ASEK1

Envision Hawaii!

dbed

DEPARTMENT OF BUSINESS
AND ECONOMIC DEVELOPMENT

UNDERSEA CABLE TO TRANSMIT GEOTHERMAL-GENERATED ELECTRICAL ENERGY FROM THE ISLAND OF HAWAII TO OAHU: ECONOMIC FEASIBILITY

February 1988

UNDERSEA CABLE TO TRANSMIT GEOTHERMAL-GENERATED ELECTRICAL ENERGY FROM THE ISLAND OF HAWAII TO OAHU:
Economic Feasibility

Prepared by:

Decision Analysts Hawaii, Inc.

for:

State of Hawaii
Department of Business and Economic Development

February 1988

CONTENTS

	Page
LIST OF TABLES	T- 1
LIST OF FIGURES	F- 1
ABBREVIATIONS	A- 1
PREFACE	P- 1
Purpose	1
Content and Organization	2
Independence	3
Sources of Information	3
Project Analyst	4
EXECUTIVE SUMMARY	ES- 1
Introduction	1
Highlights of Analysis	2
Profitability to Geothermal Investors	4
Economic Risks to Geothermal Investors	5
Development Strategy	7
Total Benefits and Distribution of Benefits	9
TECHNICAL FOREWORD	TF- 1
Analytical Perspective	1
Economic Feasibility versus System Optimization	1
Exclusion of Maui	1
Distribution of Profits	1
Economic Assumptions	2
Economic Life of the Geothermal/Transmission System	2
Current and Constant Dollars	2

CONTENTS

	Page
TECHNICAL FOREWORD (continued)	TF-
Economic Assumptions (continued)	
Inflation	3
Cost Scale-Up Factor	3
Interest and Discount Rates: Nominal and Real Values	4
Measures of Profitability	4
Present Discounted Value (PDV)	4
Other Measures	6
Risk Analysis	6
Types of Risk	6
Adjustment to Discount Rate	7
Sensitivity Analysis	8
Normal Probability Distribution	8
The Bernoulli Process	10
Independent Variables	10
CHAPTER	
I. DEVELOPMENT SCENARIO FOR GEOTHERMAL AND TRANSMISSION SYSTEM	I- 1
II. HECO'S AVOIDED COSTS	II- 1
Fuel	1
Fuel Price	1
Geothermal Power Sales to HECO	3
Fuel Savings	3
Year 1995	3
Year 2007	4
Year 2020	4
Interpolation to Other Years	5
Present Discounted Value	5
Operations and Maintenance	5
Capital Expenditures for Generating Capacity	6
Total Avoided Costs	8
Tax Revenues	10

CONTENTS

CHAPTER	Page
III. TRANSMISSION SYSTEM	III- 1
Development Costs	1
HVDC Converter Stations	1
Overhead HVDC Lines	3
Undersea Cable System	4
Components	4
Manufacturing Costs	5
Transport and Laying	6
AC Network Modifications	7
Planning and Engineering Design	8
Total Capital Costs	9
Operations and Maintenance Costs	10
Geological Risks	10
Financing of the Transmission System via a Transmission Cable Venture	10
Transmission Cable Venture	10
Financial Objective	11
Revenues	11
Transmission Charge	11
Transmission Contract	12
Interest Earned	12
Expenses	12
Debt Financing	13
Special-Purpose Revenue Bonds	13
Cable-Company Financing	13
Schedule of Bond Sales	13
Risks to Bond Holders	14
Interest Rate	15
Bond Term	15
Bond Placement Costs	15
Taxable and After-Tax Income	15
TCV Cash Flow	16
Cash Flow to Investors	16
Implications to Geothermal Operators	16
Tax Revenues	17

CHAPTER	Page
IV. GEOTHERMAL OPERATIONS	IV- 1
Geothermal Costs	1
Development Costs	1
Wells	2
Steam-Gathering System	3
Power Plants	3
Total Development Costs	3
Expenditure Schedule	4
Replacement Wells	4
Operations and Maintenance Costs	5
Well Field	5
Power Plants	5
Summary of Geothermal Costs	6
Geological Risks	6
Financing of the Geothermal Development via a Geothermal Venture	7
Geothermal Venture	7
Revenues	7
Expenses	8
Debt Financing	9
Construction Loan	9
Corporate Bonds	9
Taxable and After-Tax Income	10
GV Cash Flow	10
Cash Flow and Profitability to Investors	10
Profit Sensitivity to Selected Changes and Break-Even Values	11
Econonomic Risks to Investors	12
Tax Revenues	13
REFERENCES	R- 1

FIGURES

Figure		Page
ES- 1.	Fuel Price Projections: 1990 to 2030	12
2.	Transmission Cable Venture, Cash Flow to Equity Investors: 1990 to 2030	15
3.	Geothermal Venture, Cash Flow to Equity Investors: 1990 to 2030	16

ABBREVIATIONS

AC	alternating current
Btu	British thermal unit (the amount of heat required to raise 1 pound of water 1° F)
CPI	Consumer Price Index
DAHI	Decision Analysts Hawaii, Inc.
DBED	Department of Business and Economic Development, State of Hawaii
DC	direct current
GC	Geothermal Venture
HECO	Hawaiian Electric Company, Inc.
HEI	Hawaiian Electric Industries
HVDC	high-voltage direct current
IDB	Industrial Development Bonds
IRC	Internal Revenue Code
kWh	kilowatt hours
LSFO	low-sulfur fuel oil
MW	megawatts
MWh	megawatt hours
O&M	operations and maintenance
PDV	present discounted value
PTI	Power Technologies, Inc.
SD	standard deviation
SPRB	Special Purpose Revenue Bonds
TCV	Transmission Cable Venture

TABLES

Table		Page
ES- 1.	Recent Forecasts of the World Price of Crude Oil: 1990, 2000 and 2010	ES- 9
2.	Geothermal Energy Sales, Transmission Charges, and Net Revenues: 1995 to 2030	13
3.	Per-Unit Geothermal Energy Payments, Transmission Charges, and Net Revenues: 1995 to 2030	14
4.	Benefits of Geothermal Development	17
TF- 1.	Conversion Factors To and From 1986 Dollars: 1983 to 2030	TF- 12
I- 1.	Schedule for Start of Operations	I- 3
II- 1.	Price Forecasts for Crude Oil, LSFO, and HECO's Fuel Price: 1995 to 2030	II- 11
2.	Geothermal Energy Sales and HECO Fuel Savings: 1995 to 2030	12
3.	Net Avoided Capital Costs for Oahu Generating Capacity: 1997 to 2007	13
4.	Costs Avoided by HECO as a Result of Geothermal Power: 1995 to 2030	14
5.	Break-Even Electric Rate for HECO's Purchase of Geothermal Energy: 1995 to 2030	15
III- 1.	Transmission System, Capital Cost Schedule: 1988 to 2003	III- 18
2.	Transmission Cable Venture, Revenues: 1989 to 2030	19
3.	Transmission Cable Venture, Expenses: 1988 to 2030	20
4.	Transmission Cable Venture, Bond Schedule: 1988 to 2030	21
5.	Transmission Cable Venture, After-Tax Income: 1988 to 2030	22
6.	Transmission Cable Venture, Cash Flow: 1988 to 2030	23
7.	Transmission Cable Venture, Cash Flow to Investors: 1988 to 2030	25

TABLES

Table		Page
IV- 1.	Geothermal Power Generation, Development Costs And Property Tax Base: 1992 to 2007	IV- 14
2.	Geothermal Power Generation, Development Expenditure Schedules: 1992 to 2007	15
3.	Geothermal Power Generation, O&M Costs: 1992 to 2030	16
4.	Geothermal Venture, Revenues: 1995 to 2030	17
5.	Geothermal Venture, Expenses: 1992 to 2030	19
6.	Geothermal Venture, Construction Loan Schedule: 1992 to 2030	21
7.	Geothermal Venture, Bond Schedule: 1994 to 2030	22
8.	Geothermal Venture, After-Tax Income: 1992 to 2030	23
9.	Geothermal Venture, Cash Flow: 1992 to 2030	24
10.	Geothermal Venture, Cash Flow to Investors: 1992 to 2030	26

PREFACE

PURPOSE

The State of Hawaii and various public and private organizations are exploring the feasibility of transmitting geothermal-generated electrical energy from the Island of Hawaii to Oahu and Maui via a 500-megawatt (MW) overland and undersea transmission system. Geothermal power is being explored because:

—nearly all oil analysts expect that oil, which is the primary fuel for Hawaii's electric generators, will become increasingly expensive starting in the early 1990s;

—geothermal energy could displace a very large amount of expensive fuel oil imported from overseas, as well as reduce Hawaii's vulnerability to oil-supply disruptions;

—geothermal energy would be reliable in that energy could be supplied whenever required, as opposed to such intermittent devices as windmills, hydroelectric generators, and solar panels;

—it is a proven technology, with well over 100 geothermal power plants throughout the world;

—it has provided a competitive source of energy elsewhere, being able to compete (1) against oil-fuel generators and most other forms of energy (with the exception of hydroelectric energy based on Federally-funded dams), (2) in communities having much lower electrical rates than those of Hawaii, and (3) even before 1973 when oil prices were much lower and before the introduction of alternative-energy tax credits; and

—the Big Island has a very high-quality geothermal resource, being the hottest of any geothermal field in the world (high temperature is very important in that a small increase in temperature allows a large increase in energy generation), and at a depth comparable to that of geothermal resources which have been developed successfully elsewhere.

In summary, geothermal power is an energy resource which, unlike other alternative-energy resouces in Hawaii, offers the promise of a near-term, abundant, reliable, and cost-competitive source of baseload electrical energy.

However, the complete geothermal/transmission system (drilling, steam-gathering and disposal systems, generating plants, cables, converters, etc.) would be very expensive to develop—the capital costs are expected to be nearly $1.7 billion in 1986 dollars. Of this amount, an estimated $413 million (about 25 percent) would be for the overland and undersea transmission system linking the geothermal plants in the Puna District of the Big Island to Oahu. The high capital cost for the transmission system partially reflects the high cost of a specially designed undersea cable which would be much longer (138 miles) and would reach depths much deeper (6,300 feet) than any existing power cable.

As mentioned above, this very large development cost would be offset by greatly reduced requirements to import expensive oil to fuel the conventional power plants on Oahu and Maui, along with other cost savings. A major issue is the economic feasibility of the geothermal/transmission system: would the fuel-oil and other savings be sufficient to compensate for the large costs required to develop and operate the geothermal power plants and transmission system? A positive and convincing answer to this question is necessary in order to proceed with development of the geothermal and transmission system. Otherwise, development should not proceed because of the risk of substantial financial losses; and it is very probable that development would not proceed because it would be extremely difficult to attract the substantial amount of investment capital required.

In order to guide public and private decision-makers, this report presents an in-depth analysis of the economic feasibility of transmitting geothermal-generated electrical energy from the Island of Hawaii to Oahu via an overland and undersea transmission system. In order to simplify the analysis, Maui is excluded from this report; however, in practice, the inclusion of Maui would either have no effect on the economic feasibility of the geothermal/tranmsission system, or would enhance it.

CONTENT AND ORGANIZATION

The Technical Foreword clarifies the analytical approach used to determine the economic feasibility of the geothermal/transmission system. Chapter I presents the plan for geothermal and transmission system development, including key components, capacities, and a development schedule. Because of the availability of geothermal-generated electrical energy, the electric companies would not have to import fuel oil, build additional oil-fueled generating plants, and maintain and operate these plants. The cost for these avoided items is derived in Chapter II, and converted to a break-even cost (cents per kilowatt hour) which the electric companies could pay for geothermal-generated electrical energy.

Chapter III presents the cost to develop and operate the transmission system, and financing of the system via a cable transmission charge. This charge is subtracted from the results found in Chapter II to give the dollar amount which the electric companies could pay geothermal operators net of cable charges.

The expected profitability of geothermal operations is addressed in Chapter IV. The analysis covers expected revenues, development and operating costs, financing, profitability, sensitivity in the results to selected changes in assumptions, economic risks, and impacts on tax revenues.

INDEPENDENCE

This report was prepared by Decision Analysts Hawaii, Inc. (DAHI) as part of a larger contract from the State of Hawaii, Department of Business and Economic Development (DBED) to Hawaiian Electric Company, Inc. (HECO). The economic analysis was subcontracted to DAHI via Parsons Hawaii. General direction for the analysis was provided by DBED.

The mandate was for an <u>independent</u> analysis—independent of any assumptions, extrapolations, interpretations, analytical approach, findings, conclusions, or opinions which may be favored by DBED, HECO, or others. DAHI was free to use, modify, or reject any information provided by others based on its professional judgment. As a consequence, the analysis and results are those of DAHI, and not those of DBED, HECO, or others, although there may be agreement in a number of areas.

SOURCES OF INFORMATION

The analysis contained in this report is based on the best information available as of early 1987. The primary sources of information were: (1) Power Technologies, Inc. (PTI), a consulting firm which specializes in electric-power systems; (2) HECO; and (3) geothermal developers. The information from PTI was extracted primarily from their report, <u>HDWC Phase IIC Studies, Progress Report</u>, December 1986. The information from HECO was developed especially for the analysis contained herein based on considerable analysis by various divisions within HECO. Information from geothermal developers was provided via HECO, then verified directly with the developers, with modifications made to reflect the most recent information available.

PROJECT ANALYST

Dr. Bruce S. Plasch, President of Decision Analysts Hawaii, Inc. (DAHI) performed the economic analysis. Dr. Plasch has a background in economics, finance, probability theory and statistics, quantitative analysis, and electrical engineering. He holds B.S. and M.S degrees in electrical engineering from the University of California and Stanford University, respectively, and a Ph.D. in Engineering-Economic Systems from Stanford University; his Ph.D. thesis addressed how to evaluate investments that have uncertain cash flows. After graduation, Dr. Plasch taught graduate-level economics, probability theory and statistics, and other analysis courses. For the last 17 years, he has served as a private consultant in Hawaii specializing in economic development, economic and financial feasibility, resource management, and economic and fiscal impact analysis. Clients have included the Federal, State, and County governments; Big Five corporations; major land-owning estates; developers; attorneys; and others.

EXECUTIVE SUMMARY

INTRODUCTION

The State of Hawaii and various public and private organizations are exploring the feasibility of transmitting geothermal-generated electrical energy from the Island of Hawaii to Oahu and Maui via a 500-megawatt (MW) overland and undersea transmission system. The undersea portion of the system would be a specially designed cable which would be much longer (138 miles) and would reach depths much deeper (6,300 feet) than any existing underwater power cable.

The potential of geothermal power for Hawaii is being explored because it would be a large and continuous source of locally produced power, based on a technology which has been proven through the successful development and operation of over 100 geothermal power plants throughout the world. Geothermal power has provided a competitively priced source of energy to communities having much lower electric-generation costs and lower electric rates than those in Hawaii. In fact, geothermal power was competitive even before 1973, when oil prices were much lower than they are now, and before alternative-energy tax credits were introduced. The Big Island has a very high-quality geothermal resource, being the hottest of any geothermal field in the world (high temperature is very important in that a small increase in temperature allows a large increase in energy generation), and is at a depth comparable to that of geothermal resources which have been developed successfully elsewhere.

The development cost for the complete system (geothermal wells, injection wells, steam gathering and disposal systems, generating plants, overland transmission lines, undersea cables, AC-to-DC converter stations, etc.) is estimated to be nearly \$1.7 billion (1986 dollars). This large development cost would be offset by a greatly reduced dependence on expensive imported fuel for the conventional power plants on Oahu and Maui, along with other cost savings. **A major issue is the economic feasibility of the geothermal/transmission system: Will the fuel and other savings be** sufficient to compensate for the large capital costs required to develop the geothermal power plants and transmission system? In order to simplify the analysis, Maui is excluded from consideration; however, in practice, the inclusion of Maui would either have no effect on the economic feasibility of the geothermal/transmission system, or would enhance it.

HIGHLIGHTS OF ANALYSIS

It is envisioned that geothermal power would be developed to 500 MW based on twenty 25-MW generating plants, and that the transmission system would consist of two overland transmission lines and three undersea cables. For the sake of analysis, it is assumed that the starting date for construction would occur in the late 1980s, with the first geothermal plant delivering energy to Oahu in 1995, and the final plant delivering energy starting in 2006.

The geothermal plants would be run continuously to provide "baseload" power to Oahu and, at full development, would deliver 4.38 million kilowatt-hours (kWh) of energy annually; this translates into a savings to HECO of about 7.025 million barrels of fuel per year in the year 2010, which declines to 6.644 million barrels in later years because future oil-fueled generators are expected to be more efficient than current ones.

If HECO's fuel price were to follow the average forecasts made by energy experts as shown in Table ES-1, then in the year 2010, HECO's fuel-oil savings would be enormous: $346.8 million 1986 dollars ($42.93 per barrel for crude oil + 15-percent premium for low-sulfur fuel oil (LSFO) and State excise taxes x 7.025 million barrels of fuel per year). The potential for avoiding this huge annual expenditure explains Hawaii's search for alternative energy, and why an expenditure of $1.7 billion for geothermal power appears to be a potentially attractive investment.

Instead of tracking the forecasts of increasing crude-oil prices, it is assumed that HECO's fuel price is limited to an LSFO equivalent of $35 per barrel (see Figure ES-1); this price corresponds to a crude-oil price of $30.43 per barrel. The price limit is a preliminary assumption that is subject to further analysis, and reflects the fact that (1) coal could become the avoided fuel if oil prices were to become sufficiently high, (2) the avoided fuel price could be limited by negotiated agreement between HECO and geothermal developers, and/or (3) the price could be limited by State policy. With this price limit, HECO's fuel savings would still be substantial: $245.9 million in the year 2010.

Additional avoided costs to HECO would include annual debt service on the cost of new conventional oil-fueled generators costing about $244 million, and the associated operations and maintenance (O&M) costs. Subtracted from this, however, would be $19.2 million for the cost of modifying existing generators to provide them with cycling capability.

The total and per-unit avoided cost which HECO could pay for geothermal power without affecting its profits (i.e., the break-even payment) is shown in Tables ES-2 and ES-3, respectively. About 95 percent of the avoided cost derives from avoided fuel.

The cost of the transmission system and geothermal power would offset these savings, however:

Development Cost for 500 MW of Geothermal Power and a Transmission System from Hawaii to Oahu
(millions of 1986 dollars)

	Amount	Share
Transmission System:		
Undersea Cable System	$ 228.4	13.6%
Overland Transmission Lines and Other Components	184.9	11.0
Total	$ 413.3	24.7%
Geothermal Power	$1,262.2	75.3
TOTAL	**$1,675.5**	100.0%

Although these development costs are large, it is significant that **the dominate capital cost is for geothermal power, rather than for the undersea cable system.**

Additional estimated costs would include cable O&M ($1 million per year); allowances for occasional cable repair ($2.8 million every 10 years); drilling of replacement wells ($15 million per year); wellfield O&M ($12.8 million per year at full development); and generating plant O&M expenses ($27.4 million per year at full development); management expenses; financing fees; royalties; property insurance; and taxes (property, excise, and income).

It is assumed that the transmission system would be developed by a private entity which would pass tax benefits on to one or more corporations, with debt financing being provided in the form of State of Hawaii special-purpose revenue bonds. The transmission system would be operated in a manner similar to that of a toll bridge, where a per-kWh transmission charge would be sufficient to cover debt service and other costs, and would provide a guaranteed after-tax, 14-percent return to equity investors. The charge would not depend on the price of fuel, and geothermal operators would be obligated to pay the charge whether or not they transmit energy. The total and per-unit charges for the transmission are shown in Tables ES-2 and ES-3, respectively. The charge declines over time because it is given in constant 1986 dollars. With inflation added, the per-unit charge remains level over time.

The after-tax cash flow to the investors in the transmission system is shown in Figure ES-2. After geothermal power is fully developed, dividends decline due to the decrease in the transmission charges, as measured in constant dollars. The jumps in dividends in later years reflect the termination of the debt-service payments.

Similar to the case of the transmission system, it is assumed that geothermal power would be developed by one or more private entities which would pass tax benefits on to one or more corporations. Debt financing would be provided through commercial construction loans and corporate bonds. Total and per-unit revenues to geothermal operators are shown in Tables ES-2 and ES-3, respectively.

PROFITABILITY TO GEOTHERMAL INVESTORS

The analysis indicates that the development of geothermal power on the Big Island and a connecting transmission system to Oahu would indeed be economically feasible. If the development proceeds as projected (which is a technically feasible scenario but is not necessarily the optimum one in terms of maximizing profitability), then HECO's savings resulting from not having to buy expensive fuel, in addition to other savings, would compensate easily for the large capital costs which would be required to develop the geothermal power plants and the transmission system, cover all O&M and other costs, and generate substantial profits to the geothermal investors.

The after-tax cash flow to these investors, including invested equity and returned dividends, is shown in Figure ES-3. The jumps in dividends in later years reflect the termination of debt-service payments. A visual inspection of this figure, without additional analysis, demonstrates the high profitability of the investment.

The principal measure of the economic feasibility of geothermal power is the value of this cash flow of invested equity and returned dividends: $550.7 million. This value is termed the "present discounted value" (PDV), with the discounting to the year 1992 based on corporate Aaa bond rates, and with dollar amounts expressed in terms of 1986 purchasing power.

Another measure of profitability is **a high rate of return on invested equity: 23.8 percent** as measured in nominal (inflating) dollars.

In terms of payback period, equity investors would expend about $86 million (1986 dollars) during the first 10 years of development, but this would be recovered fully during the next 5 years, and would be followed by another 24 years of dividends.

Another measure of economic feasibility is a benefit-cost ratio of 1.37-to-1; a ratio exceeding 1-to-1 indicates feasibility. If all capital and O&M costs—including those for the transmission system as well as those for geothermal power—were to increase by 37 percent, the geothermal/transmission system would still remain economically feasible. If all benefits are included—not just those which accrue to the geothermal investors—then the **benefit-cost ratio is 1.6-to-1.**

In terms of 1986 dollars, the **break-even fuel price is about $25 per barrel (LSFO equivalent); this price, which corresponds to a crude-oil price of about $22 per barrel, is expected to occur in the early 1990s.** The break-even HECO payment for geothermal power would be 4.29 cents per kWh. These break-even prices would drive to zero the PDV of the cash flow to geothermal investors. Since the geothermal investors would receive only 47.5 percent of the total benefits from the proposed development (see Table ES-4), a reallocation of the benefits in favor of the geothermal investors would lower the break-even prices. Such a reallocation could be achieved if the State were to grant an 8-year exemption in State royalties as allowed under State law, or reduce the percentage rate at which royalties are calculated, or delay or exempt property taxes, etc.

The above finding of economic feasibility of the geothermal/transmission system is consistent with the fact that geothermal power has provided a competitive source of energy for communities elsewhere. In the case of Hawaii, the large economic benefits of geothermal energy overwhelm the costs added by the transmission system.

ECONOMIC RISKS TO GEOTHERMAL INVESTORS

Even though the benefits to geothermal investors would be substantial, so would the risks. The analysis was structured so that nearly all of the economic risk associated with both the transmission system and geothermal development would be absorbed by the geothermal investors. Based on current information, there are nearly 2 chances in 11 that the investment would be unprofitable (more precisely, that the investment would provide a return lower than the return on corporate Aaa bonds, which is the basis for comparison established in the analysis). However, as discussed below, the major sources of uncertainty and risk will be reduced greatly before major irreversible investment commitments are made.

Assuming that all permits are obtained before development proceeds and, correspondingly, the risk of delayed or partial development is eliminated, then the dominant source of uncertainty derives from the future price of HECO's fuel—uncertainty which will be resolved largely by the passage of time. If energy experts are correct, growth in the demand for oil will outpace supply in the early 1990s, with a corresponding dramatic increase in oil prices—events which should be evident before investors make major financial commitments. At this time, the issue may be whether geothermal power, coal, or some mix is the preferred choice for generating baseload electrical energy in Hawaii to replace oil-fueled generation.

A secondary but much smaller source of uncertainty and risk concerns the nature of the geothermal resource itself—particularly with respect to the cost of drilling geothermal wells sufficient in number and capacity to provide 500 MW of power. This uncertainty would be reduced greatly by conducting extensive and expensive exploratory drilling before major investments are made.

Uncertainty regarding other geothermal and transmission system development costs, the risk of cost overruns, and O&M costs are small in comparison to the uncertainty regarding the price of HECO's fuel and the cost to develop the geothermal resource. Also, any uncertainty regarding future growth in electrical demand is irrelevant because geothermal power would replace baseload generating capacity and, furthermore, development would not proceed until HECO contracts to purchase the geothermal energy.

The risk of a transmission line outage due to a lava flow from Mauna Loa would be essentially eliminated by routing the overhead HVDC lines close to Hilo and around the north side of Mauna Kea. The risk of losing one or more power plants and/or nearby transmission lines due to lava flows from Kilauea would be minimized, to the extent possible, by careful siting of facilities; generally, the north side of the Kilauea East Rift Zone exposes facilities to less risk than sites in the Rift Zone itself. Nevertheless, the risk of losing facilities due to lava flows would be significant. Paradoxically, the economic risk to geothermal operators would be insignificant because of the fact that up to three, and possibly more, power plants could be lost simultaneously (an event which is very improbable) with no reduction in the amount of energy transmitted, and with no reduction in revenues. The temporary loss of capacity would be compensated for by increasing the output from the remaining power plants. Funds for rebuilding lost plants, if any, would come from insurance proceeds.

Assuming that uncertainty regarding the price of fuel will be resolved by the passage of time, and that exploratory drilling decreases the uncertainty regarding the cost of developing the geothermal resource, then the risk to geothermal investors would be reduced greatly. Under these circumstances, the economic risks would be negligible provided that HECO pays a price in excess of 5.08 cents per kWh, or that HECO's avoided fuel price is the LSFO equivalent of about $30 per barrel (which corresponds to a crude-oil price of about $26 per barrel).

Economic risk could also be reduced by reallocating more of the benefits to geothermal investors as discussed previously, and/or by shifting some risk to others—possibly to the State and/or consumers. Such a reallocation of risk may be desirable during the development years in exchange for a second reallocation of benefits in favor of consumers and the State. This second reallocation of benefits to the consumers and the State would occur when and if fuel prices increase to the projected level. This strategy would reduce the risk and impact of high energy prices to consumers and taxpayers.

DEVELOPMENT STRATEGY

In view of the level of economic risk discussed above, a three-stage development strategy is appropriate:

(1) **Obtain all permits.**

The first step would be to obtain all the necessary permits required to install the transmission system and achieve full development of geothermal power. Until these permits are obtained, it would be uneconomical to proceed with expensive exploratory drilling because of the high risk of delayed, partial, or denied development. Since a very large number of agencies with the Federal and State governments, the Counties of Hawaii and Maui, and the City & County of Honolulu are required, State assistance (and possibly special legislation) will be required.

(2) **Conduct exploratory drilling, subject to a favorable price outlook.**

After all permits are obtained, and assuming that the then-current energy outlook is for fuel prices exceeding an LSFO equivalent of about $30 per barrel (which corresponds to a crude-oil price in excess of about $26), then the second stage would involve exploratory drilling to better determine the cost of developing the geothermal resource.

(3) **Develop geothermal power and the transmission system fully and as rapidly as possible, subject to a favorable determination of the quality of the resource and to a favorable price outlook.**

Assuming that it is determined that the resource can be developed at a reasonable cost, and again assuming that the then-current energy outlook is for fuel prices exceeding an LSFO equivalent of about $30 per barrel (which corresponds to a crude-oil price exceeding about $26), then the third stage would be to develop geothermal power and the transmission system as fully and as rapidly as possible. Full development would be required in order to realize economies of scale. Rapid development would allow a faster return on the investment, thereby enhancing profitability.

It should be noted that these price guidelines can be reduced by improving the development scenario (possibly by increasing the size of the geothermal power plants to achieve economies of scale, and by accelerating the development schedule), by having a non-profit entity develop the transmission system, reallocating benefits as previously discussed, etc.

TOTAL BENEFITS AND DISTRIBUTION OF BENEFITS

The development of geothermal power on the Big Island and a connecting transmission system to Oahu would provide **net benefits of nearly $1.2 billion,** which is the PDV of the stream of profits, royalties to the State and land owners, and taxes, net of lost State excise taxes which normally would be derived from HECO's purchase of fuel and construction of power plants on Oahu (see Table ES-4). As would be expected, geothermal investors would receive the largest share of the benefits ($550.7 million), which is appropriate since they also assume nearly all of the economic risks. Nevertheless, their share of benefits amounts to only 47.5 percent of the total benefits. Substantial benefits would also accrue to equity investors in the transmission system ($72.1 million), landowners ($88.4 million), the County of Hawaii ($157.9 million), the State of Hawaii ($136.516 million), and the Federal government ($151.1 million). **Increased State and County tax revenues would translate into improved services and/or reduced taxes to residents.**

Other benefits of geothermal power would include **improved economic stability due to increased energy independence; increased employment** on the Big Island due to geothermal operations (65 jobs), as well as contracted plant and well maintenance employment; and **reduced air pollution on Oahu** because of burning less fuel (oil and/or coal). In addition, **the potential exists to stabilize electric rates to the benefit of consumers** rather than having the rates increase with the price of LSFO.

Table ES-1.— **RECENT FORECASTS OF THE WORLD PRICE OF CRUDE OIL: 1990, 2000 AND 2010**[1,2,3]
(1986 dollars)

	1990	2000	2010
Centro de Estudios Energeticos, Mexico (11/86)	$31.95	$44.55	$63.90
PlanEcon, Inc., for the Soviet Union and Eastern Union (10/86)	19.80	39.15	61.20
Chevron Corporation, World Energy Outlook (6/86):			
Base	18.00	32.85	60.30
Low	12.15	18.90	25.20
East-West Center (2/86):			
High-Price Scenario	23.44	34.65	57.08
Medium-Price Scenario	18.35	24.46	33.64
Low-Price Scenario (unlikely)	15.29	15.29	28.54
Data Resources Inc. (Spring 86)	19.35	39.15	54.00
US Department of Energy, National Energy Plan (early 1987)	20.27	33.01	52.85
Liston International Energy Forecasts, London (10/86)	25.65	44.55	52.65
Academy of Sciences, USSR (4/86):			
High	33.75	40.50	51.75
Medium	29.25	35.10	42.75
Low	24.30	28.35	33.75
Central Research Institute of Electric Power Industry, Japan (7/86)	26.55	30.60	48.15
Cambridge Energy Research Group (9/86)	24.75	31.50	45.00
Gas Research Institute (9/86)	22.05	28.80	42.30
Pacific Gas and Electric Company, Oil Price Forecast (4/86)	18.00	26.55	37.35
A. Manne and T., Rutherford, Long-term Model, Stanford University (7/86)	18.90	27.00	35.10
Center for International Energy Studies, Erasmus University (11/86):			
Low Energy Demand Forecast	35.55	32.17	29.25
High Energy Demand Forecast	27.45	24.75	22.05
Pakistan Atomic Energy Commission, Applied Systems Analysis Group (7/86)	20.25	22.50	24.75
D. Gately, New York University (9/86)	27.00	61.20	
Petroleum Authority of Thailand (10/86)	31.95	48.15	

Table ES-1.— **RECENT FORECASTS OF THE WORLD PRICE OF CRUDE OIL: 1990, 2000 AND 2010**[1,2,3]
(1986 dollars)
(continued)

	1990	2000	2010
KFA (Nuclear Research Center), Julich, Federal Republic of Germany (10/86)	$35.55	$45.45	
K. Roland and Associates (10/86):			
High	22.50	41.40	
Low	16.20	35.55	
National Petroleum Council (10/86):			
Upper	22.05	36.00	
Lower	13.95	20.70	
F. Wirl, University of Technology, Vienna (11/86)	19.80	35.55	
Lawrence Berkeley Laboratory, (12/86)	19.80	34.20	
US Energy Information Administration, mid-price scenario (12/86)	18.00	32.85	
Ashland Oil, baseline scenario (8/86)	18.00	30.60	
Conco, World Energy Outlook through 2010 (8/86)	16.20	28.35	
J. Rowse, University of Calgary (11/86)	24.30	26.55	
World Bank (12/86)	16.38	24.39	
IPE Model, N. Choucri, Massachusetts Institute of Technology (6/86)	27.67	23.08	
Respondent S (9/86)	14.08	18.76	
Economic Council of Canada (10/86)	31.23		
MEDIAN	**$21.16**	**$32.17**	**$42.75**
AVERAGE	**$22.62**	**$32.38**	**$42.93**
STANDARD DEVIATION	**$ 6.18**	**$ 9.23**	**$12.80**
Percent of Average	**27.3%**	**28.5%**	**29.8%**

Table ES-1.— **RECENT FORECASTS OF THE WORLD PRICE OF CRUDE OIL: 1990, 2000 AND 2010**[1,2,3]
(continued)

Sources:

For all entries other than the U.S. DOE and the East-West Center:

Alan S. Manne and Leo Schrattenholzer, International Energy Workshop: Overview of Poll Responses, January 1987.

East-West Center:

Fereidun Fesharaki and David T. Isaak, "Refining and Petrochemicals in the Asia-Pacific Region: Outlook and Investment Potential Over the Next 25 Years," For presentation to Asian Development Bank/Asia-Pacific Bankers Club Seminar "Industrial Analysis in the 21st Century," Singapore, February 17-18, 1986; adjusted from 1985 to 1986 dollars.

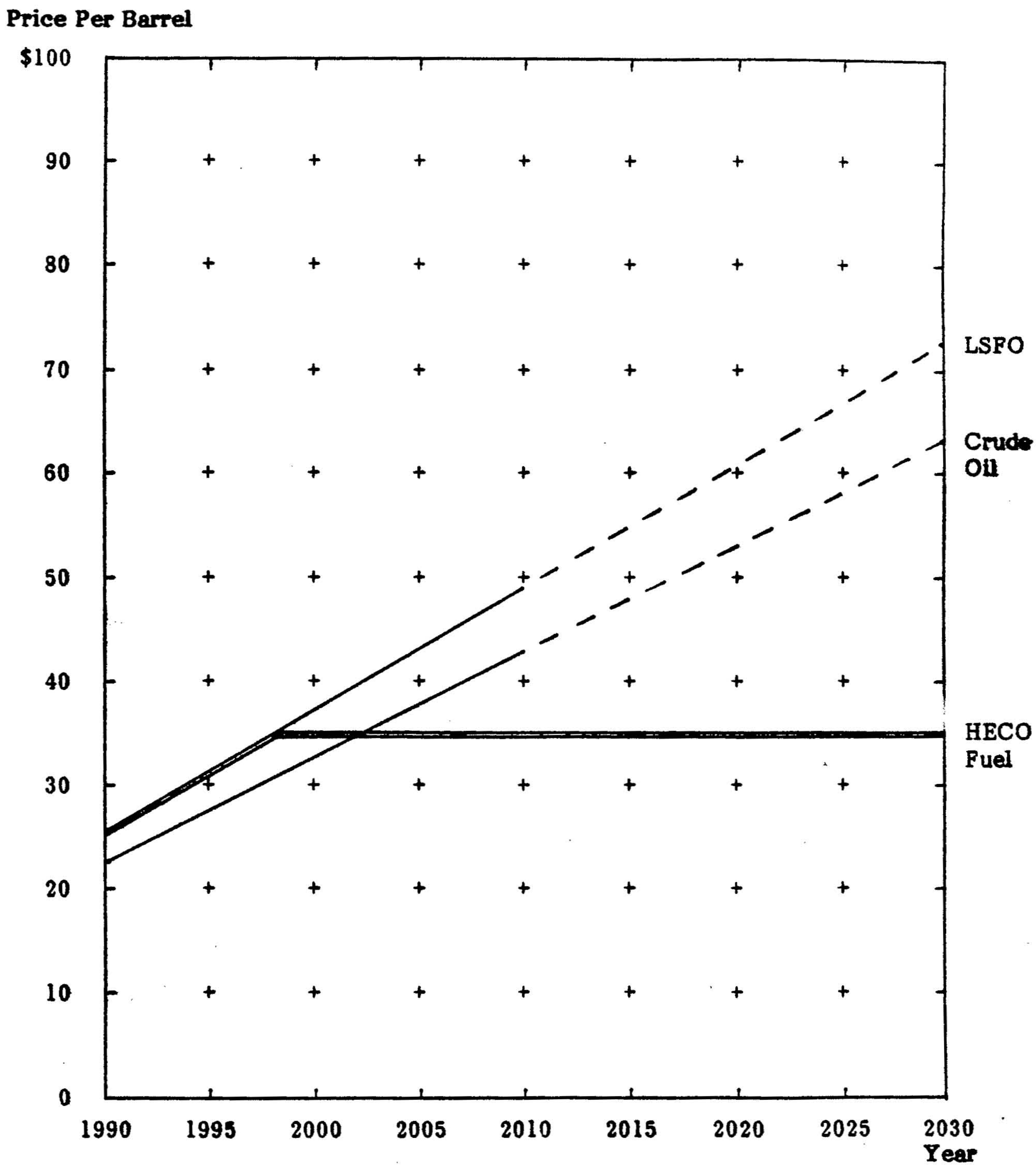
U.S. Department of Energy: telephone conversation.

[1]Includes forecasts developed after January 1, 1986. As noted in the first source document, current and previous forecasts provide: ". . . clear evidence of an 'adaptive expectations' process among energy analysts. That is, each year's long-term projections are heavily influenced by current prices and by trends during the recent past." Thus, recent forecasts of oil prices are lower than those of previous years because of depressed oil prices during 1986.

[2]A forecast by M. Adelman of the Massachusetts Institute of Technology is not included in the table because it a very low price forecast based on a complete breakdown of OPEC discipline, with oil prices dropping to the marginal cost of production of Middle East countries. In a December 1986 letter, Adelman notes that: "No such market condition is imminent."

[3]The forecasts are ranked from high to low prices based on the last year forecasted.

Figure ES-1.— FUEL PRICE PROJECTIONS: 1990 TO 2030
(1986 dollars.)



LSFO: Low-sulfur fuel oil, including excise tax.

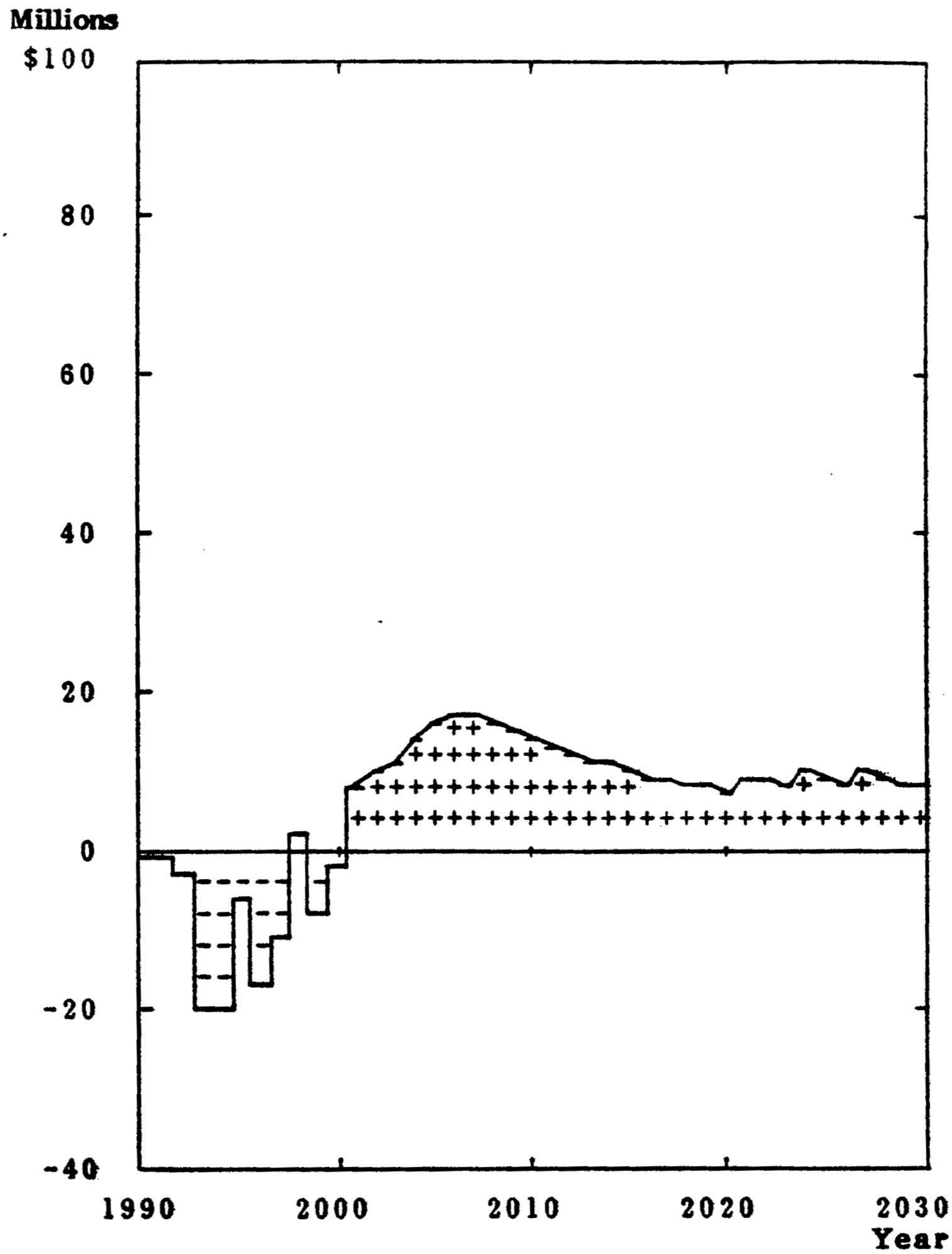
Table ES-2.— **GEOTHERMAL ENERGY SALES, TRANSMISSION CHARGES, AND NET REVENUES: 1995 TO 2030**
(1986 dollars)

Year	Energy Sold[1] (1,000 kWh)	HECO Payment[2] (millions)	Transmission Charge[3] (millions)	Net Revenue[4] (millions)
1995	310.279	$ 17.475	$ 5.721	$ 11.753
1996	675.221	40.499	11.819	28.680
1997	1,022.029	63.438	16.983	46.455
1998	1,405.279	89.266	22.168	67.098
1999	1,770.221	113.821	26.509	87.312
2000	2,117.029	134.860	30.096	104.765
2001	2,500.279	157.852	33.742	124.110
2002	2,865.221	181.338	36.707	144.631
2003	3,212.029	201.368	39.064	162.304
2004	3,595.279	223.325	41.509	181.816
2005	3,960.221	243.832	43.404	200.428
2006	4,307.029	262.935	44.812	218.122
2007	4,380	265.341	43.261	222.079
2008	4,380	264.213	41.068	223.145
2009	4,380	262.269	38.986	223.287
2010	4,380	260.356	37.010	223.346
2015	4,380	251.202	28.533	222.669
2020	4,380	242.615	21.998	220.617
2025	4,380	241.133	16.960	224.174
2030	4,380	239.991	13.075	226.916

Table ES-3.— **PER-UNIT GEOTHERMAL ENERGY PAYMENTS, TRANSMISSION CHARGES, AND NET REVENUES:** 1995 TO 2030
(Cents per kWh, 1986 dollars)

Year	HECO Payment	Transmission Charge	Geothermal Revenue
1995	5.632	1.844	3.788
1996	5.998	1.750	4.247
1997	6.207	1.622	4.545
1988	6.352	1.577	4.775
1999	6.430	1.498	4.932
2000	6.370	1.422	4.949
2001	6.313	1.350	4.964
2002	6.329	1.281	5.048
2003	6.269	1.216	5.053
2004	6.212	1.155	5.057
2005	6.157	1.096	5.061
2006	6.105	1.040	5.064
2007	6.058	0.988	5.070
2008	6.032	0.938	5.095
2009	5.988	0.890	5.098
2010	5.944	0.845	5.099
2015	5.735	0.651	5.089
2020	5.539	0.502	5.037
2025	5.505	0.387	5.118
2030	5.479	0.299	5.181

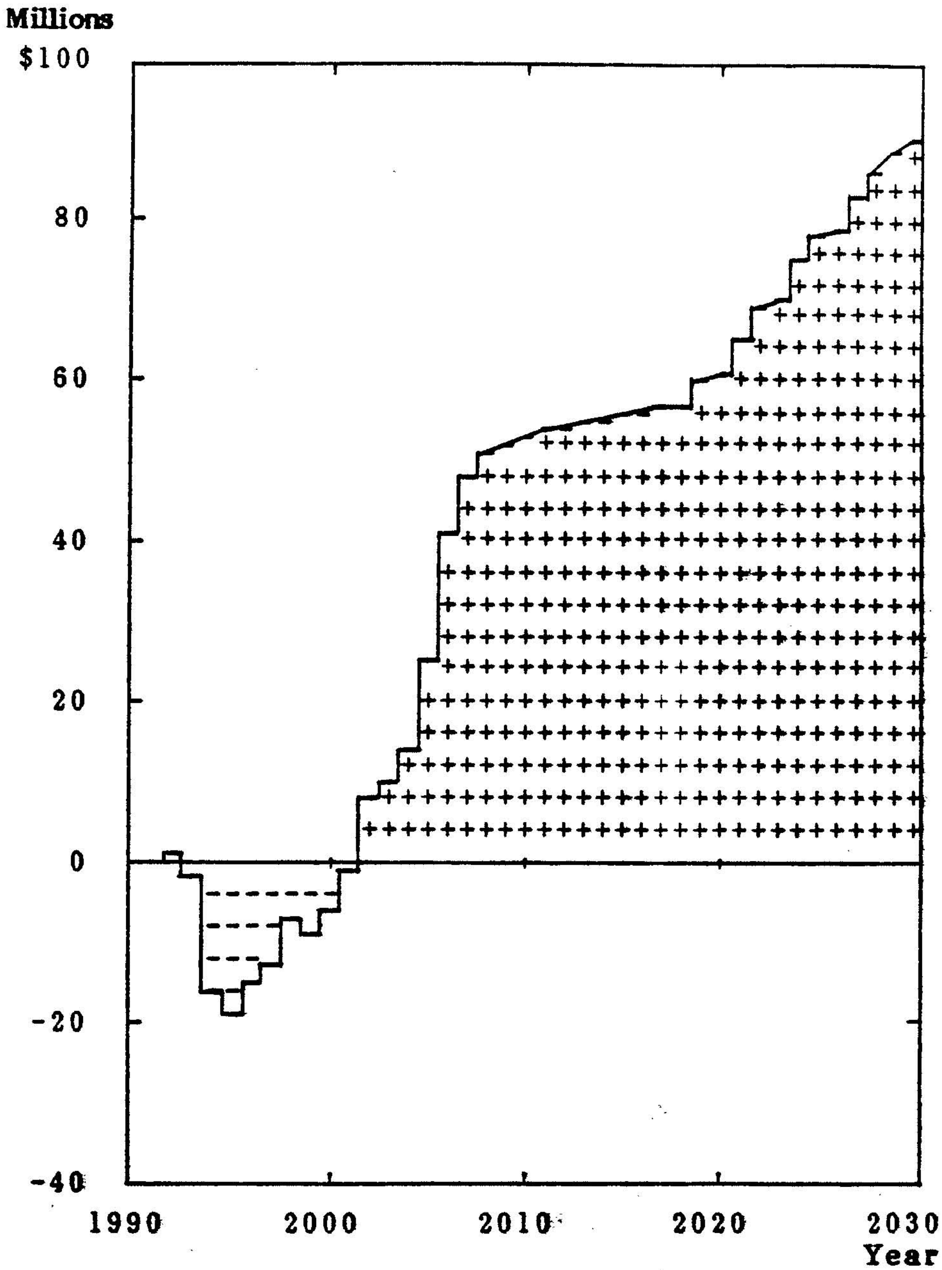
Figure ES-2.— **TRANSMISSION CABLE VENTURE, CASH FLOW TO EQUITY INVESTORS: 1990 TO 2030**
(1986 dollars)



Each negative symbol (-) represents a $4 million investment.
Each positive symbol (+) represents a $4 million dividend.

PDV = $72.137 million.
Rate of Return = 14% (nominal dollars).

Figure ES-3.— **GEOTHERMAL VENTURE, CASH FLOW TO EQUITY INVESTORS: 1990 TO 2030**
(1986 dollars)



Each negative symbol (-) represents a $4 million investment.
Each positive symbol (+) represents a $4 million dividend.

PDV = $550.685 million.
Rate of Return = 23.8% (nominal dollars).

Table ES-4.— **BENEFITS OF GEOTHERMAL DEVELOPMENT**
(PDV, in millions of 1986 dollars)

Item	Amount	Percent
Equity Investors:		
Transmission Cable Venture	$ 72.137	6.2%
Geothermal Venture	$ 550.685	47.5%
Landowners	$ 88.414	7.6%
County	$ 157.908	13.6%
State:		
Royalties	$ 147.357	
Excise Tax:		
Construction	61.166	
O&M, Geothermal	20.695	
Transmission Cable Venture	2.452	
Geothermal Venture	14.736	
Corporate Income Tax:[1]		
Transmission Cable Venture	10.958	
Geothermal Venture	17.645	
Subtotal	$ 275.009	
Lost Excise Taxes (Fuel and Construction)	-136.516	
Net to State	$ 138.493	12.0%
Federal Government:		
Corporate Income Tax:[1]		
Transmission Cable Venture	$ 57.870	
Geothermal Venture	93.183	
Subtotal	$ 151.053	13.0%
TOTAL BENEFITS	**$1,158.690**	**100.0%**

[1]Excludes individual income taxes.

TECHNICAL FOREWORD

This Technical Foreword presents the analytical approach which was used to evaluate the economic feasibility of transmitting geothermal-generated electrical energy from the Island of Hawaii to Oahu.

ANALYTICAL PERSPECTIVE

Economic Feasibility versus System Optimization

The approach used to determine economic feasibility was to begin the analysis with a feasible scenario of the general specifications, schedule, ownership, and financing, then progressively refine the scenario until conclusive results were obtained—either clearly proving or disproving economic feasibility, whichever the case might be. With this approach, economic feasibility may be shown without determining the optimum scenario; that is, the analysis may end with a scenario which indicates profitable operations rather than the scenario which yields the highest potential profits.

Exclusion of Maui

Consistent with a simple initial scenario, the analysis excludes Maui. This is a conservative assumption in that the addition of Maui would either have no effect on the economic feasibility of the geothermal/transmission system, or would enhance it. A given amount of energy would displace more fuel oil on Maui than would be the case on Oahu because less geothermal energy would be lost to line resistance, and the Maui generators are less efficient than those on Oahu. Also, the diesel fuel used on Maui is more expensive than the low-sulfur fuel-oil used on Oahu, and a portion of the capital expenditures for new generating capacity on Maui could be avoided.

Distribution of Profits

The analysis is developed from the perspective of a number of entities: electricity consumers, HECO, a cable organization (which may be owned by one of the other entities), geothermal developers/operators, land owners, and governments. In order to enhance the economic feasibility of the geothermal/transmission system, it is assumed for the sake of analysis that consumers of the electricity would pay the same for it with or without geothermal power, and that HECO's profits would be unaffected. The result of these and other assumptions is that the profits to geothermal developers are maximized, thereby showing what the profits could be. In actual practice, however, profits may be distributed differently than what is assumed for this report, and could even include a moderation in the increase in future electric rates.

ECONOMIC ASSUMPTIONS

Economic Life of the Geothermal/Transmission System

An energy facility typically has a useful economic life of many decades. Therefore, for the geothermal/transmission system, it is assumed that the useful life continues to at least the year 2030. Since it is expected that the various components would be placed into operation between the years 1995 and 2006, it is assumed that the useful life of a particular component is at least 24 to 35 years, depending on the year the component begins operating; the average life is assumed to be at least 30 years. Any economic benefits which occur because the system or components survive past the year 2030 are ignored, as is the salvage value of components if and when the system ceases operation.

Current and Constant Dollars

The economic analysis is carried out in "constant" dollars which are expressed in terms of 1986 purchasing power; future dollar values have inflation factored out so that the 1986 purchasing power is maintained for all years. This is in contrast to "current" or "nominal" dollars which are expressed in terms of the purchasing power of the current year, and which erode in purchasing power over time due to inflation.

The reason for conducting the analysis in constant dollars is that the purchasing power of 1986 dollars is known, so that the value of future resources expressed in these dollars is easy to comprehend. In contrast, analysis conducted in nominal dollars leads to future values which are extremely difficult to comprehend. For example, an item which costs $1 in 1986 would cost $9.87 in the year 2030 if inflation averages 5.34 percent per year.

The conversion of past cost estimates to 1986 costs was based on the U.S. Consumer Price Index (CPI). This index provides a general measure of inflation and the corresponding erosion of the purchasing price of the dollar. The U.S. index was used rather than the Honolulu index because oil prices and most cost items will reflect world and national economic conditions rather than Hawaii conditions. The year 1986 was chosen as the year for measuring values because it is the most recent year for which the U.S. CPI is known. Conversion factors between dollar amounts of past years and 1986 dollars is shown in Table TF-1.

Inflation

It is not necessary to forecast inflation to demonstrate economic feasibility. However, in order to reflect the effects of financing accurately in terms of constant dollars—i.e., how a capital expenditure is translated into annual debt-service payments expressed in 1986 dollars—it is necessary to forecast inflation. This is because debt-service payments usually are level payments when expressed in nominal dollars; when expressed in constant dollars, the debt-service payments decrease over time. For example, a $1 million capital expense financed with a 9.25-percent, 30-year bond would have debt service payments of $99,501 per year as measured in nominal (or inflating) dollars. If the inflation rate is 5.34 percent per year, the debt service payments expressed in constant (non-inflating) dollars would decrease 5.34 percent annually: $94,457 at the end of the first year, $89,669 at the end of the second year, $85,123 at the end of the third year, etc. By the 30th year, the debt service falls to $20,894 in terms of constant dollars.

The authoritative source for the long-term outlook for inflation is a monthly survey conducted by Drexel Burnham Lambert, Inc. ("Decision-Makers Poll"). The survey includes chief investment officers, corporate financial officers, bond portfolio managers, stock portfolio managers, industry analysts, economists, and others. The May 1987 consensus for inflation over the next 10 years was 5.34 percent per year. Based on this outlook for inflation, conversion factors between future dollars and 1986 dollars is shown in Table TF-1.

Cost Scale-Up Factor

Some of the cost estimates used in this report were derived from estimates developed for a 12.5-MW geothermal power plant. However, the assumed plant size would be 25 MW, or double the size originally assumed. The generally accepted approach for estimating cost for a larger plant is to apply the 0.6 scale-up factor whereby the size ratio is raised to the 0.6 power (Vosseller and Kerridge). That is, for a plant which doubles in size, the cost estimate is increased by a factor of $2^{0.6}$ = 1.516, or a 51.6 percent increase.

Interest and Discount Rates: Nominal and Real Values

The interest rates used in the economic analysis are based on yields as of May 15, 1987—a date which corresponds to the above-mentioned survey of the outlook for inflation. These rates, in terms of both nominal and real values (with inflation, and with inflation factored out, respectively), are:

	Interest Rates (May 15, 1987)	
Type of Security	**Nominal**	**Real**[1]
Municipal Bonds	7.82	2.35
Long-Term Treasury Securities	8.82	3.3
Corporate Aaa Bonds	9.25	3.7
Corporate Baa Bonds	10.45	4.85

[1]Based on an inflation rate of 5.34%. For the first entry, 1.0782/1.0534 = 1.0235 = 2.35%.

Source: The Federal Reserve Bank of St. Louis, "U.S. Financial Data," June 11, 1987.

The real interest rates above are typical of long-term average rates. As discussed below, these interest rates are also discount rates used to calculate present discounted values.

MEASURES OF PROFITABILITY

Present Discounted Value (PDV)

Except for its larger magnitude, the geothermal/transmission system is typical of many investments in that a large outflow of cash is required in the early years to finance capital costs before compensating returns would be realized from operations. The funds to finance the cash outflow are contributed by equity investors, and/or "borrowed" from financial institutions or from the "market" by selling bonds. In order for the investment to be profitable over the life of the system, the eventual returns from operations must be sufficiently large to pay operating costs, repay the borrowed funds, pay interest on the borrowed funds, repay the equity invested, and pay a profit to the equity investors at least as large as that which they could have earned in interest had they invested their funds in a safe alternative investment, such as high-quality corporate bonds. In other words, the net operating profits must be sufficiently large to repay the equity and borrowed funds used to finance the capital costs, plus interest. Equivalently, the maximum amount which can be borrowed against future net operating profits—that is, the amount which can be borrowed from financial institutions or by selling securities—must exceed the amount needed to cover capital costs (i.e., the amount which would have to be deposited in a financial institution so that withdrawals of principal plus earned interest would just cover all capital costs over the initial years of construction). This difference (the maximum amount which can be borrowed against future net earnings minus the amount needed to cover capital costs) is termed the present discounted value (PDV), and is the appropriate measure of the profitability of a project; the higher the PDV, the more profitable the project, and the more it increases the wealth of the project investors as well as society.

The PDV is calculated from the cash flow generated by the investment. This is done by summing the cash flows for each year after each has been "discounted" to the present. The discount factor converts each year's cash flow into the current amount which can be borrowed against the cash flow; this discount factor is based on growth at compound interest. The formula for calculating the PDV is:

$$\mathrm{PDV} = C(0) + C(1)/(1 + r) + C(2)/(1 + r)^2 + C(3)/(1 + r)^3 + \ldots + C(Y)/(1 + r)^Y ,$$

where

$C(0)$ = the initial cash-flow (usually a negative amount which represents an investment);

$C(1), C(2), C(3), \ldots, C(Y)$ = cash-flows for the years $1, 2, 3, \ldots, Y$;

Y = the last year a cash-flow is generated;

r = the discount rate expressed in decimal form; and

$(1 + r)^2 = (1 + r) \times (1 + r)$; $(1 + r)^3 = (1 + r) \times (1 + r) \times (1 + r)$; etc.

For example, if the discount rate is 3.7 percent, then a cash flow of \$100 received in the third year would contribute \$89.67 to the PDV ($\$100/1.037^3 = \$89.67$).

For risk-free projects, the discount rate r is the same as the market interest rate, which is typically chosen to be the corporate Aaa bond rate.

The PDV calculation can be performed in either nominal or constant dollars, so long as the discount rate corresponds (i.e., a nominal discount rate should be used with nominal dollars since both include inflation, and a real discount rate should be used with constant dollars since both have inflation factored out). Regardless of which approach is taken, the result will be the same if done properly. But the mixing of a nominal discount rate with constant dollars or a real discount rate with nominal dollars will result in substantial errors.

The analysis for economic feasibility contained in this report is based on PDV, which is the measure for the net economic value or worth of the geothermal/transmission project. If the PDV is positive, then the project is expected to be profitable and will be judged feasible; if the PDV is negative, then the project is expected to be unprofitable. Furthermore, the greater the value of the PDV, then the more profitable the project.

Unless otherwise noted by a subscript, the year to which the various cash flows are discounted is 1992, which is the assumed year for the start of construction for geothermal development. Cash flows generally are assumed to occur at the end of a year, and discounting is to the beginning of a year.

Other Measures

Other, but less reliable, measures of profitability include:

Payback Period: the number of years until profits cover the capital investment.

Rate of Return: the discount rate (or rates) which drive the PDV to zero (an approach which unrealistically assumes that any excess funds can be invested at the calculated rate of return).

Benefit-Cost Ratio: the ratio of the PDV of revenues to the PDV of expenditures (a ratio greater than 1 correctly indicates profitability, but a project which has a high ratio may not indicate greater profitability than a project which has a low ratio).

Another and more intuitive measure of profitability included in the report is to assume a reasonable financing scheme and demonstrate how net operating profits can cover repayment of equity and borrowed funds, plus interest or its equivalent.

RISK ANALYSIS

Types of Risk

Like most investments, the geothermal/transmission system would involve considerable uncertainty and risks. For example, uncertainty exists regarding the success of obtaining, and the time required to obtain, necessary government approvals from various agencies of United States, the State of Hawaii, and three separate Counties; delays and costs which may be imposed by legal challenges; and the financing of the system. These problems are ignored for the analysis contained in this report; that is, the analysis for economic feasibility is conditioned upon having overcome these permit hurdles, including all legal challenges. Similarly, the report is conditioned on success in obtaining necessary financing.

A second type of uncertainty and risk concerns the impact of interrupted service, either because of a transmission line or cable outage, or because of a volcanic eruption which destroys one or more of the geothermal power plants. The probability of these events and their impact on profitability are addressed in Chapters III and IV.

The third type of uncertainty and risk concerns estimates of such key variables as the future price of fuel and the development costs of such major system components as the drilling of wells, steam collection and disposal systems, power plants, overland transmission lines, undersea cables, and converter stations.

Adjustment to Discount Rate

The typical approach for incorporating investment risk is to increase the discount rate used to calculate the PDV. This approach is based on how financial instruments are evaluated. For example, corporate bonds are rated for risk by investment advisory services, the major ones being Standard & Poor's Corporation, Moody's Investors Service, and The Value Line Investment Survey. For a given risk class (such as Aaa or Baa bonds), the average return or interest rate is calculated based on the bond price and the face value of the semi-annual coupons. This average interest rate is then used as a discount rate to calculate the price of other bonds in the same risk class; the price of a given bond equals the PDV of the face value of the coupon amounts. However, this approach has practical difficulties when evaluating such investments as the geothermal/transmission system. The major difficulty is that such investments are not rated for risk; consequently, an established discount rate does not exist.

Note that in the approach for evaluating bonds, the coupon amounts are the maximum amounts which would be paid, and not the amount which may be expected because of the risk of non- or partial payment. If expected values rather than coupon values are used—where the expected values are a weighted average of all possible outcomes, with the weights being probabilities—then a lower discount rate would be calculated. In fact, the theoretically proper approach for evaluating risky investments, and the approach used in this report, is to discount the expected values of the cash flow using a discount rate that incorporates little or no adjustment for risk; this approach is proper provided that there is a well functioning financial market which allows risks to be shared among investors through the purchase and sale of stocks, options, and other financial instruments—i.e, a financial market such as that which exists in the United States.

Sensitivity Analysis

In order to appreciate the economic risk inherent in an investment, a sensitivity analysis is often conducted whereby key variables are scanned over their possible range, from their lowest to their highest value, to determine how the PDV and other measures of profitability change. Ideally, a project would be profitable for all possible values, although this rarely occurs for risky investments. Practical difficulties include how to define the ranges when some variables can increase to extreme values, although extreme values become increasingly improbable. Also, a particular series of reasonable high and low values (such as low oil prices and high cost estimates for each of the many components), may be very improbable—an analogy is the occurrence of ten heads when flipping a coin ten times; the probability of such an occurrence is only 0.1 percent ($0.5^{10} = 0.001$). The more probable occurrence for a risky investment reflects a mixture of values, most near their expected value, some near their high values, and some near their low values—which is the same as for coin flipping; the more probable occurrence reflects a mixture of heads and tails.

To properly communicate the risk inherent in an investment, it is necessary to address the probability of possible outcomes. Such an approach allows an explicit estimate of how probable it is that an investment would be unprofitable, while avoiding the problem of having to interpret a vast number of computer runs generated as part of a sensitivity analysis.

Normal Probability Distribution

In this report, the uncertainty associated with key variables is approximated in terms of a "normal" probability distribution. The name for this distribution derives from the fact that it is the most frequently encountered probability distribution, with many other distributions tending to the normal distribution under many conditions. Also, it is a robust distribution in its ability to "model" the uncertainty associated with a given variable, and is an appropriate distribution for the analysis contained in this report. The normal distribution is fully characterized by two variables: a mean (M) and standard deviation (SD). The mean M is the expected value or best guess for the particular variable, while the standard deviation SD is a measure of the uncertainty associated with a particular variable. The standard deviation may be measured in the same units as the mean, or as a percentage of the mean if the mean has a value other than zero. The farther from the mean, as measured in terms of the number of standard deviations, the more improbable is a particular event. The following probability statements apply to a normal distribution:

Normal Probability Distribution

Event	Probability (percent)
Right (or left) tail: the true value will occur within a range that is from X standard deviations above (below) the expected value, to an unlimited value above (below) the expected value, where	
X = 1	15.87
1.5	6.68
1.96	2.5
2	2.28
2.58	0.5
3	0.13
Excluding the 2 tails: the true value will occur within a range that is within X standard deviations of the expected value, where	
X = 1	68.26
1.5	86.64
1.96	95
2	95.44
2.58	99
3	99.74
Excluding the left (right) tail: the true value will occur within a range that is from X standard deviations below (above) the expected value, to an unlimited value above (below) the expected value, where	
X = 1	84.13
1.5	93.32
1.96	97.5
2	97.72
2.58	99.5
3	99.87

Many of the probability distributions in this report are based on estimates provided by engineers—estimates which include expected, high, and low values. The high and low values were described as extreme values which provide upper and lower limits which are not expected to be exceeded. A conservative interpretation of such a statement is that the high and low values are 2 standard deviations from the expected value. This implies that the true value of the variable will be between the high and low values with a probability slightly exceeding 95 percent, or that the true value will fall outside this range with a probability slightly below 5 percent. For those cases where the high and low values were not symmetrical about the expected value, the average value was used to estimate 2 standard deviations.

The Bernoulli Process

Geological risks were analyzed as a Bernoulli Process, which is the same process as flipping a biased coin. If p is the probability of a success for each of n trials, and (1 - p) is the probability of failure, then:

- —the probability of no failures is $P = p^n$;
- —the expected number of successes is $M = p \cdot n$, and the expected number of failures would be $M_f = (1 - p) \cdot n$; and
- —the standard deviation in the number of successes would be $SD = (n \cdot p \cdot (1 - p))^{1/2}$.

For example, if p = 0.97 is the probability that a power line would not be cut by lava in a given year, then in 35 years:

- —the probability of no failures would be 34.4 percent, which indicates a probability of 65.6 percent that the line would be cut at least once;
- —the expected number of successes would be 33.95 and the expected number of failures would be 1.05; and
- —the standard deviation in the number of successes (and the number of failures) would be 1.01.

The risk of losing geothermal plants to lava flows is equivalent to flipping a biased coin for each power plant.

In a large number of trials, the distribution on the number of successes can be approximated by a normal distribution.

Independent Variables

For the geothermal/transmission system, many of the variables are "independent." That is, knowledge of the value of one variable would not affect the description of the uncertainty associated with another variable; for a normal distribution, the mean M and standard deviation SD for one variable remain unchanged regardless of what is known about the value of the other variable. For example, knowledge of the cost of a geothermal plant would not affect the description of the uncertainty associated with the price of fuel oil.

When variables are independent, the expected value of their sum equals the sum of the expected values: for $s = x + y$, $M_s = M_x + M_y$. For example, if two independent variables have expected values of 30 and 40, the sum of these two variables will have an expected value of 70. Furthermore, the standard deviation of the sum equals the square root of the sum of each of the standard deviations squared: $SD_s = (SD_x^2 + SD_y^2)^{1/2}$. For example, if two independent variables have standard deviations of 3 and 4 (10 percent of the expected values above), the sum of these two variables will have a standard deviation of 5, and not 7 as one might expect: $(3^2 + 4^2)^{1/2} = 5$. For this case, the standard deviation of the sum is 7.1 percent of the expected value (5/70). This narrowing in the uncertainty is a common characteristic of adding independent variables.

The expected value of the product of two independent variables equals the product of the expected values: for $s = x \cdot y$, $M_s = M_x \cdot M_y$. For the above example, $M_s = 30 \times 40 = 120$. The standard deviation of x is: $SD_s = (SD_x^2 \cdot SD_y^2 + SD_x^2 \cdot M_y^2 + M_x^2 \cdot SD_y^2)^{1/2}$. For the above example, $SD_s = 170$.

For any variable that is a multiple of another, the expected value and standard deviation are the same multiple of the expected value and standard deviation of the first variable: for $y = k \cdot x$, where k is a constant and x and y are variables, $M_y = k \cdot M_x$, and $SD_y = k \cdot SD_x$. For example if $y = 2 \cdot x$, and $M_x = 30$ and $SD_x = 3$, then $M_y = 60$ and $SD_x = 6$.

These relationships among independent variables, combined with the above information on normally distributed variables, provide a simple means of calculating probabilities regarding the profitability of a geothermal/transmission system. Further details and characteristics of the normal distribution and independent variables can be found in any beginning textbook on probability.

Table TF-1.- **CONVERSION FACTORS TO AND FROM 1986 DOLLARS: 1983 TO 2030**

Year	U.S. Consumer Price Index (CPI)	Conversion factor to 1986	Conversion factor from 1986
Actual:			
1983	298.4	1.1005	0.9086
1984	311.1	1.0556	0.9473
1985	322.2	1.0192	0.9811
1986	328.4	1	1
Projected:[1]			
1988		0.9012	1.1097
1989		0.8555	1.1689
1990		0.8121	1.2313
1991		0.7710	1.2971
1992		0.7319	1.3663
1993		0.6948	1.4393
1994		0.6596	1.5162
1995		0.6261	1.5971
1996		0.5944	1.6824
1997		0.5643	1.7723
1998		0.5356	1.8669
1999		0.5085	1.9666
2000		0.4827	2.0716
2001		0.4582	2.1822
2002		0.4350	2.2988
2003		0.4130	2.4215
2004		0.3920	2.5508
2005		0.3722	2.6870
2006		0.3533	2.8305
2007		0.3354	2.9817
2008		0.3184	3.1409
2009		0.3022	3.3086
2010		0.2869	3.4853
2015		0.2212	4.5207
2020		0.1705	5.8637
2025		0.1315	7.6057
2030		0.1014	9.8652

[1]Based on 5.34 percent annual inflation. This is the consensus of opinion for the long-term outlook for inflation as of May 1987 (Drexel Burnham Lambert, Inc., "Decision-Makers Poll").

CHAPTER I

DEVELOPMENT SCENARIO FOR GEOTHERMAL AND TRANSMISSION SYSTEM

This report presents an analysis of the economic feasibility of transmitting geothermal-generated electrical energy from the Island of Hawaii to Oahu. The analysis is based on a development scenario which is conservative in terms of the size of individual power plants and the pace of development. The capacity of the system would be 500 megawatts (MW) of delivered power, which is a rough estimate of the amount of continuously-run (or baseload) electrical power which Hawaiian Electric Company (HECO) could accommodate when geothermal power becomes available near the turn of the century.

It is assumed that the electrical energy would be generated by 20 steam-driven 25-MW geothermal plants located along the East Rift Zone of Kilauea Volcano in the Puna District of the Island of Hawaii (more recent plans are for 50 MW plants which, because of economies of scale, would be cheaper in terms of cost per MW). To allow for line losses estimated at 5 percent, and 2-week downtime annually for maintenance, actual generating capacity for each power plant would be nearly 27.5 MW. Hot steam would be extracted from deep under the ground via a field of production wells, collected via a network of surface pipes, then used to drive steam turbines which in turn would drive electric generators. Water which surfaces with the steam and water which condenses from the spent steam would then be injected back into the ground. Further details of the geothermal system are given in Chapter V.

Before transmission from Puna, the electricity would be converted from alternating current (AC) to high-voltage direct current (HVDC) via four devices called "valve groups." The conversion is made because the transmission system for HVDC is cheaper than that for AC when transmitting large amounts of energy over long distances.

The energy would then be transmitted to Oahu via an overland and undersea transmission system. The route would extend from Puna on the Big Island, cross overland to the northern tip of the island, then undersea to Maui, overland a short distance on Maui, then undersea to Oahu. The land portions of the transmission system would involve two HVDC overhead lines, each having a capacity of 500 MW. In the event of a line outage, the other line would have the capacity to handle the entire geothermal energy load. The two lines would be physically separated to reduce the probability of simultaneous outages. The sea portion of the transmission system would involve three undersea cables, each having a capacity of 250 MW; this allows one of the cables to be a backup in case of a temporary outage. After coming ashore on the east side of Oahu, the energy would be converted from HVDC back to AC, and then fed into the HECO electric grid. Further details of the transmission system are given in Chapter IV.

The assumed schedule for the start of operations for the geothermal plants and the transmission system is shown in Table I-1. As indicated, operations would begin with 25 MW of capacity in January 1995, and reach full capacity at 500 MW 11 years later in May 2006. It is anticipated that a geothermal plant would be built about every 7 months, but with a 1-month slippage with every fifth plant. This is a relatively conservative schedule; geothermal developers have indicated that they plan a schedule having a duration about half as long as that given in Table I-1.

Table I-1.— **SCHEDULE FOR START OF OPERATIONS**

Date		Geothermal Plants		Transmission System		
Month	Year	Unit	MWs	HVDC Valve Groups	HVDC Overhead Lines	Undersea Cables
Jan	1995	1	25	1	1	1
Aug		2	50			
Mar	1996	3	75			
Oct		4	100			
May	1997	5	125			
Jan	1998	6	150	2	2	2
Aug		7	175			
Mar	1999	8	200			
Oct		9	225			
May	2000	10	250			
Jan	2001	11	275	3		3
Aug		12	300			
Mar	2002	13	325			
Oct		14	350			
May	2003	15	375			
Jan	2004	16	400	4		
Aug		17	425			
Mar	2005	18	450			
Oct		19	475			
May	2006	20	500			

CHAPTER II

HECO'S AVOIDED COSTS

The availablity of geothermal energy would enable HECO to avoid expenditures on (1) a large volume of expensive fuel from overseas sources; (2) some operations and maintenance (O&M) activities; and (3) expansion of generating capacity on Oahu. The amount saved on these items, which is derived in this chapter, is the amount which HECO could pay for geothermal energy. In either case—whether with or without geothermal power—HECO's cost for providing electricity to consumers would be the same.

FUEL

Fuel Price

A critical assumption for determining avoided fuel cost, and hence the economic feasibility of the geothermal/transmission system, is the future price of fuel oil. This has been a subject of considerable analysis by many research organizations because of the great importance of oil to the economic health of the world, nearly all nations, and a great many businesses. Advantage was taken of the many studies available, including the listing in Table ES-1 of long-term forecasts, projections, and planning assumptions for the world price of crude oil. The listing includes those prices which were developed after January 1, 1986; these forecasts indicate that oil prices will generally be lower than those developed in previous years, reflecting the depressed prices during 1986. The forecasts are ranked from high to low prices based on the last year forecasted, and are expressed in constant 1986 dollars.

Analysis of the forecasts in Table ES-1, as well as supporting documents, reveals insight into the consensus of opinion among oil experts regarding future crude-oil prices. Most experts believe that crude-oil prices will increase steadily starting in the early 1990s. The average of the forecasts is a crude-oil price of about

$23 per barrel in 1990, $32 in 2000, and $43 in 2010. The increase is nearly linear, with the price increasing slightly faster than $1 per barrel per year; in contrast, the increase is not geometric—instead of a constant percentage increase, the percentage increase becomes progressively smaller over time. The extent of disagreement among the experts, as measured in terms of 1 standard deviation (SD), is nearly 30 percent of the average prices.

In the absence of geothermal power, it is possible that increasingly expensive oil would eventually force HECO to switch to coal as their primary fuel. This would require appropriate modifications to existing generators, and/or installation of new coal-fired generators. With a sufficiently large price differential between coal and oil, and sufficient pollution control devices, coal may become acceptable to the public. Coal has the additional advantage of being an abundant and stable fuel source.

In this report, HECO's avoided fuel price is asssumed to follow the world crude-oil price up to a certain point, after which it remains relatively level because of the additional assumption that coal would become the avoided fuel. To determine HECO's fuel cost, the crude-oil price is increased 15 percent to reflect the historic premium which HECO pays for low-sulfur fuel oil (LSFO), plus 4 percent excise tax. LSFO produces about 5 percent more heat than crude oil, and generates less air pollution when burned. After coal becomes the avoided fuel, it is assumed that the avoided cost is equivalent to an LSFO price of $35 per barrel, which corresponds to a crude-oil price of $30.43 per barrel. This is a preliminary assumption subject to change based on further analysis.

The resulting forecast for the price of HECO's avoided fuel, which is referred to as the "expected price trend," starts with a price of $31.69 per barrel in 1995, and increases $1.168 per year thereafter until it reaches $35 in 1998 (see Table II-1, and Figure ES-1).

The uncertainty in the forecast, measured in terms of 1 SD, is 30 percent of the expected price trend. This level of uncertainty corresponds to the divergence of opinion among oil experts, and the uncertainty over the avoided cost associated with coal (which, as indicated, is a preliminary assumption subject to change based on further analysis). The interpretation of this uncertainty, based on the material presented in the Technical Forward (page TF-9), is that the true long-term price trend (with short-term fluctuations filtered out) will fall within 30 percent of the expected trend with probability 68.26 percent, or about 2 chances out of 3. Also, the true long-term price trend will be above a low price trend that is 30 percent below the expected price trend with probability 84.13 percent, or about 5 chances out of 6 (which can be compared to rolling a single die, with 5 out of the 6 numbers representing a favorable outcome). Similar interpretations can be made with price trends based on a different number of SDs from the expected price trend.

Geothermal Power Sales to HECO

For each megawatt of geothermal capacity, about 8,760 megawatt-hours (MWh) per year of geothermal energy would be delivered to HECO on Oahu (1 MW x 8,760 hours per year). Therefore, eventual geothermal energy sales on Oahu would reach about 4.38 million MWh per year when geothermal capacity is developed to 500 MW of capacity (8,760 MWh per year/MW x 500 MW = 4.38 million MWh per year).

The annual buildup in geothermal capacity and the geothermal energy sales on Oahu is shown in Table II-2. The build-up in capacity is consistent with that shown in Table I-1.

Fuel Savings

Once geothermal power is available, the operating plan is for HECO to buy as much of the energy as can be delivered. This would reduce the amount of electrical energy which would have to be generated on Oahu which, in turn, reduces the amount of fuel-oil or coal that would have to be burned to drive the Oahu generators. The reduction in fuel depends on the efficiency of the generators which would no longer be used to generate electrical energy.

Year 1995

When geothermal power first becomes available, the amount of power would be relatively small, and the power reduction on Oahu would come from the least efficient generators. During the 14-hour on-peak period, which lasts from about 7:00 AM to 9:00 PM, the least efficient cycling generators are projected to require an average of 11,316 British thermal units (Btu) of heat in order to generate 1 kWh of electricity. This projection assumes that the generators which currently are the least efficient will have already been displaced by other sources of power.

When power is cycled down to the off-peak, middle-of-the-night hours, the energy output from the Oahu base-load generators must be reduced in order to compensate for the addition of geothermal energy. This reduction must come from a base-load generator or generators which can be cycled. The power reduction cannot come from the least efficient base-load generators because they must be operated continuously so that they will be available during the on-peak hours. The least efficient base-load generators which can be cycled are projected to require an average of 9,965 Btu of heat in order to generate 1 kWh of energy.

The weighted average of the on-peak and off-peak heat rates is 10,753 Btu per kWh (14 hours at 11,316 Btu, and 10 hours at 9,965 Btu). At this heat rate, 1 MWh of geothermal energy would save 1.734 barrels of fuel (1 MWh x 1,000 kWh/MWh x 10,753 Btu/kWh x 1 barrel of fuel/6,200,000 Btu = 1.734 barrels). Thus, as shown in Table II-2, when 310,280 MWh of geothermal energy are delivered to Oahu in the first year of operations, the fuel savings would amount to about 538,000 barrels (310,280 MWh x 1.734 barrels/MWh). At the projected price of $31.69 per barrel, the savings amounts to $17.1 million in terms of 1986 purchasing power (538,000 barrels x $31.69/barrel).

Year 2007

When geothermal power reaches full development, excess generating capacity would exist on Oahu, and the fuel savings would come from not having to operate a number of the generators, including some fairly efficient ones. The average heat rates for the displaced units are projected to be 10,243 and 9,918 Btu per kWh for on-peak and off-peak hours, respectively. The weighted average would be 10,108 Btu per kWh (14 hours at 10,243 Btu, and 10 hours at 9,918 Btu). At this heat rate, 1 MWh of geothermal energy would save 1.630 barrels of fuel (1 MWh x 1,000 kWh/MWh x 10,108 Btu/kWh x 1 barrel of fuel/6,200,000 Btu = 1.630 barrels). Thus, when 4.38 million MWh of geothermal energy are delivered to Oahu in the first year of full operations, the fuel savings would amount to about 7.139 million barrels (4.38 million MWh x 1.630 barrels/MWh), as shown in Table II-2. At the projected price of $35 per barrel, the savings amounts to a very substantial $249.9 million, given in terms of 1986 purchasing power (7.139 million barrels x $35/barrel).

Year 2020

Based on information provided by HECO, it is assumed that excess capacity created by the introduction of geothermal power would be absorbed by about the year 2020. At this date and thereafter, all existing generators would be in operation, including inefficient ones which have high heat rates. Correspondingly, the fuel savings associated with geothermal energy results from not having to operate generators which would have had to be purchased new in the absence of geothermal power. The heat rate for new steam turbine generators having cycling ability is about 9,405 Btu per kWh. This would be the appropriate heat rate for both on-peak and off-peak operations. At this heat rate, 1 MWh of geothermal energy would save 1.517 barrels of fuel (1 MWh x 1,000 kWh/MWh x 9,405 Btu/kWh x 1 barrel of fuel/6,200,000 Btu = 1.517 barrels). Therefore, 4.38 million MWh of geothermal energy translates into a fuel savings of about 6.644 million barrels (4.38 million MWh x 1.517 barrels/MWh), as shown in Table II-2. At the projected price of $35 per barrel, the savings amounts to $232.6 million in terms of 1986 purchasing power (6.644 million barrels x $35/barrel).

Interpolation to Other Years

For the years falling between 1995 and 2007, and 2007 and 2020, the savings in fuel per MWh is based on a linear interpolation (see Table II-2, Column 4).

Present Discounted Value (PDV)

The projected fuel savings for other years are shown in Table II-2, and repeated in Table II-4. The PDV of the entire cash flow of savings, discounted back to 1992 at 3.7-percent interest, is $3.255 billion. The major source of uncertainty for this PDV is the price of fuel, for which 1 SD is 30 percent of the forecasted price. Consequently, the uncertainty for the PDV of the cash flow of fuel expenditure savings, measured in terms of 1 SD, is 30 percent of the PDV, or $0.976 billion.

OPERATIONS AND MAINTENANCE (O&M)

In addition to fuel savings, geothermal power would allow a savings on O&M expenditures for that portion of energy which no longer needs to be generated on Oahu. These savings are estimated at $2 million per year starting in 1999, an additional $2 million per year starting in 2002, plus $0.85 million per year starting in 2008. These dates correspond to when new generators are projected to come on line in the absence of geothermal power, with the first full year of O&M expenditures assumed to occur in the year after the expenditure on construction. The third entry of $0.85 million beginning in the year 2008 is a 42.5-percent prorated share of O&M costs for a new generator (see the following section).

However, an estimated $1.26 million for O&M for the transmission system, which is assumed to be absorbed by HECO, would offset these O&M savings.

The resulting schedule of O&M costs, which has a PDV of $38 million, is shown in Table II-4. Uncertainty is estimated at 15 percent for 1 SD.

CAPITAL EXPENDITURES FOR GENERATING CAPACITY

The availability of geothermal power would enable HECO to avoid expenditures on expanding generating capacity on Oahu. However, because considerable uncertainty exists over the magnitude and timing of this avoided expenditure—particularly with respect to how other alternative energy projects may affect HECO's decisions on expanding capacity—the analysis which follows is meant to illustrate the magnitude of a potential HECO payment for avoided capacity, and should not be regarded as a forecast.

The avoided capacity expansion on Oahu would be less than the 500 MW of delivered geothermal capacity because one 146-MW steam turbine is to provide back-up capacity in case of a partial failure of the geothermal/transmission system, even though such an event is considered to be very improbable. Therefore, the potential expansion of Oahu generating capacity which can be avoided amounts to 354 MW (500 minus 146). This exceeds the combined capacity of two 146-MW steam turbines which, until recently, were scheduled to begin operations in 1998 and 2001. The costs of these two generators, in 1986 dollars, are estimated to be $87 and $120 million, respectively (see Table II-3). The first generator is the pair to Kahe 7 with which it would share facilities, while the second generator would require a new building and permits for a yet-to-be-determined location; this is the reason why the costs for the two generators differ. The 62-MW generator shown in Table II-3 is a 42.5-percent prorated share of a third 146-MW steam turbine, which is assumed to be needed by the year 2007 and, for cost purposes, is assumed to be the second half of a pair. With this third generator, the avoided capacity sums to 354 MW.

Except for these three generators, any added capacity to accommodate further growth in demand would be approximately the same whether or not geothermal power is developed (unless, of course, an additional transmission system is installed.)

Expenditures made to modify some existing steam-turbine generators would partially offset the avoided capital cost. Currently, these generators are run continuously to provide baseload electrical energy. The modifications are needed so that these generators can be cycled after geothermal energy becomes available. As indicated in Table II-3, five modifications would be required at a cost of $3.84 million each (1986 dollars).

Table II-3 also shows the net capital costs which HECO would avoid because of geothermal power. The PDV of these costs, discounted to 1995 at 3.7-percent interest and assuming expenditures are made at the beginning of the year, is $176 million. The year 1995 is the first year of geothermal energy sales. A discount rate of 3.7

percent is the interest rate for corporate Aaa bonds after inflation is factored out; it is the approximate real interest rate at which HECO can borrow funds for capital improvements.

In annual terms, the debt service on a long-term corporate bond of $176 million is the amount which, because of geothermal power, HECO saves on expanding generating capacity on Oahu. After adjusting for the scheduled build-up in geothermal energy sales, HECO could pay this amount to geothermal operators, with no effect on total expenditures. However the effect on HECO's profits would not be the same because of different tax treatments.

A payment for geothermal energy to cover avoided capital costs would be an expense which is fully deductible before computing profits subject to corporate income taxes. However, for a debt-financed capital expenditure, only the interest payments are deductible, while the principle component of the debt service is not. But the cost of the capital improvement can be depreciated over its useful life. For major improvements, HECO uses 30-year straight line depreciation—that is, 1/30 = 3.33 percent of the capital costs is expensed over each year over the 30-year life of the facility. Although the total amount depreciated equals the total principal payments, the schedule of payments for the two differ over time, with depreciation exceeding principal payments in the early years. Therefore, for the early years, the total deduction of interest plus depreciation exceeds the debt service. This larger deduction decreases taxes, which in turn results in larger after-tax profits which can then be invested. This makes debt financing of a capital expense more attractive than paying a fee for geothermal energy that would be the same as the debt service.

A facility financed entirely with 30-year bonds at a 9.25-percent nominal interest rate (the approximate nominal interest rate which corresponds to a real interest rate of 3.7 percent), and depreciated over 30 years using a straight-line schedule, has a PDV of interest payments and depreciation which exceeds the capital costs of the facility—and exceeds the PDV of the debt service—by 14.3 percent. The effect of this artificial increase in cost is to reduce the PDV of taxes (and increase the PDV of profits) by 5.43 percent of the capital costs (the 14.3 percent for the artificial increase in costs x HECO's effective corporate income tax rate of 38 percent).[1] To have the same effect on profits, the payment for geothermal energy for avoided capital costs must be reduced below the debt-service payment on the capital costs by

[1] Tax rates of 34 and 6.05 percent for the Federal and State governments, respectively, less 2.057 percent for the fact that State taxes are a deductible expense (34 percent of 6.05 percent).

8.75 percent (the decrease D in geothermal payments would increase profits by 62 percent of the decrease, with the other 38 percent going to corporate income taxes; this increase must equal 5.43 percent of the capital costs C of the avoided improvements: $0.62 \times D = 0.0543 \times C$, or $D = 0.0875 \times C = 8.75\%$ of C).

Based on the above, HECO's payments to geothermal operators for avoided capital costs should have a 1995 PDV of approximately $161 million in order to have a neutral effect on the PDV of HECO's profits ($176 million - 8.75%). When discounted back to 1992 (the base year for the financial analysis), the PDV drops to $144 million (1986 dollars). Uncertainty is estimated at 20 percent for 1 SD.

This same PDV would be generated by a flat avoided-capital payment of 0.866 cents per kWh. This rate is expressed in current dollars; when converted to constant dollars, the rate falls over time because inflation erodes the purchasing power of the dollar. A flat rate in terms of current dollars was chosen for two reasons. First, it is consistent with debt service for a bond-financed capital improvement; generally, debt-service payments are flat in terms of current dollars. Second, in the early years of geothermal development when revenues are most needed, this approach provides higher revenues than would be the case with payments which increase with inflation (i.e., payments which remain constant in terms of constant dollars).

The avoided capital payment of 0.866 cent per kWh translates into an annual payment of $75.86 per kW of capacity (0.866 cent per kWh x 1 kW x 8,760 hours per year), or $37.7 million for 500 MW. This annual payment appears high compared to the avoided capital amounts in Table II-3 because the former is expressed in current dollars (which <u>in</u>cludes inflation), while the latter is expressed in constant 1986 dollars (which <u>ex</u>cludes inflation).

Based on the current-dollar rate of 0.866 cent per kWh, the projected cash flow of HECO's payments to geothermal operators for avoided capital costs is as shown in Table II-4. The payments are shown in constant 1986 dollars rather than current dollars.

It should be noted that the annualized avoided capital expenditures shown in Table II-4 would be higher if HECO's funds for capital improvements are obtained at an interest rate higher than that for corporate Aaa bonds.

TOTAL AVOIDED COSTS

The total cost avoided by HECO due to the introduction of geothermal power is shown in the last column of Table II-4; this is the amount which HECO could pay for geothermal energy and break even. The PDV of the total avoided costs is a very substantial $3.437 billion (discounted to 1992 at 3.7% interest, with the amount expressed in terms of 1986 purchasing power). About 95 percent of this PDV results from avoided expenditures on imported fuel. The uncertainty for the PDV, as measured in terms of 1 SD, is $0.977 billion, or 28.4 percent of the PDV. The dominate source of this uncertainty derives from the uncertain outlook for fuel prices.

The electric rates which, when applied to the total geothermal energy delivered to HECO, would generate the total avoided costs is shown in Table II-5, with the rate split into its components for avoided fuel, O&M and capital expenditures. As indicated, the rate starts at 5.632 cents per kWh in 1995, grows slowly to 6.430 cents in 1999 primarily because of the increase in fuel prices then, after fuel prices are stabilized at $35-per-barrel LSFO equivalent (because of the assumption that coal will become the avoided fuel), gradually declines to 5.479 cents in the year 2020. This gradual decline in the electric rate occurs because of the decline in fuel savings per MWh (see Table II-2, Column 4), and the decline in avoided capital payments as a result of inflation.

If, instead of an electric rate which changes over time as shown in Table II-5, HECO were to pay a flat rate for geothermal power as measured in terms of constant 1986 dollars—that is, a rate which increases only with inflation, regardless of the increase in fuel prices—the rate which would give the same PDV for avoided costs is 5.887 cents per kWh. Conceptually, this is the value for 1 kWh of geothermal power when appropriately averaged over the 35-year life of the geothermal/transmission project.

If HECO's avoided fuel cost were to increase by $1 per barrel (LSFO equivalent) over the expected price trend, the PDV for the total avoided cost would increase by $93.1 million. For crude-oil, a $1 per barrel increase translates into a $107.1 million increase in the PDV. In terms of payments for geothermal power, an increase of 1 cent per kWh would increase the PDV by $583.9 million.

The potential payments for geothermal energy increase enormously if it is assumed that: (1) coal is not an acceptable energy alternative, (2) LSFO remains the avoided fuel, and (3) LSFO follows the price trend shown in Table II-1 and Figure ES-1. Under these assumptions, in the year 2030, LSFO would increase in price to $72.57 per barrel, and HECO's payment for geothermal power would reach $489.9, or 11.18 cents per kWh. The PDV of total HECO payments would be $4.960 billion, or $1.523 billion more than that under the original assumption that the avoided fuel price will level off at $35 per barrel.

TAX REVENUES

Because of geothermal power, the State would lose excise tax revenues on fuel which would otherwise be purchased by HECO, and on avoided construction. For fuel, the PDV of lost excise taxes is $130.2 million (4 percent of $3,254.9 million). For construction, the PDV of lost excise taxes is $6.3 million (4% of $144.159 million/(1 - 8.75%)).

Table II-1.— **PRICE FORECAST FOR CRUDE OIL, LSFO, AND HECO'S FUEL PRICE: 1995 TO 2030**
(Price per barrel, 1986 dollars)

Year	Crude Oil Price[1]	LSFO Price[2]	HECO's Fuel Price[3]
1995	$27.56	$31.69	$31.69
1996	28.58	32.86	32.86
1997	29.59	34.03	34.03
1998	30.61	35.20	35
1999	31.62	36.37	35
2000	32.64	37.53	35
2001	33.65	38.70	35
2002	34.67	39.87	35
2003	35.68	41.04	35
2004	36.70	42.20	35
2005	37.72	43.37	35
2006	38.73	44.54	35
2007	39.75	45.71	35
2008	40.76	46.88	35
2009	41.78	48.04	35
2010	42.79	49.21	35
2015	47.87[4]	55.05	35
2020	52.95[4]	60.89	35
2025	58.03[4]	66.73	35
2030	63.10[4]	72.57	35

[1]Linear approximation of the average of the price forecasts from Table ES-1.

[2]Crude oil price, plus 15 percent for fuel premium and State excise tax.

[3]Based on the assumption that coal becomes the avoided fuel at an LSFO price equivalent to $35 per barrel.

[4]Extrapolation of price trend.

Table II-2.— **GEOTHERMAL ENERGY SALES AND HECO FUEL SAVINGS: 1995 TO 2030**
(1986 dollars)

	Geothermal		Fuel Savings			
			Barrels		Amount ($)	
Year	**Capacity**[1] (MW)	**Delivered Energy**[2] (1,000 MWh)	**per MWh**[3]	**Total** (million)	**per Barrel**[4]	**Total** (million)
1995	35.42	310.279	1.734	0.538	$31.69	$ 17.052
1996	77.08	675.221	1.725	1.165	32.86	38.283
1997	116.67	1,022.029	1.717	1.754	34.03	59.704
1998	160.42	1,405.279	1.708	2.400	35	84.007
1999	202.08	1,770.221	1.699	3.008	35	105.286
2000	241.67	2,117.029	1.691	3.579	35	125.270
2001	285.42	2,500.279	1.682	4.205	35	147.190
2002	327.08	2,865.221	1.673	4.794	35	167.804
2003	366.67	3,212.029	1.665	5.347	35	187.141
2004	410.42	3,595.279	1.656	5.954	35	208.379
2005	452.08	3,960.221	1.647	6.524	35	228.329
2006	491.67	4,307.029	1.639	7.058	35	247.017
2007	500	4,380	1.630	7.139	35	249.879
2008	500	4,380	1.621	7.101	35	248.547
2009	500	4,380	1.613	7.063	35	247.215
2010	500	4,380	1.604	7.025	35	245.882
2015	500	4,380	1.560	6.835	35	239.222
2020	500	4,380	1.517	6.644	35	232.556
2025	500	4,380	1.517	6.644	35	232.556
2030	500	4,380	1.517	6.644	35	232.556
PDV						$3,254.919
SD						$ 976.476 30%

[1] Average capacity for year derived from Table I-1.

[2] Based on 8,760 MWh per year for each MW of capacity: 1 MW x 8,760 hours/year.

[3] See text for derivation.

[4] See text and Figure ES-1.

Table II-3.— **NET AVOIDED CAPITAL COSTS FOR OAHU GENERATING CAPACITY: 1997 TO 2007**
(1986 dollars)

Year	Avoided Cost for New Generators: Unit	Avoided Cost for New Generators: Cost (millions)	Added Cost to Modify Generators for Cycling: Unit	Added Cost to Modify Generators for Cycling: Cost (millions)	Net Avoided Cost (millions)
1997			Kahe 6	$3.84	$ -3.84
1998	146 MW Steam Turbine	$ 87	Kahe 1	3.84	83.16
1999					
2000					
2001	146 MW Steam Turbine	120	Kahe 4	3.84	116.16
2002					
2003			Kahe 2	3.84	-3.84
2004			Kahe 3	3.84	-3.84
2005					
2006					
2007	62 MW	37			37
PDV_{1995}					$176.176
$PDV'_{1995} = PDV_{1995} - 8.75\%$					$160.761
PDV'					$144.159

Source: Derived from information provided by HECO.

Table II-4.— **COSTS AVOIDED BY HECO AS A RESULT OF GEOTHERMAL POWER: 1995 TO 2030**
(millions of 1986 dollars)

Year	Fuel[1]	O&M[2]	Capital[3]	TOTAL
1995	$ 17.052	$-1.260	$ 1.682	$ 17.475
1996	38.283	-1.260	3.476	40.499
1997	58.704	-1.260	4.994	63.438
1998	84.007	-1.260	6.519	89.266
1999	105.286	0.740	7.795	113.821
2000	125.270	0.740	8.850	134.861
2001	147.190	0.740	9.922	157.852
2002	167.804	2.740	10.794	181.338
2003	187.141	2.740	11.487	201.368
2004	208.379	2.740	12.206	223.325
2005	228.329	2.740	12.764	243.832
2006	247.017	2.740	13.178	262.935
2007	249.879	2.740	12.722	265.341
2008	248.547	3.590	12.077	264.214
2009	247.215	3.590	11.464	262.269
2010	245.883	3.590	10.883	260.356
2015	239.222	3.590	8.391	251.202
2020	232.556	3.590	6.469	242.615
2025	232.556	3.590	4.987	241.133
2030	232.556	3.590	3.845	239.991
PDV	$3,254.919	$38.287	$144.159	$3,437.365
SD	$ 976.476 30%	$ 5.743 15%	$ 28.832 20%	$ 976.918 28.4%

[1] From Table II-2.
[2] See text.
[3] Derived.

Table II-5.— **BREAK-EVEN ELECTRIC RATE FOR HECO'S PURCHASE OF GEOTHERMAL ENERGY: 1995 TO 2030**
(Cents per kWh, 1986 dollars)

Year	Fuel[1]	O&M[2]	Capital[3]	TOTAL
1995	5.496	-0.406	0.542	5.632
1996	5.670	-0.187	0.515	5.998
1997	5.842	-0.123	0.489	6.207
1998	5.978	-0.090	0.464	6.352
1999	5.948	0.042	0.440	6.430
2000	5.917	0.035	0.418	6.370
2001	5.887	0.030	0.397	6.313
2002	5.857	0.096	0.377	6.329
2003	5.826	0.085	0.358	6.269
2004	5.796	0.076	0.340	6.212
2005	5.766	0.069	0.322	6.157
2006	5.735	0.064	0.306	6.105
2007	5.705	0.063	0.290	6.058
2008	5.675	0.082	0.276	6.032
2009	5.644	0.082	0.262	5.988
2010	5.614	0.082	0.248	5.944
2015	5.462	0.082	0.192	5.735
2020	5.310	0.082	0.148	5.539
2025	5.310	0.082	0.114	5.505
2030	5.310	0.082	0.088	5.479

[1] Column 2 of Table II-4 divided by Column 3 of Table II-2.
[2] Column 3 of Table II-4 divided by Column 3 of Table II-2.
[3] Column 4 of Table II-4 divided by Column 3 of Table II-2.

CHAPTER III

TRANSMISSION SYSTEM

Under the geothermal/transmission development scenario discussed in Chapter I, energy from the geothermal power plants in Puna on the Big Island would be transmitted to Oahu via a 500-MW tranmission system. Presented in this chapter is the estimated development costs for the transmission system, the expenditure pattern required to complete the system according to the schedule of Table I-1, O&M costs, geological risks, a possible financing scheme for the transmission system, implications of the financing scheme to geothermal operators, and impacts on tax revenues.

DEVELOPMENT COSTS

Components of the transmission system would include an AC-to-DC converter station located near the geothermal power plants in Puna, overhead HVDC transmission lines across the Big Island to to a point near Mahukona, undersea transmission cables between the Big Island and Maui, a Maui-based oil repressurization system for the Hawaii-to-Maui cables, overhead HVDC transmission lines across a portion of Maui, undersea transmission cables between Maui and Oahu, a DC-to-AC converter station on Oahu in the Aniani area, and an interconnection to the electric grid on Oahu. Cost estimates and expenditure schedules for each component are presented below.

HVDC Converter Stations

The conversion to DC is made because DC bulk power transmission over long distances is cheaper than is the case for AC. The lower cost occurs because a DC system requires only two conductors versus three conductors for an AC system. Furthermore, with only two conductors, the transmission towers can be smaller, and the right-of-way narrower.

Each of the two converter stations would consist of a pair of valve groups, for a total of four valve groups. In terms of 1986 dollars, the converter stations are expected to cost $63.190 to $82.555 million, with a mid-price of $72.873 million (based on actual 1985 costs which range from $61 to $81 million; Power Technologies, Inc., Phase IIB Final Report, November 1986, Table 7.2). Using the mid-value, each of the first two valve groups is expected to cost $21.862 million, and each of the second two $14.575 million (about two-thirds the cost of the first two). The second two valve groups are less expensive than the first two because each is the second half of a pair for which the housing and certain control equipment already would have been built. For each valve group, manufacturing, construction, and installation is expected to require 3 years: 1 year for manufacturing, and 2 years for construction and installation. Expenditures would be divided about evenly between the second and third years. The resulting capital expenditure schedule for the HVDC Converter Station, expressed in 1986 dollars, is projected to be:

HVDC Converter Station Capital Costs: 1992 to 2004
(millions of 1986 dollars)

	Amount
Valve Group 1:	
1992: Equipment Manufacturing	$ --
1993: Construction and Installation	10.931
1994: Construction and Installation	10.931
1995: Start Operations	--
Valve Group 2:	
1995: Equipment Manufacturing	--
1996: Construction and Installation	10.931
1997: Construction and Installation	10.931
1998: Start Operations	--
Valve Group 3 (pair to Valve Group 1):	
1998: Equipment Manufacturing	--
1999: Construction and Installation	7.287
2000: Construction and Installation	7.287
2001: Start Operations	--
Valve Group 4 (pair to Valve Group 2):	
2001: Equipment Manufacturing	--
2002: Construction and Installation	7.287
2003: Construction and Installation	7.287
2004: Start Operations	--
Total	**$ 72.873**
SD	$ 4.842
	6.644%

The uncertainty in the cost estimate for the HVDC Converter Station, as measured in terms of 1 SD, is estimated to be 6.64 percent of the total value. This estimate is based on the estimated high and low extreme values mentioned previously, with the extreme values interpreted as 2 standard deviations.

Overhead HVDC Lines

As mentioned in Chapter 1, the land portion of the transmission system would involve two HVDC overhead transmission lines, each having a capacity of 500 MW. In case of a line outage, the other line would have the capacity to handle the entire geothermal energy load. The two lines would be physically separated in order to reduce the probability of simultaneous outages.

Based on actual HECO cost experiences, the 1986 cost per mile for overhead HVDC lines is estimated to be $239,300 per mile:

Cost per Mile for Overhead HVDC Lines
(1986 dollars)

	Cost per Mile
Photogrammetric Mapping	$ 7,600
Easement Document Preparation	1,000
Right-of-Way Purchase	3,200
Construction Stakeout	1,700
Engineering	20,500
Overhead Tower Material and Construction	175,200
Conductor	30,100
TOTAL, Hawaii and Maui	$239,300

The estimated distance transversed by the overhead transmission lines is 136 miles. Therefore, the total cost for the 2 HVDC transmission lines, including an additional $1 million for an Environmental Impact Statement (EIS), would be $66.090 million (1986 dollars; $1 million + 136 miles x $239,300/mile x 2 lines). For each line, 10 percent of the cost would be for engineering and start-up, with these costs expended over 4 years; 90 percent of the cost would be for actual construction, with these cost expended over 3 years. From Table I-1, the first line is scheduled for completion by 1995, and the second line by 1998. The anticipated expenditure schedule for the two HVDC transmission lines is:

Overhead HVDC Lines, Development Costs: 1989 to 1997
(millions of 1986 dollars)

	Line #1		Line #2		Total
	Amount	Percent	Amount	Percent	Amount
1988	$ 0.224	0.677			$ 0.224
1989	0.654	1.979			0.654
1990	1.213	3.672			1.213
1991	1.213	3.672	$ 0.826	2.5%	2.039
1992	9.913	30	0.826	2.5	10.739
1993	9.914	30	0.826	2.5	10.740
1994	9.914	30	0.826	2.5	10.740
1995			9.913	30	9.913
1996			9.914	30	9.914
1997			9.914	30	9.914
Total	$33.045	100%	$33.045	100%	**$66.090**
SD					$ 3.305 5%

The uncertainty in the cost estimate for the two overhead HVDC lines, as measured in terms of 1 SD, is estimated at 5 percent of the total cost. This is a relatively low amount of uncertainty which reflects the experience HECO has had with power line design and construction.

Undersea Cable System

Components

The specially-designed undersea cable system would be much longer (138 miles) and reach depths much deeper (6,300 feet) than any existing power cable. The system would include three cables, each having a capacity of 250 MW, based on 300 kV DC and 833 amperes of current (300 kV x 833 A = 250 MW). Therefore, only two of the three cables would be required for 500 MW of geothermal power; this allows the third cable to serve as a backup in the event of a temporary outage, thereby providing higher reliability in the transmission of energy from the Big Island to Oahu.

Three types of cables would be involved: a double armored, self-contained, oil-filled (SCOF) cable specially designed for the long distance, great depths, and strong currents of the Alenuihaha Channel between Maui and Hawaii; a single armored, solid-conductor cable for the shallower depths between Maui and a point in the Kaiwi Channel between Oahu and Molokai where the depth reaches 820 feet; and a double armored, solid-cable for the remainder of the Kaiwi Channel to Oahu. The lengths of the Hawaii/Maui and Maui/Oahu portions of the cable would be about 42 and 96 miles, respectively. Other components of the undersea cable would include cable terminations, and a land-based oil repressurization system located on Maui.

Manufacturing Cost

The estimated cost to manufacture all of the cable components is $187.305 million:

Undersea Cable Manufacturing Cost
(millions of 1986 dollars)

	Amount
Cables:	
SCOF	$ 56.547
Solid Cable, Single Wire Armor	96.288
Solid Cable, Double Wire Armor	27.270
Terminations	1.200
Pressurization Equipment	6.000
Total	**$187.305**

Source: Pirelli Cable Corporation and Societa Cavi Pirelli, July 11, 1986. Table 5, Cable Scheme No. 2A.

The cost for the Hawaii-to-Maui portion of the cable is $85 per foot ($56.547 million for three cables covering 42 miles). For the Maui to Oahu portion of the cable, the cost is $81.25 per foot ($96.288 million + $27.270 million for three cables covering 96 miles).

For each of the three cables, the estimated manufacturing cost is $62.435 million ($187.305/3 cables), with construction expected to take 2 years. The entire payment for manufacturing would be made upon its completion, which is schedule to be 2 years before operations would begin. The schedule of costs for the undersea cable system, which is consistent with the schedule given in Table I-1, is:

Undersea Cable Manufacturing Cost: 1992 to 2001
(millions of 1986 dollars)

	Amount
Cable 1:	
1992: Start Manufacturing	$ --
1993: End Manufacturing	62.435
1994: Transport and Laying	—
1995: Start Operations	—
Cable 2:	
1995: Start Manufacturing	—
1996: End Manufacturing	62.435
1997: Transport and Laying	—
1998: Start Operations	—
Cable 3:	
1998: Start Manufacturing	—
1999: End Manufacturing	62.435
2000: Transport and Laying	—
2001: Start Operations	—
Total	**$187.305**
SD	$ 19.854 10.6%

The uncertainty in the estimate for the undersea cable manufacturing costs, as measured in terms of 1 SD, is estimated at 10.6 percent of the total cost. This is based on a SD of 10 percent for each of the components except for the SCOF cable for which 1 SD is estimated at 12 percent; the weighted average for the uncertainty is 10.6 percent, assuming a 100-percent correlation among the component costs (i.e., if the bid on one component is high, then the bid on all components would be high).

Transport and Laying

Cable transport and laying includes transportation to Hawaii, mobilization of resources, loading of the cable onto the cable deploying vessel, laying of the cable, at-sea cable splicing, connection to terminals, embedment of the cable, and testing. Cable laying is assumed to occur under relatively harsh ocean conditions: wind speeds up to 35 knots or more, corresponding surface waves up to 8 feet for at least 30 percent of the time, open-ocean swells up to 4 feet, and surface currents up to 3 knots.

The estimate for cable transport and laying is $41.053 million (based on an estimate of $37.321, plus 10 percent to adjust for a longer time period of cable laying than originally assumed; Hawaiian Dredging and Construction, July 3, 1986). The uncertainty in the cost estimate, as measured in terms of 1 SD, is estimated at 15 percent of the total cost. The cost for a single cable would be one-third the cost of the three cables, or $13.684 million per cable, with 1 year required to transport and lay a cable. The expenditure schedule for the cable transport and laying, which is consistent with the schedule given in Table I-1, is:

Undersea Cable Transport and Laying Cost: 1994 to 2000
(millions of 1986 dollars)

	Amount
1994: Cable 1	$13.684
1995	
1996	
1997: Cable 2	13.684
1998	
1999	
2000: Cable 3	13.684
Total	**$41.053**
SD	$ 6.158
	15%

AC Network Modifications

Connection of the geothermal transmission lines to the AC network on Oahu would require modification of two AC lines, and development of a third. The total distance involved is 13.43 miles: 3.78 miles for Line #1, 4.54 miles for Line #2, and 5.11 miles for Line #3. The estimated cost for this AC network modification is $24.211 million, or an average of $1.803 million per mile (based on a 1983 cost of $22 million; Power Technologies, Inc.). This is a high estimate which exceeds HECO experience for new lines. The proportional costs are $6.815, $8.186, and $9.213 million for Lines #1, #2, and #3, respectively.

Modification of Lines # 1 and #2 is expected to require 4 years for design, engineering, and mobilization, followed by 2 years of construction. For the new Line #3, construction is expected to require 3 years. The schedule for the AC network modifications on Oahu, which is consistent with the schedule given in Table I-1, is:

AC Network Modification Cost: 1989 to 2000
(millions of 1986 dollars)

	Line #1		Line #2		Line #3		Total
	Amount	Percent	Amount	Percent	Amount	Percent	Amount
1989	$ 0.341	5%					$ 0.341
1990	0.341	5					0.341
1991	0.341	5					0.341
1992	0.341	5	$ 0.409	5%			0.750
1993	2.726	40	0.409	5			3.135
1994	2.726	40	0.409	5	$ 0.230	2.5%	3.365
1995			0.409	5	0.230	2.5	0.639
1996			3.274	40	0.230	2.5	3.504
1997			3.274	40	0.230	2.5	3.504
1998					2.764	30	2.764
1999					2.764	30	2.764
2000					2.764	30	2.764
Total	$ 6.815	100%	$ 8.186	100%	$ 9.213	100%	**$24.214**
SD							$ 1.211 5%

The uncertainty in the cost estimate for the AC network modifications as measured in terms of 1 SD, is estimated at 5 percent of the total cost. This is a relatively low amount of uncertainty which reflects the experience HECO has had with installing power lines.

Planning and Engineering Design

Planning would occur for each HVDC valve group and each undersea cable, with planning costs estimated at 1 percent of the costs for the HVDC converter stations, undersea cable manufacturing costs, and undersea cable transport and laying. The expenditure would occur during the first year of construction and installation for a HVDC valve group, and the year preceding transport and laying of an undersea cable.

Engineering costs for the various components required to connect the undersea cable are estimated at 10 percent of the cost of the manufacturing cost of the cable, or $18.73 million. Eighty percent would be expended on the first cable, and 10 percent for each of the following two cables. The expenditures would be made in the same year as the transport and laying of the cable.

The combined schedule of expenditures for planning and engineering design is:

Transmission System Cost for Planning and Engineering Design: 1993 to 2002
(millions of 1986 dollars)

	Planning	Engineering Design	Total
1993	$ 0.980		$ 0.980
1994		$ 14.984	14.984
1995			
1996	0.980		0.980
1997		1.873	1.873
1998			
1999	0.907		0.907
2000		1.873	1.873
2001			
2002	0.146		0.146
Total	$ 3.013	$ 18.730	**$ 21.743**
SD			$ 2.174 10%

Even though the cost for planning and engineering design is derived as a percentage of other costs, the uncertainty in the estimate is regarded as independent of that of other cost estimates. As indicated above, this uncertainty, as measured in terms of 1 SD, is estimated at 10 percent of the total cost.

Total Development Costs

As summarized in Table III-1, the total cost of the transmission system is $413.3 million, measured in constant 1986 dollars. This sum would be expended over a 16-year period beginning in 1988. The PDV of these expenditures, discounted to 1992 at a real discount rate of 3.7 percent, is $346.2 million. The uncertainty in this value, as measured in terms of 1 SD, is 5.24 percent of the PDV. This small amount of uncertainty compared to that of the individual components is a consequence of high and low estimation errors cancelling one another, and is characteristic of summing independent variables (see Technical Foreword).

Also shown in Table III-1 is the capital cost schedule used for calculating depreciation. This schedule allocates the capital costs according when the various components become operational (see Schedule I-1). As noted in the footnote to Table III-1, the sum of the capital costs used for depreciation is lower than the original sum of capital costs because of the values are expressed in constant dollars; when converted to current dollars, the two sums are equal.

OPERATIONS AND MAINTENANCE COSTS

O&M costs for the transmission system are estimated at $1 million per year (from HECO). In addition, $0.26 million is assumed to be set aside for occasional cable repair. This amount, plus accumulated interest at a short-term real interest rate of 1.4 percent (about 6.8-percent nominal interest), is sufficient for a cable repair every 10 years at an estimated cost of $2.8 million. The total O&M and cable repair costs are $1.26 million per year, measured in constant 1986 dollars.

GEOLOGICAL RISKS

The preferred route for the transmission lines would pass relatively close to Hilo, proceed up the Hamakua Coast, and pass to the north of Mauna Kea. This route would be sufficiently far away from Mauna Loa's potential lava flows to reduce nearly to zero the probability of a simultaneous outage of the two lines due to a lava flow.

FINANCING OF THE TRANSMISSION SYSTEM VIA A TRANSMISSION CABLE VENTURE

The approach described below for demonstrating the feasibility of financing the transmission system is one of many possible approaches. It is a reasonable and workable approach, but not necessarily the optimum approach.

Transmission Cable Venture

It is assumed that a private entity, referred to as the Transmission Cable Venture (TCV), would assume responsibility for the construction, financing, and ownership of the transmission system. However, as mentioned in Chapter II, it is assumed that operation and maintenance of the transmission system, and the $1.26 million-per-year cost to perform these functions, would be transferred to HECO. This would allow HECO to have complete control of transmission operations in order to coordinate it with generating operations on Oahu, and to use a portion of their already existing staff and resources for repair and maintenance.

It is further assumed that the TCV is organized so that any tax losses which occur in the early years of transmission system ownership can be passed on to a parent organization or organizations which can take immediate and full advantage of the losses to shelter profits from other activities. One option would be for the TCV to be a subsidiary of a larger organization, such as HECO or its parent, HEI. Possibly more promising would be for the TCV to be a partnership or joint venture involving the geothermal developers; these two options would foster close coordination of geothermal and transmission system development. Under any of the above three options, profits and losses of the TCV would not be taxed until after they were combined with the profits and losses of the parent organization(s).

The projected finances for the TCV are presented in Tables III-2 through III-7, which cover revenues, expenses, debt schedule, taxable and after-tax income, the cash flow for the TCV, and the cash flow to the equity investors.

Financial Objective

The assumed financial objective for the TCV is to provide a **guaranteed after-tax rate of return to equity investors of 14 percent measured in current dollars, or a real return of 8.22 percent** after factoring out the assumed inflation rate of 5.34 percent. For comparison, the return to HECO's equity investors approved by the Public Utilities Commission is 14.75 percent. However, this return is seldom achieved, and was established when interest rates and yields on securities were higher than current rates.

Revenues

Transmission Charge

The principal revenue source for the TCV is assumed to come from a per-kWh transmission charge similar to that of a toll charge for automobiles crossing a toll bridge. The derived transmission charge and revenues generated from such a charge are shown in Table III-2. It is assumed that the charge would be applied to the energy delivered to Oahu net of transmission losses rather than to the slightly larger amount of energy sent from the Big Island. Also, it is assumed that the transmission charge would be level as expressed in current dollars; in terms of constant dollars, the charge would decline over time because of inflation eroding the purchasing power of the dollar. A level charge in terms of current dollars is assumed because it yields a level current-dollar revenue stream once geothermal power is fully developed, and this is desirable because of the certainty provided to lenders that the revenue stream would be sufficient to service a level current-dollar stream of bond payments.

Another assumption is that the transmission charge would be adjusted as necessary in order to meet the financial objective discussed above. For example, if a construction-cost overrun occurs, then it is assumed that the transmission charge would be increased accordingly so that the financial objective is still met.

Transmission Contract

To insure that the required revenue stream does in fact occur, it is assumed that the TCV would have a contract which obligates geothermal operators to pay the transmission charge for the projected amount of energy transmitted regardless of whether or not the energy is produced and transmitted. The only exception would be if the system could not transmit the projected amount. To insure that the geothermal operators have the funds necessary to make the payment to the TCV, it is further assumed that they would have contracts with HECO which would require the purchase of all geothermal-energy made available (see Chapter IV).

Interest Earned

Additional revenues would include interest on funds held in reserve to pay debt service (see Table III-2). The assumed "short-term" interest rate is 6.8 percent on current dollars, or a real interest rate of 1.4 percent after inflation (5.34 percent) is factored out. The amount held in reserve is assumed to be equal to the semi-annual debt-service payment.

Expenses

Projected expenses for TCV are shown in Table III-3. Bond placement costs and interest payments are discussed in the following subsection. Depreciation costs of the capital improvements (Table III-1) are calculated according to a 30-year, straight-line schedule. This provides for level expensing of capital costs when measured in current dollars, but declining expensing when measured in constant dollars. An insignificant error is included in terms of depreciating the cost of purchasing right-of-ways for the overhead HVDC transmission lines.

Operations, which would consist primarily of accounting functions once full operations are achieved, are estimated at $0.3 million per year (1986 dollars). As discussed previously, the estimated $1.26 million per year for the cost of operating and maintaining the transmission system is included in HECO's costs.

Excise tax on TCV revenues is assumed to be charged at the wholesale rate of 0.5 percent. Such a rate would require special State legislation; otherwise the rate would be 4 percent. In addition, property taxes are assumed to be exempted.

Debt Financing

Of the estimated $413.3 million required to construct the transmission system, it is assumed that about 80 percent of the funds would be borrowed, which amounts to $330.6 million in 1986 dollars. The remainder of the funds would come from investment of equity by the owners, and retained earnings.

Special-Purpose Revenue Bonds

It is assumed that the borrowed funds would be raised by selling State of Hawaii special-purpose revenue bonds (SPRB). The advantage of these bonds is that their interest rate is low relative to corporate bonds of comparable risk because the interest paid to buyers of SPRB is tax exempt. SPRB are industrial development bonds (IDB) under the Internal Revenue Code (IRC), Section 103; these bonds can be used to finance the proposed transmission system under IRC §103(b)(4)(E) (Sumida, p. 73). For Hawaii, a limit of $200 million per year on the issuance of IDB would apply.

Under H.R.S. Chapter 39A, Part VI, and subject to an affirmative vote of two-thirds of the members of each House of the State Legislature, the State Department of Budget and Finance (B&F) is authorized to issue SPRB in order to assist a regulated utility to provide electric energy to the general public under the "two county rule," (Sumida, p. 75). However, since the TCV would not be a regulated utility, a special amendment to the H.R.S. Chapter 39A, Part VI would be required to authorize the selling of SPRBs to assist the TCV.

Debt service on the SPRB would be the responsibility of the TCV via payments to B&F. Payments would not be a general obligation of the State, nor would State revenues be pledged as security to guarantee performance.

Cable-Company Financing

In actual practice, it is likely that cable manufacturing, transport, and laying—which represents an estimated 55 percent of the transmission system—would be financed by the cable manufacturing company. Such financing is often provided in order to increase sales, with the interest rate and other terms more favorable than that provided by SPRV.

Schedule of Bond Sales

Bond sales are assumed to occur according to the schedule shown in Table III-4, which is based on 80 percent of the capital cost schedule given in Table III-1. An alternative schedule for the selling of bonds which would be more likely in actual practice, but which differs little in terms of financial implications, would be to have fewer bond sales involving larger amounts, with the proceeds from the bond sales invested in a high-yield account for later withdrawal when needed. Federal law requires that at least 85 percent of the proceeds from any bond sale be expended in 3 years. Furthermore, any profit which occurs because interest earned exceeds interest paid must be turned over to the Federal government. Note, however, that planning costs are regarded as an expense which can be deducted from the profit before it is turned over to the Federal government.

Risks to Bond Holders

In order to sell the SPRB at an attractive interest rate, risk of nonpayment to the buyers of the bonds must be reduced to as low a level as possible. Assumed measures to reduce risks include:

—notice to proceed with manufacturing and construction of the transmission system only after all permits are obtained for both the transmission system and geothermal power, thereby eliminating any risk of subsequent delays due to permit problems;

—a route for the overhead transmission lines which avoids areas of historic lava flows in order to minimize geological risk;

—redundant transmission lines and undersea cables which allow transmission of the geothermal energy at full capacity, even if one of the lines or cables breaks;

—contracts with the geothermal operators which insure projected revenues to the TCV regardless of the amount of geothermal energy actually transmitted so long as the transmission system is capable of handling the projected load, thereby eliminating any market risks;

—surety bonds paid by the geothermal operators to insure that contract obligations would be met regardless of the amount of geothermal power generated and the financial strength of the geothermal operators;

—flexibility to adjust the transmission charge to insure that financial objectives are met, including full and prompt payment of debt service, thereby eliminating any risks because of cost overruns;

—a reserve account sufficient to service scheduled bond payments (assumed to be half the annual debt service because of semi-annual bond payments);

—insurance carried by the TCV to insure debt service payments; and

—additional security for bond payments provided by participation in the TCV of at least one financially substantial organization having a high credit rating.

The effect of these measures is to eliminate nearly all risks to the bond holders.

Interest Rate

A low-risk SPRB having a high credit rating typically commands an interest-rate premium of 0.5 percent over the interest rate for municipal bonds, although the premium can exceed 1.5 percent for a high-risk SPRB. In addition, bond-payment insurance is expected to add an additional 0.25 percent. Assuming the 7.82-percent interest rate for municipal bonds as given in the Technical Foreword, and adding 0.5 percent for the SPRB and 0.25 percent for insurance, the resulting total interest is 8.57 percent. Factoring out the assumed 5.34-percent inflation rate, the real rate is 3.07 percent for the interest and insurance.

Bond Term

The term for each bond issue is assumed to be 27 years; this allows all bonds to be retired by the year 2030.

Bond Placement Costs

A negotiated private placement of the SPRB is assumed because of the reduced documentation requirements and lower underwriting fees compared to those for a public issue. Such underwriting fees, including accounting and attorneys' fees to prepare necessary documents, typically range from 1.8 to 2.6 percent of the bond sale, with 2.2 to 2.3 percent being the most common. The mid-value of 2.25 percent is assumed for this analysis. These costs are assumed to be expensed in proportion to the schedule of bond sales.

Taxable and After-Tax Income

Taxable income, income taxes, and after-tax income are shown in Table III-5. The assumed tax rates are those of a corporation: 34 and 6.05 percent for the Federal and State governments, respectively, with State income taxes being a deductible expense. The income tax would be paid by the owners of the TCV. A negative entry represents a tax savings to the owners.

TCV Cash Flow

The projected cash-flow of the TCV is as shown in Table III-6. Credits to after-tax income include depreciation, bond sales, and equity invested. Depreciation is a credit because it cancels an accounting expenditure which is not an actual cash expenditure. Debits include construction expenditures, bond principal payments, and dividend payments. Dividend payments are derived so as to provide the previously mentioned financial objective.

The resulting addition to (or subtraction from) retained earnings was specified so as to provide a reserve account sufficient to make semi-annual debt-service payments.

Cash Flow to Investors

The after-tax cash flow to the equity investors is shown in Table III-7. This cash flow provides an 8.22-percent real return (14-percent nominal return) to the equity investors—a return which is the target financial objective. Assuming that operations would continue past the year 2030, the actual return would be slightly higher.

IMPLICATIONS TO GEOTHERMAL OPERATORS

From the perspective of the geothermal operators, the effect of the TCV and the above approach for financing the transmission system is that a per-kWh charge for transmitting the geothermal energy is imposed (Table III-2). Furthermore, the geothermal operators would absorb much of the risk associated with the transmission system. For example, if construction costs turn out to be higher (lower) than projected, then the transmission charge would be increased (decreased) accordingly. Also, the geothermal operators would be obligated to pay the transmission charge based on projected energy transmitted—whether or not the energy is actually transmitted—provided that the system is capable of transmitting the energy.

The benefit to the geothermal operators of absorbing much of the risk associated with the transmission system is a lower transmission charge. If the owners of and/or lenders to the TCV were to absorb more risk, then the transmission charge would have to be higher in order to compensate them for their increased risk.

It should be noted, however, that the owners of the TCV could be the geothermal developers.

The PDV of the transmission charges is $490.2 million. The uncertainty in the transmission charge, measured in terms of 1 SD, is the same as that of development cost for the transmission system: 5.24 percent.

TAX REVENUES

In addition to the excise and income tax revenues shown in Tables III-3 and III-5, additional tax revenues would derive from State excise taxes on construction. The PDV of these taxes is $13.8 million (4 percent of $346.2 million).

Table III-1.— **TRANSMISSION SYSTEM, CAPITAL COST SCHEDULE: 1988 TO 2003**
(millions of 1986 dollars)

Year	HVDC Converter Stations	Overhead HVDC Lines	Undersea Cables: Manufacturing	Undersea Cables: Transport and Laying	AC Network Modifications	Planning and Engineering Design	TOTAL
1988	$	$ 0.2	$	$	$		$ 0.2
1989		0.7			0.3		1.0
1990		1.2			0.3		1.6
1991		2.0			0.3		2.4
1992		10.7			0.8		11.5
1993	10.9	10.7	62.4		3.1	1.0	88.2
1994	10.9	10.7		13.7	3.4	15.0	53.7
1995		9.9			0.6		10.6
1996	10.9	9.9	62.4		3.5	1.0	87.8
1997	10.9	9.9		13.7	3.5	1.9	39.9
1998					2.8		2.8
1999	7.3		62.4		2.8	0.9	73.4
2000	7.3			13.7	2.8	1.9	25.6
2001							
2002	7.3					0.1	7.4
2003	7.3						7.3
TOTAL	**$72.9**	**$66.1**	**$187.3**	**$41.1**	**$24.2**	**$21.7**	**$413.3**
PDV	$58.2	$59.0	$156.8	$33.1	$20.2	$18.8	**$346.2**
SD	$ 3.9 6.6%	$ 3.0 5%	$ 16.6 10.6%	$ 5.0 15%	$ 1.0 5%	$ 1.9 10%	$ 18.1 5.2%

Capital Cost Schedule for Depreciation:[1]

1995	$140.1
1998	128.8
2001	93.5
2004	6.4

[1]Derived by (1) converting capital costs from 1986 to current dollars, (2) aging cost components to corresponding dates for start of operations, then (3) converting back to 1986 dollars. Because of the conversion between 1986 and current dollars, the sum of capital costs for depreciation does not equal the original sum of capital costs.

Table III-2.— **TRANSMISSION CABLE VENTURE, REVENUES: 1989 TO 2030**
(1986 dollars)

Year	Transmission Charge: Energy Sold[1] (1,000 MWh)	Transmission Charge: Cents per kWh[2]	Transmission Charge: Total Charge (millions)	Interest Earned[3] (millions)	TOTAL REVENUES (millions)
1989			$	$ 0.001	$ 0.001
1990				0.003	0.003
1991				0.007	0.007
1992				0.012	0.012
1993				0.040	0.040
1994				0.257	0.257
1995	310.3	1.844	5.721	0.377	6.099
1996	675.2	1.750	11.819	0.384	12.204
1997	1,022.0	1.662	16.983	0.583	17.566
1998	1,405.3	1.577	22.168	0.652	22.820
1999	1,770.2	1.498	26.509	0.626	27.136
2000	2,117.0	1.422	30.096	0.777	30.872
2001	2,500.3	1.350	33.742	0.801	34.543
2002	2,865.2	1.281	36.707	0.760	37.467
2003	3,212.0	1.216	39.064	0.740	39.804
2004	3,595.3	1.155	41.509	0.721	42.229
2005	3,960.2	1.096	43.404	0.684	44.088
2006	4,307.0	1.040	44.812	0.649	45.462
2007	4,380	0.988	43.261	0.617	43.878
2008	4,380	0.938	41.068	0.585	41.654
2009	4,380	0.890	38.986	0.556	39.542
2010	4,380	0.845	37.010	0.527	37.538
2015	4,380	0.651	28.533	0.407	28.940
2020	4,380	0.502	21.998	0.304	22.302
2025	4,380	0.387	16.960	0.082	17.041
2030	4,380	0.299	13.075	0.005	13.080
PDV			$490.219	$ 8.898	$499.117
SD			$ 25.694 5.2%		

[1] From Table II-4.

[2] Derived to achieve the financial objective (see text).

[3] Based on a reserve account having sufficient funds to pay one-half of the debt service for the year (Table III-4) after conversion to current dollars, 6.8-percent interest, and conversion of the interest to 1986 constant dollars.

Table III-3.— **TRANSMISSION CABLE VENTURE, EXPENSES: 1988 TO 2030**
(millions of 1986 dollars)

Year	Bond Placement Costs[1]	Bond Interest Payment[2]	Depreciation[3]	Operations	Excise Tax[4]	TOTAL EXPENSES
1988	$0.004	$	$	$ 0.3	$	$ 0.304
1989	0.018	0.015		0.3		0.332
1990	0.028	0.078		0.3		0.406
1991	0.043	0.175		0.3		0.518
1992	0.207	0.319		0.3		0.814
1993	1.588	1.047		0.3		2.935
1994	0.967	6.725		0.3	0.001	7.993
1995	0.190	9.811	4.670	0.3	0.030	15.002
1996	1.580	9.896	4.433	0.3	0.061	16.270
1997	0.718	14.991	4.208	0.3	0.088	20.306
1998	0.050	16.653	8.289	0.3	0.114	25.406
1999	1.321	15.783	7.869	0.3	0.136	25.408
2000	0.461	19.545	7.470	0.3	0.154	27.930
2001		19.953	10.208	0.3	0.173	30.634
2002	0.134	18.649	9.691	0.3	0.187	28.960
2003	0.131	17.885	9.199	0.3	0.199	27.715
2004		17.137	8.946	0.3	0.211	26.594
2005		15.938	8.493	0.3	0.220	24.951
2006		14.789	8.062	0.3	0.227	23.379
2007		13.689	7.654	0.3	0.219	21.862
2008		12.633	7.266	0.3	0.208	20.407
2009		11.620	6.897	0.3	0.198	19.015
2010		10.646	6.548	0.3	0.188	17.682
2015		6.300	5.048	0.3	0.145	11.792
2020		2.651	3.892	0.3	0.112	6.954
2025		0.470	2.020	0.3	0.085	2.875
2030		0.011	0.745	0.3	0.065	1.121
PDV	$6.231	$195.629	$ 106.224	$ 7.411	$2.452	$317.991

[1] 3.25 percent of the bond sales, from Table III-4.

[2] From Table III-4.

[3] Capital expenditures from Table III-1 converted to current dollars, then straight-line depreciation over 30 years, then conversion to constant dollars.

[4] 0.5 percent of revenues, from Table III-2.

Table III-4.— **TRANSMISSION CABLE VENTURE, BOND SCHEDULE: 1988 TO 2030**[1]
(millions of 1986 dollars)

Year	Bond Sale[2]	Debt Service[3] Total Payment	Debt Service[3] Interest	Debt Service[3] Principal	Principal Owed
1988	$ 0.179	$	$	$	$ 0.179
1989	0.796	0.016	0.015	0.002	0.964
1990	1.243	0.088	0.078	0.010	2.149
1991	1.904	0.197	0.175	0.022	3.922
1992	9.191	0.361	0.319	0.042	12.872
1993	70.577	1.182	1.047	0.134	82.662
1994	42.963	7.563	6.725	0.838	120.597
1995	8.442	11.101	9.811	1.289	121.636
1996	70.211	11.308	9.896	1.413	184.268
1997	31.925	17.143	14.991	2.152	204.700
1998	2.211	19.188	16.653	2.534	194.000
1999	58.714	18.417	15.783	2.634	240.246
2000	20.486	22.842	19.545	3.297	245.257
2001		23.554	19.953	3.601	229.223
2002	5.946	22.360	18.649	3.711	219.838
2003	5.830	21.769	17.885	3.884	210.640
2004		21.198	17.137	4.061	195.901
2005		20.123	15.938	4.185	181.785
2006		19.103	14.789	4.314	168.256
2007		18.135	13.689	4.446	155.281
2008		17.215	12.633	4.582	142.827
2009		16.343	11.620	4.723	130.864
2010		15.514	10.646	4.868	119.362
2015		11.961	6.300	5.661	67.848
2020		8.931	2.651	6.280	24.653
2025		2.399	0.470	1.929	3.561
2030		0.138	0.011	0.127	
PDV	$276.938	$261.699	$ 195.629	$66.070	

[1]As given in constant 1986 dollars, this debt schedule does not balance. However, when converted to current dollars based on 5.34-percent inflation, the schedule does balance.

[2]80% of capital costs, from Table III-1.

[3]Based on 27-year bonds at 8.82-percent interest, converted to constant dollars using 5.34-percent inflation.

Table III-5.— **TRANSMISSION CABLE VENTURE, AFTER-TAX INCOME: 1988 TO 2030**
(millions of 1986 dollars)

Year	Revenues[1]	Expenses[2]	Taxable Income	Income Tax[3]	AFTER TAX INCOME
1988	$	$ 0.304	$ -0.304	$-0.116	$ -0.189
1989	0.001	0.332	-0.332	-0.126	-0.206
1990	0.003	0.406	-0.403	-0.153	-0.250
1991	0.007	0.518	-0.511	-0.194	-0.317
1992	0.012	0.826	-0.814	-0.309	-0.504
1993	0.040	2.935	-2.895	-1.100	-1.795
1994	0.257	7.993	-7.736	-2.940	-4.796
1995	6.099	15.002	-8.903	-3.383	-5.520
1996	12.204	16.270	-4.066	-1.545	-2.521
1997	17.566	20.306	-2.740	-1.041	-1.699
1998	22.820	25.406	-2.586	-0.983	-1.603
1999	27.136	25.408	1.727	0.656	1.071
2000	30.872	27.930	2.942	1.118	1.824
2001	34.543	30.634	3.909	1.486	2.424
2002	37.467	28.960	8.507	3.233	5.274
2003	39.804	27.715	12.090	4.594	7.496
2004	42.229	26.594	15.635	5.941	9.694
2005	44.088	24.951	19.137	7.272	11.865
2006	45.462	23.379	22.083	8.392	13.691
2007	43.878	21.862	22.016	8.366	13.650
2008	41.654	20.407	21.247	8.074	13.173
2009	39.542	19.015	20.527	7.800	12.727
2010	37.538	17.682	19.856	7.545	12.311
2015	28.940	11.792	17.148	6.516	10.632
2020	22.302	6.954	15.348	5.832	9.515
2025	17.041	2.875	14.166	5.383	8.783
2030	13.080	1.121	11.959	4.544	7.414
PDV	$499.117	$317.991	$181.126	$68.828	$112.298

[1] From Table III-2.

[2] From Table III-3.

[3] 38% of Taxable Income, based on corporate income tax rates of 34 and 6.05 percent for the Federal and State governments, respectively, and adjusted for the fact that the State income tax is a deductible expense.

Table III-6.— **TRANSMISSION CABLE VENTURE, CASH FLOW: 1988 TO 2030**
(millions of 1986 dollars)

Year	After-Tax Income[1]	Credits		
		Depreciation[2]	Bond Sales[3]	Equity Invested[4]
1988	$ -0.189	$	$ 0.179	$ 0.233
1989	-0.206		0.796	0.415
1990	-0.250		1.243	0.607
1991	-0.317		1.904	0.872
1992	-0.504		9.191	2.931
1993	-1.795		70.577	19.993
1994	-4.796		42.963	19.596
1995	-5.520	4.670	8.442	6.210
1996	-2.521	4.433	70.211	17.438
1997	-1.699	4.208	31.925	10.827
1998	-1.603	8.289	2.211	
1999	1.071	7.869	58.714	8.474
2000	1.824	7.470	20.486	1.804
2001	2.424	10.208		
2002	5.274	9.691	5.946	
2003	7.496	9.199	5.830	
2004	9.694	8.946		
2005	11.865	8.493		
2006	13.691	8.062		
2007	13.650	7.653		
2008	13.173	7.266		
2009	12.727	6.897		
2010	12.311	6.548		
2015	10.632	5.048		
2020	9.515	3.892		
2025	8.783	2.020		
2030	7.415	0.745		
PDV	$112.298	$106.224	$276.938	$77.454

[1]From Table III-5.

[2]From Table III-3.

[3]From Table III-4.

[4]Derived.

Table III-6.— **TRANSMISSION CABLE VENTURE, CASH FLOW: 1988 TO 2030**
(millions of 1986 dollars)
(continued)

	Debits			
Year	Construction Expenditures[5]	Bond Principal Payments[6]	Dividend Payments[7]	Added Retained Earnings[8]
1988	$ 0.224	$	$	$
1989	0.995	0.002		0.008
1990	1.554	0.010		0.036
1991	2.380	0.022		0.057
1992	11.489	0.042		0.087
1993	88.221	0.134		0.419
1994	53.704	0.838		3.221
1995	10.552	1.289		1.961
1996	87.764	1.413		0.385
1997	39.906	2.152		3.204
1998	2.764	2.534	2.142	1.457
1999	73.393	2.634		0.101
2000	25.608	3.297		2.679
2001		3.601	8.096	0.935
2002	7.433	3.711	9.767	
2003	7.287	3.884	11.082	0.271
2004		4.061	14.313	0.266
2005		4.185	16.173	
2006		4.314	17.440	
2007		4.446	16.858	
2008		4.582	15.856	
2009		4.723	14.901	
2010		4.868	13.991	
2015		5.661	10.018	
2020		6.280	7.230	-0.103
2025		1.929	9.231	-0.358
2030		0.127	8.099	-0.067
PDV	$346.173	$ 66.070	$149.591	$11.080

[5]From Table III-1. [6]From Table III-4. [7]Derived.

[8]Deposits and withdrawals into a reserve account so as to provide sufficient funds to pay one-half of the debt service for the year as measured in current dollars, and conversion to constant dollars assuming 5.34-percent inflation.

Table III-7.— **TRANSMISSION CABLE VENTURE, CASH FLOW TO INVESTORS: 1998 TO 2030**
(millions of 1986 dollars)

Year	Equity Invested[1]	Dividend Payments[2]	NET CASH FLOW
1988	$ -0.233	$	$ -0.233
1989	-0.415		-0.415
1990	-0.607		-0.607
1991	-0.872		-0.872
1992	-2.931		-2.931
1993	-19.933		-19.933
1994	-19.596		-19.596
1995	-6.210		-6.210
1996	-17.438		-17.438
1997	-10.827		-10.827
1998		2.142	2.142
1999	-8.474		-8.474
2000	-1.804		-1.804
2001		8.096	8.096
2002		9.767	9.767
2003		11.082	11.082
2004		14.313	14.313
2005		16.173	16.173
2006		17.440	17.440
2007		16.858	16.858
2008		15.856	15.856
2009		14.901	14.901
2010		13.991	13.991
2015		10.018	10.018
2020		7.230	7.230
2025		9.231	9.231
2030		8.099	8.099
PDV	$-77.454	$149.591	$ 72.137
Rate of Return:			
Real			8.22%
Nominal[2]			14.00%

[1]From Table III-6.

[2]Based on 5.34-percent inflation.

CHAPTER IV

GEOTHERMAL POWER GENERATION

This chapter addresses the economics of generating geothermal power. Topics covered include geothermal development and O&M costs, geological risks, financing of geothermal development and operations, profitability to geothermal investors, sensitivity in the results to selected changes in assumptions, economic risks, and impacts on tax revenues.

GEOTHERMAL COSTS

The generation of geothermal energy on the Big Island would involve a number of interconnected components, including: a great many deep wells, with the successful wells tapping into underground steam resources to bring the steam to the surface; a network of surface pipes to deliver the steam to one of a number of power plants; power plants which include standard steam-driven turbine generators, steam condensers, pollution-control devices; surface piping to deliver water condensed from the steam to injection wells; injection wells to dispose of this water; and overhead AC power lines to deliver the generated electric energy to a nearby AC-to-DC converter station. Delivered capacity is assumed to be 500 MW based upon 20 25-MW power plants. In order to account for line losses and maintenance downtime, generating capacity would be about 27.5 MW. The cost estimates were compiled by HECO engineers based on an analysis of proposed geothermal development on the Big Island, and existing and proposed geothermal development on the mainland and elsewhere; these cost estimates were then reviewed by the developers who are proposing geothermal projects on the Big Island.

Development Costs

This section includes estimates of development costs for each of the geothermal components, and the expenditure pattern required to complete the various components according to the schedule shown in Table I-1.

Wells

For each 25-MW power plant, it is assumed that a sufficient number of successful production wells would be developed to provide a reserve of at least 20 percent (i.e., 30 MW of well capacity) in the event that one of the wells should cease producing. This requires eight successful production wells for each power plant, assuming about 4 MW of power per well (30 MW/4 MW per well = 7.5 wells, rounded up to 8 wells). In addition, it is assumed that three injection wells would be required for each power plant. In order to provide these 11 usable wells, it is further assumed that an average of two unusable wells would be drilled—wells which must be abandoned because they are unusable for production or disposal of the condensed steam. The total cost for these wells, assuming $2.5 million for each production well and $2 million for each injection and unusable wells, is $30 million for each 25-MW power plant:

Well Cost per Power Plant
(costs in millions of 1986 dollars)

Well Type	Number	Per-Unit Cost	Cost
Production	8	$2.5	$ 20
Injection	3	2	6
Unusable	2	2	4
Total	13		**$ 30**

A low estimate for the cost of wells would be six 5-MW production wells at a cost of $2 million each, three injection wells at $1.5 million each, and one unusable well at $1.5 million, for a total cost of $18 million per power plant. The high estimate would be ten 3-MW production wells at a cost of $3 million each, three injection wells at $2.5 million each, and three unusable wells at $2.5 million each, for a total cost of $45 million per power plant. This cost range indicates uncertainty of nearly 45 percent of the expected cost as measured in terms of 2 SD, or 22.5 percent as measured in terms of 1 SD.

The total cost for the wells for 20 25-MW power plants is about $600 million ($30 million per well group x 20 power plants), with the uncertainty in this estimate being 22.5 percent as measured in terms of 1 SD.

For income-tax purposes, an option exists to expense 70 percent of the expenditures on well development in the year funds are expended, rather than to depreciate the costs over the useful life of a project as is normally the case for development costs. For this report, the first option was chosen.

Steam-Gathering System

In 1983, the piping and installation of the steam-gathering system was estimated to be about $3.223 million for a 12.5-MW power plant (Power Technology, Inc.). The 1983 cost was escalated by 10.05 percent for inflation to 1986 (see Technical Foreword, Table TF-1). Furthermore, the cost was scaled up by another 51.6 percent because the plant size is assumed to be double that assumed in 1983—25 MW versus 12.5 MW (see Technical Foreword for the scale-up factor). In terms of 1986 dollars, the estimated cost for the steam gathering system is $5.377 million. The total cost for all 20 power plants is $107.5 million, with the uncertainty being 5 percent as measured in terms of 1 SD.

Power Plants

The cost of a 12.5-MW power plant was estimated to be $16.623 to $24.935 million in 1983, with an average cost of $20.779 million (Power Technology, Inc.). This translates into a cost of $34.667 million for a 25-MW power plant in terms of 1986 dollars, with an uncertainty of 10 percent measured in terms of 1 SD.

The 20 power plants are assumed to be grouped into five sets of four plants, with each group sharing certain facilities and equipment. Because of this sharing, the second and fourth plants of each group are assumed to cost 70 percent of the cost of the first plant ($24.267 million), and the third plant 80 percent of the cost of the first plant ($27.734 million). Therefore, the average plant cost is $27.734 million. The total cost for all 20 plants is $554.7 million, with the uncertainty being 10 percent as measured in terms of 1 SD.

Rather than 20 25-MW power plants, current planning is for 10 50-MW power plants. The use of larger plants would reduce the total cost for the power plants below that assumed in this report.

Total Development Costs

For the complete 500-MW geothermal power-generating system—including the well fields, steam gathering system, and power plants—the estimated development costs are $1,262.2 million in 1986 dollars. The uncertainty in this estimate is 11.8 percent measured in terms of 1 SD.

Of the $1,262.2 million development costs, $420 million would be for well development costs which would be expensed in the year funds are expended, while the remaining $854.2 million are capital costs subject to depreciation.

Expenditure Schedule

The construction period for each power plant and related components is estimated to be 3 years, with 10 months for developing the wells, 10 months for the steam-gathering system, and 36 months for the power plant itself. Construction expenditures for the wells and power plant would begin in the first month of the 3-year period, while expenditures for the steam-gathering system would begin in the twenty-first month.

The resulting schedule of construction expenditures is shown in Table IV-1, along with the resulting increase in the property tax base. The division of the development costs between expensed and capital costs for depreciation is shown in Table IV-2.

Replacement Wells

It is expected that many production wells would have to be replaced over time because of a loss of steam pressure. The useful life of a well is expected to be random, with many of the early wells having a relatively short life. However, during the first 5 years of operation, replacement wells are not anticipated because of the reserve capacity that would be available. But starting in the year 2000, it is anticipated that approximately six replacement wells would be required annually—a rate which amounts to approximately 5 percent of the capacity replaced annually (6 wells x 4 MW/well = 24 MW/500 MW = 4.8 percent). This translates into an annual cost of $15 million, based on $2.5 million per well. The uncertainty in this estimate corresponds to that for the initial well development—22.5 percent as measured in terms of 1 SD. The schedule of replacement-well expenditures is shown in Table IV-3.

Operations and Maintenance Costs

Well Field

As indicated above, each power plant is expected to have eight producing wells and three injection wells, for a total of eleven usable wells per plant. For 20 power plants, there would be 240 usable wells. At an estimated cost of $58,000 per well, the total annual O&M cost at full development would be $12.76 million. The uncertainty in this estimate is 10 percent, measured in terms of 1 SD. Table IV-3 gives the scheduled increase in well-field O&M cost consistent with that of Table I-1.

Power Plants

At full development, operation of the geothermal power plants is expected to require 65 employees at a labor cost of $3.258 million:

Power Plant Labor Costs
(cost in 1986 dollars)

Position	Employees (by Power-Plant Group) 1	2	3	4	5	Total	Salary	Total Salary Payments (1,000)
Supervisor	1					1	$66,500	$ 66.5
Engineers		1		1		2	57,400	114.8
Operators	10	10	10	10	10	50	52,800	2,640.0
Electricians	1	1	1	1	1	5	40,100	200.5
Instrument Technician	1	1	1	1	1	5	40,100	200.5
Secretary	1		1			2	17,900	35.8
Total	14	13	13	13	12	65		**$3,258.1**

For each power plant, annual non-labor O&M costs would include $209,000 for chemicals, $44,000 for waste disposal, and $952,000 for maintenance, for a total cost of $1.205 million per year in non-labor O&M costs. At full development of 20 power plants, non-labor O&M costs would total $24.1 million per year. With the addition of labor costs, the total O&M cost amounts to $27.358 million per year at full development. The uncertainty in this estimate is 5 percent, measured in terms of 1 SD. The scheduled increase in power-plant O&M costs, which is consistent with that of Table I-1, is shown in Table IV-3.

Summary of Geothermal Costs

For the financial analysis, the relevant schedules of geothermal costs are the Total Capital Cost and Total O&M Costs shown in Tables IV-2 and IV-3, respectively. For tax purposes, Total O&M Costs includes expensed well development and replacement costs.

GEOLOGICAL RISKS

Geothermal operators would be exposed to significant geological risks inasmuch as the power plants would be built in an active volcanic rift zone. The risks include a partial or complete interruption in energy production and/or transmission, a reduction or complete loss in revenues, and loss of valuable improvements.

The geothermal plants would be located within and along the northern boundary of the Kilauea Volcano East Rift Zone—an area which falls within three hazard zones for lava flows (Mullineaux):

—Zone 1 includes the Kilauea East Rift Zone. About 25 percent of Zone 1 has been covered by lava during historic time.

—Zone 2 includes the area to the north of the Rift Zone and to the east of Pahoa. About 15 percent of this area has been covered by lava during historic time.

—Zone 3 includes the area to the north of the East Rift Zone and to the west of Pahoa. Less that 5 percent of this area has been covered by lava during historic time.

Risks of a catastrophic loss resulting from a lava flow would be minimized by placing as many facilities as possible in Zone 3 where the risks are lowest, by placing as many facilities as possible on high ground which is less subject to being covered by lava, by building protective berms sufficient to withstand minor flows, and by using non-flammable construction materials.

Based on historic volcanic activity in the East Rift Zone and proposed locations of geothermal plants, it is estimated that 15 percent of the area planned for geothermal operations would be covered by lava over a 200-year period. This translates into a 0.08 percent probability that any given area would be covered by lava in a given year, or about a 2.4 percent probability in the 30-year life of each power plant. In order to reduce the risk of a catastrophic loss of a single large power plant, a large number of small power plants are to be built. Paradoxically, this increases the risk of losing a power plant; to understand this, assume that the area were completely blanketed with power plants, then the loss of power plants would be a near certainty, although only 2.4 percent of the plants would be expected to be lost. With the assumed 20 power plants, the probability of losing one or more power plants in a given year would be about 1.6 percent; over a 30-year period, the probability would be nearly 40 percent. However, the probability of losing two or more power plants falls to 8.3 percent; losing three or more plants has a probability of 1.2 percent, and four or more has a probability of only 0.1 percent.

If a power plant is in fact covered by lava, it is assumed that rebuilding would occur immediately, financed by insurance (or possibly by retained earnings). During the 3-year reconstruction period, the energy sales from the power plant would not be lost, however. This is because output of the remaining plants would be increased to compensate for that of the lost plant. Replacement of a lost power plant (including wells and the steam-gathering system) would be about \$70.044 million; this cost would be spread out over the 3-year reconstruction period. The long-term annual average for plant-replacement cost would be only \$1.1 million, with an uncertainty of \$1.6 million, measured in terms of 1 SD. O&M and certain other expenses would be decreased whenever a power plant is lost to a lava flow. However, this cost savings is ignored in the analysis.

Additional geological risks would include earthquakes, ground fractures, and ground subsidence. It is assumed that these risks would be managed successfully by placement of facilities in low-risk areas, stringent design standards which require the facilities to withstand geological incidents, and quick repair of any failures.

FINANCING OF GEOTHERMAL DEVELOPMENT VIA A GEOTHERMAL VENTURE

Geothermal Venture

It is expected that geothermal power would be developed and operated by a number of private entities. For the sake of analysis, however, these private entities are grouped together and analyzed as a single entity, referred to as the Geothermal Venture (GV). Furthermore, it is assumed that the GV is organized so that any tax losses which occur during the development phase can be passed on to a parent organization or organizations which can take immediate and full advantage of the losses to shelter profits from other activities. The GV may be a subsidiary of a larger organization, or a partnership or joint venture involving other organizations. Under any of these options, profits and losses of the GV would not be taxed until after they are combined with the profits and losses of the parent organization(s).

The projected finances for the GV are presented in Tables IV-4 through IV-10, which cover revenues, expenses, construction loan schedule, bond schedule, taxable and after-tax income, the cash flow for the GV, and the cash flow to the equity investors.

Revenues

Revenues to geothermal operators are shown in Table IV-4, and would equal HECO's payments for geothermal energy (Table II-4), minus the transmission charge (Table III-2). Revenues per kWh of delivered energy are also shown in Table IV-4.

Additional revenues would include interest on funds held in reserve to pay debt service (see Table IV-7). The assumed "short-term" interest rate is 6.8 percent on current dollars, or a real interest rate of 1.4 percent after inflation of 5.34 percent is factored out. The amount held in reserve is assumed to be equal to the semi-annual debt-service payment. Earned interest, and the resulting total revenues are shown in the second page of Table IV-4.

The PDV of the stream of total revenues is $2,970.7 million, and the uncertainty is 32.9 percent as measured in terms of 1 SD.

Expenses

Projected expenses for the GV are shown in Table IV-5. Management costs are estimated at $1 million per year, which would be sufficient for an office of about 10 people having an average salary of $50,000, and an overhead rate of 100 percent. O&M costs are from Table IV-3. Surety bond payments to guarantee transmission-charge payments (see p. III-14) are assumed to be 0.25 percent of the transmission charges.

Royalties to the land owners are assumed to be 6 percent of the revenues allocated to the steam resource, which is estimated to be one-half of the net revenues (Table IV-4). Royalties to the State are estimated at 10 percent of the revenues allocated to the steam resource. Although not included in the analysis, the State allows an 8-year exemption in its royalties in order to encourage geothermal development.

Construction-loan and bond interest payments, and bond-placement costs are taken from Tables IV-5 and IV-6. Terms for the construction loan and bonds are discussed in the following subsection.

Depreciation costs of the capital improvements (Table IV-2) are calculated according to a 20-year, 150-percent declining balance schedule. The depletion allowance is 15 percent of the revenues allocated to the steam resource, net of royalties.

Property insurance is calculated at the rate of 0.3 percent of the development costs, with no adjustment for depreciation. This substitutes for the replacement cost of $1.1 million per year as the adjustment for geological risks as discussed in the previous section. This shifts the risk of replacing lost improvements to insurance companies.

Property taxes are assumed to be assessed at 1 percent of the Property Tax Base (Table IV-1), with no adjustment for depreciation. The tax liability for each plant would begin with its completion according to the schedule in Table I-1. State excise taxes are charged at the wholesale rate of 0.5 percent of revenues.

Although royalties and taxes are expenses to the geothermal operators, it should be noted that these items are benefits to landowners, the County, the State, and the Federal government.

Debt Financing

Of the estimated $1,262.2 million required to drill geothermal wells, install a steam gathering system, and construct power plants, it is assumed that about 80 percent of the funds would be borrowed, which amounts to $1,009.8 million in 1986 dollars. The remaining $252.4 million would come from the investment of equity by the owners, and retained earnings.

Construction Loan

During the 3-year construction period for each power plant and associated improvements, the initial debt financing is assumed to be an interest-only construction loan at 12-percent interest, which corresponds to a real interest rate of 6.3 percent. The construction-loan debt schedule is shown in Table IV-6.

Corporate Bonds

Immediately following the completion of construction of each power plant, it is assumed that the construction loan for that plant would be replaced by funds borrowed by selling 24-year corporate bonds (see Table IV-7 for the debt schedule). In order to sell the bonds at an attractive interest rate, risk of nonpayment to the buyers of the bonds must be reduced to as low a level as possible. Assumed measures to reduce risks include:

—notice to proceed with geothermal development only after all permits are obtained for both the transmission system and geothermal power, thereby eliminating any risk of subsequent delays due to permit problems;

—a contract with HECO which requires them to buy all delivered geothermal energy;

—redundant overland lines and undersea cables which allow transmission of the geothermal energy at full capacity, even if one of the lines or cables breaks;

—a reserve account sufficient to service scheduled bond payments (assumed to be half the annual debt service because of semi-annual bond payments);

—insurance carried by the GV to insure debt service payments; and

—additional security for bond payments provided by participation in the GV of at least one financially substantial organization having a high credit rating.

The effect of these measures is to eliminate nearly all risks to the bond holders. The corresponding bond rating would be Aaa, which would carry a nominal interest rate of about 9.25 percent (see Technical Foreword). Adding 0.25 percent for insurance would increase the interest rate to 9.5 percent; this corresponds to a real interest rate of 3.95 percent after factoring out the assumed inflation rate of 5.34 percent. Bond placement costs are assumed to be 1 percent of the amount borrowed.

Taxable and After-Tax Income

Taxable income, income taxes, and after-tax income are shown in Table III-8. The assumed income-tax rates are those of a corporation: 34 and 6.05 percent for the Federal and State governments, respectively. Because the State income taxes are a deductible expense, the net State and Federal income-tax rate is 38 percent. The income tax would be paid by the owners of the GV. A negative entry represents a tax savings to the owners.

Offsetting the Federal income tax would be a geothermal-energy tax credit of 10 percent of the development costs. However, because this credit is schedule to expire at the end of 1988 and renewal is uncertain, this credit is ignored in the analysis. If the tax credit were included, this would enhance greatly the profitability of geothermal power.

GV Cash Flow

The projected cash-flow of the GV is as shown in Table III-9. Credits to the after-tax income include depreciation, depletion, construction loans, and equity invested. Depreciation and depletion are credits because they cancel accounting expenditures which are not actual cash expenditures. Debits include nonexpensed capital costs, bond principal payments, and dividend payments.

The resulting addition to (or subtraction from) retained earnings was specified so as to provide a reserve account sufficient to pay semi-annual debt-service payments.

Cash Flow and Profitability to Investors

The after-tax cash flow to the equity investors is shown in Table IV-10. The PDV of this cash flow is $550.7 million. Assuming that operations would continue past the year 2030, the actual PDV would be higher.

Profit Sensitivity to Selected Changes and Break-Even Values

The rate-of-return of the cash flow shown in Table IV-8 is 17.5 percent as measured in terms of constant dollars, or 23.8 percent as measured in terms of inflating dollars (1.175 x 1.0534 = 1.238, or 23.8 percent). The discount rate for evaluating the PDV would have to increase to this level in order to drive the PDV to zero.

The PDV of the cash flow to the geothermal equity investors can be simplified to the following formula:

P = 0.59124 x R - $1,481.621 million,

where,

P = the PDV of the cash flow to geothermal equity investors, and

R = the PDV of the HECO payments,

= $3,437.365 million, or

= $3,254.919 million for avoided fuel + $38.287 for avoided O&M + $144.159 for avoided capital costs.

From Chapter II:

—a $1 increase in fuel prices (LSFO equivalent) would increase R by $93.14 million,

—a $1 increase in crude-oil prices would increase R by $107.1 million, and

—a 1 cent increase in the kWh payment by HECO would increase R by $583.8 million.

From this information, the following can be derived:

—a $1 increase in fuel prices (LSFO equivalent) would increase P by $55.1 million,

—a $1 increase in crude-oil prices would increase P by $63.3 million, and

—a 1 cent increase in the kWh payment by HECO would increase P by $345.2 million.

It can also be shown that a $1 million cost overrun in the transmission system would decrease P by $0.7012 million.

The break-even prices or changes which would drive P to zero are: a HECO payment of 4.292 cents per kWh, an LSFO equivalent price of $24.95 per barrel (which corresponds to a crude-oil price of $21.69 per barrel), or an increase in all capital and O&M cost by 37 percent. With these prices or changes, the return to geothermal equity investors would be the same as investing funds into corporate Aaa bonds.

Economic Risks to Investors

As indicated in Table IV-10, the uncertainty in the PDV of the cash flow to geothermal equity investors is estimated to be a SD of $607.2 million, or 110.3 percent of the PDV. This indicates that the expected value for the PDV is only 0.91 SD from zero ($550.7 million/$607.2 million). Based on normal probability tables, and ingoring that much of the uncertainty will be resolved by the passage of time (see below), then this information indicates an 18.2-percent probability (about two chances in eleven) that investing in geothermal development would be unprofitable (more precisely, that the investment would be inferior to that of buying corporate Aaa bonds). However, the major souces of uncertainty and risk will be greatly reduced before committing to any major irreversible investments.

The uncertainty in the PDV of the cash flow to geothermal investors, which presumes that development will not occur until all permits are obtained for full development of geothermal power and the transmission system, can be factored into the following independent components:

PDV of the Cash Flow to Geothermal Investors: Components of Uncertainty

	Standard Deviation (millions)	Percentage Distribution
Avoided HECO Costs:		
Fuel Prices	$577.332	90.4%
O&M and Capital	15.529	0.1
Cable Costs	15.152	0.1
Geothermal Costs:		
Well Drilling	183.232	9.1
Steam System and Power Plants	32.350	0.3
O&M	16.557	--
Other	1.269	--
TOTAL	$607.190[1]	100.0%[2]

[1]Square root of the sum of squares (see Technical Forward).
[2]Based on the distribution of the square of standard deviations.

As indicated, the dominate source of uncertainty is the outlook for fuel prices, followed by well drilling costs. The uncertainty regarding fuel costs, as well as avoided O&M and capital costs, will be resolved by the passage of time, and is likely to be eliminated by negotiated agreement before any commitment is made to geothermal development. If energy experts are correct, then oil supplies will become increasingly tight by the early 1990s, with a corresponding dramatic increase in oil prices. Also, the uncertainty regarding well drilling costs would be reduced by exploratory drilling before developers commit to full development.

Assuming the passage of time and negotiations with HECO eliminate the uncertainty over avoided HECO costs, and that exploratory drilling reduces the uncertainty of well development cost to a SD of 10 percent, then the remaining uncertainty in the PDV of the cash flow to geothermal investors would fall to about $90.5 million. With this level of uncertainty, and assuming cost estimates are found to be relatively accurate, then the probability that investing in geothermal development would be unprofitable (i.e., that the investment would be inferior to that of buying corporate Aaa bonds) would be negligible: about 1 chance out of 1.7 billion (based on normal probability tables for the expected value 6.1 SDs from zero; 6.1 = $550.7 million/ $90.5 million).

In order to have a probability of 99.9 percent that the geothermal would be profitable under the above assumptions, the PDV would have to be about 3 SDs from zero, or about $271.5 million (3 x $90.5 million). Based on the previously given formulas (see above for P and R), the price requirements would be 5.08 cents per kWh, or an LSFO price equivalent of $29.87 per barrel, which corresponds to a crude-oil price of $25.98 per barrel.

TAX REVENUES

In addition to the excise, property, and income tax revenues shown in Tables IV-5 and IV-8, the PDV of additional State excise taxes would include $38.7 million from development (4% of $966.9 million), $8.6 million from well replacement (4% of $216.1 million), $7.8 million from wellfield O&M (4% of $193.9 million), and $12.9 million from plant O&M (4% of $323.4 million, which is the non-labor portion of plant O&M).

Table IV-1.— **GEOTHERMAL POWER GENERATION, DEVELOPMENT COSTS AND PROPERTY TAX BASE: 1992 TO 2007**
(millions of 1986 dollars)

Year	Wells	Steam Gathering System	Power Plants	TOTAL DEVELOPMENT COSTS	Property Tax Base[1]
1992	$ 36.6	$	$ 2.278	$ 38.878	$
1993	55.8	0.968	7.218	63.986	
1994	51.6	9.786	43.365	104.751	
1995	42.6	8.334	44.155	95.089	89.229
1996	55.8	8.765	49.511	114.076	95.630
1997	51.6	9.786	43.164	104.550	95.614
1998	42.6	8.334	45.213	96.147	102.288
1999	55.8	8.765	49.591	114.156	97.362
2000	51.6	9.786	42.831	104.217	95.904
2001	42.6	8.334	49.563	100.497	100.844
2002	55.8	8.765	45.303	109.868	101.407
2003	51.6	9.786	44.391	105.777	92.148
2004	6.0	8.334	45.050	59.384	102.866
2005		7.797	38.186	45.983	99.674
2006			4.853	4.853	90.704
2007					18.548
Total	$600	$107.540	$554.672	$1,262.212	$1,182.217
PDV	$474.431	$ 80.020	$412.416	$ 966.867	
SD	$106.747	$ 4.001	$ 41.242	$ 114.507	
	22.5%	5%	10%	11.8%	11.2%

[1] Excludes $80 million for unusable wells, with the component costs for each power plant aged until the plant becomes operational.

Table IV-2.— **GEOTHERMAL POWER GENERATION, DEVELOPMENT EXPENDITURE SCHEDULES: 1992 TO 2007**
(millions of 1986 dollars)

Year	Expensed Well Costs[1]	Capital Costs[2] Actual	Capital Costs[2] For Depreciation
1992	$ 25.62	$ 13.258	$
1993	39.06	24.926	
1994	36.12	68.631	
1995	29.82	65.269	44.442
1996	39.06	75.016	35.992
1997	36.12	68.430	73.772
1998	29.82	66.327	79.412
1999	39.06	75.096	38.534
2000	36.12	68.097	79.028
2001	29.82	70.677	74.481
2002	39.06	70.808	35.980
2003	36.12	69.657	78.749
2004	4.20	55.184	74.390
2005		45.983	43.643
2006		4.853	73.866
2007			35.244
Total	$420.00	$842.212	$767.533
PDV	$332.102	$634.765	$537.154
SD	$ 74.723	$ 52.368	
	22.5%	8.25%	8.25%

[1] 70% of the well costs from Table IV-1 are expensed in the year spent.

[2] Remainder of Development Costs from Table IV-1 after subtracting expensed well costs.

Table IV-3.— **GEOTHERMAL POWER GENERATION, O&M COSTS: 1992 TO 2030**
(millions of 1986 dollars)

Year	Well Development[1]	Replacement Wells	Wellfield O&M	Power Plant O&M	TOTAL
1992	$ 25.62	$	$ 0.425	$	$ 26.045
1993	39.06		1.382		40.442
1994	36.12		2.446		38.566
1995	29.82		3.509	2.400	35.729
1996	39.06		4.572	4.409	48.041
1997	36.12		5.636	6.760	48.516
1998	29.82		6.699	9.091	45.610
1999	39.06		7.762	11.256	73.078
2000	36.12	15	8.826	13.633	73.579
2001	29.82	15	9.889	15.741	70.450
2002	39.06	15	10.952	18.305	83.317
2003	36.12	15	12.016	20.323	83.459
2004	4.20	15	12.654	22.686	54.540
2005		15	12.760	25.048	52.808
2006		15	12.760	26.957	54.717
2007		15	12.760	27.358	55.118
.		.	.	.	
.		.	.	.	
.		.	.	.	
2030		15	12.760	27.358	55.118
PDV	$332.102	$216.076	$193.941	$367.161	$1,109.280
SD	$ 74.723[2]	$ 48.617[2]	$ 19.394	$ 18.358	$ 126.198
	22.5%	22.5%	10%	5%	11.4%

[1]From Table IV-2.

[2]Well development and well replacement costs are not independent.

Table IV-4.— **GEOTHERMAL VENTURE, REVENUES: 1995 TO 2030**
(1986 dollars)

Year	Energy Sold[1] (1,000 kWh)	HECO Payments[2] (millions)	Cable Transmission Charge[3] (millions)	Net Revenues[4] (millions)	Cents per kWh
1995	310.279	$ 17.475	$ 5.721	$ 11.753	3.788
1996	675.221	40.499	11.819	28.680	4.247
1997	1,022.029	63.438	16.983	46.455	4.545
1998	1,405.279	89.266	22.168	67.098	4.775
1999	1,770.221	113.821	26.509	87.312	4.932
2000	2,117.029	134.860	30.096	104.765	4.949
2001	2,500.279	157.852	33.742	124.110	4.964
2002	2,865.221	181.338	36.707	144.631	5.048
2003	3,212.029	201.368	39.064	162.304	5.053
2004	3,595.279	223.325	41.509	181.816	5.057
2005	3,960.221	243.832	43.404	200.428	5.061
2006	4,307.029	262.935	44.812	218.122	5.064
2007	4,380	265.341	43.261	222.079	5.070
2008	4,380	264.213	41.068	223.145	5.095
2009	4,380	262.269	38.986	223.287	5.098
2010	4,380	260.356	37.010	223.346	5.099
2015	4,380	251.202	28.533	222.669	5.089
2020	4,380	242.615	21.998	220.617	5.037
2025	4,380	241.133	16.960	224.174	5.118
2030	4,380	239.991	13.075	226.916	5.181
PDV		$3,437.365	$490.219	$2,947.146	
SD		$ 976.918 28.4%	$ 25.694 5.2%	$ 977.256 33.2%	

[1] From Table II-2.

[2] From Table II-4.

[3] From Table III-2.

[4] HECO payments minus cable transmission charge.

Table IV-4.— **GEOTHERMAL VENTURE, REVENUES: 1995 TO 2030**
(continued)
(millions of 1986 dollars)

Year	Net Revenues	Earned Interest[5]	TOTAL REVENUES
1995	$ 11.753	$ 0.184	$ 11.938
1996	28.680	0.328	29.008
1997	46.455	0.624	47.079
1998	67.098	0.926	68.023
1999	87.312	1.041	88.353
2000	104.765	1.320	106.085
2001	124.110	1.568	125.678
2002	144.631	1.642	146.273
2003	162.304	1.889	164.193
2004	181.816	2.108	183.925
2005	200.428	2.183	202.611
2006	218.122	2.385	220.507
2007	222.079	2.414	224.493
2008	223.145	2.291	225.437
2009	223.283	2.175	225.458
2010	223.346	2.065	225.411
2015	222.669	1.592	224.261
2020	220.617	1.133	221.750
2025	224.174	0.496	224.670
2030	226.916	0.045	226.961
PDV	$2,947.142	$23.552	$2,970.698
SD	$ 977.256 33.2%	$ 2.789 11.8%	$ 977.260 32.9%

[5] Based on a reserve account having sufficient funds to pay one-half of the debt service for the year (Table IV-7) after conversion to current dollars, 6.8 percent interest, and conversion of the interest to 1986 constant dollars.

Table IV-5.— **GEOTHERMAL VENTURE, EXPENSES: 1992 TO 2030**
(millions of 1986 dollars)

Year	Management Expenses[1]	O&M[2]	Surety Bond Payment[3]	Royalties[4]	Bond Placement Costs[5]	Interest Payments[6]
1992	$ 1	$ 26.045	$	$	$	$
1993	1	40.442				3.543
1994	1	38.566			0.533	9.195
1995	1	35.729	0.014	0.940	0.443	17.010
1996	1	48.041	0.030	2.294	0.903	23.706
1997	1	48.516	0.042	3.716	0.964	30.653
1998	1	45.610	0.055	5.368	0.470	36.139
1999	1	73.078	0.066	6.985	0.959	41.644
2000	1	73.579	0.075	8.381	0.912	47.290
2001	1	70.450	0.084	9.929	0.443	51.742
2002	1	83.317	0.092	11.570	0.956	56.627
2003	1	83.459	0.098	12.984	0.911	60.832
2004	1	54.540	0.104	14.545	0.524	64.433
2005	1	52.808	0.109	16.034	0.904	64.415
2006	1	54.717	0.112	17.450	0.434	62.183
2007	1	55.118	0.108	17.766		57.300
2008	1	55.118	0.103	17.852		53.160
2009	1	55.118	0.097	17.862		49.182
2010	1	55.118	0.093	17.868		45.354
2015	1	55.118	0.071	17.814		28.157
2020	1	55.118	0.055	17.649		13.585
2025	1	55.118	0.042	17.934		3.920
2030	1	55.118	0.033	18.153		0.116
PDV	$20.474	$1,109.280	$1.226	$235.771	$ 6.788	$629.763
SD	$ 2.047 10%	$ 126.198 11.4%	$0.064 5.2%	$ 78.180 33.2%	$ 0.804 11.8%	$ 74.583 11.8%

[1] See text.

[2] From Table IV-3.

[3] 0.25 percent of the Cable Transmission Charge, Table IV-4.

[4] Royalties of 6% and 10% of one-half of net revenues for land owners and the State, respectively.

[5] 1 percent of the Bond Sales, from Table III-7.

[6] From Tables IV-6 and IV-7.

Table IV-5.— **GEOTHERMAL VENTURE, EXPENSES: 1992 TO 2030**
(continued)

Year	Depreciation[7]	Depletion[8]	Property Insurance[9]	Property Tax[10]	Excise Tax[11]	TOTAL
1992	$	$	$ 0.117	$	$	$ 27.162
1993			0.309			45.294
1994			0.623			49.916
1995	3.333	0.740	0.908	0.892	0.059	61.069
1996	5.626	1.807	1.250	1.849	0.143	86.650
1997	10.473	2.927	1.564	2.805	0.232	102.893
1998	15.153	4.227	1.852	3.828	0.335	114.038
1999	16.196	5.501	2.195	4.801	0.437	152.861
2000	20.149	6.600	2.508	5.760	0.524	166.778
2001	23.279	7.819	2.809	6.769	0.621	174.944
2002	23.140	9.112	3.139	7.783	0.723	197.459
2003	26.226	10.225	3.456	8.704	0.812	208.706
2004	28.608	11.454	3.634	9.733	0.909	189.484
2005	28.394	12.627	3.772	10.730	1.002	191.795
2006	30.473	13.742	3.787	11.637	1.091	196.625
2007	29.402	13.991	3.787	11.822	1.110	191.405
2008	25.818	14.058	3.787	11.822	1.116	183.834
2009	22.671	14.067	3.787	11.822	1.116	176.723
2010	19.908	14.071	3.787	11.822	1.117	170.137
2015	10.394	14.028	3.787	11.822	1.113	143.304
2020	5.426	13.899	3.787	11.822	1.103	123.444
2025	2.833	14.123	3.787	11.822	1.121	111.700
2030	1.479	14.296	3.787	11.822	1.135	106.938
PDV	$260.948	$185.670	$56.482	$157.908	$14.736	$2,679.046
SD	$ 21.528 8.25%	$ 61.567 33.2%	$ 6.689 11.8%	$ 17.714 11.2%	$ 4.886 33.2%	$ 277.626 10.4%

[7] Depreciation of Capital Costs from Table IV-2, based on 20-year, 150-percent-declining balance.

[8] One-half of Net Revenues from Table IV-4, minus royalty payments, times 15%.

[9] 0.3 percent of the Total Development Costs, Table IV-1.

[10] 1 percent of the Property Tax Base, Table IV-1.

[11] 0.5 percent of Net Revenues, from Table IV-4.

Table IV-6.— **GEOTHERMAL VENTURE, CONSTRUCTION LOAN SCHEDULE: 1992 TO 2006**[1]
(millions of 1986 dollars)

Year	Borrowings[2]	Loan Repayments[3]	Outstanding Balance[4]	Interest Payments[5]
1992	$ 31.102	$	$ 31.102	$
1993	51.189		80.715	3.543
1994	83.801	53.303	107.120	9.195
1995	76.071	44.317	133.444	12.203
1996	91.261	90.334	127.607	15.202
1997	83.640	96.366	108.411	14.537
1998	76.918	47.008	132.825	12.350
1999	91.325	95.872	121.545	15.131
2000	83.374	91.172	107.585	13.846
2001	80.398	44.317	138.211	12.256
2002	87.894	95.576	123.523	15.745
2003	84.622	91.076	110.807	14.071
2004	47.507	52.389	100.308	12.623
2005	36.786	90.432	41.577	11.427
2006	3.882	43.351		4.736
PDV	$773.494	$678.808		$123.001
SD	$ 91.605 11.8%	$ 80.391 11.8%		$ 14.567 11.8%

[1] As given in constant 1986 dollars, this debt schedule does not balance. However, when converted to current dollars based on 5.34-percent inflation, the schedule does balance.

[2] 80 percent of Total Development Costs, from Table IV-1.

[3] Borrowings repaid based on completion of each power plant, based on Table I-1.

[4] Previous borrowings minus previous loan payments

[5] Based on 12-percent interest on Outstanding Balance.

Table IV-7.— **GEOTHERMAL VENTURE, BOND SCHEDULE: 1994 TO 2030**[1]
(millions of 1986 dollars)

Year	Bond Sale[2]	Debt Service[3] Total Payment	Interest	Principal	Principal Owed
1994	$ 53.303	$	$	$	$ 53.303
1995	44.317	5.421	4.807	0.614	94.304
1996	90.334	9.653	8.505	1.149	178.709
1997	96.366	18.351	16.117	2.235	263.781
1998	47.008	27.222	23.789	3.433	293.985
1999	95.872	30.623	26.513	4.110	370.844
2000	91.172	38.821	33.444	5.376	437.841
2001	44.317	46.125	39.486	6.639	453.323
2002	95.576	48.294	40.883	7.412	518.507
2003	91.076	55.566	46.761	8.805	574.494
2004	52.389	62.012	51.810	10.202	587.559
2005	90.432	64.197	52.989	11.208	636.998
2006	43.351	70.140	57.447	12.692	635.366
2007		70.993	57.300	13.693	589.464
2008		67.394	53.160	14.234	545.348
2009		63.978	49.182	14.796	502.907
2010		60.734	45.354	15.380	462.003
2015		46.824	28.157	18.667	277.727
2020		33.330	13.585	19.745	123.250
2025		14.597	3.920	10.678	30.582
2030		1.333	0.116	1.217	
PDV	$678.808	$692.806	$506.762	$186.044	
SD	$ 80.391 11.8%	$ 82.049 11.8%	$ 60.016 11.8%	$ 22.033 11.8%	

[1]As given in constant 1986 dollars, this debt schedule does not balance. However, when converted to current dollars based on 5.34-percent inflation, the schedule does balance.

[2]Based on repayment schedule for construction loan, Table IV-6.

[3]Based on 24-year bonds at 9.5-percent interest, converted to constant dollars using 5.34-percent inflation.

Table IV-8.— **GEOTHERMAL VENTURE, AFTER-TAX INCOME: 1992 TO 2030**
(millions of 1986 dollars)

Year	Total Revenues[1]	Expenses[2]	Taxable Income	Income Tax[3]	Energy Tax Credit[4]	AFTER TAX INCOME
1992	$	$ 27.162	$-27.162	$-10.322	$	-16.840
1993		45.294	-45.294	-17.212		-28.082
1994		49.916	-49.916	-18.968		-30.948
1995	11.938	61.069	-49.132	-18.670		-30.462
1996	29.008	86.650	-57.643	-21.904		-35.738
1997	47.079	102.893	-55.814	-21.209		-34.604
1998	68.023	114.038	-46.014	-17.485		-28.529
1999	88.353	152.861	-64.508	-24.513		-39.995
2000	106.085	166.778	-60.693	-23.0633		-37.630
2001	125.678	174.944	-49.266	-18.721		-30.545
2002	146.273	197.459	-51.186	-19.451		-31.735
2003	164.193	208.706	-44.513	-16.915		-27.598
2004	183.925	189.484	-5.560	-2.113		-3.447
2005	202.611	191.795	10.815	4.110		6.705
2006	220.507	196.625	23.882	9.075		14.807
2007	224.493	191.405	33.088	12.574		20.515
2008	225.437	183.834	41.603	15.809		25.794
2009	225.458	176.723	48.735	18.519		30.216
2010	225.411	170.137	55.274	21.004		34.270
2015	224.261	143.304	80.957	30.764		50.193
2020	221.750	123.444	98.306	37.356		60.950
2025	224.670	111.700	112.970	42.929		70.042
2030	226.961	106.938	120.023	45.609		74.414
PDV	$2,970.698	$2,679.046	$291.652	$110.828	$	$180.824
SD	$ 977.260	$ 277.626	$864.940	$328.678	$	$536.263
	32.9%	10.4	296.6%	296.6%		296.6%

[1]From Table IV-4.

[2]From Table IV-5.

[3]38% of Taxable Income, based on corporate income tax rates of 34 and 6.05 percent for the Federal and State governments, respectively, and adjusted for the fact that the State income tax is a deductible expense.

[4]Excluded from the analysis (see text).

Table IV-9.— **GEOTHERMAL VENTURE, CASH FLOW: 1992 TO 2030**
(millions of 1986 dollars)

Year	After-Tax Income[1]	Credits			
		Depreciation[2]	Depletion Allowance[2]	Loans[3]	Equity Invested[4]
1992	$-16.840	$	$	$ 31.102	$
1993	-28.082			51.189	1.819
1994	-30.948			83.801	15.778
1995	-30.462	3.333	0.740	76.071	18.911
1996	-35.738	5.626	1.807	91.261	15.463
1997	-34.604	10.473	2.927	83.640	12.822
1998	-28.529	15.153	4.227	76.918	6.891
1999	-39.995	16.196	5.501	91.325	8.570
2000	-37.630	20.149	6.600	83.374	5.856
2001	-30.545	23.279	7.819	80.398	1.002
2002	-31.735	23.140	9.112	87.894	
2003	-27.598	26.226	10.225	84.622	
2004	-3.447	28.608	11.454	47.507	
2005	6.705	28.394	12.627	36.786	
2006	14.807	30.473	13.742	3.882	
2007	20.515	29.402	13.991		
2008	25.794	25.818	14.058		
2009	30.216	22.671	14.067		
2010	34.270	19.908	14.071		
2015	50.193	10.394	14.028		
2020	60.950	5.426	13.899		
2025	70.042	2.833	14.123		
2030	74.414	1.479	14.296		
PDV	$180.824	$260.948	$185.670	$773.494	$ 72.070
SD	$536.263	$ 21.528	$ 61.567	$ 91.606	$ 79.465
	296.6%	8.25%	33.2%	11.8%	110.3%

[1] From Table IV-8.

[2] From Table IV-5.

[3] Construction Borrowings, from Table IV-6.

[4] Derived.

Table IV-9.— **GEOTHERMAL VENTURE, CASH FLOW: 1992 TO 2030**
(continued)

	Debits			
Year	Capital Costs[5]	Principal Payments[6]	Dividend Payments[7]	Added Retained Earnings[8]
1992	$ 13.258	$	$ 1.004	$
1993	24.926			
1994	68.631			
1995	65.269	0.614		2.711
1996	75.016	1.149		2.254
1997	68.430	2.235		4.594
1998	66.327	3.433		4.900
1999	75.096	4.110		2.390
2000	68.097	5.376		4.875
2001	70.677	6.639		4.636
2002	70.808	7.412	7.938	2.254
2003	69.657	8.805	10.152	4.860
2004	55.184	10.202	14.105	4.631
2005	45.983	11.208	24.658	2.664
2006	4.853	12.692	40.760	4.599
2007		13.693	48.010	2.204
2008		14.234	51.437	
2009		14.796	52.158	
2010		15.380	52.868	
2015		18.667	55.948	
2020		19.745	61.176	-0.647
2025		10. 678	77.650	-1.330
2030		1.217	90.292	-1.319
PDV	$ 634.765	$186.044	$ 622.755	$29.441
SD	$ 52.368 8.25%	$ 22.033 11.8%	$ 686.655 110.3%	$ 3.487 11.8%

[5]From Table IV-2.

[6]Repayment of Bond Principal Payments, from Table IV-7.

[7]Derived.

[8]Deposits and withdrawals into a reserve account so as to provide sufficient funds to pay one-half of the debt service for the year as measured in current dollars, and converted to constant dollars assuming 5.34-percent inflation.

Table IV-10.— **GEOTHERMAL VENTURE, CASH FLOW TO INVESTORS: 1992 TO 2030**
(millions of 1986 dollars)

Year	Equity Invested[1]	Dividend Payments[1]	NET CASH FLOW
1992	$	$ 1.004	$ 1.004
1993	-1.819		-1.819
1994	-15.778		-15.778
1995	-18.910		-18.910
1996	-15.463		-15.463
1997	-12.822		-12.822
1998	-6.891		-6.891
1999	-8.570		-8.570
2000	-5.856		-5.856
2001	-1.002		-1.002
2002		7.938	7.938
2003		10.152	10.152
2004		14.105	14.105
2005		24.658	24.658
2006		40.760	40.760
2007		48.010	48.010
2008		51.437	51.437
2009		52.158	52.158
2010		52.868	52.868
2015		55.948	55.948
2020		61.176	61.176
2025		77.650	77.650
2030		90.292	90.292
PDV	$-72.070	$622.755	$550.685
SD	$ 79.465	$686.655	$607.190
	110.3%	110.3%	110.3%
Rate of Return:			
Real			17.5%
Nominal			23.8%

[1] From Table IV-9.

REFERENCES

Derridge, A. E., "Evaluate Project Cost Factors," Hydrocarbon Processing, July 1982, p. 203.

The Federal Reserve Bank of St. Louis, "U.S. Financial Data," May 14, 1987.

Hoey, Richard B., and Helen Hotchkiss, "Decision-Makers Pool," Drexel Burnham Lambert, Inc., New York, monthly.

Mountford, J.D., HDWC Phase IIC Studies, Progress Report, Power Technologies, Inc., December 1986.

Sumida, Gerald A., Alternative Approaches to the Legal, Institutional and Financial Aspeets of Developing an Inter-Island Electrical Transmission Cable System, Carlsmith, Wichman, Case, Mukai and Ishiki and First Intersate Cogeneration Capital Associates for the Department of Planning and Economic Development, State of Hawaii, April 1986.

Mullineaux, Donald R., Donald W. Peterson, and Dwight R. Crandell, "Volcanic Haszards in the Hawaiian Islands," Volcanism in Hawaii, Edited by Robert W. Decker, Thomas L. Wright, and Peter H. Stanffer, U.S. Geological Survey Professional Paper 1350, U.S. Printing Office, Washington, D.C., 1987.

Vosseller, George V. "Nomogram Simplifies Use of Cost Scaling Factors," Power Engineering, July 1982, p. 76.