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ECONOMICS OF A CONCEPTUAL 75 MW HOT DRY ROCK GEOTHERMAL ELECTRIC POWER STATION

by

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Abstract

Man-made, Hot Dry Rock (HDR) geothermal energy reservoirs have been investigated for over ten years. As early as 1977 a research-sized reservoir was created at a depth of 2.9 km near the Valles Caldera, a dormant volcanic complex in New Mexico, by connecting two wells with hydraulic fractures. Thermal power was generated at rates of up to 5 MW(t) and the reservoir was operated for nearly a year with a thermal drawdown less than 10°C. A small 60kW(e) electrical generation unit using a binary cycle (hot geothermal water and a low boiling point organic fluid, R-114) was operated. Interest is now worldwide with field research being conducted at sites near Le Mayet de Montagne, France; Falkenberg and Urach, Federal Republic of Germany; Yakedake, Japan; and Rosemanowes quarry in Cornwall, United Kingdom. To assess the commercial viability of future HDR electrical generating stations, an economic modeling study was conducted for a conceptual 75 MW(e) generating station operating at conditions similar to those prevailing at the New Mexico HDR site. The reservoir required for 75 MW(e), equivalent to 550 MW of thermal energy, uses at least 9 wells drilled to 4.3 km and the temperature of the water produced should average 230°C. Thermodynamic considerations indicate that a binary cycle should result in optimum electricity generation and the best organic fluids are refrigerants R-22, R-32, R-115 or R-600a (Isobutane). The break-even bus bar cost of HDR electricity was computed by the levelized life-cycle method, and found to be competitive with most alternative electric power stations in the U.S.

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INTRODUCTION

The basic idea in extracting energy from hot dry rock is to form a man-made geothermal reservoir by drilling into high-temperature, low permeability rock. A circulation loop is then formed by connecting a second drill hole to the first by hydraulic fracturing and forcing water to sweep heat from the rock in the fractured region between the wellbores. The hot water produced at the surface may be used for generating electricity, space heating, or other direct uses. Research has been conducted by the Los Alamos National Laboratory at a site called Fenton Hill, on the flank of a a dormant volcanic complex, the Valles Caldera, in Northern New Mexico (Fig. 1). Initial feasibility studies were conducted by creating a small reservoir, called Phase I, in biotite granodiorite, a hard crystalline rock, at a depth of 2.9 km, where the temperature was 190°C. Reservoir testing results are reported in detail elsewhere[1], but the major conclusions are summarized as follows.

(1) Resistance to flow was low enough that the power required to pump the water through the fractures and wells was only a small fraction of the thermal power extracted from the rock,

(2) Rate of water loss due to permeation of the rock surrounding the fractures was approximately 10% of that circulated through the fractures.

(3) Heat extraction characteristics of even the small Phase I reservoir were sufficient that 3 to 5 MW(t) of heat were produced for more than 9 months with a decline of production temperature of only 8°C.

(4) Quality of water circulated through the reservoir was good, with a pH of 6.5 ± 0.5 and a total dissolved solids content of 3000 ppm.

(5) Seismic activity was negligible; microearthquakes associated with heat extraction measured less than minus one on the extrapolated Richter scale.

Interest is now world-wide and field research is being conducted in the Federal Republic of Germany, France, Japan and the United Kingdom. In the U.S. further work continues with a new reservoir, Phase II, which will be created at the Fenton Hill site also. Drilling of two new wells to a depth of 4.3 km, where the rock temperature is 325°C, was completed in 1982 and a reservoir capable of sustaining a thermal power of 35 MW(t) for at least 10 years is being developed by creating multiple fractures in the rock between the two wells. This new reservoir is intended as a preliminary demonstration

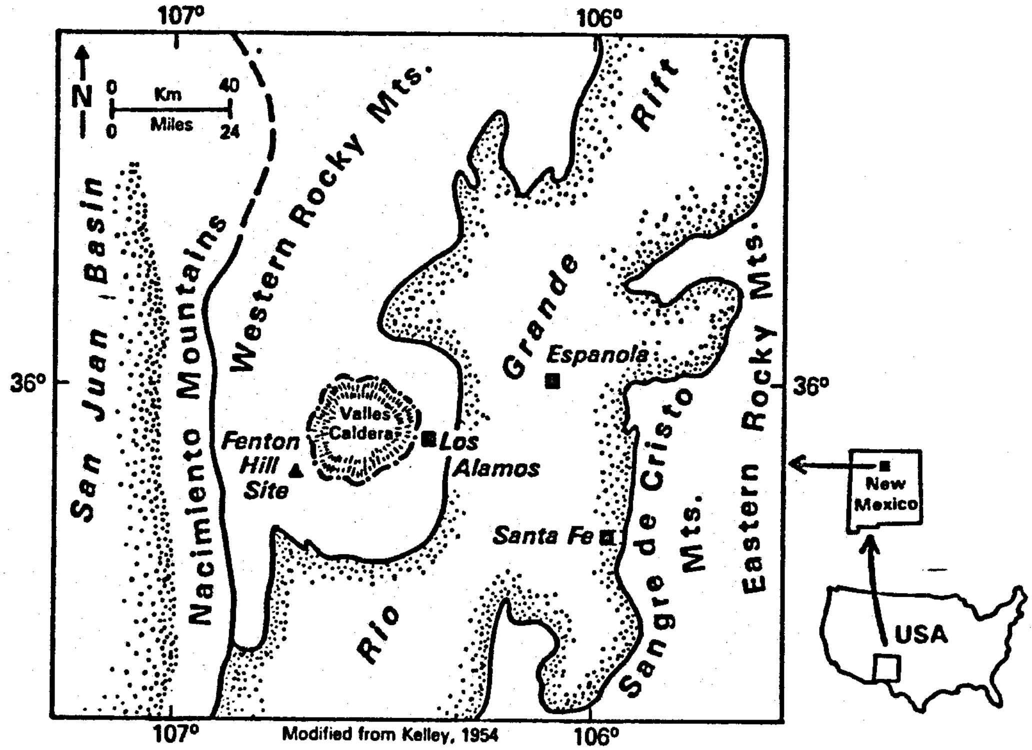

Fig. 1.
Location map of Los Alamos National Laboratory HDR drill holes.

of commercial viability of electricity generation from HDR reservoirs, and serves as a building block reservoir such that the much larger reservoirs required for generation of significant amounts of electrical power can be created by repeating the Phase II unit. The present economic study is based precisely on such a scaled-up design, and thus it differs from the pioneering studies of Tester et al.[2] and Cummings et al.[3], which were generic in nature, rather than detailed analyses of specific reservoirs.

Design of the Phase II reservoir is summarized in the following section and then scaled to a size capable of 75 MW(e) of electricity generation. The succeeding sections summarize power generation thermodynamics and economics.

RESERVOIR DESIGN

The goal for the Phase II reservoir is to produce thermal power of 35 MW(t) with no more than 20% drawdown in 10 years. From one-dimensional heat conduction theory[4] and using thermal transport properties for crystalline rock, it can be shown that an effective heat transfer area of approximately

1×10^6 m^2 is required. This area requirement represents one side of a fracture only and could be satisfied by one single fracture, or several parallel fractures. A single fracture would require, if circular, a radius of 580 m, which is beyond the fracturing technology so far demonstrated in HDR reservoirs. Consequently, the conservative philosophy has been adopted that the Phase II fractures will not be much larger than that created in the earlier Phase I reservoir, which had an effective heat-transfer area of about 50,000 m^2, as established by its thermal-drawdown characteristics. Fracturing capabilities will be expanded for the Phase II reservoir, so it is planned to create fractures about 50% larger. Consequently, approximately 15 such fractures will be required for a total of one million m^2.

Because the horizontal earth stresses at depth are usually smaller than the vertical, or overburden stress, fracture planes are expected to be vertical. In order, then, to accommodate 15 fractures with reasonable horizontal separation distance between fractures, it is necessary to deviate the wells from the vertical direction in the hot downhole region, as shown in Fig. 2. A well deviated too far from the vertical is impractical because it becomes difficult to center and set casing, and even more difficult to run logging tools. As a compromise, an angle of 35° was chosen.

To avoid excessive heat-extraction deterioration because of thermal interference between the fractures, they must be horizontally separated by approximately two times the thermal diffusion distance, $\sqrt{\kappa t}$, where κ is the rock thermal diffusivity and t is time. For 10 yr the required separation is 35 m, which for 15 fractures requires a total horizontal distance of about 500 m. After turning the wells to 35° from vertical, the wells were drilled to a depth of 4.3 km. The vertical distance between wells was maintained at approximately 360 m as intended. The total heat energy over the temperature interval 50 to 260°C of a cylinder of rock 360 m in diameter and 535 m long is 3.2×10^{16} J. Over a 10-yr period, with 100% water sweep efficiency, an ideal volumetric source of heat from such a cylinder could provide energy at the rate of 103 MW(t).

Results of more realistic calculations in which the water injected to extract the rock heat is confined to the fractures, so that heat must be inefficiently conducted through the rock to reach the water, are presented in

Fig. 3. These computations are based upon parallel equi-distant fractures in which the intra-fracture water sweep efficiency was 70% and the thermal draw-down was limited to 20%. The effects of buoyancy, which can often enhance sweep efficiency in vertical fractures was neglected because experience in the Phase I reservoir suggests that buoyancy is unimportant with normal operating procedures.

Figure 3 illustrates an expected result: for a given number of fractures one can produce more <u>power</u>, i.e., rate of energy, if one reduces the expected lifetime. But unlike the theory for an ideal, volumetric source of heat, the conduction theory for a finite number of fractures does not result in a fixed, total energy. For example, for say 10 fractures, one can extract 25 MW for 10 yr, a total energy of 250 MW-yr, or one can extract 18 MW for 20 yr, a total energy of 360 MW-yr. In the second case the thermal boundary layers spreading into the rock from the fracture surfaces propagate further, so that the effective reservoir volume is larger. These boundary layers propagate proportionately to the square root of time, so it is not surprising that the ratio of total energies for the two cases, 1.44, is very close to the square root of two, the ratio of the lifetimes. In the extreme of very many

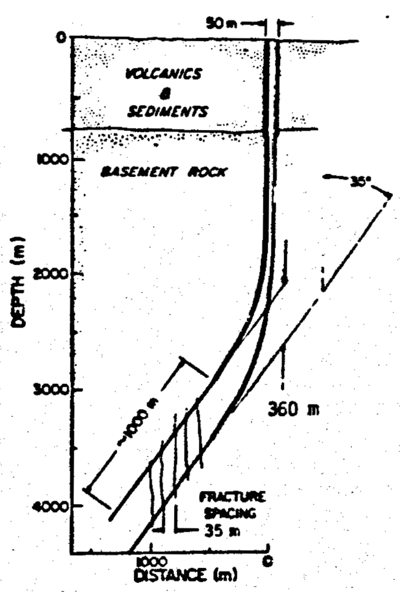

Fig. 2.
Proposed Phase II fracture system.

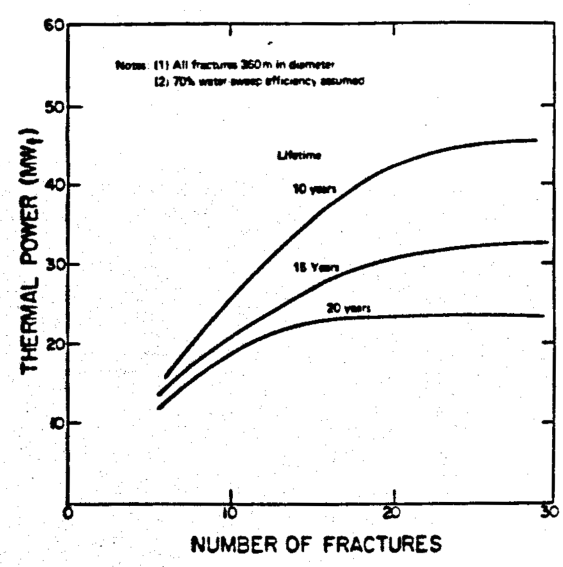

Fig. 3.
Effect of life-time and number of fractures on thermal power.

fractures, so that the spacing between them is small, the thermal boundary layer thickness quickly attains a value equal to the spacing between fractures. In this case the thermal interference between fractures is severe, and in fact the energy per fracture is limited by the total energy of the volume of rock between fractures. In the limit of many fractures, the reservoir approaches the ideal volumetric source model. This is observed in Fig. 2; when the number of fractures exceeds 25, the thermal power no longer increases with number of fractures, and the maximum power for a 10-yr lifetime is exactly twice that of a 20-yr lifetime.

A suitable heat production rate can be obtained by varying either the number of fractures or the lifetime. Focusing on the 10-yr results for example, 35 MW(t) could be extracted with 15 fractures; but 45 MW(t), only 30% more power, requires nearly twice as many fractures. Fracturing is expensive, so increasing power by increasing the number of fractures soon runs counter to the law of diminishing returns. Consequently it was decided to keep the number of fractures in a reasonable range, say 10 to 20 fractures. Turning now to the question of lifetimes, compare two cases with the same number of fractures, but quite different lifetimes: (1) 10-yr life with 15 fractures, and, (2) 20-yr life with 15 fractures. In the first case 35 MW(t) will be produced, whereas 23 MW(t), some 33% less, will be produced in the second situation. A clear trade-off of power-level vs lifetime is presented. For a fixed, total generating capacity the second situation will require 33% more reservoirs and 33% more wells. Drilling is expensive, so at today's high interest rates the yearly cost of amortizing the extra wells, even though over a longer period, is more than amortizing, in the first situation, a lesser number of wells over a shorter period. In other words, the present value of future heat production is low when interest rates are high.

Therefore it was decided to adhere closely to the original Phase II reservoir design, i.e., to consider a building-block reservoir of 16 fractures capable of providing 37 MW(t) over 10 yr. This design is rather conservative because it disregards the beneficial effects of additional fracturing due to cooling-induced thermal stresses, which were demonstrated in Phase I[5]. Furthermore, reuse of the wells, for example, by deepening or side-tracking them into virgin rock, was not considered. In theory a new building-block reservoir could be produced by drilling an additional horizontal length of 535 m, which, at an angle of 35°, requires an additional drilling of 940 m. However, as a consequence of the nearly exponential depth-cost relation discussed later, the cost of deepening a 4.3-km-deep well only 940 m is 70% of the cost of drilling a new well from the surface to approximately 4.3 km. While an economic argument could thus be made to deepen existing wells, nevertheless the conservative view was adopted that the old wells may have suffered some damage over a 10-yr period, and it was assumed that new wells would be drilled. The situation with regard to sidetracking, or deviating, a well into laterally adjacent rock is more difficult to evaluate. Despite the great difficulty and expense experienced while sidetracking Fenton Hill wells GT-2 and EE-3, one would assume that in a commercially mature HDR industry such costs could be significantly decreased; and a program of research in this area is recommended. However, the outcome of such a program could not be anticipated here, so again, it was conservatively assumed that completely new wells would be drilled.

Scaling up to 75 MW(e)

As shown in the next section, the net efficiency of converting thermal power to electrical power is low, and consequently the Phase II building-block reservoir will generate only 6.5 MW(e); 12 such reservoirs, a total of 192 fractures, would generate 78 MW(e). It will be necessary to derate the system by 2 to 3 MW(e) to provide dry cooling, resulting in a nominal 75 MW(e) system. Figure 4 shows that twelve building-block reservoirs could be created by drilling nine wells in the pattern shown. No actual reservoir could be created in quite so idealized a manner as presented in Fig. 4. While it is unlikely, following initial exploration, that a completed HDR well could ever be a complete failure, some wells may have to be abandoned before completion due to unforeseen difficulties. Furthermore, it may not be possible to fracture all the wells at the frequent intervals desired. To account for these difficulties, it was assumed in the following calculations that four additional wells, a 44% contingency factor, would have to be drilled, and, as discussed later, a contingency of 150% is applied to fracturing time and costs.

It will be observed that each reservoir fracture in Fig. 4 is a square, of length $S/\sqrt{2}$ on each side, where S is the spacing between wells, and the wells are at opposite corners. In contrast the Phase II fractures will likely

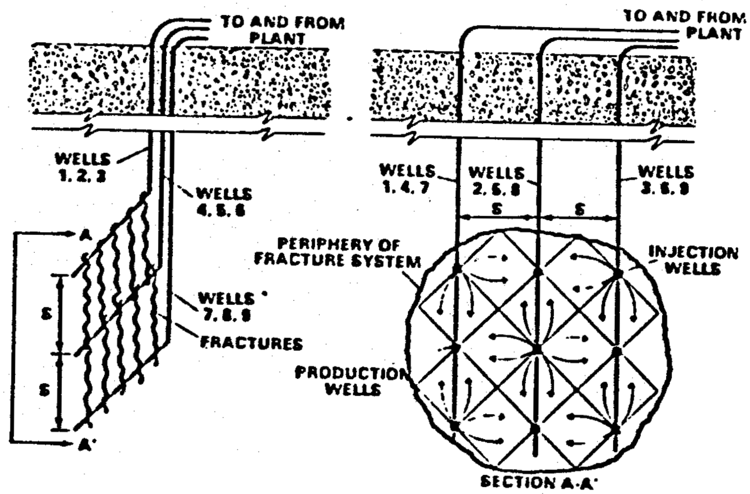

Fig. 4.
Conceptual nine-well HDR reservoir for 75 (MW(e) generating plant.

resemble circles of diameter S. The area of each circle is $\pi S^2/4$ whereas the area of the square is $S^2/2$, i.e., only 64% as large as the circle. Recall however that the water sweep efficiency of the circle was only 70%. While the sweep efficiency of the square will not attain 100%, it certainly will be considerably greater than 70% because the wells are located at the extremes of each square in the corners. Thus the effective heat-transfer areas of the circles and squares should not differ significantly, and furthermore, some contingency for additional heat transfer area was provided above in the contingencies for additional wells and fractures.

THERMODYNAMICS

Consider[6] an infinite number of reversible heat engines each generating an infinitesimal amount of work δW and rejecting heat at the temperature T_o. Integration over the temperature range T_{gf}^{in} to T_{gf}^{out} then yields the maximum work, or the change in availability, ΔB.

$$\Delta B = \Big[\Delta H - T_0 \Delta S\Big]_{T_{gf}^{in}}^{T_{gf}^{out}} , \tag{1}$$

where ΔH and ΔS are the enthalpy and entropy changes. One can then develop[6] an approximate expression for the maximum Carnot cycle efficiency, η_c^{max}:

$$\eta_c^{max} \doteq \frac{\Delta B}{\dot{m}_{gf} C_p [T_{gf}^{in} - T_{gf}^{out}]} \doteq \frac{T_{gf}^{in} - T_o - T_o \ln \frac{T_{gf}^{in}}{T_o}}{T_{gf}^{in} - T_{gf}^{out}} \tag{2}$$

where $\dot{m}_{gf}$ is the mass flow rate through the reservoirs and C_p is the specific heat of the water. In eq (2) all temperatures must be expressed as absolute quantities. In the limit of a perfect power conversion process $T_{gf}^{out} = T_o$: therefore η_c^{max} reduces to:

$$\eta_c^{max} = 1 - \frac{T_o}{T_{gf}^{in} - T_o} \ln \frac{T_{gf}^{in}}{T_o} \tag{3}$$

Using an average temperature of 230°C for T_{gf}^{in} as stated earlier and a heat rejection temperature, T_o, equal to the average ambient air temperature, approximately 3°C, η_c^{max} is 0.27.

Next we must address the question of the proper utilization efficiency, η_u, to use to obtain the overall conversion efficiency, $\eta_u \cdot \eta_c^{max}$. Two questions arise: first, what is the optimum thermodynamic efficiency, and second, how close to this thermodynamic optimum should one operate for <u>economically</u> optimum conditions to prevail? The thermodynamically optimum η_u depends on:

1. power cycle fluid choice
2. geothermal fluid temperature
3. ambient temperature,
4. mechanical efficiencies for the turbine and the power cycle feed pump, with the usual assumptions being $\eta_{turbine} = 0.85$ and $\eta_{pump} = 0.80$
5. approach temperatures in the primary heat exchanger and condenser system, (pinch point ΔT's).

A single fluid organic binary cycle, as shown in Fig. 5, is the best choice, rather than, say, a direct flashing cycle, because: (1) in semi-arid locations like New Mexico water consumption should be minimized by avoiding flashing cycles, (2) water should not be used as the working fluid in the power cycle

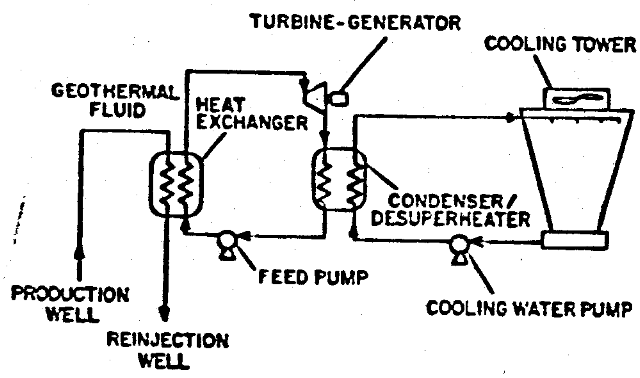

Fig. 5.
Binary-fluid cycle generating system.

because of its low vapor density at temperatures below 35°C, and (3) the turbine exhaust end areas are too large when water is the working fluid.[6] Typical binary cycle utilization efficiencies are shown in Fig. 6. For the expected geothermal fluid temperature of 230°C, maximum η_u's would range from 50 to 65% depending on the choice of working fluid.[7] This range of η_u's has not only been documented in previous work,[6-8] but it also agrees with Pope et al.[9] and Eskesen[10] who give a range of 52 to 55% for 3 binary fluids: isobutane, isopentane, and propane.

The second question is the more controversial one. How close to this maximum η_u can a real, economically feasible, cycle be operated? As pointed out by Milora and Tester[6] and Pope et al.,[9] the cost of producing the water (drilling wells, etc.), relative to the cost of converting the heat to electric power (heat exchangers, pumps, turbines, condensers, etc.) is critical in determing how close to this optimum one operates. For the 75 MW(e) HDR generating station the reservoir development costs are 1.5 times the conversion equipment costs, so the maximum η_u resulting with supercritical operation and ΔT's of 10-15°C would be near-optimal from an economic standpoint. This is to be contrasted to results for a hydrothermal resource[9], where η_u = 40 to 45% for situations where the ratio of well costs to total equipment cost is less than 50%. Based upon these discussions we assume an operating economic η_u of 55% on average. Therefore, the net thermal conversion efficiency is 15%.

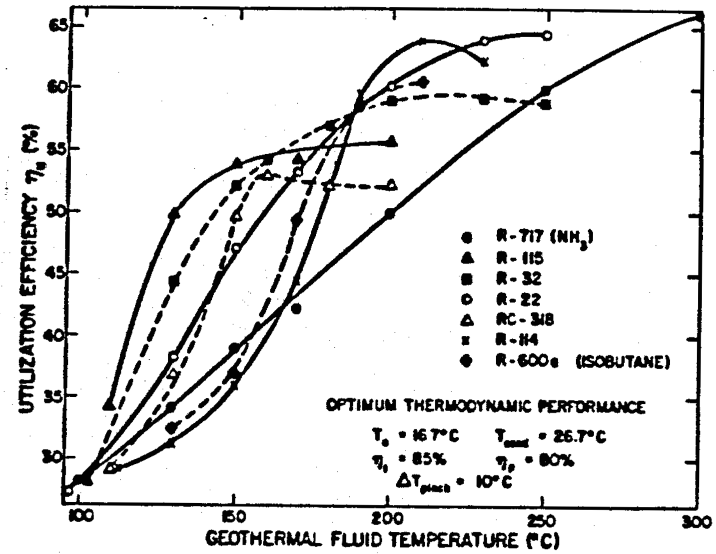

Fig. 6.

Geothermal utilization efficiency η_u as a function of geothermal fluid temperature for optimum thermodynamic operating conditions. A condensing temperature of 26.7°C was used with a 10°C approach to an average ambient temperature of 16.7°C. A 10°C minimum approach on the primary heating side was also used with an 85% turbine and 80% feed pump efficiency, (adapted from Milora and Tester).[6]

ECONOMICS

Costs of generating electricity are divided into two broad categories: (1) operating and maintenance (O & M) costs, and (2) costs due to capital investment.

O & M Costs

These expenses stem from water consumption, maintenance of wells and piping, reservoir fracturing, auxiliary power requirements for pumps and fans, revenue and property taxes, insurance, and personnel salaries. A major expense is for makeup water due to permeation and leakage from the fractures to the surrounding rock during reservoir heat extraction, as well as additional water losses during fracturing. Based upon previous reservoir tests, the average water loss over a ten year lifetime for a 75 MW(e) reservoir will be 800 000 m^3 per year. Unlike normal oil and gas wells,, in which wells are sporadically fractured and are far apart, HDR wells are close together and each well will be fractured many times. Under these circumstances the utility, or operator of the HDR reservoir, may find it more economical to purchase fracturing equipment and maintain an on-site fracturing crew for fracturing, rather than rent such services.

Following earlier experience in the Phase I reservoir fractures will be made with ordinary water, although it is possible that small amounts of additive may be included to reduce friction losses as well as to decrease permeation losses. At Fenton Hill it was found that upon the cessation of pumping and fracturing, the fracture faces are "self-propped" due to asperity-to-asperity contacts. Therefore proppants in the fracturing fluid were not required, resulting in considerable cost savings, but this may not be the case for the Phase II reservoir. Early Phase II hydraulic fracturing operations have been more difficult than expected, and are not necessarily representative of future operations. However using these early attempts as a pessimistic case basis, pumping rates of up to 0.1 m^3/s, pressures of 50 MPa , and total injection volumes of 15,000 m^3 of water may be required to create each fracture. This would require 2 days of round-the-clock pumping, and allowing time for maintenance and repairs, approximately one week might be required for each fracture. Consequently, the 75 MW(e) system could require up to 4 years of fracturing and, allowing a 150% contingency, as much as 10 yrs may be required. However, this is not as alarming as it first seems and it may be more pessimistic than is actually the case. In the earlier reservoir design calculations we assumed that all fractures were available at the beginning of operations and subsequently were slowly drawn down. However, the net thermal energy is the same if a fewer number of fractures is available to begin with, and are drawn down more rapidly, until the next series of fractures is created, and so forth.

Thus, fracturing might be a continuous operation; as old fractures draw-down, new ones will be created. In actual operation most of the wells could be in use, while, for example, two wells are out of service for fracturing. A permanent crew of about 12 people will be required for operating the fracturing pump and workover rig, costing approximately $350,000 per year, or about 0.06 cents per kWh. Assuming no water recovery from the fracturing operations and a schedule of about 20 fractures per year, about 300,000 m^3 of water per year will be required for fracturing. The total water requirement is thus estimated to be about 1,100,000 m^3 per year. Its cost will be highly site specific, but even if it is assumed that such large usage does not permit commercial rates, and the utility must pay rates similar to the typical small business in the area, the yearly cost would still be only $580,000, or 0.1 cents per kWh. Fuel costs for operating fracturing pumps are estimated to be $416,000 per year, or 0.07 cents per kWh. Total O & M costs are summarized in Table I. Additional details can be found in reference 12.

Capital Costs

Capital expenses consist of geophysical exploration and site acquisition costs, surface plant costs, well drilling and completion costs, and cost of fracturing equipment. Surface plant, well drilling and fracturing equipment are by far the most important capital costs and are summarized below.

Surface Plant Costs. Following Tester et al.,[1] the cost per kW of electrical power capacity, C_p, without dry cooling, is taken as

$$C_p = 977 - 2.15\ T_D \quad (1978\$)$$

where T_D is the design surface temperature. For T_D = 230°C, and escalating for inflation at 15% per year for 1979, 1980 and 1981, and at 6% for 1982 and 1983, the cost per kW(e) in 1983 dollars is $825. The 15% inflation factor is very conservative; inflation of fixed non-residential equipment has only been

TABLE I
OPERATING AND MAINTENANCE COSTS FOR A 75 MW(e) HDR POWER STATION

Item	Cost, cents per kWh
Water	0.1
Pumping	0.07
Revenue and Property Taxes, and Insurance	0.2
Personnel	0.16
Miscellaneous	0.1
Total	0.63

7% for 1978 to 1981.[13] Add to this cost another $100 for dry cooling condensers[14] and the total surface cost is $925 per kW(e), including engineering and installation.

Drilling and Completion Costs

Drilling costs are estimated from actual Fenton Hill costs and are guided futher by the average costs of onshore oil and gas wells drilled to comparable depths. Figure 7 presents average costs of onshore oil and gas wells drilled in the U.S. based upon 1979 data.[15] Well costs increase dramatically with depth; over the depth range of 1 to 4 km the data in Fig. 7 can be fitted with a straight line, implying that costs increase exponentially with depth. Also shown for comparison are the actual costs of drilling and completing the four deep geothermal wells at Fenton Hill, as well as the "learning and disaster-free" costs which, as described below, are believed to be more representative of future, more commercially mature HDR drilling. All costs in Fig. 7 are presented in 1983 dollars. Following Carson and Lin[16] an

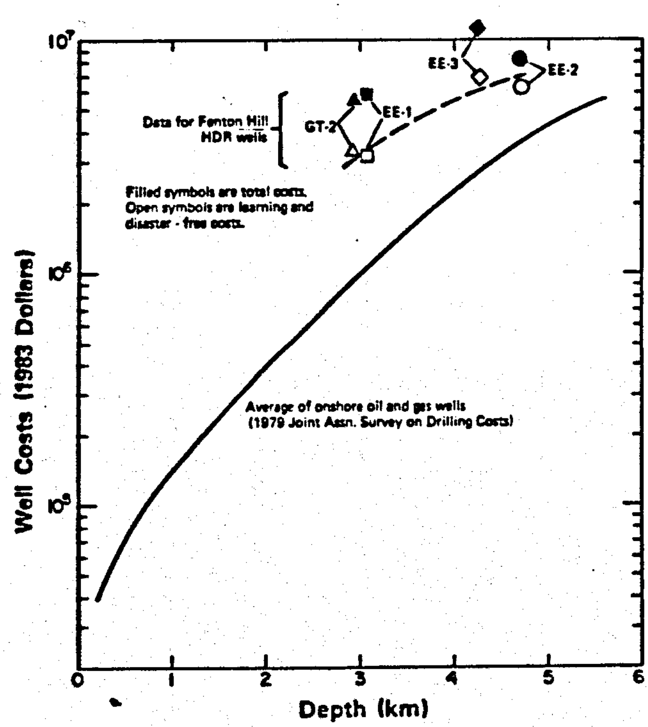

Fig. 7.
Well costs.

average of 17% yearly escalation factor was taken for drilling costs from 1972 to 1981. For 1982 and 1983 the escalation was taken as 0%, reflecting the severe contraction of drilling demand in these years.

Cost data for Fenton Hill wells GT-2, EE-1, EE-2, and EE-3 are summarized in Table II. Both the costs at the time of completion, as well as restated 1983 costs are shown. For each well we also present the costs taken from Fig. 7 for the average oil and gas well drilled to the same depth. Refer to the table heading, Ratio of 1983 Actual Cost to Oil/Gas Average, where it can be seen that the older wells, GT-2 and EE-1, cost about five times the oil/gas average, whereas EE-3 cost four times the average, and EE-2 cost only two times the average. Thus, drilling has significantly improved at Fenton Hill, in the sense that HDR well costs are approaching those of oil/gas average costs. This is more apparent when one observes that GT-2 and EE-1 were drilled nearly vertically, with no directional drilling, whereas EE-2 and EE-3 were directionally drilled at an angle of 35° from the vertical for the bottom 2.5 km. This convergence of HDR and oil and gas well costs was foreseen in Ref. 17. For very deep wells HDR costs can actually be lower than conventional oil and gas wells because use of expensive drilling muds and fluid additives can be avoided in hard crystalline rocks.

Having shown that HDR drilling is improving with experience, consider further improvements that may lie in the future by referring again to Table II, this time to the column headed "Learning and Disaster Free Costs." These costs are actual costs from which are subtracted costs due to delays for experiments and "disasters." It is important to note that these are <u>not</u> the same as "trouble free" costs. Wells will always have the usual unavoidable troubles, but in deriving costs to which HDR drillers might aspire we subtracted costs due to experiments that need not be reported and "disasters" that one might reasonably expect to avoid as drilling matures and the number of HDR wells increases. As examples, for GT-2 the costs for the continuous coring experiments, stuck pipe, and subsequent washovers were subtracted. For EE-1 the cost of 26 days of experiments at 2 km, and the excessive time lost in locating the bottom of the hole in relationship to GT-2, an art which we seem to have mastered in EE-2 and EE-3, was subtracted. For EE-2 the casing collapse cost, which may have been caused by a simple miscount of casing joints, was subtracted, and for EE-3 the cost due to the prolonged fishing job and subsequent sidetracking was removed. <u>Not</u> subtracted were the costs of more typical troubles: losses of circulation, twistoffs and the more usual fishing jobs, and directional drill motor and tool failures. Nor, of course, were the costs of reaming, cementing, circulating, inspection, logging, and casing subtracted.

The ratios of these "learning and disaster-free" costs to average oil/gas costs are presented in Table II. Wells GT-2 and EE-1 have ratios of 3.5 and 2.9, whereas EE-2 and EE-3 are 1.8 and 2.5, respectively. In view of, once again, the marked improvement with the last two wells, we adopt their average ratios. The actual average cost ratio was 3.2, and the "learning and disaster free" average ratio was 2.2. We propose, for the purpose of estimating future costs, that the nine wells in a commercially mature, 75 MW(e) system can be drilled for 2.7 times the oil/gas average. This is exactly midway between the average actual and the "disaster free" ratios. In other words it is conservatively assumed that no further progress will be made in drilling technology; that only by dint of many repetitions one-half the disasters that occured earlier can be avoided. The oil and gas equivalent costs of EE-2 and EE-3 in 1983 are $\$6.4 \times 10^6$, per Table II. Multiplying this by 2.7 results in the average cost of an HDR well pair, $\$17 \times 10^6$. Consequently a nine-well, 75-MW(e) system will require $\$77 \times 10^6$, and allowing a contingency for four additional wells, as discussed earlier, the total is $\$111 \times 10^6$.

TABLE II
DRILLING AND COMPLETION COSTS

Well	Drilling Time (Mos.)	Completion Date	Total Depth Along the Wellbore km	Actual Cost, Millions of Dollars: At Comp. Time	Actual Cost, Millions of Dollars: Escalated to 1983+	Oil/Gas Av. Cost*, Millions of 1983 Dollars	Ratio, 1983 Actual Cost To Oil/Gas Avg.	Learning- & Disaster-Free Cost, Millions of $ 1983	Ratio, Learning & Disaster Free Cost to Oil/Gas Average	Major Disaster Events
GT-2	8	10/74	2.93	1.9	5.7	0.94	6.1	3.3	3.5	"Stuck" drill pipe, Washover Required.
EE-1	5	10/75	3.06	2.3	5.9	1.1	5.4	3.2	2.9	Expts. at 2 km, surveying expts.
EE-2	13	5/80	4.66	7.3	8.5	3.6	2.3	6.3	1.8	Collapsed casing.
EE-3	15	8/81	4.25	11.5	11.5	2.8	4.1	6.9	2.5	Major fish job, and sidetracking.
						Avg, All Wells =	4.5	Avg, All Wells =	2.7	
						Avg. EE-2 + EE-3 =	3.2	Avg. EE-2 + EE-3 =	2.2	

+Drilling Cost Escalation taken as 17% per year through 1981, 0% thereafter.

*Ref. 15

Fracturing Equipment Costs

The cost of fracturing pumps is estimated[18] to be $9 million. A well completion rig (comparable to a full size drilling rig, but with a smaller mud circulation and handling system) will be required for zone isolation so that fractures can be initiated in selected intervals. The rig will be required to operate to depths of 4.5 km with 9 cm drill pipe and will cost approximately $6 million if purchased new. This price includes drill pipe and collars and does not account for today's depressed prices for used rigs. Allowance must also be made for the possible use of expensive downhole isolation techniques such as cemented packers or perforated liners which could total as much as $12 million. Total fracture equipment costs thus range from 15 to 27 million dollars, but the average, $21 million, is used in the economic estimates below.

Table III summarizes all capital costs. HDR power stations are capital-intensive, requiring $2,750 per kW(e) of installed capacity. Two items alone account for 84% of capital costs: drilling and well completions (54%), and surface plant costs (30%). In amortizing the capital costs a distinction must be made between the wells and fracturing equipment, which have a useful life of only 10 yr, and the other, longer-lived costs. Typical surface plant equipment has a useful life of 30 yr, so the plant can be used for more than one

TABLE III
CAPITAL COSTS OF 75 MW(e) HDR STATION, 1983 DOLLARS

Item	Total Cost (millions of $)	Cost per kW(e) $	Fraction of Cost
Geophysical Exploration	4.4	58	0.02
Site Acquisition & Development	0.5	7	
Dry Cooling Heat Rejector	7.5	100	0.04
Other Surface Plant Costs	62.	825	0.30
Well Drilling and Completions	111.	1,480	0.54
Fracturing Equipment	21.	280	0.10
Total	206.	2,750	1.00

HDR reservoir system. In fact, since the great advantage of HDR is its ability to exploit the earth's heat in nearly any type of formation, subsequent reservoirs could be developed immediately adjacent to the first system, so not only can the surface plant be reused, it need not even be moved.

Break-even Bus Bar Costs of Electricity

The actual cash flow resulting from operating any electric plant will vary over its lifetime. The capital expenditures will be made before production starts and then the interest payments, dividends, and return of capital to investors will take place over time in a manner depending on the method chosen for financial capital retirement. Likewise, operating and maintenance expenses may vary; inflation will alter absolute levels of costs and revenues; and tax payment schedules may be changed by accelerated depreciation rules and exploitation of various tax incentives. So the actual yearly costs of electricity production will not be constant and it becomes difficult to directly compare the costs of competing plants or technologies. The solution to this problem is to use the "levelized life-cycle cost," so that plants based on different technologies, lifetimes, financing schemes, etc. can be directly compared by life-cycle cost. A particular format for implementing this method is found in BICYCLE - A Computer Code for Calculating Levelized Life-Cycle Costs.[20]

Because an HDR station is so capital cost intensive, the most important parameter for cost estimates is the interest rate on investment. A nominal 13% interest rate for both bonds and equity was assumed here. This rate is approximately 2% higher than current rates of return in the U.S. electric utility industry, and it reflects the riskier nature of the HDR industry as it would be perceived by initial investors. The nominal interest rate, i, consists of a "real" component, r, the true return on invested capital, and the inflation rate, p. These rates are related as $(1 + i) = (1 + r)(1 + p)$. The long term U.S. inflation rate is 6%[21], so a nominal 13% interest rate reflects a "real" interest rate of 6.6%, and it is this real rate which determines constant dollar bus bar costs. The only reason for including the inflation rate in the calculation at all is that it does have tax effects which change final revenue requirements slightly.[22,23] (It was found that if inflation was zero the bus bar cost was reduced by only 0.6 mills/kWh, whereas raising inflation to 11%

increased bus bar cost by 0.6 mills/kWh.) Figure 8 shows levelized bus bar costs as a function of real interest rates, and the sensitivity of HDR costs to interest rate is readily apparent.

Comparison With Conventional Power Stations

Table IV summarizes U.S. cost characteristics of a number of typical generating stations. All calculations were performed with the levelized cost method, a "real" interest rate of 4.5%, and an inflation rate of 6% so that the final bus bar costs can be directly compared. The only exception is that the HDR base case assumes a less favorable real interest rate, 6.6%. However, also shown in the table is a calculation for an HDR system with a mature financial structure, so that r=4.5%. For the fuel burning plants we first show a bus bar cost assuming that present fuel prices will remain unchanged. A second set of costs is also shown to indicate how expected fuel price increases will affect the cost of electricity for these stations. For coal-fired steam stations, for example, results are shown for a current cost of $25

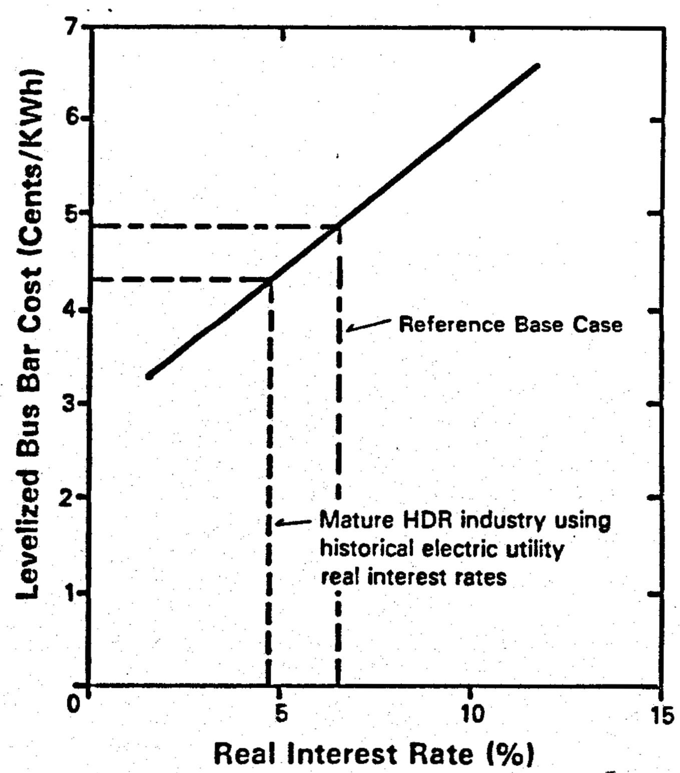

Fig. 8.
Levelized HDR electric plant bus bar cost as a function of real interest rate.

per ton, but even today actual costs vary from a low of \$15 to \$50 per ton in the USA. The anticipated future typical cost was taken as \$40 per ton, a price which many stations are paying already. Fuel costs are a significant, even the dominant, factor in bus bar prices for fuel burning plants. For example, at \$25 per ton, the coal cost alone represents 1.1¢ per kWh, and at \$30 per barrel the cost of oil represents 5.0¢ per kWh. Most importantly, HDR system costs do not depend on fuel prices, so that HDR's relative economic position can only improve in the face of rising real fuel costs for conventional power stations. The stability of the HDR cost is a dual benefit: to utilities in their capital financing, and to consumers in their use of the final product.

Referring to Table IV, the HDR station, even with less favorable interest rate, is already lower in cost than petroleum-using plants of any type: 4.9¢/kWh compared to 6.3¢ for oil-fired steam, and 7.6¢/kWh for diesel-electric. HDR is roughly competitive now with gas turbine peaking units, 4.9¢/kWh compared to 4.3¢/kWh, and is expected to further improve its position rapidly as gas deregulation results in dramatic gas price increases in the U.S. So only coal and nuclear stations, at 3.4 and 3.6¢/kWh, are expected to be cheaper than HDR stations, but their position is expected to deteriorate with further fuel price increases.

DISCUSSION AND CONCLUSIONS

It is concluded that a 75 MW(e) HDR generating station can sell electricity at the bus bar for 4.9 cents per kWh and "break even", i.e., pay its debts and O & M costs, satisfy tax liabilities, and still return 13% per year to its investors. This HDR bus bar cost is based on calculations assuming a real rate of return of 6.6.%, about 2% higher than historical U.S. electric utility levels. A mature HDR industry with rates of return at more normal levels would have a bus bar cost of 4.2¢/kWh. HDR costs are dominated by capital expenses, which amount to 87% of the total cost. The capital cost, in turn, is dominated by just two items, surface plant equipment, and the drilling and completion of wells. The surface plant equipment, including dry cooling, comprises 34% of the capital cost and, accordingly, 30% of the bus bar cost. The drilling and completion costs comprise 54% of capital and 47% of the bus bar cost, consequently any percentage increase or decrease in drilling costs is immediately reflected as about one-half that percentage change in bus bar cost.

Drilling costs were assumed to be similar to those recently experienced in the drilling of the Phase II reservoir at Fenton Hill, New Mexico. Despite the expected commercial maturation of HDR drilling it was assumed that conventional rotary drilling would be used, with no further technical improvements, that only one-half the "disasters" that befell EE-2 and EE-3 could be avoided, and that nearly 50% extra wells would be required for contingency. These are extremely stringent assumptions -- in the comparison of HDR costs to coal- and oil-fired costs we make comparisons to technologies that have matured over 60 years, but deep, hard rock drilling is still in its infancy and much improvement can be expected even in rotary drilling. In the longer view, new means of drilling, for example impulse and thermal spallation methods, may offer even more significant cost savings. A halving of geothermal drilling costs, which would simply make them comparable to oil and gas drilling costs, would

TABLE IV

COMPARISON OF ELECTRICITY GENERATING COSTS IN LEVELIZED, CONSTANT 1983 DOLLARS

Type of Generating Station	Application	Capital Cost ($/kW of Capacity)	Fuel Cost	Levelized Bus Bar Cost (¢/kWh)
Hot Dry Rock Geothermal	Baseload	$2300	None	4.9* 4.2**
Coal Fired Steam	Baseload	1100	$25/ton $40/ton	3.4 4.1
Oil Fired Steam	Baseload	725	$30/BBL $50/BBL	6.3 9.7
Nuclear LWR	Baseload	1500	$25/lb U_3O_8 $75/lb U_3O_8	3.6 4.2
Gas Turbine	Peaking	230	$2.72/mcf $5.00/mcf	4.3 7.3
Diesel Electric	Peaking	340	$30/BBL $50/BBL	7.6 12.0

*Base Case, 6.6% real interest rate.
**Using mature industry capital structure and real interest rate = 4.5% to make plant-independent parameters identical to other generating stations listed.

Sources of input data: Refs. 21, 24, 25, and 26.

put the bus bar cost of HDR at only 3.7 cents per kWh, nearly as cheap as coal fired steam or nuclear LWR stations at current fuel prices.

HDR costs were based upon reservoir heat extraction characteristics measured in the Phase I reservoir. On the one hand they are conservative in that it was assumed that future fractures are limited to a diameter no greater than 360 m, merely 20% greater than the one demonstrated in the Phase I reservoir; that only about one-third of the total heat of the reservoir volume would be extracted; and that the beneficial effects of thermal stress cracking were negligible. Furthermore it was assumed that even when this small fraction of the total heat was extracted, the wells would be completely abandoned -- the possibility of mining heat from adjacent regions of rock by either deepening the wells or sidetracking was ignored. On the other hand the economic calculations assumed that the reservoir will be developed in the manner presently intended for the Phase II reservoir. Each building-block reservoir must have 15 fractures with the requisite heat-transfer area and flow capacity. This is clearly a formidable task, and represents one of the most important technical tasks remaining in the HDR development project.

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