Summary of Section XI Economic and Financial Aspects

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INTRODUCTION

Capital is a resource more scarce than oil, gas, coal, uranium, or geothermal energy. The marketplace, if permitted to function, and the efficient use of scarce capital will assure adequate supplies of energy in various forms to the common benefit of society as a whole. Geothermal energy for electrical power generation is viewed as competitive with conventional fuels as a source of energy. In order to substantiate this view, geothermal utilization must therefore be developed on a scale equivalent to millions of barrels of oil production per day.

The data presented in these papers to describe the economics of geothermal energy are generally based on experience from activities in the United States. The economic parameters established for operations in the United States are most likely representative of the highest costs to be encountered because of regulatory and environmental constraints and therefore may be used for conservative worldwide economic analysis. World oil prices, the geothermal geologic setting, the means of converting geothermal energy into electricity, and the financial parameters associated with existing and planned additions to electrical generating capacity by the western United States utilities combine to make up the geothermal marketplace in this discussion.

DISCUSSION

Banwell (p. 2257) describes the status of world geothermal development by country and by areas of known or probable geothermal potential. To this list we have added daily production of oil based on data published in the December 29, 1975 *Oil and Gas Journal* (Appendix I). By adding world oil prices to daily oil production and to Banwell's list of countries with geothermal potential, the international potential social and economic benefits of geothermal energy become more apparent.

Using the western United States as a basis for economic analysis of geothermal energy is appropriate because of the potentially vast size of the resource there. The United States Geological Survey, in a reconnaissance study published as "Geological Survey Circular 726," has estimated that geothermal energy could supply 11 700 MW of electrical generating capacity using current technology at current prices, 11 700 MW at higher prices, and up to 154 400 MW for 30 MW-years if proven and undiscovered reserves are taken into account. The significance of this potential is highlighted with the observation that the presently installed electrical generating capacity of the United States is 450 000 MW. The private sector, that is, investor-owned public utilities, own 75% of the generating facilities and sell electricity. The energy to operate the generating facilities is supplied by investor-owned oil, gas, and coal-mining companies, although a number of utilities have their own coal reserves.

The prices for electricity sales are set by the utilities but are regulated by state agencies based on rate-of-return criteria. This method of pricing has led to some misconceptions associated with the construction of new facilities by the utility industry. From the 1920s to 1970 the utilities enjoyed continuing cost reductions from improved conversion technology, economies of scale from larger power plants, inexpensive fuels, and low interest expenses. These events permitted the utilities to lower prices on a regular basis. This meant that as the utilities increased capital spending, they increased their rate base from which the rate of return was calculated and therefore also increased their profits. The trend to lower prices flattened out in 1970 or 1971 and reversed itself with the advent of increased interest costs, construction costs, and lost conversion efficiency arising from environmental constraints. The trend was compounded with the dramatic increase in fuel prices which followed the acceptance of the fact that United States reserves of oil and gas were declining substantially. This was brought to light by the oil embargo in October of 1973.

Prices for electricity stabilized from 1970 to 1973, but have increased 20 to 40% since then, depending upon the geographical area served by the individual utilities and their historic fuel mix. The price increases served their historic role in the marketplace by dampening the rate of growth for electricity in 1975 to 0.6% compared with a historic rate of growth of 6 to 7%.

Greider (p. 2305) compares electrical generation from geothermal energy in the context of electrical generation in the world, and specifically in the United States. He points out first that the growth in total energy consumption will likely be held to 2.5 to 3.5% per year for the next decade, but that the energy used in generation of electricity may be expected to increase between 5.5 and 6.5%. The increased market penetration of electricity will increase to 5.5 to 6.5% because present uses of oil and gas for space heating and cooling will be transferred to electricity. He reports that electricity use is expected to increase because it can be transported cheaply long distances (0.3 to 0.4 mills per kWh per 1000 miles).

Table 1. Capital costs for electricity generation.

Power ($/kW)	200	300	400	500	600	700	800	900	1000	1100
Energy (mills/kWh)	4.94	7.41	9.88	12.35	14.82	17.30	19.76	22.23	24.70	27.17

Table 2. Equivalent fuel costs. Each column shows the price of oil, gas, and coal which would result in a particular fuel cost for electrical energy assuming that 10^4 Btu are required to generate 1 kWh.

Oil ($/bbl)	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00	11.00	12.00
Gas ($/$10^3$ft^3)	0.50	0.66	0.83	1.00	1.16	1.33	1.50	1.66	1.83	2.00
Coal ($/ton)	12.49	16.66	20.83	25.00	29.16	33.32	37.49	41.66	45.82	50.00
Fuel cost (mills/kWh)	5.0	6.6	8.3	10.0	11.6	13.3	15.0	16.6	18.3	20.0

The market shifts in aggregate electrical energy demand may be expected to seriously strain the financial capabilities of the utilities as viewed in the context of recent developments. In order to properly compare the cost of geothermal energy with conventional sources of electrical generation, and in order to permit a direct comparison of capital costs with fuel costs, Table 1 shows capital costs at various operating rates in mills/kWh for fixed charges (interest, depreciation, and rate of return on capital) of 17.3%.

Fuel costs are shown by Barr (p. 2269) in terms of British thermal units (assuming 10 000 Btu are required to generate 1 kWh), and Table 2 shows the same relationship in mills/kWh.

Appendix II presents the actual operating financial data for the 13 major western United States public utilities for operations conducted over a 12-month period, as reported to the United States Securities and Exchange Commission (SEC). The actual scheduled additions to new capacity and their projected costs as shown cumulatively in line 17 of Appendix 2 are shown in the reports filed with the SEC. The highlights of the operating data are shown in Table 3 for the 13 major investor-owned utilities and also for 11 utilities, excluding the 2 largest. The accounting procedure "AFDC" (Allowance for Funds used During Construction) in this table permits utilities to capitalize all but a small percentage of all interest expenses incurred from funds used to build new generating facilities. Because interest expenses require cash outlays, the real cash earnings (income for common stock) of the utilities are lower than those actually reported. The accounting procedure "Total Capitalization" includes the long-term debt as shown, the equity of preferred-stock shareholders, and the shareholder equity or "book value" of the common-stock shareholders. The total capitalization represents the savings of the investing American public through their direct ownership of the various utilities' bonds or stocks, or their indirect ownership through the pension and retirement funds of their employers.

The capital costs of nuclear power plants presently operating in the United States historically have ranged between $250 and $400 per kW. Nuclear plants due for completion in 1980 and after, however, are projected to cost $800 to $1100 per kW. When nuclear power generation costs are described as inexpensive or cheaper than oil, the reference is to those already in operation. Those scheduled for future completion, however, will be extremely expensive. A similar situation exists for coal-fired plants. Costs historically have run $150 to $200 per kW of installed capacity, but those plants scheduled for completion in 1980 are projected to cost from $600 to $800 per kW. Using historical and projected capital costs for oil-fired facilities of $150/kW and $350/kW, respectively, these observations may be highlighted in Tables 4a and b by converting capital costs into mills/kWh using Tables 1 and 2.

The transitional phase of the electrical generating industry is illustrated with the observation that the projected costs for new plant construction as estimated by the 13 Western utilities is $593/kW of installed capacity compared to an estimated cost for existing facilities of $203/kW (Table 3). By the time the new plants are constructed they will represent 40.5% of the utilities' total generating facilities. The estimat-

Table 3. Selected cumulative financial data for western utilities.

Category	13 utilities ($)	11 utilities* ($)	Reference line†
Revenue	4 466 900 000	1 892 900 000	1
Income for common stock—AFDC	476 300 000	172 300 000	8
Dividend cash required for total shares	436 900 000	207 200 000	35
Cash earnings after dividend	39 400 000	(34 900 000)	–
Existing generating capacity	8 318 000 000	3 428 000 000	13
Cost of projected additions to generating capacity	16 500 000 000	10 800 000 000	18
Long-term debt	9 068 000 000	4 022 000 000	9
Total capitalization	17 424 000 000	7 698 000 000	12
Existing cost of capacity ($/kW)	203	223	–
Estimated cost of planned additions ($/kW)	593	631	–
Existing capacity (MW)	40 827	15 344	14
Scheduled additions to capacity (MW)	27 812	17 113	17

Source: Earth Power Group, October 1975.
*Pacific Gas & Electric and Southern California Edison omitted.
†The line in the table of Appendix II from which the data are taken.

Table 4(a). Historical electrical generation costs.

Type of plant	Plant cost ($/kW)	Fuel cost†	Plant cost (mills/kWh)	Fuel cost (mills/kWh)	Total cost (mills/kWh)
Oil	150	3	3.70	5.0	8.70
Coal	150	12	3.70	5.0	8.70
Nuclear	250	8	7.61	2.5*	10.11

Table 4(b). Projected electrical generation costs (1980–1982).

Type of plant	Plant cost ($/kW)	Fuel cost†	Plant cost (mills/kWh)	Fuel cost (mills/kWh)	Total cost (mills/kWh)
Oil	350	12	9.88	20.0	29.88
Coal	600	25	14.82	20.0	34.82
Nuclear	1000	40	24.70	8.5*	33.20

*Source: Atomic Industrial Forum and NRC Docket No. 751206 (Spangler).
†Oil ($/bbl), coal ($/ton), nuclear ($/lb U_3O_8).

ed costs for new facilities represent a 292% increase to costs estimated for existing generating facilities. A 292% increase in the rate base expanded 40.5% will require rate increases of 118.26% by 1982 or 1983, exclusive of increased fuel or operating expenses. The conclusion to be drawn from the financial data is that the utilities cannot afford to build the plants which are currently planned and that instead they are going to have to build smaller and less capital-intensive facilities.

There clearly exists a market for electricity and just as clearly there exists a market for new generating facilities. The economies of scale for geothermal power plant construction are achieved at the 50-MW to 100-MW level. The balance of this report will focus on the economics of producing electricity by using vapor- and liquid-dominated geothermal energy systems and the attendant importance of reservoir temperatures on the economics.

Greider (p. 2305) outlines a budget for anticipated exploration and development costs required to delineate a field with a capacity of 200 MW in this country. The costs range from $2.0 million to $13.5 million. He outlines the parameters affecting development as follows: (1) exploration and evaluation costs, (2) volume and temperature of the carrier of the energy, (3) development schedule, (4) power plant design, (5) government regulation and taxes, and (6) market price of electricity.

Goldsmith (p. 2301) outlines the costs for wells, pipeline, and power plant for a vapor-dominated (dry steam) plant such as exists at The Geysers. The actual costs at The Geysers are described by Greider (p. 2305) but do not include the cost to the utility, Pacific Gas and Electric Company (PG&E), associated with the purchase of fuel (geothermal steam). PG&E's costs are described in detail in the paper by Finn (p. 2295).

Greider points out the importance of distinguishing costs incurred by the steam supplier versus those incurred by the purchaser or other utility. The costs for dry steam production described by Greider may be combined with the compensation arrangements described by Finn to illustrate PG&E's cost experience with vapor-dominated production at The Geysers.

The economics for the steam suppliers are not accounted for, using the experience of PG&E, but would not be representative of geothermal economics at any rate. First, no exploration costs (relatively speaking) were incurred in the discovery, and second, a significant portion of the development costs were incurred prior to recent drilling expense increases. It would also be difficult to factor in an estimated $20.0 to $30.0 million in productive wells which in some instances have been shut in for 5 to 10 years awaiting regulatory approval by the State of California to connect them to a turbine.

Finn (p. 2295) sets forth the formula by which the steam suppliers are compensated for the delivery of steam to Pacific Gas and Electric Company. The title of the paper is perhaps misleading, however, because it is not really the steam that is sold for which the steam supplier is compensated at The Geysers, but rather the amount of electricity that is generated by the steam delivered to the utility. The steam suppliers are required to supply, or have available at all times, certain minimum quantities of steam at specified temperatures and pressures; but PG&E is not required to accept delivery. Thus, the steam does not actually have a price, but rather the steam supplier is compensated by the amount of electricity that is actually produced. This may seem like a curious situation in light of present energy markets, but is explainable in its historic context.

A short history on development at The Geysers is a prerequisite to understanding both the nature of the contract between steam supplier and utility, and also the compensation formula for the steam suppliers. At The Geysers, PG&E and Magma-Thermal entered into the original contract in 1959. In that year, the project was one-half owned by Magma Power Company and one-half owned by the Thermal Power Company. Understanding the nature of the contract is not difficult, but the realization that there was no government support of any kind involved in the project, and that both Magma and Thermal had committed substantially all of their corporate resources to The Geysers development, is worthy of note. PG&E had ample generating facilities at the time and did not have to expose themselves financially. They did have a substantial investment in the generating facilities and obviously intended to produce all of the kilowatt-hours they could.

There was no precedent for pricing natural steam at the time, and the formula that exists today, which is presented in Finn's paper, was the inspiration of Earl English, at that time an engineer with The Thermal Power Company. He was experienced in other sources of power generation; and knowing that PG&E operated fossil-fuel steam generating facilities and had plans to operate nuclear power plants, he weighed these considerations to come up with the formula described by Finn.

The critical element for determining the economic viability

Table 5. Well productivity—binary cycle (flow rate 550 000 lb/hr).

Temperature	Hot water required (lb/kWh)	MW/ well	Wells/ 110 MW
250°F/120°C	400	1.375	82.3
300°F/148°C	210	2.620	42.0
350°F/176°C	110	5.000	22.0
400°F/210°C	80	6.875	16.0
450°F/231°C	75	7.333	15.0
500°F/259°C	60	9.166	12.0

Source: Holt, B., and Brugman, J., 1974, Investment and operating costs of binary cycle geothermal power plants: U.S. National Science Foundation Conference on Research for the Development of Geothermal Energy Resources (September).

of geothermal hot-water systems for electrical power generation is temperature. The importance of temperature is twofold: first, fewer wells are needed by the energy supplier, and second, plant costs are significantly lower for the utility. Lower plant costs result from the fact that lower-pressure (temperature) turbines are larger (more expensive) than higher-pressure turbines.

Tables 5 and 6 show the number of wells required for the binary-stage and single-flash methods of converting hot water to electricity. Both tables assume a flow rate of 550 000 pounds of hot water per hour.

Sapre and Schoeppel (p. 2343) have designed a model for assessing the cost of electrical power based on the binary-cycle plant design. In his model, Sapre has defined a liquid-dominated reservoir as a "bed of hot porous rocks saturated with pressurized water at some equilibrium temperature. Such a reservoir may be characterized by its geothermal gradient, pressure gradient, and flow capacity." We have emphasized temperature (geothermal gradient) because of its importance and the effect of temperature causing pressures greater than hydrostatic. In fact, Sapre states, "If an area could be found where the natural hydrostatic gradient was 0.1 psi per foot more than normal, then the cost of power could be reduced by as much as one-half." This statement refers to his observation that electricity from geothermal energy will be economic where the temperature gradient is greater than 5°F/100 ft. That "such reservoirs can be identified easily" and that "with present technology, these reservoirs are available for almost immediate exploitation" still holds. Electricity can be generated profitably from geothermal energy where the temperature gradient is 5°F/100 ft according to the model.

Table 6. Flash steam well productivity (flow rate, 550 000 lb/hr).

Temperature	Percent flash	Steam (lb/hr)	MW/ well	Wells/ 110 MW
302°F/150°C	—	—	—	—
350°F/176°C	5.8	31 900	1.59	69.1
392°F/200°C	11.0	60 500	3.02	36.4
400°F/210°C	12.0	66 000	3.30	33.3
450°F/231°C	18.0	99 000	4.95	22.2
500°F/259°C	24.2	133 100	6.65	16.5
572°F/300°C	33.0	181 500	9.07	12.1

The flash percentages at 302°F (150°C), 392°F (200°C), and 572°F (300°C) are taken directly from U.S. Geological Survey, #726, p. 7; the other percentages are extrapolations. The percentage of flash is based on pressures of 50 psi and does not reflect multistage flashing, and, therefore, a potentially greater MW-capability per well. The MW/well data are based on converting 20 pounds of steam per hour to 1 kWh.

A conclusion of Sapre and Schoeppel may also be used to describe Table 5. "Initially as the temperature increases from 325°F to about 350°F, the cost of power decreases drastically. First, as the temperature of water at the plant inlet increases, the flow rate required to produce the same amount of power decreases. As shown in Figure 2, for a particular plant design this decrease is very rapid until a temperature of around 360°F is reached. Beyond this temperature (the decrease is still logarithmic) the rate of decrease is much smaller and hence it does not affect the flow rate in the same proportion. Also, with reduced water flow rate requirements, the number of production and injection wells is reduced proportionately."

The importance of temperature is illustrated by Bloomster (p. 2273) somewhat differently. Where Sapre and Schoeppel have taken turbine inlet requirements and hypothesized temperature and flow rates to satisfy inlet conditions, Bloomster takes different temperatures and then shows what flow rates are required, assuming the same cost criteria, in his Figures 7 and 10. Note that the flow rates are three to four times greater for temperatures of 149°C than they are for 200°C. If these data were shown for the same flow rate, the production cost for the lower-temperature resource would be three to four times greater (and most likely uneconomic).

Juul-Dam and Dunlap (p. 2315) employ a computer modeling device based on a Monte Carlo simulation to estimate overall rate of return on a geothermal exploration budget large enough to assure a commercial discovery. The costs of all phases of development are included from reconnaissance and land acquisition through development drilling and plant construction. Probabilities have been assigned for the successful results for all stages of exploration, depth of production, temperature, and other factors affecting the economics of commercial geothermal power production.

Because of computer programming complexities, the model assumes that only one target is explored at a time by one group of technicians. When the results are negative, another target is selected for exploration and the computer simulation is run again. There is a deficiency, therefore, in applying the simulation to real-world exploration activities because, in fact, a group exploring for geothermal energy can work on any number of targets simultaneously and therefore are not faced with the extremely long time lag that occurs in the method employed in the paper. Included in the Juul-Dam and Dunlap paper is a chart which shows a range of projected flow rates as a function of production depth. As pointed out by Sapre and Schoeppel, pressure will also influence the production rate.

Peterson (p. 2333) discusses the rate of depletion of geothermal reservoirs as a factor which may be optimized when setting well production rates. At such time as the factors influencing production, such as temperature, pressure, and reservoir depth (see Juul-Dam and Dunlap, p. 2315, Figures 4 and 5) are better understood, the production optimization models described by Peterson will become extremely useful. Even without these data, his description of the discounted value of an income stream should be required reading for everyone associated with the regulation of geothermal energy, in order to impress upon them the costs incurred when production and the resulting generation of income is delayed.

Table 7 shows estimated capital costs for the construction

Table 7. Geothermal power plant costs (\$/kW).*

Type		Barr	Greider
Vapor-dominated:	dry	127	210
Liquid-dominated:	flash	212	392
Liquid-dominated:	binary	312	439

*Source: Barr, p. 2269; Greider, p. 2305.

Table 8. Example of comparative Btu output value approach.

Power plant size: 100 000 kW	1.0×10^{5}	kW
Time duration: one year = 8760 hours	$\times\ 8.76 \times 10^{3}$	hours
Maximum output: one year	8.76×10^{8}	kWh
Btu oil for 1 kWh = 10 000 Btu	$\times\ 1.0 \times 10^{4}$	Btu
Maximum Btu/year	8.76×10^{12}	Btu
Btu per bbl oil: 6.0×10^{6}	$\div\ 6.0 \times 10^{6}$	Btu/bbl
Maximum bbl/year	1.46×10^{6}	bbl
Price \$12.00/bbl	$\times\ 1.2 \times 10$/bbl	
Maximum comparative cost per year	17.52×10^{6}	\$
kWh produced one year	$-\ 8.76 \times 10^{8}$	kWh
Cost/kWh	2.0×10^{-2} or 20.0 mills/kWh	

of geothermal power plants. From Table 1 it may be seen that capital costs are 2.74 mills/kWh at \$100/kW and 9.88 mills/kWh at \$400/kW, assuming an 80% operating rate. Banwell (p. 2257) shows historical costs ranging from 6.7 mills/kWh to 16.0 mills/kWh which are inclusive of both energy supply and plant construction costs. The costs are based on 1971 data and generally assume subsidized interest expense.

Sapre and Schoeppel (p. 2343) and Bloomster (p. 2273) also show estimated costs based on total costs. The Sapre and Schoeppel cost estimates are based on 1972 data and show a range of costs of 12.0 mills/kWh to 40.0 mills/kWh expressed as direct functions of temperature gradient and pressure. The Bloomster cost estimates are shown ranging from 14 mills/kWh to 38 mills/kWh. Both papers include an allowance for a fixed rate of return, but neither includes exploration costs.

The problem with combining energy supply and plant costs is twofold. First, total geothermal power generation costs are often compared with plant construction costs for conventional forms of power generation. Second, geothermal energy will be developed along the lines of conventional fuels, and the costs should be shown separately for exploration and field development and for plant construction. This will permit a comparative analysis of the economics of geothermal energy compared with oil, gas, coal, or nuclear power generation and serves to emphasize the risk element associated with exploration activities.

The separation of costs into field exploration and development and plant construction raises the question of establishing a value or price for geothermal energy. Some would say that geothermal energy is "free" because it flows from the earth, but on this basis oil is also "free."

In a market economy the value of geothermal energy will be based on the price at which it can be sold. Price will be a matter of negotiation, and will take into consideration the amount of electricity which can be produced from a reservoir and the cost to the power producer to convert the geothermal energy to electricity. When considering what price should be paid for the geothermal energy, the utility will also consider alternative fuels such as oil, gas, coal, or nuclear energy.

Three approaches may be used to enter price negotiations which would establish the value for geothermal energy: (1) comparative Btu output at market prices to Btu's, (2) market cost for electricity, and (3) cost plus rate of return.

The comparative Btu output value may be established by estimating the quantity of an alternative energy source such as oil required to generate an equal amount of electricity. Table 8 illustrates this approach. The total revenues of \$17 520 000 assume a 100% operating rate. The per-mill value will remain the same at lower operating rates, but the total cost (income to geothermal supplier) will obviously be lower.

Having calculated the value of an alternative energy source, the quantity of either geothermal steam or hot water required to produce 1 kWh may be established and priced for delivery accordingly. For example, if 20 pounds of steam produces 1 kWh and the alternative cost is 20 mills, then the steam would be priced at 1.0 mill per pound, or perhaps more conveniently, \$1.00 per thousand pounds (1000 lb). Similarly, if 200 pounds of hot water were required to produce 1 kWh, the value of the hot water would be \$0.10 per thousand pounds. If only 100 pounds were required to produce 1kWh, the value would be \$0.20 per thousand pounds or twice the value of the hot water, assuming 200 pounds were required for 1 kWh. These conversion factors indicate hot water temperatures of 150°C compared to 180°C (Table 4b) and illustrate the importance of temperature on the economics of geothermal energy.

The market cost for electricity approach is based on the total cost for electricity for the next conventional plant in a particular service area. This is the approach used by Juul-Dam and Dunlap (p. 2315), based on a market price of 20.0 mills/kWh to calculate discounted cash flow after allowing for exploration costs and the cost of a plant. The approach may be termed the "ARCO" approach after their employer, The Atlantic Richfield Company. After converting the geothermal plant cost into mills/kWh, this amount is subtracted from the total cost of the conventional plant in mills/kWh to determine the mills/kWh rate used to evaluate the geothermal energy. Table 9 is an example of this approach. If 110 pounds of hot water per hour are required to produce 1 kWh, then the value of 110 pounds produced for 1 hour will be 14.94 mills/kWh. One thousand pounds produced for an hour will therefore have a value of \$0.1358/1000 lb.

Should the resource in Table 9 be a vapor-dominated system rather than a hot-water system, the capital cost of the plant would be \$200/kW or 4.94 mills/kWh (Table 1). Using the "ARCO" market cost approach, this amount gives

Table 9. Example of market cost for electricity approach.

	Unit cost	Energy cost (mills/kWh)
Capital cost for new coal-fired unit	\$600/kW	14.82
Fuel cost for delivered coal	\$ 25/ton	+ 10.00
Total cost conventional	–	24.82
Binary cycle geothermal plant	\$400/kW	– 9.88
Value geothermal hot water	–	14.94

Note: Conversion from unit cost to mills/kWh from Tables 1 and 2.

a value of 19.88 mills/kWh (24.82 mills/kWh total cost—4.94 mills/kWh capital cost geothermal plant = 19.88 mills/kWh value of geothermal steam fuel). The per-mill valuation would then convert to \$0.994/1000 lb based on 20 pounds/hour for 1 kWh.

The rate-of-return approach would involve all costs incurred leading to a discovery of geothermal energy, the separation of development drilling and plant construction costs, and the addition of a profit for the geothermal energy supplier. Maslan, Gordon, and Deitch (p. 2325) state that geothermal energy can be economically developed and project that 190 000 MW to 250 000 MW of electrical capacity can be established by the year 2000 out of an estimated capacity at that time of 2 000 000 MW. By 1985, 7000 MW to 20 000 MW may be produced by using geothermal energy. Maslan, Gordon, and Deitch list and discuss eight major areas on which geothermal energy may have an impact: (1) electric utility fuel mix; (2) growth of supply businesses for geothermal expenditures (\$95 billion by the year 2000); (3) meeting of overall electricity demand and marginal effects on other energy sources; (4) stimulation of a national electricity grid; (5) coordination of research, regulation, and other institutional considerations; (6) relocation of industrial activities to new regions and cities; (7) international energy markets; and (8) environmental issues and land use.

De Marchi (p. 2291) outlines the basis on which an understanding of the economics of geothermal energy can be used to help formulate national energy policies. This outline is then applied to a country with a pattern of high per-capita energy consumption and a negative balance of trade. There are three observations which immediately become apparent. First, any steps taken in the direction of independence will aim to reduce rather than to annul energy importation. Second, determining the form of energy imports to be reduced will take into account, or provide some means of maintaining, an energy base not subject to interruption by extra-national influences. Third, he points out that energy investments are capital intensive and that financial considerations which would be a drain on a country's near-term resources must be weighed against energy development over the long term. Energy conservation can be helpful in temporarily reducing energy imports, but in the long term increased energy must be made available in order to maintain the economic growth necessary to overcome trade imbalances while maintaining or improving existing standards of living.

De Marchi proceeds to describe a mathematical framework for extracting useful energy from geothermal waters. He concludes that actual utilization versus that hypothesized is dependent upon output rate of a single well, and that for purposes of utilization the potential number of wells become the base for an economic evaluation.

In order to determine the merits of a geothermal system a simple comparison can be made with the costs of other alternatives. The comparison would include an evaluation of the costs for the extraction of geothermal energy, the effects on the balance of payments, and a comparison with the capital requirement needs. A mathematical formula further demonstrates how these considerations would be evaluated. A financial consideration will require the analysis of raw material or "know-how" which must be imported.

COMMENTS

Geothermal energy is not an inexpensive alternative fuel for making electricity. The economics of geothermal energy are complex and dependent upon the geologic setting of the reservoir and the reservoir's temperature. Vapor-dominated systems capable of supplying over 200 MW can be developed at relatively low costs and will therefore yield a higher-than-normal rate of return to the geothermal energy supplier. High-temperature liquid-dominated reservoirs may also be commercially developed on a basis profitable to the energy supplier. Even where a government is the geothermal energy supplier, it will need these higher temperature reservoirs to offset research and development expenditures.

The expanded utilization of geothermal energy requires a significantly higher rate of exploratory drilling. As the more desirable reservoirs are discovered, they will be put into production expeditiously by those charged with the responsibility of producing electricity. Only 5 out of the 13 utilities in the western United States have had geothermal wells drilled within their service areas. In each case they are progressing as rapidly as permitted under existing institutional constraints, such as obtaining permits to conduct exploration and evaluating hypothesized environmental impacts. Except in The Geysers' area, where Pacific Gas and Electric Company is aggressively endeavoring to develop geothermal energy, the production history of the wells drilled to date is almost negligible. Not only do more wells need to be drilled, they must be allowed to flow. The evidence contained in the papers presented at the Second United Nations Geothermal Symposium point conclusively to the commercial feasibility of high-temperature geothermal reservoirs; and as operating histories are developed, commercialization of the resource at a more moderate temperature will occur.

The expertise and application of existing technology for the conversion of geothermal energy to electricity, developed in the United States and synthesized through international forums such as those sponsored by the United Nations, appear certain to assure development of geothermal energy on a scale equivalent to millions of barrels of oil per day.

Appendix I. Geothermal potential and daily world oil production.

Region and Country	Geothermal Setting*	Daily Oil Production†
Africa (North)		
Algeria	B, C	915 300
Morocco	B, C	628
United Arab Republic	B, C	214 185
Sudan	B	NL
Africa (Central)		
Cameroon	B	NL
Chad	B	NL
Nigeria	B, C	1 711 253
Virunga volcanoes	A	NL
Africa (East)		
Ethiopia	B, C	NL
Somali Republic	B	NL
Kenya	B	NL
Uganda	B	NL
Rwanda	B	NL
Congo (East)	B	37 523
Zambia	B	NL
Mozambique	B, C	NL
Rhodesia	B	NL
Malagasy Republic	B	NL
America (North)		
Canada	A, C	1 209 170
Mexico	A, B, C	680 766
United States	A, B, C	8 201 000
America (Central)		
Guatemala	A	NL
El Salvador	A	NL
Honduras	A	NL
Nicaragua	A	NL
Costa Rica	A	NL
Panama	A	NL
British Honduras	A	NL
America (South)		
Colombia	A, C	166 398
Venezuela	C	2 529 659
Trinidad, Tobago	C	210 526
Ecuador	A	137 704
Peru	A, B	76 590
Chile	A, B	25 014
Brazil (Andean)	A	173 865
Bolivia	A	38 414
Paraguay	A	NL
Argentina	A	401 388
Galapagos Islands	A	NL
Antarctica		
South Shetlands	A	NL
Graham Land	A	NL
Europe		
Austria	C	41 400
France	C	20 883
Germany (West)	C	125 624
Great Britain	C	15 644‡
Holland	C	26 388
Hungary	C	NL
Italy	A, B, C	20 217§
Poland	C	NL
Romania	C	NL
Spain (S. coast Canary Islands)	A, B	33 850
Far East		
Australia	C	413 510
Burma	C	23 000
China (E. provinces)	A, B	?
China Sea (South)	A, B, C	?
Bengal (East)	C	NL
India	B, C	165 000
Indonesia	A, C	1 231 271
Japan	A, C	12 943
New Guinea	A, C	NL
Timor	A, C	NL
Middle East		
Afghanistan	A, B, C	150
Baluchistan	A, B, C	NL
Pakistan	A, B, C	5 839
Persian Gulf	A, B, C	‖
Iran	A, B, C	5 445 193
Israel	B	718
Jordan	B	NL
Lebanon	B	NL
Saudi Arabia	B, C	6 574 655
Syria	B	174 296
Tibetan Highlands	B	NL
Turkey	A, B	59 933
Island Arcs.		
(1) Pacific		
Aleutians	A	NL
Fuji-Bonin Zone	A	NL
Halmahera	A	NL
Japan (N. and W.)	A	12 943
Indonesia Sumatra-Java	A	1 231 271
Marianas	A	NL
Kamchatka	A	NL
New Britain	A	NL
New Hebrides	A	NL
New Zealand	A	3 601
N. Celebeses	A	NL
Philippines	A	NL
Ryuku Is.	A	NL
Solomon Is.	A	NL
Tonga Kermadec Is.	A	NL
(2) Caribbean		
Lesser Antilles	A	NL
Puerto Rico	A	NL
(3) E. Mediterranean		
Aegean Islands	A	NL
Greece	A	NL#
Northern Crete	A	NL
Mid-Atlantic Ridge		
Iceland	A	NL
Jan Mayen	A	NL
Spitzbergen	A	NL
Russia (USSR)	C	8 500 000 est.

Note: A, acid volcanic association; B, high-temperature zones; C, high-pressure reservoirs; NL, none listed.
*Source: Banwell (p. 2257).
†Source: *Oil and Gas Journal*, December 29, 1975.
‡Excludes North Sea.
§Excludes offshore discovery.
‖Countries not listed by Banwell; oil production significant.
#Excludes significant offshore discovery.

Appendix II. Western utilities financial analysis, latest 12-month period ($ millions except *).

STATE PROSPECTUS DATE UTILITY †	ARIZ 8/26/75 TG&E	CAL 4/29/75 PG&E	CAL 4/16/75 SDG&E	CAL 3/6/75 SoCalEd	COL 2/30/75 PS Colo	IDAHO 10/24/74 Id P Co	MONT 7/8/75 MontPCo	NEV 3/4/75 Sierra	N. MEX 8/26/75 PS NM	ORE 9/4/75 Pac P&L	ORE 8/21/75 Puget	ORE 8/21/75 Port GE	UTAH 4/23/75 Utah P&L
1. REVENUE	144.0	1103.0	289.0	1471.0	363.0	90.3	125.0	70.5	74.1	269.0	149.0	159.0	160.0
2. INCOME FOR COMMON	16.5	195.0	28.6	182.0	29.6	23.8	24.1	8.4	9.3	55.0	19.0	27.0	23.0
3. DEPRECIATION	13.6	166.0	25.1	116.0	36.4	8.5	8.3	6.4	8.3	33.0	14.0	13.0	17.0
4. REPORTED CASH FLOW	30.1	361.0	53.7	298.0	66.0	32.3	32.4	14.8	17.6	88.0	33.0	40.0	40.0
5. AFDC (NON-CASH)	8.6	57.0	4.2	16.0	8.1	10.1	4.7	2.6	1.7	23.0	5.0	19.0	5.0
6. DIVIDENDS PAID COM.	10.2	124.0	16.8	74.0	21.2	13.6	14.6	6.3	5.3	40.0	13.0	20.0	17.0
7. NET CASH(4)-(5)+(6)	11.3	180.0	32.7	208.0	36.7	8.6	13.1	5.9	10.6	25.0	15.0	1.0	18.0
8. INC FOR COM(2)-AFDC(5)	7.9	138.0	24.4	166.0	21.5	13.7	19.4	5.8	7.6	32.0	14.0	8.0	18.0
9. LONG TERM DEBT	169.0	2952.0	438.0	2094.0	574.0	336.0	254.0	130.0	144.0	828.0	351.0	402.0	396.0
10. PREFERRED EQUITY	82.0	689.0	133.0	562.0	169.0	36.0	21.0	39.0	40.0	117.0	66.0	110.0	125.0
11. COMMON EQUITY	175.0	2002.0	281.0	1424.0	353.0	194.0	236.0	77.0	102.0	558.0	186.0	283.0	290.0
12. TOTAL CAPITALIZATION	428.0	5645.0	853.0	4081.0	1097.0	567.0	512.0	247.0	286.0	1496.0	604.0	796.0	812.0
13. ELEC GEN CAP ($ OLD MW)	248	2846	417	2044	548	328	190	119	159	744	100	88	487
14. ELEC GEN CAP MW OLD *	1116	13292	2141	12191	2538	1636	766	566	882	2659	592	661	1787
15. EG CAP ($COST/KW)(13)÷(14) *	222	214	194	168	215	200	248	210	180	279	168	133	272
16. EG CAP ($NEW/KW) (18)÷(17) *	518	360	809	726	355	689	428	600	708	782	491	668	654
17. ELEC GEN CAP MW NEW *	685	5656	1727	5043	1680	1166	750	250	905	2595	2154	3126	2075
18. ELEC GEN CAP ($NEW MW)	355	2037	1398	3663	598	800	321	150	641	2031	1059	2089	1358
19. NEW EGP $(18) AS % TO TOT CAP*	82 %	36 %	163 %	89 %	54 %	141 %	62 %	60 %	224 %	135 %	175 %	262 %	167 %
20. YR-YRS FOR NEW MW COMPLETION *	'81-6	'81-6	'83-8	'82-7	'80-5	'81-6	'80-5	'80-5	'86-11	'85-10	'85-10	'86-11	'84-9
21. COM STOCK PRICE 9/15/75 $ *	10.75	19.75	10.82	18.25	14.00	28.62	22.37	9.62	17.00	18.37	25.37	16.25	25.62
22. AVE COM SHR REPORTED (000)*	10,635	66,145	13,697	44,580	17,657	7,350	7,937	5,288	4,408	24,920	4,624	13,125	7,279
23. TOT COM SHR OUT (000)*	13,000	80,030	17,000	47,484	21,256	7,350	10,247	5,791	5,101	26,725	5,751	15,500	9,109
24. EPS AVE SHRS REPORTED $ *	1.56	3.27	2.09	4.10	1.68	3.25	2.75	1.60	2.13	2.22	4.24	2.13	3.24
25. EPS TOT COM OUT $ *	1.26	2.43	1.68	3.83	1.39	3.25	2.35	1.45	1.82	2.05	3.30	1.74	2.52
26. DIV AVE SHR REPORTED $ *	.90	1.88	1.20	1.68	1.20	1.86	1.80	.89	1.22	1.62	2.02	1.55	2.35
27. DIV RATE 9/15/75 $ *	.96	1.88	1.20	1.68	1.20	2.06	1.80	.92	1.28	1.70	2.16	1.58	2.36
28. YIELD 9/15/75 $ *	8.9%	9.5%	11.0%	9.2%	8.5%	7.1%	8.0%	9.5%	7.5%	9.2%	8.5%	9.7%	9.2%
29. INCOME-AFDC/TOT SHR(8÷ 25) $ *	.60	1.72	1.43	3.49	1.01	1.86	1.89	1.00	1.48	1.19	2.43	.51	1.97
30. BOOK VALUE: AVE SHRS $ *	16.45	30.26	20.51	31.90	20.00	26.39	29.73	14.56	23.13	22.39	40.22	21.56	39.84
31. BOOK VALUE: TOTAL OUT $ *	13.46	25.01	16.52	29.80	16.60	26.39	23.03	13.29	20.00	20.87	32.34	18.25	31.83
32. P-E AVE SHRS (21)÷(22) *	6.8x	6.0x	5.1x	4.4x	8.3x	8.0x	8.1x	6.0x	7.9x	8.2x	5.9x	7.6x	7.9x
33. P-E TOT COM OUT (21)÷(23) *	8.5x	8.1x	6.4x	4.7x	10.7x	8.0x	9.5x	6.6x	9.3x	8.9x	7.6x	9.3x	10.1x
34. P-E/TOT SHR-AFDC (21)÷(29) *	17.9x	11.4x	7.5x	5.2x	13.8x	15.3x	11.8x	19.6x	11.4x	12.4x	10.4x	31.8x	13.0x
35. DIV CASH REQ'D 9/15 TOT SHR	12.4	150.0	20.4	79.7	25.5	15.1	18.4	5.3	6.5	45.4	12.4	24.4	21.4

Note: Utilities included are the following: TG&E, Tucson Gas & Electric Co.; PG&E, Pacific Gas and Electric Co; SDG&E, San Diego Gas and Electric Co.; SoCalEd, Southern California Edison Co.; PS Colo, Public Service Co. of Colorado; Id P Co, Idaho Power Co.; MontPCo, The Montana Power Co.; Sierra, Sierra Pacific Power Co.; PS NM, Public Service Company of New Mexico; Pac P&L, Pacific Power & Light Co.; Puget, Puget Sound Power & Light Co.; Port GE, Portland General Electric Co.; Utah P&L, Utah Power & Light Co.