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THE ECONOMICS OF THE HEAT PUMP AS A DEVICE TO ASSIST IN GEOTHERMAL DISTRICT SPACE HEATING

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Can heat pumps economically assist in geothermal space and water heating? If so, common cooler waters can be developed in addition to the rare hot resources which are now exploited. Though a lack of data prevents us from assessing actual reserves, it can be assumed that a mathematical distribution similar to a Poisson distribution applies. The curve would peak somewhere near the temperature of normal ground water (· 20° C) as shown in Figure 1. The curve, does not incorporate normal, near-surface, run-off water that resides in the ground only for brief periods (a year or so) and never has the opportunity to be geothermally heated. If such transient waters were included, the curve would be peaked at an even lower temperature, enclosing a much greater amount of water suitable for heat pump applications. At any rate, there is clearly an enormous energy potential if heat-pump assistance is practical.

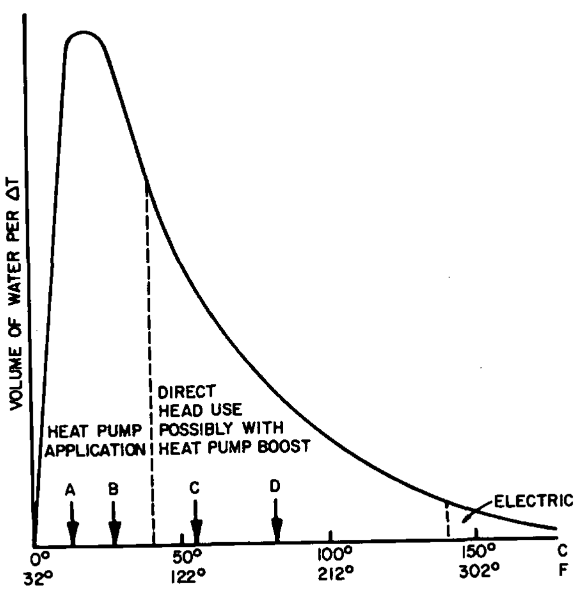

Figure 1 - A probable distribution for geothermal ground water.

The analysis summarized below considers source water of four temperatures: 55° F, 80° F, 130° F and 180° F, i.e. A, B, C and D shown in Figure 1. Case A represents a typical groundwater heat-pump application of the type recently popularized (1) for which a number of package heat pumps are available. This application has been quite successful for both heating and cooling some large buildings, particularly in climates that experience extremely cold winters when the coefficient of performance (COP) of an "air-cooled" heat pump drops to near unity. The typical COP of a "water-cooled" heat pump operating on 55° F water is 3.5, if it is assumed that 10° F is extracted from the water.

Case B represents the coolest waters normally considered geothermal. At 80° F, the water is too cool to be used directly for space heating, yet it is too warm to be used as domestic water. If homes and buildings are to use heat pumps and this water, in general, two water circuits will be necessary. A heat pump operating at this temperature and extracting 25° F will typically have a COP of 4.5.

Case C at 130° F considers the coolest waters practical for direct geothermal use, without heat-pump boosting. The direct use extracts 20° F from the water. There may still be an advantage, however, to providing a heat-pump boost under those circumstances. With heat-pump boost to extract 50° F from the water, a coefficient of performance of 5.5 might be expected.

Case D at 180° F represents a traditional direct use of geothermal energy at an ideal temperature for space heating and water heating. Typically, 50° F can be easily extracted from the water. Waters in this temperature range have been successfully used in district space heating systems in Iceland and Boise, Idaho for years. The current economics of building such a system into an existing city has been studied (2).

To evaluate the economics of these four resources, two different climates were compared. The first is an 8400° F.-day situation (#1) with an ASHRAE design temperature of -11° F., corresponding to cities with a climate similar to Idaho Falls. The second situation is 5600° F.-day (#2) with an ASHRAE design temperature of +3° F., corresponding to the climate in Boise, Idaho. However, for Situation #1, we recommend design water supply rates to adequately supply the needs at +15° F., using supplemental heat for colder conditions, which consume 5% of the annual heating load. For Situation #2, a +25° F. design load for the water supply system has been shown to be the economical optimum (2), for which supplemental heat supplies 5% of the annual requirements. For this analysis we have also assumed that all of the normal domestic water heating load is also supplied by the ground water heat source.

Reference #2 stressed the economics that required a large district heating system if a main pipeline was to be used economically, particularly a pipeline to be installed in existing streets. In new subdivisions, pipeline economics can be considerably more favorable, making smaller-sized systems economically practical. However, for the cases shown below, we have chosen a district system of homes and businesses equivalent to 7500 average homes, approximately the size of a city of 20,000 population.

This represents half of the city of Idaho Falls (Situation #1), 1/6 of the city of Boise (Situation #2). These homes were assumed to have a net average heat load of 600 Btu/hr.°F temperature difference, where "net" refers to the actual heat loss minus the sensible (internally generated) heat. The main pipelines for such a section of a city will cost about $2 million, installed.

For comparison, a city of 20,000 people in Idaho consumes about 12,000 acre-ft. per year of domestic water. Hence, the water supply needs for space heating exceed the domestic needs if a typical ground water space heating pump is to be used. However, it should be noted that the domestic use peaks in the summer, while the space heating needs peak in the winter, making a synergistic solution possible.

Capital costs of the above cases are based on assumptions of well depth and productivity. These can vary substantially, depending on the geohydrology. For purposes of comparison, however, a geothermal gradient of 2 1/3 times the "world average" was assumed, probably characteristic of the likely situations throughout the west. Well productivity was assumed to worsen with depth, and larger pumping heads were required, not because of lower ambient water levels, but because the well would

	Climate Situation #1	Climate Situation #2
Total Heating °F	8400	5600
ASHRAE Design Temperature °F.	-11	+3
"Geothermal" System Design Temp.°F	+15	+25
Total Yearly Space Heating Needs(Btm)	9.1×10^{11}	6.1×10^{11}
Yearly Hot Water Needs	1.5×10^{11}	1.5×10^{11}
Total "Geothermal" Heat Market	10.6×10^{11}	7.6×10^{11}
Gross Revenues at Competitive Price of $3/M Btu	$3.18 million	$2.28 million

The water use requirements annually for each of the cases is as follows:

			Climate 1 Acre-ft/year	Climate 2 Acre-ft/year
a)	10°	T Heat Pump	39,000	28,000
b)	25°	T Heat Pump	16,000	11,000
c)	20°	T Geothermal	20,000	14,000
c-1)	50°	T Geothermal with Heat Pump Boost	7,800	5,500
d)	50°	T Geothermal	7,800	5,500

be pumped to get the highest reasonable productivity. The following table shows the assumptions for each case and the capital cost of each.

Case	Well Depth ft.	Avg.Prod. per well Gal/Min	Climate #1 No. of Prod. Wells	Total Pumping Head including disposal	Avg.Prod. Well + Pump Cost	Climate #1 Total supply system cost including $2 million for main Pipelines	Climate #2 Total supply system cost including $2 million for main Pipelines
a	400	2000	19	300'	$50K	$3,140,000	$3,020,000
b	800	1500	10	400'	90	3,080,000	2,907,000
c	1500	1000	19	500'	180	7,130,000	6,549,000
c-1	1500	1000	8	500'	180	4,160,000	3,890,000
d	2500	700	11	700'	300	6,950,000	6,500,000

*For disposal of the used fluid, 20% of the production well costs was assumed for cases "a" and "b", 50% for "c", "c-1" and "d".

Annual electric power requirement for each of these cases is as follows. It is assumed that the cost of electricity is 3 cents/kwh.

Case	Climate #1 Pumping Million Kwh	Climate #1 Heat Pump Million Kwh	Climate #1 Total Cost Million $	Climate #2 Pumping Million Kwh	Climate #2 Heat Pump Million Kwh	Climate #2 Total Cost Million $
a	1.6	88.7	3.14	11.5	63.6	2.25
b	8.6	69.0	2.33	6.2	49.5	1.67
c	13.3	0	.40	9.6	0	.29
c-1	7.5	56.5	1.92	5.3	40.5	1.37
d	7.5	0	.23	5.3	0	.16

Conclusions

The comparison of the five different "geothermal" heating cases must be made with an understanding of the economic criteria upon which the organization (company) that supplies the geothermal water must work. A municipal system that enjoys low borrowing rates will be less affected by high capital costs than would a capitalized system. For the latter, a "pay back" guideline of three years may be considered typical and appropriate. With these assumptions, the following conclusions can be drawn relative to the costs of conventional oil and gas heating systems having fuel costs of $3/M Btu (the equivalent of about $450/hour).

Case A - Heat pumps using 55° F ground water would cost as much to operate as an oil or gas system. The initial installed cost by the home owner is about $500 more per home, and the water-supply system would add about $50/year, amortized, if the supply system were common with the regular domestic water supply. If a separate set of lines were needed, the system is not now cost competitive. The disposal of the continual high flow rates during winter does represent a problem for sewage treatment, and separate discharge lines may be the least costly solution. The application is pollution free at the user facility, giving it a definite advantage over fossil-fuel heating.

Case B - A system using 80° F groundwater heat pumps, requiring separate supply and disposal circuits for the domestic water system would save 25% in operating cost. But amortization of the capital cost exceeds this saving by $50/year per home, similar to Case A. However, the relative cleanliness, convenience, and compactness represent advantages well worth the extra cost.

Case C - Geothermal water of 130° F has negligible operating cost, and the savings are easily greater than the amortized capital cost. Home-owner equipment investment is $500 less than for heat pump.

Case C-1 - Using 130° F geothermal water with a heat-pump boost to extract more heat from the water is more expensive than Case C, the direct use. However, the heat pump will cool the water to 80° F, virtually eliminatig any problem of thermal pollution if disposal is to be into a stream. This intangible advantage may, in certain cases, translate to a less expensive overall system than the direct use without heat-pump boost. Because of the substantially lower water supply requirements, the main pipeline system could accomodate significant expansion to serve 2 to 3 times as many homes and businesses.

Case D - The direct use of 180° F geothermal water has virtually no operating cost. For Climate #1 (8400° F-days), investment amortization is easily covered by the savings. In the case of Climate #2 (5600° F-days), the overall costs are equivalent to gas and oil. The homeowner investment if $500 less for the geothermal system, and cleanliness, convenience and compactness are further advantages.

Note that the conclusions are based on a $3/M Btu net cost of fossil-fuel heating. These current costs are expected to excalate faster than will the cost of electricity to drive heat pumps. Thus, the heat-pump cases should show improved economical competitiveness in the future.

A general conclusion to be drawn is that pumping costs are an insignificant part of the total (less than 20%). Hence, wells should be pumped to their fullest capability for reasonable pump capital costs.

Since every one of the five cases showed a combination of attractive economics and convenience, the test drilling for geothermal water is a sound investment. Regardless of the water temperature discovered, the typical situation should lead to a "geothermal" heating system that is attractive if implemented on a large enough scale. We have made no mention of maintenance and operating-labor cost comparisions for the five cases, for we feel these will be comparable, and will represent only an approximately 10% addition to the overall costs quoted above. If heat-pump applications are required, these do offer the added advantage of being able to air condition in the summer.

Finally we note that in certain areas of the country neither fuel oil or natural gas can be obtained in adequate supplies for newly constructed facilities. Any of the five cases above is significantly more attractive than electric heat or an air-to-air heat pump for climates at least as severe as approximately 5000°F-days annual heating needs.

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References

(1) "Ground Water Heat Pumps - Home Heating and Cooling From Your Own Well", Popular Science, Feb. 1978, p.78.

(2) J.F. Kunze, L.E. Donovan, J.L. Griffith, "The Size Effect for District Space Heating in Boise, Idaho", Transaction of FRC, Vol. 1, May 1977. p.179.

ENVIRONMENTAL NECESSITY AND SUFFICIENCY: THE CASE OF THE RAFT RIVER PROJECT

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Long before it was drilled, the Raft River geothermal reservoir in southern Idaho was correctly characterized by geothermometry as a moderate-temperature resource. Three deep-hole wells have since been drilled into the paleozoic quartz-monzanite basement, reaching the predicted 150°C (300°F) temperatures well before encountering the poorly-fractured basement. Described below is the environmental program that began prior to drilling and accompanied the development of a complete well field for a 5-MW(e) [40-MW(th)] pilot plant.

Initial Considerations

A primary concern was to involve all organizations having an interest in the area's environment. Figure 1 shows the matrix of organizations whose involvement and help was solicited. The names with asterisks are those organizations which received funding to participate, in return for specific data and evaluations of the existing environment.

The major environmental concerns initially addressed were as follows:

1. The area is a fragile desert environment which once was a rich grazing area, a high steppe-grass country, prior to its being overgrazed in the latter part of the 19th century. Precipitation on the valley floor averages 25 cm (10 in.) per year.

2. Sensitive species could be disturbed by noise or habitat encroachment during drilling and construction.

3. Historical materials and artifacts could be destroyed. The area was traversed by the old Oregon-California trail.

4. With injection of the geothermal fluids being a planned necessity because of the huge quantities that must be flowed (42 L/sec/net-MW-output, or 680 gpm), would there be:

i) selective subsidence if the injected fluids are not of full quantity or do not mix with the producing reservoir?

ii) possible seismic activity from changes in reservoir pressures or fault lubrication?

5. Could the near-surface domestic aquifer be contaminated either during drilling or later during production and injection?

6. Could well testing, construction activities, or cooling-tower operation cause atmospheric contamination?

	AIR	WATER	PHYSIOGRAPHY	BIOLOGICAL	HUMAN	INTEGRATED PROGRAM
IDAHO NATIONAL ENGINEERING LAB	X	X	X	X	X	X
ERDA - IDAHO OPERATIONS	X					X
U.S. EPA		X				X
U.S. FISH AND WILDLIFE				X		
U.S. SOIL CONSERVATION SERVICE			X			
NOAA	X					
U.S. BUREAU OF LAND MANAGEMENT				X		X
U.S. GEOLOGICAL SURVEY		X	X			
U.S. BUREAU OF RECLAMATION		X				
ID DEPT OF WATER RESOURCES		X				
ID BUREAU OF MINES AND GEOLOGY		X				
ID DEPT OF FISH AND GAME				X		
ID DEPT OF HEALTH AND WELFARE	X	X				X
BATTELLE HUMAN AFFAIRS*					X	
BATTELLE NORTHWEST		X				
U OF UTAH RESEARCH INSTITUTE*	X			X		X
U OF UTAH*		X	X	X		
IDAHO STATE U*				X	X	
U OF IDAHO*		X		X		
BRIGHAM YOUNG U*				X		
U OF CALIFORNIA - BERKELEY*			X			
COLORADO SCHOOL OF MINES*			X			
UTAH STATE U*		X	X	X		
PRIVATE CONSULTANTS*		X	X	X		X
SERVICE COMPANIES*	X	X				

Fig. 1 Primary Participants in Raft River Environmental Program

The Fragile Ecosystem

The baseline assessments of the biota were conducted by three universities -- University of Utah, Idaho State University, and Brigham Young University. The significant aspects that can be labeled fragile were:

1. The ferruginous hawk nesting grounds. Though the species is not officially threatened or endangered, the Raft River Valley is one of its few habitats. Figure 2 shows the nesting sites, with suggested 1-mile radius exclusion areas.

2. Sage grouse strutting grounds and brood-rearing areas. This species' environment is being encroached upon throughout the West.

The recommendations were made to prohibit drilling and construction during nesting periods. These recommendations are inadequate as a permanent solution--instead, an evaluation of the disturbance-effects patterns has been planned during the small pilot-plant programs, before major geothermal development begins.

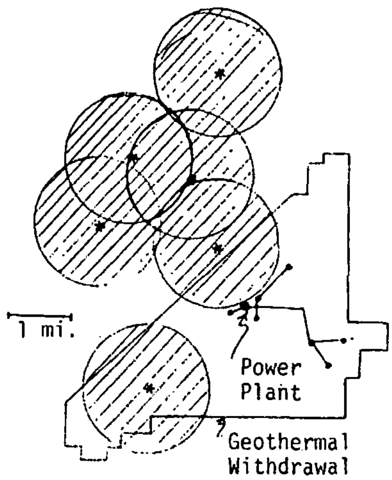

Fig. 2 Ferruginous Hawk Nests and Buffer Zones

Seismics

The Colorado School of Mines, under contract during 1974, conducted a study of the natural microseismic activity in the valley. During the entire 90 days of the study, only seven events with S-P times of less than 2.0 sec (corresponding to epicentral distances of less than 17 km) were detected. The scarcity of events and the low magnitude of their force seem to indicate that the area is more closely related to the aseismic Snake River Plain than to the active Basin and Range Province. Though naturally aseismic, the valley could become active as a result of long-term production and injection of the geothermal resource. Therefore, monitoring of microseismic activity is continuing, with four stations operating in the valley.

Subsidence

When benchmarks were releveled by the USGS in 1974, it became apparent that significant elevation changes had occurred in the northern part of the valley. Two types of movement were suggested; regional movements, probably as a result of tectonism, and a cone of subsidence of more than 0.8 m (2.6 ft) in an area of groundwater decline. The USGS line has been extended to include a grid around the production-injection field. No subsidence has been detected to date, although geothermal fluids have been produced and reservoir pressures have declined. Extensometers are being installed at various depths in the near-surface and geothermal aquifers to differentiate among: 1) subsidence that may result from production of the geothermal resource; 2) that which results from pressure declines in upper aquifers hydraulically connected to the geothermal resource; and 3) that which results from normal groundwater withdrawal for irrigation.

Water Quality Monitoring

Because of the major dependence on water for irrigation and domestic purposes in the area, the possible contamination of these supplies has been of prime concern. Both the surface and groundwaters have been sampled frequently during the past four years. Several irrigation wells show the influence of natural leakage from the geothermal resource (see Table 1). Because injection may alter or enhance this natural communication, a series of monitor wells has been drilled to depths of from 150 to 460 m.

TABLE 1

	RRGE-1	RRGE-3	Typical Irrigation Well*	Raft River
Depth, m, (ft)	1521 (4989)	1790 (5840)	110 (360)	--
T(°C)	147	149	29	18
pH	Avg. 7.2	6.3 to 7.5	7.7	8.4
Conductivity	3373	9530	4400	1060
Ca	53.5	193	92	104
K	31.3	97.2	19.6	9
Li	1.5	3.1	1.7	0.04
Na	445	1185	777	92
Cl^-	776	2170	1257	220
F^-	6.3	4.6	5.1	.72
HCO^-_3	63.9	44.4	131	229

* Near geothermal wells

Air Quality

Geothermal power plants at the Geysers in California have at times faced stiff opposition from environmentalists claiming that air quality standards had been violated. The primary concern was H_2S; secondarily, water vapor was a concern (in essence it would be an "enrichment" to the arid climate of that region). Because of the poor image regarding air quality attached to ideas of geothermal development, a very thorough baseline study was begun at Raft River shortly after the first well "came in."

Both high-volume and low-volume air samplers were installed near the site and 15 miles to the north of Malta, the only nearby town. A complete meteorological system was installed, and pollution-monitoring cameras were mounted, aimed principally toward Pocatello (80 miles to the northeast) and the Salt Lake Valley (80 miles to the southeast).

The air samplers picked up significant quantities of phosphates (from local farming operations) and of sulphates (identified as those characteristic of the smeltering operations in the Salt Lake Valley). Pollution monitoring showed very significant ingress over the Strevell Pass from Salt Lake, with minor (1/4 as much) ingress from the Pocatello area.

Injection of most of the used geothermal fluid at Raft River is intended, except for that to be used beneficially for agriculture and aquaculture. Furthermore, H_2S has never exceeded 0.15 ppm in any of the deep wells. These factors alone would indicate that the extensive air-quality monitoring program was technically unessential. But when one deals with a preconceived negative image of geothermal development and air quality, it is politically essential to establish a thorough baseline for comparison at a later time.

Today's Concerns

Most of the initial concerns listed above have been adequately addressed and evaluated well in advance of developing a geothermal area in the valley. However, there remain two concerns which were not appropriately recognized until the wells were drilled and certain reservoir evaluation results were available:

1. Operation of the production and injection wells may well affect the near-surface aquifer. It is not certain that these effects will be detrimental, however.

2. Water consumption from wet cooling towers in a moderate-temperature geothermal power plant is three to five times greater, per unit net electric output power, than for fossil or nuclear power plants.

Better evaluation of the vertical connections in the aquifers, of the natural convective flows among strata, and of the chemistry of the various strata is the major data requirement for the current phase of the environmental program. Presently, the near-surface aquifer does not appear to be much purer than the geothermal aquifer. There seem to be connections between these aquifers, which implies that consumptive use of _any_ water affects the inventory of the domestic and agriculture water resources in the valley.

Conclusions

The Raft River environmental program was designed to address the concerns associated with geothermal development. As development progressed, and more data became available, more emphasis was placed on particular concerns. The program is continually being modified to reflect these changes. The baseline-characterization studies represent an investment of $400,000. The environmental report preparation represents an additional $100,000. Routine monitoring of the parameters that may be affected by geothermal development is costing $150,000 per year. Is this excessive for a $15 million pilot plant development? Certainly we would hope to learn from the early pilot programs what environmental parameters are sensitive to geothermal development, and which are not, so that costs can be reduced. Geothermal developments tend to involve small quantities of power, with small environmental impact. Environmental study costs should be adjusted according to the potential impact.

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ECONOMIC FEASIBILITY MODEL FOR DIRECT HEAT APPLICATIONS OF GEOTHERMAL ENERGY

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ABSTRACT

An Economic Feasibility Model (GEYSER) to determine the viability of direct heat applications of geothermal energy is described. The Price of the Product or the Return on Investment can be determined given the required economic parameters. Variables can be adjusted to perform sensitivity analysis, the key economic variables can be highlighted, and the range of profitability can be forecasted.

Work performed under the auspices of the U.S. Department of Energy, Contract No. ET-78-C-03-1529.

A model has been developed which evaluates the economic feasibility of direct heat applications of geothermal energy. The model, named GEYSER (Geothermal Energy Yearly Statements of Expenses and Revenues), is a generic model encompassing a wide range of investment possibilities and concerns a potential investor would have regarding the development of a new product, such as the rate of inflation, the future costs of alternative energy sources, and the present and future market demand for his product.

The GEYSER model will enable the potential investor to evaluate an investment possibility by using known information and ranges of projections for uncertain data, along with his own perceptions of the risks involved, to determine the viability of a potential geothermal operation. Many of the direct heat applications involve existing technologies which can be utilized to lower potential risks. Some direct heat uses, including space heating, industrial and agribusiness applications, are being presented at this conference.

This economic feasibility model is designed to provide two major functions:

1) to project the range of prices of a product developed with a geothermal resource, and

2) to project the range of return on investment for the venture.

These projections are based upon assumptions which form the basis of the model input. The investor with the highest degree of certainty regarding these assumptions will perceive a lower degree of risk.

The price and return on investment is calculated by projecting the income statements of the venture over the life of the investment. (An income statement is a standard accounting tool which displays income and expenses for the year.) The time series of expected income statements can also serve as a guide to measure and monitor the success of the investment. The project managers will be able to compare the actual income statements with the projected income statements to determine where cost projections differ.

The model has two forms of outputs: one assumes total revenues and forecasts the return on investment; the other works in reverse, assuming a return on investment and forecasting total revenues. Tables 1 and 2 display the income statement and "reverse income statement" formats, by which the investments are analyzed.

Unlike electric power plants which have long lead-times before development, most direct heat applications can be developed and put into operation in a short time, usually less than a year. Therefore, the current competing market prices and the projections of near-term and long-term future market prices are of critical concern. The following discussion shows how the economic feasibility model can be used to help evaluate present and future markets.

A. Present Markets

Given the variables listed below, the economic feasibility model is used to estimate the price of, and the return on investments for, the product. The model can be divided into two components.

Since geothermal energy will replace a portion of the energy cost to the operation, if the component data are available, a series of income statements can be generated for the energy costs and assumptions separately. In this way, it would be as if the energy producer functioned independently of plant production.

If desired, all components can be included in the overall income statement projections, as shown below. Many of the inputs to the model are optional. By using the inputs listed below, an algorithm is utilized, which calculates the expected revenues from the project and thus, the price of the product. Conversely, if the price of the product and the level of output are assumed, the return on investment can be calculated.

Using these inputs, the potential ininvestor can generate a price for his product in constant dollars for comparison with the alternative price of the product, i.e., the alternative price of energy in the market, in the region at that point in time.

B. Projected Markets

Markets do not remain stable over time as witnessed by the increasing costs of oil, uranium and most other products. Inflation plays a major role in many investment decisions and must always be considered a variable. In addition, many prices increase as a result of increased demand. If a geothermal product is produced in a region which currently has adequate supplies, the price and return on investment will decrease for all producers in that region. Energy costs are very responsible to increases in demand (decreases in supply). The less dependent geothermal energy is on these fluctuations, the more viable and desirable it is. One of geothermal energy's potentially attractive attributes is that it

INPUT PARAMETERS FOR ECONOMIC FEASIBILITY MODEL

		Assumptions for Example
1.	Life of Investment	20 years
2.	Units of Output (Production Rate)	$176,360/yr. Total Revenue (TR)
3.	Price Per Unit of Output	
4.	Capital Costs	$967,879 (1978)
5.	Operating Costs (Fixed)	$39,541
6.	Operating Costs (Variable)	0
7.	Rent and/or Royalties	5% of TR
8.	Depreciation Method a. Straight Lined b. Declining Balance c. Sum of Years Digits	Double Declining Balance
9.	Percent of Debt (% Equity)	50% debt
10.	Interest Rate	8%
11.	Discount Rate	8%
12.	Tax Rates a. Federal b. State c. Property (Ad Valorem)	 48% 9% 3% TR
13.	Depletion Allowance	None
14.	Intangible Drilling Cost Expensing	70%
15.	Drilling Costs	$300,000
16.	Investment Tax Credits	10%
17.	Return on Investment (Reverse Income Statement)	15%
18.	Exploration and Development Times	0
19.	Specific Tax Benefits or Subsidies a. As Percent of Capital Costs b. As Percent of Taxes c. Per Unit of Output	 0 0 0
20.	Price of Energy (Additional or Alternative)	0

is a capital intensive investment, which is not subject to fuel price increases. Once the well is drilled and the pipes, exchangers, etc., installed, the energy source, in many cases, has very little additional cost. Operating and maintenance costs may increase, but in most cases, this is a small component of the overall cost. Therefore, it is advisable to evaluate the geothermal prospect with regard to the specific alternative energy sources available to the investor (gas, electric, fuel oil, etc.) to obtain projections of future supply and demand for these components and their corresponding costs and assumptions. The feasibility model is generic, in that assumptions for the alternatives can be substituted and a direct comparison of the costs performed.

The two effects which will influence future costs and which can be reflected in the income statements are included in the model. They are:

1) Cost Escalation Factors
   a. operating and maintenance costs
   b. additional capital cost
   c. energy (product prices)
   d. learning curve effects
2) Inflation Factors.

The income statements displayed do not include cost escalation or inflation factors. The line items in the income statement can be adjusted to account for forecasted rates. Several indexes are available, such as the Consumer Price Index, which can help evaluate this impact on a product's economic feasibility.

Tables 1 and 2 illustrate sample outputs in constant 1978 dollars for a direct heat application. The assumptions are based upon cost and economic information from the *Total Energy Recovery System for Agribusiness* (International Engineering Company, Inc., May 1977), as well as drilling cost assumptions for a hypothetical site. The example is designed to illustrate the output of the model, rather than advocate the input assumptions to the model. The assumptions used in this presentation are not validated with any particular site in mind, but serve as an example.

This example illustrates the benefits which would accrue to a small developer operating the resource as a primary investment. Unlike a large corporation or conglomerate, the small developer cannot take advantage of early expensing of intangibles and investment tax credits in the immediate year. (This is shown in the income statements.) The expensing of intangible drilling costs can only be utilized until the net income before taxes is zero, because the deduction cannot be greater than total revenues. In addition, the small developer is unable to use the investment tax credit until the seventh year of operation. A large company would be able to efficiently use these tax advantages by utilizing them in conjunction with other investments, and thus receive a higher return on investment.

Table 1 forecasts the income statements in constant dollars. To determine the return on investment, the actual cash flow of the operation must be considered. The incomestatements allow for the calculation of tax expenses. Net income on the income-statements is zero during the first 6 years of production, nevertheless there is still a positive net cash flow. Depreciation is an accounting method used to determine taxes it reflects the recovery of capital but is not included in the calculation of the true cash flow. The cash flow is calculated by substituting the actual expenses such as the amortized loan payment for the paper expenses such as depreciation, expensing of intangibles and depletion. The cash flow and the net present value of the cash flow with an 8% discount rate is displayed for each year in the table. The internal rate of return of the cash flow is 11%.

At this point the investor might ask what conditions would be necessary to get a 15% return on his investment. How much would he have to raise the price of the product to satisfy this requirement? The model then goes through an iterative process whereby the price required for a 15% return is calculated. Table 2 displays the corresponding income statements in a reverse format. In this case total revenues increased to $199,000 per year indicating that a 12.8% increase in the price of the product would be necessary for a 15% Internal Rate of Return.

The investor, at this point, must look at the market for his products and determine future demand and cost and price escalations. The Total Energy Recovery System investment produces several products in a synergistic cascading system. The market for each of these products must be analyzed to determine the worth of each component of the investment. A finer breakdown of the capital costs and a review of market demands might indicate the net benefit of each component, as well as highlight any inefficiencies in the system.

In summary, the GEYSER model has been developed to analyze the economic feasibility of potential users of geothermal energy. The model allows for many applications using as few inputs as necessary for a simplified analysis of investment possibilities. The model can be modified to accommodate specific additions for further analysis.

TABLE 1. PROJECTED INCOME STATEMENTS (1978 DOLLARS*)

INCOME STATEMENTS AND CASH FLOW	YEARS																			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
TOTAL REVENUES	$176,360	176,360	176,360	176,360	176,360	176,360	176,360	176,360	176,360	176,360	176,360	176,360	176,360	176,360	176,360	176,360	176,360	176,360	176,360	176,360
ROYALTIES (RENT)	8,818	8,818	8,818	8,818	8,818	8,818	8,818	8,818	8,818	8,818	8,818	8,818	8,818	8,818	8,818	8,818	8,818	8,818	8,818	8,818
OPERATING & MAINTENANCE	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541
ENERGY EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEPRECIATION (DOUBLE DECLINING BALANCE)	69,960	62,964	56,667	51,000	45,901	41,310	37,180	33,462	30,115	27,107	27,104	27,104	27,104	27,104	27,104	27,104	27,104	27,104	27,104	27,104
EXPENSING INTANGIBLE DRILLING COSTS ($244,944)	14,035	21,876	29,087	35,741	41,906	47,647	1,631	0	0	0	0	0	0	0	0	0	0	0	0	0
INTEREST ON DEBT	38,715	37,868	36,955	35,968	34,902	33,762	32,509	31,166	29,716	28,151	26,460	24,633	22,660	20,530	18,229	15,687	13,061	10,162	7,033	3,652
DEPLETION ALLOWANCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PROPERTY TAX & INS.	5,291	5,291	5,291	5,291	5,291	5,291	5,291	5,291	5,291	5,291	5,291	5,291	5,291	5,291	5,291	5,291	5,291	5,291	5,291	5,291
NET INCOME BEFORE TAXES	0	0	0	0	0	0	51,390	58,082	62,878	67,455	69,147	70,973	72,945	75,076	77,377	79,919	82,545	85,443	88,572	91,954
STATE TAXES	0	0	0	0	0	0	4,625	5,226	5,658	6,070	6,223	6,387	6,564	6,756	6,963	7,192	7,429	7,690	7,971	8,276
FEDERAL TAXES	0	0	0	0	0	0	22,447	25,369	27,465	29,464	30,203	31,000	31,862	32,793	33,797	34,908	36,054	37,321	38,688	40,165
INVESTMENT TAX CREDIT	0	0	0	0	0	0	22,447	25,369	27,465	21,507	0	0	0	0	0	0	0	0	0	0
NET INCOME	0	0	0	0	0	0	24,317	27,484	29,753	31,920	32,720	33,584	34,517	35,526	36,614	37,817	39,059	40,432	41,912	43,512
CASH FLOW	73,420	73,420	73,420	73,420	73,420	73,420	73,284	68,430	67,975	63,211	36,582	35,620	34,580	33,458	32,246	30,937	29,523	27,997	26,347	24,566
NET PRESENT VALUE OF CASH FLOWS @ 8%	67,981	62,945	58,283	53,965	49,968	46,267	42,760	36,971	34,004	29,279	15,689	14,146	·12,715	11,392	10;165	9,030	7,979	7,006	6,105	5,270

TABLE 2. REVERSE INCOME STATEMENTS (1978 DOLLARS*)

REVERSE INCOME STATEMENTS AND CASH FLOW	YEARS																			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
CASH FLOW	94,248	94,248	94,248	94,248	90,962	88,183	86,194	53,547	51,118	48,933	48,042	42,080	46,041	44,919	43,707	42,398	40,984	39,457	37,808	36,027
NET INCOME	0	0	0	0	17,278	31,887	34,281	36,560	38,741	40,704	41,504	42,368	43,302	44,310	45,399	46,574	47,844	49,216	50,687	52,297
INVESTMENT TAX CREDIT	0	0	0	0	15,949	29,434	30,110	0	0	0	0	0	0	0	0	0	0	0	0	0
FEDERAL TAXES	0	0	0	0	0	0	1,534	33,747	35,761	37,573	38,311	39,109	39,971	40,901	41,906	42,992	44,164	45,430	46,797	48,274
STATE TAXES	0	0	0	0	3,286	6,064	6,620	6,953	7,368	7,741	7,893	8,058	8,236	8,427	8,634	8,858	9,099	9,360	9,642	9,946
NET INCOME BEFORE TAXES	0	0	0	0	36,514	67,387	72,446	77,261	81,871	86,019	87,710	89,536	91,509	93,639	95,940	98,425	101,109	104,007	107,137	110,518
PROPERTY TAX & INSURANCE	5,970	5,970	5,970	5,970	5,970	5,970	5,970	5,970	5,970	5,970	5,970	5,970	5,970	5,970	5,970	5,970	5,970	5,970	5,970	5,970
DEPLETION ALLOWANCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INTEREST ON DEBT	38,715	37,869	36,955	35,968	34,902	33,751	32,508	31,166	29,716	28,150	26,459	24,632	22,660	20,529	18,229	15,744	13,060	10,162	7,032	3,651
EXPENSING OF INTANGIBLES	36,878	43,839	50,318	56,368	25,527	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEPRECIATION	67,945	61,830	56,265	51,201	46,593	42,399	38,583	35,111	31,951	29,369	29,369	29,369	29,369	29,369	29,369	29,369	29,369	29,369	29,369	29,369
ENERGY EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OPERATING & MAINTENANCE	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541
ROYALTIES (RENT)	9,950	9,950	9,950	9,950	9,950	9,950	9,950	9,950	9,950	9,950	9,950	9,950	9,950	9,950	9,950	9,950	9,950	9,950	9,950	9,950
TOTAL REVENUES	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000

* (1976 Dollars with 8% inflation per year)

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GELCOM: A GEOTHERMAL ELECTRIC LEVELIZED COST MODEL[1]

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ABSTRACT

The model described in this paper is designed to project the costs of electricity generated from liquid-dominated hydrothermal geothermal resources. It exists in the form of an interactive computer program called GELCOM, written in FORTRAN IV. This paper provides an analytic explanation of the methodology.

This work was performed for the purpose of conducting site-specific analyses of the likely economic competitiveness of geothermal energy. These analyses are being published separately.[2] The model has also been used as a reference point in comparing and analyzing other methods of projecting geothermal energy costs.

GELCOM consists of an engineering cost estimating model and a levelized busbar cost model, as shown in figure 1. The field owner and operator ("Producer") and the conversion and generating plant owner and operator ("Utility") are treated as separate financial entities with different capital structures and subject to different tax and other regulations.

The engineering cost estimating model starts from resource characteristics data (such as temperature, salinity, well flow rate, depth, and rock hardness), and estimates the capital and operating costs for the production field and electrical generating plant. These estimates are made by interpolating between, or extrapolating from, twelve generic geothermal plant designs for different resource temperatures, salinities and conversion cycles. Well costs are estimated separately, from resource depth and rock hardness. The interactive nature of the program allows the program generated parameters to be overriden by the user, if desired.

The capital and operating costs are used as inputs to the levelized busbar cost model. This part of the program also requires financial data (debt/equity ratio, cost of money, tax rates, etc.). The algorithm used is based upon one which is standard in METREK, with certain extensions which have been found necessary to cope with factors specific to geothermal energy (e.g., capital reinvestment in replacement of production wells, injection wells and production plant).

Inflation and escalation are specifically taken account of in these calculations. The levelized busbar cost is computed as the cost in mills/kWh whose present value over the life of the project exactly equals the present value of all cost streams associated with the project (including return on equity). GELCOM includes the option of levelizing the imputed revenue stream obtained from energy production with or without accounting for inflation, i.e. in either constant or current dollars.

The program is designed to easily estimate the effects on busbar costs of reductions in the capital and O&M costs of components (perhaps achieved through RD&D or through experience), with different reductions being applicable for plants coming on-line in different years. It can also perform sensitivity analyses for the cost of electricity for varying resource and plant parameters. Fiscal incentives, such as depletion allowance, investment tax credit, and expensing intangible drilling costs are explicitly included in the program and may be used to evaluate the impact of these incentives on electricity costs. Figure 2 shows a flow chart for the program logic.

Figure 3 illustrates part of a typical program output, for, in this case, the geothermal prospect at Heber, California. The output starts by giving the field name, and the plant cycle, size and on-line date, followed by the physical field parameters and well flow rates and costs, indicating whether these were obtained from operator input or through the internal (default) program algorithms. Next, financial data are given for the Producer and the Utility.

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[1]Work performed under the auspices of the U.S. Energy Research and Development Administration, Contract No. EG-77-C-01-4014.

[2]"Site-Specific Analysis of Geothermal Development--Scenarios and Requirements", R. K. Trehan, A. Cohen, J. N. Gupta, W. E. Jacobsen, J. G. Leigh, S. True, The MITRE Corporation, METREK Division, MTR-7586, Volume II. in process.

Then the estimated capital and operating costs for the plant, obtained from the engineering cost estimating model are displayed. The capital cost basis includes interest during construction. These cost estimates are for current (1977) technology. Finally, the levelized busbar costs or revenue requirements for this plant are given; the Producer costs are converted to mills/kWh of electrical output for convenience.

The next section of the output takes into account certain R&D advances postulated to be available when the plant design is finalized. The revenue requirements impact of each R&D advance is shown separately, then the revenue requirements impact for all advances together are shown. Finally, a sensitivity analysis is performed for the factors shown. Subsequent pages of the printout (not reproduced here) show similar information for subsequent plants on-line at this site.

The GELCOM data files currently contain characteristics of twenty-four geothermal (hydrothermal) prospect areas. Figure 4 illustrates estimated levelized costs of electricity (using current technology) from these prospects, including ranges of uncertainty due to resource temperature and plant reliability. The costs of likely competing energy sources are shown, computed using the same levelized busbar cost methodology.

A descriptive guide and users' manual for GELCOM has been prepared and is available in limited quantities.[3]

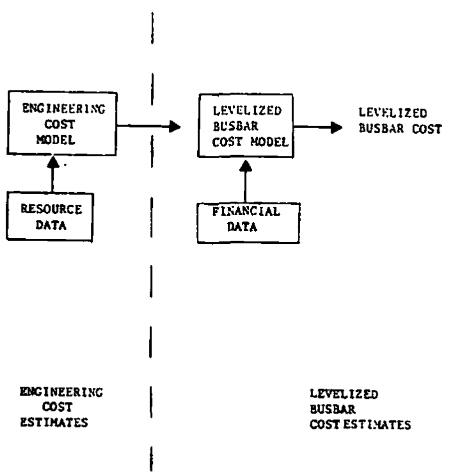
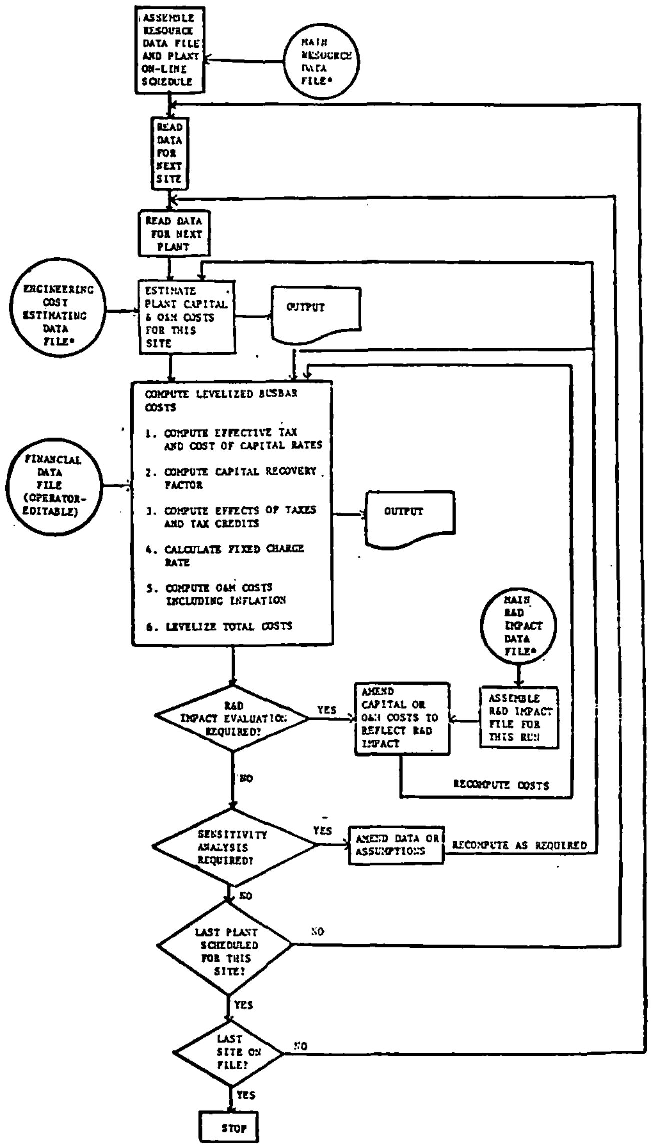


FIGURE 1

STRUCTURE OF GELCOM



*THESE FILES SHOULD NOT BE ALTERED BY THE OPERATOR.

FIGURE 2: LOGIC FLOW FOR GELCOM

[3] "GELCOM: A Geothermal Levelized Busbar Cost Model - Description and Users' Guide", J. N. Gupta, J. G. Leigh, The MITRE Corporation, M78-17, March, 1978.

FIGURE 3

EXAMPLE OF OUTPUT.

HEBER , CALIFORNIA
BINARY SYSTEM , 50 MW ELECTRIC PLANT
FIRST PLANT ON LINE DATE : 1983

TEMPERATURE IN CENTIGRADE DEGREES (BEST ESTIMATE) : 190
WELL DEPTH IN METERS : 1500
BRINE SALINITY : LOW
OVERLYING ROCK TYPE : SOFT
THE WELL FLOW RATE IS NOT SPECIFIED : THE DEFAULT FLOW RATE USED (KGM./HR.) = 266270
SPECIFIED COST PER PRODUCTION WELL ($) : 600000.0
SPECIFIED COST PER INJECTION WELL ($) : 600000.0

PRODUCER FINANCIAL DATA

DEBT FRACTION :	0.30
ANNUAL INTEREST RATE ON DEBT (FRACTION) :	0.08
REQUIRED RATE OF RETURN ON EQUITY (FRACTION) :	0.20
PROPERTY TAX RATE (FRACTION) :	0.01
REVENUE TAX RATE OR ROYALTY (FRACTION) :	0.10
EFFECTIVE TOTAL INCOME TAX RATE (FRACTION) :	0.50
EFFECTIVE INVESTMENT TAX CREDIT (FRACTION) :	0.04
ESCALATION FACTOR FOR O&M COSTS :	0.05
ESCALATION FACTOR FOR ENERGY COSTS :	0.0
ESCALATION FACTOR FOR CAPITAL COSTS :	0.05
LIFE SPAN OF PRODUCTION WELLS (YEARS) :	10.00
LIFE SPAN OF INJECTION WELLS (YEARS) :	10.00
LIFE SPAN OF PRODUCER PLANT (YEARS) :	20.00
START UP COST MULTIPLIER :	1.081

UTILITY FINANCIAL DATA

DEBT FRACTION :	0.50
ANNUAL INTEREST RATE ON DEBT (FRACTION) :	0.08
REQUIRED RATE OF RETURN ON EQUITY (FRACTION) :	0.12
PROPERTY TAX RATE (FRACTION) :	0.01
REVENUE TAX RATE OR ROYALTY (FRACTION) :	0.0
EFFECTIVE TOTAL INCOME TAX RATE (FRACTION) :	0.50
EFFECTIVE INVESTMENT TAX CREDIT (FRACTION) :	0.04
ESCALATION FACTOR FOR O&M COSTS :	0.05
ESCALATION FACTOR FOR ENERGY COSTS :	0.0
ESCALATION FACTOR FOR CAPITAL COSTS :	0.05
LIFE SPAN OF UTILITY PLANT (YEARS) :	30.00
ULTIMATE CAPACITY FACTOR :	0.80
START UP COST MULTIPLIER :	1.038

* NUMBER OF WELLS , CAPITAL COSTBASIS AND O&M COSTS , AND REVENUE REQUIREMENTS WITHOUT ANY R&D IMPACTS *

CAPITAL COSTBASIS (1977 $M)

16 PRODUCTION WELLS :	11.556	
7 INJECTION WELLS :	5.056	
PRODUCER PLANT EXCLUDING WELLS :	7.284	
REPLACEMENT PRODUCTION WELLS :	9.869	
REPLACEMENT INJECTION WELLS :	4.318	
REPLACEMENT PLANT :	3.214	
TOTAL FOR PRODUCTION FIELD :		41.296
GENERATING PLANT :		35.785
TOTAL :		77.081

O&M COSTS (1977 $M/YR.)

PRODUCER		
GENERAL :	0.409	
WELL :	0.138	
DEEP WELL PUMP :	0.721	
SPENT BRINE TREATMENT :	0.0	
CHEMICAL & MECHANICAL CLEANING :	0.0	
TOTAL :		1.268
UTILITY		
GENERAL :	1.288	
CHEMICAL & MECHANICAL CLEANING :	0.0	
TOTAL :		1.288

** REVENUE REQUIREMENTS **

PRODUCER : 39.684 MILLS/KWHR
UTILITY : 18.813 MILLS/KWHR
TOTAL : 58.497 MILLS/KWHR

FIGURE 3

EXAMPLE OF OUTPUT (CONTINUED)

HEBER , CALIFORNIA
(CONTINUED)

* R&D IMPACTS FOR PLANT NO. 1 - ON LINE DATE : 1983 *

R&D COMPONENT	ANTICIPATED CHANGE (%)	CHANGE IN REVENUE REQUIREMENTS (MILLS/KWHR)
NUMBER OF PRODUCTION WELLS	+22.00	-4.6978
CAPITAL COST PER PRODUCTION WELL	-5.00	-0.9395
CAPITAL COST PER INJECTION WELL	-5.00	-0.4110
CAPITAL COST OF PROCESS MECHANICAL (UTILITY)	-50.00	-1.1125
CAPITAL COST OF CONDENSER & HEAT REJECTION EQUIPMENT	-20.00	-1.0635
PRODUCER DEEP WELL PUMP O&M COST FACTOR (BINARY SYSTEM , TEMP <260 C)	-33.00	-1.1564

** REVENUE REQUIREMENTS WITH ALL THE R&D IMPACTS INCLUDED. **

PRODUCER : 30.614 MILLS/KWHR
UTILITY : 16.637 MILLS/KWHR
TOTAL : 47.251 MILLS/KWHR *

* SENSITIVITY OF COST OF ELECTRICITY (FROM PLANT NO. 1 , R&D IMPACTS INCLUDED) *

RESOURCE & OPERATING PARAMETERS	MILLS/KWHR
HIGH RESOURCE TEMPERATURE ESTIMATE (225 DEGREES CENTIGRADE)	36.450
LOW RESOURCE TEMPERATURE ESTIMATE (150 DEGREES CENTIGRADE)	86.188
HIGH CAPACITY FACTOR VALUE : 0.85	44.471
LOW CAPACITY FACTOR VALUE : 0.60	63.001
EXPENSING OF INTANGIBLE DRILLING COSTS (70.0% OF WELL COSTS EXPENSED)	44.051
DEPLETION ALLOWANCE (22.0% OF GROSS INCOME)	41.237
INVESTMENT TAX CREDIT (26.2% GROSS, 15.0% EFFECTIVE)	44.776

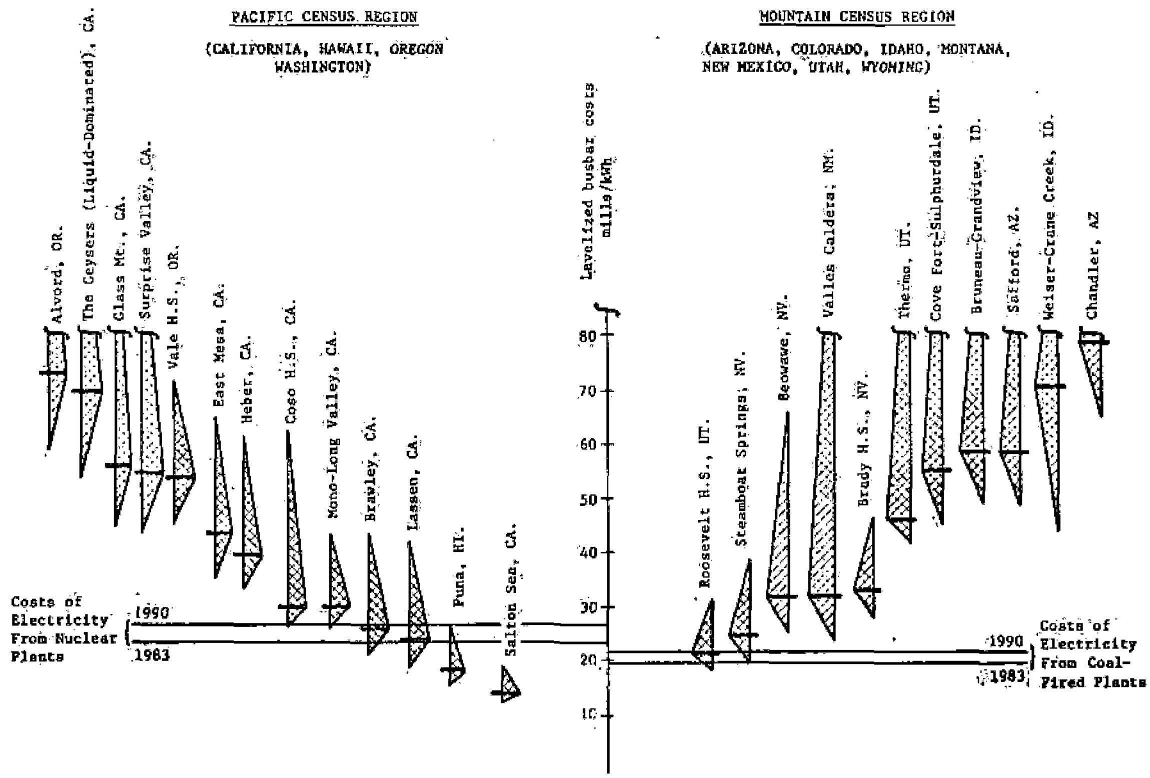


FIGURE 4: RANGES OF PROJECTED COSTS OF ELECTRICITY FROM HYDROTHERMAL LIQUID DOMINATED PROSPECTS (WITHOUT RD&D ADVANCES)