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ENERGY EXTRACTION CHARACTERISTICS OF HOT DRY ROCK GEOTHERMAL SYSTEMS*

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Abstract

The LASL Hot Dry Rock Geothermal Energy Project is investigating methods to extract energy at useful temperatures and rates from naturally heated crustal rock in locations where the rock does not spontaneously yield natural steam or hot water at a rate sufficient to support commercial utilization. Several concepts are discussed for application to low and high permeability formations. The method being investigated first is intended for use in formations of low initial permeability. It involves producing a circulation system within the hot rock by hydraulic fracturing to create a large crack connecting two drilled holes, then operating the system as a closed pressurized-water heat-extraction loop. With the best input assumptions that present knowledge provides, the fluid-flow and heat-exchange calculations indicate that unpumped (buoyant) circulation through a large hydraulic fracture can maintain a commercially useful rate of heat extraction throughout a usefully long system life. With a power cycle designed for the temperature of the fluid produced, total capital investment and generating costs are estimated to be at least competitive with those of fossil-fuel-fired and nuclear electric plants. This paper discusses the potential of the hot dry rock resource, various heat extraction concepts, prediction of reservoir performance, and economic factors, and summarizes recent progress in the LASL field program.

RESOURCE POTENTIAL

An extraordinary combination of high rock temperature, a high geothermal temperature gradient, adequate matrix or fracture permeability, sufficient *in situ* water supply, and reasonable reservoir pressures is required for a natural hydrothermal resource to be practically if not economically feasible. Even with the intrinsically low probability that all these conditions will be met, the United States Geological Survey (USGS) [1] estimates that vapor and liquid dominated systems could be used to recover about 1.5 x 10^{21}J (1500 x 10^{15} BTU or 1500 quads) of energy as heat from hydrothermal reservoirs with initial temperatures above 150°C. Using the approach suggested by Diment, et al.[2] and McGetchin, et al.[3] one can expand the geothermal resource base to include hot dry rock (HDR) geothermal energy stored as heat in crustal rock hotter than 150°C beneath the United States (including Alaska and Hawaii) at depths less than 10 km. This amounts to 13,000 x 10^{21}J (13,000,000 quads) [3].

As McGetchin, et al.[3] point out, two general heat-source categories of HDR exist: (1) igneous-related crustal heat caused by magma bodies and (2) conductional heat from the deep interior of the earth. Smith and Shaw [4] estimate that molten and crystallized igneous systems to depths of 10 km in the conterminous U.S. contribute about 105 x 10^{21}J (105,000 quads) to the HDR resource base. McGetchin, et al.[3] estimate that 74 x 10^{21}J (74,000 quads) exist as heat in rock at temperatures over 150°C to depths of 10 km. The results of Diment, et al.[2] suggest that at least 5% of the total U.S. land area has underlying rock with geothermal gradients of 40°C/km or more. In a similar conservative approach, one could assume that over 33% of the U.S. land area is characterized by above average heat flow and gradients ranging from 30 to 36°C/km [5].

The HDR heat content estimates discussed above represent the resource base and not the amount of heat that can be recovered. If only a small fraction (~0.2%) of the available 13,000,000 quads of the HDR resource base is recoverable as heat, this would be comparable to the energy content of all the coal remaining in the U.S.

The useful heat contained in a HDR resource can be depicted on a graph of rock temperature versus depth. The case shown in Figure 1 is for a mean gradient of 30°C/km with utilizable temperatures taken above 100°C at 1.6 km to 220°C at 6 km (assumed maximum economically drillable depth) with a minimum fluid reinjection temperature of 60°C.

*Work done under the auspices of the U.S. Energy Research and Development Administration.

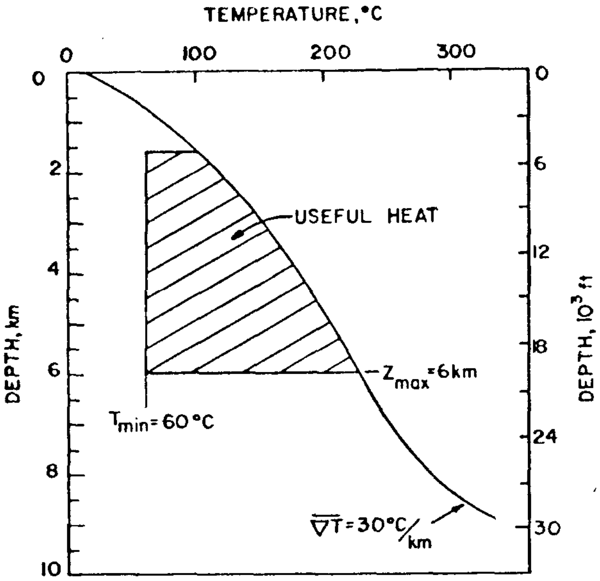

Figure 1. Generalized geothermal temperature gradient diagram for a 30°C/km HDR resource base. Cross-hatched area represents useful heat contained above 100°C to a depth of 6 km.

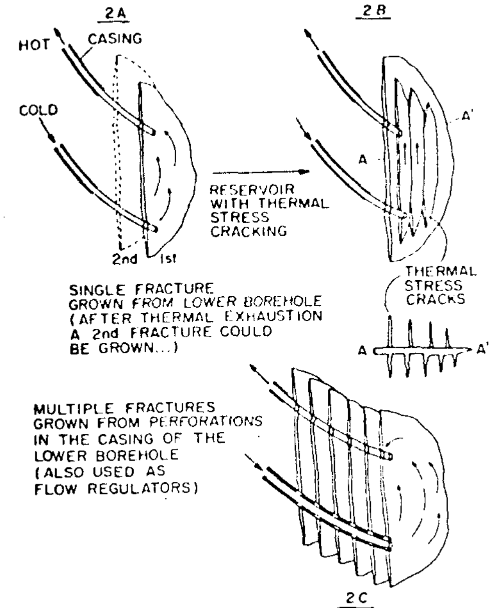

Figure 2. Single and multiple fracture concepts applicable to low permeability formations. Fracture planes divided at a vertical axis of symmetry.

ENERGY EXTRACTION CONCEPTS

Reasonable rates of energy extraction and sufficient reservoir lifetimes (~20 yr or greater) from HDR systems can be achieved using two fundamental approaches to mining the heat [6]. If in situ formation permeabilities are low then an artificial system must be created to expose a circulating heat transfer fluid (e.g. water) to hot rock by creating high conductance flow passages with a sufficiently large heat-transfer surface area. In this case, recovery of a large fraction of injected fluid may be achieved quite easily by taking advantage of natural containment provided by the low formation permeability. Extraction methods developed for these formations should also be directly applicable to the stimulation of some sub-economic hydrothermal systems. If permeabilities are high, the problem of circulating fluid is probably not as demanding as containment and recovery of the fluid and insuring uniform fluid contact with the hot rock surface. Approaches used for recovery of gas and oil by water-drive or flooding methods may be quite applicable [7]. Both production- and injection-well arrays would be required and arranged in a manner to minimize fluid loss to surrounding permeable formations at the perimeter of the developed field.

Figure 2 depicts several possible concepts for low permeability formations. These concepts are presently being investigated by the Los Alamos Scientific Laboratory (LASL) [6, 8]. In Figure 2A, the first concept is introduced. A single vertical hydraulic fracture is grown from one wellbore by fluid pressurization to create the required surface area for heat extraction. The downhole system is completed by directionally drilling a second wellbore to intersect the fracture plane with sufficient separation from the first wellbore to avoid flow short-circuiting. Pressurized fluid would then be circulated down one hole through the fractured region to remove energy from the rock, and recovered in a second hole connected to the surface where heat could be extracted. Because reservoirs of this type would most likely be formed at depths sufficient to insure that the least principal earth stress is in the horizontal plane, the hydraulic fracture should have a near vertical orientation; and assuming that the stress field is uniform and the physical strength properties of the formation are approximately isotropic and homogeneous, an ideal fracture of circular shape with elliptical cross section should be formed [6,8,10]. Fracture radii would be typically 100 m or greater with widths of a few millimeters in cross section. Because the inherently low thermal conductivity of the rock quickly controls the rate of heat transfer to the circulating fluid, large fracture surface areas are required. In order to optimize the performance of a reservoir of this type, fluid should contact as much of the fracture surface as possible, taking advantage of the natural buoyant effects between the cold and hot holes connected to the fracture. Fracture conductances or permeabilities for self- or pressure-propped fractures should be sufficiently high to permit buoyant circulation between the inlet and outlet points of the system. Furthermore, the total pressure drop through the entire surface and downhole heat extraction loop could be low enough for buoyant forces to "self-pump" the system.

If thermal exhaustion of the reservoir occurs because of its rock conduction-limited characteristic, remedial treatment to stimulate production is possible. By proper orientation of the boreholes in a parallel, inclined arrangement as shown in Figure 2A, additional fracturing might be used to provide new surface area in a hot region of rock. Sidetracking of the original wellbores to a new region and refracturing might also be an attractive method of re-stimulation. As suggested by Harlow and Pracht's early modeling [9] of HDR energy extraction, removal of heat from the vicinity of the fracture surface may introduce sufficient thermal contraction and induced stresses to cause additional cracking of the rock. If these thermal stress cracks propagate in such a way as to provide accessible flow channels for the circulating fluid, as shown in Figure 2B, the performance and lifetime of the reservoir will be substantially enhanced. Thermal stress cracking of this type increases the heat transfer efficiency by forming an extended surface penetrating into the hotter regions of the formation. As McFarland and Murphy [10] point out, even if thermal stress cracking does not occur, the thermal contraction of the rock will increase the fracture gap width, thus allowing buoyancy effects to sweep fluid more uniformly over the available fracture surface area.

Assuming that thermal stress cracking does not occur in the manner described by Harlow and Pracht [9] and that large stable fracture areas cannot be produced, multiple parallel fracturing from a pair of parallel inclined boreholes, as suggested by Raleigh, et al [11] and R. M. Potter of LASL and analyzed by Gringarten, et al. [12], may provide a tractable technique for generating sufficient surface area to maintain reservoir lifetime.

In addition to the two-spot, five-spot, and similar peripheral flooding techniques for water-drive in high permeability formations (see ref [7]), another concept might be able to provide good water recovery and maintain uniform contact between the circulating fluid and reservoir rock. Figure 3 shows a system consisting of three parallel fractures of similar area. The centrally located fracture serves as the fluid injection surface while the two outside fractures receive fluid by permeation through the rock. If near uniform plug flow can be maintained in such a system, reservoir lifetime will be determined by the heat content of the contained rock volume.

Additional discussion of anticipated performance and economics for the system described above is presented in later sections.

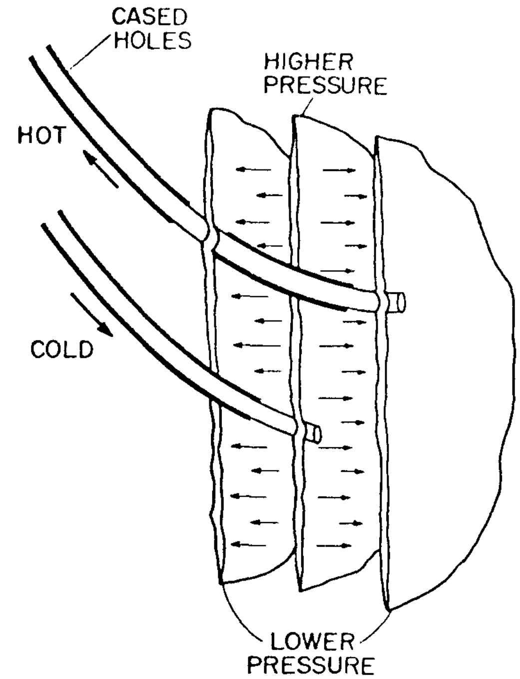

Figure 3. Double parallel fracture water drive concept for extraction of HDR energy applicable to high permeability formations. Fracture planes divided at a vertical axis of symmetry.

RESERVIOR PERFORMANCE

Single and Multiple Fracture Concepts - (low permeability formations)

The predicted lifetime and the rate at which energy can be extracted from a single fracture depend on several major factors [9,10,12]:

(1) thermal conductivity of the rock, λ_r

(2) accessible surface area of the fracture, A

(3) rate and distribution of fluid flowing across the fracture surface.

A simplified approach to estimating reservoir performance would assume that a certain fraction η of the recoverable power, corresponding to uniform flow across the face of the fracture, could be extracted. By following a procedure suggested by McFarland and Murphy [10] and analogous to the approach of Gringarten, et al. [12] for multiple parallel fractures, the recoverable power, P(t) in J/sec, for uniform flow can be expressed as:

$$P(t) = \eta \dot{m}_w C_w (T - T_{min}) \operatorname{erf}\left(\sqrt{\frac{(\lambda \rho C)_r}{t}} \frac{\pi R^2}{\dot{m}_w C_w}\right) \quad (1)$$

where:

- $A = \pi R^2$ = area of one face of the fracture, m^2
- C_w = heat capacity of water = 4200 J/kg K
- C_r = heat capacity of granite = 1000 J/kg K
- $\dot{m}_w$ = water flow rate through the fracture, kg/sec
- R = fracture radius, m
- t = time, sec
- T = mean rock temperature, °C
- T_{min} = fluid reinjection temperature, 60°C

λ_r : = thermal conductivity of granite, 3.0 W/mK

ρ_r = rock density, kg/m^3

McFarland and Murphy [10] compare P(t) to estimated values which account for non-uniform flow across the accessible fracture area. Fluid buoyancy and convection effects within an ideal fracture as well as transient conduction of heat through the surrounding rock are treated in a numerical solution of the four coupled two-dimensional non-linear partial differential equations describing continuity, fluid momentum, and rock and fluid energy balances. Depending on the location and separation of fluid injection and recovery points within the fracture and the internal fracture permeability (gap width versus radius), the recovered fraction of power η may vary from $\sim$0.4 to 0.9. When these conditions are fixed, Eq. (1) shows that P(t) depends directly on the error function of $\left[K \frac{R^2}{\dot{m}_w\sqrt{t}}\right]$ for constant rock and fluid properties where $K = \pi\sqrt{\frac{(\lambda\rho C)_r}{C_w^{\ 2}}}$. Consequently, reasonably accurate predictions of reservoir lifetime can be made for specified ideal fracture sizes and flow rates. Figure 4 presents parametric results for the power ratio (P(t)/P(t=o)) versus time t using different values of $\dot{m}_w/R^2$ to generate a family of curves for a granitic HDR reservoir.

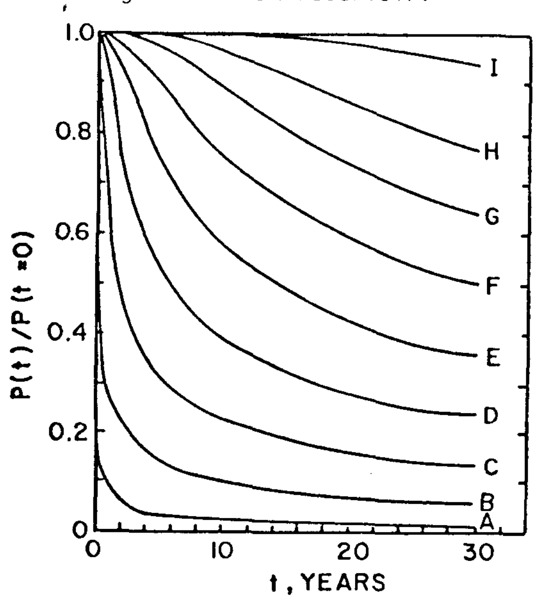

Figure 4. Parametric thermal power drawdown curves for a single fracture η = 0.9, T_{min} = 60°C

Legend	$\dot{m}_w/R^2$, kg/m^2-sec
A	5.0×10^{-3}
B	1.3×10^{-3}
C	5.6×10^{-4}
D	3.1×10^{-4}
E	2.0×10^{-4}
F	1.4×10^{-4}
G	1.0×10^{-4}
H	7.8×10^{-5}
I	5.0×10^{-5}

The quantity $\dot{m}_w/R^2$ reflects the mass flow capacity of the system for a given accessible fracture area. Gringarten, et al. [12] present elaborate power and temperature drawdown curves for multiple parallel fracture systems showing the effects of variable fracture number and spacing.

Neither the approach presented here nor the one presented by Gringarten, et al. [12] include any beneficial effects caused by thermal stress cracking. Harlow and Pracht [9], using a simplified model, were able to demonstrate that substantial enhancement of reservoir performance could be anticipated. The mechanisms associated with thermal stress cracking are extraordinarily complex and not well understood even under well-defined laboratory conditions. Consequently, LASL will use its field reservoir as a way of identifying *in situ* thermal stress effects. It is important to emphasize that economically acceptable rates of energy extraction ($\geq$50 kg/sec per pair of wells) and reservoir lifetimes ($\geq$20 yr) may be achieved by either growing large fractures (R $\sim$ 1000 m), using smaller multiple parallel fractures, or by remedial refracturing to generate new surface area.

Water-drive Concepts (high permeability formations)

Fluid flow distribution and rate through the rock matrix, the amount of accessible fracture surface area, and the formation permeability are the major factors in controlling the performance of water-drive systems like the double parallel fracture system described in Figure 3. Assuming plug flow and good heat transfer contact between fluid and the matrix contained by the parallel fracture set, the mean lifetime $\bar{\tau}$ of the system can be estimated from an energy balance:

$$\bar{\tau} = \frac{C_r AL\ \rho_r(1-\theta)}{\dot{m}_w C_w} \qquad (2)$$

where

L = spacing between outer fractures, m
θ = porosity
with the remaining terms defined by Eq. (1).

Because the double parallel fracture system relies on direct contact with the matrix to extract heat, substantial amounts of rock surface are exposed to circulating fluid creating an ideal situation for *in situ* solution mining if there are any elements contained in the reservoir that might be economically recovered. The permeability also is important because by Darcy's law it relates $\dot{m}_w$, A, and L for a given pressure drop and viscosity:

$$\Delta P = \frac{\mu}{2\bar{k}}\frac{\dot{q}L}{A} \qquad (3)$$

where

$\bar{k}$ = mean permeability, m^2 or darcies
μ = fluid viscosity, Pa-sec
ΔP = pressure drop between injection and recovery fractures, Pa
$\dot{q}$ = volumetric flow rate = $\dot{m}_w/\rho_w$, m^3/sec
ρ_w = fluid density, kg/m^3

Pumping power will depend directly on $\dot{q}\Delta P$; consequently an optimum relationship between A and L will result depending on $\bar{k}$ and prevailing economic conditions. An upper limit for ΔP is fixed by the difference between the formation breakdown pressure and the ambient pore pressure. Fracture area might also have a practical upper limit specified by in situ stress and geologic conditions (e.g. contacts). If $\bar{k}$ is low, large areas and small separation distances would be desirable to reduce pumping power. If $\bar{k}$ is large, smaller areas and larger separation distances would be acceptable.

LASL FIELD PROGRAM

At the Fenton Hill site, about 32 km (20 mi) west of Los Alamos, the conceptual heat extraction system shown schematically in Figure 2 is now being investigated in low permeability, Precambrian crystalline rock underlying the Jemez Plateau of Northern New Mexico. Initial efforts have been directed toward the two-borehole single-fracture concept. The first 24.5 cm (9-5/8 in) diameter borehole (GT-2) was drilled to a final depth of 2930 m (9610 ft), where the rock temperature was 197°C, and was used for a long series of hydraulic-fracturing, crack-extension, pressurization, and fluid-loss studies. It was determined that a surface pumping pressure of the order of 120 bars (1750 psi) was sufficient to fracture the rock, that the fractures produced were substantially vertical, and that the overall permeability of the rock was low enough (less than one microdarcy at hydrostatic pressure) to contain pressurized water with acceptably low permeation losses [8].

After one of the fractures in GT-2 had been extended to a calculated radius of about 120 m (400 ft), a second 24.5 cm (9-5/8 in) diameter hole (EE-1) was drilled directionally in an attempt to intersect the fracture. Because of uncertainties concerning the azimuthal orientation and vertical height of the fracture and in the hole surveys made during drilling, this intersection did not occur. After EE-1 had been drilled to a final depth of 3064 m (10,053 ft), where the rock temperature was 206°C, another hydraulic fracture was made from it, at a surface pumping pressure of 165 bars (2400 psi). This did produce a connection to GT-2, creating a continuous flow loop through the two wellbores and a connected system of hydraulic fractures.

Investigation of the pressure-flow behavior of the connected EE-1/GT-2 system under transient and steady state conditions continued along with the development of downhole instruments and techniques (including temperature, acoustic, and tracer concentration measurements) for determining borehole and fracture geometry [6,8,13]. Data obtained from the mapping and pressurization experiments suggest that the hydraulic fractures leaving EE-1 and GT-2 are nearly vertical and essentially parallel but separated by $\sim$10 m of biotite granodiorite without any direct fracture intersection. The nature of the flow path through the rock separating the two major fractures is still being investigated, but its flow behavior has been adequately modeled by Fisher [13] assuming a pressure-dependent permeating system of secondary microfractures spaced 1 to 10 m apart contained between the major fracture features [13]. The main hydraulic fractures appear to be self-propped and maintain high fracture conductances even at pressures well below the minimum earth stress. Thus with a direct connection to the fracture with two wellbores, buoyant circulation should be possible. Consequently, the high pressure drop per unit flow rate (impedance) of $\sim$1.1 x 10^4 MPa-sec/m^3 (100 psi/gpm) that characterizes the present EE-1/GT-2 system resides primarily in the overlapped rock region contained between the vertical, parallel fractures of GT-2 and EE-1. Of the total impedance, only about 0.055 x 10^4 MPa-sec/m^3 (5 psi/gpm) can be attributed to the combined total wellbore-to-fracture pressure drop.

To avoid an unstable situation where either of the hydraulic fractures extends without limit, the surface pressure of injected water must be kept below about 9.4 MPa (1360 psi). An impedance of 1.1 x 10^4 MPa-sec/m^3 (100 psi/gpm) therefore limits the flow rate to something less than 1 x 10^{-3} m^3/sec (15 gpm), well below the nominal 2 x 10^{-2} m^3/sec (300 gpm) required to operate a 10 MW(t) heat extraction experiment.

At this point, several alternative methods were considered to reduce the flow impedance:

1. Additional fracture extension or growth to increase the overlapped area.
2. Selective dissolution of quartz from the rock matrix contained between the fractures.
3. Redrilling (sidetracking) one hole to directly intersect the fracture originating from the other hole.

Although fracture extension in EE-1 has been achieved with little or no difficulty in our field experiments and in fact decreased the impedance to 0.83 x 10^4 MPa-sec/m^3 (75 psi/gpm), massive extension of the EE-1 fracture system did not reduce the impedance to the value of 5.5 x 10^2 MPa-sec/m^3 (5 psi/gpm) or less required for a 10 MW(t) heat extraction rate. Additional extension of the GT-2 fracture system finally became impossible because of an annulus leak that developed around the tubing used to pressurize the hole.

The use of chemicals to selectively dissolve rock in fractured oil or gas reservoirs to increase formation permeability or conductance is in practice today. In particular, acid treatment of carbonate formations is commonly used to increase oil and gas production. In an analogous fashion, the selective dissolution of quartz (SiO_2) was thought to be an effective method for decreasing the high flow impedance that presently characterizes the EE-1/GT-2 fracture system. Laboratory experiments conducted during the past year at LASL have demonstrated that dilute aqueous solutions (0.1 to 4.0 N) of sodium carbonate (Na_2CO_3) react with EE-1/GT-2 core specimens to dissolve SiO_2 primarily by attacking the quartz component of the granite [14].

The reaction is sufficiently irreversible to result in essentially stoichiometric conversion of crystalline silica ($SiO_{2(c)}$) into a soluble form. Na_2CO_3 acts to buffer the solution into the moderately basic region (∿pH=10) and thus provides an active source of hydroxide ions (OH^-) which can react with dissolved silicic acid $Si(OH)_4$ to form soluble metasilicates, thus increasing the effective solubility of silica.

$$CO_3^{2-} + H_2O = HCO_3^- + OH^- \quad (4)$$

$$SiO_{2(c)} + 2H_2O + nOH^- = Si(OH)_{4+n}^{-n} \quad (5)$$

In order to optimize the design of a field experiment for carbonate leaching, a series of laboratory tests was performed to collect data on the reaction kinetics of Na_2CO_3 solutions on granite and on the fluid flow characteristics expected in the reservoir. In effect, we would like to control the location and extent of silica dissolution in the system. Reaction kinetic data tells us how fast silica dissolves as a function of time, and fluid-residence-time data collected in the EE-1/GT-2 reservoir tells us how long the reacting fluid will be exposed to the reservoir rock. By combining this information we can select solution concentration and volumes for specified flow rates to insure that the carbonate will not be expended before it reaches the zone of high impedance.

Based on laboratory reaction rate measurements [14], a composition of 1-Normal Na_2CO_3 was selected for the field test. To evaluate precisely the condition of the fracture system before leaching was attempted, approximately 1000 m^3 (275,000 gal) of water were pumped through it and a residence-time-distribution study was made by injecting a pulse of sodium-fluorescein dye into EE-1, and monitoring its appearance at the GT-2 wellhead as a function of time and throughput volume. Then 190 m^3 (50,000 gal) of 1N Na_2CO_3 solution--about 5 fracture-volumes--were pumped through in a 25-hour period at a constant pumping pressure of 83 bars (1200 psi). Finally the system was thoroughly flushed with water and the dye-injection residence-time study was repeated. As was expected, at least 1000 kg (1 ton) of silica was dissolved and removed with no significant effect on system volume or residence time of the fluid. Unexpectedly, however, instead of reducing flow impedance this chemical treatment increased it slightly, from about 0.83 x 10^4 MPa-sec/m^3 (75 psi/gpm) during pre-leach circulation to about 1.0 to 1.1 x 10^4 MPa-sec/m^3 (90 to 100 psi/gpm) during post-leach flushing. Since these measurements were made at pressures too low to inflate the fractures, one possible explanation is that their self-propping is primarily by quartz grains which, being stressed, were sufficiently attacked to permit partial closure of the fractures. Another, since there was considerable attack of the cement behind the EE-1 casing, is that the fractures were partially plugged by residual fines from the cement. Plugging by mineral alteration is a third possibility, although this did not occur during leaching and permeability experiments on core samples in the laboratory.

In any case, the chemical dissolution attempt was unsuccessful. It is of course possible that additional leaching with sodium carbonate would eventually result in substantial increases in matrix permeability, and another possibility is acid treatment to dissolve the calcite which is the major secondary mineral that fills and seals old fractures in the crystalline rock. However, as a result of successful development of more sophisticated downhole instruments and wellbore- and fracture-mapping techniques, it is felt that the geometry of the underground circulation loop is now reasonably well understood. Accordingly, instead of attempting additional chemical treatments, the next effort to improve it will be re-drilling to create the single fracture system geometry shown in Figure 2.

Directional re-drilling is now in progress at Fenton Hill, from near the bottom of hole GT-2. The drilling target is the hydraulic fracture originating in EE-1, at a point about 100 m (300 ft) above that at which the fracture leaves the inclined EE-1 borehole. If this target is reached and the anticipated impedance reduction results, a surface air-cooled heat exchanger with 20 MW(t) capacity will be assembled and operated for several months in order to investigate the thermal, chemical, and mechanical behavior of the entire system, in particular to study how thermal stress cracking and geochemical effects influence the performance of the reservoir.

ECONOMICS

Hot dry rock systems share similar requirements with hydrothermal systems in order to attain economic feasibility. Installed electrical generating costs will depend on geothermal well, fluid pumping and equipment costs associated with the surface conversion plant [5]. Well and pumping costs will be controlled by the characteristics of the reservoir; namely its:

(1) fluid-flow capacity or productivity, $\dot{m}_w$
(2) depth from surface, Z
(3) fluid composition
(4) pressure losses
(5) lifetime.

All of the above have inherent uncertainties because the detailed character of the reservoir is frequently unknown. This makes reservoir cost estimation difficult and subject to error. Surface equipment costs, although easier to estimate, may be strongly dependent on fluid composition and therefore are also somewhat uncertain, for example, if serious scaling or corrosion problems exist. For preliminary economic assessments, Milora and Tester [5] have developed a simplified approach based on detailed analyses of several geothermal reservoir and power plant types. The total installed generating cost, including drilling and equipment related costs, is expressed as a function of geothermal fluid temperature (T_{gf}), geothermal gradient (∇T), and reservoir capacity given by well flow rate ($\dot{m}_w$). The model assumes a two-hole circulating HDR system.

Well costs as shown by Milora and Tester [5] could be represented as an exponential function of depth. Given the mean geothermal gradient, depth can be specified by T_{gf}. Equipment costs for a cost-optimized binary-fluid conversion cycle in \$/kW were expressed as a linearly decreasing function of T_{gf} in the range from 100 to 300°C. This is primarily due to increased cycle efficiency as T_{gf} increases thereby decreasing heat exchange requirements. Assuming that an appropriate working fluid can be found in this temperature range to provide a utilization efficiency (η_u) of at least 60%, required total flow rates per kW ($\dot{m}/P$, kg/sec-kW) can be estimated from the following equation:

$$\frac{\dot{m}}{P} = \frac{1}{\eta_u \Delta B} = \frac{1000}{\eta_u C_w}\left[T_{gf} - T_o - T_o \ell n\left(T_{gf}/T_o\right)\right]^{-1} \qquad (6)$$

where T_o = minimum heat rejection temperature
ΔB = availability, J/kg K or W-sec/kg K
and all temperatures are expressed in degrees K.

For a given T_o, η_u, ∇T, T_{gf}, and $\dot{m}_w$, total generating cost (C) can be estimated using the set of generalized equations from Milora and Tester [5] if a uniform reservoir productivity is assumed for 20 years under self-pumped (buoyant-circulation) conditions. Uniform productivity could be obtained by large fractures, multiple smaller fractures, thermal stress cracking enhancement, and/or remedial refracturing. To express the total generating cost in ¢/kWh, additional assumptions are required. These include an 85% (7446 h/yr) load factor, 17% annual fixed-charge rate, and 0.13 ¢/kWh added to cover annual operating and maintenance costs. Furthermore, equipment costs are assumed not to decrease beyond 300°C because anticipated difficulties with scaling in the primary heat exchanger (caused by a higher concentration of dissolved silica and other materials) will offset the benefits of higher cycle efficiency.

Figures 5 and 6 show the optimum reservoir conditions, well depth, and temperature for a specified geothermal gradient with η_u=0.60 and T_o=26.7°C. In Figure 5, optimum temperatures and depths correspond to a minimum in the total generating cost as a function of T_{gf} and ∇T for a fixed $\dot{m}_w$ of 50 kg/sec. These optima represent a trade-off between well and equipment costs. At a fixed gradient, increasing temperature by drilling deeper increases cycle efficiency and ΔB in Eq. (6); therefore $\dot{m}/P$ decreases and fewer wells are required. In addition, up to 300°C equipment costs would decrease. However increasing temperature by drilling deeper increases the cost per well. The optimum or minimum generating cost will then occur where there is a balance among fewer, more expensive wells and less expensive equipment.

As seen in Figure 6, for gradients below 40°C/km and flow rates ranging from 10 to 200 kg/sec, total costs are controlled by well costs. At higher gradients and flow rates above 20 kg/sec, equipment costs dominate. Above gradients of 50°C/km, costs below 4¢/kWh are achieved for well flow rates equal to or greater than 50 kg/sec. With proper design of a HDR reservoir, well flow rates of 100 kg/sec

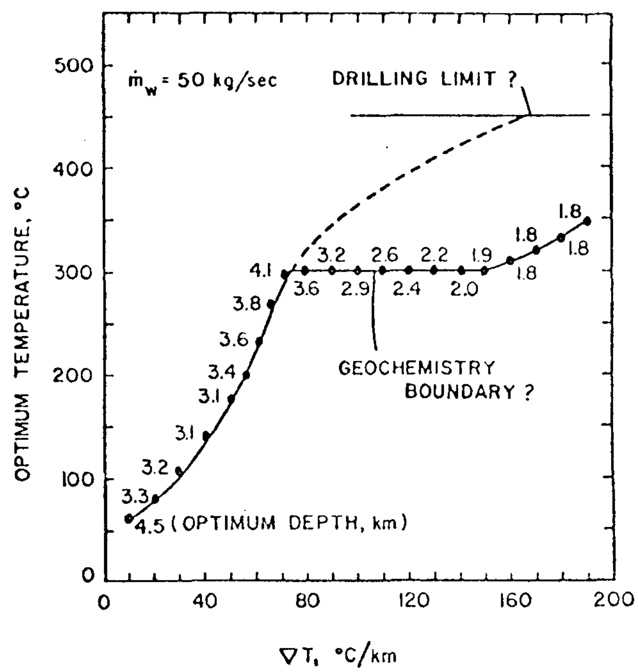

Figure 5. Optimum reservoir temperature as a function of average geothermal gradient using the generalized cost model presented in ref. [5]. Optimum temperatures and depths correspond to cost minima for given gradients and a well flow rate of 50 kg/sec, η_u=0.60 and T_o 26.7°C (1976 dollars).

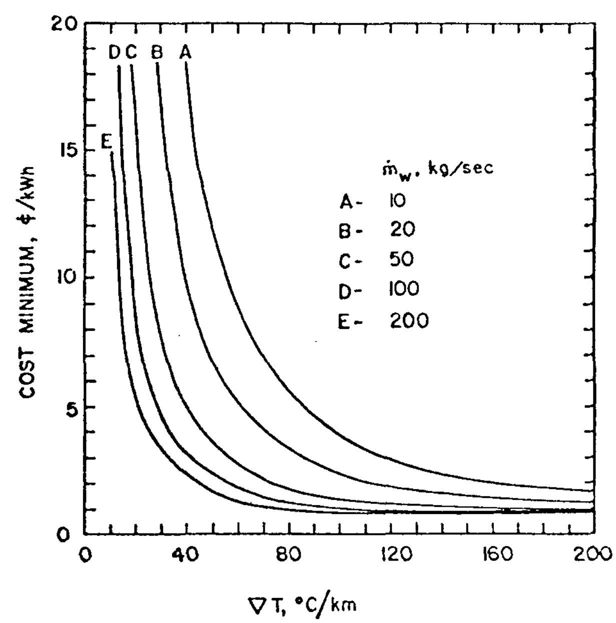

Figure 6. Estimated cost minima as a function of average geothermal gradient for a series of well flow rates with η_u=0.60 and T_o=26.7°C (1976 dollars).

or greater should be possible. For these cases, generating costs would be 3¢/kWh or below for gradients of 40°C/km or above. If non-electric uses are introduced, economic feasibility of HDR systems even with gradients of 20 to 30°C/km is possible for well flow rates considerably below 50 kg/sec.

Figure 5 shows that optimum reservoir temperatures increase as the geothermal gradient increases to ∿70°C/km where the optimum temperature stays at 300°C until ∿ 140°C/km. At 300°C, the constant equipment cost constraint fixes the optimum until gradients over 140°C/km are reached. If this constraint were not applied the curve might follow the dotted line shown in Figure 5 until a drilling temperature limit is approached.

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