this condition is satisfied for fracture spacing of 3 m or less. Thus, the size of the parameter Bi_m alone determines the behavior of the thermal front with time and space as influenced by heat transfer from the rock.

Thermal Model: Within a single plug flow path, for low Bi_m heat transfer, the produced fluid will be at the initial rock temperature until all of the heat is swept from the path, after which the fluid outlet temperature equals the fluid inlet temperature. The time required for the thermal front to reach the outlet is calculated by equating the total extractible energy in the rock to the cumulative energy extracted by the fluid raising its temperature from T_i to T_o. For the rock:

$$E_r = (\rho c)_r V_r (T_o - T_i) \qquad (4)$$

and fluid:

$$E_f = (\dot{m}c)_f (T_o - T_i)\, t \qquad (5)$$

Combining Eqns. (5) and (6), the thermal breakthrough time t_b for the thermal front to reach the outlet is

$$t_b = (\rho c)_r V_r / (\dot{m}c)_f \qquad (6)$$

In reality, the heat sweep process from a volume of rock will not result in a perfect step function for the outlet temperature. Dispersion in the temperature field will occur due to temperature gradients in the rock (nonzero Bi_m), nonuniform flow, and irregular-shaped and different sized blocks. Levenspiel (1983) has attempted to quantify temperature-front spreading in a regenerative heat exchanger using a heat transfer analog of the one-dimensional convective-dispersion equation for tracer transport:

$$\frac{\partial T}{\partial t^*} = Pe_H^{-1} \frac{\partial^2 T}{\partial y^{*2}} - \frac{\partial T}{\partial y^*} \quad (7)$$

The difference in time and length scales in the HDR reservoir precludes the direct use of Levenspiel's analysis. Nonetheless, in the calculations presented below, Eqn. (7) is solved by finite differences to model the temperature field in each flow path. We choose values of Pe_H that produce smooth thermal drawdown curves of produced fluid. Future work will attempt to provide justification for this approach by developing a model for determining the shape of the individual drawdown curves based on block size and shape. However, we believe that the fundamental physics of heat extraction from a highly fractured bed of rock is adequately represented by Eqn. (7).

The final step in the thermal model is to form a flow-rate-weighted average of the thermal contributions of the individual flow paths, the mixing-cup outlet temperature.

$$T_m = \sum_{i=1}^{N} Q_i \, T_{e,i}/Q \quad (8)$$

We must have some means for setting values for the flow rates and rock volumes of individual flow paths. Next, we show how the reservoir tracer response and an estimate of mean fracture porosity provide a way to set these parameters.

Model for Tracer Response: Robinson and Tester (1984, 1986) have examined methods for using the response of an inert tracer for characterizing nonuniform flow in continuous flow systems. In the parallel plug flow reactor (PPFR) model, flow rates and fluid volumes for an arbitrary number of parallel flow paths are chosen to be consistent with the observed tracer residence time distribution (RTD). Mathematics can be developed for an infinitely large number of flow paths, and then generalized for a finite number. The first step is to normalize the tracer response using:

$$f(t) = QC(t)/m_p \quad (9)$$

in which f(t)dt is the fraction of fluid leaving the system with residence times between t and t + dt. For a large number of flow paths, the flow path of residence time t has a fluid flow rate of Qf(t)dt. The fluid volume is then Qtf(t)dt.

For modeling purposes, a finite number of paths must be chosen. To set flow rates and volumes, the tracer response curve is split into time intervals 0 to t_1, t_1 to t_2, t_2 to t_3, etc., and the flow rate and fluid volume are given by the following expressions:

$$Q_i = Q \int_{t_{i-1}}^{t_i} f(t)dt \quad (10)$$

$$V_i = Q \int_{t_{i-1}}^{t_i} tf(t)dt \quad (11)$$

To simplify the interpretation, the time intervals can be selected so that the flow rates or fluid volumes are identical in each path.

Estimation of Fracture Porosity: The final step in the model is to convert the fluid volume of a flow path V_i to a rock volume by dividing by porosity. In-situ methods, rather than experiments on cores, must be employed since not all fractures necessarily flow fluid. Various approaches for bounding the likely values for in-situ fracture porosity of HDR reservoirs are now described.

During hydraulic stimulation tests used to enhance the permeability of an HDR reservoir, microseismic events are located in space and time to determine where water is traveling. The volume of rock defined by the microearthquake boundary defines the effective reservoir rock volume stimulated. The net fluid volume injected divided by the rock volume which has been stimulated is one estimate of fracture porosity. This approximation is apt to underestimate porosity because it is a reservoir-wide average rather than that near the wellbores where more intense hydraulic stimulation, and therefore reservoir flow, takes place.

Perhaps a more accurate technique for estimating porosity is to use data from steady-state operation to obtain values for V_f, the fluid volume of connected fracture-flow paths and V_r, the rock volume containing those flow paths. Two method exist for estimating V_f. An interwell tracer experiment can be analyzed using the methods of Robinson and Tester (1984) to obtain the integral mean volume, which is the void volume of all fractures transmitting flow, regardless of permeability. A second technique is to assume that the total volume of fluid left downhole during a closed-loop flow test, commonly denoted as water loss, went simply into charging the reservoir void volume, and thus equals V_f. The latter estimate for V_f is likely to be an upper bound since some fluid is truly lost to far-field permeation.

Various techniques can be employed to estimate the rock volume V_r. The simplest is to assume that for a highly fractured medium the swept rock volume will be approximately a sphere of diameter equal to the separation distance of the injection and production points. Other estimation methods use reservoir compressibility arguments employing the following equation:

$$\beta = \Delta V/(V_r \Delta P) \quad (12)$$

When the reservoir is inflated, it has been raised from hydrostatic pressure to approximately its instantaneous shut-in pressure. The change in fluid volume ΔV accompanying this pressure rise is the cumulative water left in the formation, determined from the integral over time of the difference between injection and projection flow rates. Then V_r is calculated using a value of β appropriate for a rock mass at zero effective stress.

Another method can be used after the reservoir is depressurized. By pumping the injection well and monitoring the shut in production well, the reservoir pressure rise per unit increase in volume ($\Delta P/\Delta V$) is obtained. Then V_r is obtained from Eqn. (12). In this case the value used for reservoir compressibility β must be lower, since the system is deflated to low pressure and thus is at higher effective stress.

In summary, several methods for estimating V_f and V_r have been developed. When used consistently, they will provide a range of possible values for fracture porosity.

MODELING THE FENTON HILL PHASE I RESERVOIR

In the late 1970's, a prototype HDR reservoir was created and tested extensively at the Fenton Hill geothermal site (Dash et al., 1981). A validation test of the volumetric heat extraction model is its ability to simulate the produced fluid temperature behavior of this reservoir. The thermal response of this system was complex due to the history of operations performed. The first energy extraction experiment lasted for 75 days, resulting in a severe temperature depression in the facture system. The injection well was then repaired to eliminate flow behind the casing to achieve a greater separation distance between the inlet and outlet positions. The new reservoir had a deeper injection region but the same production zones, which remained cooled because of the earlier test. The new reservoir was tested for 286 days (Zyvoloski et al., 1981).

Based on the tracer response, a two-path model was selected with internal path fluid volume of 120 m^3, external path fluid volume of 1191 m^3, with each path accepting 50% of the flow. Because of the series of operations outlined above, the reservoir possessed a complex initial temperature profile. Figure 3 shows the assumed initial temperature profile of the small flow path, while the large path is assumed to be at the initial geothermal gradient, unaffected by previous energy heat extraction tests. The temperature profile was constrained in two ways. First, it is qualitatively consistent with a temperature log in the injection well, which passed through the active reservoir region and was used to monitor the reservoir temperature field. Second, the profile was selected to be consistent with the total energy extracted from the system in the previous operation. Having selected this profile, the only adjustable parameter is fracture porosity ϕ.

Figure 4 compares the model results and the produced fluid temperature measured downhole in a series of temperature logs for ϕ = 0.00029. The agreement is close because of the adjustability in the initial temperature profile. Nonetheless, the model accurately represents the observed temperature response as well as tracer and temperature log information. Figure 5 is a prediction of the produced temperature behavior had the test continued for 1500 days. Apparently the initial observed temperature drop was due to the initial temperature profile and not to temperature-front breakthrough from cold water injection. The true thermal front breakthrough is predicted to occur after about 700-1000 days.

APPLICATION TO THE CURRENT FENTON HILL RESERVOIR

In May and June of 1986, a 30-day closed-loop flow test of the current Fenton Hill HDR reservoir was carried out to measure flow parameters needed to design a long-term test of one year or longer (Hendron, 1987). This 30-day flow test was not long enough to achieve produced fluid thermal drawdown to verify the heat transfer model. Rather, in this section we use data from this flow test to predict the likely thermal behavior of the reservoir.

To justify the volumetric heat extraction model, we first calculate an average fracture spacing. For a network of cubic rock blocks separated by fractures, ϕ = 3b/s. Below we estimate fracture porosities on the order of 0.004. The pressure drop across the reservoir places an upper bound on the aperture of about 1 mm. This results in an average fracture spacing s of 0.75 m, which is small enough to justify the volumetric energy extraction model.

Figure 6 shows the normalized tracer response f(t) using radioactive isotope ^{82}Br. Techniques developed in Robinson and Tester (1986) have been used to extrapolate the tracer response curve to long times. The tracer curve is consistent with a combined model of channeling through smaller, short-residence-time paths and a large volume of rock containing low-permeability joints. Our base case for heat transfer modeling consists of six flow paths. The first five divide the measured portion of the curve into five paths of equal flow rate and different fluid volume to account for 30% of the flow, and the sixth is an extremely large path accepting the remaining 70% of the flow.

The porosity estimates are summarized in Tables 1 and 2. Table 1 lists the various methods for estimating V_f and V_r, while Table 2 shows the combinations of estimates used to calculate ϕ. Disregarding the estimate based on microseismic analysis which probably underestimates ϕ, the remaining values of porosity range from about 0.003 to 0.008. This range is quite narrow considering the diverse methods used to calculate ϕ.

Figure 7 shows the results from a simulation of produced fluid temperature versus time for the base case, assuming $Q = 0.0159\ m^3/s$ and $\phi = 0.004$. The first observed breakthrough of the thermal front occurs within the first 30 days, and the temperature declines gradually thereafter. The characteristic slope is due to the combination of rapid cooldown in channeling paths and slower drawdown in larger-volume paths. Also shown is an estimate based on a much simpler model assuming a single fracture. The single adjustable parameter of surface area is determined from a correlation of effective heat transfer surface area versus cumulative produced volume from the time of tracer injection to the peak tracer response. This model predicts a much slower thermal drawdown than the volumetric heat extraction model. Verification of the more appropriate estimate of reservoir capacity will take place when long-term energy extraction is carried out.

PARAMETER SENSITIVITY

The choice of parameter values and model geometry (number of paths, flow rates and volumes of each) will affect the results. Eqn. (6) shows a first order dependence on flow rate and rock volume. Thus, the conversion from fluid volume to rock volume using porosity is the most sentitive part of the model. An incorrect estimate of ϕ has a first order effect on the estimated thermal breakthrough time. Figure 8 shows the predicted thermal behavior for the complete range of porosity values estimated earlier. The less optimistic simulations for the three largest porosity values probably span the range of uncertainty in thermal performance.

The effect of model geometry on predicted thermal drawdown for the same values of Q and ϕ is shown in Figure 9. The simulations shown are: 1) the base case, 2) six paths with the first five of constant volume and varying flow rates and the sixth obtained from the tail of the tracer curve, and 3) two paths, one representing the measured portion of the tracer response, and the other representing the tail. The two six-path models give virtually indistinguishable drawdown curves, while the two-path model predicts a qualitatively similar result. The reason the model is so insensitive to geometry is that the flow rates and volumes are constrained by the tracer response, which prescribes the level of nonuniformity of flow and degree of channeling. Thus, when changing the number of paths, the flow rates and volumes are changed so as to preserve the essential features of the flow field and energy extraction process. Accurate estimation of porosity (and thus rock volume) and degree of channeling are far more important than the exact details of flow geometry within the rock volume.

LIMITATIONS OF THE MODEL

The success of the proposed model hinges on the accuracy of the low Biot number approximation and estimated value for porosity, and also spatial and temporal independence of porosity and temporal independence of reservoir rock volume. For rock thicknesses of 3 m and smaller and for fluid flow rates typical of those in HDR reservoirs, the approximation of low Biot number heat transfer is valid. For Biot numbers larger than 0.01, internal thermal resistance in the rock is important and a more sophisticated model than the one described here is needed. To accurately represent the entire possible range of Biot numbers, a heat transfer model that includes two-dimensional conduction in the rock is needed to quantify the extent of thermal-front smearing. The existence of inter-mixing among the fluid flow paths likewise produces smearing of the thermal front.

Transient effects such as reservoir growth due to fracture extension and thermal stress cracking are also not accounted for in the proposed model. Time-dependent porosity and reservoir rock volume can be included by performing several tracer tests over time, and shifting the flow rates and volumes of each path so as to be consistent with the tracer data. By using a suitable extrapolation technique, a conservative estimate of reservoir thermal performance for the lifetime of the reservoir can be estimated which accounts for both effects.

Implicit in the proposed model is the assumption of spatially independent porosity. In reality, different flow paths are likely to possess different porosities. However, porosity estimation techniques are not accurate enough to provide values as a function of residence time or flow path. To minimize this limitation, the conservative approach is to assume the highest likely value for porosity for the entire reservoir.

Finally, we re-emphasize the importance of accurately estimating porosity, which has a first order effect on thermal performance. Improvements to the techniques outlined in the present study for determining ϕ will add to the usefulness of the model.

CONCLUSIONS

1. A heat transfer model has been developed for HDR reservoirs which prescribes the degree of channeling based on the tracer response. The model is valid for fracture spacing of about 5 m or less.
2. The model accurately simulates the produced fluid temperature response of an HDR reservoir operated at the Fenton Hill, NM geothermal site in the late 1970's. The adjustable parameter used to achieve the fit is the fracture porosity. The initial temperature field was known qualitatively, but was also adjustable within prescribed limits.
3. Porosity estimates of the current reservoir at Fenton Hill range from 0.00048 to 0.0084, with a more realistic range of 0.0029 to 0.0084. These values, when applied to a tracer response curve for the reservoir, predict an initial drop in produced fluid temperature within 50-100 days, followed by a very gradual decline thereafter.

4. The most sensitive parameter in the model is fracture porosity ϕ. New field techniques for estimating ϕ would result in more accurate predictions of reservoir performance. The model is very insensitive to flow path geometry parameters such as the number of paths, and the flow fractions and fluid volumes of each path. This is because the method for setting the flow fractions and fluid volumes automatically prescribes the appropriate level of flow channeling, which is one of the most inportant factors governing the reservoir thermal performance.
5. The proposed model is currently being improved by: 1) including redistribution of flow as evidenced by changes in tracer residence time distribution, 2) incorporating a more realistic packed bed heat extraction model valid for a broad range of rock thicknesses, and 3) developing improved field techniques for estimating fracture porosity from data obtained during the upcoming long term flow test scheduled to last one year or more.

NOMENCLATURE

A_{ht} interfacial heat transfer area (m^2)
b fracture aperture (m)
Bi_m modified Biot number = $(\dot{m}c)_f/K$
c heat capacity (J/kg-K)
C concentration
E_f cumulative energy extracted by fluid (J)
E_r total extractible energy in the rock (J)
$f(t)$ residence time distribution (s^{-1})
k_r rock thermal conductivity (W/m-K)
L length of flow path (m)
$\dot{m}$ fluid mass flow rate (kg/s)
m_p mass of tracer injected (kg)
Pe_H heat transfer Peclet number
Q fluid volumetric flow rate (m^3/s)
Q_i fluid volumtric flow rate in path i (m^3/s)
r distance in rock (m)
s fracture spacing (m)
t time (s)
t_b thermal breakthrough time (s)
t^* dimensionless time = t/t_b
T temperature (K)
$T_{e,i}$ exit fluid temperature from path i (K)
T_f fluid temperature
T_i injection fluid temperature (K)
T_m mixing cup outlet fluid temperature (K)
T_o undisturbed initial rock temperature (K)
T_r rock temperature (K)
$\bar{u}$ average fluid velocity (m/s)
V fluid volume (m^3)
V_i fluid volume of path i (m^3)
y axial distance along flow path (m)
y^* dimensionless axial distance = y/L
ρ density (kg/m^3)

Subscripts

f fluid
r rock

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TABLE 1.

Estimates of Fluid Volume and Rock Volume for Fenton Hill Reservoir.

Fluid Volume

Method	Volume (m^3)	Comments
Injected volume during hydraulic fracturing	21600	Consistent only with microseismic rock volume
Tracer-Determined Fracture Volume	8440	Integral mean volume of curve in Fig. 6
Volume based on water inventory	12700	Based on integrated injection and production rates during flow test

Rock Volume

Method	Volume (m^3)	Comments
Microseismic Volume	4.5×10^7	House et al. (1985)
Steady State Compressibility Method	4.3×10^6	Using ΔP = 4200 psi, ΔV = 12700 m^3, $\beta = 7\times10^{-7}$ psi^{-1}
Pressure Buildup Method	2.1×10^6	Experiment performed on 12/5/86 assuming $\beta = 2\times10^{-7}$ psi^{-1}
Sphere of diameter defined by well-bore separation	1.0×10^6	diameter of 125 m

TABLE 2

Porosity Estimates for the Fenton Hill Reservoir

Method for Determining Fluid Volume	Method for Determining Rock Volume	ϕ
Injected Volume During Fracturing	Microseismic Cloud Volume	0.00048
Water Inventory	Steady State Compressibility	.0029
Tracer	Pressure Buildup	.004
Tracer	Spherical Model	.0084

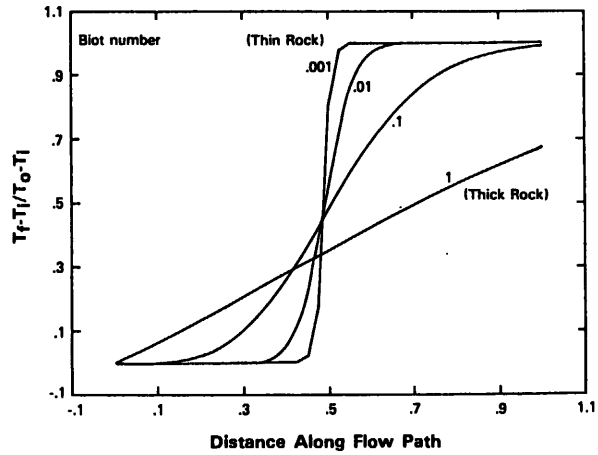

Figure 1. Fluid temperature profiles for different values of the Biot number including limiting cases of thin and thick rock.

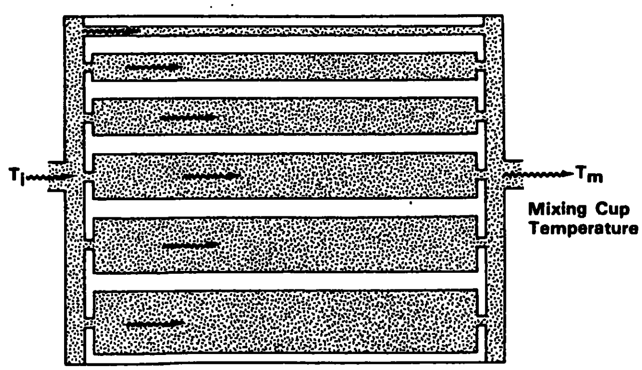

Figure 2. Schematic of the parallel path heat extraction model.

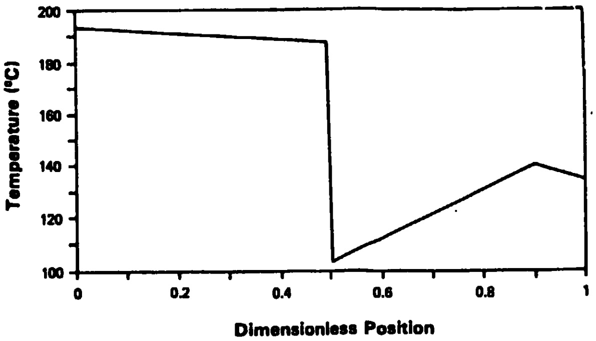

Figure 3. Assumed initial temperature profile for rock in the small flow path for the Fenton Hill Phase I Simulation.

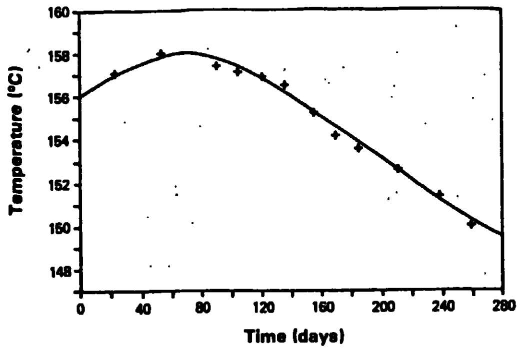

Figure 4. Comparison of results from model with measured production fluid temperature for the Fenton Hill Phase I simulation.

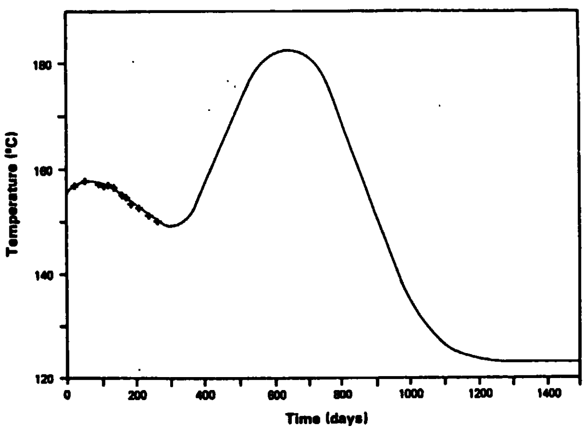

Figure 5. Projected production fluid temperature versus time for the Fenton Hill Phase I Reservoir.

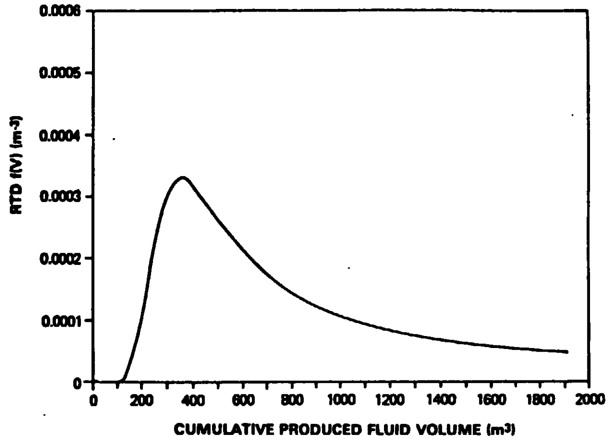

Figure 6. Measured residence time distribution versus cumulative produced fluid volume for the Fenton Hill Phase II reservoir.

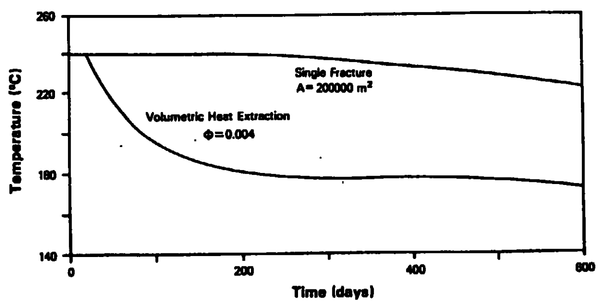

Figure 7. Predicted production fluid temperature versus time for the Phase II Reservoir: A comparison of the volumetric heat extraction model and the single-fracture heat transfer correlation.

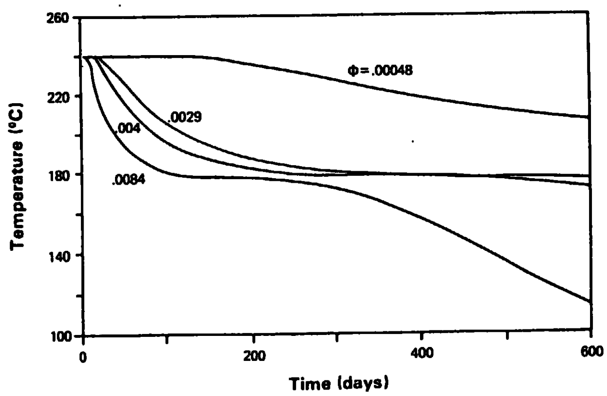

Figure 8. Prediction of production fluid temperature for different values of fracture porosity for the Phase II reservoir.

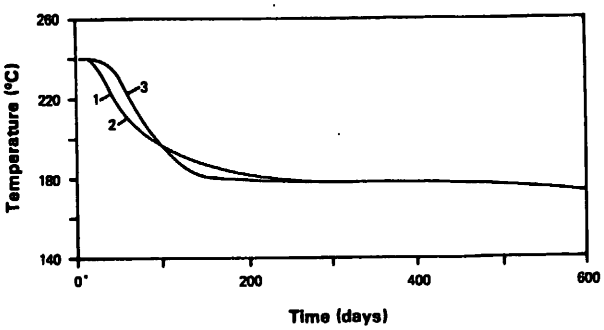

Figure 9. Comparison of predicted results for different assumed flow geometries. 1) 6 paths, the first five at constant flow rate, the sixth representing the tail of the distribution, 2) 6 paths, the first five of constant volume, the sixth representing the tail, and 3) 2 paths, the first representing the measured portion of the RTD and the second representing the tail.