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HYDROTHERMAL RESEARCH AND DEVELOPMENT
ASSESSMENT

TASK FORCE REPORT

PROJECTIONS FOR
ELECTRIC SYSTEMS

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The Review Panel members were most helpful in presenting the industry perspective with regard to this analysis. Their objective critique led to very beneficial changes in the methodology for the analysis. The following experts constituted the review panel for this task: Mr. Vic Johnson (Washington Public Power Service), Dr. C.W. Berge (Phillips Petroleum Company), Mr. Jim Kuwada (Geothermal Kinetic Inc.), Mr. John Woods (Bank of Montreal), and Mr. John Broderick (DOE).

The contributions made by the four non-government participants comprising the Task Force--Engineering and Economics Research, Inc.; EG&G, (Idaho) Inc.; Technecon Analytic Research Inc.; and the University of Utah Research Institute--are recognized throughout this document.

The Hydrothermal Electric

Research and Development Assessment Task Force

The following organizations constituted the Hydrothermal R&D Assessment Task Force to determine the extent to which hydrothermal resources will be exploited in the United States during the next 20 years. The University of Utah Research Institute (UURI) was responsible for the development of the resource data base. The plant and field cost estimates were prepared by EG&G Idaho, Inc. The regional economic data base development and market modeling tasks were undertaken by Technecon Analytic Research, Inc. Technecon also conducted the assessment of the Federal/DOE programs with the support of Engineering and Economics Research, Inc., (EER) and UURI. EER was responsible for overall project management, as well as the coordination and documentation of Task Force activity. Figure I illustrates the responsibilities of Task Force members.

FIGURE I
RESPONSIBILITIES OF TASK FORCE MEMBERS

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Research and Development Assessment
for Hydrothermal Electric Power Applications

Executive Summary

The U.S. Geological Survey estimates that high temperature (greater than 150°C or 300°F) hydrothermal resources in the western United States have the potential for producing about 140,000 megawatts of electric power for 30 years. The objectives of the present analysis were to realistically evaluate the extent to which these resources might be utilized over the next 20 years, and to assess the probable impact of Federal programs on that utilization.

Previous forecasts of hydrothermal electric power development have been based solely on price, assuming market penetration would occur when the price of hydrothermal energy was competitive with alternative sources. Investment decisions, however, are based on other factors in addition to price (e.g., rate of return on investment, size of the project, capital at risk). Additionally, the investment decision criteria of resource developers and utilities are quite different, both in kind and in emphasis.

The R&D assessment team interviewed industry personnel to determine the nature and the relative significance of investment decision criteria for developers and utilities. The results of these interviews were used to develop a probabilistic model to simulate the investment decision behavior of these two groups toward hydrothermal resources. Estimations of the characteristics of anticipated available resources (e.g., temperature, salinity, depth) and predictions of the geographic distribution of new resource discoveries were based upon the characteristics and distribution of known reservoirs.

The impact of a minimal R&D program and the impact of expanded R&D program were estimated on the basis of its effect upon industry investment decision criteria (e.g., the cost of power). Table I presents the Task Force estimates comparing three different scenarios: (1) no program, (2) minimal R&D, and (3) expanded R&D.

The accuracy of the predictions based on the current model is dependent upon the input data, which are changing even as this report is being written. Significant fluctuations are likely to occur during the next 20 years, particularly in terms of price trends and availability of competing fuels. Nonetheless, because of the conservative nature of the current analysis, the results clearly indicate the presence of a substantial resource that could be made available in the near term with a modest Federal program.

The Federal program components that appear to have the greatest accelerating effect on development are those involving high risk/high payoff RD&D.

TABLE I

HYDROTHERMAL ELECTRIC POWER ESTIMATES

(Expected value installed capacity in megawatts)

SCENARIO	YEAR			
	1985	1990	1995	2000
NO PROGRAM	2,000	4,140	6,730	7,710
MINIMAL R&D	2,100	4,240	7,340	9,720
EXPANDED R&D	2,110	5,150	9,280	17,310

The electric power produced from hydrothermal resources could be a significant portion of the additional generating capacity needed in the United States by the year 2000. The approximately 9,700 MWe that is expected to be on-line in the year 2000, if a minimum R&D program is continued, would be about two percent of the incremental base and intermediate generating capacity installation projected for the United States as a whole, and between 10% and 15% of the increase projected for the West, where high temperature resources are found. This generating capacity could contribute an equivalent of almost 1 million barrels of oil per week to the nation's energy supply.

The Federal cost of substituting hydrothermal electric energy for petroleum based electric generation would amount to less than 30¢ per barrel of oil equivalent. This makes the Federal support of hydrothermal electric power development one of the most cost-effective programs for promoting alternatives to the consumption of imported petroleum. In addition, it is a program that develops a dispersed and secure energy source, whose availability could be substantially increased if the need arose due to reductions in the availability of imported oil.

1.0 RESULTS, METHODOLOGY, AND RECOMMENDATIONS

1.1 Results

The Research and Development Task Force Model generated estimates of power-on-line by projecting the probability of development of hydrothermal electric system capacities at several identified and unidentified sites. These sites were classified as "actual" or "potential" resource discoveries. This development assessment is intended to provide a basis for the evaluation of alternative Federal programs.

The model results are based on several assumptions associated with the model and the data bases. The Task Force made every attempt to select assumptions that were valid and reasonable; the Review Panel members concurred with the methods and assumptions used by the Task Force. Principal assumptions are documented in appropriate sections of this report.

The results generated by the model are summarized below: The

- Table 1.1 compares estimated installed capacity of hydrothermal electric systems for three different scenarios: (1) No Program, (2) Minimal Research and Development, and (3) Expanded Research and Development. These scenarios are described in Section 5.2.
- Figure 1.1 illustrates the aforementioned comparison.
- Although detailed evaluation of the individual previous and ongoing elements of the Federal/DOE program has not been performed, four program segments appear to have had a significant positive impact on the projected installed capacity of hydrothermal electric power systems:
 - (1) Programs aimed at accelerating the rate of discovery of high temperature resources.
 - (2) Reservoir demonstration pilot plants with government cost-sharing (10 to 20 MWe ice-breaker plants).

TABLE 1.1
PROJECTED INSTALLED CAPACITY OF
HYDROTHERMAL ELECTRIC POWER SYSTEMS (MW_e)

YEAR	NO PROGRAM	MINIMAL R&D	EXPANDED R&D
1985	2,000	2,100	2,110
1990	4,140	4,240	5,150
1995	6,730	7,340	9,280
2000	7,710	9,720	17,310

FIGURE 1.1

HYDROTHERMAL ELECTRIC POWER ESTIMATES

- (3) R&D programs for reducing the cost and number of production and exploration wells necessary to attain a given generating capacity.
- (4) R&D programs for developing the binary energy conversion systems needed to generate electricity at moderate temperature reservoirs.
- As shown in Figure 1.2, there is a high correlation between the estimates generated by the Task Force Model and estimates released by the Electric Power Research Institute. This is an indication that the model accurately simulates investment decision behavior and that the data bases developed by the Task Force appear to be valid.
- The price escalation rate for hydrothermal electric energy is estimated at 7%. If the prices of alternate sources of energy (e.g., oil, natural gas) increase significantly beyond those assumed in the model and show a higher escalation rate than 7%, hydrothermal electric energy will become even more attractive, and the development estimates would be revised upwards.

1.2 Methodology

Past attempts to estimate the potential installed capacity of hydrothermal electric power systems during the last quarter of this century were generally deficient in addressing the various factors associated with the discovery and subsequent development of high temperature hydrothermal resources (cf. Table 1.2). These estimates ranged from aggregates based entirely on known resources (as estimated by USGS), to much smaller estimates based on the announced plans of field developers and utilities. Other implementation estimates, based on comparison of the busbar costs of hydrothermal electricity and the busbar costs of electricity generated through alternatives, fell between these extremes.

As the busbar costs for electricity generated by fossil- and nuclear-fueled power plants have increased during the last seven years, at rates faster than that for geothermal energy, it has become

FIGURE 1.2
COMPARISON OF TASK FORCE MINIMAL R&D ESTIMATES
AND EPRI PROBABLE ESTIMATES*

*This comparison between estimates made by EPRI and by the Task Force does not imply that similar assumptions underlie the two sets of estimates.

TABLE 1.2

COMPARISON OF HYDROTHERMAL ELECTRIC POWER FORECASTS
(MWe On-Line by End of Stated Year)

SOURCE	YEAR	TYPE OF ESTIMATE	1985	1990	1995	2000
Commerce Department ^a	1977	"Most likely" Supply/Demand Balance	2,000	--	--	20,000
EIA Annual Report to Congress 1978 ^b	1978	Mid Range Economic Growth and Oil Price Case	2,600	4,500	6,200	--
ERPR Survey ^c	1978	Survey of Industry Estimates:				
		- Announced	2,019	3,019	3,619	3,919
		- Probable	2,664	5,414	7,473	9,023
		- Possible	3,374	7,664	11,323	14,723
DGRM ^d	1979	General Knowledge of Developer/Utility Plans	2,478	3,330	--	--
EPRI Forecast ^e	1979	EPRI R&D Plans	6,000	9,650	--	--
NRS CONAES Geothermal Resource Panel ^f	1979	Panel of Experts:				
		- Business as Usual	1,480	2,520	--	5,500
		- Moderately Accelerated Development	2,160	3,500	--	8,400
		- Strongly Accelerated Development	2,620	6,600	--	16,100
		- Crash Development	3,130	9,900	--	26,600
EPRI Survey ^g	1981	Survey of Industry Estimates:				
		- Announced	1,865	3,399	3,920	4,481
		- Probable	1,887	3,849	5,440	7,851
		- Possible	1,887	4,448	7,390	10,811

- a Forecast of likely U.S. Energy Supply/Demand Balances for 1985 and 2000, and Implications for U.S. Energy Policy/U.S. Department of Commerce, 20 January 1977.
- b U.S. DOE Energy Information Administration, Annual Report to Congress 1978, Vol. 3, Supplement 1.
- c V. Roberts and P. Kruger, Geothermal Resource Council Transactions, September 1980.
- d Geothermal Progress Monitor Report #1, December 1979.
- e EPRI New Energy Resource Department Strategy Paper, January 1979.
- f Geothermal Resources and Technology in the United States, National Academy of Sciences, 1979.
- g V. Roberts and P. Kruger, Geothermal Resource Council Transactions, 1981.

apparent that a favorable busbar cost alone will not induce developers and utilities to construct and operate hydrothermal electric power systems. This has invalidated those benefit-cost analyses of Federal/DOE geothermal programs in which the benefits were derived directly from estimated cost reductions.

Recent studies based on extensive inputs from geothermal developers, utilities, and financial institutions have confirmed that, in addition to a favorable busbar cost of geothermal electricity, factors such as rate-of-return on investment, size of the project, and capital-at-risk determine whether a field developer-utility combination will undertake the development of a geothermal site.

The Hydrothermal R&D Assessment Task Force Model is unique in that it is the only study in which the potential utilization of hydrothermal electric systems was estimated on the basis of a simulation of the investment decision behavior of the private sector.

To pursue the task of estimating the utilization of hydrothermal electric systems, the Division of Geothermal and Hydropower Technology (DGHT, nee Division of Geothermal Energy) established the R&D Assessment Task Force, in which senior DGHT officials, DOE laboratories, universities, and private contractors with the requisite expertise participated. A Review Panel comprised of individuals with established credentials in the geothermal industry was constituted.

There were six major segments of the analysis:

- Resource Data Base Development
- Plant and Field Cost Data Base Development
- Regional Economic Data Base Development
- Modeling

- Assessment of Federal/DOE programs and Sensitivity Analysis
- Documentation

This report documents the methodology of the study and presents the results generated by the Task Force Model.

1.3 Recommendations

Based on the experience gained during R&D Assessment Project, the following recommendations are made:

- Projected resource discovery rates for identified and unidentified reservoirs must be carefully examined in the context of the economics of exploitation of each reservoir.
- Results of preliminary sensitivity analysis are presented in this document. Although these results give a fair indication of the contribution made by some program elements, it is recommended that detailed sensitivity analysis be carried out, based on a quantitative exploration model
- The optimal levels of expenditure for various Federal DOE program elements and the optimal program composition should be determined by conducting sensitivity analyses of the impacts of various combinations of program elements on the installed capacity of hydrothermal electric power systems.
- Sensitivity analyses of the impacts of individual program elements should be conducted to identify cost-effective modifications to the program.

1.4 Organization of the Report

The remainder of the report on the R&D Assessment Task Force for electric power is organized in the following fashion:

- Section 2: The Hydrothermal Electric Model
The model developed by Technicon Analytic Research is presented in this section. A description of the model structure and an analysis of the model are presented. The major assumptions underlying the model are also discussed.
- Section 3: Resource Data Base
The basic assumptions underlying the estimation of resource discovery probabilities are presented. The magnitude of available resources is discussed; and the terms "prospect," "discovery," "confirmed reservoir," and "developed site" are defined. The methods used by UURI to estimate resources available for discovery are presented, and reservoir capacity estimates for known and projected resources are provided. In

addition, the relationship between resource categorization and model results is presented.

- Section 4: Plant and Field Costs
Typical capital costs and operation and maintenance costs for both field and plant development are presented. Basic assumptions for determining plant and exploration costs are also discussed.
- Section 5: Impact of Federal DOE Programs on Model
The Federal DOE program and its impact upon model parameters are discussed. The methods used to analyze the program are illustrated. Quantitative estimates of some of the impacted parameters are included. An illustrative estimate of impacts on a particular site (Roosevelt H.S., Utah) is also included.
- Appendix A: Resource Discovery Model
This appendix describes the procedures used to determine reservoir confirmation probabilities.
- Appendix B: Technical Discussion of Hydrothermal Electric Power Decision Models
This appendix presents detailed technical discussion of the hydrothermal electric power decision model.

2.0 THE TASK FORCE MODEL

2.1 Introduction

The 20-year hydrothermal electric utilization model was developed by Technecon Analytic Research, Inc. Based on input from UURI/ESL, the model projects reservoir confirmation probabilities. Quantitative investment decision analysis techniques were employed to estimate power development profiles for individual reservoirs as a function of time. This analysis yielded estimates of the amount of power-on-line to be developed through the year 2000.

Hydrothermal power development at each confirmed reservoir is dependent upon joint investment decisions to develop the well field and to construct power plant and transmission facilities. The technecon methodology considered multiple investment objectives of both well field developers and electric utilities as they relate to their respective investment decisions. This methodology is capable of simulating the investment behavior of major resource corporations, independent operators, third-party financiers, investor-owned utilities, and tax-exempt municipal utilities.

In early 1978, under contract to the U.S. Department of Energy,¹ Technecon conducted interviews with more than seventy executives from geothermally-active firms in the above categories. Many of these interviews have periodically been repeated since 1978 to update the data base. The interviews provided both qualitative and quantitative insights into the investment objectives and decision criteria of

¹ Contract No. DE-AC-02-79ET27242; Dr. Fred Abel, U.S. DOE Division of Geothermal Energy, Program Manager.

these firms. The decision models applied by Technecon in the current project are based upon statistical regression analyses of data obtained from these firms over the past three years.

2.2 Model Design

Figure 2.1 illustrates the structure of the hydrothermal electric power model. Hydrothermal power utilization estimates are prepared on a site-by-site basis. Confirmed reservoir characteristics are projected by the Geothermal Exploration Model based on input provided by UURI/ESL. These projections are then input to two detailed cash flow programs. One program simulates the life of a well field project, while the other program simulates the life of a hydrothermal power plant. The economically optimal combination of pumped versus unpumped wells and binary versus flash plant design is selected for each site. Well field and power plant performance data from EG&G Idaho, Inc. were used in these computerized cash flow programs. Tables 2.1 through 2.4 list input data parameters of the cash flow analyses.

The two cash flow programs are executed probabilistically to account for uncertainties and risk perceptions inherent to many geothermal ventures. Eight stochastic variables of the cash flow analyses vary over time as functions of on-site production experience, number of wells drilled, and acreage in production.² Figure 2.2 presents these stochastic parameters, the probability profile

² Reservoir risk perceptions and time-dependent variances are based upon recommendations of 3 consultants: Dr. S. Sanyal of Stanford Univ., Mr. D. Goldman of EG&G Idaho, Inc., and Mr. E. Ciancanelli of Cascadia Exploration Corp., San Diego.

SOURCE: TECHNECON

FIGURE 2.1

INTEGRATED HYDROTHERMAL ELECTRIC POWER SYSTEM SIMULATOR
 AND INDUSTRIAL DECISION MODEL (Illustrative Example)

TABLE 2.1
RESOURCE PARAMETERS

RESOURCE PARAMETERS

BRINE CONTAMINATION INDEX
CONFIRMATION WELLS REQUIRED
DEVELOPMENT COMMITMENTS TO DATE
DRY WELL COST
DRY WELL FRACTION
FINDING COST CAPITALIZED
FINDING COST EXPENSED
FIRMS IN JOINT VENTURE
FLOW TEST AND MODELING COST
LAND RENT
LEASE BONUS
OPERATION AND MAINTENANCE EXPENSE
PERMITTING EXPENSE
PRODUCER/INJECTOR RATIO
PRODUCIBLE ACREAGE AT 50% CONFIDENCE
PRODUCIBLE ACREAGE AT 99% CONFIDENCE
REDRILL COST
REDRILL FRACTION
REWORK COST
REWORK FRACTION
ROYALTY RATE
SPARE WELL FRACTION
SURFACE FACILITY COST
SURFACE PIPING COST
TEMPERATURE OF RESOURCE
TYPE OF RESOURCE DEVELOPER
WELL COST
WELL FLOW, FREE
WELL FLOW, PUMPED
WELL LIFE
WELL PUMP THRESHOLD
WELL SPACING
YEAR OF DISCOVERY

SOURCE: TECHNECON

TABLE 2.2

POWER PLANT PARAMETERS

POWER PLANT PARAMETERS

BOOK LIFE OF ALTERNATIVE PLANT
BOOK LIFE OF HYDROTHERMAL PLANT
CAPACITY FACTOR OF ALTERNATIVE PLANT
CAPACITY FACTOR OF HYDROTHERMAL PLANT
CAPITAL COST OF ALTERNATIVE PLANT
CAPITAL COST OF HYDROTHERMAL PLANT
CAPITAL COST OF TRANSMISSION
EFFICIENCY OF HYDROTHERMAL PLANT
FUEL PRICE OF ALTERNATIVE PLANT
INSURANCE PREMIUMS
LAST YEAR OF PROJECT OPERATION
RECURRING ANNUAL COST OF ALTERNATIVE PLANT
RECURRING ANNUAL COST OF HYDROTHERMAL PLANT
REPLACEMENT POWER COST
REPLACEMENT POWER COST ALLOWABLE
SIZE OF HYDROTHERMAL PLANT
TIME FROM DECISION TO PLANT ON-LINE
TIME INTERVAL BETWEEN PLANTS
TYPE OF PLANT (FLASH/BINARY)
TYPE OF UTILITY
WRITE-OFF PERIOD ALLOWABLE

SOURCE: TECHNECON

TABLE 2.3

ECONOMIC AND FINANCIAL PARAMETERS

ECONOMIC & FINANCIAL PARAMETERS

ALTERNATIVE PLANT COMMON STOCK COST
ALTERNATIVE PLANT COMMON STOCK FRACTION
ALTERNATIVE PLANT LONG TERM DEBT COST
ALTERNATIVE PLANT LONG TERM DEBT FRACTION
ALTERNATIVE PLANT PREFERRED STOCK COST
ALTERNATIVE PLANT PREFERRED STOCK FRACTION
ELECTRIC UTILITY DEBT OBLIGATIONS
ELECTRIC UTILITY GROWTH RATE
ELECTRIC UTILITY NET INCOME
HYDROTHERMAL PLANT COMMON STOCK COST
HYDROTHERMAL PLANT COMMON STOCK FRACTION
HYDROTHERMAL PLANT LONG TERM DEBT COST
HYDROTHERMAL PLANT LONG TERM DEBT FRACTION
HYDROTHERMAL PLANT PREFERRED STOCK COST
HYDROTHERMAL PLANT PREFERRED STOCK FRACTION
INFLATION RATE FOR GOODS AND SERVICES
INFLATION RATE FOR POWER PLANT CONSTRUCTION
INFLATION RATE FOR POWER PLANT FUEL (REGIONAL)
RESOURCE DEVELOPER'S DISCOUNT RATE
THIRD PARTY'S DEBT INTEREST RATE
THIRD PARTY'S DISCOUNT RATE
THIRD PARTY'S EQUITY FRACTION
THIRD PARTY'S RETURN ON EQUITY

SOURCE: TECHNECON

TABLE 2.4

TAX PARAMETERS

TAX PARAMETERS

FEDERAL TAX RATE FOR RESOURCE DEVELOPER
FEDERAL TAX RATE FOR ELECTRIC UTILITY ALTERNATIVE
FEDERAL TAX RATE FOR ELECTRIC UTILITY HYDROTHERMAL
FEDERAL TAX RATE FOR THIRD PARTY
INTANGIBLE FRACTION OF WELL COST
INVESTMENT TAX CREDIT FOR NON-UTILITY HYDROTHERMAL
INVESTMENT TAX CREDIT FOR ELECTRIC UTILITY ALTERNATIVE
INVESTMENT TAX CREDIT FOR ELECTRIC UTILITY HYDROTHERMAL
LOCAL TAX RATES
MINIMUM TAX RATE ON PREFERENCE ITEMS
PERCENTAGE DEPLETION ALLOWANCE SCHEDULE
STATE TAX RATE FOR ELECTRIC UTILITY ALTERNATIVE
STATE TAX RATE FOR ELECTRIC UTILITY HYDROTHERMAL
STATE TAX RATE FOR RESOURCE DEVELOPER
STATE TAX RATE FOR THIRD PARTY
TAX LIFE FOR ALTERNATIVE PLANT
TAX LIFE FOR HYDROTHERMAL PLANT
TAX LIFE FOR WELL FIELD CAPITAL

SOURCE: TECHNECON

UNCERTAIN PARAMETER	DISTRIBUTION	FACTORS AFFECTING VARIANCE
<ul style="list-style-type: none"> • POWER PLANT CAPACITY FACTOR • WELL LIFE, INJECTORS • WELL LIFE, PRODUCERS • RESERVOIR TEMPERATURE • WELL FLOW RATE • WELL COST • DRY WELL FRACTION		<ul style="list-style-type: none"> • ON-SITE PRODUCTION TIME; ABSOLUTE TIME • ON-SITE PRODUCTION TIME; ABSOLUTE TIME • ON-SITE PRODUCTION TIME; ABSOLUTE TIME • ON-SITE PRODUCTION TIME; ABSOLUTE TIME; WELLS DRILLED • ON-SITE PRODUCTION TIME; ABSOLUTE TIME; WELLS DRILLED • ABSOLUTE TIME; WELLS DRILLED • ABSOLUTE TIME; WELLS DRILLED
<ul style="list-style-type: none"> • PRODUCIBLE ACREAGE		<ul style="list-style-type: none"> • ACREAGE IN PRODUCTION
<ul style="list-style-type: none"> • ECONOMIC RESERVOIR LIFE		<ul style="list-style-type: none"> • ON-SITE PRODUCTION TIME; ABSOLUTE TIME

SOURCE: TECHNECON

FIGURE 2.2
HYDROTHERMAL POWER PROJECT UNCERTAINTIES

associated with each, and the independent variables that influence time-dependent changes in the probability profiles.

Results from the well field and power plant cash flow simulations were input to the respective decision models for the resource developer and the electric utility. The decision models analytically compare geothermal investments to alternative investment opportunities available to each type of firm. For the resource developers, comparisons are made in terms of rate of return, duration of investment exposure, project size, amount of capital at risk, and the probability of project failure. For the electric utilities, comparisons are made in terms of: electric energy production cost (mills/kWh) delivered to a main transmission corridor, plant availability, net plant output, and risk to corporate or municipal bond ratings.

The resource developers decision model is described in detail in Technecon's "Geothermal Investment and Policy Analysis with Evaluation of California and Utah Resource Areas."³ This publication describes the decision modeling technique of integrated multiattribute utility analysis and logit choice estimation, which is also employed in the electric utilities decision model. Appendix B of this report includes further technical discussion of these decision modeling techniques.

The two decision models provide estimates of the likelihood of investment in a specified hydrothermal opportunity by resource developers and by electric utilities. These models have been demonstrated

³ Document DOR4713-1 dated October 1979 available from NTIS, Springfield, VA.

to simulate investment behavior of geothermally active firms. Statistical indicators of confidence include a coefficient of determination (corrected for degrees of freedom) of 0.86 and an F-statistic at the 99% confidence level.

Resource selling price is the negotiable variable that couples the well field cash flow and the power plant cash flow. A high price improves investment returns to the resource developer and generally increases the likelihood of developer investment. Conversely, a low price lowers the production cost (mills/KWh) of hydrothermal electric energy and generally increases the likelihood of investment by the electric utility. The computer-based simulation of resource price negotiation developed by Technecon uses an iterative technique to converge on a price that maximizes the joint likelihood of investment (cf. Figure 2.1).

When estimating the development of a reservoir, each plant addition is evaluated separately. This evaluation is repeated in successive time periods until either the 20-year time horizon is exceeded or the likelihood of the joint well field/plant investment approaches 100 percent. Subsequent plant additions at the specified resource are evaluated in the same manner, and this process continues until the resource is fully utilized or until the 20-year time horizon has elapsed.

2.3 Modeling Assumptions

Assumptions underlying the utilization estimates provided include:

- Regionality. Figure 2.3 and Table 2.5 illustrate the regional boundaries established by the Task Force for the purposes of this project. State tax rates, local ad valorem tax rates, and regional electric utility characteristics and

FIGURE 2.3

U.S. DEPARTMENT OF ENERGY
HYDROTHERMAL R&D ASSESSMENT TASK FORCE
MAP OF REGIONAL BOUNDARIES

TABLE 2.5

U.S. DEPARTMENT OF ENERGY HYDROTHERMAL
R&D ASSESSMENT TASK FORCE
REGIONAL BOUNDARIES

No.	REGION	BOUNDARIES
1.	NORTHERN CALIFORNIA	California north of 36° latitude
2.	SOUTHERN CALIFORNIA	California south of 36° latitude
3.	PACIFIC NORTHWEST	Oregon and Washington
4.	NEVADA	Nevada
5.	UTAH	Utah
6.	ARIZONA	Arizona
7.	MOUNTAIN NORTHWEST	Idaho, Montana, and Wyoming
8.	COLORADO	Colorado
9.	NEW MEXICO	New Mexico
10.	TEXAS	Texas
11.	DAKOTAS	North Dakota and South Dakota
12.	CENTRAL	Iowa, Kansas, Nebraska, and Missouri
13.	SOUTH CENTRAL	Arkansas, Louisiana, and Oklahoma
14.	EAST SOUTH CENTRAL	Alabama, Kentucky, Mississippi, and Tennessee
15.	GREAT LAKES	Illinois, Indiana, Ohio, Michigan, Minnesota, and Wisconsin
16.	MID-ATLANTIC	Delaware, Maryland, New Jersey, New York, and Pennsylvania
17.	SOUTH ATLANTIC	Florida, Georgia, North Carolina, South Carolina, Virginia, and West Virginia
18.	NEW ENGLAND	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont
19.	ALASKA	Alaska
20.	HAWAII	Hawaii

economics were researched and assigned to each region respectively. Regions 1 through 9, inclusive, are expected to develop appreciable hydrothermal electric power generating facilities within the next twenty years. In each of the nine regions except Arizona, utilities reported that the economic competitiveness of hydrothermal generation will be evaluated in comparison with coal-fired generation. In Arizona, nuclear generation was the reported basis for comparison. Table 2.6 provides regional economic data as used in the model.

- Capital Structure. Both investor-owned and municipal electric utilities were examined in this project. The long term debt/common equity/preferred stock proportion for investor-owned utility capital was assumed to be 0.50/0.35/0.15 at average annual costs of 8%, 13 1/2%, and 8 1/2%, respectively. Municipal financing was assumed to be with tax exempt bonds.
- Inflation Rates. Table 2.7 presents the average annual inflation rates used in this project. These rate assumptions were based upon data derived from the Wharton Econometric Model.
- Tax Incentives. An investment tax credit for non-utility geothermal capital of 25% was assumed through 1985. After 1985, 10% investment tax credit was assumed. A percentage depletion allowance of 22% was employed through 1980, 20% in 1981, 18% in 1982, 16% in 1983, and 15% thereafter. Seventy-five percent (75%) of successful well costs were assumed to be "intangible" and expensed for tax purposes.
- Well Field Development. The success fraction for post confirmation production wells was determined by a triangular probability distribution with a maximum of 0.9, mode of 0.85, and minimum of 0.65. The costs for abandoned dry wells were assumed to be 90% of successful well costs. Thirty percent of all new wells were assumed to require redrilling for successful production. Redrilling was assumed to add 35% to the well cost. One injection well was assumed for every two production wells, and a standby or spare production well fraction of 20% was assumed. The assumed spacing of production wells was forty acres.
- Power Plant Development. At resource sites where power plants were either on-line or committed, plant size (in megawatts) and on-line years were input to the model. In the absence of existing plants or commitments, assumptions were made regarding sequential plant sizes and the minimum number of years between plants. The first plant was assumed to be a 20MWe unit placed in service no sooner than five years after reservoir confirmation. This five year minimum lag estimate was based upon the mean lag observed at seven known resource areas. Following the initial 20MWe unit, two 50MWe units were assumed to be placed in service at intervals of 3 years

TABLE 2.6
REGIONAL ECONOMIC DATA

	Regions ¹				
	1,2	4,5,7,8	3	6	9
State Corporate Income Tax Rate	9%	5%	7%	10.5%	5%
Local Ad Valorem Tax Rate ²	1%	1.3%	2%	1%	0.7%
Competing Baseload Generation	Coal	Coal	Coal	Nuclear	Coal
Capital Cost (1980 \$/kWe) ³	935	935	935	1255	935
Fuel Cost (1980 Mills/kWh) ⁴	17.1	11.8	14.5	8.1	15.8
Fuel Escalation Rate ⁵	8%	8%	8%	8%	8%
Recurrent Cost Fraction ⁶	6.2%	6.2%	6.2%	3%	6.2%
Recurrent Cost Escalation Rate ⁵	7.5%	7.5%	7.5%	7.5%	7.5%

¹ Refer to Figure 2.3 and Table 2.5 for definition of regional boundaries. Region 10 through 20 are not likely to experience any development hydrothermal resources for generating electricity prior to the year 2000.

² On full cash value; i.e. includes assessment rate and tax on assessed value.

³ Capital cost of competing baseload plant including transmission.

⁴ Fuel cost of competing baseload generation.

⁵ Annual rate for 20-Yr outlook.

⁶ Includes operating, maintenance, administrative, general and insurance expense for competing baseload generation; expressed as fraction of 1980 capital cost of plant.

TABLE 2.7
EXPECTED INFLATION RATES FOR 1980-2000

Sector	Twenty Year Estimate of Average Annual Rate of Inflation	Comment
All Goods and Services (Consumer Price Index)	7-8%	
Fuel Oil and Related	8-11%	Approximately 2-3% Real growth
Natural Gas		7-8% Real growth over next 5 years
		Because of deregulation, there after similar to oil products
Labor costs:		
a) Construction	8-10%	Assuming no major change in productivity, Real wages will continue the historical real growth
b) Maintenance - Repair	9-11%	
Capital:		
a) Inputs for plant/equipment (non-drilling)	6-8%	May not beat inflation
b) Pipes and drilling related	7-10%	Likely to do a little better than general rates of infla- tion
Long Term Interest Rates	10-11%	Reflects 1-3% Real Rate of Return
Coal	7-8%	

SOURCE: TECHNECON

and 2 years, respectively. Subsequent units were assumed to be 100 MWe at one year minimum intervals. The decision model estimated the numerical likelihood that plants were placed in service with these minimum lag intervals as well as with longer intervals. Federal program elements intended to reduce these minimum lags were also evaluated.

2.4 Federal Program Evaluation

Impacts of the Federal program intended to accelerate hydrothermal power development were assessed as a major objective of the current project. Engineering and Economics Research, Inc., provided estimates of the quantifiable effect this program is expected to have on engineering performance and cash flow model parameters. To assess the effectiveness of the program, the likelihood of hydrothermal power development was estimated both with and without a Federal program, for each resource discovery.

In summary, Technecon's role on the Task Force was to apply decision analysis techniques to estimate the development of hydrothermal electric power in the United States. These techniques were based upon investment decision criteria exhibited by firms in the geothermal industry. The approach used in this work was unique in that it was capable of evaluating multiple investment criteria of both well field developers and power plant investors. Tests of statistical significance indicated that the computerized methods used in the current project provided a statistically valid representation of industry investment practices.

3.0 RESOURCE DATA BASE

3.1 Introduction

This section describes the techniques employed and the assumptions made in characterizing hydrothermal resources, in establishing reservoir confirmation probabilities, and in evaluating the effects of Federal programs on hydrothermal electric power development. The Earth Science Laboratory Division of the University of Utah Research Institute (UURI) provided most of the input for these tasks. Separate but parallel consideration was given to resources suitable for electric power generation (temperatures greater than 150°C or 300°F) and those suitable for direct application (temperatures less than 150°C or 300°F). The results for electric quality resources are reported here.

Characteristics of known hydrothermal resources were used to predict characteristics of the yet to be discovered hydrothermal resources. These data were input to the investment decision model developed by Technecon.

3.1.1 Definitions

In this and other sections of the current report the following terminology will be used:

- Hydrothermal Resource - An underground source of geothermal fluids.
- Prospect - A site with a hydrothermal resource potential.
- Discovery - A prospect in which drilling has demonstrated the existence of geothermal fluids potentially suitable for application.
- Confirmed Reservoir - A discovery for which detailed geologic and reservoir engineering assessment have confirmed the existence of geothermal fluids of sufficient quantity and quality for electric power generation and/or direct application.

- Exploitable Reservoir - A confirmed reservoir for which utilization engineering studies and economic evaluation have shown economic viability for electric power generation and/or direct applications.
- Developed Site - An exploitable reservoir that supplies geothermal fluids to an application plant.

Figure 3.1 illustrates the manner in which a successful site might move through the sequence of classifications.

3.2 Characterization of the Resource

Hydrothermal reservoirs available in the resource base were postulated based on the characteristics of known reservoirs. The hydrothermal resource data for this project came from a variety of sources. Publications were revised for information on both domestic and foreign hydrothermal resources. A large portion of the information on fracture controlled water-dominated high-temperature geothermal systems was obtained from industrial sources through the DOE/DGHT-funded Industry Coupled Program in Utah and Nevada. Additionally, discussions with personnel from geothermal exploration companies active in the western United States provided information about geothermal resource characteristics and exploration activities. Information was also gleaned from USGS Circular 790 (Muffler, 1978). Table 3.1, consisting of information from Circular 790, lists known hydrothermal prospects having temperatures higher than 150°C. Data were also obtained from USGS open file reports on specific geothermal systems, and from personal conversations with USGS scientists in Menlo Park.

FIGURE 3.1

DEVELOPMENT SEQUENCE FOR GEOTHERMAL SITES

TABLE 3.1

HYDROTHERMAL PROSPECTS POTENTIALLY SUITABLE FOR ELECTRIC UTILIZATION

SITE	ESTIMATED RESERVOIR MEAN TEMPERATURE (°C)	ESTIMATED POTENTIAL ELECTRICAL ENERGY (MWe for 30 yrs)
<u>ALASKA</u>		
Hot Springs Cove	164	27
Geyser Bight	208	136
Bailey Hot Springs	162	26
<u>ARIZONA</u>		
Power Ranches, Inc. Wells	165	23
<u>CALIFORNIA</u>		
Border	160	31
Brawley	253	640
Clear Lake	190	900
Coso Hot Springs	220	650
East Mesa	182	360
Geysers	237	1610
Heber	175	650
Long Valley	227	2100
Morgan Springs-Growler Springs	217	116
Randsburg	172	84
Salton Sea	323	3400
Surprise Valley	152	1490
Sulfur Bank Mine	194	75
Westmorland	217	1710
<u>COLORADO</u>		
Paradise Hot Springs	154	24
<u>HAWAII</u>		
Kamaili Homesteads	273	210
Kapoho Reservoir (Puna)	275	41
<u>IDAHO</u>		
Big Creek Hot Springs	162	26
Crane Creek-Cove Creek	171	340
Raft River	149	100

TABLE 3.1 (Cont'd)

HYDROTHERMAL PROSPECTS POTENTIALLY SUITABLE FOR ELECTRIC UTILIZATION

SITE	ESTIMATED RESERVOIR MEAN TEMPERATURE (°C)	ESTIMATED POTENTIAL ELECTRICAL ENERGY (MWe for 30 yrs)
<u>NEVADA</u>		
Baltazor Hot Spring	158	46
Beowawe	229	127
Brady Hot Springs	155	157
Desert Peak Area	221	750
Fernley Area	182	33
Great Boiling Springs	178	32
Hot Sulphur Springs	165	27
Humboldt House	217	47
Kyle Hot Springs	159	97
Leach	162	77
Lee Hot Springs	166	28
Pinto Hot Springs	173	90
San Emedio Desert Area	166	28
Soda Lake Area	157	146
Steamboat Springs	200	350
Stillwater Area	159	450
Sulphur Hot Springs	178	74
<u>NEW MEXICO</u>		
Valles Caldera	273	2700
<u>OREGON</u>		
Alvord	181	49
Crump's Hot Springs	167	61
Hot (Borax) Lake Area	191	91
Mickey Hot Springs	205	160
Neal Hot Springs	188	36
Newberry Caldera	230	740
Trout Creek Area	154	24
Vale Hot Springs	157	870
<u>UTAH</u>		
Cove Fort/Sulphurdale	167	330
Roosevelt Hot Springs	265	970
<u>WASHINGTON</u>		
Gamma Hot Springs	165	27
TOTAL POTENTIAL ELECTRIC ENERGY		23,385

The estimation of geothermal resource availability is based upon available data concerning the characteristics of known reservoirs. While geothermal resource data are in the public domain through the technical and open file literature, many hydrothermal systems are still poorly understood. Because few of the liquid-dominated hydrothermal reservoirs in the United States are actually under production, the data needed to assess production rates and reservoir lifetimes for these reservoirs are not yet available. Based on the understanding of existing data, the following assumptions were made:

- a) New reservoir confirmations to the year 2000 will occur in known areas of high geothermal potential, in known geologic environments.
- b) New areas for exploration will be within the known geothermally favorable environments.
- c) Each resource area contains a spectrum of temperatures. Low- and moderate-temperature resources occur along the margins of many high-temperature resources.

3.2.1 Establishing Generic Resource Categories

To facilitate the handling of the large quantity of resource data, a categorization scheme was established. The first step in the categorization process was to determine the relevant resource characteristics that could be used to meaningfully distinguish between resource sites.

Two assumptions underlie the categorization scheme. It is assumed that data from known hydrothermal resources can be selectively extrapolated to both identified and unidentified resources that lack such data (i.e., known resources are a valid sample of the entire resource population). Further, it is assumed that the observed lognormal distribution of temperatures (described in USGS Circular 790) applies to the entire population of hydrothermal resources.

Researchers at Technecon have determined the resource characteristics relevant to the economic decision-making processes for hydrothermal electric power development. The characteristics of major known hydrothermal resources were compiled and analyzed, and ranges of values for each characteristic were determined. These ranges were input to the Technecon economic model to determine the sensitivity of the model.

The model was found to be significantly sensitive to six major variables. These variables constituted the basis for categorizing resource sites according to the ranges listed in Table 3.2.

Observed variations in certain other variables were found to have little impact on the model. In some cases this resulted from the fact that the characteristic did not vary significantly. In the other cases it resulted from insensitivity of the model to variability in the characteristic. In either event, for purposes of the model, these characteristics were considered to have constant values.

Other investigated characteristics were found to be derivative from (or dependent upon) the variables listed in Table 3.2. These characteristics were considered to be dependent variables in the model. Table 3.3 lists constants and dependent variables.

3.2.2 Generic Resource Types

The generic resource type is expressed as a six-digit number. The six digits refer to value ranges (cf. Table 3.2) for the resource characteristics of temperature, unpumped flow rate, brine contamination index, well costs, pumped flow rate, and maximum producible acreage, in that order. The typology is illustrated in Table 3.4, which shows the characteristics typical of a resource of the generic

TABLE 3.2

VARIABLE GENERIC RESOURCE CHARACTERISTICS AND THEIR RANGES

PARAMETER	RANGES							
Range No.	a 1	2	3	4	5	6	7	8
Temperature ($^{\circ}$ F)	=>100 <150	=>150 <200	=>200 <250	=>250 <300	=>300 <350	=>350 <400	=>400 <450	=>450
Unpumped Flow Rate (10^3 lbs/hr)	<50	=>50 <100	=>100 <200	=>200 <400	=>400 <600	=>600 <800	=>800	
Brine Contamination Index (TDS)	0 (<2000)	1 (2000- 100,000)	2 (>100,000)					
Well Costs (\$M)	>2	<2 =>1	<1 =>0.5	<0.5				
Pumped Flow Rate (10^3 lbs/hr)	<50	=>50 <100	=>100 <200	=>200 <400	=>400 <600	=>600 <800	=>800	
Max. Produc. Acreage	1,550	2,000	3,000	3,500	4,000	5,000	6,000	10,000

^a The generic resource characteristics parameter values for a given reservoir can be located in more than 1 column (e.g., a reservoir could have temperature range 1, flow rate 3 and well cost rate 4).

SOURCE: UURI

TABLE 3.3

CONSTANT OR DEPENDENT RESOURCE CHARACTERISTICS

<u>Parameter</u>	<u>Value</u>		<u>Function Of</u>
	<u>Electric</u>	<u>Non-Electric</u>	
Exploration Costs	\$6m	\$1m	-
Well Spacing	40 acres	NA	-
Reservoir Life	30 yrs.	30 yrs.	-
Injection Well Costs	0.9	0.9	Well Costs
Injection Well Fraction	0.5*	0.8*	No. Production Wells
Redrilling (Workover) Costs	0.35	0.35	Well Costs
Redrilling (Workover) Fraction	0.33	0.33	No. Production Wells
Dry Well Costs	0.9	0.9	Well Costs
Dry Well Fraction	0.25	0.25	No. Production Wells
Spare Well Fraction	0.2	0	No. Production Wells

SOURCE: UURI

*At least one injection well needed.

TABLE 3.4

RESOURCE CATEGORIZATION
ROOSEVELT HOT SPRINGS, UT
GENERIC CATEGORY 862371

PARAMETER	VALUE	RANGE NUMBER
TEMPERATURE	>450°F	8
UNPUMPED FLOW RATE	700,000 lbs/hr	6
BRINE CONTAMINATION INDEX	2 (7,000 ppm)	2
WELL COSTS	\$ 1 M	3
PUMPED FLOW RATE	>800,000 lbs/hr	7
MAXIMUM PRODUCIBLE ACREAGE (50% prob.)	6,700	1

type 862371. The current study has identified 20 generic resource types to be reasonably representative of all known and undiscovered hydrothermal resources suitable for electric power generation. It is important to note that the presence of a range category in Table 3.2 does not imply that resources exist within that range. A number of assumptions have been made in selecting the appropriate range numbers defining a generic resource type and in categorizing known resources and predicted discoveries. Additionally, estimates for certain resource characteristics are not as reliable as estimates for other characteristics. The following paragraphs discuss some of the assumptions and limitations related to the studied resource characteristics.

- Well-Head Temperature. In general, temperature data are considered to be accurate and reliable. Well-head temperature values are based on measured downhole temperatures or on geothermometer estimates (Muffler, 1978).
- Unpumped Well Flow Rate. The confidence level for this parameter is considerably lower than that for well-head temperature. Flow rates are known only for the reservoirs with production test data. However, flow rates can be variable within a single hydrothermal reservoir. They reflect not only intrinsic characteristics of the resource itself, but also successful selection of a drilling site and use of appropriate drilling and completion techniques to allow maximum obtainable flow.
- Brine Contamination Index. The values for brine contamination index are considered to be reliable.
- Producer Well Cost. Well costs are expressed in 1978 dollars. Actual well costs are given for resources for which they are known. Other well costs were estimated using the data from Chappell et al. (1979) and were checked with the well-cost analysis provided by Lawford (1980). Drilling costs are well known, resulting in a high level of confidence for producer well-costs, assuming that perceptions of target drilling depths are accurate. Depth of the resource enters the economic model through the well-cost parameter.

- Pumped Well Flow Rates. The considerations for Unpumped Well Flow Rate also apply to pumped flow rate. Two additional assumptions were made in determining pumped flow rates: (1) In systems with high unpumped flow rates, pumping will not be necessary, and (2) For systems with moderate or low unpumped flow rate, pumping will increase the flow by one or two range numbers.
- Maximum Produccible Acreage. Information on maximum producible acreage is available for few reservoirs. Estimates were given for acreage at three levels of confidence, 99%, 50% and 1%. In most cases estimates were made on the basis of geologic setting. The conceptual model for the Basin-and-Range type of fault-controlled resource suggests that these resources are site-specific. It was thus assumed that the 99% confidence area was very limited and generally restricted to no more than 1000 acres. The 50% confidence zone averages about 3200 acres and the 1% confidence level averages about 6,400 acres. In contrast, the 99% confidence level area for a resource controlled by an aquifer in a deep sedimentary basin is quite large, since a properly drilled and completed well drilled anywhere into the hot aquifer has an excellent chance of production.

3.3 Estimation of the Resource Base

Researchers at UURI developed regional estimates of the frequency and temperature distribution of reservoirs in the hydrothermal resource base. These resource base estimates were input to the Geothermal Exploration Model (described in Appendix A), which produced a probability distribution of hydrothermal resource confirmations by generic resource code through the year 2000.

A relatively small number of confirmations have been anticipated for the near-term (1981-1985), because the current pace of exploration is slow. Several factors currently contribute to this slow pace:

1. There is competition within most major geothermal exploration companies between funds for geothermal exploration and funds for petroleum exploration.
2. There are too few companies currently performing geothermal exploration to achieve a high confirmation rate.

3. Institutional barriers, the most severe of which pertain to land leasing and exploration and development permitting, will significantly diminish near-term exploration. It is anticipated, however, that these barriers will be mitigated in the long-term.

4. Utilities are reluctant to depend on hydrothermal resources for part of their firm generating capacity.

3.4 The Impact Of Federal Geothermal Programs On Reservoir Confirmation Rate

Electric power generation system using hydrothermal energy can be developed by industry or by Government. The current philosophy within the Government emphasizes that development by industry is preferable. Whenever practical, the current program relies upon free market forces to stimulate the development of hydrothermal resources. Resources that can be profitably developed in the near-term are being exploited by the private sector. The role of the government is currently perceived to be to undertake research, development, and demonstration projects intended to find solutions to problems that can not or will not be tackled by private industrial firms concerned with near-term profitability. This means that the current Federal emphasis is on high risk or long term RD&D projects, and on taking the preliminary steps aimed at improving the ultimate viability of currently marginal resources.

If the hydrothermal electric industry is expected to become self-sustaining, Federal program elements should be only transitory. The Federal program is not expected to increase the ultimate number of resources confirmed and exploited. Rather, it is expected to influence the timing of confirmation of resources. Table 3.5 shows the program elements that are judged to be most important in terms of increasing the confirmation rate during the next 20 years, and the additional

TABLE 3.5
ADDITIONAL TIME NEEDED FOR FULL PROGRAM EFFECTIVENESS

<u>Program Element</u>	<u>Time for Success (yrs.)</u>
Regulatory Streamlining	5
Resource Confirmation	2 (operating now, needs substan- tially more funding)
Power Plant Incentives	3
Technology Development	3
Technology Demonstration	3

time that will be required before the full impact of each element will occur.

Because of the tendency of commercial organizations oriented toward near-term profits to respond to market forces, rather than anticipate them, it is assumed that private industry will do little by itself to increase the resource confirmation rate until the cost of electric power increases to the point where hydrothermal resources become cost competitive. This means that the developed capacity of hydrothermal electric power generation will lag behind the market forces that stimulate its development unless government activities facilitate development. Projecting that market forces will result in the development of an aggressive hydrothermal electric industry after about ten years, and assuming that a minimal R&D program will result in the commencement of aggressive industrial development after about three years, the program is expected to speed hydrothermal development by about 7 years.

4.0 PLANT AND FIELD COSTS

4.1 General

All development costs are categorized as either plant or field costs. Figure 4.1 gives an illustration of the pertinent components of the two categories. Both plant and field development expenses include capital costs, operation and maintenance costs, and miscellaneous costs. Typical capital costs for a 50 MWe binary plant and a 50 MWe dual flash steam plant are presented in Tables 4.1 and 4.2, respectively. To further illustrate the differences between capital costs for dual flash plants and binary plants, Table 4.3 presents plant components as a percentage of total plant costs both for dual flash plants and for binary plants at three different temperature levels.

Capital costs are determined by indirect factors such as temperature and brine content. Figure 4.2 illustrates that at higher temperatures there will be a corresponding higher level of brine effectiveness.

4.2 Major Assumptions

The estimates of power plant costs were based on the following assumptions: (1) costs are escalated 13.5% per year from the date of quotation on estimate, (2) labor cost is estimated to be 30% of total equipment cost, (3) contracts mark-up and construction management are estimated to be 15% of total direct cost, (4) a 10% contingency rate is added, and (5) plant startup is estimated at \$2,500,000.

4.3 Plant Capital and O&M Costs

As illustrated in Figure 4.3 both plant capital costs and plant operating and maintenance costs decrease as brine temperature

FIGURE 4.1

FIELD AND PLANT DEVELOPMENT COSTS

TABLE 4.1
BINARY PLANT CAPITAL COST 50 MWe NET

ITEM	290°F (1980 \$)	360°F (1980 \$)	500°F (1980 \$)
<u>Land and Land Rights</u>	100,000	100,000	100,000
<u>Structures and Improvements</u>			
Plant Site Preparation	400,000	400,000	400,000
Foundations and Structures	2,300,000	2,300,000	2,300,000
<u>Major Equipment</u>			
Turbine Generator	6,143,000	4,740,000	4,120,000
Condensers	5,736,000	2,619,000	2,236,000
Cooling Water Piping	1,401,000	1,242,000	774,900
Cooling Tower and Basin	5,206,000	2,377,000	1,939,300
Cooling Water Pumps	1,006,500	823,600	361,900
Heat Exchangers	5,380,000	4,882,000	3,313,000
Condensate Tanks	348,900	204,300	115,700
<u>Construction and Small Equipment</u>			
Crane	287,000	287,000	287,000
Electrical and Switchgear	2,729,900	2,729,900	2,729,900
Instrumentation and Controls	1,599,600	1,599,600	1,599,600
Working Fluid Piping and Valves	2,318,000	1,176,800	836,900
Brine Piping and Valves	530,000	327,100	182,100
Miscellaneous Tanks and Piping	400,000	400,000	400,000
Fire Protection System	225,000	225,000	225,000
Miscellaneous Mechanical Equipment	1,400,000	1,400,000	1,400,000
Spare Parts and Tools	250,000	250,000	250,000
Reinjection Pumps	450,000	319,800	142,200
Reinjection Filters	2,671,000	1,200,000	447,300
Feed Pumps	898,600	526,000	298,100
Sales Tax @ 5%	1,949,000	1,366,500	1,082,900
Labor & Labor OH, 30% of Equipment	12,278,900	8,608,800	6,822,600
Total Direct Cost, Excl Land Rights	55,908,400	40,004,900	32,264,400
Contractor Markup and Cost Mgt. (15%)	8,386,300	6,007,400	4,839,700
Contingency (10%)	6,429,500	4,600,600	3,710,400
Design	2,500,000	2,500,000	2,500,000
Plant Startup	300,000	300,000	300,000
TOTAL	73,524,200	53,512,900	43,714,500

SOURCE: EG&G

TABLE 4.2

CAPITAL COST OF A DUAL FLASH STEAM PLANT
(1980 \$)
240° C (464°), NEGLIGIBLE TDS AND DISSOLVED NON-CONDENSIBLES

<u>ITEM</u>	<u>EQUIPMENT</u>	<u>LABOR</u>	<u>TOTAL</u>
<u>Land and Land Rights</u>			100,000
<u>Structures and Improvements</u>			400,000
Plant Site Preparation			400,000
Foundations and Structures			<u>2,300,000</u>
Subtotal			<u>2,700,000</u>
<u>Major Equipment</u>			
Turbine Generator	7,000,000		
Condensers	1,450,000		
Cooling Water Piping	860,000		
Cooling Tower and Basin			
Cooling Water Pumps	550,000		
Vacuum Compressors	<u>200,000</u>		
Subtotal	<u>10,060,000</u>		
<u>Construction and Small Equipment</u>			
Crane	287,000		
Electrical & Switchgear	2,729,900		
Instrumentation & Controls	1,279,700		
Steam & Brine Piping	300,000		
Valves	760,500		
Secondary Flash Tanks	450,000		
Misc. Tanks & Piping	400,000		
Fire Protection System	112,500		
Spare Parts & Tools	250,000		
Misc. Mechanical Equipment	1,400,000		
Reinjection Pumps	190,000		
Reinjection Filters	<u>610,000</u>		
Subtotal	<u>8,770,000</u>		
TOTAL EQUIPMENT	18,830,000		
Sales Tax @ 5%	941,500		
Labor & OH @ 30% of Equipment		5,931,400	
Total Direct Cost, Excl. Land Rights			30,710,700
Contractor Markup & Constr. Mgt. (15%)			4,606,600
Contingency (10%)			3,531,700
Design			2,500,000
Plant Startup			300,000
TOTAL			42,749,000 (\$826/KWe net)

SOURCE: EG&G

TABLE 4.3

POWER PLANT COST PARAMETERS AS PERCENT OF TOTAL PLANT COST

ITEM	Dual Flash	290°F Binary	360°F Binary	500°F Binary
Turbine-Generator	16.37	8.36	8.86	9.42
Process Mechanical	6.11	2.44	3.36	4.12
Piping and Insulation	1.64	3.87	2.81	2.33
Instrumentation and Control	3.00	2.18	2.99	2.66
Electrical and Switchyard	6.39	3.71	5.10	6.24
Civil and Structures	7.00	3.52	4.84	5.92
Condenser and Heat Rejection	12.49	18.63	13.58	12.42
Heat Exchangers	--	7.32	9.12	7.58
Engineering and Administration	5.85	3.40	4.67	5.72
Other Items, Including Taxes	<u>41.15</u>	<u>46.57</u>	<u>49.34</u>	<u>42.59</u>
Total	100.00	100.00	100.00	100.00
Operations and Maintenance	2.07	1.12	1.42	1.66

SOURCE: EG&G

SOURCE: EG&G

FIGURE 4.2
NET BRINE EFFECTIVENESS

4-7

Plant Operating and Maintenance Cost

FIGURE 4.3

PLANT CAPITAL AND OPERATING AND MAINTENANCE COSTS

SOURCE: EG&G

increases. Figure 4.3 shows that, compared to low salinity brine, high salinity brine results in higher operation and maintenance costs. This relationship is most pronounced in the lower temperature ranges. Typical power plant operation and maintenance costs are shown in Table 4.4. Power plant operation and maintenance costs are divided into four major categories: staffing, equipment maintenance, cooling water treatment, and miscellaneous.

4.4 Field Capital and O&M Costs

Field system capital costs were applied to dual flash steam and binary plants as well as pumped and flashing flow wells. However, well costs are not part of the field system equipment capital cost. Figure 4.4 shows situations of a dual flash steam plant with a single pipe system and a dual pipe system under conditions of low salinity. The capital cost for a single pipe system is substantially less than the capital cost of a dual pipe system.

Figure 4.5(a) illustrates that field surface equipment capital costs for both dual flash steam plants and binary plants decrease as resource temperature increases, and Figure 4.5(b) shows that, as a percentage of total field cost, field operation and maintenance costs increase as temperature increases. Table 4.5 outlines the cost elements for field system operation and maintenance.

The allocation of exploration costs is dependent on the estimated output expected from the reservoir. The average cost for exploration leading to one producible hydrothermal discovery as determined by the Department of Energy is \$7,300,000 (cf. Table 4.6). UURI has estimated that the average cost of exploration per discovery will be \$6 million. Well capital costs include drilling, completion,

TABLE 4.4

POWER PLANT O&M COSTS

COST ELEMENTS

- STAFFING - - - - - (440K/YR)
 - 4 OPERATORS
 - 1 LABORER
 - 1 ELECTRICIAN
 - 1 MECHANIC
 - 1 OFFICE MANAGER
 - 1 SUPERINTENDENT
- EQUIPMENT MAINTENANCE @ 2% OF EQUIPMENT COST
 - (+ \$112K for scale removal with high salinity brines)
 - (+ 11¢/1000 gal. clarifier operation with high salinity brines)
- COOLING WATER TREATMENT
 - \$19.5K (DFS PLANTS)
 - \$58K (BINARY PLANTS)
- MISCELLANEOUS - \$50K

SOURCE: EG&G

FIGURE 4.4

FIELD CAPITAL COSTS FOR SINGLE
AND DUAL FLASH SYSTEMS

SOURCE: EG&G

Field Surface Equipment Capital Cost

Field O and M Cost

FIGURE 4.5

FIELD CAPITAL AND OPERATING AND MAINTENANCE COSTS

SOURCE: EG&G

TABLE 4.5

FIELD SYSTEM O&M COSTS

COST ELEMENTS

- STAFFING - - - - - (\$320K/YR)
 - 1 ROUSTABOUT
 - 1 ELECTRICIAN
 - 1 MECHANIC
 - 1 FOREMAN
 - 1 OFFICE MANAGER
 - 1/2 MECHANICAL ENGINEER
 - 1/2 PRODUCTION ENGINEER
- SURFACE EQUIPMENT MAINTENANCE
 - (2% of capital cost for low and medium salinity brines)
 - (4% of capital cost for high salinity brines)
- WELL MAINTENANCE (MEDIUM SALINITY BRINES)
 - PRODUCTION WELLS (\$157K/WELL/YR)
 - ACIDIZE YEARLY
 - DOWN HOLE SURVEY YEARLY
 - HYDROFRAC AFTER 5th YEAR
 - DRILL REPLACEMENT WELL AFTER 10 YEARS
 - CAP AND ABANDON WELL AFTER 10 YEARS
 - INJECTION WELLS (\$125K/WELL/YR)
 - STIMULATE YEARLY
 - DOWN HOLE SURVEY YEARLY
 - HYDROFAC AFTER 4th and 7th YEAR
 - REDRILL WELL AFTER 10 YEARS
- WELL MAINTENANCE (LOW SALINITY BRINES)
 - 15-YEAR WELL LIFE WITH ABOVE OPERATIONS SPACED ACCORDINGLY
- WELL MAINTENANCE (HIGH SALINITY BRINES)
 - 6-3/4-YEAR WELL LIFE WITH ABOVE OPERATIONS SPACED ACCORDINGLY

SOURCE: EG&G

TABLE 4.6

PRE-PRODUCTION COST ESTIMATE
FOR ONE PRODUCIBLE HYDROTHERMAL DISCOVERY

YEAR	ITEM	AREAS ¹	CAPITALIZED COST	EXPENSED ² COST
1	RECONNAISSANCE - Literature search & analysis - Photography, imagery & photogeology	62	\$0	\$ 40,000
	PRE-LEASE SURFACE EXPLORATION - Permits & Notice of Intent - Geology, geochemistry & thermal gradients	35	\$50,000	1,700,000
2 & 3	LAND ACQUISITION - Application & environmental studies (if req'd) - Competitive bonus bid (if req'd)	18	Site-Specific ³	1,400,000
	POST-LEASE SURFACE EXPLORATION - Geophysical & electrical - Market assessment & financing	18	15,000	250,000
4	SHALLOW SUB-SURFACE EXPLORATION - Drill & log thermal gradient wells - Permits, drill & test shallow wells - Conceptual models	13	40,000	480,000
5	DETAILED EXPLORATION - Geology, geophysics & geochemistry	5	75,000	300,000
	DEEP EXPLORATORY WELLS - Permits, mobilize rig & drill deep well - Test & evaluate	5	Site-Specific	1,800,000 ⁷
	CONFIRMATION - Permits, 2 step-out wells & injection wells - Sustained flow test	1	Site-Specific	0
6	MODELING & ENVIRONMENTAL STUDIES - Fault pattern definition - Environmental assessments - Consumer evaluations & negotiations	1	800,000	0
7	WELL FIELD ENGINEERING ⁸ - Permits & development plan - Engineer surface facilities	1	125,000	0
8 & 9	CONSTRUCT SURFACE FACILITIES - Permits & procurement - Construct roads & buildings	1	225,000	0
	WELL FIELD DEVELOPMENT - Mobilize drilling rig - Drill & case producer & injection wells - Construct surface piping	1	Site-Specific	Site-Specific

¹ One Area = 7,500 acres.

² Expenses will also include annual land rental, ad valorem taxed, and (for tax purposes) the

³ Based upon site-specific lease bonus (cash flow model input parameter) on ultimately productive acreage.

⁴ Equivalent to an average lease bonus of \$11/acre @ 7,500 acres/area.

⁵ Estimated access ratios for deep exploration wells vary from 1:15 (Ref. University of Utah, 1978, p. 58) to 5:15 (Ref. Ward, 1977). The 1:5 estimate used here represents a compromise between these estimates and is consistent with the 21% success rate for exploratory wells outside well-known areas per University of Utah (1978) p. 51.

⁶ Site-specific deep well cost is a function of reservoir depth and geology. Refer to text.

⁷ Assumes 3 failures @ \$350,000 and 1 failure with casing run @ \$750,000.

⁸ Industry responses to the question of the number of deep wells required for confirmation varied from two to more than five with three (i.e. one successful exploratory well plus two step-out wells) being the best responses.

⁹ Includes active and spare producer wells and injector wells plus additional redrill costs. Refer to text.

¹⁰ Includes dry wells encountered in field development. Refer to text.

SOURCE: TECHNECON

and short-term testing, but exclude well equipment. The data source for the model is composed of 32 wells, which include wells drilled under geothermal loan guaranty applications, the industry coupled drilling program, the PON program, the Raft River program, and the INEL deep well program. Figure 4.6 illustrates that, for a down hole pump, purchase and installation costs decrease and maintenance costs increase as well flow rate increases. Figure 4.7 shows the relationship between well depth, geologic conditions, and well costs.

DOWNHOLE PUMP CAPITAL COST
PURCHASE AND INSTALLATION

DOWNHOLE PUMP MAINTENANCE COST

FIGURE 4.6

DOWNHOLE PUMP CAPITAL AND MAINTENANCE COSTS

SOURCE: EG&G

SOURCE: EG&G

FIGURE 4.7

WELL COSTS

5.0 IMPACT OF THE FEDERAL/DOE PROGRAM ON THE MODEL

5.1 Introduction

If a hydrothermal electric industry is eventually to be self-sustaining, federal program elements which provide assistance to industry should be only temporary and should be phased down after the near-term problems have been solved. In the long-term, the Federal program should be focussed on high-risk, high payoff R&D, which the private sector finds too risky to pursue. Most of the Federal program elements are designed to reduce barriers to hydrothermal development. This is expected to make hydrothermal development more economically attractive to industry and utilities in the near-term, and thereby accelerate development.

5.2 The Federal/DOE Program

Activities of the Division of Geothermal and Hydropower Technology and of other Federal agencies are intended to assist private sector hydrothermal development. Major elements of the Federal/DOE program are presented in Table 5.1. The analysis for the current report is based on three scenarios regarding the level of Federal/DOE support for hydrothermal R&D. The "No Program" scenario is based on a dismantling of the current Federal/DOE program. Under this scenario, it is assumed that annual Federal funding would rapidly decline from less than \$15 million to an eventual zero budget. The "Minimal R&D" scenario assumes annual Federal hydrothermal R&D funding in the \$15-\$35 million range, and the "Expanded R&D" scenario assumes annual outlays in the \$35-\$50 million range.

TABLE 5.1

HYDROTHERMAL PROGRAM ELEMENTS

ACTIVITIES SPONSORED BY DOE	
A. Planning and Coordination	
(1) Progress Monitoring	
(2) Inter-Agency Coordination	
B. Technology Development	
(1) Geosciences Program	
(2) Geochemical Engineering and Materials	
(3) Energy Extraction	
(4) Environmental Control	
C. Technology Demonstration	
(1) Flash Steam Power Plant Demonstration	
ACTIVITIES NOT SPONSORED BY DOE	
A. Regulatory Streamlining and Administration	
(1) Federal Streamlining Plan	
(2) Leasing and Land Use Coordination	
B. Resource Assessment/Confirmation	
(1) Removal of Tax Disincentives	
C. Power Plant Provisions	
(1) Non-Utility Owner Producer Regulatory Mitigation	
- Tax Credits	
- Regulatory Exemptions	
- Interconnection Authority	
- Wheeling Authority	

SOURCE: DOE

5.3 Methodology for Analysis

The nature of the impacts on the parameters depends on three variables:

- (1) Timing of an event
 - timing of discoveries
 - post-discovery development period
- (2) Investment behavior and economic utility of a project
 - risk
 - cost
 - rate of return
- (3) Technical
 - equipment life time
 - plant reliability
 - plant/component performance

Table 5.2 lists the hydrothermal electric model parameters. Table 5.3 outlines the impact of Federal program elements on model parameters.

To provide a quantitative estimate of the impacted parameters, percentage increase/decrease estimates for parameter values are shown in Tables 5.4 and 5.5. Thus, for example, a "-2.5" figure in the table would indicate an expected decrease of 2.5% in the value of the relevant parameter. Each parameter is given a set of estimates shown as P, M, and O in the Tables. The value of P corresponds to the lower or pessimistic estimate; M corresponds to the modal or most likely estimate, and O corresponds to the upper or most optimistic estimate.

5.4 Estimation of Impacts of Federal Programs on the Values of Parameters for a Selected Site (Roosevelt Hot Springs)

Located in Beaver County, Utah, Roosevelt Hot Springs has been actively explored, confirmed, and evaluated. Both Phillips Petroleum

TABLE 5.2
HYDROTHERMAL ELECTRIC MODEL PARAMETERS

<u>NO.</u>	<u>MODEL PARAMETER</u>
1.	Minimum time path of post-discovery resource development
2.	Timing of resource discoveries (UURI Task)
3.	Tax rates (Federal, State, Local ad valorem)
4.	Tax preference items
5.	Tax credits (investment tax credits)
6.	Allowable tax deductions (depletion, expenses, etc.)
7.	Well capital cost
8.	Well field investment at risk
9.	Developer's capital structure (debt/pref. stock/com. stock)
10.	Developer's cost of debt
11.	Developer's cost of preferred
12.	Developer's cost of common
13.	Developer's investment utility functions
14.	Reservoir risk perception (premature failure w.r.t. time)
15.	Surface piping capital cost
16.	Surface piping investment at risk
17.	Power plant capital cost
18.	Power plant investment at risk
19.	User's utility function for reservoir capacity
20.	User's capital structure (debt/pref./com.)
21.	User's cost of debt
22.	User's cost of preferred
23.	User's cost of common
24.	User's investment utility functions
25.	Geothermal electric energy price support
26.	Inter-regional transmission costs and feasibility (WEPL Task)
27.	Power plant performance (watt·hrs/lb of fluid)
28.	Well life
29.	Well field O&M cost
30.	Power plant O&M cost
31.	Power plant capacity factor
32.	Exploratory dry well fraction
33.	Developmental dry well fraction
34.	Vector of sequential plant sizes
35.	Probability of first plant on line

SOURCE: TECHNECON

TABLE 5.3

HYDROTHERMAL MODEL PARAMETERS LIKELY TO BE IMPACTED
BY FEDERAL PROGRAM FOR HYDROTHERMAL ELECTRIC DEVELOPMENT

ACTIVITY AREA	IMPACTED PARAMETERS
<ul style="list-style-type: none"> • Planning and Coordination <ul style="list-style-type: none"> - Progress Monitoring - Inter-Agency Coordination • Technology Development <ul style="list-style-type: none"> - Geosciences Program - Geochemical Engineering and Materials - Energy Extraction and Conversion Technology - Environmental Controls • Technology Demonstration <ul style="list-style-type: none"> - Flash Steam Power Plant Demonstration • Regulatory Streamlining and Administration <ul style="list-style-type: none"> - Federal Streamlining Plan - Leasing and Land Use Coordination • Resource Assessment/Confirmation <ul style="list-style-type: none"> - Removal of Tax Disincentives • Power Plant Provisions <ul style="list-style-type: none"> - Non-Utility Owner Producer Regulatory Mitigation <ul style="list-style-type: none"> Tax Credits Regulatory Exemptions Interconnection Authority Wheeling Authority 	<p>1</p> <p>2, 14, 32, 33</p> <p>7, 15, 28, 29, 30, 31</p> <p>7, 17, 27, 28, 29, 30, 31</p> <p>17</p> <p>17, 18, 27, 30, 31, 35</p> <p>1, 2</p> <p>3, 4, 5, 6</p> <p>5, 20, 21, 22, 23, 24, 25</p> <p>26</p>

SOURCE: DOE

TABLE 5.4

IMPACT OF COMBINED R&D PROGRAMS
ON SELECTED PARAMETERS

IMPACTED PARAMETER	R&D PROGRAMS*	DRY STEAM M		DOUBLE FLASH M		290 °F BINARY M		360 °F BINARY M		500 °F BINARY M	
		A	B	A	B	A	B	A	B	A	B
WELL LIFE	III IV D	28.0	20.0 32.0	28.0	20.0 32.0	28.0	20.0 32.0	28.0	20.0 32.0	28.0	20.0 32.0
WELL CAPITAL COST	II III IV	-5.0	-2.6 -8.0	-5.0	-2.6 -8.0	-5.0	-2.6 -8.0	-5.0	-2.6 -8.0	-5.0	-2.6 -8.0
WELL FIELD O&M COST	III IV D	-10.0	-7.1 -13.9	-10.0	-7.1 -13.9	-10.0	-7.1 -13.9	-10.0	-7.1 -13.9	-10.0	-7.1 -13.9
POWER PLANT CAPITAL COST	III IV D	-3.0	-2.8 -3.9	-0.6	-0.5 -0.8	-2.5	-2.0 -2.6	-2.0	-1.5 -2.4	-2.0	-1.6 -2.3
POWER PLANT PERFORMANCE	D	9.0	6.0 12.1	9.0	6.0 12.1	9.0	6.0 12.1	9.0	6.0 12.1	9.0	6.0 12.1
SURFACE PIPING CAPITAL COST	IV	-2.2	-1.8 -2.4	-4.0	-3.3 -5.1	-7.9	-7.6 -8.0	-7.9	-7.6 -8.0	-7.9	-7.6 -8.0
POWER PLANT CAPACITY FACTOR	III IV D	5.0	1.0 7.0	5.0	1.0 7.0	5.0	1.0 7.0	5.0	1.0 7.0	5.0	1.0 7.0
POWER PLANT O&M COST	III IV	-1.0	-0.5 -1.1	-8.4	-4.5 -9.0	3.2	8.8 -0.6	3.2	8.8 -0.6	3.2	8.8 -0.6

* KEY TO GEOTHERMAL PROGRAM CODES

SOURCE: EER

- I. GEOSCIENCES PROGRAM (Not reflected in this table because the model handles these impacts on a site-specific basis. Impacts are in the areas of discovery rate enhancement and exploration cost reduction).
- II. GEOTHERMAL DRILLING TECHNOLOGY
- III. ENERGY EXTRACTION AND UTILIZATION
- IV. GEOCHEMICAL AND MATERIALS ENGINEERING
- D. TECHNOLOGY DEMONSTRATION

TABLE 5.5

IMPACT OF INDIVIDUAL R&D PROGRAMS
ON SELECTED PARAMETERS

IMPACTED PARAMETERS	R&D PROGRAMS	DRY STEAM M		DOUBLE FLASH M		290 °F BINARY M		360 °F BINARY M		500 °F BINARY M	
		A	B	A	B	A	B	A	B	A	B
WELL LIFE	III	24.8	20.0 30.0	24.8	20.0 30.0	24.8	20.0 30.0	24.8	20.0 30.0	24.8	20.0 30.0
WELL LIFE	IV	4.5	3.5 4.9	4.5	3.5 4.9	4.5	3.5 4.9	4.5	3.5 4.9	4.5	3.5 4.9
WELL CAPITAL COST	III	0.0	1.8 -1.0	0.0	1.8 -1.0	0.0	1.8 -1.0	0.0	1.8 -1.0	0.0	1.8 -1.0
WELL CAPITAL COST	IV	-1.7	-0.8 -2.6	-1.7	-0.8 -2.6	-1.7	-0.8 -2.6	-1.7	-0.8 -2.6	-1.7	-0.8 -2.6
WELL CAPITAL COST	II	-4.1	-3.6 -5.6	-4.1	-3.6 -5.6	-4.1	-3.6 -5.6	-4.1	-3.6 -5.6	-4.1	-3.6 -5.6
WELL FIELD O&M COST	III	-7.6	-5.0 -10.0	-7.6	-5.0 -10.0	-7.6	-5.0 -10.0	-7.6	-5.0 -10.0	-7.6	-5.0 -10.0
WELL FIELD O&M COST	IV	-3.2	-2.1 -3.9	-3.2	-2.1 -3.9	-3.2	-2.1 -3.9	-3.2	-2.1 -3.9	-3.2	-2.1 -3.9
POWER PLANT CAPITAL COST	IV	-3.0	-2.8 -3.9	-0.6	-0.5 -0.8	-0.5	-0.5 -0.7	-0.7	-0.6 -0.9	-0.9	-0.8 -1.1
POWER PLANT CAPITAL COST	III	0.0	0.0 0.0	0.0	0.0 0.0	-2.5	-1.5 -2.9	-1.5	-0.9 -1.5	-1.2	-0.8 -1.2
POWER PLANT O&M COST	IV	-1.0	-0.5 -1.1	-8.4	-4.5 -9.0	0.0	0.0 0.0	0.0	0.0 0.0	0.0	0.0 0.0

* KEY TO GEOTHERMAL PROGRAM CODES

SOURCE: EER

- I. GEOSCIENCES PROGRAM (Not reflected in this table because the model handles these impacts on a site-specific basis. Impacts are in the areas of discovery rate enhancement and exploration cost reduction).
- II. GEOTHERMAL DRILLING TECHNOLOGY
- III. ENERGY EXTRACTION AND UTILIZATION
- IV. GEOCHEMICAL AND MATERIALS ENGINEERING
- D. TECHNOLOGY DEMONSTRATION

TABLE 5.5 (Concluded)

IMPACT OF INDIVIDUAL R&D PROGRAMS
ON SELECTED PARAMETERS

IMPACTED PARAMETERS	R&D PROGRAMS	DRY STEAM M		DOUBLE FLASH M		290 °F BINARY M		360 °F BINARY M		500 °F BINARY M	
		A	B	A	B	A	B	A	B	A	B
POWER PLANT O&M COST	III	0.0	0.0	0.0	0.0	3.2	-0.6	3.2	-0.6	3.2	-0.6
POWER PLANT PERFORMANCE	D	9.0	12.1	9.0	12.1	6.1	8.1	6.1	8.1	6.1	8.1
SURFACE PIPING CAPITAL COST	IV	-2.2	-2.4	-4.0	-5.1	-7.9	-8.0	-7.9	-8.0	-7.9	-8.0
POWER PLANT CAPACITY FACTOR	ALL	5.0	7.0	5.0	7.0	5.0	7.0	5.0	7.0	5.0	7.0

SOURCE: EER

* KEY TO GEOTHERMAL PROGRAM CODES

- I. GEOSCIENCES PROGRAM (Not reflected in this table because the model handles these impacts on a site-specific basis. Impacts are in the areas of discovery rate enhancement and exploration cost reduction).
- II. GEOTHERMAL DRILLING TECHNOLOGY
- III. ENERGY EXTRACTION AND UTILIZATION
- IV. GEOCHEMICAL AND MATERIALS ENGINEERING
- D. TECHNOLOGY DEMONSTRATION

Company and Thermal Power Company have conducted well flow tests, and are attempting to attract utility interest. At present, a 20 MWe power plant is planned by Phillips and Rogers International, with power to be purchased by Utah Power and Light.¹

Table 5.6 shows the resource parameters for Roosevelt Hot Springs. (To estimate the impact of Federal programs are specific model parameters for different types of plants refer to Tables 5.4 and 5.5.) The estimated impacted parameters for Roosevelt Hot Springs will be well life and well capital cost. The mean value of well life for Roosevelt Hot Springs is 15 years. Thus, for a dual-flash plant with combined R&D programs, a pessimistic estimate would be a 20% increase and most likely 28% increase in well life. Well capital cost of Roosevelt Hot Springs is \$718,000 for a dual-flash plant, a pessimistic estimate would be a 2.6% decrease, an optimistic 8% decrease and a most likely decrease of 5%.

¹ UPL has agreed with Phillips to purchase an additional 200 MWe power from a commercial plant to follow the initial 20 MWe pilot plant.

TABLE 5.6

RESOURCE AND DEVELOPMENT PARAMETERS
AT ROOSEVELT HOT SPRINGS KGRA

RESOURCE PARAMETERS

1. State.....	UT
2. Type of Geology (I/P).....	Igneous
3. Reservoir Depth, Ft:	
-Minimum Value (I/P)....	1300
-Value at Mode (I/P)....	3700
-Maximum Value (I/P)....	7300
-Mean Value (O/P).....	4014
4. Mean Well Cost, \$1000 (O/P).....	718
5. Dry Well Cost Fraction (I/P).....	0.9
6. Redrill Well Cost Fraction (I/P).....	0.35
7. Dry Well Fraction:	
-Minimum Value (I/P)....	0.09
-Value at Mode (I/P)....	0.1
-Maximum Value (I/P)....	0.11
-Mean Value (O/P).....	0.1
8. Spare Well Fraction (I/P).....	0.2
9. Producer/Injector Ratio (I/P).....	2
10. Initial Redrill Fraction (I/P).....	0.3
11. Replacement Redrill Fraction (I/P).....	0.33
12. Wellhead Resource Temperature, F:	
-Minimum Value (I/P)....	400
-Value at Mode (I/P)....	430
-Maximum Value (I/P)....	460
-Mean Value (O/P).....	430
13. Net Specific Energy, WHR/LB (O/P).....	10.9
14. Well Flow Rate, 1000 lb/hr:	
-Minimum Value (I/P)....	900
-Value at Mode (I/P)....	1000
-Maximum Value (I/P)....	1100
-Mean Value (O/P).....	1000
15. Well Spacing, Acres/Well (I/P).....	40
16. Salinity Index [0:Low→4:High] (I/P).....	1
17. Well Life, Yrs:	
-Minimum Value (I/P)....	10
-Value at Mode (I/P)....	15
-Maximum Value (I/P)....	20
-Mean Value (O/P).....	15.0
18. Book Life of Wells, Yrs (I/P).....	15
19. Book Life of Surface Capital, Yrs (I/P).....	30
20. Tax Life of Wells, Yrs (I/P).....	15
21. Ad Valorem Tax, on Actual Value (I/P).....	0.0125
22. Royalty Fraction (I/P).....	0.125
23. Lease Bonus, \$/Acre (I/P).....	100
24. Land Rental, \$/Acre (I/P).....	2
25. Power Transmission Cost, \$1000 (I/P):	
-To 200000 KWe.....	4900
-Additional Increments of 600000 KWe.....	7600
26. Alternative Generation:	
-Capital Cost, \$/KWe (I/P).....	1100
-Fuel Cost, Mills/KWh (I/P).....	8

APPENDIX A

GEOTHERMAL EXPLORATION MODEL

The Geothermal Exploration Model, developed by Technecon is capable of estimating future resource confirmation rates, both nationally and sub-nationally, as a function of current knowledge of the geologic resource base; financial return and risk perceptions by development and production firms; and the regulatory and other programmatic actions of various government agencies. While it was designed to provide resource discovery forecasts used as input to Technecon's Geothermal Industry Development Model, it can be used independently for other more specialized types of analyses. When the exploration and resource development models are coupled, however, a completely integrated forecasting system is available to policymakers that can be used to evaluate the differential impacts of federal programs on every stage of geothermal discovery and use.

Three major submodels constitute the basic structure of the Exploration Model. The Well Drilling Model first estimates the number of wildcat wells drilled in a given year. This forecast is based on: (1) the rate of return which could be earned on development of an undiscovered resource of "average" quality, and (2) the rate of return offered by investments in petroleum operations. Given these well drilling forecasts, the Discovery Model estimates the number of resultant resource confirmations that are likely, based on historical well drilling success rates and the cumulative amount of drilling to date. The Resource Model next establishes a temporal series of probability distributions that describes changes in the expected quality of each succeeding discovery.

As shown in Figure A.1, the Geothermal Model is simulated in a dynamic manner. This expected temperature of succeeding discoveries will decline as each discovery is removed from the total resource base. This, in turn, affects the well drilling model by generally reducing the quality of sequential investment opportunities. Any reduction in well drilling activity will necessarily slow the rate of resource discovery. This interaction between model components accurately replicates the actual stages of the geothermal exploration process.

A rich selection of Federal policy levers are available for manipulation in each of the major submodels: R&D program design and funding levels, financial and economic variables, regulatory delay times, leasing policies, etc. Moreover, the exploration model can be readily updated and refined to reflect actual well drilling and discovery experience as the exploration path of the geothermal industry unfolds.

For a more detailed explanation and description of exploration model, please refer to "National Forecast for Geothermal Resource Exploration and Development", DOE/ET/27242-T2, March, 1982, prepared by Technecon Analytic Research for the Division of Geothermal and Hydropower Technology.

FIGURE A.1 GEOTHERMAL EXPLORATION MODEL

Source: Technecon

APPENDIX B

TECHNICAL DISCUSSION OF HYDROTHERMAL ELECTRIC POWER DECISION MODELS

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As summarized in Section 2 of this report, the numerical likelihood of electric development at specified resource sites is estimated by quantitative decision analysis methods. Specifically, the likelihood of well field development by resource developers, and the likelihood of power plant construction by electric utilities, is estimated by methods that integrate multiattribute utility techniques and logit regression techniques. Decision modeling of the resource developers and electric utilities is discussed below. Also discussed is the iterative method used to converge on a resource selling price that maximizes the joint likelihood of investment by both the resource developer and the electric utility.

B.1 Resource Developers' Decision Model

In 1978 and 1979, Technecon analysts interviewed management representatives from twenty resource firms to determine their decision criteria for hydrothermal well field investments. Four investment objectives were found to be of primary concern to the firms' decision makers:

- maximize the efficiency of invested capital (as assessed in terms of the anticipated net after-tax rate of return)
- minimize the length of time during which invested capital is at risk (as assessed in terms of the anticipated investment payback time)
- undertake projects that are compatible with the firm's scale of operations (as assessed in terms of the anticipated net present value of the profit stream)

- avoid financial ruin (as assessed in terms of the amount of invested capital at risk).

The quality of the hydrothermal opportunity is assessed by these four investment attributes (i.e., rate of return, payback time, present value of profits, and capital at risk). The degree to which each of these attributes meets the firms' investment objectives may be expressed in terms of "numerical utility." A minimum utility of zero implies "no investment incentive" and a maximum utility of one implies "high positive incentive."

Utility functions, which translate attribute values into corresponding numerical utilities, were estimated from industry-supplied data for two classes of resource developers: major diversified energy corporations and smaller non-diversified independent operators. After testing the industry responses for statistical heteroskedasticity (i.e., nonequality of variance across sample observations) the data were regressed either by simple least squares techniques, weighted least squares techniques, or non-linear multiple regression methods. The results of this statistical analysis, as illustrated in Figures B.1, B.2, B.3, and B.4, are utility functions of rate of return $U_R(r)$, payback time $U_P(p)$, present value of profits $U_V(v)$ and capital loss $U_L(v)$, respectively. These functions represent the maximum likelihood estimates (MLE) and best linear unbiased estimated (BLUE) of the industry responses.

Rate of Return. It may be noted that, in Figure B.1, a minimum acceptable rate of return exists which is consistent with the discussions of threshold return as expressed in industry interviews. Furthermore, the curves in Figure B.1 are monotonic increasing with r which is consistent with the industry responses of increasing pre-

Figure B.1
Rate of Return on Investment

Figure B.2
Investment Payback Period

Figure B.3
Present Value of Profits

Figure B.4
Present Value of Loss

ference for increasing return. Figure B.1 also exhibits decreasing marginal utility in the direction of increasing preference which would indicate that preference asymptotically approaches an upper bound at high levels of return (i.e., at sufficiently high returns negligible additional investment incentive is provided by increasing the return¹).

Payback Time. Figure B.2 illustrates the utility functions for payback time, $U_p(p)$, which are produced from this assessment. It may be noted that the curves in Figure B.2 are everywhere monotonic decreasing with increasing payback time which is consistent with decreasing industry preferences for long paybacks. Figure B.2 also exhibits decreasing marginal utility as payback times get very short which would indicate that, at sufficiently short payback times, there is negligible additional investment incentive provided by further reduction in payback time.

It is also interesting to note that payback times in line with those of 8-10 years as estimated for outer continental shelf oil ventures are just above neutral preference (i.e., $U = 0.5$) for the major producers. This same payback period is below neutral preferences for the smaller firms, one of which indicated in a personal interview that available venture capital requires, at most, a 7 year payback.²

¹ t-statistics for the regression parameters of the corporate producers curve are at the 90% and 99% level of confidence; for the independent producer curve they are at the 80% and 99% level. Coefficients of determination (R^2) are 0.48 and 0.73 for the two curves, respectively.

² t-statistics for the corporate producer curve and for the independent producer curve are at the 99% level of confidence; coefficients of determination (R^2) for the two curves are 0.86 and 0.90, respectively.

Present Value of Profits. Figure B.3 illustrates the utility functions for net present value of profits, $U_V(v)$, which were produced from this analysis. From Figure B.3 it is interesting to note that the utility curve for the small firm is reasonably consistent with that found by Grayson (1960) for a small operator. Grayson's curve appears to asymptotically approach a maximum preference at monetary gains in excess of \$1 million. The value today of \$1 million in 1958 (the time of Grayson's work) is \$2-3 million which is consistent with the lower limit of values in Figure B.3 that approach maximum preference.

It is also interesting to note that the utility curve for the major producers demonstrates neutral preference (i.e., $U = 0.5$) at monetary gains of \$5-10 million and near maximum preference at about \$50 million. According to Greider (1978), a 5-10 million barrel onshore oil field is an average discovery and has a net present value of \$6-10 million. A 40 million barrel discovery is highly attractive, but rare, and has an estimated N.P.V. of \$43 million. These estimates for "average" and "attractive" N.P.V.'s are consistent with the "neutral" and "high" preference values shown in Figure B.3.³

Capital Loss. The utility -- or more appropriately the disutility or aversion -- associated with various levels of monetary loss is estimated by the following method:

³ t-statistics for the corporate producer curve are at the 80% to 90% level of confidence; those for the independent producer are all at the 99% level. Coefficients of determination (R^2) for the two curves are 0.70 and 0.85, respectively.

Industry decision makers were presented with sixteen hypothetical lotteries in which two outcomes were possible: there was possibility P_j that a monetary loss, L_i , would be incurred and probability, $1-P_j$, that a monetary gain would be received. The gain was defined as the "maximum realistic gain" possible from a venture. Preferences for the sixteen combinations of four values of P_j and four values of L_i were provided by the decision maker on a 12-point scale.

The preference scale was normalized between zero, at the least preferable combination(s) of P_j and L_i , and one, at the most preferable combination(s). Industry responses were interpreted as being the expected utility of each lottery which was:

$$EU_{ij} = P_j U(L_i) + (1-P_j) U(G) \quad (B.1)$$

The utility of the "maximum realistic gain," $U(G)$, was defined at the maximum value of one. It follows that:

$$U(L_i) = 1 - \frac{1 - EU_{ij}}{P_j} \quad (B.2)$$

After testing the industry data for heteroskedasticity, as discussed earlier, simple or weighted least squares techniques were employed to regress the data and produce the utility functions for monetary loss, $U_L(v)$, as illustrated in Figure B.4.

It is interesting to note that, according to Figure B.4, a major corporation shows fairly strong aversion to risks in the hundreds of millions of dollars while the smaller firm shows the same aversion to losses in the millions of dollars. Recent reports of exploratory oil drilling activities by major firms on the outer continental shelf indicate investment losses of \$60-\$150 million prior to abandonment.

These reports are consistent with Figure B.4. The risk aversion levels of the smaller firms represent a major fraction of their total assets which is not unexpected for independent, "wildcatting" operators.⁴

Multiattribute Utility Analysis. When assessing an opportunity having uncertain, probabilistic outcomes, a resource producing firm is concerned with three attributes if an outcome represents a monetary gain:

- rate of return on investment (r)
- investment payback time (p), and
- net present value of profits ($V > 0$).

If an outcome represents a monetary loss, the firm is concerned with one attribute:

- net present value of investment at risk ($V < 0$).

Conditional preferences for these four attributes are expressed in terms of the univariate utility functions -- U_R , U_P , U_V and U_L respectively -- as discussed above.

Multiobjective preferences for the positive outcomes (i.e., outcomes representing a monetary gain) are expressed in terms of a multiattribute utility function which is a nested function of the three conditional univariate utility functions:

$$U = f [U_R(r), U_P(p), U_V(v)] \quad \text{if } v > 0. \quad (\text{B.3})$$

⁴ t-statistics for the corporate producer curve and for the independent producer curve are at the 99% level of confidence. Coefficients of determination (R^2) are 0.31 and 0.62 for the two curves, respectively.

Aversions to a monetary loss are expressed in terms of the univariate utility functions:

$$U = U_L(v) \quad \text{if } v \leq 0. \quad (\text{B.4})$$

To estimate the functional form of the multiattribute utility function, f , in equation (B.3), industry decision responses were observed at 80 combinations of the three attributes. After statistically testing for properties of utility independence (see Cassel, 1979), a step-wise multiple regression analysis was employed to converge on the most efficient multilinear form of f . Separate regression analyses were performed for the major corporate firms and for the independently operating firms.

For the major corporate firms, the resulting functional form of multiattribute utility is:⁵

$$U = \begin{cases} k_{11}U_R(\tilde{r}) + k_{12}U_V(\tilde{v}) + k_{13}U_R(\tilde{r})U_P(\tilde{p}) & \text{for } \tilde{v} > 0 \\ U_L(\tilde{v}) & \text{for } \tilde{v} \leq 0 \end{cases} \quad (\text{B.5})$$

and for the independently operating firms the resulting functional form is:

$$U = \begin{cases} k_{31}U_V(\tilde{v}) + k_{32}U_R(\tilde{r})U_V(\tilde{v}) + k_{33}U_R(\tilde{r})U_P(\tilde{p})U_V(\tilde{v}) & \text{for } \tilde{v} > 0 \\ U_L(\tilde{v}) & \text{for } \tilde{v} \leq 0 \end{cases} \quad (\text{B.6})$$

An explanation of investment behavior by potential geothermal resource producers is provided by inspection of the multiattribute utility functions given in equations (B.5) and (B.6). Decisions by major resource corporations appear heavily weighted by the uncon-

⁵ t-statistics for all "k" coefficients in both equation (B.5) and (B.6) are at the 99% level of confidence as are the F-statistics which test the joint confidence of the three additive terms. Coefficients of determination (R²) for the two equations are 0.86 and 0.83, respectively.

ditional rate of return offered by an investment opportunity. This is consistent with both investment theory and the industry interviews discussed earlier. Anticipated payback time enters into the decision process only conditional upon a satisfactory rate of return; however, the combined influence of rate of return and payback time is strong. The influence of unconditional net present value of profits offered by an opportunity is appreciable but carries only a fraction of the weight of the rate of return criterion.

Decisions by the independent operators appear very heavily influenced by the conditional net present value of profits offered by an investment opportunity. The rate of return criterion is conditional upon satisfactory N.P.V. of profits and the payback time criterion is conditional upon both satisfactory rate of return and satisfactory N.P.V. of profits. The joint influence of rate of return and N.P.V. of profits is strong as is the joint influence of rate of return, N.P.V. of profits, and payback time. The unconditional influence of N.P.V. of profits is appreciable but not strong if the other two criteria are not satisfactory.

Probabilistic Logit Analysis of Positive Response. When choosing among alternatives with uncertain outcomes (i.e., opportunities characterized by probabilistic gains and losses) rational decision makers behave as maximizers of "expected utility"; that is, they will select opportunities offering the highest expected utility, EU:

$$E_U = \sum U_i \Pi_i \quad (B.7)$$

where U_i is the utility of outcome i and Π_i is its probability of occurrence. Expected utility, EU, is the explanatory variable for rational decision behavior under conditions of uncertainty.

Theoretic literature on probabilistic models of binary choice (see Cassel, 1979) presents several models for making estimates of individual decision behavior (i.e., the probability that one will choose rather than reject opportunity A as a function of one's utility for A). One particular model, the "logit" model, is selected for application here on the basis of conceptual propriety and analytical simplicity compared to alternative linear and "probit" models.

The logit model employed in this analysis is of the form:

$$P(A/EU_A) = \frac{1}{1 + e^{-EU_A}} \quad (B.8)$$

which represents the probability of selecting opportunity A conditional upon the expected utility of A, EU_A . Figure B.5 illustrates the general form of the logit model. The parameters of (B.8) were estimated separately for the major corporate firms and the independently operating firms by applying least squares regression techniques to the industry-supplied investment behavior data.⁶

B.2 Electric Utilities' Decision Model

Over the past two years, Technecon has surveyed eighteen investor-owned and municipal electric utilities to determine their decision criteria for hydrothermal power plant investments. As a regulated and capital intensive industry, the utilities' investment objectives are understandably different from those of the unregulated and profit-oriented resource developers discussed above. Four investment objectives were found to be of primary concern to decisionmakers within the electric utility industry. These objectives are to:

⁶ t-statistics to the parameters are at the 99% level of confidence for both the major corporate model and the independent operator model.

Figure B.5
The Logit Model of Probabilistic Choice

- minimize ratepayers' burden (as assessed in terms of the ratio of the cost -- in mills/kWh -- of alternative baseload generation delivered to a main transmission corridor to that of the hydrothermal generation)
- maintain desirable margins of generation reserve by matching baseload growth profiles (as assessed in terms of the megawatt capacity of the hydrothermal power plant)
- maximize generation system reliability (as assessed in terms of the anticipated capacity factor of the hydrothermal power plant)
- minimize adverse effects on the availability and cost of construction capital (as assessed in terms of the impact upon the "times interest earned ratio" -- TIER, a measure of bond health -- of a probabilistic hydrothermal failure).

The quality of a hydrothermal power plant project is assessed by the four attributes given in parentheses above, i.e., electricity cost ratio, reservoir capacity, plant capacity factor, and TIER impact. The degree to which each of these attributes meets the electric utilities' investment objectives may be expressed in terms of "numerical utility."⁷ As defined earlier under heading B.1, a minimum utility of zero implies "no investment incentive" and a maximum utility of one implies "highest positive incentive."

Utility functions were estimated for the four power plant attributes by applying the same statistical procedures outlined under heading B.1 to industry-supplied decision data. The results of this analysis, as illustrated in Figures B.6, B.7, B.8, and B.9, are utility functions of electricity cost ratio $U_C(c)$, reservoir capacity

⁷ To avoid confusion between electric utilities (companies) and numerical utilities (preferences), the former will always be prefaced with electric.

Figure B.6
Electric Energy Cost Ratio

Figure B.7
Reservoir Capacity

Figure B.8
Capacity Factor

Figure B.9
Times-Interest-Earned Ratio Decrease

$U_M(m)$, plant capacity factor $U_F(f)$, and TIER impact $U_T(t)$, respectively.⁸

Electricity Cost Ratio. As indicated in Figure B.6, electric utilities express no desire to use hydrothermal generation if an alternative type of baseload generation is available at less than 65% of the hydrothermal cost. The electric utilities utility (preference) for hydrothermal power increases steadily from this 65% value and approaches a maximum level of preference when the alternative generation is about 50% more costly than hydrothermal. Hydrothermal utility is marginally diminishing at high cost ratios and approaches an asymptote which indicates that a level of sufficiently favorable economics exists beyond which there is little additional incentive to be gained by reducing hydrothermal costs.⁹

Reservoir Capacity. Industry responses to questions of preference for hydrothermal generation as a function of the megawatt capacity of a resource varied, according to the size of an electric utility's system demand. As shown in Figure B.7, small municipal and rural electric utilities expressed a fairly high preference for generation sources of 20 to 50 megawatts. Larger electric utility systems, on the other hand, expressed the same high level of preference for generation sources of 200 to 300 megawatts. Disaggregation of industry responses into two groups depending on

⁸ In Figure B.6 through B.9 the term "preference level" has been introduced in place of "utility." The terms may be considered synonymous for the purposes of this report.

⁹ t-statistics for the regression parameters of the electric utilities cost ratio curve are at the 99% level of confidence; the curves' coefficient of determination is 0.75.

system baseload demand provided the statistically-sound regression results shown in Figure B.7.¹⁰

Plant Capacity Factor. Capacity factor is the fraction of the hours in a year during which a power plant is in commercial operation. It provides a measure of outage due to forced and scheduled maintenance as well as discretionary down-time due to lack of system demand. Hydrothermal generation is viewed throughout the electric utility industry as baseload generation and, as such, hydrothermal power plants will be required to maintain relatively high capacity factors. Baseload generation typically has a reliable capacity factor in the range of 0.65 to 0.85. Figure B.8 was developed from industry responses and is consistent with capacity factor expectations as published in electric power literature.¹¹

TIER Impact. The financial conditions of the utility can play an important role in the capacity expansion decision. Because of the capital-intensive nature of the industry, utilities need to maintain ready access to capital markets at interest rates that are not excessive. The generation expansion planning process must be careful to incorporate any financial limitations of the utility, and the general conditions of the current financial market. Failure to include these financial parameters in the ultimate decision may result in a high cost of capital or, in the extreme case, a total inability to raise needed capital in the financial market.

¹⁰ t-statistics and F-statistics for the regression parameters of the reservoir capacity curves are at the 99% level of confidence; the curves' coefficient of determination is 0.63.

¹¹ t-statistics for the regression parameters of the capacity factor curve are at the 99% level of confidence; the curves' coefficient of determination is 0.82.

Capacity additions may be financed with debt issues, equity issues, and internally generated funds. Because of the increasing capital expenditure requirements of the industry, primary reliance is placed on debt issues and equity issues (both common and preferred stock). Debt issues and preferred stock are the least expensive source of capital available to the utility. Expansion programs cannot be financed exclusively by low cost debt issues, however. Utilities have optimal capital structures which determine the proportion of long term debt, preferred stock and common stock which will minimize overall capital cost. Recently the optimal capital structure is approximately 50 percent long term debt, 15 percent preferred stock, and 35 percent common stock.

The ability of a utility to finance a proposed capacity addition is tied to the bond rating assigned to its debt issues. The bond rating procedure involves the analysis of a wide variety of factors impacting the economic health of the utility, including:

- 1) economic analysis of service area
- 2) type of system
- 3) facilities
- 4) capital improvements plan
- 5) rate structure
- 6) bond security
- 7) key financial ratios

The most important of these criteria are the key financial ratios describing the utility's ability to repay debt issues (Rand, 1977; Standard and Poor's, 1976 and 1978). These include the pretax and after-tax coverage ratios (called "times interest earned ratios," TIER) defined by:

After-tax coverage ratio	$\frac{(\text{after taxes}) \text{ Net Income before Interest Expenses}}{\text{Interest Expenses}}$
--------------------------	---

Pretax coverage ratio	$\frac{\text{Net Income before Taxes and Interest Expenses}}{\text{Interest Expenses}}$
-----------------------	---

Standard and Poor's Corporation suggests the following general relationship between pretax TIER coverage, bond rating, and cost of capital (Standard and Poor's, 1976).

<u>TIER</u>	<u>Bond Rating</u>	<u>Average Yield</u>
3.0 - 3.5	AA	11.0%
2.5 - 2.75	A	11.3%
< 2.0	BBB	12.1%

Capacity expansion programs must, therefore, be carefully structured to avoid lowering the debt service coverage ratios below the threshold levels cited above. Should a new debt issue have to be derated, interest charges can be expected to rise accordingly. Further, the ability to finance additional future construction projects may be effectively eliminated if a utility finds itself with minimum coverage ratios, as specified in the utility's covenant requirements.

Hydrothermal plant additions may have one of two effects on the critical debt service coverage ratios of the utility. If the plant provides a reliable source of power over its 20-30 year service life, the utility would increase in its debt service ratios by replacing more capital intensive conventional base load units with hydrothermal capacity. Further, if hydrothermal power proved to have lower variable costs per kWh, the earnings or net income of the utility would be enhanced. Both of these factors would leave the utility in a more secure capital position over the conventional base load option, with

a lower overall cost of capital.

Potentially adverse financial consequences could result from a major failure of the hydrothermal plant, however. Loss of any hydrothermal unit would force the utility to purchase more expensive power, causing a reduction in net income if rates were not immediately increased. In the case of a privately-owned utility, the remaining undepreciated value of the plant could be removed from the rate base at the discretion of the public utility commission. The utility would no longer be able to earn the regulated rate of return of the hydrothermal plant, further compounding the utility's financial dilemma. The impact that such potential plant or reservoir failures may have on debt coverage ratios and bond rating must be carefully analyzed. Hydrothermal investment may be deferred or effectively eliminated if the probability of plant failure and its subsequent financial impacts is thought to seriously jeopardize the utility's access to capital markets. Figure B.9 illustrates the utility function of TIER impact which was developed by a regression analysis of industry survey responses.¹²

As discussed in Section 2, three consulting geothermal reservoir engineers and geologists were retained by Technecon to assess the numerical probabilities of premature reservoir failure over the 30 year book life of a hydrothermal power plant. These assessments were coupled with the power plant cash flow model to estimate probabilis-

¹² T-statistics for the regression parameters of the TIER curve are at the 99% level of confidence; the curves' coefficient of determination is 0.93.

tic impacts on an electric utility's TIER.

Multiattribute Utility Analysis. Conditional preferences for the four primary attributes of a power plant investment are expressed in terms of the four univariate functions -- U_C , U_M , U_F and U_T -- as discussed above. These univariate functions are combined into a single multiattribute measure of multiobjective preference by statistical regression of industry-supplied data as discussed under heading B.1. The resulting functional form of a multiattribute utility for electric utilities is:¹³

$$U = k_1 U_C(\bar{c}) U_F(\bar{f}) + k_2 U_C(\bar{c}) U_M(\bar{m}) + k_3 U_C(\bar{c}) U_T(\bar{t}) \quad (B.9)$$

Inspection of equation B.9 indicates that an electric utility's decision to invest in a hydrothermal project is heavily influenced by the economics of hydrothermal generation relative to alternative forms of conventional baseload generation. The electricity cost ratio utility $U_C(\bar{c})$ enters into every term of the equation. All other attributes (i.e., capacity factor f , reservoir capacity m , and TIER impact t) enter into the decision process conditional upon economic considerations.

Probability of Positive Response. Given the uncertainties associated with hydrothermal projects, probability distributions are associated with each of four project attributes. This produces a probabilistic measure of multiattribute utility (U in equation B.9) such that a numerical probability Π_i is associated with each multiattribute utility U_i . As discussed earlier under heading B.1,

¹³ t-statistics and F-statistics for equation B.9 are all at the 99% level of confidence; the coefficient of determination (corrected for degrees of freedom) is 0.74.

rational decision makers select opportunities having the highest "expected utility" E_U , where:

$$E_U = \sum U_i \Pi_i \quad (B.7)$$

Estimates of the numerical likelihood that an electric utility will respond positively to a hydrothermal opportunity are provided by a logit model (as discussed earlier) of the form:

$$P = \frac{1}{1 + e^{\alpha - \beta \cdot E_U}} \quad (B.8)$$

where the α and β parameters are estimated by regression analysis of decision data provided by the electric utility industry.¹⁴

The logit decision models of both the hydrothermal resource development industry and the electric utility industry are statistically strong. Furthermore, results of the model's applications to date are well supported by the actual behavior of these industries.

B.3 Joint Decision Modeling

As discussed in Section 2, the cash flow models (and related investment decision models) of the well field and power plant are coupled by a negotiable resource selling price. The price at which the resource developer sells hydrothermal fluid to the electric utility is modeled as that price which maximizes the joint likelihood of positive investment decisions by both parties. This price is arrived at by an iterative technique that converges on the optimal value.

The iterative technique selected by Technecon for this applica-

¹⁴ T-statistics for the α and β parameters of the electric utility logit model are at the 99% level of confidence. The models' coefficient of determination is 0.74.

tion is known as a Fibonacci search. The Fibonacci search is a classical search procedure developed in the early 1950's by Kiefer (1953) and Johnson (1956) that located the optimal value of an arbitrary unimodal function over a given interval with a theoretically minimal number of functional evaluations. The key to the search procedure is that if the search intervals are selected according to a sequence of Fibonacci numbers, the extreme points of successive search intervals are computed in the previous search iteration, i.e., given the Fibonacci sequence:

$$F_1 = 1; F_2 = 2$$

$$F_n = F_{n-1} + F_{n-2} \text{ for } n > 2$$

successive search interval sizes can be shown to be the following the relationship

$$L_n = L_i \left(\frac{1}{F_n} \right)$$

For example, after only 8 functional evaluations the interval of uncertainty of the maximum will be $1/F_8 = 1/34$ or less than 3% of the original interval.

In the problem of finding the hydrothermal resource price that maximizes the joint probability of undertaking the venture, it is reasonably assumed that the probabilities of positive decisions by the resource developer and electric utility are monotonic increasing and decreasing functions, respectively, with resource price. Hence, the joint probability of a positive decision is a unimodal function of resource price and can be resolved by use of the Fibonacci search technique.

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