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May 21, 1982

Dr. P. Michael Wright
University of Utah Research Institute
Earth Science Laboratory
420 Chipeta Way, Suite 120
Salt Lake City, UT 84108

Dear Mike:

Enclosed is a copy of our final report covering the work we have been performing for DOE over the past two years.

I want to both personally and on behalf of our crew at Technecon pass along our sincere appreciation for your interest and assistance in this project. We have enjoyed and profited from our association with you, Duncan Foley and your colleagues at UURI during the course of this work.

Best personal regards,

Very truly yours,

Tom

Thomas A.V. Cassel

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enclosure

WRIGHT

March 31, 1982 DOE/ET/27242-T2

National Forecast for Geothermal Resource Exploration and Development

with

Techniques for Policy Analysis and Resource Assessment

BY:

Thomas A.V. Cassel, Ph.d. (Project Manager)

Glenn T. Shimamoto (Project Coordinator)

Chris B. Amundsen

Peter D. Blair, Ph.d.

William F. Finan, Ph.d.

M. Richard Smith

Robert H. Edelstein, Ph.d.

TECHNECON ANALYTIC RESEARCH, INC.

Philadelphia

Prepared for:

THE U.S. DEPARTMENT OF ENERGY

Under Contract No. DE-AC02-79ET27242

ABSTRACT

This report documents the background, structure and use of modern forecasting methods for estimating the future development of geothermal energy in the United States. These computer-based instruments have been developed over the past 4 years by Technecon Analytic Research, Inc. under contract to the U.S. Department of Energy. They represent an effective application of techniques from the fields of decision science and econometrics to provide statistically-sound estimates of geothermal resource development.

The forecasting instrument may be divided into two sequential submodels. The first predicts the timing and quality of future geothermal resource discoveries from an underlying resource base. This resource base represents an expansion of the widely-publicized USGS Circular 790, and was developed with the cooperation of several highly qualified geothermal geologists. The second submodel forecasts the rate and extent of utilization of geothermal resource discoveries. It is based on the joint investment behavior of resource developers and potential users as statistically determined from extensive industry interviews.

The report concludes that geothermal resource development, especially for electric power development, will play an increasingly significant role in meeting U.S. energy demands over the next 2 decades. Depending on the extent of R&D achievements in related areas of geosciences and technology, expected geothermal power development will reach between 7700 and 17300 MWe by the year 2000. This represents between 8 and 18% of the expected electric energy demand (GWh) in western and northwestern states.

PREFACE

During the past four years, Technecon has undertaken substantial research focused on the investment practices of geothermal resource developers and potential user industries. The purpose of this research was to develop an investment decision model capable of predicting -- in a statistically accurate and cost efficient manner -- the investment decisions of geothermal industry participants. This report documents the results of these efforts. In Part I of this report, the model used to forecast hydrothermal electric power development is presented. Part II describes the development and application of a hydrothermal non-electric market penetration model.

The hydrothermal electric power model has evolved over the past four years. Earlier reports[1] have documented the cash flow and decision analysis techniques used to forecast the joint likelihood of investment by a resource producer and an electric utility. National power on-line forecasts have been presented, based on a set of postulated resource discoveries, over the next 20 years. This report carries our analysis one step further by providing a means to analytically forecast both the rate of geothermal exploration and discovery, and the likely quality of new discoveries. Modeling techniques, based upon those commonly used in oil and gas evaluations, are for the first time applied to geothermal exploration. This resource discovery model is then coupled with the joint investment decision model to forecast hydrothermal power on-line to the year 2000.

Part I of this report is organized as follows:

Chapter One summarizes the forecasting methodology, results, and on-going investigations.

Chapter Two describes the development and application of the hydrothermal exploration, discovery and resource quality model.

Chapter Three presents a review of the cash flow and decision analysis models, and updates pertinent model parameters.

Chapter Four describes the application of the model to provide power on-line forecasts. The sensitivity of investment decisions to well field and power plant environmental control costs is also demonstrated.

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[1]See Cassel et al., 1979 and 1981.

Part II of this study describes the market penetration model used to forecast the rate of hydrothermal non-electric utilization over the next twenty years. The market penetration model was developed by Technecon as part of a DOE Task Force effort to estimate the extent to which energy markets will develop and utilize resources for non-electric applications. The modeling approach utilizes the decision criteria of the relevant market sectors, and includes provisions for "learning curve" effects, implementation lags, variations in fuel prices and utilization across region and industrial sector, and industry relocation potential.

Throughout these investigations, a generous degree of cooperation and participation by the resource and electric power industries has been received. Many hours of management interviews and a high response rate to quantitative surveys were contributed during the course of this work. The decision models which evolved from analysis of industry responses take the form of weighted functions of multiple investment criteria. Some of these criteria were explicitly discussed in management interviews while others were implicit but, nonetheless, found to be important variables for explaining industry investment behavior.

The decision models represent a new approach to investment analysis; however, their components and the collective influence of these components upon company decisions should be familiar and apparent to individuals within industry. Of primary importance are the models' abilities to reproduce or estimate industry investment decisions at acceptable levels of confidence. This capability is of significant value, particularly to program and policy analysts involved in the structuring of responsible incentive and research strategies for supporting the development of geothermal resources.

This work is sponsored and managed by Mr. Gene De LaTorre of the U.S. Department of Energy, Division of Geothermal and Hydropower Technology. During the project, Mr. De LaTorre, Dr. James C. Bresee, Dr. Fred Abel, Mr. Ralph Burr, Mr. Randall Stephens and Dr. John Salisbury provided valuable support and constructive comments. In addition, the research also benefited from expertise provided by: Mr. Eugene Ciancanelli of the Cascadia Exploration Corp. and Arthur Andersen & Co., Technecon's two subcontractors; and from the advice of Dr. Subir Sanyal of Geotherm-Ex, Inc. Significant technical aid was provided by Dr. P. Michael Wright and Dr. Duncan Foley of the Earth Science Laboratory at the University of Utah Research Institute and Mr. Thomas W. Lawford of EG&G Idaho, Inc. Personal interviews and information were provided by no fewer than eighty individuals from the geothermal industry during the course of this work. These industry participants -- who are too numerous to acknowledge here -- represent 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; though the authors, alone, assume responsibility for the interpretation and presentation of this information.

Last, though by no means least, the authors acknowledge Mrs. Norma Crouse and Gloria Phelan for their patient and very capable assistance in the production of this report.

Thomas A.V. Cassel
Glenn T. Shimamoto
Chris B. Amundsen
Peter D. Blair
William F. Finan
M. Richard Smith
Robert H. Edelstein

Technecon Analytic Research, Inc.
Philadelphia
March 31, 1982

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Chapter One

HYDROTHERMAL ELECTRIC POWER FORECASTS

EXECUTIVE SUMMARY

The first commercial geothermal electric power plant in the United States began operation at The Geysers in 1960 as the result of joint development by Magma Power Company, Thermal Power Company, and Pacific Gas and Electric Company. Utilization of the 240°C steam found at The Geysers offered the potential of producing electricity at costs significantly below fossil fueled baseload units. The successful operation of this first unit fully realized the promised potential of geothermal power. Subsequent development proceeded slowly as production experience was gained. Development accelerated substantially seven years later when Union Oil Company of California, with its substantial supply of investment capital, joined the developers (see Figure 1-1). Today there are more than 900 MW_e of installed capacity at The Geysers, supplying an appreciable fraction of demand in Northern California at costs which are significantly below those of conventional baseload alternatives.

The Geysers' success, coupled with today's strategic concern for more fully utilizing domestic energy resources, has contributed to a timely interest in geothermal development. Whereas virtually all of the commercial geothermal power in this country to date has been produced from The Geysers vapor-dominated resource, the next four years will witness the first significant development of more technologically challenging liquid-dominated resources. As shown in Table 1-1, over the next 5 years, 25 percent of planned geothermal plant additions are expected to be at liquid-dominated resources in California, Utah and Nevada.

The ability to generate power reliably and at competitive prices has clearly been demonstrated at The Geysers. However, this is likely to be the only vapor-dominated reservoir available for development in the United States at the present time. [2] Liquid-dominated resources are more prevalent in nature, but carry an appreciable degree of investment risk.

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[2] Vapor-dominated systems have been identified at Lassen, California and at the Yellowstone Caldera. Because these sites lie partially within existing National Park boundaries, further exploration and development is prohibited.

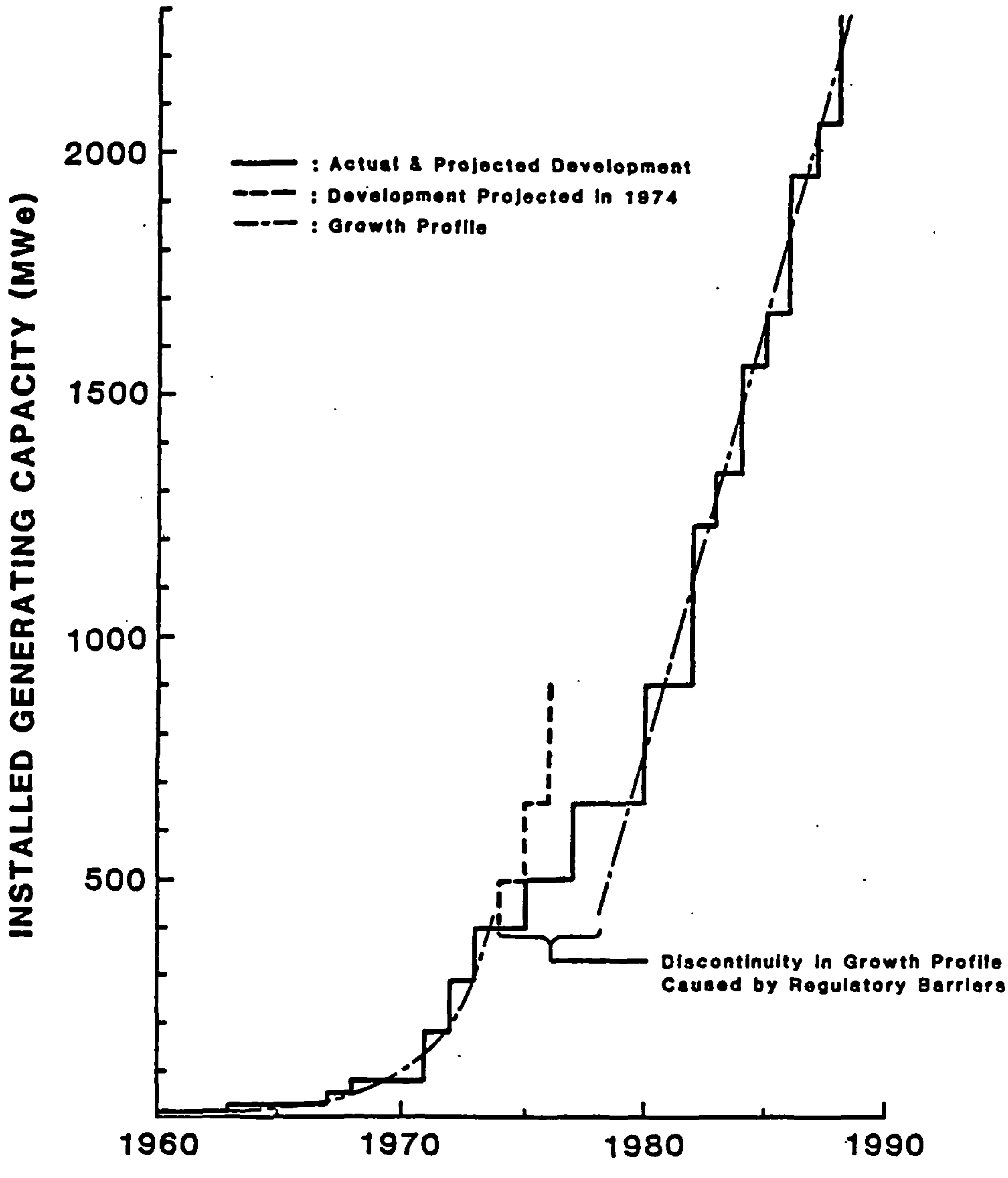

Figure 1-1
GEOTHERMAL POWER DEVELOPMENT AT THE GEYSERS
VAPOR-DOMINATED RESOURCE, N. CALIFORNIA

Source: Cassel (1982).

Table 1-1
GEOTHERMAL ELECTRIC POWER PROJECTION FOR 1985 (MWe net)
RESULTS OF INDUSTRY SURVEY

	Currently in Service	Planning Commitments (1982-1985)	Speculative Additions (1982-1985)	Possible Total by 1985
Vapor-Dominated Resource:				
The Geysers (CA)	902	785	66	1,753
Liquid-Dominated Resources:				
Baca (NM)			45	45
Beowave (NV)		10		10
Brawley (CA)	10	45		55
Coso (CA)			20	20
East Mesa (CA)		21		21
Heber (CA)		47	45	92
Mono-Long Valley (CA)		7		7
Niland (CA)		38	25	63
Puna (HA)	3			
Raft River		5		5
Roosevelt	2	20		22
Westmoreland				48
SUBTOTAL:	15	193	183	391
TOTAL PROJECTION FOR 1985:	917	978	249	2,144

Source: Cassel (1982)

Among the technical problems faced by developers at many of these resources are:

- o Materials corrosion,
- o Scale formation,
- o Effluent disposal,
- o Fluid reinjection,
- o Temperature and pressure drawdown,
- o Land surface subsidence,
- o Lack of effective well pumps, and
- o Poor energy conversion efficiency at low temperature resources.

The severity of these problems, and their impact on generation economics, are highly site-specific. Known hydrothermal resources differ greatly in fluid composition, depth, temperature, lithology, porosity, and permeability. Even resources in close geographic proximity have been shown to be geologically and geochemically dissimilar. To date, research and development activities have successfully ameliorated several technical problems at a number of these liquid-dominated resources.

1.1 ESTIMATING THE FUTURE POTENTIAL OF HYDROTHERMAL POWER

The rate and extent to which the Nation's hydrothermal resource base will be developed depend on a number of uncertain factors, including:

- o The rate at which hydrothermal exploration uncovers new resources for development
- o The quality of newly discovered resources
- o The willingness of resource producers and electric utilities to jointly undertake well field and power plant development
- o The ability of research and development activities to overcome the technological problems associated with hydrothermal energy utilization.

The understanding and estimation of these factors are the topics of this report.

To address these topics, a new forecasting methodology has been developed to estimate the intensity and relative success of future hydrothermal exploration. The estimation techniques are commonly used in oil and gas industry evaluations, and provide statistically-sound estimates of the number of new wildcat wells drilled, the number of discoveries which can be anticipated from the drilling effort, and the likely quality of the newly discovered resources.

The probability of investment at each discovered resource is then evaluated using a forecasting methodology which incorporates the combined use of two modern techniques from the decision sciences, namely "multiattribute utility analysis" and "logit choice estimation" (see Blair, Cassel & Edelstein, 1982). This methodology analytically compares time-wise geothermal investment opportunities to other investment opportunities available to resource developers and electric utilities. A computerized multiobjective analysis then provides estimates, over time, of the joint likelihood of investments by resource companies to develop well fields and by electric utilities to construct on-site geothermal power plants and transmission facilities.

1.2 SUMMARY FORECASTS OF GEOTHERMAL ELECTRIC GENERATION CAPACITY, 1982-2000

Technecon's hydrothermal exploration and development models were used to forecast hydrothermal electric power growth, for the period 1982-2000, under three scenarios. These scenarios are:

Current Technology and Incentives (Base Case): Assumes current state of geothermal technology with the introduction of a mature binary-type power plant in the mid-1990's. Tax incentives are assumed consistent with regulations in effect in early 1982.

Minimal Technological Advances (Case I): Assumes low-level of R&D effort resulting in minor performance and cost improvements during the mid- and late-1980's in geosciences, well drilling, well stimulation, piping materials and flash-type power plants. Also assumes mature binary-type power plants are available in the early-1990's. Tax incentives same as Base Case.

Significant Technological Advances and Enhanced Incentives (Case II): Assumes appreciable R&D effort resulting in significant performance and cost improvements during the late 1980's in geosciences, well drilling, well stimulation, downhole pumps, piping materials and binary- and flash-type power plants. Also assumes a mature advanced binary-type power plant is introduced in the early-1990's for use at lower temperature resources. Tax incentives, in the form of a 15% energy investment tax credit, are assumed to be available for both well field and power plant investments through 1995.

Forecasts of expected geothermal power capacity and energy production, under each scenario, are presented in Tables 1-2 and 1-3, and illustrated in Figure 1-2. A summary discussion of each forecast is presented below. More detailed analyses and data are presented in Chapter 4.

As shown in Table 1-2, geothermal power development is expected to grow at a compound annual rate of 12-17% over the next 2 decades, depending on levels of R&D accomplishment. Over this same period in western regions of geothermal activity, the comparable growth rate for overall baseload power plant additions is predicted to be on the order of 3-4% (ref. WSCC, 1981). Based upon these comparative figures, geothermal power is expected to fulfill an increasingly larger proportion of the electric demand in western states over the next twenty years. These figures indicate that utilities will be able to displace generation currently planned from depletable fuels.

1.2.1 Current Technology and Incentives (Base Case).

During the period 1958-1980, hydrothermal wildcat well completions increased at an average annual compound growth rate of 9%. Under the Base Case assumptions, wildcat well drilling levels abruptly stabilize, ending this 20 year period of rapid growth. Stagnant drilling levels combined with resource depletion effects cause an actual decline in hydrothermal reservoir discovery rate through the mid-1990's. Technological advances which serve to increase investment returns (e.g., binary conversion, high temperature down hole pumps) are assumed to be delayed. With fewer hydrothermal discoveries to exploit, and development of many currently identified resources impeded by their marginal economic attractiveness, expected geothermal power capacity (including The Geysers) grows to only 7710 MW by the year 2000.

1.2.2 Minimal Technological Advances (Case I).

The pre-1980 rate of increase in wildcat well drilling activity is preserved under the case of Minimal Technological Advances (Case I), though at somewhat lower than historical levels. The 15 year period of stagnation in drilling rates which occurs under Base Case assumptions, therefore, is avoided. Similarly, the decline in hydrothermal discovery rate is reduced, yielding a net 2-3 year acceleration in the timetable of discoveries that

Table 1-2
EXPECTED GEOTHERMAL GENERATION CAPACITY (MWe net)

	Actual[a] 1981	Survey[b] 1985	Forecast[c] 1985	1990	1995	2000	Annual Growth Rate[d] 1982-2000
THE GEYSERS ALONE	902	1753	1720	2380	2680	2890	+6%/yr
LIQUID-DOMINATED ALONE							
Base Case............	15	391	280	1760	4050	4820	+36%/yr
Case I...............	15	391	380	1860	4660	6830	+38%/yr
Case II..............	15	391	390	2770	6600	14420	+44%/yr
TOTAL GEOTHERMAL							
Base Case............	917	2144	2000	4140	6730	7710	+12%/yr
Case I...............	917	2144	2100	4240	7340	9720	+13%/yr
Case II..............	917	2144	2110	5150	9280	17310	+17%/yr

Note: "Base Case" assumes current technology and tax incentives
"Case I" assumes minimal technological advance and current incentives
"Case II" assumes significant technological advance and enchanced incentives

[a]Refer to Table 1-1; adapted from Cassel (1982).

[b]Includes both "Planning Commitments" and "Speculative Additions;" refer to Table 1-1.

[c]Expected Values; confidence intervals are displayed in Figures 4-5 through 4-7.

[d]Compound average growth over a 19 year period using 1981 actual values as a base.

Table 1-3
EXPECTED OIL-FIRED EQUIVALENT ENERGY PRODUCTION[d]
OF GEOTHERMAL POWER PLANTS
(Quads = 10^{15} Btu/Yr)

	Actual[a] 1981	Survey[b] 1985	Forecast[c] 1985	1990	1995	2000
THE GEYSERS ALONE	.065	.126	.124	.171	.193	.208
LIQUID-DOMINATED ALONE						
Base Case............	.001	.028	.020	.127	.292	.347
Case I...............	.001	.028	.027	.134	.336	.492
Case II..............	.001	.028	.028	.199	.475	1.04
TOTAL GEOTHERMAL						
Base Case............	.066	.154	.144	.298	.485	.555
Case I...............	.066	.154	.151	.305	.529	.700
Case II..............	.066	.154	.152	.370	.668	1.25

Note: "Base Case" assumes current technology and tax incentives
"Case I" assumes minimal technological advance and current incentives
"Case II" assumes significant technological advance and enhanced incentives.

[a]Refer to Table 1-1; adapted from Cassel (1982).

[b]Includes both "Planning Commitments" and "Speculative Additions;" refer to Table 1-1.

[c]Expected Values

[d]Assumes an average hydrothermal capacity factor of .85 and an oil-fired plant average heat rate of 9680 Btu/kWh.

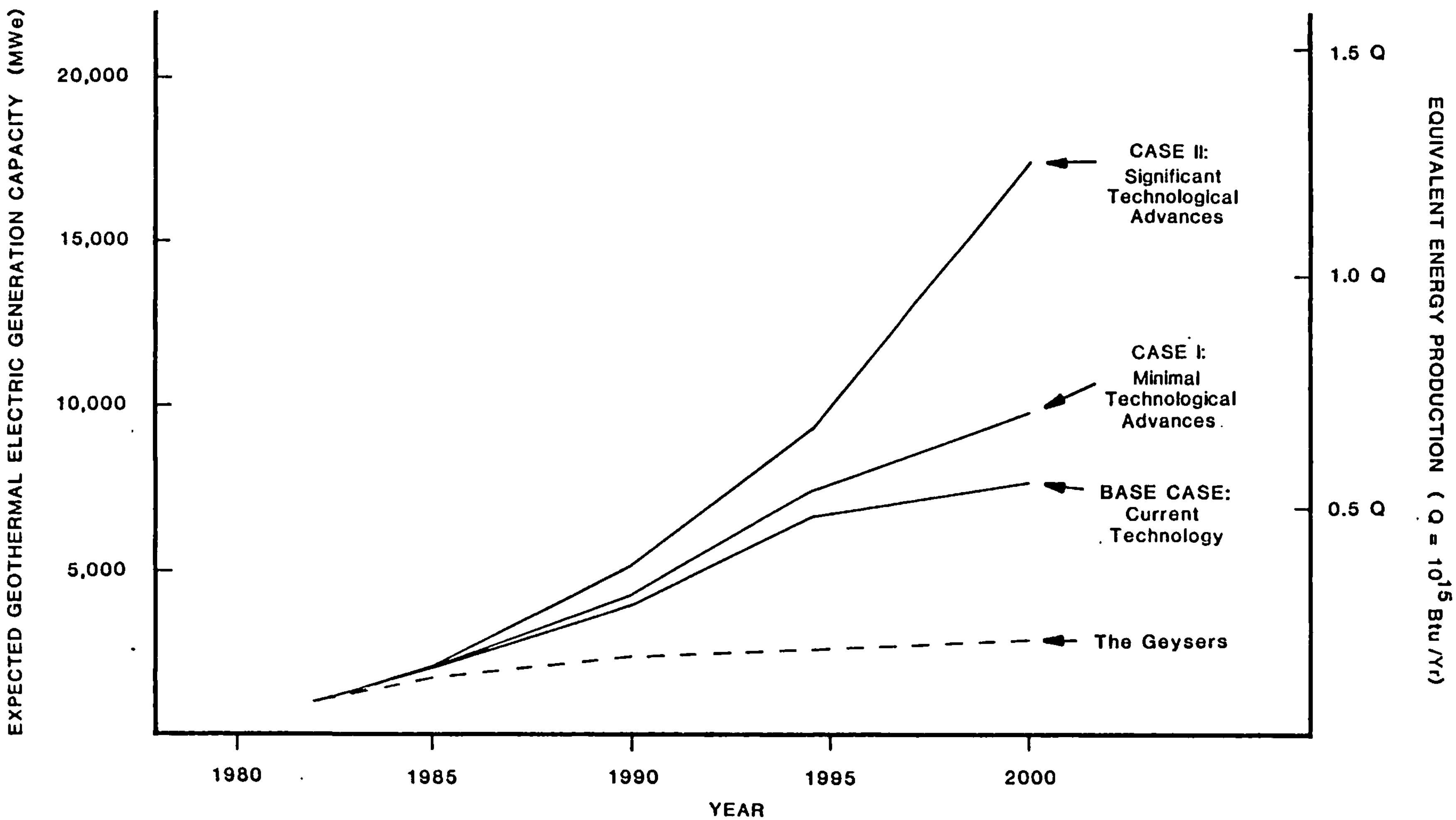

Figure 1-2. GEOTHERMAL POWER FORECAST COMPARISON

would occur under the Base Case. Gains in total discoveries over the period, as well as the introduction of binary conversion technology in the late 1980's, account for an additional 2010 MW of hydrothermal capacity above the Base Case by the year 2000.

1.2.3 Significant Technological Advance and Enhanced Incentives (Case II).

The assumptions of Case II have a notable, positive effect on every stage of geothermal development -- wildcat well drilling, discovery, and power plant construction. Wildcat well drilling increases at the historic rate of 9% per year through 1995, and hydrothermal discovery rates are significantly higher than those of the previous cases. Not only are there more discoveries in Case II, but these discoveries are more efficiently and economically utilized by the technological advances which are brought about by the assumed R&D successes of this case. Major contributors to this enhanced resource utilization are the assumed availability, in the late 1980's and early 1990's, of high-temperature (to 425F) downhole pumps, more cost-effective drilling technology and advanced binary-type power plants. Total expected geothermal capacity grows to 17,310 MW by the year 2000, more than doubling levels expected under Base Case assumptions.

1.3 REGIONAL BENEFIT OF GEOTHERMAL POWER

Practically all of the development of geothermal power in the United States is expected to take place within the California-Nevada Power Area and the Northwest Power Pool (excluding Canada). These two utility regions include the states of California, Nevada, Utah, Oregon, Washington, Idaho and Montana which collectively account for about 95% of expected geothermal power development (ref. WSCC 1981 and Cassel 1982).

As illustrated in Table 1-4, the regional impact of geothermal power in this area is likely to be quite significant. Depending upon the degree of R&D achievements over the next two decades, geothermal power plants are expected to comprise between 10% and 26% of the new baseload generating capacity installed through the year 2000 in the California-Nevada and Northwest regions. By the year 2000, this geothermal capacity is expected to provide between 8% and 18% of the total regional electric energy demand. Furthermore, if one looks at only the California-Nevada Power Area

Table 1-4
REGIONAL[a] GEOTHERMAL ELECTRIC POWER
CONTRIBUTION IN YEAR 2000

	Geothermal Capacity Forecast (MWe)	Percent of Regional Baseload Capacity[b]	Percent of Baseload Additions 1981-2000[c]	Geothermal Electric Energy[d] (GWh)	Percent of Regional GWh Energy Production[e]
THE GEYSERS ALONE	2890	2.1%	3.2%	21500	3.0%
LIQUID-DOMINATED ALONE					
Base Case............	4820	3.4%	7.6%	35900	5.1%
Case I...............	6830	4.9%	10.8%	50900	7.2%
Case II..............	14420	10.3%	22.9%	107400	15.1%
TOTAL GEOTHERMAL					
Base Case............	7710	5.5%	10.8%	57400	8.1%
Case I...............	9720	6.9%	14.0%	72400	10.2%
Case II..............	17310	12.3%	26.1%	128900	18.1%

Note: "Base Case" assumes current technology and tax incentives
"Case I" assumes minimal technological advance and current incentives
"Case II" assumes significant technological advance and enhanced incentives.

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[a]Region comprised of California-Nevada Power Area and Northwest Power Pool (excluding Canada).

[b]Regional baseload capacity in year 2000 estimated to be 140,440 MWe (net) based upon Western System Coordinating Council (WSCC) forecast of 104,280 MWe for 1990 and a compound annual growth rate of 3.0% (WSCC, 1981).

[c]Regional baseload additions from 1981 to 2000 estimated to be 62,900 MWe based upon installed baseload capacity of 77,540 MWe in 1980 and abovementioned estimate for 2000.

[d]Geothermal electric energy estimate based upon an 85% capacity factor.

[e]Regional net electric energy production in year 2000 estimated to be 709,600 GWh based upon WSCC forecast of 511,100 GWh for 1990 and a compound annual growth rate of 3.3% (WSCC, 1981).

which accounts for roughly 75% to 90% of the expected geothermal power development in the United States, the regional benefit in terms of both generating capacity and electric energy production is proportionately much greater than the values represented in Table 1-4.

1.4 CONCLUSION

The substantial promise of geothermal electric power in the United States is demonstrated in these forecasts of resource development. However, it is clear that the future expansion of the geothermal industry will be quite sensitive to the availability and timing of technological advances that serve to reduce investment risk and/or increase investment return. A central question, which remains to be addressed, is whether the fragmented geothermal industry is sufficiently motivated and capable of producing technological innovations, through R&D activities, within a time frame that is consistent with national needs as they unfold over the next several decades.

Only a few geothermal industry participants (typically large oil companies) are sufficiently capitalized to undertake major, high-risk and long-payoff R&D ventures. Because of limited and scattered leaseholdings, the potential payoff at a particular resource may be insufficient to warrant significant R&D investment. While the aggregate benefit of geothermal power to the nation appears substantial, the benefits of significant R&D program investments to individual firms may, at best, be marginal.

Chapter Two

HYDROTHERMAL EXPLORATION, DISCOVERY AND RESOURCE QUALITY MODEL

Previous forecasts of hydrothermal power development have been based largely on judgmental forecasts of the number and quality of high temperature resources available for development. In this section an analytical framework for projecting the number of future resource discoveries is presented. The model is capable of forecasting the yearly rate of exploration activity, the number of discoveries which can be anticipated, and the likely quality of these resources. Incorporated in the analysis are such factors as resource depletion, economic and investment climate, and historical trends in discovered resource quality. The modeling techniques are for the first time applied to the geothermal industry, although they have been extensively used in recent oil and gas industry evaluations. The model components are estimated from historic data, and will be shown to accurately replicate past hydrothermal exploration, discovery, and resource quality trends.

2.1 INTRODUCTION

Long term forecasts of hydrothermal electric capacity growth depend, at least implicitly, on assumptions of future resource availability. Perhaps the simplest method of estimating future resource availability is to extrapolate present discovery rates assuming fixed growth along historical trends (Mitre, 1977). To the extent the future is unlike the past or present, however, such estimates will suffer. Equivalently, one may assume that some certain resource level will be discovered by a particular date in the future, and then interpolate intermediate values back to the present (Battelle NW, 1976). At the least, it is not clear how such a resource level or date of ultimate discovery should be chosen.[3]

An alternate approach grounds future resource availability estimates more firmly in current knowledge about particular hydrothermal systems. Based on a "discovery table", comprising 27 known geothermal prospects and dates at which they first may see development, Mitre (1978a) developed an

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[3]Battelle, in one scenario, assumes that the "Identified" and "Total" Resource base estimates presented in USGS 726 (1975) are confirmed by 1985 and 2020, respectively.

initial power-on-line forecast for the Intergovernmental Geothermal Coordinating Council (IGCC). Discovery tables based on known prospects, however, ignore the undiscovered resource base that, in the long term, may be more significant to development than the presently regarded "best" collection of prospects. Moreover, development timing is difficult to assess even if we assume to know what prospects will be available, and this itself is uncertain.

The discovery table approach can be extended to alleviate the first of these problems by treating the undiscovered resource base in a fashion similar to that of the set of "best" currently-known prospects. A family of "generic" resources, assumed to be descriptive of all reservoirs in the undiscovered resource base, is allocated both temporally and spatially according to the judgment of a group of experts (UURI, 1980a and 1980b). Although this procedure is an improvement on all previous approaches, two basic problems remain:

(1) Resource discovery rates are estimated a priori without explicit consideration of any relations between current development and future exploration activity. Compelling evidence in other mineral and energy development industries (e.g., gold, uranium, oil and gas), however, suggests a significant relationship between current development returns and future exploration activity.[4] Hence, any sequential analysis, first of the exploration/discovery process and then of development, cannot be expected to accurately treat this dynamic interrelationship.

(2) Static discovery tables, because of the way they are constructed, are inherently inflexible for the purpose of sensitivity analysis. Any changes in assumptions concerning external economic conditions, technological advances, or other factors that may affect hydrothermal exploration and discovery rates, require complete, time consuming revisions to the discovery table.

It was with the intent of resolving these problems that Technecon developed the analytical models described in the remainder of this chapter. Section 2.2, below, provides an overview of the geothermal exploration process -- its stages, time durations, and costs -- followed in Section 2.3 by a discussion of different methods by which this process can be analyzed. Section 2.4 reviews data which document the history of U.S. geothermal exploration activity. These data then are used to support development of the Wildcat Well Drilling Model (Section 2.5), the Discovery Model (Section 2.6), and the Resource Quality Model (Section 2.7). Finally, Section 2.8

[4] See, for instance, MacAvoy and Pindyck (1974) or Epple (1975).

presents a summary of the important findings of our analysis of the hydrothermal exploration and discovery process.

2.2 GEOTHERMAL EXPLORATION PROCESS

Confirmation of a single hydrothermal reservoir requires a substantial committment of capital over a 9-10 year period. As shown in Table 2-1, the effort begins with reconnaissance activities such as reviews of published literature, aerial photography, imagery, and photogeology. In this process, an area as large as 1,000,000 acres may be evaluated in an initial search for prospects. Field surface exploration is then conducted on perhaps 400,000 acres which appear promising based on the reconnaisance studies. This effort is likely to include geochemistry and geologic mapping of the area. Lease applications can then be made on areas of special interest, generally totaling about 200,000 acres. Total expenditures during this first year may range from $1,000,000 to $2,800,000.[5]

Detailed field exploration typically begins in the second year with geophysical studies and the drilling of shallow temperature gradient holes. Leases may also be issued at this time, although historically there have been long delays in the leasing process. At the completion of this phase of the exploration process, roughly 100,000 leased acres are retained for further study. Total expenditures during this period may range from $300,000 to $1,800,000, depending on the lease bonuses paid for the acreage.

In the third year of the process, environmental and geophysical studies are conducted on the leased acreage. This includes drilling anywhere from 15 to as many as 60 deep temperature gradient holes to depths ranging from 500 to 2000 feet. Expenditures for these operations can be expected to total from $800,000 to $4,600,000.

Following the preparation and evaluation of geologic and geophysical models, deep confirmation wells are typically drilled in the fourth year of exploration. The purpose of these wells is to identify the location and depth of a reservoir, as well as to verify its temperature and producibility. Each well may cost between $800,000 and $1,700,000.

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[5]All costs estimates shown in this study are reported in 1981 dollars.

Table 2-1
PRE-PRODUCTION COST ESTIMATE FOR ONE PRODUCIBLE DISCOVERY
($1000)

YEAR	EXPENDITURE	
1	$1,000 - $2,800	Reconnaissance activities: literature review, aerial photography, imagery, and photogeology
2	$300 - $1,800	Detailed field exploration: geophysical studies, shallow temperature gradient holes
3	$800 - $4,600	Environmental and geophysical studies: deep temperature gradient holes
4	$2500 - $10,000	Geophysical and geologic model evaluation: deep confirmation wells
5-6	*	Contract negotiation, project financing and permitting Well field development; well field engineering
7-8	*	Production and injector well drilling
9	*	Power plant on-line

* Site-specific

Source: Technecon Analytical Research, Inc. and Cascadia Exploration Corporation, 1981.

If the confirmation wells prove successful, negotiations directed at obtaining a long-term sales contract begin with potential fluid purchasers (generally electric utilities). This has historically been a prolonged process, often concluding without a mutually acceptable agreement. However, if negotiations proceed in a timely manner, and a contractual agreement is reached in the fifth year, well field development may begin as early as the sixth year. This task includes project financing and permitting, as well as reservoir engineering. In the seventh and eighth year of the process, drilling rigs are mobilized and production and injection wells are drilled (including an adequate number of spare wells). In addition, surface piping and ancillary facilities are constructed during this period. Finally, in the ninth year of development, well field and power plant facilities are completed, and revenue-generating electricity production begins.

Because of the extremely long time over which geothermal properties are developed, the decision to undertake exploration and development efforts at a geothermal resource site should be viewed as a long-term capital investment decision. That is, exploration activities will be conducted only if the resource producer believes that the revenues generated over the project life will provide a sufficient return to justify the front-end expenditures incurred over the lengthy "start-up" phase. This capital budgeting decision will be based, in part, on the prevailing and projected economic and investment climate, as well as capital availability and the quality of alternative investment opportunities.

2.3 MODELING THE GEOTHERMAL EXPLORATION PROCESS

In modeling the geothermal exploration process, several alternative approaches were evaluated. One possible approach would be to construct a set of "generic" resource exploration firms. The exploration process then could be simulated at a micro-level, tracing a firm's development activity at an individual resource from aerial reconnaisance through final confirmation. There are several problems with implementing this approach. First, the quantity and precision of the data which would be required to construct such a model is immense and far beyond that currently publicly available. Without very detailed knowledge of the industry's current and future structure, such an approach also would be limited in its ability to forecast aggregate industry response to technological advances brought about by research and development efforts.

For these reasons, the hydrothermal exploration process is modeled on an aggregate industry basis. Statistical modeling techniques are employed to forecast the national rate of hydrothermal exploration and discovery, based on the risk/return perceptions of the industry. The modeling techniques applied here are commonly used by commercial firms in the assessment of individual investment opportunities.

The rate of geothermal exploration and discovery is modeled as a three stage process. As shown in Figure 2-1, the level of effort expended in a given year (defined in terms of the number of new wildcat wells drilled) is first estimated. It will be shown that drilling activity can be forecast based on the projected returns on geothermal investments relative to the returns on alternative oil and gas investments. A resource discovery model then predicts the number of discoveries which can be anticipated, based on the projected level of drilling activity. This discovery model incorporates such factors as the impact of resource depletion on the drilling success rate and disparities in regional drilling success ratios. Finally, a resource quality model is used to project probabilistic temperature profiles for each discovered resource. This model reflects the historic bias for discovering resources of high rather than medium temperatures. The following sections outline the derivation, structure, and results of each model.

2.4 WILDCAT WELL DRILLING DATABASE

As discussed above, the simulation begins with a forecast of wildcat well drilling activity. Such estimation requires a comprehensive and fully documented historical time series of drilling activity. Because of the diversity in the types of wells which may be drilled during the geothermal exploration and development process, it was necessary to explicitly define several critical terms:

Wildcat Well: A deep well (drilled to a depth in excess of 500 meters), at a site which has not yet been declared a "discovery". This does not include temperature gradient or observation wells.

Discovery Well: The first well at a site which identifies a resource in excess of 300°F, and is declared "producible" by the well driller.

Production Well: Any well spudded in a resource area where a discovery well has already been identified.

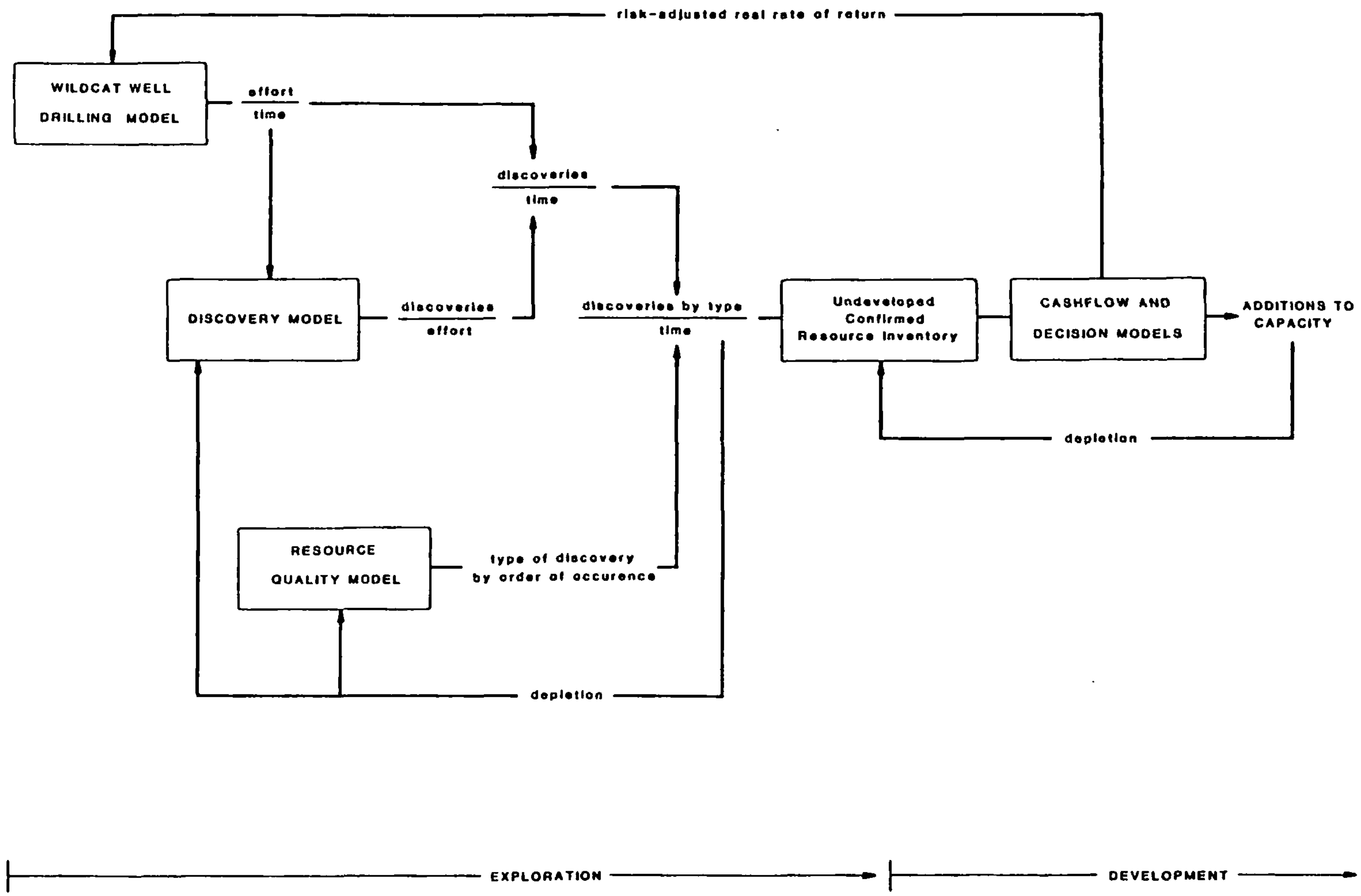

Figure 2-1
HYDROTHERMAL EXPLORATION AND DEVELOPMENT FORECASTING MODEL

In estimating the well drilling model, only the wildcat and discovery wells, as defined above, were considered in the analysis.

The data required for model development and estimation were substantial. It was necessary to compile an historical series (dating back to 1958) of the annual number of wildcat wells drilled, the number of discoveries, as well as other variables (such as depth, well owner, location, etc.) which might aid in identifying a well drilling activity relationship. All publicly available databases of well drilling activity were reviewed to establish which might best be used in this analysis.

2.4.1 Geothermal Resource Areas Database.

The Geothermal Resource Areas Database (GRAD) was selected for use in developing the historical series of well drilling activity. Developed and maintained by the University of California's Lawrence Berkeley Laboratory, the GRAD database is a compilation of information encompassing all aspects of geothermal resource development, including pre-lease activity, leasing activity, and post-lease activity. Data is subdivided into 14 separate "records", with each record providing information on a specific type of geothermal resource development activity. The record subjects include:

- o Area Description
- o Permit Record
- o Lease Record
- o Well (Deep Drilling) Record
- o Exploratory Survey Record
- o Shallow Temperature Gradient Hole Record
- o Area Resource Evaluation Record
- o Land Acquisition (Leasing) Record
- o Feasibility Study Record
- o Plant Construction and Operation Record

Several of the above records were used to compile the dataset used to evaluate geothermal wildcat well drilling activity.

Of immediate importance were the Well Drilling Records, containing 2008 observations on geothermal wells dating back to 1935. For each observation, a number of data useful in our analysis are reported, including:

- o Location (state, county, township, range, section)
- o Area Name
- o Well Owner
- o Date Spudded and Completed
- o Well Type (abandoned, injection, observation, idle, suspended, temperature gradient, potential producer, producible)
- o Well Depth
- o Temperature Data

This collection of over 2000 records provided the basis for our preliminary dataset. In subsequent analysis, it was established that a substantial number of observations should not be included in an analysis of geothermal wildcat well drilling activity. A screening process was then undertaken to derive the appropriate dataset. In this process, the number of observations was reduced to only 110. Each of the steps used to derive the final wildcat well drilling dataset is documented below.

2.4.2 Identification of "Dry" and "Successful" Wildcat Wells

The desired data set was to contain only wildcat wells (as defined in Section 2.4.). However, many observations in the GRAD data clearly did not meet the definition of "wildcat" used in this study. Observations defined as neither wildcat nor production wells (e.g., temperature gradient, observation) were immediately removed from the data set. To remove production wells from the data, the observations were sorted first by date, and then by area. The sequence of wells drilled at each area was then examined, and all observations dated after completion of the first "producible" well (whether or not subsequent wells were "dry" or also producible) were removed from the set. Because the modeling effort is directed strictly towards liquid-dominated exploration activity, all wells drilled in the vapor-dominated regions of The Geysers KGRA also were removed. Finally, the remaining observations contained some 400 records for which no drilling data was reported. Discussions with Lawrence Berkeley Laboratory representatives revealed that a very high percentage of these wells were, in fact, never drilled. In most of these cases, permits were filed as a preliminary step in the drilling process, but subsequent development was never undertaken. For this reason, all observations for which a date was not reported were discarded from the dataset. At the conclusion of this process, the dataset consisted of approximately 160 observations.

2.4.3 Data Refinements

To ensure that the wildcat well drilling history was represented as accurately as possible, several additional refinements to the dataset were made. First, all records with reported depths of less than 500 meters were withdrawn from the dataset. This is consistent with the definition of a wildcat well used in this study and is intended to eliminate shallow test wells and temperature gradient holes from consideration. Secondly, to confine the historical series to private-sector ventures only, all wells drilled by governmental (or quasi-governmental) agencies were deleted. A number of the wells remaining in the database clearly were drilled in an attempt to identify resources capable of supporting non-electric, rather than electric, applications. Such records, identified largely on a judgmental basis, were likewise removed. A final screen was conducted to eliminate any wells which were drilled for geopressured resources.

The dataset which remained following the screening process described above was presented to consulting geologists for their review. [6] They examined the list of discoveries to ascertain whether or not the list was complete and comprehensive, both with regard to "discovered" resources as well as the timing (or date) of discovery. Several modifications were suggested, and these changes were incorporated into the final database. As a result of this review, the final dataset comprised 110 observations. Of these, 21 of the wells were classified as discoveries, with the remaining 89 defined as unsuccessful wildcat attempts. Table 2-2 presents a summary of wildcat well drilling activity from 1958 to 1980.

To assist in the estimation of a fully-specified well drilling relationship, a number of additional data elements were compiled. For each of the 110 observations, the following associated data were recorded:

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[6] Consulting geologists included Duncan Foley of the University of Utah Research Institute and Eugene Ciancanelli of Cascadia Exploration.

Table 2-2
WILDCAT WELL DRILLING HISTORY

	Yearly Summary		Cumulative Total to Date		
Year	Wildcat Wells	Discoveries	Wildcat Wells	Discoveries	Drilling Success Ratio
1958	1	0	1	0	0
1959	4	0	5	0	0
1960	1	1	6	1	16.7
1961	2	0	8	1	12.5
1962	2	0	10	1	10.0
1963	3	0	13	1	7.7
1964	9	3	22	4	18.2
1965	2	0	24	4	16.7
1966	0	0	24	4	16.7
1967	2	0	26	4	15.4
1968	1	1	27	5	18.5
1969	0	0	27	5	18.5
1970	1	1	28	6	21.4
1971	0	0	28	6	21.4
1972	10	2	38	8	21.1
1973	7	1	45	9	20.0
1974	9	1	54	10	18.5
1975	9	3	63	13	20.6
1976	5	1	68	14	20.6
1977	7	2	75	16	21.3
1978	10	1	85	17	20.0
1979	15	3	100	20	20.0
1980	10	1	110	21	19.1

- o Well depth (in meters)
- o Location (by state)
- o Well owner (classified by "active" geothermal firms and "others")
- o Expected aerial extent of resource site (in acres)
- o Cumulative drilling footage at each resource site (in meters)
- o Cumulative number of wells drilled at each resource site.

In cases in which any of the above data were not reported in the GRAD database, attempts were made to use other outside sources[7] to generate the missing data.

2.5 WILDCAT WELL DRILLING MODEL

The Wildcat Well Drilling Model provides forecasts of the number of wildcat wells completed yearly, based on the perceived profitability of geothermal ventures relative to alternative oil and gas investment opportunities. The model is estimated using the wildcat well drilling time series discussed above, coupled with historical estimates of the risk-adjusted rate of return in both the geothermal and oil and gas industries.

2.5.1 Background.

As shown in Table 2-2, annual drilling activity picked-up markedly after 1971. Before 1972, the average number of wildcat wells per year was only 2, while after 1971 the average was over 9. Similarly, of the 21 high temperature geothermal discoveries identified between 1958 and 1980, only 6 occurred prior to 1972. The cumulative drilling success ratio has stabilized to approximately 20 percent in recent years, where in early years it oscillated between 10 and 16 percent.

These data illuminate several aspects of the history of U.S. geothermal exploration. First, there are a very small number of geothermal discoveries to use to estimate a relationship between drilling effort and discoveries. There have been only 110 wildcat wells drilled in total, with a total footage of 700,000 feet. By contrast, in the oil and gas industry there were over 13,000 wildcat wells drilled in 1980 alone, with total footage on all completed wells of 60 million feet. Not only are there a relatively small number of observations for the geothermal industry, but

[7]Other sources used in the data gathering process included the U.S.G.S. Geotherm Database and the Petroleum Information Corporation, and U.S.G.S. open file reports.

there were structural changes which caused a shift in the underlying relationships determining geothermal drilling activity. These were partially a result of the passage of the Geothermal Steam Act in 1970. This legislation upgraded federal support for geothermal exploration activities and established procedures to open federal lands for geothermal exploration. Since many of the most promising new areas for exploration were on federal lands, the 1970 Act provided an important impetus to leasing activity.

In addition to these effects, the more supportive federal posture towards geothermal development, in part, induced an expansion in the types of firms conducting geothermal exploratory programs. During the 1950's and 1960's, most firms conducting geothermal programs were small independent operators, often having very limited experience in exploration activities. After 1970, however, major oil companies joined the ranks of companies seeking to find and develop high temperature geothermal resources. Large oil firms brought their exploration expertise and, perhaps more importantly, their greater financial resources into the geothermal industry. The effect of this rather sudden infusion of capital and technological expertise on exploration activity is discussed below.

2.5.2 Well Drilling Relationship

The structure of the Well Drilling Model and the techniques used to estimate its parameters were chosen to account for these major structural changes within the industry. The pivotal period seems to have come in the early 1970's when a combination of factors yielded a significantly different set of industry participants when the rising cost of conventional generation enhanced the profitability of geothermal projects. These changes have been reflected in the way the model has been constructed.

The well drilling relationship relates the annual number of wildcat wells to two principal variables. The first is the risk-adjusted real rate of return on geothermal projects. The second variable is the risk premium on new oil drilling projects. This variable is included to capture the interaction which exists between the geothermal industry and the oil and gas industry. Since many of the principal geothermal exploration firms are also in the oil and gas industry, cash flow from oil and gas projects may be used to support exploration in the geothermal industry. Many oil companies may invest some of their incremental income from oil-related projects to expand into other energy resources. Therefore, as cash flow from producing oil wells increases, funds available for geothermal wildcat drilling may increase. The adjusted rate of return on new oil discoveries is used as a proxy for cash flow.

Rate of Return on Geothermal Investments. As discussed above, a major determinant of geothermal wildcat well drilling activity is the anticipated return offered on geothermal investment opportunities. Exploration effort will not be undertaken unless the proposed project is expected to satisfy minimal corporate profitability criteria (e.g., net present value of profits, internal rate of return, payback period). To derive a historical series of geothermal investment profitability, the internal rate of return was estimated for typical geothermal investment opportunities over the past 20 years. The methodology and results of this analysis are presented below.

A detailed cash flow analysis program was used to generate a twenty-year time series of the internal rate of return offered by hydrothermal investment opportunities. Included in the analysis were all capital costs and expenses related to:

1) Pre-Confirmation Cashflow
   - Pre-lease exploration
   - Land acquisition
   - Shallow subsurface exploration
   - Deep exploratory wells

2) Reservoir Confirmation and Field Development Cashflow
   - Confirmation wells
   - Reservoir modeling and environmental studies
   - Average rentals
   - Ad valorem taxes
   - Deep well costs (producers, injectors, and spares)
   - Well field surface equipment
   - Income taxes and credits

3) Production Cashflow
   - Revenue cash flow
   - Capital replacements
   - Well field operation and maintenance expenses
   - Royalty payments
   - Ad valorem taxes
   - Income taxes

The cash flow program was simulated on a yearly basis, beginning in 1957. An "average" quality resource was assumed in this simulation. Fully documented descriptions of the cash flow program can be found in Cassel et al., 1981 and 1979.

Input data required for the cash flow was compiled from literature reviews and industry interviews. Price indices prepared by the United States Department of Commerce, United States Department of Energy, and Wharton Econometric Forecasting Associates were used to adjust some cashflow components to reflect historical changes in relative costs. In estimating the internal rate of return which a decision maker perceives at a given point in time, an important element in the analysis is the expected future movements in project related costs and revenue. To reflect these judgmental considerations, perceived escalation rates (for fuel cost, well cost, etc.) were based on a weighted moving average of the previous three years of observations.

The results of this analysis are provided in Figure 2-2. As shown, the profitability of hydrothermal investment opportunities declined during the 1964-1969 period. This was due largely to the actual decline in the cost of alternative baseload generating capacity, coupled with significant yearly increases in well drilling costs. Post-1970 investments show rapidly rising rates of return, triggered by large increases in both the fuel and capital cost of alternative generating capacity. Well drilling costs rose, but with a lag, yielding significantly higher returns for geothermal projects.

Rate of Return Return on Alternative Oil Investments. Because many of the major geothermal exploration firms are also active in the petroleum industry, investments in geothermal ventures may compete for funds with oil-related projects. It may be argued that in years in which potential oil profits are unusually high, firms will be unwilling to allocate scarce capital to potentially less lucrative geothermal ventures. Alternatively, it is argued by some that geothermal exploration programs are funded out of "discretionary" capital sources. This would suggest that firms may make more liberal capital allocations to geothermal exploration budgets in periods where oil and gas profits are exceptionally high.

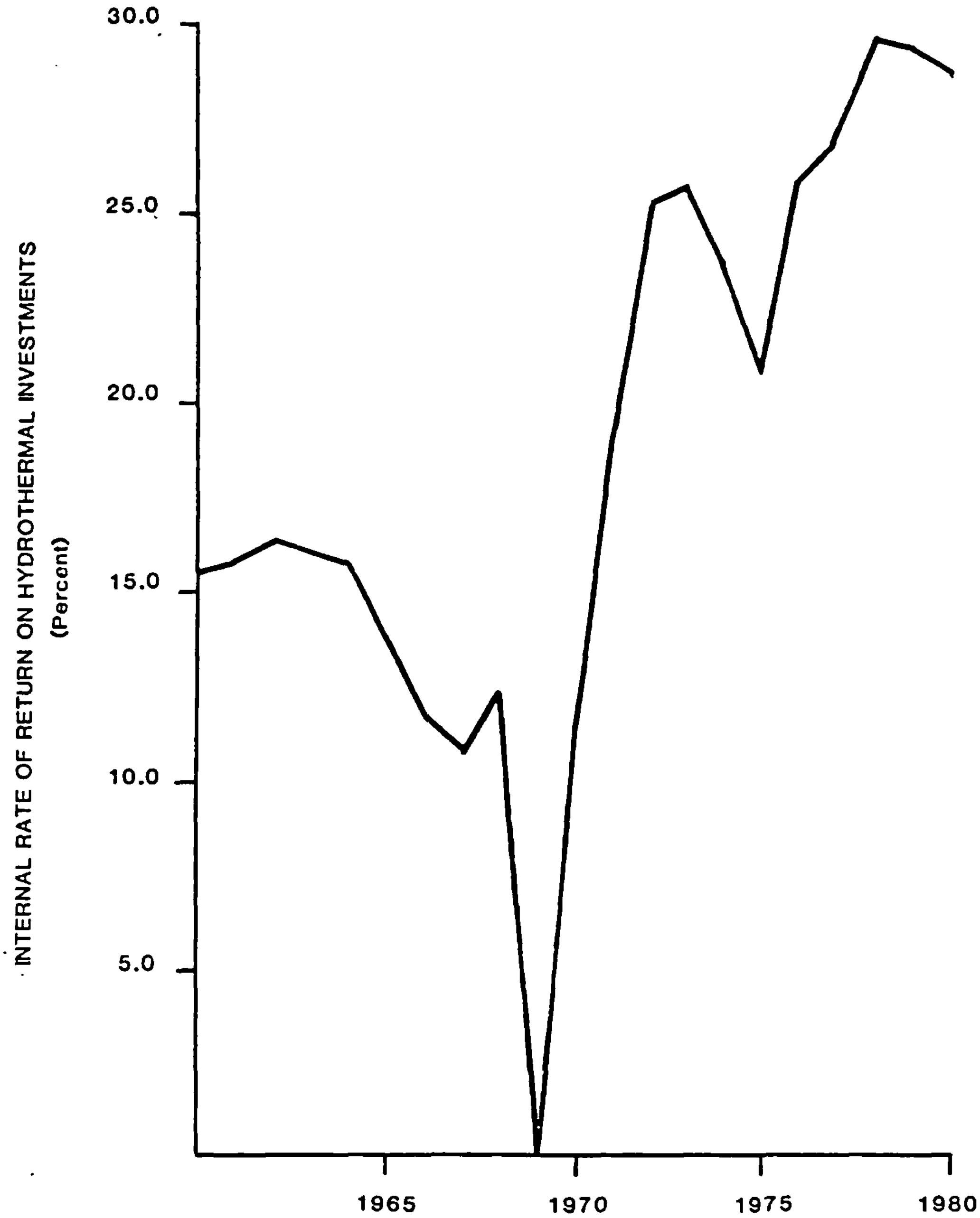

Figure 2-2
HYDROTHERMAL INVESTMENT PROFITABILITY

To test both hypotheses, yearly changes in the rate of hydrothermal exploration were compared to changes in the profitability of oil and gas ventures. The Washington Analysis Corporation (1980) derived annual estimates of profits per barrel of newly discovered oil in the United States from 1967-1980. Estimates also were provided for the internal rate of return on oil and gas ventures, and were adopted for use in our analysis as industry profitability measures.

As shown in Figure 2-3, the internal rate on oil ventures generally declined over the 1967-1973 period due to relatively stable selling prices (rising only 3.0 percent per year) and escalating exploration costs. The impact of the OPEC oil embargo is observed in 1974-1975, as returns more than doubled over the previous year. Returns then fell to depressed levels due in part to federal price control and price rollback policies. The stimulus brought about by the government's 1979 decontrol initiative led to increases in profitability in 1979 and 1980.

2.5.3 Model Estimation

Regression analysis was used to estimate the well drilling relationship as a function of the rate of return on geothermal investment and oil and gas returns. The return variables were reduced by the return on six-month Treasury Bills to produce real, risk-adjusted profitability measures for both time series. In estimating the drilling function, the explanatory power of both variables was enhanced when entered into the equation with a one year lag.

The third explanatory variable in the drilling function is a shift variable used to capture structural changes in the geothermal industry caused by the passage of the Geothermal Steam Act in 1970. The variable is set at 1.0 before 1970 and at zero thereafter. As discussed above, the Steam Act altered the drilling-return relationship for the industry by expanding leasing opportunities, subsidizing new drilling technologis and generally improving the investment climate for development of geothermal resources.

The form of the estimated relationship is:

$$\underset{(5.9)}{WCAT = 0.60 * RORG_{-1}} + \underset{(8.4)}{0.54 * RORO_{-1}} - \underset{(1.26)}{1.39 * GSA} \qquad (1)$$

$R^2 = 0.94$ R = 0.89 F-Stat = 48.5 Period = 1958-1980

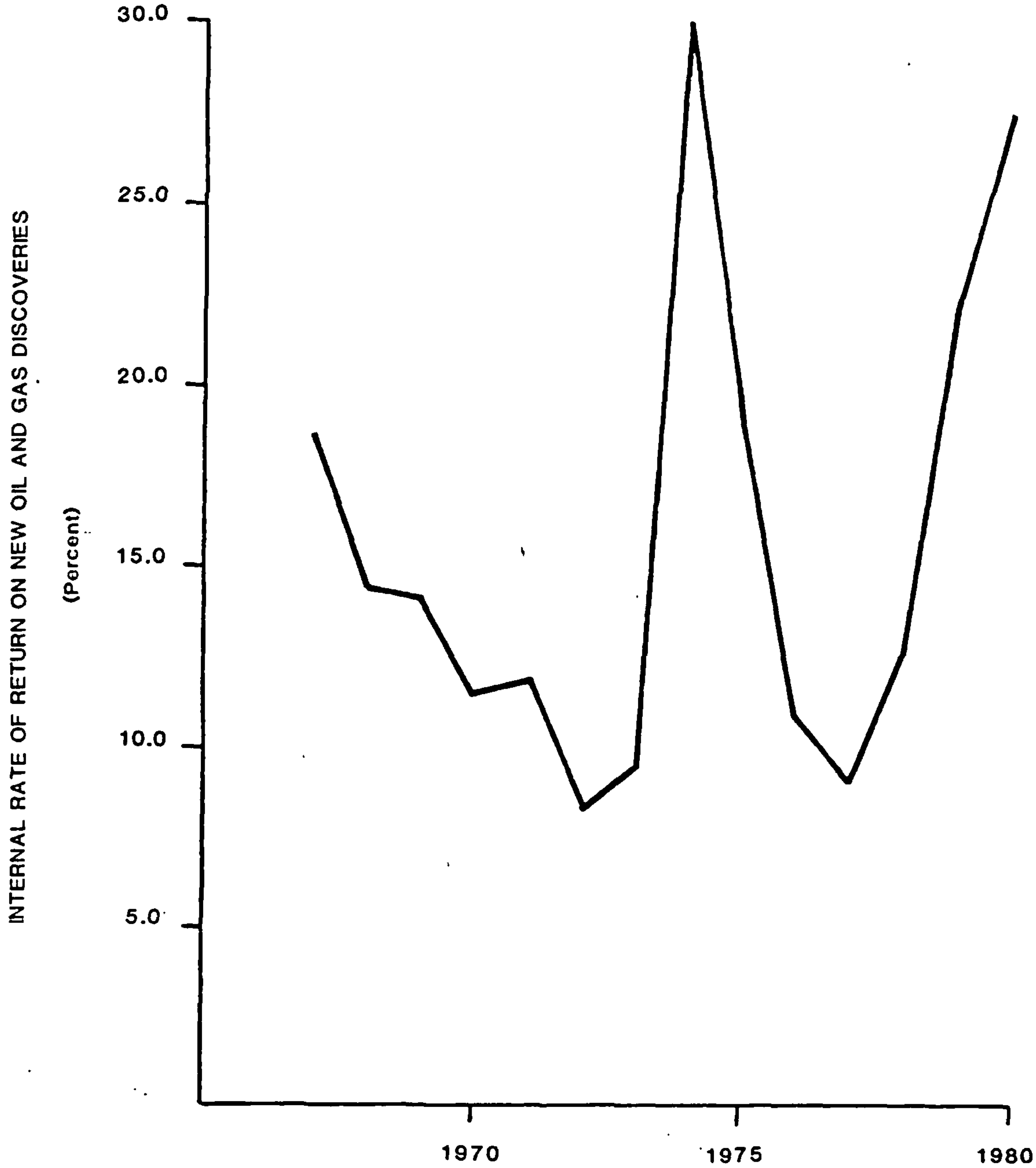

Figure 2-3
OIL AND GAS INVESTMENT PROFITABILITY

Where:

WCAT = annual number of geothermal wildcat wells

$RORG_{-1}$ = expected real, risk-adjusted rate of return on geothermal projects, lagged one year

$RORO_{-1}$ = risk-adjusted return for new oil discoveries, lagged one year

GSA = Geothermal Steam Act Shift Variable (i.e. "1" before 1970, "0" thereafter).

Equation (1) was estimated using ordinary least squares on annual data for the period 1958 to 1980. Statistical measures of the goodness of fit are shown below the equation; figures in parentheses are t-statistics.[8] The equation was estimated suppressing the constant term.

Equation (1) explains the observed number of geothermal wildcat wells extremely well. Drilling for new geothermal resources is highly dependent on the risk-adjusted return on geothermal projects. For each two percentage point increase in the real, risk-adjusted rate of return, one additional wildcat well will be drilled. The risk premium on new oil discoveries is equally important, indicating the importance of oil-related cash flow in supporting geothermal activities. The shift variable accounting for the impact of the Geothermal Steam Act is marginally significant. The Steam Act evidently had a modest positive impact on geothermal drilling, raising the average rate of exploration by 10 percent.

2.6 DISCOVERY MODEL

The Discovery Model estimates a relationship between the probability of a geothermal wildcat well being successful and the level of effort expended in exploring for the resource. It projects the outcome of the exploration process by estimating the number of new resources discovered yearly, based on the number of new wildcat wells drilled. The derivation and application of this model is presented below.

2.6.1 Relating Effort and Success

As discussed in Section 2.4.3, there have only been 110 wildcat wells drilled since 1958 by the geothermal industry. These wildcat wells have

[8]As shown, all coefficients are significant at the 90 percent confidence level.

located 21 high temperature hydrothermal resources (see Table 2-2). This is equivalent to a cumulative overall drilling success rate of approximately 20 percent. The purpose of this analysis is to define a relationship which links effort expended to the probability of success.

Effort is considered to be reflected not only in the number of wildcat wells attempted, but also in the depth of the well drilled. We would expect that as the easiest-to-locate resources are found, the effort needed to produce a success would increase over time. Such depletion effects must be accounted for in forecasting discovery rates. Similarly, the location of the wildcat attempt can influence the effort-success relationship because, in some regions, producible resources are located at relatively shallow depths. The basic form of the relation can be outlined as:

Probability of a Geothermal Wildcat Well Being Successful = F [Level of Effort, Depletion, Location, other variables]

The 110 wildcat wells were drilled at 57 distinct resource areas. In some locations, as many as seven dry wildcat wells were drilled. Rather than define success or failure for each wildcat attempt, we have instead defined success or failure for a given Known Geothermal Resource Area (KGRA). This is an important distinction, made to reflect the nature of the geothermal exploration process, in which cumulative drilling experience dictates the course of future activity. Formulated in this manner, the well drilling database represents 57 overall trials, with 21 successes. The relationships to be established will relate exploratory effort per unit area, where the area is the identified acreage of the KGRA.

Another characteristic of high temperature geothermal resource which must be recognized is that they generally have been found at depths below 800 meters but usually not greater than about 2,500 meters. Unlike the oil and gas exploration process where cumulative depth reflects both effort and knowledge, the probability of success in geothermal exploration does not strictly monotonically increase as cumulative depth increases. What seems to be important is effort expended per KGRA, where the number of wells drilled in combination with the depth of the wells per unit area is the measure of exploratory effort.

2.6.2 Model Specification and Estimation

The measure of exploratory effort is defined to be the cumulative depth per wildcat well drilled per unit area. For each of the 57 areas where wildcat wells were drilled, the total footage drilled was cumulated and divided by the cumulative number of wells drilled, yielding the average depth per well. The exploratory effort variable, K, equals the average depth per area, where area is the surface extent of the KGRA.

The cumulative number of successes was used to measure depletion. Over time, as more resources are located, effort must increase to maintain a constant probability of success. The cumulative number of successes is a proxy for this shifting supply curve.

Location was captured by including shift variables for drilling activity in Southern California and Nevada. These areas seem to require significantly less effort, on average, to produce a success. Other effects examined were the impact of the company type on the probability of success. Companies were categorized by the extent of geothermal exploratory effort and the overall success of their geothermal program. Such effects, however, did not prove to be significant.

The general form of the discovery function is:

$$P = f\,[K, K^2, S_{-1}, ND, SCD] \qquad (2)$$

where

P = the probability of a wildcat well being successful
K = exploratory effort, cumulative depth per well per area
K^2 = second order term for exploratory effort
S_{-1} = cumulative successes to date
ND = 1, for wells drilled in Nevada
= 0, elsewhere
SCD = 1, for wells drilled in Southern California
= 0, elsewhere

Because the dependent variable in the relationship is binary, and the independent variables are continuous, a probit model[9] specification was used. This allowed the dependent binary variable to be transformed into a continous variable through the use of the cumulative normal function. The standardized cumulative normal function is written:

[9]See Pindyck and Rubinfeld, 1981.

$$P_i = F(Z_i) = \frac{1}{\sqrt{2\pi}} \int_{-\infty}^{Z_i} e^{-s^2/2}\, ds \tag{3}$$

where

$$Z_i = f\ (\text{Level of Effort},\ldots\text{etc.}) = a_0 + b_1X_1 + b_2X_2 + \ldots + b_nX_n \tag{4}$$

or equivalently[10]:

$$Z_i = F^{-1}(P_i) = a + b_1\ (\text{Level of Effort}) + b_2\ (\text{Cum. Successes}_{-1}) + b_3\ (\text{Location}) \tag{5}$$

In estimating equation (5), all terms were normalized. The parameters were initially estimated using maximum likelhood, and then reestimated using ordinary least squares. The results in both cases were very similar. The results reported below are for the OLS estimates.

$$\text{Probability of Success} = -\ 0.16 - 2.35\ \ln[K] - 1.66\ \ln[K^2] - 0.65\ \ln[S_{-1}] + 1.03\ \text{SCD} + 0.96\ \text{NVD} \tag{6}$$

A second order term for drilling effort $\ln(K^2)$ was included to capture non-linearity between effort and success. As discussed above, success is not a simple monotonic function of depth. An analysis of the drilling records suggests that wells drilled below a certain "threshold" are not more likely to produce a success.

The drilling effort term shows that as levels of drilling effort increase, the probability of success increases, but there is a point at which additional effort no longer improves the likelihood of success. The proxy for depletion (cumulative successes) enters with the correct sign. Likewise the geographic shift variables enter as significant. If we set the level of acceptance for Z, (i.e., Z*), to be -0.5 or greater, the relationship correctly predicts 80 percent of the observed wildcat efforts.

The discovery model used the above relationship to establish threshold levels of effort which must be expended before a discovery can be expected. Before a discovery can be anticipated, the level of effort must be great enough such that the following inequality holds:

$$Z^*_i \leq .16 - 2.35\ \ln(K) + 1.66\ \ln(K^2) - .65\ \ln(S_{-1}) + 1.03\ \text{SCD} + .96\ \text{NVD}. \tag{7}$$

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[10]See Theil, 1971.

Once this threshold level of effort is reached in a region, a discovery is forecasted and drilling effort is directed at the next available resource. It is noted that sequential discovery attempts require additional effort to offset the impact of the depletion term (S_{-1}).

2.7 RESOURCE QUALITY MODEL

Previous sections of this chapter have described the primary depletion effect of cumulative resource discovery on future exploration success. As more resources are discovered and withdrawn from the undiscovered hydrothermal resource base, increasing effort must be devoted to find additional reservoirs. A second, more subtle type of depletion effect is evident, however. Not only are reservoirs more difficult to find with each succeeding discovery, but the average quality of newly found discoveries tends to decline.

The rate of decline of average resource quality will depend on two basic factors which change over time:

(1) the relative distribution of quality among reservoirs in the undiscovered resource base; and,

(2) the likelihood that "better" rather than "poorer" quality reservoirs will be found at every discovery attempt.

In Section 2.7.1, we discuss how the undiscovered hydrothermal resource base can be characterized by a limited number of prototypical "generic resources," and present expert judgments, based on the most current evidence, of the frequency with which these resources are estimated to occur. These generic resources, together with their associated relative frequencies of occurrence, constitute a snapshot description of the quality of the undiscovered resource base at any time. In section 2.7.2, we develop theoretical methods for simulating changes in this resource quality derived from data on historic depletion patterns.

2.7.1 Characterizing the Undiscovered Hydrothermal Resource Base

Estimation of the size and character of the undiscovered hydrothermal resource base presents unusually difficult problems because of the heterogeneity of the resource, and the relatively early state of its development history. One of the first systematic estimates of U.S. geothermal potential appeared in USGS Circular 726 (1976), later updated in 1978 (USGS Circular 790). In Circular 790, a site specific analysis of the known hydrothermal resource base was used by the Geological Survey to estimate the temperature and energy distribution of the undiscovered portion of the resource. This information has provided the basis for many geothermal development projections conducted to date. In response to requirements of the present and several related studies (USDOE, 1980 and 1981), however, the Earth Science Lab of the University of Utah Research Institute (UURI), later assisted by Cascadia Exploration Corp. and Geotherm-Ex, Inc. under subcontract to Technecon, developed an updated and considerably refined characterization of the undiscovered hydrothermal resource base.

Their estimates were developed in two basic stages. A limited set of "generic" resource types first was constructed, each of which describes a class of reservoirs having similar physical characteristics. Collectively, the set of generic types are designed to describe any geothermal reservoir in the undiscovered resource base. Characterization of the undiscovered resource base then is completed by estimating the frequency of occurrence of each generic resource type. The construction of this undiscovered resource base estimate is described below.

Generic Resource Code. Although there are perhaps hundreds of geologic, chemical, or physical measures of the "quality" of geothermal reservoirs, a much smaller number may be sufficient to assess a reservoir's economic potential for development. The starting point for identification of these economically important reservoir traits is an analysis of the known resource base. Descriptions of known hydrothermal systems were compiled from sources such as USGS Circular 790, the USGS GEOTHERM Data file, and through informal discussions with personnel from geothermal exploration companies active in the western United States. Additional data were obtained from USGS open file reports on particular geothermal systems, conversations with the USGS staff in Menlo Park, and the personal experience and files of staff from UURI, Cascadia Exploration, and Geotherm-Ex. Table 2-3 lists the resource characteristics that were considered in this preliminary review. The relative economic importance of many of these characteristics then was evaluated in cash flow simulations of a number of prototypical geothermal developments. From these cash flow and investment decision analysis simulations, six reservoir characteristics (listed in Table 2-3) were found to be key determinants of the economic viability of geothermal development. These resource characteristics affect development cash flows either directly through capital and operating cost requirements, or indirectly by limiting the rate of extraction or the total amount of energy producible from a given reservoir. Other resource characteristics (e.g., well life) are simulated as functions of these six key characteristics.

Data from known geothermal reservoirs and the results of the sensitivity analyses were used to select appropriate ranges for these characteristics, and interval-classes within each range. Table 2-4 displays the six generic resource characteristics, along with the range values selected for each characteristic. A geothermal reservoir can be described within this classification system by translating its observed or estimated mean temperature, unpumped flow rate, etc., into a range number for each characteristic to produce a 6-digit "generic code".

Consulting geologists and reservoir engineers developed a family of 30 generic resources which can be expected to adequately describe reservoirs in the population of undiscovered resources. This listing was based on the observed correlation between individual resource characterics embodied in the generic code. Under the assumption that data from known hydrothermal systems are descriptive of the entire population of known and undiscovered resources, the quality of the resources yet to be discovered can be characterized by the relative frequency of occurrence of each of the 30 generic codes (see Table 2-5).

To estimate frequencies of occurrence of each generic resource type, the temperature frequency profile for reservoirs identified in USGS Circular 790 was assumed to be similar to that of the entire population of hydrothermal reservoirs. Given the national temperature profile estimate, reservoirs were allocated by temperature class to each of the 20 DOE geothermal regions. Regional temperature frequency estimates are presented

Table 2-3
SELECTED RESOURCE CHARACTERISTICS

<u>Physical Characteristics</u>

* * Temperature
* * Salinity
* Fluid Phase
* Reservoir Lithology
* Type of Porosity
* Permeability/Transmissivity
* * Areal Extent and Geometry
* Depth
* Surface Manifestations
* Geologic Setting

<u>Exploration Characteristics</u>

* Exploration Costs
* Topography
* Number of Wells Drilled

<u>Development and Production Characteristics</u>

* * Well Free Flow Rate
* * Well Pumped Flow Rate
* * Well Costs
* Well Spacing
* Well Life
* Reservoir Decline Characteristics
* Reservoir Production Capacity
* Reservior Life
* Injection Well Costs
* Injection Well Fraction
* Injection Well Pumping Costs
* Redrilling (Workover) Costs
* Redrilling (Workover) Fraction
* Dry Well Costs
* Dry Well Fraction
* Spare Well Fraction
* Current Development Status

*Key independent resource-related characteristics used for generic coding in this analysis. Other characteristics modeled as either non-site-specific or as a function of these key characteristics.

Table 2-4
VARIABLE GENERIC RESOURCE CHARACTERISTICS AND THEIR RANGES

PARAMETER	RANGES[a]							
Range No.	1	2	3	4	5	6	7	8
Temperature (^{o}F)	=>100 <150	=>150 <200	=>200 <250	=>250 <300	=>300 <350	=>350 <400	=>400 <450	=>450
Unpumped Flow Rate (10^3 lbs/hr)	<50	=>50 <100	=>100 <200	=>200 <400	=>400 <600	=>600 <800	=>800	
Brine Contamination Index (TDS)	0 (<2,000)	1 (2,000-100,000)	2 (>100,000)					
Well Costs ($M)	>2	>2 =>1	<1 =>0.5	<0.5 =>0.3	<0.3 =>0.1	<0.1		
Pumped Flow Rate (10^3 lbs/hr)	<50	=>50 <100	=>100 <200	=>200 <400	=>400 <600	=>600 <800	=>800	
Produc. Acreage[b]	5,000 10,000	5,000 7,000	3,000 7,000	1,000 7,000	650 5,000	2,000 5,000	650 3,000	650 1,500

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

[b]The top figure is the producible acreage at a 99% confidence level, and the bottom figure is the producible acreage at a 50% confidence level.

Table 2-5
GENERIC HYDROTHERMAL RESOURCES >300°F

Resource No.	Temperature	Unpumped Well Flow	Salinity Index	Well Cost	Pumped Well Flow	Producible Acreage
1.	5	1	2	2	3	3
2.	5	1	2	3	3	8
3.	5	2	1	4	3	8
4.	5	3	2	3	4	7
5.	5	3	1	4	4	8
6.	5	4	1	3	5	7
7.	5	4	2	2	5	7
8.	5	4	2	3	5	3
9.	5	4	2	4	5	8
10.	6	2	2	3	4	7
11.	6	3	2	2	5	3
12.	6	3	2	3	5	4
13.	6	4	2	2	5	4
14.	6	4	2	3	5	3
15.	6	4	2	3	5	4
16.	6	5	2	2	6	4
17	7	2	2	2	3	7
18.	7	3	2	2	5	7
19.	7	4	2	2	5	7
20.	7	5	1	3	6	5
21.	7	5	2	2	6	5
22.	7	5	2	3	6	5
23.	7	6	2	2	7	4
24.	8	3	2	2	4	6
25.	8	4	2	2	6	7
26.	8	4	2	2	6	3
27.	8	5	2	1	6	3
28.	8	5	3	2	6	3
29.	8	6	2	2	6	7
30.	8	6	2	3	6	7

Note: See Table 2-4 for translations of generic code entries in these columns.

in Table 2-6. A map of these regions is presented in Figure 2-4. Fully 75% of higher temperature, undiscovered reservoirs are thought to lie in the western states of California, Oregon, Washington, Nevada, Utah, and New Mexico.

Upon estimating temperature class frequencies that were consistent with available data, both interregionally and nationally, resources were allocated according to the remaining five digits of the generic code. The resulting frequency profiles of the range numbers of each remaining resource characteristic were then cross-checked against available data on known hydrothermal systems, and adjusted where necessary to achieve consistency. The relative frequencies of each resource characteristic range number, for the aggregate national undiscovered hydrothermal resource base estimate, are summarized in Table 2-7.

2.7.2 Resource Quality Model

The Well Drilling and Discovery Models in tandem provide estimates of high temperature discoveries per unit time. Discovery rates by themselves, however, are an incomplete measure of the resources available for development. In order to determine the economic potential of these discoveries, we must be able to characterize their expected quality, and any changes in this expected quality with each succeeding discovery.

Following Barouch and Kaufman's analysis of oil supply (1976) and subsequent elaborations by Smith and Ward (1980), we view the discovery process as a sampling experiment in which a population of reservoirs is sequentially sampled without replacement, according to a probability law that reflects the industry's search for high rather than medium or low temperature resources. Specifically, we assume that the probability of discovery of a reservoir of mean temperature T, is proportional to a power of T that is to be estimated from historical data. The dependence of the probability of discovery on temperature reflects the dominant emphasis on thermally-based methods[11] seen in U.S. geothermal exploration. That thermal technologies rank universally highest in frequency of use is shown in Mitre (1978b), McEuen et al. (1979), and Ward et al.'s (1979) review of information generated through the DOE-sponsored Industry Coupled Program.

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[11]Thermally based methods include shallow and deep thermal gradient surveys, chemical geothermometry and aqueous geochemistry, etc.

Table 2-6
REGIONAL TEMPERATURE CLASS FREQUENCIES
(Number of Resources)

		100 - 150	- 200	- 250	- 300	- 350	- 400	- 450	(°F)
Region	Total	1	2	3	4	5	6	7	8 (Temp.Class)
1. N. CA	119	49	29	17	10	6	4	2	2
2. S. CA	104	41	24	14	8	5	4	4	4
3. OR/WA	171	71	42	25	15	9	5	3	1
4. NV	236	99	58	34	20	12	6	5	2
5. UT	109	49	29	14	8	5	2	2	
6. AZ	90	41	24	13	7	3	2		
7. ID/MT/WY	135	58	34	20	12	7	4		
8. CO	59	29	17	6	4	2	1		
9. NM	115	49	29	17	10	6	3	1	
10. TX*	-	x	x	2	1	1			
11. - 18.	-	x	x						
19. AK	52	24	14	4	3	3	2	1	1
20. HI	50	24	14	4	3	2	1	1	1
Totals by Temp. (excludes Regs.10-18)		534	314	168	100	60	34	19	11

* x = extended reservoirs

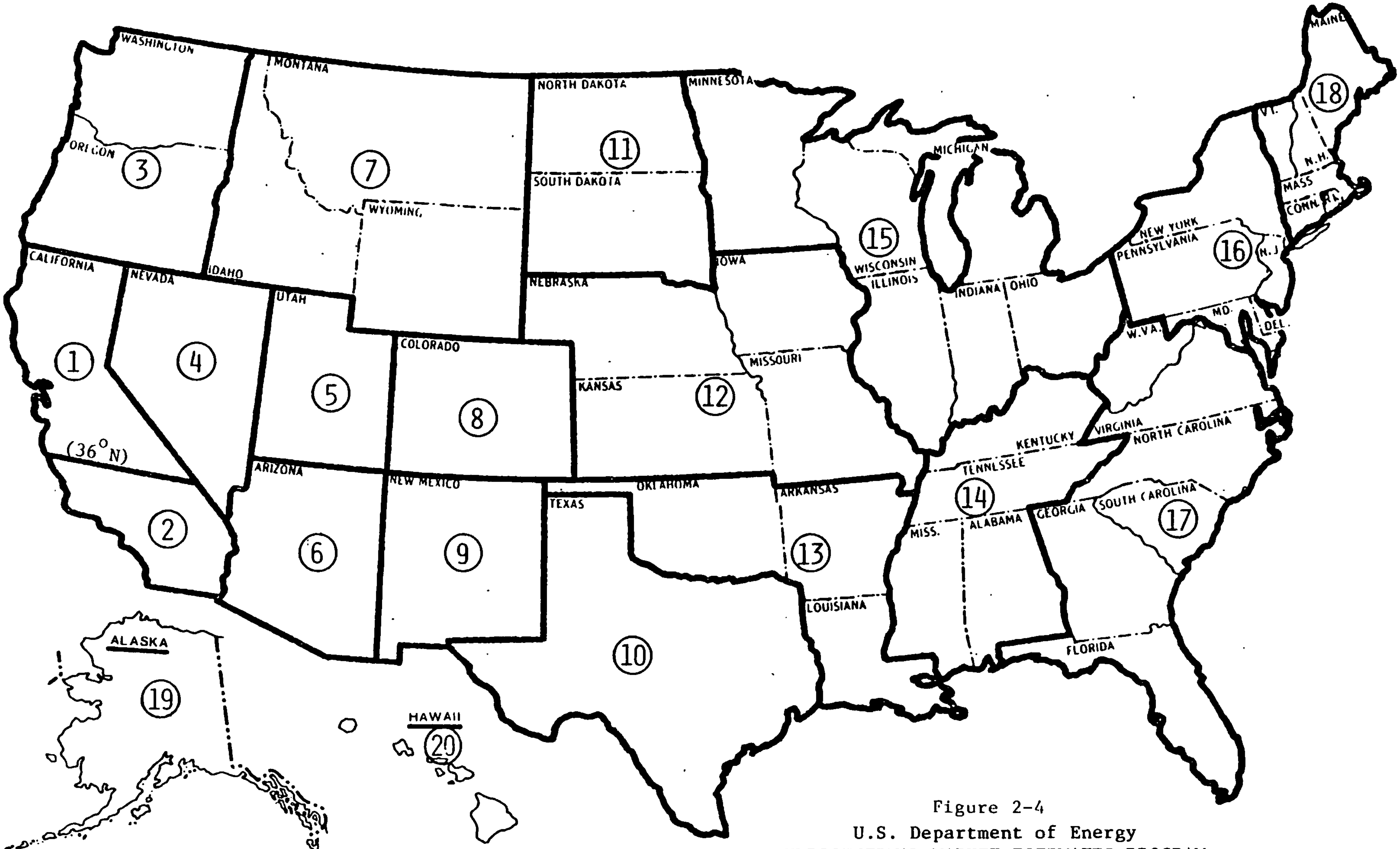

Figure 2-4

U.S. Department of Energy

HYDROTHERMAL MARKET ESTIMATES PROGRAM

Map of Regional Boundaries

Table 2-7
ESTIMATED RELATIVE FREQUENCIES (%) OF RESOURCE CHARACTERISTICS FOR THE NATIONAL, UNDISCOVERED HYDROTHERMAL RESOURCE BASE >300°F

Resource Characteristic	GENERIC CODE NO.[1]							
	1	2	3	4	5	6	7	8
Temperature	*	*	*	*	48%	27%	15%	9%
Unpumped Flow	6%	12%	15%	51%	11%	4%	0	*
Brine Contamination	8%	91%	1%	*	*	*	*	*
Well Cost	2%	43%	48%	7%	0	0	*	*
Pumped Flow	0	0	10%	19%	53%	16%	2%	*
Producible Acreage[2]	0	0	18%	19%	6%	1%	46%	11%

[1] Refer to Table 2-4 for Generic Code Translation

[2] Note Discontinuous Classes of Table 2-4

* Undefined Range No.

Using such an analytic framework, and given an initial estimate of the temperature distribution of the undiscovered resource base, we can derive a sequence of probability distributions that describes the likelihood of discovering a reservoir of temperature T_k at the i^{th} future discovery:

$$P_i\ (T_k | N_o, M_i, a) = \frac{(n_k - m_{ik})\ T_k{}^a}{\sum_{j=1}^{J} (n_j - m_{jk})\ T_j{}^a} \tag{8}$$

where: $P_i\ (T_k|\ \ )$ = conditional probability of discovering a reservoir of temperature class T_k at the i^{th} discovery

$N_o = (n_1,\ldots,n_j)$ = initial discrete temperature distribution of the undiscovered resource base

$M_i = (m_{i1},\ldots,m_{ij})$ = cumulative discoveries prior to i for each temperature class $(1,\ldots,J)$.

a = discoverability parameter governing the bias in exploration toward high temperature resources.

Equation [8] denotes the probability of discovering a reservoir of temperature T_k at the i^{th} discovery given: N_o, the initial temperature distribution of the undiscovered reservoir population; M_i, the sequence of discoveries made prior to the i^{th}; and (a), the "discoverability" parameter. In this manner, our description of changes in reservoir quality depend on estimates of the initial temperature characteristics of the reservoir population, subsequent depletion, and the degree to which temperature provides clues in aiding discovery.

Estimating the Discoverability Parameter. To estimate the discoverability parameter, (a), we let $D_q = (d_1, d_2,\ldots,d_q)$ be a sequence of q discoveries, where the temperature of discovery $d_i = T(d_i)$. The likelihood of occurrence of such a sequence is the product of the probabilities of each discovery, d_i, conditioned on the discovery of the i-1 reservoirs found prior to the i_{th}. That is,

$$L(Dq) = \prod_{i=1}^{q} P_i[T(d_i);\ N_o;\ a;\ T(d_1),\ T(d_2),\ldots,\ T(d_{i-1})] \tag{9}$$

where: $L(D_q)$ = likelihood of discovery sequence D_q

P_i = probability of discovering a reservoir of temperature $T(d_i)$ given the temperatures of the (i-1) preceding

Equation [9]'s importance is evident upon noting that with an observed sequence of historical discoveries (i.e., a known D_q), as well as an estimate of the initial temperature distribution, N_o, only (a), the discoverability parameter remains as a free variable. Thus, with this information, the discoverability parameter can be estimated using maximum likelihood techniques. [12]

As we described in Section 2.4, the LBL GRAD well file was examined to find records of producible wells in discrete areas, and to develop the sequence of historical discoveries presented in Table 2-8. This discovery sequence, as well as estimates of initial temperature frequencies, were disaggregated regionally, and used to determine separate discoverability parameters for Southern California, Nevada, and "all other" regions. As shown in Figure 2-5, the the discoverability parameter was chosen to maximize the likelihood of occurrence of each region's historical discovery sequence, using Equation [8].

While the discoverability parameter, as described below, can be used to forecast the expected quality of future discoveries, it is an important measure in its own right of the technological effectiveness of geothermal exploration methods. A value of a = 0 indicates a probability of discovery proportional to the underlying temperature frequency of the undiscovered resource base, i.e., a random search not guided by temperature considerations. In this case, explorationists would be expected to find low to moderate temperature reservoirs much more frequently than high temperature reservoirs simply because of their greater numbers. With other factors held constant, however, positive values of (a) indicate an increased propensity to discover higher rather than lower temperature reservoirs.

The observed extent of this bias in discovering higher rather than lower temperature reservoirs is indicated in Figures 2-6 through 2-8 for Southern California, Nevada, and Other Regions, respectively. The heavy line in each figure displays our estimate of the temperature distribution

[12]Maximum likelihood techniques, as their name suggests, rely on the maximization of a likelihood function to identify the "best" estimate of a distribution parameter; see Theil (1971).

Table 2-8

HISTORICAL GEOTHERMAL DISCOVERIES (1960-1980)

Discovery #	Year	Area Name	Region Name	Probability of Confirmation**
1	1960	Mono-Long Valley	N. CA	.25
2	1964	Salton Sea	S. CA	1.00
3	1964	Brady-Hazen	NV	.25
4	1964	Sulfur Bank	N. CA	.05
5	1968	Wilbur H.S.	N. CA*	.10
6	1970	Baca Loc #1	NM*	1.00
7	1972	East Mesa	S. CA	1.00
8	1972	Heber	S. CA	1.00
9	1973	Power Ranches	AZ*	.25
10	1974	Soda Lake	NV	.25
11	1975	Brawley	S. CA	1.00
12	1975	Beowawe	NV	.25
13	1975	Roosevelt H.S.	UT*	1.00
14	1976	Westmoreland	S. CA	1.00
15	1977	Coso	S. CA	1.00
16	1977	Clear Lake	N. CA	.25
17	1978	Humboldt House	NV	.25
18	1979	Dixie Valley	NV	.25
19	1979	Steamboat H.S.	NV	.50
20	1979	Redondo	NM*	.25
21	1980	S. Brawley	S. CA	.25

* Included in "ALL OTHER" Region

** Refer to discussion in Section 4.5

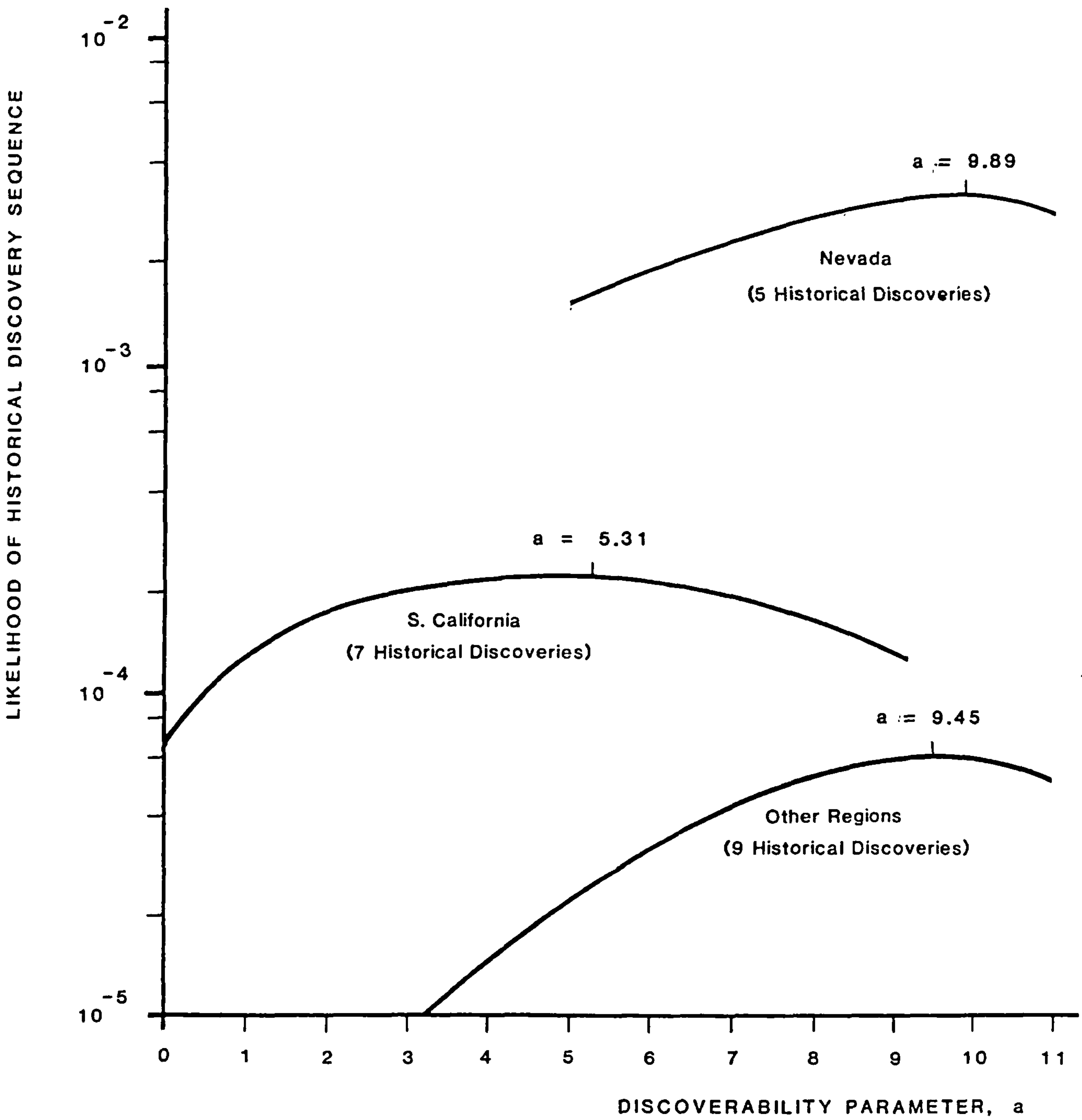

Figure 2-5
ESTIMATION OF DISCOVERABILITY PARAMETER, a,
BASED ON MAXIMIZATION OF LIKELIHOOD OF
HISTORICAL DISCOVERY SEQUENCE

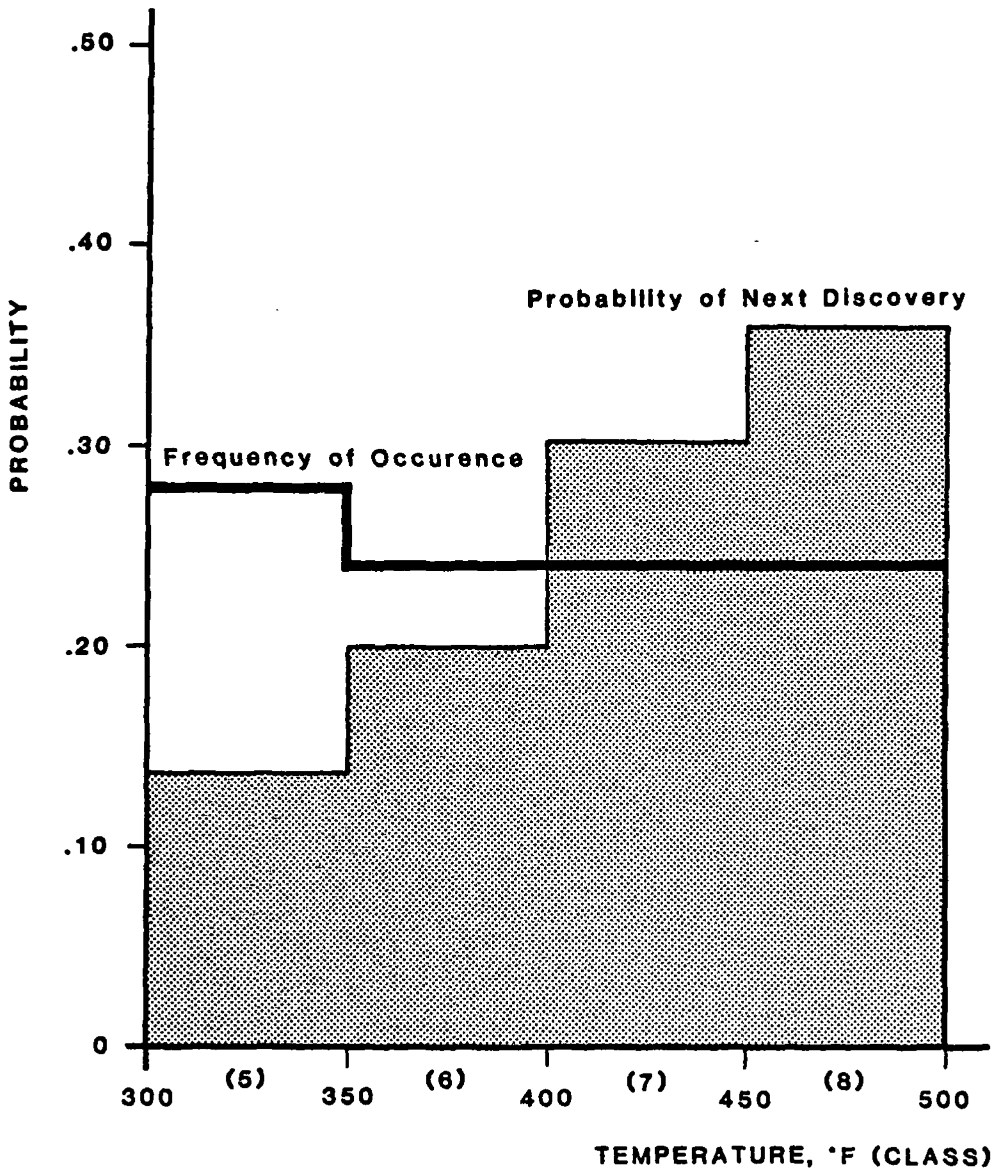

Figure 2-6
TEMPERATURE DISTRIBUTION AND
PROBABILITY OF NEXT DISCOVERY FOR S. CALIFORNIA

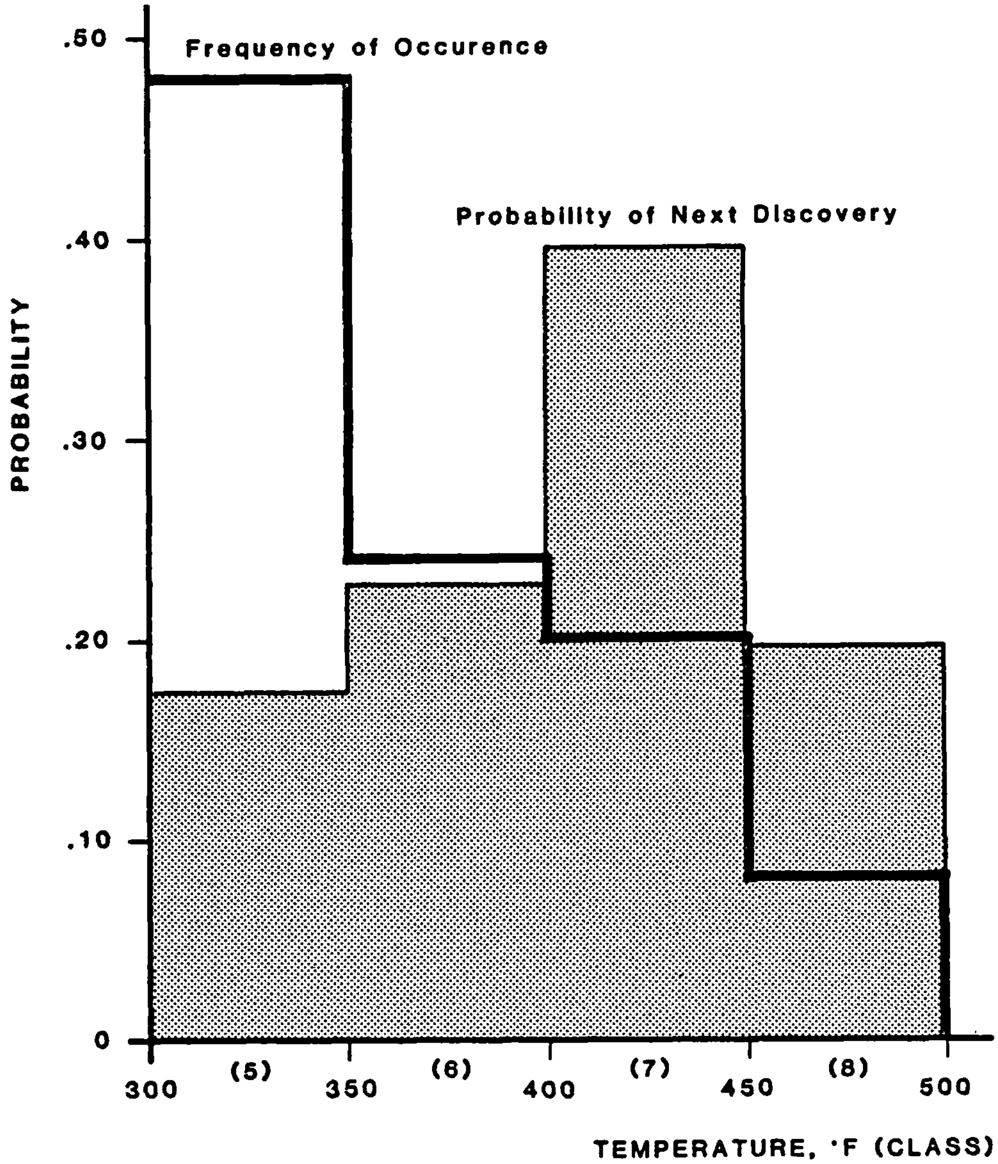

Figure 2-7
TEMPERATURE DISTRIBUTION AND
PROBABILITY OF NEXT DISCOVERY FOR NEVADA

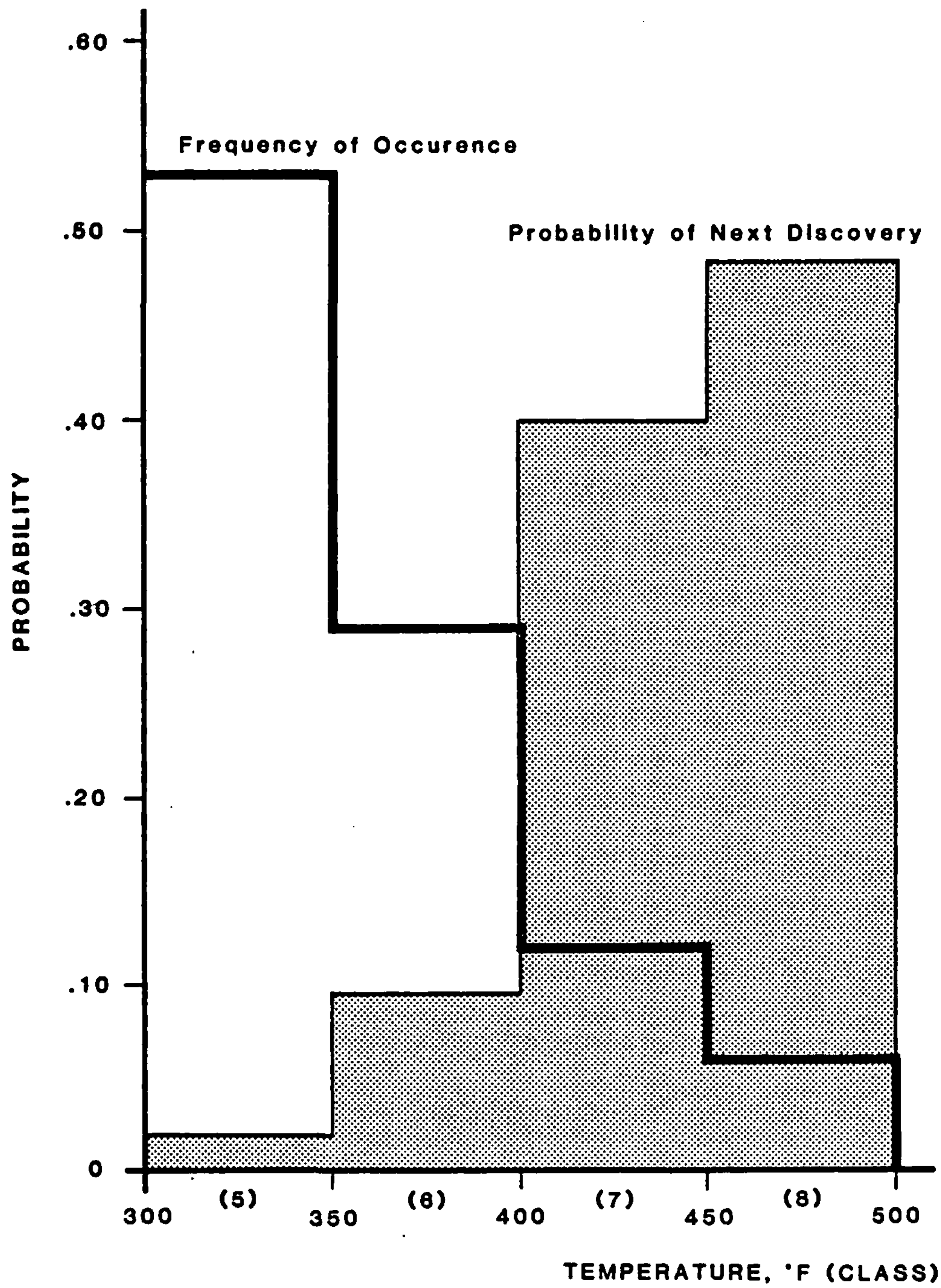

Figure 2-8
TEMPERATURE DISTRIBUTION AND
PROBABILITY OF NEXT DISCOVERY FOR OTHER REGIONS

of the undiscovered resource base in each region, and corresponds to the case of a = 0. The shaded region is the estimated probability distribution, for the first future discovery, that will be viewed by an exploration firm in each region. It is based on the region's observed historical discovery sequence and calculated using Equation (8). Discovery probabilities, here, are weighted heavily toward higher temperature resources. If we examine the expectations of these temperature distributions, we find, for instance in Southern California, that random search would discover a reservoir with an expected temperature of 375°F. Based on historical discovery experience, however, the expected temperature of Southern California's next discovery is estimated to be 418°F. Roughly speaking, exploration technology, experience, and other factors brought to bear by exploration firms will increase the expected temperatures of near-term discoveries over levels that would be likely on a random basis alone.

Simulating the Quality of Future Discoveries. With the estimation of statistically-derived discoverability parameters for each region, Equation [8] can be used as the basis of a Monte Carlo simulation[13] to forecast the expected temperatures of future discoveries. Repeated discovery sequences are generated and recorded to determine equilibrium discovery probability distributions as a function of discovery number. Initially, the discovery probability distributions for each region are very negatively skewed, as displayed previously by the shaded areas of Figures 2-6, 2-7 and 2-8. As the discovery sequence unfolds, however, fewer and fewer high temperature reservoirs are discovered because of previous resource depletion. Thus, the modes of the discovery probability distributions would be expected to shift increasingly leftward reflecting the discovery, over time, of lower quality resources. Historical and forecast regional expected temperatures of discovery are displayed in Figure 2-9. Figures 2-10 through 2-12 illustrate the behavior of the probability distributions as a function of increasing discovery number, for future discoveries in each of the three regions.

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[13]Monte-Carlo simulation is a method for estimating the behavior of a complex, random system by performing repeated statistical experiments; see, for instance, Hillier and Lieberman.

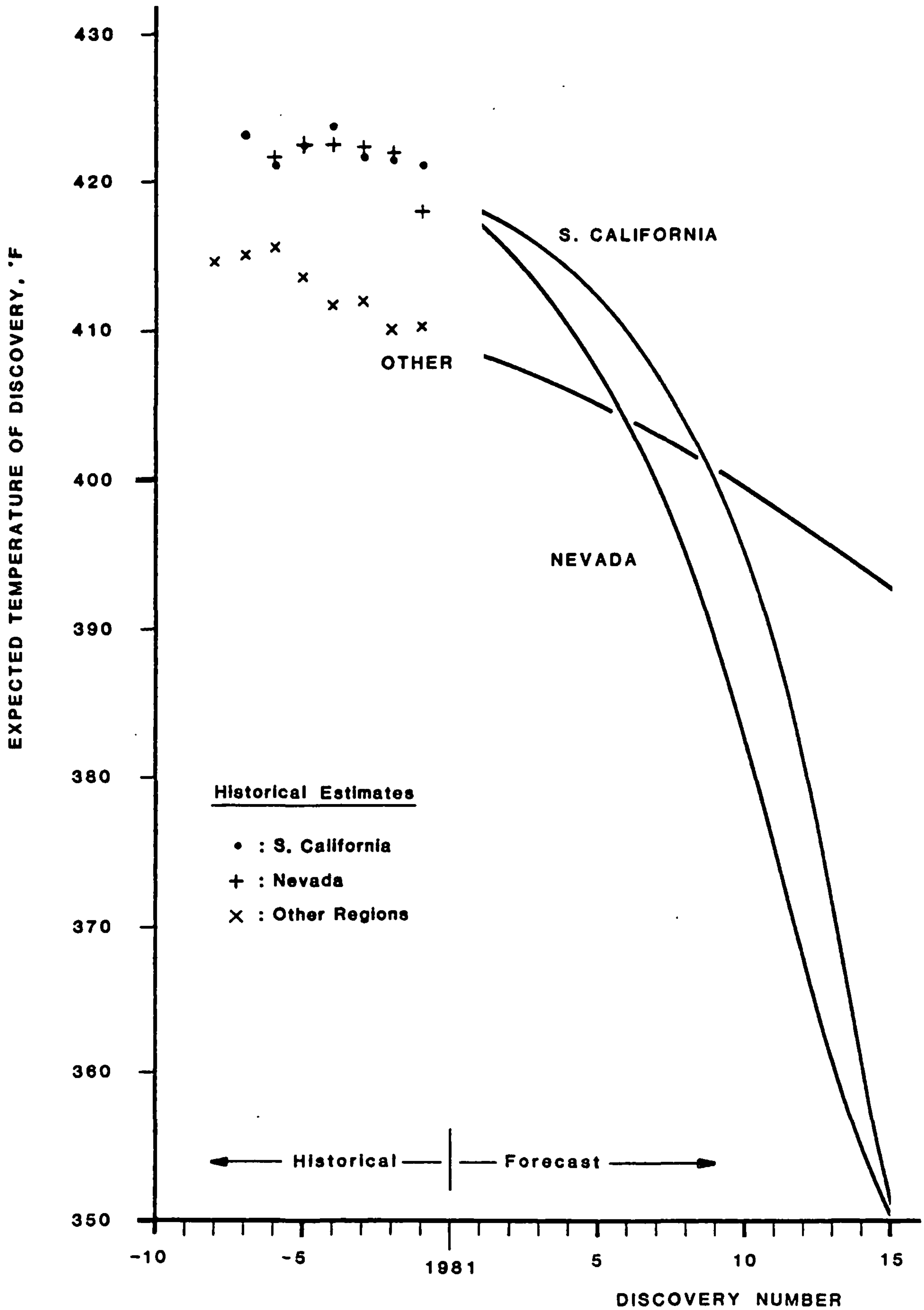


Figure 2-9
HISTORICAL AND FORECAST
REGIONAL EXPECTED TEMPERATURES OF DISCOVERY

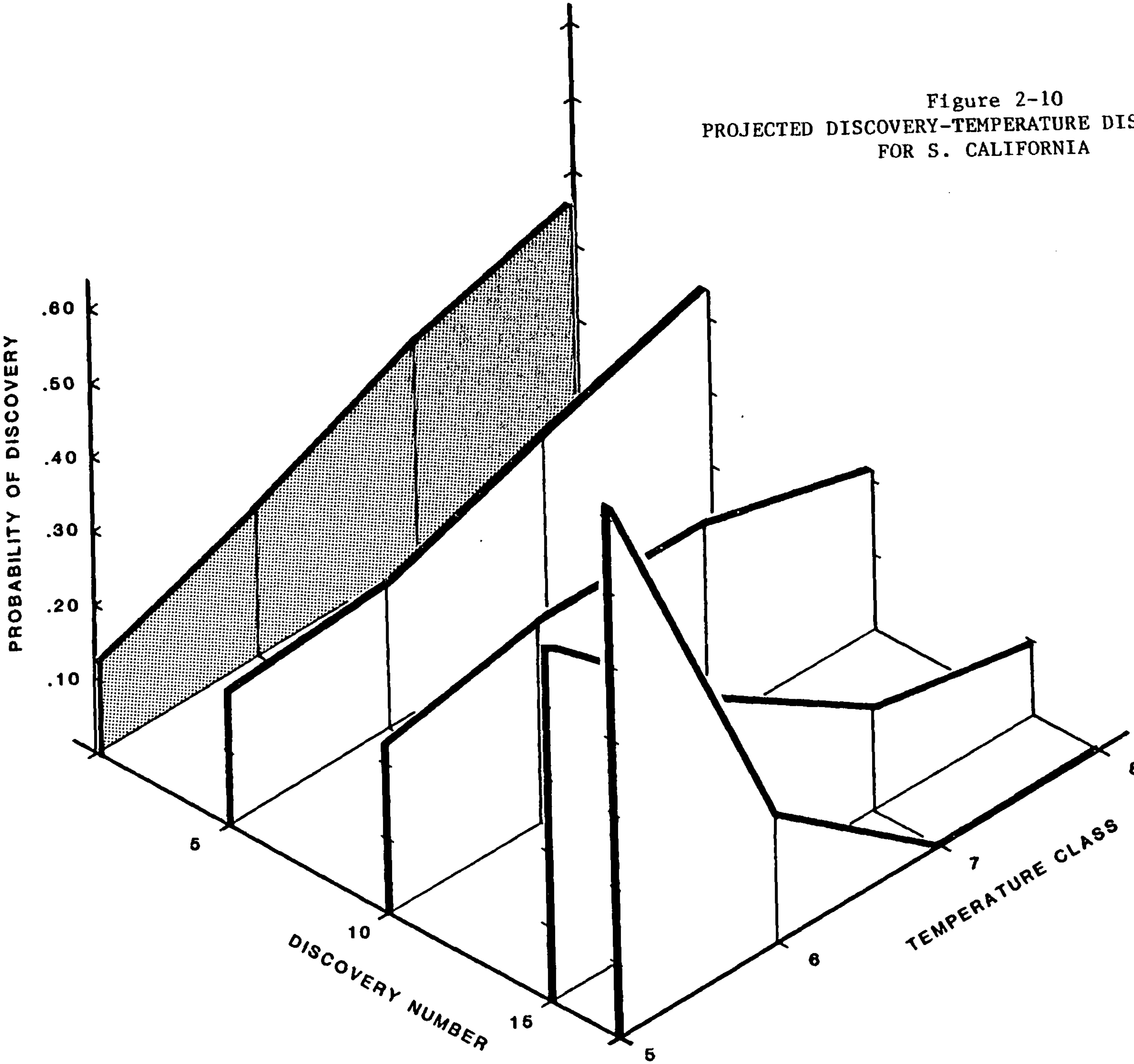
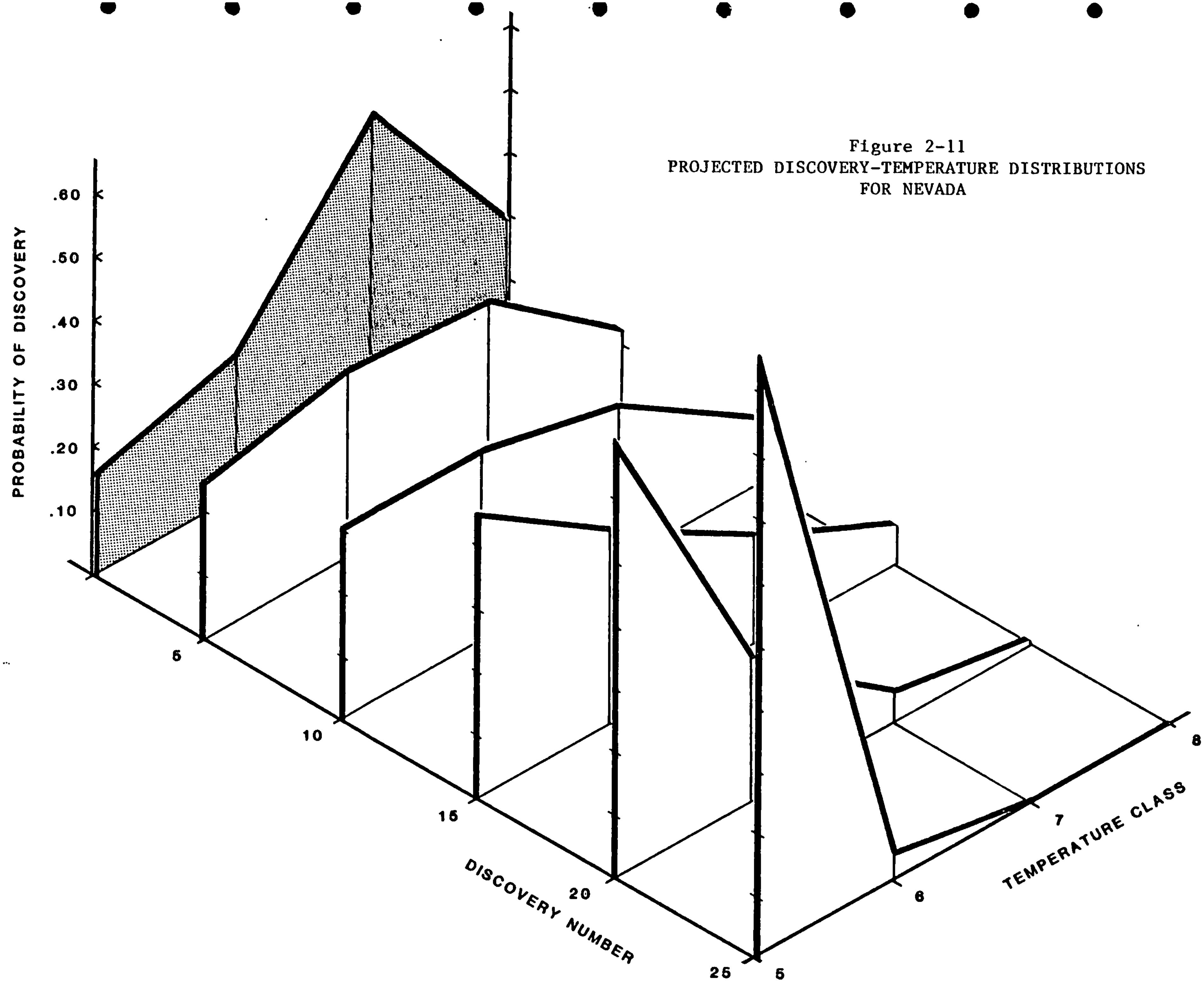


Figure 2-10
PROJECTED DISCOVERY-TEMPERATURE DISTRIBUTIONS
FOR S. CALIFORNIA

Figure 2-11
PROJECTED DISCOVERY-TEMPERATURE DISTRIBUTIONS
FOR NEVADA



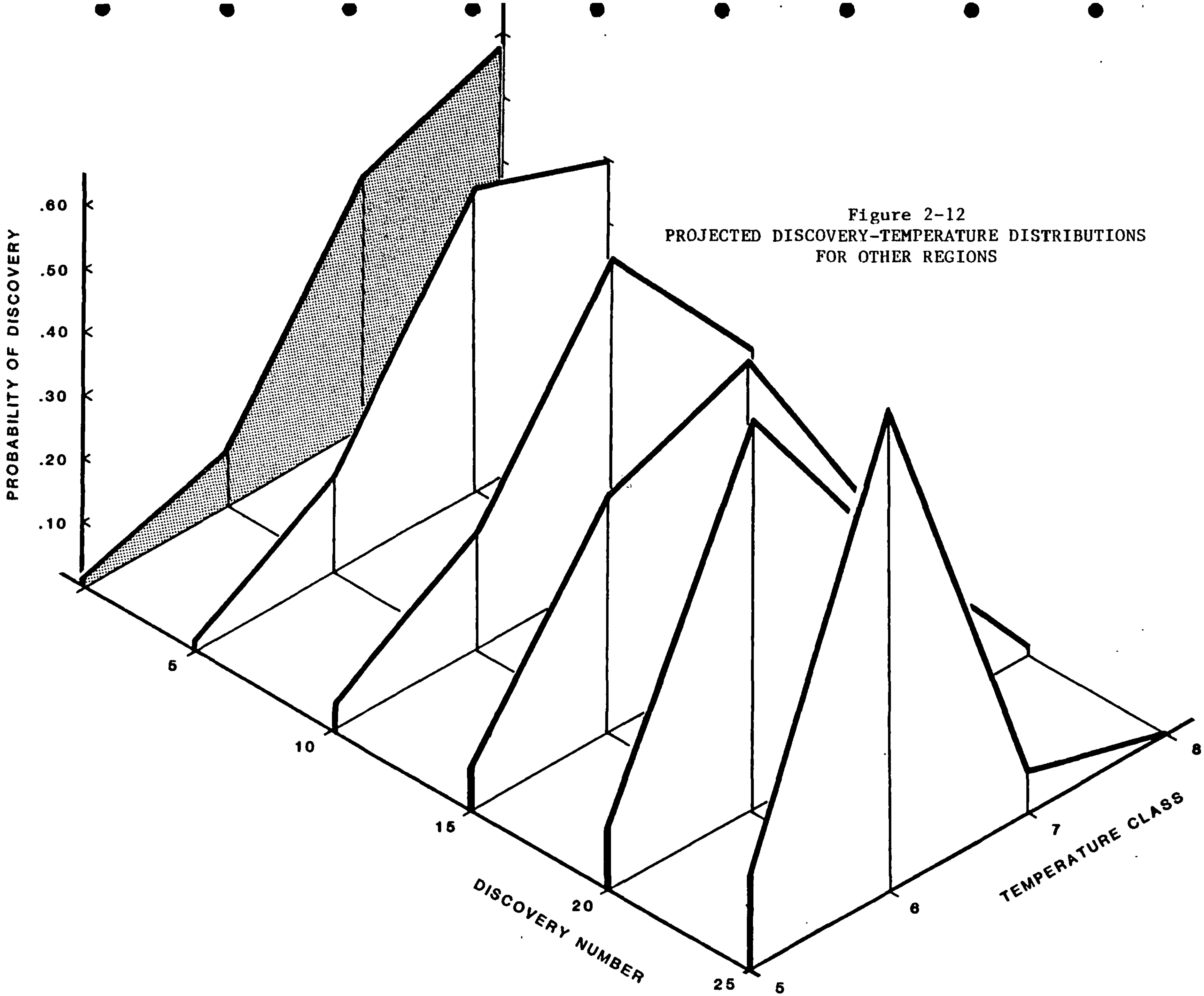


Figure 2-12
PROJECTED DISCOVERY-TEMPERATURE DISTRIBUTIONS
FOR OTHER REGIONS

2.8 SUMMARY

In this chapter, we have described the geothermal exploration process, examined the historic pattern of wildcat well drilling and reservoir discovery in the United States, and then developed theoretically-sound methods by which the outcome of the exploration and discovery process can be estimated for future time periods. Statistically-significant relations were identified between wildcat well drilling rates and the expected profitability of ventures in both the geothermal and petroleum industries. The number of high-temperature hydrothermal discoveries yielded by each increment of drilling effort was seen to decrease as a function of the cumulative exhaustion of the undiscovered resource base. Moreover, the historic trend, in which higher quality reservoirs have been discovered disproportionately-often compared to their occurrence in the undiscovered resource base, is expected to continue. Together, these findings permit an empirically-based projection of the number and quality of hydrothermal resources discovered in future time periods, based on estimates of the rate of return offered by hydrothermal resources developed in earlier periods. Chapter 3 describes the investment and decision analysis models by which this critical feedback loop between development rates of return, and subsequent exploration activity and resource discovery, can be established.

Chapter Three
HYDROTHERMAL CASH FLOW AND DECISION MODEL

Hydrothermal power development at each confirmed reservoir is dependent upon joint investment decisions to (a) develop the well field and (b) construct power plant and transmission facilities. Technecon's methodology considers multiple investment objectives of both (a) well field developers and (b) electric utilities as they relate to the respective investment decisions. This methodology is capable of estimating the likely investment behavior of major resource corporations, independent operators, third-party financiers, investor-owned utilities and tax-exempt municipal utilities.

In early 1978, under contract to the U.S. Department of Energy, Technecon conducted interviews with no fewer than seventy executives from firms active in the geothermal industry. During the course of this current study, a number of these interviews have been repeated to update pertinent data. These interviews have provided both qualitative and quantitative insights to the investment objectives and decision criteria of these firms. The decision models applied in the current project are based upon econometric analysis of data obtained directly from these firms over the past four years.

3.1 MODEL DESIGN

Figure 3-1 illustrates the structure of the hydrothermal electric power model. The following discussion of the model summarizes the sequence of computerized operations (progressing from left to right) illustrated in the schematic diagram.

The hydrothermal power forecasts are prepared on a site-by-site basis. Confirmed reservoir characteristics as derived jointly from the Exploration, Discovery, and Resource Models (recall Chapter Two) are provided to two detailed cash flow programs. One program simulates the life of a well field project while the other program simulates the life of a hydrothermal power plant. The economically optimal combination of pumped versus unpumped wells and binary versus flash plant design is selected for each site. Well field and power plant performance data from EG&G Idaho, Inc. are used in these computerized cash flow programs. A complete list of

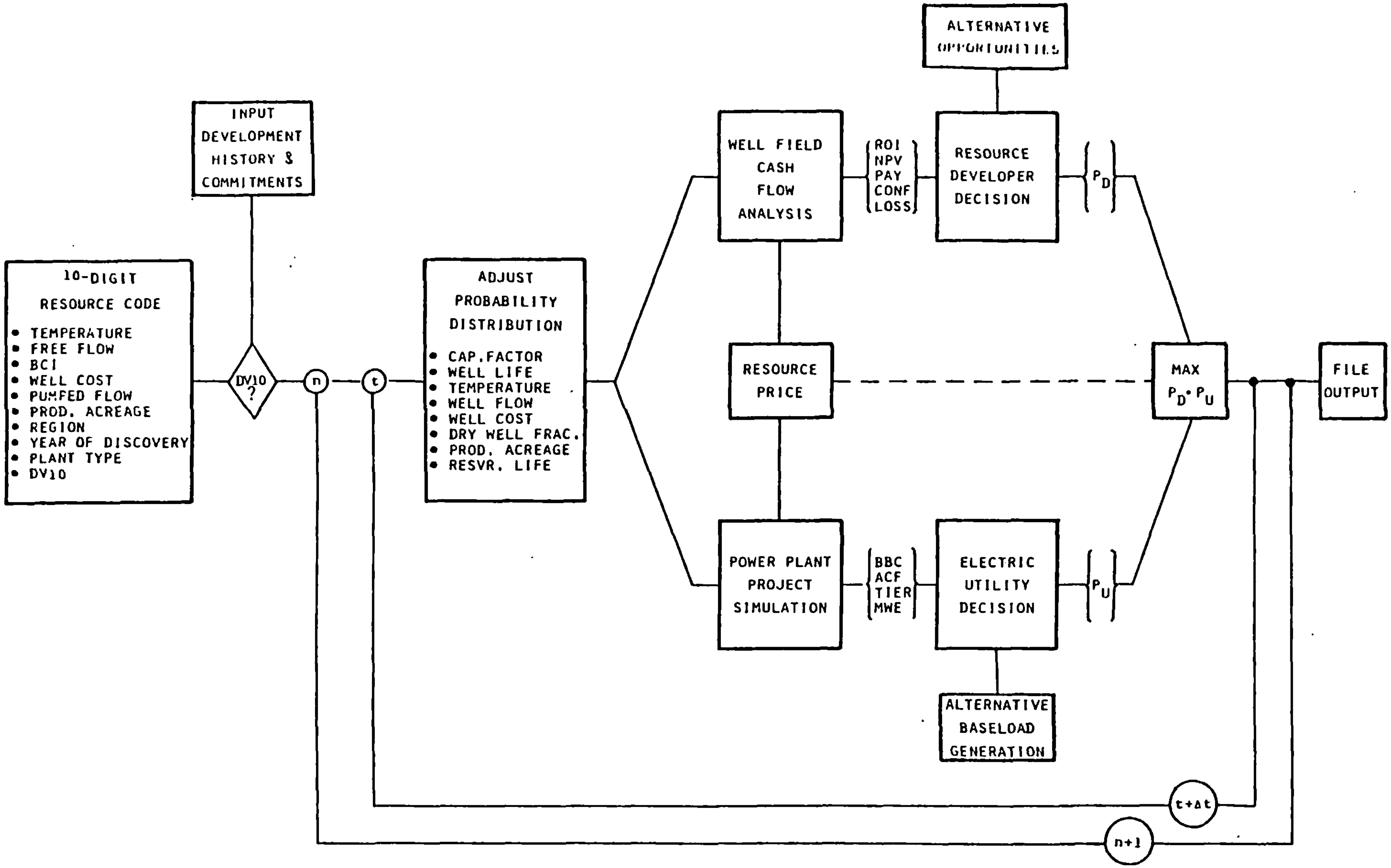


Figure 3-1
HYDROTHERMAL ELECTRIC POWER SIMULATION MODEL

input parameters of the cash flow analyses is provided in Chapter 4. A fully documented description of both the well field and power plant model may be found in Cassel et al., 1981.

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

The two decision models provide estimates of the numerical likelihood of investment in a specified hydrothermal opportunity by resource developers and by electric utilities, respectively. These models are statistically-strong in their ability to reproduce investment preferences as expressed by the respective firms in executive interviews and in demonstrated field practice. Statistical indicators of confidence include a high coefficient of determination (corrected for degrees of freedom) of 0.86 and an F-statistic at the 99% confidence level.

Resource selling price is the negotiable variable which couples the well field cash flow and the power plant cash flow. A high price improves investment returns to the resource developer and generally increases his likelihood of investment. Conversely, a low price lowers the production cost (mills/kWh) of hydrothermal electric energy and generally increases the electric utility's likelihood of investment. Technecon's computer-based simulation of resource price negotiation uses an iterative technique to converge on a price which maximizes the joint likelihood of investment ($P_D.P_U$ in Figure 3-1) by both parties.

3.2 MULTIATTRIBUTE DECISION ANALYSIS

In previous studies, Technecon has demonstrated the use of multiattribute utility decision analysis in the estimation of investment behavior. The methodology has been applied to both the resource producer and electric utility industry. As documented in prior reports, both decision models have been shown to accurately predicate the decision processes of industry participants in a computational and cost efficient manner. The discussion below presents an overview of the methodology followed by the results of Technecon's efforts to update pertinent decision parameters.

3.2.1 Decision Analysis Overview

Since 1978, Technecon analysts have interviewed management representatives from over forty firms active in the hydrothermal industry. Through the use of carefully structured interviews and questionnaires, the investment objectives of primary concern to the decision makers of the resource producer and electric utility industry were identified. Utility functions for key investment attributes were developed, based on econometric analysis of industry supplied data. Each utility function translates attribute values into numerical utilities. A minimum utility of zero implies "no investment incentive" and a maximum utility of one implies "highest positive incentive."

In evaluating hydrothermal investment opportunities, the multiple objectives of both the resource producer and electric utility must be considered. This is accomplished via estimation of a multiattribute utility function. A multiobjective preference function can be specified as a nested function of each conditional (and statistically-independent) univariate utility function:

$$U = f[U_X(x),\ U_Y(y),\ U_Z(z)] \tag{10}$$

Multiattribute utility functions for resource producers and electric utilities were estimated from industry supplied questionnaire responses. 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:

$$EU = \Sigma\, U_i\, \pi_i \tag{11}$$

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:

$$P(A \mid EU_A) = \frac{1}{1 + e^{-\alpha+\beta\, EU_A}} \tag{12}$$

which represents the probability of selecting opportunity A conditional upon the expected utility of A, EU_A. The α and β parameters of (12) were estimated separately for major corporate firms and independently operating firms by applying least squares regression techniques to the industry-supplied investment behavior data. [14]

3.2.2 <u>Decision Analysis Estimation</u>

During the course of this present study, Technecon analysts conducted a number of interviews with industry representatives to re-estimate pertinent decision parameters. As stressed in previous reports, several of the estimated parameters may be time-dependent -- reflecting the changing investment climate, inflation effects, or, in the case of the electric utility, changes in the economic characteristics of alternative capacity additions. The results of this reassessment are reported below.

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[14] t-statistics for the α and β parameters are at the 99 percent level of confidence.

Resource Producer's Decision Model. Since 1978, Technecon analysts interviewed management representatives from over twenty resource firms to determine their criteria for hydrothermal well field investments. Four investment objectives were found to be of primary concern to the firms' decision makers. These objectives are to:

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

The overall quality of a hydrothermal opportunity is assessed by the four investment attributes given in parentheses above, i.e., rate of return, payback time, present value of profits and capital at risk.

Table 3-1 presents the estimated univariate utility functions for each attribute described above, as well as the estimated multiattribute utility function. Univariate utility functions are displayed graphically in Figure 3-2.

Table 3-1
RESOURCE DEVELOPERS' DECISION ANALYSIS PARAMETERS

Univariate and Multiattribute Utility Equations:

Rate of Return: $U_R(r) = 1 - \exp\,[2.09 - 18.33r]$

Payback Period: $U_P(p) = 1 - [1 + \exp\,(.54p - 5.484]$

NPV of Gain: $U_V(g) = 1 - \exp\,[-.106\ g]$

NPV of Loss: $U_L(l) = 1 - \exp\,[\,.009\ l]$

Multiattribute Utility of a gain: $U = .419\ U_R(r) + .133\ U_V(v) + .448\ U_R(r)U_P(p)$

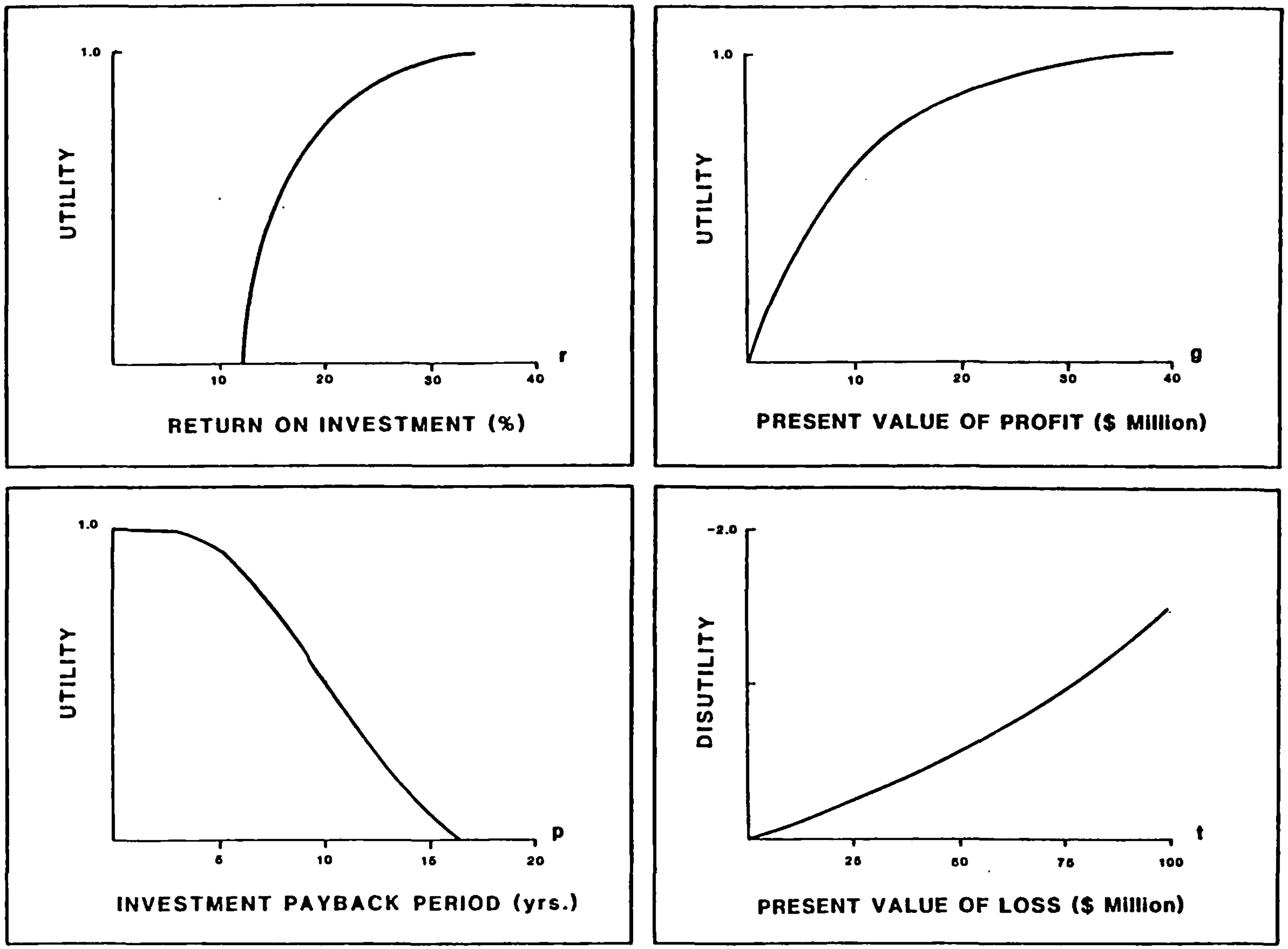

Figure 3-2
UNIVARIATE UTILITY FUNCTIONS: RESOURCE PRODUCERS

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

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

Univariate utility functions for busbar cost ratio, reservoir capacity, and impact on times interest earned ratio displayed no significant changes during Technecon's reassessment. The capacity factor utility function shifted slightly to the left, reflecting a slight deterioration in the capacity factor of alternative base load capacity. Table 3-2 presents estimated univariate, multiattribute, and logit equations used in the electric utility decision model. Univariate functions are illustrated in Figure 3-3.

Table 3-2
ELECTRIC UTILITY DECISION ANALYSIS PARAMETERS

Busbar Cost Ratio: $U_B(b) = 1 - \exp[5.85 - 7.137b]$

TIER Impact: $U_T(t) = \exp[.023 + 4.34t]$

Capacity Factor: $U_C(c) = 1 - (1 + \exp[11 - 16.1c])$

Reservoir Capacity: $U_R(r) = 1 - \exp[-1.433 - .0044r]$

Multiattribute Functions: $U = .3299\, U_B(b)U_T(t) + .466\, U_B(b)U_C(c) + .203U_B(b)$

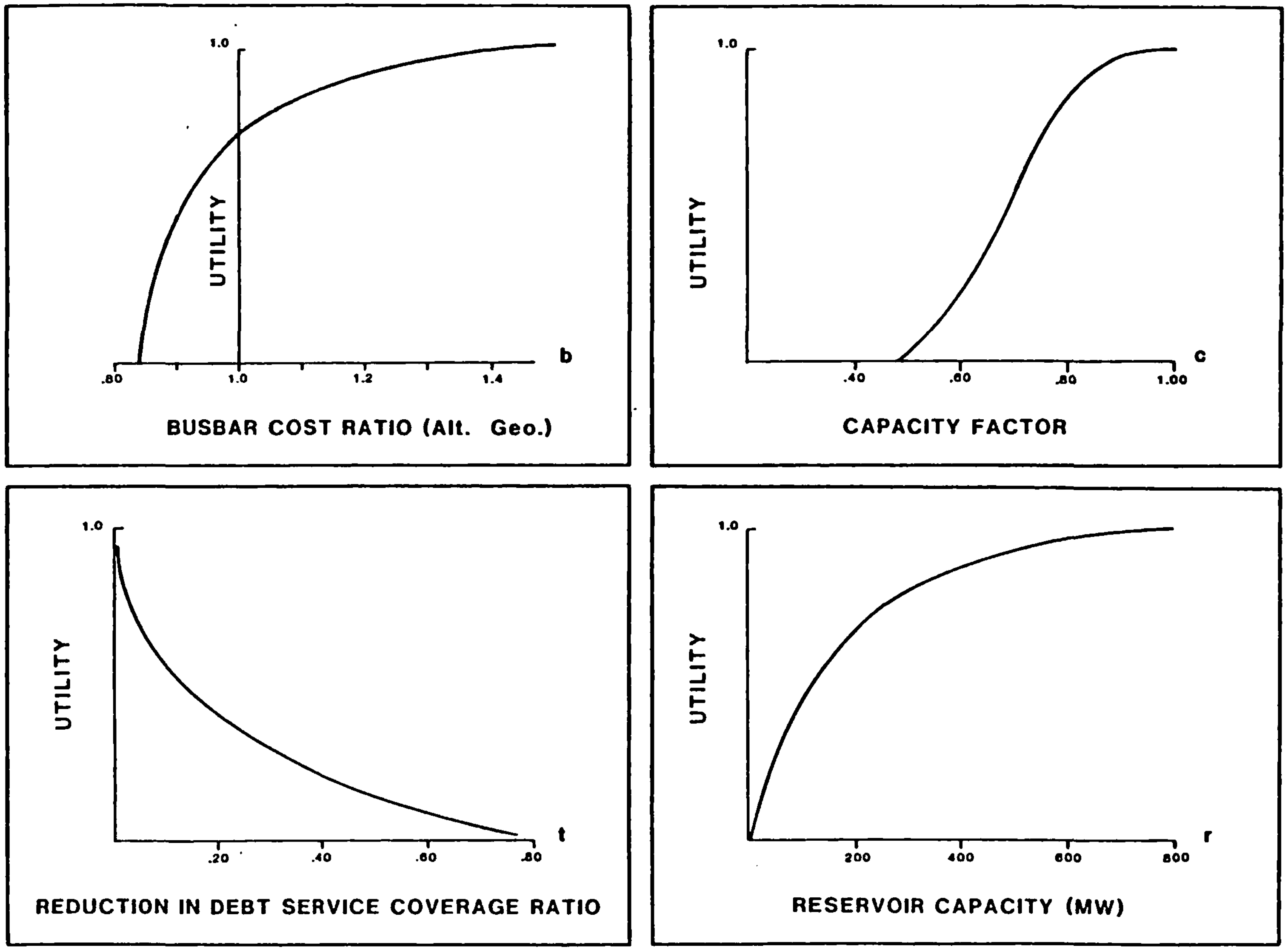

Figure 3-3
UNIVARIATE UTILITY FUNCTIONS: ELECTRIC UTILITIES

Chapter Four

NATIONAL GEOTHERMAL POWER FORECASTS AND SENSITIVITY ANALYSES

This chapter provides the results of a national hydrothermal electric power forecast based upon use of the models discussed earlier in this report. Technecon's hydrothermal exploration and development models were used to forecast hydrothermal electric power growth, for the period 1982-2000, under three scenarios. These scenarios are:

Current Technology and Incentives (Base Case): Assumes current state of geothermal technology with the introduction of a mature binary-type power plant in the mid-1990's. Tax incentives are assumed consistent with regulations in effect in early 1982.

Minimal Technological Advances (Case I): Assumes low-level of R&D effort resulting in minor performance and cost improvements during the mid- and late-1980's in geosciences, well drilling, well stimulation, piping materials and flash-type power plants. Also assumes mature binary-type power plants are available in the early-1990's. Tax incentives same as Base Case.

Significant Technological Advances and Enhanced Incentives (Case II): Assumes appreciable R&D success resulting in signifcant performance and cost improvements during the late 1980's in geosciences, well drilling, well stimulation, downhole pumps, piping materials and binary- and flash-type power plants. Also assumes a mature advanced binary-type power plant is introduced in the early-1990's for use at lower temperature resources. Tax incentives, in the form of a 15% energy investment tax credit, are assumed to be available for both well field and power plant investments through 1995.

The assumptions and parameters used in the forecasting process are reported in the following two sections.

4.1 FORECASTING PROCEDURE

Figure 4-1 illustrates the sequential components of the integrated hydrothermal power forecasting model. The model is executed in a dynamic rather than static manner, because results from the first year simulation determine, in part, the output for subsequent years. Such "feedback" loops, as has been demonstrated, are important elements in the accurate replication of the hydrothermal exploration and development process.

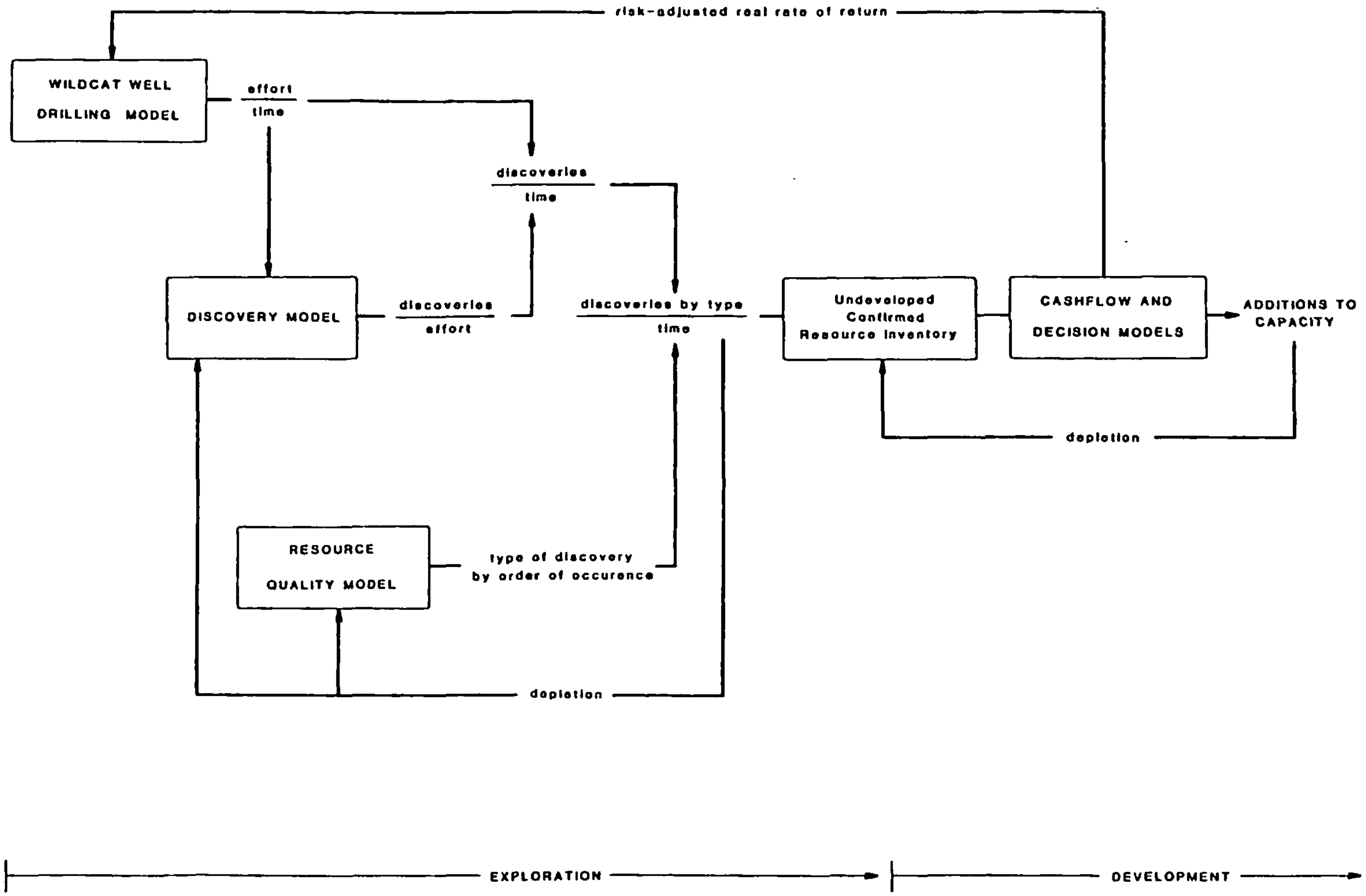

Figure 4-1
HYDROTHERMAL EXPLORATION AND DEVELOPMENT FORECASTING MODEL

The simulation begins with the estimation of a rate of return from a hydrothermal reservoir whose geologic characteristics are considered to be of "average" quality. This return, coupled with the rate of return on oil and gas investment opportunities, provides the necessary input to the Well Drilling Model. The output of this model is the number of wildcat wells drilled at time (t), allocated regionally.[15] The Discovery Model then provides estimates of new regional discoveries, based on wildcat drilling forecasts and the level of effort "discovery thresholds" determined endogenously within the Discovery Model. The Resource Model then computes probabilistic temperature profiles of each discovery (as described in Section 2.7.2) and determines the probability of discovery of each of the 30 generic resources. Each resource is then processed by the cash flow and decision analysis models to determine temporal and probabilistic estimates of hydrothermal power on-line. These estimates, when multiplied by the probability of occurrence of each resource, provide a probabilistic forecast of future development from resources discovered in time (t).

The simulation is then repeated for the next time period, (t+1). The dynamic nature of the model is observed as the number of discoveries estimated in time (t) deplete the undiscovered resource base. This depletion effect impacts the second period simulation in several ways. First, because of the observed historical bias for discovering resources of above average temperature, any discoveries in one period will tend to reduce the expected temperature of subsequent discoveries. As the expected temperatures of future discoveries degrade, the expected rate of return on future geothermal investments also will tend to decline. The result is a reduction in wildcat drilling activity and, thus, a reduction in new discoveries. The second impact of depletion is noted as the temperature profiles of new discoveries (the output of the resource model) reflect the increased propensity to find resources of lower quality. Cumulative resource depletion, therefore, creates three basic effects: (1) drilling effort is reduced; (2) the efficiency of drilling activity deteriorates; and (3) the quality of resource discoveries deteriorates.

The simulation proceeds in the above manner until all years in the

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[15] Drilling forecasts are estimated for S. California, Nevada and all other regions.

forecast period have been evaluated. The output of the model is then compiled to provide national power on-line estimates over 5-year intervals from 1982-2000. Estimates are reported probabilistically to account for inherent uncertainties in resource availability and in the investment decision process (recall Section 3). The modeling parameters used in the simulations are reported below.

4.2 MODELING ASSUMPTIONS AND PARAMETERS

Input parameters for the base case simulation (i.e., Current Technology) are provided in Tables 4-1 to 4-5. The values assigned to each parameter are based on the combined judgment of Department of Energy Task Force members, personal interviews with industry representatives, and extensive reviews of the published literature. More extensive documentation of selected input parameters can be found in Cassel et al. (1981).

To investigate the effect of R&D advances and tax incentives upon geothermal power development, several variables relating to technological costs and performance and to tax credits were adjusted in the forecasting model. These adjustments are provided in Table 4-6.

4.3 WILDCAT WELL DRILLING FORECASTS

Historical and forecast wildcat well drilling completions directed toward electric-quality hydrothermal resources (>300°F) are displayed in Figure 4-2. The data used in construction of this figure are presented in Table 4-7(a).

Historical wildcat well drilling displays a generally increasing trend from 1958-1980, averaging an annual compound growth rate of 9%. An explanation for the dip in drilling activity during 1965-1970 and a more detailed discussion of these historical data are offered in Section 2.4.3. Analyses of the wildcat well drilling forecasts under each scenario, in turn, are presented below.

4.3.1 <u>Current Technology and Incentives (Base Case)</u>

Under a base case assumption wildcat well drilling levels abruptly stabilize, ending a 20-year period of rapid growth. This stagnation continues into the mid-1990's, at which time growth resumes. An important

Table 4-1
ECONOMIC PARAMETERS

DESCRIPTION	PROGRAM CODE	VALUE
Capital cost of competing baseload power plant	CALT	$1100/kWe
Annual O&M cost of competing power plant[1]	BETAA	.062
Capacity factor of competing power plant	CAPA	.75
General inflation rate	G	.075
Capital cost escalation rate	GC	.08
Fuel cost escalation rate	GF	.09
Cost of fuel: competing coal-fired power plant	PALT	18.8 mills/kWh
Plant life: competing baseload power plant	PLFA	30
Plant life: hydrothermal power plant	PLFH	30
Royalty fraction	RLF	.10
Base price year	YP	1982
Discount rate	DTL	.12
Transmission interconnection cost and threshold[2]	TXC	*200 50 2700*
Depletion allowance	PDPL	.22 .20 .18 .16 .15
Depletion allowance years	YDPL	1980 1981 1982 1983 1984
Pre-production expenses	PEXP	(see Section 2)
Pre-production capital expenses	PCAP	(see Section 2)

[1]fraction of capital cost (includes operation, maintenance, administration, ad valorem taxes).
[2]\$200/kw for $\leq$ 50 MW_e, \$2,700,000 for >50 MW_e

Table 4-2
FINANCIAL PARAMETERS

DESCRIPTION		PROGRAM CODE	VALUE
Fraction of common stock:	hydrothermal plant	FCH	.35
	baseload alternative	FCA	.35
Fraction of debt equity:	hydrothermal plant	FDH	.50
	baseload alternative	FDA	.50
Fraction of preferred stock:	hydrothermal plant	FPH	.15
	baseload alternatives	FPA	.15
Cost of common stock:	hydrothermal plant	KCH	.16
	baseload alternative	KCA	.16
Cost of debt equity:	hydrothermal plant	KDH	.11
	baseload alternative	KDA	.11
Cost of preferred stock:	hydrothermal plant	KPH	.11
	baseload alternative	KPA	.11

Table 4-3
RESOURCE PARAMETERS

DESCRIPTION	PROGRAM CODE	VALUE
Ratio of producer to injector wells	PIR	2
Dry well cost as fraction of successful well cost	DWC	.90
Intangible fraction of producer well cost	IF	.75
Fraction of new wells requiring redrilling	IRD	.30
Redrilling cost as fraction of initial cost	RDC	.35
Rework cost as fraction of initial cost	RWC	.35
Spare well fraction	SWF	.20
Well spacing (acres per production well)	WSPACE	40

Table 4-4
TAX PARAMETERS

DESCRIPTION	PROGRAM CODE	VALUE
Ad Valorem tax rate	ADV1	.04
Ad Valorem tax assessment rate	ADV2	.25
Investment tax credit: baseload alternative	ITCA	.10
Well tax life	PTLF	3
Federal tax rate: hydrothermal plant owner	TFH	.46
Federal tax rate: baseload plant owner	TFA	.46
Federal tax rate: resource producer	TF2	.46
Tax life: hydrothermal plant	TLFH	15
Tax life: baseload alternative	TLFA	15
State tax rate: hydrothermal plant owner	TSH	.09
State tax rate: baseload alternative plant owner	TSA	.09
State tax rate: resource producer	TS2	.09

TABLE 4-5
MISCELLANEOUS MODEL PARAMETERS

DESCRIPTION	PROGRAM CODE	VALUE
Sequential plant capacities in MW (1st, 2nd, 3rd, 4th, all others)	MWV5	20 50 50 100 200
Representative geothermal plant capacity (MW)	MWN	50
First year of simulation	TFIRST	1982
Last year of simulation	TLAST	1997
Years between decision and plant on-line (plants 1-5)	DELDP5	5 3 3 3 3
Utility function parameters	K	(see Section 3)
Multiattribute function parameters	UC	(see Section 3)
Interval between successive plants in years (plants 2-5)	PIV5	0 3 2 1 1
Years from first plant-related cost until plant on-line	DVT	3

Table 4-6
VARIABLE PARAMETERS IN SENSITIVITY TESTS
(All changes assumed post-1987 except as otherwise noted)

	VARIABLE NAME	BASE CASE Current Technology	CASE I Minimal Advances	CASE I Significant Advances
Hydrothermal plant O&M cost: binary plant	BETAH	NC	3% increase	1% decrease
Hydrothermal plant O&M cost: flash plant	BETAH	NC	7% decrease	9% decrease
Hydrothermal plant capacity factor	CAPH	NC	2% increase	7% increase
Hydrothermal plant capital cost: binary plant	CH	NC	2% increase	3% decrease
Hydrothermal plant capital cost: flash plant	CH	NC	0.5% decrease	1% decrease
Dry well fraction	DWF	.20	.20	.10
Intangible well fraction	IF	.75	.70	.65
Investment tax credit: resource producer[1]	ITC2	.10	.10	.25
Investment tax credit: hydrothermal plant owner	ITCH	.10	.10	.25
Reworked well fraction	RWF	.33	.33	.50
Surface piping cost: binary plant	SRP	NC	8% decrease	8% decrease
Surface piping cost: flash plant	SRP	NC	4% decrease	4% decrease
Well cost (1985-1990)	WC	NC	5% decrease	15% decrease
Well cost (post-1990)	WC	NC	10% decrease	25% decrease
Plant type: earliest binary on-line date	PTYPE	1995	1991	1989
Plant type: earliest advanced binary on-line date	PTYPE	--	--	1991
Downhole pump temperature limit	PUMP	370F	370F	425F
Well life	WLF	NC	24% increase	30% increase
Net specific energy (binary)	NSE	NC	7% increase	20% increase
Net specific energy (flash)	NSE	NC	7% increase	12% increase
Decision lead-time for first plant	DELDP5	5 yr.	5 yr.	3 yr.

[1]Pre-1985 value of .25 for all cases

NC = No change

Table 4-7
HISTORICAL AND FORECAST WILDCAT WELL COMPLETIONS

(a) Wildcat Wells Completed in Period

1958-1960	6
1961-1965	18
1966-1970	4
1971-1975	35
1976-1980	47
TOTAL HISTORIC (1958-1980)	110

(b) Wildcat Wells Forecasted

	BASE CASE Current Technology and Incentives	CASE I Minimal Technology Advances	CASE II Significant Advance & Enhanced Incentives
1981-1985	63	63	69
1986-1990	65	71	109
1991-1995	65	96	164
1996-2000	80	88	65
TOTAL FORECAST (1981-2000)	273	318	407

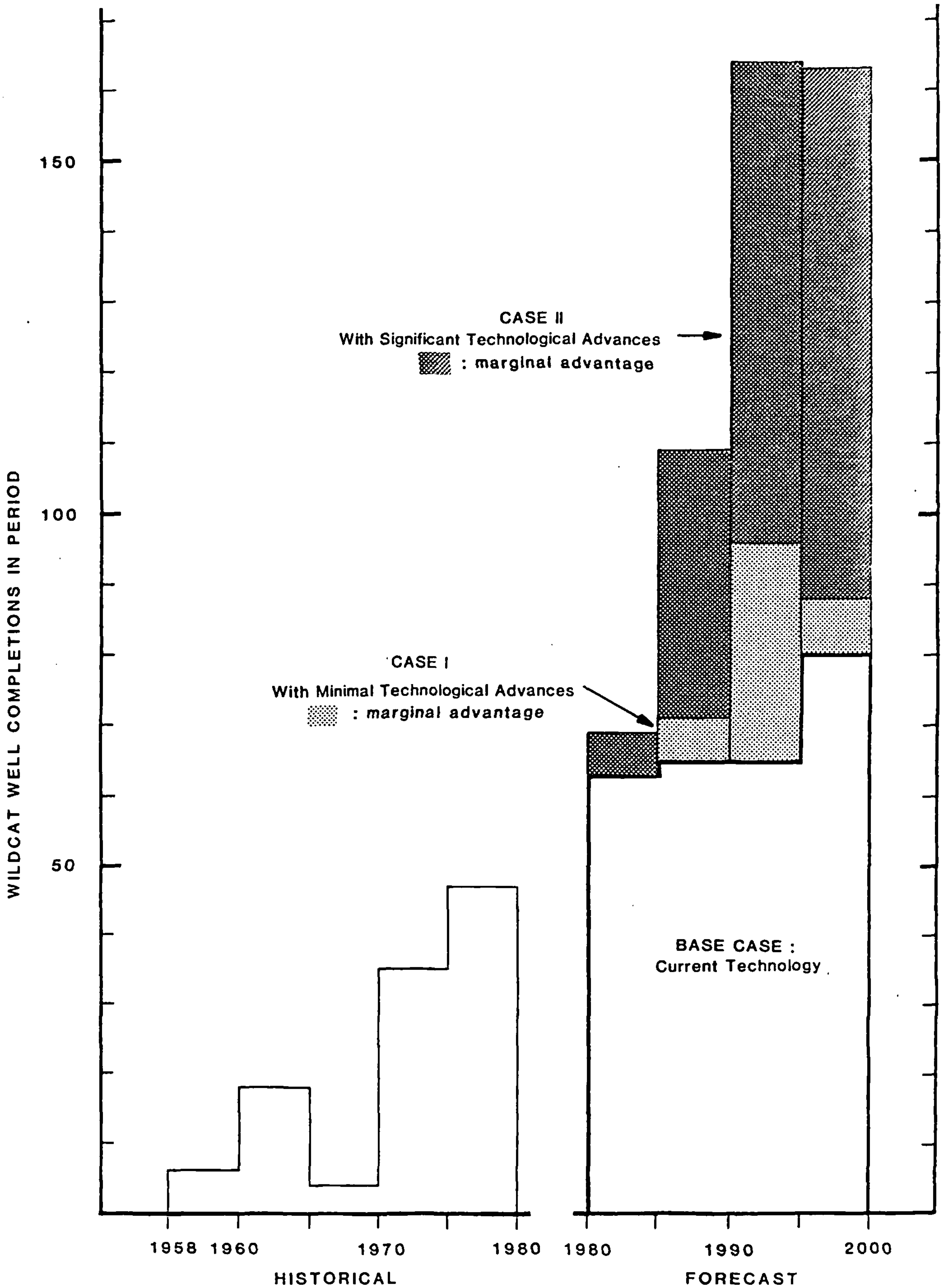


Figure 4-2
HISTORIC AND FORECAST WILDCAT WELL DRILLING

reason for the 23% well drilling increase in the last forecast period appears to be the predicted availability of binary energy conversion technology which is assumed to be introduced in the mid-1990's.

4.3.2 Minimal Technological Advances (Case I)

Increases in wildcat well drilling activity prior to 1980 are preserved under Case I assumptions, though at somewhat lower than historical levels. The 15 year period of stagnation in drilling rates which occurs under base case assumptions, thus, is avoided. Drilling activity increases 9% over base case levels during 1985-1990, primarily because of the technological advances assumed in the late 1980's. A further 48% increase occurs in the following period (1991-1995), when binary conversion technology is assumed to become available. Again, recognition of the cost reduction rewards and, hence, rate-of-return increases associated with these technologies spurs exploration capital investment.

4.3.3 Significant Technological Advance & Enhanced Incentives (Case II)

The effect of the Case II assumptions, with its array of tax credit incentives and rapid technological gains is pronounced when compared to the base case. Perhaps the most significant outcome of this scenario is the maintenance, for the next 15 years, of the historical annual drilling rate increase of 9%.

In the first forecast period, various near-term economic incentives, not present in other scenarios, contribute to a modest increase in the financial attractiveness of hydrothermal generation. Such inducements, in combination, yield a 10% increase over base case drilling levels. During 1986-1990, however, the early implementation of both high temperature down hole pumps and binary conversion technologies offer financial gains which trigger a 68% increase in wildcat drilling over levels that would have occurred in the absence of any Federal geothermal programs. This increase grows to 109% in the next time period, as these and other technological advances penetrate further into the market place. In the final forecast period, 1996-2000, wildcat well drilling levels, though still quite high, marginally decrease as cumulative resource depletion decreases the rate-of-return potential of future exploration investment.

4.4 HIGH TEMPERATURE RESERVOIR DISCOVERY FORECASTS

As discussed in Sections 2.6 and 4.1, the primary determinants of the temporal rate of hydrothermal reservoir discovery are (1) the level of wildcat well drilling; (2) the technological effectiveness of this drilling; and (3) the size of the remaining resource base. Cumulative depletion of a finite resource base ensures, in the long run, a decrease in the marginal returns to drilling. Alternately, to maintain constant discovery rates, drilling levels must increase or the technological efficiency of discovery must improve. The effect of these factors clearly is evident in Figure 4-3, a display of historical and forecast hydrothermal reservoir discovery rates. Data used in construction of this figure are presented in Table 4-8(a).

During the period 1958-1980, rapidly increasing drilling rates, combined with the entrance of technically advanced firms during the early 1970's, yielded an average annual growth in discovery rate of 9.5%. The future increase or decline of these historic discovery rates, as discussed below, will depend on wildcat drilling rates and the ability of technological advance to offset the effect of resource depletion.

4.4.1 Current Technology and Incentives (Base Case)

Under Base Case assumptions, the discovery rate rapidly declines through 1995 from that of the current period. This is a direct consequence of the near-level rate of wildcat drilling in the base case, and the decrease in marginal drilling returns caused by resource depletion. The maintenance of a constant discovery rate from 1990-2000 is caused by the 23% increase in wildcat drilling during 1995-2000. Under base case assumptions, therefore, the temporal rate of hydrothermal reservoir discovery will peak in the current period and then decline at a compound annual rate of -3%.

4.4.2 Minimal Technological Advances (Case I)

Under Case I assumptions, the decline in discovery rate seen in the base case is reduced, reflecting the higher wildcat drilling rates forecast under this scenario. The total expected number of discoveries over the forecast period grows to 35, from 31 under the base case, an increase of

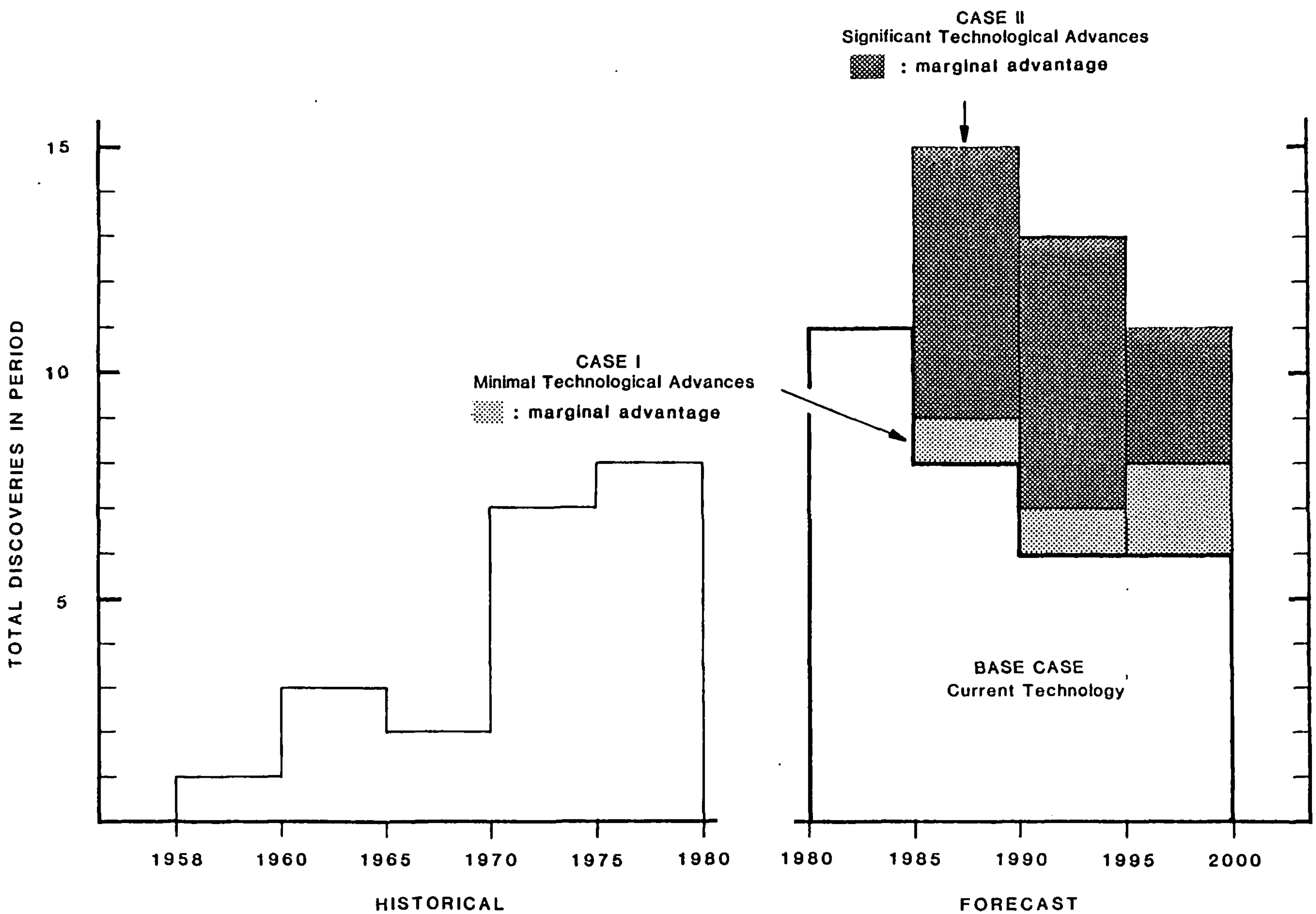


Figure 4-3
HISTORICAL AND FORECAST HYDROTHERMAL DISCOVERIES

Table 4-8
HISTORICAL AND FORECAST HYDROTHERMAL DISCOVERIES

	(a) Discoveries in Period
1958-1960	1
1961-1965	3
1966-1970	2
1971-1975	7
1976-1980	8
TOTAL HISTORIC (1958-1980)	21

(b) Discoveries Forecasted

	BASE CASE Current Technology and Incentives	CASE I Minimal Technology Advances	CASE II Significant Advance & Enhanced Incentives
1981-1985	11	11	11
1986-1990	8	9	15
1991-1995	6	7	13
1996-2000	6	8	11
TOTAL FORECAST (1981-2000)	31	35	50

17%. When cumulative discoveries are examined, the net effect of Case I is a 2-3 year acceleration in the timetable of discoveries that would occur under base case assumptions.

4.4.3 Significant Technological Advances and Enhanced Incentives (Case II)

The increase in discovery rate under Case II assumptions, like the increase in wildcat well drilling rates, is marked when compared to the outcome of the base case. Discovery rates, rather than declining during 1985-1990 as in the other scenarios, increase 36% over pre-1985 levels. This increase is caused not only by high levels of exploration activity, but also by advances in exploration technology that partially offset declines in the industry wide drilling success ratio. Over the entire forecast period, the Case II accounts for a 60% increase in total discoveries (50 vs. 31), and a 7 year advance in the discovery timetables forecast under the Base Case Scenario.

In addition to these gains in the gross number and relative timing of reservoir discoveries, the enhanced geoscience elements of the Case II scenario are expected to influence the quality of future discoveries. Figure 4-4 displays the temperature profile of the total number of discoveries forecast under each scenario. Considering the Base Case temperature profile as a base, the increases attributable to Case I and Case II assumptions are distributed disproportionally with respect to temperature. The average temperature of discoveries (1981-2000) under the base case is 389°F; under the Case I and Case II scenarios average temperatures are 390°F and 395°F, respectively.

4.5 HYDROTHERMAL POWER FORECASTS

The discovery forecasts described above, and the set of previously discovered reservoirs discussed in Section 2.7, were used as the resource base for hydrothermal electric power forecasts under each of the three scenarios described earlier. Since the discoveries listed in Table 2-8 have not all yet been confirmed, the forecasted development at each of these reservoirs has been weighted by the confirmation probabilities presented in the table's fourth column. Figures 4-5 through 4-7 display the expected hydrothermal generation capacity (dark line), and 50% and 90% confidence intervals for projected development under the Current Technology, Minimal Technological Advance, and Significant Technological

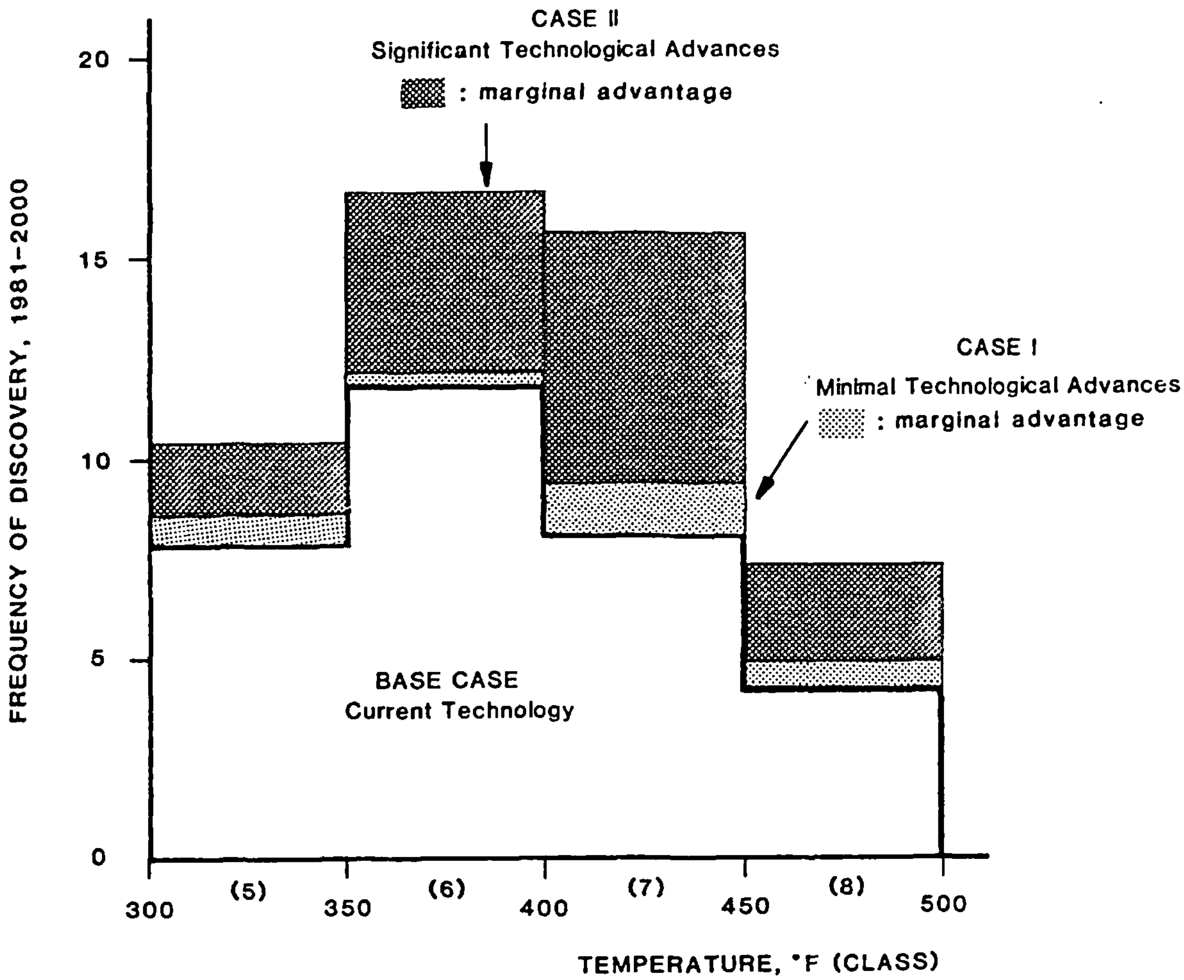


Figure 4-4
TEMPERATURE DISTRIBUTIONS OF FORECASTED DISCOVERIES

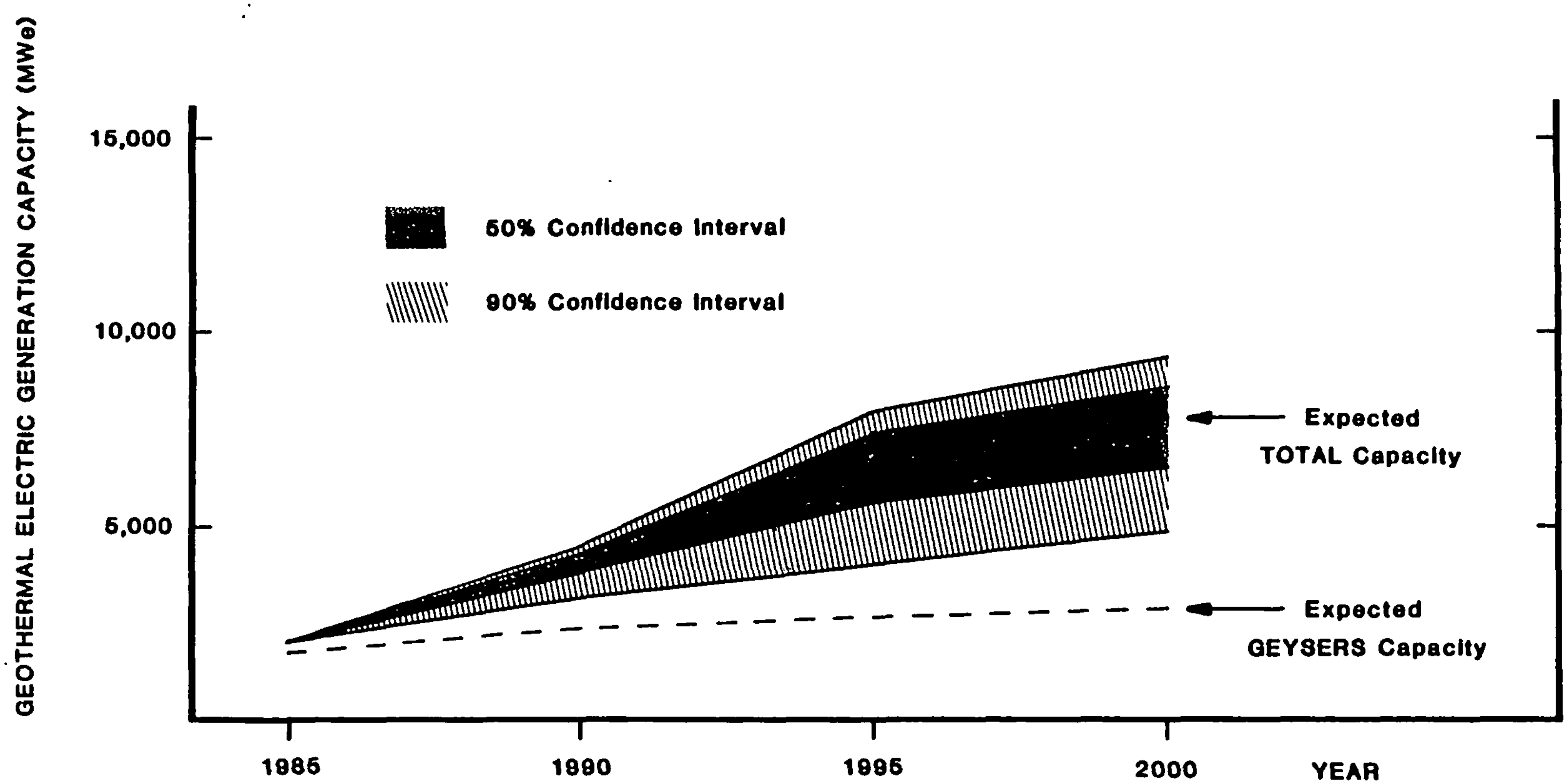


Figure 4-5
FORECAST GEOTHERMAL POWER ON-LINE WITH CURRENT TECHNOLOGY (BASE CASE)

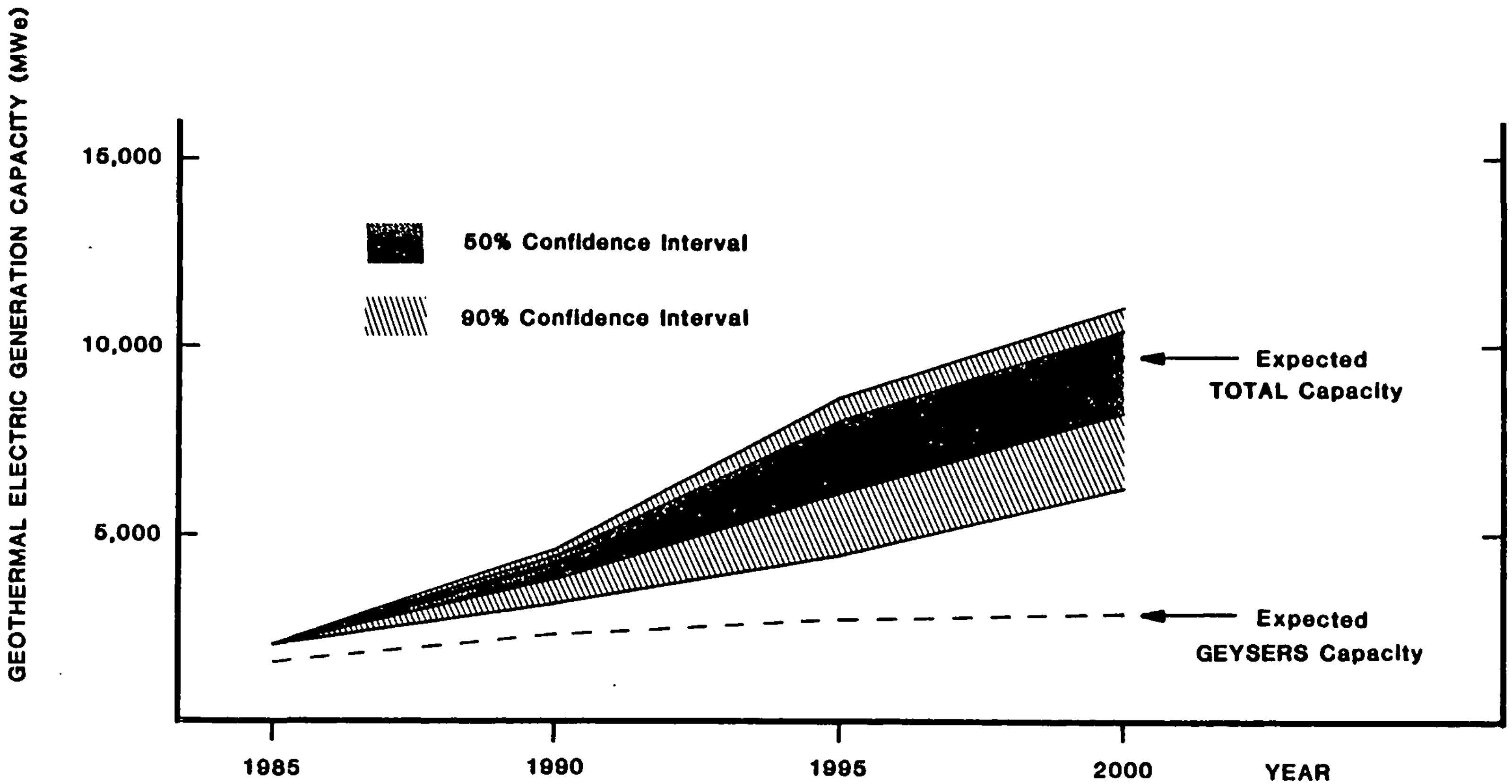


Figure 4-6
FORECAST GEOTHERMAL POWER ON-LINE WITH MINIMAL TECHNOLOGICAL ADVANCE (CASE I)

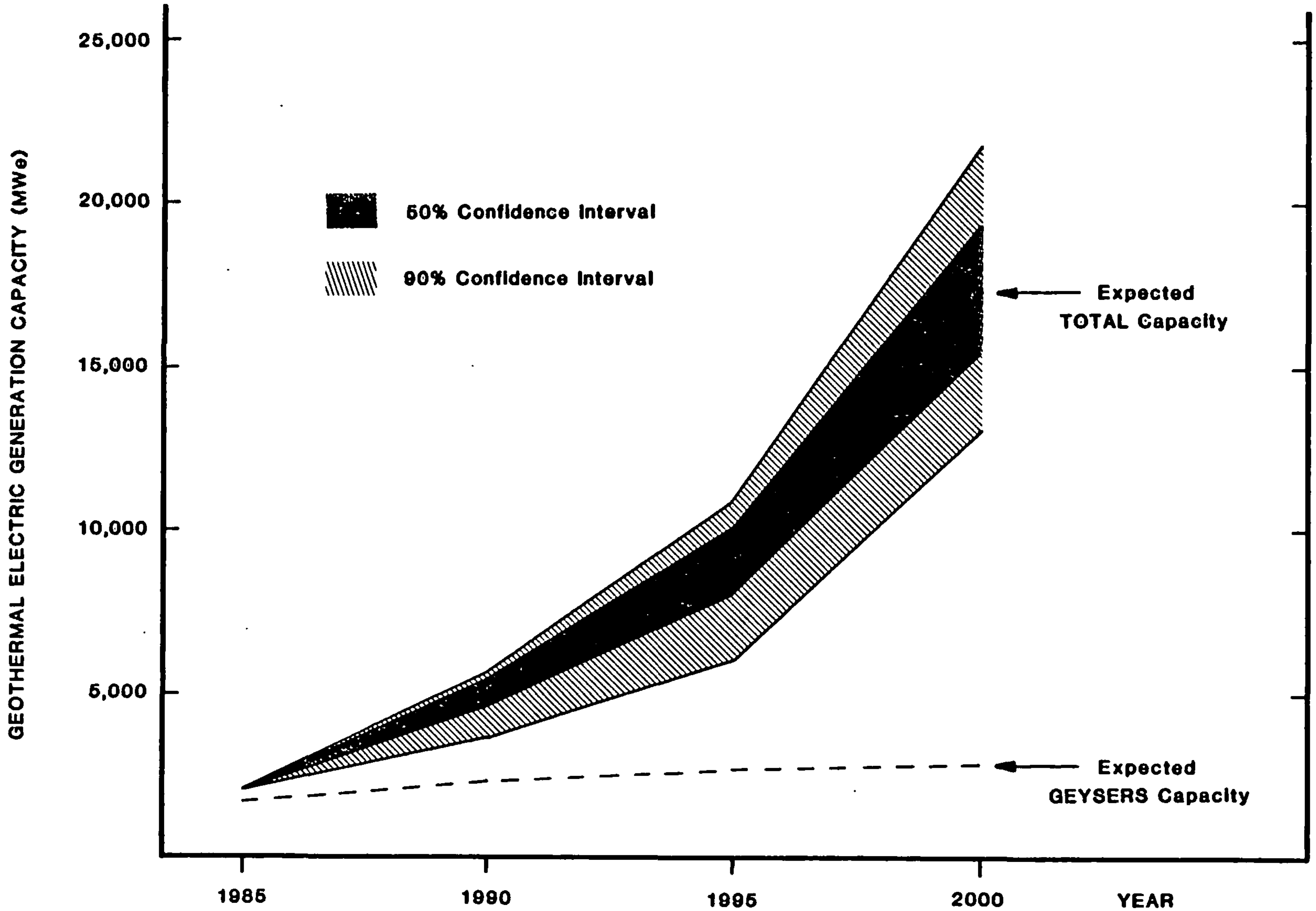


Figure 4-7
FORECAST GEOTHERMAL POWER ON-LINE WITH SIGNIFICANT TECHNOLOGY ADVANCEMENT (CASE II)

Advance scenarios, respectively. Table 4-9 presents the expected values of the forecasts in each period. These figures include capacity additions at The Geysers. The total uncertainty in these estimates is created by both resource and investment uncertainty.

The expected power on-line forecasts for each scenario are compared in Figure 4-8. The mean estimate of geothermal generation capacity in the year 2000, given current technology (Base Case) assumptions, is 7710 MW. This level represents a 12.0% compound annual growth rate during the forecast period of 1982-2000 (inclusive).

The influence of Case I assumptions (Minimal Technological Advancement) is evident from the widening gap above Base Case levels in total capacity additions over the long term. Capacity gains in expected liquid dominated generation, over the Base Case, are 6% in 1990, 15% in 1995, and 42% in 2000. The marginal expected capacity advantage of the Case I Scenario is 2010 MW by the end of year 2000. (See Table 4-9).

Significant technological advancements and enhanced tax incentives (i.e., Case II assumptions) are estimated to increase hydrothermal generation capacity in every time period. By the end of year 2000, an additional 9600 MW_e of geothermal power is estimated to be on-line above that which would be available under the Base Case with current technology. This is equivalent to a long-term marginal capacity advantage of 125% over the Base Case.

4.6 ENVIRONMENTAL CONTROL SENSITIVITY ANALYSIS

Hydrothermal power development at some resource areas will require abatement measures to prevent undesirable environmental impacts. The extent to which environmental controls may impede the rate of development at specific resource areas is examined in this section. In performing this sensitivity analysis, the costs of advanced control technologies are incorporated into the cash flow and decision analysis model described in Chapter Three. Power generation levels both with and without the control strategies are then estimated and compared to determine the extent to which environmental control costs affect the time paths of site specific resource development. Two areas of environmental concern are addressed:

(1) Hydrogen sulfide emission control, and

(2) Liquid effluent disposal options.

Table 4-9
PROJECTED GEOTHERMAL ELECTRIC GENERATION CAPACITY, 1985-2000

		1985	1990	1995	2000
Base Case	Expected TOTAL Capacity, MW[1] (Standard Deviation, MW)[2]	2000 (10)	4140 (300)	6730 (1500)	7710 (1800)
Case I	Expected TOTAL Capacity, MW (Standard Deviation, MW)	2100 (10)	4240 (300)	7340 (1600)	9720 (2000)
Case II	Expected TOTAL Capacity, MW (Standard Deviation, MW)	2110 (10)	5150 (500)	9280 (1700)	17310 (3500)
	Expected GEYSERS Capacity, MW[3]	1720	2380	2680	2890

[1]Includes expected capacity at The Geysers.

[2]Standard deviation of forecast in each period: refer to Figures 4-5 through 4-7 for 50% and 90% confidence intervals.

[3]Mean estimate only; see Cassel (1982).

<u>Note</u>: "Base Case" assumes current technology and tax incentives
"Case I" assumes minimal technology advancement
"Case II" assumes significant technological advances and enhanced tax incentives.

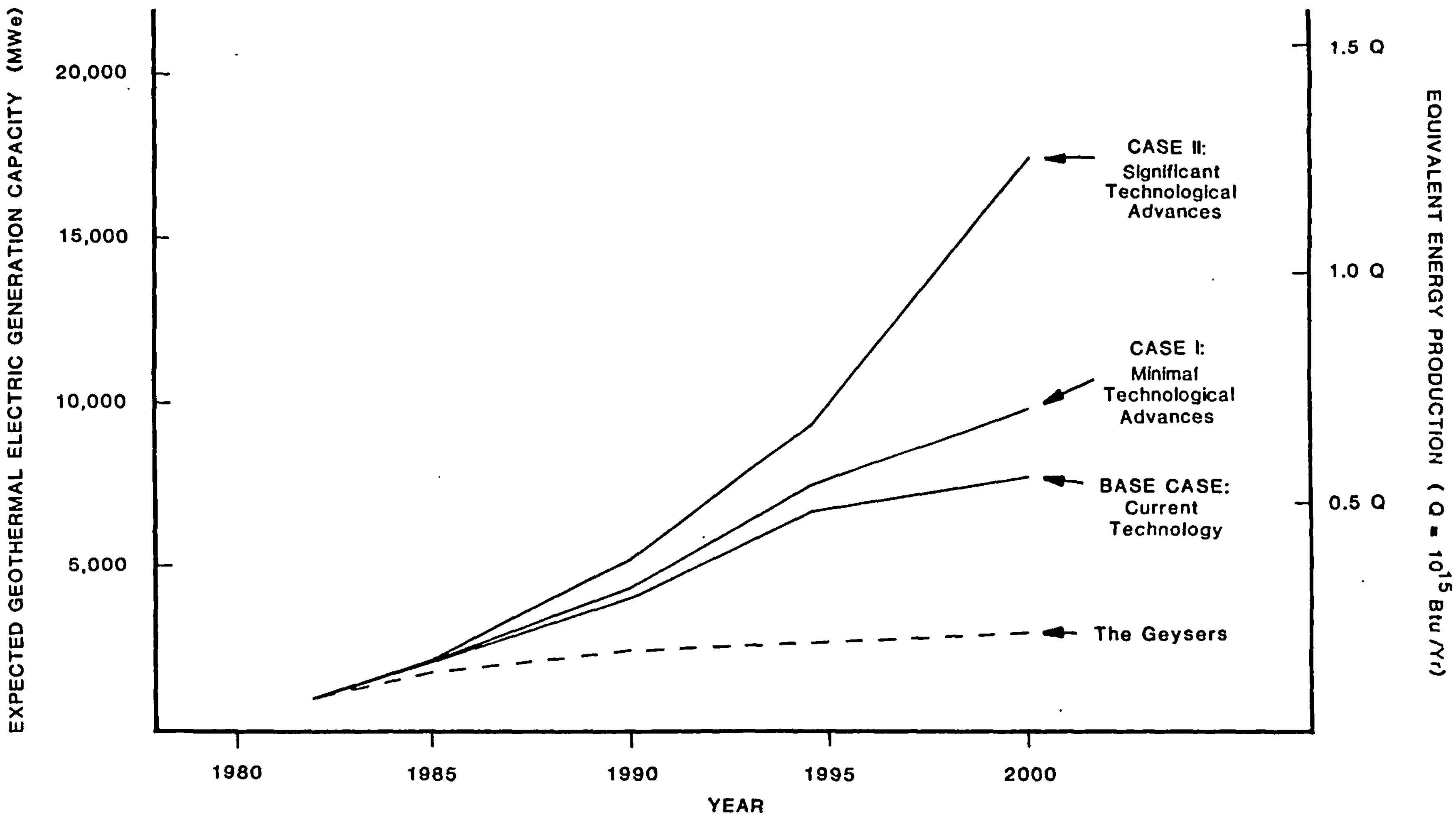


Figure 4-8. GEOTHERMAL POWER FORECAST COMPARISON

Both concerns may play an important role in determining the future rate of hydrothermal electric power development.

4.6.1 Hydrogen Sulfide Emission Control Requirements and Options

Brines from U.S. hydrothermal resources contain varied concentrations of hydrogen sulfide (H_2S). This gas is normally separated from the brine during the electric power generation process and, if not contained, is released to the atmosphere. At some geothermal development sites, uncontrolled release of H_2S may result in unacceptably high local ambient concentrations of the gas. Therefore, it is expected that some degree of H_2S control will be required as part of the geothermal development.

Hydrogen sulfide emissions limitations for future geothermal developments have not yet been promulgated. Federal New Source Performance Standards and ambient air quality criteria do not include H_2S. California and New Mexico have imposed ambient air quality criteria; however, these ambient criteria cannot be directly interpreted to yield emission limits for point sources.

Future emissions limits are suggested by recent experience at The Geysers. Table 4-10 summarizes the H_2S criteria applicable to that area. Air permits for geothermal development must be based on Best Available Control Technology and are currently considered on a case by case basis. EPA recommendations as well as performance of available technology indicate that approximately 90% control of H_2S will be required at The Geysers.

Table 4-10
H_2S AMBIENT CRITERIA

		Calif. Air Res. Board (For The Geysers)		
EPA Recommended	State of California	New Units	Wellheads	Steam Stacking[a]
90% Control[c] or a range of control from 200 gm/MWh to 400 gm/MWh	30 parts per billion by weight[b]	175 gm/MWh (1/1/1979) (d)	5 gm/MWh (1/1/1980)	65% [c,e] (1/1/1980)

(a) Steam stacking losses of H_2S occur when a particular turbine is shut down and its steam source is vented.
(b) Stricter regulations exist in portions of New Mexico. The 30 ppb_w limitation is the average threshold for human detection.
(c) Control of H_2S loading in the raw fluid by weight.
(d) Scheduled for 100 gm/MWh on 1/1/1980 and 50 gm/MWh on 1/1/1990.
(e) Scheduled for 90% control on 1/1/1990.

Source: Wells (1981)

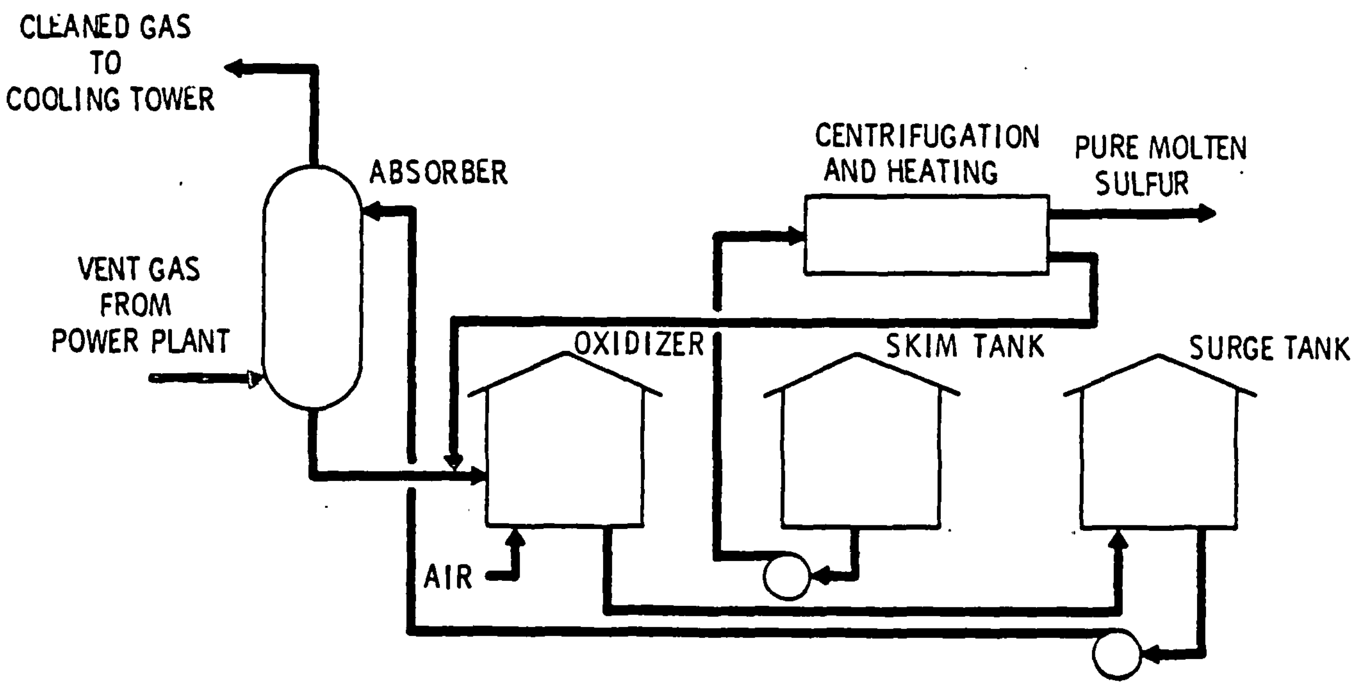
Numerous processes exist or are being developed for the control of H_2S emissions and several have been applied to geothermal energy conversion systems. The most recent plants at The Geysers incorporate the Stretford process for removing H_2S from noncondensible gases. At older plants, an iron catalyst is injected into the cooling towers to react with the H_2S gas. The developmental EIC process which treats the steam before it enters the turbine has also been applied in pilot scale tests at The Geysers and is being considered for future plants. In addition, other techniques and processes are being studied. Wells (1981b) and Kestin (1980) describe many of these control technologies.

Hydrogen sulfide abatement increases both the capital and operating cost of geothermal electric power plants. Battelle Pacific Northwest Laboratory (PNL) recently published capital and operating cost data for five candidate processes (Wells, 1981b). This work showed costs to be a function of geothermal steam flow rate, H_2S concentration in the steam, and the degree of H_2S control required. The results indicated that the Stretford process has the lowest total cost penalty when H_2S control of less than 90% is required. For greater control, the EIC process has the lowest cost penalty. Two cases having different levels of H_2S control were analyzed in this study. These were compared to a base case in which no H_2S control was applied.

Case I: Stretford Process - (89% Control). In this case, the Stretford process is applied to remove H_2S from the noncondensible gases leaving the power plant condenser. The level of H_2S emission control is assumed to be 89%, the approximate maximum level of control achievable with the Stretford process. This case represents the best commercially proven control technology in terms of control efficiency and cost.

The Stretford process is shown schematically in Figure 4-9. Noncondensible gas from the power plant is scrubbed with an aqueous solution containing sodium carbonate, sodium amonium polyvanadate, and anthraquinone disulfonic acid. The H_2S is oxidized in solution prior to catalyst regeneration with air. The resulting sulfur froth is skimmed, centrifuged and melted to produce high quality sulfur. This by-product may be marketed or deposited in a land fill.

Figure 4-9
STRETFORD PROCESS FLOW DIAGRAM



Source: Wells (1981b)

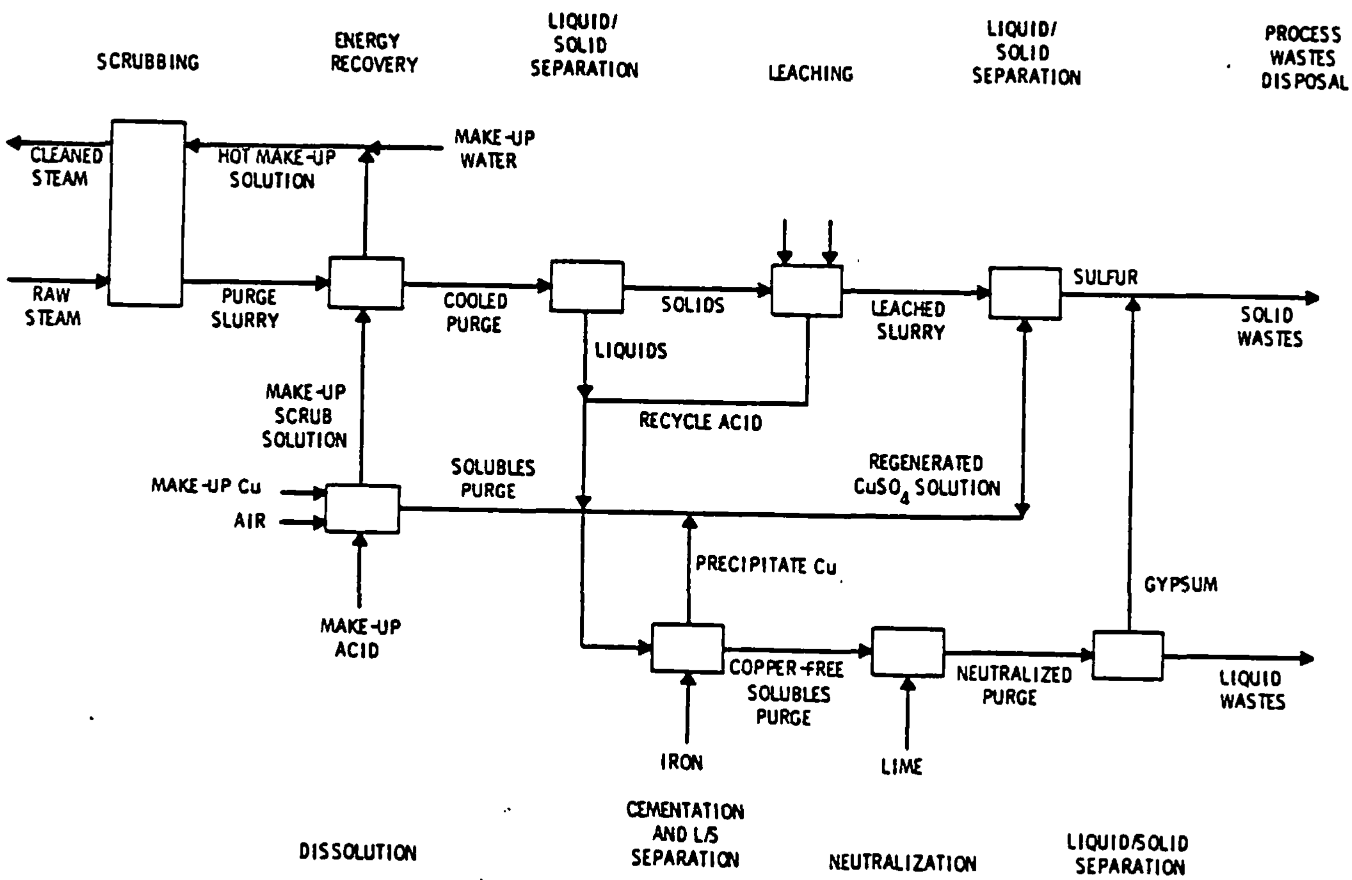
The Stretford process is over 99% effective, removing essentially all of the H_2S from the noncondensible gas stream. The maximum overall H_2S control level is reduced to approximately 89% however, since a portion of the H_2S is absorbed by the condensate in the power plant condenser and not vented with the noncondensible gases. This absorbed gas is vented to the atmosphere via the plant cooling towers.

Case II: EIC Process - (97% Control). In this case, the EIC process is used to remove H_2S from the geothermal steam upstream of the steam turbine. This process has not been proven in commercial geothermal applications but has received pilot scale tests at The Geysers. Based on these tests and other development work, control efficiencies of 95 to 99% are expected (Wells, 1981b). A control efficiency of 97% was assumed for this case.

The EIC process shown in Figure 4-10, treats the flashed geothermal steam, prior to expansion through the turbine, by scrubbing the steam with an aqueous solution of copper sulfate. The H_2S and copper sulfate react in the scrubber forming a copper sulfide precipitate which is carried away in a purge slurry. Cleaned steam leaves the scrubber without significant degradation in quality. The purge slurry from the scrubber is separated into solid and liquid wastes and copper sulfate for refuse. The waste, ammonium sulfate, may either be placed in a landfill or reclaimed for fertilizer manufacture.

Figure 4-10

EIC HYDROGEN SULFIDE REMOVAL PROCESS



Source: Wells (1981b)

Costs of H_2S Control Systems. The capital and operating costs of H_2S control systems used in this analysis are based on information recently published by Battelle Pacific Northwest Laboratory (PNL) (Wells, 1981). The PNL report presents cost functions for both the Stretford and EIC processes. The functions relate incremental capital and operating costs incurred by incorporating the systems in a geothermal power plant to the following design parameters:

- o Plant output and steam flowrate
- o H_2S concentration in the steam
- o Degree of H_2S control

The cost functions were developed by PNL based on a survey of previous analyses and experience with the processes. The costs for the Stretford process stem from experience at The Geysers as reported by PG&E and R.M. Parsons Company, a licensee of the process. PNL developed the capital and operating cost functions for the EIC process using data reported by the EIC Corporation, the developer of the process.

The cost functions used in this analysis are given in Table 4-11. The capital costs include installation, overhead (direct and indirect), contingencies and contractors' fees. Annual operating costs include: (1) operating and maintenance labor; (2) utilities (electricity and steam); (3) chemicals and; (4) solid waste disposal. For the Stretford process, a credit from sale of the byproduct sulfur reduces operating costs. Annual operation and maintenance costs for both processes are also provided in Table 4-11.

Potential Impact of H_2S Abatement Costs on Power Development. The cash flow and decision analysis models described in Chapter Three are used to examine the degree to which adoption of H_2S control technologies may impact development at Mono-Long Valley KGRA and Clear Lake KGRA. Because of the relatively high concentrations of H_2S found at Mono-Long Valley (100.0 ppm) and Clear Lake (42.0 ppm), power development at both areas may require the use of H_2S abatement technology. To estimate development impacts, the capital and operation and maintenance costs associated with each technology are incorporated into the electric power plant cash flow. The joint probability of investment then is determined by the multiattribute decision model described in Section 3.2. The results of this analysis are reported below.

Table 4-11
COST OF H_2S CONTROL PROCESSES

Stretford Process Cost Functions

PE_{1980} = IB x (SDA/SDB)^X

AOC_{1980} = (LC x LU) + (THR x CS x CF) x [(ER x EC) + (WR1 x AC) + (WR2 x VC) + (WR3 x NC) - (SR x SRE x SC)]

Variables:

AC = ADA (Anthraquinone Disulfonic Acid) Cost ($5.25/lb ADA)

AOC_{1980} = Annual Operating Cost in January 1980 Dollars

CF = Capacity Factor (0.80)

CS = Condenser H_2S Split (0.90)

EC = Electricity Cost ($0.043/kWh)

ER = Electricity Ratio (380 kWh/MT H_2S)

IB = Purchased Equipment Cost in the Design Facility ($2,250,000)

LC = Labor Costs ($16.80/Manhour)

LU = Labor Units (4000 Manhours/yr)

NC = Na_2CO_3 Cost ($0.075/lb Na_2CO_3)

PE_{1980} = Purchased Equipment Cost in 1980 Dollars

SC = Sulfur Credit ($500/MT Sulfur)

SR = Sulfur Ratio (32 MT Sulfur/34 MT H_2S)

SDA = MT Sulfur to be Disposed of in Proposed Facility (MT/day)

SDB = MT Sulfur to be Disposed of in Design Facility (5.5 MT Sulfur/day)

SRE = System Removal Efficiency (0.99)

THR = H_2S Flow Rate Through Turbine at 100% of Capacity (MT/yr)

VC = Vanadium Cost ($500/lb Vanadium)

WR1 = Weight Ratio of ADA (Anthraquinone Disulfonic Acid) (0.52 lbs ADA/ MT H_2S)

WR2 = Weight Ratio of Vanadium (0.52 lbs Vanadium/ MT H_2S)

WR3 = Weight Ratio of Na_2CO_3 (65.1 lbs Na_2CO_3/MT H_2S)

X = Capital Sizing Factor (0.5)

Table 4-11 (continued)

EIC Process H_2S Abatement Cost Functions

$$PE_{1980} = P1 \times IB \times (SA/SB) + P2 \times IB \times (HA/HB)^X$$

$$AOC_{1980} = (LU \times LC) + (THR \times CF) \times [(ER \times EC) + (WR1 \times OC) + (WR2 \times AC) + (WR3 \times CC) + (WR4 \times HC) + (RR \times RC)] + MR \times PE_{1980}$$

Variables:

AC = NH_3 Cost (\$190 MT NH_3)

AOC_{1980} = Annual Operating Cost in January 1980 Dollars

CC = $CuSO_4$ Cost (\$.815/lb $CuSO_4$)

CF = Capacity Factor (0.80)

EC = Electricity Cost (\$0.043/kWh)

ER = Electricity Ratio (1210 kWh/MT H_2S)

HA = H_2S Concentration in the Proposed Facility (ppm_w)

HB = H_2S Concentration in the Design Facility (240 ppm_w)

HC = H_2SO_4 Cost (\$0.030/lb H_2SO_4)

IB = Purchased Equipment Cost in the Design Facility (\$4,500,000)

LC = Labor Cost (\$16.80/Manhour)

LU = Labor Units (8320 Manhours/yr)

MR = Maintenance Rate (0.065)

OC = O_2 Cost (\$90/MT O_2)

P1 = Percent of Purchased Equipment Cost Represented by Scrubbers (0.75)

P2 = Percent of Purchased Equipment Determined by H_2S Conc. (0.25)

PE_{1980} = Purchased Equipment Cost in 1980 Dollars

RC = Resin Cost (\$115.00/ft^3 Resin)

RR = Resin Ratio (0.0686 ft^3 Resin/MT H_2S)

SA = MWe (gross) of the Proposed Facility

SB = MWe (gross) of Design Facility (110)

THR = H_2S Flow Rate Through Facility at 100% of Rated Capacity (MT/yr)

WR1 = Weight Ratio of O_2 (1.025 MT O_2/MT H_2S)

WR2 = Weight Ratio of NH_3 (0.25 MT NH_3/MT H_2S)

WR3 = Weight Ratio of $CuSo_4$ (17.6 lb $CuSO_4$/MT H_2S)

WR4 = Weight Ratio of H_2SO_4 (68.6 lb H_2SO_4/MT H_2S)

X = Equipment Sizing Factor (0.60)

As shown in Table 4-12, the adoption of advanced H_2S abatement technologies may have a significant impact on development at resource areas with marginally economic resource characteristics. At Clear Lake KGRA for example, use of the Stretford Process to control 89 percent of H_2S emissions results in a significant, 300 MW_e reduction in power development levels. Control at the 97 percent level does not further impede development. At Mono-Long Valley KGRA, a resource having both higher temperature and higher well flow rate than Clear Lake KGRA, adverse impacts on development are not observed following utilization of H_2S control technologies. At this resource area, 97 percent control of H_2S emissions is possible without significantly reducing power development levels.

Table 4-12
H_2S ABATEMENT COST SENSITIVITY ANALYSIS

	Estimated Mean Power Development Level (MW)		
	1990	1995	2000
Clear Lake KGRA (6-5-1-3-6-1)*			
No control	105	400	600
89% control	75	300	300
97% control	75	300	300
Mono-Long Valley KGRA (7-6-1-3-7-7)*			
No control	75	135	170
89% control	60	120	170
97% control	20	120	170

*Generic Resource Code (See Table 2-4)

4.6.2 Liquid Effluent Disposal Requirements and Options

Utilization of hydrothermal resources for electric power generation results in relatively large volumes of waste liquids which require disposal. This liquid principally is spent geothermal brine which may be unsuitable for ground waste drainage systems because it is contaminated with natural constituents from the geothermal reservoir. Other disposal options are available including subsurface reinjection, ponding and treatment; however, these may add significantly to the cost of power generation.

The quantity of liquid effluent from a geothermal power plant is inversely related to resource temperature and may vary from 100,000 to 300,000 lb/hr per MWe for plants at liquid dominated resources. This effluent consists primarily of two kinds of waste water. The main constituent is residual brine left after flashing or otherwise extracting the heat from the geothermal fluid. The other constituent is excess cooling water and condensate.

Geothermal brines from U.S. hydrothermal resources which are candidates for electric power generation contain disolved solids in concentrations ranging from a few hundred parts per million to over two hundred thousand parts per million. The elements present in the brine vary widely according to the geology of the resource area. Figure 4-11 shows the range of chemical constitutent concentrations found in geothermal fluids. Except for the disolved gases, these constituents largely remain in the residual brine to be discharged by the plant.

The waste stream may also include excess condensate and cooling tower blowdowns. Cooling water and condensate discharges are relatively clean. The cooling water can be from an external source or be condensate which is recycled through cooling towers.

Two disposal options, (1) treatment and subsurface reinjection and (2) surface treatment and use, were considered in this analysis. These options were compared to a base case which incorporates subsurface reinjection without treatment.

Case I: Treatment and Subsurface Injection. Subsurface injection of residual geothermal fluid currently appears to be the most feasible alternative for liquid waste disposal. Injection has been demonstrated

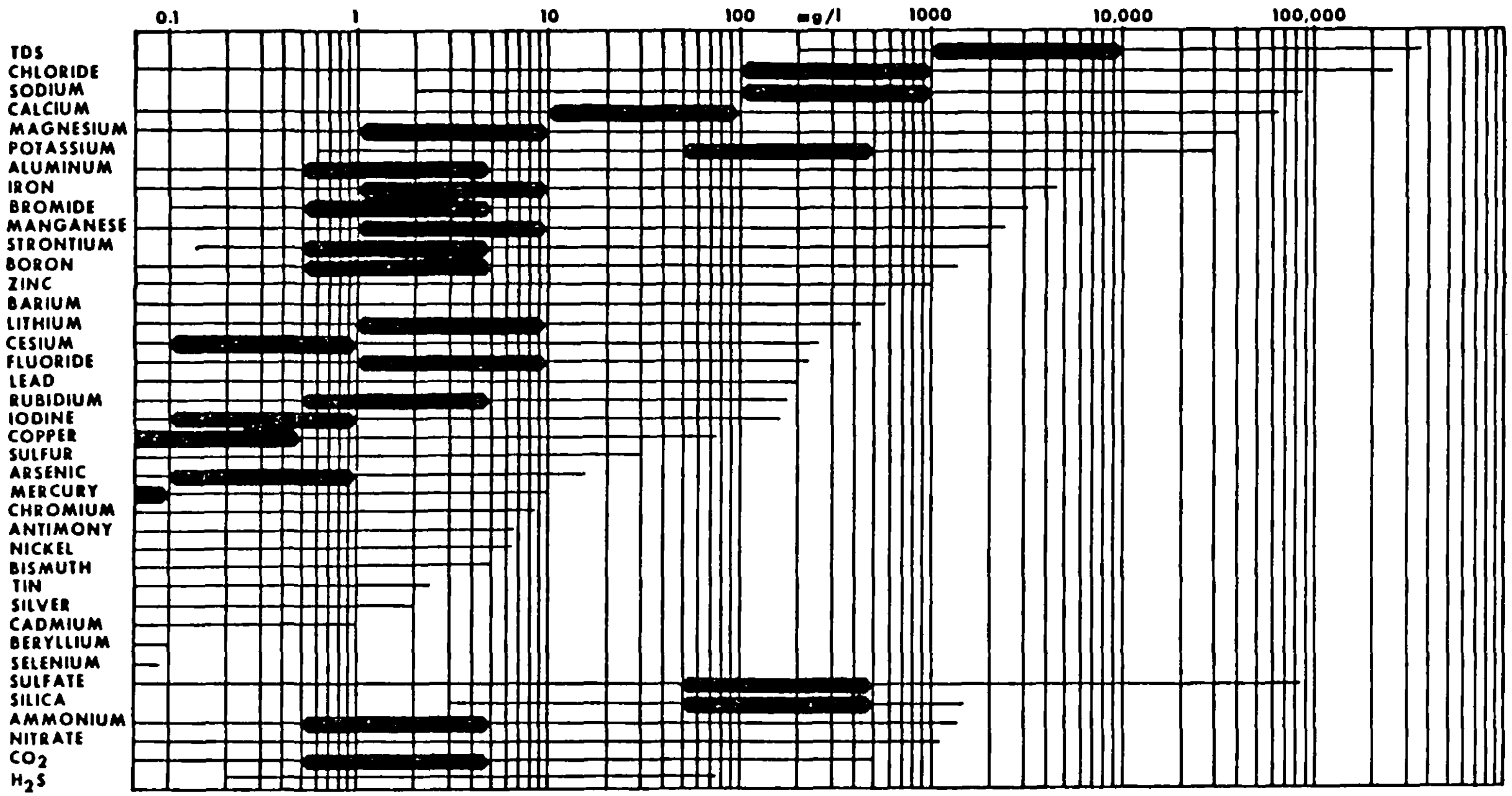


Figure 4-11
CHEMICAL CONSTITUENTS FOUND IN HYDROTHERMAL FLUIDS

Source: Kestin (1980).

with varying degrees of success at numerous reservoirs including the Geysers and Imperial Valley in California and at Valles Caldera in New Mexico. In addition to providing liquid waste disposal, subsurface injection may also replenish the reservoir with fluid, minimizing reservoir depletion and surface subsidence.

The principal problems associated with subsurface injection are plugging, scaling and corrosion in pipes and well casings due to the contaminents in the residual brine. As the brine is cooled during power generation, it becomes saturated and the dissolved solids begin to precipitate out of solution. The main constituents that cause scaling and plugging are silica and silicates, calcium carbonate and metal sulfides, sulfates, oxides, hydroxides and carbonates. The chemical processes involved vary from reservoir to reservoir due to variations in brine composition and temperature.

Surface treatment may be necessary to minimize these problems if subsurface injection is to be operationally feasible. Generally this treatment would involve one or more of the following (Kestin, 1980):

- o Storage, settling and physical separation of unwanted components in the brine;
- o Corrosion control by pH control, and use of inhibitors;
- o Coagulation and clarification;
- o Filtration and bactericide addition for bacteria control;
- o Application of electric potential to reduce scaling.

The treatment required must be tailored to address the specific mechanisms of plugging, scaling and corrosion present at the reservoir. For example, recent experimental work by Republic Geothermal, Inc. East Mesa, CA Field has shown that Dequest 2060, a low cost inhibitator, is an effective treatment for $CaCO_3$ scale problems (Vetter, 1979). At Niland, where silica scaling problems result from the high salinity brine, a reactor-clarifier system is required to remove silica from the brine before reinjection.

There are other potential problems which must also be considered when applying subsurface injection. These include:

- o Groundwater contamination due to faulty injection well casings;
- o Cooling of production well fluid due to mixing of the cooler reinjected brine
- o Triggering of seismic activity due to injection.

Any one of these problems could cause subsurface injection to be unfeasible at certain sites.

In the case studies reported on below, it is assumed that chemical treatment of the brine is necessary to prevent corrosion, scaling and plugging. In addition, for reservoirs with total dissolved solids greater than 100,000 PPM, a solids contact reactor and gravity filters are provided to remove solids from the brine. Figure 4-12 shows this brine treatment system.

Case II: Advanced Treatment and Surface Disposal. An alternative to subsurface injection is to reclaim the power plant waste water for domestic or agricultural use. To do this, the waste water must be treated to remove unwanted constitutents. The treatment is generally more expensive than subsurface injection. However, it may be warranted when the additional cost is justified by the value of the reclaimed water or when subsurface injection is not technically feasible.

The level of treatment required will depend upon the intended use for the reclaimed water and on the contaminents contained in the effluent. Federal water quality standards require total dissolved solids concentrations of less than 500 PPM for drinking water, and 500-15,000 PPM for irrigation use. Effluent treatment may also be dictated by Federal limitations of specific constituents (e.g., arsenic, borom, mercury) and by state and local regulations.

PNL has surveyed conventional and advanced water treatment systems which are candidates for geothermal plant effluent treatment (Wells, 1981). Table 4-13 summarizes their findings regarding removal efficiencies and treatment cost variables.

In Case II, the brine is treated to remove unwanted constituents, making it suitable for reuse. The power plant includes a conventional waste water treatment system, as shown in Figure 4-12, followed by advanced treatment. Advanced treatment is selected to reduce total dissolved solids in the treated stream to 500 PPM at the lowest cost. A reverse osmosis system is used when removal efficiencies of less than 95% are required. For greater removal efficiency, distillation is required.

Costs of Liquid Effluent Disposal Systems. The capital and operating costs used in this analysis for liquid effluent treatment and disposal options are based on information recently published by PNL (Wells, 1981a). This PNL report presents cost functions for conventional and advanced waste

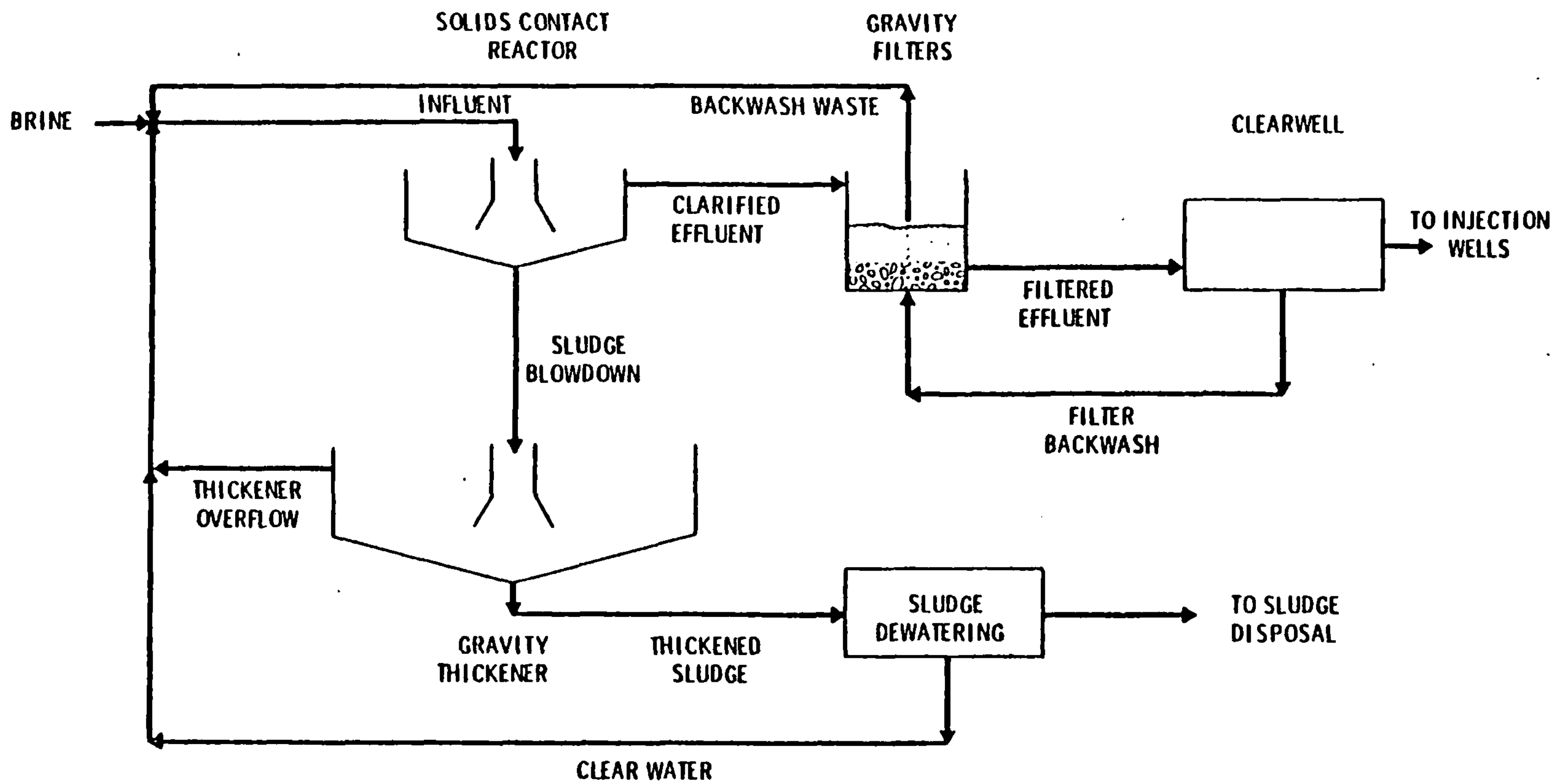


Figure 4-12
BRINE TREATMENT AND SUBSURFACE INJECTION PROCESS

Table 4-13
LIQUID EFFLUENT TREATMENT SYSTEM SUMMARY

Treatment System	Removal Efficiencies (%)				TDS Limit for System Application	Cost Variables
	TDS	Boron	Mercury	Arsenic		
Conventional:						
Sedimentation	10	10	10 to 30	10 to 30	no limit	volumetric flow rate
Filtration	10	20 to 40	70 to 80	79 to 95	no limit	volumetric flow rate TDS concentration labor cost power cost
Chemical Precipitation	20 to 40	20 to 40	40 to 60	80 to 98	1000 ppm TDS	volumetric flow rate chemical cost
SSDS Removal[(a)]	19	28	73	78	no limit	
SSDS Removal[(a)] enhanced by chemical precipitation	35	42	84	96	no limit	
Advanced:						
Electrodialysis	30 to 40 per stage	10	30 to 40	30 to 40	5000 ppm TDS	volumetric flow rate
Ion Exchange	80 to 90	80 to 90	80 to 90	80 to 90	5000 ppm TDS	volumetric flow rate change in TDS concentration
Reverse Osmosis	85 to 95	60 to 80	85 to 95	85 to 95	50,000 ppm TDS	volumetric flow rate
Distillation	99				300,000 ppm TDS	volumetric flow rate

(a) Supersaturated dissolved solids removal.

water treatment systems. The functions relate incremental capital and operating cost to the flow rate of effluent treated and of the fraction of solids removed. The cost functions for purchased equipment costs (PE) and annual operating costs (AOC) are given in Table 4-14.

Potential Impact of Effluent Control Costs on Power Development. To evaluate the impacts on development of utilizing advanced liquid effluent disposal options (in place of direct re-injection), the cash flow and decision model is used forecast development at two resource area in California's Imperial Valley. Power development under the base case effluent disposal method (direct reinjection) is compared to the development levels which can be expected if reinjection following treatment or surface treatment and disposals techniques are used. The relatively high concentration of total dissolved solids (TDS) found in the brine at Brawley KGRA (53,700 ppm TDS) and East Mesa KGRA (30,000 ppm TDS) make both areas likely candidates for advanced disposal techniques.

As shown in Table 4-15, the results of this analysis indicates that at relatively high quality resources, effluent treatment and reinjection disposal methods can be employed without impeding power development. At Brawley KGRA, the high temperature and well flow rates of the resource permit the additional costs of effluent treatment to be absorbed without reductions in development. At a lower quality resource such as East Mesa, the costs of effluent treatment cannot be incurred without significantly impairing anticipated resource development. At both Brawley and East Mesa, the costs of advanced treatment and surface disposal are prohibitive.

Table 4-14
COST FUNCTIONS FOR LIQUID EFFLUENT TREATMENT SYSTEMS

Chemical Addition Cost Functions

- o Polymer storage and feed systems:
  Total purchased equipment = $\$19,900 \times MGD^{0.68}$
- o Alum or iron compound storage and feed systems:
  Total purchased equipment = $\$22,300 \times MGD^{0.73}$
- o Lime storage, slaking, and feed systems:
  Total purchased equipment = $\$36,400 \times MGD^{0.68}$
- o Annual operation and maintenance of any of the above systems (not including chemicals):
  O&M costs = $\$31,500 \times MGD^{0.36}$

Solids Contact Reactor Cost Functions

- o Assuming an upflow rate of 1 gpm/ft^2:
  Total purchased equipment = $\$220,000 \times (0.75 \times MGD)^{0.66}$
- o Annual operation and maintenance cost:
  O&M costs = $\$51,700 \times (0.75 \times MGD)^{0.48}$

Dual Media Gravity Filter Cost Functions

- o Assuming a loading rate of 4 gpm/ft^2:
  Total purchased equipment = $\$602,000 \times (0.18 \times MGD)^{0.66}$
- o Annual operation and maintenance cost:
  O&M costs = $\$70,400 \times (0.18 \times MDG)^{0.63}$

Gravity Thickener Cost Functions

- o Total purchased equipment = $\$10^{(0.35 \times \log(PD) + 3.64)}$
  where PD = pounds per day of dry solids
- o Annual operating and maintenance costs:
  O&M costs = $\$0.281\ (PD)^{0.75} + \$1.12\ (PC)\ (PD)^{0.84} + \$1.78(LC)\ (PD)^{0.01}$
  where PC = power cost in \$kWh = \$0.04/kWh
  LC = labor cost in fully burdened \$/yr = \$30,000

Table 4-14 (continued)

Vacuum Filter Cost Functions

- Total purchased equipment = $10^{(0.52 \times \log (PD) + 1.52)}$
- Annual operation and maintenance costs:

  O&M costs = $\$8.71\ (PD)^{0.70} + \$0.07\ (PC)\ (PD)^{0.83} + \$0.02\ (LC)\ (PD)^{0.67}$

  where C = \$15.00 per hour.

Sludge Disposal

- Sludge disposal costs were updated from Sung et al. (1977)
- Sludge disposal costs = \$25 per ton of dry solids

Distillation Cost Functions

- Total purchased equipment = $\$4,600,000 \times MGD^{0.77}$
- Annual operation and maintenance costs:

  Labor cost = $\$258,500 \times MGD^{0.47}$

  Energy cost = $\$726,000 \times MGD^{0.95}$

Reverse Osmosis Cost Functions

- Total purchased equipment = $\$1,056,000 \times MGD^{0.86}$
- Annual operation and maintenance costs:

  Labor cost = $\$67,200 \times MGD^{0.45}$

  Power cost = \$241,000 x MGD

  Membrane replacement = \$88,000 x MGD

Electrodialysis Cost Functions

- Assuming stack capacity of 0.10 MGD:

  Total purchased equipment = $\$242,000 \times (10 \times MGD)^{0.68}$
- Annual operation and maintenance costs:

  Labor cost = $\$67,200 \times MGD^{0.45}$

  Power cost = \$321,200 x MGD

  Membrane replacement = \$18,700 x MGD

Table 4-15
LIQUID EFFLUENT DISPOSAL COST SENSITIVITY ANALYSIS

	Estimated Mean Power Development Level (MW)			
	1985	1990	1995	2000
Brawley KGRA (8-6-2-3-7-7)*				
Direct Reinjection	55	334	386	402
Treatment and Reinjection	55	334	386	402
Advanced Treatment and Surface Disposal	55	55	55	55
East Mesa KGRA (6-5-2-3-5-3)*				
Direct Reinjection	21	243	298	368
Treatment and Reinjection	21	21	21	90
Advanced Treatment and Surface Disposal	21	21	21	21

*Generic Resource Code (See Table 2-4)

PART II

Chapter Five

HYDROTHERMAL NON-ELECTRIC DEVELOPMENT FORECASTS

Although geothermal energy has been used for centuries as a direct source of heat, geothermal resources in the United States received little consideration as a modern energy source for non-electric (direct-use) applications until the late 1960's. Since then, the escalating prices, uncertainty of supply, and environmental concerns associated with conventional energy sources, have caused a growing interest in the use of geothermal energy. Geothermal energy is now being used in the U.S. on a limited basis in numerous diverse non-electric applications including space heating, vegetable dehydration, agriculture, aquaculture, and light manufacturing.

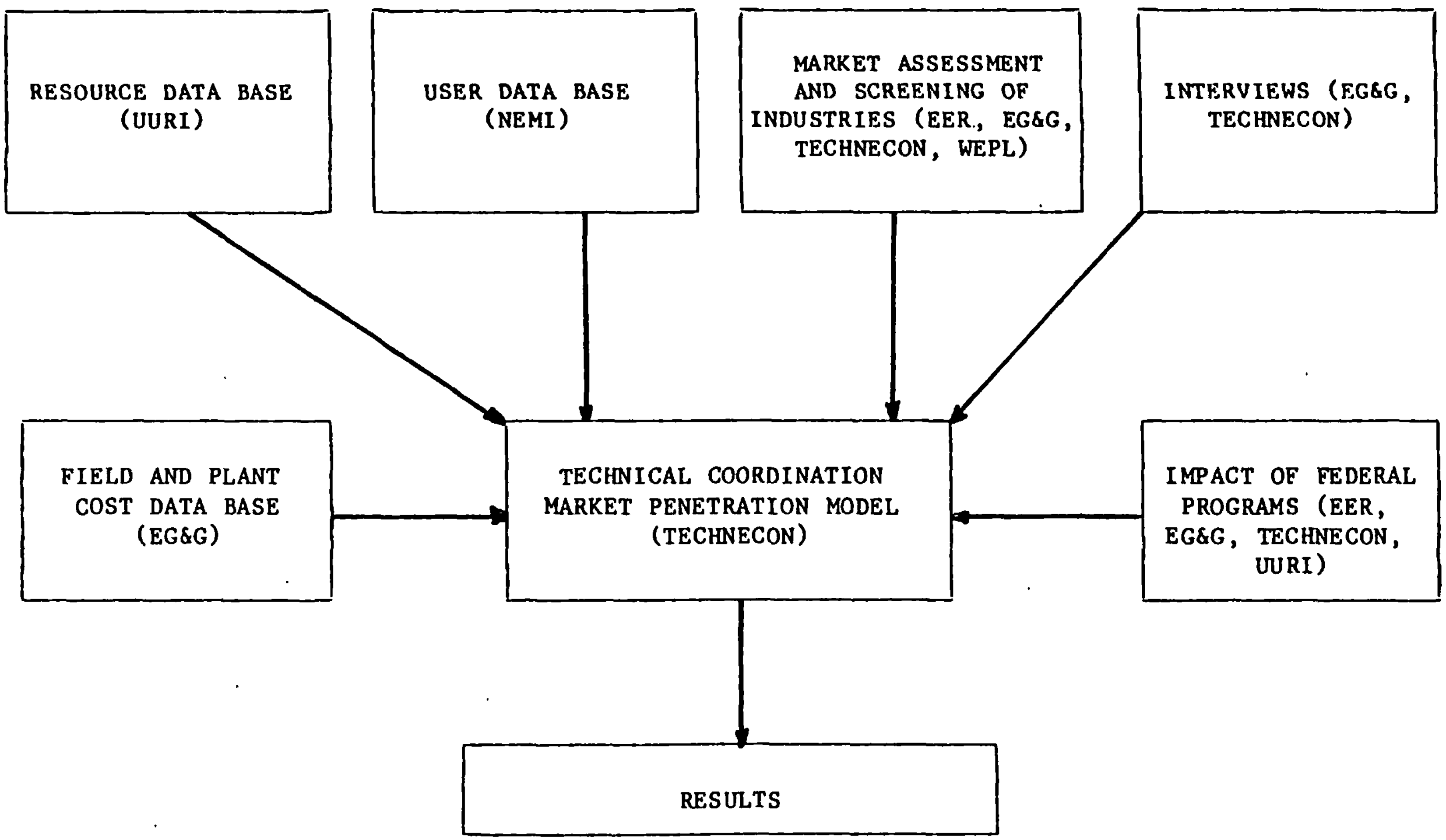
A large hydrothermal resource base for direct use has been identified in the United States. The rate and extent to which this resource base is developed will depend upon the rate and extent to which industry will invest capital into hydrothermal development and construction. The understanding and estimation of this investment behavior, and of incentives which will prompt positive industry response, are the topics of this chapter.

A Task Force was organized by the U.S. Department of Energy/Division of Geothermal Energy (DGE) in early 1980 to estimate the likely market penetration of hydrothermal energy through the year 2000. As part of this Task Force, Technecon developed and implemented an investment decision model for hydrothermal non-electric applications.

The DOE Task Force was comprised of: Engineering and Economics Research, Inc. (EER); EG&G Idaho, Inc.; New Mexico Energy Institute (NMEI); University of Utah Research Institute, Earth Science Laboratory (UURI/ESL); Western Energy Planners, Ltd. (WEPL); and Technecon. The role of each member is indicated in Figure 5-1. An Industry Review Panel was also organized to provide periodic critiques of the methods and assumptions used by the Task Force. The Review Panel included representatives from the financial community, resource companies, public utilities, non-electric users and governmental agencies.

This report focuses on the model development and application for which

Figure 5-1
RESPONSIBILITIES OF TASK FORCE MEMBERS



Technecon was principally responsible. As indicated throughout the report, however, other Task Force members assisted Technecon in providing required data. A recent publication (DOE, 1981) describes the overall Task Force effort.

The purposes of this work are twofold:

- o To provide a means for making probabilistic estimates of the commercial potential and rate of development of hydrothermal non-electric applications in the United States.
- o To provide a means for evaluating the impact which improvements in non-electric utilization technologies, brought about by research and development efforts, may have on market penetration.

These objectives are met by a quantitative decision model that forecasts capital investments in specified hydrothermal ventures. This decision model estimates the likelihood of a positive investment response as a function of a few key attributes of the investment opportunity. The attributes (e.g. capital requirements, energy cost savings, risk of loss, etc.) were selected by econometric techniques for their ability to efficiently explain industrial investment behavior.

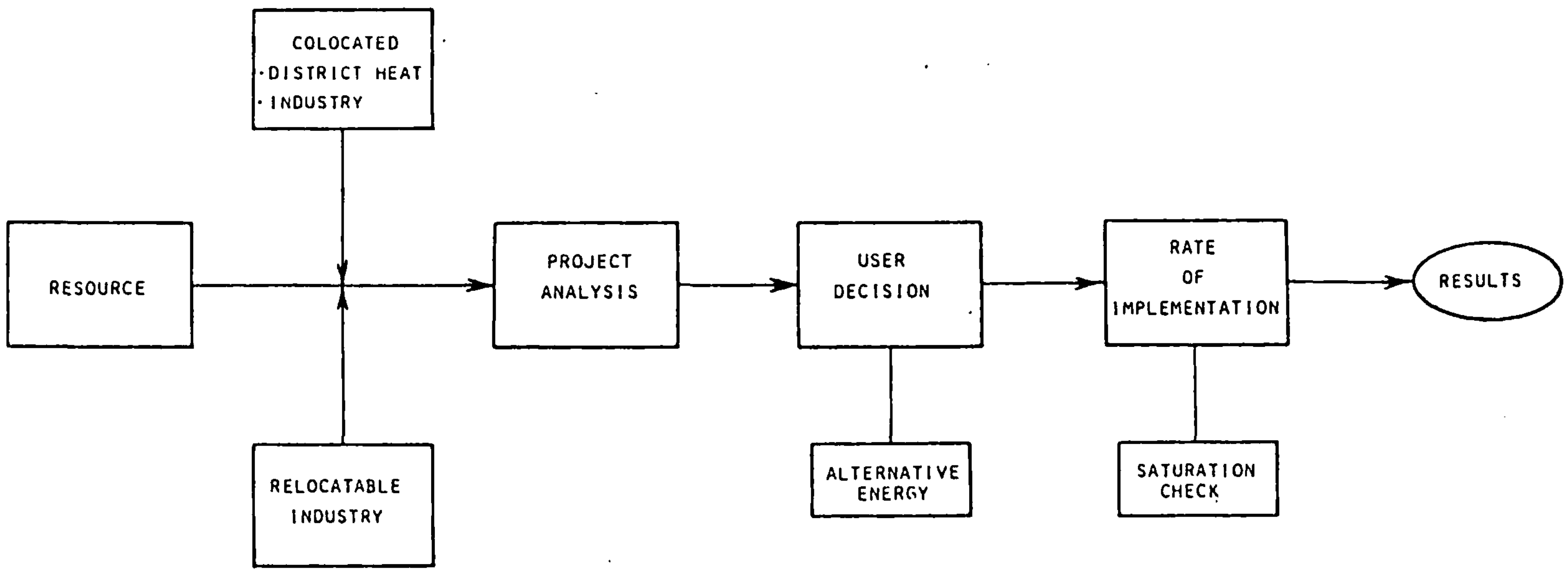
Modeling efficiency is crucial to achieving the purposes of this work. Resource assessment on a national level requires the processing of a great number of known and projected resource sites through the decision model. Therefore the selection of a limited number of investment attributes, and the structuring of efficient computer models to both estimate and act upon these attributes, are important concerns for providing a cost-effective analytic instrument.

In this regard, the objective here is to efficiently estimate the outcome of an industrial investment decision based upon an investment analysis that is considerably less rigorous than than employed in the actual industrial decision process. Whereas the industrial decision-maker considers a multitude of attributes when weighing the risks and returns of an investment opportunity, it is possible to predict the numerical likelihood of a positive decision — within an acceptable confidence interval -- by employing fewer investment attributes in a somewhat less rigorous analysis.

5.1 MODELING APPROACH

Figure 5-2 illustrates the structure of the investment analysis model developed by Technecon for non-electric geothermal applications. In

Figure 5-2
NON-ELECTRIC HYDROTHERMAL MARKET ANALYSIS



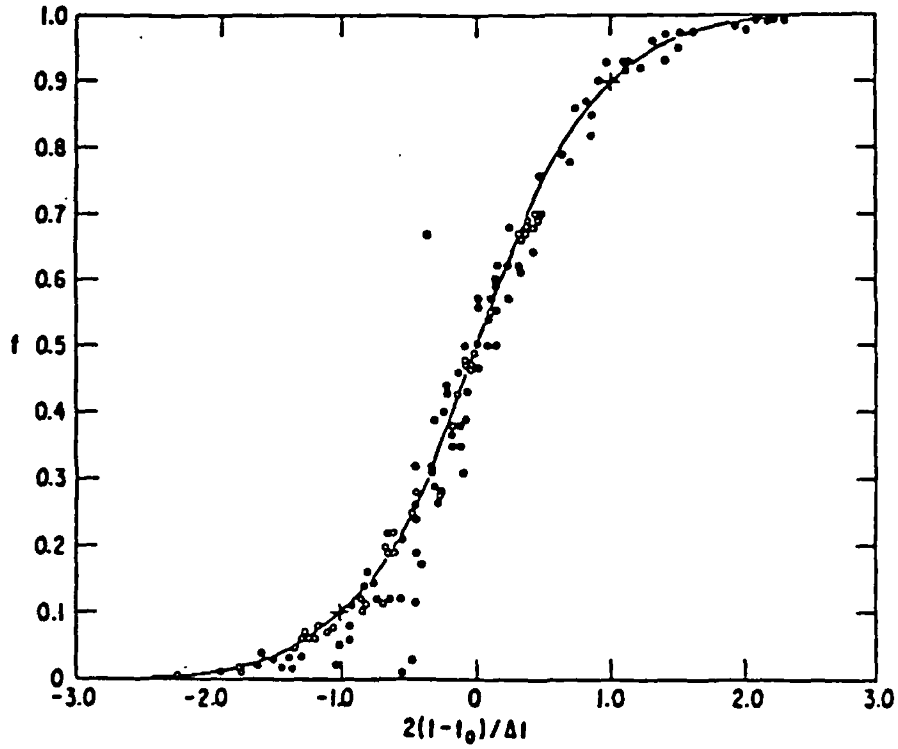
summary, the analysis is initiated by the specification of the characteristics of a hydrothermal resource. Potenital colocated and relocatable users are identified at the resource and a discounted cash flow (DCF) analysis is performed for each user/resource pair. Using modern decision analysis methods, the likelihood of a positive decision to use the resource is then estimated for each potential user, taking into account alternative energy forms available to each. If a positive user decision is indicated, then the rate of resource development is estimated to accommodate implementation lags. Resource development is constrained by saturation of the available resource as a last step in the analysis.

5.2 MARKET PENETRATION ANALYSIS OVERVIEW

There is a substantial body of literature pertaining to the market diffusion of new technologies and to various analogue forms for modeling diffusion characteristics (see, for example, Linstone and Sahal, 1976). These analogues have been remarkably successful in projecting the rate of new technologies' market penetration. Figure 5-3, for example, illustrates the close correlation between an S-shaped diffusion model used by Fisher and Pry (1971) and aggregate empirical data for the market penetration of seventeen technological advances (e.g. synthetic fibers, plastics, electric arc steel furnaces, etc.). The general form of the S-shaped or "logistic" curve used for estimating technological substitution may be expressed as:

$$f = \frac{K}{1 + \exp\left[-(a+bt)\right]}$$

Figure 5-3
FIT OF FISHER-PRY MARKET PENETRATION
MODEL TO EMPIRICAL DATA



where f is the fraction of the market penetrated at time t, K is the asymptotic upper bound of f (i.e. the maximum achievable level of market penetration), and a and b are constant parameters which specify the location on a time scale and rate of penetration, respectively. Other forms of the S-shaped diffusion model are specified in the literature -- see, for example, Blackman (1972) and Floyd (1968) -- though most represent a variation of the fundamental logistic function specified above.

Forecasts of market penetration using a logistic analogue are generally performed by extrapolating the S-shaped curve on the basis of penetration trends derived from statistical analysis of historical data. Satisfactory forecasts have been achieved by using econometric techniques (to estimate a and b) based upon data on as little as 3-5% penetration. In the absence of empirical data, or in cases of insufficient data, it is sometimes possible to assume the parameters of the S-shaped curve by using historical data for technological substitution in similar industries or sectors (ref. Sahal, 1976). Whether the functional parameters are estimated by regression analysis or assumed, it is understood that the new technology provides a technological advance or economic benefit to the market.

5.2.1 Hydrothermal Non-Electric Modeling Approach

In the hydrothermal non-electric case, there are unique problems involved with forecasting industry investment behavior. First, there is neglible penetration to date and, therefore, it is not possible to extrapolate an S-shaped curve based upon econometric analysis of historical data. Second, penetration is anticipated in numerous industrial, commercial and residential markets. There is insufficient historical information available on these diverse markets to support an assumption pertaining to the appropriate quantification of a penetration curve. Third, it cannot be assumed that hydrothermal energy provides either a technological advance or economic benefit to each and every market being studied.

To confront these special problems, it was necessary to depart from the aforementioned traditional means of market penetration analysis. Instead, after a review of the theory behind the S-shaped diffusion analogue, a model was developed by: (a) disaggregating the traditional analogue into several subelements, (b) quantifying each subelement separately, and then (c) re-coupling the several subelements in an integrated model.

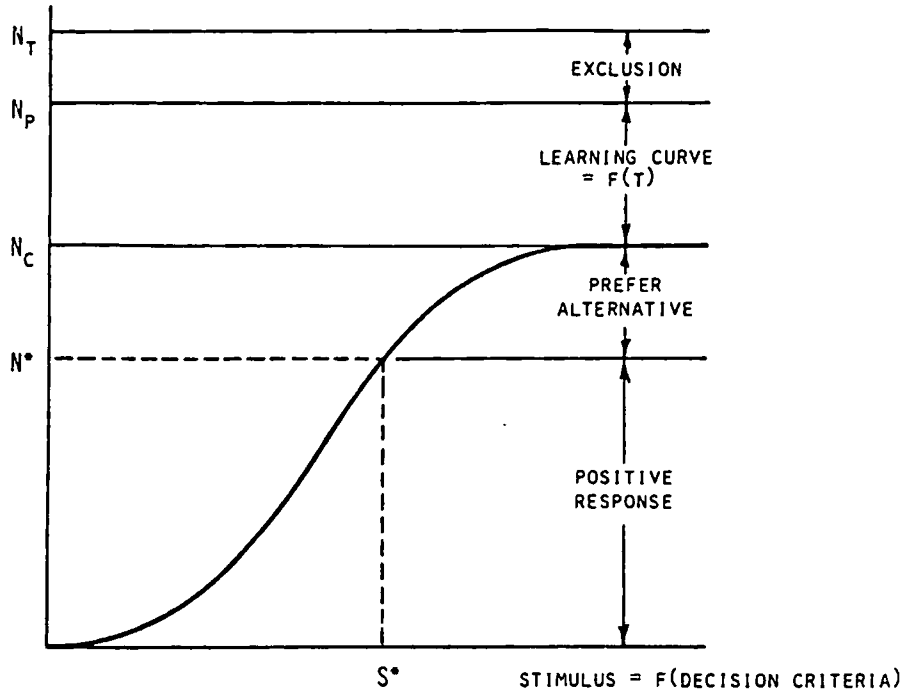
The modeling approach involves first identifying the number of candidate users in the total market (with "market" defined here by a 4-digit Standard Industrial Classification Code) who would consider adopting a direct-use project. A fraction of the firms in a potential non-electric market are unlikely to ever consider the use of hydrothermal energy, due to a variety of reasons including incompatible heat requirements, logistical concerns, or financial limitations. An <u>Exclusion Factor</u> is used to identify this segment of the market, and acts to define the "upper bound" on market penetration (N_P in Figure 5-4).

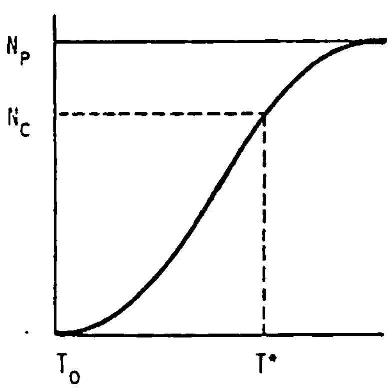
Because of limited hydrothermal market penetration to date, a large share of the candidate users (i.e., those not excluded for technical, logistical, or financial reasons) may be unaware of the potential viability of hydrothermal energy sources. Over time, however, an increasing proportion of the potential market will become aware of hydrothermal energy as "messages" from early innovators and pilot projects diffuse through the market. Within the market, differing levels of resistance exist among the potential users. The time required to inform the market and to overcome varying degrees of resistance are incorporated into the analysis by the <u>Learning Curve</u> subelement as shown in Figure 5-4. At a given point in time, T*, the fraction of the market which is informed and willing to consider the hydrothermal alternative is specified as N_C.

The stimulus for a potential user to adopt hydrothermal energy is a function of several variables including technological evolution, relative energy economics, and availability and reliability of energy supply. In a diverse market, these stimuli will be perceived differently by different potential users. As shown in Figure 5-4, an S-shaped logistic curve is employed to estimate the fraction of the market that will respond positively, N*, to a specified multivariate level of stimulus, S*. This <u>Logistic Curve of Positive Response</u> was quantified by a systematic survey of the market and an econometric

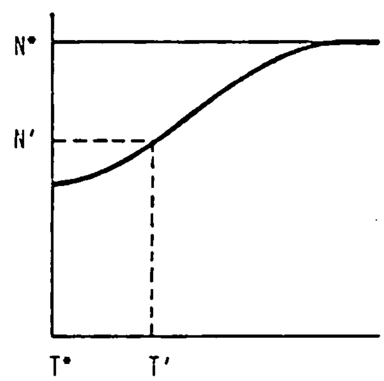
Figure 5-4

NON-ELECTRIC HYDROTHERMAL USER DECISION MODEL





LEARNING CURVE



IMPLEMENTATION RATE

analysis of survey results.

From the time, T*, that a fraction, N*, of the market is informed and also likely to respond positively to the hydrothermal stimuli, a time lag will be encountered until implementation of this hydrothermal technology is actually realized. This lagged response is modeled by the Implementation Rate Curve shown in Figure 5-4. At time T' following T*, the fraction of the market that will have implemented hydrothermal technology energy is given by N'. Several factors contribute to this lagged response: (i) lead time from the time of decision, T*, until project financing can be arranged; (ii) lead time requirements for engineering, procurement, permitting, and construction; and (iii) the age and unit operating cost of existing equipment which will be gradually replaced over time with the hydrothermal equipment (ref. Mansfield, 1968).

The sampling procedure and survey results used to estimate the market penetration analogue are presented below. Forecasts of the rate of direct-use market penetration are illustrated in Chapter 6.

5.3 MARKET ANALYSIS

A market survey developed jointly by the DOE Task Force, and distributed by EG&G Idaho, provided the source of information on which several elements of the market penetration model were based. This section first describes the sampling procedure and interview process used to collect the data. It then discusses how the results of the survey were used in the estimation of several elements of the market penetration analogue.

5.3.1 Identification of User Candidates.

The utilization of hydrothermal energy as a source of process heat is not feasible for a number of specific manufacturing activities. Many industries require process heat at temperatures in excess of 400^{o}F, and thus are not suited for hydrothermal direct-use applications. Other manufacturing processes generate more waste process heat than can be utilized internally during the course of other plant operations. These industries, similarly, are not candidates for direct-use application. Finally, some industries are apt to be unable to use hydrothermal energy for other technical, logistical or geographic reasons. Such industries were eliminated from consideration at the outset of this study.

A compilation of industries utilizing sub-400°F process heat, at the 4-digit Standard Industrial Classification level, was prepared. This listing was based primarily on industrial process heat demands estimated by Brown (1980) and Fraiser (1977). Task Force members then reviewed the remaining industry classifications, and identified several industries which generate excess quantities of waste process heat internally (e.g. steel mills or petrochemical complexes) and other industries which are unlikely to utilize hydrothermal energy.

5.3.2 Market Sample.

To estimate the component elements of the market penetration model, a carefully designed questionnaire was prepared by the Task Force for use in assessing the perceptions and investment decision criteria of specific firms. A number of statistical tests and screening procedures were used to determine which candidate user groups would be contacted, as well as which specific firms within a group would be interviewed. These procedures enabled the accuracy of the survey results to be maximized, given the desired sample size.

Firms within 24 4-digit Standard Industrial Classifcation industries emerged from this screening process and were then targeted for surveying. The 24 surveyed industries are listed in Table 5-1. Analysis of this group showed that although there are roughly ten times as many potential user establishments outside the selected group as are in the group, the potential hydrothermal energy use outside the selected group is only about 18% of that within the group. This fact attests to the efficiency of the screening process.

It should be emphasized that the purpose of the screening procedure was only to enhance interviewing accuracy and model efficiency. The market potential of users outside these surveyed categories was included in the analysis by extrapolation of the market penetration results obtained within the surveyed user categories.

Table 5-1
CANDIDATE HYDROTHERMAL NON-ELECTRIC USERS

SURVEY GROUP #	SIC	INDUSTRY
1.	018	GREENHOUSES
	0181	Ornamental Floriculture & Nurseries
	0182	Food Crops Grown Under Cover
2.	024	DAIRY FARMS
3.	025	POULTRY & EGGS
4.	0279	FISH FARMS
5.	1311	TERTIARY OIL RECOVERY
6.	201	MEAT PRODUCTS
	2011	Meatpacking Plants
	2013	Sausages & Prepared Meats
7.	202	DAIRY PRODUCTS
	2022	Cheese, Natural & Processed
	2023	Condensed & Evaporated Milk
8.	203	FRUIT & VEGETABLE PRODUCTS
	2034	Dehydrated Fruits, Veg & Soups
	2037	Frozen Fruits & Vegetables
9.	2046	WET CORN MILLING
10.	206	SUGAR REFINING
	2062	Cane Sugar Refining
	2063	Beet Sugar Refining
11.	207	FATS & OILS
	2075	Soybean Oil Mills
	2077	Animal & Marine Fats & Oils
12.	208	ALCOHOLIC BEVERAGES
	2082	Malt Beverages
	2085	Distilled Liquor (except Brandy)
13.	2436	SOFTWOOD VENEER & PLYWOOD
14.	26	PULP AND PAPER PRODUCTS
	2611	Pulpmills
	2631	Paperboard Mills
	2641	Paper Coating & Glazing
	2661	Building Paper & Board Mills
	2653	Corrugated & Solid Fiber Boxes

Table 5-1 (continued)

15.	281,2	CHEMICAL PRODUCTS
	2812	Alkalies & Chlorine
	2819	Industrial Inorganic Chemicals
	2822	Synthetic Rubber
	2823	Cellulosic Manmade Fibers
	2824	Organic Fibers, Noncellulosic
16.	283	MEDICINES
	2833	Medicinals & Botanicals
	2834	Pharmaceutical Preparations
17.	2865	CYCLIC CRUDES & INTERMEDIATES
18.	2869	INDUSTRIAL ORGANIC CHEMICALS (note: includes Ethanol Plants)
19.	2873	NITROGENOUS FERTILIZERS
20.	3011	TIRES & INNER TUBES
21.	3241	CEMENT, HYDRAULIC
22.	3271	CONCRETE BLOCK & BRICK
23.	3275	GYPSUM PRODUCTS
24.	3295	MINERALS, GROUND & TREATED
25.	-	DISTRICT HEATING SYSTEMS

5.4 RESULTS OF SAMPLE ANALYSIS

The following sections discuss the interview results pertaining to specific elements of the market penetration analogue illustrated earlier in Figure 5-2.

5.4.1. Likelihood of Relocation

The potential users of a geothermal resource include both those currently "colocated" with the resource and those not colocated but who are willing to "relocate" to the resource site. The number of colocated establishments is an input to the market penetration model, provided by NMEI.

The interview results provided the likelihood of relocation to the resource site by each category of user in the market sample. Relocation was examined in terms of both intra-regional and inter-regional migration according to the regional boundaries defined on the map in Figure 5-5. From the interview responses, the proportion of the surveyed firms willing to relocate within their region and outside of their region was tabulated, as shown in Table 5-2. In cases where the number of firms interviewed was insufficient, or where unrealistic or biased responses were evident, tabulations were corrected in light of the responses to other pertinent questions and the relocation preferences of other similar industry categories.

Inter-regional relocation data were tabulated in a matrix for each user category to indicate the proportion of firms willing to migrate from one specific region to another specific region. Each of the 24 matrices (i.e. one per user category excluding district heat) contained 20 rows of regional origin and 20 columns of regional destination. Values presented in Table 5-2 are representative matrix entries for each respective user category.

5.4.2 Exclusion Factor

Part of the interview format was designed to provide data for estimating the fraction of firms within each user category that would be unwilling to use hydrothermal energy regardless of the stimuli to do so. (Recall "exclusion factor" discussion in Section 5.2.2). Interviews were conducted such that unwillingness due to lack of

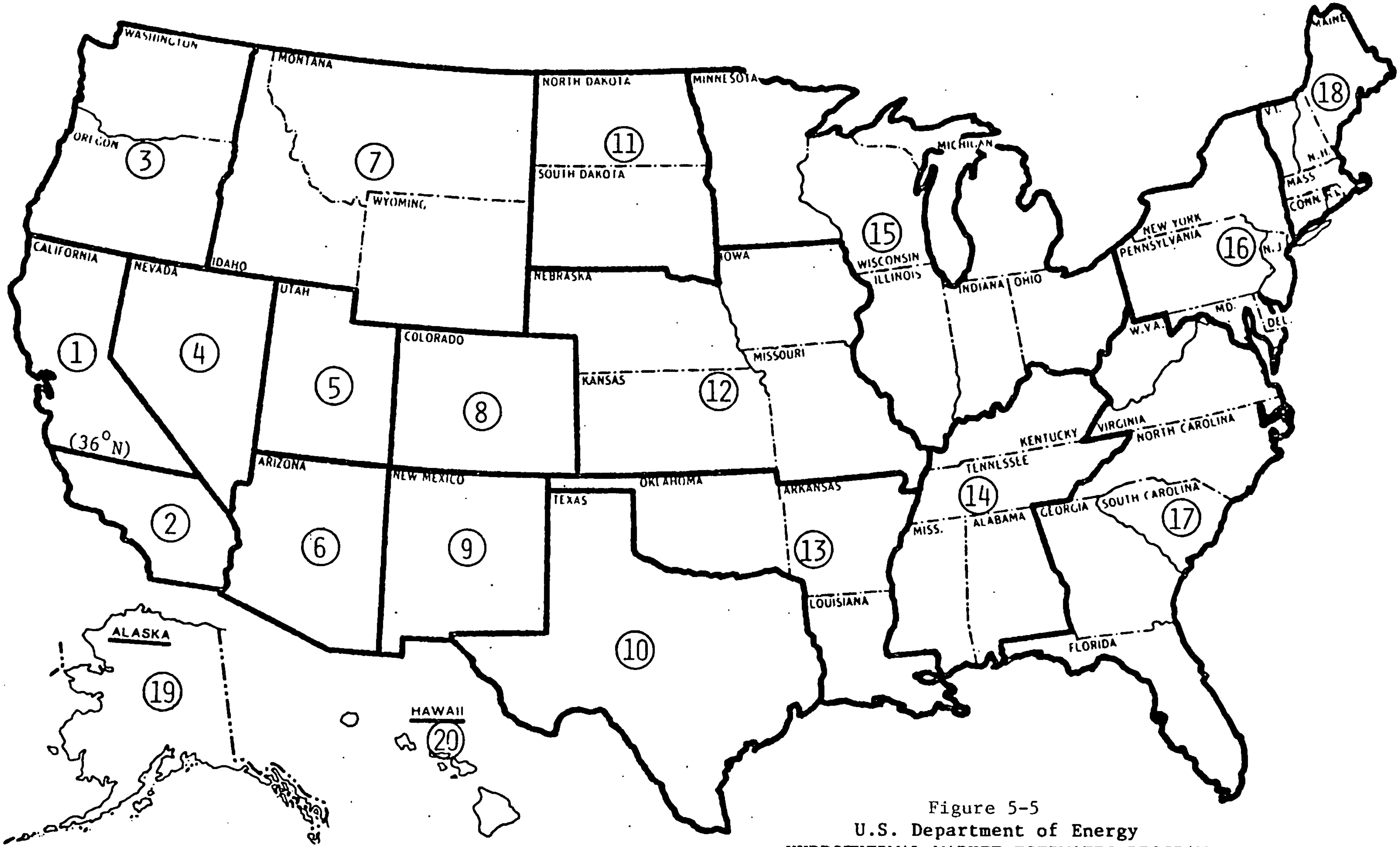


Figure 5-5
U.S. Department of Energy
HYDROTHERMAL MARKET ESTIMATES PROGRAM

Map of Regional Boundaries

Table 5-2

IDENTIFICATION OF NON-COLOCATED USER CANDIDATES

	SIC CODE	INDUSTRY CATEGORY	EXCLUSION FACTOR	LIKELIHOOD OF RELOCATION	
				INTRA-REGIONAL	INTER-REGIONAL
1.	018	GREENHOUSES	.04	.75	.30
2.	024	DAIRY FARMS	1.00	0	0
3.	025	POULTRY & EGGS	.10	.60	0
4.	0279	FISH FARMS	.25	.75	.20
5.	1311	TERTIARY OIL RECOVERY	--	0	0
6.	201	MEAT PRODUCTS	.31	.50	0
7.	202	DAIRY PRODUCTS	.08	.60	.10
8.	203	FRUITS & VEGETABLES	.18	.50	.10
9.	2046	WET CORN MILLING	.42	.40	.10
10.	206	SUGAR REFINING	.33	0	0
11.	207	FATS & OILS	.29	.50	.10
12.	208	ALCOHOLIC BEVERAGES	.38	.50	0
13.	2436	SOFTWOOD VENEER & PLYWOOD	.20	.20	0
14.	26	PULP & PAPER PRODUCTS	.26	.20	0
15.	281,2	CHEMICAL PRODUCTS	.28	.60	.40
16.	283	MEDICINES	.16	.60	.30
17.	2865	CYCLIC CRUDES & INTERMEDIATES	.11	.60	0
18.	2869	INDUSTRIAL ORGANIC CHEMICALS	.04	.60	.40
19.	2873	NITROGENOUS FERTILIZERS	.08	.60	.30
20.	3011	TIRES & INNER TUBES	.50	.30	.30
21.	3241	CEMENT LPRODUCTS	1.00	0	0
22.	3271	CONCRETE BLOCK & BRICK	.15	.50	0
23.	3275	GYPSUM PRODUCTS	.65	.60	.40
24.	3295	MINERALS, GROUND & TREATED	.10	.30	0
25.	--	DISTRICT HEATING SYSTEMS	.12	0	0

familiarity (i.e. learning curve effects) could be distinguished from unwillingness due to objective and time-independent considerations which are pertinent to the exclusion factor. Such considerations included available waste heat from on-site high temperature processes, relatively insignificant expense for sub-400 degree process heat, and the ability to burn waste products for satisfying process heat requirements.

Table 5-2 provides the exclusion factors which were derived from the market interviews. These exclusion factors were estimated by tabulating pertinent negative interview responses and dividing these tabulations by the total number of useful interviews. When unrealistically biased responses were evident, data were adjusted in view of other relevant interview questions.

5.4.3 Learning Curve

Learning curve influences (recall "learning curve" discussion in Section 5.2) on aggregate markets account for the progressive diffusion of information and for the penetration of varying degrees of resistance to change. Works by Blackman (1974), Sahal (1976) and many others demonstrate the appropriateness of S-shaped learning curve analogues and the quantification of these curves for various industrial market sectors. For the hydrothermal market analysis, S-shaped learning curves were quantified by data extracted from the literature and from specific questions in the interview format. The works of Blackman, and Bressler and Hanemann (1980; A, B and C) were particularly valuable to this part of the analysis. The functional form of the curve is given by:

$$f_L = \frac{1}{1 + [B \times \exp(-At)]}$$

Table 5-3 provides a ranking of the user categories within the market sample in descending order of propensity toward change and current degree of education relevant to hydrothermal adaptation. The A and B coefficients of the learning curve for each user category are also provided in this table.

5.4.4 Logit Model of Positive Response

The logit model of positive response (recall Section 5.2) estimates the fraction of the potential market (net of exclusion, learning curve, colocation and relocation considerations) which is likely to choose to

TABLE 5-3 HYDROTHERMAL NON-ELECTRIC
MARKET SAMPLE LEARNING CURVE CHARACTERISTICS

USER CATEGORY	YEARS UNTIL 50% "LEARNED" ACHIEVED	LEARNING CURVE COEFFICIENTS	
		A	B
GREENHOUSES	0	1	0
FISH FARMS	0	1	0
DAIRY PRODUCTS	2.5	.879	9
SOFTWOOD VEENER & PLYWOOD	2.5	.879	9
POULTRY & EGGS	5	.439	9
ENHANCED OIL RECOVERY	5	.439	9
MEAT PRODUCTS	5	.439	9
FRUITS & VEGETABLES	5	.439	9
SUGAR REFINING	5	.439	9
FATS & OILS	5	.439	9
CHEMICAL PRODUCTS	5	.439	9
MEDICINES	5	.439	9
INDUSTRIAL ORGANIC CHEMICALS	5	.439	9
NITROGENOUS FERTILIZERS	5	.439	9
CONCRETE BLOCK & BRICK	5	.439	9
DISTRICT HEAT SYSTEMS	5	.439	9
WET CORN MILLING	7.5	.293	9
ALCOHOLIC BEVERAGES	7.5	.293	9
PULP & PAPER PRODUCTS	7.5	.293	9
CYCLIC CRUDES & INTERMEDIATE	7.5	.293	9
TIRES & INNER TUBES	7.5	.293	9
GYPSUM PRODUCTS	7.5	.293	9
MINERALS, GROUND & TREATED	7.5	.293	9

adopt hydrothermal energy as a function of the stimuli to do so. It is an S-shaped function and a variation of the logistic function. The logit model accounts for the heterogeneous nature of the non-electric market and, specifically, that hydrothermal energy will provide differing degrees of benefits to differing users.

A decision to implement hydrothermal energy will incorporate trade-offs and weighing of various criteria including investment requirements, investment returns through energy cost savings, and reliability of energy supply among others. Studies by the Earl Warren Legal Institute (ref. Bressler and Hanemann, 1980) were particularly valuable for identifying key decision criteria. In the case of such multiobjective decision behavior, a multivariate logit model may be used to account for the relative weights and interactions of the several criteria in the decision process. Multivariate logit models are described in useful detail by Cassel (1979), Walker and Duncan (1967), Theil (1969), Grizzle (1971), McFadden (1976), and Joskow and Mishkin (1977).

Included in the industry interviews conducted by the Task Force were questions pertaining to a firm's preference for (or aversion to) utilizing hydrothermal energy under various combinations of: (a) delivered energy cost relative to that of their alternative fuel; (b) capital investment requirements; (c) energy supply reliability; and (d) project risk. Binary (yes = 1, no = 0) responses to each combination of project attributes were tabulated by user category. Step-wise multiple regression analyses were performed on several aggregations of the interview data until efficient and statistically acceptable logit functions were achieved.

The functional form of the logit model used in this analysis is expressed as:

$$f_p = \frac{1}{1 + e^{-X}}$$

where f_p is the fraction of the market which responds positively and X is a multivariate polynomial of stimuli. Results of the abovementioned multiple regression analysis provided the several forms of the polynomial, X, which are presented in Table 5-4.

Subsequent discussions between the Task Force and Industry Review Panel led to modifications in the logit models. It was concluded that back-up, fossil-fueled heat sources would most likely be provided with hydrothermal systems and, therefore, the reliability and capital loss concerns are effectively eliminated. This view is also supported by the successful track record of hydrothermal non-electric projects to date. The logit models were then modified by assuming 100% reliability and no expected loss (i.e. R = 1.00 and L = 0) which simplified the functions as shown on the right side of Table 5-4.

5.4.5 <u>Implementation Rate</u>

The logit model of positive response, described below, estimates the market fraction which will respond positively to the hydrothermal decision as a function of several time-dependent decision criteria. From the time of a positive decision, studies indicate that, on an average, about 2 years will be required to implement the decision (ref. Linstone and Sahal, 1976). Additional lag may be expected to account for the current age of equipment that will be retired and replaced by the hydrothermal technology. These response lags due to implementation delay and due to the retirement of existing equipment are incorporated in the market penetration analysis by an implementation rate submodel (recall, also, Section 5.2).

Two approaches to response lag are used in this analysis. One treats positive responses to replace existing heat sources and one treats positive responses to utilize hydrothermal heat to meet industry or district heat growth requirements.

Existing process heat equipment is assumed to have a 20 year life, for the purposes of this analysis, and the current age of installed equipment is assumed to be normally distributed across the market (ref. Sahal, 1976). The fraction of today's equipment which will have been replaced at a future point in time is, therefore, given by a cumulative normal distribution. In functional form, this replacement fraction can be approximated by the expression:

Table 5-4
LOGIT MODELS OF POSITIVE RESPONSE FOR THE HYDROTHERMAL NON-ELECTRIC MARKET SAMPLE

Logit Model: $f = \dfrac{1}{1 + e^{-X}}$

Variables:
- f = fraction of market sector responding positively
- C = capital cost differential (Hydroth.-Conv.), $Millions (1980)
- E = energy cost ratio (Hydroth./Conv.)
- L = expected value of capital loss, $Millions (1980)
- R = reliability, fraction of year available

MARKET SECTOR	UNMODIFIED POLYNOMIAL "X"	SIMPLIFIED FORM OF "X"
Agricultural, Food & Kindred Products (SIC 018, 024, 025, 0279, 201, 202, 203, 2046, 206, 207 and 208)	$X = -4.01 - 0.16C + 5.83R - 3.44ER - 11.7LR + 0.51CER$ (2.86) (2.34) (2.88) (3.25) (3.28) R^2=.50 F=5.98, df=30	$X = 1.82 - 0.15C - 3.44E + 0.51CE$
Stone, Glass, Clay & Concrete Products (SIC 3241, 3271, 3275 and 3295)	$X = 1.41 - 12.6E + 8.84ER - 0.19CER$ (2.99) (1.94) (2.41) R^2=.52 F=9.16, df=25	$X = 1.41 - 3.76E - 0.19CE$
Other Manufacturing Categories (SIC 1311, 2436, 26, 281, 282, 283, 2865, 2869, 2873 and 3011)	$X = -5.39 + 8.59R - 5.35ER - 7.42CR + 9.06CER + 8.63CLR$ (2.79) (3.74) (2.59) (2.30) (2.53) R^2=.59 F=5.11, df=18	$X = 3.20 - 5.35E - 7.42C + 9.06CE$
Municipal District Heat	$X = 4.32 - 10.31 \exp(5.85 - 7.14E^{-1})$ (9.28) (11.7) R^2=.64 F=137, df=76	(no change)

Note: t-statistics given in parentheses
R^2 = coefficient of determination
df = degrees of freedom
F = F-statistic

$$f_R = \frac{1}{1 + e^{4.60 - 0.46t}}$$

The market fraction, f_P, for which a positive hydrothermal response is estimated today, will be implemented (including a 2 year minimum lag) according to a distribution over time given by:

$$f_I(t) = f_P(t=0) \times f_R(t-2)$$

5.5 HYDROTHERMAL NON-ELECTRIC MARKET ESTIMATES

Hydrothermal non-electric market estimate forecasts are presented in the following discussion. Because of the uncertain rate of advancement in non-electric utilization technologies, national forecasts are prepared for three assumed levels of research and development advancements:

Current Technology and Incentives (Base Case): Assumes current state of hydrothermal non-electric drilling of utilization technology. Tax incentives are assumed consistent with regulations in effect in early 1982.

Minimal Technological Advances (Case I): Assumes low level of research and development effort resulting in minor improvements in well drilling techniques and improved operating efficiencies. Tax incentives are the same as Base Case.

Significant Technological Advances (Case II): Assumes appreciable R&D success resulting in significant performance and cost improvements in non-electric utilization technologies. Tax incentives are expanded to include a 15 percent investment tax credit and a reduced tax life for plant equipment.

The modeling procedures, assumptions and parameters used in each simulation are reported in the following sections.

5.5.1 Modeling Assumptions and Parameters

Table 5-5 lists the major parameters used in the market estimate simulation. As noted, many of the inputs provided to the model are site specific. Input variable values were derived from consultation with DOE Task Force members, discussions with industry representatives, and extensive literature reviews. More extensive documentation of the non-electric model parameters can be found in U.S.D.O.E. (1981).

Table 5-5
NON-ELECTRIC ECONOMIC MODEL PARAMETERS

RESOURCE PARAMETERS	ECONOMIC & TAX PARAMETERS
o Well-Head Temperature	o Inflation Rates: Energy
o Contamination Index	o Energy Prices
o Well Flow Unpumped	o Energy Use Efficiencies
o Well Flow Pumped	
o Well Cost	Project Book Life
o Producible Acreage	Project Tax Life
o Fluid Specific Heat	Depletion Allowance
	Royalty Fraction
Spare Well Fraction	Intangible Well Cost Fraction
Producer/Injector Ratio	Investment Tax Credit
Well Spacing	Add'l Investment Tax Credits
Well Rework Fraction	Equity Fraction
Well Rework Cost	Equity Return
Well Redrill Fraction	Long Term Debt Cost
Well Redrill Cost	Local Tax Rates
Dry Well Fraction	State Tax Rate
Dry Well Cost	Federal Tax Rate
	User's Discount Rate
USER PARAMETERS	GNP Deflator
	Inflation Rate: Maintenance
o Annual Heat Requirement	Inflation Rate: Construction
o Temperature Requirement	
o Annual User Factor	
o Alternative Fuel Type	
Temperature Loss and Pinch	

o Site Specific

Source: Technecon

With technological advances brought about by R&D, significant economic or plant performance benefits may be realized. By improving both available technology and providing economic incentives to potential non-electric users, market penetration rates can be expected to increase. To evaluate the magnitudes of such increases, DOE Task Force Members reviewed model inputs and estimated the likely effect of "Minimal Technological Advances" (Case I), and "Significant Technological Advances" (Case II) on input variables. Table 5-6 list the impacted parameters, and the values assumed in each case.

5.5.2 Hydrothermal Non-Electric Market Forecasts.

The results of the hydrothermal non-electric market penetration model are summarized below. Forecasts were made for 5 year intervals during the 1980-2000 development period. To reflect the inherent uncertainty in market penetration estimates, results are reported for three levels of likelihood (>5, >50, and >95 percent).

Wtih "Current Technology and Incentives", there is a >50 percent likelihood that hydrothermal non-electric usage would reach .140 quads by 2000. This contrasts with a utilization rate of .019, .058, and .110 quads in the years 1985, 1990, and 1995 respectively. Approximately 85 percent of the utilization is likely to be the result of district heat applications. Forecasts at each level of likelihood are reported in Table 5-7.

"Minimal Technological Advances" will accelerate and increase hydrothermal non-electric development. By 1990, non-electric applications can be expected to reach .061 quads at greater than 50 percent likelihood. This represents a 22 percent increase over the base case (Current Technology) estimate. By 2000, non-electric market penetration is expected to reach .132 quads.

If "Significant Technological Advances" are achieved, hydrothermal non-electric utilization can be expecsted to almost triple over the Base Case. There is a greater than 50 percent likelihood that by 2000, .334 quads will be consumed. The economic and technologic benefits resulting from the program significantly increase new applications during the 1985-2000 time period. Forecasts show development levels to .204 quads by 1990, and .407 quads by the year 2000. There is a greater than 95 percent likelihood that consumption will reach .297 quads by 2000.

Table 5-6
NON-ELECTRIC RESEARCH AND DEVELOPMENT IMPACTS

	BASE CASE Current Technology	CASE I Minimal Technological Advances	CASE II Significant Technological Advances
Dry well fraction	NC	NC	10% decrease
Equity fraction	NC	NC	75% decrease
Investment tax credit	NC	NC	15% increase
Cost of debt equity	NC	NC	17% increase
O&M cost (unpumped wells)	NC	7% decrease	15% decrease
O&M cost (pumped wells)	NC	7% decrease	15% decrease
Surface piping cost (unpumped wells)	NC	NC	35% decrease
Surface piping cost (pumped wells)	NC	NC	35% decrease
Tax life	NC	NC	8 yr. decrease
Well cost (1985)	NC	15% decrease	15% decrease
Well cost (1990)	NC	25% decrease	25% decrease
Well life	NC	24% decrease	35% increase
Time of resource discovery	NC	NC	40% increase
Learning curve acceleration	NC	NC	35% increase
O&M costs (district heat only)	NC	7% decrease	15% decrease

Table 5-7
TOTAL NON-ELECTRIC MARKET ESTIMATE (QUADS)

STRATEGY	LIKELIHOOD	1985	1990	1995	2000
BASE CASE Current Technology	> 5%	.043	.105	.186	.244
	>50%	.019	.058	.110	.140
	>95%	.008	.031	.061	.073
CASE I Minimal Technological Advances	> 5%	.054	.120	.206	.260
	>50%	.028	.070	.127	.153
	>95%	.015	.040	.074	.083
CASE II Significant Technological Advances	> 5%	.126	.266	.441	.541
	>50%	.092	.204	.343	.407
	>95%	.069	.156	.260	.297

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COMPUTER CODE LISTING

Program-Variable Listing
Wildcat Drilling and Discovery Model[a]

DESCRIPTION	PROGRAM CODE	VALUE
Vector of expected temperature of next discovery	ETEMP	Output from Resource Quality Model
First Year of Simulation	YEAR	1982
1982 Depletion Factors[b]	DFAC	.65 .85 .71
1982 Well Inventory[b]	WINV	3 0 1
1982 Undiscovered Resource Base[b]	RBASE	17 25 70
Initial Discovery Threshold Rate[b]	HURD	4.2 7.17 5.6
Oil Risk Premium	ORP	23 percent
Treasury Bill Rate	TBILL	10 percent
Well Cost	WC	*
Well Temperature	WT	*
Well Flow Rate	WF	*
Well Life	WL	*
Producible Acreage (50% Confidence Level)	A50	*
Producible Acreage (90% Confidence Level)	A90	*
Pumped Well Flow Rate	WFP	*
Committed Plant at Site (1=Yes)	DV10	*
Year of Discovery	TDSC	*
	S	*

[a]Other Variables used in computation of internal rate of return function (TCN6100) are provided in following program listing of Cash Flow and Decision Models.

[b]California, Nevada and "All Other Regions" respectively.

* Site Specific

```
      ∇DRILL[⎕]∇
      ∇ DRILL S;DF;WINV;RBASE;HURD;ETEMP;YEAR;WCAT;WCAT;DISC;D
[1]     OUTPUT← 20 20 ⍴0
[2]     DF←DFAC
[3]     WINV←WINV
[4]     RBASE←RBASE
[5]     HURD←HSC,HNV,HOT
[6]     'ENTER EXPECTED TEMPERATURE VECTOR'
[7]     ETEMP←⎕
[8]     YEAR←1981
[9]   TOP:TEMP←ETEMP[1]
[10]    R←ETEMP[1] TCN6100 YEAR
[11]    WCAT←WINV+WCAT←⌊0.5+((44.5×R-TBILL)+0.433×ORF)×RBASE÷+/RBASE
[12]    DISC←⌊(((((DF+2×HURD)*2)+8×DF×WCAT)*0.5)-DF+2×HURD)÷2×DF
[13]    OUTPUT[YEAR-1980;]←(YEAR),WINV,(+/WCAT),WCAT,(+/DISC),DISC,(R×100)
        ,HURD,(+/RBASE),RBASE
[14]    WINV←WCAT-⌊(DISC×HURD)+0.5×DF×DISC×DISC+1
[15]    RBASE←RBASE-DISC
[16]    ⍎(YEAR=1987)/'HURD←HURD×∆HURD'
[17]    HURD←HURD+DISC×DF
[18]    ETEMP←(+/DISC)↓ETEMP
[19]    →TOP×⍳2000≥YEAR←YEAR+1
[20]    ' '
[21]    ' '
[22]    '            PREVIOUS
                                                  REMAINING'
[23]    '           INVENTORY          WILDCAT WELLS DRILLED    DISCOVERIES
                          HURDLE         RESOURCE BASE   '
[24]    '          -----------------  ----------------------  --------------
        --------      ---------------  ---------------'
[25]    '  YEAR    S.CA    NEV    OTH   TOTAL   S.CA   NEV    OTH   TOTAL   S.CA   N
        EV    OTH    ROR   S.CA   NEV    OTH   S.CA   NEV    OTH'
[26]    ' ----    ----    ---    ---   ------ ----   ---    ---- -----  ----- --
        -  ----  ----   ---   ---    ----   ---   ----   ----'
[27]    6 0 ⍕OUTPUT
[28]    D←OUTPUT[; 10 11 12]
[29]    DISC← 4 3 ⍴(+⌿D[⍳4;]),(+⌿D[4+⍳5;]),(+⌿D[9+⍳5;]),+⌿D[15 16 ;]
      ∇
```

```
      ∇TCN6100[⎕]∇
      ∇ R←ETMP TCN6100 YEAR
[1]   MWV←PYV←0ρADD←0×N←1
[2]   I←YEAR+PDU←0
[3]   TCN3011
[4]   CODE←ALTP←DELP←FIB←CONF←IRR←PAY←PVLS←PINV←PROB←CNF←TOL←MOL←0
[5]   TCN6020
[6]   TCN6030
[7]   →PD0×⍳PDU=0
[8]   TCN6140
[9]  PD0:R←IRR
[10]  X←⎕EX 35 3 ρ'DVTDWCFCAFCHFDAFDHFPAFPH  G GC GF IFIRDKCAKCHKDAKDHKP
      AKPHMWN NPPIRRDCRLPRWCRWPSWPTPATPHTP2TSATSHTS2TYP YP'
[11]  X←⎕EX 24 4 ρ'ADV1ADV2CALTCAPAGLGPITCAITCHITC2MWV5PALTPLPAPLPHPTLPT
      LPATLPH  DE   KPCAPPDPLPEXPPIV5 IXC  UCIDEL'
[12]  X←⎕EX 6 6 ρ' BETAA PPAC3TFIRST TLASTWSPACEDELDE5'
[13]  'RUN COMPLETE'
      ∇


      ∇TCN3011[⎕]∇
      ∇ TCN3011;V;V1;DPFA;TA
[1]  ⍝CONSTANT PARAMETERS FOR MARGINALLY COMPETITIVE RESOURCE PRICING
[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]   GAHT←((1-(TA×DPFA)+ITCA)÷1-TA)+BETAA×((1+GC)÷KA-GC)×1-((1+GC)÷1+KA
      )*PLFH
[5]   GAA←((1-(TA×DPFA)+ITCA)÷1-TA)+BETAA×((1+GC)÷KA-GC)×1-((1+GC)÷1+KA)
      *PLFA
[6]   EPA←CAPA×8.76×((1+GF)÷KA-GF)×1-((1+GF)÷1+KA)*PLFA
      ∇
```

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      ∇TCN6020[□]∇
      ∇ TCN6020
[1]   WF←WE
[2]   ⍎(PUMP←(WT≤370)∨(S=2)∧(I>1987)∧WT≤425)/'WF←WFE'
[3]   CAPH←0.85×1+(0.02×(S=1)∧I>1987)+0.07000000000000001×(S=2)∧I>1987
[4]   WC←WC×1-(0.05×(S=1)∧I>1987)+(0.05×(S=1)∧I>1990)+(0.15×(S=2)∧I>1987
      )+0.1×(S=2)∧I>1990
[5]   PTYPE←(PTYPE≠0)∧((S=0)∧I≥1995)∨((S=1)∧I≥1991)∨(S=2)∧I≥1989
[6]   ⍎((PTYPE=2)∧(S=2)∧I≥1991)/'PTYPE←2'
[7]   DWF←0.35-(0.15×((S=0)∧I>1990)∨(S≠0)∧I>1987)+0.1×(S=2)∧I>1990
[8]   WLF←⌊0.5+WLE×1+(0.24×(S=1)∧I>1987)+0.3×(S=2)∧I>1987
[9]   NSE←(TCN6097 WT)×1+(0.07000000000000001×(S=1)∧I>1987)+((S=2)∧I>
       1987)×(0.12×PTYPE=0)+0.2×PTYPE≠0
[10]  IF←0.75-(I>1987)×0.05×S
[11]  ITC2←0.25-(S≠2)×0.15×1985<I+1
[12]  RWF←0.33+(I>1987)×0.17×S=2
[13]  ITCH←0.1+0.15×S=2
[14]  DELDP5[1]←5-2×S=2
      ∇


      ∇TCN6097[□]∇
      ∇ R←TCN6097 T
[1]  ⍝BRINE EFFECTIVENESS PER EG+G IDAHO
[2]   R←((0.0615×T)+(2.34×PTYPE=1)+(3.53×PTYPE=2)-0.534×BCI)-16.9+PUMP×
       0.57
      ∇


      ∇TCN6030[□]∇
      ∇ TCN6030;SDRL;SRF;NACTM
[1]   TCN6031
[2]   →0×⍳PDU=0
[3]   TCN6032
[4]   TCN6035
[5]   TCN6036
      ∇


      ∇TCN6031[□]∇
      ∇ TCN6031;V
[1]   CONF←TCN3091 WSPACE×(1+SWF÷1-SWF)×(1000×+/MWV,MWN)×V←÷NSE×WF×PDU←1
[2]   ⍎(TYP=1)/'→OUT1×⍳0.26>CONF'
[3]   ⍎(TYP=3)/'→OUT1×⍳0.32>CONF'
[4]   SDRL←(⌈NACTM÷PIR)+⌊0.5+(1+SWF÷1-SWF)×NACTM←⌊0.9+V×1000×MWN
[5]   SRF←MWN×TCN6094 WT
[6]   →0
[7]  OUT1:PIR←2⍴PDU←PINV←PROB←0×CODE←1
      ∇
```

```
∇TCN3091[⎕]∇
∇ R←TCN3091 A
⍝CONFIDENCE=F(ACRES)
 R←÷1+*150⌊A̲L̲+B̲E̲×A
∇


∇TCN6094[⎕]∇
∇ R←TCN6094 T
⍝SURFACE PIPING COST, $/KWE=F(TEMP), NON-STOCHASTIC EXCEPT BY T
 ⍎((PTYPE=0)∧PUMP=0)/'R←*9.245+(¯0.008×T)+(¯0.00121×WF)+0.055×BCI'
 ⍎((PTYPE=0)∧PUMP=1)/'R←*9.806+(¯0.0105×T)+(¯0.00134×WF)+0.064×BCI'
 ⍎((PTYPE=1)∧PUMP=0)/'R←*8.139+(¯0.0063×T)+(¯0.00115×WF)+0.066×BCI'
 ⍎((PTYPE=1)∧PUMP=1)/'R←*9.508+(¯0.0109×T)+(¯0.00135×WF)+0.071×BCI'
 ⍎(PTYPE=2)/'R←*8.274-(0.007×T)+(0.0013×WF)+0.367×PUMP'
 →ENV×⍳(I̲≤1987)∨S̲=0
 R←R×1-0.04×1+PTYPE≠0
ENV:R←R+EFLOM
∇


∇TCN6032[⎕]∇
∇ TCN6032;V;V1;WFOM;EC2;CC2
⍝POST-CONFIRMATION CASH FLOW INCLUDING DEVELOPMENT AND PRODUCTION
 EC2←CC2←(DVT+PLF+PLFH)⍴0
 EC2[DVT+WLF×⍳(⌈PLF÷WLF)-1]←SDRL×WC×1+RWF×RWC-1
 CC2[DVT]←(WC×1+IRD×RDC)×SDRL
 EC2←EC2+V1←IF×CC2
 CC2←CC2-V1
 EC2[DVT]←EC2[DVT]+WC×DWC×⌊0.5+(DWF÷1-DWF)×SDRL
 WFOM←320×(MWN÷100)*0.7
 WFOM←WFOM+(SRP×0.01×2-BCI-BCI*2)+((1+BCI)×(30×⌈NACTM÷PIR)+13.5×V)+
 PUMP×(V←⌊0.5+NACTM×1+SWF÷1-SWF)×56.3+23.5×⍟0.001×WF
 WFOM←WFOM×1-(I̲>1987)×0.07000000000000001×S̲
 WFOM←WFOM+EFLOM
 EC2[DVT+⍳PLF]←EC2[DVT+⍳PLF]+WFOM
 EC2[⍳DVT]←EC2[⍳DVT]+(-DVT)↑E̲E̲X̲P̲
 CC2[⍳DVT]←CC2[⍳DVT]+(-DVT)↑E̲C̲A̲P̲
 CC2[DVT]←CC2[DVT]+SRP
 Y←(I̲+DVT)+(-⌽⍳DVT),¯1+⍳PLF
 AEC←EC2×V←(1+GC)*Y-YP
 ACC←CC2×V
∇


∇TCN6035[⎕]∇

∇ TCN6035;V;V1;V2;ADVT;TAX
⍝AFTER-TAX NEGATIVE CASH FLOW (W/O INT DEDUC)
 ADVT←ADV1×ADV2×(⍴Y)↑(-PLF)↓(+\ACC)-+\SYD←PTLF TCN2041 ACC
 PDPL←((~V2)\E̲D̲P̲L̲[V1-(⍴I̲D̲P̲L̲)⌊V1←I̲D̲P̲L̲⍳V])+E̲D̲P̲L̲[1]×V2←I̲D̲P̲L̲[1]>V←(-PLF
 )↑Y
 TAX←((T2←TS2+(1-TS2)×TF2)×-AEC+SYD+ADVT)-ITC2×ACC
 NET1←-ACC+AEC+TAX+ADVT
∇
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      ∇TCN2041[⎕]∇
      ∇ R←L TCN2041 CAP;V;N
[1]   ⍝SUM OF YEARS DIGITS METHOD OF ACCELERATED TAX DEPRECIATION
[2]    R←⌊0.5+((-L)↓⌽+\⌽V-(L⍴0),(-L)↓V←+\V,L⍴0)-⌽+\⌽(1↓(V←CAP÷+/⍳L)×L),0
      ∇

      ∇TCN6036[⎕]∇
      ∇ TCN6036;V;CT;CH;EPHF;EPHT;GAHF;V1
[1]   ⍝ALTERNATIVE BUSBAR COST AND HYDROTHERMAL PLANT DIFFERENTIAL
[2]    CT←(IXS[2]×IXS[1]>V)+(IXS[3]÷V)×IXS[1]≤V←+/MWV,MWN
[3]    V←(((1+GC)÷1+G)*V)÷((1+GF)÷1+G)*V←T[(⍴T)-PLF]-TF
[4]    CHT←CT+CH←TCN6095 WT
[5]    ALTF←FALT+GAA×(CALT÷EFA)×V
[6]    EPHF←CAPH×8.76×((1+GF)÷KH-GF)×1-((1+GF)÷1+KH)*PLFH
[7]    EPHT←CAPH×8.76×((1+GF)÷KA-GF)×1-((1+GF)÷1+KA)*PLFH
[8]    V1←(548.5×(MWN÷100)*0.7)+(0.021+ADV1×ADV2)×CH×MWN
[9]    ⍎(PTYPE=0)/'V1←(509.5×(MWN÷100)*0.7)+((0.021+ADV1×ADV2)×CH×MWN)+BC
       I×(BCI-1)×(112+92.88×MWN÷NSE)÷2'
[10]   BETAH←V1÷CH×MWN
[11]   ⍎((PTYPE=0)∧I>1987)/'BETAH←BETAH×1-(0.07×S=1)+0.09×S=2'
[12]   ⍎((PTYPE≠0)∧I>1987)/'BETAH←BETAH×1+(0.03×S=1)-0.01×S=2'
[13]   BETAH←BETAH+BH2S
[14]   GAHF←((1-(TH×DPFH)+ITCH)÷1-TH)+BETAH×((1+GC)÷KH-GC)×1-((1+GC)÷1+KH
       )*PLFH
[15]   DELF←V×(GAHF×CH÷EPHF)+GAHT×CT÷EPHT
[16]   ⍎(DELF≥PFAC3[2]×ALTF)/'FIB←2⍴PFAC3[2]+PDU←PINV←PROB←0×CODE←2'
      ∇

      ∇TCN6095[⎕]∇
      ∇ R←TCN6095 T
[1]   ⍝HYDROTHERMAL POWER PLANT CAPITAL COST, $/KWE(DEG F)
[2]   ⍝PTYPE: 0=FLASH  1=BINARY  2=ADV.BINARY
[3]    R←*7.874+(¯0.0025×T)+(0.0775×PTYPE=1)+0.1762×PTYPE=2
[4]    ⍎(PTYPE=0)/'R←R×1+0.075×BCI'
[5]    →ENV×⍳I≤1987
[6]    ⍎(PTYPE=0)/'R←R×1-0.005×S'
[7]    ⍎(PTYPE≠0)/'R←R×1-(0.02×S=1)+0.03×S=2'
[8]   ENV:R←R+CH2S
      ∇

      ∇TCN6140[⎕]∇
      ∇ TCN6140
[1]   ⍝INTERNAL RATE OF RETURN
[2]    PFAC←1
[3]    TCN6041
[4]    TCN6142A
      ∇
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```
      ∇TCN6041[⎕]∇
      ∇ TCN6041;ROYL;DPL;ADVT;TAX;GREV
[1]   ⍝REVENUE RELATED CASH FLOW
[2]    ROYL←RLF×GREV←(8.76×CAPH×MWN×MCPH←((1+G)*T[(⍴T)-PLF]-TP)×(PFAC×
        ALTF)-DELF)×(1+GF)*⍳PLF
[3]    DPL←PDPL×GREV-ROYL
[4]    ADVT←0⌈ADV1×GREV-ROYL+DPL+(-PLF)↑SYD+AEC
[5]    TAX←T2×GREV-ROYL+DPL+ADVT
[6]    NET←NET1+(-⍴Y)↑GREV-ROYL+ADVT+TAX
      ∇

      ∇TCN6042[⎕]∇
      ∇ TCN6042;V;V1;V2;NPV
[1]   ⍝CASH FLOW ANALYSIS
[2]    PINV←1+CODE←0
[3]    →LOSS×⍳0≥NPV←+/V2←NET÷(1+D̲R̲)*Y-I̲
[4]    PVLS←(1-T2)×+/(-PLF)↓V2
[5]    IRR←D̲R̲
[6]   LN1:V1←0<+/NET÷(1+IRR←IRR+(0.002×IRR<0.2)+0.01×IRR≥0.2)*Y-I̲
[7]    →LN1×⍳V1∧IRR<0.5
[8]    PAY←(⌽⍳V)+⍉+/×\(⍉(PLF,V)⍴-+\V1←V2[((⍴Y)-PLF+V)+⍳V])>(V,PLF)⍴(+\(-
        PLF)↑V2)++/(-PLF+V←DVT)↓V2
[9]    PAY←+/PAY×V1÷+/V1
[10]   →0
[11] LOSS:PINV←PROB←0×CODE←3
      ∇
```

Program-Variable Listing
Resource Quality Model

DESCRIPTION	PROGRAM CODE	VALUE
Regional probability of discovery of each temperature class for next 25 discoveries	DSEQ	see below
Total discoveries in 4 time periods, 3 regions (S.Ca, Nv., (other)	DISC	see below
Regional expected number of discoveries indexed by 4 time periods and 4 temperature classes	TDISC	Computed in function "MFORECAST"
Regional expected number of generic resource discoveries indexed by 4 time periods	INVENTORY	Computed in function "MFORECAST"
Relative frequency of generic resources within each temperature class, indexed by region	CODEFRACS	see below
Cumulative probability distributions (at 5, 25, 50, 75 and 90% probability) of forecast power-on-line indexed by 4 time periods	MW	Computed in function "TCN6000"
Probability of confirmation for 21 discovered reservoirs	CPROB	see below

```
      ∇MFORECAST[⎕]∇
      ∇ DSEQ MFORECAST DISC;R;TDISC;INVENTORY
[1]   ⍝ MASTER PROGRAM TO DETERMINE REGIONAL AND NATIONAL
[2]   ⍝  DISCOVERY INVENTORIES; AND NATIONAL POWER FORECASTS.
[3]    TDISC← 3 4 4 ⍴0
[4]    INVENTORY← 3 30 4 ⍴0
[5]   ⍝ DETERMINE EXPECTED DISCOVERIES, BY TEMPERATURE, FOR EACH REGION A
       ND PERIOD
[6]    R←1
[7]   L:TDISC[R;;]←DSEQ[R;;] COLLAPSE DISC[;R]
[8]    →L×⍳3≥R←R+1
[9]   ⍝ ALLOCATE EXPECTED DISCOVERIES TO GENERIC CODES
[10]   R←1
[11]  L2:INVENTORY[R;;]←CODEFRACS[;R] DISAGG TDISC[R;;]
[12]   →L2×⍳3≥R←R+1
[13]  ⍝ DETERMINE NATIONAL INVENTORY AND FORECAST
[14]   FORECAST+/[1] INVENTORY
[15]   'DONE'
      ∇


      ∇FORECAST[⎕]∇
      ∇ FORECAST INV;X;P;HOLD
[1]   ⍝  OUTPUTS FORECAST FOR A SCENARIO GIVEN MW AND INVENTORY
[2]    HOLD← 5 5 4 ⍴0
[3]    P←1
[4]   L:'MW FROM DISCOVERIES IN PERIOD '
[5]    P
[6]    MW←⎕
[7]    X← 2 3 1 ⍉ 5 4 30 ⍴INV[;P]
[8]    HOLD[P;;]←+⌿X×MW
[9]    →L×⍳4≥P←P+1
[10]   'MW FROM DISCOVERED RESOURCES'
[11]   MW←⎕
[12]   HOLD[5;;]←CPROB+.×MW
[13]   STATS+⌿HOLD
      ∇


      ∇STATS[⎕]∇
      ∇ STATS M;MID;MEAN;SIG
[1]   ⍝ COMPUTES  EXPECTED VALUE AND MEAN OF
[2]   ⍝   CUMULATIVE DISTRIBUTIONS STORED IN M.
[3]    MEAN←(4⍴0.25)+.×MID← 4 4 ↑(M+1⊖M)÷2
[4]    SIG←(+⌿0.25×(MID- 4 4 ⍴MEAN)*2)*0.5
[5]    10 0 ⍕M
[6]    ''
[7]    'MEAN:'
[8]    10 0 ⍕MEAN
[9]    ''
[10]   'STANDARD DEVIATION:'
[11]   10 0 ⍕SIG
      ∇
```

```
      ∇COLLAPSE[⎕]∇
      ∇ OUT←X COLLAPSE Y;X1;X2;X3;X4
[1]   ⍝ DETERMINES EXPECTED NO. OF DISCOVERIES, BY TEMPERATURE, PER PERIO
      D.
[2]   ⍝  X = EXPECTED DISCOVERIES BY TEMPERATURE
[3]   ⍝  Y = DISCOVERIES/PERIOD
[4]    X1←+⌿X[⍳Y[1];]
[5]    X2←+⌿X[Y[1]+⍳Y[2];]
[6]    X3←+⌿X[(+/Y[⍳2])+⍳Y[3];]
[7]    X4←+⌿X[(+/Y[⍳3])+⍳Y[4];]
[8]    OUT← 4 4 ⍴X1,X2,X3,X4
      ∇


      ∇DISAGG[⎕]∇
      ∇ OUT←Y DISAGG Z;C8;C7;C6;C5;HOLD;P
[1]   ⍝ DISAGGREGATES TEMPERATURES BY GENERIC TYPE
[2]    HOLD← 30 4 ⍴0
[3]    P←1
[4]   L:C8←Y[⍳7]×Z[P;1]
[5]    C7←Y[7+⍳7]×Z[P;2]
[6]    C6←Y[14+⍳7]×Z[P;3]
[7]    C5←Y[21+⍳9]×Z[P;4]
[8]    HOLD[;P]←C8,C7,C6,C5
[9]    →L×⍳4≥P←P+1
[10]   OUT←HOLD
      ∇
```

DISC

2	1	8
2	2	5
1	2	4
1	1	2

DSEQ

0.09	0.17	0.31	0.43
0.14	0.15	0.36	0.35
0.09	0.13	0.31	0.47
0.14	0.14	0.29	0.43
0.09	0.22	0.36	0.33
0.11	0.26	0.29	0.34
0.1	0.21	0.33	0.36
0.21	0.2	0.38	0.21
0.17	0.34	0.25	0.24
0.24	0.26	0.25	0.25
0.24	0.26	0.25	0.25
0.4	0.31	0.19	0.1
0.4	0.3	0.16	0.14
0.38	0.42	0.12	0.08
0.59	0.29	0.11	0.01
0.73	0.22	0.04	0.01
0.88	0.12	0	0
0	0	0	0
0	0	0	0
0	0	0	0
0	0	0	0
0	0	0	0
0	0	0	0
0	0	0	0
0	0	0	0

0.12	0.13	0.49	0.26
0.1	0.15	0.52	0.23
0.07	0.13	0.38	0.42
0.11	0.2	0.44	0.25
0.11	0.2	0.44	0.25
0.13	0.29	0.46	0.12
0.12	0.24	0.47	0.17
0.21	0.28	0.4	0.11
0.21	0.32	0.42	0.05
0.27	0.42	0.25	0.06
0.22	0.49	0.25	0.04
0.39	0.47	0.13	0.01
0.43	0.42	0.14	0.01
0.46	0.41	0.12	0.01
0.5	0.46	0.03	0.01
0.64	0.33	0.03	0
0.7	0.3	0	0
0.72	0.25	0.03	0
0.8	0.2	0	0
0.86	0.14	0	0
0.94	0.06	0	0
0.93	0.07	0	0
0.97	0.03	0	0
1	0	0	0
0.99	0.01	0	0

0.13	0.27	0.38	0.22
0.15	0.24	0.31	0.3
0.09	0.24	0.41	0.26
0.15	0.23	0.31	0.31
0.13	0.22	0.45	0.2
0.16	0.27	0.38	0.19
0.14	0.31	0.27	0.28
0.11	0.3	0.41	0.18
0.16	0.31	0.28	0.25
0.11	0.23	0.33	0.33
0.12	0.39	0.27	0.22
0.21	0.41	0.28	0.1
0.14	0.38	0.3	0.18
0.16	0.31	0.32	0.21
0.17	0.33	0.33	0.17
0.19	0.39	0.31	0.11
0.21	0.33	0.28	0.18
0.18	0.35	0.29	0.18
0.22	0.41	0.24	0.13
0.25	0.37	0.21	0.17
0.21	0.47	0.24	0.08
0.18	0.44	0.27	0.11
0.21	0.43	0.24	0.12
0.33	0.39	0.22	0.06
0.28	0.47	0.16	0.09

CODEFRACS

0.25	0.5	0
0	0	0.2
0.25	0	0
0	0.5	0.4
0.25	0	0
0.25	0	0.2
0	0	0.2
0.25	0.2	0
0.25	0.2	0
0	0.2	0.3
0	0.2	0
0.25	0.2	0.4
0.25	0	0
0	0	0.3
0.25	0.167	0.042
0.25	0.167	0.208
0	0	0.042
0.25	0.167	0.25
0	0.167	0.083
0	0	0.083
0.25	0.333	0.292
0.2	0.167	0.07
0.4	0.167	0.163
0.2	0.167	0.279
0.2	0.083	0.093
0	0	0.023
0	0.167	0.209
0	0.083	0.023
0	0.083	0.093
0	0.083	0.047

Program-Variable Listing
Cash Flow and Decision Model

DESCRIPTION: ECONOMIC PARAMETERS	PROGRAM CODE	VALUE
Capital cost of competing baseload power plant	CALT	\$1100/kWe
Annual O&M cost of competing power plant[1]	BETAA	.062
Capacity factor of competing power plant	CAPA	.75
General inflation rate	G	.075
Capital cost escalation rate	GC	.08
Fuel cost escalation rate	GF	.09
Cost of fuel: competing coal-fired power plant	PALT	18.8 mills/kWh
Plant life: competing baseload power plant	PLFA	30
Plant life: hydrothermal power plant	PLFH	30
Royalty fraction	RLF	.10
Base price year	YP	1982
Discount rate	DTL	.12
Transmission interconnection cost and threshold[2]	TXC	200 50 2700
Depletion allowance	PDPL	.22 .20 .18 .16 .15
Depletion allowance years	YDPL	1980 1981 1982 1983 1984
Pre-production expenses	PEXP	(see Section 2)
Pre-production capital expenses	PCAP	(see Section 2)

[1] fraction of capital cost (includes operation, maintenance, administration, ad valorem taxes).
[2] \$200/kw for $\leq$ 50 MW_e, \$2,700,000 for >50 MW_e

DESCRIPTION: FINANCIAL PARAMETERS		PROGRAM CODE	VALUE
Fraction of common stock:	hydrothermal plant	FCH	.35
	baseload alternative	FCA	.35
Fraction of debt equity:	hydrothermal plant	FDH	.50
	baseload alternative	FDA	.50
Fraction of preferred stock:	hydrothermal plant	FPH	.15
	baseload alternatives	FPA	.15
Cost of common stock:	hydrothermal plant	KCH	.16
	baseload alternative	KCA	.16
Cost of debt equity:	hydrothermal plant	KDH	.11
	baseload alternative	KDA	.11
Cost of preferred stock:	hydrothermal plant	KPH	.11
	baseload alternative	KPA	.11

DESCRIPTION: RESOURCE PARAMETERS	PROGRAM CODE	VALUE
Ratio of producer to injector wells	PIR	2
Dry well cost as fraction of successful well cost	DWC	.90
Intangible fraction of producer well cost	IF	.75
Fraction of new wells requiring redrilling	IRD	.30
Redrilling cost as fraction of initial cost	RDC	.35
Rework cost as fraction of initial cost	RWC	.35
Spare well fraction	SWF	.20
Well spacing (acres per production well)	WSPACE	40

DESCRIPTION: TAX PARAMETERS	PROGRAM CODE	VALUE
Ad Valorem tax rate	ADV1	.04
Ad Valorem tax assessment rate	ADV2	.25
Investment tax credit: baseload alternative	ITCA	.10
Well tax life	PTLF	3
Federal tax rate: hydrothermal plant owner	TFH	.46
Federal tax rate: baseload plant owner	TFA	.46
Federal tax rate: resource producer	TF2	.46
Tax life: hydrothermal plant	TLFH	15
Tax life: baseload alternative	TLFA	15
State tax rate: hydrothermal plant owner	TSH	.09
State tax rate: baseload alternative plant owner	TSA	.09
State tax rate: resource producer	TS2	.09

DESCRIPTION: OTHER MODEL PARAMETERS	PROGRAM CODE	VALUE
Sequential plant capacities in MW (1st, 2nd, 3rd, 4th, all others)	MWV5	20 50 50 100 200
Representative geothermal plant capacity (MW)	MWN	50
First year of simulation	TFIRST	1982
Last year of simulation	TLAST	1997
Years between decision and plant on-line (plants 1-5)	DELDP5	5 3 3 3 3
Utility function parameters	K	(see Section 3)
Multiattribute function parameters	UC	(see Section 3)
Interval between successive plants in years (plants 2-5)	PIV5	0 3 2 1 1
Years from first plant-related cost until plant on-line	DVT	3

```
      ∇TCN6000[⎕]∇
      ∇ R←RES TCN6000 S;RES8
[1]    'ENTER YEAR OF DISCOVERY'
[2]    RES8←⎕
[3]    ⍎(RES8≠9999)/'RES[;8]←RES8'
[4]    R← 0 5 4 ⍴0
[5]    NI←1↑⍴RES
[6]    ΔT←5×I←1
[7]   NEWR:RSLT← 5 4 ⍴0
[8]    TCN6010 E←RES[I;]
[9]    (⍕'RSVR '),⍕I
[10]   MWV←FYV←0⍴ADD←0×N←1
[11]   ⍎(DV10=1)/'TCN6015'
[12]   I←TDNF+FDU←0
[13]   TCN3011
[14]  NEWT:CODE←ALTF←DELF←FIB←CONF←IRR←PAY←PVLS←PINV←PROB←CNF←YOL←MOL←0
[15]   (⍕'T '),⍕I
[16]   TCN6020
[17]   TCN6030
[18]   ⍎(DV10=1)/'TCN6030A'
[19]   →FD0×⍳FDU=0
[20]   FDU←FDU×0.05≤FDU← SEARCH*
[21]   TCN6060
[22]  FD0:X←⍴,CNF
[23]   FDUV←((N-1)⍴1),(X-N-1)⍴FDU
[24]   Z←((X,13)⍴I,CODE,T,ALTF,DELF,(1↑FIB),CONF,IRR,PAY,PVLS,PINV,PROB,
        FDU),⍉(4,X)⍴CNF,YOL,MOL,FDUV×CNF
[25]   RSLT←RSLT⌈TCN6070 Z
[26]   →NEWT×⍳(TLAST≥I←I+ΔT)∧FDU<0.9
[27]   R←R,[1] RSLT
[28]   →NEWR×⍳NI≥I←I+1
[29]   X←⎕EX 35 3 ⍴'DVTDWCFCAFCHFDAFDHFPAFFH  G GC GF IFIRDKCAKCHKDAKDHKP
       AKPHMWN NFPIRRDCRLFRWCRWFSWFTFATFHTF2TSATSHTS2TYF YP'
[30]   X←⎕EX 24 4 ⍴'ADV1ADV2CALTCAFAGLGPITCAITCHITC2MWV5FALTFLFAFLFHFTLFT
       LFATLFH  DR   KPCAPFDELFEXFPIV5 IXC  UCYDFL'
[31]   X←⎕EX 6 6 ⍴' BETAA PFAC3TFIRST TLASTWSFACEDELDF5'
[32]   'RUN COMPLETE'
      ∇
```

* The function "SEARCH" was developed for work unrelated to this project by Dr. Peter D. Blair and is considered proprietary.

```
      ∇TCN6010[⎕]∇
      ∇ TCN6010 V;A50;A99
[1]   ⍝SITE SPECIFIC DATA ASSIGNMENTS
[2]    WC̲←RMX̲[4;V[4]]
[3]    WT←RMX̲[1;V[1]]
[4]    WE̲←RMX̲[2;V[2]]
[5]    WLE̲←15-5×BCI←RMX̲[3;V[3]]
[6]    A̲L̲←-A50×B̲E̲←4.595÷(0.1×A50)⌈(A50←RMX̲[7;V[6]])-A99←RMX̲[6;V[6]]
[7]    TDNP←TFIRST⌈1+TDSC←V[8]
[8]    DV10←V[10]
[9]    PTYPE̲←V[9]
[10]   WFP̲←750⌊78+1.22×WE̲
      ∇
```

```
      ∇TCN6015[⎕]∇
      ∇ TCN6015
[1]   ⍝EXECUTES FOR EXISTING DEVELOPMENT
[2]    (⍞'SEQ MWE ON-LINE AND COMMITTED; RESOURCE '),⍞I̲
[3]    N←1+⍴,MWV←⎕
[4]    ⍎(1=⍴,MWV)/'MWV←1⍴MWV'
[5]    'SEQ YRS ON-LINE AND COMMITTED'
[6]    PYV←⎕
[7]    TDNP←TFIRST⌈(¯1↑PYV)+P̲I̲V̲5[5⌊N]-D̲E̲L̲D̲P̲5[5⌊N]
[8]    ADD̲←WSPACE×(1+SWF÷1-SWF)×(1000×+/MWV)÷(NSE←TCN6097A WT)×WE̲
      ∇
```

```
      ∇TCN6097[⎕]∇
      ∇ R←TCN6097 T
[1]   ⍝BRINE EFFECTIVENESS PER EG+G IDAHO
[2]    R←((0.0615×T)+(2.34×PTYPE=1)+(3.53×PTYPE=2)-0.534×BCI)-16.9+PUMP×
       0.57
      ∇
```

```
      ∇TCN3011[⎕]∇
      ∇ TCN3011;V;V1;DPFA;TA
[1]   ⍝CONSTANT PARAMETERS FOR MARGINALLY COMPETITIVE RESOURCE PRICING
[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]    GAHT←((1−(TA×DPFA)+ITCA)÷1−TA)+BETAA×((1+GC)÷KA−GC)×1−((1+GC)÷1+KA
       )*FLFH
[5]    GAA←((1−(TA×DPFA)+ITCA)÷1−TA)+BETAA×((1+GC)÷KA−GC)×1−((1+GC)÷1+KA)
       *FLFA
[6]    EFA←CAPA×8.76×((1+GF)÷KA−GF)×1−((1+GF)÷1+KA)*FLFA
      ∇

      ∇TCN6020[⎕]∇
      ∇ TCN6020
[1]    WF←WE̲
[2]    ⍎(PUMP←(WT≤370)∨(S̲=2)∧(I̲>1987)∧WT≤425)/'WF←WFE̲'
[3]    CAPH←0.85×1+(0.02×(S̲=1)∧I̲>1987)+0.07000000000000001×(S̲=2)∧I̲>1987
[4]    WC←WC̲×1−(0.05×(S̲=1)∧I̲>1987)+(0.05×(S̲=1)∧I̲>1990)+(0.15×(S̲=2)∧I̲>1987
       )+0.1×(S̲=2)∧I̲>1990
[5]    PTYPE←(PTYPE̲≠0)∧((S̲=0)∧I̲≥1995)∨((S̲=1)∧I̲≥1991)∨(S̲=2)∧I̲≥1989
[6]    ⍎((PTYPE̲=2)∧(S̲=2)∧I̲≥1991)/'PTYPE←2'
[7]    DWF←0.35−(0.15×((S̲=0)∧I̲>1990)∨(S̲≠0)∧I̲>1987)+0.1×(S̲=2)∧I̲>1990
[8]    WLF←⌊0.5+WLE̲×1+(0.24×(S̲=1)∧I̲>1987)+0.3×(S̲=2)∧I̲>1987
[9]    MSE←(TCN6097 WT)×1+(0.07000000000000001×(S̲=1)∧I̲>1987)+((S̲=2)∧I̲>
        1987)×(0.12×PTYPE=0)+0.2×PTYPE≠0
[10]   IF←0.75−(I̲>1987)×0.05×S̲
[11]   ITC2←0.25−(S̲≠2)×0.15×1985<I̲+1
[12]   RWF←0.33+(I̲>1987)×0.17×S̲=2
[13]   ITCH←0.1+0.15×S̲=2
[14]   D̲E̲L̲D̲E̲S̲[1]←5−2×S̲=2
      ∇

      ∇TCN6030[⎕]∇
      ∇ TCN6030;SDRL;SRP;NACTM
[1]    TCN6031
[2]    →0×⍳PDU=0
[3]    TCN6032
[4]    TCN6035
[5]    TCN6036
      ∇
```

```
      ∇TCN6031[⎕]∇
      ∇ TCN6031;V
[1]   CONF←TCN3091 WSFACE×(1+SWF÷1−SWF)×(1000×+/MWV,MWN)×V←÷NSE×WF×FDU←1
[2]   ⍎(TYF=1)/'→OUT1×⍳0.26>CONF'
[3]   ⍎(TYF=3)/'→OUT1×⍳0.32>CONF'
[4]   SDRL←(⌈NACTM÷FIR)+⌊0.5+(1+SWF÷1−SWF)×NACTM←⌊0.9+V×1000×MWN
[5]   SRF←MWN×TCN6094 WT
[6]   →0
[7]  OUT1:FIB←2⍴FDU←FINV←FROB←0×CODE←1
      ∇


      ∇TCN3091[⎕]∇
      ∇ R←TCN3091 A
[1]  ⍝CONFIDENCE=F(ACRES)
[2]   R←÷1+⋆150⌊AL+BE×A
      ∇


      ∇TCN6094[⎕]∇
      ∇ R←TCN6094 T
[1]  ⍝SURFACE PIPING COST, $/KWE=F(TEMP), NON-STOCHASTIC EXCEPT BY T
[2]   ⍎((PTYPE=0)∧PUMP=0)/'R←⋆9.245+(¯0.008×T)+(¯0.00121×WF)+0.055×BCI'
[3]   ⍎((PTYPE=0)∧PUMP=1)/'R←⋆9.806+(¯0.0105×T)+(¯0.00134×WF)+0.064×BCI'
[4]   ⍎((PTYPE=1)∧PUMP=0)/'R←⋆8.139+(¯0.0063×T)+(¯0.00115×WF)+0.066×BCI'
[5]   ⍎((PTYPE=1)∧PUMP=1)/'R←⋆9.508+(¯0.0109×T)+(¯0.00135×WF)+0.071×BCI'
[6]   ⍎(PTYPE=2)/'R←⋆8.274-(0.007×T)+(0.0013×WF)+0.367×PUMP'
[7]   →ENV×⍳(I≤1987)∨S=0
[8]   R←R×1-0.04×1+PTYPE≠0
[9]  ENV:R←R+EFLOM
      ∇


      ∇TCN6032[⎕]∇
      ∇ TCN6032;V;V1;WFOM;EC2;CC2
[1]  ⍝POST-CONFIRMATION CASH FLOW INCLUDING DEVELOPMENT AND PRODUCTION
[2]   EC2←CC2←(DVT+PLF←PLFH)⍴0
[3]   EC2[DVT+WLF×⍳(⌈PLF÷WLF)−1]←SDRL×WC×1+RWF×RWC−1
[4]   CC2[DVT]←(WC×1+IRD×RDC)×SDRL
[5]   EC2←EC2+V1←IF×CC2
[6]   CC2←CC2−V1
[7]   EC2[DVT]←EC2[DVT]+WC×DWC×⌊0.5+(DWF÷1−DWF)×SDRL
[8]   WFOM←320×(MWN÷100)⋆0.7
[9]   WFOM←WFOM+(SRF×0.01×2−BCI−BCI⋆2)+((1+BCI)×(30×⌈NACTM÷FIR)+13.5×V)+
      PUMP×(V←⌊0.5+NACTM×1+SWF÷1−SWF)×56.3+23.5×⍟0.001×WF
[10]  WFOM←WFOM×1−(I>1987)×0.0700000000000001×S
[11]  WFOM←WFOM+EFLOM
[12]  EC2[DVT+⍳PLF]←EC2[DVT+⍳PLF]+WFOM
[13]  EC2[⍳DVT]←EC2[⍳DVT]+(−DVT)↑BEXE
[14]  CC2[⍳DVT]←CC2[⍳DVT]+(−DVT)↑ECAE
[15]  CC2[DVT]←CC2[DVT]+SRF
[16]  Y←(I+DVT)+(−⌽⍳DVT),¯1+⍳PLF
[17]  AEC←EC2×V←(1+GC)⋆Y−YF
[18]  ACC←CC2×V
      ∇
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      ∇TCN6035[⎕]∇
      ∇ TCN6035;V;V1;V2;ADVT;TAX
[1]   ⍝AFTER-TAX NEGATIVE CASH FLOW (W/O INT DEDUC)
[2]    ADVT←ADV1×ADV2×(ρY)↑(-FLF)↓(+\ACC)-+\SYD←FTLF TCN2041 ACC
[3]    PDPL←((~V2)\EDEL[V1-(ρYDEL)⌊V1←YDEL⍳V])+EDEL[1]×V2←YDEL[1]>V←(-FLF
      )↑Y
[4]    TAX←((T2←TS2+(1-TS2)×TF2)×-AEC+SYD+ADVT)-ITC2×ACC
[5]    NET1←-ACC+AEC+TAX+ADVT
      ∇


      ∇TCN2041[⎕]∇
      ∇ R←L TCN2041 CAP;V;N
[1]   ⍝SUM OF YEARS DIGITS METHOD OF ACCELERATED TAX DEPRECIATION
[2]    R←⌊0.5+((-L)↓⌽+\⌽V-(Lρ0),(-L)↓V←+\V,Lρ0)-⌽+\⌽(1↓(V←CAP÷+/⍳L)×L),0
      ∇


      ∇TCN6036[⎕]∇
      ∇ TCN6036;V;CT;CH;EPHP;EPHT;GAHP;V1
[1]   ⍝ALTERNATIVE BUSBAR COST AND HYDROTHERMAL PLANT DIFFERENTIAL
[2]    CT←(IXC[2]×IXC[1]>V)+(IXC[3]÷V)×IXC[1]≤V←+/MWV,MWN
[3]    V←(((1+GC)÷1+G)*V)÷((1+GF)÷1+G)*V←Y[(ρY)-FLF]-YP
[4]    CHT←CT+CH←TCN6095 WT
[5]    ALTP←PALT+GAA×(CALT÷EPA)×V
[6]    EPHP←CAPH×8.76×((1+GF)÷KH-GF)×1-((1+GF)÷1+KH)*FLFH
[7]    EPHT←CAPH×8.76×((1+GF)÷KA-GF)×1-((1+GF)÷1+KA)*FLFH
[8]    V1←(548.5×(MWN÷100)*0.7)+(0.021+ADV1×ADV2)×CH×MWN
[9]    ⍎(PTYPE=0)/'V1←(509.5×(MWN÷100)*0.7)+((0.021+ADV1×ADV2)×CH×MWN)+BC
      I×(BCI-1)×(112+92.88×MWN÷NSE)÷2'
[10]   BETAH←V1÷CH×MWN
[11]   ⍎((PTYPE=0)∧I>1987)/'BETAH←BETAH×1-(0.07×S=1)+0.09×S=2'
[12]   ⍎((PTYPE≠0)∧I>1987)/'BETAH←BETAH×1+(0.03×S=1)-0.01×S=2'
[13]   BETAH←BETAH+BH2S
[14]   GAHP←((1-(TH×DPFH)+ITCH)÷1-TH)+BETAH×((1+GC)÷KH-GC)×1-((1+GC)÷1+KH
      )*FLFH
[15]   DELP←V×(GAHP×CH÷EPHP)+GAHT×CT÷EPHT
[16]   ⍎(DELP≥PFAC3[2]×ALTP)/'FIB←2ρPFAC3[2]+PDU←PINV←PROB←0×CODE←2'
      ∇


      ∇TCN6095[⎕]∇
      ∇ R←TCN6095 T
[1]   ⍝HYDROTHERMAL POWER PLANT CAPITAL COST, $/KWE(DEG F)
[2]   ⍝PTYPE: 0=FLASH  1=BINARY  2=ADV.BINARY
[3]    R←*7.874+(¯0.0025×T)+(0.0775×PTYPE=1)+0.1762×PTYPE=2
[4]    ⍎(PTYPE=0)/'R←R×1+0.075×BCI'
[5]    →ENV×⍳I≤1987
[6]    ⍎(PTYPE=0)/'R←R×1-0.005×S'
[7]    ⍎(PTYPE≠0)/'R←R×1-(0.02×S=1)+0.03×S=2'
[8]   ENV:R←R+CH2S
      ∇
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      ∇TCN6030A[⎕]∇
      ∇ TCN6030A
[1]   CNF←(N-1)⍴1
[2]   YOL←PYV
[3]   MOL←MWV
      ∇

      ∇TCN6040[⎕]∇
      ∇ R←TCN6040 PFAC
[1]  ⍝JOINT PROB OF INVESTMENT
[2]   TCN6041
[3]   TCN6042
[4]   →LN6×⍳FINV=0
[5]   TCN6043
[6]   TCN6052
[7]  LN6:R←FINV×PROB
      ∇

      ∇TCN6041[⎕]∇
      ∇ TCN6041;ROYL;DFL;ADVT;TAX;GREV
[1]  ⍝REVENUE RELATED CASH FLOW
[2]   ROYL←RLF×GREV←(8.76×CAFH×MWN×MCFH←((1+G)*Y[(⍴Y)-PLF]-YP)×(PFAC×
       ALTF)-DELF)×(1+GF)*⍳PLF
[3]   DFL←PDFL×GREV-ROYL
[4]   ADVT←0⌈ADV1×GREV-ROYL+DFL+(-PLF)↑STD+AEC
[5]   TAX←T2×GREV-ROYL+DFL+ADVT
[6]   NET←NET1+(-⍴Y)↑GREV-ROYL+ADVT+TAX
      ∇

      ∇TCN6042[⎕]∇
      ∇ TCN6042;V;V1;V2;NPV
[1]  ⍝CASH FLOW ANALYSIS
[2]   FINV←1+CODE←0
[3]   →LOSS×⍳0≥NPV←+/V2←NET÷(1+D̲R̲)*Y-I̲
[4]   PVLS←(1-T2)×+/(-PLF)↓V2
[5]   IRR←D̲R̲
[6]  LN1:V1←0<+/NET÷(1+IRR←IRR+(0.002×IRR<0.2)+0.01×IRR≥0.2)*Y-I̲
[7]   →LN1×⍳V1∧IRR<0.5
[8]   PAY←(⌽⍳V)+⍉+/×\(⍉(PLF,V)⍴-+\V1←V2[((⍴Y)-PLF+V)+⍳V])>(V,PLF)⍴(+\(-
       PLF)↑V2)++/(-PLF+V←DVT)↓V2
[9]   PAY←+/PAY×V1÷+/V1
[10]  →0
[11] LOSS:FINV←PROB←0×CODE←3
      ∇
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      ∇TCN6043[⎕]∇
      ∇ TCN6043;UR;UP;UV;UL;UG;EU
[1]  ⍝FIELD DEVELOPERS DECISION ANALYSIS (1978 INDUSTRY BASE)
[2]   PVLS←PVLS÷(1+G)*I̲-1978
[3]   ⍎(GLGP=1)/'IRR←0.10⌈4×IRR-.75×((1-T2)×KD2)÷1-(1+((1-T2)×KD2))*-10'
[4]   UR←0⌈1-*U̲C̲[TYF;1]-U̲C̲[TYF;2]×IRR-0.02
[5]   UP←0⌈÷1+*-U̲C̲[TYF;3]-U̲C̲[TYF;4]×PAT
[6]  ⍝FOR NATIONAL MARKET ESTIMATE U(NPVR) IS SET  0 1
[7]   UV←1
[8]   ⍎(GLGP=1)/'PVLS←PVLS×.25'
[9]   UL←1-*-U̲C̲[TYF;8]×PVLS÷1000×NF
[10]  ⍎(TYF=1)/'UG←(K̲[1;1]×UR)+(K̲[1;2]×UV)+K̲[1;3]×UR×UP'
[11]  ⍎(TYF=3)/'UG←(K̲[3;1]×UV)+(K̲[3;2]×UR×UV)+K̲[3;3]×UR×UP×UV'
[12]  FINV←÷1+*U̲C̲[TYF;9]-U̲C̲[TYF;10]×EU←(CONF×UG)+(1-CONF)×UL
      ∇
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      ∇TCN6052[⎕]∇
      ∇ TCN6052;UBBC;UTIER;UCF;UCAP;UMA
[1]  ⍝ELECTRIC UTILITY DECISION MODEL
[2]   UBBC←0⌈1-*5.8513-7.1357÷PFAC
[3]   UTIER←1⌊*0.0231+4.34×TIER←0
[4]   UCF←÷1+*11-16.1×ACF←CAPH
[5]   UMA←(0.3299×UBBC×UTIER)+(0.4666×UBBC×UCF)+0.2035×UBBC
[6]   PROB←÷1+*5.9946-10.3051×UMA
      ∇
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      ∇TCN6060[⎕]∇
      ∇ TCN6060;ADD;NN;TT
[1]   CNF←(N-1)⍴1
[2]   ADD←ADD̲
[3]   NN←N
[4]   TT←I̲
[5]   YOL←PTV
[6]   MOL←MWV
[7]  LN:YOL←YOL,TT+D̲E̲L̲D̲E̲5[5⌊NN]
[8]   MOL←MOL,MWV5[5⌊NN]
[9]   WF←WE̲
[10]  ⍎(PUMP←(WT≤370)∨(S̲=2)∧(TT>1987)∧WT≤425)/'WF←WFP̲'
[11]  PTYPE←(PTYPE̲≠0)∧((S̲=0)∧TT≥1995)∨((S̲=1)∧TT≥1991)∨(S̲=2)∧TT≥1989
[12]  ⍎((PTYPE̲=2)∧(S̲=2)∧TT≥1991)/'PTYPE←2'
[13]  NSE←(TCN6097 WT)×1+(0.07000000000000001×(S̲=1)∧TT>1987)+((S̲=2)∧TT>
       1987)×(0.12×PTYPE=0)+0.2×PTYPE≠0
[14]  CNF←CNF,TCN3091 ADD←ADD+WSPACE×(1+SWF÷1-SWF)×(1000×MWV5[5⌊NN])÷NSE
      ×WF
[15]  →LN×⍳(0.25<¯1↑CNF)∧TLAST≥TT←(¯1↑YOL)+P̲I̲V̲5[5⌊NN]-D̲E̲L̲D̲E̲5[5⌊NN←NN+1]
[16]  ⍎(0.25≥¯1↑CNF)/'MOL[NN-1]←MOL[NN-1]×(CNF[NN-2]-0.25)÷CNF[NN-2]-CNF
      [NN-1]'
[17]  CNF←CNF⌈0.25
      ∇
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      ∇TCN6070[⎕]∇
      ∇ R←TCN6070 M
[1]   M←M[; 3 15 16 17]
[2]   R←(((5,1↑⍴M)⍴M[;3])×(0.05 0.25 0.5 0.75 0.9)∘.≤M[;4])+.×M[;2]∘.≤
       1985 1990 1995 2000
      ∇
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