LA-UR -92-1424

083--

LA-UR--92-1424

DE92 013427

TITLE **PRE-TEST ESTIMATES OF TEMPERATURE DECLINE FOR THE LANL FENTON HILL LONG-TERM FLOW TEST**

AUTHOR(S) **Bruce A. Robinson, EES-4**

Paul Kruger, Stanford University

SUBMITTED TO **Geothermal Resources Council**
1992 Annual Meeting
San Diego, CA
October 4-7, 1992

PRE-TEST ESTIMATES OF TEMPERATURE DECLINE FOR THE LANL FENTON HILL LONG-TERM FLOW TEST

Bruce A. Robinson
GeoEngineering Group
Earth and Environmental Sciences Division
Los Alamos National Laboratory

Paul Kruger
Heat Extraction Project
Stanford Geothermal Program
Stanford University

Abstract

Pre-test predictions for the Long-Term Flow Test (LTFT) of the experimental Hot Dry Rock (HDR) reservoir at Fenton Hill were made using two models. Both models are dependent on estimates of the "effective" reservoir volume accessed by the fluid and the mean fracture spacing (MFS) of major joints for fluid flow. The effective reservoir volume was estimated using a variety of techniques, and the range of values for the MFS was set through experience in modeling the thermal cooldown of other experimental HDR reservoirs. The two pre-test predictions for cooldown to 210 °C (a value taken to compare the models) from initial temperature of 240 °C are 6.1 and 10.7 years. Assuming that a minimum of 10 °C is required to provide an unequivocal indication of thermal cooldown, both models predict that the reservoir will not exhibit observable cooldown for at least two years.

Introduction

In anticipation of the initiation of the Long-Term Flow Test of the LANL Fenton Hill experimental HDR reservoir, it is desirable to consider the key aspects of the test and its relation to the future of HDR geothermal technology as a U.S. alternate energy resource. There are two major aspects with respect to the interpretation of the results of the LTFT. One involves the ability to understand the heat extraction conditions of the existing Fenton Hill HDR reservoir itself during the flow period of the LTFT, while the other involves the extrapolation of the results to conditions of other reservoirs. The estimates of temperature decline herein consider only the heat extraction conditions of the existing Fenton Hill reservoir and the anticipated production strategy for the LTFT.

Two key parameters for evaluating an HDR geothermal reservoir, on the basis of a classical mining operation, are the size (and heat content) of the reservoir and the potential rate of heat extraction. These parameters involve an estimate of (1) the volume of fractured-rock formation whose heat content is accessible for heat transfer to a circulating fluid, and (2) the distribution of fractures, which determines the fluid flow geometry and thus the rate with which thermal energy can be transferred to the circulating fluid. Estimates of the extractable energy from HDR resources requires realistic choice of these two parameters and solution of the heat transfer equations to estimate the rate of heat transfer and thus the expected fluid temperature decline curve to an abandonment temperature selected for the specific application (e.g., generation of electricity).

As a heat mining operation from an uncertain volume of fractured rock of uncertain temperature distribution, an estimate of the total energy resource is rather difficult. Several means have been considered to allow such estimates, including: (1) swept volume from the geometric arrangement of the two wellbores; (2) seismic volume attributed to the hydraulic stimulations that created the reservoir; (3) tracer fluid volume and estimated mean reservoir porosity; (4) fluid inflation volume from pre-LTFT pressure testing; and (5) thermal extraction analysis from other reservoirs. For heat extraction calculations, estimates of the Fenton Hill reservoir volume for the LTFT resulting from several methods described later range over a factor of ten, from 2.8 to 28 million cubic meters. For the test conditions of an estimated initial temperature of 240 °C to an abandonment temperature of 150 °C for the granitic rock with specific heat capacity of 954 J/kgK and rock density of 2700 kg/m^3, the reservoir volumes correspond to a resource heat content of 0.65 to 6.5 x 10^{18} J, a rather large value even for an experimental facility.

For a given production strategy (flowrate over a given time period) the actual amount of heat extracted from the reservoir depends on the flow geometry through the reservoir. The two extremes of heat extraction are: (1) homogeneous flow though distributed porosity around small rock particle sizes with rapid thermal equilibrium, resulting in effective heat extraction by the sweeping fluid; and (2) flow in one or more major fractures from the injection well to the production well with insufficient time to achieve thermal equilibrium between the large rock masses and the circulating fluid, resulting in rapid temperature decline of the produced fluid. The conditions of the actual, but uncertain, flow geometry is modeled by the mean fracture spacing (MFS). In one of the models presented below (the SGP model), for example, this parameter defines the radius of a mean spherical rock block for heat transfer.

To model the potential for produced fluid temperature decline over the period of the LTFT, a set of predictions have been prepared for a practical range of reservoir size and mean fracture spacing. The input data for the simulations were compiled from previous experience (e.g., Robinson and Kruger, 1988) and have been updated since, while the LTFT program was being formu lated. The set of input data used for the present simulations are listed in Table 1. Predictions were prepared for the range of reservoir sizes with mean fracture spacings of 20 to 160 m and for the range of anticipated flowrates from 3 bbl/min (unlikely to increase the size of the reservoir) to 7.5 bbl/min (likely to result in fracture extension and increased water consumption).

Table 1. Heat Extraction Parameters

I. Variable Parameters

A. Reservoir Dimensions

Volume (10^6 m^3)	Length (m)	Width(m)	Thickness (m)
2.8	150	78	239
5.3	185	97	295
6.45	134	129	373
16	267	140	428
28	323	168	516

B. Mean Fracture Spacing (m)

20	Large network of closely interconnected fractures
40	Mean value from prior Fenton Hill studies
80	Small network of main fluid-flow fractures
160	Few short-circuiting fractures

II. Constant Parameters

A. Reservoir Temperature (°C)

Mean Initial	240
Injection	50
Abandonment	150
Model Comparison	210

B. Reservoir Porosity ϕ 0.003

C. Production Flow Rate (kg/s)

Low reservoir growth	8
Onset of growth	12
Growing reservoir	16
Maximum attainable	20

D. Thermal Properties

	Rock	Fluid
Density (kg/m^3)	2700	862
Heat Capacity (J/kg K)	954	4190
Thermal conductivity (W/m-K)	2.7	---
Heat Trans. Coeff. (W/m^2-K)	1700	

Estimates of Accessible Rock Volume for Heat Extraction

The rock volume appropriate for heat transfer calculations must represent the effective volume from which heat will be extracted. The appropriate volume must account for the fact that not all rock stimulated during hydraulic fracturing is necessarily part of the swept volume when a flow field is established between the wells.

Several methods have been used to estimate the available heat-content rock volume for the LTFT reservoir. The results of the following methods are summarized in Table 2:

- rock volume estimate from simple geometric arguments related to the positions of wellbores (swept volume);
- determination of the volume of rock in which microseismic events occurred during the hydraulic stimulations that created the reservoir (microseismic rock volume);
- computation of the rock volume by dividing the tracer-determined fluid volume by an appropriate estimate of fracture porosity (tracer-determined rock volume);
- estimation based on hydraulic and mechanical considerations (hydro-mechanical rock volume);
- estimation from prior cooldown experience (cooldown-matching volume). This technique is the most reliable since it uses temperature decline data to size the reservoir. Of course, an estimate using this technique is not yet available for the Fenton Hill reservoir.

Table 2. Estimates of Reservoir Volume for the Fenton Hill HDR Reservoir

Method	Ref.	Test Conditions	Estimated Volume (10^6 m^3)	Basis
Swept volume	1	interwell dipole	2.9 5.3	Geometric flow arrangement around wellbore locations
Microseismic events	1	minimum 1σ estimate S-wave vel.	6.45 16 28	Envelope of hypocenters of seismic events
Tracer tests	2	$\phi = 10^{-4}$ $\phi = 0.003$	22 6.6	Measured tracer fluid volume and formation porosity
Pressure tests	3	bulk mod. of 55 GPa	16	Hydraulic stressing of the reservoir

1. Robinson and Fehler (1991)
2. Dash et al. (1989)
3. Brown (1991)

Swept Volume. The most conservative estimate of the effective rock volume swept by fluid is obtained from geometric spacing of the wells. This model assumes that when a flow field is set up between two wells, most of the circulating fluid travels directly between the wells, thus contacting only the rock in the vicinity of the two wellbores. For the LTFT, it was assumed that an appropriate geometry is a right-circular cylinder with diameter equal to the well separation distance. The height is taken to be the depth along the wellbores in which fluid is entering or leaving the well. The distance between wells in the depth intervals where fluid is entering and exiting the wells is approximately 110 m. From temperature log information, the reservoir height is approximately 300 m. These dimensions yield a swept rock volume of 2.9 x 10^6 m^3.

In reality, fluid is probably forced to sweep through a somewhat larger volume of rock. For example, in dipole flow, some fluid circulates in paths behind each well before reaching the production well. A more appropriate equivalent diameter for such flow was estimated as 150 m, resulting in a swept volume of 5.3 x 10^6 m^3.

Microseismic Rock Volume. The ensemble of microseismic event locations determined during hydraulic stimulation effectively outlines the region of rock in which the joints were stimulated. To estimate the stimulated rock volume using microseismic data, it was assumed that the reservoir is of ellipsoidal shape. These methods were employed to bound the microseismic rock volume estimate. The lower bound is obtained by taking only those events within the openhole regions of the injection and production wells. The resulting estimate is 6.5×10^6 m^3 (Fehler, pers. comm., June 18, 1990). For an ellipsoid encompassing 68% of all events, regardless of their locations (1σ estimate), the microseismic rock volume is 16×10^6 m^3. However, perhaps a more sophisticated technique is to determine, through inversion techniques that simultaneously determine the event locations and the shear wave velocity as a function of position, the volume of rock whose properties have been influenced by the hydraulic stimulation (Block, 1991). From the analysis of Robinson and Fehler (1991), the resulting estimate of rock volume is 28×10^6 m^3.

Tracer-Determined Rock Volume. Assuming steady-state fluid flow and a tracer that follows the same flow paths as the fluid, the total fluid volume V_f can be estimated from the first moment of the tracer-determined residence time distribution. Then, assuming an appropriate value for the porosity of the rock mass ϕ, the rock volume V_r is computed using $V_r=V_f/\phi$. The fluid volume determined from a tracer experiment during the Initial Closed Loop Flow Test (ICFT) was 2200 m^3 (Dash et al., 1989). For the porosity value of 0.003 given in Table 1 the corresponding tracer-determined volume would be 6.6×10^6 m^3, in good agreement with the minimum seismic estimate of 6.45×10^6 m^3. However, the estimate of porosity is itself uncertain, and has a linear effect on the rock volume estimate. Thus, for a porosity of 10^{-4}, assuming joints of 1 mm aperture with an average spacing of 10 m, the resulting tracer-determined rock volume is 22×10^6 m^3.

Hydro-Mechanical Rock Volume. In the pressure transient experiments prior to the LTFT (Brown, 1991), fluid was injected into the rock mass while monitoring the reservoir pressure at the shut-in production well. An estimate of the rock volume affected is given by $V_r=K\Delta V/\Delta P$, where K is the bulk modulus of the minerals, ΔV is the volume change, and ΔP is the corresponding pressure change. During the initial stages of this experiment, a change in reservoir pressure of 7.5 MPa resulted from the injection of 2715 m^3 of fluid. Assuming a bulk modulus of 55 GPa, the relation above results in a hydro-mechanical rock volume estimate of 20×10^6 m^3. Later in the experiment, pressurization from 15 to 19 MPa yielded a rock volume estimate of 16×10^6 m^3. This measurement is considered reliable since it was carried out at pressures closer to the reservoir pressure during circulation.

Matching of Observed Cooldown Data. An effective volume for heat extraction can be obtained from analysis of actual cooldown histories where injection-production flowrates have been measured during a sustained steady flow test. An example is the matching of the observed production fluid temperature during the 3-year flow test at the 2.5 km deep Rosemanowes HDR reservoir in Cornwall, England. For the mean flowrate of 14.5 kg/s over the test period and the regression slope of the cooldown curve of 0.146/yr (from data provided by Nicol, 1989), Kruger (1990) used the SGP model (described below) to match the cooldown curve for a reservoir volume of $3.25 (\pm 0.25) \times 10^6$ m^3 in comparison to the microseismic volume estimate of 5 to 10×10^6 m^3 reported by Parker (1989). Similarly, Nicol and Robinson (1990) obtained a match using a reservoir volume of 3.6×10^6 m^3 using the LANL model.

Summary of the SGP and LANL Heat Extraction Models

The two heat transfer models used for the cooldown predictions in this study, the Stanford Geothermal Program 1-dimensional linear heat sweep model (denoted by SGP) and the Los Alamos National Laboratory tracer-based heat transfer model (denoted by LANL), have been described previously, (e.g., Robinson and Kruger, 1988; Hunsbedt et al., 1983); and Robinson and Jones, 1987). Features of the two models are summarized below.

SGP Model. The SGP heat sweep model was developed to simulate heat extraction in fractured reservoirs with fluid reinjection or circulation as a one-dimensional heat extraction process. The model was initiated by Hunsbedt et al. (1978) based on heat transfer properties of regular-shaped rock blocks swept by circulating heat-carrier fluid. Kuo et al. (1977) showed from experimental observations that heat transfer properties of irregular-shaped rock blocks can be successfully approximated as spherical-shaped rocks of equivalent radius for which the heat transfer equations can be solved analytically (Carslaw and Jaeger, 1973). For a reservoir consisting of a wide range of block sizes, Hunsbedt et al. (1979) showed that the statistical distribution of sizes could be effectively modeled as a system with a single mean equivalent radius. The governing equations describing heat transfer from the equivalent spherical rocks are given in Hunsbedt et al. (1983). The solution for prescribed linear sweep boundaries and initial conditions is accomplished by converting them to Laplace transform equations with numerical inversion by the Stehfest (1970) algorithm. The two model parameters are the effective reservoir volume and the mean fracture spacing.

LANL Model. The LANL heat transfer model for two-well HDR reservoirs is based on the assumption that the process of heat extraction from a fixed volume of rock depends on the flow patterns established between the injection and production wellbores. The model uses the measured tracer response during circulation to approximate the extent of flow channelling between the wells, thus accounting for the effect of non-uniform flow on the heat extraction performance. It assumes that the reservoir can be modeled as a set of flow paths of different size and flowrate adjusted to match the observed tracer response. The thermal response of each path is calculated individually, then the composite outlet behavior is calculated as the flowrate weighted mean of the individual responses. Heat transfer within an individual flow path is calculated using a model that is fundamentally the same as the SGP heat extraction model, although the solution is obtained numerically using finite difference techniques to model the heat transfer within the rock. The same two adjustable parameters, the mean fracture spacing and the total rock volume, are present in the LANL model.

The key difference in the approach is that the LANL model incorporates information from tracer experiments into the model to characterize the degree of flow non-uniformity between the wells, whereas the SGP model relates the heat extraction to the number of heat transfer units (given by the ratio of the mean residence time of the fluid to the conduction time constant of the mean rock block) for uniform flow.

Comparison of Results

Table 3 lists a summary of the LANL model results, for the five estimated reservoir volumes, of cooldown times to the model-comparison temperature of 210 °C and the abandonment temperature of 150 °C as a function of mean fracture spacing at the anticipated steady flowrate of 8 kg/s (3 bbl/min) over the life of the test. Table 4 shows the same results for the SGP model. Tables 5 and 6 list the results for cooldown times for the range of steady circulation flowrates at an assumed mean fracture spacing of 40 m over the reservoir volume. Cooldown curves for the five estimated reservoir volumes by both models are shown in Figures 1 to 5. The cooldown curves for the range of flowrates are shown in Figure 6.

The data of Tables 3 and 4 show clearly for both models that cooldown to the comparison temperature of 210 °C at the flowrate of 8 kg/s is very much dependent on both the total 'heat-transfer-accessible' reservoir volume and the mean fracture spacing for fluid flow. For short-circuiting conditions (given by MFS = 160 m) the lifetime to the comparison temperature ranges from less than 4 days (LANL model) for a reservoir volume of 2.8 x 10^6 m^3 to 26 years (SGP model) for a reservoir volume 10 times as large. The spread in calculated cooldown times to the abandonment temperature T_a = 150 °C is not quite so large, ranging from 0.16 years (LANL model) for the smallest volume to 59 years (SGP model) for the reservoir 10 times as large.

The comparison also shows a major difference in the two models at early test times based on the model assumptions and formulation. A major aspect of the difference is attributed to the sweep flow geometry in the two models. In the LANL model, greater weighting is given to the short-circuiting flow paths which corresponds, for a given mean fracture spacing, to a larger reservoir volume compared to the SGP 1-D sweep model in which uniform-flow conditions are assumed over all fractures. For example, Table 4 shows a cooldown time to 210 °C of 8.31 years for a reservoir volume of 5.3 x 10^6 m^3 for the SGP model, which corresponds in Table 3 to a cooldown time of 8.76 years for a reservoir volume of 28 x 10^6 m^3 for the LANL model.

Discussion and Conclusions

The range of rock volumes and thermal cooldown times obtained using these various rock volume estimation techniques illustrates that we currently do not have a proven technique for estimating the rock volume accessible for heat transfer. Actually, the nature of the discrepancies are probably due in large part to the method of estimation, and are reasonable given our understanding of the physical processes involved. For example, the microseismic rock volume (1σ estimate) yields the largest volume estimate because the volume of rock affected in a high pressure stimulation is likely to be greater than the swept volume during circulation at lower pressure. In addition, estimation techniques such as the hydro mechanical rock volume method do not account for the fact that a non-uniform flow field will exist between the wells, resulting in an effective heat transfer rock volume that is smaller than this estimate. In the experiment used for the hydro mechanical method, the accessible rock is compressed uniformly, regardless of whether all flow paths contribute equally to the circulating flow system. As long as the paths

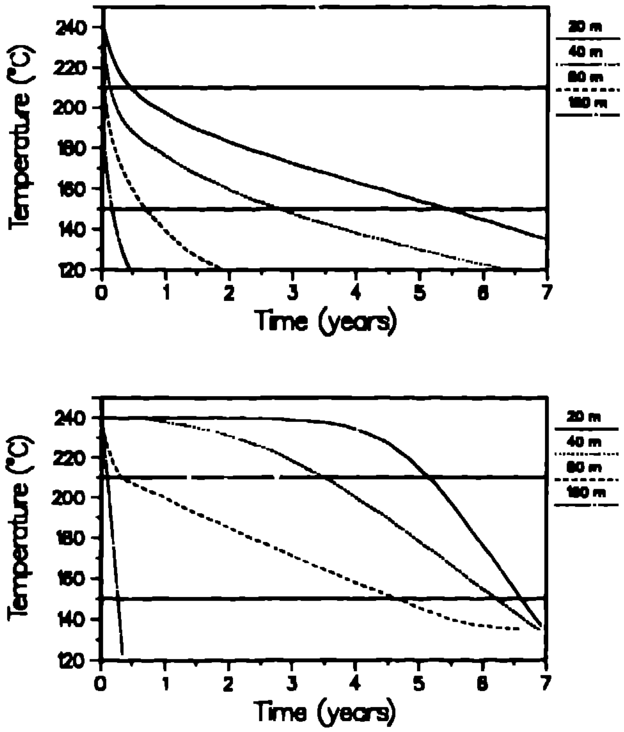

Figure 1. Predicted production well cooldown curves for various mean fracture spacings for a heat transfer rock volume of 2.8 x 10^6 m^3. Top figure - LANL model. Bottom figure - SGP model.

Table 3. Estimated Cooldown at 8 kg/s - LANL Model

Mean Fracture Spacing	Comparison Temp. (°C)	Time (years) to abandonment temperature for reservoir volume (10^6 m^3) 2.8	5.3	6.45	16	28
20	210	0.44	1.45	1.97	6.08	11.2
	150	5.45	11.7	14.8	42.4	78.6
40	210	0.11	0.41	0.60	3.61	8.76
	150	2.79	8.22	10.8	33.5	65.4
80	210	0.03	0.10	0.15	0.99	2.74
	150	0.68	2.49	3.70	21.2	48.2
160	210	0.01	0.02	0.04	0.26	0.66
	150	0.16	0.59	0.89	5.75	17.4

Table 4. LTFT Estimated Cooldown at 8 kg/s - SGP Model

Mean Fracture Spacing	Comparison Temp. (°C)	Time in years to abandonment temperature for reservoir volume (10^6 m^3) 2.8	5.3	6.45	16	28
20	210	5.14	10.4	12.9	33.3	58.6
	150	6.61	12.6	15.4	38.6	67.2
40	210	3.49	8.31	10.7	30.9	56.2
	150	6.21	12.2	15.0	38.2	66.9
80	210	0.34	3.87	5.70	23.2	47.2
	150	4.63	10.7	13.4	36.6	65.3
160	210	0.09	0.26	0.38	7.9	26.4
	150	0.27	3.44	6.63	30.3	59.0

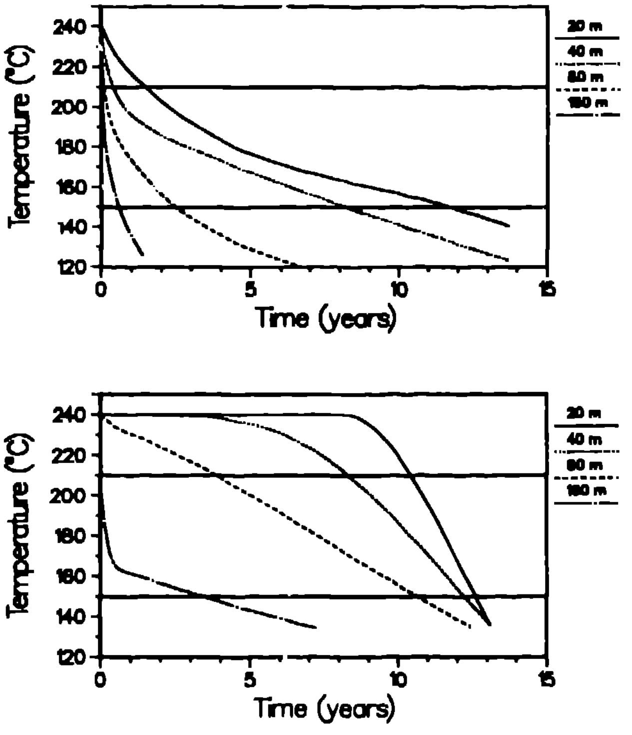

Figure 2. Predicted production well cooldown curves for various mean fracture spacings for a heat transfer rock volume of 5.3 x 10^6 m^3. Top figure - LANL model. Bottom figure - SGP model.

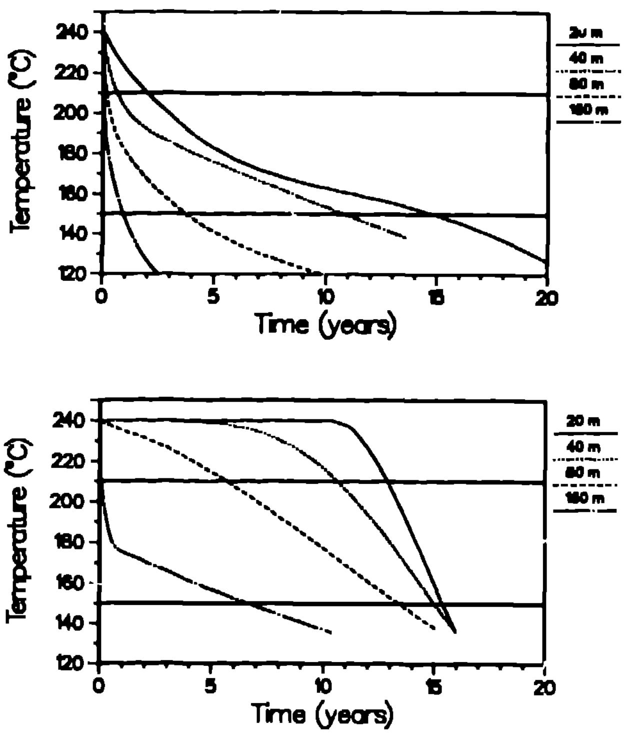

Figure 3. Predicted production well cooldown curves for various mean fracture spacings for a heat transfer rock volume of 6.45 x 10^6 m^3. Top figure - LANL model. Bottom figure - SGP model.

Table 5. Estimated Cooldown at MFS=40 m - LANL Model

Flow Rate (kg/s)	Comparison Temp. (°C)	Time in years to abandonment temperature for reservoir volume (10^6 m^3) 2.8	5.3	6.45	16	28
8	210	0.11	0.41	0.60	3.61	8.76
	150	2.79	8.22	10.8	33.5	65.4
12	210	0.05	0.18	0.26	1.59	4.60
	150	1.23	4.25	5.92	20.4	40.1
16	210	0.03	0.10	0.15	0.88	2.74
	150	0.69	2.47	3.59	14.2	28.4
20	210	0.02	0.06	0.10	0.58	1.75
	150	0.44	1.57	2.34	10.6	21.6

Table 6. Estimated Cooldown at MFS=40 m - SGP Model

Flow Rate (kg/s)	Comparison Temp. (°C)	Time in years to abandonment temperature for reservoir volume (10^6 m^3) 2.8	5.3	6.45	16	28
8	210	3.49	8.31	10.7	30.9	56.2
	150	6.21	12.2	15.0	38.2	66.9
12	210	1.85	4.86	6.34	19.6	36.4
	150	3.96	7.98	9.84	25.3	44.5
16	210	1.08	3.22	4.28	14.0	26.5
	150	2.84	5.85	7.24	18.9	33.2
20	210	0.66	2.27	3.09	10.6	20.6
	150	2.17	4.58	5.69	15.0	26.5

are physically connected to the well (directly or through other paths), the volume is included in the estimate.

The appropriate rock volume for a given reservoir thus depends on the assumptions in the heat transfer model. For the SGP heat sweep model, the heat transfer prediction based on a swept volume estimate of 6.45 x 10^6 m^3 is recommended because it is more likely to represent the effective, one-dimensional swept volume. By contrast, the LANL tracer-based heat transfer model implicitly accounts for flow non-uniformities. Thus the larger value of 16 x 10^6 m^3 (hydro-mechanical rock volume), the volume over which a hydraulic pressure response is transmitted, is more appropriate for the LANL heat transfer model. To reconcile the difference in these two volumes, another view of the fracture flow path distribution in the LANL model was considered. For the seven-flow-path model used, the sum of the rock volumes of the smallest six paths is 2.8 x 10^6 m^3. A total of 42% of the circulating fluid travels in these paths. Thus, there is a core inner region much smaller than the total volume of 16 x 10^6 m^3 in which a significant fraction of the fluid flows. An equivalent one dimensional uniform flow heat transfer volume can be obtained by normalizing each flow path volume by its fractional flow rate. The resulting equivalent heat content volume for uniform flow is 8.4 x 10^6 m^3, which agrees more closely with the value used in the SGP model (6.45 x 10^6 m^3). The value is also

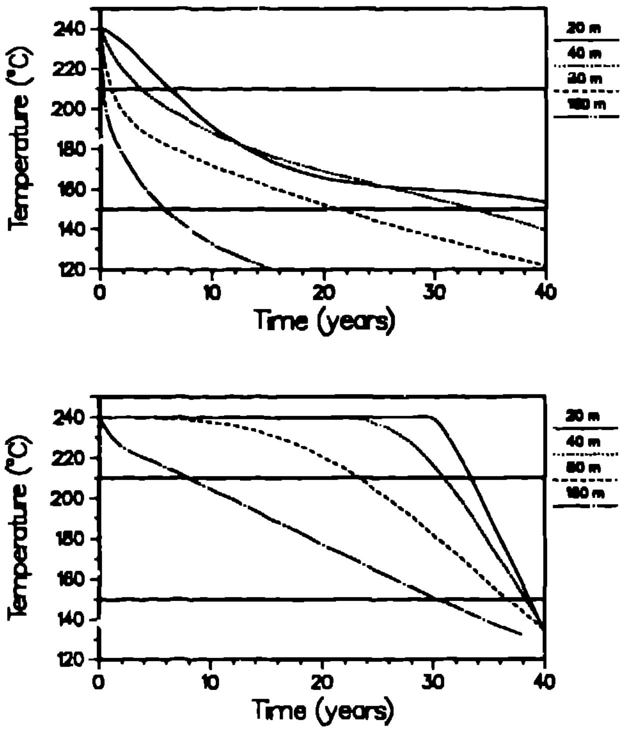

Figure 4. Predicted production well cooldown curves for various mean fracture spacings for a heat transfer rock volume of 16 x 10^6 m^3. Top figure - LANL model. Bottom figure - SGP model.

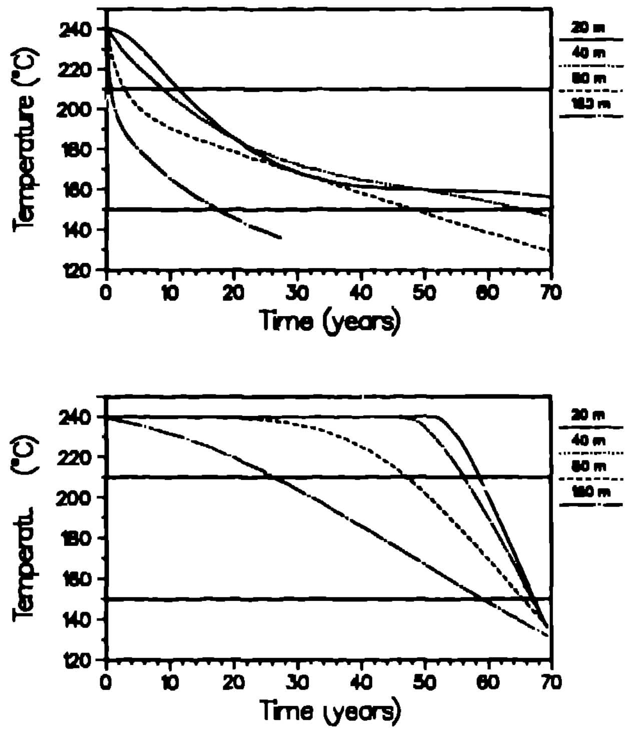

Figure 5. Predicted production well cooldown curves for various mean fracture spacings for a heat transfer rock volume of 28 x 10^6 m^3. Top figure - LANL model. Bottom figure - SGP model.

in agreement with the value of 5.3 x 10^6 m^3 from the dipole estimate of the swept volume and the tracer-determined volume of 6.6 x 10^6 m^3 for the selected porosity of 0.003. The other parameter in the model is the mean fracture spacing. For the SGP model, previous experience in simulating thermal cooldown behavior of the Rosemanowes reservoir (Kruger, 1990) suggests that a value of 40 m is appropriate for the LTFT, whereas Nicol and Robinson (1990) showed that a lower value of 15 m provided a good match to the data using the LANL tracer based model. As with the rock volume estimate, the appropriate mean fracture spacing to use seems to depend on the assumptions of the heat extraction model. This difference can be reconciled largely by the fact that the MFS in the SGP model is the radius of an equivalent sphere, whereas the LANL model employs a slab geometry with fractures of infinite extent in the third dimension. Thus the fracture spacing in the LANL model should be on the order of one-half the MFS of the SGP model for the two models to correspond.

On the basis of this correspondence, our best estimate for the thermal cooldown behavior of the Fenton Hill reservoir is based on a rock volume and mean fracture spacing of 6.45 x 10^6 m^3 and 40 m, respectively, for the SGP model, and 16 x 10^6 m^3 and 20 m, respectively, for the LANL model. Figure 7 shows the results of these predictions for the 8 kg/s flow rate. The general features of the predictions are similar, particularly in regards to the design and duration of a heat extraction experiment. Both models predict that several years will pass before significant thermal cooldown will be observed. *The pre-test predictions for cooldown to 210 °C resulting from this joint study are 6.1 years for the LANL model and 10.7 years for the SGP model.* Assuming that a minimum of 10 °C is required to provide an unequivocal indication of thermal cooldown, the conclusion is that the LTFT will not exhibit observable cooldown for at least two years. Cooldown occurs first in the LANL model, due to the more direct way in which channelling is simulated. However, both models predict that the resource will produce fluid at useful temperature for at least 10 years. The onset of thermal cooldown, though in itself not a desirable result, does not portend a rapid degradation of the quality of the resource. The reservoir appears to be large enough to support a long flow test in which heat can be mined for many years. Current plans call for the lowest flow rate in Tables 5 and 6 to be used. Even if higher flow rates and increased power production can be managed, the model results suggest that cooldown should be moderate in a 1 to 2 year flow test.

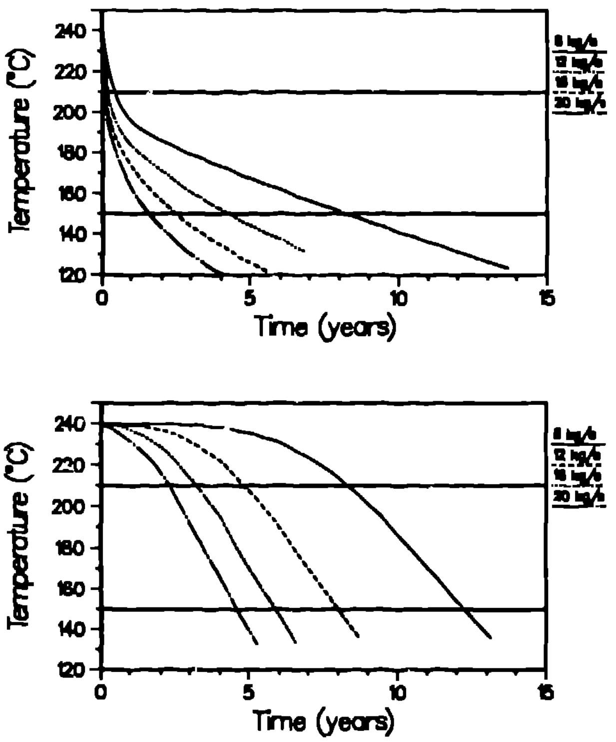

Figure 6. Predicted production well cooldown curves for various flow rates for MFS=40 m and heat transfer rock volume of 5.3×10^6 m^3. Top figure - LANL model. Bottom figure - SGP model.

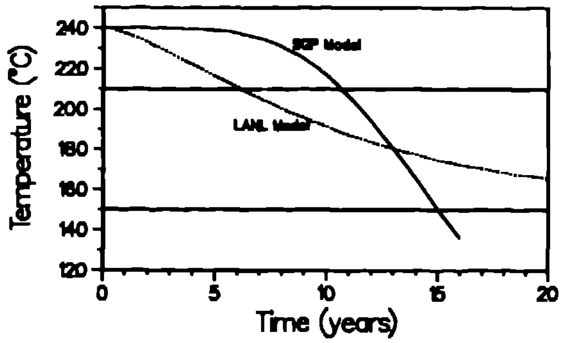

Figure 7. "Best estimate" of production well cooldown. LANL model - MFS=20 m and heat transfer rock volume of 16×10^6 m^3. SGP model - MFS=40 m and heat transfer rock volume of 6.45×10^6 m^3.

Acknowledgments

This work was performed under the auspices of the U. S. Department of Energy, Geothermal Technology Division. Discussions with Zora Dash, Jim Albright, and Mike Fehler are gratefully acknowledged.

References

Block, L. V., "Joint Hypocenter-Velocity Inversion of Local Earthquake Arrival Time Data in Two Geothermal Regions," Sc.D. Thesis, Massachusetts Institute of Technology, 1991.

Brown, D. W., "Recent Progress in HDR Reservoir Engineering," proc. Geothermal Program Review IX, 153-157, San Francisco, CA, March 19-21, 1991.

Carslaw, H. S., and J. C. Jaeger, *Conduction of Heat in Solids*, Second Edition, Oxford University Press, Glasgow, 1973.

Hunsbedt, A., P. Kruger, and A. L. London, "Energy Extraction from a Laboratory Model Fractured Geothermal Reservoir," *J. Pet. Tech.*, 30, 5, 712-718, 1978.

Hunsbedt, A., R. Iregui, P. Kruger, and A. L. London, "Energy Recovery from Fracture-simulated Geothermal Reservoirs," proc. ASME/AIChE Heat Transfer Conference, Paper 79-HT-92, 1979.

Hunsbedt, A., S. Lam, and P. Kruger, "User's Manual for the 1-D Linear Heat Sweep Model", Stanford Geothermal Program Technical Report SGP-TR-75, 1983.

Kuo, M. C. T., P. Kruger, and W. E. Brigham, "Shape-Factor Correlations for Transient Heat Conduction from Irregular-Shaped Rock Fragments to Surrounding Fluid," Proceedings, AIChE-ASME Heat Transfer Conference, Paper 77-HT-54, 1977.

Kruger, P., "Heat Extraction from Microseismic Estimated Geothermal Reservoir Volume," *Geoth. Res. Coun. Trans.*, 14, 1225-1232, 1990.

Nicol, D. A. C., and B. A. Robinson, "Modelling the Heat Extraction From the Rosemanowes HDR Reservoir," *Geothermics*, 19, 3, 247-257, 1990.

Parker, R., "Hot Dry Rock Geothermal Energy Research at the Camborne School of Mines," *Geoth. Res. Council Bull.*, 18, 3-7, 1989.

Robinson, B. A, and M. Fehler, Estimates of Rock Volume Suitable for Heat Transfer Calculations, LANL Memorandum EES-4-91-208, September 30, 1991.

Robinson, B. A., and G. E. Jones, "A Tracer Based Model for Heat Extraction in a Hot Dry Rock Reservoir," presented at Geothermal Resources Council Annual Meeting, Sparks, Nevada, 1987.

Robinson, B. A., and P. Kruger, "A Comparison of Two Heat Transfer Models for Estimating Thermal Drawdown in Hot Dry Rock Reservoirs", Proceedings, Thirteenth Workshop on Geothermal Reservoir Engineering, 113-120, January, 1988.

Stehfest, H., "Numerical Inversion of Laplace Transforms. Algorithm No. 368," *Comm. ACM*, 13, 1, 47-49, January, 1970.