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# The Geothermal Probabilistic Cost Model with an Application to a Geothermal Reservoir at Heber, California

Lowell H. Orren
G. Michael Ziman
Sue Campbell Jones

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16. Abstract


A financial accounting model that incorporates physical and institutional uncertainties has been developed for geothermal projects. Among the uncertainties it can handle are well depth, flow rate, fluid temperature, and permit and construction times. The outputs of the model are cumulative probability distributions of financial measures such as capital cost, levelized cost, and profit. These outputs are well suited for use in an investment decision incorporating risk. The model has the powerful feature that conditional probability distribution can be used to account for correlations among any of the input variables. The model has been applied to a geothermal reservoir at Heber, California, for a 45-MW binary electric plant. Under the assumptions made, the reservoir appears to be economically viable.


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# ABSTRACT

A financial accounting model that incorporates physical and institutional uncertainties has been developed for geothermal projects. Among the uncertainties it can handle are well depth, flow rate, fluid temperature, and permit and construction times. The outputs of the model are cumulative probability distributions of financial measures such as capital cost, levelized cost, and profit. These outputs are well suited for use in an investment decision incorporating risk. The model has the powerful feature that conditional probability distribution can be used to account for correlations among any of the input variables. The model has been applied to a geothermal reservoir at Heber, California, for a 45-MW binary electric plant. Under the assumptions made, the reservoir appears to be economically viable.

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## EXECUTIVE SUMMARY

Geothermal energy entails risks resulting from unknowns in physical factors such as required well depth, fluid temperature, and flow rates, and from unknowns in institutional factors such as length of permit procedures, negotiations for price between the energy producer and the energy user, and liability for faulty performance. To the potential investor in a geothermal development these risks create uncertainty about the economic viability of the project. In this study we present a tool to quantify the risks of geothermal development, the Geothermal Probabilistic Cost Model (GPCM), and use the model to evaluate the economics of a geothermal reservoir at Heber, California.

The GPCM is a financial accounting model that incorporates physical and institutional uncertainties. (See Section II.) The primary output of the GPCM is the distribution of key financial parameters such as profit, capital requirements, and cost. These distributions can be used to make a rational investment decision incorporating the investor's attitude toward risk.

Two characteristics of the GPCM make it distinct from other probabilistic financial models. First, the GPCM does not merely solve for the mean and variance of the distributions of financial variables; it solves for the distributions themselves. This is important because many decision makers care about more than merely the first two moments of a distribution. Second, the GPCM can model cases where different uncertain events are not stochastically independent; that is, the GPCM does allow the outcome of an uncertain event to be influenced by the outcome of another uncertain event. Such correlations between different events is often reality, but cannot be modeled in the standard Monte-Carlo-type simulation model.

A geothermal reservoir for a 45-MW binary-cycle electric plant at Heber, California was evaluated using the GPCM. (See Section I.) The basic result of the Heber Site Study is that under the assumptions and data used, the reservoir is an economically viable project that would allow the reservoir developer to recover all his costs and earn a rate of return suitable for projects of this nature. While the evaluation of the project is sensivive to changes in input assumptions, the basic economic viability of the reservoir did not change under a broad range of circumstances.

# SECTION I

## THE HEBER GEOTHERMAL RESERVOIR SITE STUDY

### A. INTRODUCTION

The Geothermal Probabilistic Cost Model (GPCM) evaluated the economics of a geothermal reservoir at Heber, California, to provide geothermal fluid for a 45-MW (net) binary-cycle electric generating plant. If such a commercial-size binary facility could be successfully built at Heber, it would mean that many medium temperature geothermal sites could produce economical electricity. The proposed Heber Geothermal Project consists of the reservoir, binary-cycle plant, and a demonstration period. The power plant and demonstration period would be a demonstration project to prove the binary technology,[1] but the reservoir would be developed as a for-profit commercial venture.[2] One conclusion of this study is that the reservoir portion of the Heber Geothermal Project seems to be economically viable, although the degree of profitability is sensitive to certain key parameters.

The Heber site was chosen for study using the GPCM model for two reasons: (1) the desire to study a binary site; and (2) extensive engineering evaluation has been done for the Heber Geothermal Project and much of the work has been made public. Although the Jet Propulsion Laboratory (JPL) contacted the major participants in the Heber Project, this study is based primarily on publicly available information.

This study models the reservoir at Heber, but not the power plant. The difficulty with the power plant is that the relationship between costs and changes in physical parameters is not thoroughly understood. For the reservoir, the relationship between physical parameters such as well depth, flow rate, resource temperature, and cost is understood.[3] With sufficient additional engineering relationships, or by ignoring physical uncertainties and considering only time uncertainties, the power plant could be modeled by the GPCM.

This study models a reservoir development at Heber with the same technical characteristics as the proposed reservoir development; however, the

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[1]The proposed participants in the funding of the generating plant are the U.S. Department of Energy (DOE), San Diego Gas and Electric Co. (SDG&E), Imperial Irrigation District, Southern California Edison Co., California Department of Water Resources, Electric Power Research Institute, and others. The plant would be operated by SDG&E.

[2]The reservoir is a joint venture of Chevron Resources Co., Union Oil Co., and New Albion Resources (a subsidiary of SDG&E). Chevron would develop and manage the reservoir.

[3]See Discussion of OPT Functions in Section II of this report.

actual reservoir to be developed could have a slightly different development path and possibly different costs. The reasons for the difference are that the initial exploratory activities with the Heber Reservoir were in search of oil, not geothermal heat. Therefore, it seemed unwise to model this period based on what had occurred as the intent was not to find a geothermal reservoir. Thus, we have modeled the early developments on the Heber Reservoir based on a reasonable pattern of development for a geothermal reservoir beginning in 1980. Much of the pertinent data about the Heber Reservoir, particularly cost data, is proprietary and is not available to JPL. To the extent that our secondary source data differ from the true data, our predicted results for the reservoir may differ from the actual results of the project.

## B. DATA DESCRIPTION

The data description is divided into five parts: financial variables, technical description, costs by stage of development, revenue, and probabilistic assumptions. Specific assumptions have been made and references are given. Unless otherwise stated, all dollar amounts are in 1980 dollars.

The description of the Reference Scenario and other described inputs form what is termed the Base Case Set of Assumptions. The Base Case Set of Assumptions includes the Reference Scenario (which is supplied as input) and all other scenarios that are created by the model from perturbations in the Reference Scenario's stage times or physical parameter values.[4] Sensitivities to specific parameters in the Base Case are made in a later section.

### 1. Financial Variables

(1) Energy Price: 17.5 mills/kWh. This is the price received by the reservoir for each kilowatt-hour of electricity produced gross. The price used is the price which Cassel (Reference 1) claims is the competitive price for Heber. Based on 9 years required to develop the field before operation and the 10% escalation rate assumed below, this would grow to 41.3 mills/kWh for the first year of operation.

(2) Energy Price Escalation: 10%/yr. It is assumed that the energy price will escalate along with fuel costs. Data Resources, Inc. (DRI) (Reference 2) forecasts residual fuel wholesale price escalation of 13.3% between 1980 and 1990 and 8.9% between 1990 and 2000. The 10% rate selected is a compromise between these figures.

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[4] If any of the financial parameters, cost accounts, or probabilistic assumptions are changed by the user, a new set of assumptions, different from the Base Case Set, is created. Any such new case would again include a Reference Scenario, and the model would generate other scenarios as perturbations of this Reference Scenario. For a discussion of this aspect of the model, see Section II-D.

(3) General Inflation: 9%/yr. All prices other than electricity will be assumed to grow at this rate. It is based on the DRI (Reference 2) forecast of the wholesale price index growing at 10.1% from 1980 to 1990 and 6.7% from 1990 to 2000.

(4) Discount Rate: 15%/yr. The rate used is the required after-tax rate of return on capital invested in projects of this risk class. The figure was obtained from the Atlantic Richfield Co.

(5) Royalty Rate: 10% on Gross Revenue. A common rate used for geothermal property.

(6) Federal Tax Rate: 46%. Standard corporate tax rate.

(7) State Tax Rate: 9%. Corporate tax for California.

(8) Local Tax Rate: 1%. Standard for California.

(9) Investment Tax Credit (ITC): 10%. Geothermal would receive an additional credit of 15% for a total ITC of 25%. However, this extra 15% is due to expire December 31, 1985, before the major capital expenditures for this site study would occur (Reference 3).

(10) Depletion Allowance: 15%. Although the present rate is 21%, it will decline to 15% by 1984, which is before scheduled operation of the plant.

(11) Depreciation Method: Sum of years digits. This form of accelerated depreciation is used.

2. Technical Description

The pertinent technical details about the reservoir are in Tables 1-1, 1-2, and 1-3.

3. Cost Accounts by Stage of Development

The development of the geothermal reservoir is divided into four stages of development: (1) resource proving, (2) permit process, (3) developing the resource, and (4) operating the reservoir.[5] In this section we describe the cost accounts in the stages for the Heber site study, and list the actual costs used in the Reference Scenario.

a. <u>Description of Costs in Stage I: Resource Proving</u>.

(1) Rent. This is the payment to the owners of the land. This payment is replaced by royalty payments when production

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[5]This is more thoroughly discussed in Section II.

Table 1-1. Production Wells[a]

| | | |
|---|---|---|
| Number | 11 in production, plus 2 spares for total of 13 | |
| Depth | 6 at 1219.2 M (4000 ft)<br>6 at 1828.8 M (6000 ft)<br>1 at 3048 M (10,000 ft) | |
| Diameter | 24.5 cm (9 5/8 in. at bottom) | |
| Flow per well | Start 1380 GPM<br>Maximum 1600 GPM | |
| Total flow to plant | Start 3.26 M Kg/h at 182°C (7.14 M lb/h at 360°F)<br>End 4.06 M Kg/h at 170°C (8.88 M lb/h at 338°F) | |
| Well lifetime | 15 yr | |
| Cost estimate[b] | Depth | Cost Per Well 1980$ |
| | 1219.2 M (4000 ft) | 611,000 |
| | 1828.8 M (6000 ft) | 805,000 |
| | 3048 M (10,000 ft) | 1,212,000 |

[a]Number, depth, diameter, flows, and well lifetime are from San Diego Gas & Electric (see Reference 6) and conversations with Chevron. Well cost estimates are from Livesay Consultants, modified by JPL.

[b]This cost is an estimate for a trouble-free well, pumps not included. To this cost must be added a "dry hole/drilling problem" expense.

Table 1-2. Injection Wells[a]

| | | |
|---|---|---|
| Number | 6 in use, plus 1 spare for total of 7 | |
| Depth | 3 at 1219.2 M (4000 ft)<br>3 at 1828.8 M (6000 ft)<br>1 at 3048 M (10,000 ft) | |
| Diameter | 27.3 cm (10 3/4 in. at bottom) | |
| Well Lifetime | 15 years | |
| Cost Estimate[b] | Depth | Cost Per Well 1980 $ |
| | 1219.2 M 4000 ft) | 693,000 |
| | 1828.8 M 6000 ft) | 897,000 |
| | 3048 M (10,000 ft) | 1,317,000 |

[a]Number, depth and diameter are from conversations with Chevron. Well cost estimates are from Livesay Consultants, modified by JPL.

[b]Cost is an estimate for trouble-free well. To this cost must be added a "dry hole/drilling problem" expense.

Table 1-3. Power Production and Consumption[a]

| Function | Start | End |
|---|---|---|
| Gross Power Production (MW) | 61.9 | 64.1 |
| Auxiliary Power Consumption (MW) | | |
| Plant | 14.6 | 15.3 |
| Chevron Production Well Pumps | 2.3 | 3.8 |
| Total Auxiliary Consumption | 16.9 | 19.1 |
| Net Power Production (MW) | 45.0 | 45.0 |
| Capacity Factor | 70% | 70% |

[a]San Diego Gas & Electric (see Reference 6).

starts in Stage IV.
Source: Estimate from SDG&E

(2) Exploration Permits. Cost of securing permits for surface exploration and exploratory drilling.
Source: Estimate from SDG&E

(3) Exploration and Well Logging. Expenses of surface exploration, drilling exploratory wells and well logging.
Source: Grieder (see Reference 5)

(4) G&A. General and administrative expenses, including project management.
Source: Estimate from SDG&E

(5) Contingency. Additional allowance of 10% of all the above Stage I expenses for contingency.

(6) Lease Acquisition Cost. Payment to land owners to obtain lease.
Source: Estimate from SDG&E

(7) Surface Occupancy. Purchase of 5 acres for surface installation facilities such as pad for wells, pipes, roads, and required structures.
Source: Estimate from SDG&E

b. Description of Costs in Stage II: Permit Process

(1) Rent. See description in Stage I.

(2) G&A. See description in Stage I.

(3) Regional Environmental Assessment. Preparation of required document on environmental assessment before obtaining permit to develop the reservoir.
Source: Estimate from SDG&E

(4) Contingency. 10% of all the above.

c. Description of Costs in Stage III: Developing the Resource.

(1) Rent. See description in Stage I.

(2) Development Well Cost. This is the expense of drilling all production and injection wells. This expense is divided into in 75% intangible drilling costs and 25% capitalized expense.
Source: Livesay Consultants

(3) Dry Hole and Drilling Problem. The development well costs are for trouble-free wells. To account for expected trouble

during drilling, 20% of the development well cost is added. This expense is divided into 75% intangible drilling costs and 25% capitalized expense.
Source: Livesay Consultants

(4) Surface Installation. This is the expense of all facilities other than the wells. It also includes down-hole pumps. This expense is divided into 50% intangible drilling costs and 50% capitalized expense.
Source: Holt/Procon (see Reference 7)

(5) G&A. As discussed in Stage I.

(6) Contingency. 10% of surface installation, leasing, and G&A.

d. <u>Description of Costs in Stage IV: Operating the Reservoir</u>.

(1) Redrilling of Wells. Depending on the lifetime assumption, all wells will be redrilled. This expense will be made in the last year of the lifetime of the well. The expense will be divided into 75% intangible drilling costs and 25% capitalized expense.

(2) Dry Hole and Drilling Problem. Same as described in Stage III.

(3) Operation and Maintenance (O&M). This is the expense of G&A, well maintenance, surface maintenance, down-hole surveys, and miscellaneous supplies.
Source: Holt/Procon (see Reference 7)

(4) Electricity Expense for Pumping. This is the cost of electricity to drive the down-hole pumps on the production wells. The power required increases from an initial 2.3 MW to an eventual 3.8 MW. We assume that power consumption increases linearly. The price of the electricity is based on the assumption that the reservoir buys electricity from the plant at cost, and 48% of the cost of electricity is geothermal heat. Thus, the price paid for electricity is (1/.48) x (heat mill rate/kWh).
Source: SDG&E (see Reference 6)

(5) Contingency. 10% of O&M expense.

e. <u>Costs used in the Reference Scenario</u>. The costs used in the Reference Scenario for the Heber Site Study are in Tables 1-4, 1-5, 1-6 and 1-7.

The set of distributions for the four uncertain variables generates

(3) x (2) x (1) x (3) x (3) = 54 scenarios.

These scenarios and their associated probabilities are shown in Tables 1-8 and 1-9.

Table 1-4. Cost Accounts: Stage I in 1980 Dollars (Thousands)

| Stage I | | | | | | | |
|---|---|---|---|---|---|---|---|
| Interval | Rent $75/ acre/yr | Exploration Permits | Exploration and Well Logging | G&A: Project Management $100,000/yr | Contingency | Lease Acquisition Cost: $325/acre per 1000 acres | Surface Occupancy: 5 acres at $12,000/acre |
| 1 | 68.75 | 0 | 240.0 | 91.67 | 79.0 | 325.0 | 60.0 |
| 2 | 68.75 | 25.0 | 240.0 | 91.67 | 43.0 | 0 | 0 |
| 3 | 68.75 | 0 | 800.0 | 91.67 | 96.0 | 0 | 0 |
| 4 | 68.75 | 0 | 800.0 | 91.67 | 96.0 | 0 | 0 |
| 5 | 68.75 | 0 | 800.0 | 91.67 | 96.0 | 0 | 0 |
| 6 | 68.75 | 0 | 800.0 | 91.67 | 96.0 | 0 | 0 |
| Accounting Lifetime, yr | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Cost Escalation, % | 9 | 9 | 9 | 9 | 9 | 9 | 9 |

Table 1-5. Cost Accounts: Stage II in 1980 Dollars (Thousands)

| Stage II | | | | |
|---|---|---|---|---|
| Interval | Lease | G&A | Regional Environmental Assessments | Contingency |
| 1 | 75.0 | 100.0 | 200.0 | 38.0 |
| Accounting Lifetime, yr | 1 | 1 | 1 | 1 |
| Cost Escalation, % | 9 | 9 | 9 | 9 |

Table 1-6. Cost Accounts: Stage III in 1980 Dollars (Thousands)

| | Stage III | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Interval | Development Well Cost: 5% of Total IDC | Dry Hole and Drilling Problems: IDC Portion | IDC Portion of Surface Installation | Leasing-$75,000/yr | G&A $100,000/yr | Contingency 10% | Development Well Cost 25% Capitalized | Dry Hole and Drilling Problems: Capitalized Portion | Surface Installation 50% Capitalized | Contingency (10% of Surface Installation) |
| 1 | 3948.75 | 789.5 | 1566.7 | 62.5 | 83.33 | 171.0 | 1316.25 | 263.25 | 1566.7 | 157.0 |
| 2 | 3948.75 | 789.5 | 1566.7 | 62.5 | 83.33 | 171.0 | 1316.25 | 263.25 | 1566.7 | 157.0 |
| 3 | 3948.75 | 789.5 | 1566.7 | 62.5 | 83.33 | 171.0 | 1316.25 | 263.25 | 1566.7 | 157.0 |
| Accounting Lifetime, yr | 1 | 1 | 1 | 1 | 1 | 1 | 10 | 10 | 10 | 10 |
| Cost Escalation, % | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |

## Table 1-7. Cost Accounts: Stage IV in 1980 Dollars (Thousands)

| | Stage IV | | | | | | |
|---|---|---|---|---|---|---|---|
| Interval | Redrilling Program: IDC Portion 75% | Dry Hole Expense During Redrilling: IDC, Portion 75% | Operations and Maintenance including G&A | Contingency 10% of O&M | Electricity Expense Well Pumping | Redrilling Program: Capitalized Portion, 25% | Dry Hole Expense During Redrilling Capitalized Portion, 25% |
| 1 | 0 | 0 | 2093.0 | 209.0 | 514.0 | 0 | 0 |
| 2 | 0 | 0 | 2093.0 | 209.0 | 526.0 | 0 | 0 |
| 3 | 0 | 0 | 2093.0 | 209.0 | 537.0 | 0 | 0 |
| 4 | 0 | 0 | 2093.0 | 209.0 | 549.0 | 0 | 0 |
| 5 | 0 | 0 | 2093.0 | 209.0 | 560.0 | 0 | 0 |
| 6 | 0 | 0 | 2093.0 | 209.0 | 572.0 | 0 | 0 |
| 7 | 0 | 0 | 2093.0 | 209.0 | 584.0 | 0 | 0 |
| 8 | 0 | 0 | 2093.0 | 209.0 | 595.0 | 0 | 0 |
| 9 | 0 | 0 | 2093.0 | 209.0 | 607.0 | 0 | 0 |
| 10 | 0 | 0 | 2093.0 | 209.0 | 618.0 | 0 | 0 |
| 11 | 0 | 0 | 2093.0 | 209.0 | 630.0 | 0 | 0 |
| 12 | 0 | 0 | 2093.0 | 209.0 | 641.0 | 0 | 0 |
| 13 | 0 | 0 | 2093.0 | 209.0 | 653.0 | 0 | 0 |
| 14 | 0 | 0 | 2093.0 | 209.0 | 665.0 | 0 | 0 |
| 15 | 12450.0 | 2490.0 | 2093.0 | 209.0 | 676.0 | 4150.0 | 830.0 |
| 16 | 0 | 0 | 2093.0 | 209.0 | 688.0 | 0 | 0 |
| 17 | 0 | 0 | 2093.0 | 209.0 | 699.0 | 0 | 0 |
| 18 | 0 | 0 | 2093.0 | 209.0 | 711.0 | 0 | 0 |
| 19 | 0 | 0 | 2093.0 | 209.0 | 722.0 | 0 | 0 |
| 20 | 0 | 0 | 2093.0 | 209.0 | 734.0 | 0 | 0 |
| 21 | 0 | 0 | 2093.0 | 209.0 | 745.0 | 0 | 0 |
| 22 | 0 | 0 | 2093.0 | 209.0 | 757.0 | 0 | 0 |
| 23 | 0 | 0 | 2093.0 | 209.0 | 769.0 | 0 | 0 |
| 24 | 0 | 0 | 2093.0 | 209.0 | 780.0 | 0 | 0 |
| 25 | 0 | 0 | 2093.0 | 209.0 | 792.0 | 0 | 0 |
| 26 | 0 | 0 | 2093.0 | 209.0 | 803.0 | 0 | 0 |
| 27 | 0 | 0 | 2093.0 | 209.0 | 815.0 | 0 | 0 |
| 28 | 0 | 0 | 2093.0 | 209.0 | 826.0 | 0 | 0 |
| 29 | 0 | 0 | 2093.0 | 209.0 | 838.0 | 0 | 0 |
| 30 | 0 | 0 | 2093.0 | 209.0 | 850.0 | 0 | 0 |
| Accounting Lifetime, yr | 1 | 1 | 1 | 1 | 1 | 10 | 10 |
| Cost Escalation, % | 9 | 9 | 9 | 9 | 10 | 9 | 9 |

Table 1-8. Density Functions of Uncertain Input Variables[a]

| Variable | Possible Values | Associated Probability |
|---|---|---|
| Stage 1 | 3 yr | 0.2 |
| | 5.5 yr[b] | 0.6 |
| | 8 yr | 0.2 |
| Stage 2 | 1 yr[b] | 0.8 |
| | 1.5 yr | 0.2 |
| Stage 3 | 2.5 yr[b] | 1.0 |
| Stage 4 | 20 yr | 0.2 |
| | 30 yr[b] | 0.7 |
| | 35 yr | 0.1 |
| Well Flow Rate, GPM | 035 | 0.2 |
| | 1380[b] | 0.6 |
| | 1725 | 0.2 |

[a]Based on information provided by Chevron.

[b]This value is used in the Reference Scenario.

## Table 1-9. Base Case Set Scenarios

| SCENARIO | Stage 1 | Stage 2 | Stage 3 | Stage 4 | Flow Rate |
|---|---|---|---|---|---|
| 1 | 3.000000 | 1.000000 | 2.500000 | 20.000000 | 1035.000000 |
| 2 | 3.000000 | 1.000000 | 2.500000 | 20.000000 | 1380.000000 |
| 3 | 3.000000 | 1.000000 | 2.500000 | 20.000000 | 1725.000000 |
| 4 | 3.000000 | 1.000000 | 2.500000 | 30.000000 | 1035.000000 |
| 5 | 3.000000 | 1.000000 | 2.500000 | 30.000000 | 1380.000000 |
| 6 | 3.000000 | 1.000000 | 2.500000 | 30.000000 | 1725.000000 |
| 7 | 3.000000 | 1.000000 | 2.500000 | 35.000000 | 1035.000000 |
| 8 | 3.000000 | 1.000000 | 2.500000 | 35.000000 | 1380.000000 |
| 9 | 3.000000 | 1.000000 | 2.500000 | 35.000000 | 1725.000000 |
| 10 | 3.000000 | 1.500000 | 2.500000 | 20.000000 | 1035.000000 |
| 11 | 3.000000 | 1.500000 | 2.500000 | 20.000000 | 1380.000000 |
| 12 | 3.000000 | 1.500000 | 2.500000 | 20.000000 | 1725.000000 |
| 13 | 3.000000 | 1.500000 | 2.500000 | 30.000000 | 1035.000000 |
| 14 | 3.000000 | 1.500000 | 2.500000 | 30.000000 | 1380.000000 |
| 15 | 3.000000 | 1.500000 | 2.500000 | 30.000000 | 1725.000000 |
| 16 | 3.000000 | 1.500000 | 2.500000 | 35.000000 | 1035.000000 |
| 17 | 3.000000 | 1.500000 | 2.500000 | 35.000000 | 1380.000000 |
| 18 | 3.000000 | 1.500000 | 2.500000 | 35.000000 | 1725.000000 |
| 19 | 5.500000 | 1.000000 | 2.500000 | 20.000000 | 1035.000000 |
| 20 | 5.500000 | 1.000000 | 2.500000 | 20.000000 | 1380.000000 |
| 21 | 5.500000 | 1.000000 | 2.500000 | 20.000000 | 1725.000000 |
| 22 | 5.500000 | 1.000000 | 2.500000 | 30.000000 | 1035.000000 |
| 23 | 5.500000 | 1.000000 | 2.500000 | 30.000000 | 1380.000000 |
| 24 | 5.500000 | 1.000000 | 2.500000 | 30.000000 | 1725.000000 |
| 25 | 5.500000 | 1.000000 | 2.500000 | 35.000000 | 1035.000000 |
| 26 | 5.500000 | 1.000000 | 2.500000 | 35.000000 | 1380.000000 |
| 27 | 5.500000 | 1.000000 | 2.500000 | 35.000000 | 1725.000000 |
| 28 | 5.500000 | 1.500000 | 2.500000 | 20.000000 | 1035.000000 |
| 29 | 5.500000 | 1.500000 | 2.500000 | 20.000000 | 1380.000000 |
| 30 | 5.500000 | 1.500000 | 2.500000 | 20.000000 | 1725.000000 |
| 31 | 5.500000 | 1.500000 | 2.500000 | 30.000000 | 1035.000000 |
| 32 | 5.500000 | 1.500000 | 2.500000 | 30.000000 | 1380.000000 |
| 33 | 5.500000 | 1.500000 | 2.500000 | 30.000000 | 1725.000000 |
| 34 | 5.500000 | 1.500000 | 2.500000 | 35.000000 | 1035.000000 |
| 35 | 5.500000 | 1.500000 | 2.500000 | 35.000000 | 1380.000000 |
| 36 | 5.500000 | 1.500000 | 2.500000 | 35.000000 | 1725.000000 |
| 37 | 8.000000 | 1.000000 | 2.500000 | 20.000000 | 1035.000000 |
| 38 | 8.000000 | 1.000000 | 2.500000 | 20.000000 | 1380.000000 |
| 39 | 8.000000 | 1.000000 | 2.500000 | 20.000000 | 1725.000000 |
| 40 | 8.000000 | 1.000000 | 2.500000 | 30.000000 | 1035.000000 |
| 41 | 8.000000 | 1.000000 | 2.500000 | 30.000000 | 1380.000000 |
| 42 | 8.000000 | 1.000000 | 2.500000 | 30.000000 | 1725.000000 |
| 43 | 8.000000 | 1.000000 | 2.500000 | 35.000000 | 1035.000000 |
| 44 | 8.000000 | 1.000000 | 2.500000 | 35.000000 | 1380.000000 |
| 45 | 8.000000 | 1.000000 | 2.500000 | 35.000000 | 1725.000000 |
| 46 | 8.000000 | 1.500000 | 2.500000 | 20.000000 | 1035.000000 |
| 47 | 8.000000 | 1.500000 | 2.500000 | 20.000000 | 1380.000000 |
| 48 | 8.000000 | 1.500000 | 2.500000 | 20.000000 | 1725.000000 |
| 49 | 8.000000 | 1.500000 | 2.500000 | 30.000000 | 1035.000000 |
| 50 | 8.000000 | 1.500000 | 2.500000 | 30.000000 | 1380.000000 |
| 51 | 8.000000 | 1.500000 | 2.500000 | 30.000000 | 1725.000000 |
| 52 | 8.000000 | 1.500000 | 2.500000 | 35.000000 | 1035.000000 |
| 53 | 8.000000 | 1.500000 | 2.500000 | 35.000000 | 1380.000000 |
| 54 | 8.000000 | 1.500000 | 2.500000 | 35.000000 | 1725.000000 |

(Stages are in years, flow rate is GPM per production well)

4. Revenue

Revenue to the reservoir will be based on the gross output of the generating plant during Stage IV. We assume that the effective operating capacity of the plant will be 70%. Thus, for the first year of operation the plant will produce:

$$(0.70)(8760)(61.9 \text{ MW}) = 3.80 \times 10^8 \text{ kWh}$$

The revenue during the first year will be this energy multiplied by the energy price. The energy price will escalate as described in Subsection B, paragraph 1. The energy output will grow linearly as the gross power output expands to 64.1 MW at the end of 30 years.

There is no other source of revenue for the reservoir other than the sale of heat for electricity production during Stage IV. We assume a zero scrap value; this is based on the assumption that the resale value of the land and facilities at the end of Stage IV, would be offset by the expense of restoring the land for the alternative uses in agriculture.

5. Probabilistic Assumptions

Uncertain variables are entered in the GPCM as probability distribu-butions rather than point estimates. In the Heber site study there are four uncertain variables: length of Stages I, II, and IV, and well flow rate. The density functions for the Base Case Set of Assumptions are shown in Table 1-8. The Base Case Set scenarios and their associated probabilities are shown in Tables 1-9 and 1-10.

The probability for an entire scenario is the product of the probabilities of the outcomes for each of the uncertain events. For example, using Table 1-10 the probability of Scenario 1 is:

$$(0.2) \times (0.8) \times (1.0) \times (0.2) \times (0.2) = 0.0064.$$

(This is shown in Table 1-11.)

In the Base Case, uncertain events are not conditional upon the outcomes of other uncertain events; however, the GPCM does have the power to have uncertain events conditional upon the outcome of other events. This capability is used in a sensitivity analysis in Subsection D-2.

C. RESULTS OF THE BASE CASE SET OF ASSUMPTIONS

This section presents the results of operating the GPCM with the Base Case Set inputs as described in Subsection B.

1. Profit in the Base Case Set

The present value of profit in the Base Case Set has an expected value of \$5.78 million; however, the Reference Scenario value is \$7.64 million. It

Table 1-10. Probabilities in Base Case Set Scenarios

| SCENARIO | Stage 1 | Stage 2 | Stage 3 | Stage 4 | Flow Rate |
|---|---|---|---|---|---|
| 1 | 0.200000 | 0.800000 | 1.000000 | 0.200000 | 0.200000 |
| 2 | 0.200000 | 0.800000 | 1.000000 | 0.200000 | 0.600000 |
| 3 | 0.200000 | 0.800000 | 1.000000 | 0.200000 | 0.200000 |
| 4 | 0.200000 | 0.800000 | 1.000000 | 0.700000 | 0.200000 |
| 5 | 0.200000 | 0.800000 | 1.000000 | 0.700000 | 0.600000 |
| 6 | 0.200000 | 0.800000 | 1.000000 | 0.700000 | 0.200000 |
| 7 | 0.200000 | 0.800000 | 1.000000 | 0.100000 | 0.200000 |
| 8 | 0.200000 | 0.800000 | 1.000000 | 0.100000 | 0.600000 |
| 9 | 0.200000 | 0.800000 | 1.000000 | 0.100000 | 0.200000 |
| 10 | 0.200000 | 0.200000 | 1.000000 | 0.200000 | 0.200000 |
| 11 | 0.200000 | 0.200000 | 1.000000 | 0.200000 | 0.600000 |
| 12 | 0.200000 | 0.200000 | 1.000000 | 0.200000 | 0.200000 |
| 13 | 0.200000 | 0.200000 | 1.000000 | 0.700000 | 0.200000 |
| 14 | 0.200000 | 0.200000 | 1.000000 | 0.700000 | 0.600000 |
| 15 | 0.200000 | 0.200000 | 1.000000 | 0.700000 | 0.200000 |
| 16 | 0.200000 | 0.200000 | 1.000000 | 0.100000 | 0.200000 |
| 17 | 0.200000 | 0.200000 | 1.000000 | 0.100000 | 0.600000 |
| 18 | 0.200000 | 0.200000 | 1.000000 | 0.100000 | 0.200000 |
| 19 | 0.600000 | 0.800000 | 1.000000 | 0.200000 | 0.200000 |
| 20 | 0.600000 | 0.800000 | 1.000000 | 0.200000 | 0.600000 |
| 21 | 0.600000 | 0.800000 | 1.000000 | 0.200000 | 0.200000 |
| 22 | 0.600000 | 0.800000 | 1.000000 | 0.700000 | 0.200000 |
| 23 | 0.600000 | 0.800000 | 1.000000 | 0.700000 | 0.600000 |
| 24 | 0.600000 | 0.800000 | 1.000000 | 0.700000 | 0.200000 |
| 25 | 0.600000 | 0.800000 | 1.000000 | 0.100000 | 0.200000 |
| 26 | 0.600000 | 0.800000 | 1.000000 | 0.100000 | 0.600000 |
| 27 | 0.600000 | 0.800000 | 1.000000 | 0.100000 | 0.200000 |
| 28 | 0.600000 | 0.200000 | 1.000000 | 0.200000 | 0.200000 |
| 29 | 0.600000 | 0.200000 | 1.000000 | 0.200000 | 0.600000 |
| 30 | 0.600000 | 0.200000 | 1.000000 | 0.200000 | 0.200000 |
| 31 | 0.600000 | 0.200000 | 1.000000 | 0.700000 | 0.200000 |
| 32 | 0.600000 | 0.200000 | 1.000000 | 0.700000 | 0.600000 |
| 33 | 0.600000 | 0.200000 | 1.000000 | 0.700000 | 0.200000 |
| 34 | 0.600000 | 0.200000 | 1.000000 | 0.100000 | 0.200000 |
| 35 | 0.600000 | 0.200000 | 1.000000 | 0.100000 | 0.600000 |
| 36 | 0.600000 | 0.200000 | 1.000000 | 0.100000 | 0.200000 |
| 37 | 0.200000 | 0.800000 | 1.000000 | 0.200000 | 0.200000 |
| 38 | 0.200000 | 0.800000 | 1.000000 | 0.200000 | 0.600000 |
| 39 | 0.200000 | 0.800000 | 1.000000 | 0.200000 | 0.200000 |
| 40 | 0.200000 | 0.800000 | 1.000000 | 0.700000 | 0.200000 |
| 41 | 0.200000 | 0.800000 | 1.000000 | 0.700000 | 0.600000 |
| 42 | 0.200000 | 0.800000 | 1.000000 | 0.700000 | 0.200000 |
| 43 | 0.200000 | 0.800000 | 1.000000 | 0.100000 | 0.200000 |
| 44 | 0.200000 | 0.800000 | 1.000000 | 0.100000 | 0.600000 |
| 45 | 0.200000 | 0.800000 | 1.000000 | 0.100000 | 0.200000 |
| 46 | 0.200000 | 0.200000 | 1.000000 | 0.200000 | 0.200000 |
| 47 | 0.200000 | 0.200000 | 1.000000 | 0.200000 | 0.600000 |
| 48 | 0.200000 | 0.200000 | 1.000000 | 0.200000 | 0.200000 |
| 49 | 0.200000 | 0.200000 | 1.000000 | 0.700000 | 0.200000 |
| 50 | 0.200000 | 0.200000 | 1.000000 | 0.700000 | 0.600000 |
| 51 | 0.200000 | 0.200000 | 1.000000 | 0.700000 | 0.200000 |
| 52 | 0.200000 | 0.200000 | 1.000000 | 0.100000 | 0.200000 |
| 53 | 0.200000 | 0.200000 | 1.000000 | 0.100000 | 0.600000 |
| 54 | 0.200000 | 0.200000 | 1.000000 | 0.100000 | 0.200000 |

Table 1.11  Profit for the Base Case Set of Assumptions  (1980 $K)

| SCENARIO | PROBABILITY | PRESENT VALUE PROFIT |
|---|---|---|
| 46 | 0.001600 | 363617.18 |
| 37 | 0.006400 | 395292.93 |
| 28 | 0.004900 | 867066.37 |
| 19 | 0.019200 | 894750.00 |
| 10 | 0.001600 | 1415179.00 |
| 1 | 0.006400 | 1432167.00 |
| 47 | 0.004800 | 2568566.00 |
| 38 | 0.019200 | 2664117.00 |
| 29 | 0.014400 | 3388082.00 |
| 20 | 0.057600 | 3484234.00 |
| 48 | 0.001600 | 3891534.00 |
| 49 | 0.00[illegible]600 | 3925105.00 |
| 39 | 0.006400 | 4023011.00 |
| 40 | 0.022400 | 4035070.00 |
| 11 | 0.004800 | 4247562.00 |
| 2 | 0.019200 | 4392824.00 |
| 31 | 0.016800 | 4797375.00 |
| 30 | 0.004800 | 4900695.00 |
| 22 | 0.067200 | 4902187.00 |
| 21 | 0.019200 | 5037917.00 |
| 52 | 0.000800 | 5276714.00 |
| 43 | 0.003200 | 5405812.00 |
| 13 | 0.005600 | 5745437.00 |
| 4 | 0.022400 | 5846937.00 |
| 12 | 0.001600 | 6026992.00 |
| 3 | 0.006400 | 6165218.00 |
| 50 | 0.016800 | 6256953.00 |
| 34 | 0.002400 | 6286062.00 |
| 25 | 0.009600 | 6420750.00 |
| 41 | 0.067200 | 6426132.00 |
| 16 | 0.000800 | 7369312.00 |
| 32 | 0.050400 | 7458854.00 |
| 7 | 0.003200 | 7523625.00 |
| 53 | 0.002400 | 7631246.00 |
| 23 | 0.201600 | 7635976.00 |
| 51 | 0.005600 | 7653664.00 |
| 44 | 0.009600 | 7828285.00 |
| 42 | 0.022400 | 7860769.00 |
| 14 | 0.016800 | 8788500.00 |
| 5 | 0.067200 | 8572625.00 |
| 35 | 0.007200 | 8578125.00 |
| 54 | 0.000800 | 9043972.00 |
| 33 | 0.016800 | 9055828.00 |
| 26 | 0.026800 | 9105875.00 |
| 24 | 0.067200 | 9276265.00 |
| 45 | 0.003200 | 9279367.00 |
| 17 | 0.002400 | 10467312.00 |
| 36 | 0.002400 | 10593375.00 |
| 15 | 0.005600 | 10614375.00 |
| 8 | 0.009600 | 10665187.00 |
| 27 | 0.009600 | 10845000.00 |
| 6 | 0.022400 | 10845062.00 |
| 18 | 0.000800 | 12314062.00 |
| 9 | 0.003200 | 12582125.00 |

EXPECTED PRESENT VALUE PROFIT = 5779855.000000 DOLLARS
STANDARD DEVIATION = 2502105.000000

MINIMUM PRESENT VALUE PROFIT = 363617.187500
MAXIMUM PRESENT VALUE PROFIT = 12582125.000000
REFERENCE PRESENT VALUE PROFIT = 7635972.000000

must be remembered that the model uses a revenue-requirements method of computation (Reference 8). Therefore, profit is the residue from revenues after substracting all costs including taxes and a 15% capital payment.

The profit for all scenarios is shown in Table 1-11. The cumulative distribution profit function is shown in Figure 1-1.

## 2. Cost in the Base Case Set

The costs of producing heat in the Base Case Set are shown on Table 1-12. For each scenario the cost shown is the cost in a real levelized stream beginning in the first year of the operation, Stage IV, and continuing to the end of the operation.[6] The stream is real levelized and will rise with the rate of energy inflation. Thus, for the Reference Scenario, the cost is 36.97 mills/kWh beginning 9 years after the start of exploration in 1980. This cost will be 40.67 mills/kWh, or 10% higher, the following year. In the ninth year after exploration, the energy price will have risen from 17.5 mills/kWh to 41.26 mills/kWh. Comparing the first year real levelized cost, 36.97 mills/kWh, to the first year price, 41.26 mills/kWh, we see there is a profit based on levelized costs of 3.70 mills on each kWh sold. There will also be positive profits in each of the remaining years of operation as both the price and the real levelized cost stream rise at 10%.

Comparisons of cost between different scenarios with different times before operation can be misleading. For example, the first year real levelized cost for Scenario 10 is 33.35 mills/kWh. Because this cost is less than the first year real levelized cost of the Reference Scenario, one is tempted to conclude that Scenario 10 is more profitable than the Reference Scenario. However, the real levelized stream for Scenario 10 would start only 7 years after exploration, rather than 9, and the energy price would be only 34.10 mills/kWh. The actual profit for Scenario 10 is $1.41 million, which would make it less profitable than the Reference Scenario, even though its first year levelized cost is lower.

When first year levelized costs are deflated to 1980 dollars, the cost can be compared to the energy price of 17.5 mills/kWh to determine whether a scenario is profitable. However, comparing the LEC in 1980 dollars for scenarios with different tim before the start of operations can still be misleading. For example, comparing the LEC in 1980 dollars for scenarios 26 and 51, it might be concluded that Scenario 51 is more profitable because it has a lower cost; however, Table 1-11 shows that Scenario 26 is more profitable. This is true because the profit in Scenario 51 must be discounted back more periods than Scenario 26 as it is 12 years before Stage IV in Scenario 51, and only 9 years in Scenario 26.

## 3. Base Case Set in 1990

While the project has been viewed from the year 1980, it is also useful to examine the project in terms of a different year to see the impact of

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[6] For a discussion of real levelized cost see Reference 8.

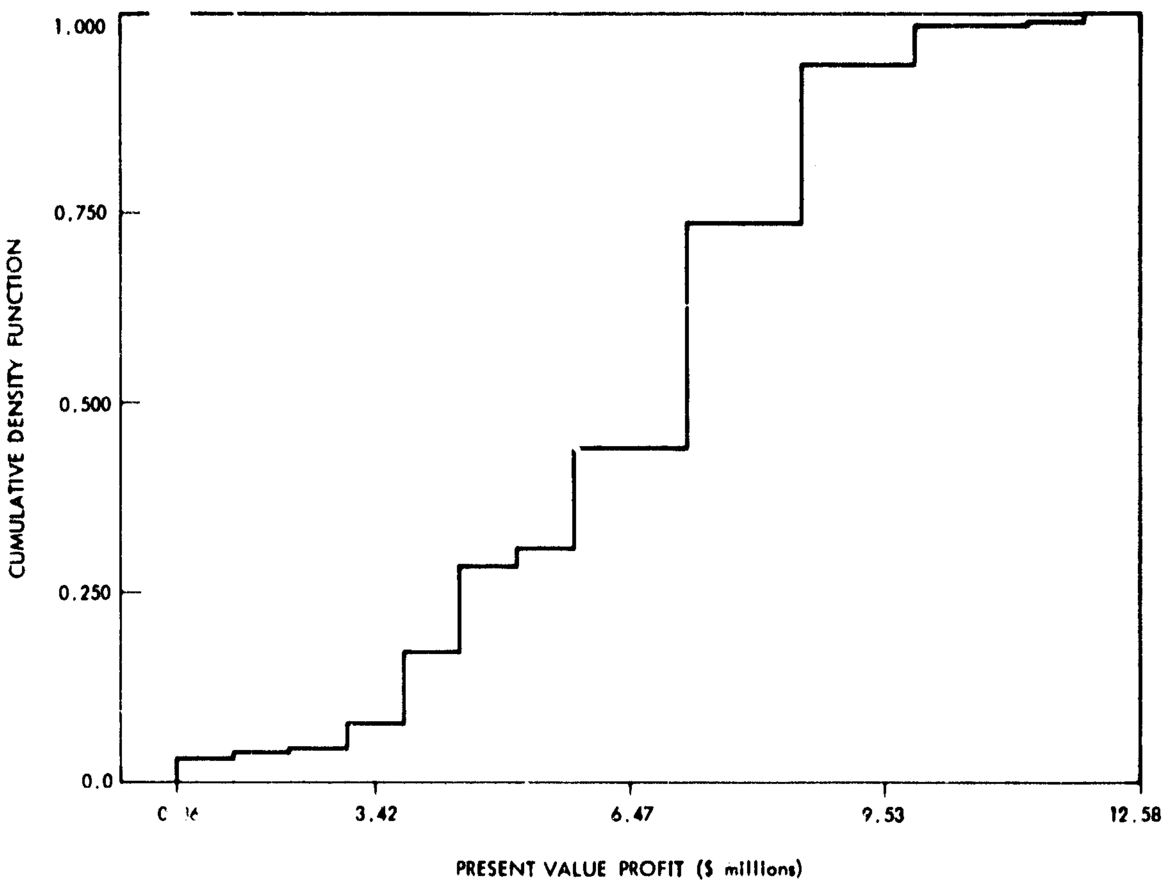



Figure 1-1. Cumulative Distribution Function of Profit in the Base Case Set

Table 1-12. Base Case Set Levelized Cost for First Year of Operation

| Scenario | Years to Operation | LEC[a] | LEC, 1980$ | Scenario | Years to Operation | LEC[a] | LEC, 1980$ |
|---|---|---|---|---|---|---|---|
| 1 | 6.5 | 31.80 | 17.12 | 28 | 9.5 | 42.52 | 17.23 |
| 2 | 6.5 | 30.33 | 16.32 | 29 | 9.5 | 40.72 | 16.46 |
| 3 | 6.5 | 29.45 | 15.85 | 30 | 9.5 | 39.57 | 16.00 |
| 4 | 6.5 | 30.19 | 16.25 | 31 | 9.5 | 40.38 | 16.33 |
| 5 | 6.5 | 28.95 | 15.58 | 32 | 9.5 | 38.77 | 15.68 |
| 6 | 6.5 | 28.20 | 15.18 | 33 | 9.5 | 37.80 | 15.29 |
| 7 | 6.5 | 29.72 | 16.00 | 34 | 9.5 | 39.73 | 16.07 |
| 8 | 6.5 | 28.55 | 15.37 | 35 | 9.5 | 38.21 | 15.45 |
| 9 | 6.5 | 27.65 | 14.99 | 36 | 9.5 | 37.30 | 15.08 |
| 10 | 7 | 33.35 | 17.11 | 37 | 11.5 | 51.97 | 17.37 |
| 11 | 7 | 31.81 | 16.32 | 38 | 11.5 | 49.70 | 16.51 |
| 12 | 7 | 30.89 | 15.85 | 39 | 11.5 | 48.34 | 16.15 |
| 13 | 7 | 31.65 | 16.24 | 40 | 11.5 | 49.14 | 16.42 |
| 14 | 7 | 30.35 | 15.58 | 41 | 11.5 | 47.23 | 15.78 |
| 15 | 7 | 29.58 | 15.18 | 42 | 11.5 | 46.08 | 15.40 |
| 16 | 7 | 31.16 | 15.99 | 43 | 11.5 | 48.33 | 16.15 |
| 17 | 7 | 29.94 | 15.36 | 44 | 11.5 | 46.52 | 15.55 |
| 18 | 7 | 29.20 | 14.98 | 45 | 11.5 | 45.44 | 15.18 |
| 19 | 9 | 40.63 | 17.23 | 46 | 12 | 54.43 | 17.38 |
| 20 | 9 | 38.81 | 16.46 | 47 | 12 | 52.17 | 16.62 |
| 21 | 9 | 37.71 | 15.99 | 48 | 12 | 50.75 | 16.17 |
| 22 | 9 | 38.50 | 16.33 | 49 | 12 | 51.55 | 16.43 |
| 23 | 9 | 36.96 | 15.67 | 50 | 12 | 49.56 | 15.79 |
| 24 | 9 | 36.03 | 15.28 | 51 | 12 | 48.36 | 15.41 |
| 25 | 9 | 37.88 | 16.07 | 52 | 12 | 50.70 | 16.15 |
| 26 | 9 | 36.43 | 15.45 | 53 | 12 | 48.81 | 15.55 |
| 27 | 9 | 35.55 | 15.08 | 54 | 12 | 47.68 | 15.19 |

[a]LEC is real levelized energy cost starting the year of operation in Stage IV, expressed in mills/kWh.

inflation. Table 1-13 examines selected items of the Reference Scenario for the year 1990, which is the second year of the operating stage, Stage IV. Table 1-14 expresses the profits in terms of 1990 dollars.

## D. SENSITIVITY ANALYSIS OF THE BASE CASE SET OF ASSUMPTIONS

Sensitivity analysis on the Base Case Set was done for energy, price, discount rate, capacity factor, investment tax credit, energy escalation, general price escalation, well life, and correlated uncertain events. Results are shown in Table 1-15.

### 1. Sensitivity to Energy Price

As would be expected, profit is very sensitive to the price received for the electricity produced. A 2.5-mills/kWh increase in price translates into a $4.4 million increase in the present value of expected profits and a $4.6 million increase for the Reference Scenario.

A change in the energy price also affects the cost of production. A 2.5-mills/kWh increase in the 1980 price results in a 3.3-mills/kWh increase, or 1.4 mills/kWh in 1980 dollars, in first year real levelized cost for the Reference Scenario. Costs increase with price because cost includes royalty and taxes; royalty payments increase with price, and taxes increase with profit which increases with price.

### 2. Sensitivity to Discount Rate

An increase in the discount rate will lower profits and raise costs. When cash flows are evaluated using a 20% discount instead of 15%, as in the Base Case Set, present value of expected profits declines by $7.1 million dollars, making it negative; and first year real levelized cost rises by 5 mills/kWh.

The discount rate used in this analysis is the required after tax return on capital. Although 20% may seem high, it must be remembered that it is a nominal rate of return. When adjusted for 9% general inflation, nominal returns of 15 and 20% become 5.5 and 10.1% real returns, respectively. For a project with the risks of a geothermal reservoir, these are not unreasonable.

### 3. Sensitivity to Capacity Factor

A reduction in capacity factor from 70 to 65% will reduce the quantity of output sold. It lowers both expected profits and Reference Scenario profits by $2.5 million, and increases first year levelized cost by 1.2 mills/kWh.

### 4. Sensitivity to Investment Tax Credit

The investment tax credit (ITC) was increased from 10 to 25% and only marginal changes were observed. Present value profit rose about $1.2 million

Table 1-13. Reference Scenario in 1990 Dollars

| | |
|---|---|
| Energy Price | 45.39 mills/kWh |
| Real Levelized Energy Cost | 40.67 mills/kWh |
| Annual Operating Expenses (1990$K) | |
| O&M | 4955 |
| Electricity Expense for Pumping | 1245 |
| Contingency | 495 |
| Cost of Wells[a] (1990$K) | |
| 1828.8 M (6000 ft) Production | 1445 |
| 1828.8 M (6000 ft) Injection | 1640 |

[a]No wells are drilled in 1990.

Table 1-14. Present Value of Profits in 1980 for the Base Case Set Expressed in 1990 Dollars (Millions)

| | |
|---|---|
| Expected Profit | 13.68 |
| Standard Deviation | 5.92 |
| Minimum Profit | .86 |
| Maximum Profit | 29.79 |
| Reference Scenario | 18.07 |

Table I-15. Sensitivity Results to Base Case Set at Heber

| | | Present Value Profit in 1980 Dollars (Millions) | | | | | Reference Scenario LEC[a] | |
|---|---|---|---|---|---|---|---|---|
| | | Expected Value | Standard Deviation | Minimum | Maximum | Reference Scenario | Nominal | 1980$ |
| Base Case | | 5.78 | 2.50 | 0.36 | 12.58 | 7.64 | 36.97 | 15.68 |
| Energy | 15 | 1.34 | 2.16 | - 2.90 | 7.06 | 3.02 | 33.67 | 14.28 |
| Price | 20 | 10.16 | 2.84 | 3.59 | 18.11 | 12.25 | 40.24 | 17.07 |
| (mills/kWh) | 30 | 27.30 | 4.70 | 16.50 | 40.20 | 30.70 | 53.44 | 22.66 |
| Discount | 16% | 3.48 | 2.02 | - 0.84 | 9.26 | 5.06 | 37.85 | 16.05 |
| Rate | 20% | - 1.30 | 1.03 | - 3.44 | 1.68 | - 0.52 | 41.95 | 17.79 |
| Capacity | 65% | 3.27 | 2.30 | - 1.42 | 9.53 | 5.09 | 38.17 | 16.19 |
| Factor | 60% | 0.91 | 2.12 | - 3.25 | 6.48 | 2.54 | 39.58 | 16.78 |
| Investment Tax Credit | 25% | 7.06 | 2.43 | 1.53 | 13.78 | 8.82 | 36.31 | 15.40 |
| Energy | 11% | 12.21 | 3.44 | 5.12 | 20.42 | 14.55 | 37.42 | 14.63 |
| Escalation | 9% | 0.61 | 1.84 | - 3.55 | 6.25 | 2.04 | 36.73 | 16.91 |
| General | 10% | 2.26 | 2.25 | - 2.86 | 8.96 | 4.02 | 39.00 | 16.54 |
| Inflation | 8% | 8.77 | 2.68 | 3.13 | 15.60 | 10.67 | 35.24 | 14.95 |
| Well Life | 10 yr | 2.50 | 2.65 | - 2.50 | 9.67 | 4.62 | 38.67 | 16.40 |
| | 30 yr | 8.63 | 2.40 | 3.00 | 15.16 | 10.37 | 35.42 | 15.02 |
| Correlated Events | | 5.84 | 2.46 | .36 | 12.58 | 7.64 | 36.97 | 15.68 |

[a]LEC is real levelized energy cost starting the first year of operation in Stage IV, expressed in mills/kWh.

for most scenarios. The change in ITC had the greatest impact on scenarios with the greatest capital investment, namely, those with low flow rates and high investment in wells.

The increase in ITC would have had a greater effect if a lower percentage of drilling and surface installation expenses had been indirect drilling costs (IDC). In the Base Case, 75% of drilling and 50% of surface installation costs were IDC. With ITC at 25% rather than 10%, one might consider capitalizing a greater proportion.

5. Sensitivity to Energy Escalation Rates

Profit is very sensitive to the energy escalation rate, the rate at which the price of the heat increases. A 1% increase in the energy escalation rate, from 10 to 11%, increases expected profit by about $6.4 million. Because these projects are long, a total of 39 years for the Reference Scenario, the addition of a 1% escalation increase is very significant.

6. Sensitivity to General Inflation Rate

Profit was slightly less sensitive to changes in general inflation than to changes in energy escalation. A 1% rate of increase in general inflation from 9 to 10% reduced expected profits by about $3.5 million.

The high sensitivity of profits to energy inflation rate and the general inflation rate indicates the use of caution when choosing their values.

7. Sensitivity to Well Life

The Base Case Set assumed well life was 15 years. That meant the wells would all be replaced once in a 30-year operating life. If well life were only 10 years, wells would have to be replaced twice, and if well life were 30 years, no replacement would be required.

As the results show, profit is sensitive to well life. It is especially sensitive for scenarios where there is a low flow rate and more wells are needed.

8. Sensitivity to Correlated Events

In this study we exploit a property of the GPCM not used in the Base Case Set: the ability to model the reservoir where the distribution of an uncertain variable depends upon the value taken by another uncertain variable. We will assume that the distribution of the flow rate depends upon the length of time required in exploration, Stage I. The distribution used is defined in Table 1-16.

Table 1-16. Flow Rate Correlated to Stage I[a]

| Outcome of Stage I, yr | Possible Value, GPM | Associated Probability |
|---|---|---|
| 3 | 1035 | 0.1 |
| | 1380 | 0.1 |
| | 1725 | 0.8 |
| 5.5 | 1035 | 0.15 |
| | 1380 | 0.35 |
| | 1725 | 0.50 |
| 8.0 | 1035 | 0.2 |
| | 1380 | 0.6 |
| | 1725 | 0.2 |

[a]JPL Estimates

The cumulative distribution of profit in this case is shown in Figure 1-2. Comparison of Figures 1-1 and 1-2 shows that the distribution of profit in the base case is probabilistically dominated by the distribution of profit in the correlated event case.[7] With no assumptions about the utility function of an investor other than that more profit is preferred to less, we can conclude that an investor would prefer to invest in a geothermal project with the characteristics of the correlated events case, rather than a project with the base case characteristics.

The correlated events case cannot be handled by the standard Monte-Carlo-type model, and the ability to handle such correlated input data is a prominent feature of the GPCM.

[7]Probabilistic dominance is also known as stochastic dominance. For a discussion of probabilistic dominance see Reference 9.

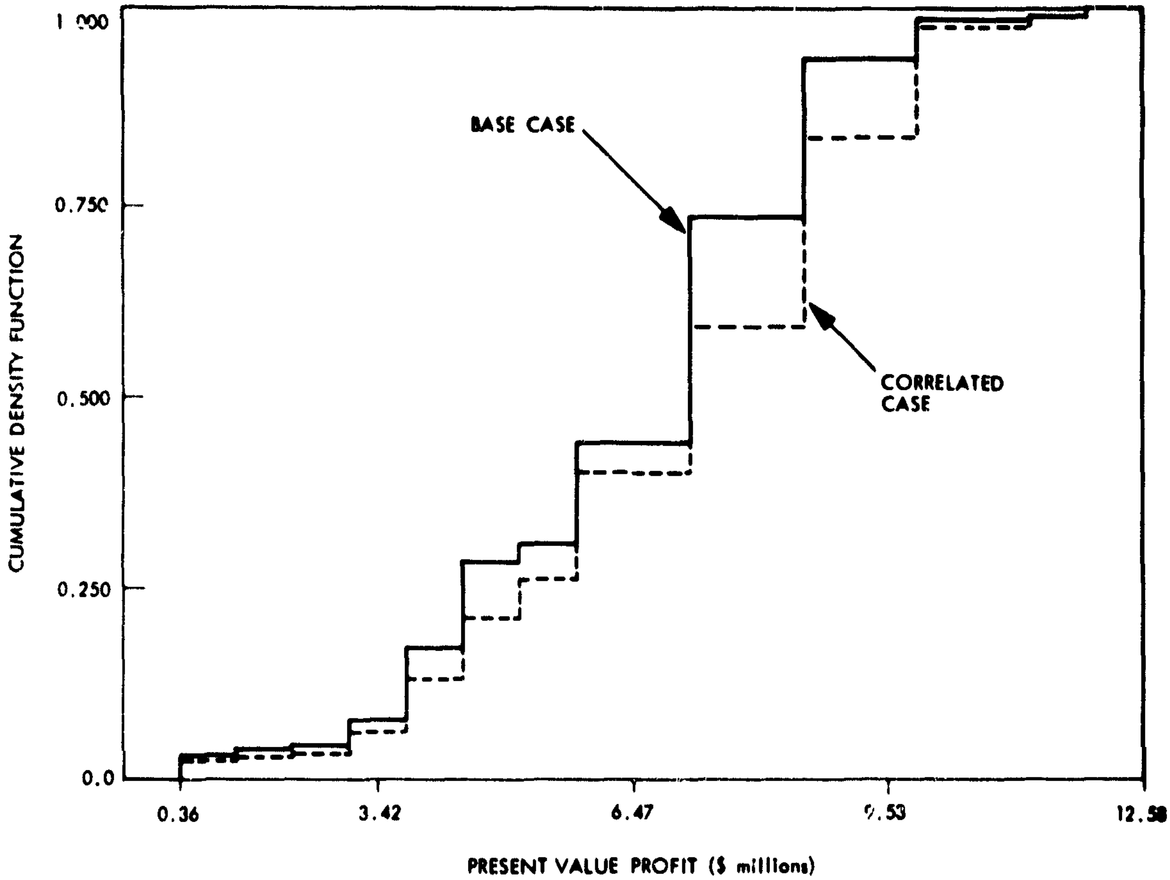



Figure 1-2. Cumulative Distribution Functions of Profit in the Base Case Set and Correlated Events Case

## SECTION II

## THE GEOTHERMAL PROBABILISTIC COST MODEL

### A. INTRODUCTION TO THE MODEL AND THE REFERENCE SCENARIO

The development of a geothermal energy resource presents a potential investor with a number of uncertainties, both in the geothermal resource and in the development process itself. These elements of uncertainty can be incorporated into cost estimates properly if probabilistic cost models are used. This chapter provides the reader with a description of one such model that has been developed at the Jet Propulsion Laboratory. The model calculates the probability distribution for the cost of a project, as well as for other financial factors such as profit and required capital. It has long been a tradition to provide a single point estimate for these factors, but it is our conviction that at best such estimates are expected costs and more often tend to be on the low side. Expected cost alone provides a limited amount of information. Usually, the expected cost for a new technology is higher than the current conventional energy cost. Thus, based on the criteria of expected cost alone, such a new technology would not appear economicalv attractive. However, the variance of the cost estimate may be large enough to indicate that there may be a significant probability that the new technology is competitive. This is illustrated in Figure 2-1.

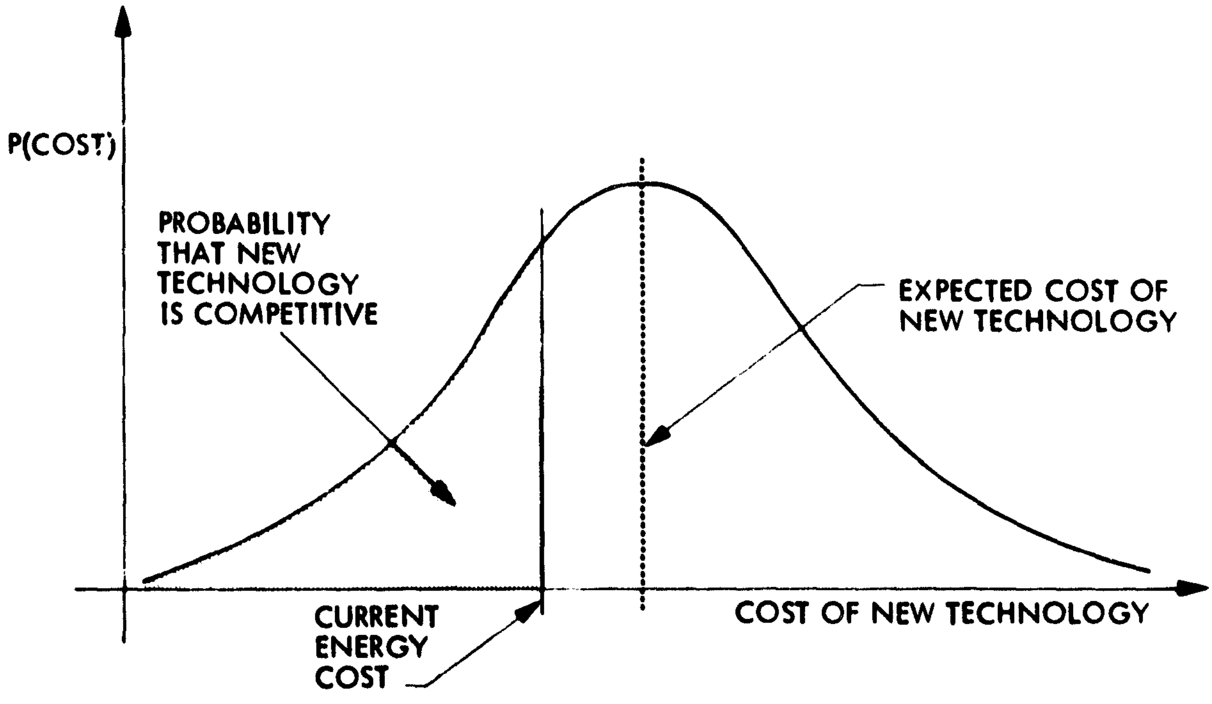



Figure 2-1. Expected Cost of a New Technology

1. Reference Scenario

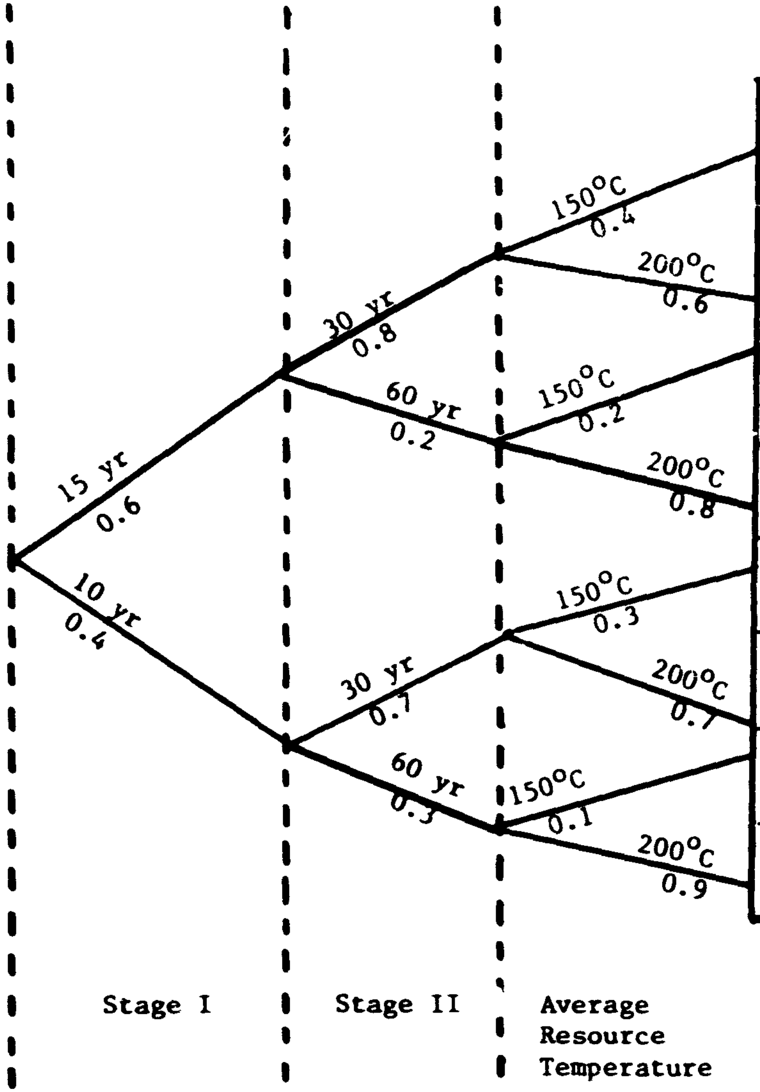
Many projects or processes can be considered as occurring in stages, with the cost of the activities for the project being dependent upon the duration of the stage in which they occur. In projects of this type with long time-horizons, it is often the case that the duration of at least some of the stages (and hence the cost of the activities in those stages) will be uncertain. Thus, final cost and profit will be sensitive to the length of time required to complete each of those stages. In addition to the stage durations, other variables that have an effect on cost, such as physical parameters, may also be uncertain.

The model described in this report deals with these uncertainties by considering individually all permutations of times (for the stage durations) and values (for the uncertain physical variables). From each such permutation of times and values, a 'scenario' is constructed and then analyzed. It would be quite costly to have an architectural/engineering firm actually calculate the costs associated with all possible combinations of these variables (e.g., well flow rates, reservoir depth, fluid temperature, and permitting and construction times) for a given site. To avoid the enormous information costs of generating these cost accounts for each such combination, the model makes use of a Reference Scenario. A Reference Scenario is defined as the most likely developmental pattern. Cost-accounts are input into the program for only this Reference Scenario. For all other scenarios, only their stage times, physical parameter values, and the associated probabilities are input: their cost accounts are derived within the program by modifying the appropriate Reference Scenario cost accounts for any differences in the length of the stages or for any differences in the values of the physical parameters. Thus, as described in Section II-D, the Reference Scenario is really a baseline case from which all other scenarios are derived. As a result, the lengthy and difficult task of providing detailed cost accounts for the site under study has to be performed only once (for the Reference Scenario).

The Reference Scenario also serves as a standard form for presenting data for the model. It is important to note that the mathematical model developed is flexible enough to handle as many stages and cost accounts as the user desires. The Reference Scenario framework described in Subsection B provides a suggested framework for aggregating the accounts in the model and for organizing the data collection.

The user of this model should realize that the amount of data required, and therefore the computer cost, will vary with the number of stages identified, as can be seen from the sample decision tree in Figure 2-2. For example, if there were eight stages with two alternatives in each stage, there would be 256 ($2^8$) scenarios. If, additionally, there were two physical variables with two possible outcomes each, the total number of scenarios would be only $2^8 \times 2^2 = 2^{10}$. Therefore, the user should always try to delineate the essential stages.

The next section describes the Reference Scenario framework for the model. Subsection C provides the rationale for treating specific factors as random variables. These are presented before the formal model (Subsection D) to provide the reader with background information that should be useful for understanding the model.




| | Stage I | Stage II | Average Resource Temperature, °C |
|---|---|---|---|
| Scenario 1 | $\frac{15}{0.6}$ | $\frac{30}{0.8}$ | $\frac{150}{0.4}$ |
| Scenario 2 | $\frac{15}{0.6}$ | $\frac{30}{0.8}$ | $\frac{200}{0.6}$ |
| Scenario 3 | $\frac{15}{0.6}$ | $\frac{60}{0.2}$ | $\frac{150}{0.2}$ |
| Scenario 4 | $\frac{15}{0.6}$ | $\frac{60}{0.2}$ | $\frac{200}{0.8}$ |
| Scenario 5 | $\frac{10}{0.4}$ | $\frac{30}{0.7}$ | $\frac{150}{0.3}$ |
| Scenario 6 | $\frac{10}{0.4}$ | $\frac{30}{0.7}$ | $\frac{200}{0.7}$ |
| Scenario 7 | $\frac{10}{0.4}$ | $\frac{60}{0.3}$ | $\frac{150}{0.1}$ |
| Scenario 8 | $\frac{10}{0.4}$ | $\frac{60}{0.3}$ | $\frac{200}{0.9}$ |

Figure 2-2. Completion Time of each Stage and the Conditional Probability of its Occurrence: Project of Two Stages and One Resource Characteristic

## B. REFERENCE SCENARIO FOR A GEOTHERMAL RESERVOIR

As described in the preceding section, a probabilistic cost model has been developed to analyze the development of a geothermal resource. Although the model can be applied to the development of the reservoir for the production of steam as well as to the construction of a power plant for the generation of electricity, this section describes only the development of the reservoir.[8] The model examines the time-dependent activities, as well as the time-independent activities, that must be completed before the developer of the geothermal reservoir can provide steam to the owner of a power plant on an ongoing basis. About 60% of the cost of electricity from a geothermal facility is attributable to the production of steam (Figure 2-3). About 10% is due to annual expenses related to the power plant, and the remaining 30% is allocated to the initial power plant investment. The cost of geothermal steam is about equally dependent on the cost of field development (45%) and the cost of operating the field (45%). The remainder of the cost is due to field exploration.[9]

The Reference Scenario for the development of a geothermal reservoir is structured around the essential processes or stages of development. Only the stages that are important from the standpoint of cost or time will be explicitly incorporated in the Reference Scenario. Minor stages have been aggregated to form these generic stages.

Each geothermal area has different geologic characteristics and construction requirements and perhaps even different permitting procedures depending on the state in which it is located and whether it is on private, state, or federal property. Therefore, data collected from the experience at one site might not be relevant to another. The application of the cost model will require the definition of a Reference Scenario at each site. The specific data (cost, time, conditional probabilities, and technology) is site-dependent.

The developer is responsible for the exploration of the geothermal resource and the definition of its capacity and characteristics. His responsibilities also include the subsequent drilling of the production and reinjection wells, and the construction and operation of the transmission system that brings the geothermal resource to the "front door" of the utility's power plant. In essence, the developer's activities can be viewed as occurring in four stages. The next four subsections will elaborate on these stages.

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[8]The model may be applied to any investment project with uncertainty, as long as the user can provide all the required cost data and engineering relationships.

[9]The percentages differ for individual sites. The objective here is to give the reader a reference point for evaluating the importance of various cost accounts.

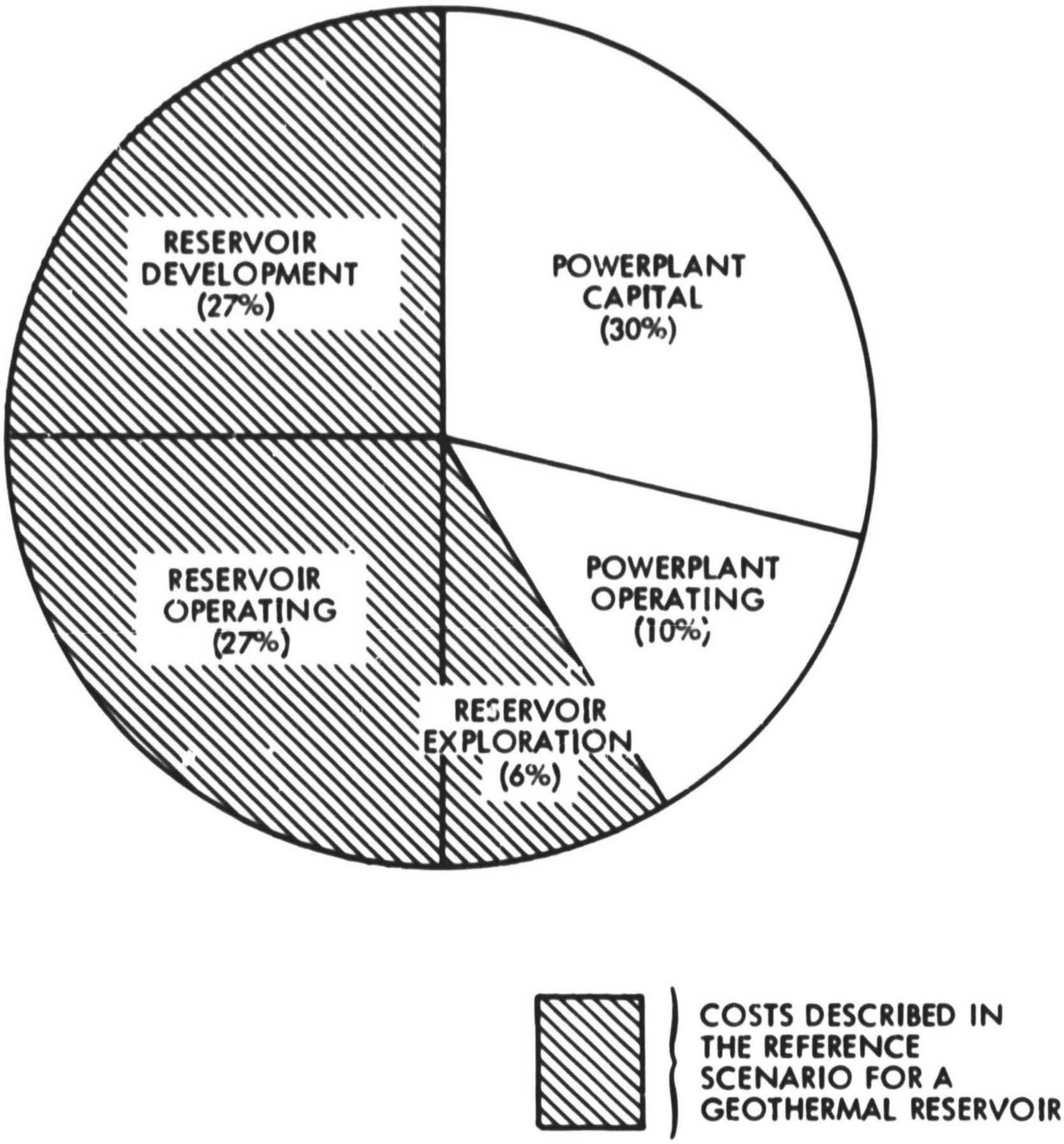


Figure 2-3. Approximate Distribution of the Cost of Electricity Generated from a Geothermal Source (from Reference 10)

1. Stages of Geothermal Reservoir Development

a. Stage I: Proving the Resource. The objective of Stage I is to find a geologic anomaly that allows for the extraction of the Earth's internal heat at a cost competitive with other electrical generation technologies. Establishing the temperature of the resource, as well as the existence of water to transfer heat from the deep igneous heat source to a geothermal reservoir shallow enough to be tapped by drill holes, is the goal for this stage.

Stage I includes three major activities: (1) preliminary resource identification and land leasing; (2) exploration well permitting; and (3) exploratory drilling and complete well logging. Beginning now, the parties involved in the geothermal development (e.g., the field developer and plant operator) will start to negotiate the contractual terms for sale of the geothermal energy to the electric utility.

The criteria for success in this stage is the existence of the confirmatory geologic data required to convince an electric utility company that its investment at the field is warranted. The last activity in the stage is an agreement with the utility to pursue the necessary permits for building a power plant.

The amount of time necessary to complete the above activities is the major element of uncertainty in this stage, reflecting the geological uncertainty about the quality and size of the reservoir based on preliminary geologic data. For example, Reference 11 estimates that 128 areas must be examined in order to get one successful site. This assumption is not appropriate to the Heber site because earlier exploration by oil and gas companies had revealed the geothermal anamoly while looking for natural gas reserves.

b. Stage II: Development Permits Application, Review, and Approval. Having completed Stage I, the producer and the electric utility must now apply for the necessary permits from the federal, state, and local authorities to develop the resource and construct a power plant. No capital investment by either the producer or the electric utility will take place prior to the completion of approval on all necessary permits. Therefore, this stage must eventually include the activities of both the utility and the developer.

c. Stage III: Reservoir Development. The developer and the electric utility are now in a position to begin the actual development and construction of their respective facilities. By now, the characteristics of the resource have been established,the developer has agreed with the utility on the price and amount of heat to be sold, and all the necessary permits and authorizations have been received.

This stage for the developer includes the development and start-up operation for all the production and reinjection wells, and the construction and testing of the geothermal transmission system.

Stage III is different from Stages I and II in that engineering and procurement uncertainties affect the actual time involved. Stage I is characterized by the geologic uncertainty, and Stage II is determined by the administrative procedures of several bureaucracies. The following section looks at the cost accounts and their relationships to the tasks.

d. Stage IV: Operation of the Facility. Stage IV describes the costs incurred by the developer over the economic life of the power plant. These include the general operation and maintenance of the existing equipment as well as the development of new production wells to maintain the necessary energy flow to the power plant. For example, if the flow rate from existing wells decreases or the temperature of the resource degrades, more wells will be required to make up the difference. Also, with time, some wells might fail and have to be abandoned necessitating new wells to be drilled nearby to take advantage of the known resource. Although this degradation is not modeled explicitly by this study, a redrilling program is assumed to take place and new wells are scheduled to keep the heat content constant for the life of the geothermal field.

Success in this stage is defined as being able to continually operate the reservoir at some stated capacity for the life of the power plant. The treatment of various levels of non-success and its effect on cost has not yet been completed.

## C. SOURCES OF UNCERTAINTY IN THE DEVELOPMENT OF GEOTHERMAL RESOURCES

The uncertainty surrounding the successful development of a geothermal can arise from a large number of sources. But, although many sources may contribute to the uncertainty, only those that impact the ultimate cost to a substantial degree need to be considered further. If changing the value of a variable within a realistic range introduces significant changes in the costs of power, then that variable is considered to be important. In this section the identification of important variables will be done in two steps.

The first step is to identify those variables whose per-unit variations have the greatest impact on final cost. This is obtained by varying the value of a given parameter, and dividing the resulting change in power cost by the change in the parameter. The first step is exemplified by Table 2-1, which is the result of a sensitivity analysis from Reference 12. This shows the change in final cost due to a change in a given parameter. The first item has the highest final cost change per unit parameter change (obtained by dividing the reduction in power cost by the change in the parameter), with the following items listed in descending order.

At this point, one problem with Table 2-1 should be mentioned. It provides sensitivities at a given point (at the reference cost given in the table). Like the concept of point elasticity, this sensitivity is dependent on the point at which it is measured. It is a variable, and thus linear extrapolations may not be accurate.

The second step is the determination of how much each parameter might reasonably be expected to vary from an assumed mean value. Some variables can

Table 2-1. Results of Sensitivity Analysis for Reference Case with Power Cost = 28.2 mills/kWh (from Reference 12)

| Parameter | Reference Value | New Value | Change in Parameters, % | Reduction in Power Cost, % |
|---|---|---|---|---|
| Wellhead Temperature | 200°C | 250° | + 25 | 19 |
| Cost of Capital | | (Reduced by half) | - 50 | 31 |
| Cost per Well | $500,000 | $300,000 | - 40 | 20 |
| Well Flow Rate | 500,000 lb/h | 750,000 lb/h | - 50 | 17 |
| Plant Capital | $14.9 million | $7.5 million | - 50 | 14 |
| Internal Power Consumption | 10.5 MWe | 5.25 MWe | - 50 | 11 |
| Taxes | (All tax rates reduced by 1/2) | | - 50 | 10 |
| Cost of Transmission and Disposal Systems | | (Reduced by half) | - 50 | 9 |
| Reinjection Costs | Reinjection | No Reinjection | -100 | 16 |
| Well Life | 10 years | 20 years | +100 | 10 |
| Excess Producing Wells | 20% of Projection Wells | 5% of Production Wells | - 75 | 6 |
| Cooling Tower | Included | Excluded | -100 | 6 |
| Operating Expenses | | (Reduced by half) | - 50 | 3 |
| Royalty Payments | 10% | 0 | -100 | 5 |
| Dry Wells | 20% of Production Wells | 5% of Production Wells | - 75 | 4 |
| Exploration Costs | Included | Excluded | -100 | 4 |
| Plant Life | 30 years | 40 years | + 33 | 1 |
| Transmission and Disposal Systems Maintenance Rate | 0.05 | 0.025 | - 50 | 1 |
| Intangible Write-off | Allowed | Not Allowed | -100 | -10[a] |
| Plant Life | 30 years | 20 years | + 33 | - 5[a] |

[a]Indicates an increase in cost of power.

be expected to have a value that falls within a narrow range, while others can be expected to fall somewhere within a wide range of values. Thus, the second step identifies those variables that can be expected to have the largest fluctuation in their own values, while the first step identifies those variables whose per unit changes cause the largest variation in cost. Accordingly, those variables whose per unit influence on total cost is high and which can fluctuate widely will be more important sources of uncertainty than those variables whose per unit influence on total cost is likewise high, but which are not expected to fluctuate very much, and so on. For example, although the cost of capital is the second most sensitive variable, producing a 0.62% reduction in power cost for every 1% change in the cost of capital, it is not likely that the cost of capital would vary by more than 5% for a particular company. This number is known as soon as a utility company is known, and thus the cost of capital would not be considered an important variable as far as it's contribution to the uncertainty of the final cost of the resource is concerned.

The first five variables in Table 2-1 are:

(1) Wellhead temperature.

(2) Cost of capital.

(3) Cost per well.

(4) Well flow rate.

(5) Plant capital cost.

The following subsections discuss the uncertainty inherent in wellhead temperature, the cost of wells, and well flow rates. The mathematical model presented in Subsection D shows how these variables (wellhead temperature, cost per well, and well flow rate) are incorporated in the model. The computer program can handle any number of cost and resource uncertainties, but the user has to specify the scaling equations for each uncertainty.

## 1. Wellhead Temperature

Wellhead temperature, as seen by Table 2-1, heads the list as the variable to which power cost is most sensitive. Using Figure 2-4, it is clear that, although a characteristic reservoir temperature can be listed, individual well temperatures can vary significantly. Taking a 5000-ft well, temperatures as shown in Figure 2-4 vary from 300°F to about 360°F, a 20% variation. Because most wells reach 360°F somewhere near that depth, and hold it over a wide range of depths, 360°F would be considered the resource temperature.

## 2. Cost per Well as a Function of Well Depth and Rock Type

In the literature, the quoted value for the cost per well has ranged from $300,000 to $2 million dollars. Most of this variation is due to well

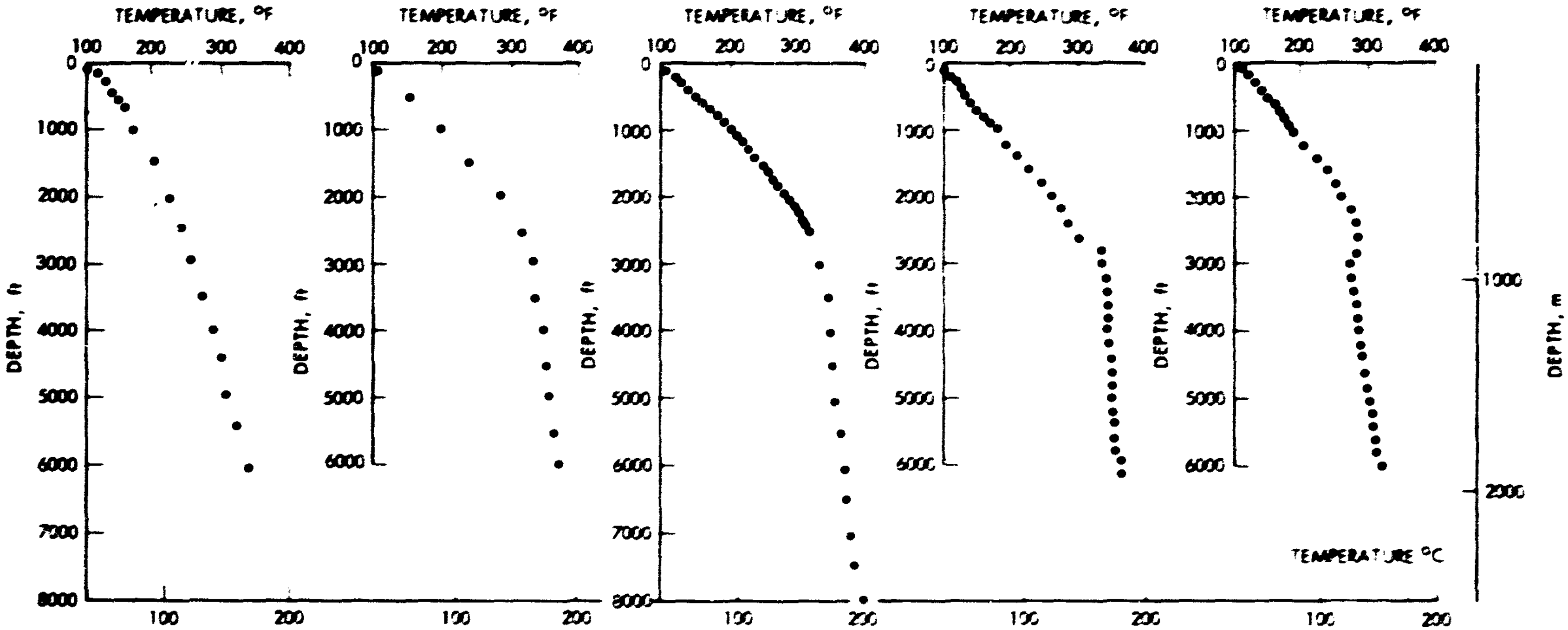


Figure 2-4. Distribution of Temperature with Depth for Five Geothermal Wells. The Depth Ranges are Shown in Feet and Correspond to the Clay Cap (0 to 600 m), the Transition Zone (600 to 750 m), the Upper Portion of the Geothermal Reservoir (750 to 900 m), Two Additional Segments of the Reservoir 900 to 1525 m and 1525 to 2175 m), and Below the Reservoir (2175 to 2448 m). (from Reference 9)

depth. Figure 2-5 shows an estimate as to well cost per meter, with a 90% confidence interval. This estimate compares favorably with the medium hard to hard rock curves in Figure 2-6 which shows that the hardness of rock is an important determinant of drilling costs and thus well cost. The actual drilling costs used in the Heber site-study have been discussed further in Section I-B.

3. Well Flow Rates

Figure 2-7 shows a 90% confidence interval for wellhead flow rate versus well depth. Using a 1524-m (5000-ft) deep reservoir, flow rates are about 375 ±125 Mlb/h, a variation of about 33%. Table 2-1 indicates that this variation would produce an 11% change in power costs. Figure 2-8 shows the variability of well flow rate over time.

4. Other Sensitive Variables

Table 2-1 indicates that the cost of power is also sensitive to the cost of capital and to plant capital requirements. Cost of capital is not treated stochastically in the model for the reasons given previously.

As regards plant capital requirements, Table 2-2 shows a variety of "predictions" of geothermal capital costs. Variation is due to different resource temperatures, technologies used, cooling water availability and environmental controls required. Thus, one must be careful as to which plants can be compared. For the 200-mW steam plants, the cost per kilowatt was found to vary by 27% around the mean. Flash plant predictions for the same size plant varied by 30% about their average, and binary plants varied by 21% about their average. There were not enough small plants of the binary and flash type to do this for any but the 200-mW plants. Based on these results, if a 25% variation in power plant capital costs is assumed, only a 7% change in power cost is expected.

The other variables listed in Table 2-1 can be similarly evaluated. Their effects on power cost can be calculated, with end result being the demonstration of the importance of the three variables: (1) wellhead temperature, (2) cost per well (well depth and rock type), and (3) well flow rate, relative to the others.

The only variable whose effect on cost has not been examined in the literature is the length of time required for the stages of development discussed in Subsection B. Figure 2-9 shows the effect of the time lag from the signing of a contract between the producer and the electric utility to the start of fluid sales on the expected present worth of the venture. Data from Pacific Gas and Electric Co. (PG&E) demonstrate the uncertainty about the time elapsed during one stage. The last three units (13, 14, 15) at Geysers were expected to take 28, 36, and 28 months, respectively, to acquire the California Public Utilities Commission Certificate of Public Convenience and Necessity. These predictions were made almost two years before the certificate

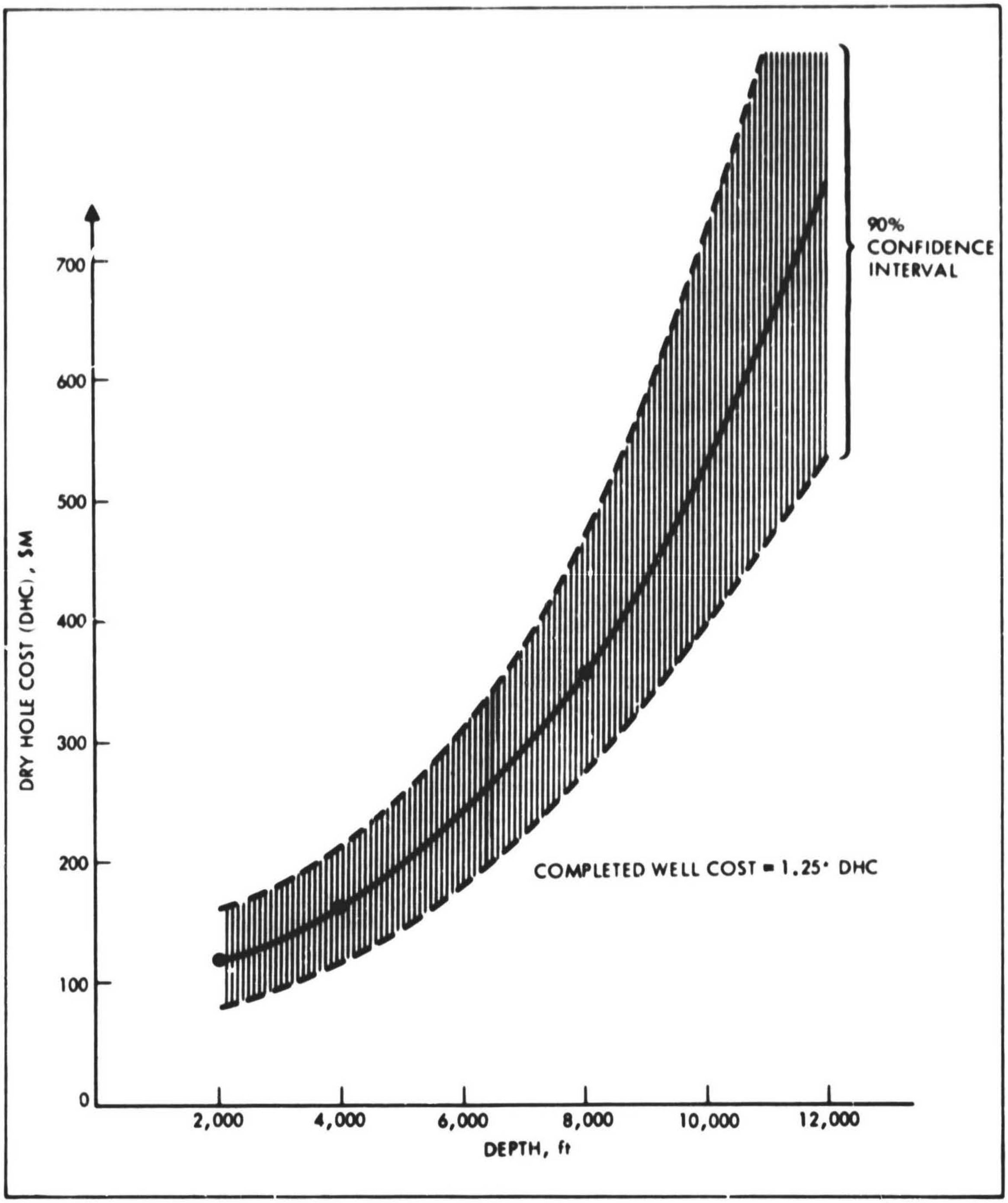


Figure 2-5. Effect of Depth on Geothermal Drilling Costs (in 1975 dollars) (from Reference 14)

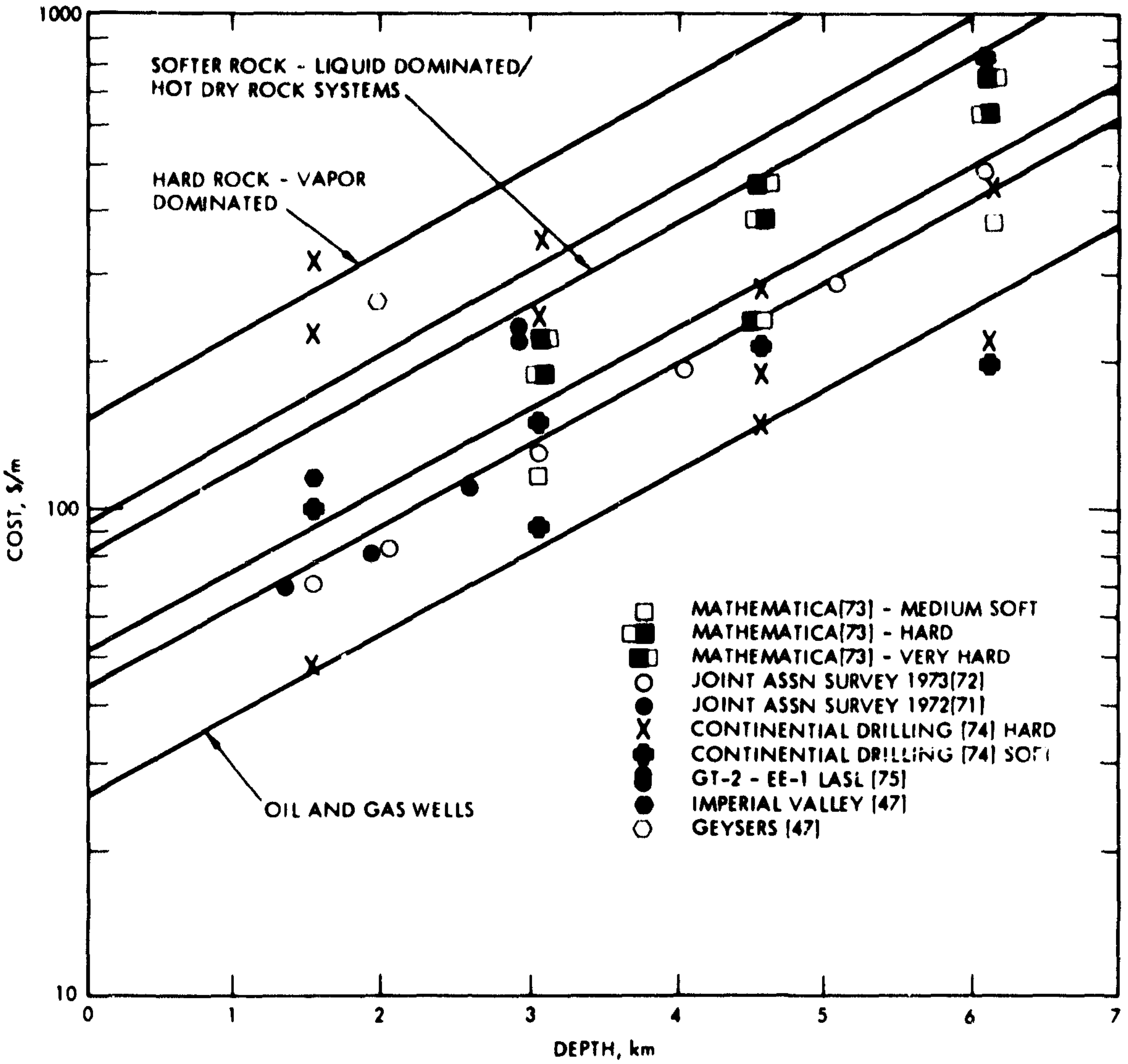


Figure 2-6. Well Costs Including Drilling and Casing as a Function of Depth (All costs are adjusted to 1976 dollars)(from Reference 15)

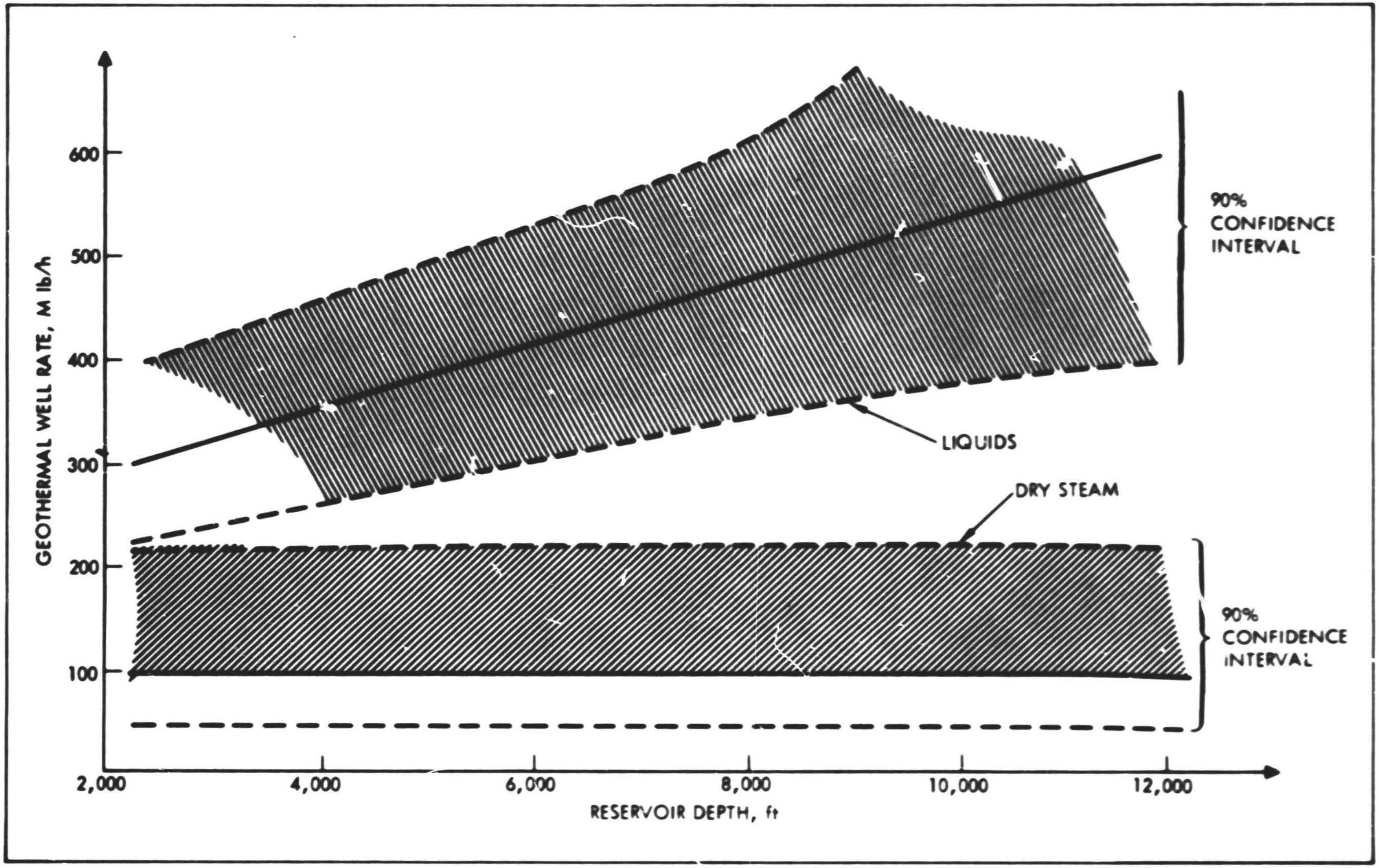


Figure 2-7. Effect of Reservoir Depth on Production Rate (from Reference 14)

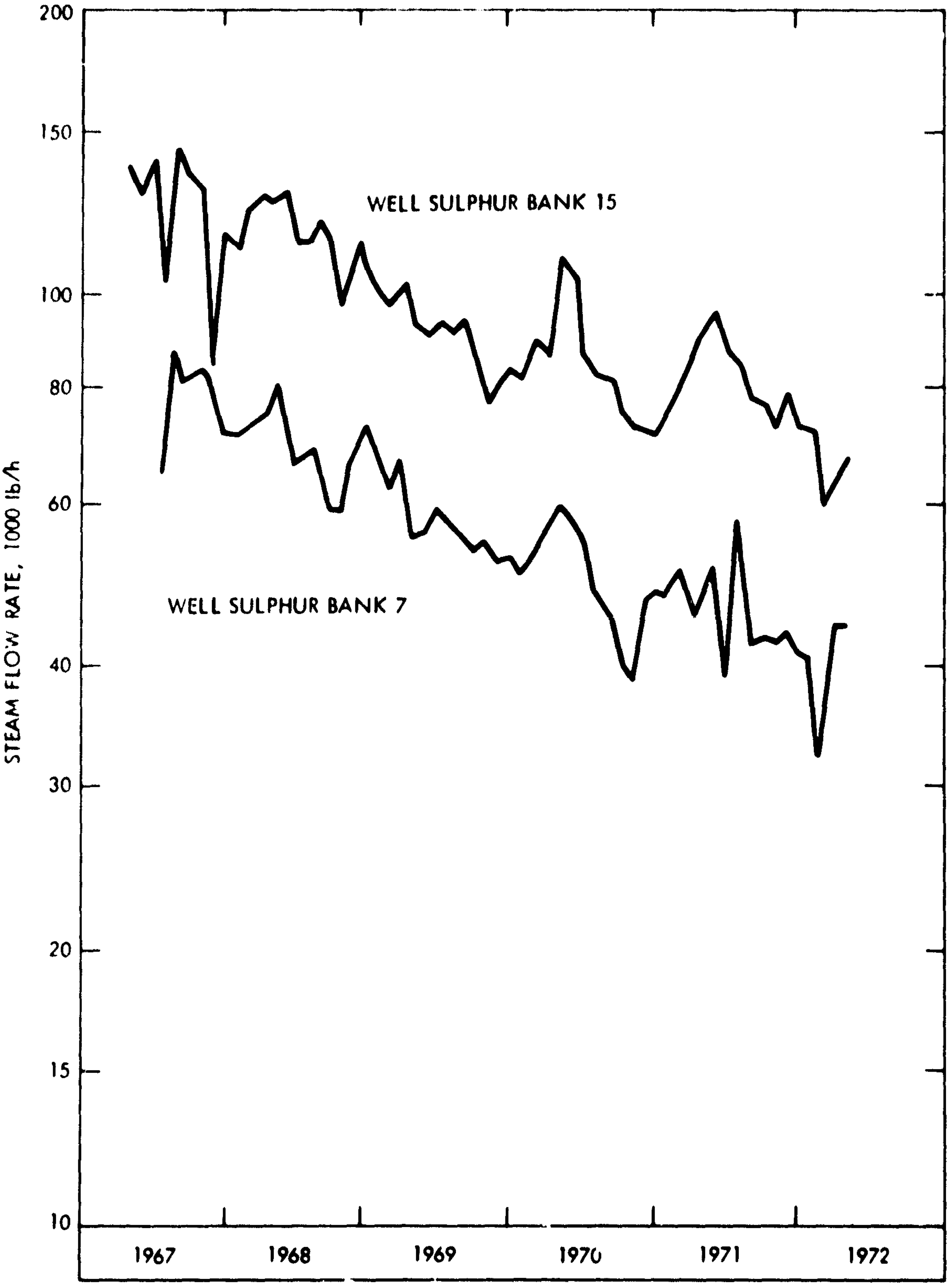


Figure 2-8. Steam-Production Rate vs Time for Geothermal Steam Wells at the Geysers (from Reference 16)

Table 2-2. Capital Costs (Field and Plant)(from Reference 17)

| Source | Type | Capacity, MW | Field Investment Costs (1976$), $/kW | Generating Plant Investment, $/kW | Total, $/kW |
|---|---|---|---|---|---|
| Greider | Steam | 200 | 162/kW | 230 | 407 |
| Greider | Flash | 200 | 172 | 429 | 617 |
| Greider | Binary | 200 | 173 | 527 | 717 |
| Barr | Steam | 200 | | 140 | |
| Barr | Flash | 200 | | 232 | |
| Barr | Binary | 200 | | 341 | |
| Armstead | Steam | 200 | 103 | 173 | 277 |
| Bloomster | Flash | 55 | 174 | 274 | 447 |
| Holt and Brugman | Binary | 50 | | | |
| at 250°F | | | | 560 | |
| at 500°F | | | | 297 | |
| Holt[a] | Flash | 50 | 200-300 | 450-550 | 650-850 |
| | Binary | 50 | 200-300 | 450-550 | 650-850 |
| Dan, Hersam Kho and Krumland | Geysers Unit 14 | 110 | | 149 | |
| Krumland[b] | Geysers Unit 14 | 110 | | 260 | |
| Goldsmith | (Flash) | | 150-200 | 159-310 | |
| Geysers[c] | Geysers Historical | 502 | 116 | 166 | |
| Cerro Prieto[c] | (Flash) | 75 | | | 314 |
| Racine | (Binary) | 50 | | 700-800[d] | |
| Hankin | (Flash) | 50 | | 742 | |
| Project Independence | (Brine) | 200 | | | 560-860 |
| | (Geysers) | 1000 | | | 364[e] |

[a] Holt supersedes Holt and Brugman.

[b] Krumland supersedes Dan, Hersam, Kho, and Krumland.

[c] From Greider.

[d] Racines costs projected for 1982.

[e] Project Independence projected costs for 1980.

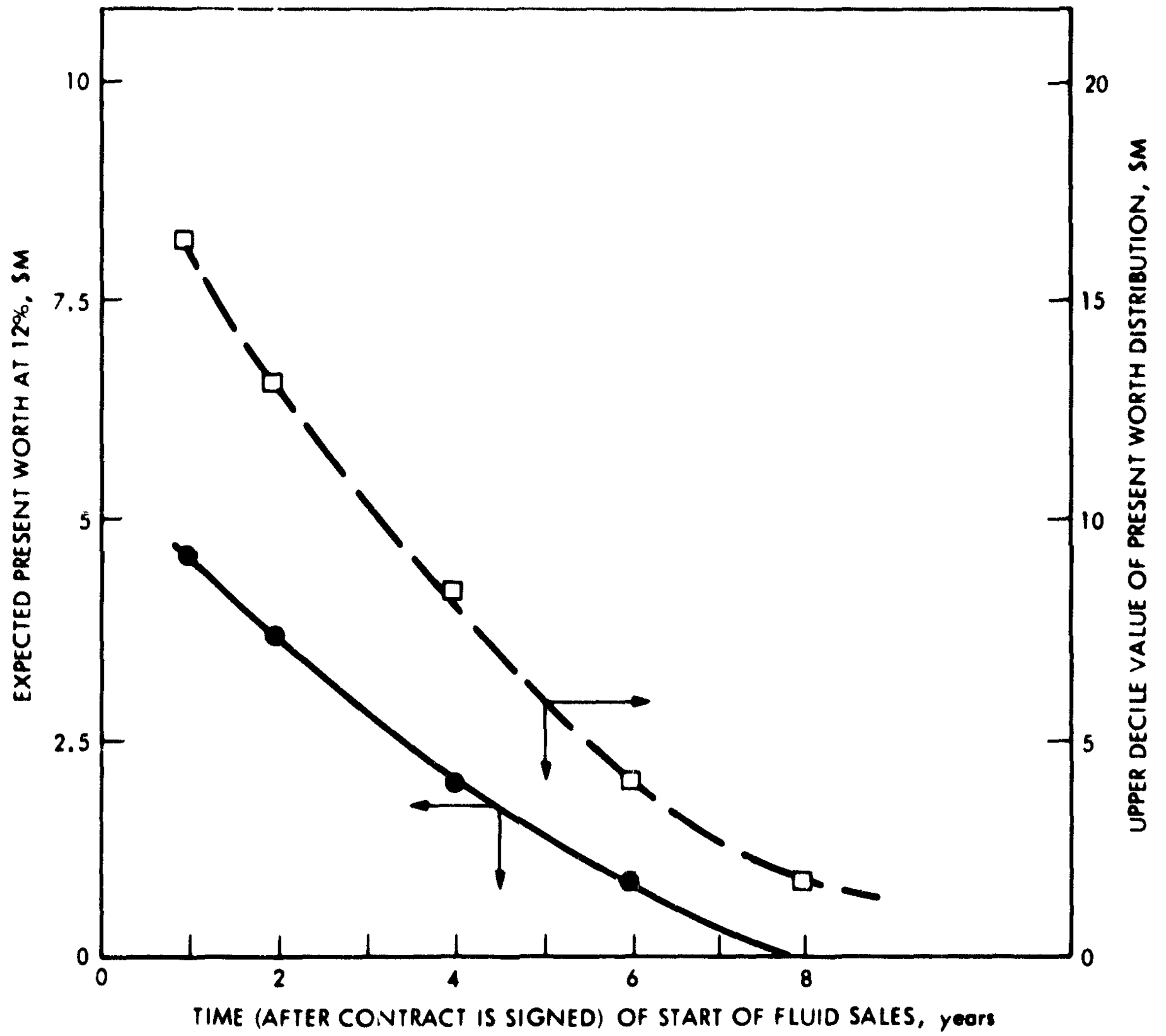


Figure 2-9. Effect of Time of Start of Fluid Sales on Expected Present Worth (from Reference 14)

process. The actual realized times for units 13, 14, and 15 certification processes were 32, 33, and 26 months, respectively.[11]

The time effect is explicitly discussed and stressed in the previous section. The computer model has the capability to handle this important factor, in addition to the resource uncertainties discussed above.

## D. GEOTHERMAL PROBABILISTIC COST MODEL

### 1. Introduction to Probabilistic Modeling

Because the cost of developing a geothermal resource is intrinsically uncertain, no venture analysis technique can evaluate the cost or profit of a project with any degree of confidence without considering the uncertainties present. Partial accommodation of these uncertainties can produce results which are misleading. Probabilistic cost modeling, however, does provide the opportunity to properly incorporate these uncertainties into the final results. This paper describes one such model that has been developed at the Jet Propulsion Laboratory and discusses its application to a geothermal site at Heber, California.

The concept underlying probabilistic modeling is that the values for the model inputs are not known, but that their distributions can be estimated. A decision tree showing each possible sequence of events and the associated probabilities can then be constructed, and from this, project costs and other financial measures can be appropriately aggregated into probability distributions. By generating entire distributions, this model enables the inclusion of a decision-maker's risk preference into his investment decisions. The shaded area in Figure 2-1 shows that even though the expected cost of a new technology may be higher than the current cost of conventional technologies, there might be a considerable probability that the new technology is competitive with the existing technology. Likewise, there may be a significant probability that the cost of the new technology will reach unacceptable levels.

The possibility for a decision maker to consider risk preference is precluded when only point estimates are made. It might be argued that calculating a point estimate requires less information than constructing a complete distribution. This is not true, however, because calculating the expected value implicitly uses all the relevant information contained in a probability distribution. This model uses that information explicitly and calculates the probability distributions for cost, required capital, and profit. The expected value and variance can be derived from these distributions, and risk preference may then be introduced.

The most distinguishing feature of the Geothermal Probabilistic Cost Model is that it allows the outcome of one variable to be dependent upon the outcomes of the other variables. Conditional probability distributions

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[11] Data from attachment to letter from Richard H. Peterson, Vice-Chairman of the Board, Pacific Gas and Electric Company to Mr. Leo T. McCarthy, Speaker of the Assembly, California. The attachment is dated January 12, 1976.

can thus be used. For example, the probability distribution for the length of a development stage may be dependent upon the lengths of the stages that precede it or upon the depths of the wells that have to be drilled, none of which may be known at the beginning of the project. In this way, any correlation--either positive or negative--between characteristics can be considered explicitly and a joint probability distribution that has all existing dependency relationships factored into it can be constructed.

Therefore, this model can correctly aggregate the statistical variances in the stage time distributions. Unlike the expected value of the sum of two random variables (which is the sum of their expected values), the variance of the sum may be greater than, equal to, or less than the sum of their variances. It depends on whether the two random variables are positively, neutrally, or negatively correlated to one another.[12] The distributions in Figures 2-10a and 2-10b are of the same shape. The only difference is their orientation. With the major axis tilted to the right (indicating positive correlation), the distribution leads to a corresponding distribution of total project cost with a widespread (large) variance (see Figure 2-11a). The opposite case is obtained for the distribution having its major axis tilted to the left (indicating negative correlation). The corresponding distribution is more concentrated around its mean (low variance; see Figure 2-11b). The expected value approach can not capture all these results.

## 2. Formal Model

Four stages have been identified for the Reference Scenario of a geothermal resource development. These stages are:

(1) Stage 1: Proving the resource.

(2) Stage 2: Development permits application, review, and approval.

(3) Stage 3: Reservoir development.

(4) Stage 4: Operation of the facility until the field is depleted of an economically valuable geothermal resource.

These four stages have been used to model the Reference Scenario here. Although any number of stages is possible, to maintain a manageable number of stages and to prevent the number of alternative scenarios from being too large, six stages should be set as the upper limit. To illustrate the problem, let there be two alternatives in each stage. With 6 stages, there are 64 scenarios. If the number of alternatives is three, there is a total of 729 scenarios! Thus, the users of this model are urged to economize on the choice of stages and physical parameters under consideration while disaggregating the problem to capture some major elements of uncertainty.

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[12] Let x and y be two random variables. Variance $(x + y)$ = Variance $(x)$ + Variance $(y)$ + 2 Covariance $(x,y)$. Variance $(x + y)$ = Variance $(x)$ + Variance $(y)$ if and only if Covariance $(x,y) = 0$.

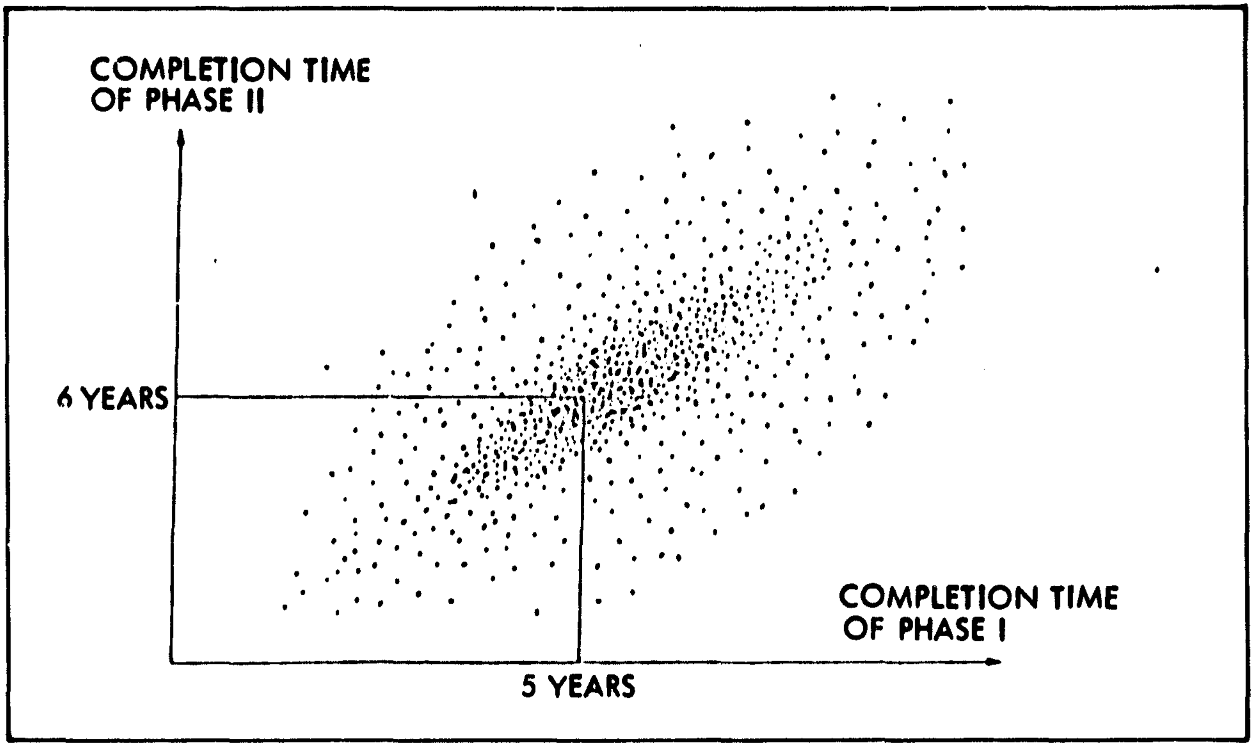


Figure 2-10a. Positively Correlated Events

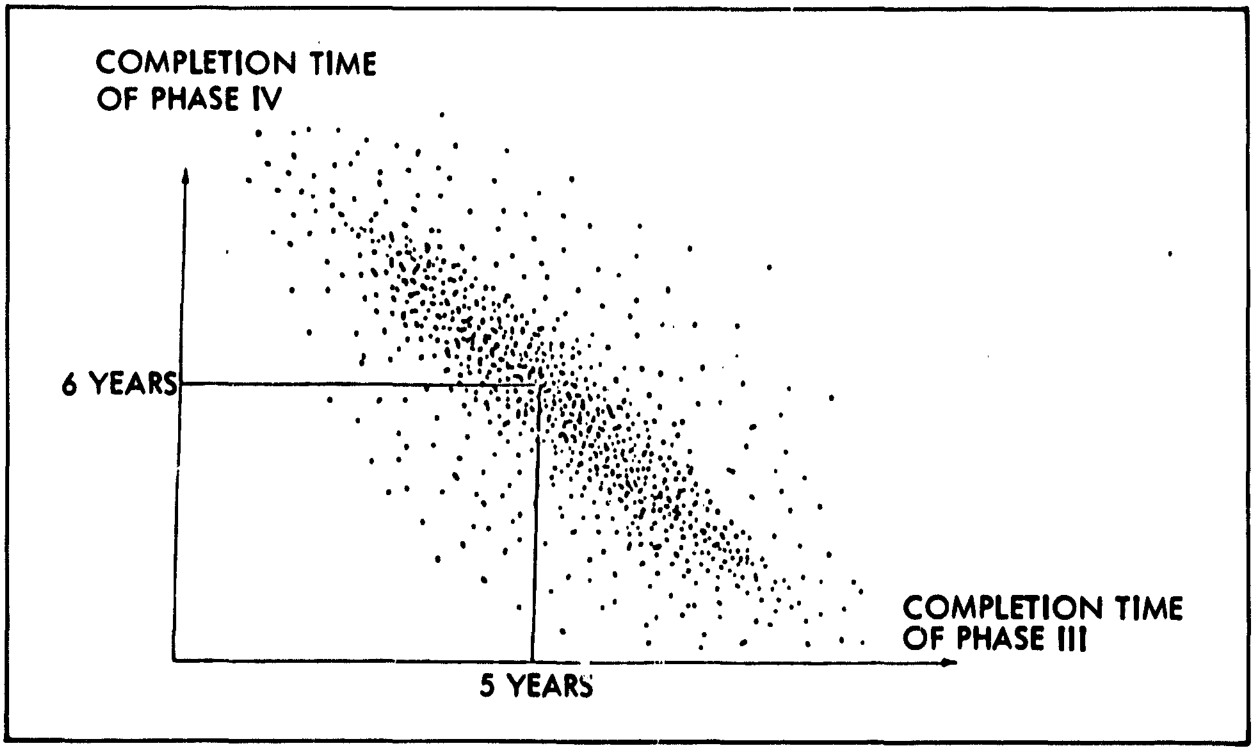


Figure 2-10b. Negatively Correlated Events

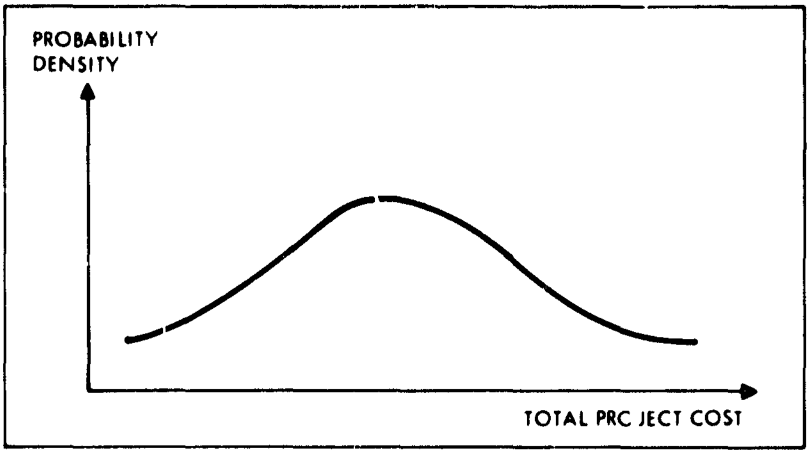


Figure 2-11a. Total Cost of a Project When Time Durations are Positively Correlated

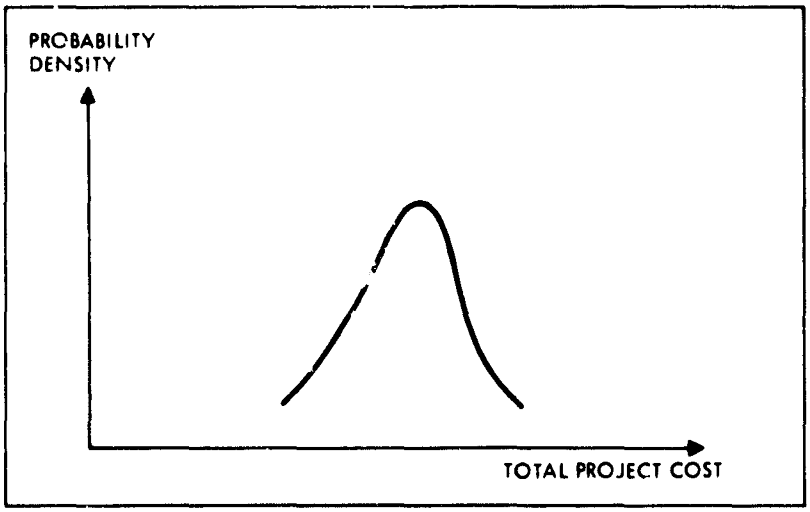


Figure 2-11b. Total Cost of a Project When Time Durations are Negatively Correlated

a. The Methodology: An Overview. To incorporate the uncertainty arising from stage length times and uncertain variables into the analysis of project cost, the model considers individually in succession all different possible permutations of values for those uncertain variables. From each such permutation of values and times, a "scenario" is constructed and then analyzed.

A scenario thus represents one possible path through a decision tree. Specifically, a scenario is defined by four attributes:

(1) A set of durations specifying the length of each of the stages.

(2) A set of values for the uncertain physical parameters (e.g., wellhead temperature, flow rate).

(3) The probabilities that each stage and each physical parameter takes the value specified for it in (1) and (2).

(4) The dollar value costs for all cost accounts in all stages.

To avoid the enormous information costs of deriving the cost accounts (4 above) for each possible scenario, the model uses a baseline case, or Reference Scenario. The Reference Scenario is defined as the most likely path through the decision tree. In the computer program, the cost accounts are input to the program only for this Reference Scenario. (These along with Reference stage times and Reference physical parameter values completely specify the Reference Scenario.) For all other scenarios, only their stage times, physical parameter values, and associated probabilities are input: their cost accounts are derived within the program by modifying the Reference cost accounts for any differences in the length of each stage or for any differences in the values of the physical parameters. Thus, as described below, the Reference Scenario is really a baseline case from which all other scenarios are derived. If this were not so, based on the previous description, the required amount of information would be enormous. Dollar costs for every cost account for each scenario would be required. Because a Reference Scenario is used, the lengthy and difficult task of providing detailed cost accounts for the site under study has to be performed only once (for the Reference Scenario).

To illustrate this procedure, if in the Reference Scenario, Stage J is assumed to take 10 years, then a Cost Account i in Stage J is estimated based upon the 10 year figure. If, however, Stage J is later assumed in another scenario to last 20 years, then Cost Account i in Stage J for that scenario would be doubled to reflect the now longer stage time. Additionally, if a particular cost account is affected by an uncertain physical variable, the model would make an adjustment through the use of appropriately defined scaling functions. These adjustments are done in subroutine GSCALE.

In a like manner, the cost-accounts for each of the other scenarios are derived. Because the lengths of the stages are different from scenario to scenario, the occurrence of the cost-account expenditures in each scenario will be staggered. The model accounts for the staggered time frames by appropriately accounting for time differences when the financial analysis is performed. The financial subroutine in the model calculates levelized energy cost, life-cycle cost, and profit for each scenario. With the probability of occurrence for each scenario (and thus of their outputs) having been input[13] as part of the scenario description, a complete set of values and their probabilities are obtained for levelized energy cost, life-cycle cost, and for profit. From these, separate probability functions for both of the cost categories and for profit can be constructed.

b. <u>The Computer Program</u>.

<u>Stages</u>. In the model the stages are designated by the variable JX, with JX ranging in value from 1 to J. The operational stage, the last stage, is the Jth stage.

<u>Stage Duration</u>. Corresponding to each stage JX there is a time lapse for completing all activities in that stage. In order to reflect the uncertainty for the completion time of any given stage, the stage time is treated as a random variable and assumed to have a discrete set of outcomes. In the Reference Scenario, the length of Stage JX is denoted by TPR(JX); in any other scenario, the length of Stage JX is denoted by TP(JX,MM), where MM is the number of that scenario. Likewise, the length of the final stage (Stage J) in the Reference Scenario is TPR(J), and the length of Stage J in any other scenario is TP(J,MM) where again MM identifies that scenario.

<u>Stage Intervals</u>. Each stage is divided into intervals. The number of intervals into which a specific Stage JX will be subdivided is denoted by M(JX). The M(JX) remain fixed for all scenarios. All intervals in a given stage are the same length, and thus are found by the quotient TP(JX,MM)/M(JX). The M(JX) are judiciously chosen to correspond generally to the number of times costs will recur within a stage. By dividing long stages into intervals, it is possible to specify costs for periods on the order of one year which enables the modeling of non-uniform cash flows throughout the stage.

<u>Cost Accounts</u>. There are two kinds of costs: time-dependent and time-independent. Time-dependent costs, as their name implies, vary as the length of a stage (and hence as the length of the stage's intervals) varies. (Stage times vary from scenario to scenario; the number of the stages and the number of intervals in each stage are specified at the outset and remain fixed for all scenarios.) Time-independent costs are assumed to remain constant regardless of the length of the interval in which they occur.

An example of a time-dependent cost could be the legal fees paid during the permitting process. The longer the process, the longer legal services are required, and the greater will be the cost. An example of a time-independent cost could be a bulldozer purchased for the development of the field. Once purchased, the cost will not change if the development of the field takes an additional length of time. (Although strictly speaking, operations and maintenance costs might change.)

---

[13] Actually, only the conditional probabilities for each stage length time and physical parameter values are input. Their product calculated in the program, yields the probability of occurrence for each scenario and its output.

As mentioned before, detailed cost accounts are input for the Reference Scenario only. For each time-dependent cost account, expenditures are input for each interval of the specific stage in which that dependent cost account occurs. This expenditure, or dependent cost for the Reference Scenario, is denoted by CDR(JX,NX,MX,KDX). The index JX denotes the stage in which the cost account occurs; NX signifies the accounting lifetime of the expenditure; MX denotes the interval in which the cost occurs; and KDX designates which cost account is being described. Thus, CDR (2, 1, 4, 3) signifies the time-dependent expenditure of the first accounting lifetime for the third cost account in the fourth interval of Stage 2 of the Reference Scenario.

A typical cost account for a time-dependent activity is shown below. It is the Exploration and Well Logging account for Stage 1 of the Reference Scenario. Note that the expenditure rate is not necessarily uniform for the duration of Stage 1. This is indicated by different dollar costs (in thousands of 1980 dollars) for each of the six intervals into which Stage 1 is divided.

| | | | | | |
|---|---|---|---|---|---|
| 240.0 | 240.0 | 800.0 | 800.0 | 800.00 | 800.0 |

The entire "matrix" of time-dependent cost accounts for Stage 1 would appear then as follows:

| | | | | | |
|---|---|---|---|---|---|
| 68.75 | 68.75 | 68.75 | 68.75 | 68.75 | 68.75 |
| 0.0 | 25.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 240.0 | 240.0 | 800.0 | 800.0 | 800.0 | 800.0 |
| 91.67 | 91.67 | 91.67 | 91.67 | 91.67 | 91.67 |
| 79.0 | 43.0 | 96.0 | 96.0 | 96.0 | 96.0 |

An individual entry has the label CDR(JX,NX,MX,KDX) where JX,NX,MX and KDX are defined as before. All costs given in this report and used by the model are in 1980 dollars; if occurring any number of years after 1980, these costs are escalated appropriately by the model to account for inflation and real increases in price at rates specified by the user.

Subroutine GSCALE. The aforementioned adjustments to the Reference Scenario Costs Accounts are performed for each scenario in the GSCALE subroutine. Time-dependent costs are assumed to be proportional to the length of Reference Scenario stages. Thus, if another scenario has a stage length (and hence stage interval length) twice that of the Reference Scenario, all of its time-dependent cost accounts would be twice that of the Reference Scenario. This effect is captured by the TP(JX,MM)/TPR(JX) term in ADMOD.

The cost accounts are also escalated in GSCALE. The cost accounts are multiplied by their cost escalation factors, AD(JX,NX,KDX), raised to the exponent PWR, where PWR is the number of years up until the cost actually occurs. PWR is composed of two parts: PSUM(JX,MM), the number of years up to the JX stage; and MX * (TP(JX,MM)/RMJX), the number of years into the stage that the cost occurs.

Once the cost accounts have been adjusted for time differences, GSCALE then calls subroutines that make adjustments for differences in the levels of physical variables. These subroutines are OPT 1 through OPT .. These are user specified and their forms are dependent on the specific site.

<u>OPT Function Subroutines</u>. The "OPTn" function subroutines are called by the FCTMOD subroutine in GSCALE to modify the cost accounts for any differences between the Reference Scenario levels for the physical parameters and the levels of those parameters in the scenario being examined. The three physical parameters considered in this study are wellhead fluid temperature, flow rate, and well depth. The OPT functions are physical relationships that must be supplied by the user for the project being studied. The following OPT functions are used for the Heber Reservoir.

<u>OPT 1</u>: <u>Effect of Temperature</u>. The references equation for OPT1 is

$$\Phi_w(\$/kW) = \frac{51.107\ Z\ \exp\left[3.8884 \times 10^{-4}\ Z\right]}{\dot{m}_w\left[T_{gf} - T_o - (T_o + 273.15)\ \ln\left(\frac{T_{gf} + 273.15}{T_o + 273.15}\right)\right]}$$

from Reference 5. When the equation is used to evaluate the effect of resource temperature on well cost, the well depth, Z, and flow rate, $\dot{m}_w$, are held constant to define the temperature ratio only. The cost relationship then becomes

$$\text{Cost (scenario)} = \text{Cost (reference)} * \frac{\text{Temperature equation (scenario)}}{\text{Temperature equation (reference)}}$$

or

$$\begin{aligned}\text{OPT1} = \text{RVAL} * \{&\text{P2-CON(1)} - (\text{CON(1)+273.}) * [\text{ALOG (P2+273.)/}\\ &(\text{CON(1)+273.})]\} / \text{P1-CON(1)} - (\text{CON(1)+273.}) *\\ &\quad \text{ALOG}[(\text{P1+273.})/(\text{CON(1)+273.})]\}\end{aligned}$$

where

OPT1 = adjusted cost returned to FCTMOD

RVAL = cost account data input to OPT1

P2 = reference fluid temperature (Tgf), $^{o}C$

P1 = scenario fluid temperature, $^{o}C$

CON(1) = ambient temperature, $T^{o}$ input for each site, $^{o}C$

Note that the constant $3.8884 \times 10^{-4}$ is used when Z is input in meters. If well depth is in feet, the constant must be adjusted

<u>OPT 2</u>: <u>Effect of Flow Rate</u>. The same equation from Reference 5 can be used to define a flow rate relationship with

$$\text{Cost}_{\text{well}}\ (\text{scenario}) = \text{Cost}_{\text{well}}\ (\text{reference}) * \frac{\text{Flow rate equation (scenario)}}{\text{Flow rate equation (reference)}}$$

If the well depth, Z, and temperature $T_{gf}$, are held constant, this relationship gives

$$\text{OPT2} = \text{RVAL} * \frac{1/\dot{m}_w \text{ scenario}}{1/\dot{m}_w \text{ reference}} = \text{RVAL} * \frac{P2}{P1}$$

where

OPT2 = adjusted cost returned to FCTMOD

P2 = reference flow rate

P1 = scenario flow rate

RVAL = cost account data input to OPT2

<u>OPT 3</u>: <u>Effect of Well Depth</u>. Again, in the same reference equation, temperature and flow rate can be held constant to look at the effect of well depth on well cost. This gives:

$$\Phi_w\ (\$/\text{kW})(\text{scenario}) = \Phi_w\ (\$/\text{kW})(\text{reference}) * \frac{Z_s \exp\left[3.8884 \times 10^{-4}\ Z_s\right]}{Z_R \exp\left[3.8884 \times 10^{-4}\ Z_R\right]}$$

or

OPT3 = RVAL * (P1/P2) * EXP[(CON(6) * (P1-P2))]

where

OPT3 = adjusted cost returned to FCTMOD

RVAL = cost account data input to OPT4

P2 = reference well depth

P1 = scenario well depth

CON(6) = constant $3.8884 \times 10^{-4}$ from Reference 5

Note that the constant $3.8884 \times 10^{-4}$ is used when Z is input in meters. If well depth is in feet, the constant must be adjusted.

With these equations, we can incorporate any uncertainty in the resource characteristics into the derivation of the probability density function for resource development costs.

Subroutine RCOST. After the modifications by GSCALE to each scenario, RCOST discounts all cost accounts in all the stages to present dollars as of the beginning of Stage 1. This is performed one stage at a time. For each stage in succession the entries for each cost account (i.e., the costs in all the time intervals) are discounted to the beginning of that stage and summed together. This yields a single figure for all the costs in that stage. This number (CDT in the program) is expressed in dollars as of the beginning of that stage; it is then discounted back to the beginning of Stage 1 and summed into the variable CD. Referring to Figure 2-12, the costs in a given interval are added together into variable CDTT, and then discounted to the beginning of the stage as CDTT*d** [MX * TPR(JX)/MLIM]. This is summed into variable CDT. CDT is then discounted to the beginning of the project by CDT*D**PSUMR(JX), where PSUMR(JX) is the number of years prior to the beginning of Stage JX in the scenario being considered. This is done for all stages, JX = 1 to J.

The present value cost figures thus obtained are then operated upon in RCOST to find levelized cost and life cycle cost for the scenario under consideration. Because cost accounts with different accounting lifetimes are treated differently for tax purposes, the cost accounts of differing accounting lifetimes must be segregated by accounting type. This is accomplished by the first Do Loop in RCOST. It first performs the above discounting for accounts with a 1-year life; then does so for the second accounting type; then for the third, and so on. Thus, costs will be indexed by accounting type, NX, e.g., CAPR(NX), CR(NX).

RCOST also computes "upfront capital cost" or the costs of the stages prior to the final or operating stage. To do this the cost of the upfront stages must initially be kept separate from the cost of the final stage. This separation is achieved by the second Do Loop which considers all stages except the last. After that Loop, the cost accounts for the final stage are discounted. CAPR(NX) designates the upfront capital costs for accounting type NX, and CR(NX) the total project capital costs for that accounting type. Thus, the total project cost of the second accounting type, CR(2), consists of the upfront capital costs of the second accounting type, CAPR(2), plus the discounted time-dependent and time-independent cost accounts of the second accounting type for the final stage, Stage J.

After the present value cost is obtained for each accounting type with a lifetime longer than one year,[14] the effects of taxes, depreciation, and investment tax credits are accounted for through the use of the fixed charge rate (FCR). Because the FCR is a function of the accounting lifetime, it can now be seen why, up to this point, the costs have been segregated by accounting lifetime. Multiplying CR(NX) by the FCR yields the constant annual amount that exactly pays back this capital investment with interest over the lifetime of the project, after taxes (which have been adjusted for the effect of depreciation and any investment tax credit) have been paid. Dividing this constant

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[14]Costs with a lifetime of one year are expensed; no taxes are paid on the income required to cover them, and no depreciation or tax credits are applied.

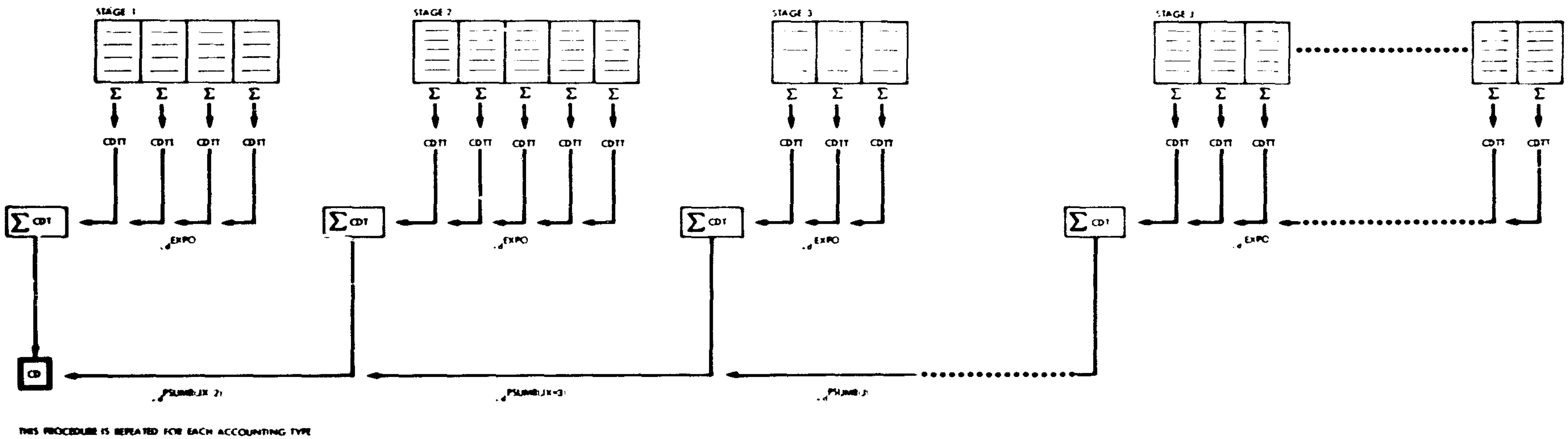


Figure 2-12. Flow of Time-Dependent Cost Account Funds in Subroutine RCOST

annual payment by the capital recovery factor (CRF) gives the present value sum of those payments. The present value sums for each accounting type can then be added together. In the program, this aggregate sum is denoted by CDUM, an intermediate "dummy" variable for cost.

Thus far, this sum does not include the effects of depletion allowance and royalties. To account for these, the final sum, CDUM, obtained above is multiplied by

$$\frac{1 - t}{1-t+at-ROY+tROY},$$

where ROY is the royalty rate, t the tax rate, and a the depletion allowance rate. The quotient is simply the ratio:

$$\frac{1 - t}{1-t+at-ROY+tROY} = \frac{PV\left[\text{all costs } \underline{\text{with}} \text{ depletion allowance and royalties}\right]}{PV\left[\text{all costs } \underline{\text{without}} \text{ depletion allowance and royalties}\right]}$$

When multiplied by the amount necessary to cover all costs <u>without</u> a depletion allowance and royalty payments, which is what is thus far obtained above, the amount necessary to cover all costs <u>with</u> depletion allowance and royalty payments is obtained. If the depletion allowance is calculated on gross revenues net of rents and royalties, the life cycle cost of the project can be expressed as

$$LCC = \left[E1 * CDUM\right] + \left[\frac{at}{ESCAL} * (RENROY)\right],$$

where

$$E1 = \frac{1 - t}{1-t+at-ROY+tROY}$$

and RENROY is the sum of rents and royalties. This is for the regulated case. (Note that in order for the program to handle them correctly, rents and leases for each stage, except the last, must be inputted into the program as the first time-dependent cost account for those stages.)

Profit, in the non-regulated case, is obtained by Revenue minus Life Cycle Cost. As the effects of taxes, depletion allowance, and royalties have been factored in on only the cost side, and not the revenue side, the difference REV - LCC must be multiplied by (1-t+at-ROY+tROY) to appropriately reduce the revenue retained by the firm as profit to reflect the effects of depletion and royalty payments. This leads to an expression for LCC as

$$\left(\left[E1 * CDUM\right] + \left[\frac{at}{ESCAL} * RENROY\right]\right) ESCAL + \left[(1-ESCAL) * REV\right],$$

where ESCAL is (1-t+at-ROY+tROY).

To find Levelized Energy Cost, calculating the Life Cycle Cost alone is not sufficient. The economically recoverable part of the resource and the life of the resource must be known to determine the energy cost. Over time, the temperature of the resource and possibly the flow rate from the wells will degrade. While this degradation is not modeled explicitly by this study, a redrilling program is assumed to take place and new wells are scheduled to keep the heat content, E, from the wells constant for the life of the geothermal field. The costs of this program are included in the cost accounts for Stage IV and are reflected in the final cost figures.

With a given E, we can calculate the generalized energy cost as

$$CEL = \frac{1000 \cdot CCL}{GG \cdot E}$$

This follows directly from Equation D-12, in Reference 8, when both numerator and denominator are multiplied by annual energy output. (The constant 1000 is a conversion factor to yield \$/kWh from mills/kWh.)

Generalized energy cost is defined as that price per unit of energy which, if held constant in real terms throughout the project life would provide the required revenue to finance the life cycle cost of the project, assuming that all cash flow interim requirements or excesses are borrowed or invested at the utility's internal rate of return. Levelized energy cost is defined as that price per unit of energy which, if held constant in nominal terms throughout the project life would provide the required revenue to finance the life cycle cost of the project, assuming that all cash flow interim requirements or excesses are borrowed or invested at the utility's internal rate of return. We caution that the concept of levelized energy cost as an energy cost index is defective. It can be used to rank order different energy projects only if they have the same project life. Clearly, the optimal project life design should depend on the physical characteristics and economic trade-offs thereof, and should not be arbitrarily standardized. If projects have different lifetimes, choices based on levelized energy costs may bias towards short life projects, even though they have the same fixed costs and proportionate variable costs. Generalized energy cost will not have this problem. Thus, we suggest using the latter as an output from the computer model. In the computer program, a generalized energy cost is used. Uniform energy cost is a special case of the latter with nominal energy cost escalation factor being one.

Probabilistic Analysis. The probability associated with the energy cost for a scenario is simply the product of the conditional probabilities specified for stage times and physical variables in that scenario. These are input as P(JX,I). If the stage times and/or the physical variables are assumed to be independent, then the probability of a specific value occurring for a variable remains the same regardless of what the preceding variables might turn out to be. If any of the variables are correlated, the inputted probabilities would have to reflect this correlation.

As discussed in the introduction to the formal model, it is likely that the number of scenarios for a specific project under evaluation may be very large. In that event, the costs of calculating all these scenario costs may be prohibitively large. Fortunately, we have a well-known statistical theory, the Kolmogorov-Smirnov Theorem, which shows that we can randomly select 150 scenarios as a sample to approximate the required probability distribution.

The likelihood of selecting a scenario should be weighted by its probability, and the approximate distribution will be good within 90% confidence. (However, we caution the user of this model that even though the computational cost is cut to a minimum, the data collection costs may still be prohibitive.) The Kilmogorov-Smirnov Theorem is: Let F(x) be the underlying continuous cost distribution, and $X_1, \ldots, X_n$ be a sample from F(x). Define $F_n(x)$ as the proportion of observed values in the sample which are less than or equal to X. Let

$$D_n = \sup_{-\infty < X < \infty} |F_n(x) - F(x)|$$

The Kilmogorov-Smirnov Theorem states that

$$\lim_{n \to \infty} \Pr\left(D_n < \frac{t}{n^{1/2}}\right) = 1 - 2 \sum_{i=1}^{\infty} (-1)^{i-1} \; e^{-2t^2 i}$$

Let H(t) be the value on the right hand side of the equation. A table of H(t) is given in Table 2-3. As an example, consider 90% confidence, i.e., (H(t) = 0.90. The corresponding t is 1.22. Suppose we want $D_n$ - 0.1. The required sample size, n, will then be calculated as:

$$n = \frac{1.22^2}{0.1}$$

$$\simeq 150$$

Table 2-3. Probability Limit for the Kolmogorov-Smirnov Theorem

| t | H(t) | t | H(t) |
|---|---|---|---|
| 0.30 | 0.0000 | 1.20 | 0.8878 |
| 0.35 | 0.0003 | 1.25 | 9.9121 |
| 0.40 | 0.0028 | 1.30 | 0.9319 |
| 0.45 | 0.0126 | 1.35 | 0.9478 |
| 0.50 | 0.0361 | 1.40 | 0.9603 |
| 0.55 | 0.0772 | 1.45 | 0.9702 |
| 0.60 | 0.1357 | 1.50 | 0.9778 |
| 0.65 | 0.2080 | 1.60 | 0.9880 |
| 0.70 | 0.2888 | 1.70 | 0.9938 |
| 0.75 | 0.3728 | 1.80 | 0.9969 |
| 0.80 | 0.4559 | 1.90 | 0.9985 |
| 0.85 | 0.5347 | 2.00 | 0.9993 |
| 0.90 | 0.6073 | 2.10 | 0.9997 |
| 0.95 | 0.6725 | 2.20 | 0.9999 |
| 1.00 | 0.7300 | 2.30 | 0.9999 |
| 1.05 | 0.7798 | 2.40 | 1.0000 |
| 1.10 | 0.8228 | 2.50 | 1.0000 |
| 1.15 | 0.8580 | | |

## SECTION III

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## SECTION IV

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