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The Economics of Heat Mining: An Analysis of Design Options and Performance Requirements of Hot Dry Rock (HDR) Geothermal Power Systems

Jefferson W. Tester and Howard J. Herzog
Massachusetts Institute of Technology
Energy Laboratory, Room E40-455
Cambridge, MA 02139

Abstract

A generalized economic model was developed to predict the breakeven price of HDR generated electricity. Important parameters include: (1) resource quality-- average geothermal gradient (°C/km) and well depth, (2) reservoir performance-- effective productivity, flow impedance, and lifetime (thermal drawdown rate), (3) cost components-- drilling, reservoir formation, and power plant costs and (4) economic factors-- discount and interest rates, taxes, etc. Detailed cost correlations based on historical data and results of other studies are presented for drilling, stimulation, and power plant costs. Results of the generalized model are compared to the results of several published economic assessments.

Critical parameters affecting economic viability are drilling costs and reservoir performance. For example, high gradient areas are attractive because shallower well depths and/or lower reservoir production rates are permissible. Under a reasonable set of assumptions regarding reservoir impedance, accessible rock volumes and surface areas, and mass flow rates (to limit thermal drawdown rates to about 10°C per year), predictions for HDR-produced electricity result in competitive breakeven prices in the range of 5 to 9 cents/kWh for resources having average gradients above 50°C/km. Lower gradient areas require improved reservoir performance and/or lower well drilling costs.

Introduction

The HDR geothermal energy resource is associated with accessible regions of hot rock beneath the earth's surface that do not contain sufficient natural porosity or permeability. Energy can be extracted by creating artificial permeability using hydraulic stimulation techniques to propagate and open joints or fractures. The resulting fracture network is connected to a set of injection and production wells where heat is removed by circulating water under pressure from the surface, down one well, through the fractured zone, and up a second well (see Figure 1). Electricity and/or process steam would then be generated using the heated water in an appropriately designed plant. This *heat mining* concept is closed-loop on the geothermal side so there are no effluents, thus minimizing the environmental impact of the entire HDR "fuel cycle" to site preparation, well drilling, and other land use issues.

Because HDR systems do not require natural, indigenous hot fluids and high permeability, the HDR resource itself can be defined by the accessible thermal energy in the earth's crust above some minimum temperature level. Thus the size of the HDR resource is very large and more widely distributed than natural geothermal systems. For example, in the U.S., to a 10 km depth assuming an average geothermal temperature gradient of 25°C/km and a minimum initial rock temperature of 150°C (deg C), the amount of thermal energy in place is about 10 million quads (Tester, Brown, and Potter (1989)). The worldwide HDR resource base is estimated at over 100 million quads (Armstead and Tester (1987)). Based on the enormous size and ubiquitous distribution of the resource and its positive environmental characteristics, HDR could provide an acceptable alternative to the fossil and nuclear options for meeting a substantial fraction of worldwide electric power and space and process heat demand.

The main objectives of this study were first, to review and analyze several economic assessments of Hot Dry Rock (HDR) geothermal energy systems, and second, to reformulate an economic model for HDR with revised cost components. This paper in large part is an extension of our earlier work on HDR economic forecasting (see Tester and Herzog (1990) for a detailed discussion of the methodology used). The economic models reviewed include the following studies sponsored by:

- Electric Power Research Institute (EPRI)-- Cummings and Morris (1979)
- Los Alamos National Laboratory (LANL)-- Murphy, et al. (1982)

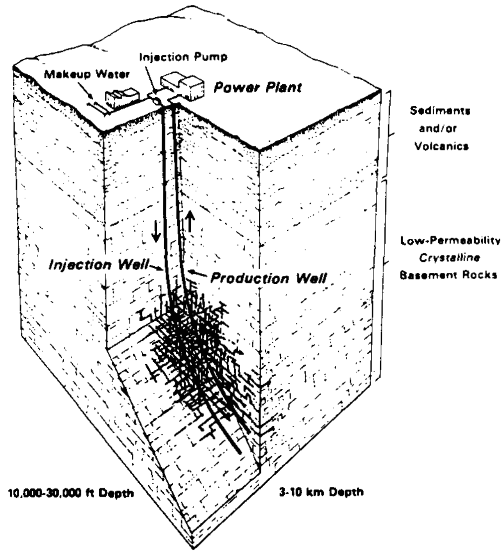

Figure 1. HDR reservoir concept for an interconnected network of fractures stimulated in a low-permeability formation (from Tester, Brown, and Potter (1989)).

- United Kingdom (UK)--Shock (1986) with an update by Harrison, et al. (1989)
- Japan--Hori, et al. (1986)
- Meridian--Entingh (1987)
- Bechtel (1988)
- Geothermik--Smolka and Kappelmeyer (1990)

Before discusssing the predictions of these models, HDR resource and performance parameters are reviewed.

Key Resource and Performance Parameters

The development of the HDR resource at a particular location depends largely on being able to gain access to high rock temperatures which will lead to acceptable fluid temperatures for generating electric power. Although some exploration for locating high quality HDR resources is required, the difficulty and costs associated with locating a suitable HDR site are far less than for hydrothermal or fossil fuel resource development. In fact, the more or less ubiquitous nature of the HDR resource suggests that its *grade* in terms of average geothermal gradient will be the single key factor influencing the "commercial-quality" of a particular site. In *Heat Mining*, Armstead and Tester (1987) subdivide the grade of HDR resources in the U.S. into two categories, *thermal* with above average gradients ≥38°C/km and *non-thermal* with gradients of about 20 to 25°C/km. About 16% of the land area in the U.S. can be categorized as a thermal area with a significant fraction existing in hyperthermal regions near or within active hydrothermal systems. A typical range for average gradients in such hyperthermal systems would be from 60 to 80°C/km. Fenton Hill, NM and Roosevelt Hot Springs, UT fall into this latter category.

Although HDR reservoir temperatures are selected as a design choice, an acceptable range can easily be bracketed for electric power applications. In any situation, one balances the cost of producing the fluid against the cost of converting its thermal energy into electric power. Effectively, this is equivalent to balancing drilling costs against power plant capital costs to reach a minimal total cost corresponding to optimal design temperature or reservoir depth for a particular HDR site. These effects are illustrated in Figure 2. Using the dashed line for reference, one can see that reservoir design temperature range from about 140°C for low gradient areas (20°C/km) to about 250°C or more for high gradient areas (>80°C/km) with a fairly flat minimum. Strictly speaking, the actual values of these reservoir design temperature optima depend on the capital costs and system performance assumptions used. These points are revisited again later in the paper.

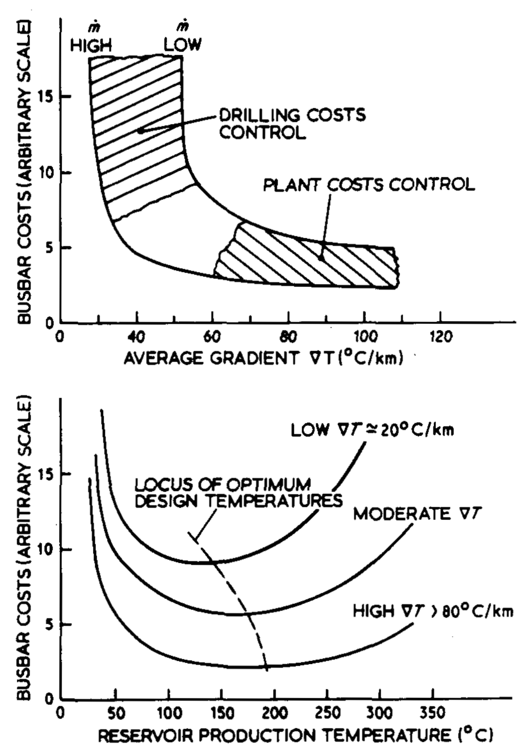

Figure 2. Generalized effects of resource quality and reservoir performance on busbar generating costs for HDR-produced electricity (from Armstead and Tester (1987)).

The temperature changes that may occur in the reservoir output fluid, as well as the rate of power production over the 20 to 40 year lifetime of an HDR system, are crucial in determining economic viability and in developing an optimal strategy for reservoir management. The most desirable approach is to maintain a constant output temperature while maximizing the mass flow rate of fluid through the reservoir. This will not be possible because any finite-sized HDR system will have a finite rate of temperature decline or drawdown. The energy drawdown rate for a fractured HDR reservoir with low formation permeability will depend on the following factors:

- Accessible fracture surface area and rock volume
- Mass flow rate of produced fluid
- Reservoir temperature distribution
- Distribution of fluid across the factured surface, and through the fractured region
- Thermal properties of the rock (density, heat capacity, and conductivity)
- Net impedance to flow and allowable pressure drop
- Water loss rates

High reservoir temperatures, low reservoir flow impedances, and large reservoir surface areas and volumes are desirable--leading to lower rates of thermal drawdown at specified fluid production rates. A key design objective is to maximize the rate of fluid throughput and energy production while minimizing the rate of drawdown. How closely this is achieved is the primary measure of energy extraction effectiveness. Furthermore with low impedance to flow, parasitic pumping losses will be minimized and in the optimal situation, "*self-pumped*" systems are possible as a result of buoyancy drive.

The issue of water loss raises some speculation about induced seismic effects and the possible economic impact of a large makeup supply of water in arid regions of the U.S. It should be emphasized that proper pressure management of the HDR system, which in extreme cases may require downhole pumping from the production well, can control or eliminate all water losses should they become a critical issue. Furthermore, in all testing to date, no measurable seismic risk has occurred.

The production of electricity from HDR geothermal resources can be accomplished in several ways. Technologies developed for low temperature energy sources such as solar, geothermal, and process waste heat are easily adaptable to the HDR system. Because pressurized hot water ranging in temperatures from about 150 to 300°C will be produced from HDR reservoirs, the following conversion options are possible (see Kestin, et al. (1980) and Tester (1982) for details):

- Single and multi-stage flash cycles
- Binary Rankine cycles employing organic working fluids (ORC)
- Trilateral Wet Vapor Cycle (TWVC) (Smith (1981))
- Total flow concepts such as the helical screw expander or the biphase turbine

Because HDR-produced fluids will most likely have low concentrations of dissolved salts and non-condensible gases, any of the four options cited above are technically acceptable in terms of performance -- economic factors will eventually determine what specific design selections are best suited to a particular HDR system and its heat rejection conditions.

HDR systems are flexible in their application to a variety of end uses. For example, they could be retrofitted to improve fossil conversion plants using cogeneration and feed water heating concepts. In some new design concepts under development, peaking with cyclic energy storage as well as the more traditional, base load applications are possible for HDR systems. A key point to remember is that HDR fluid/rock temperatures are selected by choice depending on end use requirements and the economic "grade" of a specific resource which is largely expressed by its average thermal gradient.

For all HDR applications that are envisioned, "off-the-shelf," commercial power plant systems are available. Further development of newer conversion technology such as the TWVC and total flow systems will undoubtedly increase the attractiveness of HDR by permitting operation at higher conversion efficiencies.

Comparison of HDR Economic Models

Key parameters and results for the seven analyzed studies have been tabulated in Tables 1 and 2 where one can easily see the extremely wide range of resource, reservoir, and economic parameters and assumptions. Therefore, any agreement in predicted breakeven electricity price must be regarded with

TABLE 1. COMPARISON OF KEY RESOURCE AND POWER PLANT PARAMETERS

PARAMETER	HDR ECONOMIC STUDY						
	EPRI (1979)	LANL (1982)	Japan (1986)	UK TWVC (1986)	Meridian III (1987)	Bechtel (1988)	Geothermik (1990)
Site Grade	low	high	high	low	high	high	low
Average Gradient (deg C/km)	40	55	120	35	62	78	41
Average Well Depth (km)	4	4.5	3	6	3	3.6	5.5
Initial Ave Reservoir Temp (C)	175	260	300	220	200	270	240
Flowrate per Well Pair (kg/s)	75	46	74	75	78	120	75
Water Loss Rate (%)	5	5	13	2	–	10	20
Reservoir Impedance (GPa-s/cum)	–	0.09	0.14	0.1	–	0.08	0.01
Drawdown (a)	low	moderate	moderate	low	moderate	high	moderate
Net Installed Capacity (MWe)	50	75	68.7	35.275	112	70	–
Reservoir Pumping Power (MWe)	–	0	9.2	2.275	7	20	–
Average Net Power Output (MWe)	50	75	59.5	33	105	50	–
Project Lifetime (yrs)	30	10/30	15	25	20	30	25

(a) Low corresponds to a drawdown parameter <0.0001 kg/sqm-s; moderate 0.0001–0.0002 kg/sqm-s; and high >0.0002 kg/sqm-s.

TABLE 2. COMPARISON OF NORMALIZED CAPITAL COST COMPONENTS AND PREDICTED ELECTRICITY PRICES (1989 $ BASIS)

PARAMETER	HDR ECONOMIC STUDY						
	EPRI (1979)	LANL (1982)	Japan (1986)	UK TWVC (1986) (d)	Meridian III (1987)	Bechtel (1988)	Geothermik (1990) (e)
Net Installed Capacity (MWe)	50	75	68.7	35.275	112	70	–
Individual Well Cost (M$)	–	6.3	5.8	8.2	3.0	4.0	–
($/kWe installed)	–	84.2	85.1	232.6	26.5	57.2	–
Total Well Costs (M$)	(b)	57.2	74.0	82.1	110.0	32.0	–
($/kWe installed)	–	762.9	1077.7	2326.4	982.2	457.8	–
Exploration Costs (M$)	7.9	3.6	44.2	8.1	49.6	–	–
($/kWe installed)	158.1	48.5	643.8	229.2	442.4	–	–
Stimulation Costs (M$)	(b)	7.4	22.4	8.2	54.5	15.2	–
($/kWe installed)	–	99.1	326.1	232.6	486.7	216.5	–
Fluid Distribution Costs (M$)	1.8	9.6	30.3	–	26.1	10.1	–
($/kWe installed)	37.0	128.6	336.7 (c)	–	233.1	144.4	–
Power Plant Costs (M$)	72.6	70.7	85.3	67.3	107.3	61.4	–
($/kWe installed)	1452.2	943.1	947.7 (c)	1908.8	957.8	877.3	–
Total Capital Cost (M$) (excl. AFDC)	137.1	148.7	256.3	165.7	347.4	118.7	–
($/kWe)	2741.3	1982.2	3730.1	4697.1	3102.2	1696.0	–
Average Net Power Output (MWe)	50	75	59.5	33	105	50	–
Total Capital Cost ($/kWe output)	2741.3	1982.2	4306.9	5020.9	3309.0	2374.4	–
Redrilling/Restimulation Costs (M$)	14.9	–	45.4	–	–	94.4	–
(M$/yr)	0.50	–	3.03	–	–	3.15	–
Other O & M Costs (M$/yr)	0.81	3.02	–	4.66	5.68	4.24	–
Electricity Breakeven Price (cents/kWh)	6.46	4.56	11.03	6.67	7.74	5.62	12.2

Notes: (a) All costs normalized to 1989$ using cost indexes in Figure 3 for drilling and plant construction costs. Stimulation and exploration cost normalization based on drilling cost index. Electricity breakeven price normalized on a hybrid, weighted cost index.

(b) Total well and stimulation costs are $55.8M or $1117/kWe installed.

(c) Based on 90 MWe installed.

(d) Conversion rates: $1 per pound for wellfield; $1.6 per pound for power plant.

(e) Conversion rate: 1.64 Dm/$. Individual component costs not available in this paper.

caution. Nonetheless, one can see why certain studies predict high prices and others lower ones or where particular cost components are out of line. We will discuss these predictions again later in the context of our generalized HDR economic model.

A major purpose of analyzing each study was to extract component cost information in order to guide us in developing a set of composite conditions. In addition, by reviewing the other assumptions regarding reservoir and power plant performance used in each study, we can construct a reasonable model that brackets the range of values assumed. Furthermore, by studying the range of costs and other factors, we have developed suitable intervals for parameter sensitivity studies.

HDR Component Costs

Drilling and Completion Costs

To establish base case costs and a cost range for HDR drilling, we reviewed all available drilling and completion cost data for geothermal (hydrothermal and HDR) and oil and gas wells for the period 1972-1988. The geothermal well costs came from a number of sources including Carson and Lin (1981), Entingh (1989), Batchelor (1989a), and Armstead and Tester (1987) as well as from the seven case studies being examined. Joint Association Survey (JAS) data for drilling and completing oil and gas wells in the continental U.S. in a particular year were used as a reference point to compare actual HDR well costs against.

In order to normalize well costs to a common year dollar, a drilling cost index was established as shown in Figure 3. To develop this index, JAS average oil and gas well costs based on total footage for depths ranging from 1250 ft (0.38 km) to 20,000 ft (6.1 km) were used from 1977 to 1988. In addition, Energy Information Administration (EIA) costs for 1976 to 1977 (Anderson and Funk (1986)) was used to supplement the JAS data base. For wells drilled before 1976, a 17% annual inflation factor was assumed.

Table 3 gives actual and predicted drilling and completion costs for individual wells for HDR and hydrothermal systems. 1988 JAS composite costs for completed oil and gas wells are also included in Table 3. Dry well costs were not included in deriving the JAS composite. Costs for average well depths are shown. Figure 4 presents a composite of actual and predicted well costs normalized to 1989 $. The collection of individual well cost data from a number of hydrothermal sites in the U.S. compiled by Carson and Lin (1981) was normalized to 1989 $ and plotted in Figure 5. The straight line plotted in Figures 4 and 5 corresponds to a least squares fit of the 1988 JAS oil and gas composite well cost data extrapolated to 1989 $. One immediately sees that without exception, all hydrothermal and HDR well costs are higher than a typical, average oil and gas well drilled to the same depth. Furthermore, the *bandwidth* of costs for HDR wells lies somewhat above the scatter of hydrothermal wells.

Following the methodology described earlier by Milora and Tester (1976) and later updated by Armstead and Tester (1987), we chose to establish a range of expected drilling costs for HDR wells drilled to 10 km depths. In Figure 4, an HDR base case curve has been plotted with an upper bound (HDR problem burdened) and a lower bound (HDR commercially mature) shown.

Stimulation Costs

Developing and perfecting HDR stimulation methods have been a major focus of the U.S. and UK R&D programs during the past 15 years (see Armstead and Tester (1987), Batchelor (1984 (a,b), 1987, 1989b), Tester et al. (1989) and Brown et al. (1990) for details). Although the field efforts have made considerable progress, there is not yet sufficient knowledge regarding rock fracturing characteristics to absolutely guarantee that a fractured network of sufficient size and viability can be created and connected to an appropriately designed injection and production well system. Given this inherent uncertainty, we must make several assumptions regarding the formation of such a reservoir system in order to proceed with an economic assessment of HDR.

All studies have assumed that current fracturing technology (or some modest extension of it) is sufficient to create a viable HDR reservoir at depths of interest. In addition, they have estimated the costs associated with these stimulation methods. These include the costs of pumping at high pressures and rates, costs for fluids with special rheological properties, and the costs of diagnostic geophysical testing. Figure 6 provides an estimate of stimulation costs per kWe of net installed capacity for different temperature reservoirs. Also plotted on the same figure are specific estimates for stimulation costs taken from the economic assessment studies. Note that we have tried to account for the effect of resource grade on the stimulation costs by plotting costs as a function of initial reservoir temperature. Lower gradient regions will in general require deeper wells and/or higher well flow rates and therefore proportionately higher stimulation costs will result.

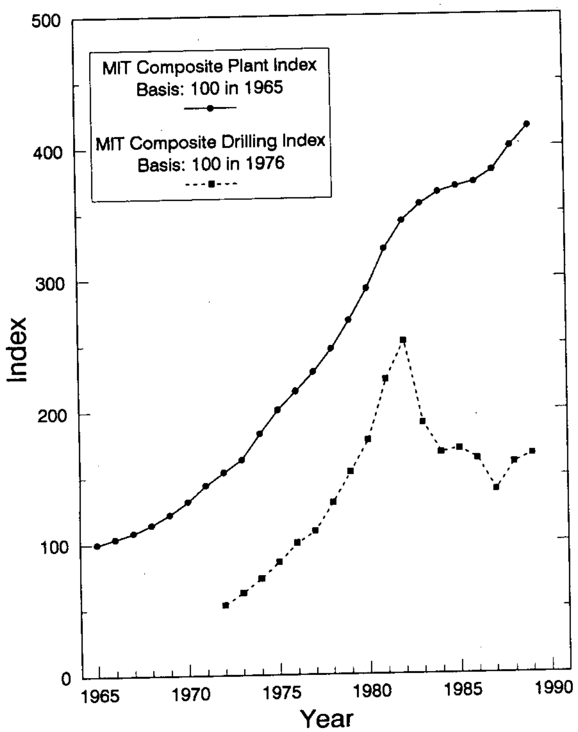

Figure 3. Estimated plant construction and drilling cost inflation indexes.

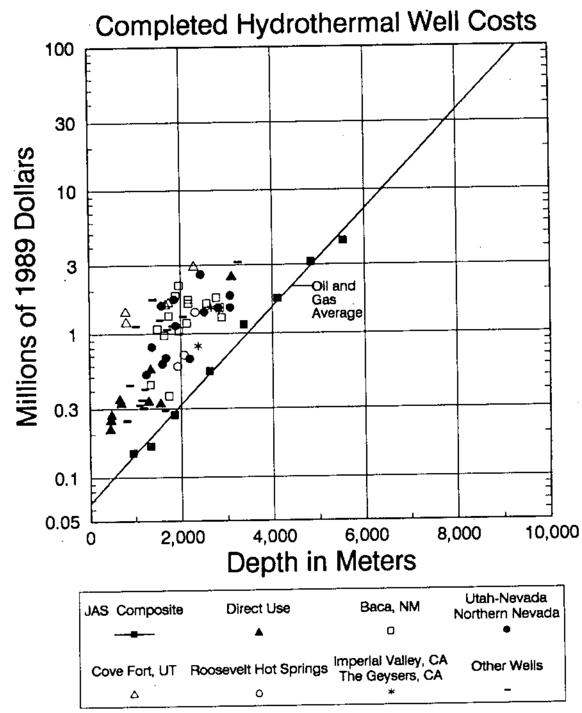

Figure 5. Actual hydrothermal completed well costs as a function of depth (adapted from Carson and Lin (1981), Batchelor (1989a), and the Joint Association Survey (1988)).

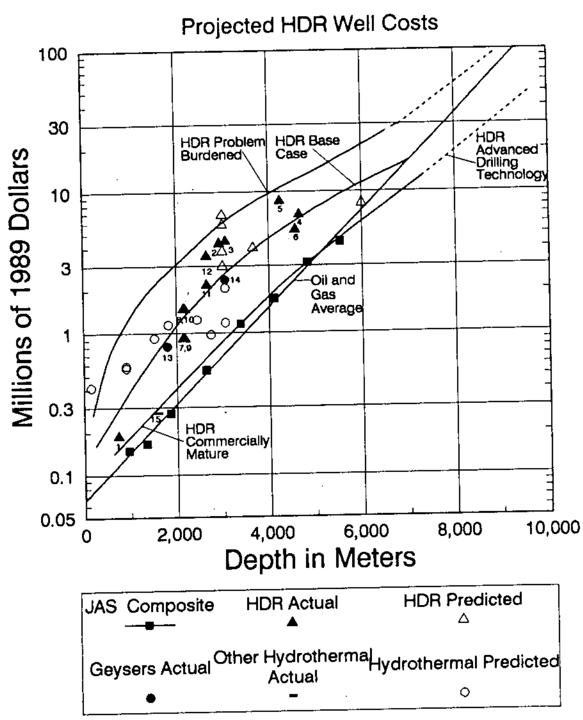

Figure 4. Projected HDR well drilling and completion costs for the base case with limits for problem-burdened, commercially mature, and advanced drilling technology shown.

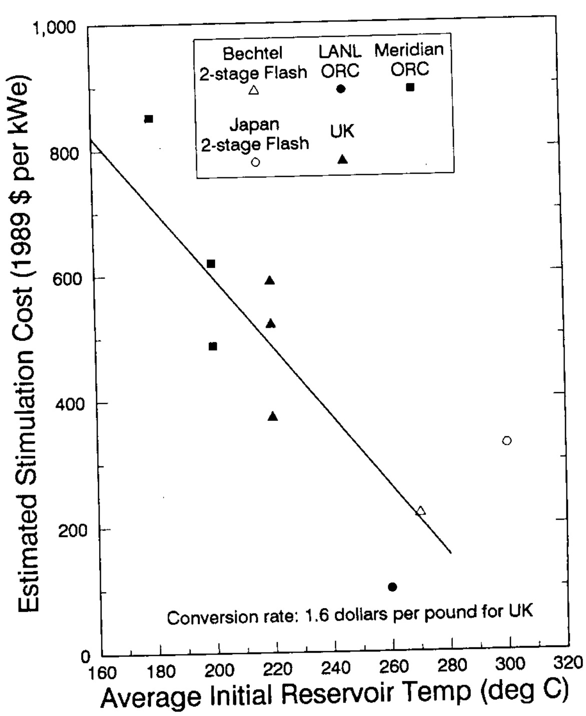

Figure 6. Estimated HDR reservoir stimulations costs in $ per kWe installed as a function of average initial reservoir temperature. Note that ORC (Organic Rankine Cycle) and 2-stage flash refer to power plant choices.

TABLE 3. ACTUAL AND PREDICTED DRILLING AND COMPLETION COSTS (1989$)

Plot #	Well ID	Depth Meters	Cost M$	Year Com-pleted	Cost 1989 M$	Comments
1	GT-1	732	0.060	1972	0.187	Fenton Hill Site, New Mexico, USA.
2	GT-2	2,932	1.900	1974	4.315	Actual costs.
3	EE-1	3,064	2.300	1975	4.465	
4	EE-2	4,660	7.300	1980	6.827	
5	EE-3	4,250	11.500	1981	8.545	
6	EE-3A	4,572	5.160	1988	5.364	
7	RH-11 (low)	2,175	1.240	1981	0.921	Rosemanowes Site, Cornwall, UK.
8	RH-11 (high)	2,175	1.984	1981	1.474	Actual costs.
9	RH-12 (low)	2,143	1.240	1981	0.921	Conversion rates:
10	RH-12 (high)	2,143	1.984	1981	1.474	low = $1 per pound.
11	RH-15 (low)	2,652	2.250	1985	2.192	high = $1.6 per pound.
12	RH-15 (high)	2,652	3.600	1985	3.507	as recommended by A.S. Batchelor (1989a).
	UK (Shock, 1987)	6,000	8.424	1985	8.206	From Camborne School of Mines ($1 per pound).
	Bechtel (1988)	3,657	3.359	1987	4.006	Predictions for Roosevelt Hot Springs, UT Site.
	Japan (1986)	3,000	6.000	1985	5.845	Predicted costs.
	Meridian (1987) I	3,000	6.900	1984	6.838	Predicted costs based on Heat Mining.
	Meridian (1987) II	3,000	3.800	1984	3.766	
	Meridian (1987) III	3,000	3.000	1984	2.973	
	Heat Mining (1987)	3,000	3.000	1984	2.973	Predicted costs.
13	Geysers	1,800	0.486	1976	0.807	Actual costs cited in Milora and Tester (1976).
14	Geysers	3,048	2.275	1989	2.275	Actual costs from A.S. Batchelor (1989a).
15	Other Hydrothermal	1,600	0.165	1976	0.274	Actual costs cited in Milora and Tester (1976).
	IM-GEO IV-FL	1,829	1.123	1986	1.146	Meridian predictions of hydrothermal wells
	IM-GEO IV-BI	2,743	0.956	1986	0.975	from their IM-GEO data base (Entingh, 1989).
	IM-GEO BR-FL	2,438	1.217	1986	1.242	Only base well costs shown.
	IM-GEO BR-BI	914	0.556	1986	0.567	See key below for hole details.
	IM-GEO CS-FL	3,048	2.032	1986	2.073	
	IM-GEO CS-BI	914	0.576	1986	0.588	
	IM-GEO YV-FL	1,524	0.906	1986	0.924	
	IM-GEO YV-BI	152	0.406	1986	0.414	
	IM-GEO GY-DS	3,048	1.155	1986	1.178	
	JAS	954	0.142	1988	0.148	Actual costs for oil and gas wells
	JAS	1,340	0.160	1988	0.166	from Joint Association Survey (1988).
	JAS	1,859	0.263	1988	0.273	
	JAS	2,628	0.528	1988	0.549	
	JAS	3,376	1.111	1988	1.155	
	JAS	4,108	1.682	1988	1.748	
	JAS	4,834	3.019	1988	3.138	
	JAS	5,539	4.236	1988	4.403	

Plot #'s refer to Figure 4.
M$ = Millions of US Dollars.
Key:
IV-FL – Imperial Valley Flash, Salton Sea, CA field.
IV-BI – Imperial Valley Binary, Heber, CA field.
BR-FL – Basin and Range Flash, Dixie Valley, NV field.
BR-BI – Basin and Range Binary, generic NV field.
CS-FL – Cascades Flash, Newberry, OR field.
CS-BI – Cascades Binary, generic OR, WA field.
YV-FL – Young Volcanics Flash, Coso, CA field.
YV-BI – Young Volcanics Binary, Mammoth, CA field.
GY-DS – Dry Steam, The Geysers, CA field (Costs from B.J. Livesay).

This methodology for estimating stimulation costs falls short of providing a clear dependence of costs on the size of the reservoir. Consequently, we examined an alternate approach. In Figure 7, the estimated cost of stimulating an HDR doublet system is plotted as a function total effective reservoir surface area in m^2 per kWe of installed capacity. By using the installed capacity to normalize costs and reservoir size, the effect of fluid temperature (and hence gradient and depth) on conversion efficiency is accounted for. Data from the Bechtel, LANL, Meridian, Japan, and UK HDR economic studies are plotted along a regressed line (solid) for the composite base case that will be used in the economic projections described later in this paper. One should note that the Meridian Organic Rankine Cycle (ORC) estimates were not used in the regression. The dotted lines shown represent twice (200%) and one half (50%) of the composite base case stimulation costs to illustrate the range of estimates.

Following the Shock (1987) study, Mortimer and Minett (1990) reexamined drilling and stimulation costs for HDR development in the UK. For a doublet well system 6 km in depth, they estimate a drilling and completion cost of 10.314 million £ ($16.5 million per doublet or $8.25 million per well at $1.6/£). This is essentially identical to the normalized Shock (1987) estimate of $8.42 million per well. Nonetheless, Mortimer and Minett's stimulation costs are considerably different than those from the Shock study and from this study's projections. For the same 6 km doublet, Mortimer and Minett estimate a cost for 3 stimulations of 6.004 million £ ($9.6 million) or 37% of the total subsurface system costs. Shock used 10% of the well costs ($1.68 million for a 6 km doublet system), which lies on our base case line in Figure 7. We feel that Mortimer and Minett's approach of using large volumes of expensive rheologic gelled fluids is too pessimistic based primarily on U.S. fracturing experience at Fenton Hill. However, in all cases, stimulation cost estimates should be regarded as only approximate in that the technology for creating commercial-sized HDR reservoirs is still under development. In the discussion that follows, we perform sensitivity analyses to further quantify the uncertainties associated with the stimulation cost component.

Power Plant Costs

Estimated costs in 1989 $/kWe installed for HDR power plants are shown in Figure 8 as a function of the fluid production temperature that would enter the plant. An upper limit of 300°C was chosen to avoid problems of mineral transport and deposition with the HDR reservoir/power plant system. A nominal 50 MWe sized plant has been selected with costs shown for an appropriate range of conditions that would be expected for applications in the U.S. A median or base case line is shown, but some variations are anticipated for different sites, geologic and ambient conditions, and plant designs. For example, heat rejection using wet cooling with ocean or river water would result in more efficient cycles, in general, with lower costs. Dry cooling or wet/dry cooling in regions of high ambient temperature and/or limited water availability would have lower efficiencies and somewhat higher costs on a $/kWe basis.

In order to achieve a common 1989 $ cost basis for plant costs, a composite cost index was developed. The data used to develop the composite came from several sources including the Chemical Engineering (CE) Plant Cost Index, Marshall and Swift (M & S) Equipment Cost Index, Nelson Refinery Construction Cost Index, and the Engineering News-Record (ENR) General Construction Cost Index. All cost indexes were normalized to 100 in 1965 and a linear average for each year was used to estimate the MIT composite index as shown in Figure 3. The composite index was then used to convert all plant costs from the studies to a 1989 $ basis. The generic cost curve from *Heat Mining* (Armstead and Tester (1987)) was also normalized and plotted for reference, and as can be seen from Figure 8, the base case line selected is approximately the same as the generic example from *Heat Mining* at a condensing temperature of 37°C. It is important to emphasize that these cost estimates are only to be used for HDR resources in the temperature range shown from 125 to 300°C; extrapolation outside the range could lead to serious errors.

Also plotted in Figure 8 are estimated power plant installed costs for the specific designs selected in the HDR economic studies. No total flow plant costs, other than the TWVC, were provided in the seven studies. Based on the observed agreement among U.S. cost estimates, we would anticipate that estimated installed HDR power plant costs would be accurate to ±20%. At any rate, the uncertainty in plant costs is significantly lower than for HDR drilling and stimulation costs as discussed above.

Generalized HDR Economic Model for Electricity Production

Building on the models and correlations presented above, a generalized HDR economic model was developed. To distinguish it from other treatments, we have labelled it the *MIT HDR* economic model, with no Institute endorsement implied. For a given

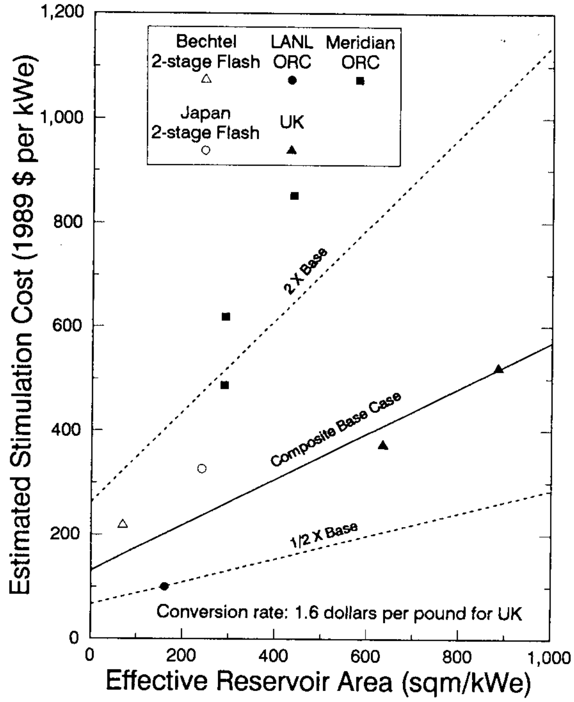

Figure 7. Estimated HDR reservoir stimulation costs in $ per kWe installed as a function of normalized effective reservoir surface area in m^2/kWe installed.

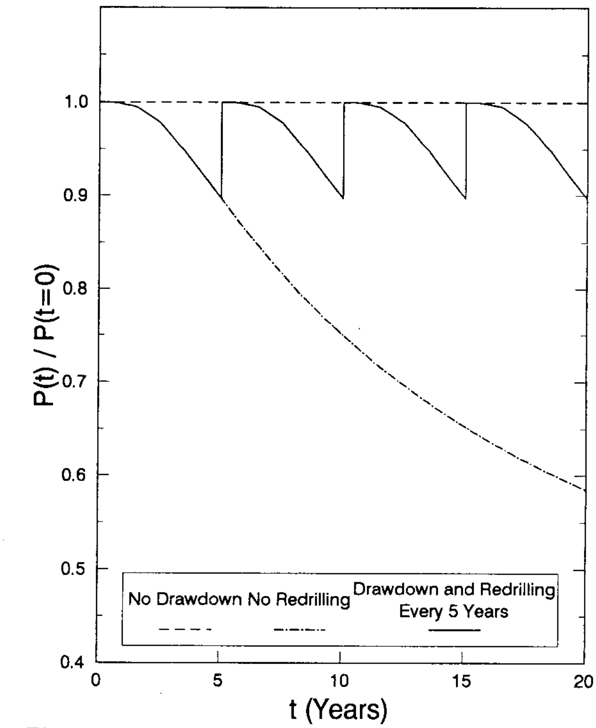

Figure 9. Net thermal performance levels as a result of thermal drawdown and redrilling/restimulation. For comparison, the cases of no drawdown and drawdown with no redrilling are shown. P(t) is the thermal power extracted at time t.

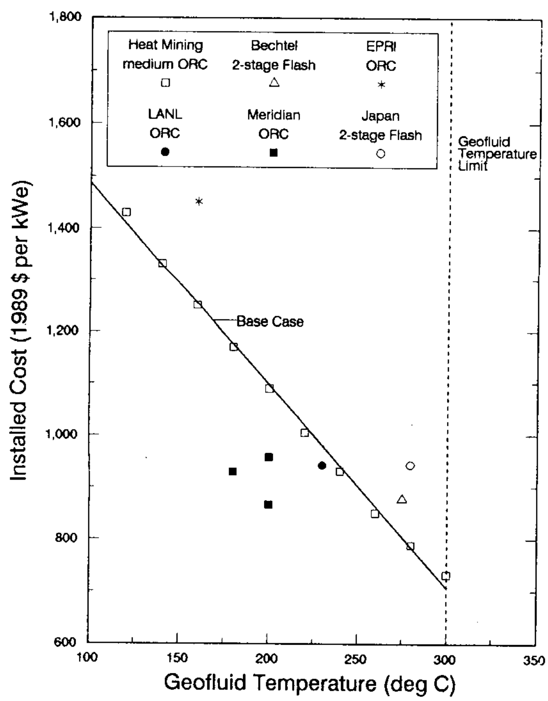

Figure 8. Estimated HDR power plant construction costs for the U.S. Base case cost estimates should only be used in the geofluid temperature range from 100° to 300°C.

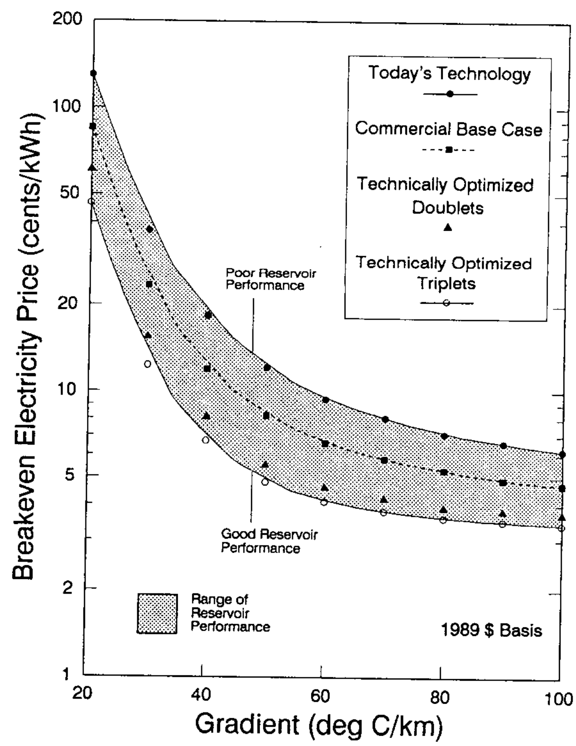

Figure 10. *MIT HDR* economic model results for electricity breakeven price as a function of gradient and reservoir performance.

set of parameters which define a technology case, the model calculates breakeven electricity price as a function of gradient. To cover a range of reservoir performances and costs, the following four technology cases were considered:

- **Today's Technology (TODAY) Case** - Reflects today's relatively high drilling and completion costs (see Figure 4, HDR Base Case line) with poor reservoir performance at a level comparable to the Fenton Hill System.

- **Commercial Base (BASE) Case** - Keeps same drilling and completion costs as the TODAY case, but reflects the improved reservoir performance required for commercial operation.

- **Technically Optimized Doublet (DOUBLET) Case** - Combines good reservoir performance with optimized drilling and completion costs (see Figure 4, HDR Commercially Mature line).

- **Technically Optimized Triplet (TRIPLET) Case** - Maintains same optimized drilling costs as DOUBLET case, but improves reservoir performance with a configuration of 1 injector and 2 producer wells per reservoir.

The specific parameters used to define these cases are detailed in Table 4. A thermal drawdown rate of 2% per year was selected. This corresponds to an effective drawdown parameter of 1.4 x 10^{-4} kg/m^2•s. Redrilling and restimulation are done at 5 year intervals to restore reservoir temperatures to their initial values. This is shown in Figure 9. For comparison, the cases of no drawdown and drawdown with no redrilling are also shown. For the cases with drawdown, the thermal power levels (P(t)) follow an error function dependence on effective reservoir heat transfer area (<A>), mass flow rate ($\dot{m}$) and time (t) as given by equation A-5 in Appendix A.

The model calculates several important engineering parameters, including average well depth, initial reservoir temperature, geothermal fluid temperature and availability, utilization efficiencies, effective reservoir area, overall pressure drop, and pumping power. Costs are calculated on a per kWe installed basis. This has the advantage of eliminating plant size as a model parameter. However, results will be most accurate for facilities in the 25-100 MWe installed capacity range, since this is the range upon which most of the correlations are based. This capacity range also corresponds to the most probable size of HDR plants to be built.

A fixed annual charge rate approach is employed because it is easy to implement and use. A 15.34% annual charge rate suggested by Entingh (1987) was incorporated. In our preliminary analyses, we used both a fixed annual charge rate and a levelized lifecycle approach. Our results showed both methods give the same trends, with the fixed charge rate yielding about 15% higher electricity breakeven prices.

The drilling and completion, stimulation, and power plant costs used were estimated from the base cases shown in Figures 4, 7, and 8, respectively. Redrilling and restimulation costs were averaged over the plant lifetime and treated as increments to the operating and maintenance (O&M) costs. All results are presented in 1989 dollars.

The key results of the *MIT HDR* economic model are given in Figure 10 and Table 5. To get a better feel for the results, compare Figure 10 to Figure 2. (Note: Figure 10 has a logarithmic y-axis compared to a linear one for Figure 2). These graphs have the same form and the discussion of Figure 2 applies equally to Figure 10. As the gradient decreases, drilling and completion costs become more dominant and drive the busbar costs up exponentially. Much of the range in costs at a given gradient is a result of reservoir performance. Poor performance translates into low geothermal fluid flowrates per well pair or per reservoir, which drive up the costs.

One place the model results differ with the earlier discussion is in optimum reservoir production temperatures (i.e., drilling depths). Figure 11 summarizes the model results. At 40°C/km and above, the model suggests drilling to a depth associated with the maximum allowable reservoir temperature (300°C). Only at lower gradients is an optimum found at lower reservoir temperatures (180-200°C for 20°C/km and 220-245°C for 30°C/km). The optimization of other reservoir and power plant design parameters are discussed in a general treatment outlined in Appendix A.

Figure 12 compares the *MIT HDR* economic model results to the breakeven electricity price reported in the seven other economic studies analyzed. Predictions using the generalized HDR economic model are in general agreement with the normalized results of the several of seven previous HDR economic studies. This agreement, however, is fortuitous unless the individual component costs for each model are close to one another. Most of the time, there was only minimal agreement on specific component costs such as drilling, stimulation, or power plant costs. But to the extent that the studies agreed on their methodology, we were able to use their data to justify and specify critical cost components in the revised composite model.

On another note, we recently received a copy of a

TABLE 4. MIT HDR ECONOMIC MODEL - CASE DEFINITIONS

TECHNOLOGY CASE	TODAY	BASE	DOUBLET	TRIPLET
ENGINEERING PARAMETERS				
Water Loss Rate (%)	5	5	5	2.5
Capacity Factor (%)	86	86	86	90
Redrilled Wells / Initial Wells	0.5	0.5	0.5	0.17
# Injectors / # Producers	1.0	1.0	1.0	0.5
Pump Efficiency (%)	80.0	80.0	80.0	80.0
Drawdown Parameter (kg/sqm-s)	0.00014	0.00014	0.00014	0.00007
T Reservoir - T Geofluid (deg C)	15.0	15.0	15.0	15.0
Maximum Reservoir T (deg C)	300.0	300.0	300.0	300.0
Production Well Flowrate (kg/s)	40.0	75.0	75.0	75.0
Reservoir Impedance (GPa-s/cum)	0.30	0.10	0.08	0.08
Injector Well Casing ID (in)	7	7	7	8.681
Producer Well Casing ID (in)	7	7	7	7
ECONOMIC PARAMETERS				
Fixed Charge Rate (%)	15.34	15.34	15.34	15.34
AFDC Rate (%)	9.0	9.0	9.0	9.0
Project Lifetime (yrs)	20.0	20.0	20.0	20.0
COST CORRELATIONS				
Drilling and Completion (Figure 4)	Base	Base	Mature	Mature
Stimulation (Figure 7)	2X Base	Base	0.5X Base	0.5X Base
Power Plant (Figure 8)	Base	Base	0.9X Base	0.9X Base

TABLE 5. MIT HDR ECONOMIC MODEL - RESULTS

GRADIENT deg C/km	BREAKEVEN ELECTRICITY PRICE (1989 $ basis) cents/kWh			
	TODAY	BASE	DOUBLET	TRIPLET
20	129.8	85.3	60.9	46.6
30	37.5	23.5	15.5	12.3
40	18.4	11.9	8.1	6.7
50	12.1	8.2	5.5	4.8
60	9.4	6.6	4.6	4.1
70	8.1	5.8	4.2	3.8
80	7.1	5.3	3.9	3.6
90	6.6	4.9	3.8	3.5
100	6.2	4.7	3.7	3.4

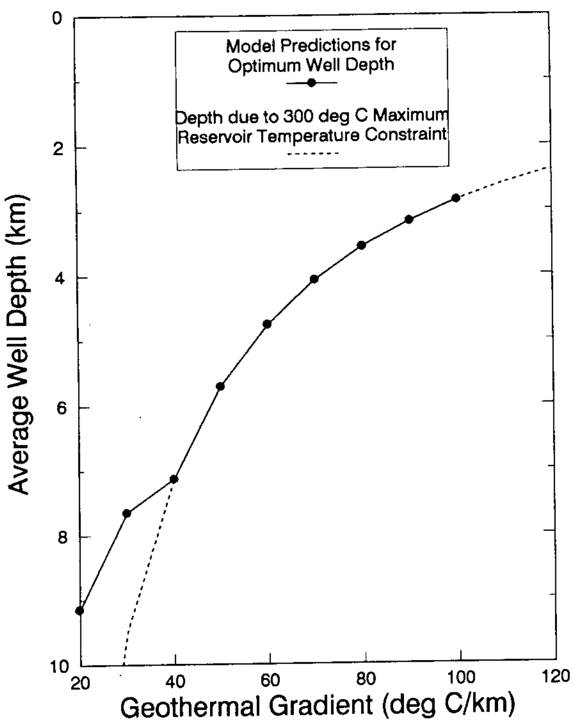

Figure 11. *MIT HDR* economic model predictions for optimum well depth as a function of gradient for the commercial base case.

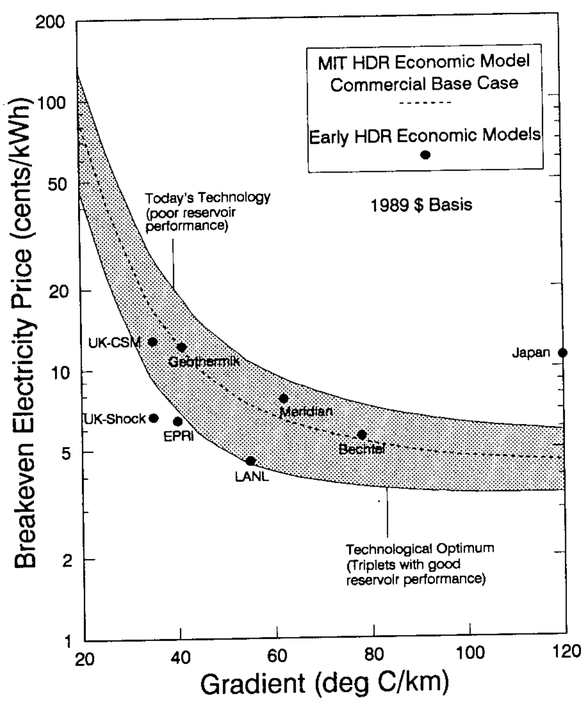

Figure 12. Comparison of *MIT HDR* economic model results to those of the seven economic studies analyzed for this report. UK estimates based on Harrison, et al. (1989) study (UK-CSM point) added at a conversion rate of $1.6/£.

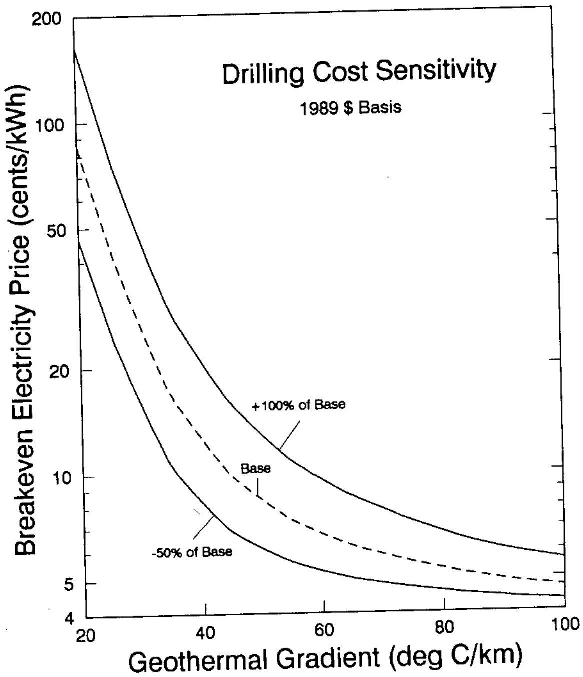

Figure 13. Sensitivity of the *MIT HDR* economic model base case to doubling and halving the drilling and completion costs.

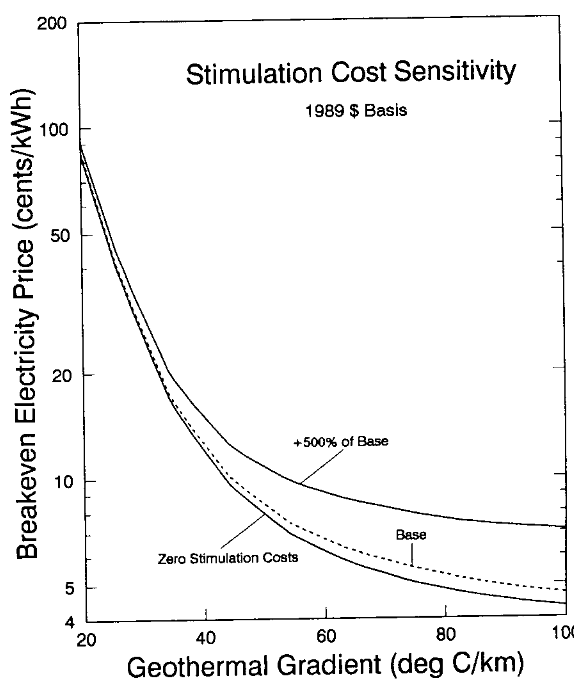

Figure 14. Sensitivity of the *MIT HDR* economic model base case to stimulation costs. The two sensitivity cases considered are zero stimulation costs and six times the base case stimulation costs (+500% of base).

paper by Harrison, Doherty, and Coulson (1989) that updates the Shock (1986) study of HDR economics in the UK. The resource and reservoir performance parameters used by Harrison, et al. are identical to those used by Shock (see Table 1). However, Harrison and coworkers based their power plant design on a two stage-flash system. Although their results are not presented in detail, their estimate of 8 pence/kWh (approximately 12.8¢/kWh) is very consistent with our projections for mid- to low-grade HDR resources.

Case studies were performed with the *MIT HDR* economic model to determine breakeven price sensitivity to certain model parameters. This phase of the investigation focused on areas with the greatest uncertainty, specifically optimum well depth, drilling and completion costs, stimulation costs, and thermal drawdown rates. Our analysis showed:

1. The price versus depth curve is fairly flat near the optimum (see Figure 2). This leads to some uncertainty as to optimum drilling depth.

2. Price is highly sensitive to drilling and completion costs (see Figure 13). At low and mid-gradients, this sensitivity is an order of magnitude greater than sensitivity to stimulation costs (see Figure 14) or to power plant costs.

3. The MIT HDR model is much more sensitive to production flowrate than drawdown. Thus, maximizing flowrate per reservoir is desirable, even at the expense of increasing drawdown rate. Of course, this principle cannot be carried to the extreme limit of an unacceptably high rate of drawdown that would not permit an adequate payback of the capital investment in drilling and stimulation.

Conclusions and Recommendations

Several general conclusions can be drawn from our projections assuming base case performance and costs:

1. High-grade (80°C/km) HDR resources are competitive at today's energy prices.

2. Mid-grade (50°C/km) HDR resources are only marginally competitive at today's energy prices. With higher oil prices >30$/bbl and/or environmental costs associated with fossil-fuel fixed systems, e.g., an acid rain or carbon tax, mid-grade HDR systems would be competitive.

3. Low-grade (30°C/km) HDR resources would not be competitive for electricity production until significantly higher energy prices exist. Although it should be noted for direct heat (space or process heating) or for cogeneration applications, low-grade HDR resources would compete much more favorably because Second Law efficiencies for conversion of HDR thermal energy into electricity are not relevant.

As a result of our economic analysis, we can identify where research should be focussed to improve the commercial viability of lower grade HDR resources (<50°C/km). The technologically optimized cases are first guesses of how far advanced drilling and reservoir stimulation technology might go with a sustained R&D effort. An R&D effort should be sustained in order to continue the development of the following crucial elements of HDR technology:

- Improved drilling technology to lower drilling and completion costs. This will open up the low- to mid-grade HDR resource for commercial development.

- Reservoir formation and stimulation technique development to improve reservoir performance, including flow impedance reduction. This will lower costs proportionately.

- Reservoir diagnostic technique development using seismic, tracer, and other geophysical methods for geometry characterization and system design optimization to reduce risk.

- Modeling of the thermal-hydraulic and geochemical behavior of fractured HDR reservoirs to reduce risk.

- Evaluation of untested concepts such as operation with multiple production wells (e.g. triplet arrangement); cyclic operation with pumped storage for peaking power supply or hybrid/cogeneration applications to demonstrate flexibility of HDR systems.

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Appendix A A general approach to optimizing the performance of an HDR system

In our earlier work (Milora and Tester, 1976; Tester, 1982; and Armstead and Tester, 1987) we considered how several control variables affected the breakeven price of HDR-generated electricity. These included well depth (Z), gradient (∇T), and mass flow rate ($\dot{m}$). Given that we have constructed an analytical representation of system performance in terms of thermal or electrical power output, it is possible, at least conceptually within a somewhat idealized framework, to describe a general multiparameter optimization to include the effects of all important input and control variables relating to resource and reservoir properties. The set of variables includes:

Input Variables

1. gradient (∇T)
2. initial flow impedance ($I(t=0)$)
3. rock and water thermophysical properties ($\rho, C_p, \lambda, ...$)
4. ambient heat rejection condition (T_o)

Control Variables

1. mass flow rate ($\dot{m}$)
2. reservoir size (<A>)
3. reinjection temperature (T_{inj})
4. well depth (Z)
5. redrilling strategy

The total electrical output over the production period of the reservoir (t_f) can be expressed in integral form as:

$$E_e(t_f) = \int_0^{t_f} [\dot{m}\eta_u(T(t))\Delta B(T(t),T_{inj},T_o) - P_{pump}(\dot{m},t)]\,dt \quad \text{(A-1)}$$

where

$\dot{m}$	=	mass flow rate
η_u	=	utilization efficiency
ΔB	=	availability = $\Delta H - T_o\Delta S$ over $\{T(t), T_{inj}\}$
P_{pump}	=	pumping power required to circulate fluid at a flow rate $\dot{m}$ and time t
T(t)	=	reservoir fluid production temperature
T_{inj}	=	reinjection temperature
T_o	=	ambient temperature

In turn, we can express the dependence of η_u on T(t) as:

$$\eta_u = 0.21 + 0.41\left[\frac{1}{1 + \exp\left[-\frac{T(t)+\beta}{\alpha}\right]}\right] \quad \text{(A-2)}$$

to empirically match plant performance data where α and β are adjustable parameters (see Armstead and Tester (1987), Figure 14.3, p. 404). The availability, in turn, can be calculated rigorously as:

$$\Delta B = \int_{T_{inj}}^{T(t)} C_p(T)[1 - T_o/T]\,dt \quad \text{(A-3)}$$

where $C_p(T)$ is the heat capacity of saturated liquid water which can be approximated as:

$$C_p(T) = A + BT + CT2 \quad \text{(A-4)}$$

where A, B, C are empirically fit parameters to steam table data. The outlet reservoir fluid production temperature T(t) will, in general, be a complex function of the geometry, flow characteristics, and thermophysical properties of the reservoir. For conceptual sensitivity studies, a simple idealized model involving 1-D flow and 1-D rock conduction can be used. (Armstead and Tester (1987) and Tester and Herzog (1990)). In this case,

$$T(t) = T_{inj} + (T_r^{\infty} - T_{inj}) * \mathrm{erf}\left[\frac{\lambda_r <A>}{\dot{m} C_p \sqrt{\alpha_r t}}\right] \quad \text{(A-5)}$$

where

T_r^{∞} = initial rock temperature at depth

λ_r = rock thermal conductivity

α_r = rock thermal diffusivity

C_p = fluid heat capacity

<A> = effective reservoir heat transfer area

Redrilling and restimulating the reservoir at some time $t < t_f$ will, of course, change the formulation of equation (A-5).

The pumping power required to circulate fluid through the reservoir/well bore system is dependent on frictional losses in the well bore and reservoir. Bouyancy effects caused primarily by the density difference between the hot and cold legs of the system reduce the pumping requirement. Reservoir losses are typically expressed in the form of an impedance term (I) which must be specified while well bore losses can be estimated for given hole and casing diameters, well depth, and mass flow rate.

For a complete economic analysis, the capital and operating costs for creating and maintaining the well bore/reservoir system and for constructing and running the power plant must be incorporated. Nonetheless, much can be learned by examining how the net electrical output over a specified production period depends on the control variables. Electrical power is the commodity that is priced to meet capital and operating cost burdens to establish a so-called breakeven price.

In our earlier work, we have optimized performance with respect to only one control parameter at a time, such as geothermal gradient and optimal well depth as shown in Figure 11. Each point on that figure was established by varying depth at a fixed gradient to establish a minimum breakeven cost for electricity. (see Tester and Herzog (1990) for details). Above a gradient of 40°C/km the cost versus depth curve had a very shallow minimum or was still decreasing when the maximum 300°C reservoir temperature boundary was reached. This result was contingent on specifying all other parameters, including flow impedance, thermal drawdown rate, and well flow rate at their base case conditions as given in Table 4.

With the general model described above, we can begin to study how performance is affected by other important control variables from a fundamental perspective. For example, how does drawdown rate expressed by $\dot{m}/<A>$ influence the net electrical output from an HDR system over its lifetime or how does reinjection temperature affect output. Equation (A-1) can be modified to more clearly show this effect by setting the parasitic pumping power to zero and dividing by <A>:

$$\frac{E_e(t_f)}{<A>} = \int_0^{t_f} \left[\frac{\dot{m}}{<A>} \eta_u(T(t)) \Delta B(T(t), T_{inj}, T_o)\right] dt \quad \text{(A-6)}$$

Figures A-1 and A-2 illustrate the effect of drawdown on net output per unit reservoir area for a HDR system at 50°C/km and 5.7 km depth with a reinjection temperature of 55°C with no redrilling or pumping losses. The four graphs corresponding to points A, B, C and D show the power output versus time over a 20 year production period at particular values of $\dot{m}/<A>$. Note that maximum electrical output is achieved as the production rate $\dot{m}$ is balanced with reservoir size <A> at a drawdown parameter $\dot{m}/<A>$ of about 0.5 x 10^{-4} kg/m^{2}s.

Higher values of $\dot{m}/<A>$ result in too rapid production temperature decline reducing performance by lowering η_u and ΔB while lower values result in suboptimal output controlled by the $\dot{m}/<A>$ term in equation (A-6).

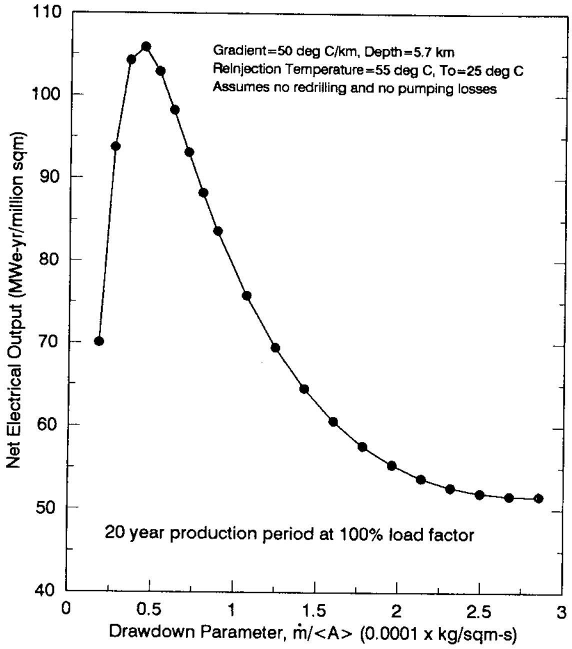

Figure A-1. Effect of reservoir thermal performance on electrical output.

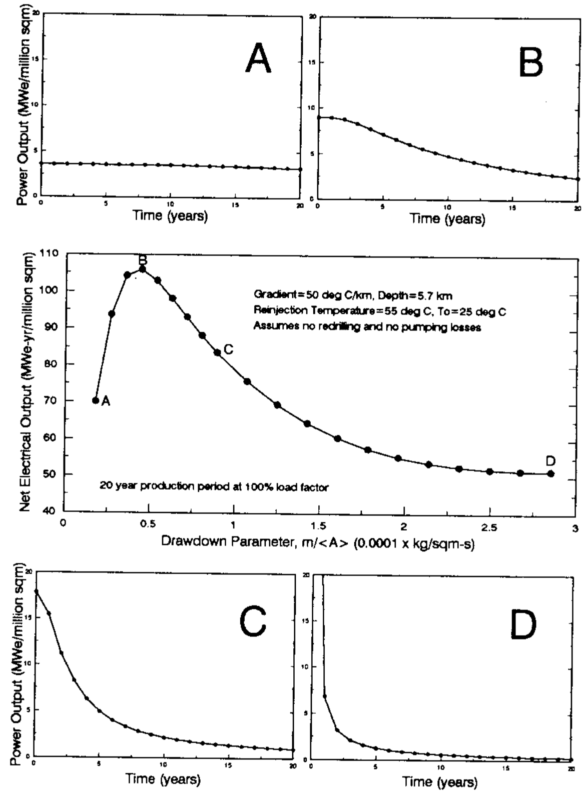

Figure A-2. Time histories of electrical power output for representative values of drawdown parameters ($\dot{m}/<A>$).