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Prospects for Universal Heat Mining: From a Jules Verne Vision to a 21st Century Reality

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ABSTRACT

The extraction of heat or thermal energy from the Earth -- heat mining -- has the potential to play a major role as an energy supply technology for the 21st century. However, even if reservoir stimulation goals are achieved, the role of heat mining with today's energy prices and development costs is limited to only a small fraction of the earth's surface, specifically to geologically active regions where geothermal gradients are high. This paper examines the prospects for universal heat mining and the types of developments required to make it a reality.

A generalized multi-parameter economic model was developed for optimizing the design and performance of hot dry rock (HDR) geothermal systems by linking an SQP nonlinear programming algorithm with a generalized HDR economic model. HDR system design parameters selected for optimization include well depth (or initial rock temperature), geofluid flow rate, number of fractures and injection temperature. The sensitivities of the optimized design parameters, HDR system performance, and levelized electricity price to average geothermal gradient, fractured area/volume, maximum allowable geofluid temperature, reservoir flow impedance, well deviation, and fracture separation have been investigated.

Key technical and institutional obstacles to universal heat mining are discussed in a more general context. These include (1) developing methods for stimulating low permeability formations to provide sustained productivity with acceptable flow/pressure losses (2) dealing with barriers to change primary energy supply options when fossil energy resources are abundant and prices are low and (3) lowering the high drilling costs for developing the deep (>5 km) reservoirs required in low gradient areas. Advanced concepts in drilling technology that could lead to a linear as opposed to exponential relationship between cost and depth are discussed in light of their potential impact on heat mining.

FUNDAMENTAL REQUIREMENTS AND TRADEOFFS

Hot Dry Rock (HDR) geothermal energy or, more generally, heat mining is envisioned by some as an environmentally sustainable primary energy supply that could replace our dependence on fossil and fissile fuels in the 21st century. In principle, thermal energy is extracted from the earth using extended oil and gas drilling and stimulation technology to create reservoirs that in many ways emulate natural hydrothermal systems. Thus HDR has all the advantages of natural geothermal energy, plus a few more. With HDR, water is recycled in a closed loop, and, with essentially no emissions, heat mining would not contribute to local or regional air or water pollution, global-scale problems of greenhouse gas build-up, or air or water quality-related health concerns (Tester *et al.*, 1989). Even with these positive attributes, HDR has been categorized as a very long-term alternative, one that has been portrayed like other renewables as a "Cinderella Option" (see Grubb, 1990).

Many potential private developers of HDR regard its current state of development too immature. In view of current energy markets and the perception that technology is inherently risky, private investment in heat mining has been very small. Although some concern about risk is certainly understandable, it seems disproportionate in that much of the required technology has either already been demonstrated for HDR specifically in government-supported R&D programs or represents an incremental extension of existing state-of-the-art techniques used for hydrocarbon or hydrothermal fluid extraction. Heat mining systems, like hydroelectric power plants, require a large, up-front capital investment that includes both the power conversion equipment and the "fuel" supply system. This built-in investment in the fuel supply system, of course, should partially reduce the risk for HDR over fossil-fired plants that face potentially unstable fuel prices.

National and international R&D programs have focused on demonstrating important heat mining requirements, such as the engineering of fractured systems in hot rock with low natural permeability (Batchelor, 1984a,b, 1987; Brown *et al.*, 1991; and Armstead and Tester, 1987). In the last 10 years, however, these programs have suffered from underfunding in the face of plentiful and cheap oil worldwide. With such subcritical support, technical milestones have not been fully realized and a few important development requirements still remain.

In the past 20 years, several economic forecasts and studies of HDR technology have been published. All of these inherently assume a set of reservoir performance levels and development costs for drilling, stimulation and power plant construction. Tester and Herzog (1990, 1991) reviewed and dissected seven HDR studies to establish base case conditions and parameter ranges for sensitivity studies, and to provide a revised level of economic predictions for heat mining. The studies reviewed were from Bechtel (1988); Cummings and Morris (1979); Murphy *et al.* (1982); Smolka and Kappelmeyer (1990); Shock (1986); Entingh (1987); and Hori *et al.* (1986). Later studies of HDR economics include those by RTZ consultants (1991) and Pierce and Livesay (1993). Although Milora and Tester (1976) and Armstead and Tester (1987) introduced more general economic modeling approaches for HDR systems to show the effect of resource grade, reservoir productivity and reservoir depth or temperature, these earlier studies did not tackle the non-linear, multi-parameter optimization problem of simultaneously selecting well depth, reservoir structure (eg. number and spacing of fractures), geofluid flow rate and redrilling management strategies to optimize performance at minimal cost. These design and operating choices are somewhat unique to heat mining systems. Figure 1 shows the tradeoffs between drilling/reservoir development and power plants costs that yield an optimal drilling depth (or initial rock temperature) for a specified HDR resource defined by its average geothermal gradient, ambient heat rejection conditions, and reservoir flow impedance. Effectively, one is trading off lower plant costs against higher individual well costs. Drilling deeper produces higher fluid production temperatures, which increases Second Law heat to work conversion efficiencies, thus reducing fluid requirements (lower kg/s per kWh_e generated) and lowering corresponding power plant costs. While power plant costs in $\$/kW_e$ tend to decrease monotonically with temperature, well drilling costs tend to increase exponentially with initial rock temperature (i.e. depth).

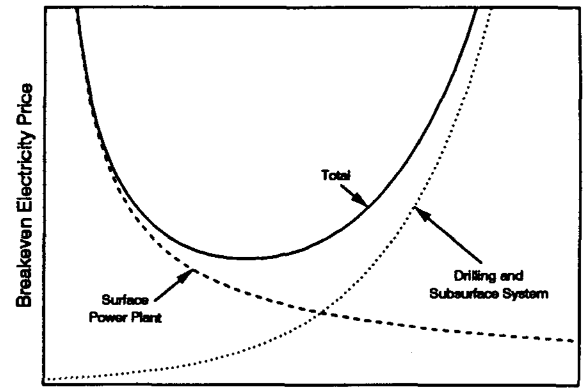

Fig. 1. Conceptual trade-offs in terms of breakeven electricity price (arbitrary scale) between power plant and drilling-related costs as a function of depth or initial reservoir temperature for a fixed geothermal temperature gradient.

In reservoirs with finite thermal lifetimes, temperature decline or drawdown will occur at different rates depending on the mass flow rate per unit of rock surface area or volume exposed to the circulating fluid. An optimal strategy to produce minimum costs requires a balanced state of utilization. The instantaneous power produced will scale as the product of the mass flow rate ($\dot{m}$) and the practical availability of the geofluid ($\eta_u \Delta B$) where η_u is the utilization efficiency of the power cycle and ΔB is the thermodynamic availability (see Milora and Tester, 1976, and Tester, 1982, for details). Both η_u and ΔB are strong functions of the geofluid temperature (T) such that the instantaneous power $P(t)$ per unit of effective reservoir size ($<A>$) is given by:

$$\frac{P(t)}{<A>} = \frac{\dot{m}(t)\,\eta_u(T)\,\Delta B(T)}{<A>} \qquad (1)$$

The magnitude of $P(t)/<A>$ is a measure of reservoir quality in terms of its productivity. Thermal drawdown rates scale directly with $\dot{m}(t)/<A>$, while electric power production potential varies with $\eta_u(T)\Delta B(T)$. As $\dot{m}(t)$ is increased for a fixed reservoir size ($<A>$), T decreases faster and, since both $\eta_u(T)$ and $\Delta B(T)$ decrease rapidly as T declines, the overall productivity of the reservoir decreases and the resource is over-utilized as shown qualitatively in Figure 2. As $\dot{m}(t)$ is decreased below its optimal value, the temperature drawdown rate is reduced, but so is the productivity $P(t)/<A>$ in direct proportion to the decline in $\dot{m}$ (see Equation (1)). This condition corresponds to an under-utilization of the reservoir as shown in Figure 2.

ECONOMIC ASSESSMENT MODEL DEVELOPMENT

A generalized multi-parameter economic model was developed for optimizing the design and performance of geothermal heat mining systems. This was accomplished by enhancing the MIT Energy Laboratory's existing HDR economic model (see Tester and Herzog, 1990, 1991). The major modifications included: reformulating our simple HDR reservoir representation by introducing a multiple parallel fracture conceptual reservoir with a well deviation parameter; adapting the model to an optimization environment and interfacing this revised HDR system model to a SQP (Successive Quadratic Programming) optimization package; and interfacing a levelized life-cycle cost (LLC) algorithm to the model and updating costs to 1991 dollars. As before, electricity production is calculated based on the geofluid (i.e. water) flow rate and the geofluid temperature using a utilization efficiency correlation. The electrical production is then corrected to account for the parasitic pumping requirement caused by system pressure drops minus the buoyancy-driven pressure gain. The model can calculate the electricity breakeven price through a fixed charge rate or LLC approach. The LLC code consistent with EPRI methodology developed by Los Alamos National Laboratory (Hardie, 1981) has been fully integrated into the revised HDR model. Results presented in this paper all use the LLC approach and are given in 1991 dollars. For simplicity, throughout the remainder of this paper we refer to this model as the HDR optimization model.

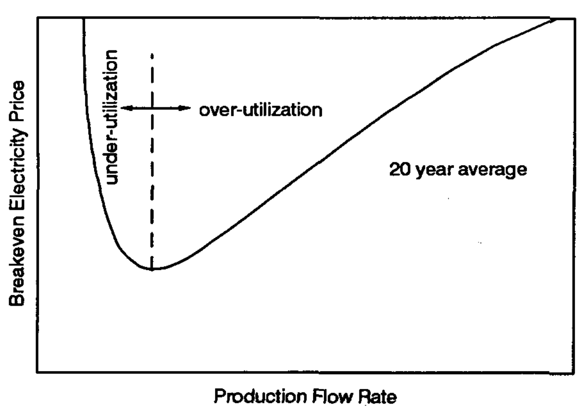

Fig. 2. Qualitative relationship for a specified heat mining resource (known gradient, reservoir area and impedance, depth, initial temperature, etc.) between breakeven electricity price and reservoir production flow rate, $\dot{m}$ (see Equation 1).

A proper understanding of the reservoir temperature drawdown rates is required to predict the geofluid temperature as a function of time. The HDR reservoir "conceptual model" incorporated into the HDR optimization model is a multiple parallel fracture system originally proposed by Gringarten, *et al.* (1975). A well deviation parameter is introduced to allow for rock formation temperature changes as a function of depth along the length of the wells. The reservoir model is labeled "conceptual" because there is insufficient evidence to prove that the parameters used to define the reservoir have exact physical meaning. Nonetheless, this conceptual model captures fundamental physical phenomena that influence the economics, such as finite thermal drawdown or decline in fluid production temperatures over the lifetime of the system. The envisaged HDR reservoir is composed of an injection and a production well which are drilled vertically to a certain depth and then deviate in parallel, linking a finite number of equispaced fractures of uniform thickness, separated by blocks of homogeneous impermeable rock. These fractures are all assumed perpendicular to the injection and production wells. Thus, the perceived reservoir looks like an inclined rectangular cubic rock mass connected to the surface by a well doublet. No heat flux is assumed across the reservoir boundary. Heat transfer in the rock mass is assumed normal to the fracture surfaces. Potential growth due to thermal stress induced effects is ignored. Water is injected at the surface, goes down the injection well, passes through the fractures with evenly distributed flow, up the production well and eventually to the power plant. Five parameters are used to define the geometry of the reservoir: well depth, well deviation, effective area of an individual fracture, number of fractures, and fracture separation. The model then predicts the well length, total effective area, average reservoir depth and average initial rock temperature. The drawdown behavior of the reservoir is predicted with a differential equation set that couples one-dimensional rock conduction to one-dimensional convection flow in planar fractures of uniform aperture.

The HDR optimization model is comprised of a non-linear equation system that can be solved explicitly. The manipulated variables are restricted by upper and lower bounds. Some of the model parameters are also subject to linear or non-linear inequalities. For example, the geofluid pressure at the bottom of the reservoir should be less than or equal to the fracturing critical pressure so as to minimize water loss. This mathematical structure requires a constrained, non-linear optimization algorithm that solves small-scale, highly non-linear problems effectively. The optimization objective is to minimize the levelized electricity price. Maximizing power generation, thermal output or geofluid availability can be specified as alternate objectives. In order to accelerate convergence and prevent the optimization from falling into local minima, the control parameters are scaled to a magnitude of unity. Other details concerning the model and sensitivity analysis can be found in an MIT Energy Laboratory report (Herzog *et al.*, 1994).

In this study, the following parameters were designated as manipulated variables to be optimized:

- ***Drilling Depth.*** Given a geothermal gradient, optimal drilling depth is determined by balancing increased drilling costs (with depth) with the increased effectiveness in electric power production due to higher geofluid temperatures.

- ***Number of Fractures.*** With well separation and fracture spacing specified, the number of fractures is the parameter that determines the reservoir volume. Larger reservoir volumes result in lower temperature drawdown rates, but are penalized by higher capital costs and somewhat lower initial geofluid temperatures. For computational convenience, the number of fractures was treated as a continuous control parameter for optimization instead of a discrete variable, although only whole numbers make practical sense.

- ***Geofluid Flowrate.*** Larger geofluid flowrates increase the initial power generation while accelerating temperature drawdown.

Simulations were run on a range of average geothermal gradients varying from 20 to 100°C/km.

Other parameters defining the base case are given in Table 1. Economic and cost parameters were based on the commercial base case described in Tester and Herzog (1991), reflecting today's relatively higher drilling and completion costs. A three-dimensional plot of breakeven electricity price against geofluid flow rate and the number of fractures is presented in Figure 3 for the base case at a geothermal gradient of 50°C/km. Note the valley on the levelized electricity price surface from low geofluid flow rate and small number of fractures to high geofluid flow rate and large number of fractures. The valley is narrow at the low geofluid rate and small number of fracture end, and widens at the other end. From the figure it can be also seen that in a fairly large region the breakeven price surface is quite flat. The optimum occurs at a geofluid flow rate of 87.9 kg/s and 26.7 fractures with a breakeven electricity price of 9.2¢/kWh$_e$. The total temperature drawdown over the 20-year plant life is about 17.6%, i.e. $[T(t=0\,yr)-T(t=20\,yr)]/[T(t=0\,yr)-T_o]$ = 0.176, where $T(t)$ is the outlet fluid temperature at time t and T_o is the ambient heat rejection temperature.

Table 1. Parameter Values for the Base Case

Parameter Description	Value
Maximum geofluid temperature	330°C
Average surface temperature	15°C
Ambient heat rejection temperature	25°C
Temperature loss in production well	15°C
Impedance per fracture	2.57 GPa-s/m^3
Water loss/total water injected	5%
Rock density	2700 kg/m^3
Rock thermal conductivity	3.0 W/m-K
Rock heat capacity	1050 J/kg-K
Well deviation from vertical	30°
Effective heat transfer area per fracture	100,000 m^2
Fracture separation distance (horizontal)	60 m
Injection temperature	55°C
Geofluid circulation pump efficiency	80%
Plant life	20 years

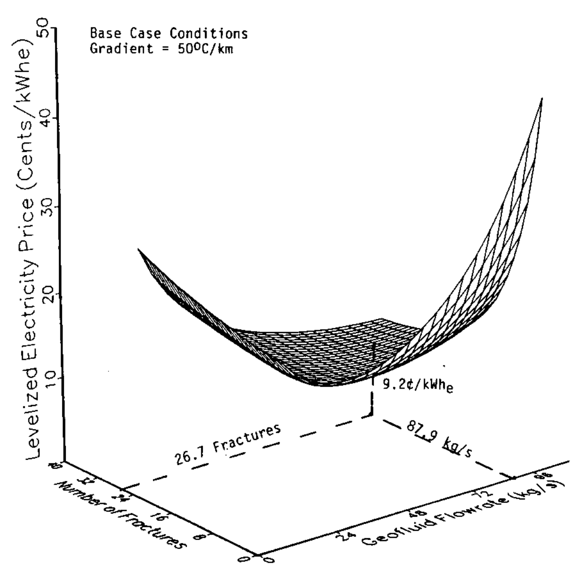

Fig. 3. HDR Optimization model results for the base case and a geothermal gradient of 50°/km. A plot of breakeven electricity prices are shown versus number of fractures and geofluid flow rate, with the optimal point indicated.

Figure 4 presents the percentage participation of each of the major key component costs in the breakeven electricity price calculation. As the geothermal gradient decreases, drilling and completion costs comprise a larger share of the overall costs. This variation highlights the importance of reducing drilling costs if HDR is to become an important energy supply technology in the low gradient areas that cover most of the world.

Figure 5 compares the HDR optimization model base case with the commercial base case from Tester and Herzog (1991). The levelized electricity prices predicted by the HDR optimization model are somewhat higher, partly because in this work redrilling/restimulation is not considered. While the breakeven electricity prices of the two models are comparable, the system designs are very different (see Table 2) due to the introduction of the Gringarten *et al.* (1975) reservoir conceptual model, which leads to a very conservative design.

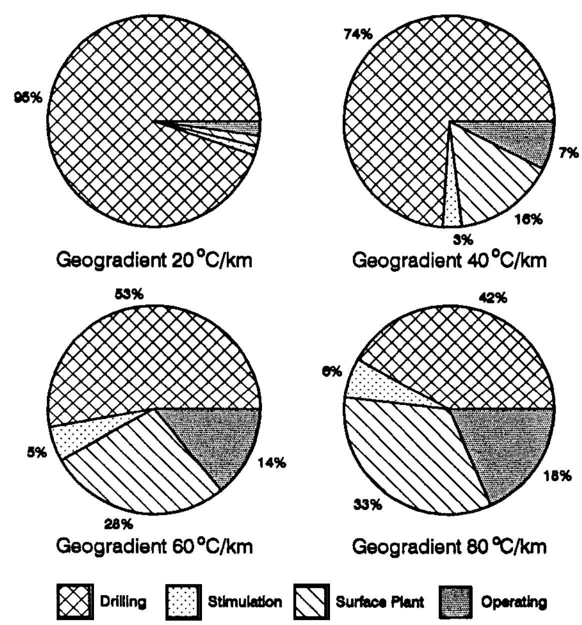

Fig. 4. Breakdown of component costs (drilling, stimulation, plant, and operating) for the HDR optimization model base case conditions at a range of geothermal gradients using today's technology and drilling costs.

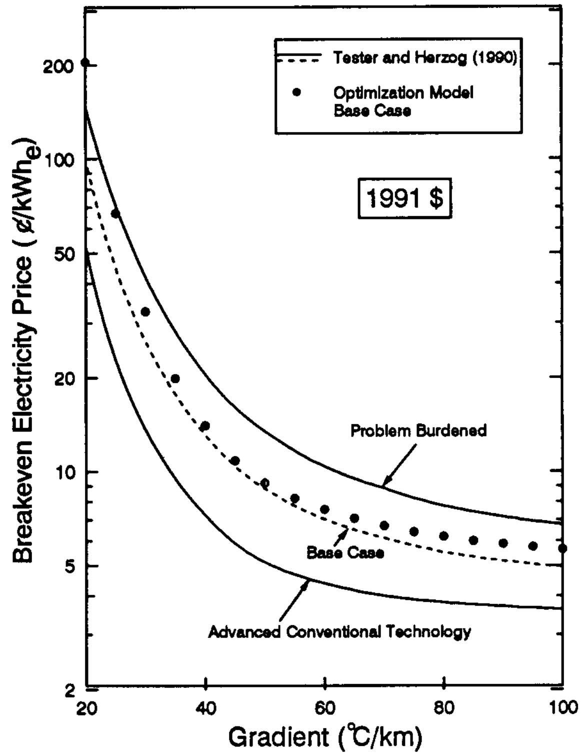

Fig. 5. Comparison of HDR optimization model base case results to those reported earlier in Tester and Herzog (1990, 1991).

Figure 6 shows the sensitivities of the three manipulated variables along with three calculated variables. At an average geothermal gradient below 40°C/km, well depth is determined by balancing drilling and completion costs with geofluid temperature. However, above 40°C/km, the drilling depth is always on the upper bound associated with maximum allowable geofluid temperature. In addition, for geothermal gradients above 40°C/km and a specified reservoir geometry, the higher the geothermal gradient is, the greater the temperature drop will be through the reservoir. That is why there is a clear trend to create smaller size reservoirs in higher geothermal gradient areas and larger size reservoirs in lower geothermal gradient areas. Because of this reservoir size differential, the optimal geofluid flow rate for a low geothermal gradient reservoir will be higher than that for a high geothermal gradient reservoir. Furthermore, the average electricity production for a single well pair over the plant life of 20 years decreases considerably with increasing geothermal gradient because of the smaller reservoir sizes and lower geofluid flows associated with the higher geothermal gradients.

Table 2. System Design Comparison for a Single Well Pair
Old = Tester and Herzog (1991)
New = This Study

	20°C/km		40°C/km		60°C/km		80°C/km	
	Old	New	Old	New	Old	New	Old	New
Breakeven Electricity Price (cents/kWh$_e$)	85	205	11.9	14.0	6.6	7.6	5.3	6.2
Well Depth (km)	9.15	9.15	7.13	7.74	4.75	5.25	3.56	3.94
Geofluid Flowrate (kg/s)	75	46	75	92	75	81	75	66
Effective Area (million m^2)	1.2	2.04	1.7	2.93	1.6	2.48	1.6	1.94
Net Power Output (MW$_e$)	3.5	1.4	14.9	13.7	14.7	11.7	14.5	9.2

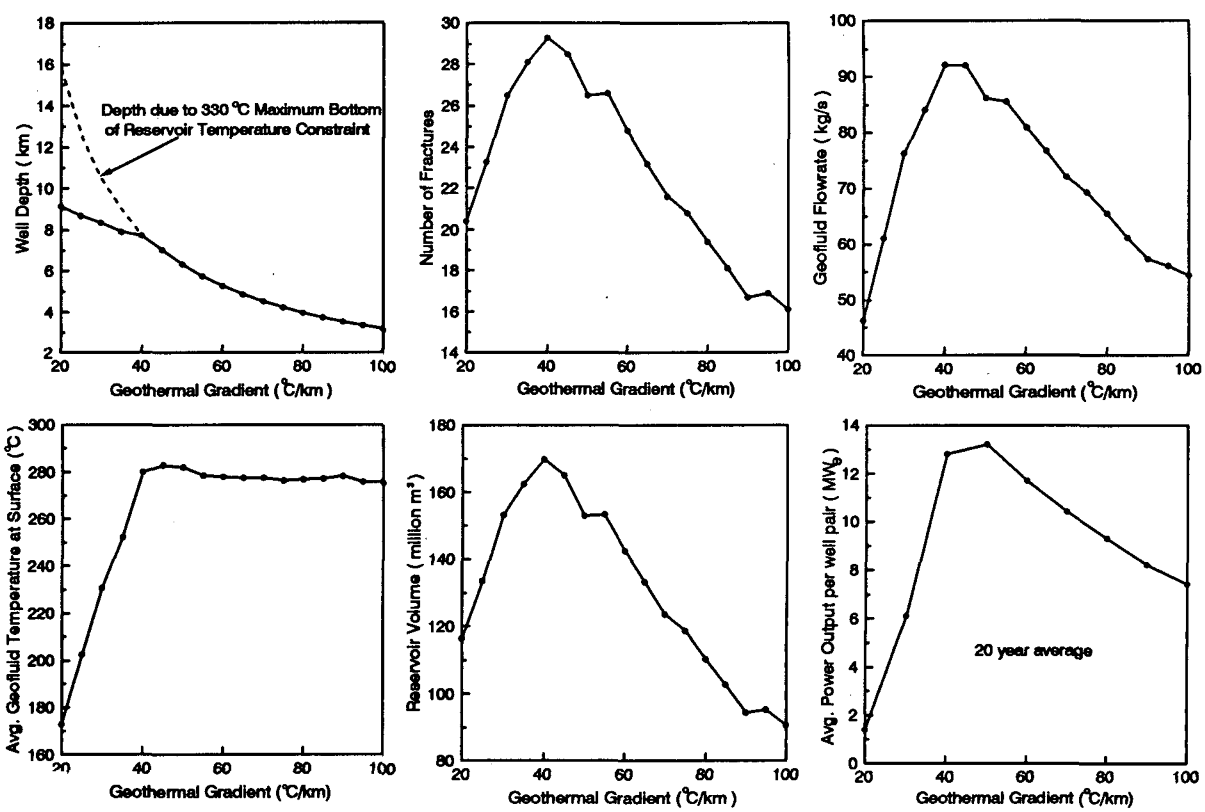

Fig. 6. Estimated values for key design parameters as a function of geothermal gradient for the HDR optimization model base case.

TECHNICAL AND INSTITUTIONAL OBSTACLES TO UNIVERSAL HEAT MINING

The economic model simulation discussed in the previous section obviously contain a certain amount of speculation on our part. For example, to produce base case conditions we have made a number of assumptions regarding anticipated levels of reservoir productivity and performance that go beyond what has been achieved in field tests to date. In effect, we are dealing with the economic feasibility of heat mining somewhat retrospectively. In 1976, Milora and Tester assimilated data for commercial hydrothermal systems to establish a range of performance criteria as a goal for HDR. Later, Entingh (1987), various groups at Los Alamos (Cummings and Morris, 1979, and Murphy *et al.*, 1982) and in the UK (Batchelor, 1984 a,b, 1987), Armstead and Tester (1987), and Tester and Herzog (1990, 1991) refined these criteria somewhat. Frequently a rhetorical question was posed as to what resource and reservoir characteristics were needed to make HDR commercially competitive. For example, breakeven prices for HDR-generated electricity were estimated and compared to the competition from oil, gas, coal, or nuclear energy sources at current market prices. Basically, we have been able to show that our initial assumptions for base case conditions reported earlier (Tester and Herzog, 1990, 1991) were consistent with the more rigorous model developed in this study that treated the non-linear multi-parameter optimization problem. Moreover, this means that the original assumptions for reservoir productivity used earlier are still at a higher level than has been demonstrated in the field.

For mid- to high-grade resources (>40°C/km) at assumed reservoir productivities of 45 to 100 kg/s, 30 to 80 MW_t per well pair and reservoir sizes large enough to ensure drawdown rates of 5% or less over 5 years of production, the HDR breakeven electricity price is 6-10¢/kWh_e. This assumes current drilling costs, power plant construction costs, and modest exploration and site development costs.

To achieve this base case level of reservoir production at Fenton Hill (a high-grade reservoir), a 5 to 10 fold reduction of flow impedance from current levels is needed with acceptable water losses. Clearly, more fundamental engineering experience is needed before HDR reservoirs can be constructed in an optimal fashion. There are no insurmountable technical barriers, but more knowledge of how to create large fracture systems in low permeability rocks is required before low impedance systems of sufficiently high productivity can be routinely engineered. The key implication here is that more time, effort, and funds should be invested in field demonstrations of heat mining. This approach will build the engineering knowledge base, technical know-how, and human resources required to develop heat mining commercially. One can think of the goal of demonstrating HDR reservoir productivity on a commercial scale as the first crucial step in the evolution of universal heat mining.

A successful demonstration would virtually guarantee commercial development of our mid- to high-grade HDR resource as an alternative to fossil or fissile-fired electricity generation. To achieve truly universal heat mining, the ubiquitously distributed low- grade (20-40°C/km) resource must become economically accessible. This will require more revolutionary developments. As seen in Figures 4 and 5, low gradient resources result in very high breakeven prices that are induced primarily by the high drilling cost component. At base case conditions for low-grade HDR, which includes reservoir productivities comparable to mid- and high-grade systems, electricity prices range from about 15 to 100¢/kWh_e or a factor of 3 to 20 too high in today's marketplace. One can see from Figure 4, that as the gradient decreases from 80°C/km to 20°C/km the fraction of total costs due to drilling increases from 42% to 95%.

Even given the inherent speculative nature of these economic projections, it is still relatively safe to predict that heat mining will not become universal until a fundamental change in drilling and/or reservoir formation costs occurs to significantly lower costs. Although one could hypothesize that the discovery of new methods of creating HDR systems could result in enormous increases in productivity per well pair, it seems more probable based on the limitation of current heat mining concepts that a breakthrough in drilling technology is more likely to give the desired result. Such a breakthrough would involve a shift away from the exponential well cost versus depth functionality that has been observed historically for essentially all U.S. oil and gas drilling experience and, although offset to higher costs, for U.S. geothermal drilling experience as well. Figure 7 shows some of these data (see Herzog *et al.* (1994) and Tester and Herzog (1990, 1991) for the sources of data that are plotted). The base case/today's technology line represents average conditions for HDR-type well drilling using conventional rotary drilling technology. The problem-burdened and advanced conventional technology lines form the envelope of drilling costs used in our sensitivity analysis that essentially captures the range of all HDR well cost data and predictions, again for rotary drilling technology. Joint Association Survey (JAS) (1978-1991) data are plotted for oil and gas wells average costs as well as for specific ultra deep wells. Note the scatter in the costs for ultra deep wells, caused primarily by variations in formation type and drilling programs.

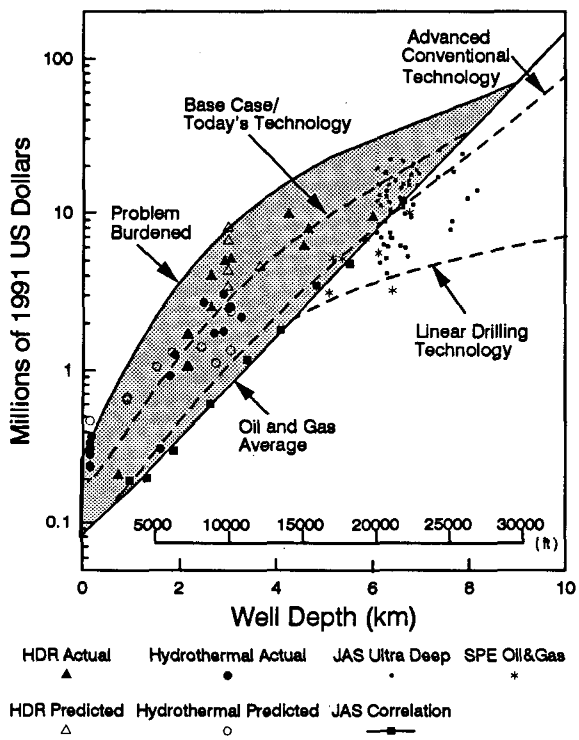

Fig. 7. Drilling costs for different technology levels used in the HDR model simulations. Also plotted are historical drilling costs for HDR, hydrothermal, oil and gas, and ultra-deep wells.

Figure 7 also shows a line for what we have called "linear drilling", where drilling costs for wells deeper than about 4 km no longer follow exponential JAS behavior -- rather costs become linear in depth at this point. We believe that such behavior is possible as a lower boundary on drilling costs when advanced technologies, such flame-jet thermal spallation or water-jet cavitation drilling methods, are employed in a fully integrated drilling system. However, for the moment it's not important what the specific enabling technology is -- only that it exists. Again we recognize we are speculating -- but let's see what happens to predicted heat mining development costs. Simulation results are shown in Figures 8 and 9 for the base case conditions cited in Table 1 but with linear rather than exponential drilling costs. In Figure 8, one notes the shift in the distribution of costs over what was found with conventional drilling technology shown in Figure 4. For example, for a 20°C/km resource only 51% rather than 95% of the total costs are due to drilling when a linear drilling model applies.

In Figure 9, the total US resource is divided into 5 classes or grades, each corresponding to an average gradient between 80 and 20°C/km. This amounts to a total supply of about 42,000 GW_e from heat mining for a 20 year period. For reference the current US generating capacity is about 500 GW_e. The bar graph in Figure 9 compares the breakeven electricity price for each HDR grade using today's drilling costs to what would be possible with linear drilling technology. For the high grade classes (60-80°C/km) the effect of this advanced drilling technology, while significant, is not as striking as for the lower HDR grades (20-30°C/km) where such technology leads to the economic feasibility of heat mining in current energy markets.

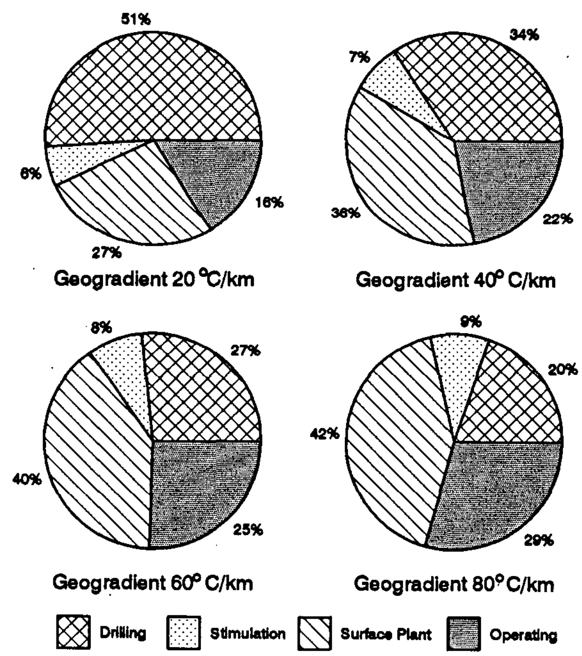

Fig. 8. Breakdown of component costs (drilling, stimulation, plant, and operating) for the HDR optimization model base case conditions at a range of geothermal gradients using linear drilling technology and costs.

CONCLUSIONS AND RECOMMENDATIONS

A multi-parameter optimization model has been developed to specify reservoir design (well depth and spacing, effective fracture size and location) and operating conditions (flow rate, pressure drop) to minimize breakeven electricity prices. The effects of finite reservoir thermal drawdown, wellbore heat losses, and parasitic losses due to fluid recirculation have been included. Sensitivity of electricity price to

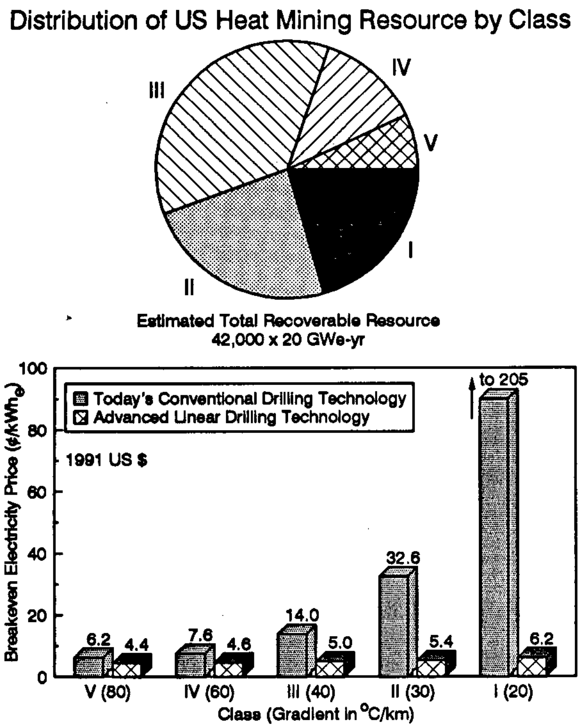

Fig. 9. Heat mining resource base for the U.S. Two sets of costs for producing electricity from this resource are shown -- one using today's conventional drilling technology and the other using advanced linear drilling technology.

resource grade, nominally expressed by the average geothermal gradient, and to important costs factors, such as individual well drilling costs as a function of depth, have been parametrically examined.

It is important to emphasize that the results reported in this paper are aimed at illustrating the sensitivity of electricity price to important reservoir and power plant design parameters and not to establish minimum costs for HDR-produced electricity. Base case conditions for the model simulations were selected somewhat conservatively based primarily on today's technology and costs for developing commercial hydrothermal geothermal resources. A key assumption throughout is that heat mining reservoir productivity levels (e.g. flow rate and impedance) can, in practice, match those found in existing hydrothermal systems. Field results to date from prototype HDR systems fall short of this goal. Based on current progress and potential, we strongly recommend continued field testing of heat mining concepts to achieve the reservoir productivity levels required for commercialization. For example, indications from recent testing of the high-grade Fenton Hill HDR system suggest that a sufficiently large reservoir system with acceptable water losses has been created -- it only lacks proper hydraulic connections to fully utilize its heat mining capacity (Duchane, *et al.*, 1991-1993).

For mid- to high-grade areas (>40°C/km), commercially competitive heat mining with risks and costs lower than estimated base case values will require somewhat higher levels of reservoir productivity and/or lower drilling costs. For universal heat mining that includes low-grade areas (20-40°C/km), a fundamental shift away from exponential drilling costs is needed. This will require revolutionary advances in drilling technology. Perhaps the proposed national program on advanced drilling and excavation could provide such technology (see Peterson, *et al.*, 1993).

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