488 2/28/80 DR 763

DOE/RA/4713-1 MASTER

Geothermal Investment and Policy Analysis With Evaluation of California and Utah Resource Areas

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Prepared for:
U.S. Department of Energy
Assistant Secretary for Resource Application
Division of Geothermal Resource Management
Under Contract No. ET-78-S-02-4713A001

Available from:

National Technical Information Service (NTIS)
U.S. Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22161

Price: Printed copy: \$8.00
Microfiche: \$3.00

DOE/RA/4713-1
Distribution Category UC-66i

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Geothermal Investment and Policy Analysis With Evaluation of California and Utah Resource Areas

October 1979

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Under Contract No. ET-78-S-02-4713A001

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Washington, D.C. 20545

ABSTRACT

As part of its mission-oriented program for accelerating the commercialization of geothermal energy, the U.S. Department of Energy is sponsoring research at Technecon Analytic Research, Inc., Philadelphia, and the University of Pennsylvania which concerns the analysis and modeling of investment decisions in the development of hydrothermal well fields. This investment behavior reflects a degree of sensitivity to public policy alternatives concerning taxation and regulation of the resource and its energy conversion facilities. The purpose of the current research is to provide a realistic and statistically sound means for estimating the impacts of such policy alternatives on likely industry investment decisions.

In approaching the expressed objectives, Technecon researchers (under subcontract to the University) have developed a geothermal investment decision model which, when coupled to a site-specific stochastic cash flow model, estimates the conditional probability of a positive decision to invest in the development of geothermal resource areas. This report describes the geothermal cash flow model, the investment decision model and their applications for assessing the likely development potential of nine geothermal resource areas in California and Utah. The sensitivity of this investment behavior to several policy incentives is also analyzed and discussed.

PREFACE

This report is an account of research into the investment practices of geothermal resource firms. Throughout these investigations, a generous degree of cooperation and participation by the resource industry has been received. Many hours of management interviews and a high response rate to sequential mailings of multi-page surveys were contributed during the course of this work.

The decision model which evolved from analysis of the industry's responses takes the form of a weighted function of multiple investment criteria. Some of these criteria were explicitly discussed in management interviews while others were implicit but, none the less, found to be important concerns in subsequent studies of industry investments.

The decision model represents a new approach to investment analysis, though its components and their collective influence upon company decisions should be familiar and apparent to individuals within the industry. Of primary importance is the model's capacity to realistically reproduce or estimate industry investment decisions at a statistically sound level of confidence. Decision makers within the industry are invited to assess these analytic techniques, particularly for their usefulness in evaluating new and uncertain investment opportunities where risk and project size are likely to be as important a concern as investment return. Practiced methods for estimating investment return, itself, are assessed in this work and recommendations are offered for appropriate modifications to these methods, particularly for evaluating geothermal opportunities.

The report is organized as follows:

- <u>Chapter One</u> summarizes the project, its methods, results and on-going investigations.
- <u>Chapter Two</u> discusses the development of a stochastic cash flow model which accounts for probabilistic resource data in its evaluation of the financial attributes and risks of a geothermal venture. Methods for competitively pricing a geothermal resource are discussed in considerable detail.

- Chapter Three discusses the concerns of decision makers within the resource industry and the methodology for incorporating these concerns into a model which estimates the probability of favorable investment decisions. Decisions by major corporations and by independently operated firms are modeled separately.
- Chapter Four presents an evaluation of likely investment behavior at nine geothermal resource areas in California and Utah. Sensitivity to resource pricing is investigated for its effect upon investment decisions by both major corporations and independent operators.
- Chapter Five is an evaluation of several incentives for geothermal development and their likely effect upon investment behavior at a given resource site. Loan guarantees, price supports and tax incentives are among the policy alternatives which are evaluated.

This work was sponsored over the past two years by Dr. Fred Abel and Dr. Inja Paik of the U.S. Department of Energy, Washington, D.C. Throughout the project, they, Mr. Randy Stephens and Dr. Lou Werner provided valuable support and constructive comments. Significant help in data gathering and analysis tasks was provided by research assistants assigned to the project by the University of Pennsylvania; namely Michael Ervolini, David Tarbel and B. Venkateshwara. Mrs. Norma Crouse of Technecon is credited for her patient formating and typing of the entire report.

Personal interviews and information were provided by no fewer than eighty individuals during the course of this work. These industry participants -- who are too numerous to individually acknowledge here -- represented twenty resource firms, thirteen electric utilities, and several banks, investment firms and government agencies. Their contributions of both time and effort are largely responsible for the results provided in this report.

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Chapter One

EXECUTIVE SUMMARY

1.1 BACKGROUND AND PURPOSE

In the mid-1950's, the pioneering efforts of B.C. McCabe and his partners in Magma Power Company produced the first commercial steam well at the Geysers in northern California. Today -- following joint development by Magma, Thermal Power Company, Pacific Gas and Electric Company and Union Oil Company of California -- natural steam from the Geysers supports the world's largest geothermal electric power complex. Geothermal electric power currently supplies a significant fraction of the generation load in northern California at costs which are competitive with any fossil-fueled or nuclear alternative.

The technological and economic success at the Geysers, coupled with today's domestic concern for energy alternatives, have contributed to a rapidly expanding and active national interest in geothermal energy. A geothermal resource base capable of supporting several thousands of megawatts of generation capacity has been identified in the United States and its development is progressing, albeit cautiously, at many areas. The rate and extent to which this resource is developed will depend upon the rate and extent to which industry will invest capital into well field exploration and development projects. The understanding and estimation of this investment behavior, and of incentives which will prompt positive industry response, are the topics of this report.

1.2 GEOTHERMAL INVESTMENT ANALYSIS

1.2.1 Investment Decisions

As witnessed at the Geysers, the large scale commercialization of hydrothermal[1] electric power will depend upon joint positive decisions by resource producing firms to develop well fields and by electric utilities to construct on-site power plants and transmission facilities. This report focuses on the investment decision of the resource producers, conditional upon specified assumptions regarding the electric utilities' decision[2].

Geothermal resource producers comprise a spectrum of firms from multinational diversified corporations with total assets in multi-billions of dollars to independently operating firms whose activities are largely financed through limited partnership agreements. Twenty of these firms, including both size extremes, actively participated in this project as discussed below.

Management interviews and voluntary checklist responses from the twenty participating firms illustrate that, regardless of asset strength, each firm is concerned with four investment objectives. These objectives are to:

- maximize the efficiency of invested capital (assessed in terms of rate of return on investment)
- minimize the duration of investment risk (assessed in terms of investment payback time)
- undertake projects which are compatible with the firm's scale of operation (assessed in terms of net present value of profits)
- avoid financial ruin (assessed in terms of the capital loss at risk).

The degree to which an investment opportunity meets the several objectives of a firm may be measured in terms of the four quantifiable financial attributes listed parenthetically above.

A statistical analysis of industry responses and investment behavior indicates that a firm's relative preference for, or aversion to,

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[1]Geothermal resources, as the name implies, originate from heat in the earth's magma core. When a geologic anomaly brings this heat to within a few miles of the earth's surface, it may be tapped by present well drilling technology. This report deals with one type of geothermal resource, namely hydrothermal energy, which occurs when such an anomaly and a natural aquifer coexist--the result being a subterranean reservoir of steam and/or hot water. Other types of geothermal resources, which are not as near term as the hydrothermal resource, include geopressured reservoirs in which the water in deep, high pressure hydrothermal reservoirs is saturated with methane gas, and hot dry rock resources which, as the name implies, have no aquifer. See Muffler (1979).

[2]On-going work as this report is being published, is directed at the electric utilities' decision to include geothermal power in their generation mix.

the four financial attributes of a proposed venture will vary depending upon the size of the firm, the availability and cost of capital, and the quality of its alternative investment opportunities. For the purposes of this analysis, it was found that the decision behavior of the resource producing industry could be effectively modeled by dividing the several firms into two catagories: major corporations, primarily in the oil and gas industry, with assets usually exceeding one billion dollars and independently operating firms with assets of usually less than $100 million.

By integrating and applying two decision analysis techniques[3]-- namely, "multiattribute utility" methods for multiobjective decision analysis, and "logit" methods for probabilistic choice estimation -- a computer model was constructed which estimates the probability of a favorable investment decision, by either a major corporate resource producer or an independent operator, in a given geothermal venture. This computerized decision model, labeled TCN2080, is based upon industry-supplied data and appears both statistically sound and realistic in its estimation capabilities.

1.2.2 Cash Flow Analysis

To estimate investment behavior at specified hydrothermal resource areas, the above mentioned decision model requires probabilistic estimates of the investment opportunity's four financial attributes: rate of return, payback time, net present value of profits and the amount of capital exposed to risk. A hydrothermal financial analysis model, labeled TCN2000, was developed to provide the required estimates. This model uses site-specific parameters to simulate well field development and all cash flows associated with well field exploration, confirmation, development and production. To accommodate uncertainties in available resource data, nine site variables (wellhead temperature, well flow rate, dry well fraction, well life, resource depth, well cost, plant capacity factor, plant cost, and piping cost) are either supplied to the model,

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[3]The decision analysis is summarized in Chapter Three; for those desiring a more rigorous theoretical justification, see Cassel (1979).

or estimated by the model, in the form of site-specific probability distributions.

In total, the financial analysis model requires 75 input variables to define the geologic, economic and financial parameters of a well field investment opportunity. The model begins execution by simulating requirements for active producing wells, spare wells, injection wells, redrilled wells and dry wells over the life of a project. During execution, it estimates 24 cash flow items including book and tax capital, book and tax expenses, long life and short life depreciation, revenues, depletion, ad valorem taxes, royalties, and income taxes. The cash flow analysis is performed probabilistically and is completed by the estimation of:

- Internal rate of return for measuring the efficiency of investments by independently operating resource firms;
- Financial management rate of return for measuring the efficiency of investments by major resource corporations;
- Weighted average discounted payback time for estimating risk duration for a series of investments;
- Net present value of profits; and
- The amount of investment capital exposed to risk.

The probability of incurring an investment loss is required for decision analysis along with the estimated amount of investment at risk. By relying upon site-specific mappings of levels of confidence over a resource area, as supplied by consulting geothermal geologists, the probability of loss is estimated at progressive levels of field development.

1.2.3 Competitive Resource Pricing

A concensus of interviews with management representatives of thirteen western electric utilities indicates that, for favorable consideration, geothermal electric energy must be competitive in cost to the least expensive alternative type of new baseload generation at the point of delivery to a major transmission corridor. A marginally competitive geothermal resource price can thus be estimated by taking the delivered electric energy cost of the competing alternative and subtracting from it the costs associated with a geothermal power plant and transmission facilities. The algorithm for estimating a competitive geothermal resource price is developed and applied in this report as the basis for estimating well field revenues.

Depending upon geographic location and resource quality, the marginally competitive resource price can vary significantly. In many Utah regions, for example, relatively inexpensive coal reserves result in a competitive geothermal resource price of 10-12 mills/kWh. In many California regions, on the other hand, alternative baseload generation is relatively expensive which boosts the competitive geothermal resource price to 14-20 mills/kWh. Site by site estimates of the marginally competitive selling price are provided in this report.

1.3 CALIFORNIA AND UTAH RESOURCE EVALUATIONS

From an extensive review of available literature and information provided by consulting geothermal geologists[4], data was compiled for nine Known Geothermal Resource Areas in California and Utah. These areas -- Brawley, Coso Hot Springs, East Mesa, Geysers, Heber, Mono-Long Valley, Salton Sea, Cove Fort-Sulphurdale and Roosevelt Hot Springs -- were selected for evaluation based upon their assumed potential for electric power generation and upon the availability of meaningful data.

Table 1-1 summarizes the estimated likelihood of investment by major resource corporations at the nine sites and Table 1-2 summarizes this likelihood of investment by independent operating resource firms. It must be noted that: (a) these investment estimates are based upon marginally competitive pricing of the geothermal resource, and (b) these estimates reflect the quality of information and levels of confidence as understood today at each site. The investment model will be periodically updated to accommodate new resource information as it becomes available.

1.3.1 Imperial Valley Resource Areas

Resources in the Imperial Valley of southern California are characterized by relatively inexpensive sedimentary well drilling costs and relatively high competitive resource prices. These factors contribute

[4]Eugene Ciancanelli, President of Cascadia Exploration Company, Escondido, California and Dr. Bill Smith of Republic Geothermal, Inc., Santa Fe Springs, California provided geologic data for the nine sites evaluated in this report.

TABLE 1-1. HYDROTHERMAL WELL FIELD DEVELOPMENT (MWe) BY MAJOR RESOURCE PRODUCING CORPORATIONS

	LIKELIHOOD OF INVESTMENT IN FIELD DEVELOPMENT						
	>95%	>90%	>75%	>50%	>25%	>10%	>5%
BRAWLEY	300	400	500	600	700	900	1000
COSO HOT SPRINGS	0	0	0	0	0	200	300
COVE FORT-SULPHURDALE	0	0	0	0	0	0	0
EAST MESA	200	200	300	400	400	400	600
GEYSERS (VAP.DOM.)[5]	1870	1870	1870	1980	2090	2090	2750
GEYSERS (LIQ. DOM.)	0	0	0	200	600	1200	3400
HEBER	200	300	400	500	600	800	900
MONO-LONG VALLEY	0	0	0	0	0	0	400
ROOSEVELT HOT SPRINGS	600	600	700	800	900	1000	1100
SALTON SEA	4500	5000	6000	7000	8000	9500	9500
TOTAL MEGAWATTS(e)	7670	8370	9770	11480	13290	16090	19950

TABLE 1-2. HYDROTHERMAL WELL FIELD DEVELOPMENT (MWe) BY INDEPENDENTLY OPERATING RESOURCE COMPANIES

	LIKELIHOOD OF INVESTMENT IN FIELD DEVELOPMENT						
	>95%	>90%	>75%	>50%	>25%	>10%	>5%
BRAWLEY	300	300	400	500	500	700	700
COSO HOT SPRINGS	0	0	0	0	0	0	0
COVE FORT-SULPHURDALE	0	0	0	0	0	0	0
EAST MESA	100	100	200	300	300	400	400
GEYSERS (VAP.DOM.)[5]	0	1870	1870	1870	1870	1870	1870
GEYSERS (LIQ.DOM.)	0	0	0	0	0	0	0
HEBER	100	200	300	300	500	600	600
MONO-LONG VALLEY	0	0	0	0	0	0	0
ROOSEVELT HOT SPRINGS	0	600	600	600	700	700	800
SALTON SEA	4000	4500	5000	6000	6500	7500	7500
TOTAL MEGAWATTS(e)	4500	7570	8370	9570	10370	11770	11870

[5]Represents development beyond Unit 15.

to attractive estimated investment returns at Brawley, East Mesa, Heber and Salton Sea[6] and result in a substantial resource base with a high likelihood of development. Low levels of confidence at peripheral sections of each resource area detract from investment attractiveness at expanded levels of development. Development estimates for Brawley, East Mesa and Heber are consistent with recent USGS estimates at these sites (see Muffler, 1979). The potential of the Salton Sea area is substantially greater than USGS estimates and represents an expanded assessment of this area which is consistent with a recent paper by Meidav, et al. (1979).

1.3.2 Eastern Sierra Resource Areas

The Coso Hot Springs and Mono-Long Valley resources in the Eastern Sierra region of California are characterized by moderately high competitive resource prices but by expensive costs for drilling wells in igneous geology. Exploration at these areas remains in its early stages and, as a result, levels of confidence are relatively low. These factors detract from the attractiveness of investments at these areas at present. The estimated investment returns at Mono indicate that, with an improvement in confidence brought about by continued exploration, this resource may provide substantial potential for development in the future. The Coso area, however, offers marginal returns and does not appear to be an attractive investment regardless of possible future improvements in confidence.

1.3.3 The Geysers

The Geysers in northern California is modeled as two reservoirs: a vapor-dominated reservoir southwest of the Collayami Fault and a liquid-dominated reservoir northeast of this fault. Substantial continued development of the vapor-dominated reservoir is estimated with high likelihood. Development of the liquid-dominated reservoir is hampered by low levels of confidence at present, and by expensive well costs. Estimated investment returns are marginal and will likely detract from

[6]The recently explored Westmoreland area in the Imperial Valley is excluded from evaluation because of a lack of meaningful data at present.

the attractiveness of the liquid-dominated resource despite possible future exploration and resulting enhanced confidence.

1.3.4 Utah Resource Areas

Cove Fort-Sulphurdale and Roosevelt Hot Springs in southern Utah are characterized by relatively expensive well costs for drilling through igneous rock and by relatively low competitive resource prices. These factors detract from the likelihood of investments at Cove Fort-Sulphurdale as the qualities of this resource are understood today. At Roosevelt Hot Springs, on the other hand, these factors are offset by high resource temperatures and high well flow rates. The present likelihood of investment at Roosevelt is high for substantial levels of development and is consistent with the potential of this resource as estimated by the USGS (see Muffler, 1979).

1.4 ANALYSIS OF INCENTIVES

The analytic capabilities of the geothermal investment model are demonstrated by assessing the likely impact of several incentives upon investment behavior at progressive levels of development of the Brawley resource. Results of these analyses are summarized below.

1.4.1 Joint Venture Arrangements

Joint venturing may provide a vehicle for some relatively small independent operators with limited supplies of capital to share the risk and rewards of geothermal ventures. The impact upon investment behavior at Brawley appears significant past the 300 megawatt level of development where development has extended out into the more risky areas of the resource. At these development levels, risk sharing by two independent firms provides an appreciable investment incentive. The marginal incentive, however, of a third firm joining the venture appears to be of minimal value.

1.4.2 Resource Pricing Variations

At Brawley an attempt to attract electric utility participation by reducing the resource price below the marginally competitive level will adversely affect likely investment behavior by either major corporate resource producers or, especially, independent producers. Increasing the resource price above the marginally competitive level appears to provide minimal added investment incentive to either large or small resource producers, with the exception of an independent operator looking at only the initial 50 megawatt level of field development. In this exception, the added selling price is of significant value in the recovery of front end resource "finding costs".

1.4.3 National Energy Act of 1978

The National Energy Act of 1978 provided geothermal resource developers with a package of tax incentives which included:

- The option to treat the intangible, 50% to 75% portion of a well's cost as a tax deductible expense;
- A 10% investment tax credit for "alternative energy property" -- excluding power plants owned by regulated utilities -- in addition to the tax credits otherwise allowed for invested capital;
- A percentage depletion allowance against gross income according to the following schedule:

through 1980:	22%
1981 :	20%
1982 :	18%
1983 :	16%
1984 & after:	15%.

These incentives, which are now legally permissible, are included in the evaluations presented earlier. To assess their impact, the investment model was modified to eliminate the incentives. Results indicate that both major corporate resource producers and independently operating producers show very significant positive reactions to these incentives. Of considerable value is the effect upon the smaller independents who, prior to the NEA, appear noticeably less willing to participate in development at Brawley than do the larger corporate producers.

1.4.4 Geothermal Loan Guarantee

The Federal geothermal loan guarantee program will provide government backing to commercial loans for up to 75% of the cost of a geothermal project. From industry interviews, it appears that this program will be of considerable value to well field development projects being undertaken by independently operating resource producers. Although the government adds 1% to the debt interest rate for administering the loan, the program provides access to relatively inexpensive debt capital which, otherwise, is difficult for equity-financed independent operators to obtain.

Major resource producing corporations and electric utilities, on the other hand, have existing access to debt capital and appear disinclined to use the Federal loan guarantee. Default provisions within the guarantee coupled with its filing and administration requirements tend to also detract form favorable consideration by these larger firms.

Results of the modeling simulation indicate that the loan guarantee program provides a very significant investment incentive to the independently operating resource producer at the Brawley area. The advantage of this program to the major corporate producers, on the other hand, appears minimal at best.

1.4.5 Maintaining 22% Depletion

As discussed above, the depletion allowance currently offered by the NEA will decline over the next few years from the present 22% to 15% in 1984. By modifying the cash flow model in TCN2000, the effect of maintaining this allowance at 22% was evaluated. Results indicate a relative insensitivity of likely investment behavior at Brawley to this modification in the depletion allowance schedule.

1.4.6 Additional Investment Tax Credits

Totally refundable investment tax credits of 20%, 30%, 40% and 50% for both well field capital and geothermal power plant capital were evaluated by modifying the Brawley cash flow analysis. Results indicate that totally refundable investment tax credits would provide a significant incentive to likely investment behavior at Brawley, particularly for the independently operating resource producers. Examination of the four levels of credits indicates that the greatest marginal incentive is provided by increasing the credit from 30% to 40%.

1.4.7 $3/bbl Equivalent Energy Production Tax Credit

A $3/bbl of oil equivalent energy production tax credit translates to a 4.3 mills/kWh credit by assuming a heating value of 153,600 Btu/gal for heavy oil and a heat rate of 9,300 Btu/kWh for an oil-fired steam power plant. The effect of this tax credit, if totally refundable and available to electric utility companies, will be to increase the marginally competitive price of a geothermal resource by 4.3 mills/kWh. The impact upon independently operating resource producers at Brawley is significant, particularly for investment limited to well field development for an initial 50 megawatts of electric power production.

1.4.8 Combined Production and Investment Tax Credits

The $3/bbl of oil equivalent energy production tax credit combined with the 50% investment tax credit are evaluated for their total effect upon likely investment behavior at Brawley. As before, the production tax credit translates to a 4.3 mills/kWh increase in the marginally competitive hydrothermal resource price which, in turn, provides increased production revenues to the resource producer. The 50% investment tax credit is assumed to be applicable to geothermal investments by both the electric utilities and the resource producers. Its effect is twofold: (1) it increased the competitive geothermal resource price by effectively reducing the utilities' capital cost for converting hydrothermal fluid to electricity, and (2) it reduces the effective capital investment required of the resource producers for well field development. Both the production tax credit and the investment tax credit are assumed to be totally refundable.

The tax credits afford a 38% increase in the competitive geothermal resource price at Brawley. The impact of the combined credits upon investment decisions at Brawley is likely to be significant for both major corporate producers and independently operating producers.

1.5 CONCLUSION

This report discusses a new approach to resource and policy analysis from the perspective of the investment decision maker. The value of this technique for assessing the economic potential of resources and technologies, and for assessing the likely effectiveness of policy incentives, is demonstrated herein. The likely impacts of R&D program objectives to reduce well costs, for example, or improve plant efficiencies or improve resource confidence can also be effectively evaluated by taking advantage of this analytic technique.

On-going work is focusing on a decision model for electric utilities which will be integrated with the resource producers' model being discussed here. The combined models will estimate the joint probability of favorable decisions to develop well fields and construct power facilities at given resource areas. Periodically the decision models will be updated to reflect changing preferences of the decision makers and changing financial and economic trends.

On-going work is also expanding the present California and Utah resource base to a national scope. This will facilitate analyses of the national impact of policy alternatives and provide the means for comprehensive resource assessments.

Chapter Two

HYDROTHERMAL FINANCIAL ANALYSIS MODEL (TCN2000)

A stochastic discounted cash flow model, TCN2000, is used to analyze hydrothermal well field investment opportunities. This model accounts for a time-series of capital investments, expenses, taxes, royalties and revenues incurred in the exploration, confirmation, development and production of hydrothermal resources for electric power generation.

With the cash flow model, probabilistic outcomes of a positive investment decision may be analyzed for each investment opportunity. For the hydrothermal well field projects being studied at present, the model provides probabilistic estimates of: (a) the rate of return on invested capital, (b) the investment payback time, and (c) the net present value of profits. The model also provides probabilistic estimates of (d) the amount of investment at risk and, based upon site-specific mappings of levels of confidence prepared by consulting geothermal geologists, the model estimates the likelihood that such loss will be incurred.

2.1 STOCHASTIC VARIABLES

Uncertainties in each hydrothermal investment opportunity are accommodated through probability distributions attached to nine key elements of the cash flow model. Power plant capacity factor, reservoir depth, well cost, dry well frequency, resource temperature, well flow rate, well life, surface piping cost, and power plant cost are uncertain to significant degrees and are, therefore, provided to the model in the form of site-specific density functions. Using iterative Monte Carlo simulation techniques, random variates are drawn from these density functions and are processed by the model. The Monte Carlo iterations produce probabilistic estimates of the four investment attributes (a thru d, above) which, together with the above mentioned likelihood of loss estimate, are necessary ingredients for investment decision analysis as discussed in Chapter 3.

As new and more substantial empirical data become available from hydrothermal developmental projects, the uncertainties associated with stochastic elements of the current model will be reduced. These new data will permit redefinition of the distribution functions associated with each variable and will refine the model's accuracy. Until such time as substantial new data are provided, significant uncertainty and investment risk will be characteristic of hydrothermal ventures.

2.2 PRE-PRODUCTION CASH FLOW

Table 2-1 presents the estimated costs of exploration, confirmation and development associated with one commercially viable hydrothermal discovery. These estimates represent a compromise between somewhat disparate figures found in recent literature[7] and information obtained through personal communication with industry experts.

Treatment of the several cost items, as to whether each is expensed as incurred or capitalized and subsequently amortized over a specified depreciable life, follows the suggestions of Greider (1974) and Porter (1965). Expensed items included regional or reconnaissance expenditures, exploration and confirmation expenditures on unretained land, unsuccessful well costs, and expenditures required to maintain commercial operations including rentals, royalties, taxes, and operating and maintenance costs. Capitalized items include exploration expenditures leading directly to acquisition or retention of land, lease bonuses, and capital costs for all surface facilities. For tax purposes, the intangible portion[8] of successful well costs is expensed and the tangible portion is capitalized. For book purposes, the total cost of a successful well is capitalized.

Pre-production cost elements not listed in Table 2-1 but which are included in TCN2000 are discussed below.

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[7] See EPRI (1976), Ward (1977) and University of Utah (1978).

[8] 50% (Ref. Sacarto, 1977) to 75% (Ref. EPRI, 1978) of a well's cost may be considered intangible and expensed as such for tax purposes.

TABLE 2-1

PRE-PRODUCTION COST ESTIMATE
FOR ONE PRODUCIBLE HYDROTHERMAL DISCOVERY

YEAR	PROCEDURES	AREAS[1]	CAPITALIZED COST	EXPENSED COST[2]
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[4]
	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[5]	Site-specific[6]	1,800,000[7]
	CONFIRMATION - Permits, 2 step-out wells[8] & injection wells - Sustained flow test	1	Site-specific[6]	0
6	MODELING & ENVIRONMENTAL STUDIES - Fault pattern definition - Environmental assessments - Consumer evaluations & negotiations	1	800,000	0
7	WELL FIELD ENGINEERING - 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 & injector wells - Construct surface piping	1	Site-specific[6,9]	Site-specific[10]

[1]One Area ≅ 7500 acres.

[2]Expenses will also include annual land rental, ad valorem taxes, and (for tax purposes) the intangible portion of capitalized well costs. The cash flow will also be credited with income tax refunds afforded by investment tax credits on installed wellfield capital and by deducting capital depreciation and expenses from unrelated taxable income. Refer to text.

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

[4]Equivalent to an average lease bonus of $11/acre on 17 unretained acres @ 7500 acres/area.

[5]Estimated success 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 mean response.

[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.

2.2.1 Rentals

Following acquisition, annual rental is paid on leased land until commercial production commences or until the land is relinquished (Porter, 1965). Annual rentals on public lands are typically $1 per acre, except on Federal KGRA land where the rent is $2 per acre. Rental rates on public lands may escalate by $1 per acre per year if diligent development has not progressed after five years from acquisition (U.S.B.L.M., 1978). Rental payments on private lands may be considerably higher until commercial production.

2.2.2 Ad Valorem Taxes

Local ad valorem tax liabilities vary from county to county in both rate and computational methodology. Lindsey and Supton (1976), Porter (1965), Sacarto (1977) and Wagner (1977) discuss ad valorem tax levies in considerable detail. For Utah resources in the Roosevelt/Cove Fort-Sulphurdale region, for example, annual ad valorem taxes are levied at a rate of 5 percent of 25 percent of the book value of installed well-field capital prior to commercial production and at 5 percent of gross revenues less expenses, resource depletion and capital depreciation during commercial production. For California resources in the Geysers area, ad valorem taxes prior to reservoir confirmation are levied at a rate of 4 percent of 25 percent of the lease cost. Once the reservoir is confirmed, the taxes are levied on the estimated before-tax net present value of the resource.

2.2.3 Deep Well Requirements

The required number of active producing wells is dependent upon the site-specific temperature of the resource, the flow rate per well and the capacity and performance of the power plant being supported by the well field. Resource temperature and well flow rate are treated stochastically in the investment model as discussed earlier in this chapter.

Power plant performance may be expressed in terms of net specific energy (watt hours generated per pound of hydrothermal fluid) as a function of the resource temperature. Figure 2-1 illustrates the relationship between net specific energy and resource temperature for liquid-

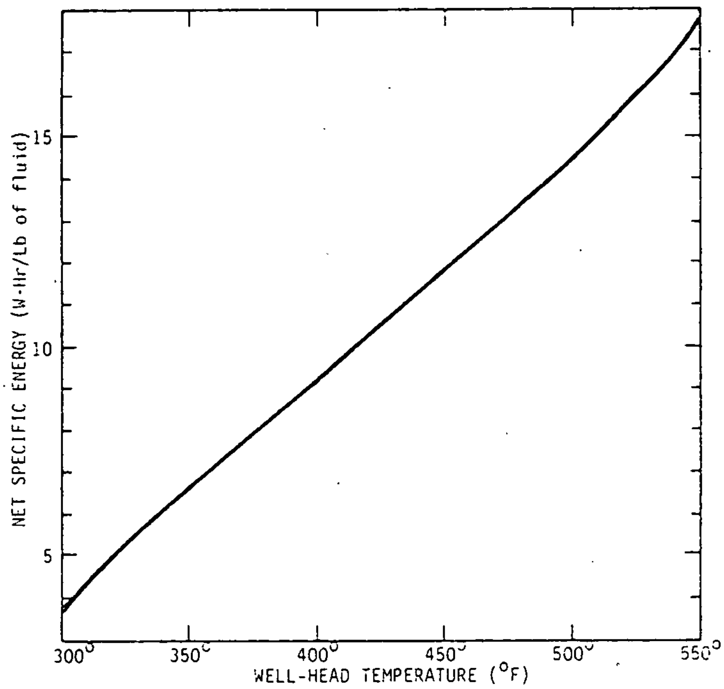

Figure 2-1. ENERGY CONVERSION EFFICIENCY
OF LIQUID-DOMINATED HYDROTHERMAL POWER PLANTS

dominated hydrothermal reservoirs as published by EPRI (1976)[9].

For investment modeling purposes, the active producing well requirement is estimated by the relation:

$$NACT = \left[kW \div \eta_s(T)\right] \div WF \qquad (2.1)$$

where kW represents the generation capacity being supported (kilowatts), η_s is the net specific energy at resource temperature T, and WF is the flow rate per active producer well (1000 lbs/hr).

Resource temperature and well flow rates may decline with time thereby increasing well requirements during production years. Although this resource drawdown phenomenon has been experienced at the Broadlands field in New Zealand (ref. Hitchcock and Bixley, 1976) and has been theoretically estimated for the Heber field in California (ref. Bechtel, 1977), it has not been experienced to any significant degree at the

[9] EPRI figures on net specific energy are in reasonable agreement with similar figures published by Bechtel (1976) and (1977).

Geysers to date. Drawdown effects may be controlled by reservoir management techniques and enhanced recovery methods. Blair and Cassel (1978) and Blair, et al. (1979) discuss the economic consequences of hydrothermal resource decline in considerable detail; however, because of its largely speculative nature at present, this phenomenon is not included in the present application of TCN2000.

In addition to the active producer wells drilled during field development, injector wells and spare producer wells are also required, the former to reinject spent geothermal fluid into the aquifer upon discharge from the power plant and the latter to provide a reasonable standby margin of reserve production capacity. The ratio of active producer to injector wells (PIR) is generally 2:1 according to industry data while the spare well fraction (SWF), i.e. fraction of total producing wells which represents spare capacity, varies from 0.25 to 0.10. Total deep well requirements for field development are therefore:

$$DRL = \left[1 + \frac{1}{PIR} + \frac{SWF}{1-SWF}\right] \times NACT \qquad (2.2)$$

2.2.4 Deep Well Costs

For investment modeling purposes, deep well costs were found to increase in proportion to the square of well depth when fit by least squares regression to available well cost data[10]. The resulting cost curves (shown in Figure 2-2) are:

$$\text{Sedimentary Geology:} \quad WC = .245 + \underset{(.0005)}{.0044}d^2 \qquad R^2 = .833$$

$$\text{Igneous Geology:} \quad WC = .378 + \underset{(.0035)}{.0211}d^2 \qquad R^2 = .72$$

with d expressed in thousands of feet and WC in millions of dollars for well, well head, and casing[11]. In TCN2000 both d and WC are treated as site-specific stochastic variables.

[10] Well cost data plotted in Figure 2-2 were provided by several resource producers and drilling firms, by Lawrence Berkeley Laboratories (1979) and by EPRI (1976).

[11] Standard error estimates from the regression analysis are given in parentheses. R^2 represents the coefficient of determination.

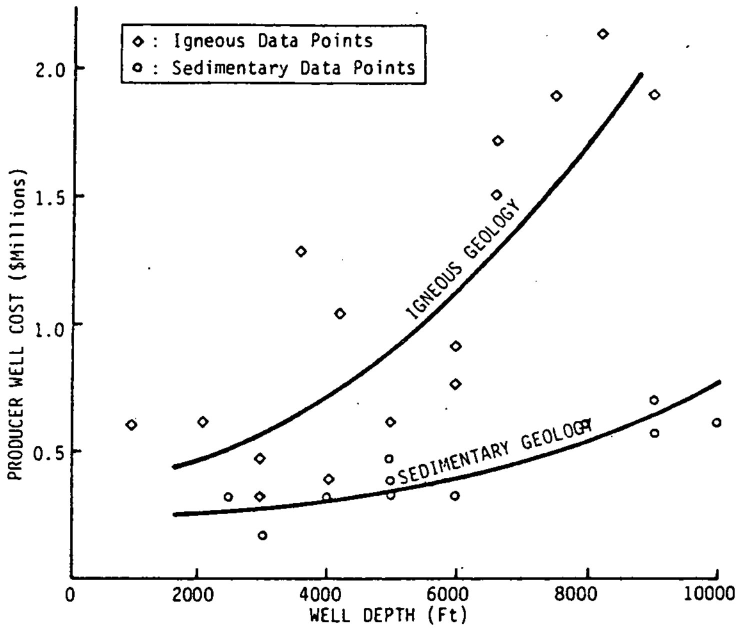

Figure 2-2. HYDROTHERMAL DEEP WELL COSTS

A fraction (IRD) of deep producer wells, typically about 30 percent based upon industry-supplied data, may be expected to require redrilling initially during field development to improve fluid flow. The cost of redrilling a well is estimated to be about 35 percent (RDC) of WC. The average cost during development of active and spare producer wells is therefore: {1 + IRD x RDC)} x WC.

During field development, a fraction (DWF) of the total number of wells drilled as producers are expected to be unsuccessful dry wells. This dry well fraction is treated as a site-specific stochastic variable in TCN2000. The expected number of dry wells is therefore:

$$DRY = \left[\frac{DWF}{1-DWF}\right] \times \left[1 + \frac{SWF}{1-SWF}\right] \times NACT \qquad (2.4)$$

Unsuccessful wells are not fully cased, and are estimated at 90 percent (DWC) of the cost (WC) of a successful deep well.

2.2.5 Surface Piping Costs

Published cost estimates for surface piping between the well heads and power plant are widely dispersed in the literature[12]. Figure 2-3 envelops these costs per kilowatt of generation capacity as a function of the temperature of a liquid-dominated resource. To accommodate the wide dispersion, for investment modeling purposes this capital cost is estimated as a site-specific stochastic variable dependent upon resource temperature.

TCN2000 treats surface piping costs as a well field capital investment for California resource areas. However, in the State of Utah, public policy pertaining to the transmission of sub-surface water will likely impose utility commission regulations upon the owner of the surface piping system. Hence, private resource producers, who seek to avoid regulation, indicate a preference for the regulated electric utility to own the surface piping system at Utah resource areas. TCN2000 treats surface piping costs as an additional power plant investment (refer to section 2.3.1) at Utah areas, rather than as a well field investment.

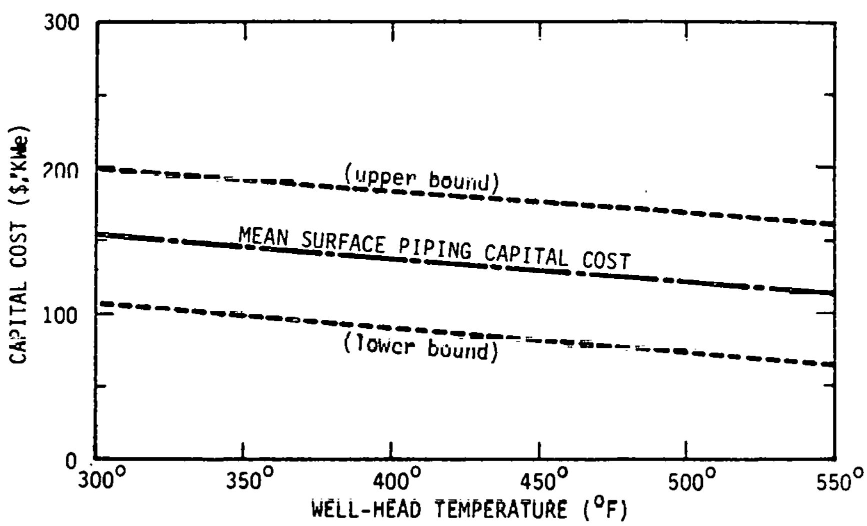

Figure 2-3. CAPITAL COST OF LIQUID-DOMINATED HYDROTHERMAL WELL FIELD SURFACE PIPING

[12]Ref. Bechtel (1977), Greider (1977) and information received in personal communication with industry contributors.

2.2.6 Income Tax Credits

Pre-production expenses, ad valorem taxes, interest on the borrowed portion of invested capital, and capital depreciation are assumed to be deductible from unrelated income for tax purposes. Reductions in income tax liability attributable to these deductions plus investment tax credits on installed well field capital combine to provide a positive credit to the resource producer's pre-production cash flow.

2.3 CASH FLOW DURING COMMERCIAL PRODUCTION

2.3.1 Resource Pricing and Revenues[13]

There is considerable literature and controversy concerning equitable pricing mechanisms for hydrothermal fluid, e.g. EPRI (1978), Finn (1975), Greider (1977), and Lindsey and Supton (1976). Legislative concern over so-called "windfall profits" to resource producers is exemplified by the California Senate Concurrent Resolution No. 37, passed on September 1, 1976, which initiated a study of regulatory policy alternatives for hydrothermal steam. After much analysis, the California State Energy Resources Conservation and Development Commission concluded that price regulation was neither warranted nor desirable from the perspective of promoting resource development.

In the absence of external price regulation, it is up to the resource producer (i.e. the seller) and the electric power producer (i.e. the buyer) to negotiate a mutually acceptable resource price. From the perspective of the electric power producer, the cost-competitiveness of hydrothermal electric energy may be determined at the point where this energy reaches a main transmission line corridor. At this point, the total energy cost - including fuel cost, power production costs, and apportioned transmission cost - competes with those costs of alternative forms of baseload generation, e.g., coal, nuclear, and oil-fired generation. Responses of nine western electric utilities to questions of concern for electric energy cost indicate that for favorable consideration, hydrothermal electric energy must be roughly competitive in cost to that

[13] This discussion is also presented by Cassel, et al. (1979a).

of the least expensive alternative form of baseload generation. Thus considered, the least expensive baseload alternative dictates the cost of hydrothermal power at the margin of acceptability.

Alternative types of generation technology may be ranked in terms of the electric utility's "utility" for each, where utility is a numerical measure of preference. Figure 2-4 illustrates the mean utility of hydrothermal power, as a function of busbar cost[14], as regressed from interview responses from nine western utilities. A slight bias in

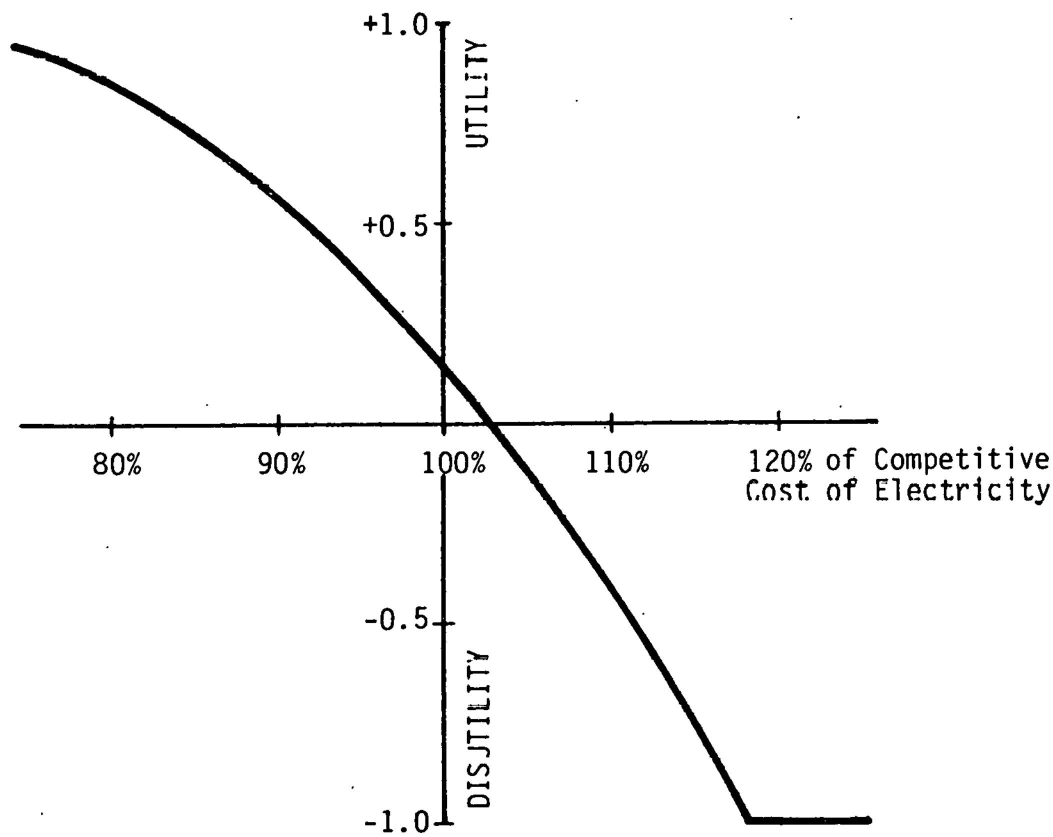

Figure 2-4. ELECTRIC UTILITIES' "UTILITY" FOR GEOTHERMAL POWER - vs - DELIVERED COST OF ELECTRIC ENERGY

[14] Busbar cost of electricity is but one of several items which comprise an electric utility's "total utility" for an alternative type of generation. Other items may include anticipated permitting delays, capital cost, outlook for fuel prices, plant reliability, etc.

favor of hydrothermal generation is illustrated at the point in Figure 2-4 where the hydrothermal busbar cost is equivalent to the least expensive alternative. A rapidly increasing aversion to hydrothermal generation is apparent when its busbar cost exceeds that of the least costly alternative by more than about 2½%. If the busbar cost of the least costly alternative is exceeded by about 18%, a maximum disutility is perceived and the hydrothermal option would, most likely, be precluded from consideration.

Competitive Resource Pricing. The above illustration supports the assumption that an acceptable pricing mechanism for hydrothermal "fuel" from the electric utilities' perspective is one which satisfies the relation:

$$\underbrace{(\overline{P}_{h,b} \times Q) + \overline{C}_{h,b}}_{\substack{\text{Level Annual Cost of} \\ \text{Hydrothermal Electric Energy}}} = \underbrace{(\overline{P}_{i,b} \times Q) + \overline{C}_{i,b}}_{\substack{\text{Level Annual Cost of} \\ \text{Alternative Electric Energy}}} \qquad (2.5)$$

where: $\overline{P}_{h,b}$ and $\overline{P}_{i,b}$ represent the levelized price per kilowatt-hour of hydrothermal and alternative fuel, respectively in some common base year (y_b) dollars; Q represents the quantity of electric energy produced annually expressed in kilowatt-hours; and $\overline{C}_{h,b}$ and $\overline{C}_{i,b}$ represent level annual production costs, exclusive of fuel costs, for hydrothermal and alternative plants, respectively, in base year dollars. This equation can be rewritten:

$$\overline{P}_{h,b} = \overline{P}_{i,b} + \frac{\overline{C}_{i,b} - \overline{C}_{h,b}}{Q} \qquad (2.6)$$

which expresses the marginally competitive levelized price for the hydrothermal resource.

Included in the annual non-fuel production cost are costs associated with: (1) recovering the power plant and apportioned transmission capital investment at the electric utilities' regulated rate of return, (b) meeting liabilities for state and federal corporate income and local ad valorem taxes, and (c) covering maintenance and operating expenses, administrative and general expenses, and insurance premiums. These cost items may be expressed as a function of the original capital investment as discussed below.

Fixed Power Production Costs. Level annual fixed costs for capital recovery and corporate income taxes may be estimated by the relation suggested by Doane (1976):

$$\overline{C}_F = CRF_{K,N} \times \left[\frac{1 - (\tau \times DPF) - \alpha}{1 - \tau}\right] \times CI_b \tag{2.7}$$

where the capital recovery factor, $CRF_{K,N}$ is:

$$CRF_{K,N} = \frac{K}{1 - (1 + K)^{-N}} \tag{2.8}$$

the weighted average after-tax cost of capital, K, of the utility is:

$$K = (1 - \tau)K_d f_d + K_c f_c + K_p f_p \tag{2.9}$$

the effective corporate income tax rate, τ, is:

$$\tau = \tau_s + (1 - \tau_s)\tau_f \tag{2.10}$$

the accelerated tax depreciation factor (based on sum of years digits method), DPF, is:

$$DPF = \frac{2(n - CRF_{K,n}^{-1})}{n(n + 1)K} \tag{2.11}$$

the present value of invested capital, CI_b, in base year dollar value, is:

$$CI_b = CI_o \left[\frac{1 + g_C}{1 + g}\right]^{y_o - y_b} \tag{2.12}$$

and other terms are defined as follows:

CI_o: capital invested at year y_o, in base year (y_b) dollar value, inclusive of short term interest charges incurred during construction

f_c: common stock fraction of utility's capital structure

f_d: long term debt fraction of utility's capital structure

f_p: preferred stock fraction of utility's capital structure

g : general inflation rate

g_C: plant cost escalation rate

K_c: annual cost of utility's common stock

K_d: annual cost of utility's long term debt

K_p: annual cost of utility's preferred stock

N : book life of facility

n : tax life of facility

y_b: base year of analysis and pricing

y_o: initial year of commercial operation

α : investment tax credit fraction

τ_s: state corporate income tax rate

τ_f: federal corporate income tax rate

Recurring Power Production Costs. Level annual recurrent costs for ad valorem taxes, operation and maintenance, administrative and general expense, and insurance may be estimated by the relation:

$$\overline{C}_R = CRF_{K,N} \times \beta \times CI_b \times \left[\frac{1 + g_R}{K - g_R}\right]\left[1 - \left(\frac{1 + g_R}{1 + K}\right)^N\right] \qquad (2.13)$$

where the recurrent cost fraction, β, is:

$$\beta = \beta_{OM} + \beta_{AG} + \beta_I + \beta_{AV} \qquad (2.14)$$

with: β_{OM} being the annual operating and maintenance expense in year y_o expressed as a fraction of the capital cost, CI_b; β_{AG} being the annual administrative and general expense fraction of CI_b; β_I being the annual insurance premium fraction of CI_b; and β_{AV} being the annual ad valorum tax fraction of CI_b. Terms to the right of CI_b above represent the expression for determining the present value of a stream of uniform payments of $\{\beta \times CI_b\}$ initial value escalating at rate, g_R. A reasonable estimate for β_{OM} is approximately 2% ($\pm\frac{1}{2}$%) based on an analysis of FPC data (1971) of operating and maintenance expenses for 29 steam power plants of the approximate size (i.e. unit capacity of 50-100 MW_e) and capacity factor (i.e. >50%) assumed for hydrothermal plants. β_{AG} is estimated by FPC (1971) to be 25% of β_{OM} or 0.5%. β_I is a nominal 0.1% based on utility information. β_{AV} depends on local tax rates and assessments and is generally between 1% and 2% for the remote locations of usual hydrothermal resource sites.

Resource Pricing Formula. For a given type of plant, the total level annual non-fuel production cost, in base year (y_b) dollars, is comprised of fixed ($\overline{C}_F$) and recurring ($\overline{C}_R$) components. Thus, the levelized resource pricing formula can be expressed:

$$\overline{P}_{h,b} = \overline{P}_{i,b} + \frac{(\overline{C}_F + \overline{C}_R)_{i,b} - (\overline{C}_F + \overline{C}_R)_{h,b}}{Q} \tag{2.15}$$

By defining:

$$\gamma \equiv \left[\frac{1 - (\tau \times DPF) - \alpha}{1 - \tau}\right] + \beta \left[\frac{1 + g_R}{K - g_R}\right] \left[1 - \left(\frac{1 + g_R}{1 + K}\right)^N\right] \tag{2.16}$$

the levelized pricing formula can be rewritten:

$$\overline{P}_{h,b} = P_{i,b} + \frac{CRF_{K,N} \times \gamma \times (CI_{i,o} - CI_{h,o}) \left[\frac{1+g_C}{1+g}\right]^{y_o - y_b}}{Q} \tag{2.17}$$

where $CI_{i,o}$ and $CI_{h,o}$ are capital investments in alternative and hydrothermal plants, respectively, at base year (y_b) cost levels for plants coming on-line in year y_o.

Assuming that fuel prices, including the hydrothermal fluid price, will escalate at an annual rate g_F, the level annual price for a fuel at base year y_b can be written:

$$\overline{P}_{\bullet,b} = CRF_{K,N} \times P_{\bullet,b} \times \left[\frac{1+g_F}{1+g}\right]^{y_o - y_b} \left[\frac{1+g_F}{K-g_F}\right] \left[1 - \left(\frac{1+g_F}{1+K}\right)^N\right] \tag{2.18}$$

where $P_{\bullet,b}$ is the fuel price (not levelized) at the base year of the analysis (y_b). By substitution, a non-levelized resource pricing formula can now be written:

$$P_{h,b} = P_{i,b} + \frac{\gamma \times (CI_{i,o} - CI_{h,o}) \left[\frac{1+g_C}{1+g}\right]^{y_o - y_b}}{Q \times \left[\frac{1+g_F}{1+g}\right]^{y_o - y_b} \left[\frac{1+g_F}{K-g_F}\right] \left[1 - \left(\frac{1+g_F}{1+K}\right)^N\right]} \tag{2.19}$$

The quantity of electric energy produced annually, expressed in kilowatt-hours, is:

$$Q = CAP \times 8760 \times KW \tag{2.20}$$

where the capacity factor, CAP, is the fraction of a year that the plant actually produces power (a stochastic variable in TCN2000). 8760 are the hours in a year, and KW is the rated plant capacity in kilowatts. By defining:

$$\varepsilon \equiv \text{CAP} \times 8.760 \times \left[\frac{1+g_F}{K-g_F}\right]\left[1-\left(\frac{1+g_F}{1+K}\right)^N\right] \tag{2.21}$$

the resource pricing formula can be written:

$$P_{h,b} = P_{i,b} + \frac{\gamma \times (CI^*_{i,o} - CI^*_{h,o})\left[\frac{1+g_C}{1+g}\right]^{y_o-y_b}}{\varepsilon \times \left[\frac{1+g_F}{1+g}\right]^{y_o-y_b}} \tag{2.22}$$

which provides the marginally competitive resource price in mills per kilowatt-hour at base year (y_b) price levels and dollar value. Note that $CI^*_{i,o}$ and $CI^*_{h,o}$ denote plant capital costs per rated kilowatt of capacity.

To estimate the hydrothermal fluid price when multiple plants are concerned, each commencing commercial operation in separate years, the pricing formula becomes:

$$P_{h,b} = P_{i,b} + \frac{\gamma \sum_j \left[\frac{1+g_C}{1+g}\right]^{y_{o,j}-y_b}\left(CI^*_{i,o_j} - CI^*_{h,o_j}\right)}{\varepsilon \sum_j \left[\frac{1+g_F}{1+g}\right]^{y_{o,j}-y_b}} \tag{2.23}$$

Hydrothermal Power Plant Capital Costs. Figure 2-5 envelops the dispersion of published capital cost estimates for liquid-dominated hydrothermal power plants as a function of the well-head temperature of the resource[15]. These estimates occur with large variance primarily because of the conceptual nature of cost data and the lack of empirical data for liquid-dominated facilities. To accommodate this wide dispersion, hydrothermal power plant costs, i.e. $CI^*_{h,o}$ in equations 2.22 and 2.23 above, are estimated as stochastic variables as a function of resource temperature within the bounds illustrated in Figure 2-5.

As discussed earlier in this chapter, costs of well field surface

[15] Figure 2-5 is comprised of estimates by Bechtel Corp. (1977), Greider (1977), EPRI (1976) and industry contributors, all escalated to mid-1978 dollar value.

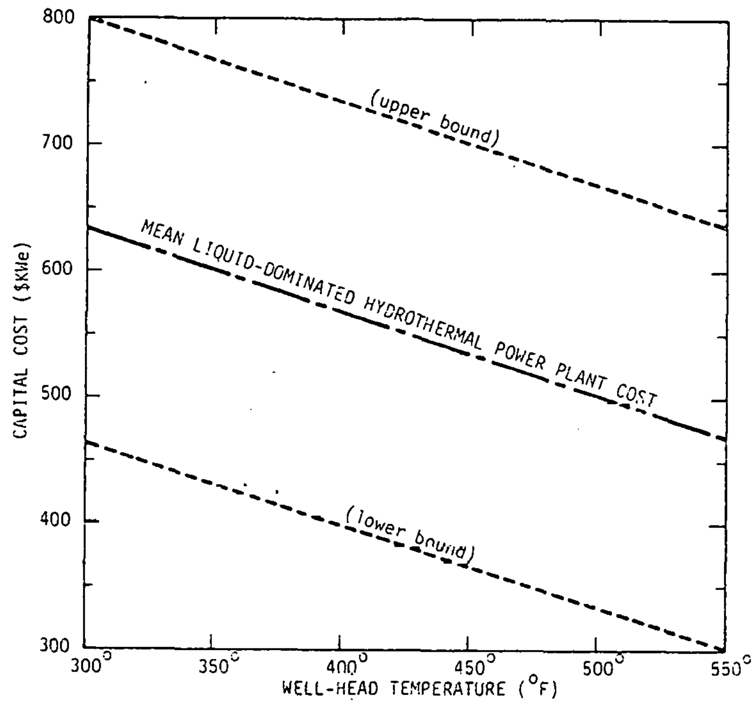

Figure 2-5. CAPITAL COST OF LIQUID-DOMINATED HYDROTHERMAL POWER PLANTS

piping between well heads and the power plant are likely to be included as a power plant capital cost, rather than a well field capital cost, in Utah applications. This is because of Utah state policies which classify the owner of such piping facilities as a regulated utility -- a role likely to be acceptable to the regulated electric power producer but unacceptable to the private resource producer.

Alternative Power Generation Costs. The capital cost and fuel cost for the competing alternative power generation plant (i.e. $CI^*_{i,o}$ and $P_{i,b}$ in the resource pricing equations 2.22 and 2.23 above) varies from one locality to the next. For the California and Utah areas of present concern, coal-fired generation appears to be the least costly alternative to hydrothermal generation at this time; therefore, the busbar cost of coal-fired generation will determine the marginally competitive busbar price of hydrothermal power in these areas.

Recent coal plant cost estimates indicate that, at mid-1978 price levels, plants with flue gas desulfurization (FGD) equipment cost $1065-1145/kWe while plants without FGD equipment cost $905-970/kWe depending on the remoteness of plant location[16]. Coal fuel prices at 1978 price levels in the Utah region are 8.0 mills/kWh based on system average costs supplied by Utah Power and Light Company (1978). In the California region coal prices are significantly higher (i.e. in the 12.0 to 13.5 mills/kWh range) because of the absence of long term purchase contracts and transportation expense[17].

Transmission Line Capital Costs. Estimating capital costs for electric transmission is a complex task entailing numerous interrelated factors including total power being transported, system voltage, design of towers and foundations, size of conductors, span between towers, and costs of obtaining corridor Right of Ways and land for substations. For the present investment model applications to California and Utah resources, the following site-specific assumptions pertaining to transmission costs are made[18].

At each resource site, transmission requirements needed to deliver hydrothermal power to load centers was determined. For power development levels below a certain threshold, a 138 kV line is to be constructed from the hydrothermal plant to the nearest local substation. As hydrothermal capacity exceeds this threshold, local substation and transmission facilities become inadequate and new double circuit 230 kV lines must be constructed to transmit power to larger regional substations. Additional double circuit 230 kV transmission capacity is provided for developmental increments of 600 MWe. Listed in Table 2-2 are site-specific threshold levels and transmission line costs, including right of way acquisition.

Revenue Cash Flow. The marginally competitive base year hydrothermal

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[16]Coal-fired plant capital cost data as published by Bechtel Power Corp. (1977) including Owners Cost and Allowance for Funds During Construction for 2 x 500 MWe plants escalated at 8.0% per year from mid-1976.

[17]California coal prices determined from estimates provided by the California Energy Commission and Pacific Gas and Electric Company.

[18]Transmission line cost in this study obtained from Utah Power and Light Co., Philadelphia Electric Co., Pacific Gas and Electric Co., Southern California Edison Company, San Diego Gas and Electric Company, and WESTEC Services, Inc.

TABLE 2-2

HYDROTHERMAL POWER TRANSMISSION COSTS

Resource Site	Threshold Level	Transmission Line Cost ($1000/mile) Below Threshold	Above Threshold for 600 MWe increments
Imperial Valley, CA	100 MWe	70	240
Mono & Coso Hot Springs KCRA, CA	50 MWe	70	155
Roosevelt Hot Springs & Cove Fort Sulphurdale KGRA, UT	200 MWe	78	122

fluid price may be the use of equations (2.22) or (2.23) with the hydrothermal and alternative plant facilities cost data and alternative fuel price data discussed above. The marginally competitive gross revenue cash flow in years of commercial operation may then be estimated as:

$$GR_y = P_{h,b} \times CAP \times 8.76 \times KW_y \times (1 + g_F)^{y-y_b} \qquad (2.24)$$

where the gross revenues, GR_y are expressed in dollars of the current year y, KW_y represents the total installed kilowatt capacity in year y and other terms are as defined earlier.

2.3.2 Capital Replacements

Estimates of the expected useful and economic life of hydrothermal wells are somewhat shorter than the expected 30 year life of the power generation facilities they will support. Depending on the fluid composition being produced, plugging and corrosion mechanisms limit well life-times to maximum expected values of 10-15 years. In the current investment model, capital replacements for active and spare producer wells and injector wells are simulated at site-specific lifetime intervals. This well life interval is a stochastic variable selected at random from a site-specific probability distribution in TCN2000. A given fraction (RRD) of the replacement wells are modeled as redrilled existing wells and the balance (1-RRD) are modeled as new wells. Typically, industry data indicates that the redrill fraction, RRD, is about 1/3.

2.3.3 Well Field Operation and Maintenance Expense

Industry estimates of annual expenses for operating and maintaining wells vary from \$20,000 to \$100,000 per well depending on the fluid composition being produced. In TCN2000 this annual expense is estimated according to the relation:

$$OME = 20 + (BCI \times 20) \tag{2.25}$$

where OME is the operating and maintenance expense per well in thousands of 1978 dollars, and BCI represents a Brine Contamination Index which ranges from 0 for low-salinity resources to 4 for high-salinity resources. Additional annual field office expense for non-manual labor and supplies is estimated at \$70,000 per well field, (Ref. Bechtel, 1977). A ten-percent overhead expense is added to the well and field office expenses.

2.3.4 Royalties

Royalty payments to the land lessor are typically one-tenth to one-eighth of gross revenues free and clear from all production expense.

2.3.5 Ad Valorem Taxes

Local ad valorem taxes paid during resource production vary from state to state and county to county. In TCN2000 these taxes are estimated differently for California and Utah resources and discussed earlier in section 2.2.2.

2.3.6 Income Taxes

State and Federal corporate income tax liabilities are based on taxable income net of expenses, local taxes, royalties, accelerated capital depreciation, interest payments on borrowed capital, and percentage depletion. The depletion deduction was held as legally permissible by the Reich case, (see Peterson and Seo, 1975) for the vapor-dominated hydrothermal resource at the Geysers. Depletion allowances for liquid dominated resources became legally permissible with the passage of the National Energy Act in 1978. According to the NEA, a 22% depletion allowance may be claimed through 1980, 20% may be claimed in 1981, 18% in 1982, 16% in 1983, and 15% may be claimed thereafter.

Other incentives offered by the NEA include: (a) the option to claim the intangible fraction (50-75%) of a well's cost as a deductible expense, and (b) an additional investment tax credit of 10% above the currently permissible 10% for "alternative" or "specially-defined energy property". Geothermal well field capital qualifies as such property. The additional tax credit is not applicable by public utilities, however, which in many cases will exclude geothermal power plant capital from this tax incentive.

2.4 INVESTMENT RISK

2.4.1 Capital at Risk

Industry interviews indicate that hydrothermal power plant technology is relatively well developed and is, for practical purposes, free of investment risk. Risks associated with reservoir confirmation and performance are of primary concern and pose significant barriers to rapid, large scale commercialization.

As discussed in section 2.2.3, hydrothermal resources may suffer degradation in the form of temperature and well flow decline as fluid is extracted over time. However, this phenomenon has not been experienced at the Geysers to date and is likely to be controllable by prudent reservoir management. For these reasons, and because of the lack of data (empirical or otherwise) upon which to estimate the likelihood and/or extent of such time-wise degradation, the post-confirmation investment risk associated with premature and unexpected resource failure is excluded from present consideration.

For modeling purposes, investment risk is confined to capital outlays through and including confirmation of a producible hydrothermal resource. Limited field experience to date indicates that once successful step-out wells have defined a resource and sustained flow tests have verified its producibility, there remains little risk to capital investments for well field development for commercial production. The risk incorporated into the present investment model is that of losing well field confirmation capital including expenditures required for three deep step-out wells. Some of this loss is assumed to be recouped via income tax deductions from unrelated income. The unrecouped balance of the loss is modeled as the investment at risk for a particular well field venture.

2.4.2 Likelihood of Loss

The probability of losing well field confirmation investments is estimated from site-specific mappings of confidence provided by consulting geothermal geologists[19]. Figure 2-6 provides an example of such a mapping for a specific resource area. These mappings represent the levels of confidence attached to currently available information at each resource site.

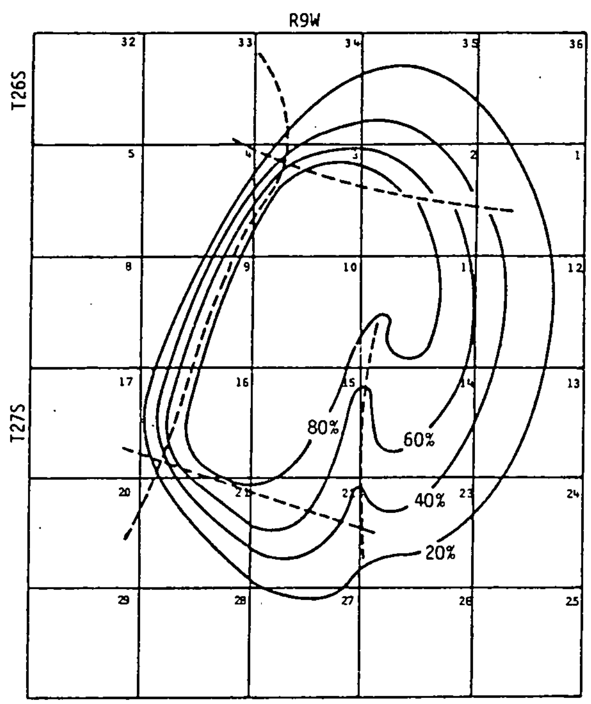

Figure 2-6. EXAMPLE OF RESOURCE AREA MAPPING OF CONFIDENCE LEVELS

[19]Confidence maps were provided by Eugene Ciancanelli of Cascadia Exploration Corp., Escondido, CA for California KGRA's outside of the Imperial Valley, and by Dr. Bill Smith of Republic Geothermal, Inc. for KGRA's within the Imperial Valley and in the State of Utah.

The probability of loss, P_L, at a particular level of well field development, i.e. kW in kilowatts, is estimated as follows:

(a) A level of confidence is estimated for each well space in the resource area by applying subroutine TCN2010. This subroutine uses an iterative iterpolation method[20], based upon the geologists' confidence contours as illustrated in Figure 2-6, to assign a level of confidence to each well space within the area. Well spacing, defined as an input parameter (WSPACE), is typically 40 acres per well. Thus, typically, TCN2010 would estimate a level of confidence for each 40 acre square in a grid covering the resource area.

(b) The number of well spaces required to achieve a development level, kW, is estimated by the relation:

$$NW = \left[1 + \frac{DWF}{1-DWF}\right] \times \left[1 + \frac{SWF}{1-SWF}\right] \times NACT \qquad (2.26)$$

where NACT represents the required number of active producing wells and is a function of kW as given in (2.1), and DWF and SWF are dry well fractions and spare well fractions, respectively, as defined in sections 2.2.3 and 2.2.4[21].

(c) A drilling sequence (WSEQ) of well spaces is order by TCN2010 such that development progresses from the well spaces of highest confidence outward to the spaces of lower confidence. The probability of loss at development level kW is estimated as one minus the confidence level of the NW-th sequential well space.

2.5 FINANCIAL ATTRIBUTES

The attributes of an investment opportunity which are required to perform the decision analysis discussed in Chapter 3 are: (a) the rate of return on invested capital, (b) the investment payback time, (c) the net present value of profits and (d) the amount of capital at risk and

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[20] The method used by TCN2010 is the Gauss-Seidel method for approximating a Laplacian operator: $\frac{\partial^2 P}{\partial x^2} + \frac{\partial^2 P}{\partial y^2} = 0.$

[21] Note that injection wells are assumed to be located outside the production area and, therefore, do not affect the well space requirement in equation (2.26).

the probability of incurring this loss. Computational methodologies and assumptions pertaining to the first three attributes (a,b,c), as incorporated into the financial analysis model TCN2000, are summarized below. The fourth attribute (d) is discussed in section 2.4.

2.5.1 Rate of Return on Invested Capital

Rate of return is an investment attribute which is of primary concern to energy resource firms as a measure of the efficiency of investment capital. Theoretically, investment opportunities to a given firm should be ranked according to the rate of return projected for each and investments should be made to the point where the marginal rate of return on the last dollar invested is equal to the marginal cost of that last dollar* . This theory is illustrated in Figure 2-7 where the marginal efficiency of investment (meI) represents the ranking of opportunities according to the rate of return projected for each, and where the marginal cost of funds (mcf) represents the increasing marginal cost of capital to the firm. The meI/mcf intersect represents the theoretically optimum level of investment.

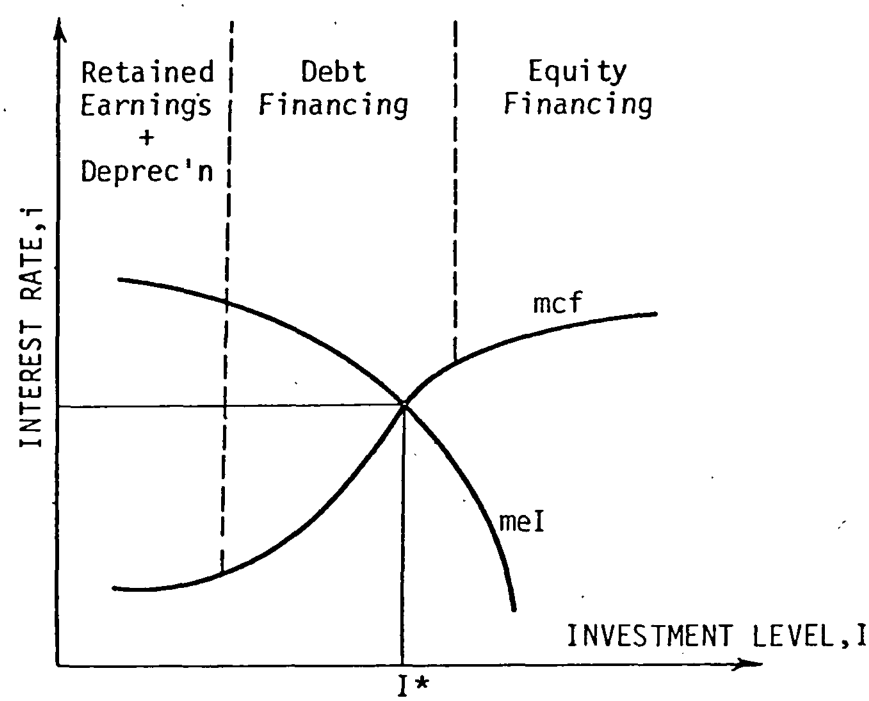

Figure 2-7. MARGINAL EFFICIENCY OF INVESTMENT AND THEORETICALLY OPTIMAL INVESTMENT LEVEL (I*).

Realistic application of this investment theory requires consideration of profit goals set by the investing firms which, in effect, increase the desired minimum return. In the major diversified firms, investment opportunities are routinely measured against a corporate minimum acceptable rate of return. This threshold reflects the rate of return realized by the firm's diversified operations and its current investment alternatives.

For the relatively small, non-diversified independent operators, the minimum acceptable rate of return reflects their marginal cost of capital plus a profit margin. With limited access to capital markets, the relatively expensive equity financing of the independents generally results in a higher threshold return than that of the major firms.

Internal Rate of Return. The method by which rate of return is estimated is an important consideration in investment analyses. The internal rate of return, IRR, concept (also referred to as the marginal efficiency of capital) was published by Keynes (1936) as a method for ranking investment opportunities. IRR is that rate of discount which equates the present worth of an opportunity's revenue stream to the present worth of its expense and investment stream, i.e., that discount rate (i) at which the net present value (NPV) of an opportunity reduces to zero...

$$NPV = \sum_{t=0}^{n} \frac{NR_t - I_t}{(1 + i)^t} \tag{2.27}$$

where, NR_t and I_t are revenues net of expenses and investments, respectively, during period t and n represents the expected economic life of the opportunity.

It is important to note that, as demonstrated by Alchian (1955) and Hirshleifer (1958), Keynes' IRR method will correctly and realistically rank investment opportunities when: (1) net receipts may be immediately and indefinitely reinvested at the IRR, and (b) when NPV(i) curves do not intersect as illustrated in Figure 2-8.

The IRR reinvestment criteria may be satisfied by independent operators whose business concentrations are in similar hydrothermal

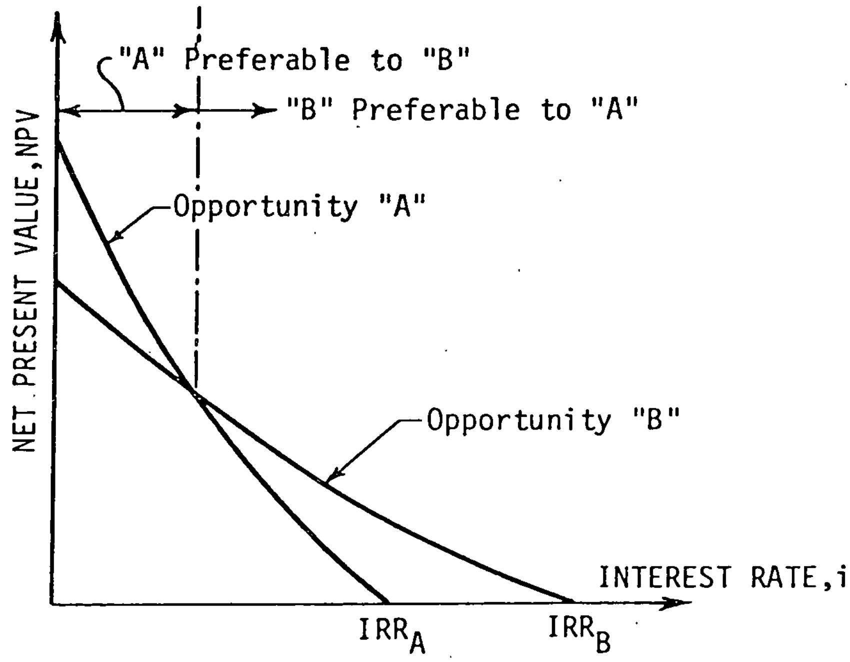

Figure 2-8. NET PRESENT VALUE - vs - DISCOUNT RATE FOR HYPOTHETICAL INVESTMENT OPPORTUNITY

opportunities. However, hydrothermal opportunities represent a relatively small fraction of the operations of major resource corporations and their impact on corporate reinvestment rates are unlikely to be significant. For this reason, when assessing hydrothermal opportunities of the major corporate producers, the IRR method is discarded in favor of the financial management rate of return, FMRR, method. With the FMRR method, discussed below, the reinvestment rate may be externally specified.

Financial Management Rate of Return. Financial management rate of return (FMRR) is a method for ranking investment opportunities recently discussed by Messner and Findley (1975). The FMRR method discounts all preproduction negative cash flows to an equivalent single initial investment and estimates the interest rate required to equate this investment to a single end-of-life return. The end-of-life return is the sum of all net production revenues compounded forward at a realistic reinvestment rate.

FMRR avoids the problems of unrealistic reinvestment rates of the IRR and is proposed and used herein as the proper rate of return for ranking hydrothermal investment opportunities of major resouce corporations. The IRR method is used for ranking hydrothermal opportunities of independently operating resouce producers as discussed previously.

2.5.2 Investment Payback Time

Unlike petroleum ventures where a single well is capable of producing revenue when complete, it takes a field of completed wells and an on-site power plant to create revenues in a geothermal electric power venture. This period from prospect discovery to revenue can extend several years and is highly dependent on uncertain institutional, logistical and technical barriers likely to be encountered along the way. Inherent in such an uncertain and long developmental time frame are investment risks associated with long range capital commitments, uncertain costs and uncertain revenues.

Payback time estimates are a second primary concern of resouce firms and indicate the length of time an investment will be subject to the above mentioned risks before it is recovered by project receipts. As a rule, longer payback requirements involve higher costs of capital because of the associated risk premiums. Independently operating resource firms are particularly sensitive to long payback times because of the limited availability of private venture capital for long term financing. The larger resource corporations appear less concerned with payback time as exemplified by recent activities by many of these firms in outer continental shelf oil production where payback estimates typically run 8-10 years.

As indicated in Table 2-1 at the beginning of this chapter, a series of capital investments extending over several years are required to confirm and develop a hydrothermal well field. Individual discounted investments are assumed to be paid back, in order of occurrence, from discounted net revenues. A weighted average discounted payback time is employed in this analysis to estimate a single measure of payback time for the investment stream.

2.5.3 Net Present Value of Profits

The estimated net present value (NPV) of an investment opportunity is a third primary concern of resource firms. It provides an indicator of the magnitude of profit expected of a venture and allows a firm to determine if the proposed venture is compatible with its scale of operations. NPV is the projected stream of net revenues and capital expenditures of an opportunity reduced to a single value at an appropriate discount rate (recall equation 2.27). As discussed at some length by Weston and Brigham (1978) and Phung (1977), a proper discount rate for NPV analyses is the firm's weighted average after-tax cost of capital[22].

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[22]Estimation of realistic values for a firm's cost of capital is not a trivial task - see Weston and Brigham (1978), Chapter 19.

Chapter Three

RESOURCE PRODUCERS' DECISION MODEL (TCN2080)

A multiobjective decision model, TCN2080, is used to estimate the probability with which a resource producing firm will elect to invest capital into a hydrothermal opportunity. Each opportunity is defined in terms of the four attributes discussed in the previous chapter, namely: (a) rate of return on invested capital, (b) discounted investment payback time, (c) net present value of profits, and (d) the amount of capital at risk and the probability of incurring this loss.

The decision model provides a new and statistically sound integration of recent advances in both multiobjective decision analysis and applied theories of probabilistic choice as developed and discussed by Cassel (1979) and Cassel, et al. (1979b). The model is based upon interview responses from management representatives of twenty resource firms solicited throughout 1978 and early 1979. Its predictive capabilities are substantiated by industry investment behavior as realized to date.

3.1 BACKGROUND AND ASSUMPTIONS

3.1.1 Hydrothermal Investment Opportunity

Hydrothermal resources represent a potentially significant source of energy in the United States from which electric power may be generated with minimal environmental intrusion and at commercially competitive costs. Various estimates of the untapped energy recoverable from hydrothermal reserves in the United States vary by at least an order of magnitude. However, recent reports by Trehan (1978), Muffler (1979), and the United States Department of Energy (1978) offer credible estimates, substantiated by available data, which indicate that 25,000 to 40,000 megawatts of power generation capacity could ultimately be supported by identified vapor-dominated and liquid-dominated resources in six western states[23]. These figures are equivalent to fully half of the conventional

[23] The 6 western states are CA, ID, NV, NM, OR and UT. WY has a vast hydrothermal capacity, estimated to be 14,000 megawatts, but its location under Yellowstone Park renders it inaccessible for development.

generation capacity installed in these six states (Ref. Edison Electric Institute, 1976).

According to Pacific Gas and Electric Company (1978), the production cost for hydrothermal electric energy at the Geysers geothermal field in northern California is 17 mills/kWh [24] which is considerably less expensive than that for baseload generation alternatives of combined cycle plants at 45 mills/kWh, coal plants at 27 mills/kWh [25], and nuclear plants at 21 mills/kWh. Such production economies are due in large part to the 350°F (177°C) vapor-dominated characteristics of the Geysers resource (Ref. Pacific Gas and Electric Co. 1974). Production economies of the more common liquid-dominated type of resource are highly dependent on site-specific resource qualities including temperature, depth, well flow rate and composition. Although somewhat more expensive than that realized at the Geysers, the production cost of electric power from liquid-dominated resources is also predicted to be cost competitive with baseload generation alternatives at a significant number of reservoir sites (Ref. Trehan, 1978).

3.1.2 Investment Modeling Assumptions

The large number of reportedly economic hydrothermal resource sites offers the potential for large scale commercial development. The rate and extent at which this potential is realized will depend on the rate and extent at which firms choose to invest capital into hydrothermal exploration, development and utilization projects. Such investment behavior is conditional upon satisfying the decision objectives of both resource producing firms and electric utilities.

The Geysers success, and the identification of attractive resources outside the Geysers, has generated considerable active interest on the part of investors, electric utilities and resource producers - the latter ranging in operational scope from relatively small independent

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[24] 35 year levelized costs on a 1977 constant dollar basis at an assumed capacity factor of 80%.

[25] 23 mills/kWh for coal plants without flue gas desulfurization equipment.

operators to major petroleum and mining corporations. At the present time however, geothermal exploration, development and utilization experience is not widespread in the industry. This lack of experience in dealing with hydrothermal resources detracts from the immediate and rapid commercialization of hydrothermal electric power facilities. In particular, substantial investment risks are perceived because of uncertainties pertaining to hydrothermal resource identification and development, reservoir performance, resource pricing, and institutional barriers. Though these uncertainties are likely to meliorate with time - as indeed they have at the Geysers - geothermal investment behavior will reflect a degree of cautious optimism in the development of new resource sites.

To a limited extent, the initial development and demonstration of hydrothermal electric power facilities at new resource sites will likely proceed prior to fully satisfying the risk averse investment criteria of the electric utility industries. Temporary incentive schemes such as the Federal Geothermal Loan Guarantee and cost sharing programs enhance the availability of funds for early development, as may leaseback financing schemes for power plant construction. A limited level of development may also occur with the construction of generation facilities by private consumers of bulk electric power including the resource producers themselves. However, unless the power is used on site - an unlikely postulation considering the remote and desert-like location of most viable geothermal reservoirs - this means of private development may be constrained by the limited excess capacity of utility-owned transmission lines.

It is assumed in this study that the eventual large scale development of hydrothermal resources for electric power generation is conditional upon satisfying the investment decison criteria of both resource producers and electric utilities. The electric utilities, it is assumed, will invest in hydrothermal power plants and thereby provide a market for the hydrothermal resource producer if the resource is priced such that the total production cost of hydrothermal electric energy--delivered to the nearest major transmission corridor--is competitive with that of the least expensive alternative type of baseload generation. Underlying this assumption are understandings that, for large scale hydrothermal development to proceed, electric utilities' concerns must be satisfied regarding: regional load growth and the need for new generating capacity, system reliability, hydrothermal reservoir and power technology demonstration, and the melioration of logistical and institutional constraints.

To model the joint probabilistic investment behavior of resource producers and electric utilities in the development of hydrothermal resources, two interacting decision models would be required, i.e., one for each entity. This task is beyond the scope of the present study, which is directed at the resource producer alone. For the present application, the above assumptions are made regarding electric utilities behavior--the key to which is the marginally competitive pricing of the resource (recall section 2.3.1 for the resource pricing approach used in this analysis).

3.2 HYDROTHERMAL RESOURCE PRODUCERS

The commercial potential of hydrothermal electric power is realized in the United States today largely due to the pioneering efforts of B.C. McCabe and his partners in Magma Power Company. In the mid-1950's, Magma drilled the first commercial steam well at the Geysers. Subsequent joint development by Magma, Thermal Power Company, and Pacific Gas and Electric Company produced the western hemisphere's first commercial geothermal electric power in 1960. In 1967, Union Oil Company of California joined the developers and, with its ample supply of capital, significantly advanced the Geysers rate of growth as illustrated in Figure 3-1. With more than 500,000 kilowatts of generation capacity installed today, the Geysers is the world's largest source of geothermal electric power.

Today the commercial feasibility of hydrothermal electric power attracts active investment and development interests of a large number and wide variety of resource producing firms. Major petroleum and mining corporations and small independent operators alike are actively

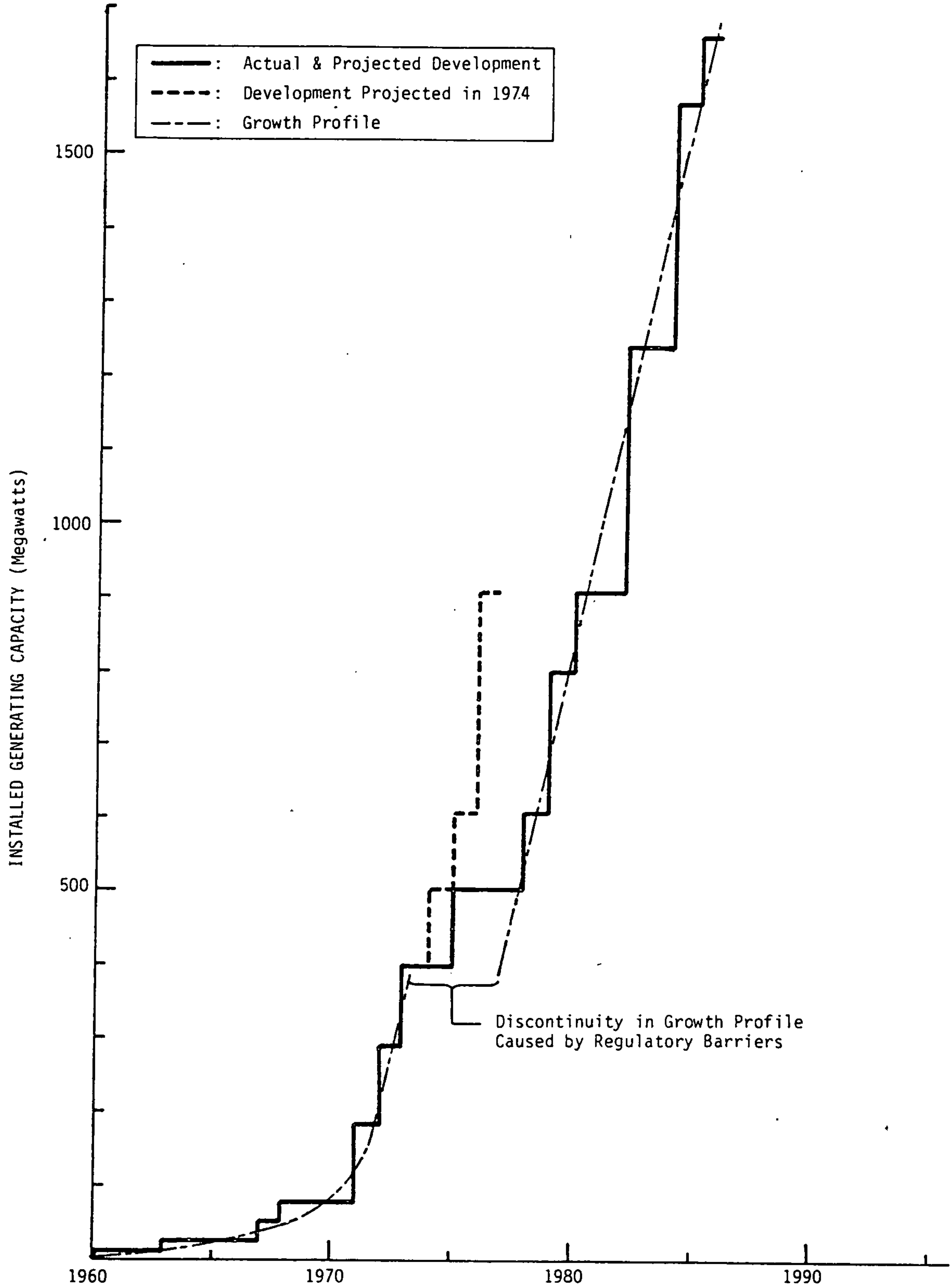

Figure 3-1. DEVELOPMENT AT THE GEYSERS GEOTHERMAL AREA

involved in exploring and developing hydrothermal reservoirs. For the purposes of this study, the resource producers are classified as follows:

- Type I. Major diversified corporations with assets typically in excess of one billion dollars and substantial income from non-geothermal operations. Annual capital investments and exploration expenditures are typically in the order of hundreds of millions of dollars. 20-30% capital structure is long term debt costing about 8-9% new today (SP Rating: BBB-AAA). Weighted averaged after-tax cost of new capital is 10-12%.
- Type II. Smaller diversified or non-diversified resource corporations with assets substantially less than one billion dollars and annual investment and exploration budgets in the order of millions of dollars. Capital structure is similar to Type I firm or long term debt fraction may be lower and cost of new capital slightly higher.
- Type III. Non-diversified independent operators with insignificant income prior to geothermal production. Annual investment and exploration budgets are typically in the order of hundred of thousands of dollars. Financing is entirely through sale of equity, frequently in the form of limited partnership interests. Minimum cost of new capital to the firm is 12-15% to attract investors. Government loan guarantees may provide access to debt financing for these firms.

Throughout this report, discussions are limited to the Type I firm and to the Type III firm as described above.

The decision model which will be discussed in this chapter is based upon information and data collected through management interviews and from voluntary check-list responses contributed by twenty resource firms. The contributing firms, each having an active or potential interest in geothermal energy, may be catagorized as follows: eleven are Type I corporations, four are Type II corporations, and five are Type III independents.

3.3 DECISION OBJECTIVES AND PREFERENCES

3.3.1 Investment Objectives

Interviews with management representatives of the twenty firms participating in this analysis indicate that four objectives are of primary concern to investment decision-makers of the energy resource industry.

These investment objectives are to:

- 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 which 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).

Qualitatively the four investment objectives are similar for all types (I, II, III) of resource firms as defined above. Quantitatively, however, significant differences exist in the utility, i.e. numerical value of preference or aversion, which each type of firm attaches to given levels of the attributes: rate of return, payback time, present value of profits, and capital loss. These differences, as perceived by the major Type I firm and smaller Type III firm are demonstrated in the following paragraphs.

3.3.2 Utility of Rate of Return

Utility functions, which estimate the firms' preferences for various levels of rate of return, are based upon regressions of voluntary checklist responses as received from the participating firms. With other investment attributes held fixed, respondents were asked to rate their preferences for six levels of return on a twelve point scale. This data sample was then normalized between a minimum utility of zero at "no investment incentive" and a maximum utility of one at "highest positive incentive". The normalized data was next partitioned into Type I, major corporation responses and Type III, independent operator responses.

After testing the industry responses for statistical heteroskedasticity, i.e. non-equality of variances across sample observations, the data was 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 Figure 3-2, are utility functions of rate of return, $U_R(r)$, which represent both

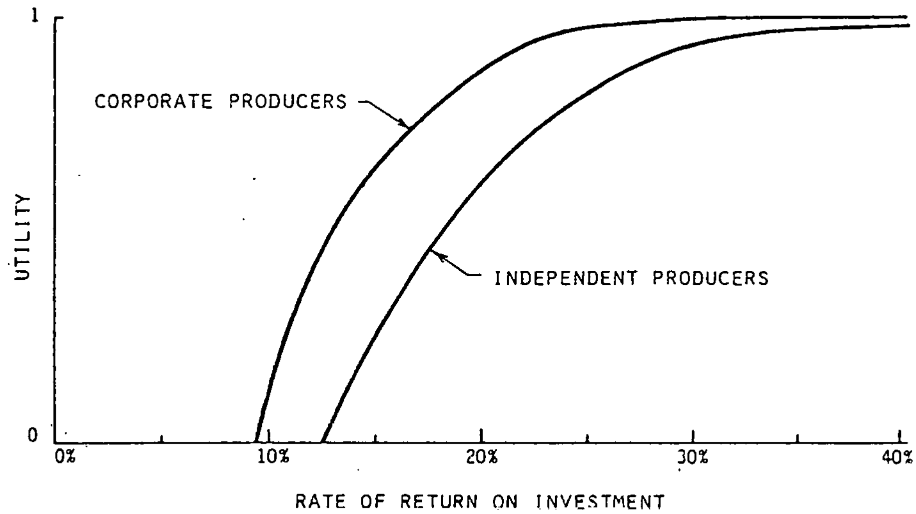

Figure 3-2. RESOURCE PRODUCERS' UTILITY FOR RATE OF RETURN ON INVESTED CAPITAL

the maximum likelihood estimates (MLE) and best linear unbiased estimates (BLUE) of the industry responses[26]. It may be noted that, in Figure 3-2, a threshold minimum acceptable rate of return exists which is consistent with the discussion of threshold return in section 2.5.1. Furthermore, the curves in Figure 3-2 are monotonic increasing with r which is consistent with the industry responses of increasing preference for increasing return. Figure 3-2 also exhibits decreasing marginal utility in the direction of increasing preference which would indicate that preference asymptotically approaches an upper bound at high positive levels of return, i.e. at sufficiently high returns negligible additional investment incentive is provided by increasing the return.

3.3.3 Utility of Payback Time

Payback utility functions were analyzed with methods similar to those used for the rate of return utility functions discussed above. Figure 3-3 illustrates the utility functions for payback time, $U_p(p)$,

[26] 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.

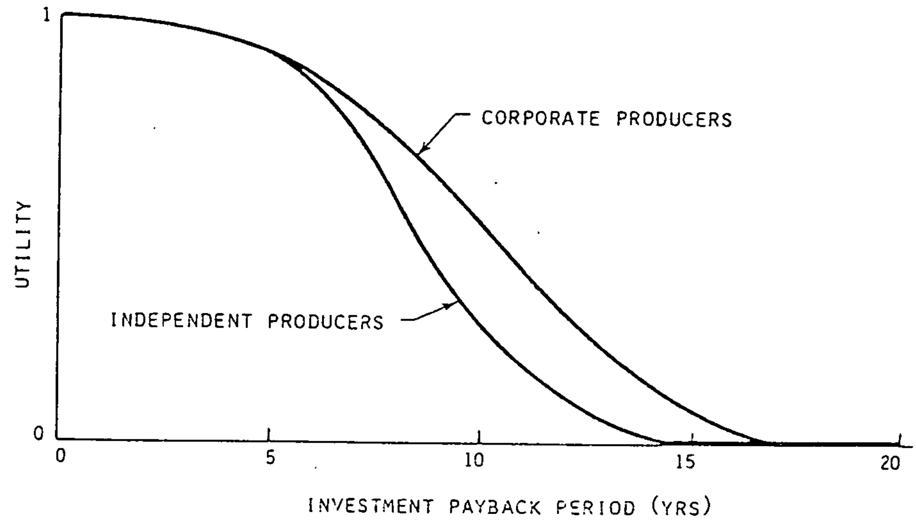

Figure 3-3. RESOURCE PRODUCERS' UTILITY
FOR INVESTMENT PAYBACK PERIOD

which were produced from this assessment[27].

It may be noted that the curves in Figure 3-3 are everywhere monotonic decreasing with increasing payback time which is consistent with decreasing industry preferences for long paybacks. Figure 3-3 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 Type I producers. This same payback period is below neutral preference for the smaller Type III firms, one of which indicated in a personal interview that available venture capital requires, at most, a 7 year payback.

3.3.4 Utility of Monetary Gain

Sampling and regression of industry preferences for the net present

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[27] 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.

value of a monetary gain followed similar methods to those used for assessing preferences for rate of return and payback time as discussed previously. Figure 3-4 illustrates the utility functions for net present value of profits, $U_V(v)$, which were produced from this analysis[28].

From Figure 3-4 it is interesting to note that the utility curve for the small, Type III 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 3-4 which approach maximum preference.

It is also interesting to note that the utility curve for the major, Type I producer 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 $6-11 million. A 40 million barrel discovery is highly attractive, but

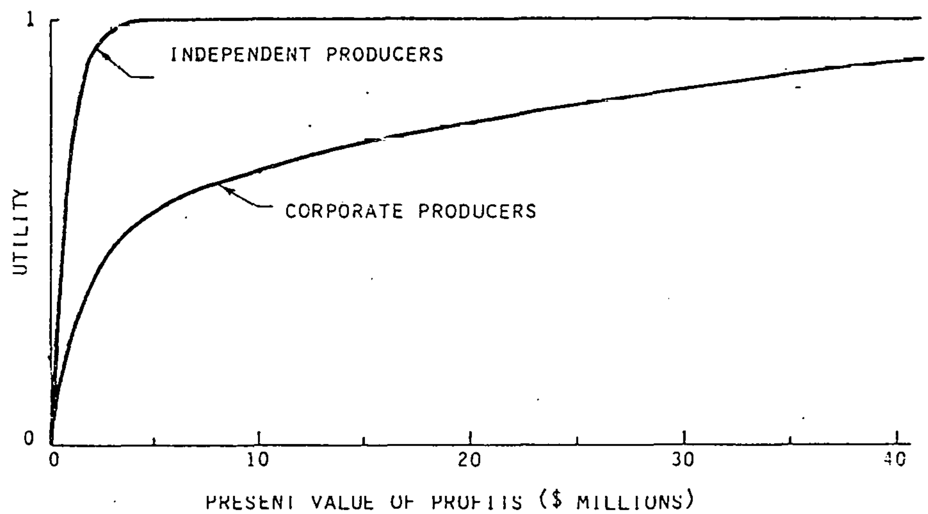


Figure 3-4. RESOURCE PRODUCERS' UTILITY FOR FINANCIAL GAIN

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

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 3-4.

3.3.5 Utility of Monetary Loss

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

Industry decision makers are presented with sixteen hypothetical lotteries in which two outcomes are possible: there is possibility, P_j, that a monetary loss, L_i, will be incurred and probability, $(1-P_j)$, that a monetary gain will be received. The gain is 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 are provided by the decision maker on a 12-point scale.

The preference scale is 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 are interpreted as being the expected utility of each lottery which is:

$$EU_{ij} = P_j\ U(L_i) + (1-P_j)\ U(G). \tag{3.1}$$

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

$$U(L_i) = 1 - \frac{1 - EU_{ij}}{P_j} \tag{3.2}$$

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 3-5[29]. It is interesting to note that, according to Figure 3-5, a major Type I corporation shows

[29] 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.

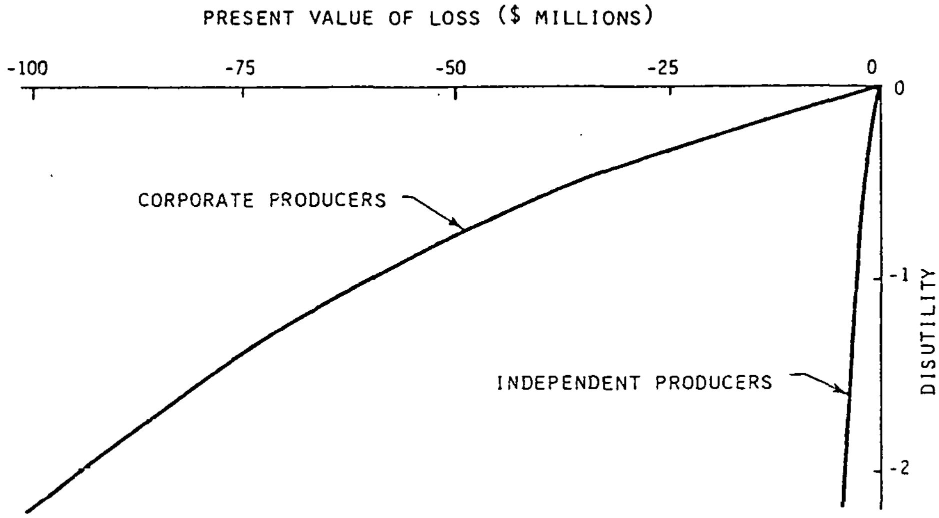


Figure 3-5. RESOURCE PRODUCERS' DISUTILITY OF FINANCIAL LOSS

fairly strong aversion to risks in the hundreds of millions of dollars while the smaller Type III firms show the same aversion to losses in the millions of dollars. Recent reports of exploratory oil drilling activities by major Type I firms on the outer continental shelf indicate investment losses of $60-150 million prior to abandonment. These reports are consistent with Figure 3-5. The risk aversion levels of the smaller Type III firms represent a major fraction of their total assets which is not unexpected for independent, "wildcatting" operators.

3.4 MODELING DECISION BEHAVIOR

3.4.1 Multiobjective Decision 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).

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

- net present value of investment at risk (v).

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 -- developed earlier in this chapter.

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:

$$U = f\left[U_R(r), U_P(p), U_V(v)\right] \quad \text{if } v>0. \tag{3.3}$$

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

$$U = U_L(v) \quad \text{if } v\leq 0 \tag{3.4}$$

To estimate the functional form of the multiattribute utility function, f, in equation (3.3), 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 Type I firms and for the independently operating Type III firms.

For the Type I firms, the resulting functional form of multiattribute utility is[30]:

$$U = \begin{cases} k_{11}U_R(\tilde{r}) + k_{12}U_V(\tilde{v}) + k_{13}U_R(\tilde{r})U_P(\tilde{p}) & \text{for } v>0 \\ U_L(\tilde{v}) & \text{for } \tilde{v}\leq 0 \end{cases} \tag{3.5}$$

and for the Type III firms the resulting functional form is:

$$U = \begin{cases} k_{31}U_V(\tilde{v}) + k_{32}U_R(\tilde{r})U_V(\tilde{v}) + k_{33}U_R(\tilde{r})U_P(\tilde{p})U_V(\tilde{v}) & \text{for } \tilde{v}>0 \\ U_L(\tilde{v}) & \text{for } \tilde{v}\leq 0 \end{cases} \tag{3.6}$$

An explanation of investment behavior by potential geothermal

[30] t-statistics for all "k" coefficients in both equation (3.5) and (3.6) 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 (R^2) for the two equations are 0.86 and 0.83, respectively.

resource producers is provided by inspection of the multiattribute utility functions given in equations (3.5) and (3.6). Decisions by major resource corporations appear heavily weighted by the unconditional rate of return offered by an investment opportunity. This is consistent with both investment theory and the industry interviews discussed earlier in this chapter. 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.

3.4.2 Probabilistic Model of Binary Choice

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:

$$EU = \sum U_i \Pi_i \tag{3.7}$$

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:

$$P(A|EU_A) = \frac{1}{1 + e^{\alpha-\beta\cdot EU_A}} \qquad (3.8)$$

which represents the probability of selecting opportunity A conditional upon the expected utility of A, EU_A. Figure 3-6 illustrates the general form of the logit model. The α and β parameters of (3.8) were estimated separately for the major corporate Type I firms and the independently operating Type III firms by applying least squares regression techniques to the industry investment behavior data discussed in section 3.4.1 above[31].

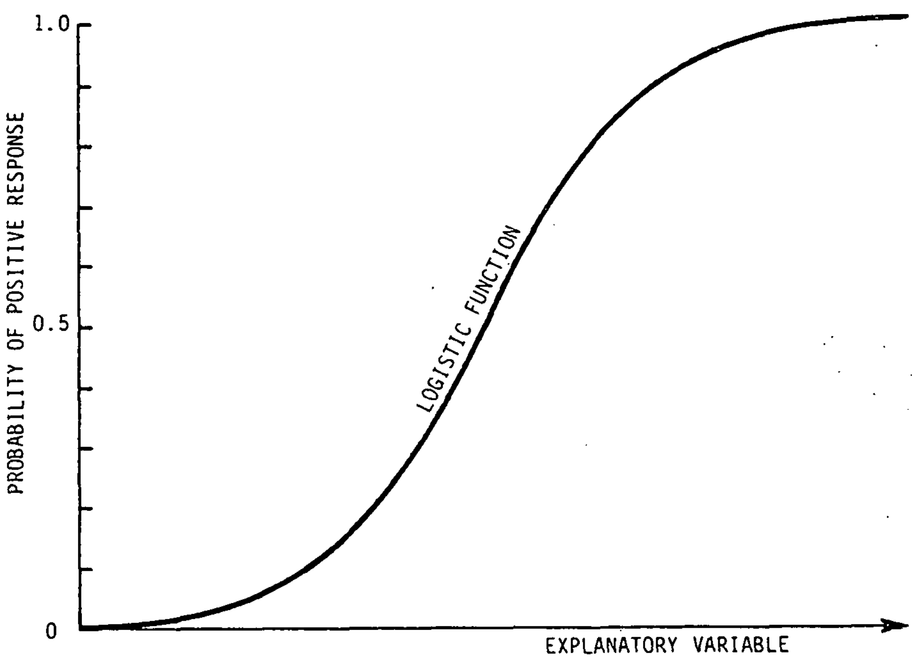


Figure 3-6. THE LOGIT MODEL OF PROBABILISTIC CHOICE

[31] t-statistics to the α and β parameters are at the 99% level of confidence for both the major corporate (Type I) model and the independent operator (Type III) model.

Chapter Four

INVESTMENT EVALUATIONS AT CALIFORNIA AND UTAH KNOWN GEOTHERMAL RESOURCE AREAS

The cash flow and investment decision model are used to evaluate resource commercialization potential for nine Known Geothermal Resource Areas (KGRA's) in California and Utah. These hydrothermal resource areas were selected on the basis of their present potential to support electric power development, based on interviews with government and industry representatives. Locations of the KGRA's analyzed in this report are shown in Figure 4-1. In addition to the nine liquid-dominated resource areas, future development potential is analyzed at the Geysers steam-dominated well field in northern California.

4.1 INVESTMENT MODELING ASSUMPTIONS

The investment decision being modeled in this report is the decision to confirm and develop a geothermal resource area to the extent necessary to support given levels of electric power. This decision is based upon currently available geologic data and financial parameters, as defined and outlined in the following site-specific figures and tables. For purposes of the current model application, input variables subject to substantial uncertainty are estimated by selecting the expected values of each parameter, based on the site-specific probability distributions discussed in section 2.1.

All investment simulation results presented below include the investment incentives provided by the 1978 National Energy Act. The resource price used to evaluate the investment decision is based on the marginally competitive resource price, as described in section 2.3.1. To determine the sensitivity of the investment decision to the resource price, investment probabilities are estimated for a selling price equivalent to 80, 100 and 120 percent of the marginally competitive resource price.

In the following sections, site specific input parameters and model results are presented. For each KGRA, a summary is provided of geothermal development to date. The site specific resource parameters are then

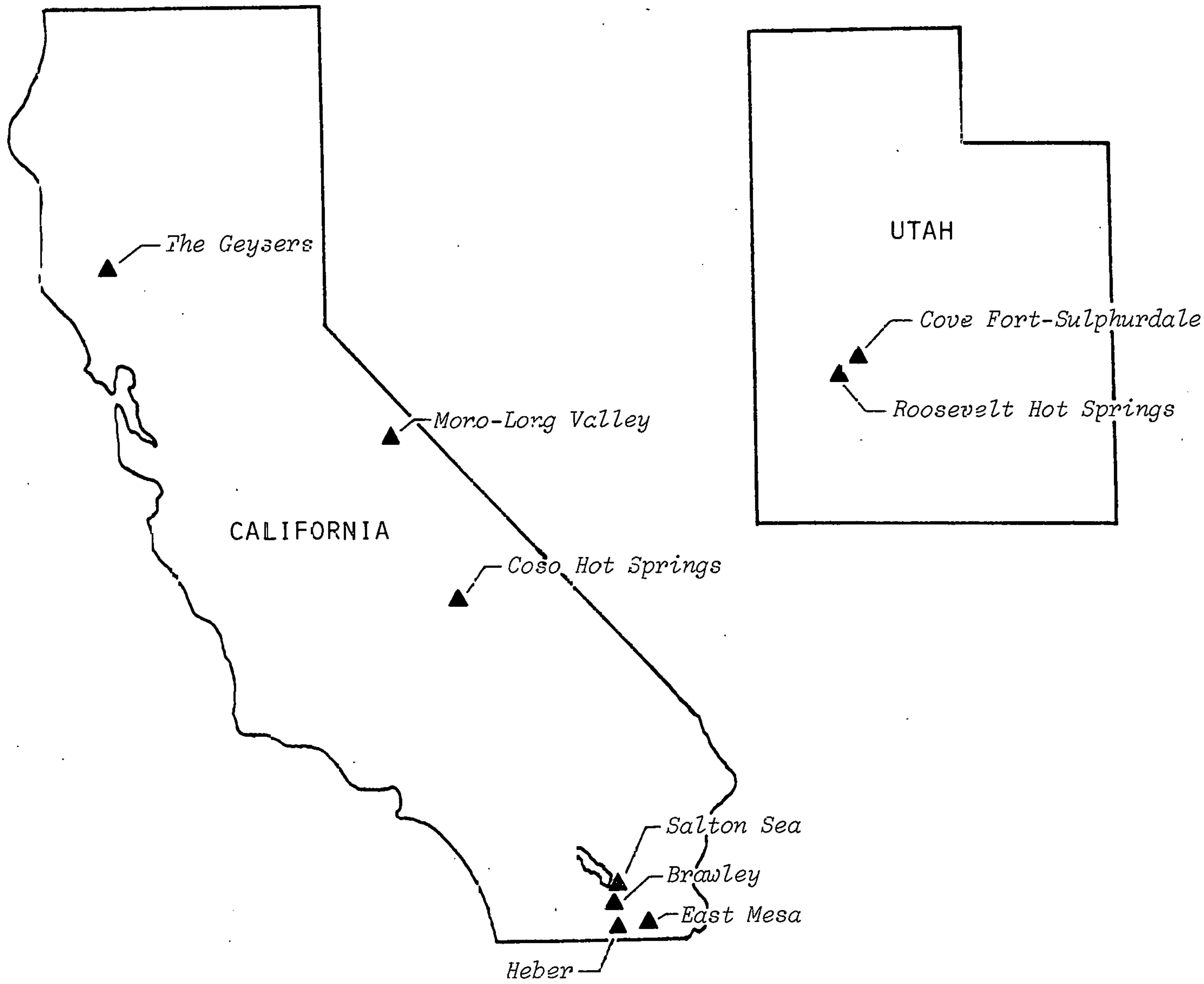


Figure 4-1. LOCATIONS OF SELECTED KNOWN GEOTHERMAL RESOURCE AREAS

presented together with a figure illustrating the confidence levels in available data (discussed in section 2.4.2). Finally, the investment simulation results are analyzed for both major "Type I" resource corporations and independent "Type III" resource producers.

4.2 CALIFORNIA RESOURCE AREAS

The seven California KGRA's analyzed in this report are located in three general geographic areas: Imperial Valley Region, Eastern Sierra Region, and the Geysers Region. Table 4-1 presents the economic, financial, and tax parameters applicable to investment decisions in all three of these California regions.

TABLE 4-1. ECONOMIC AND FINANCIAL PARAMETERS FOR CALIFORNIA SIMULATIONS

1. ECONOMIC PARAMETERS

   1.1 LONG-TERM GNP DEFLATOR (I/P)........... 0.05

   1.2 COST ESCALATION RATE (I/P)............. 0.06

   1.3 ENERGY PRICE ESCALATION RATE (I/P)..... 0.075

   1.4 BASE YEAR OF ANALYSIS (I/P)............ 1978

   1.5 YEAR OF PRICING (I/P).................. 1978

2. POWER PRODUCER FINANCIAL PARAMETERS	HYDROTHERMAL	ALTERNATIVE
2.1 AVERAGE AFTER-TAX COST OF CAPITAL (O/P).....	.087	.087
2.2 DEBT FRACTION (I/P)......................	.600	.500
2.3 COST OF DEBT (I/P).......................	.085	.085
2.4 PREFERRED EQUITY FRACTION (I/P)..........	.100	.100
2.5 COST OF PREFERRED EQUITY (I/P)...........	.085	.085
2.6 COMMON EQUITY FRACTION (I/P).............	.400	.400
2.7 COST OF COMMON EQUITY (I/P)..............	.145	.145
2.8 EFFECTIVE INCOME TAX RATE (O/P)..........	.509	.509
2.9 STATE INCOME TAX RATE (I/P)..............	.090	.090
2.10 FEDERAL INCOME TAX RATE (I/P)...........	.460	.460
2.11 INVESTMENT TAX CREDIT (I/P).............	.100	.100
2.12 POWER PLANT TAX LIFE (I/P)..............	22.000	22.000
2.13 POWER PLANT EXPECTED LIFE (I/P).........	30.000	30.000
2.14 POWER PLANT CAPACITY FACTOR:		
-MINIMUM VALUE (I/P).........................		.800
-VALUE AT MODE (I/P).........................		.850
-MAXIMUM VALUE (I/P).........................		.900
-MEAN VALUE (O/P)............................	.850	.850
2.15 PLANT RECURRENT COST FRACTION (I/P)......	.041	.041

3. RESOURCE PRODUCER FINANCIAL PARAMETERS

   3.1.1 TYPE OF FIRM (I/P)........................ 1

   3.1.2 FIRMS IN JOINT VENTURE (I/P).............. 1

   3.1.3 PRESENT VALUE DISCOUNT RATE (I/P)......... 0.115

   3.1.4 FMRR SINKING FUND INTEREST RATE (I/P)..... 0.14

   3.1.5 FMRR REINVESTMENT EARNINGS RATE (I/P)..... 0.14

   3.1.6 DEBT FRACTION (I/P)....................... 0.25

   3.1.7 COST OF DEBT (I/P)........................ 0.085

   3.1.8 EFFECTIVE INCOME TAX RATE (O/P)........... 0.5086

   3.1.9 STATE INCOME TAX RATE (I/P)............... 0.09

   3.1.10 FEDERAL INCOME TAX RATE (I/P)............ 0.46

   3.2.1 TYPE OF FIRM (I/P)........................ 3

   3.2.2 FIRMS IN JOINT VENTURE (I/P).............. 1

   3.2.3 PRESENT VALUE DISCOUNT RATE (I/P)......... 0.135

   3.2.4 FMRR SINKING FUND INTEREST RATE (I/P)..... 0.1

   3.2.5 FMRR REINVESTMENT EARNINGS RATE (I/P)..... 0.14

   3.2.6 DEBT FRACTION (I/P)....................... 0

   3.2.7 COST OF DEBT (I/P)........................ 0

   3.2.8 EFFECTIVE INCOME TAX RATE (O/P)........... 0.5086

   3.2.9 STATE INCOME TAX RATE (I/P)............... 0.09

   3.2.10 FEDERAL INCOME TAX RATE (I/P)............ 0.46

4. TAX INCENTIVES

   4.1 INVESTMENT TAX CREDIT (I/P)........... 0.2

   4.2 INTANGIBLE WELL COST FRACTION (I/P)... 0.75

   4.3 PERCENTAGE DEPLETION ALLOWANCE (I/P):

   -THRU 1980.... 0.22

   -1981......... 0.2

   -1982......... 0.18

   -1983......... 0.16

   -AFTER 1983... 0.15

4.2.1 Brawley, Imperial Valley, CA

At the Brawley KGRA, located in Imperial County, California, substantial drilling and development has taken place, largely by Union Oil Company. Current plans call for a 10 MW demonstration plant to be on line by the mid-1980's built in conjunction with Southern California Edison (SCE). Table 4-2 summarizes resource characteristics at Brawley and Figure 4-2 presents a mapping of current confidence levels over the resource area.

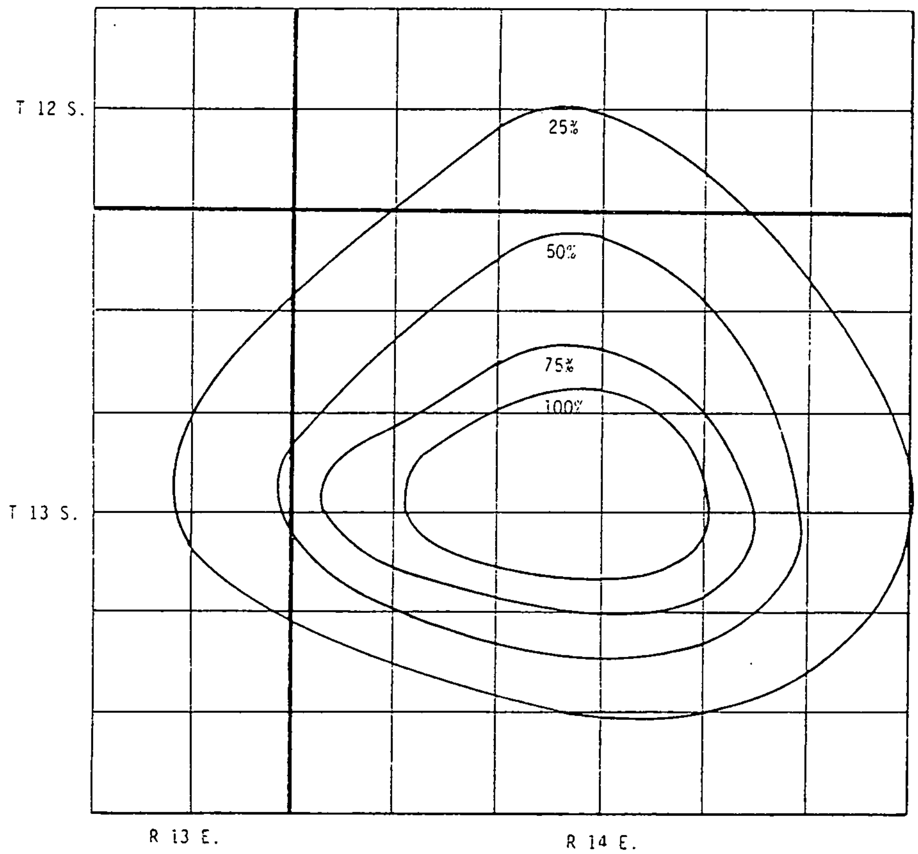


Figure 4-2. LEVELS OF CONFIDENCE
AT BRAWLEY KGRA (MID-1979)

The resource at Brawley is characterized by relatively high temperatures as well as high salinity. In the model TCN2000, the fluid composition characteristics are described by a "brine contamination index" (based on a linear scale from zero for insignificant adverse composition

TABLE 4-2. RESOURCE AND DEVELOPMENT PARAMETERS AT BRAWLEY KGRA

<u>RESOURCE PARAMETERS</u>

```
1.  STATE........................................ CA
2.  TYPE OF GEOLOGY (I/P)........................ SEDIMENTARY
3.  RESERVOIR DEPTH,FT:
    -MINIMUM VALUE (I/P).... 4900
    -VALUE AT MODE (I/P).... 7400
    -MAXIMUM VALUE (I/P).... 9800
    -MEAN VALUE (O/P)...........................  7375
4.  MEAN WELL COST,$1000 (O/P)..................  486
5.  DRY WELL COST FRACTION (I/P)................. 0.9
6.  REDRILL WELL COST FRACTION (I/P)............. 0.35
7.  DRY WELL FRACTION:
    -MINIMUM VALUE (I/P).... 0.09
    -VALUE AT MODE (I/P).... 0.1
    -MAXIMUM VALUE (I/P).... 0.11
    -MEAN VALUE (O/P)............................ 0.1
8.  SPARE WELL FRACTION (I/P).................... 0.2
9.  PRODUCER/INJECTOR RATIO (I/P)................ 2
10. INITIAL REDRILL FRACTION (I/P)............... 0.3
11. REPLACEMENT REDRILL FRACTION (I/P)........... 0.33
12. WELLHEAD RESOURCE TEMPERATURE,F:
    -MINIMUM VALUE (I/P).... 370
    -VALUE AT MODE (I/P).... 410
    -MAXIMUM VALUE (I/P).... 450
    -MEAN VALUE (O/P)............................ 410
13. NET SPECIFIC ENERGY,WHR/LB (O/P).............  9.8
14. WELL FLOW RATE,1000LB/HR:
    -MINIMUM VALUE (I/P).... 400
    -VALUE AT MODE (I/P).... 500
    -MAXIMUM VALUE (I/P).... 650
    -MEAN VALUE (O/P)...........................  513
15. WELL SPACING,ACRES/WELL (I/P)................ 40
16. SALINITY INDEX [0:LOW→4:HIGH] (I/P).......... 3
17. WELL LIFE,YRS:
    -MINIMUM VALUE (I/P).... 9
    -VALUE AT MODE (I/P).... 13
    -MAXIMUM VALUE (I/P).... 17
    -MEAN VALUE (O/P)............................ 13.0
18. BOOK LIFE OF WELLS,YRS (I/P)................. 13
19. BOOK LIFE OF SURFACE CAPITAL,YRS (I/P)....... 30
20. TAX LIFE OF WELLS,YRS (I/P).................. 13
21. AD VALOREM TAX,ON ACTUAL VALUE (I/P)......... 0.01
22. ROYALTY FRACTION (I/P)....................... 0.125
23. LEASE BONUS,$/ACRE (I/P)..................... 100
24. LAND RENTAL,$/ACRE (I/P)..................... 2
25. POWER TRANSMISSION COST,$1000 (I/P):
    -TO 100000 KWE............................... 2700
    -ADDITIONAL INCREMENTS OF 600000 KWE......... 24700
26. ALTERNATIVE GENERATION:
    -CAPITAL COST,$/KWE (I/P).................... 1040
    -FUEL COST,MILLS/KWH (I/P)................... 13.1
```

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL.TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1985	50	1.00	560	616	17.5
2	100	1986	50	.99	1120	589	17.7
3	200	1998	100	.97	2240	685	16.7
4	300	1989	100	.95	3320	644	17.0
5	400	1990	100	.81	4440	624	17.2
6	500	1991	100	.75	5560	611	17.3
7	600	1992	100	.65	6680	603	17.3
8	700	1993	100	.61	7760	632	17.0
9	800	1994	100	.53	8880	624	17.0
10	900	1995	100	.50	9960	617	17.1
11	1000	1996	100	.45	11040	611	17.1
12	1100	1997	100	.40	12160	607	17.1
13	1200	1998	100	.37	13280	603	17.1
14	1300	1999	100	.33	14400	619	16.9

to four for extremely saline, erosive and/or corrosive composition). With an estimated total dissolved solid content of 100,000 ppm, the Brawley KGRA is assigned a brine contamination index of 3. It is assumed that for development of up to 100 MWe, 138 KV feeder lines will be built from the KGRA to the SCE Niland Substation 21 miles away. Larger developments will require a double circuit 230 KV line, connecting the KGRA to the Santa Rosa Substation approximately 90 miles away. The initial 50 MW plant is assumed to come on line in 1983 for modeling purposes.

Results of the Brawley investment evaluation are provided in Table 4-3 and are illustrated in Figure 4-3. With marginally competitive pricing of the resource (i.e. price multiplier of 1 in Table 4-3), the financial attributes[32] of Brawley well field investments appear attractive to both major corporate resource producers and independent operators. Front-end finding costs detract from the attractiveness of the initial 50 MWe level of development only.

As well field development progresses beyond the 500 and 600 MWe levels -- for independent and major corporate producers, respectively -- risks of investment loss cause the likelihood of investment to fall below 50%. These present perceptions of risk may change as continued exploration better defines the confidence mapping presented in Figure 4-2. Results given here reflect the Brawley resource potential as it is understood today. The 1979 USGS assessment of Brawley (see Muffler, 1979) estimates its electric power potential at 640 MWe which is consistent with the investment evaluation presented here.

Variations in the resource pricing at Brawley have a noticeable impact on estimated investment behavior, particularly of the independently operating resource producer. The impacts of pricing variations are graphically illustrated in Figure 4-3.

[32] Financial attributes include return on investment, payback time and net present value as provided in Table 4-3.

TABLE 4-3. BRAWLEY INVESTMENT EVALUATION

Part A: Major "Type I" Corporate Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.16	.15	10.2	11030	.00	763	.39
2	100	.22	.16	6.4	26553	.01	697	.95
3	200	.22	.16	6.5	46554	.03	745	.95
4	300	.23	.17	6.5	75991	.05	751	.95
5	400	.24	.17	6.5	104327	.19	762	.78
6	500	.24	.17	6.5	131735	.25	770	.63
7	600	.25	.17	6.5	158282	.35	779	.32
8	700	.25	.17	6.5	174743	.39	784	.22
9	800	.25	.17	6.5	199886	.47	796	.09
10	900	.25	.17	5.6	224652	.50	801	.07
11	1000	.25	.17	5.6	248207	.55	810	.04
12	1100	.26	.17	5.6	271107	.60	822	.02
13	1200	.26	.17	5.6	293176	.63	831	.01
14	1300	.26	.17	5.6	306539	.67	840	.00
PRICE MULTIPLIER:1								
1	50	.20	.16	7.6	23065	.00	763	.90
2	100	.27	.18	4.8	49144	.01	697	.99
3	200	.29	.18	4.8	89672	.03	745	.99
4	300	.29	.18	4.8	136777	.05	751	.98
5	400	.30	.18	4.8	182967	.19	762	.90
6	500	.30	.18	4.8	227484	.25	770	.80
7	600	.31	.18	4.8	270795	.35	779	.50
8	700	.31	.18	4.8	302511	.39	784	.36
9	800	.31	.18	4.8	342638	.47	796	.15
10	900	.31	.18	4.7	381743	.50	801	.11
11	1000	.31	.18	4.7	419023	.55	810	.06
12	1100	.32	.18	4.7	455044	.60	822	.03
13	1200	.32	.18	4.7	489663	.63	831	.02
14	1300	.32	.18	4.7	515029	.67	840	.01
PRICE MULTIPLIER:1.2								
1	50	.22	.17	6.3	35100	.00	763	.97
2	100	.32	.18	4.0	71736	.01	697	.99
3	200	.34	.18	3.9	130789	.03	745	.99
4	300	.34	.19	3.9	197559	.05	751	.99
5	400	.35	.19	3.9	261612	.19	762	.93
6	500	.35	.19	3.9	323223	.25	770	.86
7	600	.35	.19	3.9	382489	.35	779	.58
8	700	.35	.19	3.9	430283	.39	784	.44
9	800	.36	.19	3.9	485398	.47	796	.19
10	900	.36	.19	3.9	538835	.50	801	.14
11	1000	.36	.19	3.9	589855	.55	810	.07
12	1100	.37	.19	3.9	638983	.60	822	.04
13	1200	.37	.19	3.9	686149	.63	831	.02
14	1300	.37	.19	3.9	723506	.67	840	.01

TABLE 4-3. Part B: Independently Operating "Type III" Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.16	.14	12.5	4748	.00	763	.00
2	100	.22	.16	7.9	13897	.01	697	.63
3	200	.22	.16	8.2	24269	.03	745	.47
4	300	.23	.16	7.4	41437	.05	751	.69
5	400	.23	.16	7.4	57628	.19	762	.24
6	500	.24	.16	7.4	73068	.25	770	.13
7	600	.24	.16	6.5	87775	.35	779	.05
8	700	.24	.16	6.5	95554	.39	784	.03
9	800	.24	.16	6.5	109158	.47	796	.00
10	900	.25	.16	6.5	122416	.50	801	.00
11	1000	.25	.16	6.5	134783	.55	810	.00
12	1100	.25	.17	6.5	146634	.60	822	.00
13	1200	.26	.17	6.5	157848	.63	831	.00
14	1300	.26	.17	6.5	163366	.67	840	.00
PRICE MULTIPLIER:1								
1	50	.19	.15	8.3	13876	.00	763	.28
2	100	.27	.17	5.5	30613	.01	697	.98
3	200	.28	.17	5.6	54537	.03	745	.98
4	300	.29	.17	5.6	84419	.05	751	.98
5	400	.30	.17	4.8	112572	.19	762	.82
6	500	.30	.17	4.8	139248	.25	770	.62
7	600	.30	.18	4.8	164521	.35	779	.20
8	700	.31	.18	4.8	182224	.39	784	.11
9	800	.31	.18	4.8	205167	.47	796	.03
10	900	.31	.18	4.8	227173	.50	801	.02
11	1000	.31	.18	4.8	247781	.55	810	.00
12	1100	.32	.18	4.8	267346	.60	822	.00
13	1200	.32	.18	4.8	285821	.63	831	.00
14	1300	.32	.18	4.8	298127	.67	840	.00
PRICE MULTIPLIER:1.2								
1	50	.22	.16	7.1	23006	.00	763	.83
2	100	.32	.18	4.8	47337	.01	697	.99
3	200	.34	.18	4.8	84799	.03	745	.99
4	300	.35	.18	3.9	127407	.05	751	.99
5	400	.35	.18	3.9	167520	.19	762	.90
6	500	.35	.18	3.9	205420	.25	770	.75
7	600	.36	.18	3.9	241274	.35	779	.31
8	700	.36	.18	3.9	268913	.39	784	.17
9	800	.36	.18	3.9	301179	.47	796	.04
10	900	.37	.19	3.9	331944	.50	801	.02
11	1000	.37	.19	3.9	360756	.55	810	.00
12	1100	.37	.19	3.9	388059	.60	822	.00
13	1200	.37	.19	3.9	413773	.63	831	.00
14	1300	.37	.19	3.9	432888	.67	840	.00

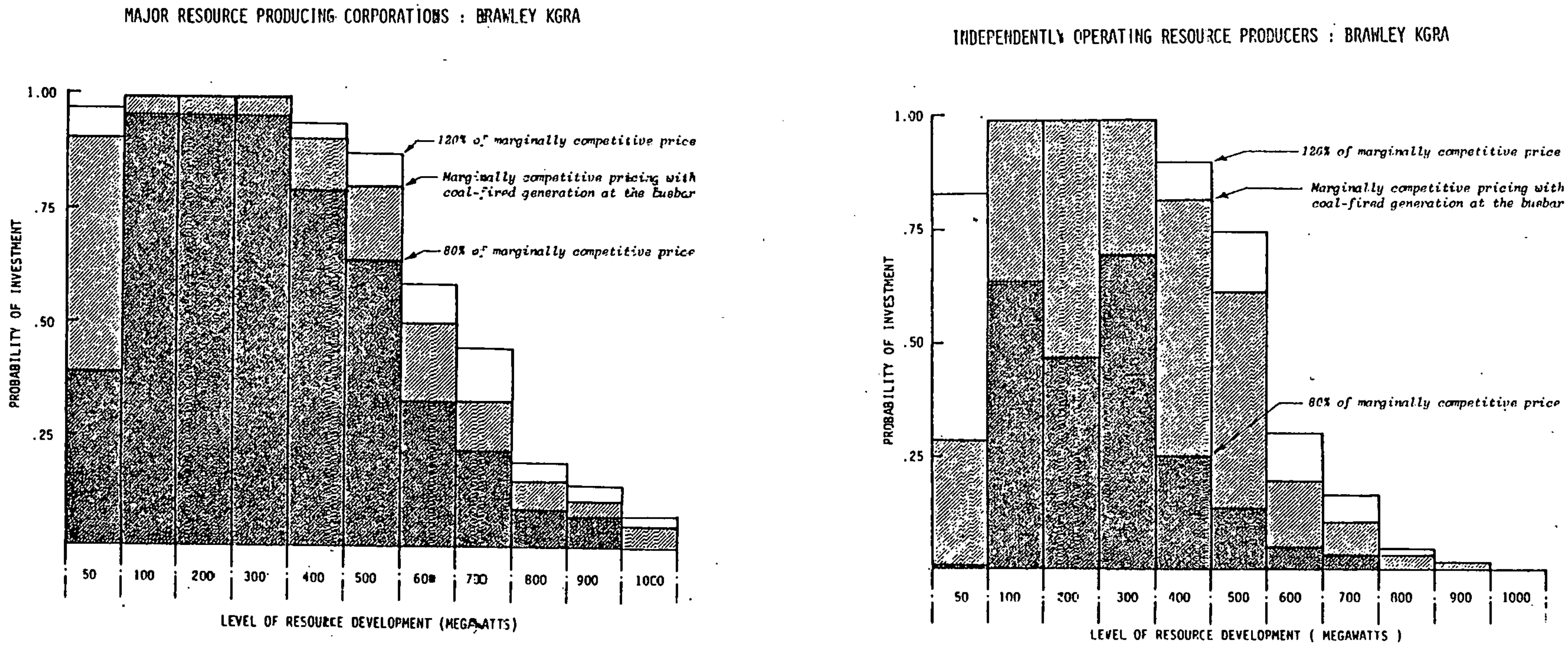


Figure 4-3. ESTIMATES OF INVESTMENT BEHAVIOR AT BRAWLEY GEOTHERMAL RESOURCE AREA

4.2.2 East Mesa, Imperial Valley, CA

Located in Imperial County, California, the East Mesa KGRA is being actively explored and developed by both the Magma Power Company and Republic Geothermal Company. Magma has applied for a permit to construct an 11 MWe pilot plant for research and development. Republic Geothermal is also considering development of a 50 MWe plant at East Mesa. San Diego Gas and Electric, in conjunction with its resource company, New Albion Resources, is also actively investigating the commercial potential of the KGRA. Table 4-4 summarizes East Mesa resource characteristics and Figure 4-4 illustrates levels of confidence over the KGRA as it is presently understood.

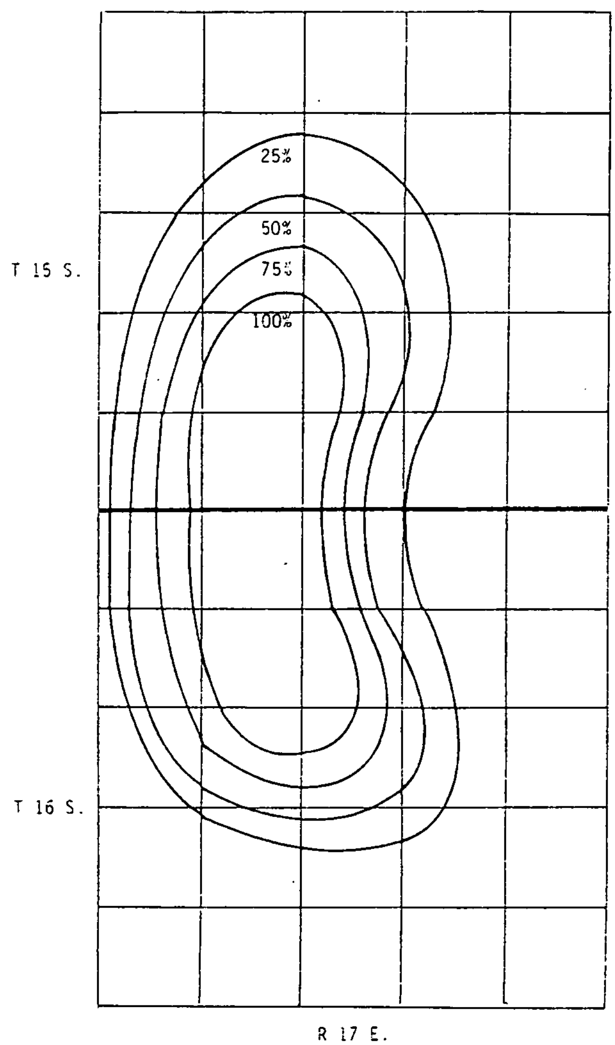


Figure 4-4. LEVELS OF CONFIDENCE
AT EAST MESA KGRA (MID-1979)

TABLE 4-4. RESOURCE AND DEVELOPMENT PARAMETERS AT EAST MESA KGRA

RESOURCE PARAMETERS

1. STATE.. CA
2. TYPE OF GEOLOGY (I/P)...................... SEDIMENTARY
3. RESERVOIR DEPTH,FT:
   - -MINIMUM VALUE (I/P).... 3300
   - -VALUE AT MODE (I/P).... 6200
   - -MAXIMUM VALUE (I/P).... 9100
   - -MEAN VALUE (O/P)........................... 6200
4. MEAN WELL COST,$1000 (O/P).................. 416
5. DRY WELL COST FRACTION (I/P)................ 0.9
6. REDRILL WELL COST FRACTION (I/P)............ 0.35
7. DRY WELL FRACTION:
   - -MINIMUM VALUE (I/P).... 0.09
   - -VALUE AT MODE (I/P).... 0.1
   - -MAXIMUM VALUE (I/P).... 0.11
   - -MEAN VALUE (O/P)........................... 0.1
8. SPARE WELL FRACTION (I/P)................... 0.2
9. PRODUCER/INJECTOR RATIO (I/P)............... 2
10. INITIAL REDRILL FRACTION (I/P)............. 0.3
11. REPLACEMENT REDRILL FRACTION (I/P)......... 0.33
12. WELLHEAD RESOURCE TEMPERATURE,F:
    - -MINIMUM VALUE (I/P).... 320
    - -VALUE AT MODE (I/P).... 340
    - -MAXIMUM VALUE (I/P).... 360
    - -MEAN VALUE (O/P)........................... 340
13. NET SPECIFIC ENERGY,WHR/LB (O/P)........... 5.9
14. WELL FLOW RATE,1000LB/HR:
    - -MINIMUM VALUE (I/P).... 400
    - -VALUE AT MODE (I/P).... 530
    - -MAXIMUM VALUE (I/P).... 700
    - -MEAN VALUE (O/P)........................... 540
15. WELL SPACING,ACRES/WELL (I/P).............. 40
16. SALINITY INDEX [0:LOW→4:HIGH] (I/P)........ 1
17. WELL LIFE,YRS:
    - -MINIMUM VALUE (I/P).... 10
    - -VALUE AT MODE (I/P).... 15
    - -MAXIMUM VALUE (I/P).... 20
    - -MEAN VALUE (O/P)........................... 15.0
18. BOOK LIFE OF WELLS,YRS (I/P)............... 15
19. BOOK LIFE OF SURFACE CAPITAL,YRS (I/P)..... 30
20. TAX LIFE OF WELLS,YRS (I/P)................ 15
21. AD VALOREM TAX,ON ACTUAL VALUE (I/P)....... 0.01
22. ROYALTY FRACTION (I/P)..................... 0.125
23. LEASE BONUS,$/ACRE (I/P)................... 100
24. LAND RENTAL,$/ACRE (I/P)................... 2
25. POWER TRANSMISSION COST,$1000 (I/P):
    - -TO 100000 KWE.............................. 1900
    - -ADDITIONAL INCREMENTS OF 600000 KWE........ 29900
26. ALTERNATIVE GENERATION:
    - -CAPITAL COST,$/KWE (I/P)................... 1040
    - -FUEL COST,MILLS/KWH (I/P).................. 13.1

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL,TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1985	50	1.00	880	643	17.1
2	100	1988	50	.97	1760	624	17.2
3	200	1990	100	.91	3520	755	15.9
4	300	1991	100	.79	5240	705	16.3
5	400	1992	100	.69	6960	680	16.5
6	500	1993	100	.50	8680	665	16.6
7	600	1994	100	.48	10400	655	16.7
8	700	1995	100	.29	12120	691	16.3
9	800	1996	100	.25	13840	680	16.4
10	900	1997	100	.17	15560	672	16.5

The East Mesa resource is of moderate temperature and salinity. With an estimated total dissolved solid content of 2500 ppm, a brine contamination index of 1 is assigned to the resource. Transmission requirements for the first 100 MWe of power development can be met by installation of 138 KV transmission lines extending from the KGRA to the substation at El Centro, 50 miles away. Additional capacity will require installation of a double circuit 230 KV line from East Mesa to the Santa Rosa substation, approximately 110 miles away. For modeling purposes, it is assumed that the first 50 MWe plant will be brought on line in 1985.

Results of the East Mesa investment evaluation are provided in Table 4-5 and Figure 4-5. As at Brawley, with marginally competitive pricing of the geothermal resource, the financial attributes of East Mesa well field investments appear attractive to both major corporate resource producers and independent operators. These attributes are slightly less attractive than at Brawley primarily because of the cooler resource temperature at East Mesa. Cooler well head temperatures have an adverse effect on power plant efficiency -- see item 13 in Table 4-4 -- which dictates: (a) a requirement for more producer wells to support a given level of electric power, and (b) a lower competitive resource price because of higher power plant costs. The adverse effects of cooler resource temperatures at East Mesa, however, are favorably offset to some degree by higher estimated well flow rates, less expensive wells, and longer estimated well lives -- items 14, 4 and 17, respectively, in Table 4-4.

Front end resource finding costs detract from the attractiveness of the initial 50 MWe level of development at East Mesa, particularly for the independently operating resource producer. As well field development progresses beyond the 300 and 400 MWe levels -- for independent and major corporate producers, respectively -- risks of investment loss cause the likelihood of investment to fall below 50%. These risk perceptions reflect the mappings of resource confidence (Figure 4-4) as East Mesa is understood today and may change as exploration continues to better define the resource. The 1979 USGS assessment of East Mesa

TABLE 4-5. EAST MESA INVESTMENT EVALUATION
Part A: Major "Type I" Corporate Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.16	.15	10.3	10741	.00	699	.36
2	100	.21	.16	7.3	24692	.03	630	.90
3	200	.21	.16	8.4	40828	.09	699	.75
4	300	.22	.16	7.5	68315	.21	705	.60
5	400	.22	.16	7.5	94839	.31	713	.33
6	500	.23	.16	7.4	120434	.50	722	.05
7	600	.23	.16	6.6	145053	.52	730	.04
8	700	.23	.16	6.6	158901	.71	739	.00
9	800	.23	.17	6.6	182433	.75	748	.00
10	900	.24	.17	6.6	205273	.83	757	.00
PRICE MULTIPLIER:1								
1	50	.19	.16	7.6	21783	.00	699	.89
2	100	.26	.17	5.6	45424	.03	630	.98
3	200	.27	.17	5.7	79484	.09	699	.95
4	300	.28	.17	5.6	124119	.21	705	.83
5	400	.28	.17	5.6	167054	.31	713	.56
6	500	.28	.18	5.6	208359	.50	722	.09
7	600	.29	.18	4.8	248000	.52	730	.07
8	700	.29	.18	4.8	276242	.71	739	.00
9	800	.29	.18	4.8	313548	.75	748	.00
10	900	.29	.18	4.8	349574	.83	757	.00
PRICE MULTIPLIER:1.2								
1	50	.22	.17	6.8	32824	.00	699	.96
2	100	.30	.18	4.7	66156	.03	630	.99
3	200	.31	.18	4.8	118149	.09	699	.98
4	300	.32	.18	4.7	179922	.21	705	.89
5	400	.33	.18	4.7	239265	.31	713	.66
6	500	.33	.18	4.7	296270	.50	722	.12
7	600	.33	.18	3.9	350950	.52	730	.09
8	700	.33	.18	3.9	393585	.71	739	.00
9	800	.34	.18	3.9	444672	.75	748	.00
10	900	.34	.18	3.9	493860	.83	757	.00

TABLE 4-5. Part B: Independently Operating "Type III" Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.15	.14	13.4	4248	.00	699	.00
2	100	.20	.16	8.9	11784	.03	630	.21
3	200	.20	.15	9.3	18817	.09	699	.08
4	300	.21	.16	8.4	33815	.21	705	.06
5	400	.22	.16	8.3	48046	.31	713	.02
6	500	.22	.16	8.3	61540	.50	722	.00
7	600	.22	.16	7.5	74301	.52	730	.00
8	700	.22	.16	8.3	79960	.71	739	.00
9	800	.23	.16	7.5	91935	.75	748	.00
10	900	.23	.16	7.5	103418	.83	757	.00
PRICE MULTIPLIER:1								
1	50	.19	.15	9.0	12333	.00	699	.18
2	100	.26	.17	6.4	26595	.03	630	.95
3	200	.26	.17	6.6	45633	.09	699	.87
4	300	.27	.17	5.7	71898	.21	705	.63
5	400	.28	.17	5.7	96733	.31	713	.24
6	500	.28	.17	5.7	120198	.50	722	.01
7	600	.28	.17	5.7	142326	.52	730	.00
8	700	.28	.17	5.7	156788	.71	739	.00
9	800	.29	.17	5.7	177026	.75	748	.00
10	900	.29	.17	5.7	196277	.83	757	.00
PRICE MULTIPLIER:1.2								
1	50	.22	.16	7.5	20412	.00	699	.74
2	100	.30	.18	4.8	41400	.03	630	.99
3	200	.31	.18	4.8	72440	.09	699	.97
4	300	.32	.18	4.8	109985	.21	705	.82
5	400	.33	.18	4.8	145410	.31	713	.43
6	500	.33	.18	4.8	178842	.50	722	.02
7	600	.33	.18	4.8	210335	.52	730	.01
8	700	.33	.18	4.8	233602	.71	739	.00
9	800	.34	.18	4.8	262125	.75	748	.00
10	900	.34	.18	4.8	289138	.83	757	.00

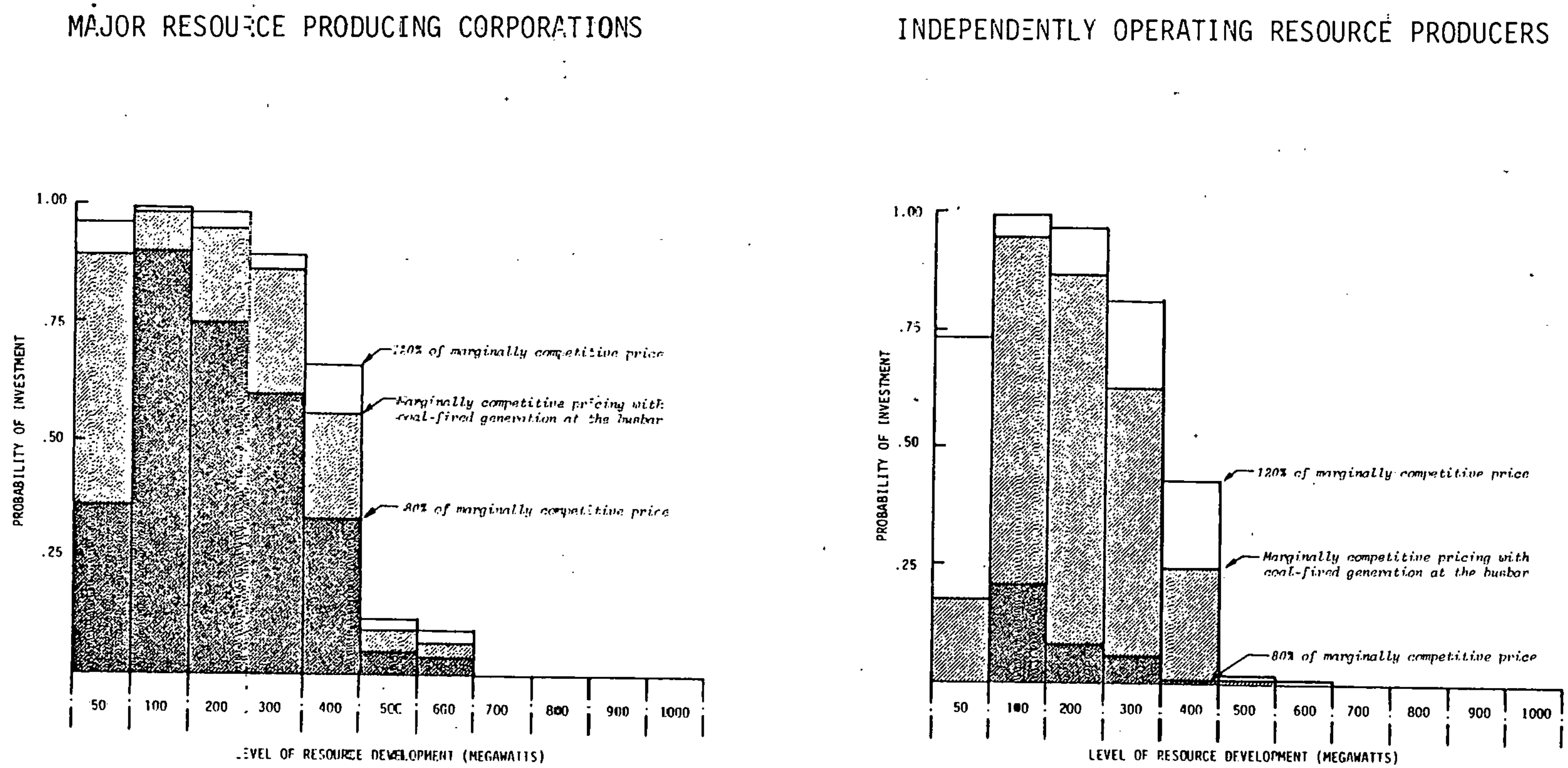


Figure 4-5. ESTIMATES OF INVESTMENT BEHAVIOR
AT EAST MESA GEOTHERMAL RESOURCE AREA

(see Muffler, 1979) estimates its electric power potential at 360 MWe which is consistent with this investment analysis. Variations in the resource pricing at East Mesa have a very pronounced impact on estimated investment behavior by both major corporate producers and independent operators. These effects are illustrated in Figure 4-5.

4.2.3 Heber, Imperial Valley, CA

At the Heber, KGRA, located in Imperial County, California, a substantial amount of effort has been directed to resource assessment and evaluation of potential equipment applications. A number of utilities and resource producers have been actively involved including San Diego Gas and Electric, Los Angeles Department of Water and Power, Southern California Edison, Chevron Resources Company, Magma Power Company, and Republic Geothermal Corporation. Both Southern California Edison and San Diego Gas and Electric plan to construct demonstration plants in the 1980's. Table 4-6 summarizes Heber resource characteristics and Figure 4-6 maps levels of confidence as currently perceived over this area.

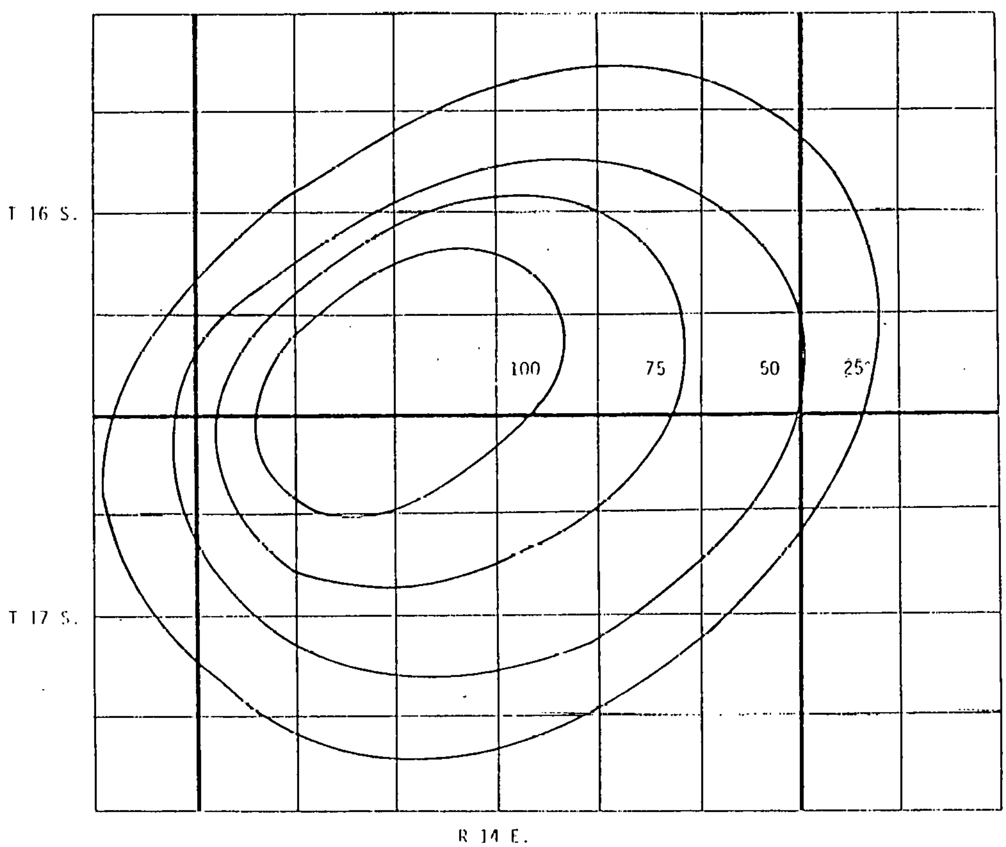


Figure 4-6. LEVELS OF CONFIDENCE
AT HEBER KGRA (MID-1979)

TABLE 4-6. RESOURCE AND DEVELOPMENT PARAMETERS AT HEBER KGRA

RESOURCE PARAMETERS

1. STATE.. CA
2. TYPE OF GEOLOGY (I/P)........................ SEDIMENTARY
3. RESERVOIR DEPTH,FT:
   - -MINIMUM VALUE (I/P).... 3300
   - -VALUE AT MODE (I/P).... 4900
   - -MAXIMUM VALUE (I/P).... 6600
   - -MEAN VALUE (O/P)........................... 4925
4. MEAN WELL COST,$1000 (O/P).................. 353
5. DRY WELL COST FRACTION (I/P)................. 0.9
6. REDRILL WELL COST FRACTION (I/P)............. 0.35
7. DRY WELL FRACTION:
   - -MINIMUM VALUE (I/P).... 0.09
   - -VALUE AT MODE (I/P).... 0.1
   - -MAXIMUM VALUE (I/P).... 0.11
   - -MEAN VALUE (O/P)........................... 0.1
8. SPARE WELL FRACTION (I/P).................... 0.2
9. PRODUCER/INJECTOR RATIO (I/P)................ 2
10. INITIAL REDRILL FRACTION (I/P)............... 0.3
11. REPLACEMENT REDRILL FRACTION (I/P)........... 0.33
12. WELLHEAD RESOURCE TEMPERATURE,F:
    - -MINIMUM VALUE (I/P).... 320
    - -VALUE AT MODE (I/P).... 340
    - -MAXIMUM VALUE (I/P).... 360
    - -MEAN VALUE (O/P)........................... 340
13. NET SPECIFIC ENERGY,WHR/LB (O/P)............. 5.9
14. WELL FLOW RATE,1000LB/HR:
    - -MINIMUM VALUE (I/P).... 400
    - -VALUE AT MODE (I/P).... 500
    - -MAXIMUM VALUE (I/P).... 600
    - -MEAN VALUE (O/P)........................... 500
15. WELL SPACING,ACRES/WELL (I/P)................ 40
16. SALINITY INDEX [0:LOW→4:HIGH] (I/P).......... 2
17. WELL LIFE,YRS:
    - -MINIMUM VALUE (I/P).... 9
    - -VALUE AT MODE (I/P).... 13
    - -MAXIMUM VALUE (I/P).... 17
    - -MEAN VALUE (O/P)........................... 13.0
18. BOOK LIFE OF WELLS,YRS (I/P)................. 13
19. BOOK LIFE OF SURFACE CAPITAL,YRS (I/P)....... 30
20. TAX LIFE OF WELLS,YRS (I/P).................. 13
21. AD VALOREM TAX,ON ACTUAL VALUE (I/P)......... 0.01
22. ROYALTY FRACTION (I/P)....................... 0.125
23. LEASE BONUS,$/ACRE (I/P)..................... 100
24. LAND RENTAL,$/ACRE (I/P)..................... 2
25. POWER TRANSMISSION COST,$1000 (I/P):
    - -TO 100000 KWE.............................. 400
    - -ADDITIONAL INCREMENTS OF 600000 KWE......... 29600
26. ALTERNATIVE GENERATION:
    - -CAPITAL COST,$/KWE (I/P).................... 1040
    - -FUEL COST,MILLS/KWH (I/P).................. 13.1

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL.TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1983	50	1.00	960	813	17.5
2	100	1986	50	1.00	1880	609	17.5
3	200	1988	100	.98	3760	753	16.0
4	300	1989	100	.87	5600	704	16.4
5	400	1990	100	.79	7520	679	16.6
6	500	1991	100	.75	9320	664	16.8
7	600	1992	100	.64	11240	655	16.8
8	700	1993	100	.58	13120	690	16.4
9	800	1994	100	.52	14960	679	16.5
10	900	1995	100	.50	16840	671	16.6
11	1000	1996	100	.42	18720	664	16.6
12	1100	1997	100	.36	20560	659	16.6
13	1200	1998	100	.31	22440	655	16.6
14	1300	1999	100	.25	24280	674	16.4

The Heber resource is of moderate temperature and salinity. Because of the moderate dissolved solid content of the brine, a brine contamination index of 2 was assigned to the resource. Power will likely be delivered to the El Centro substation over 138 KV lines for development of up to 100 MWe of power. For larger capacities, a 230 KV line will be built to carry the power from the KGRA to the Santa Rosa substation. Investment simulation is based on an assumed start up date of 1983 for the first 50 MWe plant.

Results of the Heber investment evaluation are provided in Table 4-7 and Figure 4-7. With marginally competitive pricing of the geothermal resource, the financial attributes of Heber well field investments appear attractive to both major corporate resource producers and independent operators. Investment characteristics at Heber are very similar to those at the East Mesa area with slight differences in return attributable to shorter estimated well life at Heber. This reduced life is, however, somewhat off-set by lower estimated well costs at Heber.

Front end resource finding costs detract from the attractiveness of the initial 50 MWe level of development at Heber, especially for the independently operating firm. As well field development progresses beyond the 500 MWe level, risks of investment loss cause the likelihood of investment to fall appreciably below 50%. These risk perceptions reflect the mappings of resource confidence (Figure 4-6) as Heber is understood today. Continued exploration may redefine the confidence levels in the future. The 1979 USGS assessment of Heber (see Muffler, 1979) estimates its electric power potential at 650 MWe, which is slightly more optimistic than the development potential estimated through this investment analysis at marginally competitive resource prices.

Variations in the resource price at Heber have a very significant impact on estimated investment behavior at all levels of development. These effects are graphically illustrated in Figure 4-7.

TABLE 4-7. HEBER INVESTMENT EVALUATION

Part A: Major "Type I" Corporate Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.14	.14	12.3	7727	.00	607	.10
2	100	.19	.16	8.2	18724	.00	535	.84
3	200	.19	.15	9.3	28367	.02	606	.69
4	300	.20	.16	8.4	51434	.13	611	.64
5	400	.20	.16	8.4	73019	.22	624	.41
6	500	.21	.16	7.5	95194	.25	623	.46
7	600	.21	.16	7.5	115639	.36	639	.18
8	700	.21	.16	7.5	124690	.42	644	.10
9	800	.21	.16	7.5	145081	.48	650	.05
10	900	.21	.16	7.5	164251	.50	660	.04
11	1000	.22	.16	7.5	183207	.58	669	.02
12	1100	.22	.16	7.5	201940	.64	674	.00
13	1200	.22	.16	7.5	219861	.69	685	.00
14	1300	.23	.16	6.6	227920	.75	690	.00
PRICE MULTIPLIER:1								
1	50	.18	.16	8.4	19762	.00	607	.82
2	100	.25	.17	5.6	41318	.00	535	.98
3	200	.25	.17	5.7	70481	.02	606	.98
4	300	.26	.17	5.7	112218	.13	611	.92
5	400	.26	.17	5.7	151663	.22	624	.79
6	500	.27	.17	5.7	190928	.25	623	.73
7	600	.27	.17	5.7	227753	.36	639	.37
8	700	.27	.17	5.7	252460	.42	644	.21
9	800	.28	.17	5.6	287840	.48	650	.11
10	900	.28	.17	5.7	321357	.50	660	.08
11	1000	.28	.17	5.6	354009	.58	669	.03
12	1100	.29	.18	4.8	385884	.64	674	.01
13	1200	.29	.18	4.8	416331	.69	685	.00
14	1300	.29	.18	4.8	436416	.75	690	.00
PRICE MULTIPLIER:1.2								
1	50	.21	.16	6.9	31795	.00	607	.95
2	100	.29	.18	4.7	63905	.00	535	.99
3	200	.30	.18	4.8	112602	.02	606	.99
4	300	.31	.18	4.8	172993	.13	611	.96
5	400	.31	.18	4.8	230307	.22	624	.87
6	500	.32	.18	4.7	286664	.25	623	.82
7	600	.32	.18	4.7	339862	.36	639	.48
8	700	.32	.18	4.7	380231	.42	644	.28
9	800	.33	.18	4.7	430597	.48	650	.15
10	900	.33	.18	4.7	478466	.50	660	.11
11	1000	.33	.18	3.9	524832	.58	669	.04
12	1100	.34	.18	3.9	569811	.64	674	.02
13	1200	.34	.18	3.9	612823	.69	685	.00
14	1300	.34	.18	3.9	644888	.75	690	.00

TABLE 4-7. Part B: Independently Operating "Type III" Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.14	.14	15.9	1923	.00	607	.00
2	100	.18	.15	9.8	7506	.00	535	.06
3	200	.18	.15	11.1	10154	.02	606	.02
4	300	.19	.15	10.2	22549	.13	611	.02
5	400	.19	.15	10.2	33837	.22	624	.00
6	500	.21	.15	9.3	45534	.25	623	.02
7	600	.20	.15	9.3	55960	.36	639	.00
8	700	.20	.15	9.3	58619	.42	644	.00
9	800	.21	.16	8.4	69021	.48	650	.00
10	900	.21	.16	9.3	78545	.50	660	.00
11	1000	.21	.16	8.4	87899	.58	669	.00
12	1100	.22	.16	8.4	97096	.64	674	.00
13	1200	.22	.16	8.4	105691	.69	685	.00
14	1300	.22	.16	8.4	107888	.75	690	.00
PRICE MULTIPLIER:1								
1	50	.18	.15	9.6	11055	.00	607	.07
2	100	.24	.16	6.4	24231	.00	535	.95
3	200	.25	.16	6.6	40415	.02	606	.93
4	300	.26	.17	6.6	65550	.13	611	.76
5	400	.26	.17	6.6	88783	.22	624	.43
6	500	.27	.17	5.7	111715	.25	623	.48
7	600	.27	.17	5.7	132711	.36	639	.12
8	700	.27	.17	5.7	145293	.42	644	.04
9	800	.27	.17	5.7	165026	.48	650	.02
10	900	.27	.17	5.7	183316	.50	660	.01
11	1000	.28	.17	5.7	200888	.58	669	.00
12	1100	.29	.17	5.7	217003	.64	674	.00
13	1200	.29	.17	5.7	233653	.69	685	.00
14	1300	.29	.17	5.7	242644	.75	690	.00
PRICE MULTIPLIER:1.2								
1	50	.21	.16	7.6	20188	.00	607	.66
2	100	.29	.17	5.5	40943	.00	535	.99
3	200	.30	.17	4.8	70688	.02	606	.99
4	300	.31	.18	4.8	108539	.13	611	.95
5	400	.31	.18	4.8	143717	.22	624	.79
6	500	.33	.18	4.8	177898	.25	623	.72
7	600	.32	.18	4.8	209461	.36	639	.24
8	700	.32	.18	4.8	231769	.42	644	.10
9	800	.33	.18	4.8	261032	.48	650	.04
10	900	.33	.18	4.8	288082	.50	660	.02
11	1000	.33	.18	4.8	313881	.58	669	.00
12	1100	.34	.18	4.8	338521	.64	674	.00
13	1200	.34	.18	4.8	361615	.69	685	.00
14	1300	.34	.18	4.8	377392	.75	690	.00

MAJOR RESOURCE PRODUCING CORPORATIONS

INDEPENDENTLY OPERATING RESOURCE PRODUCERS

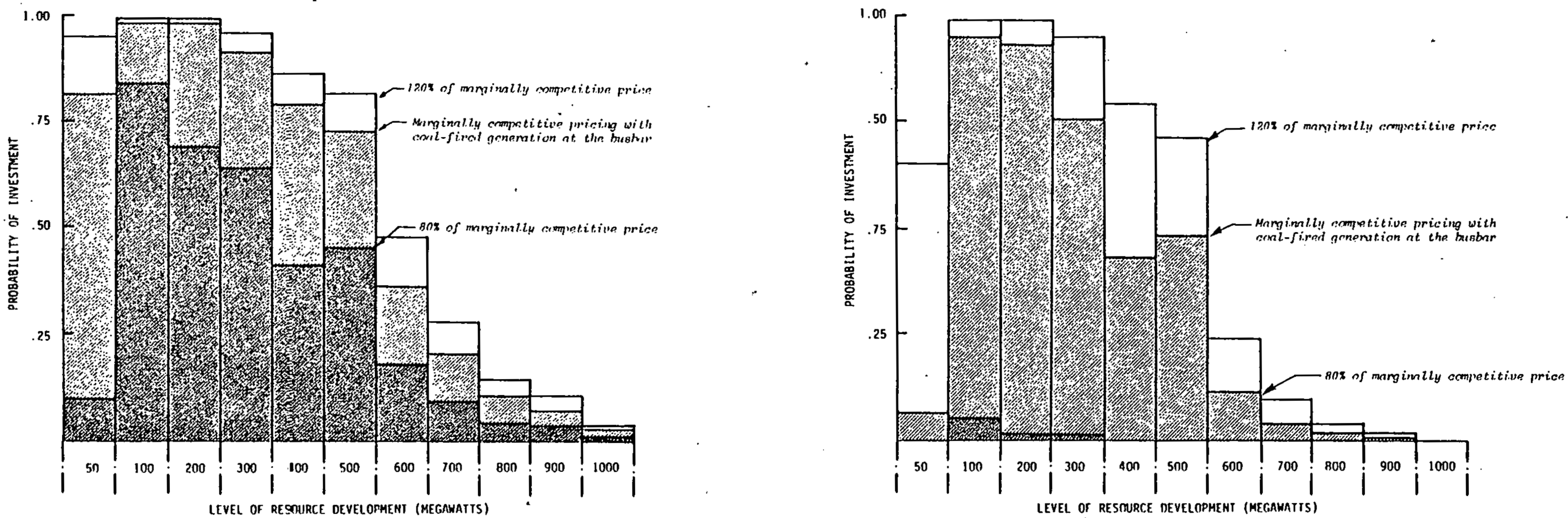


Figure 4-7. ESTIMATES OF INVESTMENT BEHAVIOR
AT HEBER GEOTHERMAL RESOURCE AREA

4.2.4 Salton Sea, Imperial Valley, CA

The final Imperial Valley resource area evaluated here is the Salton Sea KGRA. Development to date has consisted of exploratory drilling and the construction of an experimental 10 MWe equivalent test loop facility operated by San Diego Gas and Electric. Also evaluating the commercial potential of the resource are Southern California Edison, Magma Power Company, Republic Geothermal Company, Phillips Petroleum, and Union Oil. Table 4-8 summarizes Salton Sea resource characteristics and Figure 4-8 maps levels of confidence as currently perceived over this area.

As shown in Figure 4-8, a substantial portion of the field has a level of confidence in excess of 75 percent. This reflects extensive exploration and confirmation efforts made by the resource producers cited above. The resource parameters cited in Table 4-8 show the resource to be of high temperature; however, the extremely high salinity of the brine is slowing field development. The total dissolved solids content of the brine ranges from 250,000 to 300,000 ppm, equivalent to a maximum brine contamination index of 4 in the model TCN2000. Power transmission will be handled via 138 KV feeder lines to the Niland substation for the first 100 MW of capacity. A double circuit 230 KV line will be required for additional capacity, running from the KGRA to the Santa Rosa substation, a total distance of 77 miles.

Results of the Salton Sea investment evaluation are provided in Table 4-9 and Figure 4-9. As at the other three resource areas in the Imperial Valley, the financial attributes of well field investments at the Salton Sea appear attractive to both large and small resource producers given marginally competitive pricing of the resource. Despite a short estimated well life caused by highly saline brine, the relatively high resource temperature at the Salton Sea enhances the resource value and investment returns.

As with the other resource areas, front end exploration costs for the Salton Sea detract somewhat from the attractiveness of a single, initial 50 MWe level of development. However, subsequent development levels recoup these costs and investment likelihood is high for levels

TABLE 4-8. RESOURCE AND DEVELOPMENT PARAMETERS AT SALTON SEA KGRA

RESOURCE PARAMETERS

1. STATE.. CA
2. TYPE OF GEOLOGY (I/P)........................ SEDIMENTARY
3. RESERVOIR DEPTH,FT:
   - -MINIMUM VALUE (I/P).... 3300
   - -VALUE AT MODE (I/P).... 6800
   - -MAXIMUM VALUE (I/P).... 10300
   - -MEAN VALUE (O/P).......................... 6800
4. MEAN WELL COST,$1000 (O/P).................. 450
5. DRY WELL COST FRACTION (I/P)................. 0.9
6. REDRILL WELL COST FRACTION (I/P)............. 0.35
7. DRY WELL FRACTION:
   - -MINIMUM VALUE (I/P).... 0.09
   - -VALUE AT MODE (I/P).... 0.1
   - -MAXIMUM VALUE (I/P).... 0.11
   - -MEAN VALUE (O/P)........................... 0.1
8. SPARE WELL FRACTION (I/P).................... 0.2
9. PRODUCER/INJECTOR RATIO (I/P)................ 2
10. INITIAL REDRILL FRACTION (I/P)............... 0.3
11. REPLACEMENT REDRILL FRACTION (I/P)........... 0.33
12. WELLHEAD RESOURCE TEMPERATURE,F:
    - -MINIMUM VALUE (I/P).... 450
    - -VALUE AT MODE (I/P).... 500
    - -MAXIMUM VALUE (I/P).... 530
    - -MEAN VALUE (O/P).......................... 495
13. NET SPECIFIC ENERGY,WHR/LB (O/P)............. 14.5
14. WELL FLOW RATE,1000LB/HR:
    - -MINIMUM VALUE (I/P).... 300
    - -VALUE AT MODE (I/P).... 450
    - -MAXIMUM VALUE (I/P).... 600
    - -MEAN VALUE (O/P).......................... 450
15. WELL SPACING,ACRES/WELL (I/P)................ 40
16. SALINITY INDEX [0:LOW→4:HIGH] (I/P).......... 4
17. WELL LIFE,YRS:
    - -MINIMUM VALUE (I/P).... 2
    - -VALUE AT MODE (I/P).... 7
    - -MAXIMUM VALUE (I/P).... 12
    - -MEAN VALUE (O/P).......................... 7.0
18. BOOK LIFE OF WELLS,YRS (I/P)................. 7
19. BOOK LIFE OF SURFACE CAPITAL,YRS (I/P)....... 30
20. TAX LIFE OF WELLS,YRS (I/P).................. 7
21. AD VALOREM TAX,ON ACTUAL VALUE (I/P)......... 0.01
22. ROYALTY FRACTION (I/P)....................... 0.125
23. LEASE BONUS,$/ACRE (I/P)..................... 100
24. LAND RENTAL,$/ACRE (I/P)..................... 2
25. POWER TRANSMISSION COST,$1000 (I/P):
    - -TO 100000 KWE............................. 900
    - -ADDITIONAL INCREMENTS OF 600000 KWE......... 21900
26. ALTERNATIVE GENERATION:
    - -CAPITAL COST,$/KWE (I/P).................... 1040
    - -FUEL COST,MILLS/KWH (I/P)................... 13.1

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL.TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1983	50	1.00	440	527	18.4
2	100	1986	50	1.00	880	518	18.4
3	200	1988	100	1.00	1720	619	17.3
4	300	1989	100	1.00	2600	582	17.6
5	400	1990	100	1.00	3440	564	17.8
6	600	1991	200	1.00	5160	546	17.9
7	800	1992	200	1.00	6840	564	17.7
8	1000	1993	200	.99	8560	553	17.8
9	1500	1994	500	.99	12840	553	17.7
10	2000	1995	500	.98	17120	553	17.7
11	2500	1996	500	.97	21400	553	17.6
12	3000	1997	500	.95	25600	546	17.7
13	3500	1998	500	.92	29880	547	17.6
14	4000	1999	500	.86	34160	548	17.6
15	4500	2000	500	.81	38440	548	17.5
16	5000	2001	500	.77	42720	549	17.5
17	5500	2002	500	.75	47000	549	17.5
18	6000	2003	500	.73	51290	546	17.5
19	6500	2004	500	.67	55480	546	17.4
20	7000	2005	500	.64	59760	547	17.4
21	7500	2006	500	.60	64040	547	17.3
22	8000	2007	500	.56	68320	548	17.3
23	8500	2008	500	.52	72600	549	17.3
24	9000	2009	500	.50	76880	546	17.3
25	9500	2010	500	.50	81120	546	17.3

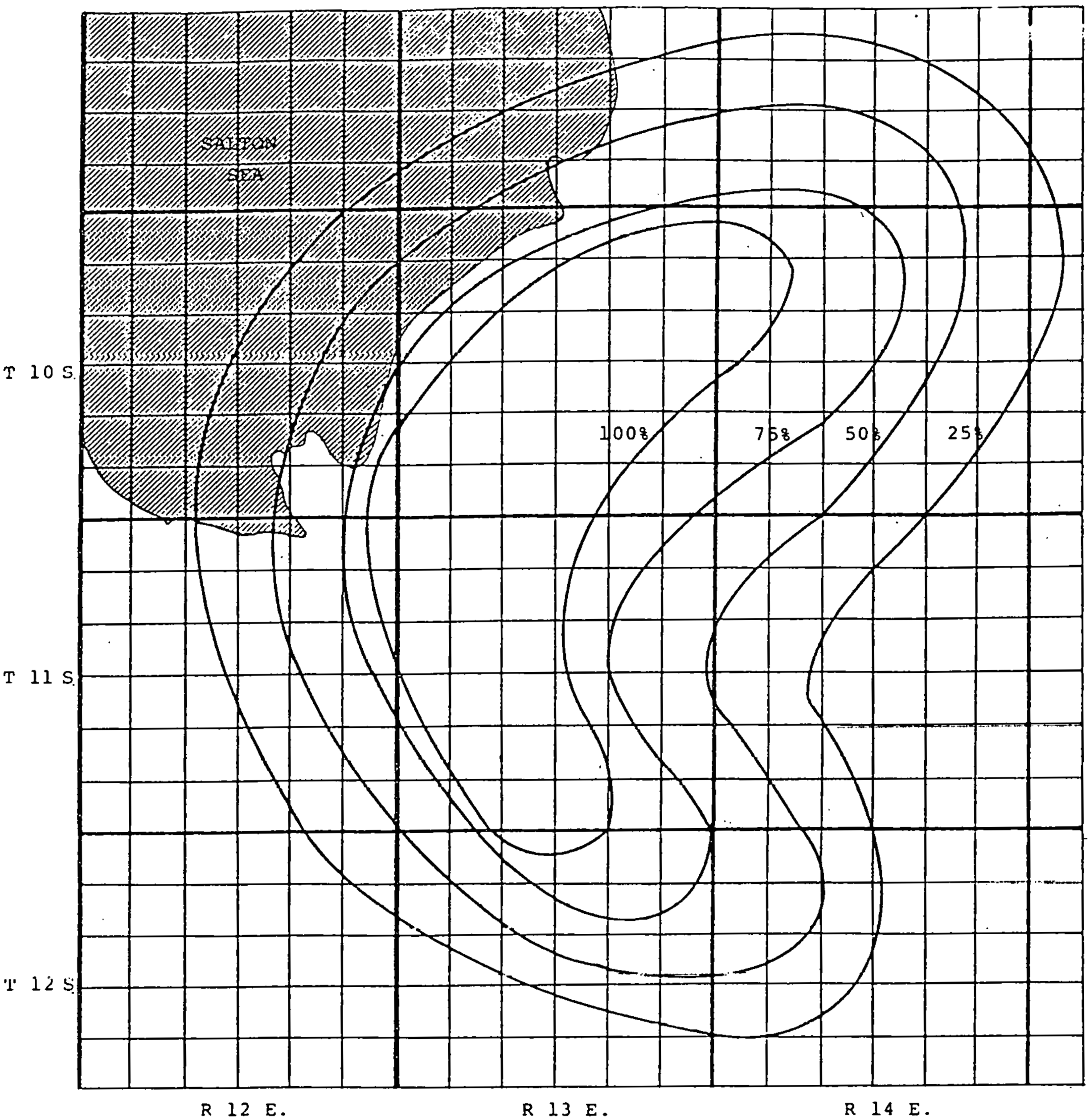


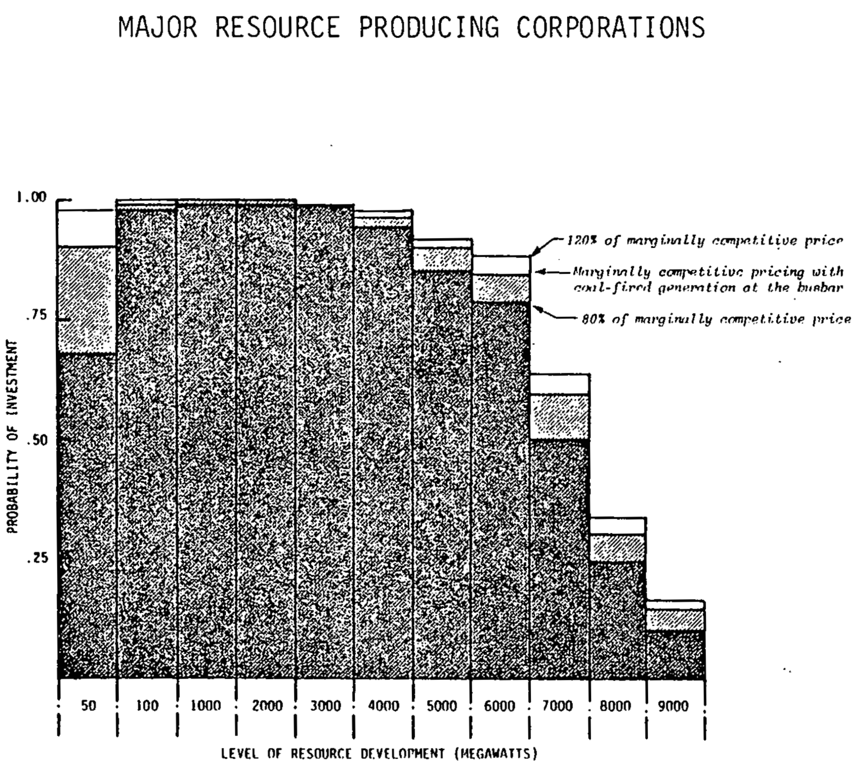
Figure 4-8. LEVELS OF CONFIDENCE
AT SALTON SEA KGRA (MID-1979)

TABLE 4-9. SALTON SEA INVESTMENT EVALUATION
Part A: Major "Type I" Corporate Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.17	.15	9.0	13811	.00	708	.68
2	100	.25	.17	5.6	30323	.00	640	.98
3	200	.26	.17	5.6	53834	.00	678	.98
4	300	.26	.17	5.6	85269	.00	688	.99
5	400	.28	.17	4.8	117011	.00	692	.99
6	600	.29	.18	4.8	178246	.00	758	.99
7	800	.29	.18	4.8	229609	.00	764	.99
8	1000	.30	.18	4.8	286991	.01	776	.99
9	1500	.31	.18	4.8	419977	.01	966	.99
10	2000	.31	.18	4.8	549147	.02	979	.99
11	2500	.32	.18	4.8	673710	.03	993	.99
12	3000	.32	.18	4.8	801932	.05	1000	.99
13	3500	.32	.18	4.8	918198	.08	1020	.98
14	4000	.33	.18	4.8	1030667	.14	1034	.95
15	4500	.33	.18	3.9	1139741	.19	1048	.92
16	5000	.33	.18	3.9	1244788	.23	1062	.86
17	5500	.33	.18	3.9	1346277	.25	1077	.83
18	6000	.34	.18	3.9	1450286	.27	1091	.79
19	6500	.34	.18	3.9	1545523	.33	1099	.61
20	7000	.35	.18	3.9	1637211	.36	1120	.51
21	7500	.35	.18	3.9	1725415	.40	1135	.37
22	8000	.35	.18	3.9	1810560	.44	1150	.25
23	8500	.35	.18	3.9	1892701	.48	1165	.16
24	9000	.36	.19	3.9	1977333	.50	1181	.12
25	9500	.36	.19	3.9	2054157	.50	1192	.12
PRICE MULTIPLIER:1								
1	50	.21	.16	7.5	25848	.00	708	.93
2	100	.30	.18	4.1	52916	.00	640	.99
3	200	.33	.18	3.9	95948	.00	678	.99
4	300	.33	.18	3.9	146052	.00	688	.99
5	400	.34	.19	3.9	195648	.00	692	1.00
6	600	.36	.19	3.9	291394	.00	758	1.00
7	800	.36	.19	3.9	375788	.00	764	1.00
8	1000	.37	.19	3.9	464774	.01	776	1.00
9	1500	.38	.19	3.9	674304	.01	966	1.00
10	2000	.39	.19	3.9	876769	.02	979	1.00
11	2500	.39	.19	3.8	1071458	.03	993	.99
12	3000	.40	.19	3.8	1266815	.05	1000	.99
13	3500	.40	.19	3.8	1447333	.08	1020	.99
14	4000	.40	.19	3.8	1621282	.14	1034	.97
15	4500	.40	.19	3.8	1789158	.19	1048	.95
16	5000	.41	.19	3.8	1950453	.23	1062	.91
17	5500	.41	.19	3.0	2105765	.25	1077	.88
18	6000	.41	.19	3.0	2261206	.27	1091	.85
19	6500	.42	.19	3.0	2405628	.33	1099	.70
20	7000	.42	.19	3.0	2544325	.36	1120	.60
21	7500	.42	.19	3.0	2677454	.40	1135	.45
22	8000	.43	.19	3.0	2805509	.44	1150	.31
23	8500	.43	.19	3.0	2928650	.48	1165	.20
24	9000	.43	.19	3.0	3052415	.50	1181	.15
25	9500	.44	.20	3.0	3166595	.50	1192	.16
PRICE MULTIPLIER:1.2								
1	50	.24	.17	5.8	37879	.00	708	.98
2	100	.35	.19	4.0	75504	.00	640	1.00
3	200	.38	.19	3.9	138062	.00	678	1.00
4	300	.38	.19	3.9	206828	.00	688	1.00
5	400	.39	.19	3.1	274302	.00	692	1.00
6	600	.42	.19	3.0	404548	.00	758	1.00
7	800	.42	.19	3.0	521961	.00	764	1.00
8	1000	.42	.20	3.0	642557	.01	776	1.00
9	1500	.44	.20	3.0	928638	.01	966	1.00
10	2000	.45	.20	3.0	1204374	.02	979	1.00
11	2500	.45	.20	3.0	1469209	.03	993	1.00
12	3000	.46	.20	3.0	1731717	.05	1000	.99
13	3500	.46	.20	3.0	1976458	.08	1020	.99
14	4000	.46	.20	3.0	2211881	.14	1034	.98
15	4500	.47	.20	3.0	2438570	.19	1048	.96
16	5000	.47	.20	3.0	2656127	.23	1062	.93
17	5500	.47	.20	3.0	2865245	.25	1077	.91
18	6000	.47	.20	3.0	3072129	.27	1091	.88
19	6500	.48	.20	3.0	3265729	.33	1099	.74
20	7000	.48	.20	3.0	3451438	.36	1120	.64
21	7500	.48	.20	3.0	3629487	.40	1135	.49
22	8000	.49	.20	3.0	3800444	.44	1150	.34
23	8500	.49	.20	3.0	3964597	.48	1165	.22
24	9000	.49	.20	3.0	4127467	.50	1181	.17
25	9500	.50	.20	3.0	4279030	.50	1192	.17

TABLE 4-9. Part B: Independently Operating "Type III" Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.17	.15	10.0	7290	.00	708	.03
2	100	.24	.17	7.0	17458	.00	640	.92
3	200	.26	.17	5.6	30875	.00	678	.98
4	300	.26	.17	5.6	49868	.00	688	.99
5	400	.27	.17	5.6	68919	.00	692	.99
6	600	.29	.17	4.9	105181	.00	758	.99
7	800	.29	.17	4.8	134374	.00	764	.99
8	1000	.30	.17	4.8	167327	.01	776	.99
9	1500	.31	.17	4.8	242070	.01	966	.99
10	2000	.31	.17	4.8	313589	.02	979	.99
11	2500	.32	.17	4.8	381406	.03	993	.99
12	3000	.32	.18	4.8	450829	.05	1000	.99
13	3500	.32	.18	4.8	512007	.08	1020	.98
14	4000	.33	.18	4.8	570241	.14	1034	.93
15	4500	.33	.18	4.8	625819	.19	1048	.84
16	5000	.33	.18	4.8	678388	.23	1062	.70
17	5500	.34	.18	4.8	728341	.25	1077	.61
18	6000	.34	.18	4.8	779337	.27	1091	.51
19	6500	.35	.18	3.9	824630	.33	1099	.26
20	7000	.35	.18	3.9	867473	.36	1120	.15
21	7500	.35	.18	3.9	907908	.40	1135	.07
22	8000	.35	.18	3.9	946264	.44	1150	.03
23	8500	.36	.18	3.9	982610	.48	1165	.01
24	9000	.36	.18	3.9	1020103	.50	1181	.00
25	9500	.37	.18	3.9	1052869	.50	1192	.00
PRICE MULTIPLIER:1								
1	50	.21	.16	7.7	16418	.00	708	.68
2	100	.30	.18	4.8	34178	.00	640	.99
3	200	.33	.18	4.0	61141	.00	678	1.00
4	300	.33	.18	4.0	92854	.00	688	1.00
5	400	.34	.18	4.0	123861	.00	692	1.00
6	600	.37	.18	3.9	182824	.00	758	1.00
7	800	.37	.18	3.9	233349	.00	764	1.00
8	1000	.37	.18	3.9	286335	.01	776	1.00
9	1500	.39	.18	3.9	408832	.01	966	1.00
10	2000	.40	.19	3.9	525241	.02	979	1.00
11	2500	.40	.19	3.9	635229	.03	993	1.00
12	3000	.41	.19	3.9	744306	.05	1000	1.00
13	3500	.41	.19	3.9	842753	.08	1020	.99
14	4000	.41	.19	3.9	933988	.14	1034	.97
15	4500	.42	.19	3.9	1024418	.19	1048	.91
16	5000	.42	.19	3.9	1107851	.23	1062	.82
17	5500	.42	.19	3.9	1186779	.25	1077	.74
18	6000	.43	.19	3.0	1264945	.27	1091	.67
19	6500	.43	.19	3.0	1335726	.33	1099	.35
20	7000	.43	.19	3.0	1402460	.36	1120	.21
21	7500	.44	.19	3.0	1465306	.40	1135	.10
22	8000	.44	.19	3.0	1524622	.44	1150	.04
23	8500	.44	.19	3.0	1580623	.48	1165	.02
24	9000	.45	.19	3.0	1636467	.50	1181	.01
25	9500	.45	.19	3.0	1686427	.50	1192	.01
PRICE MULTIPLIER:1.2								
1	50	.24	.17	6.6	25550	.00	708	.93
2	100	.35	.19	4.0	50899	.00	640	1.00
3	200	.38	.19	3.9	91410	.00	678	1.00
4	300	.39	.19	3.9	135844	.00	688	1.00
5	400	.40	.19	3.1	178797	.00	692	1.00
6	600	.43	.19	3.0	260470	.00	750	1.00
7	800	.43	.19	3.0	332325	.00	764	1.00
8	1000	.43	.19	3.0	405365	.01	776	1.00
9	1500	.46	.19	3.0	575589	.01	966	1.00
10	2000	.47	.19	3.0	736878	.02	979	1.00
11	2500	.47	.19	3.0	889067	.03	993	1.00
12	3000	.47	.19	3.0	1037795	.05	1000	1.00
13	3500	.48	.19	3.0	1173490	.08	1020	.99
14	4000	.48	.19	3.0	1301716	.14	1034	.98
15	4500	.48	.20	3.0	1423023	.19	1048	.93
16	5000	.49	.20	3.0	1537328	.23	1062	.85
17	5500	.49	.20	3.0	1645223	.25	1077	.78
18	6000	.49	.20	3.0	1750553	.27	1091	.69
19	6500	.50	.20	3.0	1846832	.33	1099	.38
20	7000	.50	.20	3.0	1937449	.36	1120	.23
21	7500	.51	.20	3.0	2022684	.40	1135	.11
22	8000	.51	.20	3.0	2102991	.44	1150	.05
23	8500	.51	.20	3.0	2178608	.48	1165	.02
24	9000	.52	.20	3.0	2252828	.50	1181	.01
25	9500	.52	.20	3.0	2319966	.50	1192	.01



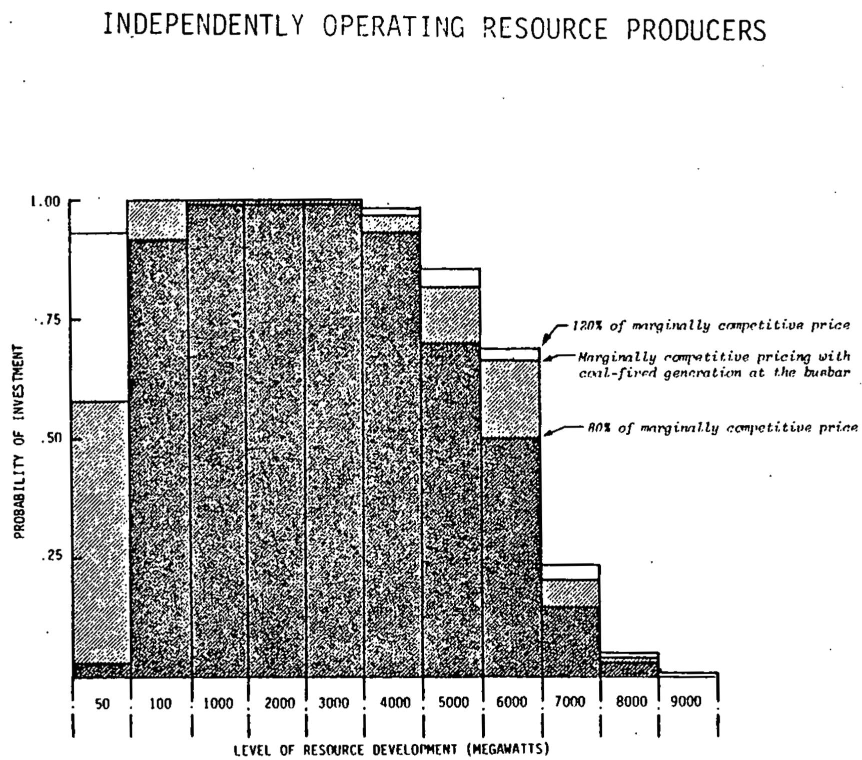


Figure 4-9. ESTIMATES OF INVESTMENT BEHAVIOR
AT SALTON SEA GEOTHERMAL RESOURCE AREA

of development of several thousand megawatts. As well field development progresses beyond the 6000 to 7000 MWe levels, the likelihood of investment falls below 50% because of increasing risks of loss. These risk perceptions are based on the mappings of confidence available at present (Figure 4-8) and may be redefined as exploration continues at the Salton Sea.

The 1979 USGS assessment of the Salton Sea (see Muffler, 1979) estimates its electric power potential at 3400 MWe. However, Meidav, et al. (1979) state that the Salton Sea potential may be many times this estimate. The investment evaluation presented here indicates that attractive investment opportunities are provided at nearly double the USGS estimate of resource potential at the Salton Sea at competitive resource prices.

Variations in the competitive resource price at the Salton Sea have a significant impact on investments in a single 50 MWe development, as illustrated in Figure 4-9, particularly for the independently operating resource producer. Effects of 80% and 120% price adjustments beyond the initial 50 MWe level of development are somewhat less pronounced.

4.2.5 Coso Hot Springs, Eastern Sierra Region, CA

Located in Inyo County, California, Coso Hot Springs KGRA is primarily located on lands owned by the United States Navy. As a result, the development of the resource has been largely controlled by the Navy, rather than private developers. A number of gradient temperature and deep wells have been drilled in the area. An analysis of the economic/environmental consequences of field development has also been undertaken by the Navy.

As summarized in Table 4-10, the Coso resource is characterized by moderate temperature and low salinity (brine contamination index of 0 for modeling purposes). Until well flow tests have been conducted in the field, estimated well flow rates are subject to substantial uncertainty. Transmission requirements are expected to be met by interconnecting with the Inyokern substation, 38 miles from the KGRA. For development levels in excess of 50 MW, a 230 KV line will be required in place of the 138 KV line. Also 50 miles of transmission line restringing will be required on the existing line between the Inyokern and Kramer substations. Levels of confidence mappings are illustrated in Figure 4-10, as compiled by geologists from currently available information.

Results of the Coso Hot Springs investment evaluation are provided in Table 4-11 and Figure 4-11. Unlike the sedimentary geology of the Imperial Valley, the Eastern Sierra Region is characterized by hard igneous geology which, as illustrated in Figure 2-2 of Chapter 2, substantially increases well drilling costs. The combined effects of high well costs, moderate resource temperature and moderate well flow rate adversely affect the financial attributes of well field investments at Coso. Independently operating resource producers, with their relatively high investment returns required by supportive venture capitalists, do not appear likely to participate in the development at Coso. Major corporate producers demonstrate a low likelihood of investment at competitive resource prices. A 20% increase above competitive price levels will significantly affect likely investment behavior by the major firms only.

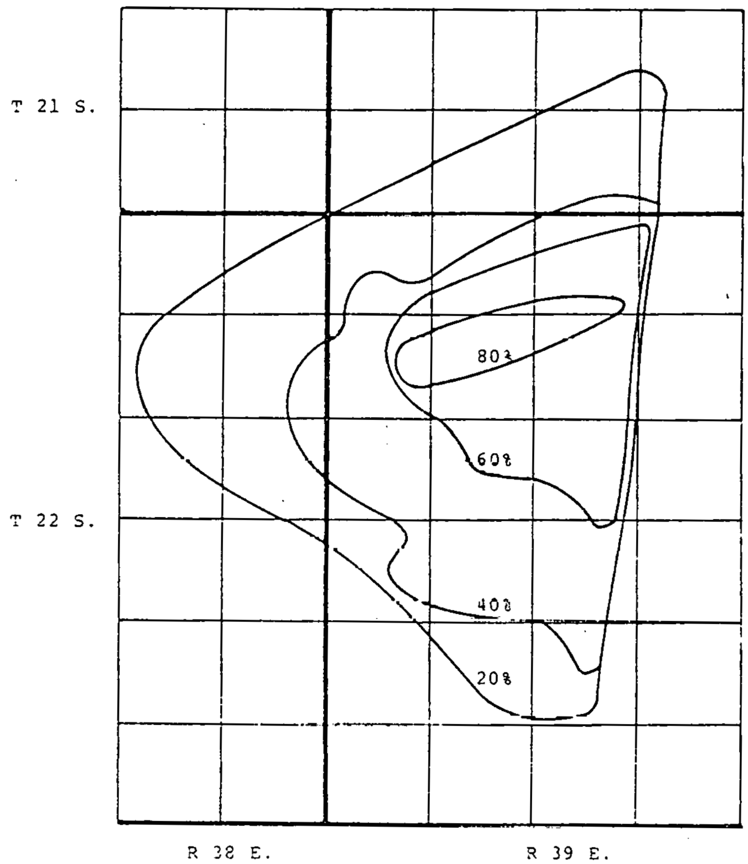


Figure 4-10. LEVELS OF CONFIDENCE
AT COSO HOT SPRINGS (MID-1979)

At competitive resource prices, major resource producing corporations appear likely to invest in the development at Coso with less than a 20% probability. Beyond a 500 MWe level of development, there appears to be no likelihood of investment as this resource is understood today. The USGS currently estimates the electric power potential at Costo to be 650 MWe (see Muffler, 1979) -- a highly optimistic estimate from the perspective of this investment evaluation.

TABLE 4-10. RESOURCE AND DEVELOPMENT PARAMETERS AT COSO HOT SPRINGS

RESOURCE PARAMETERS

```
1.  STATE......................................... CA
2.  TYPE OF GEOLOGY (I/P)......................... IGNEOUS
3.  RESERVOIR DEPTH,FT:
    -MINIMUM VALUE (I/P).... 3300
    -VALUE AT MODE (I/P).... 6600
    -MAXIMUM VALUE (I/P).... 9800
    -MEAN VALUE (O/P)............................  6575
4.  MEAN WELL COST,$1000 (O/P)................... 1290
5.  DRY WELL COST FRACTION (I/P)................. 0.9
6.  REDRILL WELL COST FRACTION (I/P)............. 0.35
7.  DRY WELL FRACTION:
    -MINIMUM VALUE (I/P).... 0.09
    -VALUE AT MODE (I/P).... 0.1
    -MAXIMUM VALUE (I/P).... 0.11
    -MEAN VALUE (O/P)............................ 0.1
8.  SPARE WELL FRACTION (I/P).................... 0.2
9.  PRODUCER/INJECTOR RATIO (I/P)................ 2
10. INITIAL REDRILL FRACTION (I/P)............... 0.3
11. REPLACEMENT REDRILL FRACTION (I/P)........... 0.33
12. WELLHEAD RESOURCE TEMPERATURE,F:
    -MINIMUM VALUE (I/P).... 350
    -VALUE AT MODE (I/P).... 400
    -MAXIMUM VALUE (I/P).... 430
    -MEAN VALUE (O/P)............................ 395
13. NET SPECIFIC ENERGY,WHR/LB (O/P).............  9.0
14. WELL FLOW RATE,1000LB/HR:
    -MINIMUM VALUE (I/P).... 300
    -VALUE AT MODE (I/P).... 450
    -MAXIMUM VALUE (I/P).... 650
    -MEAN VALUE (O/P)............................  463
15. WELL SPACING,ACRES/WELL (I/P)................ 40
16. SALINITY INDEX [0:LOW→4:HIGH] (I/P).......... 0
17. WELL LIFE,YRS:
    -MINIMUM VALUE (I/P).... 10
    -VALUE AT MODE (I/P).... 15
    -MAXIMUM VALUE (I/P).... 20
    -MEAN VALUE (O/P)............................ 15.0
18. BOOK LIFE OF WELLS,YRS (I/P)................. 15
19. BOOK LIFE OF SURFACE CAPITAL,YRS (I/P)....... 30
20. TAX LIFE OF WELLS,YRS (I/P).................. 15
21. AD VALOREM TAX,ON ACTUAL VALUE (I/P)......... 0.01
22. ROYALTY FRACTION (I/P)....................... 0.125
23. LEASE BONUS,$/ACRE (I/P)..................... 100
24. LAND RENTAL,$/ACRE (I/P)..................... 2
25. POWER TRANSMISSION COST,$1000 (I/P):
    -TO 50000 KWE............................... 2100
    -ADDITIONAL INCREMENTS OF 600000 KWE......... 12400
26. ALTERNATIVE GENERATION:
    -CAPITAL COST,$/KWE (I/P).................... 1040
    -FUEL COST,MILLS/KWH (I/P)................... 13.1
```

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL,TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1985	50	.80	680	613	17.4
2	100	1988	50	.70	1400	695	16.5
3	200	1990	100	.60	2720	633	17.1
4	300	1991	100	.53	4040	613	17.2
5	400	1992	100	.44	5400	602	17.3
6	500	1993	100	.40	6720	596	17.3
7	600	1994	100	.35	8040	592	17.3
8	700	1995	100	.30	9400	607	17.1
9	800	1996	100	.27	10720	602	17.1

TABLE 4-11. COSO INVESTMENT EVALUATION

Part A: Major "Type I" Corporate Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.14	.14	13.7	7669	.20	1870	.01
2	100	.15	.14	11.3	13683	.30	1837	.02
3	200	.17	.15	10.1	36929	.40	1911	.03
4	300	.17	.15	10.1	59619	.47	1931	.01
5	400	.18	.15	9.2	81648	.56	1953	.00
6	500	.18	.15	9.2	102814	.60	1971	.00
7	600	.18	.15	9.2	123635	.65	1991	.00
8	700	.18	.15	9.2	139622	.70	2014	.00
9	800	.18	.15	9.2	159201	.73	2031	.00
PRICE MULTIPLIER:1								
1	50	.17	.15	9.6	18709	.20	1870	.15
2	100	.19	.16	8.2	34412	.30	1837	.18
3	200	.21	.16	7.4	75590	.40	1911	.11
4	300	.21	.16	7.4	115420	.47	1931	.05
5	400	.22	.16	7.4	153850	.56	1953	.02
6	500	.22	.16	7.4	190729	.60	1971	.01
7	600	.22	.16	7.4	226574	.65	1991	.00
8	700	.22	.16	7.4	256963	.70	2014	.00
9	800	.22	.16	7.4	290308	.73	2031	.00
PRICE MULTIPLIER:1.2								
1	50	.19	.16	8.3	29748	.20	1870	.39
2	100	.22	.16	6.6	55145	.30	1837	.37
3	200	.24	.17	6.5	114251	.40	1911	.18
4	300	.25	.17	5.7	171225	.47	1931	.09
5	400	.25	.17	5.7	226067	.56	1953	.03
6	500	.25	.17	5.7	278647	.60	1971	.02
7	600	.25	.17	5.7	329529	.65	1991	.00
8	700	.26	.17	5.7	374304	.70	2014	.00
9	800	.26	.17	5.7	421425	.73	2031	.00

Part B: Independently Operating "Type III" Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.00	.13	18.2	32	.20	1870	.00
2	100	.14	.14	16.0	221	.30	1837	.00
3	200	.16	.14	12.7	9748	.40	1911	.00
4	300	.17	.15	12.7	19047	.47	1931	.00
5	400	.17	.15	11.8	28017	.56	1953	.00
6	500	.17	.15	11.8	36463	.60	1971	.00
7	600	.17	.15	11.8	44836	.65	1991	.00
8	700	.17	.15	11.8	50149	.70	2014	.00
9	800	.17	.15	11.8	57882	.73	2031	.00
PRICE MULTIPLIER:1								
1	50	.16	.14	11.6	8117	.20	1870	.00
2	100	.18	.15	10.4	15026	.30	1837	.00
3	200	.20	.15	9.2	36561	.40	1911	.00
4	300	.21	.16	8.3	57140	.47	1931	.00
5	400	.21	.16	8.3	76705	.56	1953	.00
6	500	.21	.16	8.3	95109	.60	1971	.00
7	600	.21	.16	8.3	112851	.65	1991	.00
8	700	.21	.16	8.3	126966	.70	2014	.00
9	800	.22	.16	8.3	142968	.73	2031	.00
PRICE MULTIPLIER:1.2								
1	50	.19	.15	8.9	16197	.20	1870	.00
2	100	.21	.16	8.1	29838	.30	1837	.00
3	200	.24	.16	7.4	63368	.40	1911	.00
4	300	.24	.16	6.5	95220	.47	1931	.00
5	400	.25	.16	6.5	125390	.56	1953	.00
6	500	.25	.16	6.5	153766	.60	1971	.00
7	600	.25	.16	6.5	180871	.65	1991	.00
8	700	.25	.17	6.5	203786	.70	2014	.00
9	800	.25	.17	6.5	229069	.73	2031	.00

MAJOR RESOURCE PRODUCING CORPORATIONS

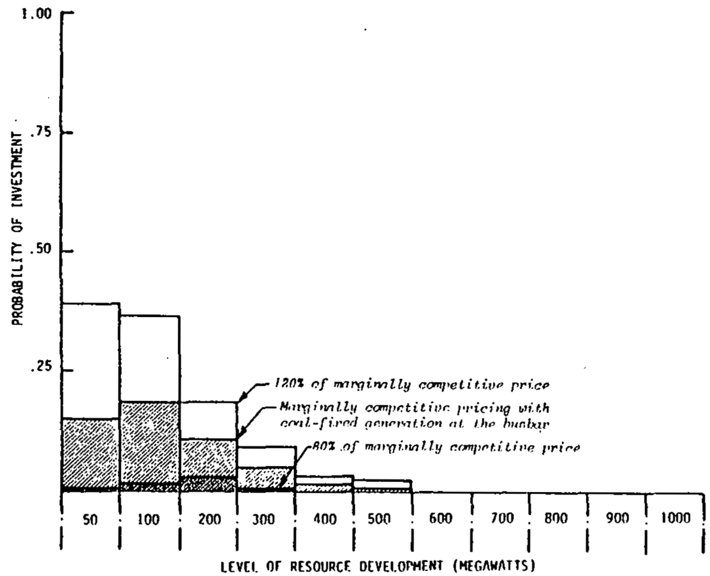


Figure 4-11. ESTIMATES OF INVESTMENT BEHAVIOR AT COSO HOT SPRINGS GEOTHERMAL RESOURCE AREA

4.2.6 Mono-Long Valley, Eastern Sierra Región, CA

Geothermal exploration is at a very early stage in Mono-Long Valley. Exploratory wells have been drilled by Magma Power Company and Republic Geothermal Company. The utilities who have shown interest in future development include Southern California Edison and the City of Burbank. Direct heat applications are also being evaluated. Located in an environmentally sensitive area in Mono County, environmental concerns may delay future development.

Table 4-12 summarizes resource characteristics at Mono as understood today. Like the resource at Coso, the fluid is found at moderate temperatures with a low total dissolved solid content (brine contamination index of 0 for modeling purposes). Future development may be impeded by substantial transmission requirements. For the first 50 MWe of installed capacity, it is assumed 138 KV feeder lines will be adequate to deliver the power to the Casa Diablo Substation 5 miles away. As additional units are added, a 230 KV line will be needed to export the power to the Inyokern substation approximately 200 miles from the KGRA. The level of confidence contours shown in Figure 4-12 reflect the limited drilling program undertaken thus far.

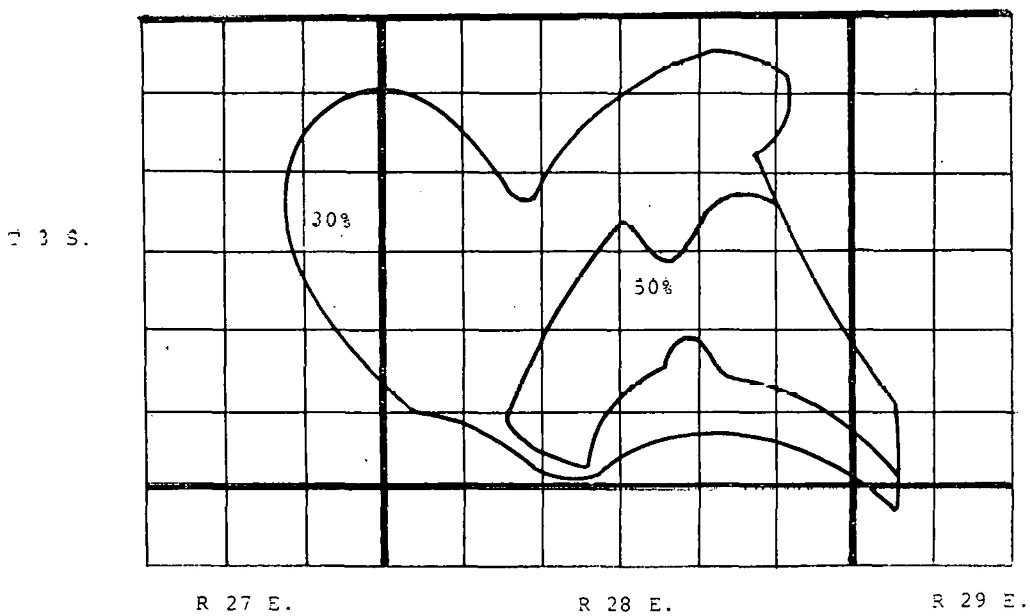


Figure 4-12. LEVELS OF CONFIDENCE
AT MONO-LONG VALLEY (MID-1979)

TABLE 4-12. RESOURCE AND DEVELOPMENT PARAMETERS AT MONO-LONG VALLEY

```
RESOURCE PARAMETERS
1.  STATE......................................... CA
2.  TYPE OF GEOLOGY (I/P)......................... IGNEOUS
3.  RESERVOIR DEPTH,FT:
    -MINIMUM VALUE (I/P).... 3300
    -VALUE AT MODE (I/P).... 4300
    -MAXIMUM VALUE (I/P).... 5300
    -MEAN VALUE (O/P)...........................  4300
4.  MEAN WELL COST,$1000 (O/P)..................  768
5.  DRY WELL COST FRACTION (I/P)................. 0.9
6.  REDRILL WELL COST FRACTION (I/P)............. 0.35
7.  DRY WELL FRACTION:
    -MINIMUM VALUE (I/P).... 0.09
    -VALUE AT MODE (I/P).... 0.1
    -MAXIMUM VALUE (I/P).... 0.11
    -MEAN VALUE (O/P)............................ 0.1
8.  SPARE WELL FRACTION (I/P).................... 0.2
9.  PRODUCER/INJECTOR RATIO (I/P)................ 2
10. INITIAL REDRILL FRACTION (I/P)............... 0.3
11. REPLACEMENT REDRILL FRACTION (I/P)........... 0.33
12. WELLHEAD RESOURCE TEMPERATURE,F:
    -MINIMUM VALUE (I/P).... 350
    -VALUE AT MODE (I/P).... 400
    -MAXIMUM VALUE (I/P).... 430
    -MEAN VALUE (O/P)............................ 395
13. NET SPECIFIC ENERGY,WHR/LB (O/P)............  9.0
14. WELL FLOW RATE,1000LB/HR:
    -MINIMUM VALUE (I/P).... 300
    -VALUE AT MODE (I/P).... 450
    -MAXIMUM VALUE (I/P).... 650
    -MEAN VALUE (O/P)...........................  463
15. WELL SPACING,ACRES/WELL (I/P)................ 40
16. SALINITY INDEX [0:LOW->4:HIGH] (I/P)......... 0
17. WELL LIFE,YRS:
    -MINIMUM VALUE (I/P).... 10
    -VALUE AT MODE (I/P).... 15
    -MAXIMUM VALUE (I/P).... 20
    -MEAN VALUE (O/P)............................ 15.0
18. BOOK LIFE OF WELLS,YRS (I/P)................. 15
19. BOOK LIFE OF SURFACE CAPITAL,YRS (I/P)....... 30
20. TAX LIFE OF WELLS,YRS (I/P).................. 15
21. AD VALOREM TAX,ON ACTUAL VALUE (I/P)......... 0.01
22. ROYALTY FRACTION (I/P)....................... 0.125
23. LEASE BONUS,$/ACRE (I/P)..................... 100
24. LAND RENTAL,$/ACRE (I/P)..................... 2
25. POWER TRANSMISSION COST,$1000 (I/P):
    -TO 50000 KWE.............................. 300
    -ADDITIONAL INCREMENTS OF 600000 KWE......... 35500
26. ALTERNATIVE GENERATION:
    -CAPITAL COST,$/KWE (I/P).................... 1040
    -FUEL COST,MILLS/KWH (I/P)................... 13.1
```

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL.TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1985	50	.50	680	577	17.8
2	100	1988	50	.50	1400	926	14.2
3	200	1990	100	.50	2720	749	15.9
4	300	1991	100	.49	4040	690	16.5
5	400	1992	100	.47	5400	660	16.7
6	500	1993	100	.44	6720	642	16.9
7	600	1994	100	.41	8040	630	16.9
8	700	1995	100	.40	9400	673	16.5
9	800	1996	100	.37	10720	660	16.6
10	900	1997	100	.34	12040	650	16.7

Results of the Mono-Long Valley investment evaluation are provided in Table 4-13 and Figure 4-13. Like Coso Hot Springs, the investment potential at Mono-Long Valley appears very limited at present because of the combined adverse effects of expensive well costs in igneous geology, moderate reservoir qualities, and relatively low levels of confidence as the area is understood today. Continued exploration at Mono-Long Valley may redefine the confidence mappings illustrated in Figure 4-12. Until such a better understanding of the resource area is achieved, at competitive resource prices there appears to be no likelihood of approaching the electric power potential of 2100 MWe estimated for this area by the USGS (see Muffler, 1979).

TABLE 4-13. MONO-LONG VALLEY INVESTMENT EVALUATION

Part A: Major "Type I" Corporate Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.16	.15	9.6	13816	.50	1165	.00
2	100	.16	.15	10.5	13653	.50	1111	.00
3	200	.20	.16	8.3	45741	.50	1171	.03
4	300	.21	.16	7.4	76408	.51	1184	.03
5	400	.22	.16	7.4	105945	.53	1199	.03
6	500	.22	.16	7.4	134315	.56	1209	.02
7	600	.22	.16	7.4	161884	.59	1222	.01
8	700	.22	.16	7.4	176366	.60	1238	.01
9	800	.22	.16	7.4	202320	.63	1248	.00
10	900	.23	.16	6.6	227526	.66	1261	.00
PRICE MULTIPLIER:1								
1	50	.19	.16	7.6	24855	.50	1165	.03
2	100	.21	.16	7.2	34380	.50	1111	.04
3	200	.25	.17	5.7	84402	.50	1171	.07
4	300	.26	.17	5.7	132210	.51	1184	.06
5	400	.26	.17	5.7	178155	.53	1199	.05
6	500	.27	.17	5.7	222233	.56	1209	.04
7	600	.27	.17	5.6	264831	.59	1222	.02
8	700	.27	.17	5.7	293713	.60	1238	.02
9	800	.27	.17	5.6	333440	.63	1248	.01
10	900	.27	.17	5.6	371826	.66	1261	.00
PRICE MULTIPLIER:1.2								
1	50	.22	.16	6.8	35893	.50	1165	.04
2	100	.25	.17	5.6	55114	.50	1111	.07
3	200	.29	.18	4.8	123066	.50	1171	.09
4	300	.30	.18	4.8	188017	.51	1184	.09
5	400	.30	.18	4.8	250361	.53	1199	.07
6	500	.31	.18	4.8	310145	.56	1209	.05
7	600	.31	.18	4.8	367771	.59	1222	.03
8	700	.31	.18	4.8	411051	.60	1238	.03
9	800	.31	.18	4.8	464556	.63	1248	.02
10	900	.32	.18	4.8	516120	.66	1261	.01

TABLE 4-13. Part B: Independently Operating "Type III" Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.16	.14	12.7	5960	.50	1165	.00
2	100	.16	.14	13.6	2840	.50	1111	.00
3	200	.20	.15	9.2	20440	.50	1171	.00
4	300	.21	.15	9.2	36889	.51	1184	.00
5	400	.21	.16	8.3	52445	.53	1199	.00
6	500	.21	.16	8.3	67103	.56	1209	.00
7	600	.22	.16	8.3	81186	.59	1222	.00
8	700	.21	.16	8.3	86660	.60	1238	.00
9	800	.22	.16	8.3	99615	.63	1248	.00
10	900	.22	.16	7.4	112047	.66	1261	.00
PRICE MULTIPLIER:1								
1	50	.19	.15	8.8	14041	.50	1165	.00
2	100	.21	.16	8.1	17656	.50	1111	.00
3	200	.25	.16	6.5	47259	.50	1171	.00
4	300	.26	.17	6.5	74972	.51	1184	.00
5	400	.26	.17	6.5	101130	.53	1199	.00
6	500	.26	.17	6.5	125755	.56	1209	.00
7	600	.27	.17	5.7	149207	.59	1222	.00
8	700	.27	.17	5.7	163473	.60	1238	.00
9	800	.27	.17	5.7	184718	.63	1248	.00
10	900	.27	.17	5.7	204917	.66	1261	.00
PRICE MULTIPLIER:1.2								
1	50	.22	.16	7.6	22121	.50	1165	.00
2	100	.25	.17	6.4	32463	.50	1111	.00
3	200	.29	.17	5.7	74078	.50	1171	.00
4	300	.30	.17	4.8	113058	.51	1184	.00
5	400	.30	.17	4.8	149809	.53	1199	.00
6	500	.30	.18	4.8	184396	.56	1209	.00
7	600	.31	.18	4.8	217220	.59	1222	.00
8	700	.31	.18	4.8	240300	.60	1238	.00
9	800	.31	.18	4.8	269797	.63	1248	.00
10	900	.32	.18	4.8	297788	.66	1261	.00

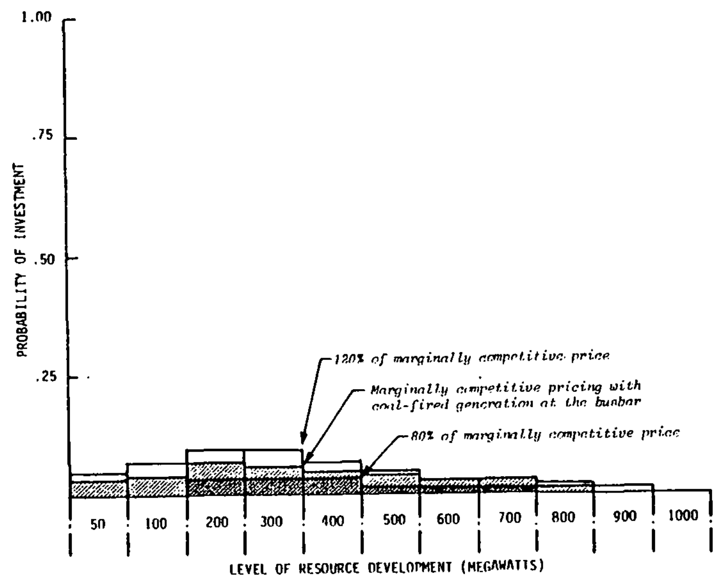


Figure 4-13. ESTIMATES OF INVESTMENT BEHAVIOR AT MONO-LONG VALLEY GEOTHERMAL RESOURCE AREA

4.2.7 The Geysers, CA

The vapor-dominated hydrothermal resource at the Geysers has been supporting commercial electric power generating plants since 1960. By mid-1980, it is estimated that 908 MWe of generation capacity will be installed at this resource. Environmental constraints pertaining to H_2S abatement and regulatory constraints pertaining to new transmission facilities are viewed as possible impediments to future development.

For investment modeling purposes, the KGRA resource is assumed to consist of both liquid and vapor-dominated reservoirs. Based on consultation with industry geologists, the vapor-dominated resource is assumed to lie southwest of the Collayami Fault, illustrated in Figure 4-14. Approximately 20 square kilometers (shown as shaded areas in Figure 4-14) were excluded from potential future development because these areas are currently committed to support existing PG and E generating units 1-15. Estimated future vapor-dominated investment potential thus represents additions to the 908 MWe expected to be on-line by 1980. The vapor-dominated resource parameters are presented in Table 4-14A. Because of the extensive operating experience at the Geysers, plant costs, well costs and net specific energy were input to the model directly, based on recent PG and E estimates.

That portion of the KGRA lying northeast of the Collayami Fault is assumed to be liquid-dominated, having the resource characteristics shown in Table 4-14B. A low brine contamination of 1 is assigned to the resource. The low levels of confidence mappings shown in Figure 4-14 reflect the limited exploration which has taken place in the northeast portion of the field. It is assumed in the simulations that the first hdyrothermal plant comes on line in 1988.

Investment potential for continued expansion at the vapor-dominated field is substantial, as shown in Figure 4-15A. Both Type I and Type III resource producers view additional levels of development up to 1760 MWe highly favorably. The risk of loss for higher development levels rises significantly as the outer boundaries of the field are reached and sharply curtail investment incentives for all types of firms. By reducing the resource selling price to 80 percent of the competitive level, independent

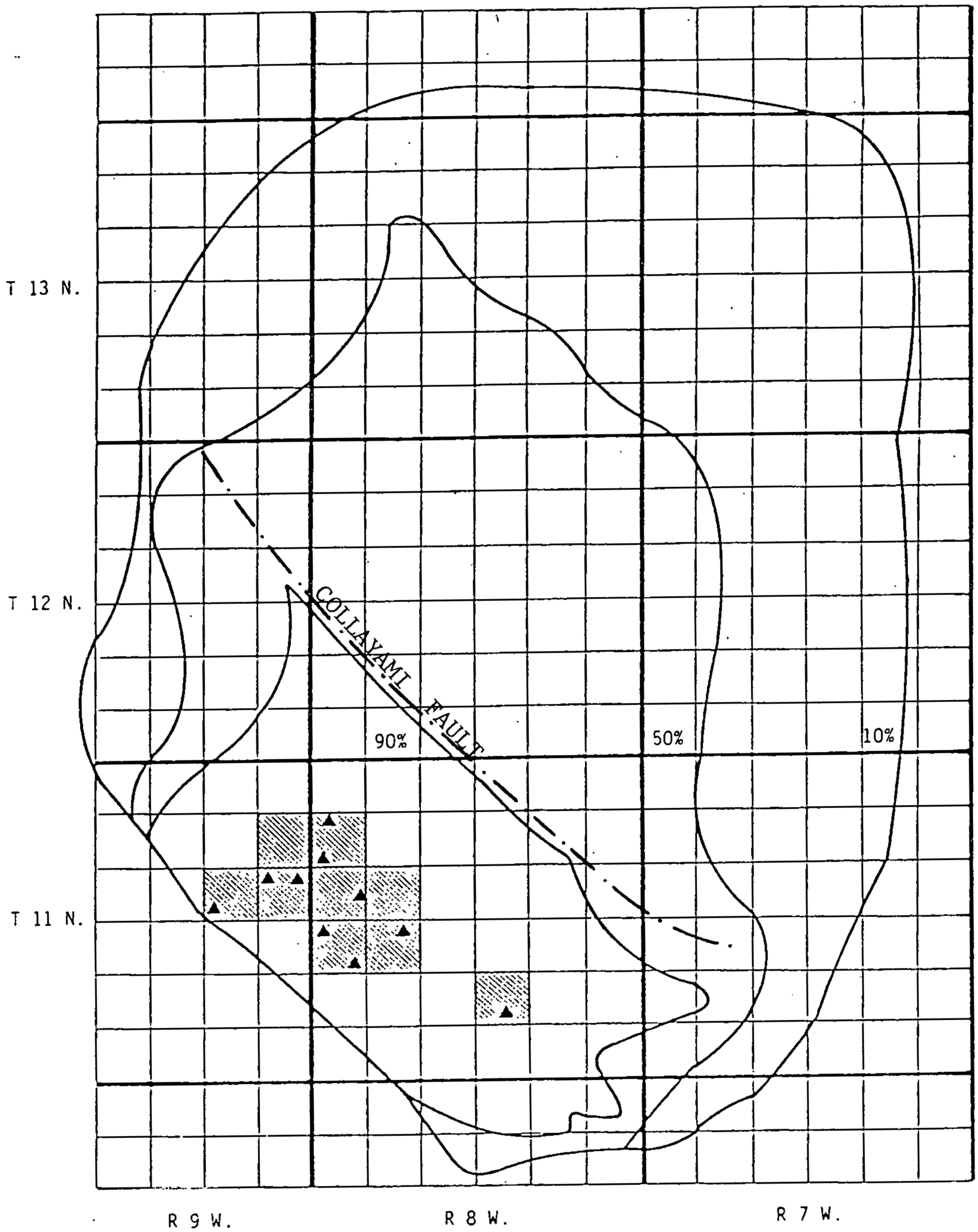


Figure 4-14. LEVELS OF CONFIDENCE
AT THE GEYSERS (MID-1979)

TABLE 4-14A. RESOURCE AND DEVELOPMENT PARAMETERS AT THE GEYSERS VAPOR-DOMINATED FIELD

```
RESOURCE PARAMETERS
1.  STATE........................................ CA
2.  TYPE OF GEOLOGY (I/P)........................ IGNEOUS
3.  RESERVOIR DEPTH,FT:
    -MINIMUM VALUE (I/P).... 4500
    -VALUE AT MODE (I/P).... 7500
    -MAXIMUM VALUE (I/P).... 10000
    -MEAN VALUE (O/P).........................    7372
4.  MEAN WELL COST,$1000 (O/P)................... 1000
5.  DRY WELL COST FRACTION (I/P)................. 0.9
6.  REDRILL WELL COST FRACTION (I/P)............. 0.35
7.  DRY WELL FRACTION:
    -MINIMUM VALUE (I/P).... 0.09
    -VALUE AT MODE (I/P).... 0.1
    -MAXIMUM VALUE (I/P).... 0.11
    -MEAN VALUE (O/P)............................ 0.1
8.  SPARE WELL FRACTION (I/P).................... 0.33
9.  PRODUCER/INJECTOR RATIO (I/P)................ 10
10. INITIAL REDRILL FRACTION (I/P)............... 0.3
11. REPLACEMENT REDRILL FRACTION (I/P)........... 0.33
12. WELLHEAD RESOURCE TEMPERATURE,F:
    -MINIMUM VALUE (I/P).... 360
    -VALUE AT MODE (I/P).... 400
    -MAXIMUM VALUE (I/P).... 430
    -MEAN VALUE (O/P)............................ 397
13. NET SPECIFIC ENERGY,WHR/LB (O/P)............. 48.8
14. WELL FLOW RATE,1000LB/HR:
    -MINIMUM VALUE (I/P).... 75
    -VALUE AT MODE (I/P).... 100
    -MAXIMUM VALUE (I/P).... 150
    -MEAN VALUE (O/P)............................  107
15. WELL SPACING,ACRES/WELL (I/P)................ 40
16. SALINITY INDEX [0:LOW→4:HIGH] (I/P).......... 0
17. WELL LIFE,YRS:
    -MINIMUM VALUE (I/P).... 10
    -VALUE AT MODE (I/P).... 15
    -MAXIMUM VALUE (I/P).... 20
    -MEAN VALUE (O/P)............................ 15.0
18. BOOK LIFE OF WELLS,YRS (I/P)................. 15
19. BOOK LIFE OF SURFACE CAPITAL,YRS (I/P)....... 30
20. TAX LIFE OF WELLS,YRS (I/P).................. 15
21. AD VALOREM TAX,ON ACTUAL VALUE (I/P)......... 0.01
22. ROYALTY FRACTION (I/P)....................... 0.125
23. LEASE BONUS,$/ACRE (I/P)..................... 1000
24. LAND RENTAL,$/ACRE (I/P)..................... 2
25. POWER TRANSMISSION COST,$1000 (I/P):
    -TO 100000 KWE............................... 3500
    -ADDITIONAL INCREMENTS OF 600000 KWE......... 21000
26. ALTERNATIVE GENERATION:
    -CAPITAL COST,$/KWE (I/P).................... 1040
    -FUEL COST,MILLS/KWH (I/P)................... 13.1
```

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL,TRANS) ($/KWE)	COMPETITIVE RESOURCE ASTRP (MILLS/KWH)
1	110	1980	110	.90	1440	417	19.9
2	220	1981	110	.90	2840	417	19.8
3	330	1982	110	.90	4240	417	19.8
4	440	1983	110	.90	5640	417	19.7
5	550	1984	110	.90	7040	417	19.7
6	660	1985	110	.90	8440	417	19.6
7	770	1986	110	.90	9800	417	19.6
8	880	1987	110	.90	11200	417	19.5
9	990	1988	110	.90	12680	417	19.5
10	1100	1989	110	.90	14080	417	19.4
11	1210	1990	110	.90	15440	417	19.4
12	1320	1991	110	.90	16840	417	19.4
13	1430	1992	110	.90	18240	417	19.3
14	1540	1993	110	.90	19640	417	19.3
15	1650	1994	110	.90	21040	417	19.2
16	1760	1995	110	.90	22440	417	19.2
17	1870	1996	110	.90	23880	417	19.1
18	1980	1997	110	.69	25280	417	19.1
19	2090	1998	110	.60	26680	417	19.0
20	2200	1999	110	.50	28040	417	19.0
21	2310	2000	110	.50	29440	417	18.9
22	2420	2001	110	.50	30840	417	18.9
23	2530	2002	110	.50	32240	417	18.8
24	2640	2003	110	.45	33640	417	18.8
25	2750	2004	110	.45	35080	417	18.8

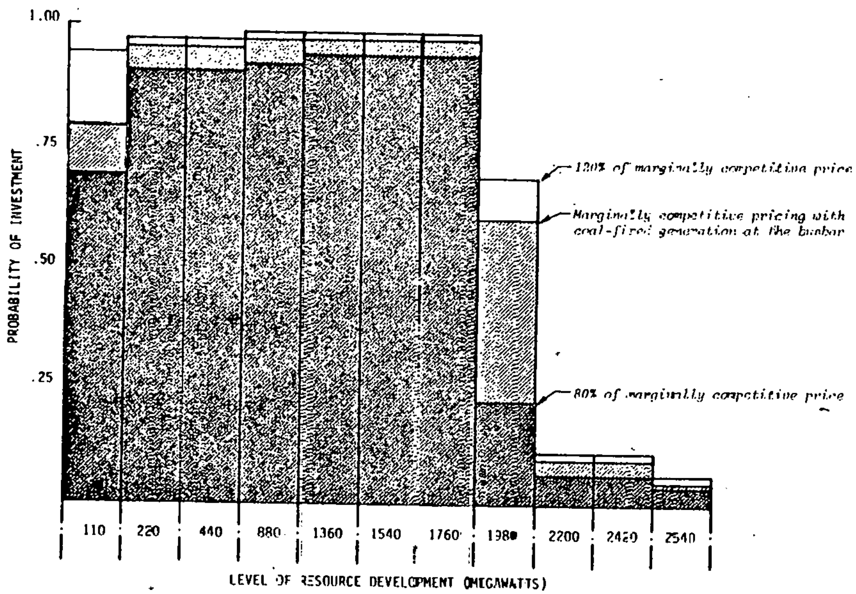
TABLE 4-14B. RESOURCE AND DEVELOPMENT PARAMETERS AT THE GEYSERS LIQUID-DOMINATED FIELD

RESOURCE PARAMETERS

1. STATE.. CA
2. TYPE OF GEOLOGY (I/P)........................ IGNEOUS
3. RESERVOIR DEPTH,FT:
   - -MINIMUM VALUE (I/P).... 4500
   - -VALUE AT MODE (I/P).... 7500
   - -MAXIMUM VALUE (I/P).... 10000
   - -MEAN VALUE (O/P).......................... 7372
4. MEAN WELL COST,$1000 (O/P).................. 1525
5. DRY WELL COST FRACTION (I/P)................ 0.9
6. REDRILL WELL COST FRACTION (I/P)............ 0.35
7. DRY WELL FRACTION:
   - -MINIMUM VALUE (I/P).... 0.09
   - -VALUE AT MODE (I/P).... 0.1
   - -MAXIMUM VALUE (I/P).... 0.11
   - -MEAN VALUE (O/P).......................... 0.1
8. SPARE WELL FRACTION (I/P)................... 0.2
9. PRODUCER/INJECTOR RATIO (I/P)............... 2
10. INITIAL REDRILL FRACTION (I/P).............. 0.3
11. REPLACEMENT REDRILL FRACTION (I/P).......... 0.33
12. WELLHEAD RESOURCE TEMPERATURE,F:
    - -MINIMUM VALUE (I/P).... 360
    - -VALUE AT MODE (I/P).... 400
    - -MAXIMUM VALUE (I/P).... 430
    - -MEAN VALUE (O/P).......................... 397
13. NET SPECIFIC ENERGY,WHR/LB (O/P)............ 9.1
14. WELL FLOW RATE,1000LB/HR:
    - -MINIMUM VALUE (I/P).... 400
    - -VALUE AT MODE (I/P).... 500
    - -MAXIMUM VALUE (I/P).... 600
    - -MEAN VALUE (O/P).......................... 500
15. WELL SPACING,ACRES/WELL (I/P)............... 40
16. SALINITY INDEX [0:LOW→4:HIGH] (I/P)......... 1
17. WELL LIFE,YRS:
    - -MINIMUM VALUE (I/P).... 10
    - -VALUE AT MODE (I/P).... 15
    - -MAXIMUM VALUE (I/P).... 20
    - -MEAN VALUE (O/P).......................... 15.0
18. BOOK LIFE OF WELLS,YRS (I/P)................ 15
19. BOOK LIFE OF SURFACE CAPITAL,YRS (I/P)...... 30
20. TAX LIFE OF WELLS,YRS (I/P)................. 15
21. AD VALOREM TAX,ON ACTUAL VALUE (I/P)........ 0.01
22. ROYALTY FRACTION (I/P)...................... 0.125
23. LEASE BONUS,$/ACRE (I/P).................... 100
24. LAND RENTAL,$/ACRE (I/P).................... 2
25. POWER TRANSMISSION COST,$1000 (I/P):
    - -TO 100000 KWE............................ 3500
    - -ADDITIONAL INCREMENTS OF 600000 KWE...... 21000
26. ALTERNATIVE GENERATION:
    - -CAPITAL COST,$/KWE (I/P)................. 1040
    - -FUEL COST,MILLS/KWH (I/P)................ 13.1

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL,TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1988	50	.83	600	640	17.0
2	100	1991	50	.82	1240	605	17.2
3	200	1993	100	.80	2440	675	16.5
4	300	1994	100	.76	3680	640	16.8
5	400	1995	100	.74	4880	622	16.9
6	600	1996	200	.70	7320	605	17.0
7	800	1997	200	.65	9760	622	16.9
8	1000	1998	200	.62	12240	612	16.9
9	1200	1999	200	.61	14680	605	16.9
10	1400	2000	200	.58	17120	615	16.8
11	1600	2001	200	.56	19560	609	16.8
12	1800	2002	200	.54	22000	605	16.9
13	2000	2003	200	.53	24440	612	16.8
14	2200	2004	200	.52	26840	608	16.8
15	2400	2005	200	.51	29280	605	16.8
16	2600	2006	200	.50	31720	610	16.7
17	2800	2007	200	.50	34160	607	16.7
18	3000	2008	200	.50	36600	605	16.7
19	3200	2009	200	.50	39040	609	16.6
20	3400	2010	200	.50	41480	607	16.6

MAJOR RESOURCE PRODUCING CORPORATIONS



INDEPENDENTLY OPERATING RESOURCE PRODUCERS

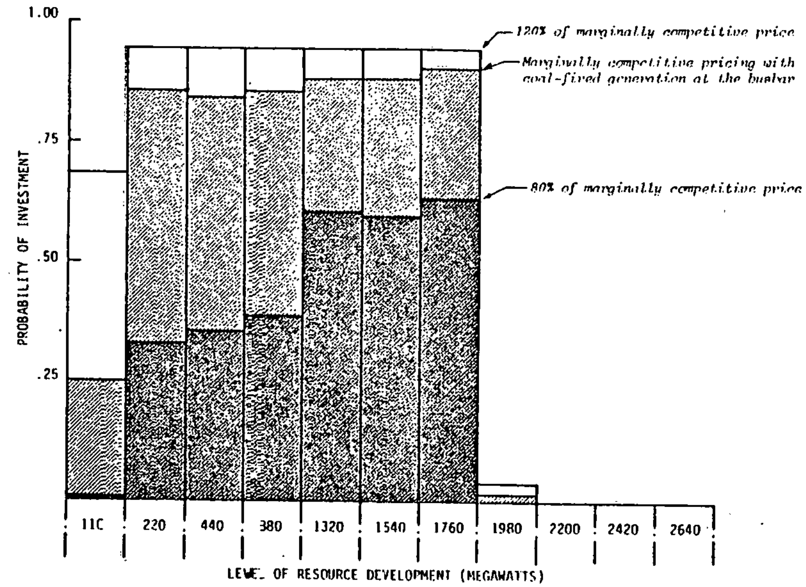


Figure 4-15A. ESTIMATES OF FUTURE INVESTMENT BEHAVIOR AT GEYSERS VAPOR-DOMINATED RESOURCE operators are shown to have sharply reduced investment probabilities. This effect is not observered for the major firms.

The liquid-dominated field appears to have only limited development potential at the present time as illustrated in Figure 4-15B. Major resource producers show only a 50 percent probability of investing in a 100 MWe development. Steadily declining probabilities are observed at higher development levels. Independent operators presently show no probability of investment at any development level. Investment opportunities in the liquid-dominated region may become more attractive if future exploration has the effect of reducing the risk of investment loss.

The USGS estimate of 1610 MWe of electric power potential at the Geysers (see Muffler, 1979) appears to significantly underestimate the potential of the combined liquid-dominated and vapor-dominated reservoirs. According to Pacific Gas and Electric Company, the Geysers field is scheduled to support 1656 MWe of power by mid-1985 when Unit 22 begins commercial service. Over 2000 MWe of power are expected by 1990. At competitive resource prices, according to this investment evaluation, development at the Geysers is likely to reach 2500 MWe before investment probabilities fall below 50%.

TABLE 4-15A. GEYSERS VAPOR-DOMINATED INVESTMENT EVALUATION
Part A: Major "Type I" Corporate Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	110	.19	.16	8.3	52952	.10	2075	.69
2	220	.24	.17	6.6	111499	.10	1992	.91
3	330	.23	.16	6.6	166768	.10	2012	.91
4	440	.24	.17	6.5	220833	.10	2033	.91
5	550	.24	.17	6.6	272624	.10	2054	.91
6	660	.24	.17	6.6	322291	.10	2075	.91
7	770	.24	.17	6.5	370432	.10	2076	.92
8	880	.24	.17	6.5	417063	.10	2118	.92
9	990	.24	.17	6.6	460348	.10	2183	.91
10	1100	.25	.17	6.5	503612	.10	2162	.92
11	1210	.24	.17	6.5	544656	.10	2162	.92
12	1320	.25	.17	5.7	584768	.10	2206	.94
13	1430	.25	.17	5.7	623194	.10	2229	.94
14	1540	.25	.17	5.7	659973	.10	2252	.94
15	1650	.25	.17	5.7	695548	.10	2275	.94
16	1760	.26	.17	5.7	729921	.10	2298	.95
17	1870	.25	.17	5.7	762203	.10	2345	.94
18	1980	.26	.17	5.7	793378	.31	2345	.48
19	2090	.26	.17	5.7	823772	.40	2369	.22
20	2200	.27	.17	5.7	853110	.50	2369	.07
21	2310	.26	.17	5.7	880917	.50	2418	.07
22	2420	.27	.17	5.7	907949	.50	2443	.07
23	2530	.27	.17	5.7	933803	.50	2467	.07
24	2640	.27	.17	5.7	958508	.55	2492	.04
25	2750	.27	.17	5.7	981882	.55	2544	.03
PRICE MULTIPLIER:1								
1	110	.22	.16	6.8	83340	.10	2075	.89
2	220	.28	.17	5.6	170878	.10	1992	.96
3	330	.27	.17	5.7	253808	.10	2012	.95
4	440	.28	.17	5.6	334318	.10	2033	.96
5	550	.28	.17	5.6	411403	.10	2054	.96
6	660	.29	.17	4.8	485282	.10	2075	.96
7	770	.28	.18	4.8	556565	.10	2076	.96
8	880	.29	.18	4.8	625363	.10	2118	.97
9	990	.20	.17	5.6	689849	.10	2183	.96
10	1100	.29	.18	4.8	753395	.10	2162	.97
11	1210	.29	.18	4.8	813823	.10	2162	.97
12	1320	.29	.18	4.8	872444	.10	2206	.97
13	1430	.29	.18	4.8	928595	.10	2229	.97
14	1540	.30	.18	4.8	982288	.10	2252	.97
15	1650	.30	.18	4.8	1034014	.10	2275	.97
16	1760	.30	.18	4.8	1083836	.10	2298	.97
17	1870	.30	.18	4.8	1130834	.10	2345	.97
18	1980	.30	.18	4.8	1176066	.31	2345	.60
19	2090	.31	.18	4.8	1219871	.40	2369	.30
20	2200	.31	.18	4.8	1262013	.50	2369	.09
21	2310	.31	.18	4.8	1302019	.50	2418	.09
22	2420	.31	.18	4.8	1340700	.50	2443	.09
23	2530	.31	.18	4.8	1377623	.50	2467	.09
24	2640	.32	.18	4.8	1412891	.55	2492	.05
25	2750	.31	.18	4.0	1446302	.55	2544	.05
PRICE MULTIPLIER:1.2								
1	110	.25	.17	5.9	113734	.10	2075	.94
2	220	.32	.18	4.8	230249	.10	1992	.97
3	330	.31	.18	4.8	340857	.10	2012	.97
4	440	.32	.18	4.8	447797	.10	2033	.97
5	550	.32	.10	4.0	550181	.10	2054	.97
6	660	.32	.18	4.8	648254	.10	2075	.97
7	770	.32	.18	4.8	742719	.10	2076	.97
8	880	.32	.18	4.8	833664	.10	2118	.98
9	990	.32	.18	4.8	919360	.10	2183	.97
10	1100	.33	.18	3.9	1003172	.10	2162	.98
11	1210	.33	.18	4.8	1082971	.10	2162	.98
12	1320	.33	.18	3.9	1160145	.10	2206	.98
13	1430	.33	.18	3.9	1233979	.10	2229	.90
14	1540	.33	.18	3.9	1304601	.10	2252	.98
15	1650	.34	.18	3.9	1372480	.10	2275	.98
16	1760	.34	.19	3.9	1437731	.10	2298	.98
17	1870	.34	.18	3.9	1499473	.10	2345	.98
18	1980	.34	.18	3.9	1558763	.31	2345	.69
19	2090	.35	.19	3.9	1616000	.40	2369	.36
20	2200	.35	.19	3.9	1670921	.50	2369	.11
21	2310	.35	.19	3.9	1723129	.50	2418	.11
22	2420	.35	.19	3.9	1773418	.50	2443	.11
23	2530	.35	.19	3.9	1821439	.50	2467	.11
24	2640	.36	.19	3.9	1867264	.55	2492	.06
25	2750	.35	.19	3.9	1910744	.55	2544	.06

TABLE 4-15A. Part B: Independently Operating "Type III" Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	110	.19	.15	9.8	31258	.10	2075	.01
2	220	.23	.16	7.4	69197	.10	1992	.33
3	330	.23	.16	7.4	104055	.10	2012	.32
4	440	.23	.16	7.4	137936	.10	2033	.36
5	550	.23	.16	7.4	169776	.10	2054	.36
6	660	.23	.16	7.4	199784	.10	2075	.36
7	770	.24	.16	7.4	228478	.10	2076	.39
8	880	.24	.16	7.4	255940	.10	2118	.39
9	990	.23	.16	7.4	280489	.10	2183	.34
10	1100	.24	.16	6.6	305164	.10	2162	.58
11	1210	.24	.16	7.4	327975	.10	2162	.38
12	1320	.25	.16	6.5	350096	.10	2206	.61
13	1430	.25	.16	6.5	370869	.10	2229	.60
14	1540	.25	.16	6.5	390376	.10	2252	.60
15	1650	.25	.16	6.5	408934	.10	2275	.59
16	1760	.25	.17	6.5	426622	.10	2298	.63
17	1870	.25	.16	6.6	442699	.10	2345	.58
18	1980	.25	.17	6.5	458017	.31	2345	.00
19	2090	.26	.17	6.5	472761	.40	2369	.00
20	2200	.26	.17	6.5	486763	.50	2369	.00
21	2310	.26	.17	6.5	499667	.50	2418	.00
22	2420	.27	.17	5.7	512071	.50	2443	.00
23	2530	.27	.17	5.7	523660	.50	2467	.00
24	2640	.27	.17	5.7	534464	.55	2492	.00
25	2750	.26	.17	5.7	544413	.55	2544	.00
PRICE MULTIPLIER:1								
1	110	.22	.16	7.6	55626	.10	2075	.25
2	220	.28	.17	5.7	116375	.10	1992	.86
3	330	.27	.17	5.7	172604	.10	2012	.84
4	440	.28	.17	5.7	226543	.10	2033	.85
5	550	.28	.17	5.7	277220	.10	2054	.85
6	660	.28	.17	5.7	324932	.10	2075	.85
7	770	.28	.17	5.7	370254	.10	2076	.86
8	880	.28	.17	5.7	413342	.10	2118	.86
9	990	.28	.17	5.7	452576	.10	2183	.84
10	1100	.29	.17	5.7	491028	.10	2162	.87
11	1210	.29	.17	5.7	526751	.10	2162	.87
12	1320	.29	.17	5.7	561005	.10	2206	.88
13	1430	.29	.17	5.7	593126	.10	2229	.87
14	1540	.29	.17	5.7	623294	.10	2252	.87
15	1650	.30	.17	4.8	651818	.10	2275	.91
16	1760	.30	.17	4.8	678849	.10	2298	.91
17	1870	.30	.17	4.8	703690	.10	2345	.90
18	1980	.30	.17	4.8	727174	.31	2345	.02
19	2090	.31	.18	4.8	749537	.40	2369	.00
20	2200	.31	.18	4.8	770692	.50	2369	.00
21	2310	.31	.18	4.8	790247	.50	2418	.00
22	2420	.31	.18	4.8	808861	.50	2443	.00
23	2530	.31	.18	4.8	826241	.50	2467	.00
24	2640	.32	.18	4.8	842459	.55	2492	.00
25	2750	.31	.18	4.8	857395	.55	2544	.00
PRICE MULTIPLIER:1.2								
1	110	.25	.16	6.1	79988	.10	2075	.68
2	220	.32	.18	4.8	163552	.10	1992	.94
3	330	.31	.18	4.8	241154	.10	2012	.94
4	440	.32	.18	4.8	315160	.10	2033	.94
5	550	.32	.18	4.8	384668	.10	2054	.94
6	660	.32	.18	4.8	450084	.10	2075	.94
7	770	.32	.18	4.8	512044	.10	2076	.94
8	880	.33	.18	4.8	570761	.10	2118	.94
9	990	.32	.18	4.8	624655	.10	2183	.93
10	1100	.33	.18	4.8	676882	.10	2162	.94
11	1210	.33	.18	4.8	725529	.10	2162	.94
12	1320	.33	.18	4.8	771901	.10	2206	.94
13	1430	.33	.18	4.8	815401	.10	2229	.94
14	1540	.34	.18	4.8	856196	.10	2252	.94
15	1650	.34	.18	4.8	894706	.10	2275	.94
16	1760	.34	.18	4.0	931089	.10	2298	.95
17	1870	.34	.18	4.8	964648	.10	2345	.94
18	1980	.34	.18	4.0	996310	.31	2345	.04
19	2090	.35	.18	4.0	1026348	.40	2369	.00
20	2200	.35	.18	4.0	1054623	.50	2369	.00
21	2310	.35	.18	4.0	1080844	.50	2418	.00
22	2420	.36	.18	3.9	1105670	.50	2443	.00
23	2530	.36	.18	3.9	1128830	.50	2467	.00
24	2640	.36	.18	3.9	1150433	.55	2492	.00
25	2750	.36	.18	3.9	1170395	.55	2544	.00

MAJOR RESOURCE PRODUCING CORPORATIONS

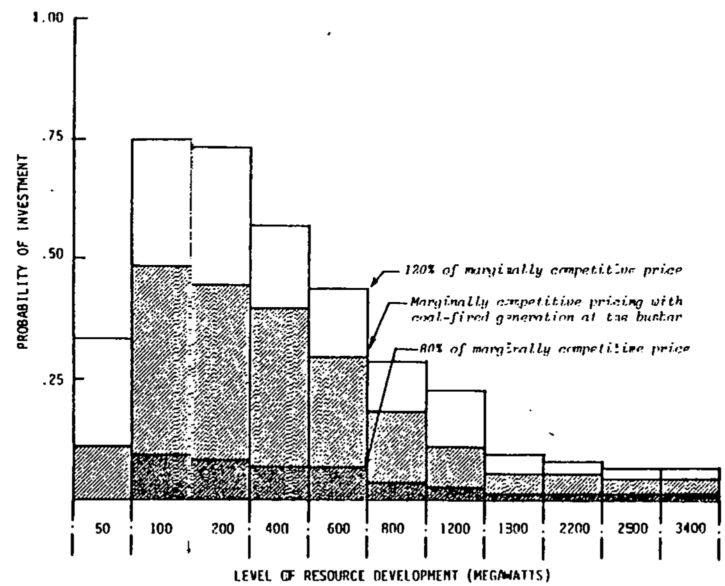


Figure 4-153. ESTIMATES OF FUTURE INVESTMENT BEHAVIOR AT GEYSERS LIQUID-DOMINATED RESOURCE

TABLE 4-15B. GEYSERS LIQUID-DOMINATED INVESTMENT EVALUATION

Part A: Major "Type I" Corporate Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.12	.14	15.1	3805	.17	2246	.00
2	100	.16	.15	10.4	12707	.18	2221	.09
3	200	.16	.15	11.0	24482	.20	2301	.08
4	300	.16	.15	11.0	41600	.24	2327	.07
5	400	.17	.15	10.9	58793	.26	2348	.07
6	600	.17	.15	10.4	92846	.30	2457	.07
7	800	.17	.15	10.4	119805	.35	2483	.04
8	1000	.17	.15	10.4	152098	.38	2512	.03
9	1200	.18	.15	10.4	183752	.39	2535	.03
10	1400	.18	.15	10.4	208912	.42	2562	.02
11	1600	.18	.15	9.5	239081	.44	2589	.03
12	1800	.18	.15	9.5	268449	.46	2616	.02
13	2000	.18	.15	9.5	291786	.47	2644	.02
14	2200	.19	.15	9.5	320048	.48	2668	.02
15	2400	.19	.15	9.5	347199	.49	2699	.02
16	2600	.19	.15	9.5	368753	.50	2727	.02
17	2800	.19	.15	9.5	394507	.50	2756	.02
18	3000	.19	.16	8.5	419392	.50	2785	.02
19	3200	.19	.16	8.5	439187	.50	2814	.02
20	3400	.20	.16	8.5	462862	.50	2843	.02
PRICE MULTIPLIER:1								
1	50	.16	.15	10.3	13515	.17	2246	.11
2	100	.19	.16	8.1	30951	.18	2221	.48
3	200	.20	.16	8.3	58510	.20	2301	.45
4	300	.20	.16	8.3	90720	.24	2327	.36
5	400	.21	.16	7.4	122356	.26	2348	.40
6	600	.21	.16	7.6	184326	.30	2457	.29
7	800	.21	.16	7.6	237987	.35	2483	.18
8	1000	.22	.16	7.6	295851	.38	2512	.13
9	1200	.22	.16	7.6	351986	.39	2535	.12
10	1400	.22	.16	7.6	400587	.42	2562	.09
11	1600	.22	.16	7.6	453198	.44	2589	.07
12	1800	.22	.16	7.6	504041	.46	2616	.06
13	2000	.23	.16	7.6	547909	.47	2644	.05
14	2200	.23	.16	6.7	595841	.48	2668	.06
15	2400	.23	.16	6.7	641784	.49	2699	.05
16	2600	.23	.16	6.7	681316	.50	2727	.04
17	2800	.23	.16	6.7	724272	.50	2756	.05
18	3000	.23	.17	6.7	765578	.50	2785	.05
19	3200	.24	.17	6.7	801096	.50	2814	.05
20	3400	.24	.17	6.7	839768	.50	2843	.05
PRICE MULTIPLIER:1.2								
1	50	.18	.15	8.9	23229	.17	2246	.33
2	100	.22	.16	6.6	49192	.18	2221	.75
3	200	.23	.17	6.5	92539	.20	2301	.73
4	300	.23	.17	6.5	139831	.24	2327	.62
5	400	.24	.17	6.5	185917	.26	2348	.57
6	600	.25	.17	6.6	275792	.30	2457	.44
7	800	.25	.17	6.6	356175	.35	2483	.29
8	1000	.25	.17	5.7	439620	.38	2512	.25
9	1200	.26	.17	5.7	520234	.39	2535	.23
10	1400	.26	.17	5.7	592266	.42	2562	.16
11	1600	.26	.17	5.7	667301	.44	2589	.13
12	1800	.26	.17	5.7	739609	.46	2616	.10
13	2000	.26	.17	5.7	804048	.47	2644	.09
14	2200	.27	.17	5.7	871629	.48	2668	.08
15	2400	.27	.17	5.7	936379	.49	2699	.07
16	2600	.27	.17	5.7	993889	.50	2727	.06
17	2800	.27	.17	5.7	1054024	.50	2756	.07
18	3000	.27	.17	5.7	1111786	.50	2785	.07
19	3200	.28	.17	5.7	1163006	.50	2814	.07
20	3400	.29	.17	5.7	1216689	.50	2843	.07

TABLE 4-15B. Part B: Independently Operating "Type III" Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.00	.00	.0	⁻2310	.17	2246	.00
2	100	.15	.14	14.9	373	.18	2221	.00
3	200	.15	.14	16.1	2457	.20	2301	.00
4	300	.15	.14	15.3	8185	.24	2327	.00
5	400	.16	.14	14.4	14165	.26	2348	.00
6	600	.16	.14	13.1	26352	.30	2457	.00
7	800	.16	.14	13.1	34333	.35	2483	.00
8	1000	.17	.14	13.1	45787	.38	2512	.00
9	1200	.17	.15	12.2	57078	.39	2535	.00
10	1400	.17	.15	12.2	64615	.42	2562	.00
11	1600	.17	.15	12.2	75357	.44	2589	.00
12	1800	.17	.15	12.2	85735	.46	2616	.00
13	2000	.17	.15	12.2	92706	.47	2644	.00
14	2200	.18	.15	11.3	102710	.48	2668	.00
15	2400	.18	.15	11.3	112166	.49	2699	.00
16	2600	.18	.15	11.3	118495	.50	2727	.00
17	2800	.18	.15	11.3	127348	.50	2756	.00
18	3000	.18	.15	11.3	135762	.50	2785	.00
19	3200	.19	.15	10.4	141417	.50	2814	.00
20	3400	.19	.15	10.4	149338	.50	2843	.00
PRICE MULTIPLIER:1								
1	50	.15	.14	14.2	4429	.17	2246	.00
2	100	.19	.15	9.5	12727	.18	2221	.00
3	200	.19	.15	10.0	24828	.20	2301	.00
4	300	.19	.15	9.2	39967	.24	2327	.00
5	400	.20	.15	9.1	54791	.26	2348	.00
6	600	.21	.15	9.4	83773	.30	2457	.00
7	800	.21	.15	9.4	107539	.35	2483	.00
8	1000	.21	.16	8.5	133859	.38	2512	.00
9	1200	.21	.16	8.5	159098	.39	2535	.00
10	1400	.21	.16	8.5	179776	.42	2562	.00
11	1600	.22	.16	8.5	202829	.44	2589	.00
12	1000	.22	.16	0.5	224707	.46	2616	.00
13	2000	.22	.16	8.5	242647	.47	2644	.00
14	2200	.22	.16	7.6	262866	.48	2668	.00
15	2400	.22	.16	7.6	281903	.49	2699	.00
16	2600	.23	.16	7.6	297228	.50	2727	.00
17	2800	.23	.16	7.6	314507	.50	2756	.00
18	3000	.23	.16	7.6	330849	.50	2785	.00
19	3200	.23	.16	7.6	343919	.50	2814	.00
20	3400	.23	.16	7.6	358788	.50	2843	.00
PRICE MULTIPLIER:1.2								
1	50	.18	.15	10.2	11174	.17	2246	.00
2	100	.22	.16	7.3	25077	.18	2221	.05
3	200	.23	.16	7.4	47200	.20	2301	.03
4	300	.23	.16	7.4	71744	.24	2327	.01
5	400	.23	.16	7.4	95411	.26	2348	.00
6	600	.24	.16	[illegible]	[illegible]	.30	2457	.00
7	800	.25	.16	6.7	180747	.35	2483	.00
8	1000	.25	.16	6.7	221916	.38	2512	.00
9	1200	.25	.16	6.7	261126	.39	2535	.00
10	1400	.25	.16	6.7	294898	.42	2562	.00
11	1600	.25	.16	6.7	330297	.44	2589	.00
12	1800	.26	.17	6.7	363832	.46	2616	.00
13	2000	.26	.17	6.7	392579	.47	2644	.00
14	2200	.26	.17	6.6	423008	.48	2668	.00
15	2400	.26	.17	6.6	451622	.49	2699	.00
16	2600	.26	.17	6.6	475957	.50	2727	.00
17	2800	.27	.17	5.8	501679	.50	2756	.00
18	3000	.27	.17	5.8	525921	.50	2785	.00
19	3200	.27	.17	5.7	546409	.50	2814	.00
20	3400	.27	.17	5.7	568226	.50	2843	.00

4.3 UTAH RESOURCE AREAS

The two Utah resource areas evaluated in this report are located in the central portion of the state, as illustrated in Figure 4-1. The economic, financial and tax parameters applicable to both Utah resources are shown in Table 4-16.

4.3.1 Cove Fort-Sulphurdale, UT

Located in Millard and Beaver Counties in Utah, Cove Fort-Sulphurdale is in the early stages of exploration. The site was unitized in 1977, with Union Oil Company named as the operator. Other companies investigating the area include Phillips Petroleum Company, O'Brien Resources Corporation, Chevron Oil Company, and Amax Exploration. Table 4-17 summarizes the resource characteristics at Cove Fort-Sulphurdale. Because relatively little documentation of the resource is available, some of the resource parameters are subject to a substantial degree of uncertainty. Figure 4-16 presents the level of confidence mappings for the KGRA. A low brine contamination index of 1 is assigned to the resource for modeling purposes. Transmission requirements will be met by constructing a line from the KGRA to the Cove Fort Substation 4 miles away, and the Sigurd Substation 45 miles away.

Results of the Cove Fort-Sulphurdale investment evaluation are provided in Table 4-18. As indicated in this table, at competitive resource prices and as currently understood with the limited exploration to date, there appears to be no likelihood of investment for resource development. A combination of factors which appear in Table 4-17 contribute to the adverse financial attributes of well field investments at Cove Fort-Sulphurdale: (a) the geology is igneous which causes high well costs; (b) the resource temperature is relatively cool which decreases its competitive price and increases well requirements; (c) well flow rates are moderate; and (d) the competing cost of alternative coal-fired generation is relatively inexpensive in Utah which reduces the competitive geothermal fluid price.

It should also be noted that, as discussed in section 2.2.5, surface piping costs are modeled as power plant, rather than well field, costs for Utah applications. While this removes a substantial investment

TABLE 4-16. ECONOMIC AND FINANCIAL PARAMETERS FOR UTAH SIMULATIONS

1. ECONOMIC PARAMETERS

1.1	LONG-TERM GNP DEFLATOR (I/P)	0.05
1.2	COST ESCALATION RATE (I/P)	0.06
1.3	ENERGY PRICE ESCALATION RATE (I/P)	0.075
1.4	BASE YEAR OF ANALYSIS (I/P)	1978
1.5	YEAR OF PRICING (I/P)	1978

2. POWER PRODUCER FINANCIAL PARAMETERS

		HYDROTHERMAL	ALTERNATIVE
2.1	AVERAGE AFTER-TAX COST OF CAPITAL (O/P)	.089	.089
2.2	DEBT FRACTION (I/P)	.500	.500
2.3	COST OF DEBT (I/P)	.085	.085
2.4	PREFERRED EQUITY FRACTION (I/P)	.100	.100
2.5	COST OF PREFERRED EQUITY (I/P)	.085	.085
2.6	COMMON EQUITY FRACTION (I/P)	.400	.400
2.7	COST OF COMMON EQUITY (I/P)	.145	.145
2.8	EFFECTIVE INCOME TAX RATE (O/P)	.482	.482
2.9	STATE INCOME TAX RATE (I/P)	.040	.040
2.10	FEDERAL INCOME TAX RATE (I/P)	.460	.460
2.11	INVESTMENT TAX CREDIT (I/P)	.100	.100
2.12	POWER PLANT TAX LIFE (I/P)	22.000	22.000
2.13	POWER PLANT EXPECTED LIFE (I/P)	30.000	30.000
2.14	POWER PLANT CAPACITY FACTOR:		
	-MINIMUM VALUE (I/P)		.800
	-VALUE AT MODE (I/P)		.850
	-MAXIMUM VALUE (I/P)		.900
	-MEAN VALUE (O/P)	.850	.850
2.15	PLANT RECURRENT COST FRACTION (I/P)	.041	.041

3. RESOURCE PRODUCER FINANCIAL PARAMETERS

3.1.1	TYPE OF FIRM (I/P)	1
3.1.2	FIRMS IN JOINT VENTURE (I/P)	1
3.1.3	PRESENT VALUE DISCOUNT RATE (I/P)	0.115
3.1.4	FMRR SINKING FUND INTEREST RATE (I/P)	0.14
3.1.5	FMRR REINVESTMENT EARNINGS RATE (I/P)	0.14
3.1.6	DEBT FRACTION (I/P)	0.25
3.1.7	COST OF DEBT (I/P)	0.085
3.1.8	EFFECTIVE INCOME TAX RATE (O/P)	0.4816
3.1.9	STATE INCOME TAX RATE (I/P)	0.04
3.1.10	FEDERAL INCOME TAX RATE (I/P)	0.46

3.2.1	TYPE OF FIRM (I/P)	3
3.2.2	FIRMS IN JOINT VENTURE (I/P)	1
3.2.3	PRESENT VALUE DISCOUNT RATE (I/P)	0.135
3.2.4	FMRR SINKING FUND INTEREST RATE (I/P)	0.1
3.2.5	FMRR REINVESTMENT EARNINGS RATE (I/P)	0.14
3.2.6	DEBT FRACTION (I/P)	0
3.2.7	COST OF DEBT (I/P)	0
3.2.8	EFFECTIVE INCOME TAX RATE (O/P)	0.4816
3.2.9	STATE INCOME TAX RATE (I/P)	0.04
3.2.10	FEDERAL INCOME TAX RATE (I/P)	0.46

4. TAX INCENTIVES

4.1	INVESTMENT TAX CREDIT (I/P)	0.2
4.2	INTANGIBLE WELL COST FRACTION (I/P)	0.75
4.3	PERCENTAGE DEPLETION ALLOWANCE (I/P):	
	-THRU 1980	0.22
	-1981	0.2
	-1982	0.18
	-1983	0.16
	-AFTER 1983	0.15

TABLE 4-17. RESOURCE AND DEVELOPMENT PARAMETERS AT COVE FORT-SULPHURDALE KGRA

RESOURCE PARAMETERS

```
1.  STATE.......................................... UT
2.  TYPE OF GEOLOGY (I/P).......................... IGNEOUS
3.  RESERVOIR DEPTH,FT:
    -MINIMUM VALUE (I/P).... 1900
    -VALUE AT MODE (I/P).... 6600
    -MAXIMUM VALUE (I/P).... 7300
    -MEAN VALUE (O/P)...........................  5462
4.  MEAN WELL COST,$1000 (O/P).................. 1008
5.  DRY WELL COST FRACTION (I/P)................. 0.9
6.  REDRILL WELL COST FRACTION (I/P)............. 0.35
7.  DRY WELL FRACTION:
    -MINIMUM VALUE (I/P).... 0.09
    -VALUE AT MODE (I/P).... 0.1
    -MAXIMUM VALUE (I/P).... 0.11
    -MEAN VALUE (O/P)........................... 0.1
8.  SPARE WELL FRACTION (I/P).................... 0.2
9.  PRODUCER/INJECTOR RATIO (I/P)................ 2
10. INITIAL REDRILL FRACTION (I/P)............... 0.3
11. REPLACEMENT REDRILL FRACTION (I/P)........... 0.33
12. WELLHEAD RESOURCE TEMPERATURE,F:
    -MINIMUM VALUE (I/P).... 290
    -VALUE AT MODE (I/P).... 330
    -MAXIMUM VALUE (I/P).... 350
    -MEAN VALUE (O/P)........................... 325
13. NET SPECIFIC ENERGY,WHR/LB (O/P)............  5.1
14. WELL FLOW RATE,1000LB/HR:
    -MINIMUM VALUE (I/P).... 100
    -VALUE AT MODE (I/P).... 500
    -MAXIMUM VALUE (I/P).... 1000
    -MEAN VALUE (O/P)...........................  526
15. WELL SPACING,ACRES/WELL (I/P)................ 40
16. SALINITY INDEX [0:LOW→4:HIGH] (I/P).......... 1
17. WELL LIFE,YRS:
    -MINIMUM VALUE (I/P).... 10
    -VALUE AT MODE (I/P).... 15
    -MAXIMUM VALUE (I/P).... 20
    -MEAN VALUE (O/P)........................... 15.0
18. BOOK LIFE OF WELLS,YRS (I/P)................. 15
19. BOOK LIFE OF SURFACE CAPITAL,YRS (I/P)....... 30
20. TAX LIFE OF WELLS,YRS (I/P).................. 15
21. AD VALOREM TAX,ON ACTUAL VALUE (I/P)......... 0.0125
22. ROYALTY FRACTION (I/P)....................... 0.125
23. LEASE BONUS,$/ACRE (I/P)..................... 75
24. LAND RENTAL,$/ACRE (I/P)..................... 2
25. POWER TRANSMISSION COST,$1000 (I/P):
    -TO 200000 KWE.............................. 3700
    -ADDITIONAL INCREMENTS OF 600000 KWE......... 5900
26. ALTERNATIVE GENERATION:
    -CAPITAL COST,$/KWE (I/P).................... 1100
    -FUEL COST,MILLS/KWH (I/P)................... 8
```

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL.TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1985	50	.80	1040	844	10.6
2	100	1988	50	.61	2120	807	10.9
3	200	1990	100	.22	4160	789	11.0
4	300	1991	100	.20	6240	790	11.0
5	400	1992	100	.16	8280	785	11.0
6	500	1993	100	.12	10400	782	11.0

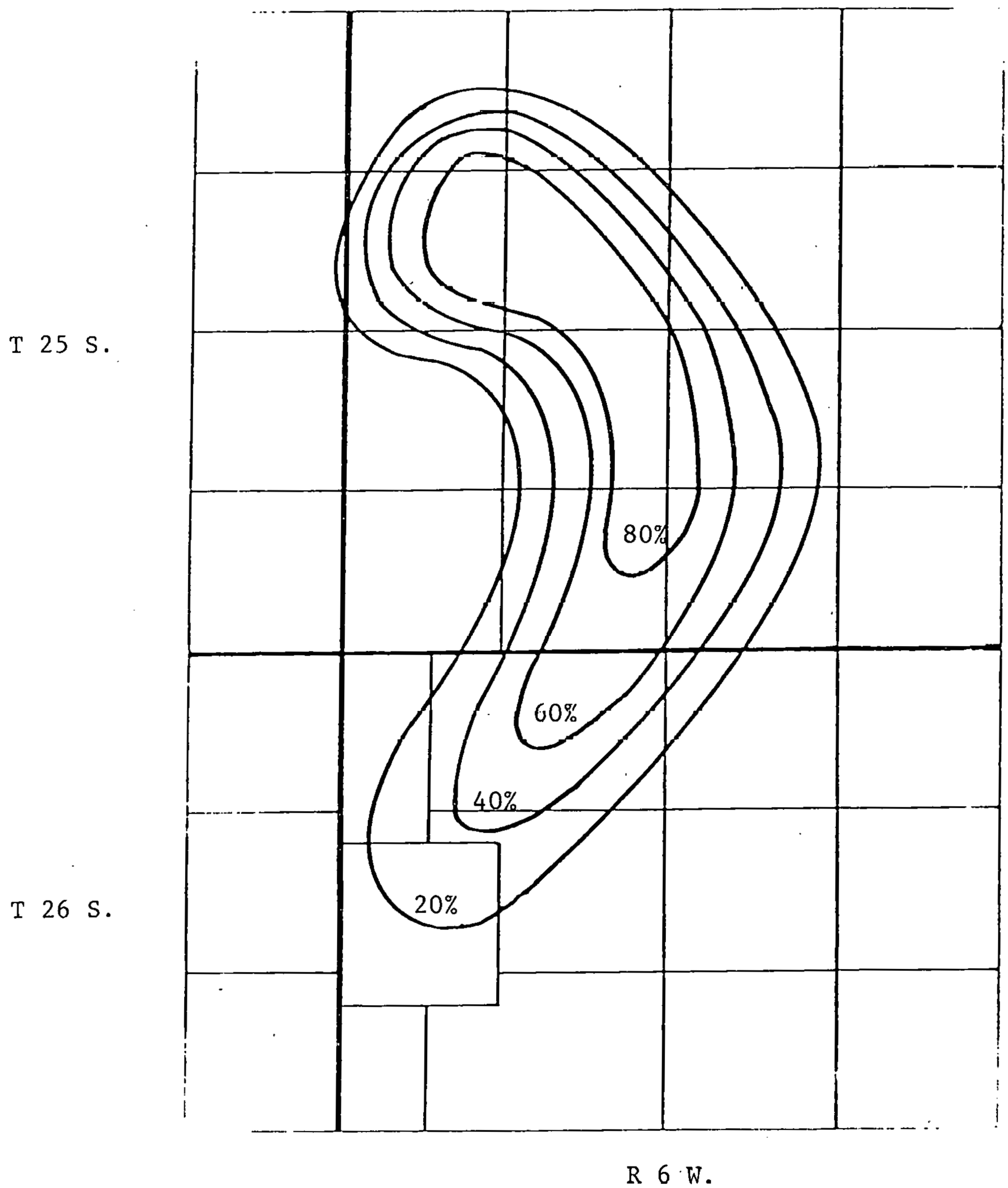


Figure 4-16. LEVELS OF CONFIDENCE
AT COVE FORT-SULPHURDALE KGRA (MID-1979)

TABLE 4-18. COVE FORT-SULPHURDALE INVESTMENT EVALUATION

Part A: Major "Type I" Corporate Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.00	.00	.0	¯12983	.20	1577	.00
2	100	.00	.00	.0	¯5560	.39	1532	.00
3	200	.00	.00	.0	¯6906	.78	1614	.00
4	300	.00	.00	.0	¯5898	.80	1634	.00
5	400	.00	.00	.0	¯5326	.84	1650	.00
6	500	.00	.00	.0	¯5563	.88	1673	.00
PRICE MULTIPLIER:1								
1	50	.00	.00	.0	¯2624	.20	1577	.00
2	100	.13	.14	14.8	1825	.39	1532	.00
3	200	.14	.14	13.0	12462	.78	1614	.00
4	300	.15	.14	13.0	22269	.80	1634	.00
5	400	.15	.14	12.1	32664	.84	1650	.00
6	500	.15	.14	13.1	41970	.88	1673	.00
PRICE MULTIPLIER:1.2								
1	50	.14	.14	13.4	7730	.20	1577	.02
2	100	.18	.15	9.2	21209	.39	1532	.04
3	200	.19	.16	8.6	48537	.78	1614	.00
4	300	.19	.16	8.6	74249	.80	1634	.00
5	400	.20	.16	8.6	99842	.84	1650	.00
6	500	.19	.16	8.6	123652	.88	1673	.00

Part B: Independently Operating "Type III" Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.00	.00	.0	¯15227	.20	1577	.00
2	100	.00	.00	.0	¯7535	.39	1532	.00
3	200	.00	.00	.0	¯10688	.78	1614	.00
4	300	.00	.00	.0	¯9525	.80	1634	.00
5	400	.00	.00	.0	¯8736	.84	1650	.00
6	500	.00	.00	.0	¯8606	.88	1673	.00
PRICE MULTIPLIER:1								
1	50	.00	.00	.0	¯7732	.20	1577	.00
2	100	.00	.00	.0	¯1255	.39	1532	.00
3	200	.00	.00	.0	¯7421	.78	1614	.00
4	300	.00	.00	.0	¯6750	.80	1634	.00
5	400	.00	.00	.0	¯5425	.84	1650	.00
6	500	.00	.00	.0	¯4708	.88	1673	.00
PRICE MULTIPLIER:1.2								
1	50	.00	.00	.0	¯243	.20	1577	.00
2	100	.17	.15	11.4	5306	.39	1532	.00
3	200	.18	.15	11.2	17300	.78	1614	.00
4	300	.18	.15	10.3	28305	.80	1634	.00
5	400	.18	.15	10.3	39320	.84	1650	.00
6	500	.18	.15	10.3	49136	.88	1673	.00

requirement from the well field developer, it effectively increases the electric utility's plant cost and lowers the competitive resource price which the utility can afford to pay. Note, for example, that the competitive resource price at Cove Fort-Sulphurdale (10-11 mills/kWh) is significantly lower than that at any of the California resource areas (14-20 mills/kWh).

It appears from Table 4-18 that, because of limited revenues at competitive resource prices, investment returns are likely to be poor and investments are likely to be unattractive regardless of the probabilities of loss at Cove Fort-Sulphurdale. Thus, at present economic conditions and inflation rates assumed in Table 4-16, it is doubtful that the Cove Fort-Sulphurdale area defined in Table 4-17 will provide an attractive investment opportunity regardless of redefined probabilities of success realized by continued exploration. On this basis, it appears that the USGS estimate of 330 MWe of electric power potential at Cove Fort-Sulphurdale (see Muffler, 1979) is unattainable at competitive resource prices.

4.3.2 Roosevelt Hot Springs, UT

Located in Beaver County, Utah, Roosevelt Hot Springs has been actively explored, confirmed and evaluated. Both Phillips Petroleum Company and Thermal Power Company have conducted well flow tests, and are attempting to attract utility interest. At present, a 50 MWe power plant is planned by Phillips and Rogers International, with power to be purchased by Utah Power and Light.

Table 4-19 summarizes resource characteristics at Roosevelt and Figure 4-17 maps levels of confidence over the resource area as it is understood today. The high resource temperature, high well flow rates and low salinity (brine contamination index of 1 for modeling purposes) of this resource make it well suited for development. Power from Roosevelt will likely be transmitted to the substation at Sigurd via Cove Fort, a total distance of 62 miles.

Results of the Roosevelt Hot Springs investment evaluation are provided in Table 4-20 and Figure 4-18. With marginally competitive pricing of the resource, the financial attributes of Roosevelt well field investments appear attractive to both major corporate producers and independently operating producers. Front end exploration costs detract from the attractiveness of the initial 50 megawatt level of development only.

As well field development progresses beyond 600 and 800 megawatt levels -- for independent and major corporate producers, respectively -- risks of investment loss cause the likelihood of investment to fall below 50%. These perceptions of risk may change as continued exploration better defines the confidence mapping presented in Figure 4-17. Results given here reflect investment potential at Roosevelt as this resource is understood today and as defined in Table 4-19. The 1979 USGS assessment of Roosevelt (see Muffler, 1979) estimates its electric power potential at 970 MWe which appears to be slightly optimistic in view of the investment evaluation presented here at competitive resource prices.

Variations in resource pricing at Roosevelt, above or below the marginally competitive price, have an appreciable impact upon estimated investment behavior. Independently operating resource firms are particularly affected by pricing variations as illustrated in Figure 4-18.

TABLE 4-19. 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,$1000 (O/P).................... 718
5. DRY WELL COST FRACTION (I/P).................. 0.9
6. REDRILL WELL COST FRACTION (I/P).............. 0.35
7. DRY WELL FRACTION:
   - -MINIMUM VALUE (I/P).... 0.09
   - -VALUE AT MODE (I/P).... 0.1
   - -MAXIMUM VALUE (I/P).... 0.11
   - -MEAN VALUE (O/P)............................ 0.1
8. SPARE WELL FRACTION (I/P)..................... 0.2
9. PRODUCER/INJECTOR RATIO (I/P)................. 2
10. INITIAL REDRILL FRACTION (I/P)................ 0.3
11. REPLACEMENT REDRILL FRACTION (I/P)............ 0.33
12. WELLHEAD RESOURCE TEMPERATURE,F:
    - -MINIMUM VALUE (I/P).... 400
    - -VALUE AT MODE (I/P).... 430
    - -MAXIMUM VALUE (I/P).... 460
    - -MEAN VALUE (O/P)............................ 430
13. NET SPECIFIC ENERGY,WHR/LB (O/P).............. 10.9
14. WELL FLOW RATE,1000LB/HR:
    - -MINIMUM VALUE (I/P).... 900
    - -VALUE AT MODE (I/P).... 1000
    - -MAXIMUM VALUE (I/P).... 1100
    - -MEAN VALUE (O/P)............................ 1000
15. WELL SPACING,ACRES/WELL (I/P)................. 40
16. SALINITY INDEX [0:LOW-4:HIGH] (I/P).......... 1
17. WELL LIFE,YRS:
    - -MINIMUM VALUE (I/P).... 10
    - -VALUE AT MODE (I/P).... 15
    - -MAXIMUM VALUE (I/P).... 20
    - -MEAN VALUE (O/P)............................ 15.0
18. BOOK LIFE OF WELLS,YRS (I/P).................. 15
19. BOOK LIFE OF SURFACE CAPITAL,YRS (I/P)....... 30
20. TAX LIFE OF WELLS,YRS (I/P)................... 15
21. AD VALOREM TAX,ON ACTUAL VALUE (I/P).......... 0.0125
22. ROYALTY FRACTION (I/P)........................ 0.125
23. LEASE BONUS,$/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

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL. TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1983	50	.80	280	[illegible]	11.3
2	100	1986	50	.80	560	736	11.7
3	200	1988	100	.80	1040	711	11.9
4	300	1989	100	.80	1560	712	11.8
5	400	1990	100	.80	2040	706	11.8
6	500	1991	100	.80	2560	702	11.8
7	600	1992	100	.80	3040	699	11.8
8	700	1993	100	.66	3600	708	11.7
9	800	1994	100	.60	4120	706	11.7
10	900	1995	100	.55	4600	704	11.7
11	1000	1996	100	.50	5120	702	11.7
12	1100	1997	100	.43	5600	700	11.7
13	1200	1998	100	.36	6120	699	11.7
14	1300	1999	100	.30	6680	704	11.6
15	1400	2000	100	.25	7160	703	11.6

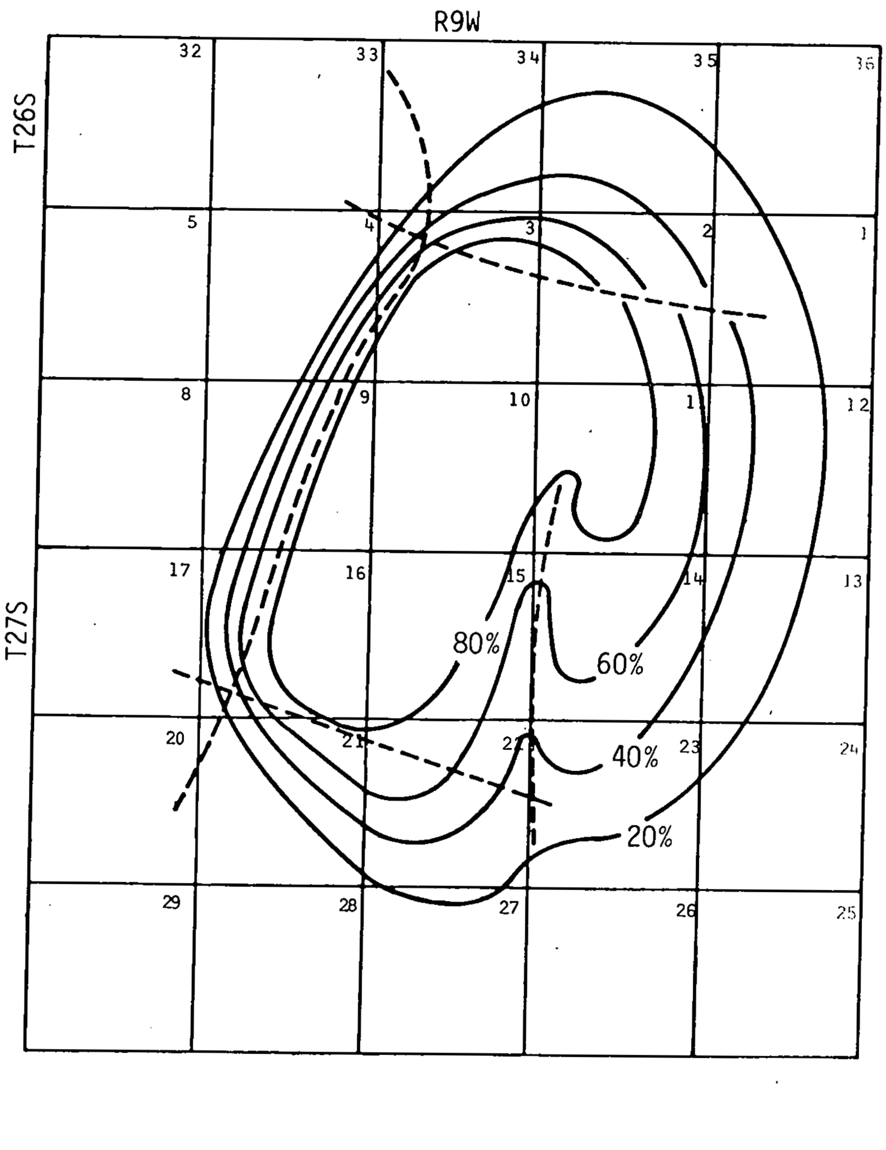


Figure 4-17. LEVELS OF CONFIDENCE
AT ROOSEVELT HOT SPRINGS KGRA (MID-1979)

TABLE 4-20. ROOSEVELT HOT SPRINGS INVESTMENT EVALUATION
Part A: Major "Type I" Corporate Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.17	.15	10.4	9872	.20	1113	.11
2	100	.27	.18	5.3	25416	.20	1051	.86
3	200	.34	.19	3.8	56164	.20	1085	.93
4	300	.36	.20	3.8	85017	.20	1099	.94
5	400	.35	.19	3.8	113648	.20	1107	.94
6	500	.36	.19	3.8	141222	.20	1121	.94
7	600	.36	.19	3.8	167636	.20	1129	.94
8	700	.35	.19	3.8	189497	.34	1147	.66
9	800	.36	.20	3.8	214234	.40	1155	.46
10	900	.36	.20	3.7	237932	.45	1164	.28
11	1000	.38	.20	3.7	261211	.50	1178	.16
12	1100	.37	.20	3.7	283298	.57	1187	.06
13	1200	.38	.20	3.7	304573	.64	1202	.02
14	1300	.37	.20	3.6	321814	.70	1218	.00
15	1400	.38	.20	3.7	341582	.75	1223	.00
PRICE MULTIPLIER:1								
1	50	.21	.17	7.8	21195	.20	1113	.56
2	100	.34	.20	4.8	46614	.20	1051	.93
3	200	.43	.21	3.1	95579	.20	1085	.96
4	300	.44	.21	3.2	141800	.20	1099	.97
5	400	.44	.21	3.1	187017	.20	1107	.96
6	500	.44	.21	3.1	230436	.20	1121	.97
7	600	.44	.21	3.1	271969	.20	1129	.96
8	700	.44	.21	3.1	308277	.34	1147	.75
9	800	.45	.21	3.1	346812	.40	1155	.55
10	900	.45	.21	3.1	383651	.45	1164	.35
11	1000	.46	.21	3.2	419493	.50	1170	.20
12	1100	.46	.21	3.1	453551	.57	1187	.08
13	1200	.46	.21	3.1	486248	.64	1202	.03
14	1300	.45	.21	3.0	514368	.70	1218	.01
15	1400	.47	.21	3.1	544523	.75	1223	.00
PRICE MULTIPLIER:1.2								
1	50	.24	.18	6.8	32508	.20	1113	.78
2	100	.40	.21	4.0	67785	.20	1051	.96
3	200	.50	.22	3.1	134981	.20	1085	.97
4	300	.51	.22	3.2	198569	.20	1099	.97
5	400	.51	.22	3.1	260373	.20	1107	.97
6	500	.51	.22	3.1	319627	.20	1121	.97
7	600	.51	.22	3.1	376279	.20	1129	.97
8	700	.51	.22	3.1	427037	.34	1147	.79
9	800	.52	.22	3.1	479341	.40	1155	.59
10	900	.52	.22	3.1	529347	.45	1164	.39
11	1000	.53	.22	3.2	577729	.50	1178	.23
12	1100	.53	.22	3.1	623777	.57	1187	.09
13	1200	.53	.22	3.1	667881	.64	1202	.03
14	1300	.52	.22	3.0	706895	.70	1218	.01
15	1400	.54	.22	3.1	747418	.75	1223	.00

TABLE 4-20. Part B: Independently Operating "Type III" Producers

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:0.8								
1	50	.16	.15	11.9	4774	.20	1113	.00
2	100	.27	.18	6.2	14760	.20	1051	.51
3	200	.33	.19	4.4	34349	.20	1085	.82
4	300	.35	.19	4.4	52429	.20	1099	.84
5	400	.34	.19	4.4	70096	.20	1107	.83
6	500	.35	.19	4.4	86817	.20	1121	.83
7	600	.34	.19	4.4	102517	.20	1129	.83
8	700	.34	.19	4.4	114976	.34	1147	.19
9	800	.35	.19	3.8	129250	.40	1155	.07
10	900	.35	.19	4.4	142644	.45	1164	.02
11	1000	.37	.19	3.9	155676	.50	1178	.00
12	1100	.36	.19	3.8	167773	.57	1187	.00
13	1200	.37	.19	3.8	179218	.64	1202	.00
14	1300	.35	.19	3.8	187928	.70	1218	.00
15	1400	.37	.19	3.8	198228	.75	1223	.00
PRICE MULTIPLIER:1								
1	50	.21	.16	8.6	13267	.20	1113	.03
2	100	.33	.19	4.9	30262	.20	1051	.81
3	200	.42	.20	3.7	62340	.20	1085	.89
4	300	.43	.21	3.2	92116	.20	1099	.90
5	400	.43	.20	3.7	120748	.20	1107	.89
6	500	.43	.20	3.2	147758	.20	1121	.90
7	600	.43	.20	3.7	173094	.20	1129	.89
8	700	.43	.20	3.7	194601	.34	1147	.27
9	800	.44	.21	3.2	217343	.40	1155	.09
10	900	.44	.21	3.1	238678	.45	1164	.03
11	1000	.45	.21	3.2	259121	.50	1178	.01
12	1100	.45	.21	3.2	278166	.57	1187	.00
13	1200	.45	.21	3.2	296123	.64	1202	.00
14	1300	.44	.20	3.1	310928	.70	1218	.00
15	1400	.46	.21	3.2	326901	.75	1223	.00
PRICE MULTIPLIER:1.2								
1	50	.24	.17	7.6	21750	.20	1113	.16
2	100	.39	.21	4.9	45748	.20	1051	.86
3	200	.48	.21	3.1	90314	.20	1085	.91
4	300	.50	.22	3.2	131788	.20	1099	.91
5	400	.49	.21	3.2	171386	.20	1107	.91
6	500	.50	.22	3.2	208674	.20	1121	.91
7	600	.50	.21	3.1	243659	.20	1129	.91
8	700	.50	.21	3.1	274203	.34	1147	.30
9	800	.51	.22	3.2	305421	.40	1155	.10
10	900	.50	.22	3.1	334679	.45	1164	.04
11	1000	.52	.22	3.2	362556	.50	1178	.01
12	1100	.52	.22	3.2	388564	.57	1187	.00
13	1200	.52	.22	3.2	413009	.64	1202	.00
14	1300	.51	.22	3.1	433890	.70	1218	.00
15	1400	.52	.22	3.2	455544	.75	1223	.00

MAJOR RESOURCE PRODUCING CORPORATIONS

INDEPENDENTLY OPERATING RESOURCE PRODUCERS

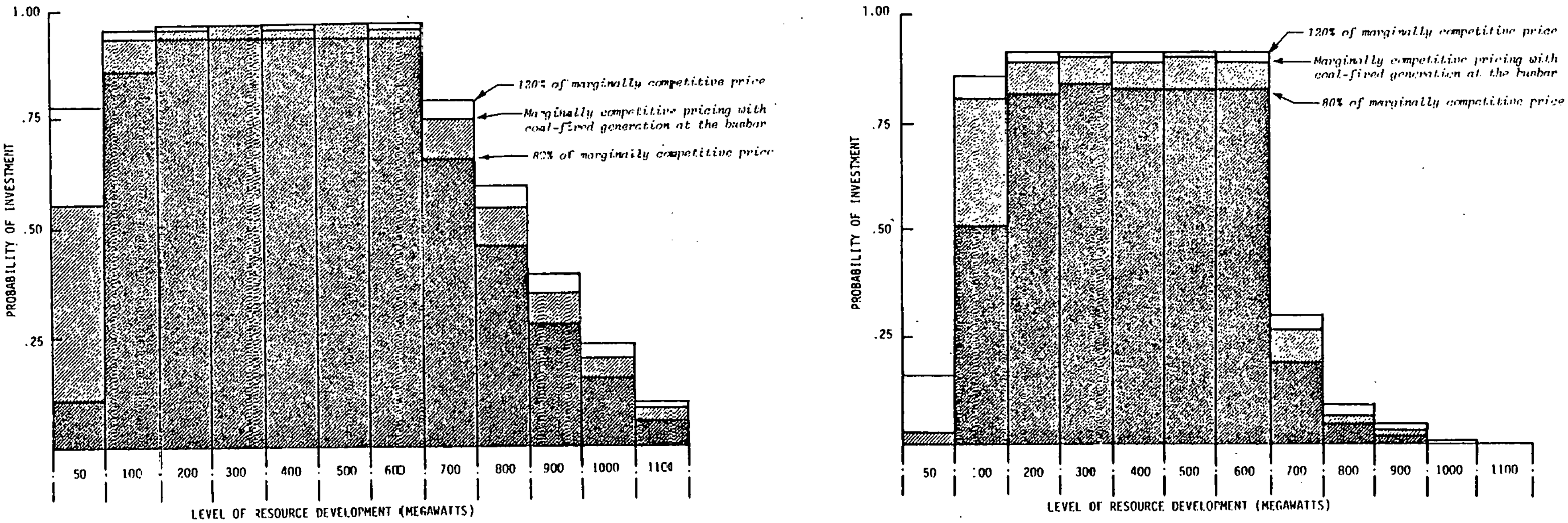


Figure 4-18. ESTIMATES OF INVESTMENT BEHAVIOR
AT ROOSEVELT HOT SPRINGS GEOTHERMAL RESOURCE AREA

Chapter Five

POLICY AND SENSITIVITY ANALYSES: BRAWLEY EXAMPLE

To demonstrate the analytic capabilities of the geothermal investment model TCN2000, a series of sensitivity tests were performed to examine the likely effects of:

- Joint venture arrangements by independently operating resource firms;
- Variations in resource pricing both above and below that required for marginally competitive electric energy costs;
- Tax incentives provided by the National Energy Act (NEA) of 1978;
- Federal geothermal loan guarantees on well field investments;
- Maintaining the geothermal depletion allowance at 22% rather than instituting the current NEA depletion allowance which declines to 15% by 1984;
- Providing new fully-refundable investment tax credits of 20%, 30%, 40% or 50% for both well field and geothermal power plant capital;
- Production tax credits of $3/bbl of oil equivalent energy for electric utilities with geothermal generating capacity;
- A combined 50% investment tax credit and $3/bbl of oil equivalent energy production tax credit.

5.1 THE BRAWLEY BASE CASE

The Brawley geothermal resource area in the Imperial Valley of southern California was selected as a representative area for evaluating these alternatives[33]. As discussed in the previous chapter and as illustrated in Figure 5-1, the Brawley area offers high investment potential through the 300 megawatt level of development for both major corporate resource producers and independently operating resource producers. Beyond the 300 megawatt level, as the area is understood today, investment risks increase and the likelihood of investment progressively declines. At the USGS estimated resource

[33]Work in progress as this report was being published is evaluating the effects of these alternatives upon the national Known Geothermal Resource Area base.

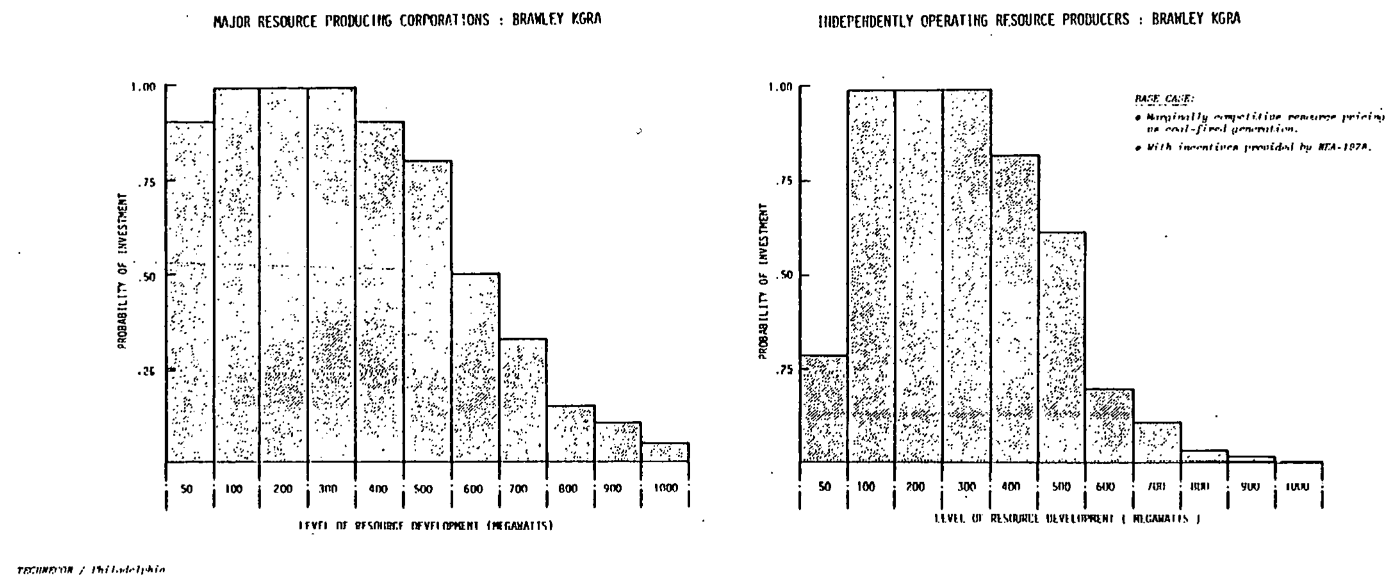


Figure 5-1. INVESTMENT LIKELIHOOD AT BRAWLEY RESOURCE AREA: BASE CASE

capacity of 650 megawatts (see Muffler, 1979), the likelihood of investment by major corporate producers and independently operating producers is estimated at 50% and 20%, respectively. As discussed in earlier chapters, the investment potential offered by just one, initial 50 megawatt well field without continued development beyond this level is constrained by the combined effects of front end resource "finding costs" and limited project revenues.

In the sensitivity analyses which follow, each alternative is graphically measured against the Brawley "base case" as illustrated in Figure 5-1. The base case evaluation includes: (a) marginally competitive pricing of the geothermal resource such that the electricity produced from it is equivalent in busbar cost to that of coal-fired generation, and (b) it includes the depletion allowances, investment tax credits and option to expense intangible well costs as stipulated in the NEA-1978.

5.2 JOINT VENTURE ARRANGEMENTS

Joint venturing may provide a vehicle for some relatively small independent operators with limited supplies of capital to share the risk and rewards of geothermal ventures. To simulate joint venturing arrangements among either two or three independent operators, the cash flow model TCN2000 was modified such that both the amount of investment required of any one firm and their subsequent revenues were divided by a factor of two or three, respectively.

Figure 5-2 and Table 5-1 provide the results of the joint venture analysis. The impact upon investment behavior at Brawley appears significant past the 300 megawatt level of development where development has extended out into the more risky areas of the resource. At these

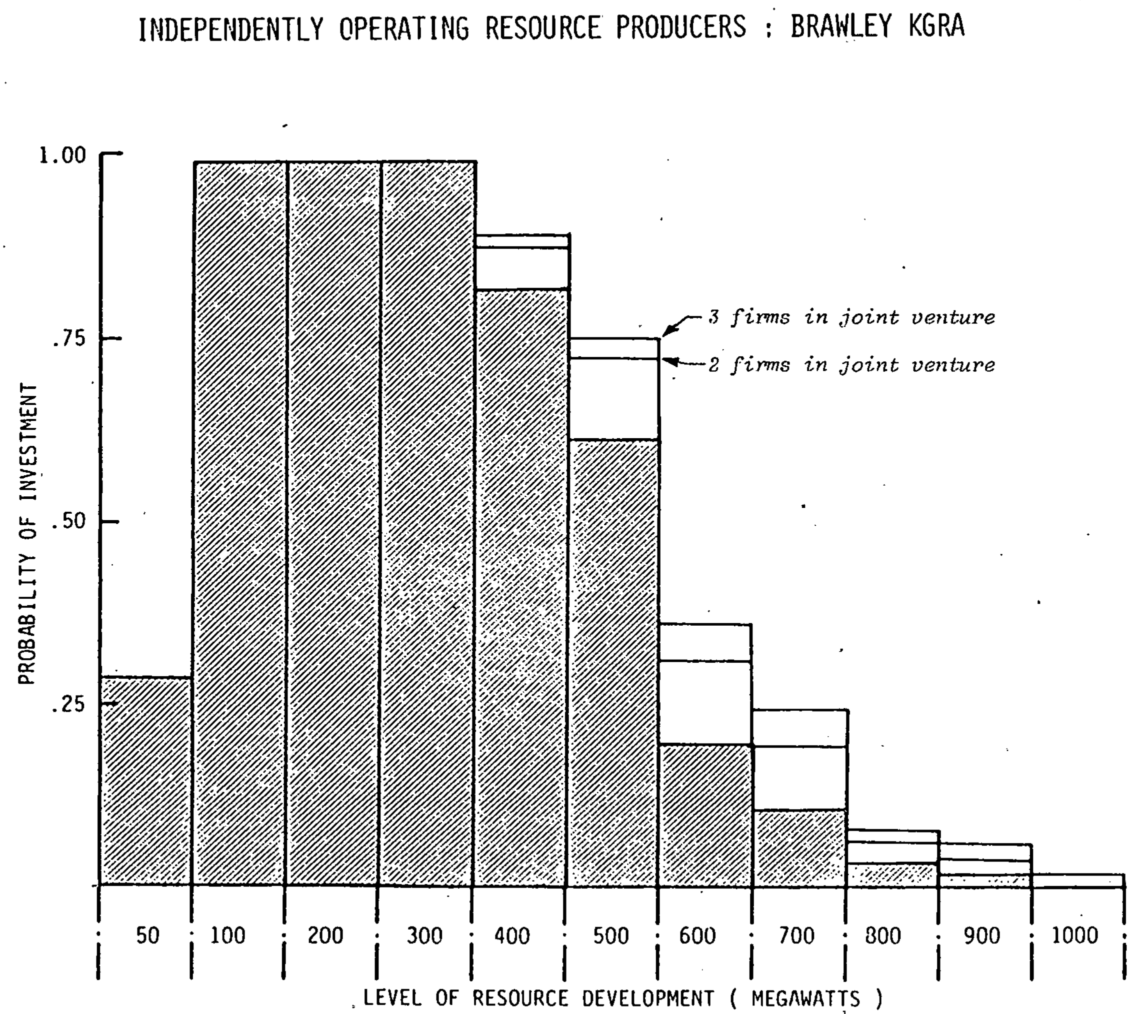


Figure 5-2. EFFECTS OF JOINT VENTURE ARRANGEMENTS AT BRAWLEY

TABLE 5-1. EFFECTS OF JOINT VENTURE ARRANGEMENTS AT BRAWLEY

1 TYPE 3 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.19	.15	8.3	13876	.00	763	.28
2	100	.27	.17	5.5	30613	.01	697	.98
3	200	.28	.17	5.6	54537	.03	745	.98
4	300	.29	.17	5.6	84418	.05	751	.98
5	400	.30	.17	4.8	112572	.19	762	.82
6	500	.30	.17	4.8	139248	.25	770	.62
7	600	.30	.18	4.8	164521	.35	779	.20
8	700	.31	.18	4.8	182224	.39	784	.11
9	800	.31	.18	4.8	205167	.47	796	.03
10	900	.31	.18	4.8	227173	.50	801	.02
11	1000	.31	.18	4.8	247781	.55	810	.00
12	1100	.32	.18	4.8	267346	.60	822	.00
13	1200	.32	.18	4.8	285821	.63	831	.00
14	1300	.32	.18	4.8	298127	.67	840	.00

2 TYPE 3 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.19	.15	8.3	13876	.00	763	.27
2	100	.27	.17	5.5	30613	.01	697	.98
3	200	.28	.17	5.6	54537	.03	745	.98
4	300	.29	.17	5.6	84418	.05	751	.98
5	400	.30	.17	4.8	112572	.19	763	.87
6	500	.30	.17	4.8	139248	.25	770	.72
7	600	.30	.18	4.8	164521	.35	779	.32
8	700	.31	.18	4.8	182224	.39	784	.20
9	800	.31	.18	4.8	205167	.47	796	.06
10	900	.31	.18	4.8	227173	.50	801	.04
11	1000	.31	.18	4.8	247781	.55	810	.02
12	1100	.32	.18	4.8	267346	.60	822	.00
13	1200	.32	.18	4.8	285821	.63	831	.00
14	1300	.32	.18	4.8	298127	.67	840	.00

3 TYPE 3 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.19	.15	8.3	13876	.00	763	.27
2	100	.27	.17	5.5	30613	.01	697	.98
3	200	.28	.17	5.6	54537	.03	745	.98
4	300	.29	.17	5.6	84418	.05	751	.98
5	400	.30	.17	4.8	112572	.19	762	.88
6	500	.30	.17	4.8	139248	.25	770	.75
7	600	.30	.18	4.8	164521	.35	779	.37
8	700	.31	.18	4.8	182224	.39	784	.24
9	800	.31	.18	4.8	205167	.47	796	.08
10	900	.31	.18	4.8	227173	.50	801	.05
11	1000	.31	.18	4.8	247781	.55	810	.02
12	1100	.32	.18	4.8	267346	.60	822	.01
13	1200	.32	.18	4.8	285821	.63	831	.00
14	1300	.32	.18	4.8	298127	.67	840	.00

development levels, risk sharing by two independent firms provides an appreciable investment incentive. The marginal incentive, however, of a third firm joining the venture appears to be of minimal value.

5.3 RESOURCE PRICING VARIATIONS

As discussed in Chapter 2, the method of resource pricing used in this report is based upon achieving an electric energy cost, at a main transmission corridor, which is competitive with the least expensive alternative type of baseload generation regionally available. The method begins with the total delivered electric energy cost of the alternative generation (in mills/kWh) and estimates a competitive geothermal resource price (in mills/kWh) by subtracting the fixed costs[34] attributable to a geothermal power plant and transmission facilities.

Interviews with electric utility executives indicate that, for favorable consideration, the delivered cost of geothermal electric energy must be roughly equivalent to that of the least expensive alternative available to the utility. As illustrated in Figure 2-4 in Chapter 2, preferences for geothermal generation increase as its cost decreases relative to that of alternative generation. At a delivered cost of roughly 80% of the alternative, a maximum preference is revealed and little added incentive is gained on behalf of the utility firm by further reducing the geothermal cost. On the other hand, the utility's preference for geothermal generation decreases as its cost increases relative to the cost of alternative generation. As also illustrated in Figure 2-4, utility firms indicate a strong aversion to geothermal power as its delivered cost approaches 120% of that of alternative power. From the electric utility's perspective, meaningful limits to an analysis of geothermal electric energy costs are, therefore, established at 80% and 120% of the delivered cost of alternative generation.

With the geothermal power plant costs fixed (recall footnote [34]), the resource price will vary as the delivered electric energy cost is

[34] Fixed power plant costs (in mills/kWh) account for amortized capital, operating and maintenance expense, taxes, administrative and general expense, insurance, and the utility's regulated return on investment.

varied. The impacts of this pricing variation upon the financial attributes of hydrothermal well field investments are provided in Chapter 4 for each of the nine resource areas evaluated in this report. For the Brawley area, the impacts on likely investment behavior are illustrated in Figure 5-3.

From Figure 5-3 it appears that, at Brawley, an attempt to attract electric utility participation by reducing the resource price below the marginally competitive level will adversely affect likely investment behavior by either major corporate resource producers or, especially, independent producers. Increasing the resource price above the marginally competitive level appears to provide minimal added investment incentive to either large or small resource producers, with the exception of an independent operator looking at only the initial 50 megawatt level of field development. In this exception, the added selling price is of significant value in the recovery of front end resource "finding costs".

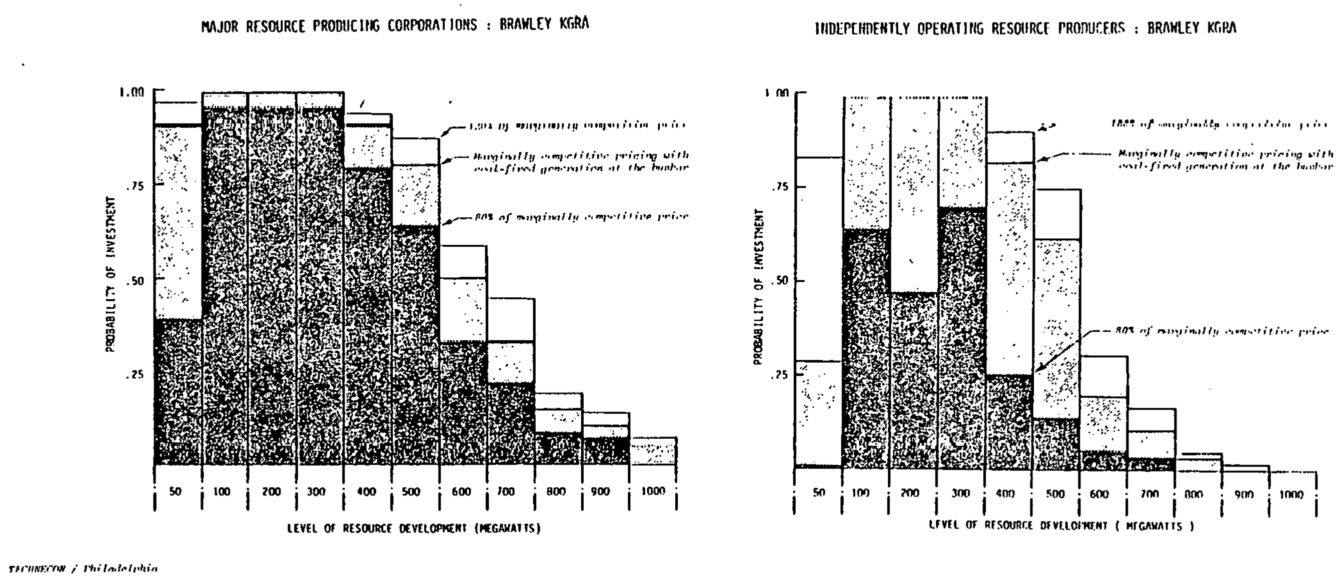


Figure 5-3. EFFECTS OF VARIATIONS IN RESOURCE PRICE AT BRAWLEY

5.4 NATIONAL ENERGY ACT INCENTIVES OF 1978

The National Energy Act of 1978 provided geothermal resource developers with a package of tax incentives which included:

- The option to treat the intangible, 50% to 75% portion of a well's cost as a tax deductible expense;
- A 10% investment tax credit for "alternative energy property"--excluding power plants owned by regulated utilities--in addition to the tax credits otherwise allowed for invested capital;
- A percentage depletion allowance against gross income according to the following schedule:

through 1980:	22%
1981 :	20%
1982 :	18%
1983 :	16%
1984 & after:	15%.

These incentives, which are now legally permissible, are included in the evaluations presented in Chapter 4 and in the Brawley base case evaluation of this section.

Table 5-2 and Figure 5-4 illustrate the very favorable impact which the NEA provisions will have upon likely investment behavior at Brawley.

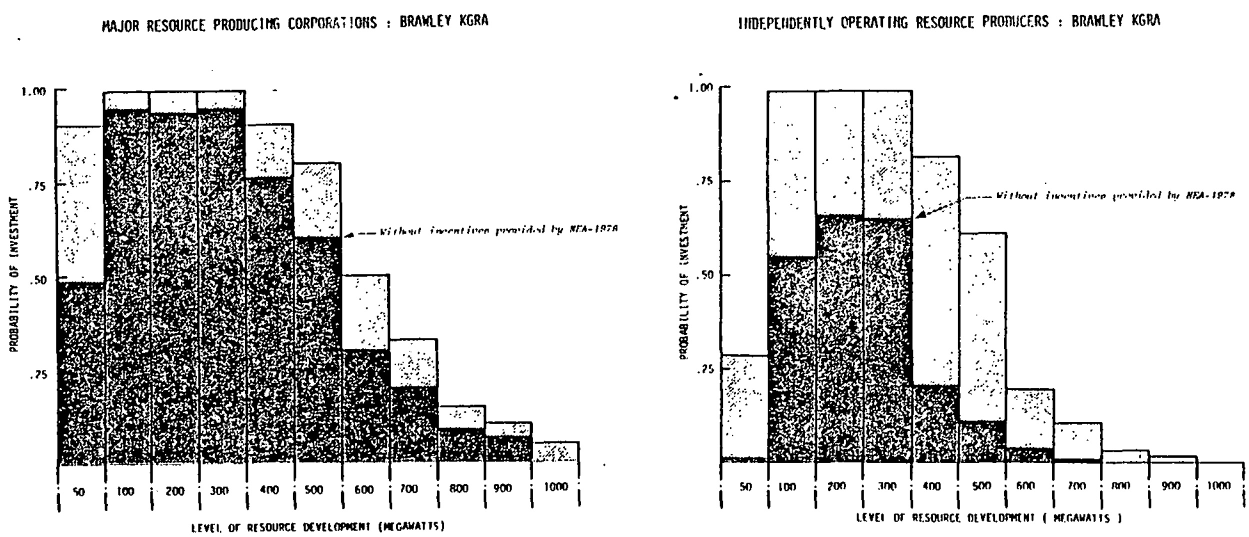


Figure 5-4. INVESTMENT BEHAVIOR AT BRAWLEY WITHOUT NEA-1978 INCENTIVES

TABLE 5-2. BRAWLEY INVESTMENT ANALYSIS WITHOUT NEA-1978 INCENTIVES

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL. TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1983	50	1.00	560	616	17.5
2	100	1986	50	.99	1120	589	17.7
3	200	1988	100	.97	2240	685	16.7
4	300	1989	100	.95	3320	644	17.0
5	400	1990	100	.81	4440	624	17.2
6	500	1991	100	.75	5560	611	17.3
7	600	1992	100	.65	6680	603	17.3
8	700	1993	100	.61	7760	632	17.0
9	800	1994	100	.53	8880	624	17.0
10	900	1995	100	.50	9960	617	17.1
11	1000	1996	100	.45	11040	611	17.1
12	1100	1997	100	.40	12160	607	17.1
13	1200	1998	100	.37	13280	603	17.1
14	1300	1999	100	.33	14400	619	16.9

1 TYPE 1 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.16	.15	9.7	13739	.00	763	.49
2	100	.21	.16	7.1	31433	.01	697	.94
3	200	.22	.16	7.4	57246	.03	745	.93
4	300	.23	.16	6.5	90480	.05	751	.95
5	400	.23	.16	6.5	122429	.19	762	.76
6	500	.23	.16	6.5	153309	.25	770	.60
7	600	.23	.17	6.5	183157	.35	779	.30
8	700	.23	.17	6.5	204381	.39	784	.20
9	800	.24	.17	6.5	232473	.47	796	.08
10	900	.24	.17	6.5	260051	.50	801	.06
11	1000	.24	.17	6.5	286270	.55	810	.03
12	1100	.25	.17	5.6	311680	.60	822	.02
13	1200	.25	.17	5.6	336144	.63	831	.01
14	1300	.25	.17	5.6	353176	.67	840	.00

1 TYPE 3 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.16	.14	12.0	6546	.00	763	.01
2	100	.21	.16	8.0	17063	.01	697	.54
3	200	.22	.16	7.4	31166	.03	745	.66
4	300	.22	.16	7.4	50594	.05	751	.65
5	400	.23	.16	7.4	68926	.19	762	.21
6	500	.23	.16	7.4	86371	.25	770	.11
7	600	.23	.16	7.4	102948	.35	779	.03
8	700	.23	.16	7.4	113568	.39	784	.01
9	800	.24	.16	6.5	128768	.47	796	.00
10	900	.24	.16	6.5	143529	.50	801	.00
11	1000	.24	.16	6.5	157295	.55	810	.00
12	1100	.25	.16	6.5	170404	.60	822	.00
13	1200	.25	.16	6.5	182828	.63	831	.00
14	1300	.25	.16	6.5	190320	.67	840	.00

Both major corporate resource producers and independently operating producers show very significant positive reactions to these incentives. Of considerable value is the effect upon the smaller independents who, prior to the NEA, appear noticeably less willing to participate in development at Brawley than do the larger corporate producers.

5.5 GEOTHERMAL LOAN GUARANTEE

The Federal geothermal loan guarantee program will provide government backing to commercial loans for up to 75% of the cost of a geothermal project. From industry interviews, it appears that this program will be of considerable value to well field development projects being undertaken by independently operating resource producers. Although the government adds 1% to the debt interest rate for administering the loan, the program provides access to relatively inexpensive debt capital which, otherwise, is difficult for equity-financed independent operators to obtain.

Major resource producing corporations and electric utilities, on the other hand, have existing access to debt capital and appear disinclined to use the Federal loan guarantee. Default provisions within the guarantee coupled with its filing and administration requirements tend to also detract from favorable consideration by these larger firms.

When simulating the loan guarantee for this evaluation, two adjustments are made to the base case model. First, the fraction of debt capital is increased to 75% for both major and independent producers, and the cost of debt capital is increased by one percentage point. This also reduces the average discount rate used by both types of firms. Second, the amount of investment at risk by the firms is reduced 75%. Results of the modified simulation are provided in Table 5-3 and in Figure 5-5 below.

As illustrated in Figure 5-5, the loan guarantee program provides a very significant investment incentive to the independently operating resource producer at the Brawley area. The advantage of this program to the major corporate producers, on the other hand, appears minimal at best.

TABLE 5-3. EFFECTS OF GEOTHERMAL LOAN GUARANTEE PROGRAM AT BRAWLEY

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL;TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1983	50	1.00	560	616	17.5
2	100	1986	50	.99	1120	589	17.7
3	200	1988	100	.97	2240	685	16.7
4	300	1989	100	.95	3320	644	17.0
5	400	1990	100	.81	4440	624	17.2
6	500	1991	100	.75	5560	611	17.3
7	600	1992	100	.65	6680	603	17.3
8	700	1993	100	.61	7760	632	17.0
9	800	1994	100	.53	0880	624	17.0
10	900	1995	100	.50	9960	617	17.1
11	1000	1996	100	.45	11040	611	17.1
12	1100	1997	100	.40	12160	607	17.1
13	1200	1998	100	.37	13280	603	17.1
14	1300	1999	100	.33	14400	619	16.9

1 TYPE 1 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.21	.16	6.8	34875	.00	191	.95
2	100	.29	.18	4.8	73168	.01	174	.99
3	200	.30	.18	4.8	134039	.03	186	.99
4	300	.31	.18	3.9	206468	.05	188	.99
5	400	.31	.18	3.9	276989	.19	190	.92
6	500	.32	.18	3.9	345808	.25	193	.83
7	600	.32	.18	3.9	412988	.35	195	.54
8	700	.32	.18	3.9	465880	.39	196	.40
9	800	.32	.18	3.9	530173	.47	199	.18
10	900	.33	.18	3.9	593437	.50	200	.13
11	1000	.33	.18	3.9	654691	.55	203	.07
12	1100	.33	.18	3.9	714539	.60	205	.03
13	1200	.33	.18	3.9	772899	.63	208	.02
14	1300	.34	.18	3.9	818470	.67	210	.01

1 TYPE 3 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.21	.16	6.9	31578	.00	191	.74
2	100	.29	.17	4.8	66204	.01	174	.99
3	200	.31	.17	4.0	120603	.03	186	.99
4	300	.32	.18	3.9	185343	.05	188	.99
5	400	.32	.18	3.9	248084	.19	190	.92
6	500	.32	.18	3.9	309021	.25	193	.82
7	600	.33	.18	3.9	368253	.35	195	.48
8	700	.33	.18	3.9	414396	.39	196	.33
9	800	.33	.18	3.9	470578	.47	199	.11
10	900	.33	.18	3.9	525643	.50	200	.07
11	1000	.33	.18	3.9	578716	.55	203	.03
12	1100	.34	.18	3.9	630331	.60	205	.02
13	1200	.34	.18	3.9	680409	.63	208	.00
14	1300	.34	.18	3.9	718990	.67	210	.00

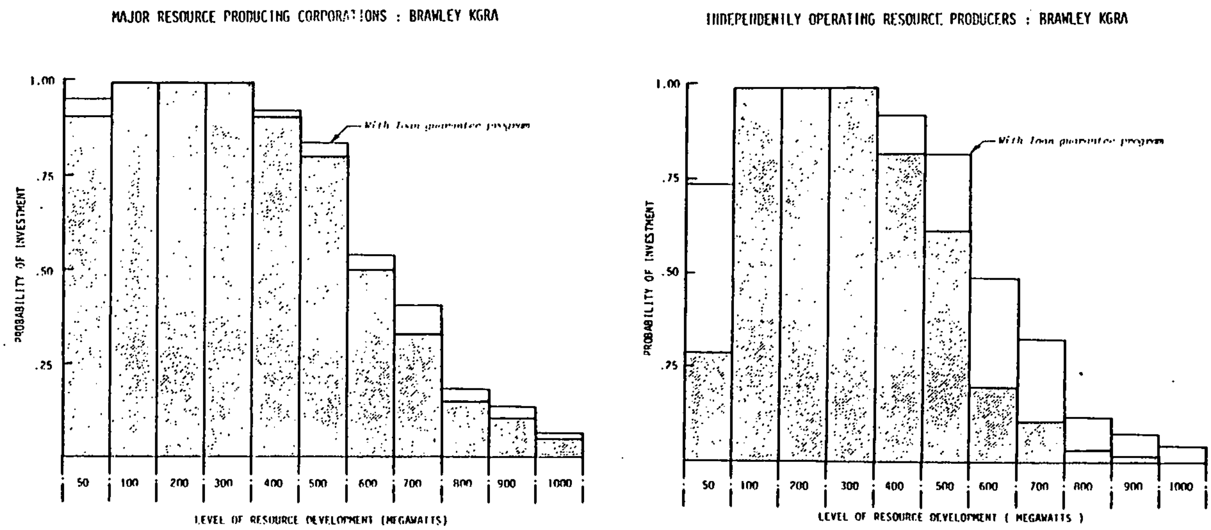


Figure 5-5. EFFECTS OF GEOTHERMAL LOAN GUARANTEE PROGRAM AT BRAWLEY

5.6 MAINTAINING 22% DEPLETION ALLOWANCE

As discussed above in section 5.4, the depletion allowance currently offered by the NEA will decline over the next few years from the present 22% to 15% in 1984. By modifying the cash flow model in TCN2000, the effect of maintaining this allowance at 22% was evaluated. Table 5-4 and Figure 5-6 illustrate the relative insensitivity of likely investment behavior at Brawley to this modification in the depletion allowance schedule.

5.7 ADDITIONAL INVESTMENT TAX CREDITS

The additional 10% investment tax credit allowed by the NEA for "alternative energy property" is currently not applicable to electric utility property. If it were applicable to utilities, existing tax credit limitations and a frequent surplus of credits from large-scale construction programs may prevent utilities from utilizing this incentive.

As an alternative, a totally refundable geothermal investment tax credit could be provided as a bonafide incentive to both electric

TABLE 5-4. EFFECTS OF A NON-DECREASING 22% DEPLETION ALLOWANCE AT BRAWLEY

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1983	50	1.00	560	616	17.5
2	100	1986	50	.99	1120	589	17.7
3	200	1988	100	.97	2240	685	16.7
4	300	1989	100	.95	3320	644	17.0
5	400	1990	100	.81	4440	624	17.2
6	500	1991	100	.75	5560	611	17.3
7	600	1992	100	.65	6680	603	17.3
8	700	1993	100	.61	7760	632	17.0
9	800	1994	100	.53	8880	624	17.0
10	900	1995	100	.50	9960	617	17.1
11	1000	1996	100	.45	11040	611	17.1
12	1100	1997	100	.40	12160	607	17.1
13	1200	1998	100	.37	13280	603	17.1
14	1300	1999	100	.33	14400	619	16.9

1 TYPE 1 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.21	.16	7.1	26625	.00	763	.94
2	100	.29	.18	4.8	55990	.01	697	.99
3	200	.30	.18	4.8	100804	.03	745	.99
4	300	.31	.18	4.8	154781	.05	751	.99
5	400	.32	.18	4.8	206594	.19	762	.91
6	500	.32	.18	4.0	256507	.25	770	.83
7	600	.32	.18	4.8	304599	.35	779	.53
8	700	.32	.18	3.9	340918	.39	784	.40
9	800	.33	.18	3.9	385847	.47	796	.17
10	900	.33	.18	3.9	429551	.50	801	.12
11	1000	.33	.18	3.9	471266	.55	810	.06
12	1100	.34	.18	3.9	511509	.60	822	.03
13	1200	.34	.18	3.9	550187	.63	831	.02
14	1300	.34	.19	3.9	578792	.67	840	.01

1 TYPE 3 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.20	.16	7.8	16543	.00	763	.52
2	100	.29	.17	4.8	35623	.01	697	.99
3	200	.30	.17	4.8	63145	.03	745	.99
4	300	.31	.18	4.8	97000	.05	751	.99
5	400	.32	.18	4.8	128875	.19	762	.86
6	500	.32	.18	4.8	159068	.25	770	.67
7	600	.32	.18	4.8	187671	.35	779	.23
8	700	.32	.18	4.8	207974	.39	784	.12
9	800	.33	.18	4.8	233876	.47	796	.03
10	900	.33	.18	4.8	258677	.50	801	.02
11	1000	.33	.18	4.8	281908	.55	810	.00
12	1100	.34	.18	4.0	303943	.60	822	.00
13	1200	.34	.18	4.0	324751	.63	831	.00
14	1300	.34	.18	4.0	338848	.67	840	.00

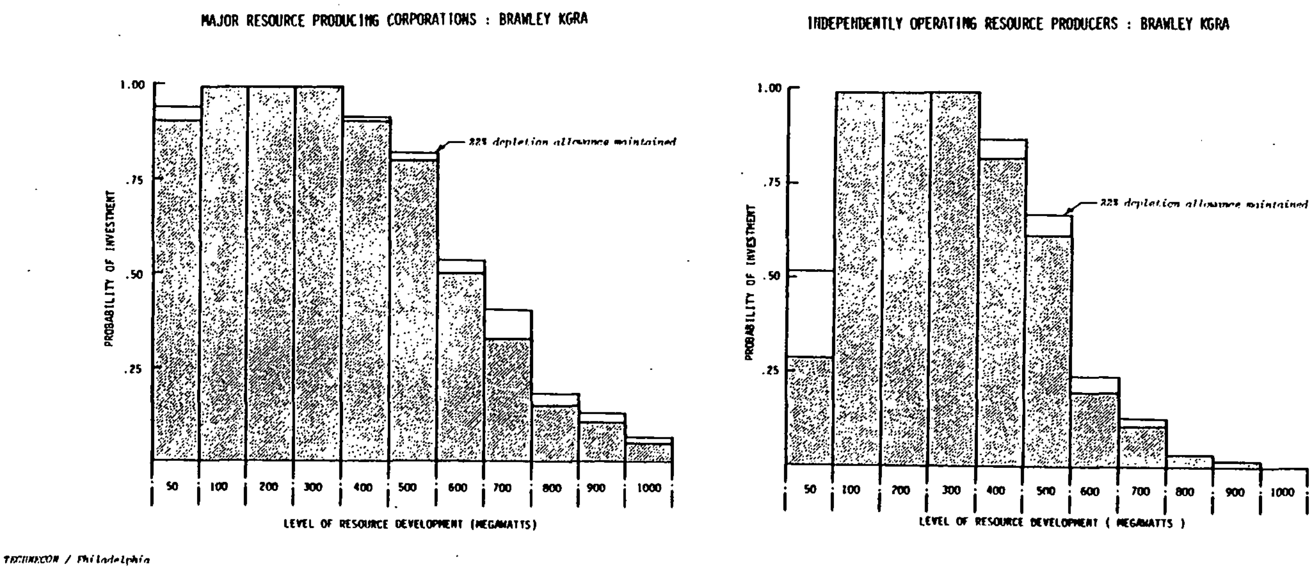


Figure 5-6. EFFECTS OF A NON-DECREASING 22% DEPLETION ALLOWANCE AT BRAWLEY

utilities and resource producers. Its effect would be twofold: (a) the credit would reduce the effective cost of a geothermal power plant and, thereby, increase the marginally competitive price[35] of the geothermal resource; and (b) the credit would effectively reduce the capital investment required for well field development.

Totally refundable investment tax credits of 20%, 30%, 40% and 50% for both well field capital and geothermal power plant capital were evaluated by modifying the Brawley cash flow analysis in model TCN2000. Results are provided in Tables 5-5, 5-6, 5-7 and 5-8, respectively, and are illustrated in Figure 5-7. For investment tax credits of 20% and 30%, the results include the resource producers' election to expense the intangible portion of well costs. Expensing of intangible costs for tax purposes is financially preferable to capitalizing these costs according to analytic results with 20% and 30% tax credits[36]. With 40% and 50%

[35] Refer to section 2.3.1 and section 5.3 for discussions of marginally competitive resource pricing.

[36] Note that expensed costs are not eligible for investment tax credits applicable to capital costs.

TABLE 5-5. EFFECTS OF 20% INVESTMENT TAX CREDIT AT BRAWLEY

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL.TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1983	50	1.00	560	616	18.1
2	100	1986	50	.99	1120	589	18.3
3	200	1988	100	.97	2240	685	17.2
4	300	1989	100	.95	3320	644	17.6
5	400	1990	100	.81	4440	624	17.7
6	500	1991	100	.75	5560	611	17.8
7	600	1992	100	.65	6680	603	17.8
8	700	1993	100	.61	7760	632	17.5
9	800	1994	100	.53	8880	624	17.6
10	900	1995	100	.50	9960	617	17.6
11	1000	1996	100	.45	11040	611	17.6
12	1100	1997	100	.49	12160	607	17.6
13	1200	1998	100	.37	13280	603	17.6
14	1300	1999	100	.33	14400	619	17.4

1 TYPE 1 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.20	.16	7.6	24490	.00	763	.91
2	100	.28	.18	4.8	51784	.01	697	.99
3	200	.29	.18	4.8	93557	.03	745	.99
4	300	.30	.18	4.8	143781	.05	751	.99
5	400	.30	.18	4.8	191975	.19	762	.91
6	500	.31	.18	4.8	238382	.25	770	.81
7	600	.31	.18	4.8	283098	.35	779	.51
8	700	.31	.18	4.7	316931	.39	784	.37
9	800	.31	.18	4.7	358683	.47	796	.16
10	900	.32	.18	4.7	399303	.50	801	.11
11	1000	.32	.18	4.7	438046	.55	810	.06
12	1100	.32	.18	4.7	475415	.60	822	.03
13	1200	.33	.18	3.9	511337	.63	831	.02
14	1300	.33	.18	3.9	537924	.67	840	.01

1 TYPE 3 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.20	.15	8.3	14959	.00	763	.33
2	100	.28	.17	5.5	32574	.01	697	.98
3	200	.29	.17	5.6	58047	.03	745	.98
4	300	.30	.17	4.8	89372	.05	751	.99
5	400	.30	.17	4.8	118867	.19	762	.83
6	500	.31	.18	4.8	146783	.25	770	.63
7	600	.31	.18	4.8	173225	.35	779	.22
8	700	.31	.18	4.8	192009	.39	784	.11
9	800	.31	.18	4.8	215953	.47	796	.03
10	900	.32	.18	4.8	238894	.50	801	.02
11	1000	.32	.18	4.8	260355	.55	810	.00
12	1100	.33	.18	4.8	280718	.60	822	.00
13	1200	.33	.18	4.8	299923	.63	831	.00
14	1300	.33	.18	4.8	312915	.67	840	.00

TABLE 5-6. EFFECTS OF 30% INVESTMENT TAX CREDIT AT BRAWLEY

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL. TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1983	50	1.00	560	616	18.7
2	100	1986	50	.99	1120	589	18.8
3	200	1988	100	.97	2240	685	17.7
4	300	1989	100	.95	3320	644	18.1
5	400	1990	100	.81	4440	624	18.3
6	500	1991	100	.75	5560	611	18.3
7	600	1992	100	.65	6680	603	18.4
8	700	1993	100	.61	7760	632	18.0
9	800	1994	100	.53	8880	624	18.1
10	900	1995	100	.50	9960	617	18.1
11	1000	1996	100	.45	11040	611	18.1
12	1100	1997	100	.40	12160	607	18.1
13	1200	1998	100	.37	13280	603	18.1
14	1300	1999	100	.33	14400	619	17.9

1 TYPE 1 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.21	.16	7.0	26827	.00	763	.95
2	100	.30	.18	4.8	56114	.01	697	.99
3	200	.32	.18	4.7	101510	.03	745	.99
4	300	.32	.18	3.9	155162	.05	751	.99
5	400	.33	.18	3.9	206618	.19	762	.93
6	500	.33	.18	3.9	256115	.25	770	.84
7	600	.33	.18	3.9	303760	.35	779	.56
8	700	.33	.18	3.9	340361	.39	784	.41
9	800	.34	.18	3.9	384754	.47	796	.18
10	900	.34	.19	3.9	427874	.50	801	.13
11	1000	.34	.19	3.9	468983	.55	810	.07
12	1100	.35	.19	3.9	508609	.60	822	.03
13	1200	.35	.19	3.9	546644	.63	831	.02
14	1300	.35	.19	3.9	575250	.67	840	.01

1 TYPE 3 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.21	.16	7.8	16868	.00	763	.57
2	100	.30	.18	4.8	36023	.01	697	.99
3	200	.31	.18	4.8	64195	.03	745	.99
4	300	.32	.18	4.8	98028	.05	751	.99
5	400	.33	.18	4.8	129866	.19	762	.87
6	500	.33	.18	4.8	159954	.25	770	.69
7	600	.33	.18	4.8	188443	.35	779	.25
8	700	.34	.18	4.8	209117	.39	784	.14
9	800	.34	.18	4.8	234815	.47	796	.03
10	900	.34	.18	4.0	259392	.50	801	.02
11	1000	.34	.18	4.0	282375	.55	810	.00
12	1100	.35	.18	3.9	304153	.60	822	.00
13	1200	.35	.18	3.9	324684	.63	831	.00
14	1300	.35	.18	3.9	338906	.67	840	.00

TABLE 5-7. EFFECTS OF 40% INVESTMENT TAX CREDIT AT BRAWLEY

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL.TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1983	50	1.00	560	616	19.2
2	100	1986	50	.99	1120	589	19.4
3	200	1988	100	.97	2240	685	18.3
4	300	1989	100	.95	3320	644	18.6
5	400	1990	100	.81	4440	624	18.8
6	500	1991	100	.75	5560	611	18.9
7	600	1992	100	.65	6680	603	18.9
8	700	1993	100	.61	7760	632	18.6
9	800	1994	100	.53	8880	624	18.6
10	900	1995	100	.50	9960	617	18.6
11	1000	1996	100	.45	11040	611	18.6
12	1100	1997	100	.40	12160	607	18.6
13	1200	1998	100	.37	13280	603	18.6
14	1300	1999	100	.33	14400	619	18.4

1 TYPE 1 FIRM(S)

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:1								
1	50	.23	.17	6.4	31360	.00	763	.97
2	100	.34	.19	4.0	64420	.01	697	.99
3	200	.36	.19	3.9	116678	.03	745	.99
4	300	.37	.19	3.9	176853	.05	751	.99
5	400	.37	.19	3.9	234497	.19	762	.94
6	500	.37	.19	3.9	289874	.25	770	.87
7	600	.38	.19	3.9	343109	.35	779	.60
8	700	.38	.19	3.9	385021	.39	784	.46
9	800	.38	.19	3.9	434439	.47	796	.20
10	900	.39	.19	3.1	482276	.50	801	.15
11	1000	.39	.19	3.1	527910	.55	810	.08
12	1100	.39	.19	3.1	571835	.60	822	.04
13	1200	.39	.19	3.1	613960	.63	831	.02
14	1300	.39	.19	3.1	646417	.67	840	.01

1 TYPE 3 FIRM(S)

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
PRICE MULTIPLIER:1								
1	50	.23	.16	7.1	20557	.00	763	.85
2	100	.33	.18	4.1	42622	.01	697	1.00
3	200	.36	.18	4.0	75877	.03	745	1.00
4	300	.37	.18	4.0	114450	.05	751	.99
5	400	.37	.18	4.0	150693	.19	762	.92
6	500	.38	.19	4.0	184927	.25	770	.78
7	600	.38	.19	4.0	217239	.35	779	.33
8	700	.38	.19	4.0	241502	.39	784	.18
9	800	.38	.19	4.0	270553	.47	796	.04
10	900	.39	.19	4.0	298205	.50	801	.02
11	1000	.39	.19	4.0	324092	.55	810	.00
12	1100	.39	.19	4.0	348573	.60	822	.00
13	1200	.39	.19	4.0	371623	.63	831	.00
14	1300	.40	.19	4.0	388184	.67	840	.00

TABLE 5-8. EFFECTS OF 50% INVESTMENT TAX CREDIT AT BRAWLEY

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL. TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1983	50	1.00	560	616	19.8
2	100	1986	50	.99	1120	589	19.9
3	200	1988	100	.97	2240	685	18.8
4	300	1989	100	.95	3320	644	19.2
5	400	1990	100	.81	4440	624	19.3
6	500	1991	100	.75	5560	611	19.4
7	600	1992	100	.65	6680	603	19.4
8	700	1993	100	.61	7760	632	19.1
9	800	1994	100	.53	8880	624	19.1
10	900	1995	100	.50	9960	617	19.1
11	1000	1996	100	.45	11040	611	19.1
12	1100	1997	100	.40	12160	607	19.1
13	1200	1998	100	.37	13280	603	19.1
14	1300	1999	100	.33	14400	619	18.9

1 TYPE 1 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.24	.17	5.9	34662	.00	763	.98
2	100	.38	.19	3.3	70499	.01	697	1.00
3	200	.41	.19	3.1	127796	.03	745	1.00
4	300	.42	.20	3.1	192755	.05	751	.99
5	400	.42	.20	3.1	254941	.19	762	.96
6	500	.43	.20	3.1	314642	.25	770	.90
7	600	.43	.20	3.1	371964	.35	779	.66
8	700	.43	.20	3.1	417755	.39	784	.51
9	800	.43	.20	3.1	470878	.47	796	.24
10	900	.44	.20	3.1	522156	.50	801	.17
11	1000	.44	.20	3.1	571122	.55	810	.09
12	1100	.44	.20	3.1	618196	.60	822	.04
13	1200	.44	.20	3.1	663305	.63	831	.03
14	1300	.44	.20	3.1	698595	.67	840	.01

1 TYPE 3 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.24	.17	6.7	23297	.00	763	.93
2	100	.38	.19	3.3	47544	.01	697	1.00
3	200	.41	.19	3.2	84600	.03	745	1.00
4	300	.42	.19	3.2	126722	.05	751	1.00
5	400	.42	.19	3.2	166287	.19	762	.94
6	500	.43	.19	3.2	203595	.25	770	.82
7	600	.43	.19	3.2	238788	.35	779	.38
8	700	.43	.19	3.2	265735	.39	784	.22
9	800	.43	.19	3.2	297285	.47	796	.05
10	900	.44	.19	3.2	327233	.50	801	.03
11	1000	.44	.19	3.1	355282	.55	810	.01
12	1100	.45	.19	3.1	381803	.60	822	.00
13	1200	.45	.19	3.1	406710	.63	831	.00
14	1300	.45	.19	3.1	425025	.67	840	.00

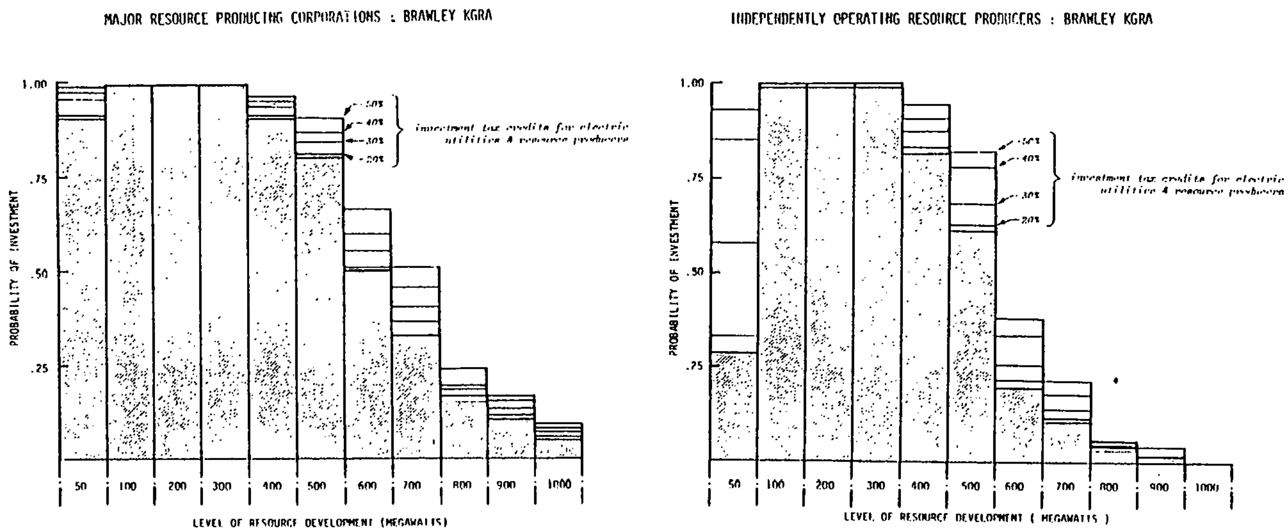


Figure 5-7. EFFECTS OF ADDITIONAL INVESTMENT
TAX CREDITS AT BRAWLEY

investment tax credits, however, the illustrated results include the financially preferable option to capitalize all well costs.

Figure 5-7 indicates that totally refundable investment tax credits would provide a significant incentive to likely investment behavior at Brawley, particularly for the independently operating resource producers. Examination of the four levels of credits indicates that the greatest marginal incentive is provided by increasing the credit from 30% to 40%.

5.8 $3/bbl EQUIVALENT ENERGY PRODUCTION TAX CREDIT

A $3/bbl of oil equivalent energy production tax credit translates to a 4.3 mills/kWh credit by assuming a heating value of 153,600 Btu/gal for heavy oil and a heat rate of 9,300 Btu/kWh for an oil-fired steam power plant[37]. The effect of this tax credit, if totally refundable and available to electric utility companies, will be to increase the marginally competitive price of a geothermal resource by 4.3 mills/kWh. Resulting increased revenues to the resource producers will provide additional incentive for well field development.

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[37]See EPRI, 1977, p.4-3.

Table 5-9 and Figure 5-8 illustrate the estimated effect of the \$3/bbl equivalent energy production tax credit upon likely investment behavior at Brawley. The impact upon the independently operating resource producers is significant, particularly for investments limited to well field development for an initial 50 megawatts of electric power production.

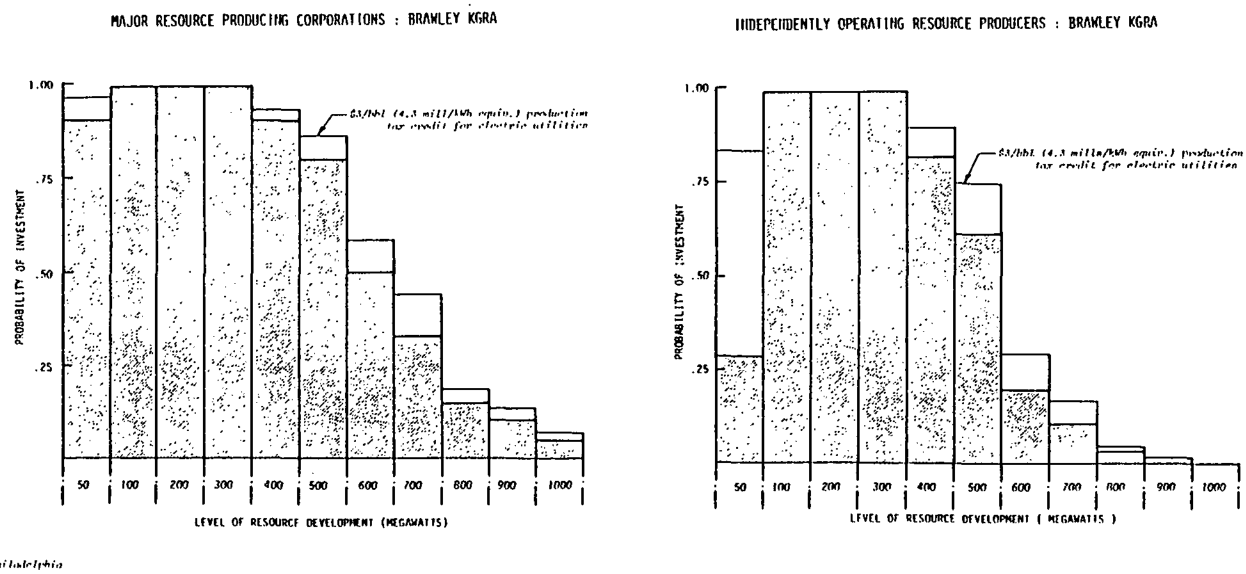


Figure 5-8. EFFECTS OF A \$3/bbl EQUIVALENT ENERGY PRODUCTION TAX CREDIT AT BRAWLEY

5.9 COMBINED PRODUCTION AND INVESTMENT TAX CREDITS

The \$3/bbl of oil equivalent energy production tax credit discussed in section 5.8, combined with the 50% investment tax credit discussed in section 5.7 are evaluated for their total effect upon likely investment behavior at Brawley. As before, the production tax credit translates to a 4.3 mills/kWh increase in the marginally competitive hydrothermal resource price which, in turn, provides increased production revenues to the resource producer. The 50% investment tax credit is assumed to be applicable to geothermal investments by both the electric utilities and the resource producers. Its effect is twofold: (1) it increased the competitive geothermal resource price by effectively reducing the utilities' capital cost for converting hydrothermal fluid to electricity, and

TABLE 5-9. EFFECTS OF A $3/bbl EQUIVALENT ENERGY PRODUCTION TAX CREDIT AT BRAWLEY

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL. TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1983	50	1.00	560	616	21.8
2	100	1986	50	.99	1120	589	22.0
3	200	1988	100	.97	2240	685	21.0
4	300	1989	100	.95	3320	644	21.3
5	400	1990	100	.81	4440	624	21.5
6	500	1991	100	.75	5560	611	21.6
7	600	1992	100	.65	6680	603	21.6
8	700	1993	100	.61	7760	632	21.3
9	800	1994	100	.53	8880	624	21.3
10	900	1995	100	.50	9960	617	21.4
11	1000	1996	100	.45	11040	611	21.4

1 TYPE 1 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.22	.17	6.3	33870	.00	763	.97
2	100	.31	.18	4.0	69632	.01	697	.99
3	200	.33	.18	3.9	127156	.03	745	.99
4	300	.34	.19	3.9	192613	.05	751	.99
5	400	.34	.19	3.9	255530	.19	762	.93
6	500	.35	.19	3.9	316169	.25	770	.86
7	600	.35	.19	3.9	374633	.35	779	.58
8	700	.35	.19	3.9	421736	.39	784	.44
9	800	.35	.19	3.9	476335	.47	796	.19
10	900	.36	.19	3.9	529372	.50	801	.14
11	1000	.36	.19	3.9	580082	.55	810	.07

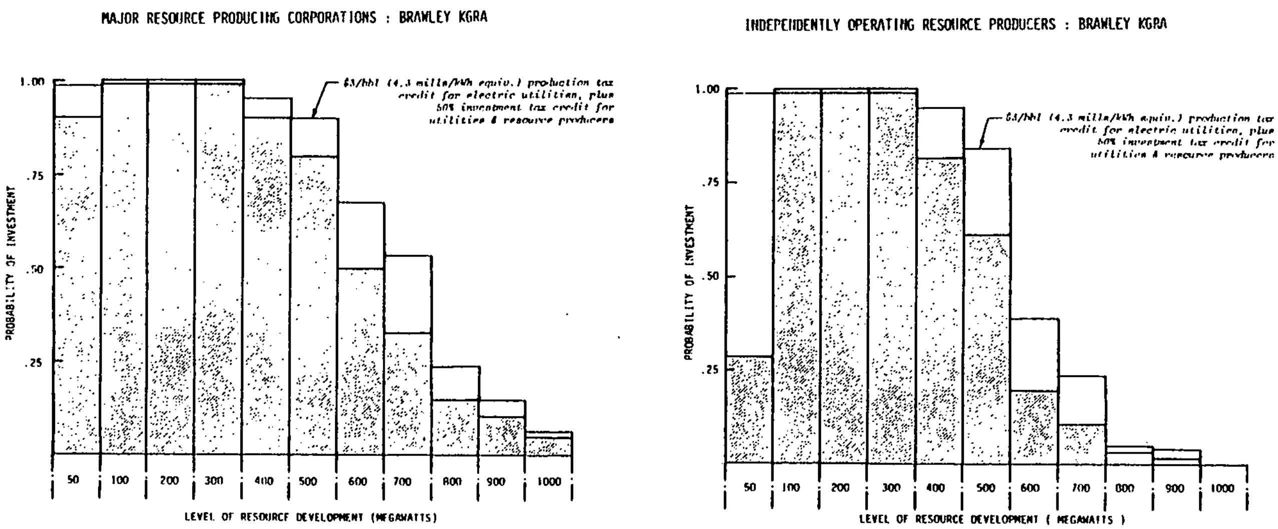
1 TYPE 3 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.22	.16	7.1	22075	.00	763	.83
2	100	.31	.19	4.8	45780	.01	697	.99
3	200	.33	.18	4.8	82193	.03	745	.99
4	300	.34	.18	3.9	123911	.05	751	.99
5	400	.35	.18	3.9	163272	.19	762	.90
6	500	.35	.18	3.9	200547	.26	770	.75
7	600	.35	.18	3.9	235893	.35	779	.30
8	700	.36	.18	3.9	263116	.39	784	.17
9	800	.36	.18	3.9	295070	.47	796	.04
10	900	.36	.18	3.9	325621	.50	801	.02
11	1000	.36	.18	3.9	354308	.55	810	.00

(2) it reduces the effective capital investment required of the resource producers for well field development. Both the production tax credit and the investment tax credit are assumed to be totally refundable.

Table 5-10 and Figure 5-9 illustrate the estimated effect of the combined tax credits upon likely investment behavior at Brawley. As indicated in Table 5-10, the tax credits afford a 38% increase in the competitive hydrothermal resource price compared to the Brawley base case evaluation presented in Table 4-2 . Figure 5-9 shows the very significant impact which the combined incentives are likely to have on investment decisions by both major corporate producers and independently operating producers.



TECHNECON / Philadelphia

Figure 5-9. EFFECTS OF COMBINED PRODUCTION TAX CREDIT AND INVESTMENT TAX CREDIT AT BRAWLEY

TABLE 5-10. EFFECTS OF COMBINED PRODUCTION TAX CREDIT AND INVESTMENT TAX CREDIT AT BRAWLEY

	DEVELOPMENT LEVEL (MWE)	YEAR ON-LINE	INCREMENTAL PLANT SIZE (MWE)	CONFIDENCE	LAND REQUIRED (ACRES)	PLANT COST (INCL.TRANS) ($/KWE)	COMPETITIVE RESOURCE PRICE (MILLS/KWH)
1	50	1983	50	1.00	560	616	24.1
2	100	1986	50	.99	1120	589	24.2
3	200	1988	100	.97	2240	685	23.1
4	300	1989	100	.95	3320	644	23.5
5	400	1990	100	.81	4440	624	23.6
6	500	1991	100	.75	5560	611	23.7
7	600	1992	100	.65	6680	603	23.7
8	700	1993	100	.61	7760	632	23.4
9	800	1994	100	.53	8880	624	23.4
10	900	1995	100	.50	9960	617	23.4
11	1000	1996	100	.45	11040	611	23.4

1 TYPE 1 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.26	.18	5.3	45470	.00	763	.99
2	100	.42	.20	3.3	90983	.01	697	1.00
3	200	.45	.20	3.1	166282	.03	745	1.00
4	300	.46	.20	3.1	248601	.05	751	1.00
5	400	.46	.20	3.1	327509	.19	762	.96
6	500	.47	.20	3.1	403327	.25	770	.91
7	600	.47	.20	3.1	476214	.35	779	.69
8	700	.47	.20	3.1	536995	.39	784	.33
9	800	.47	.20	3.1	604558	.47	796	.26
10	900	.48	.20	3.1	669785	.50	801	.18
11	1000	.48	.20	3.1	732180	.55	810	.09

1 TYPE 3 FIRM(S)

PRICE MULTIPLIER:1

	DEVELOPMENT LEVEL (MWE)	INTERNAL RATE OF RETURN	FINANCIAL MANAGEMENT RATE OF RETURN	WEIGHTED PAYBACK (YEARS)	NET PRESENT VALUE ($1000)	LOSS OF INVESTMENT PROBABILITY	INVESTMENT LOSS ($1000)	PROBABILITY OF INVESTMENT
1	50	.26	.17	5.9	31499	.00	763	.98
2	100	.42	.20	3.3	62704	.01	697	1.00
3	200	.46	.20	3.1	112257	.03	745	1.00
4	300	.47	.20	3.1	166217	.05	751	1.00
5	400	.47	.20	3.1	216980	.19	762	.95
6	500	.48	.20	3.1	264898	.25	770	.84
7	600	.48	.20	3.1	310157	.35	779	.40
8	700	.48	.20	3.1	346627	.39	784	.23
9	800	.48	.20	3.1	387189	.47	796	.05
10	900	.49	.20	3.1	425676	.50	801	.03
11	1000	.49	.20	3.1	461830	.55	810	.01

APPENDIX

Listing of Computer Models

The interactive APL computer model used on this project is listed below as developed for the U.S. Department of Energy by Technecon Analytic Research, Inc. under subcontract to the University of Pennsylvania. The function of each routine within the model is described by a comment statement appearing at the beginning of each listing.

Table A-1 identifies each of the input variables required for executing the model. During execution the model requests an alphanumeric label which becomes the name of the matrix of output data. When the execution is complete, this data may be retrieved and printed in the format illustrated in Chapter 4 by executing REPORT 1 {*label*} and REPORT 2 {*label*}.

TABLE A-1
INPUT SPECIFICATION VARIABLES FOR
MODEL TCN2000

Label	Description	Dimension*
ADV	Ad Valorem Tax (fraction of actual value)	
BCI	Brine Contamination Index (0:low salinity to 4:high salinity)	
BETAA	Recurrent Cost Fraction for Alternative Power Plant	
BETAH	Recurrent Cost Fraction for Hydrothermal Power Plant	
BKLF1	Book Life for Well Field Surface Capital (Yrs)	
BKLF2	Book Life for Wells (Yrs)	
CALT	Capital Cost of Alternative Generation incl. Transmission ($/KWe)	
CAPA	Capacity Factor for Alternative Power Plant	
CORNERS	Corner Coordinates of Resource Area Boundary col.1: X-Coordinate from Arbitrary Origin (Miles) col.2: Y-Coordinate from Arbitrary Origin (Miles)	N_1r2c
DPL	Depletion Allowance Schedule col.1: Year col.2: Allowance	7r2c
DWC	Dry Well Cost Fraction of Successful Well Cost	
FCA	Common Equity Fraction of Alternative Power Plant Capital	
FCH	Common Equity Fraction of Hydrothermal Power Plant Capital	
FDA	Long Term Debt Fraction of Alternative Power Plant Capital	
FDH	Long Term Debt Fraction of Hydrothermal Power Plant Capital	
FIRM	Resource Producers' Financial Data col.1: Present Value Discount Rate col.2: FMRR Pre-Income Discount Rate col.3: FMRR Reinvestment Earnings Rate col.4: Long Term Debt Fraction col.5: Cost of Debt col.6: Type of Firm (1:Major Corporation, 3:Independent Operator) col.7: Number of Firms in Joint Venture col.8: State Income Tax Rate col.9: Federal Income Tax Rate	N2r9c
FPA	Preferred Equity Fraction of Alternative Power Plant Capital	
FPH	Preferred Equity Fraction of Hydrothermal Plant Capital	
G	General Inflation Rate	
GC	Cost Escalation Rate	
GF	Energy Price Escalation Rate	

TABLE A-1 continued...

Label	Description	Dimension*
IF	Intangible Well Cost Fraction for Tax Deduction	
IRD	Initial Redrill Fraction	
ITCA	Investment Tax Credit for Alternative Power Plant	
ITCH	Investment Tax Credit for Hydrothermal Power Plant	
ITC2	Investment Tax Credit for Well Field Capital	
KCA	Common Equity Cost for Alternative Power Plant	
KCH	Common Equity Cost for Hydrothermal Power Plant	
KDA	Long Term Debt Cost for Alternative Power Plant	
KDH	Long Term Debt Cost for Hydrothermal Power Plant	
KPA	Preferred Equity Cost for Alternative Power Plant	
KPH	Preferred Equity Cost for Hydrothermal Power Plant	
LSB	Lease Bonus ($/acre)	
PALT	Fuel Cost of Alternative Generation (mills/kWh)	
PARM	Reservoir Parameters (col.1:Minimum, col.2:Mode, col.3:Maximum) row 1: Resource Wellhead Temperature (F) row 2: Well Flow Rate (1000 Lb/Hr) row 3: Dry Well Fraction row 4: Well Life (Yrs) row 5: Reservoir Depth (Ft) row 6: Capacity Factor for Hydrothermal Power Plant	6r3c
PDMAT	Resource Power Development Schedule col.1: Initial Year of Commercial Operation col.2: Incremental Net Power Output (kWe)	N_3r2c
PFAC	Marginally Competitive Resource Price Multipliers	N_4c
PIR	Producer/Injector Well Ratio	
PLFA	Economic Life of Alternative Power Plant (Yrs)	
PLFH	Economic Life of Hydrothermal Power Plant (Yrs)	
RDC	Redrill Well Cost Fraction of New Well Cost	
RLF	Royalty Fraction (of Gross Revenues)	
RRD	Fraction of Replacement Wells that are Redrills	
ST	State Code Number (301:California, 2120:Utah)	
SWF	Spare Well Fraction of Total Wells	
TFA	Federal Income Tax Rate for Alternative Power Plant Owner	
TFH	Federal Income Tax RAte for Hydrothermal Power Plant Owner	
TLFA	Tax Life of Alternative Power Plant (Yrs)	
TLFH	Tax Life of Hydrothermal Power Plant (Yrs)	
TSA	State Income Tax Rate for Alternative Power Plant Owner	
TSH	State Income Tax Rate for Hydrothermal Power Plant Owner	
TYPE	Geologic Classification (1:Sedimentary, 2:Igneous)	
TXC	Hydrothermal Power Transmission Cost Data col.1: Transmission Cost Below Threshold ($1000) col.2: Threshold Power Rating (kWe) col.3: Incremental Transmission Cost Above Threshold ($1000) col.4: Incremental Power Ratings Above Threshold (kWe)	4c
WDMAT	Coordinates of Levels of Confidence within Resource Area col.1: X-Coordinate from Origin of CORNERS (Miles) col.2: Y-Coordinate from Origin of CORNERS (Miles) col.3: Level of Confidence	N_5r3c
WDRY	Coordinates of Known Dry Wells within Resource Area col.1: X-Coordinate from Origin of CORNERS (Miles) col.2: Y-Coordinate from Origin of CORNERS (Miles)	N_6r2c
WSPACE	Well Spacing (Acres/Well)	
WTLF	Well Tax Life (Yrs)	
YB	Base Year of Analysis, 1978 for Utility Functions in Model as of 10/79	
YP	Pricing Year, 1978 for Cost Data in Model as of 10/79	

*All dimensions are scalar except as noted otherwise;
notation "NrMc" denotes N row x M column array; "Mc" denotes M element vector.
N_1 denotes number of right-angle corners in resouce area boundary.
N_2 denotes number of different types of firms and joint venture arrangements being analyzed.
N_3 denotes number of incremental levels of power development being analyzed.
N_4 denotes number of pricing levels being analyzed.
N_5 denotes number of coordinates at which level of confidence is provided within resource area.
N_6 denotes number of known dry wells within resource area.

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    ∇ TCN2000;LABEL;X;BICAP;CAPH;CHT;CONF;DWF;FMRR;GAIN10;NPVGL;EDT;NR;AREA;DP;IRR;SRP2;ALTP;DELP;MCPH
[1]   'TCN2000: GEOTHERMAL WELL FIELD INVESTMENT DECISION MODEL (MOD.2;VER.3)'
[2]   'TECHNECON / PHILADELPHIA : 10-79'
[3]  ⍝DRIVER PROGRAM FOR EXECUTING CASH FLOW SIMULATION, FINANCIAL ANALYSIS AND DECISION ANALYSIS
[4]  ⍝RESOURCE PRICING BASED UPON MARGINAL COMPETITION WITH ALTERNATIVE GENERATION AT BUSBAR
[5]  ⍝PRICING ANALYSIS ACCOMMODATED VIA ELEMENTS OF PFAC; A VECTOR OF PRICE MULTIPLIERS
[6]  ⍝ANALYSIS OF DISTINCT TYPES OF FIRMS ACCOMMODATED VIA ROWS OF FIRM MATRIX
[7]   ⍎((ST≠301)∧ST≠2120)/'TCN2001'
[8]   TCN2010
[9]   PDMAT1←PDMAT
[10]  EDT←9×NR←1
[11]  PLF←PLFH
[12]  'ENTER LABEL'
[13]  LABEL←⍞
[14]  TCN2020
[15]  TCN2030
[16]  'S: ';S
[17]  M←((11+S),8)⍴0
[18]  BICAP←(0,NR,EDT)⍴BEXP←(0,NR,PLF)⍴ICAP←BCAP←TEXP←STDT←(0,NR,EDT+PLF)⍴N2←0
[19] LN1:INDE←(0,NR,EDT+PLF)⍴N1←0
[20]  FIRM←FIRM[(N2←N2+1);]
[21]  'NFIRM: ';N2
[22] LN2:PFAC←PFAC[N1←N1+SS←1]
[23]  PH←(PFAC×ALTP)-DELP
[24]  'NPFAC: ';N1
[25] LN3:NPVC←NR⍴S←0
[26] LN4:→LN5×⍳(1↑⍴BCOE)≥S←S+1
[27]  TCN2040
[28] LN5:→LN6×⍳(1↑⍴INDE)≥S
[29]  TCN2050
[30] LN6:TCN2060
[31]  →LN4×⍳SS≥S+1
[32]  TCN2070
[33]  TCN2080
[34]  →LNB×⍳GAIN10
[35]  NPVG←NPVGL+FMRR←PAT←IRR←0
[36] LNB:M←M,[1] S,PFAC,IRR,FMRR,PAT,NPVG,NPVL,PINV
[37]  →LN3×⍳S≥SS←SS+1
[38]  →LN2×⍳(⍴PFAC)≥N1+1
[39]  M←M,[1] 2 8 ⍴FIRM,T2,6⍴0
[40]  →LN1×⍳(1↑⍴FIRM)≥N2+1
[41]  M[1 2 3 ;]← 3 8 ⍴G,GC,GF,TB,TP,ST,PLFA,WSPACE,ADV,BCI,CALT,PALT,RLF,TYPE,DWC,SWF,IRD,PIR,RDC,RRD,NSE,WC,WF,WLF
[42]  M[4 5 6 ;]← 3 8 ⍴WT,DWF,BETAA,CAPA,ITCA,TA,TFA,TSA,FCA,FDA,FPA,KCA,KDA,KPA,KA,TLFA,PKLF1,PKLF2,WTLF,IF,IXC
[43]  M[7 8 9 ;]←⍉PARM,[1] 2 3 ⍴(⍴PFAC),(1↑⍴FIRM),S,(DP×1000),ITC2,LSB
[44]  M[10 11 ;]← 2 8 ⍴BETAH,CAPH,FCH,FDH,FPH,ITCH,KCH,KDH,KH,KPH,PLFH,TFH,TH,TLFH,TSH,0
[45]  M[(11+⍳S);]←(+\[1] 0 1 ↓PDMAT),PDMAT,CONF,(AREA←(S,1)↑AREA),(⍉CHT),(⍉MCPH),SRP
[46]  ⍎LABEL,'←M'
[47]  X←⎕EX 18 2 ⍴'IKIRKANFPHTAT2WCWFWT M SN1N2 SSSKHTH'
[48]  X←⎕EX 12 3 ⍴'PD2KD2NSEOPCPATWLFTTFTS2TF2SRPNSCTRM'
[49]  X←⎕EX 14 4 ⍴'NPVCNPVGNPVLPFACPINVSDRLSDPTFIRMBCAPBEXPINDEICAPTEXPSTDT'
[50]  'EXECUTION COMPLETE, DATA IN MATRIX: ';LABEL
    ∇
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    ∇ TCN2001
[1]  ⍝ERROR STATEMENT FOR STATE IDENTIFIER
[2]   'EXECUTION SUSPENDED; IMPROPER STATE IDENTIFIER ';ST
[3]   'ENTER EITHER 301 FOR CA OR 2120 FOR UT'
[4]   ST←⎕
    ∇
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    ∇ TCN2010;UNITS;TCORNERS;TWDMAT;TWDRT;TBORDER;N;FIX;EPS;MATSIZE;WSMAT
[1]  ⍝PROVIDES VECTOR OF CONFIDENCE LEVELS FOR SEQUENTIAL WELL SPACES (WSEQ)
[2]   UNITS←1÷((640÷WSPACE)*0.5)
[3]   TCORNERS←UNITS TCN2011 CORNERS
[4]   X←⎕EX 'CORNERS'
[5]   MATSIZE←(⌈/TCORNERS[;1]),⌈/TCORNERS[;2]
[6]   TWDMAT←(UNITS TCN2011 WDMAT[; 1 2]),WDMAT[;3]
[7]   TWDRT←UNITS TCN2011 WDRT
[8]   X←⎕EX 2 5 ⍴'WDMATWDRT '
[9]   WSMAT←MATSIZE⍴0
[10]  TBORDER←TCN2012 TCORNERS
[11]  N←1
[12] LOOP:WSMAT[TWDMAT[N;1];TWDMAT[N;2]]←TWDMAT[N;3]
[13]  →LOOP×⍳(⍴TWDMAT)[1]≥N←N+1
[14]  FIX←TBORDER,[1] TWDRT,[1] TWDMAT[; 1 2]
[15]  EPS←0.01
[16]  SFIELD←0.01×⌊0.5+100×SFIELD←FIX TCN2013 WSMAT
[17]  WSEQ←TCN2014 SFIELD
[18]  SZ←WSPACE×⍴WSEQ
[19]  WSEQ←(WSEQ>0.1)/WSEQ
    ∇


    ∇ R←U TCN2011 V
[1]  ⍝CONVERTS MILES TO WELL SPACE UNITS
[2]   R←1+⌊(V÷U)+0.5
    ∇


    ∇ R←TCN2012 TC;TCC;LP;ND;M;NSD;NS;S;D;NSDD;N
[1]  ⍝ESTABLISHES COORDINATES OF RESOURCE AREA BOUNDARY
[2]   TCC←TC,[1] TC[1;]
[3]   LP←TC[1;]
[4]   ND←⍴TC[;1]
[5]   NS←+/NSD←+/|M←(1 0 ↓TCC)−TC
[6]   R←(NS,2)⍴0
[7]   S←D←1
[8]  LOOP2:NSDD←NSD[D]
[9]   N←1
[10] LOOP1:R[S;]←LP←LP+×M[D;]
[11]  N←N+1
[12]  S←S+1
[13]  →LOOP1×⍳(N≤NSDD)
[14]  D←D+1
[15]  →LOOP2×⍳(D≤ND)
    ∇


    ∇ R←FIX TCN2013 A;XLIM;YLIM;ORIG;FIXV;FIXM;ITERLIM;AHOLD;B;NITER;DIFF
[1]  ⍝ESTIMATES CONFIDENCE LEVELS OVER RESOURCE AREA WELL SPACE GRID
[2]  ⍝METHOD IS GAUSS-SEIDEL APPROXIMATION OF LAPLACIAN OPERATOR
[3]   XLIM←(⍴A)[1]
[4]   YLIM←(⍴A)[2]
[5]   ORIG←A
[6]   FIXV←(XLIM×YLIM)⍴1
[7]   FIXV[FIX[;2]+(FIX[;1]−1)×YLIM]←0
[8]   FIXM←(XLIM,YLIM)⍴FIXV
[9]   NITER←0
[10]  ITERLIM←100
[11] ITER:AHOLD←A
[12]  B←((0 1 ↓(¯2 ¯1 ↓A)+(2 ¯1 ↓A))+ 1 0 ↓(¯1 ¯2 ↓A)+(¯1 2 ↓A))÷4
[13]  A←(XLIM,YLIM)↑((−XLIM−1),(−YLIM−1))↑B
[14]  A←ORIG+FIXM×A
[15]  DIFF←+/+/|A−AHOLD
[16]  →ITER×⍳(DIFF>EPS)∧ITERLIM>NITER←NITER+1
[17]  R←A
    ∇


    ∇ R←TCN2014 MAT;V
[1]  ⍝ORDERS ELEMENTS OF WSEQ VECTOR BY DESCENDING LEVELS OF CONFIDENCE
[2]   V←,MAT
[3]   R←V[⍒V]
    ∇
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    ∇ TCN2020;V;V1;ACT;NACT
[1]  ⍝SIMULATES DRILLING SCHEDULE FOR PRODUCER, STANDBY, INJECTION AND DRY WELLS
[2]  ⍝ESTIMATES FIELD AREA, PROJECT CONFIDENCE, WELL LIFE, WELL COST, SURF,PIPING COST AND  CAPACITY FACTOR
[3]   NACT←⌊0.9+ACT←(+\PDMAT[;2])∘.÷(NSE←TCN2022 WT←PARM[1;] TCN2021 NR)×WF←PARM[2;] TCN2021 NR
[4]   AREA←WSPACE×V1←⌊0.5+(((1↑⍴NACT),NR)⍴1+DWF÷1-DWF←PARM[3;] TCN2021 NR)×(1+SWF÷1-SWF)×NACT
[5]   CONF←(V←(+/CONF)>0)≠CONF←(WSEQ,0)[(V1×~V)+(V←V1)⍴WSEQ)×1+⍴WSEQ]
[6]   SDRY←SDRY-0,[1] ¯1 0 ↓SDRY←⌊0.5+((⍴NACT)⍴DWF÷1-DWF)×(1+SWF÷1-SWF)×NACT←V≠NACT
[7]   SDRL←SDRL-0,[1] ¯1 0 ↓SDRL←NACT+(⌈NACT÷PIR)+⌊0.5+(SWF÷1-SWF)×NACT
[8]   TRM←((S,EDT+PLF)⍴(-EDT+1)+⍳EDT+PLF)+⍉((EDT+PLF),S←1↑⍴PDMAT)⍴(PDMAT←V≠PDMAT)[;1]
[9]   WLF←⌊0.5+WLF←PARM[4;] TCN2021 NR
[10]  WC←TCN2023 NR
[11]  SRP←(ST=301)×0.001×PDMAT[;2]∘.×SRP2←TCN2024 WT
[12]  CAPH←PARM[6;] TCN2021 NR
    ∇


    ∇ R←P TCN2021 N;V;V1;V2
[1]  ⍝PROVIDES RANDOM VARIATES FROM TRIANGULAR DENSITY FUNCTION
[2]   R←P[1]+V1×((V≥V2)×1-((1-V)×1-V2)*0.5)+(V<V2)×((V←NUNIFORM N)×V2←(P[2]-P[1])÷V1←P[3]-P[1])*0.5
    ∇


    ∇ R←TCN2022 T
[1]  ⍝NET SPECIFIC ENERGY OF POWER PLANT (WHR/LB) = F(TEMP)
[2]   R←3.75+0.055×T-300
    ∇


    ∇ R←TCN2023 N;V1;V2;V3;V
[1]  ⍝ESTIMATES STOCHASTIC WELL COST AS A 2ND-DEG FUNCTION OF DEPTH AND TYPE OF GEOLOGY
[2]   DP←0.001×PARM[5;] TCN2021 N
[3]   V1←(0.245×TYPE=1)+0.378×TYPE=2
[4]   V2←(0.00444×TYPE=1)+0.0211×TYPE=2
[5]   V3← 0.75 1 1.25 ∘.×V2←V1+V2×DP*2
[6]   R←1000×V3[1;]+V1×((V≥V2)×1-((1-V)×1-V2)*0.5)+(V<V2)×((V←NUNIFORM N)×V2←(V3[2;]-V3[1;])÷V1←V3[3;]-V3[1;])*
      0.5
    ∇


    ∇ R←TCN2024 T;V;V1;V2;V3
[1]  ⍝ESTIMATES STOCHASTIC SURFACE PIPING COST/KWE = F(TEMP)
[2]   V2←(V2-V1)÷V3-V1←¯90+V3←45+V2←160-0.175×T-300
[3]   R←V1+(V3←V3-V1)×((V≥V2)×1-((1-V)×1-V2)*0.5)+(V<V2)×((V←NUNIFORM(⍴T))×V2)*0.5
    ∇


    ∇ TCN2030;V;V1;GAA;GAHT;GAHP;EPA;EPHP;EPHT;CH;CT;DPFH;DPFA
[1]  ⍝ESTIMATES MARGINALLY COMPETITIVE RESOURCE PRICE
[2]   DPFH←(2×TLFH-(1-(1+KH)*-TLFH)÷KH)÷TLFH×(TLFH+1)×KH←((1-TH←TSH+(1-TSH)×TFH)×KDH×FDH)+(KCH×FCH)+KPH×FPH
[3]   DPFA←(2×TLFA-(1-(1+KA)*-TLFA)÷KA)÷TLFA×(TLFA+1)×KA←((1-TA←TSA+(1-TSA)×TFA)×KDA×FDA)+(KCA×FCA)+KPA×FPA
[4]   GAHP←((1-(TH×DPFH)+ITCH)÷1-TH)+BETAH×((1+GC)÷KH-GC)×1-((1+GC)÷1+KH)*PLFH
[5]   GAHT←((1-(TA×DPFA)+ITCA)÷1-TA)+BETAA×((1+GC)÷KA-GC)×1-((1+GC)÷1+KA)*PLFH
[6]   GAA←((1-(TA×DPFA)+ITCA)÷1-TA)+BETAA×((1+GC)÷KA-GC)×1-((1+GC)÷1+KA)*PLFA
[7]   EPHP←CAPH×8.76×((1+GF)÷KH-GF)×1-((1+GF)÷1+KH)*PLFH
[8]   EPHT←CAPH×8.76×((1+GF)÷KA-GF)×1-((1+GF)÷1+KA)*PLFH
[9]   EPA←CAPA×8.76×((1+GF)÷KA-GF)×1-((1+GF)÷1+KA)*PLFA
[10]  CT←((IXS[1]×V≤IXS[2])+IXS[3]×(⌈V÷IXS[4])×V>IXS[2])÷(V←+\PDMAT[;2])÷1000
[11]  V←(NR,S)⍴(V1+.×((1+GC)÷1+G)*V)÷(V1←(⍳S)∘.≥⍳S←1↑⍴PDMAT)+.×((1+GF)÷1+G)*V←PDMAT[;1]-TB
[12]  CH←(CH←TCN2031 WT)+(ST=2120)×SRP2
[13]  CHT←CH∘.+CT
[14]  MCPH←(ALTP←PALT+GAA×(CALT÷EPA)×V)-DELP←V×(⍉(S,NR)⍴GAHP×CH÷EPHP)+⍉GAHT×CT∘.÷EPHT
    ∇


    ∇ R←TCN2031 T;V;V1;V2;V3
[1]  ⍝ESTIMATES STOCHASTIC POWER PLANT COST/KWE = F(TEMP)
[2]   V2←(V2-V1)÷V3-V1←¯340+V3←170+V2←630-0.62×T-300
[3]   R←V1+(V3←V3-V1)×((V≥V2)×1-((1-V)×1-V2)*0.5)+(V<V2)×(V2×V←NUNIFORM(⍴T))*0.5
    ∇
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    ∇ TCN2040;V;V1;TCAP2;TEXP;BEXP;STD1;STD2;BCAP2;BTCAP1
  ]  ⍝ACCOUNTS FOR SHORT LIFE AND LONG LIFE BOOK CAPITAL AND TAX CAPITAL; BOOK EXPENSE AND TAX EXPENSE
  ]  ⍝ESTIMATES ACCELERATED DEPRECIATION OF SHORT LIFE AND LONG LIFE CAPITAL
 [3]  BCAP2←((NR,EDT)⍴0),(⍉(PLF,NR)⍴SDRL[S;]×WC×1+RRD×RDC-1)×(WLF∘.×⍳V)+.=((V←(⌈PLF÷⌊/WLF)-1),PLF)⍴⍳PLF
 [4]  BCAP2[;EDT]←(SDRL[S;]×V)-BCAP2[;5]←(⌈3×1+÷PIR)×V←WC×1+IRD×RDC++/BCAP2[;EDT+PLF]←0
 [5]  TCAP2←BCAP2-TEXP←IF×BCAP2
 [6]  TEXP[;EDT]←TEXP[;EDT]+(SDRY[S;]×V)-V1+0×TEXP[;5]←TEXP[;5]+V1←(⌊0.5+(DWF÷1-DWF)×3)×V←WC×DWC
 [7]  BCAP2←BCAP2+TEXP-IF×BCAP2
 [8]  TEXP[;EDT+⍳PLF]←TEXP[;EDT+⍳PLF]+BEXP←1.1×70+(20+20×BCI)×⍉(PLF,NR)⍴SDRL[S;]
 [9]  →SKIP×⍳S>1
 [10] BTCAP1←((NR,8)⍴ 50 15 0 40 75 800 125 225),SRF[S;]
 [11] BTCAP1[;2]←15+AREA[SS;]×LSB÷1000
 [12] TEXP[;⍳EDT]←TEXP[;⍳EDT]+(NR,EDT)⍴ 1740 1905 180 660 2160 0 0 0 0
 [13] TEXP[;⍳EDT]←TEXP[;⍳EDT]+0,⍉((EDT-1),NR)⍴AREA[SS;]×(RENTAL←2)÷1000
 [14] →SKIP2
 [15] SKIP:BTCAP1←((NR,8)⍴ 0 0 0 0 0 800 125 225),SRF[S;]
 [16] SKIP2:TCAP←TCAP,[1] TCAP2←⌊0.5+TCAP2×V←(NR,EDT+PLF)⍴(1+GC)*TRM[S;]-TB
 [17] TEXP←TEXP,[1] TEXP←⌊0.5+TEXP×V
 [18] BCAP←BCAP,[1] BCAP2←⌊0.5+BCAP2×V
 [19] BTCAP←BTCAP,[1] BTCAP1←⌊0.5+BTCAP1×V[;⍳EDT]
 [20] BEXP←BEXP,[1] BEXP←⌊0.5+BEXP×V[;EDT+⍳PLF]
 [21] STDT←STDT,[1]⌊0.5+(STD2←WTLF TCN2041 TCAP2)+STD1←TLFH TCN2041(NR,EDT+PLF)↑BTCAP1
    ∇

    ∇ R←L TCN2041 CAP;V;N
 [1]  ⍝SUM OF YEARS DIGITS METHOD OF ACCELERATED TAX DEPRECIATION
 [2]  R←⌊0.5+((0,-L)↓⌽+\⌽V-((N,L)⍴0),(0,-L)↓V←+\V,((N←1↑⍴CAP),L)⍴0)-⌽+\⌽(0 1 ↓(V←CAP÷+/⍳L)×L),0
    ∇

    ∇ TCN2050;BK2;BK1;V
 [1]  ⍝ESTIMATES INTEREST EXPENSE ON BORROWED CAPITAL
 [2]  V←⌊0.5+(FD2←FIRM[4])×(KD2←FIRM[5])×(BK2←BKLF2 TCN2051 BCAP[S;;])+BK1←BKLF1 TCN2051(NR,EDT+PLF)↑BTCAP[S;;]
 [3]  INDE←INDE,[1] STDT[S;;]+V
    ∇

    ∇ R←L TCN2051 CAP;V
 [1]  ⍝ESTIMATES REMAINING BOOK VALUE OF CAPITAL
 [2]  R←⌊0.5++\CAP-0, 0 ¯1 ↓V-(-⍴V)↑(0,-L)↓V←+\CAP÷L
    ∇

    ∇ TCN2060;V;DPL;ROYL;DEPL;TAX;GREV;ADVT
 [1]  ⍝ACCOUNTS FOR GROSS REVENUES, DEPLETION, ROYALTIES, TAX LIABILITIES
 [2]  ⍝ESTIMATES MARGINAL AND CUMULATIVE NET PRESENT VALUES
 [3]  GREV←⌊0.5+(0.00876×CAPH×PDMAT[S;2]×PH[;SS])∘.×(1+GF)*((-PLF)↑TRM[S;])-TB
 [4]  DPL←PLF⍴0.15
 [5]  DPL[(EDT↓TRM[S;])⍳V[;1]]←(V←(TRM[S;EDT]<DPL[;1])⌿DPL)[;2]
 [6]  DEPL←V×0<V←⌊0.5+(NR,-EDT+PLF)↑GREV×(NR,PLF)⍴DPL
 [7]  ⍎(ST=301)/'TCN2061'
 [8]  ⍎(ST=2120)/'TCN2062'
 [9]  ROYL←V×0<V←⌊0.5+(NR,-EDT+PLF)↑RLF×GREV-(NR,-PLF)↑ADVT
 [10] V←TCAP[S;;]
 [11] V[; 8 9]←V[; 8 9]+BTCAP[S;; 8 9]
 [12] TAX←⌊0.5+((T2←TS2+(1-TS2←FIRM[8])×TF2←FIRM[9])×((NR,-EDT+PLF)↑GREV)-TEXP[S;;]+ADVT+ROYL+DEPL+INDE[S;;])-ITC2×V
 [13] OPC←FIRM[1]
 [14] NET←((-BTCAP[S;;]),GREV)-TCAP[S;;]+TEXP[S;;]+TAX+ADVT+ROYL
 [15] NPVC←NPVC+NPV←+/NETPV←⌊0.5+NET÷(NR,EDT+PLF)⍴(1+OPC)*TRM[S;]-TB
    ∇

    ∇ TCN2061;V;V1;ADCAP1;ADCAP2;ADPR1;ADPR2;NILD;DNILD;ADNPV
 [1]  ⍝CALIFORNIA AD VALOREM TAX METHOD
 [2]  ADCAP1←+/BTCAP[S;;]×V←(NR,EDT)⍴(1+OPC←FIRM[1])*-TRM[S;⍳EDT]-TRM[S;EDT+1]
 [3]  ADCAP2←(NR,-PLF)↑BCAP[S;;]
 [4]  ADCAP2[;1]←ADCAP2[;1]++/BCAP[S;;⍳EDT]×V
 [5]  ADPR1←⌊0.5+⍉(PLF,NR)⍴ADCAP1÷PLF
 [6]  ADPR2←⌊0.5+V-(V1⌊V)×V1←(-WLF)⌽V←+\ADCAP2÷⍉(PLF,NR)⍴WLF
 [7]  NILD←⌊0.5+GREV-BEXP[S;;]+ADPR1+ADPR2
 [8]  ADNPV←⌽+\⌽DNILD←NILD×(NR,PLF)⍴(1+OPC)*-(⍳PLF)-1
 [9]  ADVT←(NR,-EDT+PLF)↑ADV×ADNPV←((NR,PLF)⍴(1+OPC)*(⍳PLF)-1)×ADNPV
 [10] →SKIP×⍳S>1
 [11] ADVT[; 2 3 4 5 6]←ADV×(⍉(5,NR)⍴AREA[SS;]×LSB÷1000)+(NR,5)⍴1400× 1 1 0.706 0.235 0
 [12] SKIP:ADVT[; 7 8 9]←ADVT[;10]∘.×(1+OPC)*- 3 2 1
 [13] ADVT←V×0<V←⌊0.5+ADVT
    ∇

    ∇ TCN2062
      ⍝UTAH AD VALOREM TAX METHOD
 [2]  ADVT←ADV×(+\BTCAP[S;;]+TCAP[S;;⍳EDT])-+\STDT[S;;⍳EDT]
 [3]  ADVT←ADVT,0.05×GREV-TEXP[S;;EDT+⍳PLF]+STDT[S;;EDT+⍳PLF]+DEPL[;EDT+⍳PLF]
 [4]  ADVT←V×0<V←⌊0.5+ADVT
    ∇
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    ∇ TCN2070
     ⍝EXECUTES IRR, FMRR, PAYBACK AND LOSS ROUTINES
      TCN2071
      TCN2072
      TCN2073
    ∇

    ∇ TCN2071;N10;IV;I;LOSS10
     ⍝ESTIMATES INTERNAL RATE OF RETURN (IRR)
      N10←NRρ1+IV←0×I←0.01×⌈100×OPC
      LOSS10←NPV≤0
      →LN1×⍳LOSS10=0
      IRR←0
      →0
    LN1:→LN2×⍳NR=+/LOSS10
      N10←N10+∼LOSS10←0≥+/NET÷(NR,EDT+PLF)ρ(1+I)*TRM[S;]-TB
      IV←IV,I
      →LN1×⍳0.9≥I←I+0.005
    LN2:IRR←IV[N10]
    ∇

    ∇ TCN2072;V;V0;XPC;XN;XNC
     ⍝ESTIMATES FINANCIAL MGMT RATE OF RETURN (FMRR) AND WEIGHTED PAYBACK
      V←+/NET[;EDT+⍳PLF]×(NR,PLF)ρ(1+IR←FIRM[3])*TRM[S;EDT+PLF]-TRM[S;EDT+⍳PLF]
      FMRR←¯1+(V÷-+/NET[;⍳EDT]×(1+IK←FIRM[2])*V0∘.-TRM[S;⍳EDT])*÷TRM[S;EDT+PLF]-V0←TRM[S;1++/∼0<(+\0)NET[;⍳EDT]]
      X←⎕EX 'NET'
      XPC←+\V×0<V←NETPV
      XNC←+\XN←V×0>V←(NR,EDT)↑NETPV
      X←⎕EX 3 5 ρ'NETPV   V0    V'
      PAY←+/(XN÷⍉(EDT,NR)ρXNC[;EDT])×(1++/(- 3 1 2 ⍉((EDT+PLF),NR,EDT)ρXNC)) 2 1 3 ⍉(EDT,NR,EDT+PLF)ρXPC)-(NR,EDT)ρ⍳ED
      NPVG←(GAIN10←(NPV>0)∧NPVC>0)/NPVC
      FMRR←GAIN10/FMRR
      PAY←GAIN10/PAY
      IRR←GAIN10/IRR
      NPVGL←(∼GAIN10)/(NPV×NPV<0)+NPVC×(NPV≥0)∧NPVC<0
      X←⎕EX 'NPV'
      NSC←+/GAIN10
    ∇

    ∇ TCN2073;LS;RL;C;Y;NY
     ⍝ESTIMATES INVESTMENT AT RISK
      →LNA×⍳S>1
      LS←AREA[S;]×LSB÷1000
      RL←AREA[S;]×RENTAL÷1000
      Y←TRM[S;⍳5]
      C←⍉(5,NR)ρ(NRρ50),(15+RL+LS×1+ADV),(RL+LS×ADV),(40+RL+LS×ADV),75+RL+(LS×ADV)+3×WC×DWC
      →LNB
    LNA:LS←(AREA[S;]-AREA[(S-1);])×LSB÷1000
      RL←(AREA[S;]-AREA[(S-1);])×RENTAL÷1000
      NY←TRM[S;5]-TRM[1;2]+1
     ⍝NY IS NO. YRS BETW ACQUIS AND CONF
      C←⍉((NY+2),NR)ρ(RL+LS×1+ADV),((NY×NR)ρRL+LS×ADV),RL+(LS×ADV)+3×WC×DWC
      Y←TRM[1;2]+0,⍳NY+1
    LNB:C←-(1-T2)×C×(ρC)ρ(1+GC)*Y-YP
      NPVL←⌊0.5++/C÷(ρC)ρ(1+G)*Y-TB
    ∇

    ∇ TCN2080;UR;UP;UV;UGL;UL;UG;EU
     ⍝PERFORMS RESOURCE PRODUCER DECISION ANALYSIS
      UR←UR×0<UR←1-*UC[TYF;1]-UC[TYF;2]×(FMRR×TYF=1)+IRR×(TYF←FIRM[6])=3
      UP←UP×0<UP←÷1+*-UC[TYF;3]-UC[TYF;4]×PAY
      UV←UV×0<UV←1-(UC[TYF;5]×*-UC[TYF;6]×NPVG÷1000×NF)+(1-UC[TYF;5])×*-UC[TYF;7]×NPVG÷1000×NF←FIRM[7]
      UGL←1 * UC[TYF;8]×NPVGL÷1000×NF
      UL←1-*-UC[TYF;8]×NPVL÷1000×NF
      →SKIP×⍳TYF=3
      UG←(K[1;1]×UR)+(K[1;2]×UV)+K[1;3]×UR×UP
      →SKIP2
    SKIP:UG←(K[3;1]×UV)+(K[3;2]×UR×UV)+K[3;3]×UR×UP×UV
    SKIP2:UG←(GAIN10\UG)+(∼GAIN10)\UGL←(¯1×UGL<¯1)+UGL×UGL≥¯1
      PINV←PINV×0.01<PINV←÷1+*UC[TYF;9]-UC[TYF;10]×EU←(+/(CONF[S;]×UG)+(1-CONF[S;])×UL)÷NR
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∇ REPORT1 M;N;NF;NP;S;LN
  'TCN2000: GEOTHERMAL WELL FIELD INVESTMENT DECISION ANALYSIS (MOD.2;VER.3)'
  'TECHNECON / PHILADELPHIA : 10-79'
  ''
  ''
  '1. ECONOMIC_PARAMETERS'
  '    1.1 LONG-TERM GNP DEFLATOR (I/P)........... ';M[1;1]
  '    1.2 COST ESCALATION RATE (I/P)............. ';M[1;2]
  '    1.3 ENERGY PRICE ESCALATION RATE (I/P)..... ';M[1;3]
  '    1.4 BASE YEAR OF ANALYSIS (I/P)............ ';M[1;4]
  '    1.5 YEAR OF PRICING (I/P).................. ';M[1;5]
  ''
  ''
  '2. POWER_PRODUCER_FINANCIAL_PARAMETERS                    HYDROTHERMAL  ALTERNATIVE'
  '    2.1  AVERAGE AFTER-TAX COST OF CAPITAL (O/P).....'; 12 3 ⍕M[11;1],M[5;7]
  '    2.2  DEBT FRACTION (I/P).........................'; 12 3 ⍕M[10;4],M[5;2]
  '    2.3  COST OF DEBT (I/P)..........................'; 12 3 ⍕M[10;8],M[5;5]
  '    2.4  PREFERRED EQUITY FRACTION (I/P).............'; 12 3 ⍕M[10;5],M[5;3]
  '    2.5  COST OF PREFERRED EQUITY (I/P)..............'; 12 3 ⍕M[11;2],M[5;6]
  '    2.6  COMMON EQUITY FRACTION (I/P)................'; 12 3 ⍕M[10;3],M[5;1]
  '    2.7  COST OF COMMON EQUITY (I/P).................'; 12 3 ⍕M[10;7],M[5;4]
  '    2.8  EFFECTIVE INCOME TAX RATE (O/P).............'; 12 3 ⍕M[11;5],M[4;6]
  '    2.9  STATE INCOME TAX RATE (I/P).................'; 12 3 ⍕M[11;7],M[4;8]
  '    2.10 FEDERAL INCOME TAX RATE (I/P)...............'; 12 3 ⍕M[11;4],M[4;7]
  '    2.11 INVESTMENT TAX CREDIT (I/P).................'; 12 3 ⍕M[10;6],M[4;5]
  '    2.12 POWER PLANT TAX LIFE (I/P)..................'; 12 3 ⍕M[11;6],M[5;8]
  '    2.13 POWER PLANT EXPECTED LIFE (I/P).............'; 12 3 ⍕M[11;3],M[1;7]
  '    2.14 POWER PLANT CAPACITY FACTOR:'
  '         -MINIMUM VALUE (I/P)........................          '; 12 3 ⍕M[7;6]
  '         -VALUE AT MODE (I/P)........................          '; 12 3 ⍕M[8;6]
  '         -MAXIMUM VALUE (I/P)........................          '; 12 3 ⍕M[9;6]
  '         -MEAN VALUE (O/P)...........................'; 12 3 ⍕M[10;2],M[4;4]
  '    2.15 PLANT RECURRENT COST FRACTION (I/P).........'; 12 3 ⍕M[10;1],M[4;3]
  ''
  ''
  '3. RESOURCE_PRODUCER_FINANCIAL_PARAMETERS'
  NF←M[8;7]
  NP←M[7;7]
  S←M[9;7]
  N←1
  LN←12+S+NP×S
 LN1:'    3.';N;'.1  TYPE OF FIRM (I/P)........................ ';M[LN;6]
  '    3.';N;'.2  FIRMS IN JOINT VENTURE (I/P).............. ';M[LN;7]
  '    3.';N;'.3  PRESENT VALUE DISCOUNT RATE (I/P)......... ';M[LN;1]
  '    3.';N;'.4  FMRR SINKING FUND INTEREST RATE (I/P)..... ';M[LN;2]
  '    3.';N;'.5  FMRR REINVESTMENT EARNINGS RATE (I/P)..... ';M[LN;3]
  '    3.';N;'.6  DEBT FRACTION (I/P)....................... ';M[LN;4]
  '    3.';N;'.7  COST OF DEBT (I/P)........................ ';M[LN;5]
  '    3.';N;'.8  EFFECTIVE INCOME TAX RATE (O/P)........... ';M[(LN+1);2]
  '    3.';N;'.9  STATE INCOME TAX RATE (I/P)............... ';M[LN;8]
  '    3.';N;'.10 FEDERAL INCOME TAX RATE (I/P)............. ';M[(LN+1);1]
  ''
  LN←LN+2+NP×S
  →LN1×⍳NF≥N←N+1
  ''
  '4. TAX_INCENTIVES'
  '    4.1 INVESTMENT TAX CREDIT (I/P)........... ';M[3;8]
  '    4.2 INTANGIBLE WELL COST FRACTION (I/P)... ';M[6;4]
  '    4.3 PERCENTAGE DEPLETION ALLOWANCE (I/P):'
  '        -THRU 1980.... ';DPL[3;2]
  '        -1981......... ';DPL[4;2]
  '        -1982......... ';DPL[5;2]
  '        -1983......... ';DPL[6;2]
  '        -AFTER 1983... ';DPL[7;2]
  ''
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ORT2 M;X;X1;LN;NF;NP;S
'N2000: GEOTHERMAL WELL FIELD INVESTMENT DECISION ANALYSIS (MOD.2;VER.3)'
'CHNECON / PHILADELPHIA : 10-79'

ESOURCE PARAMETERS'
'ABCDEFGHIJKLMNOPQRSTUVWXYZ'
,  STATE.......................................... ';X[ST÷100];X[ST-100×L(ST+M[1;6])÷100]
 2 11 ρ'SEDIMENTARYIGNEOUS    '
,  TYPE OF GEOLOGY (I/P)....................... ';X[(M[2;6]);]
,  RESERVOIR DEPTH,FT:' (
   -MINIMUM VALUE (I/P).... ';M[7;5]
   -VALUE AT MODE (I/P).... ';M[8;5]
   -MAXIMUM VALUE (I/P).... ';M[9;5]
   -MEAN VALUE (O/P).......................... '; 5 0 ⍕M[7;8]
,  MEAN WELL COST,$1000 (O/P).................. '; 4 0 ⍕M[3;6]
,  DRY WELL COST FRACTION (I/P)................ ';M[2;7]
,  REDRILL WELL COST FRACTION (I/P)............ ';M[3;3]
.  DRY WELL FRACTION:'
   -MINIMUM VALUE (I/P).... ';M[7;3]
   -VALUE AT MODE (I/P).... ';M[8;3]
   -MAXIMUM VALUE (I/P).... ';M[9;3]
   -MEAN VALUE (O/P).......................... ';M[4;2]
   SPARE WELL FRACTION (I/P)................... ';M[2;8]
.  PRODUCER/INJECTOR RATIO (I/P)............... ';M[3;2]
!, INITIAL REDRILL FRACTION (I/P).............. ';M[3;1]
', REPLACEMENT REDRILL FRACTION (I/P).......... ';M[3;4]
?, WELLHEAD RESOURCE TEMPERATURE,F:'
   -MINIMUM VALUE (I/P).... ';M[7;1]
   -VALUE AT MODE (I/P).... ';M[8;1]
   -MAXIMUM VALUE (I/P).... ';M[9;1]
   -MEAN VALUE (O/P).......................... '; 3 0 ⍕M[4;1]
3, NET SPECIFIC ENERGY,WHR/LB (O/P)............ '; 4 1 ⍕M[3;5]
!, WELL FLOW RATE,1000LB/HR:'
   -MINIMUM VALUE (I/P).... ';M[7;2]
   -VALUE AT MODE (I/P).... ';M[8;2]
   -MAXIMUM VALUE (I/P).... ';M[9;2]
   -MEAN VALUE (O/P).......................... '; 4 0 ⍕M[3;7]
5, WELL SPACING,ACRES/WELL (I/P)............... ';M[1;8]
;, SALINITY INDEX [0:LOW→4:HIGH] (I/P)......... ';M[2;2]
7, WELL LIFE,YRS:'
   -MINIMUM VALUE (I/P).... ';M[7;4]
   -VALUE AT MODE (I/P).... ';M[8;4]
   -MAXIMUM VALUE (I/P).... ';M[9;4]
  '-MEAN VALUE (O/P).......................... '; 4 1 ⍕M[3;8]
3, BOOK LIFE OF WELLS,YRS (I/P)................ ';M[6;2]
), BOOK LIFE OF SURFACE CAPITAL,YRS (I/P)...... ';M[6;1]
), TAX LIFE OF WELLS,YRS (I/P)................. ';M[6;3]
', AD VALOREM TAX,ON ACTUAL VALUE (I/P)........ ';M[2;1]
;, ROYALTY FRACTION (I/P)...................... ';M[2;5]
', LEASE BONUS,$/ACRE (I/P).................... ';M[9;8]
', LAND RENTAL,$/ACRE (I/P).................... ';2
5, POWER TRANSMISSION COST,$1000 (I/P):'
   -TO ';M[6;6];' KWE................................ ';M[6;5]
   -ADDITIONAL INCREMENTS OF ';M[6;8];' KWE......... ';M[6;7]
;, ALTERNATIVE GENERATION:'
   -CAPITAL COST,$/KWE (I/P)................... ';M[2;3]
   -FUEL COST,MILLS/KWH (I/P).................. ';M[2;4]


^[9;7]
 0 ¯1 ↓X←(⍳5),M[(11+⍳5);]
' 2 4]←X[; 2 4]÷1000

       DEVELOPMENT     YEAR     INCREMENTAL                      LAND     PLANT COST      COMPETITIVE'
          LEVEL       ON-LINE    PLANT SIZE   CONFIDENCE      REQUIRED   (INCL.TRANS)    RESOURCE PRICE'
          (MWE)                    (MWE)                       (ACRES)     ($/KWE)        (MILLS/KWH)'

) 10 0 12 0 10 0 13 2 12 0 11 0 17 1 ⍕X


·11+5×NF←1
;NF←1

                                        ';M[(LN+(5×M[7;7])+1);7];' TYPE ';M[(LN+(5×M[7;7])+1);6];' FIRM(S)'

       DEVELOPMENT  INTERNAL     FINANCIAL     WEIGHTED  NET PRESENT    LOSS OF      INVESTMENT  PROBABILITY'
          LEVEL      RATE OF     MANAGEMENT     PAYBACK     VALUE      INVESTMENT       LOSS          OF'
          (MWE)      RETURN    RATE OF RETURN   (YEARS)    ($1000)     PROBABILITY    ($1000)     INVESTMENT'

;X1← 1 1 1 1 1 1 0 1 1 \M[(LN+⍳5);]
;2]←X[;2]
;7]←1-X[;5]
;8]←-X1[;8]
   PRICE MULTIPLIER:';M[(LN+1);2]

) 9 0 10 2 14 2 13 1 13 0 13 2 12 0 11 2 ⍕X1

LN←5
 1×⍳M[7;7]]NF←NF+1
LN←2
 0×⍳M[8;7]]NF←NF+1
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