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Status of Economics and Financing of Geothermal Energy Power Production

B. GREIDER
Chevron Minerals, San Francisco, California, USA

ABSTRACT

Steam geothermal fields are economically attractive. The amount of money needed to find, develop, and operate a field is similar to funds needed for other energy development. Investments and operating costs of geothermal plants are similar to those of fossil-fuel plants. Engineering studies indicate that geothermal binary plants will have competitive economics although none are now operating on a commercial basis.

The ability to obtain capital, material, and personnel will influence the growth of geothermal development. Growth will be significant when the electrical companies find this form of energy as useful as nuclear and fossil fuels. The rate of return adjusted for risk must be attractive to compete with fuel investment opportunities.

The price for steam at The Geysers will be 7.4 mill/kWh by 1977. The busbar price will be 10.9 to 11.4 mill/kWh. Nuclear generation for the same market will cost approximately 15.5 mill/kWh. Coal-fueled plants had busbar costs of 14.5 mill/kWh in 1974. Increased plant operating time may offset these higher costs.

Developments in Mexico, El Salvador, and the Philippines appear to be commercially attractive. Combinations of government-private agency financing are showing that this is a reasonable method to use in developing countries. Reported prices for electricity produced in such arrangements should be increased by the amount of tax when compared with production in countries that have such tax.

INTRODUCTION

There developed in the last decade a strong movement by people concerned with the environmental effect of coal- and nuclear-fueled electric generating plants to find alternative sources of energy that would abate the specter of a nuclear disaster or a sulfur- and ash-drenched landscape. This was supposed to be a compelling argument to find and develop geothermal and solar energy. Several nontechnical articles had indicated that except for the minor investment in a few holes, geothermal energy was abundant and free for the person with imagination and modest funds. People with little experience in resource development or exploration pronounced that geothermal energy was attended by no risk, infinite production, and only minor environmental concerns. Economic calculations were usually simple arithmetic guesses at assumed costs. The full impact of taxes and indirect costs on geothermal development was not described in the literature until recently. By contrast economic papers by Armstead (1973), Banwell, Kaufman (1964), Bradbury, and Facca and Ten Dam (1964) which appeared basic to an understanding of profitability of geothermal development by governmental agencies briefly described the risk of failure, recovery of costs, and how to calculate the effects of these on profitability.

Five years ago in the United Nations Pisa symposium, actual histories of development from every geothermal project in the world were reported. From that background of information and from new field operations in the last five years, the technical world has discovered that dry-steam geothermal fields are strong competitors as a source of energy used to generate base-load electricity.

Successful flashed-steam developments located in New Zealand, Japan, and Mexico are producing electricity at costs less than fuel prices for oil or coal delivered to the generating plant. There are no economically successful low-enthalpy heat-exchange plants running today, though two heat exchange plants ran for several years in the Larderello-Castlenuovo areas using the initial fluid at 401°F and fresh water for the secondary fluid. These had a capacity of 79 MW. The Paratunka pilot plant in Russia has been running since 1967, and it is the first actual binary plant using a low-boiling-point fluid to drive the turbine.

MARKET FOR ELECTRICITY

The increasing use of energy has created an awareness that the major question facing the energy user will not be which alternate fuel to use but which fuel can be used. Electricity is becoming an important segment of world energy because it can be transported cheaply over long distances by ultra-high-voltage d.c. lines (0.3 to 0.4 mill/kWh·100 mi) and can be used for space heating, lighting, and electromechanical devices. Remote energy supply areas now become accessible for population centers' energy.

To determine the growth of the geothermal industry we must examine the electrical industry. The electric power industry in the USA is a mix of public and investor-owned utilities. Federal-owned facilities generate 10% of the U.S. electricity and investor-owned utilities provide 75% of the total. The balance is produced by municipalities, and state and local cooperatives. A fairly complex system of federal and state regulations has evolved to control the location, size, and type of electrical generating systems used by the investor-owned utilities. This has reduced the flexibility of utility planning, and plant lead times have increased by 100% in the last five years.

Electricity generation in the U.S. has doubled every 10 years during the last 40 years. During the last year the annual 7% increase in energy produced dropped to 0.6% due to the oil embargo, electricity rate increases, and reduced business activity. Fossil-fuel steam plants now produce 80% of the total power generated. Nuclear plants now produce about 9% of the power and are expected to increase their share to 35% of the U.S. annual requirement sometime between 1985 and 1990. Seventy thousand megawatts of nuclear power are generated in the world. Coal has supplied about 50 to 54% of the electrical generation fuel required since 1971.

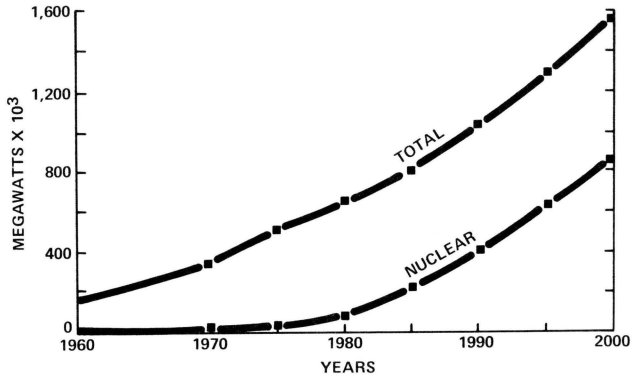

Figure 1. USA generating capacity.

FUELS FOR ELECTRICAL GENERATION

In the past, electric utility management has had a reasonable selection of fuels available at a low cost for electric power production. This selection of fuels from a large number of vendors has allowed the utilities to use the fuel most familiar to them. For many years, the fuel industry supplied the basic research and development that enhanced the competition between energy sources. Recent changes in the bountiful supply of available fuels, and environmental and regulatory procedures have required utilities to become more involved in the economics and use of fuels.

The strong demand for fuel supplies will cause competition for investment funds and technical manpower between ventures offering a low-risk normal rate of return and increased-risk ventures with a higher rate of return. As an example, the exploration for coal and uranium and the development of these fuels use well known techniques. Though the risks are high for a successful project, the costs are predictable. Sale of these products is assured and the demand has caused a favorable price. There is a delay of three to five years after finding the fuel before a producing facility (mine) can be built.

Let us review one of these energy commodities and compare its economics with those of geothermal energy. This will set the framework for examining the competitiveness of geothermal power. The development of each of these is capital intensive and funds to participate in the business must come from those expected to be available for energy investments.

The growth in total energy use will most likely be held to about 2.5 to 3.5% per year for the next decade. Figure 1 depicts the generation of electricity growing between 5.5 and 6.5% per year. Its use will be increasing at a greater rate than total energy use because present uses of oil and gas for space heating and cooling will be transferred to electricity. Within the next 10 years the use of oil and gas for any boiler fuel may not be allowed. The share now planned for nuclear power generation is shown below the "total" curve. The amount represented between "nuclear" and "total" will use the other available fuels. There is ample opportunity for geothermal energy to participate in this growth.

NUCLEAR COMPETITION

The use of nuclear reactors to generate electricity has been favored by utility planning groups as they can operate at near base-load capacity and have had a very low fuel cost. Present nuclear fuel costs of 2.1 mill/kWh can only be matched by hydropower. It is expected this fuel cost will increase by 50% within the next five years.

Prediction of uranium reserves necessary to meet the needs of reactors scheduled for completion this decade is straightforward. Late in 1974 it became apparent the reserves of uranium were not as extensive as suggested in 1969–1973. The rate of discovery for this fuel has been falling short of that needed. As inflation's effect on mining and processing costs continued, the amount of reserves that can be mined for an \$8.00/lb mining cost shrank by about 25%. The high cost of building reprocessing plants and the uncertainty of their functioning has caused the cancellation or deferral of such systems so that the amount of uranium found must be increased to fuel plants now being built. The generating plants now operating in the world use 30 000 tons of U_3O_8 per year. Figure 2 shows that this demand will, in 1990, increase to 225 100 tons per year. The rest of the world will need almost twice the amount required in the USA.

Figure 3, from the U.S. Energy Research and Development Administration (U.S. Atomic Energy Commission, 1974) shows that the capability of the present industry to produce and mill uranium ore will be exceeded by requirements in about 1978. Ore deposits identified will meet the requirements to 1980 if the mines and mills are constructed. This situation has created a strong upward move in price for U_3O_8 and has now made some deposits of less than 0.10% attractive. Figure 4, from John Klemenic's work (1974), illustrates that rates of return above 25% can be expected at today's prices and costs of mining.

The need to schedule power facilities is a requirement for the electric utility industry. Table 1 shows the lead time

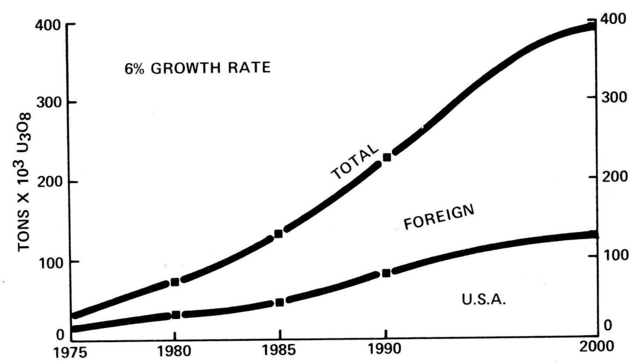

Figure 2. Annual world U_3O_8 demand from 1975 to 2000.

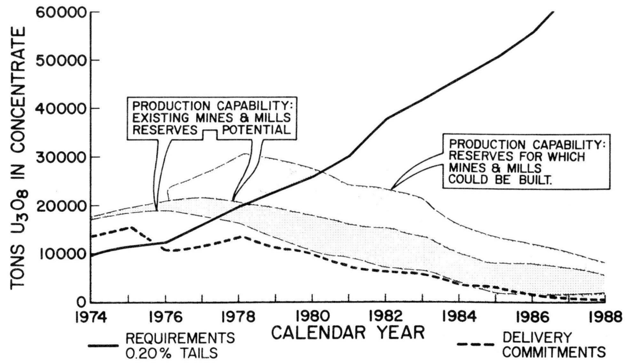

Figure 3. Domestic production capability, delivery commitments, and requirements; based on a price of $8/lb for U_3O_8.

Table 2. Investors' choice.

	COAL	URANIUM	GEOTHERMAL
OBJECTIVE	100 000 000 TONS	3 650 TONS	200 MW
INVESTMENT	$ 7 500 000	$ 3 500 000	$ 2 900 000
SUPPLY FACILITY (EXPLORATION & ACQUISITION)	$ 60 000 000	$ 30 000 000	$ 32 000 000
RATE OF RETURN	15 %	21 %	15 %
MEGAWATTS FUELED	28 000 MW YRS.	17 500 MW YRS.	6000 MW YRS.

(commitment to operation) for electric plants is 8 to 10 years for nuclear plants and around 5 years for coal, oil, and geothermal plants. With the increased regulatory overview on energy sources, these lead times are increasing. This must be considered when estimating the cost of energy from a project as the cost of capital invested during construction must be added to the fuel cost. Mines have lead times of 3 to 7 years. The lead time delay in constructing coal mines is due to a 4- to 5-year backlog for mining machines. When the federal government's moratorium on coal leasing is lifted, equipment delays will be compounded as the necessity for mining equipment is increasing while the production facilities are not.

This gives an investor interested in exploration ventures a choice. Table 2 compares the exploration and acquisition investment with the supply facility cost following a successful project. To find and acquire a 100 000 000-ton coal prospect will cost twice what either a geothermal 200-MW field or 3650 tons of U_3O_8 should cost.

The coal mine, to produce 5 000 000 t/yr for 20 years, would provide fuel for 28 000 MW·yr. The rate of return would approximate 15% (U.S. Department of the Interior, 1974). The uranium mine would produce 7300 pounds of U_3O_8 per year for 10 years and provide fuel for 17 500 MW·yr. The rate of return would be 21 to 26% (Klemenic, 1974). The geothermal prospect would provide 200-MW capacity for 30 years and may have a rate of return of 15% (Bloomster, 1975). To be competitive for dollars and manpower, better returns will be required from geothermal projects.

Table 1. Energy facility estimated lead time (Project Independence Final Report, 1974).

TYPE	YEARS LEAD TIME
ELECTRIC PLANTS	
NUCLEAR	8-10
COAL	5
OIL	5
GEOTHERMAL STEAM	4-5
GEOTHERMAL BINARY	5
HYDROELECTRIC	20
ENERGY SOURCES	
MINES	
URANIUM	3-5
COAL	5-7
FIELDS	
GEOTHERMAL	3-10
OIL ONSHORE	1-3
OIL OFFSHORE	2-4

FACTORS CAUSING LONG LEAD TIME:
1. FORTY FEDERAL GROUPS HAVE ROLE.
2. STATE & COUNTY AGENCIES EVALUATE PROPOSED WORK AND SITES.
3. NO NATIONAL REQUIREMENT TO COORDINATE ENERGY, ENVIRONMENT AND SOCIAL NEEDS.

USA GEOTHERMAL INDUSTRY

The geothermal industry in the U.S. will probably develop with an energy finder supplier and an electric utility as a converter and distributor. The finder will be an expert in using geology and geophysics to locate and evaluate reservoirs with commercial base temperatures. The mining and energy supply companies have the organization and technical experience in using these sciences. Energy supply companies have operational experience in handling large fluid-producing and injection complexes in many areas of the world. The financial resources of these two groups enables them to invest in exploration and production facilities with long lead time before income is obtained. The exploration for geothermal energy by the mining and energy supply companies makes economic sense as their experience with high-risk ventures spans the local geographic areas within which the utility companies operate.

The utility industry is experienced in assessing the most economical method for electrical generation, transmission, and marketing. The price the energy supplier charges for geothermal energy will be the competitive cost the utility is willing to pay in order to generate electricity for sale at regulated rates. There are no posted prices for geothermal energy. The pricing is similar to that used for coal sales. A negotiated price between the user and producer requires each to know or to be able to predict future costs of operation and future need for his product.

The finding and development of geothermal energy is expensive and capital intensive. The usefulness and price of this energy will depend on its quality. The utility planners must have confidence that geothermal reservoir capacity can provide for long-term delivery of uniform quality fuel and must recognize an economic advantage in this evergy source. The energy supplier must be technically capable and financially able.

PROFITABILITY FACTORS

Recent reports on the scope of geothermal resources have not been successful in expressing a consensus on the size of generating capacity that can be expected in the next 10 years. This illustrates the uncertainty that exists in determining the size and types of reserves. The rate of growth depends on the economic vitality and size of the reserves being found. To establish the profitability of geothermal investment we must know: (1) exploration and

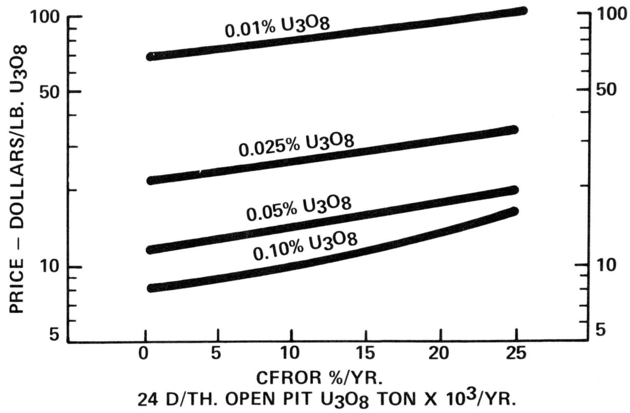

Figure 4. Price versus grade, U_3O_8.

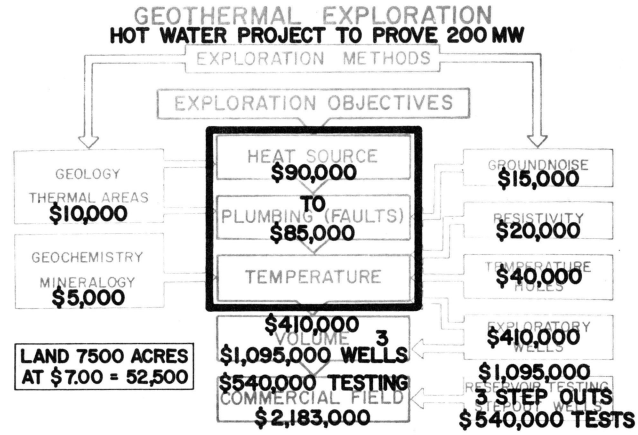

Figure 6. Geothermal exploration—costs for a hot-water project to prove 200 MW.

evaluation costs, (2) the volume and temperature of the carrier of the energy, (3) the development schedule, (4) power plant design, (5) government regulation and taxes, and (6) the market price of electricity.

EXPLORATION COSTS

In 1973, I presented a detailed breakdown of prices of services, costs of exploration, and development with expected rates of return (Greider, 1973). These costs were then presented in budget form to establish the order of magnitude of money required to find a successful hot-water-flash-steam field. A statistical risk was used in determining the net profit the energy supplier could expect and the rate of return that would result. In the last two years significant cost increases have taken place in exploration, field development, and generating plant equipment. Figure 5 consolidates 1974–1975 exploration costs by function. The significant 1975 cost increases result in these new expenditures listed by the monthly charges:

Geophysics, ground noise and microseismic studies \$20 000 to \$40 000
Resistivity surveys \$15 000 to \$20 000
Temperature holes \$40 000 to \$50 000

Land acquisition costs have increased to an average, including acquisition, of \$7.00/acre. A maximum of more than \$3000/acre has been paid for acreage near production.

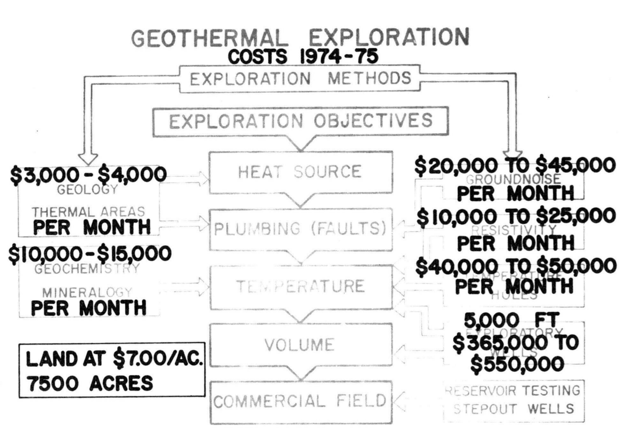

Figure 5. Geothermal exploration costs, 1974–1975.

Prices are reasonable in higher-risk areas with nonsurface indications.

Drilling costs have increased such that an exploratory well to evaluate a 5000-ft sedimentary section will require between \$365 000 and \$550 000. Geothermal wells are more expensive than onshore oil or gas wells due to the heat, abrasive sections, and low hydrostatic pressures. A typical budget of expenditures is shown in Figure 6. Geological and geophysical work will cost \$85 000 to \$90 000. In this instance the exploratory hole cost \$410 000. Three stepout wells were used to evaluate the reservoir performance. A cost of \$540 000 is listed for combinations of testing procedures to establish that production has commercial potential. A development program would follow the \$2 183 000 exploratory program.

Table 3 presents the logic of exploration risk and the effect on the amount of money needed. It is estimated that to find a geothermal field having a capacity of 200 MW, 64 prospects will be evaluated with geological and geophysical work. Half of these will require additional geophysics to select 24 that justify temperature-hole programs. From that work 16 will be attractive enough to spend the money required for drilling. If the work and anomalies selected are better than the industry average one of the 16 exploratory wells will find the objective 200-MW field. Additional testing and confirmation drilling will complete the project to the

Table 3. Statistical projection of investment needed to find and establish a 200-MW field. Optimistically, one area for drilling is located from four areas studied, and 16 drilled prospects locate one 200-MW field.

	$ COST	(TOTAL $ 000)
GEOLOGY & GEOPHYSICS 64 AREAS ($40 000)	= 2 560 000	
ADDITIONAL GEOPH. 32 AREAS ($15 000)	= 480 000	
TEMPERATURE HOLES 24 AREAS ($40 000)	= 960 000	
	4 000 000	4 000
LAND ACQUISITION: 7500 ACRES X 32 AREAS ($7.00/ACRE)	= 1 680 000	5 680
DRILLING & TESTING 5000' DEPTH		
12 FAILURES ($365 000)	= 4 380 000	
3 FAILURES W/CASING RUN ($450 000)	= 1 350 000	
1 DISCOVERY PLUS 3 CONFIRMATION	= 1 505 000	
	7 235 000	12 915
TESTING TO ESTABLISH	540 000	13 455

point that a development program would be justified. Though any given project might be explored for a little over \$2 000 000, the odds are the successful venture will have evolved from a total of \$13 500 000.

FINANCING GEOTHERMAL PROJECTS

Development Outside the USA

The financing of geothermal projects in the world outside of the USA has followed a straightforward system. Government geological surveys have usually established broad areas of interest. These surveys have been paid from local funds and involved either government agency personnel or private-public companies working on a contract. If initial work indicates an assessment should be made of the areas of interest, a second phase will require additional government funds. These may be matched by a grant from a foreign government or from the United Nations. At times a private company has been invited to conduct this phase of work. Union Oil's participation in the Tiwi area of the Philippines has followed this pattern. When the assessment has been completed and a power project is justified, the plant may be constructed and financed by the electrical operating entity. This may be a federal or state agency, or a private taxpaying company. Cerro Prieto in Mexico was developed with Mexican federal funds using national scientific personnel. Ahuachapán, El Salvador, is an example of sharing the risk in early phases by using United Nation's dollars and technical personnel as well as El Savadoran funds and scientists.

Cerro Prieto is the first successful geothermal project in Latin America and was developed with Mexican funds by the Comisión Federal de Electricidad. The geological and engineering work has outlined an area that may have a 500-MW potential. Seventy-five megawatts have now been developed and work is underway on the next 75 MW. As of October 1973 US \$19 824 000 had been spent. Table 4 summarizes the expenditures that resulted in a capital cost of \$264/kW for this hot-water-steam-flash field.

In 1965 the Republic of El Salvador signed an agreement with the United Nations to determine the potential of geothermal areas located by early geologic reconnaissance by government agencies. The program consisted of two phases with funds provided by the United Nations Development Program Fund and by the El Salvador government.

Table 4. Costs at Cerro Prieto, Mexico for a 75-MW, hot-water flash system.

	CAPITAL INVESTMENT (\$000)
STEAM PRODUCTION WELLS (19), SURFACE GATHERING, COLLECTORS, SEPARATORS, TESTING	\$ 5 072
GENERATING PLANT TURBINES, CONDENSORS, EJECTORS, BUILDINGS, WATER TREATMENT	6 272
SUBSTATIONS AND TRANSMISSION LINES	1 872
TOTAL DIRECT INVESTMENT	\$13 216
INDIRECT COSTS	6 608
TOTAL COSTS	\$19 824
CAPITAL COST \$264 /KW	*GENERATION COST \$.008/KWH

*S. Paredes, October 1973.

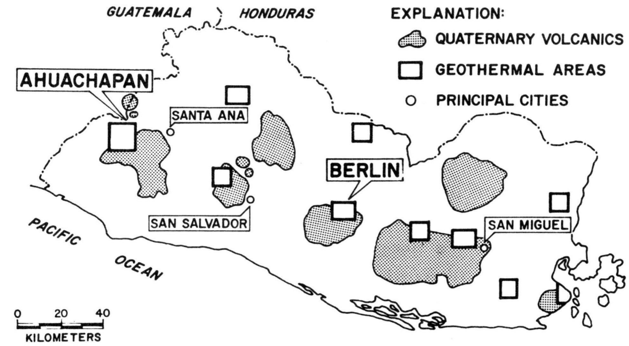

Figure 7. Geothermal areas, Republic of El Salvador.

The initial phase cost US \$1 748 048 and was shared 59% UN and 41% El Salvador. The second phase concentrated on the drilling evaluation of and plant design for Ahuachapán. This cost US \$1 191 500 and was shared 45% UN and 55% El Salvador. The project total cost of US \$3 906 043 was shared 51% UN and 49% by the Republic of El Salvador. A project with a possible 166-MW size is now having the first 33-MW plant completed. The capital cost for this project appears to be \$347/kW and will produce electricity for a price between 7.76 and 8.93 mill/kWh if an 80% load factor can be maintained (Fig. 7 and Table 5).

Development in the USA

In the USA, geothermal work is financed by government agencies using tax funds and by companies using investor funds. If the private investor projects are successful and make a profit, 50% of that profit will be paid into federal tax funds. Federal and state agencies finance research and regional assessments of natural resources occurrences. The funding results in agency grants to universities and private-public companies to conduct these studies. Funding of regulatory agencies at three levels of government provides a bit of direction to and control of geothermal development. Geothermal energy can be owned by individuals, county, state, and federal governments, and by corporations. This mixture of ownership provides an opportunity for 44 government agencies to be involved with geothermal exploration and development. If there is a deliberate restriction applied to geothermal growth in the USA, the effort is probably resident in some of those 44 entities. Private funds are used for research and prospecting and developing projects.

Table 5. El Salvador project, Ahuachapán area.

CAPITAL INVESTMENT		COST MILS/KWH* CAPITAL CHARGE RATE 10%	12%
STEAM SUPPLY AND DISPOSAL	\$ 3 145 000	1.67	1.93
POWER-SWITCH AND TRANSMISSION	5 198 000	2.75	3.19
ENGINEERING, INTEREST CONTINGENCIES	3 117 000	1.89	2.36
TOTAL	\$11 460 000	6.31	7.48
	OPERATING COST	1.45	1.45
CAPITAL COST \$347/KW	TOTAL COST MILS/KWH	7.76	8.93

*80% load factor

The diverse ownership of geothermal rights requires a land leasing activity that is unique to the U.S. exploration effort. The fact that areas must not only be identified but must be acquired if work is to be continued into a development phase adds the cost of landmen and skilled negotiators. Using these talents, such people can assemble areas of land leased by different companies or individuals over an attractive prospect into a unit of sufficient size for evaluation.

Power plants are usually built by utility companies who also operate the transmission and distribution systems associated with the plants. Several utility companies often share in the costs of building the larger, more efficient nuclear and fossil fuel plants. At this time the utilities have indicated a willingness to make a joint venture of more expensive geothermal plants in areas near their service regions.

Producing Projects—Steam

At this time in the USA only the Pacific Gas and Electric Company (PG&E) has built successful geothermal generating plants. These are located at The Geysers in northern California, about 80 miles north of San Francisco. This field is an example of a successful electrical generating geothermal project developed and operated by nongovernment funds. In May 1975 the productive capacity became 502 MW net. The efficiency of this operation is possible because the well drilling and steam production facilities are operated by an oil company to make a profit by selling the steam to an investor-owned utility that must provide service at a regulated customer price. The steam price is calculated from a base price which is adjusted by the cost of other fuels used by the utility in their other thermal plants. Presently the steam supplier is paid 6.9 mills for each kilowatt-hour generated. The supplier reinjects the excess condensed steam from the power cycle and charges a service fee of 0.5 mill.

The actual investment in the steam supply system at this field has not been published. I have estimated that wells and surface facilities to supply the first 11 plants cost about \$93/kW or \$46 700 000, and for Units 12 through 15, \$105/kW or \$42 600 000. This is a total of \$89 300 000 (Table 6). Eleven generating units, with a net output of 502 MW, have been built for a cost of \$63 300 000 for \$126/kW average. Union Oil Company of California, the operator of the steam supply system, has drilled and developed steam for almost twice the present generating capacity. An additional 406 MW of capacity is planned by PG&E and is awaiting approval by the State of California. These four plants are estimated (Worthington, 1974) to cost \$63 600 000 or \$156.6/kW. Upon completion of these, PG&E's 908 MW will represent an investment of \$126 900 000, and the average cost per kilowatt of capacity will be \$139.70. Electricity from unit 15 at 80% plant factor will have an estimated busbar price of 12.8 mills. Unit 13, 135 000 kW, at 80% plant factor is expected to produce electricity at 10.6 mill/kWh. This difference in production costs is due to construction costs for these plants. The development of The Geysers to 2000 MW by 1985 seemed to be a reasonable objective in 1972. The state's delay in certifying plants has now extended the time so that it will probably be 1990 before this can be achieved. Costs for manpower and machinery have risen to such levels that the high-risk initial development wells could not be drilled for \$40 000 to \$150 000 each as were the pioneers. The present value of money is now around 8% per year for these projects. The time value of money will increase the actual investments reported here as time lengthens for a project to be completed. Therefore the excellent economics of The Geysers should not be used as a model for what could be achieved today unless a better performing dry steam field could be located at less depth and in an easier drilling area.

Table 6. Capital costs at The Geysers dry-steam field in the USA. Capacity reached 502 MW when Plant 11 was completed in April 1975.

	CAPITAL	COST/KW
STEAM SUPPLY AND DISPOSAL*		
THROUGH PLANT UNIT 11	\$ 46 700 000	\$ 93
PLANTS 12-15	42 600 000	105
TOTAL	\$ 89 300 000	\$ 98 AVG.
GENERATION PLANT		
THROUGH UNIT 11	\$ 63 300 000	\$126.0
PLANTS 12-15, 406 MW	63 600 000	156.6
TOTAL GENERATING INV.	\$126 900 000	\$139.7 AVG.
908 MW FIELD AND PLANT	\$216 200 000	\$238/KW
FUEL SUPPLIED TO PLANT	6.9 MIL/KWH	
EFFLUENT DISPOSED	.5 MIL/KWH	
TOTAL	7.4 MIL/KWH	

*Steam supply system estimated.

Producing Projects—Hot-Water Dominated

We shall now examine the economics of low-enthalpy systems. Exploration scientists and engineers have found that there are many more geothermal areas with fluids in the 320 to 400°F range than above that range. There are no operating systems to effectively use this large resource of heat. There are also areas of high heat and high salinity in environmentally sensitive areas. These might be favorable for development if a closed system could be used to convert their heat to electrical energy. Research underwritten by government and private funds is directed to systems that can produce electricity economically. The efficiencies of these systems are such that high volumes of geothermal water must be used. The systems below 400°F become very expensive. The lower heat content requires more than twice as many wells to supply a plant at 310°F as are required at 410°F. Heat-exchanger and turbine size must be increased accordingly.

B. Holt has published studies of the requirements of binary systems (Holt and Brugman, 1974). In these systems the heat energy from the geothermal well vaporizes a low-boiling-point fluid which drives the turbine. The vapor is condensed and recycled. His studies used an ambient temperature at 60°F. Figure 8 has a curve added to this cost chart to reflect the increased exchanger and well capacity required in the Imperial Valley by ambient well bulb temperature of about 80°F. This increases construction costs by about 50%.

Table 7 shows that a 55-MW plant using 400°F fluid requires about 20 mill/kWh to pay for the hot-water energy supply system and to cover the normal fixed charges and operating maintenance charges of the power production plant. The assumed 15% fixed charge is very low for a complex experimental binary plant.

Let us compare costs expected to be associated with steam, hot-water flash, and those expected for a binary system. Each will have 200-MW capacity. Table 8 forecasts costs

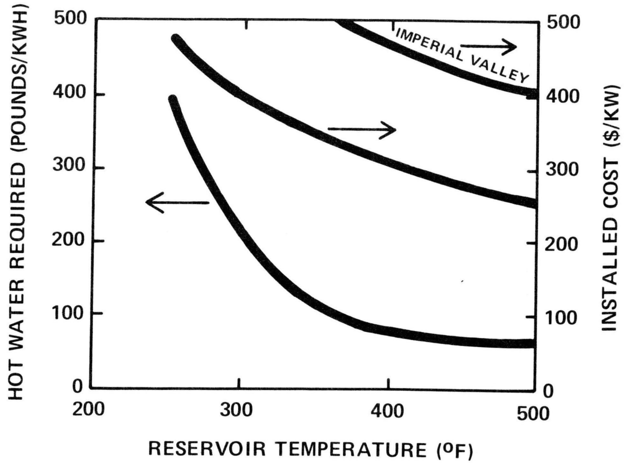

Figure 8. Cost versus water temperature and volume for a 50-MWe plant.

Table 8. Typical geothermal investment cost summary (millions of dollars) for field development and power generation. Costs are order-of-magnitude estimates based on U.S. West Coast costs in 1975 with no escalation.

INVESTMENT	400° Hot Water	500°+ Flash	Steam
Field Development			
Exploration & Field Evaluation	2.8	2.9	3.1
Producing Wells & Facilities	15.1	14.0	18.0
Injection Wells & Facilities	5.6	6.0	1.6
Pipe Lines	4.2	4.7	4.0
Contingencies & Overhead	3.8	3.5	2.9
Total Field Investment/200 MW	31.5	31.3	29.6
Generation Plant			
2-110 MW Turbo-Gen. Plants	95.0	77.0	40.6
Sub Stations	1.4	1.4	1.4
Total Generation Plants (200 MW)	96.4	78.4	42.0
Transmission			
500 KV-20 Miles	3.0	3.0	3.0
Total Investment-200 MW (Net)	130.9	112.7	74.6

for projects commenced in 1975. The energy supply section is treated separately but is the size required for each of the generating systems. Costs are shown for 20 miles of electric transmission and are the same in each case. The investor for a steam field exploration and development program should expect a cost of about $29.6 million ($148/kW) and a lot of skill and luck. The generating plant investor will need around $74.6 million, and the capital cost for energy supply and generation of electricity is $373/kW).

A review of hot-water (500°F) flash systems shows $31.3 million will be needed for the energy supply system ($157/kW). This is due to increased number of wells, larger injection volume of cooled fluid, and evaluation testing. The plant is more complex due to the lower quality of steam and physically greater amount of liquid to handle. The cost of this becomes $78.4 million ($392/kW). The supply, generation, and transmission systems total $112.7 million ($564/kW).

I have used the same field development costs for the binary system as for the flash-steam system. The best published costs for binary systems in the 400°F range are based on costs in 1972-1973. Severe escalation in construction and material costs have pushed the generating system's price near that of the basic coal-fired plants without sulfur scrubbers. The total binary supply and plant should be completed for about $655/kW. This is competitive with the capital cost for pressurized boiling-water nuclear reactors. Operation of the fuel supply and injection systems will need to be low enough to compete with the 3- to 3.5-mill fuel cost for the nuclear systems or the 10-mill cost for coal fuel.

Table 7. Theoretical binary system.

PLANT: 55 MW COST: $ 26 675 000 $ 485/KW

FIXED COST (15%) 10.4 MIL/KWH

OPERATION & MAINTENANCE (2%) 1.4 MIL

TOTAL PLANT CHARGES 11.8 MIL

VALUE OF 400° F. WATER FOR 20 MIL BUSBAR

20 MIL - (10.4 + 1.4) = 8.2 MIL

Comparison of Generating Systems

Whether a central government agency decides which system of electrical generation is used, or whether this is determined by private investors, the criteria are pretty much the same. Table 9 displays the major factors of unit size, reserve availability, plant-siting requirements, capital requirements, and the expected busbar price of electricity from coal, nuclear, diesel, and geothermal plants. Geothermal plants will be constructed in small modules, and several modules may be located together in one plant. As the ultimate capital requirements per kilowatt are not much different, the small size of the geothermal plant allows it a distinct advantage in areas that cannot finance the large investment required for 1000-MW installations. However, the geothermal electric plants must be located near the energy source; this is also true for any other direct use of the geothermal heat such as space heating and cooling, agriculture, or industrial processing.

After its environmental problems are recognized as being

Table 9. Comparison of energy sources. Cost assumptions are that coal costs $0.90/10^6$ Btu, U_3O_8 costs $20.00/lb, oil costs $12.00/bbl, and diesel oil costs $13.60/bbl.

	GEOTHERMAL	COAL	NUCLEAR	OIL-DIESEL
UNIT SIZE (MW)	55-110	750-1200	365-1200	75-1200
FUEL RESERVE	NOT IDENTIFIED	VERY LARGE	MODERATE	LIMITED
PLANT SITING	AT SOURCE (3-5 ACRES)	FLEXIBLE (260 ACRES)	RESTRICTED (550 ACRES)	FLEXIBLE (70 ACRES)
CAPITAL COST (PLANT INST. $/KW)	DRY STEAM 200 FLASH STEAM 390 BINARY SYSTEM 400-500	500-600	600-720	400-500
BUSBAR PRICE (MIL/KWH)	DRY STEAM 10-13 FLASH STEAM 10-18 BINARY SYSTEM 16-20	20-23	19-20	28-30

at most comparable to other power sources, the busbar price for geothermal electric energy will be critical to its widespread use. In areas where a valuable exportable fuel can be displaced by geothermal energy for local energy production, another economic advantage develops. The dollar exchange value in the export market of the transportable fuel then must be considered as an added value to the geothermal fuel savings forecast.

NONECONOMIC SYSTEMS, 1975

Geopressure

The potential economics for developing the geopressured reservoirs can now be estimated with a good deal more clarity than was available at the time of the Hickel National Science Foundation Report. Exploration for oil and gas along the Gulf Coast region of Texas and Louisiana has defined an area several hundred miles long and about 100 miles wide that contains sands with entrapped water at 300 to 400°F, and at formation pressures about twice normal. Figure 9 is adapted from work by P. Jones (1970) of the U.S. Geological Survey. This shows that the major geopressured section is found between 10 000 and 15 000 ft. The waters are in Tertiary sandstone reservoirs isolated from normal pressured sections by a thick shale wedge. The waters in this zone may contain methane in solution. Oil or gas production has not been sustained from these extensive and erratic sandstones. Geologists and engineers familiar with the details of these potential reservoirs are not agreed that water production in economic rates can be maintained for the required 20 years' production per power plant, but there may be areas where such production can be expected.

Dow Chemical Company has conducted a detailed analysis of the investment and costs of a system to produce electricity from this potential resource. Evaluation of this geopressured system required using the kinetic and thermal energy of the water and recovering the dissolved methane for sale at \$2.00 per million Btu. Single-stage and two-stage low-pressure flash turbine systems as well as binary systems were considered. Two models were developed. The first used the average reservoir characteristics of all deep wells in Hidalgo County, Texas. The second used avarage values for the lower Rio Grande embayment of south Texas. These compared with the actual well used in the Air Force Project

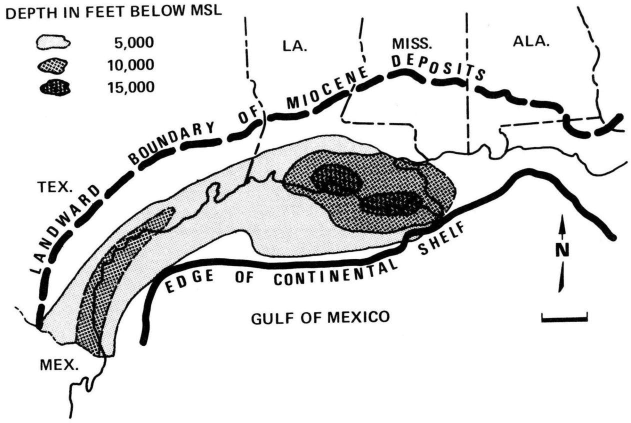

Figure 9. Geopressured zone in Neogene deposits—northern Gulf of Mexico basin.

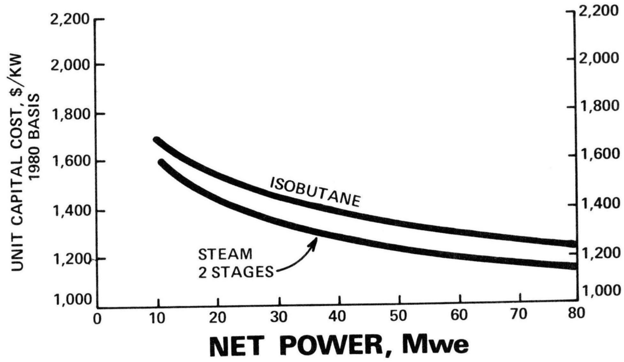

Figure 10. Net power (MWe) for isobutane and steam, two stages.

in 1972 (Herrin, 1973). At 1974 prices, a two-stage flash steam plant with 25 000-kW capacity would require \$10.5 million for the 6-well supply system, and about \$16.5 million for the surface equipment. If we use a 5%-per-year escalation to obtain project cost in 1980, the investment becomes \$34 million. A 66-MW plant would require 15 wells costing \$25 million for equipment. The total project in 1974 costs would be \$61 million, and the 1980 cost would be \$78 million. Electricity costs with a credit of a \$2.00 per 1000 ft^3 for the contained methane gas, would be around 26 mill/kWh for the larger installation and about 38 mill/kWh for the smaller Hidalgo County plant. It is possible that with design improvement and careful research on well costs, the generated power may be produced for 20 to 25 mills. A comparison of unit size and type of generation scheme is shown in Figure 10. A summary of the data used in deriving these costs is presented in Table 10 from the Dow-State of Texas Report (Kaufman, Shephard, and Wilson, 1974).

Considerable research must be completed before large sums of money should be invested by privately funded organizations. Title to this resource needs to be established as it is clouded by having kinetic energy, heat energy, and dissolved methane, each transported by (usually) low-salinity water. By establishing ownership, a form of appropriate leasing can be developed and perhaps an agreement reached as to which of the regulatory agencies will administer the development. Ownership may well establish the logical source of funds to be used in directed research on the technical aspects of this type of geothermal system. Work can now be directed toward site selection, test well design, and production facilities to make optimum use of the three types of energy expected and to assess the environmental impact. The applicability of the 1966 Shell Oil Company patents must be established.

This source of energy does not appear to be economical at this time. Since these reservoir conditions exist in most Tertiary sand and shale marine basins around the world, the potential importance of this type of geothermal prospect is very large. Research and development emphasis is justified and must be undertaken by initiating field projects.

Hot Dry Rock

Two excellent locations for hot dry rock geothermal systems were selected as the best in the U.S. and worked by federal government-sponsored groups. These very experienced teams failed to find the dry rock part of the concept.

Table 10. Summary for geopressure geothermal facilities. The assumed conditions are a well depth of 15 000 ft, a water temperature of 385°F, a methane content of 30 standard cubic feet per barrel, a methane value of $2.00 per thousand standard cubic feet, and a 20% return on investment.

POWER CYCLE	WATER BBLS/DAY	WELLS	NATURAL GAS SCF/DAY X 10^6	NET MWE	CAPITAL COST $/KW (1980)	COST MILS/KW (1980)
MODEL ONE						
HIDALDO CO., TEX.	262 600	6	7.8			
ISOBUTANE				25.28	1485	43.4
STEAM – 2 STAGE				24.50	1393	37.6
MODEL TWO						
RIO GRANDE EMBAY.	713 100	15	21.4			
ISOBUTANE				68.66	1276	33.3
STEAM – 2 STAGE				66.50	1169	26.8

The "hot" part was not there either. To provide high heat storage in a local spot, a heat collector must exist. Usually the high sensible heat of water, couped with its mobility, provides this function. The "dry" part of the concept must be considered a large part of the risk of success. There are not enough data derived from the present projects to make a prediction as to when success will be proclaimed, or what will be the cost of electricity.

GROWTH OF GEOTHERMAL POWER BY 1985

If the economic outlook for energy projects continues to improve during the next 5 years, we should witness a several-fold increase in geothermal power projects. To understand how rapidly geothermal projects can mature in the U.S., a look at what is required has been made by many diverse groups. In determining what can be developed within the next 10 years, it is paramount that the forecaster make a clear distinction between reserves and resources. Reserves can be developed with technology now available and are located where they can be legally produced at an agreed price. Resources that are thought to be present may be recoverable in the future with improved technology and higher costs. Carel Otte, working as chairman of the Project Independence Industry Liaison Committe, reported that it was geologically possible to have 20 000 MW of geothermal electricity capacity by 1985. I would like to discuss why I think it is actually possible to have about 6000 MW developed.

The world's best geothermal field is The Geysers. The last plant constructed there required about 21 months to complete and put into operation after certification. There are presently 406 MW represented by four plants waiting for California Public Utility Commission certification for construction. It has taken 15 years to add 502 MW of capacity. This rate of increase may drop further, so that it seems very unlikely that The Geysers project will exceed 1500 MW by 1985.

To find 4500 MW, successful exploration drilling must commence now. Fields that will add to the productive total by 1985 must be found and must have established their commercial worth by 1980. This results from the 5-yr lead time required between discovery of the resource and the production of electricity. If the average well produces 4 MW, then 1125 wells must be located, drilled, completed, and tested. This would require $506 million if their cost averages $450 000 during the next 7 years—a more likely figure is $642 million if costs escalate 5% per year for 5 years. Injection facilities will cost $321 million.

It is most likely that successful fields making up this 4500 MW will be high-temperature flash fields, and the plants will cost $392/kW. If this is escalated 5% per year for 5 years, then the capital cost will be $498/kW. The plant cost will be $2.24 billion for these fields. The cost of minimal transmission facilities ($75 million) brings the production facilities cost to $3.26 billion.

Twenty-three 200-MW fields will have to be discovered in the next 5 years. This will require about 23 × $13 000 000, or $299 million to be spent by industry or government on exploration. Thus it appears that about $60 million will be needed for the exploration program each year.

The total sum of $3.5 billion is less than 1% of the $420 billion that will probably be used for capital investments in the energy portion (23%) of USA business investments forecast for 1975-1985 (Project Independence). The electrical industry forecasts an investment of between $217 to $271 billion for generating plants and transmission lines. Nuclear fuel alone will cost $8.9 billion to fuel the forecast nuclear plant requirements. The coal investors will use about $7.8 billion for new coal mines. In this context, there is ample money to meet the 6000-MW geothermal goal. To reach the 20 000-MW goal, the approximately $14 billion worth of work would create strong competition for men, materials, prospects, and money.

SUMMARY

Geothermal steam used in electrical generation should provide the most economical and beneficial use of earth energy. Flash-steam fields will be competitive with fossil fuels when reservoir temperatures are above 500°F. If technology can lower binary costs, these generation units may be competitive with fossil and nuclear plants and may be extensivly used.

Key issues that must be resolved before geothermal development can become significant in the electrical generation industry are:

1. Power conversion system technology must be developed to withstand the hostile geothermal resources.
2. Competition from conventional fuel sources for capital, material, and technical manpower must be considered.
3. Field exploration expenditures must be designed for cost effectiveness.
4. The politics of environmental capriciousness must be resolved in order to reduce the soaring costs of redundant studies and reviews for which the public pays.
5. Economic planners must learn the difference between an unlimited resource base and finite reserves.

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