Economic Analysis of Heat Mining

Howard Herzog, Jefferson Tester, and Marcus Frank

Energy Laboratory, Massachusetts Institute of Technology
77 Massachusetts Avenue, Room E40-455
Cambridge, Massachusetts 02139-4307

Key Words: Hot Dry Rock, Heat Mining, Economics, Modeling

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. This paper looks specifically at the potential for hot dry rock (HDR) geothermal energy in the United States. A generalized multi-parameter economic model was developed for optimizing the design and performance of HDR geothermal systems. Assuming reservoir productivity comparable to existing hydrothermal systems, high grade HDR systems ($\nabla T > 60°C/km$) produce electricity in the 6-7¢/kWh$_e$ range. For low grade systems ($\nabla T < 40°C/km$) to become commercially attractive, much higher reservoir productivity levels and/or substantially lower drilling costs are required.

1. INTRODUCTION

Heat mining, defined as the extraction of thermal energy (i.e. heat) from the Earth, has the potential to play a major role as an energy supply technology for the 21st century. While the resource base for heat mining is large and ubiquitous, it is also very diverse (Armstead and Tester, 1987). This diversity can be viewed as a continuum of geothermal temperature gradients with differing amounts of natural fluids and fractures; defined as such, the heat mining resource encompasses all geothermal systems from dry-steam, vapor-dominated, hydrothermal systems to low permeability, deep hot dry rock (HDR) systems. Currently, there is approximately 10,000 MW$_e$ installed capacity worldwide for geothermal energy, almost all of which comes from hydrothermal resources containing natural fracture systems and fluids. However, well over 99% of the potential for heat mining lies in regions with insufficient natural fluids and/or permeabilities to exploit. It is this opportunity, heat mining from low permeability hot dry rock, that we explore in this paper.

2. HDR ECONOMIC MODELING

2.1. Background

HDR resources can be classified by the average geothermal temperature gradient as high-grade (>60°C/km), mid-grade (40-60°C/km), or low-grade (<40°C/km). The geothermal gradient is just one of many factors (see Figure 1) which influence the commercial feasibility of HDR. We have developed an economic model which considers the interactions of many of these factors.

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 Harrison and Doherty (1991) and Pierce and Livesay (1993). Recently, the U.S. Geological Survey (1993) published a report on the potential of HDR in the Eastern United States. 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 address 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. The range of these design and operating choices is unique to HDR systems in comparison to hydrothermal systems that are inherently more constrained.

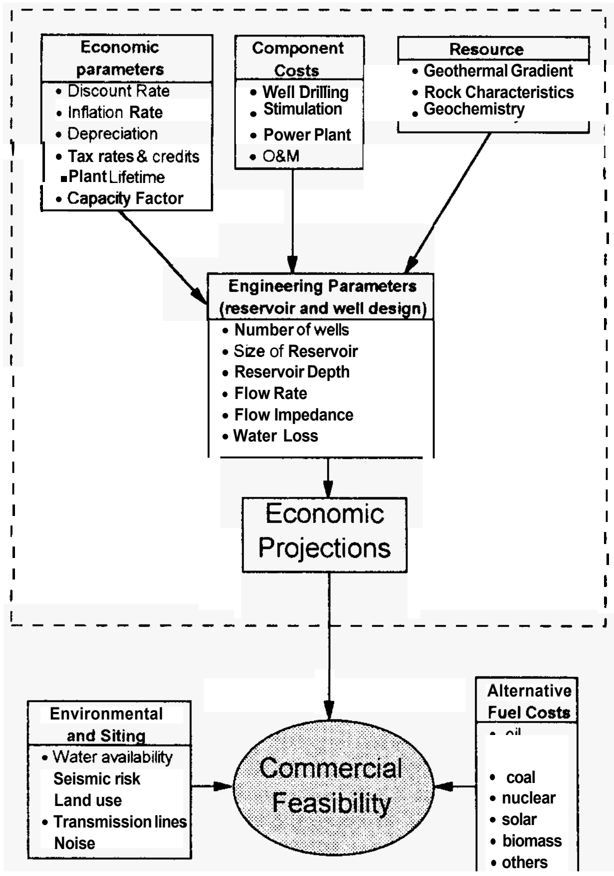


Figure 1. Factors which affect the commercial feasibility of an **HDR** system. The scope of the modeling effort is indicated by the dashed line.

Figure 2 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 well flow rates expressed as 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, see Figure 3).

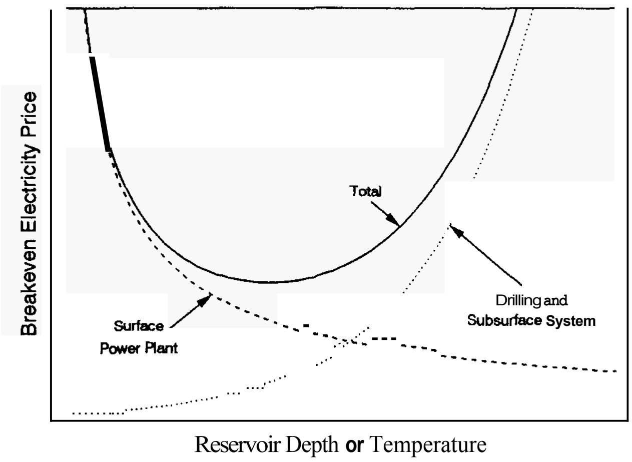


Figure 2. Conceptual trade-offs in terms of breakeven electricity price (arbitrary scale) between power plant and drilling-related costs as a function of depth or initial reservoir temperature for a fixed geothermal temperature gradient.

In real reservoirs with finite thermal lifetimes, produced fluid 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 exergy or availability, that is the maximum power production potential (see Milora and Tester, 1976, and Tester, 1982, for details). Both η_u and ΔB are strong functions of the geofluid temperature (T), which itself is a function of time (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 4. 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 4.

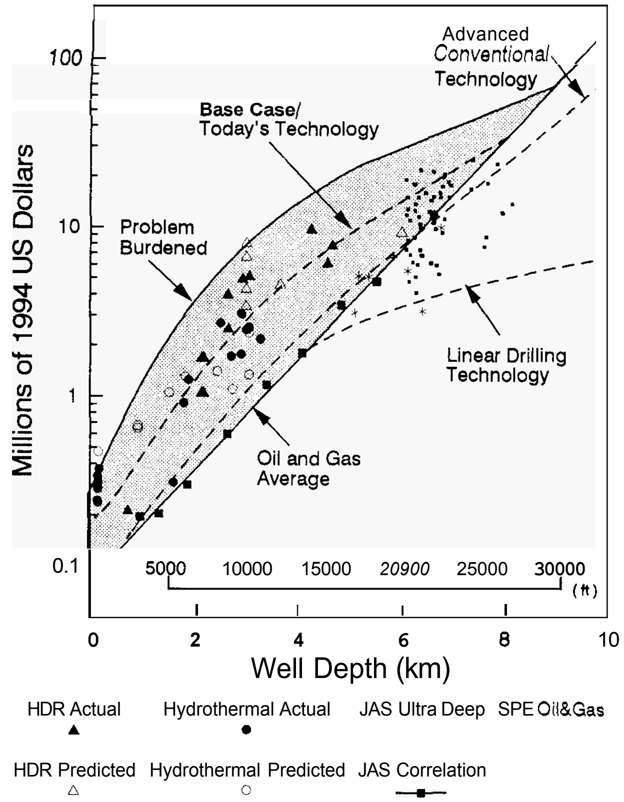


Figure 3. Historical drilling costs for HDR, hydrothermal, oil and gas, and ultra-deep wells. Also plotted are drilling costs for different technology levels used in the HDR model simulations. The "problem burdened line represents the estimated upper limit of drilling costs based on all available cost data for first generation completed HDR wells. The "base case" line approximates the trajectory of the "average" HDR well cost midway between the "problem-burdened and the "oil and gas average" line which is based on Joint Association Survey (JAS) data for completed oil and gas wells on-shore in the U.S. The "advanced conventional technology" and "linear drilling" lines that represent two scenarios for projected improvements to drilling technology.

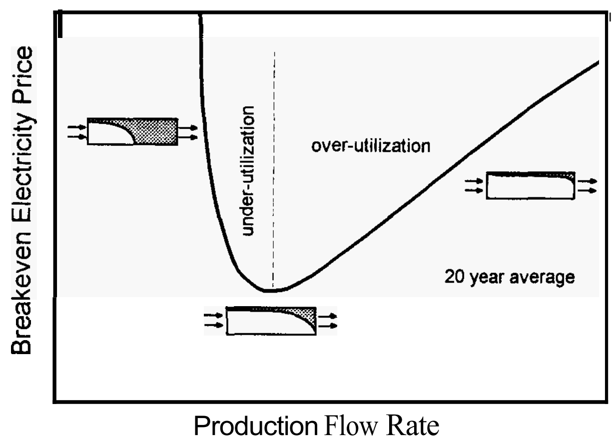


Figure 4. Qualitative relationship for a specified heat mining resource (known gradient, reservoir impedance, depth, initial temperature, etc.) between breakdown electricity price and reservoir productivity, $P(t)/<A>$ (see Equation 1). The assumed drawdown is shown schematically for the under-utilized, over-utilized, and optimum cases. The shaded area indicates hot rock; the white area, cool rock; and the weighted average at the outlet indicates the geofluid temperature.

2.2. Model Inputs

Building on the work of Tester and Herzog (1990, 1991), a generalized multi-parameter economic model was developed for optimizing the design and performance of geothermal heat mining systems. The salient features of the model are:

- A SQP (Successive Quadratic Programming) optimization algorithm to access the trade-offs discussed in Section 2.1 and determine reservoir depth, reservoir size, and geofluid flow rate.
- A LLC (levelized life-cycle) cost algorithm to determine the breakeven electricity price.
- A reservoir model to determine the production temperature drawdown of the reservoir as a function of time.
- Determination of the parasitic pumping power by calculating pressure drops in the well bore and reservoir, as well as buoyancy effects caused by temperature differences between the injection and production wells.
- A drilling cost correlation based on actual geothermal drilling experience and supplemented by extensive oil and gas well cost data published by the Joint Association Survey (see Figure 3).
- Separate cost indices for plant costs and sub-surface costs to normalize all data and results into constant year (1994) dollars.

Table 1. Parameter Values for the Base Case

Parameter Descriptioa	Value
Geothermal gradient	20-100°C/km
Depth	*
Geofluid flow rate	*
Number of fractures	*
Number of injection wells	1
Number of production wells	1
Maximum allowable bottom hole temperature	330°C
Average surface temperature	15°C
Ambient heat rejection temperature	25°C
Temperature loss in production well	
Impedance per fracture	2.51 GPa-s/m³
Water loss/total water injected	
Rock density	2700 kg/m³
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 m²
Fracture separation distance (horizontal)	60 m
Injection temperature	55°C
Geofluid circulation pump efficiency	80%
Discount rate	13%
Inflation rate	4%
Capacity factor	90%
Plant life	20 years

*Determined by model to minimize breakeven electricity price

It is important to emphasize that our modeling effort was 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 (see Table 1) were selected somewhat conservatively, based primarily on today's technology and costs for developing commercial hydrothermal geothermal resources. A key assumption throughout is that HDR reservoir productivity levels (e.g. flow rate and impedance) are, in practice. comparable to those found in existing hydrothermal systems. Also, the model contains certain simplifying constraints, such as a doublet well configuration, no redrilling over the plant lifetime, and baseload electricity output only. Section 3 discusses further opportunities to reduce costs by relaxing some of these constraints.

2.3. Model Results

The results of the model are shown in Figure 5. Despite significant modifications, the base case predictions are very similar to those reported in Tester and Herzog (1991). We recognize that many reservoir models could be used to illustrate drawdown effects. We have chosen the multiple, parallel fracture system (adapted from Gringarten et *al.*, 1975) for our base case. For comparison, Figurc 5 also shows results for three alternate reservoir models:

- The volumetric block model as adapted from Robinson and Kruger (1988).
- The ideal volumetric heat mining model is an upper bound on reservoir performance. In this model, the heat extraction is in a plug flow manner, starting at the injection well and moving towards the production well, as shown in Figure 6. This enables the production temperature to remain constant for the plant's lifetime.
- The uniform rock heat extraction model assumes the temperature is drawn down uniformly over the entire reservoir (see Figure 6). We use this as a lower bound on reservoir performance, even though poorer performance is possible if phenomena like channeling occur.

The only inputs to our model that have not been demonstrated are the reservoir productivity parameters, which are based on naturally occurring hydrothermal reservoirs. To date, man-made HDR reservoirs have not been able to replicate completely the performance of commercial hydrothermal reservoirs. For example, to achieve the model's base case level of reservoir production, a 5 to 10 fold reduction of flow impedance from Fenton Hill's (a high-grade HDR reservoir) current levels is required with acceptable water losses. Clearly, more fundamental engineering experience is required before HDR reservoirs can be constructed in an economical 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.

There is reason to be optimistic about achieving significant impedance reductions in HDR reservoirs based on field testing data from the Fenton Hill site in the U.S. and from the Soultz site in Europe. First of all, economic heat mining requires both low impedance and sufficient accessible rock reservoir volume to ensure commercially acceptable mass flows and thermal outputs for production periods of 5 years or more. Based on microseismic, tracer, and other measurements, the stimulated rock volumes at Fenton Hill and Soultz are of order 0.1 to 0.2 km³ which are adequate for sustainable levels of thermal power production. Predictions of reservoir performance of the current Fenton Hill system has verified that the placement of production

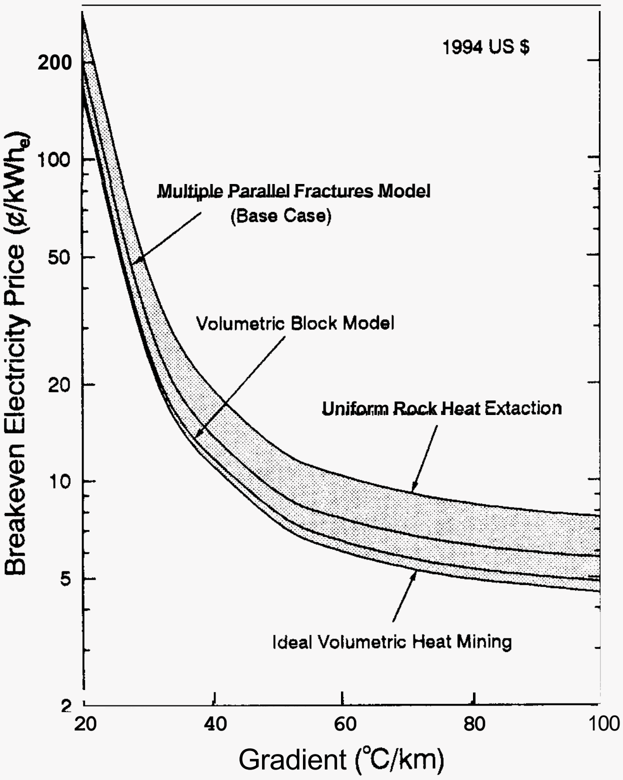


Figure 5. Results for various reservoir drawdown models, with the range shaded.

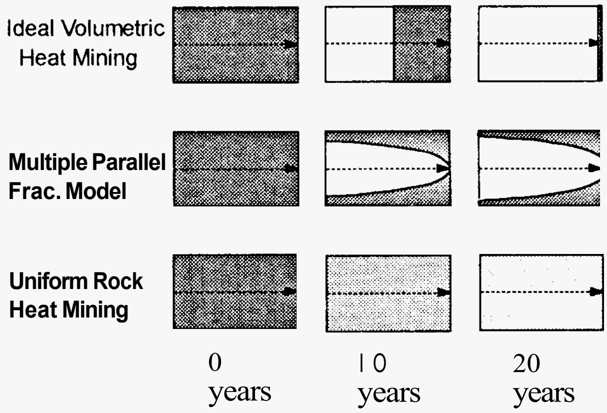


Figure 6. Schematic representation of drawdown for the various reservoir models used to generate the results in Figure 5. The darker the shading, the hotter the rock, with the geofluid temperature being the weighted average at the output.

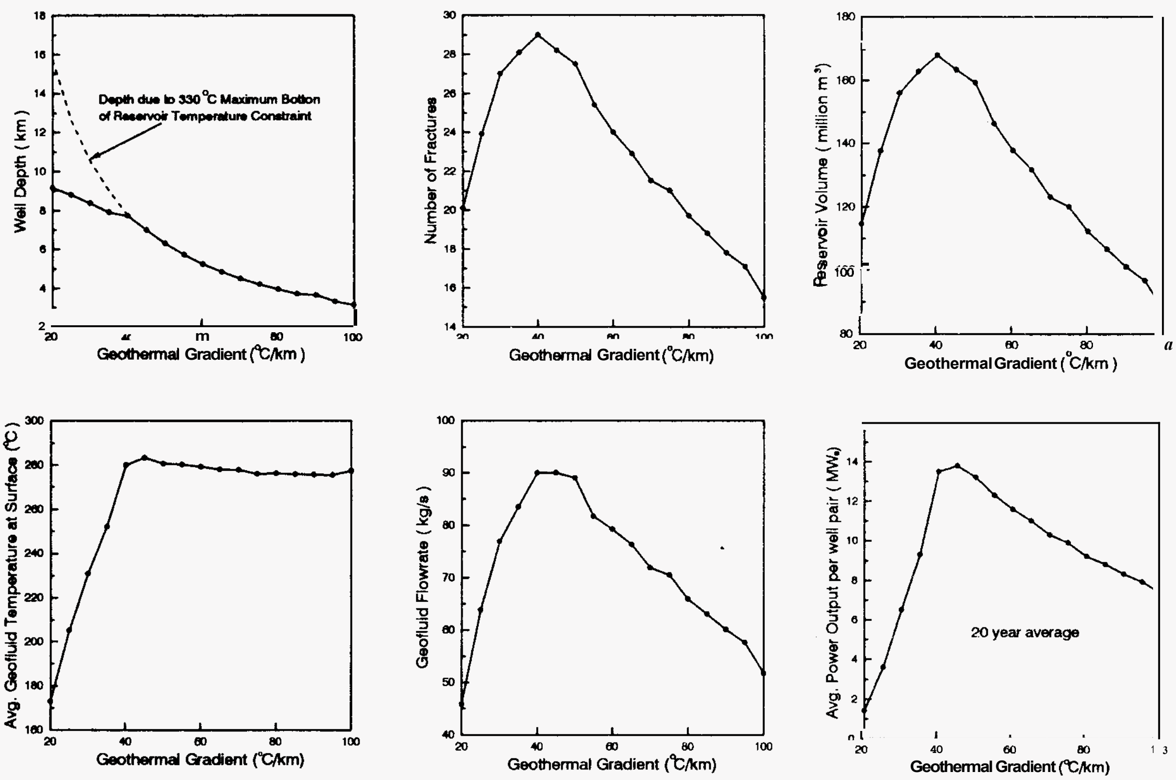


Figure 7. Estimated values for key design parameters for a single well pair (doublet system) as a function of geothermal gradient for the HDR optimization model base case.

and injection wells in the stimulated region is not optimal, leading both to the high observed impedances and tower sweep efficiencies. Possible impedance reduction procedures include:

- Redrilling the production wells with reservoir geometry fully characterized.
- Adding a second production weli to produce a triplet system.
- Chemically inducing selective dissolution of mineral matter along fractured rock faces.
- Increasing access to fractured region **using** multiple lateral sidetracked downhole completions.

In an unplanned event during testing at Fenton Hill caused by a mechanical failure at the surface, rapid venting of a large, fully-inflated, single fracture zone occurred in the deep reservoir at approximately 4.5 km. Production flows on the order of 100-150 kg/s, equivalent to a thermal output in excess of 100 MW_t, were achieved for **a** sustained period (Potter, 1994). Naturally, without continual recharge of fluid from the injection well, this production rate steadily declined. But, what is most important is that reservoir impedance (including entrance and exit losses) remained at a very low value.

Using the multiple, parallel fracture model, Figure 7 shows the sensitivities of several variabies to the geothermal gradient. For average gradients 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 through the reservoir. That is why there is a clear trend to create smaller sized reservoirs in higher gradient areas and larger sized reservoir in lower gradient areas. Because of this reservoir size differential, the optimal geofluid flow rate for a low gradient reservoir will be higher than that for a high gradient reservoir. Furthermore, the 20-year average electricity production rate for a single well pair decreases considerably with increasing geothermal gradient because of the smailer reservoir sizes and lower geofluid flow rates associated with the higher geothermal gradients.

3. OPTIMIZING HEAT MINING SYSTEM DESIGN AND PERFORMANCE

With assumed reservoir performance, the modeling results show that mid- to high-grade (>40°C/km) HDR resources are close to being commercially competitive. By relaxing some of the modei's inherent constraints, we can further optimize system design and performance of heat mining systems, thereby improving system economics. This section describes several such possibilities.

Reservoir Structure and Well Placement. The model assumes that we have one injection and one production well. However, commercial heat mining systems will almost surely consist **of** multiple injection and production wells placed **in** complex patterns to minimize water **loss** and maximize fluid sweep efficiency. For example, a triplet system (two producers per injector) or a four-spot pattern (four producers surrounding each injector) have already been suggested.

Redrilling. The model has assumed that the same wells will service the reservoir for the entire project lifetime. **A** more likely scenario will be to redrill at least some wells over the plant lifetime to exploit hotter areas of the formation. The procedure for redrilling has yet to be worked out due to the lack of data, especially from long-term reservoir flow testing. However, indications are that redrilling will be both technically and economically attractive.

Non-baseload Power Applications. The model uses heat mining strictly for baseload power applications. Due to the relatively low temperatures (compared to combustion processes), heat mining is at a thermodynamic disadvantage with power cycle efficiencies in the IO-20% range versus 40-50% for modern combined cycle combustion processes. Other applications for heat mining that do not have such an inherent thermodynamic disadvantage include:

- Direct heat applications
- Cogeneration
- Hybrid plants (e.g. use geothermal for water pre-heating)

In addition, using heat mining for peaking power instead of baseload power could have economic advantages. This could be achieved through a "huff and puff" system of cyclic operation.

4. ACCESS TO LOW-GRADE HEAT MINING RESOURCES

To achieve truly universal heat mining, the large and well distributed low-grade (20-40°C/km) resource must become economically accessible. Low geothermal gradients lead to deeper well depths and higher drilling costs, resulting in very high breakeven electricity or energy prices. At base *case* operating and design conditions for low-grade HDR resources with reservoir productivities comparable to mid- and high-grade systems, electricity prices range from about 14 to **200¢/kWh$_e$** or a factor of 3 to 40 too high in today's marketplace.

With these economic projections, a fundamental change in drilling and/or reservoir formation costs is required for universal heat mining. 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 seem more probable, based on inherent geotechnical limitations of current heat mining concepts, that a breakthrough in drilling technology **is** needed 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 oil and gas drilling experience and, although offset to higher costs, for geothermal drilling experience as well. Figure 3 shows some individual well cost data (see Herzog ***et al.*** (1994) and Tester and Herzog (1990, 1991) for data sources). 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 an envelope of drilling costs that essentially captures the range of all HDR well cost data and predictions, again for rotary drilling technology. Joint Association Survey **(JAS)** (1978-1992) data are plotted for oil and gas wells average costs as well as for specific ultra-deep w 'ls (**>6 km).** Note the order-of-magnitude scatter in the costs for ultra-deep wells, is caused primarily by variations in formation type and drilling programs.

Figure *3* also shows a speculative 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. Such linear cost versus depth behavior, if possible, would establish a lower boundary on drilling costs. Advanced technologies, such as flame-jet thermal spallation or water-jet cavitation drilling methods, employed in a fully integrated smart drilling system could provide the enabling technology (see Tester ***et al.***, 1995). However, for the moment it's not important what the specific technology is -- only that it exists.

Though we are speculating, it is interesting to see what happens to predicted heat mining development costs with advanced technologies. In Figure 8, the total **U.S.** 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, from heat mining for a 20 year period (for reference, the current U.S. generating capacity is about 700 GW_e). For each class, the bar graph in Figure 8 compares breakeven electricity prices for 3 scenarios:

- using today's hydrothermal reservoir productivity levels with today's drilling technology and costs
- using advanced reservoir productivity levels (order of magnitude greater than today's hydrothermal) with today's drilling technology and costs
- using today's hydrothermal reservoir productivity levels with advanced linear drilling technology

For the high grade classes (60-80°C/km) the effect of advanced drilling technology, while significant, is not as striking as for the lower HDR grades (20-40°C/km) where such technology leads to the economic feasibility of heat mining in current energy markets. Introducing advanced reservoir productivity also has dramatic effects, but lags behind the impact of advanced linear drilling for most classes. Note that the lower grades cannot become economically viable solely through an order of magnitude increase in reservoir productivity.

5. PROGNOSIS

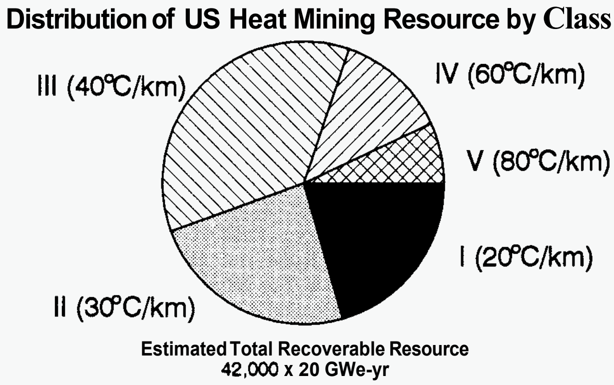
Our central focus throughout this paper has been on estimating the costs of producing electric power from low permeability hot dry rock reservoirs using heat mining methods. Several key technical and economic assumptions were used to establish a base case, including:

1) contained water losses (15%) and acceptable fluid geochemistry (no plugging or sealing of equipment or wells)
2) drilling costs 2 to 3 times average oil and gas drilling to the same depth
3) surface power plant capital and generating costs comparable to existing commercial hydrothermal installations
4) reservoir fluid production rates and temperatures and flow impedance levels comparable to existing hydrothermal systems (40-90 kg/s at $\Delta P/\dot{m}$ of about 1 bar/(kg/s))

Assumptions (1) and (2) have been repeatedly verified in reservoir testing and drilling operations of the prototype HDR systems developed at the U.S. Fenton Hill, NM site (Duchane, 1993). Assumption (3) is also quite reasonable given the fluid temperature levels and relatively benign geochemistry that have been observed in testing the Fenton Hill systems in fractured basement rock. Assumption (4), however, has not been fully demonstrated for extended periods in testing of HDR prototypes in the U.S., Japan, or Europe. However, fluid production levels of these magnitudes are common from hydrothermal reservoirs. Further, reservoir sizing tests at HDR sites in the U.S. and Europe indicate that sufficient volumes of rock have been stimulated by hydraulic fracturing to provide these assumed production levels for many years with proper hydraulic connections to the fractured volume of rock (Kruger, 1994).

Breakeven electricity prices were predicted for various HDR resource grades. High grade systems ($\nabla T > 60$°C/km) require prices in the 6 to 7¢/kWh_e range while low grade ($\nabla T < 40$°C/km) yield breakeven prices of 14¢/kWh_e or greater. Sensitivity analysis showed that either (1) production levels 2 to 10 times higher or (2) substantially lower drilling costs are needed to make HDR viable in today's energy markets. Ultimately, drilling costs approaching a linear rather than exponential dependence on depth (>4 km) are desirable.

Advocates of heat mining have urged that a larger investment in field testing be made to demonstrate that sustainable thermal energy production levels with acceptable impedances and water loss rates can be achieved for prototype HDR reservoirs. Furthermore, additional resources should be directed toward development of truly advanced drilling technologies needed to make universal heat mining possible. Regrettably, current worldwide HDR reservoir and advanced dnlling research and development activity levels are too low to achieve these technical and economic objectives in a timely manner.



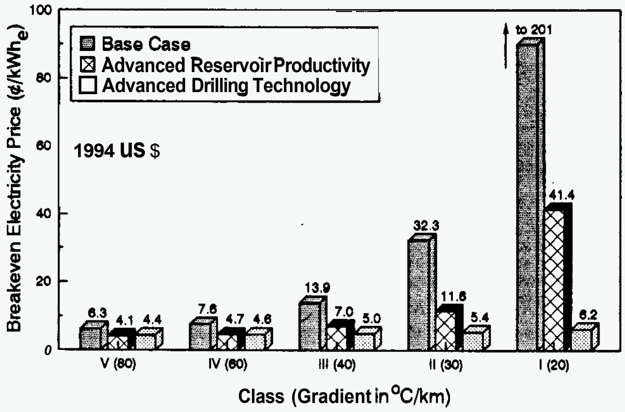


Figure 8. Heat mining resource base for the U.S. Three sets of costs for producing electricity from this resource are shown: using hydrothermal reservoir productivities with today's conventional drilling technology; using advanced reservoir productivities with today's conventional drilling technology; and using hydrothermal reservoir productivities with advanced linear drilling technology.

ACKNOWLEDGEMENT

The authors gratefully acknowledge the Geothermal Division of the U.S. Department of Energy for their partial support of this work. We appreciate the comments and suggestions made by D. Entingh, D. Duchane, R.M. Potter, P. Kruger, A. Jelacic, G. Hooper, J.E. Mock, J. Dunn, and D. Brown.

REFERENCES

Armstead, H.C.H. and Tester, J.W. (1987). *Heat Mining.* London: E.F. Spon.

Bechtel National Inc. (1988). *Hot Dry Rock Venture Risks Investigation,* Final report for the U.S. Department of Energy under contract DE-AC03-86SF16385, San Francisco, CA.

Cummings, R.G. and Moms, G.E. (1979). *Economic Modeling of Electricity productionfrom Hot Dry Rock Geothermal Reservoirs: Methodology and* ***Analysis.*** Electric Power Research Institute report EPRI EA-630, Palo Alto, CA.

Duchane, D. (1993). Hot Dry Rock Flow Testing -- What has it Told Us? What Questions Remain? *Geothermal Resources Council Transactions,* Vol.17, pp. 325-330.

Entingh, D. (1987). *Historical and Future Cost of Electricityfrom Hydrothermal Binary and Hot Dry Rock Reservoirs, 1975-2000,* Meridian Corp. report 240-GG, Alexandria, **VA.**

Gringarten, A.C., Witherspoon, P.A. and Ohnishi, **Y.** (1975). Theory of Heat Extraction from Fractured Hot Dry Rock. *J. Geophysical Research,* Vol.80(8), p. 1120.

Harrison, R. and Doherty, P. (1991). *Cost Modeling of Hot Dry Rock Systems, Volume 1: Main Report,* UK Department of Energy report ETSU G 138F-1.

Herzog, H., Chen, Z., Tester, J., and Frank, M. (1994). A *Generalized Multi-parameter Economic Model for Optimizing the Design and Performance of Hot Dry Rock (HDR) Geothermal Energy Systems,* Massachusetts Institute of Technology Energy Laboratory report MIT-EL 94-004.

Hori, Y. *et al.* (1986). ***On*** *Economics of Hot Dry Rock Geothermal Power Station* and related documents, Corporate Foundation Central Research Institute for Electric Power, Hot Dry Rock Geothermal Power Station Cost Study Committee report 385001, Japan.

Joint Association ***Survey on*** *Drilling Costs for Years 1978-1991* (1978-1991). American Petroleum Institute, Washington, D.C.

Kruger, P. (1994). Heat Extraction Analysis of Five HDR Circulation Tests. *Geothermal Resources Council Transactions,* Vol.18, pp. 465469.

Milora, S.L. and Tester, J.W. (1976). *Geothermal Energy* **as** *a Some of Electric Power.* Cambridge, **MA:** MIT Press.

Murphy, H.D., Drake, R., Tester, J.W., and Zyvoloski, G.A. (1982). *Economics of a* ***75-MW$_e$*** *Hot Dry Rock Geothermal Power Station Based upon the Design of the Phase II Reservoir at Fenton Hill.* **Los** Alamos National Laboratory report LA-9241-MS.

Pierce, KG. and Livesay, B.J. (1993). **Estimate of the** Cost of Electricity Production from Hot Dry Rock. *Geothermal Resources Council Bulletin,* Vol.22(8), pp. 197-203.

Potter, R.M. (1994). Personal communication. Los Alamos National Laboratory, Los Alamos, NM.

Robinson, B.A. and Kruger, P. (1988). A **Comparison** of Two Heat Transfer Models for Estimating Thermal Drawdown in Hot Dry Rock Reservoir. *Proceedings, 13th Workshop on Geothermal Reservoir* ***Engineering,*** Stanford University, Stanford, CA, pp. 113-120.

Shock, R.A.W. (1986). *An Economic Assessment of Hot Dry Rocks* **as** *an Energy Some for the* ***U.K.,*** U.K. Department of Energy report ETSU-R-34.

Smolka, K. and Kappelmeyer, **O.** (1990). Economic Cost Evaluation of HDR Power Plants. *Hot Dry Rock Geothermal Energy,* proceedings of the International Hot Dry Rock Geothermal Energy Conference, Camborne School of Mines, 27-30 June 1989, ed. R. Bario, London: Robertson Scientific Publications.

Tester, J.W. (1982). Energy Conversion and Economic Issues for Geothermal Energy. *Handbook of Geothermal Energy,* ed. L.M. Edwards *et al.*, ch. 10. Houston, TX: Gulf Publishing.

Tester, J.W. and Herzog, H.J. (1990). *Economic Predictions for Heat Mining: A Review and Analysis of Hot Dry Rock (HDR) Geothermal Energy Technology.* Massachusetts Institute of Technology Energy Laboratory report MIT-EL 90-001.

Tester, J.W. and Herzog, H.J. (1991). The Economics of Heat Mining: An Analysis of Design Options and Performance Requirements of Hot Dry Rock (HDR) Geothermal Power Systems. *Energy Systems and Policy,* Vol.15, pp. 33-63.

Tester, J.W., Potter, R.M., Peterson, C.R., Herzog, H.J., North, J., and Mock, J.E. (1995). Advanced Drilling and its Impact on Heat Mining. *Proceedings of the World Geothermal Congress,* forthcoming.

U.S. Geological Survey, (1993). *Potential of Hot-Dry-Rock Geothermal Energy in the Eastern United States,* U.S. Geological Survey, USGS Open-file Report 93-377.