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ELECTRIC UTILITY APPLICATION OF WIND ENERGY CONVERSION
SYSTEMS ON THE ISLAND OF OAHU

By
Charles A. Lindley
Walter C. Melton

February 23, 1979

Work Performed Under Contract No. EX-76-C-01-2439

Energy and Resources Division
The Aerospace Corporation
El Segundo, California

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FOREWORD AND ACKNOWLEDGEMENTS

This study was begun in late 1976 and was essentially completed by late 1977. The technical data, economic data, judgments and opinions obtained in the course of the study to quantify and characterize the Oahu scenario may in some instances be particular to that time frame.

This report is based on the work of many people.

Charles A. Lindley was the Principal Investigator and performed the work reported in Sections 4, 5, 8, and 9. Joseph E. Neiss performed the financial analyses reported in Section 7 by C.A. Lindley. Walter C. Melton performed the utility impact analysis reported in Sections 3 and 6, compiled the remaining sections and edited the overall document.

The computer codes (of which there were no less than 16) were programmed by Patricia Merryman, Alf H. Bogen, and Stanley T. Wray, Jr. Ms. Merryman programmed all of the wind processing procedures, the WECS simulation, and the routine for computing LOLP. A.H. Bogen programmed the Cost of Production program under Aerospace Corporation research funding with computer systems help from Stan Wray. Stan Wray also programmed the load duration computer graphics.

E. Chipman Higgins and Richard Belt of the Hawaiian Electric Company readily supplied information and data, and patiently answered innumerable questions as did Professor Colin Rammage and his colleagues at the University of Hawaii.

Continuing encouragement and guidance were provided by Mr. Tom Reddoch of the University of Tennessee and DOE. Professor Robert E. Sullivan of the University of Florida provided a critical review of the analysis in Section 6.

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SUMMARY AND CONCLUSIONS

1.1 CONTEXT AND OBJECTIVES OF STUDY

This wind energy application study was performed by The Aerospace Corporation for the Wind Systems Branch of the Department of Energy. The objective was to identify integration problems for a Wind Energy Conversion System (WECS) placed into an existing conventional utility system. The integration problems included environmental, institutional and technical aspects as well as economic matters, but the emphasis was on the economics of wind energy. The Hawaiian Electric Company utility system on the island of Oahu was selected for the study because of the very real potential for wind energy on that island, and because of the simplicity afforded in analyzing that isolated utility.

1.2 SUMMARY OF THE ANALYSIS

A short review of the study ground rules, input data and analysis approach is provided below.

1.2.1 Hawaii and the Hawaiian Electric Company

The integration of a WECS into the existing Hawaiian Electric Company (HECO) system on the Island of Oahu was considered in this study. HECO is an investor-owned utility with a nominal generating capacity of approximately 1100 MW on Oahu. Oahu is electrically isolated from the other islands. All of the HECO units are oil fired, the largest being 149 MW. There is serious concern in Hawaii for the preservation of the environment on the one hand, and the dependence on oil and vulnerability to possible upheavals in the oil market on the other. Nuclear power systems are too large for integration into the HECO system, hydro is not feasible because of poor geology, coal is a possibility but extremely expensive and dirty, so that renewable resources are particularly attractive to Hawaii. Ocean thermal, geothermal and wind electric systems are all under study for use in the Hawaiian Islands.

1.2.2 Resource Assessment and System Synthesis

Extensive wind data taken in the 1975-76 time frame by University of Hawaii researchers were available for use in this study. Review and analysis of the data showed that the most extensive high energy wind resource (~18 mph at a nominal height of 30 ft) on Oahu was in the regions of Kahuku Point on the north side. Windier (~22 mph at a nominal height of 30 ft) but much smaller areas are located in the region of Koko Head and Kolekole Pass. Because Kahuku has extensive high energy areas and meets other environmental criteria, it was selected for purposes of analysis of wind integration economics.

Data from four wind speed/direction instruments in the Kahuku Point region were available for various somewhat overlapping periods in the 1975-76 time frame. Direction-dependent speed correlations between various pairs of the four instruments in this mountainous area were used to synthesize an hourly time history of wind data at each of the four sites in the Kahuku region.

The wind speed and direction data from the four wind instrument sites were then used to layout a four-phase WECS development. The Phase 1 installation of 30 WTGs (45 MW nameplate rating) was located in what was surmised to be the highest energy area in the Kahuku Point region. The subsequent Phase 2, 3 and 4 installations (of 70, 100 and 100 WTGs for a total of 300 machines and 450 MW) utilized regions of sequentially decreasing wind energy. An elaborate calculation of WTG power output time histories including interference effects between machines was used to assimilate the total output of the four WECS Phases on an hourly basis for an entire year. These one-year WECS time histories were assumed to repeat year after year in the analysis of the WECS impact on HECO operations over a 15-year period.

1.2.3 Utility Impact Analysis

The hourly time history of the gross HECO demand for 1976 was ratioed up using HECO projections of monthly demand peaks for the 1980-94 time frame to obtain an hourly demand time history for that period. This time history was then used to calculate HECO system loss-of-load probability (LOLP) and cost-of-production with and without the power contribution of the WECS (synthesized as summarized above in 1.2.2).

The HECO system LOLP was calculated for every hour of the 1980-94 time frame using the synthesized demand and a baseline installation and maintenance schedule for HECO capacity. The LOLP was then recomputed including WECS capacity and partial outage (due to wind and mechanical failure) probabilities to determine the improvement in system LOLP due to the WECS. It was concluded that the installation of the first three Phases of the Kahuku WECS (300 MW) would displace a 70 MW gas turbine scheduled for initial operation in late 1984, corresponding to a capacity credit of 23.3 percent. This gas turbine is the smallest unit planned for future installation by HECO. If smaller units had been planned, the very productive Phase 1 Kahuku WECS (45 MW) would have displaced approximately 25 MW of conventional capacity for a credit of approximately 55 percent. These numbers are on the conservative side because the installation and maintenance schedules for the conventional equipment were not reoptimized in the presence of the WECS.

The HECO system cost of production was calculated for every hour of the 1980-94 time frame using the same schedules and demand as used in the loss-of-load analysis. The unit commitment and dispatching logic used in the cost-of-production calculations was very complex and reflected actual HECO operational practice. The cost-of-production calculations were then repeated including the synthesized WECS output for each of the four Phases to determine the WECS value in terms of operational cost savings (principally fuel cost savings). Even while maintaining a full spinning reserve (of conventional units) to protect against a complete WECS

failure, the operating cost savings were very substantial for the all-oil HECO system and greatly overshadowed the nominal capacity savings that could be attributed to the WECS.

1.2.4 Economic Analysis

Because the cost of the single 70 MW gas turbine displaced by the Kahuku WECS was only \$10 million, it was ignored and only the operational cost savings due to the WECS were used in calculating WECS value. The value of the WECS was determined in terms of the average cost of a WTG (for each Phase of the WECS development) which would break even at a rate of return equal to the HECO weighted cost of new capital. These break-even WTG costs were calculated using HECO financial parameters, projected cost of fuel oil, WECS performance synthesized as summarized in 1.2.2, and HECO cost of production calculated as summarized in 1.2.3.

1.3 SUMMARY OF RESULTS AND CONCLUSIONS

The results and conclusions of the study are summarized below in three categories: (1) findings specific to the Oahu utility application; (2) broader generic findings; and (3) methodologies, procedures and analytical tools useful to future WECS development and commercialization.

1.3.1 Specific Application Findings

The break-even WTG cost and feasible WECS penetration of the HECO system on Oahu are set by the characteristics of the limited mountain wind resource available on the island. The major wind resource, Kahuku Point, can provide about 45 to 150 MW of rated WECS capacity (four to 13 percent penetration of present HECO generation) at WTG break-even unit costs ranging from about \$1220/kW down to about \$870/kW (1977 dollars). Further penetration to 300 kW and 450 kW (26 and 39 percent, respectively) would use progressively poorer resources with break-even WTG costs ranging down from \$630 to \$360/kW (1977 dollars). At least one other small (~30 MW) but energetic site is available and others may yet be found.

The three dominating economic factors are the energy intensity of the wind resource, the unit cost of the WTGs and the projected cost of the displaced petroleum fuels. Other factors such as the WECS displacement capacity, collection and transmission cost, land cost, prior survey and planning costs, and backup fuel for load pickup are of minor consequence.

When financed according to typical utility accounting practices, the WECS also presents a cash flow problem in addition to the initial investment barrier. With 30-year amortization, the cash flow on the investment is likely to be negative for about the first six years and the cumulative negative cash flow position at that time may be 25 to 30 percent greater than the initial capital investment. This situation will be greatly eased if the WTG unit cost is low enough to allow cost recovery in much less than 30 years.

No substantive problems were found in the integration of the WECS into the HECO utility network. The WECS need not change the dispatching mode nor the spinning

reserve criteria under which HECO operates. The maintenance of spinning reserve adequate to protect against a sudden Kahuku WECS outage has negligible impact on HECO fuel costs. This conclusion is based on the HECO policy that protects against the sudden failure of the largest unit, the largest unit sometimes being a conventional unit and sometimes the WECS, depending on the current output of the WECS. The more conservative policy of protecting against the sudden simultaneous failure of the WECS and the largest conventional unit was not studied.

The WECS functions as a fuel saver. Although its capacity displacement is a large fraction (40 to 65 percent) in the best sites, the total number of good sites is not enough to displace a significant unit of planned HECO generation capacity.

1.3.2 Generic Extension of Findings

Very energetic mountain wind energy resources, such as those on Oahu (20 to 24 mph (9 to 11 m/s)), can result in WTG break-even costs up to \$1200-\$1400/kW for the reference WTG design in private utility applications, and roughly \$1600-\$1900/kW in publicly-owned utilities. Wind resources of this intensity appear to exist in many mountain locations, but supporting data are very limited, and confirming detailed resource data are almost nonexistent.

Such mountain wind resources tend to be found in small areas, from a few miles to less than a mile in extent and scattered through mountainous terrain. Each resource shows a large spread of energy intensity between WTG sites, and only a few sites in each will sustain the highest WTG break-even costs. Larger numbers of surrounding sites will sustain lower WTG break-even costs and should logically be developed in succeeding Phases as WTG unit costs are reduced.

Economically prudent development of such wind resources demands a careful and detailed survey and economic design tradeoffs before each Phase commitment. Such a detailed survey can be done using conventional wind instrumentation at costs that are very acceptable in terms of cost-benefit ratios. However, the time delays involved in the surveys are likely to become pacing items in the expansion of national WECS capacity. The problem could be aggravated by the lack of established search strategies and experienced practitioners of wind resource search.

The economic leverage of high energy mountainous resources could justify constructing long transmission lines to exploit a mountain area. This could lead to crossing the service area of other utilities as well as state lines in some instances. If WECS become a favored generation system at some future time, this could lead to many jurisdictional problems, calling for the formation of consortiums, negotiations between agencies of different states, and a need for strong Federal leadership.

Mountain wind resources appear to have a degree of intrinsic geographic diversity that may be very significant in their application. This characteristic needs more detailed experimental evaluation.

Tradewind resources also appear to have somewhat unique characteristics regarding power time-duration relationships and requirements for matching WTGs to the resource. These also need more detailed experimental evaluation.

Economics dictate that wind energy be used to displace oil-fired generation first. Displacement of coal-fired generation will require lower WTG break-even costs. Direct displacement of existing nuclear-based generation is not foreseen, although the WECS will cause a remix of conventional generation which will often lead to a smaller nuclear capacity for optimum economics.

1.3.3 Methodologies, Procedures, and Analytical Tools

Several methodologies, procedures, and analytical tools developed during this study should prove useful in further application studies and in future WECS development and commercialization.

A comprehensive set of siting factors and criteria useful in future site selection was developed and evaluated. The step-by-step organization and properly sequenced application of these procedures for mountainous terrain site selection was developed and demonstrated by scenario application to the Oahu case. Several key projected problem areas were highlighted. The site selection emphasis and procedure for flatland and mountain resources were shown to be fundamentally different. If the flatland wind resource is uniform over a wide land area, site selection will be dominated by land use, cost and esthetic considerations. The strong intrinsic variability of the energy and economic worth of mountain wind resources dictates that energy level must be the leading site selection criteria, with all other considerations following after. A few land uses and values, of course, will hold veto power over WECS development.

A scenario WECS design used to estimate Oahu WECS performance forms the skeleton of a methodology for wind resource survey, WECS application evaluation, and WECS field design layout for mountainous terrain wind resources. The following WECS design tradeoff issues are explored to the depth necessary for the present application study and thereby advanced significantly in readiness for later design application:

- (1) WTG array performance tradeoffs between array angles and prevailing wind. WTG spacing at one to two diameters can greatly increase the WECS energy output of mountain wind resources of limited size. The resulting WTG wake interference losses are very dependent on the relationship of the array angle to the prevailing wind direction and the degree of wind directionality.
- (2) WTG array performance tradeoffs between array spacing and exploitation of lower energy sites. For any required total generation capacity, closer spacing may obviate the need to use poorer resources.
- (3) Geographic diversity within mountain wind resources. Properly used, this may increase the economic benefit to specific utilities.
- (4) Capacity factor and power effects of differing WTG site resource energy levels. These greatly affect economic optimizations.

- (5) Capacity factor and power effects of varying WTG rated speed and cutout wind speed. Moderate gains in total energy conversion can be made by selective matching of more than one available WTG design to various parts of a mountain resource. Economic benefit of such matching depends on cost variables to be determined elsewhere in the National Wind Program.
- (6) Significance of ridgetop overspeed conditions to survey validity. This affects selected search strategy, survey cost and risk of misestimated energy recovery and consequent economic loss.

Projected WECS Exploitation Scenario

At this point it is possible to project with some confidence the most likely path of practical commercial exploitation of WECS. It is necessary to make certain broad, implicit assumptions that do not appear to be excessively risky. Key among these assumptions are the following:

- (1) Scarcity of fossil fuel will continue, and petroleum costs will rise slightly faster than patterns controlled by normal inflation.
- (2) Public policy of reducing national dependence on imported oil will preempt "lesser" issues, such as public versus private power arguments.
- (3) The key criterion for WECS operational expansion will be break-even or more favorable economics based primarily on the offset fuel cost savings.
- (4) Practical operationally proven WTGs in utility scale will be available in production quantities at top break-even costs in five to seven years. The (real) costs will gradually scale down as production expands.

Based on these tenets, the likely predominant mode of WECS operational development over the next 20 to 30 years is projected as follows:

- (1) The next five to seven years will be occupied with small scale production and field operational confidence testing of numerous government and privately-funded WTG designs. The length of this consolidation period can be affected by the wisdom of the designers, the foresight of the utilities, the progress of the energy crisis, and government policy/actions regarding both publicly- and privately-funded WTG designs.
- (2) The first major operational WECS deployment should be made in the highest resource energy sites known and available at the time.
- (3) The high energy level will help to assure WECS investment payout in a reasonable time at high initial production costs to minimize

risk of long-term fuel cost uncertainty. In the most favorable circumstances of very high energy siting (9-10 m/sec avg), favorable WTG prices \$600-800/kW, 1977) and favorable financing (public utility), capital payouts in as little as 10 years are credible.

- (4) Energy from these predominately mountain sites could be economically transmitted and shared by large consortiums of users, both public and private.
- (5) The Federal Government will inevitably be a major participant in the resource development because of:
 - (a) Major Federal land holdings in the majority of high energy resource areas (Western mountains).
 - (b) Major hydroelectric installations and related transmission and distribution systems in many of the areas of interest.
 - (c) Favorable economics of public utility ownership, under present ground rules, for capital intensive generation. Private utility participation will increase as WTG costs come down.
- (6) If capital investment rate limitations do not limit the development rate, the magnitude of the wind resource search and validation task will limit it, because of the extreme spacial complexity and variability of mountain resources. The up-front cost and schedule delay of adequate resource search and validation will inevitably lead in some cases to shortcutting the search, resulting in costly errors in WTG siting.
- (7) Storage systems will not be built specifically to store wind energy in a utility in the foreseeable future because:
 - (a) Backup by conventional generation is more economical.
 - (b) Distribution of WECS power over large consortiums will hold the individual utility penetration levels down.
 - (c) Long-distance transmission from multiple resources and the character of mountain resources give a substantial but undefined geographical diversity to the WECS output.

It is likely therefore that wind energy storage will never be economical or required.

- (8) The eventual penetration of wind generation will depend primarily on the balance of far future fuel costs, WTG production prices, cost of capital, and electrical power demand. It should not be forgotten that substantial WECS penetration of foreign utility generation systems is also likely, making for large potential markets and foreign product availability.

The first economical WECS developments will probably supply energy to utilities located in the vicinity of high intensity wind resources. However, later stages of development may involve transmitting the resulting energy to utilities many hundreds of miles away.

STUDY CONTEXT

2.1 BACKGROUND AND OBJECTIVES

This study is one of a series of Application Studies contracted by the Wind Systems Branch of the Department of Energy. The purpose of these Application Studies is to explore the economic, technical, and operational issues in the practical application of large Wind Turbine Generators (WTGs) to electric utilities.

The objective of this study was to assess the potential for the application of Wind Energy Conversion Systems (a field of interconnected WTGs denoted in this report by the acronym WECS) in a specific utility context to gain advance information concerning their economic feasibility; their operational problems; the criteria and procedures for site selection; environmental impacts; legal, social, and other problems; and the balance of cost and benefits from the point of view of the consumer and the utility. This study addresses the circumstances of the Hawaiian Electric Company operations on the Island of Oahu. The results have been generalized as far as possible to generically similar situations. The output of this study will be used in the design, development and application planning of the Wind Energy Branch.

The economics of wind power are still not known because of the uncertainty in WTG cost. The economic analysis in this report was designed to express the results in terms of the break-even price of WTGs rather than the energy cost for a specified WTG cost. This choice was made to maximize the value of the results in the face of continuing uncertainty as to the eventual price for which WTGs may become available.

A class of potential operational and economic problems specifically addressed here are those related to the variability of wind power during WECS operation and to conventional equipment backup of the wind system during wind resource outages. These problems were emphasized and analyzed in somewhat greater detail than in past studies of this type.

2.2 STUDY PARTICIPANTS

The Aerospace Corporation had the primary responsibility for this study and performed all quantitative and qualitative analyses. However, substantial information was obtained from the Hawaiian members of the team without whose assistance the study could not have adequately reflected local Hawaiian attitudes and interests. Participants under subcontract to The Aerospace Corporation were the University of Hawaii (UoH) and the Hawaiian Electric Company (HECO). The University participated heavily in supplying wind data from their extensive wind survey work and also supplied information on land use, zoning, land laws, and general

background. The Hawaiian Electric Company provided detailed information on the structure, operations and costs of the present HECO generating and transmission systems, and upon their future plans for expansion of generation, and projected fuel and power costs. They also provided information about local organization, planning, construction and operating permit procedures, and the local climate for technical innovation.

The Department of Planning and Economic Development of the State of Hawaii was also a contributor, but without contractual obligations in this study. They provided general background information and many specific points of data.

Much of the contribution of these local teams was in the form of background information about the social, cultural and economic climate of the island, which cannot be pointed out specifically and credited in this report, but should have a distinct value in the credibility of the effort. In other instances, specific credit can be identified and is noted in the text where appropriate.

2.3 HAWAII

As indicated earlier, the location chosen for the study is the Island of Oahu in the State of Hawaii. Oahu is the fifth island from the East in the Hawaiian chain and is the location of Honolulu, Pearl Harbor, and the only international airport in the State. The island is by far the most developed and populous of the islands. Oahu has 82 percent of the population of the State with a corresponding 86 percent of the utility power demand, but only nine percent of the state's land area. The island's electrical power needs are served entirely by one investor-owned utility, HECO. The HECO utility transmission system is totally isolated from the other islands and probably will remain so for a long time to come because of the great technological difficulty and expense of electrical power transmission across the deep water channels to the neighboring islands. The channel to Molokai, for instance, the next island east of Oahu, is 40 miles wide and 7800 feet deep. Until technology allows practical inter-island connections, the HECO utility net must operate in total isolation and its reliability and loss-of-load risks are entirely determined by internal actions.

The Island of Oahu has an angular shape with major points on the West, North and East corners and many lesser points. The mountainous backbone of Oahu consists of two ranges, the Koolau Range, running along the northeast shore, and the Wainai, along the southwest face of the island. The Wainai Range is peaked by an extinct volcano at an altitude of 4100 ft, while the much longer Koolau Range generally crests above 2000 ft with peaks up to 3100 ft. The Koolau Range drops off to the sea in a spectacular series of lava cliffs known locally and to tourists as the Pali. Because they face the oncoming tradewinds, the Pali are drenched by heavy tropical rainfall and covered by a dense growth of rain forest jungle. They are extremely rugged, and construction operation on their crests would be at the very least, difficult and expensive. They are also of great importance for their scenic values as a tourist attraction and for the local historic sites such as the Nuuanu Pali, where the great conqueror King Kamehameha won his final battle of conquest by forcing

The Vice President, Planning, is primarily responsible for maintaining the interface with the Public Utility Commission for the State of Hawaii. The planning and conduct of the rate cases and other hearings affecting HECO operations are managed here along with related functions assigned to three departments. Customer Service reads meters, bills and collects payments; handles bill inquiries, account changes, overdue accounts, etc.; and keeps customer records. The Information Systems Department does all data processing for the Company including payroll, billing, and a multitude of internal management reports. The Corporate Planning Department focuses on rate design and administration. There are a total of 160 employees in these three functions.

As of 30 June 1976, there were 1437 HECO employees on Oahu.

3.2 FINANCIAL DESCRIPTION

The Hawaiian Electric Company is an investor-owned electric utility traded on the New York Stock Exchange. There were 2230 preferred and 17,019 common stockholders as of the end of 1976. Significant financial parameters for 1976 are listed below (Ref. 3-1):

Operating Ratio	76.6%
Earnings per Share of Common	\$ 2.93
Net Tangible Assets per Share of Common	\$25.86
Percent of Total Capitalization	
Long-Term Debt	54.5%
Preferred Stock	13.0%
Common Stock	32.5%
Percentage of Long-Term Debt to Net Plant	45.2%
Ratio of Gross Plant to Gross Revenue	2.9
Gross Income as a Percent of Long-Term Debt	22.0%
Fuel Cost as a Percent of Revenue	42.6%

The 1976 sales (including Hawaii, Maui, and Lanai, as well as Oahu) breakdown is as follows:

	<u>1000s Customers</u>	<u>Avg. Rate mills/kWh</u>	<u>Sales MWH</u>	<u>% of Total Sales</u>	<u>Revenue (millions \$)</u>	<u>% of Total Revenue</u>
Residential	219.1	47	1.684E6	31.0	\$ 79.1	35.5
Commercial	33.3	54	1.087E6	20.0	58.8	26.4
Industrial	.5	32	2.598E6	47.7	81.8	36.7
Other	<u>1.5</u>		<u>.071E6</u>	1.3	<u>3.1</u>	1.4
Total	254.5*		5.440E6		222.8	

* Figures do not add due to rounding

HAWAIIAN ELECTRIC COMPANY

3.1 INSTITUTIONAL STRUCTURE3.1.1 Historical Background

The Hawaiian Electric Company, Inc. (HECO) is an investor-owned Hawaii corporation which was incorporated under the laws of the Kingdom of Hawaii on 13 October 1891. It is subject to regulation by the Hawaii Public Utilities Commission. Although HECO is a "holding company" within the meaning of the Federal Public Utility Holding Company Act of 1935, HECO and its subsidiaries are exempt from regulation under the Act because they are organized and operate totally within the State.

HECO owns all of the common stock of two subsidiaries: Hawaii Electric Light Company, Inc. (HELCO) doing business on the Island of Hawaii, and Maui Electric Company, Ltd. (MECO) doing business on the Islands of Maui and Lanai. The common stock of HELCO and MECO were acquired by HECO in 1970 and 1968, respectively. The parent company, HECO, does business under that name on the Island of Oahu. These three companies are not electrically interconnected, and HECO sells more than seven times as much electricity on Oahu as on Hawaii, Maui, and Lanai taken together. HECO does not serve the remaining islands.

3.1.2 HECO Organization

HECO is organized functionally, with six Vice Presidents in charge of distinct parts of the Oahu operation reporting to the President of the Corporation. The Presidents of HELCO and MECO report to the parent company through the President, who is also the Chairman of the Board of Directors of HELCO and MECO, respectively. The remaining discussion will pertain only to the HECO operation on Oahu.

The HECO organization is shown in Figure 3-1. Seven officers, including the Assistant Vice President and Secretary, report directly to the President.

From left to right on Figure 3-1:

The Vice President, Operations, has three departments and 929 employees (all numbers are for July 1976). The Distribution Department is responsible for constructing and maintaining the overhead and underground transmission and distribution systems, representing a plant investment of over \$250 million (more than half the total plant investment). The 19 generating units presently installed at the Honolulu, Waiau and Kahe sites are maintained and operated by 375 employees in the Generation Department. The System Operation Department is responsible for system dispatching to control the flow of load through the transmission system to meet the customer demand. This department also constructs, operates, and maintains over 100 substations and handles emergency calls from customers.

Figure 3-1. HECO Organization

The Vice President, Engineering, runs the Engineering Department (180 employees), Purchasing and Stores (42 employees), and the Environmental Department (seven employees). In the Engineering Department, System Planning is responsible for planning future additions to the generation, transmission and distribution plant. Engineering Design prepares the construction plans for these projects. Customer Engineering handles all requests for new service as well as the preparation of capital budgets and the monitoring of the progress of current projects in the budget. The Environmental Department provides technical review and direction of all Company projects and options as they related to the natural environment.

The Financial Vice President is responsible for external financing and accounting. The arrangements for new capital, annual operating forecasts, external reports to State and Federal authorities, plant records and management control reports, tax computations and various financial studies are handled in this area.

The Vice President, Marketing and Customer Relations, has 30 employees who provide information to residential, commercial, and industrial customers on energy conservation techniques and practices. These efforts are pursued through both advertising and personal contact.

his opponents over the cliff. This local bit of history has some importance to wind power, because the pass at Nuuanu Pali is almost certainly the windiest spot on the island, but under no circumstances would it be available for wind power exploitation.

The central area of the island between the two mountain chains is a broad, flat, lowland of large agricultural installations, mostly irrigated, growing sugar cane and pineapple. The majority of the population of the island is concentrated in a very narrow developed area along the south coast from a little east of Barber's Point to Koko Head. This strip contains the industrial and commercial areas of the island, tourist centers such as Waikiki Beach, with its high-rise hotels, and large residential areas, mostly up the foothills of the Koolau Range. The population over the rest of the island is very thin, consisting mostly of residences, farms and a few resort hotels scattered around the entire beach perimeter of the island. The mountain ranges are publicly owned in their entirety and are protected and managed as both wildlife reservations and watershed. Despite the large rains, water supply has been and is becoming an increasing concern on the island. The availability of these lands and the structure of the Oahu transmission system will be discussed later in this report.

Because of the volcanic origin of the Islands, there are no fossil fuel resources. But, befitting of these beautiful Islands, there appears to be an extensive potential for natural and renewable energy sources. Hydroelectric has some potential on the outer islands. Bagasse (sugar cane refuse) is used extensively on Hawaii and Oahu to produce electricity--although most of the electricity is used internally by the sugar companies for irrigation and processing. Bagasse provided eight percent of the State's fuel in 1973 (petroleum provided the remaining 92 percent) and it is projected that potentially twice as much energy can come from that source. The Islands provide ideal conditions for Ocean Thermal Electric systems and the development of geothermal sources holds great promise. Extensive geothermal explorations have been underway for several years with good results on the Island of Hawaii. Because of their sensitivity to the great beauty of their Islands, the people of Hawaii are quite aware of these natural energy sources and their importance from the standpoint of preserving the beauty and blending with the ecology. Wind energy also has great potential on the Islands and planning efforts for wind are therefore welcomed and encouraged.

The harder economic realities of life on Hawaii also encouraged the development planning for wind energy and the other renewable alternatives. Because of the warm climate and outdoors life style, the per capita consumption of electricity in Hawaii is 25 percent less than on the mainland. Thus, there is less potential for conservation. However, Hawaii is trying to conserve and the State is also actively pursuing a slow growth policy where planning is the essence. These attitudes are in no small part due to the realization of Hawaii's vulnerability to seaborne oil and the possible consequences of another embargo. Consequently, wind energy is a consciously recognized and pursued alternative in Hawaii.

Major Expenses associated with these sales in 1976 were:

Operating Expenses (millions \$)

Operations	\$125.4
Maintenance	7.3
Income Taxes	7.3
Deferred Income Taxes	6.7
Other Taxes	21.9
Depreciation	<u>16.4</u>
Total Operating Expenses	\$185.0

Other Expenses (millions \$)

Interest on Long-Term Debt	\$ 16.7
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The net income of \$19.6 million for 1976 was distributed as follows:

Preferred Stock Dividends	3.7
Common Stock Dividends	9.7
Retained Earnings	<u>6.2</u>
Net Income	\$ 19.6 million

The 1976 Balance Sheet is shown below:

BALANCE SHEET*
(millions \$)

<u>Assets</u>		<u>Liabilities & Net Worth</u>	
Plant & Property	\$651.1	Long-Term Debt	\$230.2
Depreciation	<u>129.8</u>	Current Liabilities	<u>136.9</u>
Net Fixed Assets	\$521.3	Total Liabilities	\$367.1
Cash	2.9	Preferred Stock	56.1
Receivables	25.3	Common Stock	36.2
Materials & Supplies	8.5	Premium on Capital Stock	38.3
Prepayments	<u>.8</u>	Retained Earnings	<u>66.0</u>
Current Assets	\$ 37.5	Total Net Worth	\$196.6
Deferred Charges	4.7		
Total Assets	\$563.7	Total Liabilities & Net Worth	\$563.7

* Figures may not add due to rounding

3.3 OAHU ELECTRIC ENERGY REQUIREMENTS

3.3.1 Load Growth

Prior to the 1973 energy crisis which was reflected in 1974 electricity usage, the energy consumption for the production of electricity had grown at an annual rate of 8.31 percent (1962 through 73, Table II, Ref. 3-2) in the State of Hawaii. Almost all of Hawaii's consumption is on Oahu where, except for a very small amount of electricity purchased from a sugar mill, the generation comes from oil-fired plants.

The electric energy consumption only increased by one percent from 1973 to 1974. However, the annual consumption picked up again in 1975 and in that year, HECO predicted an increase in electricity consumption at an average annual rate of 6.17 percent through the year 2000. The development of a very strong anti-growth movement which has manifested in a limited-growth statement of policy by the Hawaiian State Government has led to subsequent downward revisions.

The FPC load forecast developed by HECO on 3-17-76 is used in this study. This forecast gives an average growth rate of 4.62 percent for the 15-year period, 1980-94, ending with a peak 1994 load of 1825 MW and generation of 10.9×10^6 MWh. These numbers correspond to gross electric production (i.e., they include the power required to run generating plant auxiliary equipment).

The 3-17-76 forecast of monthly gross demand peaks for the period 1980 through 1994 used in this study are displayed in Table 3-1. Time histories of hourly demand for each of these years were generated by multiplying the actual 1976 historical demand data by monthly factors such that the peaks of the resulting sequence matched the forecasted peaks month for month.

3.3.2 Load Shape

HECO has an unusually flat seasonal variation of demand peaks. The monthly peaks occur in the Fall with October the highest and November only slightly lower as shown earlier in Table 3-1. The monthly peaks normalized with respect to the October peak are shown here in Table 3-2.

In the calculation of cost of production where minimum running time constraints and distinctions between startup costs for hot starts and cold starts are observed, it is important to preserve the actual hour-to-hour variation of demand in the simulation. Averaging is a smoothing process which decreases the hour-to-hour variation. To properly preserve and include these effects in these analyses, the actual hourly demand observed in 1976 was used in cost-of-production and reserve margin calculations. Hourly time histories for each of the years 1980 through 1994 were synthesized by multiplying the 1976 time history by monthly factors such that the resulting monthly peaks correspond to the values shown in Table 3-1. The month-to-month percentage variation is the same for each of the 15 years permitting the simplified presentation of Table 3-2. It might be noticed from analysis of Table 3-1 that the year-to-year growth varies somewhat unevenly from 4.33 percent per year in 1980 to 4.83 percent per year in 1994.

TABLE 3-1
HAWAIIAN ELECTRIC COMPANY - ISLAND OF OAHU
FORECASTED MONTHLY PEAK DEMAND (GROSS): 1980-1994
(MW)

	<u>Jan.</u>	<u>Feb.</u>	<u>Mar.</u>	<u>Apr.</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>Aug.</u>	<u>Sep.</u>	<u>Oct.</u>	<u>Nov.</u>	<u>Dec.</u>
1980	924	912	909	888	885	868	888	903	937	970	964	957
81	964	951	948	926	923	906	926	942	978	1012	1006	999
82	1006	993	989	966	963	945	966	983	1020	1056	1050	1042
83	1052	1038	1034	1010	1007	988	1010	1028	1066	1104	1097	1090
84	1099	1084	1080	1055	1052	1032	1055	1073	1114	1153	1146	1138
1985	1149	1134	1130	1103	1100	1079	1103	1123	1165	1206	1199	1190
86	1202	1185	1182	1154	1150	1129	1154	1174	1218	1261	1253	1245
87	1257	1240	1236	1207	1203	1181	1207	1228	1274	1319	1311	1302
88	1314	1296	1292	1262	1258	1234	1262	1284	1332	1379	1371	1361
89	1376	1357	1353	1321	1317	1292	1321	1344	1395	1444	1435	1425
1990	1442	1422	1418	1384	1380	1354	1384	1409	1462	1513	1504	1493
91	1511	1490	1485	1450	1446	1419	1450	1476	1531	1585	1575	1564
92	1584	1562	1557	1521	1516	1487	1521	1547	1605	1662	1652	1640
93	1659	1637	1631	1593	1588	1558	1593	1621	1682	1741	1731	1718
94	1739	1715	1710	1670	1664	1633	1670	1699	1763	1825	1814	1801

The data in this table were developed for the FPC load forecast of 3-17-76.

TABLE 3-2
NORMALIZED GROSS DEMAND MONTHLY PEAKS
(HECO, Island of Oahu)

Jan.	.953	July	.915
Feb.	.940	Aug.	.931
Mar.	.937	Sep.	.966
Apr.	.915	Oct.	1.000
May	.912	Nov.	.994
June	.895	Dec.	.987

The data in Table 3-2 were developed for the FPC Load Forecast of 3-17-76.

The diurnal load shape varies somewhat from month to month. Generally, the daily peak occurs at 7PM in the winter and 8PM in the summer. Note in interpreting these data that the demand quoted for a particular hour of the day is actually the average over the preceeding hour. Table 3-3 shows the diurnal variation of weekday average demand normalized by the peak hourly average. The average weekday load factor is shown to the right-hand column. The weekend loads are on the order of 10 percent lower than the weekday loads (except in the early morning hours when they are higher). The averages tabulated in Table 3-3 are based on 1976 demand data.

The normalized averages shown in the above tables do not reveal the hour-to-hour variability of the actual sequence of hourly data. The load duration decomposition curves shown in Figure 3-2 provide information about the serial qualities of the sequence. In Figure 3-2 the main curve is the standard hourly load duration curve for the hourly demand sequence for the years 1980-94 which was synthesized as described above from the 1976 demand and the FPC 3-17-76 monthly peak forecasts. The curve below the load duration curve labeled 2 hrs shows the fraction of the time (measured from the left border) for which the load was at the indicated level (MW) or above for two hours or less. The curve labeled 4 hrs shows the fraction of time for which the indicated load (or greater) was four hours or less. The horizontal difference between the two curves gives the fraction of time during the year for which the indicated load lasted either three or four hours. The area between the left margin and the 2-hr curve is proportional to the energy delivered in bursts of two hours or less. The Hawaiian Electric Company has a relatively smooth and flat diurnal profile which is reflected in the small area to the left of the 2-hr curve relative to other utilities. The curves continue to add up to the load duration curve in steps labeled 2, 4, 6, 8, 10, 12, 14, 16, 18, 20, 22, and 24 hrs; 2, 3, 4, 5, 6, and 7 days. The remaining horizontal distance to the far right, but below the load duration curves, is for durations exceeding one week. The curves above the load duration curve are complementary--describing the durations of the absence of load at a given level. These curves are referenced to the right-hand margin. The profiles in Figure 3-2 will be compared later to the profiles of residual demand remaining to be met by conventional generation after the Wind Energy Conversion System (WECS) supply has been added into the system.

TABLE 3-3

HECO WEEKDAY DIURNAL DEMAND PROFILES
(Based on 1976 Demand)

Month		Time of Day												L.F.
		1	2	3	4	5	6	7	8	9	10	11	12	
January	AM	.504	.476	.458	.455	.482	.581	.726	.786	.843	.864	.868	.863	
	PM	.862	.859	.856	.861	.880	.934	1.00	.954	.867	.768	.665	.568	.749
February	AM	.498	.467	.450	.446	.474	.579	.721	.792	.845	.861	.865	.855	
	PM	.856	.857	.854	.859	.885	.932	1.00	.969	.879	.778	.672	.571	.749
March	AM	.505	.476	.457	.456	.485	.593	.740	.818	.867	.874	.875	.870	
	PM	.870	.868	.870	.876	.899	.944	1.00	.978	.891	.781	.876	.571	.760
April	AM	.522	.487	.473	.471	.497	.602	.740	.835	.890	.904	.905	.897	
	PM	.895	.894	.893	.896	.916	.944	.989	1.00	.913	.802	.693	.591	.777
May	AM	.528	.497	.483	.481	.508	.604	.749	.845	.898	.911	.917	.907	
	PM	.910	.911	.911	.913	.924	.944	.967	1.00	.921	.808	.700	.594	.785
June	AM	.552	.520	.500	.496	.525	.603	.735	.849	.915	.936	.944	.934	
	PM	.936	.935	.930	.931	.938	.952	.957	1.00	.935	.832	.729	.626	.800
July	AM	.555	.520	.502	.499	.525	.598	.721	.840	.910	.943	.946	.938	
	PM	.939	.936	.935	.937	.945	.955	.960	1.00	.937	.832	.732	.630	.801
August	AM	.557	.523	.503	.500	.528	.607	.719	.845	.923	.950	.950	.948	
	PM	.949	.946	.941	.939	.943	.953	.970	1.00	.925	.826	.724	.622	.804
September	AM	.533	.504	.489	.487	.514	.611	.739	.836	.900	.916	.922	.914	
	PM	.918	.914	.915	.912	.916	.938	1.00	.985	.898	.794	.692	.592	.785
October	AM	.514	.485	.471	.469	.497	.594	.730	.817	.872	.890	.893	.887	
	PM	.890	.887	.891	.891	.902	.948	1.00	.950	.861	.769	.669	.577	.765
November	AM	.510	.481	.462	.460	.487	.583	.712	.799	.857	.877	.879	.868	
	PM	.871	.870	.868	.873	.890	.972	1.00	.943	.856	.763	.667	.569	.755
December	AM	.519	.481	.465	.461	.484	.578	.705	.791	.857	.881	.883	.874	
	PM	.871	.868	.863	.867	.888	.965	1.00	.945	.867	.784	.689	.591	.757

Figure 3-2. Normalized Load Duration Decomposition Curves
(Synthesized HECO Hourly Demand Time History: 1980-94)

3.4 TRANSMISSION SYSTEM

A map of Oahu with the HECO transmission system superimposed is shown in Figure 3-3. Most of the HECO load is in the area including Honolulu and along the coast in the southeastern part of the island. Secondary load centers are located at Wahiawa in the center of the island and the Kaneohe Bay area on the eastern side. Additional load flows around the island on the eastern and northern shores to the Kahuku Point region which has a strong wind resource.

The grid is driven by the Kahe Power Plant at Kahe Beach on the southwestern shore (currently 497 MW nominal), the Waiiau Power Plant on the East Loch of Pearl Harbor (currently 515 MW nominal) and the Honolulu Power Plant in downtown Honolulu (currently 180 MW nominal). These plants are located close to the dominant load center and the consequent grid is very tight from a load flow stability standpoint. The maximum extent of the island (from Kaena Point to Makapuu Head)

Figure 3-3. HECO Transmission System

is only 27 miles and most of the load is distributed in a 15 mile section on the south side. The maximum transmission voltage is 138 kV of which there were 146 miles of line as of the end of 1976. There were 504 miles of 46 kV transmission line with 11 miles of that underground.

3.5 GENERATING SYSTEM

Because the basic objective of installing a WECS is to generate electricity which would otherwise be generated with conventional equipment using conventional fuels, it is important that the conventional system be adequately modeled. This is especially true in the analysis of installed reserves, spinning reserves, and other operating policies as they might affect the economics of the system. Consequently, considerable emphasis is placed on the description and modeling of the HECO generation as presented in this Section. Additional operational details are presented in Section 6.0 where specific cost-of-production and reserve margin issues are analyzed.

3.5.1 Existing Generation

As mentioned earlier, the HECO generating units are colocated in one of three power plants named Kahe, Waiau and Honolulu. The unit designations are given along with their normal upper operating limits in Table 3-4. All power outputs quoted here and in the next several sections are gross (i.e., not accounting for losses in auxiliary equipment) because of the way HECO does its supply and demand accounting.

TABLE 3-4
INSTALLED HECO GENERATION

<u>KAHE P.P.</u>		<u>WAIU P.P.</u>		<u>HONOLULU P.P.</u>	
<u>Unit</u>	<u>Capacity</u>	<u>Unit</u>	<u>Capacity</u>	<u>Unit</u>	<u>Capacity</u>
K1	88 MW (Gross)	W1	8 MW (Gross)	H5	23 MW (Gross)
K2	88	W2	18	H7	42
K3	90	W3	52	H8	55
K4	90	W4	52	H9	60
K5	141	W5	60		180 MW
	497 MW	W6	57		
		W7	90		
		W8	90		
		G1	44		
		G2	44		
			515 MW		

TOTAL: 1192 MW (Gross)

All of the units in Table 3-4 with the exception of G1 and G2 are Westinghouse-built oil-fired thermal units. G1 and G2 are General Electric gas turbines that burn diesel fuel. The other units are currently using residual fuel oil of moderate sulfur content. The Honolulu plant is the oldest and Kahe the newest. The Honolulu plant will not be expanded but will continue in service as older units are retired and replaced. Only moderate expansion and modification is contemplated for Waiau. W1 and W2 are two very old units installed at Kaiau in the 1920s which are maintained for emergency use only. As a matter of policy, HECO retires units when they become uneconomical compared to alternative generation sources. Kahe is located along the southwestern shore in a relatively unpopulated area and all of the presently planned major generation expansion will be installed there.

3.5.2 Plans for New Generation

HECO is planning to install nine additional units in the next 15 to 20 years. The first eight will nominally be installed at the Kahe site although some of the gas turbines may be located at Waiau. The ninth and largest unit will probably be installed at Kahe also. These units are listed below in Table 3-5 along with a date for initial operation according to a plan which was under consideration by HECO in March of 1977. These initial operational capability dates are used in all of the analyses discussed in this report and are identified as the "baseline plan."

TABLE 3-5
BASELINE GENERATION EXPANSION PLAN

<u>Unit</u>	<u>Nom. Capacity</u>	<u>Initial Operation</u>	
K6	141 MW (Gross)	October	1982
G3	60	October	1984
G4	59	July	1986
G5	60	December	1987
K7	170	June	1989
G6	59	January	1991
G7	60	September	1991
K8	170	August	1993
X1	223	December	1994

The units G3, G4, . . . , G7 are gas turbines. The others are all oil-fired steam turbines. HECO is now studying (in parallel with this study of wind systems) coal-fired plants, but the results of those studies are not available for use in this study.

3.5.3 Generation Description

Detailed information used in modeling HECO for the cost-of-production and reserve analyses is presented here. A complete understanding of the meaning of these data will probably depend on a careful review of Section 6.0 where the analyses, which use these data, are fully discussed.

3.5.3.1 Generating Unit Operating Limits

HECO specifies four operating limits for its generating units:

- (1) Minimum
- (2) Normal Maximum
- (3) First Contingency Maximum
- (4) Second Contingency Maximum

Minimum: The minimum operating limit (MW) is that lowest gross power output at which the unit can maintain stable operation.

Normal Maximum: The upper limit of gross power output for which all monitored operating variables (pressures, temperatures, etc.) are at normal specified values. This limit is determined through tests conducted by HECO after installation and generally turns out to be somewhat greater than the manufacturer's nameplate rating.

First Contingency Maximum: The upper limit of gross power output at which the unit can apparently operate indefinitely without damage. Various operating variables may exceed specified values or limits. This operating limit is judged from test data obtained by HECO after the units have been installed.

Second Contingency Maximum: The absolute upper limit of gross power output at which the unit can be operated. Most units can be operated at this limit for short periods only. The limit is determined by HECO in conjunction with the determination of the First Contingency Maximum.

Because of the operating characteristics of certain units, it often turns out that two or more of the upper limits coalesce into a single limit, as shown below in Table 3-6. These limits are used in the calculation of installed reserve criteria, spinning reserve criteria, and other unit commitment and dispatching criteria, as explained later in Section 6.0.

3.5.3.2 Generating Unit Performance

For system planning purposes, HECO describes the input-output curve for each of their units with a parabola. The heat rate curves may be obtained by dividing the I/O curves by the unit load. The resulting second order equation is evaluated at the lower operating limit, upper normal limit and halfway between the two limits in Table 3-7. The startup costs are also shown for both hot starts and cold starts. These numbers have been rounded off for presentation purposes, and are retained with greater resolution in the computer data base.

The last column in Table 3-7 shows the hot delay time for each unit. If a unit has been shutdown for less than the hot delay time when it is restarted, the hot start cost is charged. HECO unit commitment policy (excluding emergencies) does not permit a unit to be shutdown for less than five hours—i.e., if the forecasted load will call for a unit to be brought up again within five hours, it is not shutdown. The must-run units are also identified in Table 3-7.

TABLE 3-6

**HECO GENERATING UNIT OPERATING LIMITS
(GROSS POWER OUTPUT, MW)**

<u>Unit</u>	<u>Minimum</u>	<u>Normal Maximum</u>	<u>First Contingency</u>	<u>Second Contingency</u>
W 1	6	8	8	8
W 2	10	18	18	18
H 5	10	23	23	23
H 7	12	42	42	42
W 3	15	52	52	52
W 4	15	52	52	52
H 8	20	55	55	55
H 9	20	60	60	60
W 5	15	60	60	60
W 6	15	57	57	57
W 7	30	90	90	95
W 8	30	90	90	95
K 1	30	88	88	93
K 2	30	88	88	93
K 3	30	90	90	95
K 4	30	90	90	95
G 1	5	44	52	54
G 2	5	44	52	54
K 5	40	141	141	149
K 6	40 (est.)	141 (est.)	141 (est.)	149 (est.)
G 3	5 "	60 "	70 "	70 "
G 4	5 "	59 "	69 "	69 "
G 5	5 "	60 "	70 "	70 "
K 7	48 "	170 "	170 "	178 "
G 6	5 "	59 "	70 "	70 "
G 7	5 "	60 "	70 "	70 "
K 8	48 "	170 "	170 "	178 "
X 1	63 "	223 "	223 "	234 "

3.5.3.3 Quick Load Pickup Capability

HECO is an isolated utility which is not interconnected with any other generating systems. If a HECO generating unit goes down suddenly, HECO is itself responsible for bringing up more generation to meet the emergency. Consequently, HECO has a very conservative spinning reserve criterion which is observed in all of their operations. This spinning reserve criterion is observed in the cost-of-production analyses reported in Section 6.0, and it raises several special issues regarding the use of wind power which are also addressed there. In calculating the amount of spinning reserve that must be maintained at a given level of system demand, the capability of the many spinning units to load up quickly in an emergency situation must be considered. Some units can come up very quickly while others are quite sluggish.

TABLE 3-7

HECO GENERATING UNIT PERFORMANCE

Unit	Gross Heat Rates, Btu/kWh			Startup Costs, 10 ⁶ Btu/Start		Hot Delay Time (Hrs)
	Lower Limit	Mid Point	Upper Normal	Cold Start	Hot Start	
W 1	15987	15759	15690	86	20	12
W 2	13578	13130	13174	86	20	12
H 5	18409	16482	15749	132	33	12
H 7	14222	12473	12645	99	66	12
W 3	13219	11801	11882	318	80	12
W 4	13219	11801	11882	318	80	12
H 8	11725	11072	11024	132	33	12
H 9	11725	11047	11047	132	33	12
W 5	11564	10614	10586	132	33	12
W 6	11564	10629	10575	132	33	12
W 7	10185	9498	9472	252	73	Must Run
W 8	10185	9498	9472	252	73	Must Run
K 1	10074	9270	9150	247	72	Must Run
K 2	10074	9270	9150	247	72	Must Run
K 3	9952	9133	9100	252	73	Must Run
K 4	9952	9133	9100	252	73	Must Run
G 1	42697	15408	12641	12	12	---
G 2	42697	15408	12641	12	12	---
K 5	9808	8937	8985	344	93	Must Run
K 6	9808	8937	8985	344	93	Must Run
G 3	47192	14544	12864	12	12	---
G 4	47192	14619	12879	12	12	---
G 5	47192	14544	12864	12	12	---
K 7	10321	9256	9141	418	113	Must Run
G 6	47192	14619	12879	12	12	---
G 7	47192	14544	12864	12	12	---
K 8	10320	9257	9141	418	113	Must Run
X 1	9854	9046	9030	550	146	Must Run

TABLE 3-8

QUICK LOAD PICKUP CAPABILITY OF HECO UNITS (P, QLP)
(MW, MW)

W1	(6,1)	(8,0)										
W2	(10,4)	(18,0)										
H5	(5,8)	(10,5)	(15,2)	(23,0)								
H7	(10,26)	(15,22)	(20,17)	(25,14)	(30,10)	(35,6)	(38,3)	(42,0)				
W3	(5,32)	(10,32)	(15,30)	(20,25)	(25,21)	(30,16)	(35,12)	(40,8)	(45,4)	(50,1)	(52,0)	
W4	(5,32)	(10,32)	(15,30)	(20,25)	(25,21)	(30,16)	(35,12)	(40,8)	(45,4)	(50,1)	(52,0)	
H8	(5,28)	(10,26)	(15,25)	(20,22)	(25,20)	(30,17)	(35,16)	(40,11)	(45,8)	(50,4)	(54,1)	(55,0)
H9	(5,31)	(15,31)	(20,28)	(25,24)	(30,20)	(35,17)	(40,13)	(45,9)	(50,5)	(55,2)	(57,1)	(60,0)
W5	(5,29)	(15,29)	(20,25)	(25,21)	(30,18)	(35,15)	(40,11)	(45,8)	(50,4)	(55,2)	(57,1)	(60,0)
W6	(5,29)	(15,29)	(20,25)	(25,21)	(30,18)	(35,15)	(40,11)	(45,8)	(50,4)	(55,2)	(57,1)	(60,0)
W7	(30,28)	(35,25)	(40,22)	(45,20)	(50,17)	(55,15)	(60,13)	(70,9)	(80,3)	(90,0)		
W8	(30,28)	(35,25)	(40,22)	(45,20)	(50,17)	(55,15)	(60,13)	(70,9)	(80,3)	(90,0)		
K1	(30,31)	(35,28)	(40,25)	(45,22)	(50,19)	(55,16)	(60,13)	(70,8)	(80,3)	(85,1)	(88,0)	
K2	(30,31)	(35,28)	(40,25)	(45,22)	(50,19)	(55,16)	(60,13)	(70,8)	(80,3)	(85,1)	(88,0)	
K3	(30,28)	(35,25)	(40,22)	(45,20)	(50,17)	(55,15)	(60,13)	(70,9)	(80,3)	(86,1)	(90,0)	
K4	(30,28)	(35,25)	(40,22)	(45,20)	(50,17)	(55,15)	(60,13)	(70,9)	(80,3)	(86,1)	(90,0)	
G1	(0,52)	(44,8)										
G2	(0,52)	(44,8)										
K5	(47,44)	(55,39)	(63,34)	(71,31)	(78,27)	(86,24)	(94,20)	(110,14)	(125,5)	(141,0)		
K6	(47,44)	(55,39)	(63,34)	(71,31)	(78,27)	(86,24)	(94,20)	(110,14)	(125,5)	(141,0)		
G3	(0,70)	(60,10)										
G4	(0,69)	(59,10)										
G5	(0,70)	(60,10)										
K7	(57,53)	(66,47)	(76,42)	(85,38)	(95,32)	(104,28)	(113,25)	(132,17)	(151,6)	(170,0)		
G6	(0,70)	(59,11)										
G7	(0,70)	(60,10)										
K8	(57,53)	(66,47)	(76,42)	(85,38)	(95,32)	(104,28)	(113,25)	(132,17)	(151,6)	(170,0)		
X1	(74,69)	(87,62)	(99,54)	(112,50)	(124,42)	(136,37)	(149,32)	(174,22)	(198,7)	(223,0)		

HECO runs tests on their newly installed units to determine their "Quick Load Pickup" (QLP) capability. The QLP is the increase in load that the unit can pickup in a three second period. The QLP is a function of the initial load P, of course. If the unit is operating close to its upper operating limit, it will obviously have very little QLP capability. Data pairs (P, QLP) describing the QLP for each of the HECO units are shown in Table 3-8. The argument for the table is P, and linear interpolation was used for intermediate values of P used in the analyses reported in Section 6.0. Because the HECO units are all oil fired and relatively small, the Quick Load Pickup capability is substantially greater than with a typical utility.

3.5.3.4 Generation Reliability and Maintenance

The forced outage rates (FOR) for HECO units are presented below in Table 3-9. Both "mature" and "immature" rates are shown for some of the units. In planning analyses, the immature rates are used for the year of installation and the entire following year. The mature rates are used thereafter. The forced outage rates for existing units are based on historical data taken by HECO on their own units. The outage rates for the units yet to be installed are judgments by HECO which are based on their own experience with similar units and a study of Edison Electric Institute (EEI) statistics on similar units.

TABLE 3-9
HECO GENERATION FORCED OUTAGE RATES

Unit	Immature FOR	Mature FOR	Unit	Immature FOR	Mature FOR
W 1	---	.0058	K 3	.0165	.0100
W 2	---	.0058	K 4	.0165	.0100
H 5	---	.0342	G 1	.0500	.0500
H 7	---	.0058	G 2	.0500	.0500
W 3	---	.0048	K 5	.0400	.0180
W 4	---	.0048	K 6	.0400	.0180
H 8	---	.0043	G 3	.0500	.0500
H 9	---	.0043	G 4	.0500	.0500
W 5	---	.0043	G 5	.0500	.0500
W 6	---	.0043	K 7	.0400	.0180
W 7	---	.0100	G 6	.0500	.0500
W 8	---	.0100	G 7	.0500	.0500
K 1	---	.0100	K 8	.0400	.0180
K 2	---	.0100	X 1	.0400	.0340

The FOR shown in Table 3-9 is based on forced outage days and service days, not hours as is EEI practice. That is,

$$\text{FOR} = \frac{\text{TLSD}}{\text{SD} + \text{TLSD}}$$

where TLSO is the total lost service days, SD is the service days, and a day is defined to be between 10AM and 10PM. If a unit is forced out after 10PM and returned to service that same night (i.e., before 10AM the next day), it is not considered a lost service day. FOR was defined in this way for use by HECO in their calculation of loss-of-load probability (LOLP) which is only calculated for the daily peak. This definition of FOR tends to result in smaller values than does an hourly definition as might be noticed in comparing with EEI values for similar machinery. However, HECO forced outage rates are, in fact, lower than EEI values calculated on a comparable basis because of the extra care and maintenance of their equipment taken by HECO. HECO tries harder because they are isolated without inter-connections with other utilities in a reliability pool.

The HECO definition of LOLP uses the capacities associated with the "Second Contingency" limits presented earlier in Table 3-6. Those capacities along with the FORs presented in Table 3-9 are also used in the hourly LOLP calculations discussed in Section 6.0.

The maintenance requirements (for preventive maintenance) change from year to year in a cyclical manner that depends on the specific needs and maintenance complexity of each unit. The nominal maintenance cycle repeats itself through the lifetime of the unit given that there are no major disruptions for that unit. The basic preventive maintenance cycle requirements in weeks per year are presented in Table 3-10. These maintenance periods are for contiguous weeks.

TABLE 3-10
HECO GENERATING UNIT SCHEDULED MAINTENANCE CYCLES
(Weeks/Year)

W1	0-1	(2-yr cycle)	K3	2-2-3-2-7	(5-yr cycle)
W2	0-1	"	K4	2-2-3-2-7	"
H5	0-2-0-1-4	(5-yr cycle)	G1	1-2-0-1-0-2-1	(7-yr cycle)
H7	6-0-2-0-1	"	G2	1-2-0-1-0-2-1	"
W3	6-1-0-2-0	"	K5	8-3-3-3-3	(5-yr cycle)
W4	6-1-0-2-0	"	K6	8-3-3-3-3	"
H8	6-0-2-0-1	"	G3	1-2-1-1-2	"
H9	6-1-0-2-0	"	G4	1-2-1-1-2	"
W5	6-0-2-0-1	"	G5	1-2-1-1-2	"
W6	6-1-0-2-0	"	K7	8-3-3-3-3	"
W7	3-0-7-2-0	"	G6	1-2-1-1-2	"
W8	7-0-3-0-2	"	G7	1-2-1-1-2	"
K1	2-2-3-2-7	"	K8	8-3-3-3-3	"
K2	2-2-3-2-7	"	X1	8-3-3-3-3	"

The baseline maintenance schedule presented in Table 3-11 for the 15-year period, 1980-94, levelizes the reserve with respect to the 3-17-76 FPC forecast on a weekly basis. This schedule was developed by HECO and corresponds to the installation

TABLE 3-11

BASELINE HECO MAINTENANCE SCHEDULE FOR THIS STUDY
(Weeks of Indicated Year, Inclusive)

	1980	81	82	83	84	1985	86	87	88	89	1990	91	92	93	94
W1	39	None	12	None	27	None	6	None	19	None	27	None	28	None	34
W2	38	None	13	None	1	None	52	None	20	None	14	None	27	None	36
H5	None	35-36	None	2	35-38	None	7-8	None	39	27-30	None	2-3	None	43	25-28
H7	1	1-6	None	3-4	None	20	42-47	None	37-38	None	39	38-43	None	31-32	None
W3	None	8-9	None	31-36	4	None	50-51	None	1-6	14	None	46-47	None	8-13	29
W4	32-37	None	31-32	None	5	35-40	None	51-52	None	40	15-20	None	50-51	None	30
H8	2-7	None	33-34	None	6	1-6	None	33-34	None	22	1-6	None	48-49	None	37
H9	31	None	27-28	None	27-32	34	None	31-32	None	33-38	5	None	14-15	None	8-13
W5	8-13	None	29-30	None	33	7-12	None	29-30	None	24	6-11	None	16-17	None	39
W6	None	10-11	None	9-14	34	None	48-49	None	6-11	23	None	44-45	None	14-19	38
W7	18-20	None	17-23	15-16	None	15-17	None	7-13	27-28	None	15-17	None	11-17	23-24	None
W8	14-15	12-18	None	21-23	None	29-30	17-23	None	18-20	None	29-30	27-33	None	38-40	None
K1	29-30	33-34	14-16	29-30	39-45	31-32	13-14	1-3	12-13	15-21	31-32	5-6	2-4	46-47	2-8
K2	27-28	31-32	40-42	27-28	7-13	13-14	15-16	4-6	29-30	41-47	13-14	7-8	5-7	44-45	9-15
K3	21-23	29-30	46-52	17-18	14-15	18-20	37-38	14-20	14-15	48-49	18-20	9-10	27-33	25-26	48-49
K4	16-17	27-28	43-45	19-20	46-52	27-28	35-36	48-50	16-17	33-39	27-28	38-39	8-10	51-52	27-33
G1	None	6	None	5-6	2	5	9-10	None	36	None	37-38	4	52	38-39	None
G2	None	7	None	7-8	3	6	11-12	None	35	None	35-36	52	39	28-29	None
K5	24-26	19-26	24-26	24-26	16-18	21-23	27-34	21-23	21-23	30-32	21-23	11-18	18-20	48-50	16-18
K6	Installed 40th Wk '82	Δ	None	19-26	24-26	24-26	24-26	24-26	24-26	22-29	24-26	35-37	21-23	35-37	19-26
G3	Installed 40th Week, 1984:	Δ	33	39-40	27	32	25-26	34	48-49	37	22	34-35			
G4	Installed 27th Week, 1986:	Δ	28	33-34	52	12	50-51	38	20-21	14					
G5	Installed 48th Week, 1987:	Δ	31	50-51	33	34	34-35	31	48-49						
K7	Installed 22nd Week, 1989:	Δ	None	19-26	24-26	32-34	50-52								
G6	Installed 1st Week, 1991:	Δ	36	41-42	15										
G7	Installed 35th Week, 1991:	Δ	1	30-31	1										
K8	Installed 31st Week, 1993:	Δ	None												
X1	Installed 48th Week, 1994:	Δ													

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schedule (Section 3.3.2) under consideration by HECO in March of 1977. This schedule is referred to later as the "baseline" system, but it should be remembered that it was merely one of several under consideration by the HECO at the time of its release for use in this study.

3.6 ENERGY SUPPLY AND COSTS

3.6.1 Background

All of HECO's units on Oahu are presently oil fired with either two percent sulfur residual fuel oil or 0.5 percent sulfur fuel oil or diesel fuel (a moderate amount used in the gas turbines). All of the oil is seaborne to Hawaii, there being no fossil fuel natural resources in Hawaii. The capital investment and transportation costs of oil relative to eastern coal have always mediated in favor of an oil-fired system. The opening of western low sulfur coal fields on the mainland in combination with pressure from the Federal Government has lead to an intensive study of the feasibility of installing coal-fired rather than oil-fired units in the future. This investigation is being conducted by HECO and several HECO contractors in parallel with this study. Because the results of that study are not yet available, this study is based on the assumption that all future conventional generation will be oil fired.

There are no natural circumstances on Oahu that would facilitate the construction of a hydrofacility. The topology of the Island is inadequate and the volcanic rock tends to be too porous for use in reservoirs.

Nuclear systems are generally not commercially available in sizes compatible with HECO demand projections for the next 30 years at least, and have not been considered for that reason alone. The Islands are very ecologically oriented, and nuclear units are not favorably viewed for that reason as well.

For these reasons, oil and coal are the only conventional fuels that will be economically feasible in the next several decades. Both must be shipped in and both will be expensive: (1) while cheaper per Btu, coal will be more capital intensive than oil. (2) While cleaner and less capital intensive, oil will be more expensive per Btu and exposes Hawaii to greater risk in the event of dislocations in the global oil market. Because both oil and coal are proportionately more expensive than on the mainland, Hawaii is highly motivated to search for nonconventional renewable energy sources. Wind energy is one of the leading candidates for the displacement of some amount of fossil energy usage by HECO. The current HECO oil cost projections upon which this study is based are presented next in 3.6.2.

3.6.2 HECO Oil Cost Projections

HECO's current contract for residual fuel oil expires at the end of 1980. Under this contract which has a built-in escalation factor that depends on the price escalation of both natural gas and Los Angeles bunker oil, the 1977 price (delivered) for two percent sulfur residual fuel oil is \$11.33/bbl. Several percent of HECO's consumption is diesel fuel for the gas turbine peakers. That oil is priced slightly higher. There is a public service company tax of 7.5 percent on revenues, a PUC fee of .25

percent on revenues and a franchise royalty tax of 2.5 percent on revenues for a total Hawaii State tax of 10.25 percent. The corresponding revenue requirements factor (1.1142) raises the effective cost to HECO from \$11.33/bbl to \$12.62/bbl.

HECO has forecasted the price of .5 percent residual fuel oil and diesel fuel for the 1980-2000 time frame based on analyses performed for them by Sherman Clark Associates of Menlo Park, California. The HECO forecast which was used in the baseline calculations for this study is shown in Table 3-12. These prices are for oil delivered at Oahu but not including the 11.42 percent revenue requirements factor.

TABLE 3-12

HECO FUEL OIL PRICE FORECAST: 1980-2000
(Current Dollars)

Calendar Year	.5% Low Sulfur* Residual (\$/bbl)	Diesel** Fuel (\$/bbl)	
1980	19.65	20.82
81	21.46	22.74	
82	23.43	24.83	
83	25.58	27.10	
84	27.93	29.59	
1985	30.50	32.32
86	32.76	34.71	
87	35.19	37.29	
88	37.79	40.04	
89	40.59	43.01	
1990	43.60	46.20	
91	46.80	49.59	
92	50.24	53.23	
93	53.92	57.13	
94	57.88	61.33	
1995	62.13	65.83	
96	66.69	70.66	
97	71.58	75.84	
98	76.84	81.42	
99	82.48	87.39	
2000	88.53	93.80	

* .5% Low Sulfur Residual: 6.2×10^6 Btu/bbl

** Diesel Fuel: 5.82×10^6 Btu/bbl

REFERENCES FOR SECTION 3.0

- 3-1. "Moody's Public Utility Manual," Moody's Investor's Service, Inc., New York, NY, 1977.
- 3-2. "Alternate Energy Sources for Hawaii," Published by Hawaii Natural Energy Institute, University of Hawaii and the Department of Planning and Economic Development, State of Hawaii, February 1975.

RESOURCE ASSESSMENT AND SITING

4.1 INTRODUCTION

A sequential process of resource search and assessment must be completed before a utility can bring an operational WECS on line. This process has never been completed although a few utilities are now initiating the first steps. Although past experience cannot be called upon, it is expected that the process will be drawn out and expensive for WECS sites located in mountainous terrain, such as on the Island of Oahu. A generic procedure applicable to mountainous terrain is outlined and discussed in this Section. The actual application of the procedure to Hawaiian Electric Company operations on the Island of Oahu in the State of Hawaii is discussed in Section 5.0.

Planners and researchers of wind energy systems may become enthusiastic supporters, but the decision to commit large sums of money on wind energy generation will be made at the higher levels of the utility organization by prudent and probably conservative people. In the end the cost of all such decisions will be borne by the public and pointed questions as to the wisdom of the decisions will be asked by the PUC or other organizations in the name of the public interest. To attract interest in wind power, its proponents need only show a reasonable expectation of economic performance. To gain a decision to actually invest large sums in a WECS involving a large number of WTGs will require stronger justification. For these reasons the consideration of system economics plays the lead role in the siting process.

4.2 THREE-PHASE SITING SEQUENCE

The resource search and assessment process will normally develop in a series of phases which have an increasing level of detail. The process starts with a general search and ends with the identification of specific locations for individual WTGs. Three somewhat indistinct and overlapping phases can be identified:

Phase 1: Preliminary WECS Feasibility Evaluation - to determine if there is a valuable wind resource somewhere in or near the utility service area. This Phase is primarily a top level wind resource search based for the most part on existing data. Criteria other than wind energy are reviewed only to the extent required to eliminate areas where there is no hope of building a WECS.

Phase 2: WECS Area Selection - to determine which of several possible wind energy fields should be developed. The top level search is over and the careful assessment of the discovered resources is undertaken in this Phase. The tasks

are to determine the geographical extent of high quality wind in the several candidate WECS areas, and to consider other legal, procedural and cost criteria to the extent required to make a decision on which one (or several) of the candidate WECS areas should be retained. A significant wind data instrumentation and analysis effort will usually be required.

Phase 3: WECS Site Survey and WTG Layout Design - to establish the specific location of WTGs within the WECS area defined and selected earlier in Phase 2. This Phase could conceivably include the installation of WTGs in some of the locations while other locations are still being evaluated. Various legal and procedural requirements will be complied with in this Phase.

4.3 SITING CRITERIA CATEGORIES

Five basic categories of siting criteria have been identified. They are listed below in the order of importance that will usually obtain for wind machines to be located in mountainous areas:

- (1) Wind Energy Resource
- (2) Land Use and Availability
- (3) Environmental Impact
- (4) Site-Variable Costs
- (5) Weather and Terrain Limitations, Hazards

The order of importance will vary with the specific situation. However, the following comments are offered to support the sequence shown above.

In mountainous territory the quality of the resource must be the first considered criterion because of the tremendous spatial variability of this parameter. In flatlands the spatial variation of annual wind energy will typically not be large within a fairly broad area. Land Use and Availability issues along with Environmental Impact issues will tend to dominate in flatlands.

Site-Variable Costs may have significant percentage variations between various mountainous locations, but except for the most unusual circumstances, will be a small part of the total. Such costs might preclude the installation of WTGs within a region of spectacular scarps like the High Sierra Wall or the Pali on Oahu, but these locations would not have been available anyway because of Land Use or Environmental Impact Factors.

Although it must be considered, only in the most unusual circumstances will the fifth category play a dominant role in the site-selection process for mountainous areas.

The many specific factors and criteria in these five categories are listed next in Section 4.4.

SITING FACTORS AND CRITERIA LIST

The following list of specific factors and criteria is thought to be exhaustive and it is not expected that all of the criteria will be applicable in any one situation. In addition, the importance and manner in which each criterion is considered in the decision process will depend on which of the three Phases is current. These considerations will be addressed later.

Wind Energy Resource

- a. Mean Wind Speed
- b. Extent of Energetic Area
- c. Directional Distribution of Wind Energy
- d. Diurnal Distribution vs. Demand
- e. Seasonal Distribution vs. Demand
- f. Speed Duration Profile
- g. Frequency of Long Outages
- h. Vertical Wind Profile Over Mountain Tops
- i. Diversity

Land Use and Availability

- a. Cost and Market Availability
- b. Land Use Restrictions and Zoning
- c. Interaction With Nearby Land Users

Environmental Impact

- a. Esthetic Impact
- b. Fuel Displacement
- c. Aircraft Hazards
- d. Microwave and Television Interference
- e. Public Safety
- f. Watershed Impact
- g. Wind Break
- h. Flora and Fauna
- i. Historical and Archeological Sites

Site-Variable Costs

- a. Access Road Availability and Cost
- b. Collection and Transmission Line Costs
- c. Site-Related Construction Costs
- d. Hardware Delivery Transportation Costs
- e. Energy Royalties
- f. Labor Availability

Weather and Terrain Limitations, Hazards

- a. Destructive Winds
- b. Severe Icing
- c. Deep Snow, Avalanches
- d. Wind-Borne Salt, Pumice, Dust, etc.
- e. Flood, Earthquake, and Landslide
- f. Security and Vandalism

4.5 CRITERIA DISCUSSION

4.5.1 Wind Energy Resource

The availability of an energetic wind resource is a prerequisite to economically sound wind energy conversion in the foreseeable future. The diffuse nature of wind energy is the chief obstacle to its economical conversion, and locations having higher-than-average wind energy concentration must be found and used.

Unfortunately, the wind data ordinarily available before a conscious search for wind energy sites begins is of marginal value to a wind resource search. The vast majority of weather stations and wind instruments are located to monitor and record wind conditions affecting human activities such as airport operations and urban living conditions. These activities tend to shun notoriously high wind areas because of their adverse effects on comfort and safety, and potential property damage.

In hilly or mountainous terrain the wind resource frequently varies greatly over short distances, so that a very close grid of instrument sites would be required to prove the existence and extent of a good wind site in a region, to choose wisely between several alternate possible locations, or to pick specific generator sites in an extensive wind generation system. Data will seldom exist for such a grid in a region of interest. Specific instrumentation and data analysis efforts will have to be undertaken.

When adequate data are available, the wind characteristics listed below will be of interest. Their relative importance is not yet clear and appears to depend on the details of the design and the extent of the contemplated WECS.

a. Mean Wind Speed

The mean value of wind speed at a location is a strong indicator of the feasibility of economic wind energy conversion. The median value, which is sometimes available, may be equal to or lower than the mean of the same data for typical wind speed distributions. Data from various sources may be in units of miles per hour, knots, or meters per second. The energy level is also sometimes expressed in terms of average watts per square meter, or kilowatt hours per square meter per year. Since these represent sums or averages of terms proportional to velocity cubed, and the cube of the average velocity is not the same as the average of the velocity cubed, there is no direct conversion to mean velocity without specifying the velocity duration relationships.

The height of the instrument above ground level is also a necessary part of the data, since wind velocity generally increases with height at a given location. The profile of this increase varies with surface roughness upwind (water, grassland, forest, buildings), the surface profile, and the vertical temperature gradient. It is particularly uncertain and variable over the crest of a hill. Despite these variabilities, a commonly used rule of thumb is that the velocity increases proportionate to the sixth root of the height above ground level. The DOE/NASA specification (Ref. 4-1) of WTG performance assumes this profile and relates WTG output to wind velocity at a height of 30 feet.

Calibration of the instrument must always be suspect. Instruments used to take old data are usually not available for checking or recalibration. Newly-purchased instruments may also carry severely erroneous calibrations.

Because there is substantial seasonal variation of wind energy, it is generally accepted that wind speed averages based on data durations of less than a year are likely to be misleading. Records of several years are preferred.

b. Extent of Energetic Area

This may not be an issue for WECS siting in level land, since the energy available from different sites in the region may not vary greatly. In mountainous terrain, energetic wind sites are likely to be limited to a few peaks, ridgetops, or saddles capable of sustaining only a few WTGs at conventional spacing. The available energy along a single ridge may vary greatly over distances of as little as a hundred meters. If a large WECS capacity is desired, detailed knowledge of the extent of the energetic area is required.

c. Directional Distribution of Wind Energy

The directional distribution of the wind energy is of particular interest in mountainous terrain. It affects the feasibility of closely spacing the WTGs to take maximum advantage of intensive wind energy resources which are of limited geographical extent.

d. Diurnal Distribution vs. Demand

Sites where the wind blows most strongly in the daytime provide electrical power availability better matched to the usual utility demand than night peaking sites. The result will be lower energy storage or reserve generation capacity for the utility using day peaking wind sites. Fuel savings will also be greater with day-peaking winds, since the less fuel-efficient generators are turned on when demand is high. The higher altitude mountain wind sites seem to trend toward night peaking.

e. Seasonal Distribution vs. Demand

Wind sites with summer or winter peaking that matches the seasonal utility demand distribution will have a greater effect (for a given amount of annual energy) in reducing the reserve generating capacity requirements and fuel consumption of the utility.

f. Speed Duration Profile

The shape of the wind duration curve determines the amount of time the WTG is at full power, zero power, and producing at intermediate output power levels. Golding's hypothesis that the speed duration profile is a universal shape multiplied by the local mean velocity level does not hold for tradewind areas, as shown in this report.

g. Frequency of Long Outages

If wind outages are frequent and short, conventional spinning reserves or energy storage of modest capacity and cost will be necessary to bridge over the outages. If long outage times are frequent, storage will less likely be favored.

h. Vertical Wind Profile Over Mountain Tops

Depending on the mountain profiles taken in the wind direction, the upwind surface roughness, the wind velocity, and the vertical temperature gradient, the vertical wind speed profile above a mountain crest may vary greatly. The flow may remain attached to the crest with a vertical velocity profile similar to that over flatland. For sharper curvature of the crest contour, velocities may be higher near the surface, which favors a lower WTG tower height, and may make low altitude anemometer data excessively optimistic if scaled with altitude in a manner characteristic of flatland profiles. Certain combinations of sharp crest profiles, strong positive temperature gradient, and upwind flow obstructions may favor separated flow over the mountain crest, which can lead to low energy or reversed flow close to the ground, and extreme turbulence and gust loads on the rotor blades.

i. Diversity

Geographic diversity, where two or more WECS sites are spaced far enough apart that the wind may be strong enough to generate power at one site when it is generating no power at the other, has the effect of leveling the total WECS output and reducing the WECS total outage time. In mountainous terrain substantial diversity can be found within a single WECS field, as will be shown in this report. Diversity is generally considered a desirable WECS resource characteristic, but this depends on the detailed matching of resource to utility demand.

4.5.2 Land Use and Availability

The cost and availability of land with an adequate wind resource is an essential factor in the WECS site-selection process.

a. Cost and Market Availability

Land must be available for WECS installations by either purchase or lease at an acceptable cost.

b. Land Use Restrictions and Zoning

It is presumed that WECS installations will be acceptable under conventional industrial and agricultural zoning regulations. In some cases, such as Oahu, clarification of the law by specific mention of wind power generation may simplify the permit procedure.

c. Interaction With Nearby Land Users

Residential Land - Large wind machine siting is generally incompatible with residential land use for the primary reasons of esthetics and public safety (thrown blades and high voltage wires). Additional secondary issues are electronic (TV) interference and, possibly, aerodynamic noise.

Residential areas are seldom located in high wind locations, but where they are it is common practice to use rows of trees, walls, etc., arrayed on the prevailing windward side of residential areas to improve living comfort. Wind machines might make acceptable windbreaks in some unusual circumstances.

Industrial Land Use - It is not clear that large wind machines are incompatible with industrial land use. However, until a high level of blade reliability has been demonstrated, suitable buffer land to protect against injuries and damage from thrown blades would be prudent. The esthetic impact of WTGs should be no more objectionable than many other industrial structures, except that their height may make them visible for longer distances than most. Microwave interference might be significant to a very limited number of industries. Otherwise, little interaction is foreseen.

Agricultural Land Use - WECS installations should not be seriously incompatible with agricultural land use. If buffer land for protection against thrown blades is considered necessary, some land is removed from cultivation. If confidence is built up in the integrity of the blades, it may be reasonable to cultivate to the base of the tower, as is present practice with high voltage transmission line towers. In both cases there is an overhead breakage hazard confined to times of highest wind. The few personnel at hazard are present in the area only infrequently. The WTGs would also be a hazard to crop dusting aircraft where these are in use.

Forest and Recreational Land Use - In hill and mountain country the higher terrain may be National Forest, National Park, other recreational land, controlled watershed, or commercial timber production land. The esthetic impact of the wind machines themselves, the power collecting transmission systems, and the access roads for initial installation and maintenance is likely to be a prime objection if the land is valued primarily for scenic value. In many areas of the West, land of little scenic value and no value for farming, mining, or other use, has been designated as National Forest, primarily to identify an administrative custodian. Such land will generally be available for any constructive use, including a WECS. Esthetic considerations should not be critical in commercial timber lands.

In most hill and mountain lands timber cutting and drainage alteration caused by installing roads and transmission lines are a serious consideration. Erosion resulting from careless design can damage much land downhill from the cut, disrupt groundwater flow, fill downstream flood control basins, degrade water quality, and cause new erosion patterns in streams below. Techniques and costs for minimizing these problems are well known.

4.5.3 Environmental Impact

a. Esthetic Impact

The esthetic impact of a number of wind machines on the appearance of the landscape may be important in some locations. Generally, lands in view of a large population and lands valued for their natural beauty, such as National Parks or other recreational lands, would be most sensitive. In some cases, careful site selection could remove the machines from the line of sight or range of visibility of all but a small portion of the populace. In other cases, it may be possible to locate them in lands of low esthetic value.

In considering esthetic impact, careful study of actual visibility from areas of public access should be made. The crest of a mountain range is often invisible from inhabited areas near its base. The view is often cut off by peaks of lower foothills that cut off the line of sight and screen the actual crestline. The actual crest might be visible from greater distances. However, it has been estimated (Ref. 4-2) that the DOE/NASA Mod 1 WTG will be visible to the naked eye no more than 10-12 miles in the clearest air; much less with a slight haze. The significance of the other environmental issues will generally be known to utilities serving the area.

b. Fuel Displacement

Electrical energy generated by wind machines will generally displace energy that would have to be generated by conventional means. This will reduce fossil or nuclear fuel consumption, with favorable effects on air pollution, pollution and hazards related to transportation of fuel, nuclear waste disposal, use of cooling water, consumption of fossil and nuclear fuels, and land damage due to mining them. In the case of locations dependent on imported fuel, it would also reduce vulnerability to embargo.

c. Aircraft Hazards

Wind turbine generators, like other tall structures, constitute collision hazards to low flying aircraft. They will generally be required to carry clearance lights and be painted in contrasting colors. They may be restricted from airport approach corridors.

d. Microwave and Television Interference

Metallic WTG rotor blades can reflect television signals to television receivers, giving multipath effects similar to passing airplanes (nonmetallic rotor blades can also reflect television signals, but to a lesser degree). The severity of the effect for one WTG or a full WECS array is unclear. However, where it proves important, it can probably be eliminated at modest cost by supplying cable service to the residents affected.

A variety of microwave repeating stations and telemetry links will share mountaintop sites with WECS. Since the transmission beams are very narrow, it should be sufficient to keep WTGs out of the line of a narrow sight cone between microwave stations.

e. Public Safety

Until a high level of confidence is established in the structural reliability of the WTG blades, access within the distance a broken blade could be thrown should probably be limited. As a high level of confidence and experience is built up, they may be treated more like high voltage transmission lines, with agricultural or recreational uses of the land under the WTG permitted.

f. Watershed Impact

Watershed impact of WECS should be minimal, provided normal procedures are followed to minimize erosion and landslide hazard resulting from road and foundation cuts in mountain terrain.

g. Wind Break

The WTGs will somewhat reduce the wind speed to a distance of about 10 diameters downwind. In a few locations, this may improve the comfort level of a small downwind space for livestock and for human uses, such as recreation.

h. Flora and Fauna

In a few locations there may be a problem of possible damage to local flora and fauna resulting from WECS installations. Of particular concern would be rare or endangered species, such as the California Condor.

i. Historical and Archeological Sites

Sites of strong historical or cultural interest such as the Nuuanu Pali on Oahu are likely to be unavailable as WECS sites. Important archeological sites are also likely to be unavailable, or the WECS would be delayed pending exploration of the site.

4.5.4 Site-Variable Costs

a. Access Road Availability and Cost

The costs of the access roads for construction and maintenance of the WTGs are normally very minor WECS cost components (less than one percent), but are highly variable with the site configuration. In flatland, a rural road network should usually be available nearby. Road access will be by many short roads, each connecting a few WTGs to the rural road system.

In mountainous terrain the cost per mile of access roads climbing a mountain slope to the crestline may be one or two orders of magnitude greater than similar roads on flatland or along mountain crests, both because of the difficulties of the terrain and the necessary drainage provisions and terracing to minimize induced erosion and risk of landslides. In certain locations, like the crest of Oahu's Pali, or California's High Sierra Wall, even the cost of crestline roads would be extreme. Such sites would frequently be unavailable anyway because of scenic values.

The access roads will generally be designed to minimize the slope-climbing mileage and maximize the ridgetop and valley floor mileage. Road costs in mountainous terrain may also be minimized by connecting many WTGs with one road, and by closer spacing of WTGs in the highest energy locations.

b. Collection and Transmission Line Costs

Electric collection and transmission from the WECS is a more significant cost than roads, typically running less than five percent of total WECS cost for large fields, and higher percentages for installations of only a few WTGs. Transmission line costs per mile may double or triple in mountainous terrain.

The collection cost is reduced by close spacing of WTGs in a WECS.

The transmission cost is primarily dependent on the distance to the load center, or to the nearest transmission line point that has the capacity to absorb the additional power. For a large WECS the load and cost is similar to that of a large conventional power plant.

Where a new transmission line is required, environmental impact issues and public hearings are becoming a serious impediment. One result is a strong pressure toward upgrading and joint use of existing rights of way with any nearby utility.

c. Site-Related Construction Costs

Certain additional costs may be incurred because of the site characteristics. Examples are special tower foundation costs in marshy land and costs of moving and operating large cranes and cargo trailers on tortuous mountain roads and narrow crestline construction pads. It is not yet clear where these costs will be significant.

d. Hardware Delivery Transportation Costs

Delivery of the WTG hardware and construction supplies and equipment to remote sites may be expected to entail extra problems and costs. The Hawaiian Islands, the Aleutian Islands, and certain central Sierra Nevada Mountain sites might be examples of more costly delivery locations.

e. Energy Royalties

In mountainous terrain, where the higher energy sites are limited in extent, it is conceivable that the owners of such land might consider it a scarce and valuable resource and try to charge rent or an energy royalty for its use. An analogy might be made between wind rights and water, oil, mineral or geothermal rights.

f. Labor Availability

The availability of skilled labor for assembly and erection of WECS in certain remote areas may be a problem.

4.5.5 Weather and Terrain Limitations, Hazards

a. Destructive Winds

It is presently planned that the WTGs will be designed to withstand wind speeds of 125-150 mph in the furled condition. Tropical hurricanes can on rare occasions bring winds in excess of these limits to exposed locations near shore.

Tornadoes contain much higher winds confined to an area of a few hundred yards in extent. A WTG hit by a tornado is conceded to be destroyed. Fortunately, the risk of a tornado hitting an individual machine is very low, and total destruction should normally be confined to a few WTGs in a field.

b. Severe Icing

Glaze ice can build up to thicknesses greater than a foot with ice densities greater than 50 pounds per cubic foot under unusual weather conditions. The conditions are very high wind, temperature just below freezing, and large amounts of precipitation, mostly as supercooled water. These are possible conditions in most favorable WECS locations. The WTGs will have to be designed and proof-tested against these conditions as part of the development testing process. In other situations ice may build up prior to winds high enough for operation, leading to a forced outage condition but without damage to the WTG.

c. Deep Snow, Avalanches

Deep snow in winter in a WECS field is seen primarily as an obstacle to access resulting in minor costs in construction and costs and delays in maintenance and repairs of an operational WECS. Avalanche hazards will have to be recognized in northern mountains.

d. Wind-Borne Salt, Pumice, Dust, etc.

These materials can cause corrosion and rapid wear of bearings and gears if they are not properly sealed against the environment.

e. Flood, Earthquake, and Landslide

These are normal hazards to any type of construction in various site locations. They are minimized by proper site selection and construction design.

f. Security and Vandalism

Vandalism has proven to be a serious problem to wind instrument installations, ranging from "sportsmen" who use anemometer cups as moving rifle targets to instances of large instrument towers repeatedly brought down with an axe. This problem is sufficiently severe to form an active constraint on where wind instruments may be placed during a wind resource search. One site on Oahu was never successfully surveyed because repeated instrument damage made the effort too expensive.

The dispersed nature of a WECS generating field will make it vulnerable to either vandalism or planned sabotage attempts unless special precautionary steps are taken. It is easy to visualize the whirling blades as objects of "target practice." The capital investment of a major WECS is sufficient to justify patrols and other security measures. Limited public access to a potential WECS area by reason of its geographical location may be considered a favorable point of uncertain value.

4.6 INTRODUCTION TO PHASE-DEPENDENT APPLICATION OF CRITERIA

The importance and manner of consideration of each of the above nontechnical factors and criteria depends on the Phase of the effort. Many of the factors are simply matters of judgment in Phase 1. By the time of Phase 3, they are tasks that must specifically be addressed and disposed of--often by a procedural method prescribed by law. In many cases, the Phase 3 tasks are things that must be done but will not affect any siting decisions. That is, a given factor is often a judgmental criteria early on and a task to be done later on. The judgment early on has to do with how difficult or costly it will be to accomplish that task later.

The relative importance and nature of consideration for the five categories of criteria are summarized in Table 4-1. The comments for the five categories in the column for each Phase tend to define that Phase in terms of what work is to be done. This manner of definition is consistent with the earlier definition of the Phases in terms of the Phase objectives. In either manner of definition, note that the distinction between Phases is loose and approximate and will surely depend on the specifics of a given situation for each category of criteria. With this disclaimer, a detailed discussion of the factors and criteria in the context of each of the three Phases is presented next.

4.7 PHASE 1: PRELIMINARY WECS FEASIBILITY EVALUATION

The purpose of this stage of the survey is to determine for the utility whether there is any viable wind resource in an area accessible to it. If the answer is negative, the utility would presumably abandon interest in wind energy conversion unless at a later date drastic changes in fuel costs and the cost of WTGs changes the definition of a viable resource.

TABLE 4-1

**EMPHASIS AND APPLICATION OF CRITERIA FOR EACH SEARCH AND ASSESSMENT PHASE
(MOUNTAINOUS TERRAIN)**

SEARCH & ASSESSMENT PHASE CRITERIA CATEGORY	Phase 1 Preliminary WECS Feasibility Evaluation	Phase 2 WECS Area Selection	Phase 3 WECS Site Survey and WTG Layout Design
Wind Energy Resource	<ul style="list-style-type: none"> Based on existing data plus augmentation with new instruments as required. Dominant factor in screening process. 	<ul style="list-style-type: none"> Instrument the several candidates areas for a WECS to determine extent and quality of wind resource. 	<ul style="list-style-type: none"> Instrument the selected WECS area for detailed data to be used in WTG siting.
Land Use and Availability	<ul style="list-style-type: none"> Screen out park lands and other areas <u>definitely</u> not available. 	<ul style="list-style-type: none"> Investigate land availability costs. Pickup options or establish royalties arrangement. Prepare for commitment. 	<ul style="list-style-type: none"> Commitment required to assure that the land is available at reasonable cost.
Environmental Impact	<ul style="list-style-type: none"> No Action 	<ul style="list-style-type: none"> Review any key environmental problems as possible discriminators in choice. 	<ul style="list-style-type: none"> Begin studies and analysis for environmental impact statements.
Site-Variable Costs	<ul style="list-style-type: none"> No Action 	<ul style="list-style-type: none"> Estimate costs for each candidate area. 	<ul style="list-style-type: none"> Site costs considered in detail for WTG layout design.
Weather and Terrain Limitations, Hazards	<ul style="list-style-type: none"> No Action 	<ul style="list-style-type: none"> Evaluation 	<ul style="list-style-type: none"> Weather and terrain problems considered in layout of WTGs in rugged or high altitude mountains.

The risk to the utility is likely to be several hundred thousand dollars for inhouse man-hours and possibly a few instruments. Therefore, the feasibility evaluation would only be undertaken at utility expense if the utility is convinced that an operational WTG will be available at an acceptable price within about five years. Supporting studies must indicate that there are no insurmountable integration or system problems.

A search will be made of the available wind resource data from the area of interest accessible to the utility. The limits of this area of interest should not be drawn too narrowly, because wind power, like any other electrical power, can be economically transported several hundred miles for a modest transmission surcharge on the basic generation cost. A superior resource at a distance may still be the most economical. Extremely remote mountainous and unpopulated areas may require considerable additional development and operational costs which should be considered early in the search.

The first source for available wind data are the National Climatic Center, much of whose data is summarized for various regions in References 4-3 and 4-4. In some places regional summaries exist, such as Reference 4-5. However, the region should also be surveyed for other wind data sources. Typical examples will be forest fire lookouts, small airports, microwave relay stations, nuclear power plant site instrumentation, and various types of research facilities. Most of this data will be found to be on strip charts and will not be worth reducing for analysis unless a preliminary viewing indicates the average wind to be high. The chance of finding data on a prime wind site in these miscellaneous sources is small because they usually involve various human activities that are adversely affected by bad weather and high winds. However, they should at least provide clues as to where to look for higher winds.

Indirect Sources

A preliminary search of other indirect sources is likely to be worthwhile. This should include discussion with experienced outdoor workers, such as telephone and electric utility linemen, microwave relay tower installers, forest rangers, fire fighters, and various workers in forestry and agriculture. In some cases biological evidence such as wind-flagged trees may be a strong indication of where prevailing winds are strong. In other cases, particularly in the southwestern United States, the strongest wind regions will have no vegetation at all to give biological indications. Police departments and highway planners may have information on where high winds normally cause accidents or are hazards to recreational vehicles and trailers. Highways in such areas frequently carry wind hazard warning signs.

Evaluation of the Terrain Features

Consideration should be given to analytical modeling of the flow by computer techniques for identifying general locations of interest. However, it is doubtful if they will be worth the cost in pinpointing the best wind sites before putting out instrumentation. These modeling techniques are being developed in the hope of reducing the required instrument search time and cost, but not as a substitute for definitive experimental data. Their economic value is still untested.

In any case, a careful study of contour maps of the mountain structure of the area should be made. Promising areas such as mountain passes facing a prevailing wind and mountain ranges crossing the prevailing wind, ends of ridges, and saddle structures can be identified from the contour maps. Biological indicators can be checked to give confidence to these assessments.

Instrumentation

All of the above effort is likely to provide, in a region of mountainous terrain, only a strong indication but not firm proof of the existence of an exploitable wind resource in the region accessible to the utility. The reason why proof is unlikely is that the weather in the windiest locations in mountainous terrain is so inimical to man's health, safety, and activities that no one will have bothered taking wind data there.

It will then be necessary to site instruments in several promising locations in order to obtain clear proof of at least one available wind resource of an economical level. The locations of the instrument sites will be a matter of judgment, based on interpretation of the uncertain mixture of data collected from the sources listed above. In view of this uncertainty, the number of areas instrumented should be influenced by the assumption that the majority of the initial selections will be disappointments, and that those that find usable resources will not initially strike the highest energy points in the wind field.

At the present level of understanding, one year of wind data is the minimum necessary to prove a site in terms of preliminary WECS feasibility. But after a number of months it will probably be considered appropriate to close a number of sites that show disappointing results and relocate the instruments based on the new data that have become available. It will probably take about two years to prove or disprove with reasonable confidence the existence of an economically exploitable wind resource within a large mountainous prospecting area.

Areas to be Excluded from Search

In choosing the areas for instrument search, and in determining if a resource located can actually be exploited, the criteria listed in Section 4.2.1, other than the energy resource itself, will claim some attention. However, it would be wise not to give too much attention to issues other than the wind quality of the resource in the initial search.

Almost all of the economic issues in the list can be overcome if the resource located is valuable enough. Only in the most spectacularly rugged mountainous terrain could the costs of roads and transmission lines approach the cost of the WTGs in an intensive development. The agricultural value of farm land which might be used for a WECS is several orders of magnitude below the value of wind energy collected (see Appendix G).

The only issues of Section 4.2.1 that should be taken to preclude even a wind resource search are the esthetic impact on a dedicated National Park, or a historic site of prime local significance, such as the Nuuanu Pali in Oahu. (It is assumed that a prime wind site will never be found in urban land.) On the other issues that could

discourage WECS development, it would be wise to evaluate a promising wind resource first and worry about development problems later. Again, this judgment applies to mountainous terrain resources where there is strong variation of the available energy.

4.8 PHASE 2: WECS AREA SELECTION

At some point in this process the utility will decide that enough data have been uncovered to prove the existence of one or more economically and otherwise viable wind resources for development, or that the results of the search are not sufficiently encouraging to continue. The discovery of only marginal wind resources could lead to a decision to hold further work in abeyance until future increases in fuel prices and reductions of the cost of WTGs are matched to the moderate wind regimes found in the search.

If the utility elects to continue, this next phase of the search will begin localizing to the particular WECS areas which appear energetic enough to be economically developed. The purpose is to gain enough information on the selected areas to know their approximate extent, the approximate amount of wind energy available, the maximum level of the energy or mean wind velocity in the area, and the statistical character of the resource as to day or night peaking, seasonal variation, and velocity duration curves. The one or several specific areas to be fully instrumented for WTG site selection can then be identified.

WTG Availability

Since the total resource committed in this particular portion of the effort is likely to be in the neighborhood of a million dollars, at this point the utility might reasonably delay making the commitment until they can foresee with some confidence that:

- (1) An operational and reliable WTG designed to a wind speed range adequately matching their resource will be available on the market in three to four years.
- (2) The projected price of that WTG, in which they can have some confidence, fits approximately the utility estimate of a break-even price.
- (3) No major integration or operational problems are anticipated at least to the level of penetration projected for the first phase of development.

Selection of Areas for Further Evaluation

At this point selections must be made of a number of potential WECS locations to be instrumented more completely. With the present conventional approach of standard wind instruments with a 110 volt AC power supply, strip chart recording, and manual conversion of strip chart data to magnetic tape for computer analysis, this process is likely to cost about \$20,000 per site on the average for the first year's data. Additional years and additional sites will be less expensive, assuming that the used equipment is reused in new locations. Further cost reductions are likely when the commercial market arranges recording of data for easier transcription to a digital

computer, a reduction in power requirements eliminating the external power supply, and possibly telemetric data recovery to eliminate frequent data recovery trips to the more remote sites.

Nevertheless, because of the cost, a careful review will be made of the topography, the wind data already located, biological and other indicators, and any analytical modeling available to aid in the selection of sites for further instrumentation.

Land Use and Availability

The availability and purchase or lease cost of the candidate land areas should be spot checked. Availability is the most likely problem, since the economic value of land as a wind resource greatly exceeds the value of agricultural, forestry, and almost all industrial uses. National Forest land is often available. Sites that are doubtful, but not impossible, should usually be so noted and carried on through screening.

Environmental Impact

Esthetic impact may be a difficult judgment to make. As noted earlier, even a high and exposed location may be masked by intervening foothills, atmospheric haze, or simply distance. At this time it is extremely uncertain how adverse public reaction will be to the addition of "windmills" to the landscape. Vertical axis machines may be significantly more acceptable.

Of the other issues listed, only a site of extreme historical or cultural interest might justify not even checking the resource before abandoning interest.

Site-Variable Costs

Sites in mountainous terrain should usually not be eliminated from consideration on the basis of site induced costs before the value of the wind resource is known. A mile of mountain road may, under some circumstances as shown in Section 5.0, serve 26 WTGs, representing an investment of \$20-30M. It is hard to find terrain where the cost of roads, transmission lines, and construction pads would overshadow such a WTG investment.

Weather and Terrain Limitations, Hazards

The utility should also know which of these hazards apply to the sites in question, and determine which have been covered in the WTG design and development testing.

Instrumentation Decision

A decision now must be made as to where to install instruments. The decision will involve in the neighborhood of \$20,000 per instrument tower at present costs for purchase, installation, breaking of the data and removal of the tower at the end of the program. Some of the most promising sites will be extremely inaccessible for installation, data retrieval, and instrument power supply. Compromise site selections that will be regretted when data evaluation begins should not be made.

The coverage of potential sites should be broad enough to assure that the best resources do not remain undiscovered. In a large area of complex terrain this may be difficult to accomplish at modest cost.

To minimize the number of bad instrument site selections and to speed the screening process, if this is considered urgent, use may be made of mobile field survey equipment either incorporated in a van or of the simple unpowered portable type. These units can be juggled around rapidly, first getting samples of the relative energy of the more promising sites and initial surveys of the variability of the energy at several locations surrounding the promising known locations. Eventually, however, a number of fixed installations must be installed and run for a minimum of about a year. Including the initial decision process and moving a few sites, the process will probably take a minimum of two years.

On the basis of these data the utility will undertake the task of deciding among the various resources found, which to develop first, and whether the eventual goal is to develop two or more sources for geographic diversity or to only develop a single location. The wind resource data will be analyzed in terms of total energy available per site, number of units that can be installed in the field at a reasonable energy output and capacity factor, and matching of the diurnal and seasonal availability of wind energy from the sites with the utility demand.

4.9 PHASE 3: WECS PRELIMINARY DESIGN AND INDIVIDUAL WTG SITE SELECTION

The utility must now decide whether wind power continues to look promising (for that utility) or whether to abandon the pursuit. If in the evaluation it is determined that the projected economics and operational solutions are acceptable, the utility will select the resource areas for exploitation and move on to the next stage of WECS detail design. If the decision is negative, the project should be put on the shelf until such time as major factors such as fuel cost projections and WTG prices change in a direction favorable to a positive decision.

Prerequisites for entering this stage of development are the following minimum requirements:

- (1) The utility's own application studies combined with any relevant studies from other sources must lead management to the conviction that the economical performance of the WECS system in the context of their utility will be satisfactory.
- (2) The utility's own studies in conjunction with any relevant outside studies available and preferably supported by actual hardware demonstration experience, must lead management to the conclusion that the various operational and integration problems of a WECS in their utility are acceptable.
- (3) An actual WTG of the proper size and rated velocity class must either be available on the market at a guaranteed price that meets the above economic criteria, or management must otherwise be convinced that it will become available within about two years--the time it will take to complete this Phase.

- (4) Adequate evidence of the life expectancy, operating capability, and maintenance costs of the selected design must be available.

A few of the above requirements might be waived if the utility elects to make a small investment in an experimental WECS, perhaps with an appropriate government subsidy or protection against loss. The total money at risk by the time of the completion of the WECS detailed design will rise to a few million dollars as is indicated in Section 7.0. Therefore, there must be a rather strong conviction that at the end of the design an acquisition will be possible and the design investment will not be wasted.

Having selected one or more areas for WECS development, the utility's next task is to undertake the detailed design of the WECS.

4.9.1 Initial Actions

The following actions should be taken early in Phase 3 before major data acquisition and design expenditures have been incurred.

Land Acquisition

Because of the large total investment in this section of the effort, it would be prudent to initiate the effort with certain studies and actions to assure that the WECS resource area under consideration will actually be available for development upon completion of the detailed design and resource assessment. Since the interest will have narrowed at this point to only one or a small number of WECS areas, the effort involved in determining availability should be reasonable. Most of the effort builds upon a less detailed review of the same issues in the site-screening process of Phase 2.

If the land is in private ownership, the utility must determine its value, cost and market availability. Assuming that the land cannot be acquired by eminent domain proceedings, the utility may also find it desirable to obtain a prior commitment in terms of purchase options if these are not too expensive. The options would preclude the possibility that after extensive survey and Public Utility Commission hearings, the owner might decide that the land is indeed much more valuable than he thought at the beginning and set an exorbitant price. Lease arrangements with energy royalties paid to the owner might be considered.

In most states and locales various land use restrictions must also be satisfied. This may include zoning law if the land is in or near an urban region. If the land is agricultural or forested, the land use procedures may be more flexible, but the particular case of WECS application has not been clarified and will generally not be covered under existing law.

If the land is under federal, state, or local government jurisdiction, determinations must be made whether it will be available for WECS development and on what terms. An example of this procedure is outlined for the Island of Oahu in Section 5.1.2.1. The rules are different for each level of government ownership and for each locale and may involve the joint decision-making effort of several government agencies.

Legal Staff Study of Possible Adverse Actions

It will be wise for the legal staff of the utility to examine all the possible legal hurdles and adverse legal actions that might be faced by a new generation system such as this. In some cases, for instance, as noted in Section 5.1.2.1, it may be wise to get specific clarifying or enabling legal amendments passed in advance so that the legal road through approvals and land use permissions is clearly charted in advance. Actions of this type may require a lead time of one to two years and that is about what would be available to the utility in Phase 3 of the WECS planning and design process.

Site-Variable Costs

A review of site-variable costs will be appropriate at this time. The detailed costs will not be known until the end of the design study. However, at the outset it is wise to check whether there are any costs in road building, transmission, construction pads, etc., that could be large compared to the basic costs of the WTGs. Generally there will be little work involved in this effort provided the WECS is sized to at least 100 megawatts capacity and the land involved is not extremely mountainous. This initial estimate of any large site-variable costs will also support the preparation of material for the Public Utility Commission hearings that will be necessary.

Environmental Problems

A review should also be made of the key environmental problems to determine whether any might preclude the development of the WECS after it is designed. The esthetic impact will probably be a key item. Although none of the other impacts are likely to be significant in Phase 3, they should also be reviewed to avoid a surprise after major investments have been made. The study will also provide preliminary input material for the environmental impact statement that will be necessary.

Esthetic Impact

The key environmental issue that could bar WECS development is the esthetic impact of a number of wind machines on the appearance of the landscape. Some preliminary review of this and a decision relative to various potential WECS sites will have been made in the previous area-selection effort. If in the judgment of the utility the esthetic impact is likely to be sensitive, it will be wise at this point to do a study of mutual visibilities of the various areas in the WECS resource field as seen from various sensitive regions nearby.

This kind of evaluation can be done by analysis of existing surveys and maps backed up by a small amount of field survey and photography. However, if the terrain is relatively complex it may be more efficient to do the job by various computer-mapping techniques now available. These techniques essentially develop a contour grid for the full land area involved and can then very rapidly output pictorial displays of the visibility or obscuration of all portions of the land involved as seen

from any specified point on the surface. These techniques are being used today for advanced review of the visual impact of various types of developments in mountainous terrain, such as mines, roads, fire breaks, dams, quarries, etc.

If the problem is particularly serious and requires participation by nontechnical people, such as Coastal Planning Commissions and participants in environmental impact hearings, it may be profitable to develop photomontage representations of the WECS field with a large number of machines in place as seen from a given sensitive point, such as a resort hotel or the civic center of a small town. The techniques to prepare accurate photomontages of this type have been developed by The Aerospace Corporation for the SEAM Program of the National Forest Service. The system, entitled MOSAIC, is summarized in Reference 4-6.

In this type of application, a photograph is worth far more than the proverbial one thousand words because it answers questions such as how big they really look, how many of them can really be seen from a given sensitive place, and whether they will really be invisible beyond a certain distance. The photomontage technique can be very effective in either confirming or calming public fears of the unknown by giving a clear visual statement of what the esthetic impact will be.

4.9.2 Financial Issues

The utility must be ready to finance the acquisition of the WTGs and the other equipment required for the WECS field. A detailed cost estimate and financial analysis must be undertaken in Phase 3 to assure the financial feasibility of the project.

In one sense the financing is more difficult than the normal acquisition of generation capacity because it involves a substantial capital investment that does not contribute full-generating capacity to the utility. Although the WECS has some capacity displacement, it must normally be backed up with other more reliable generation equipment.

On the other hand, the WECS investment has three very favorable features compared to conventional generating equipment. It can be bought in small segments with a total investment of as little as a few tens of millions of dollars having approximately the same cost effectiveness as a larger investment. The total money invested a few years in advance in the search for the wind resource and the study of the application will be shown in the next section to be quite small. And, once the actual WECS construction starts, the generation capacity can be on line and beginning to pay for itself in about a year from the first breaking of ground compared to the five to 10-year delay experienced by conventional plants.

Thus, although the WECS as a generating system is capital intensive, the investment can be made in reasonably small sums and does not involve a long lag time with interest paid on capital prior to the start of the return on investment.

4.9.3 Resource Data for WECS Design

In Phase 3 the utility must commit a few million dollars of instrumentation for detailed wind resource survey of the area(s) proposed for immediate WECS exploitation to obtain the necessary data for the WECS design and WTG siting. The data gathered in the previous site selection will normally tell the utility where the highest energy locations are located. Given some general idea of the distribution of energy in the surrounding field and the overall dimensions of the resource, the direction of the prevailing wind, the preferred direction of WTG arrays can be judged, but there will remain a considerable uncertainty about this and other details in the field.

For instance, there may be spots within the field where a particular shape of terrain causes a separation or otherwise masks the energy over the area of a ridgetop. WTGs sited in this masked area will fail to pay their way. This failure is not a small issue because the utility's investment is based upon the expected return in energy value of the WTGs. It will be shown elsewhere in this report that selecting a site with 2 mph less wind speed than expected can result in a loss of capital value of approximately a quarter of the WTG value. In other words if the utility can afford to pay one million dollars for a given WTG on a given site, the same machine may be worth a quarter of a million dollars less if the wind speed at the site is 2 mph lower than predicted. In a large WECS field of hundreds of units, losses of this sort on the ill-advised choice of a few dozen sites can look very large to an economically-oriented management.

If the cost of instrumentation capable of minimizing such losses is modest compared to the risk, very intensive and detailed surveying will be done. Otherwise, the risk is believed to be very high. Considerations in the detailed resource assessment of a proposed WECS site are discussed further below.

Previous to this effort the instruments in the field used to select the WECS area and define its approximate dimensions might typically be located at about 10 sites. Assuming that the size of the field will allow installation of about 100 WTGs, the designer needs to know the temporal wind speed and direction distribution at every spot in the field where he will consider siting a WTG before he can do an intelligent and conservative job of designing the field.

It would be a fortunate situation if the development status of interpolation techniques for wind data in mountainous terrain would allow interpolation of the wind flow across a space of several WTG sites between instrument locations. Unfortunately there are no generally applicable techniques available for this task. Simple linear interpolation would only be acceptable if it were known that the energy profile in the desired direction such as along a ridgetop was relatively uniform and linear. The small amount of available evidence strongly suggests the opposite to be true (References 4-7, 4-8 and 4-9). In terrain with strong regularity, as for instance ridges of constant height and simple, parallel, almost two-dimensional geometry, it may well be that interpolation of data over large spaces along a ridgeline will give acceptable results. It is reasonably certain that in badly jumbled mountainous terrain typified by Kahuku Point on Oahu, and the upwind

region of Tejon Mountain in the California Tehachapi's (Reference 4-2), the velocity at any given moment as well as the total annual energy available at nearby points along a ridgetop will vary greatly.

The scale of variability is probably in some way related to the scale of terrain features; that is, a spur on the ridge with a dimension of a quarter mile will cause an anomalous wind flow with dimensions of a quarter mile and a boulder with dimensions of 30 ft will cause a corresponding perturbation of the flow. Since in many mountainous terrains the size of variable surface features goes down to less than the size of a 200 ft diameter WTG, it can be expected that the wind velocity and energy variability will exist down to a scale smaller than a WTG.

It might be hoped that flow modeling techniques could be developed to give a more flexible interpolating ability between points of instrumentation and allow a broad instrument spacing along a ridge. Unfortunately, flows of this sort will generally involve separation zones. While it may be possible to represent the complex terrain of a given ridge in enough detail to model the flow over the terrain, it is a general impossibility to analytically model flow of a three-dimensional nature with separation. Therefore, successful analytical modeling of wind resource flow at this scale in terrain likely to cause separation cannot be expected. The state of the art will not sustain it now or in the foreseeable future.

At the present state of the art, then, it appears that the only safe survey technique is to install an instrument at every potential WTG site in the WECS region.

Fortunately, the cost of a survey of every potential WTG site before the construction is committed is not a forbidding expenditure of funds, computational effort, and time delay.

A reasonable technique for the survey is as follows:

- (1) An open grid of several dozen instrument towers will be installed first to get a moderately detailed picture of the energy resource distribution over all of the likely ridges, saddles and canyons in the mountainous region of interest. A few mobile instruments may also be used for spot checks to speed up the survey process.
- (2) After a few months of survey the decision is made that certain regions such as a few ridges show the highest energy and will be developed first.
- (3) These particular ridges will be instrumented in a tight array, containing an instrument tower on every site that is likely to support a WTG.
- (4) After about a year's data are taken at the sites, and correlation studies run on the results, commitments will be made to install on specific sites, the detailed design of that particular portion of the WECS will be completed, and most of the towers will be taken down and moved to a new series of sites.
- (5) This process will be continued through the WECS area at whatever rate of exploration and construction is desirable for the utility.

This is a safe and conservative method of designing, surveying, and constructing a WECS field, and so long as it is not too expensive to undertake, it is the preferred technique until or unless experience and research prove that shortcuts are acceptable.

4.9.3.1 Vertical Survey Requirements

A key problem in mountainous terrain is the lack of knowledge of the vertical velocity distribution over varying hill shapes. This problem has been approached with both analytical and physical modeling and the results are unsatisfactory to date. Velocity gradients over mountain tops may sometimes be similar to those in flatland, but it is known from the few instances of available data (References 4-7, 4-8) that the actual velocities sometimes have lower gradients, sometimes have higher gradients, and occasionally show a local overspeed condition close to the surface with speed decreasing with increasing height. Worse yet, Putnam in Reference 4-8 shows that a given peak may show all of these characteristics in varying degrees according to which way the wind approaches it.

A sample computation will indicate the significance of this effect. Assume a vertical velocity gradient over a ridgetop with an exponent of $n = -0.050$ in the relationship:

$$\frac{v}{v_o} = \left(\frac{h}{h_o} \right)^n$$

as shown in the left-hand profile of Figure 4-1. This negative gradient exponent corresponds to the wind tunnel results of Reference 4-7. It also corresponds to the gradients found on Mount Washington (Reference 4-8) when the wind blows from the East. At that location, the gradients from all other directions are positive. The gradient exponent between the 30 ft and 180 ft levels of the tower at Kaena Point is +.083, based on six-months data from all wind directions. The tower data shows a negative gradient exponent of 0.018 between 30 ft and 90 ft, but the 90 ft data are under some suspicion. The negative exponent assumed in Figure 4-1 could probably be described as a "worst-on-worst" case of an extremely limited data sample.

The performance of the DOE/NASA Mod 1 WTG is specified in terms of the power output for a given wind speed at a 30 ft elevation. The supporting design computations assume a gradient exponent of 0.167. This assumed profile is the right-hand curve shown in Figure 4-1.

This profile is implicitly assumed if a single wind speed reading is taken at 30 ft altitude and the WTG power is calculated from the performance specifications. For a WTG diameter of 190 ft and hub height of 140 ft, the resulting estimate of the integrated energy flow through the turbine disk is about 2.5 times too high if applied to the situation where $n = -.05$ (Table 4-2). If the wind speed is read at 60 ft, and corrected to 30 ft based on $n = +0.167$, the assumed profile inferred is the dashed line of Figure 4-1, and the energy estimated is 1.6 times the real value. If the reading is taken at 100 ft, the error is only about 20 percent, but even this is a significant error in assessing the economic value of a particular site.

Figure 4-1. Effect of Vertical Profile Uncertainty

TABLE 4-2

EFFECT OF VERTICAL PROFILE UNCERTAINTY;
WIND ENERGY ERROR vs. INSTRUMENT HEIGHT

$\frac{h}{V^3/V_o^3}$	30'	60'	100'
	x2.5	x1.6	x1.2

Major error is also possible if the instrument is located inside a crestline separation zone. This error is in the direction of underestimating the resource.

Of course, the preceeding only describes the energy flow through the disk, and approximates the energy conversion in the WTG middle speed range. When the wind is well above rated speed, the WTG will put out rated power regardless of misleading instrument readings. And the power for wind speeds well below startup remains zero. The amount of time at both extreme speed ranges moderates the above effects.

With this great uncertainty, the height of a single instrument on a design survey tower may be very critical for obtaining correct results. A 30 ft tower, which is commonly used and inexpensive, may result in drastic errors in the energy estimate. Serious error can probably be avoided if all instruments are set at approximately hub height of the planned WTGs. However, the cost of 140 ft instrument towers for every WTG site of a planned WECS will be excessive based on today's tower designs.

A reasonable alternative, recommended until more is known on the subject, is to use towers of modest cost, say 30 to 50 ft in height, at most of the WTG sites, but to intersperse them with perhaps every fourth tower going up to above 100 ft. These higher towers should be equipped with two or three instruments. The small percentage of higher towers would not greatly increase the cost, but should give warning if some of the lower towers are in local overspeed regions and giving data which is not representative.

While this exploratory technique is recommended, this is clearly an area calling for detailed experimental work to build up confidence in economical shortcuts that may be possible. This problem is illustrated with real data from the Kaena Point tower in Section 8.3.

4.9.3.2 Large Scale Array Interactions

A serious potential problem has been identified in the course of this study. In this study and the previous study (Reference 4-2) of WECS locations in mountainous terrain, it has appeared that a promising technique for maximizing energy conversion in a mountainous area with a limited geographical extent of the energetic resource is to set up arrays of WTGs at a spacing of only one to two diameters along the crests of consecutive ridges. Only those ridges where the alignment is approximately normal to the prevailing flow direction can be used in this manner. This technique is very promising for allowing maximum conversion of energy in the area in which it is most profitable. Without this technique, the amount of energy that can be converted from a given resource might be an order of magnitude lower and less economical.

In the design of such a WECS a judgment must be made as to how far downstream the next row of WTGs may be installed. The rule of thumb used in this study and the previous study has been that the wind will recover full energy in approximately 10 diameters of the wind machine; in other words, the minimum spacing between consecutive ridgetops for the WECS field should be on the order of 10 diameters (1900 ft for the Mod 1 WTG).

While this model seems reasonable, a certain phenomenology of the flow has been assumed. It is assumed that there is no separation of the flow between ridges and the minimum practical spacing is set by the rate at which the individual WTG wakes mix back into the stream.

By analogy with the flow over aircraft wings, entirely different flow phenomena can be postulated. (1) It is known that a very small barrier installed on the top of a wing will act as a spoiler and cause total separation or stall of the airfoil; and (2) it is

also known that certain carefully designed subsidiary airfoils or other obstacles known as "turbulators" can prevent separation that would otherwise occur on the top of an airfoil by encouraging the mixing of the local free stream air with the turbulent boundary layer to maintain flow momentum near the surface. The wakes of these turbulators will be dispersed in a rather short distance downstream because of the strong forced mixing they produce.

It would appear that either of these flow phenomena could be induced by a row of tightly spaced WTGs along the top of a ridge normal to the prevailing wind. The closely spaced turbines could act as an obstacle and cause a major separation from the top of the mountain whose height is governed by the mountain height rather than the WTG height. Such a separation zone might be assumed to take 10 mountain heights to remix, which is significantly different from the assumption used. On the other hand, individual WTGs could induce secondary flows which could result in the action of a turbulator (see Figure 4-2) which would discourage separation. This would accelerate the mixing of the WTG wake, allowing shorter spacing. The secondary flows postulated in Figure 4-2 are those resulting from induced vorticity when the rotor disk is normal to the oncoming stream. If these effects are desirable, they can be greatly amplified by tilting the rotor axis relative to the oncoming flow and using the rotor lift vector to forcibly deflect the flow. As shown in Figure 4-3, when the rotor is operating near the ideal 3:1 velocity ratio, dramatic flow deflections can be accomplished with small rotor tilt angles and small energy loss.

This gives a powerful tool for terrain flow control that can be used in various ways. For instance, a row of WTGs along a ridge could be alternately canted up and down as shown in Figure 4-4. This should result in forced surface layer mixing much stronger than the unforced secondary flow of Figure 4-3.

Another possible use for this flow control tool is to cant all WTGs in the row upward, forcing the leaving flow down against the lee face of the mountain, to retard lee slope separation. The action is analogous to the operation of an inefficient airfoil as a leading edge flap. In this case, the performance benefit is not only to the next row of WTGs downwind, but also to the present row. Of the two alternative flows over the ridge, separated and attached, the attached flow has substantially higher wind speed and energy at the crest than the separated flow. If the WTGs cause a lee slope separation, they will substantially reduce their own energy source.

It appears that manipulation of the mountain flows by using the WTGs as flow controls may be a profitable tool for exploitation of mountain wind resources. However, it would require substantial understanding of the wind flow, and availability of canted rotor options in the available WTGs.

If consecutive closely spaced ridges are exploited in mountainous terrain before these large scale array interactions are understood, certain actions should be taken to prevent costly surprises. A simple, but effective protection would be to develop the field in the following way. The first installation of the WECS development would be the row of WTGs on the most upstream high energy ridge. Careful surveys

Figure 4-2. Wind Turbine-Induced Secondary Flows

Figure 4-3. WTG Wake Downwash Deflection by Rotor Tilt

Figure 4-4. Alternate Canting of WTG Rotors to Augment Surface Layer Mixing

would be made of the wind/velocity ratios between this ridge and the consecutive downstream ridges starting before the WTGs are built and following through for a period of time after the construction reaches the desired spacing. If no adverse effects are noted on the downstream ridges, the next downstream ridge would be developed, etc. With this order of development any surprise of blanketing downstream arrays by the upstream row would only result in a reduction of the total planned field capacity, but not in the installation of badly blanketed machines and a severe financial loss. Plans might then be made to explore the possibility of changing the spacing or tilt angles of the existing array to recover the energy value of potential downstream arrays.

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SYSTEM SYNTHESIS

A conceptual synthesis of a WECS on the Island of Oahu is required to obtain basic data for other sections of the study and to identify technical, economic and environmental issues that will pertain in the real undertaking. The first goal of the synthesis is to define the technical design to a level that permits the calculation of a realistic WECS power output time history for use in utility impact analyses. The second goal is to provide a framework for realistic estimates of the cost of necessary support equipment and facilities (e.g., transmission systems and roads) and to identify any problems inherent in its incorporation into the HECO generation and transmission system. As a side benefit of the effort, an understanding of the problems involved in actual siting tradeoffs in the design of an operational WECS has been developed.

The power output time history of a WECS could be represented by calculating the history of a specific machine at one instrumented site for which wind data are available and multiplying by the number of machines that can be installed in the adjacent area. This technique has been used in other studies (References 5-1 and 5-2) because data were not available for a better representation. It may be an adequate description of a WECS system in flatland with no variation of surface roughness or vegetation, although there is no proof of how uniform the winds of such an area might be. But as a representation of a mountain WECS, it eliminates a key characteristic of the system which is believed important to capacity displacement, economic value, and other considerations. This characteristic is the inevitable diversity of energy and directional distribution of the wind blowing over various parts of a complex mountainous terrain.

A true description of a WECS power output time history can only be obtained from data gathered during the WECS site survey and design phase (Phase 3) described in Section 4.9. Unfortunately, information from such a study is not yet available for Oahu or any other mountain wind resource, and will not be available for perhaps three or four years. The data retrieval effort required to obtain it is both time consuming and moderately expensive.

On the other hand, the teams working the wind resource on Oahu are probably further advanced in retrieval of detailed data than those at any other site in the country. In the framework of the selection sequence described in Section 4.2, the Oahu team has completed the search necessary for preliminary WECS feasibility evaluation and has almost enough data in hand to justify a WECS area selection.

If the selected area is the Kahuku region, surveys of a total of four sites within the region are available but with inadequate time overlap (at the time of this study). While this availability of data is less by one or two orders of magnitude than that needed for a true design study and WECS performance evaluation in the context of the HECO utility, it is sufficient to build a credible model from which useful information can be extracted.

Because insufficient input data are available for support of a true WECS design and performance analysis, this effort may more accurately be described as a scenario WECS design. The goal is to build a model that looks as much as possible like a real WECS in mountainous terrain so that the unique characteristics, problems, and advantages such a WECS will show in utility application can be identified.

5.1 SCENARIO WECS SITE SELECTION FOR SYSTEM SYNTHESIS

A scenario WECS site selection for the Island of Oahu was done as a study task. It should be emphasized that the real selection for actual development has not yet been made by the Hawaiian members of the study team.

The site-selection criteria of Section 4.5 will be applied in cursory fashion to select a WECS area on Oahu for system synthesis. In the context of Section 4.5, the Oahu case involves mountainous terrain wind resources, and therefore, the value of the resource must dominate the selection procedure.

Of the remaining criteria listed in Section 4.5, the only two that do not apply on Oahu are icing and snow, since the height of the mountains is not high enough to reach the freezing point during the coldest weather in this tropical climate. However, only a few key issues will be critical to site selection. The others become minor problems and issues to be addressed in the WECS design and development.

5.1.1 Wind Energy Resource

Oahu has generally mountainous terrain, and therefore the first screening should be for the best wind energy resources.

5.1.1.1 General Topography and Flow Guidelines

The Hawaiian Islands lie in an area somewhat north of the equator where the prevailing wind over almost the whole year is the tradewind approaching from a northeast to easterly direction. In undisturbed areas over the ocean the wind averages 10 to 12 mph and varies very little diurnally or seasonally except for a brief time during the winter months. Then, the tradewind belt switches far enough south that the Islands get a few cyclonic storms and westerly winds.

Oahu has two mountain ranges lying across the tradewind directions; the Koolau Range on the windward side and the Waianae Range on the leeward side. Three mountainous points of the island on the north, west, and east corners are exposed to the tradewinds in such a way as to encounter strong local flow accelerations. Strong local accelerations are also encountered in the notches, passes, and cols of the mountain ranges. All these local accelerations are augmented by the subtropical inversion layer which usually provides a stable ceiling over the island at about 6000 ft.

5.1.1.2 Analytical Modeling

The Lawrence Livermore Laboratory (LLL) team has attempted to analytically model the flow of winds over the island. The results have been published in small

fragments through 1976 and 1977 and the studies are continuing. The results were not available in time to assist in the initial siting of instruments used by the University of Hawaii (UoH) for the wind resource search in 1975 and 1976. Comparisons with experimental results in the future may clarify the value of such modeling.

5.1.1.3 Available Sources of Wind Data

The main source of meteorological data for this study was the result of a major effort by Professor Colin Rammage and his colleagues of the UoH, beginning in 1975, to search out and quantitatively evaluate the wind resources of all the major Hawaiian Islands. This effort was originally financially supported by the Hawaii State Government and local county funds, but continuing support has been obtained from the Department of Energy. The effort has been a moderately paced and fiscally conservative one with cooperation from local people in providing secure sites and retrieving data.

In the terms of Section 4.2, the Preliminary Feasibility Evaluation is completed on Oahu and the WECS Area Selection is presently in progress. The map in Figure 5-1 shows the approximate location of the sites operated by UoH, as well as a number of older sites, mostly at airports and military bases, which carry long-term records for correlation. At first glance the coverage seems relatively complete. However, significant omissions became obvious when the data were analyzed and used. There is practically no coverage of the high mountain crests and passes of the windward Koolau Range. This omission is made understandable by onsite inspection of the terrain. Most of the windward mountain crest is a rugged lava and ash escarpment covered with rain forest jungle. It is not totally inaccessible, as there are crest road accesses at the two ends, at two central passes, and a backpackers trail along the crest. Nevertheless, a limited budget, manpower, and the need for an AC power supply to drive the available conventional instruments, discouraged the exploration of the more remote areas at higher altitudes.

It can be argued that construction of WTGs in the more remote areas will be too expensive anyway, but in Section 5.3.4 it will be shown that this differential is not conclusive except in the most extreme terrain. It does appear that the best resources are at altitudes below 1000 ft, but there are not enough data at the higher altitudes to confirm this opinion.

Subject to financial and manpower limitations, and the demands of survey work on the other islands, the wind survey of the Island of Oahu has progressed steadily. Many early sites that appear to be poor wind resources, such as those in the Central Plain, have been closed and the instruments moved to new locations. The data are recorded in digital form on inexpensive tape cassettes which are collected and transcribed to conventional computer tape.

The survey has been amplified from time to time by location of the University's two mobile meteorological vans at different sites for a few days each to obtain a better understanding of the variability of wind flow over short distances of terrain and to

Figure 5-1. Locations of Wind Survey Sites

checkout possible new instrument sites. A new phase of mobile survey is beginning at the time of this report. A review of the general flow characteristics and a large amount of the data obtained to date in the UoH wind energy surveys of the island are given in Reference 5-3.

The UoH team provided running summaries of the monthly averages of wind speeds at their sites, updated from time to time, in the format shown in Table 5-1. These summaries were of great value in the present study. However, as a consequence of running too closely on the heels of the wind search team, the data were plagued with errors of various sorts which had to be discovered and corrected. Similar problems will probably be encountered in future WECS design projects.

The data of Table 5-1 show some problems of comparing various sites. Some sites are closed and others opened at various times. The star symbols in the Table represent months for which the data are incomplete, usually due to instrument failures. The averages noted for these months may be valid if the outage was brief, but in some cases the averages are deceptive.

The instruments at the locations identified in Table 5-1 are all located at different heights on the towers, ranging from 30 ft at several sites to 100 ft at Kolekole Pass. This puts inherent biases in the data because of the wind speed gradient with increasing height. A simple instrument height correction such as the $1/6$ power law is of doubtful validity for mountain crests, as explained in Section 4.9.3.1. Nevertheless, that correction was made to provide approximate 30 ft level equivalent mean values shown in the last column.

Several problems resulted from undertaking the present study so soon after experimental data taking was begun. The first is that less than a year's data were available for a number of the sites used. The correlation system of ratioing the mean wind speeds to those of the same time periods at Honolulu Airport used by the UoH team in Reference 5-3 would have been helpful but was not yet available.

A more serious problem appeared several months into the study. In the course of moving instruments from site to site and seeing erratic results upon the change of an instrument, the UoH team became suspicious of the calibration of several new instruments that had been bought for the program. These instruments were checked. Although they had carried calibration certifications on purchase, they were found to be as much as 30 to 40 percent low in their speed readings. It was possible to rescue all data by recalibrating the instruments and applying corrections, using the records of where various instruments had been installed. However, the effect on the present scenario site-selection procedure was traumatic and time consuming.

Gaps in the wind data from various sites caused by instrument failures, which are usually not caught for several days, also proved very awkward for various types of analyses contained in this study.

These problems illustrate the hazards and shortcomings to be expected in the use of data from a typical wind resource survey. Unless a survey is generous in its financial base, some instruments will be moved to new locations without gathering so much as a year's data at one site and without adequate time overlap to allow correlation bridges between the wind resource at the two sites. Instrument calibration problems are endemic to the meteorological instrument business. While modern data can be rescued if the instrument installation records are adequate, most historical data available from reference sources cannot even be checked. Analysis, correlation, and design techniques used in developing WECS systems must take proper account of these realities and risks.

In the present case, the study effort was fortunate to have a larger wind resource data base than any application study that has come before. It was because of this availability that useful design and output simulation analyses could be run.

In support of their analytical flow modeling effort, the LLL team installed a few anemometers at sites of their selection. One of these, on Kahuku Point, proved to be of crucial value to this study. The data at this anemometer were also taken on cassette tape, recording averages every five minutes instead of the six-minute

TABLE 5-1**

AVERAGE WIND SPEED FOR VARIOUS SITES JUNE 1975 - MAY 1976
DEPARTMENT OF METEOROLOGY, UNIVERSITY OF HAWAII (7-16-76)

	<u>1975</u> <u>June</u>	<u>July</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov</u>	<u>Dec</u>	<u>1976</u> <u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>V</u>	<u>V₃₀</u>
Kaena 30'	13.3	13.5	13.7	10.4	13.2	13.0	7.1	11.9	14.5	16.4	17.8*		13.2	13.2
Kaena 90'	17.5	18.2	20.4	14.9	15.6	16.8	6.5	14.7	18.1	19.3	20.9*		16.6	13.8
Nike 50'	17.0*	15.3	15.2	12.5	14.6	14.3	9.7	12.4	12.6*	16.7*	15.4	14.9*	14.2	13.1
Koko Head 40'						14.2	10.8	12.7	12.9	9.2	17.5	11.1*	12.6	12.0
Tantalus I 40'						9.8	7.1	8.8	10.4		11.0	10.1	10.5	10.0
Opana 35'										13.8	12.6	11.0*	12.5	12.2
Kahuku Lower 60'						7.7	8.0	10.1	15.7	10.8	14.1*		11.1	9.0
Mauna Kapu 40'												12.4	12.4	11.8
Kolekole Pass 100'						13.8	11.2	11.8	14.0	15.1	16.4	13.8	13.7	11.2
Honolulu Airport	14.1	14.5	14.7	12.5	13.2	12.0	8.1	9.6	12.2	11.5	13.1	12.9	12.4	--
Honolulu Mean	12.8	13.4	13.4	11.5	10.7	11.0	10.9	10.1	10.6	11.1	11.7	12.3	11.6	--
University of Hawaii	Data not yet processed.													
Waimano 30'	Too low ~6 mph; site abandoned May 1976.													
HSPA	Site now abandoned.													
Helemano 50'	No data yet.													
Bellows	Data not processed yet.													
Makakilo 30'	No data yet.													
Olomana 30'	Very low winds.													

* Data only for parts of the month.

** Interim data. Calibration corrections and new data updates led to the representative values shown in Table 5-3.

(Wind speed in mph)

increment used by the UoH team, and with a somewhat different averaging technique inside the instrument. Because the present study was closely following the taking of data, the LLL team was able to make available data from only a four-month period. Nevertheless, these limited data were of great value.

A small problem of a correctable nature also occurred in the LLL data. The originally stated location of the LLL site proved to be incorrect by a horizontal distance of about 1500 ft and a vertical distance of about 200 ft. This error was caught and corrected before the data were used. The LLL data taken at this site are labeled "Kahuku Hill" hereafter.

5.1.1.4 Selections Based on Wind Resource Criteria

Review of the wind data as they became available led to the identification of five possible WECS areas for Oahu. These are listed in Table 5-2. Essentially they are the two ends of each of the two mountain ranges that stand across the prevailing wind direction plus a pass in the leeward range. These five potential sites were considered more carefully using the other criteria for site selection to determine which would be most appropriate for the scenario WECS design of Section 5.3.

TABLE 5-2
LIST OF POTENTIAL WECS SITES

<u>Name</u>	<u>Location</u>
Koko Head	SE Corner of Oahu
Kolekole Pass	Near Center of Waianae Range
Kahuku Point	N Corner of Oahu
Kaena Point	W Corner of Oahu
Honouliuli Region	E End of Waianae Range

Some possibly significant resources are necessarily omitted from Table 5-2. There are no data on the passes in the Koolau Range, typified by the Nuuanu Pali. No instruments were set up in the Nuuanu Pali by the UoH team out of deference to local values. This is a historical site of great local significance; the pass where King Kamehameha won the final battle of his campaign to consolidate rule of the Hawaiian Islands by forcing the last contingent of his opponents over the cliff. In addition to the local historical and cultural significance, the spot is also a tourist attraction of great scenic beauty. It probably is also the strongest wind resource on the island. Although it could not itself be developed, the Nuuanu Pali is probably representative of other sites along the crest of the range, some of which could be developed. Encouraging data are now coming in from Tantalus Tower, a newly instrumented site which is just downwind of the crest of this range. The search of the ridgetop cols and passes will be difficult because the terrain is rugged and inaccessible.

Another omission that may be significant is due to inadequate data from the Nike site on the crest above Makapuu Point. The instruments at this site were repeatedly destroyed by vandalism and the site was eventually abandoned. The small amount of data taken indicate moderate winds, but biological indicators in the area suggest that strong winds can be found. The nearby instrument sited on the same corner of the island at Koko Head survived in a fenced area. It has proved to be one of the two highest energy sites so far located on the Island of Oahu. The high energy of this part of the island is probably caused by the combination of acceleration of the tradewind around the point and crowding of the flow through the channel between Oahu and nearby Molokai Island.

On Kaena Point, it has not been possible to extend the survey up the ridge to the higher elevations beyond the tower located on the grounds of the Hawaii Tracking Station. There may be a considerable area of higher winds at the higher elevations.

5.1.1.5 Resource Magnitude Estimates

An attempt is made in Table 5-3 to develop and summarize estimates of the effects of the combination of the wind resource intensity, extent, and geometry on the output variables of a WECS exploiting that resource. The second column shows the approximate length of ridgeline normal to the prevailing wind. The mean annual wind velocity shown is that of the single data site for four of the five sites under consideration, and for all but Kaena Point represents less than one year's data. For Kahuku, which had four data instrument sites, it is the value of Kahuku Upper, the best site with one full year's data. The Kahuku Point value listed in Table 5-3 is less than the short-term average of 20.4 mph for Kahuku Hill (LLL data). Each of the mean wind speeds shown is a representation of a local average that is highly variable over the site and inadequately surveyed at this time.

For each site, the ratio of mean annual wind speed to the assumed WTG rated speed of 10.15 m/s (22.7 mph) is shown. This is approximately the optimum rated velocity for installation on a site with an 18 mph annual mean speed (Reference 5-4).

The next column shows the rated power per mile of array for the array length estimated for the site, assuming the closest possible WTG spacing of 200 ft (26 WTGs/mile) and 1.5 MW/WTG rated power. This is the largest rated power possible in the estimated lineal space. Larger spacing and lower total capacity would normally be preferred.

The capacity factors corresponding to the site mean wind speeds are given in the next column, based on correlations that are explained in Section 8.4.1.

The average WECS power and the energy collected per year are thus estimated as shown in the next two columns. These estimates are probably on the high side of realism.

It is immediately evident that the two highest energy sites, Kolehale Pass and Koko Head, are not likely to sustain a large enough WECS capacity to make significant penetration in the HECO utility, each having three percent of the

TABLE 5-3

SUMMARY OF COMPARATIVE WECS SITE EVALUATION

Potential WECS Site	Array Length Mi	Representative Mean Annual Wind Speed V_{30} mph	Number of Instrument Sites	Mean-to-Rated Speed Ratio	Approximate Rated Power Capacity P_R , MW	Approximate Capacity Factor	Approximate Mean Annual Power P , MW	Approximate Annual Energy E , kWh $\times 10^9$	Array Altitude ft.	Diurnal Peaking	Exposure	Land Title/ Zoning	Possible User Interference	Esthetic Impact	Access and Construction Cost	Comments
Koko Head	1	22	1	.97	40	0.65	26	.228	600	Mixed	NE-S All Trades	State Conservation	-----	Severe	-----	Esthetic issue controls. Too small for major impact. Search further inland.
Kolekole Pass	1	22	1	.97	40	0.65	26	.228	1800-2200	Mixed	NE-NW Partly Trade Shielded	State Conservation	-----	Slight	-----	No esthetic problem. Too small for major impact. Profitable. Survey for size.
Kāhuku Point	12	18	4	.79	480	0.50	240	2.102	50-1000	Day	NW-E All Trades	Private Agriculture	U.S. Army (Maneuvers) U.S. Navy (2 Antenna Farms) Comsat Corp (Antenna)	Slight to Moderate	-----	Moderate esthetic and user interference problems. Large enough for major impact. Very profitable. Major opportunity.
Kaena Point	8	16	1	.70	320	0.40	128	1.12	1000-2000	Mixed	S-NE Partly Trade Shielded	State Conservation	Hawaiian Satellite Tracking Station	Slight	-----	Moderate esthetic and user interference problems. Resource size and maximum uncertain. Need further survey. Economics fair to poor now.
Honouliuli Region	3	14	1	.62	120	0.30	36	0.315	2000-3100	Night	W-S Partly Trade Shielded	State Conservation	-----	Moderate	Significant	Esthetic problem moderate. Resource small. Economics look poor.

present installed capacity of 1192 MW. Kahuku Point is the highest mean wind speed site with enough capacity for significant penetration. This estimate projects 38 percent of present HECO capacity as the maximum potential penetration by the Kahuku resource.

Before going on to other factors, a few items relevant to the wind resource are noted in the Table. The elevation of the various sites above sea level varies greatly, as noted. The lowest altitude potential site, Kahuku Point, shows some day peaking of power which should improve the load matching. The highest altitude potential site, Honouliuli, is night peaking. The prime directions of wind exposure are listed.

5.1.2 Influence of Non-Resource Criteria on Oahu Site Selection

Of the remaining site-selection criteria of Section 4.2, only the land use issues and esthetic impact are clearly critical to WECS site selection on Oahu. More marginal issues are site access and construction problems and interactions with nearby land users. The remaining criteria become only WECS design considerations. A similar reduction to very few relevant criteria will probably occur for most actual site selections. The key criteria for Oahu are addressed below.

5.1.2.1 Land Use Laws

A study of Hawaii's land use laws as they relate to WECS site acquisition was made by Dr. R.M. Kamans* of the University of Hawaii under subcontract to Aerospace. The following material on the way that land use laws in Hawaii will affect the availability of land that might be used for wind energy conversion systems (WECS) was developed specifically for this report by Dr. Kamans.** More particularly, the type of land use districts or classifications where WECS are most likely to be acceptable are identified along with the government authority which regulates land use in such districts. Modes of obtaining WECS sites on public land in Hawaii are also outlined.

Centralization and relative simplicity characterize government functioning in both state and local operations in Hawaii. This also applies to land use controls. The strongest authority is held in the central government in Honolulu. The counties operate under general statutes which leave relatively little room for local variation. Varying strengths of political leadership and capabilities change the pattern slightly from time to time. This is particularly true in the City and County of Honolulu

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** Aspects of land use controls which are not of great relevance to WECS, such as property tax shelters for land covenanted to remain in agriculture and the laws relating to the Hawaiian Homes Commission and large private estates, are omitted. Also omitted, not for reasons of irrelevance but because of limitations of space, are the statutes and regulations relating to environmental controls.

where the concentration of population and wealth gives the local government a leverage much larger than that enjoyed by the counties of Kauai, Maui, or Hawaii. A uniquely strong centralization characterizes government operations in the State of Hawaii. Land use regulation must be understood within that context.

Land Use Laws

The forested areas lying above Honolulu and other centers of population in Hawaii became subject to government controls long before the state instituted general regulation over land use. Controls were imposed to protect the watersheds and other forested expanses when Hawaii was still a territory. Twenty years ago, two years before statehood, a statute (Act 234, Session Laws of Hawaii, 1957) created forest and water reserve zones in each county, including all public and private lands within existing forest reserve boundaries as they existed on 21 January 1957.

These zones are under the administrative control of the State Department of Land and Natural Resources (DL&NR). Such nonconforming uses as farming and residential sites which were being made at the time zones were created, or when controlling regulations were first adopted, may be continued, but otherwise the only uses to which these lands may be put are those permitted by the DL&NR. Two modes of authorization are provided by statute:

- (1) Temporary Variances. Where "good cause is shown" and the use if found by the DL&NR to be compatible with "good conservation practices," the department may permit temporary variances from zoned uses. While this arrangement may not be sufficient for siting a WECS, it might be appropriate for a testing facility designed to operate over a limited period of time.
- (2) Subzones. Long-term uses of forest and water reserve lands for commercial and other purposes may be allowed by the DL&NR by its creation of subzones within such areas following a public hearing of each such proposal. The statute providing for the creation of subzones (Hawaii Revised Statutes, Sec. 183-41(1)) explicitly excludes the use of forest and water reserve lands for "utility purposes." It would require an authoritative legal finding, as by the Attorney General, to determine whether using land as a WECS site would be a "utility purpose." However, it is suspected that it would be found that a testing facility would not violate the intent. On the other hand, a commercial generating unit tied in with the regular HECO distribution system would probably be found to be such a prohibited purpose.

It should be noted that the public policy enunciated by this statute is to encourage multiple use of reserved land. The DL&NR is instructed to "allow and encourage the highest economic use" of the land subzoned "consonant with requirements for the conservation and maintenance of the purity of the water supplies arising in or running or percolating through the land," as well as compatible with the preservation of open spaces. This policy might favor the use of reserve land for a purpose as important as testing the feasibility of a new and environmentally favored energy system, such as a WECS.

The DL&NR not only sets the boundaries and permitted uses of any subzone, but also prescribes regulations under which these uses may be made. Such regulations are enforceable by court order at the suit of the Department or of the owners of land directly affected (NRS 183-41(5)).

Planning and Zoning of Land Use

Hawaii has one of the earliest and most comprehensive state planning laws in the nation. First established in 1957 (when the predecessor to what is now the Department of Planning & Economic Development was started by the Territorial Government), the planning program contemplates the creation of a statewide master program for planned development to serve as the basis for coordinating public and private investment. The intention is an ambitious one and a comprehensive state plan has not yet been enacted. Land use controls, which are the chief means of governmental control over the direction and speed of socioeconomic change have been applied in the past with considerable force and consequence.

Under Hawaii's centralized system, it is the state which exerts the greater authority in land use planning. The state government itself owns approximately 35 percent of the land surface in Hawaii (1,400,000 acres, compared with 2327 acres owned by the four counties and 297,000 acres owned by the federal government), and these are under the stewardship of the DL&NR or the Department of the Hawaiian Homes Commission. Modes of making state lands available for various uses, such as the siting of WECSs, are discussed below.

All nonfederal lands, whether state, country, or privately owned, are subject to the zoning laws of the state. The principal agency of zoning is the State Land Use Commission (LUC), a nine-member body appointed by the Governor. The LUC has authority to change the boundaries of the four land use "districts," or types of zones, established by statute (HRS 205-2). These are as follows:

- (1) Urban: residential, commercial, industrial and other urban uses
- (2) Rural: small farms as well as low-density residential areas, and also public utility facilities
- (3) Agricultural: mills, storage areas, processing plants, and other facilities accessory to farming, animal husbandry, fish and game propagation, etc.
- (4) Conservation: forest and water reserves created under the earlier legislation, as well as wilderness areas, beaches, and other open or "natural" spaces.

Two state agencies and one county agency jointly exercise land use zoning powers in Hawaii. The LUC sets the boundaries of conservation districts, but administrative power over these districts is exercised by the DL&NR. The DL&NR has the power to create subzones and to grant temporary variances for particular land uses within the forest and water reserves only. With respect to agricultural districts, the LUC

shares authority with the County Planning Commission. Again, the LUC has the power to place lands in and remove them from these categories, but once in, they come under the authority of the county government. By statute (HRS 205-6), the County Planning Commissions are authorized to permit certain "unusual and reasonable" uses within agricultural and rural districts other than those for which the land is classified. It is quite conceivable that a siting for a WECS would be considered an "unusual and reasonable" use for rural or (more likely) agricultural land and thereby be eligible for a special permit. Urban lands, an unlikely place to locate a WECS, are regulated by the counties under their respective ordinances. Table 5-4 summarizes this information.

As discussed elsewhere in Section 5.0, the best WECS sites are generally in conservation districts. The best wind conditions are encountered on high slopes or peaks, and these are usually in areas zoned "conservation." In this case, the process of obtaining government permission to use the land for testing out the feasibility of a WECS would be simplified--only the state is involved. If a federally run or regulated facility, such as a satellite tracking station or an airport, is near a potential WECS site, clearance at the national level will also be required, of course.

To use conservation land, the permission of the DL&NR must be obtained, whether the land is privately owned or owned by the Hawaii government. Should the site selected be in forest and water zones, the department could allow a temporary variance, for "good cause" shown, or create a subzone if it finds the use beneficial and compatible with the purposes of conservation. The general land use statute (HRS 205-2) seems to encourage the multiple use of conservation land as does the statute dealing particularly with forest and water reserve land (183-41(1)). This statute says that the DL&NR, in establishing subzones, should "allow and encourage the highest economic use thereof" consonant with the need to ensure a pure water supply. If it can be shown that a WECS site would not be harmful to the forest cover or the ground water supply, it would seem that the multiple use policy incorporated in the land use statutes would encourage this use.

In the less likely event that good sites for a WECS should be located in areas classified as agricultural or rural, permission to utilize the sites would have to be obtained from the county government (City & County for Oahu) and particularly its Planning Commission.

The land uses for agricultural districts suggested by the statute (HRS 205-2) all relate to agriculture--broadly defined--and its processes. Since many of these processes require electric power, it is not farfetched to include an energy-converting facility which will provide electricity to agricultural enterprises among these related uses. As already noted, with respect to rural districts public utility facilities are explicitly included among the approved uses of land.

Even if a WECS should not be held to fall within the scope of normally permitted land uses in either agricultural or rural districts, it may be possible to gain permission from the county government to construct a WECS. Under the land use statutes (HRS 205-6), each County Planning Commission is authorized to grant special permits to persons within such districts who petition to use their land for

TABLE 5-4

LAND USE DISTRICTS: PUBLIC AND PRIVATE LAND

Classification	Permitted Uses	Regulating Agency*	Special Uses: How Provided:	Hawaii Revised Statutes Section
Conservation	Those compatible with protection of watersheds, forests, wilderness areas, beaches, etc.	DLNR, LUC	Temporary variances; sub-zones	205-5(a); 183-41(1,4)
Agricultural	Agriculture, plus "uses accessory" to agriculture, including mills, processing plants, etc.	LUC, CPC	County permits	205-5(b) 205-6
Rural	Small farms, plus low-density housing and <u>public utility facilities</u> .	CPC	County permits	205-5(c)
Urban	As provided by county ordinances and regulations	CPC	County ordinances	205-2

* DLNR = Department of Land and Natural Resources

LUC = State Land Use Commission

CPC = County Planning Commissions

other than agricultural or rural uses. The statute gives no guidelines for granting such "unusual and reasonable uses," presumably leaving the County Planning Commissions with broad discretion to grant them. The commissions are required, however, to hold a public hearing on each petition, a hearing of which the state LUC must be notified. A special permit is subject to approval by the LUC, and it may impose restrictions additional to those required by the County Planning Commission or it may veto the action of the county agency. The statute provides for an appeal to the State Circuit Court if there is denial by either the county or the state.

Obtaining WECS Sites on State Land

If a WECS were to be located on private land (as is the Kahuku area on windward Oahu or the leeward site near Makakilo, both owned by the Campbell Estate), the permission of the landowner plus the land use authorization just discussed would make the location available for construction of the facility. However, if the location sought is on State land (as the Kuaokala Forest Reserve on the northwest corner of Oahu or at Makapuu Point or Koko Head, at the southeastern extremity of the island), then access to the site, as well as permission to use it for the designated purpose, must be sought from the DL&NR, the custodial agency for Hawaii state land (other than those held by the Department of Hawaiian Homes Land).

By statute (HRS 171-13) the DL&NR is empowered to dispose of public land by sale or exchange in fee simple, to grant leases on the land, to grant easements, licenses or permits to use land held by the State. It is unlikely that the State would be willing to sell (or the agency constructing an experimental WECS would want to buy) the land necessary for the site. There is a general predisposition against selling State land*, and this would be particularly true of acreage in the conservation districts (the most probable location for a WECS facility) because the government is particularly protective of watershed and forestry areas.

A lease of the land for the period needed or an easement to construct the WECS facility would be more likely. Under these arrangements, the State could more readily impose and enforce the safeguarding conditions it is likely to require before making a site available. Generally, leases and easements are limited to 65 years (HRS 171-36 (2)) and must be after a public auction or public drawing (HRS 171-14 and -15). However, an easement for "specific purpose" may be granted by the DL&NR by direct negotiation and without a public auction when the value of the easement is appraised at less than \$500 (HRS 171-13 (2)).

* Under HRS 171-32, the policy is established of leasing public lands, not selling them, unless otherwise specifically authorized by law. Sales for industrial or business uses are subject to disapproval by the legislature (HRS 171-41).

Other legal modes for obtaining the right to enter on and use public land are licenses and permits. Permits are normally short-term arrangements for temporary occupancy, usually on a month-to-month basis--and as so limited, would not be adequate for constructing, testing and operating a WECS. However, the law does provide (HRS 171-55) for permits to continue in force for one year, with further extensions at the discretion of the DL&NR, for "additional one-year periods" on a month-to-month basis.

Licenses to use state land cover longer periods of up to 20 years. While the statute (HRS 171-54) requires awarding licenses at public auction, it authorizes the DL&NR to dispose of a license by negotiation without recourse to an auction when it "determines that the public interest will best be served thereby."

Summary of Land Use Laws

There are two steps in the acquisition of a site which can be used for a WECS: (1) to gain access to the land, and (2) to gain approval for its use as a site. Should the ground selected be in a conservation district (a most likely outcome, given the fact that most of the windy sites are in rugged uplands), then the two steps may be merged into a single negotiation. This results from the fact that the same government agency, the DL&NR, administers both aspects of publicly-owned conservation land; it can at once grant a lease, easement, license, or permit to use a given area of a conservation district and also grant a variance, or create a subzone, for this particular use. If it is private land in a conservation district which is sought for a WECS site, the private owner must grant the access but the DL&NR controls the use as before.

For acreage outside the conservation areas, the consent of a County Planning Commission for land classified as agricultural or rural must be obtained, in addition to the right of access and occupancy by the owner of the land. If the land is held by the state, negotiations with both levels of Hawaii government are required. In the unlikely event that the site is on county land, the two steps would be collapsed into a single negotiation with the county government.

Although the normal means of allocating rights to use state land is by public auction or drawing, Hawaii law authorizes the DL&NR to issue short-term permits or longer-term licenses by negotiation when that is deemed to be in the public interest. If the proposal to construct a WECS can demonstrate to the satisfaction of the department that it would be in the public interest, fully compatible with the environment, conservation and other concerns of the state's land use policies, it may be possible to obtain a site with a minimum of administrative procedure.

5.1.2.2 Application to Potential WECS Resources

Of the potential wind resource areas discussed earlier, only the Kahuku Point area involves private land. The Kahuku Point land belongs to the large Campbell Estate and is under agricultural zoning. It would therefore be necessary to buy the land or lease its use from the private owner. Since the United States Army is presently leasing most of the land for maneuvers, it would also be necessary to obtain some

sort of concession to allow releasing of the portions needed for a WECS installation. The Army at present exercises assault helicopters there, so a flight safety problem may be involved.

Small plots of land are also under lease to the Navy on Opana and a nearby headland for communications antennas. The Comsat Corporation has its satellite communication antenna on the ridge to the west of Opana. For the purpose of this study, it has been assumed that interference with these antenna arrays would be minimal if the nearest WECS installation were restricted to 1000 ft from each of the antenna farms. More careful analysis of these clearances would be necessary if an actual installation is contemplated. The loss of available wind resource under the 1000 ft limitation is minor.

Since the zoning is agricultural, it would be necessary to obtain a special permit for wind power generation use from the County Planning Commission which they may grant at their discretion. This permit would also require the approval of the State LUC.

The other four sites are all on state lands and in conservation districts. Thus, access to the site, as well as permission to use it, must be sought from the DL&NR. As described in the previous Section, the most likely means of obtaining use of this land is a long-term lease or easement to construct the WECS facility. The State would thus retain the right to impose safeguarding conditions to prevent damage to the topography and/or to the water supply. The State has the right to grant a license up to 20 years by negotiation without public auction if it determines that the public interest will best be served thereby. The State's strong present interest in natural energy sources suggests that it would be likely to make this determination.

The DL&NR operating instructions are to encourage the highest economic use of the land consistent with requirements for the conservation and maintenance of purity of the water supplies. It will be shown in a later section that land use for wind energy generation is probably the highest economic use possible.

The land use, title, and zoning situations are summarized in the next two columns of Table 5-3.

5.1.2.3 Esthetic Impact

The populace of the Hawaiian Islands is probably more sensitive to issues of esthetic impact than people of most other areas of the United States. There are two primary reasons for this sensitivity. One is a continuing respect for the native tradition and culture which regards the earth as a provider for human needs not to be disrupted or destroyed by human activities. The second is the realization that a large fraction of Hawaii's economy depends upon the tourist trade and the natural beauty of the islands is one of the major attractions for tourists. Both viewpoints call for considerable restraint in changing the landscape.

Of course, it is entirely possible that when large WTGs have been installed and observed by the populace and tourists for a number of years they will come to be

perceived as a thing of beauty or as an item of local color. This has precedence in Holland and Crete. The public may also recognize that they reduce adverse impacts of other power plants. In any case, a growing public awareness of the severe social and economic threat of energy boycott or high fuel prices may counterbalance the esthetic issues. The Arab oil boycott administered a severe blow to the Hawaiian economy from which it is only slowly recovering. Should additional crises of this sort occur, or be clearly threatened, there may be a public cry for power sources not dependent upon imported fossil fuel.

The esthetic impact problem is significantly different for the various WECS areas listed. The instrumented ridge at Koko Head would be a highly sensitive WECS site on esthetic grounds. It is visible from the tourist center of Waikiki, but not so prominent as the more famous Diamond Head. Also, at a distance of about 12 miles, it is unlikely that the WTGs on the crest would be visible to the naked eye from Waikiki. However, they would be clearly visible from various residential and hotel areas nearby, particularly from Hawaii Kai, a residential area adjoining the Head. They would also stand directly above Hanauma Bay, an underwater National Wildlife Preserve of coral reefs. It is assumed that esthetic objections to a WECS field on Koko Head would be very severe unless wind machines came to be considered a desirable decoration of the landscape.

A WECS installation in Kolekole Pass would be visible from only a limited number of areas to the northeast and southwest. Generally, the areas of visibility are restricted to the Scofield Military Reservation to the north and the Lualualei Naval Reservation to the south. The esthetic impact of the installation would be minimal.

The esthetic impact of a WECS on Kahuku Point could be relatively mild depending on the extent of the installation. A certain percentage of the installations at the higher elevations would be invisible to all population areas. Other locations would be clearly visible from inhabited areas around Kawela Bay and the resort hotel development on Kuilima Point. Certain locations might also be marginally visible from the town of Kahuku and from locations near the Polynesian Cultural Center at Laie. In general, the esthetic impact of WECS installations on Kahuku Point would range from small to moderate depending on the extent of the installation.

A WECS installation on Kaena Point would be relatively innocuous. Depending upon the exact location, they could either be totally invisible to the population or only marginally visible from a few beach locations near Waialua Bay.

A WECS installation at Honouliuli is in direct line of sight of several small communities surrounding Pearl Harbor and the harbor itself. However, the distances are such that WTGs would be clearly visible from the west side of the harbor, but too far away to be visible to the naked eye from the north or east shore, or from the tourist areas such as the U.S.S. Arizona.

The esthetic impact of the five WECS locations is summarized in Table 5-3.

5.1.2.4 Site Access Roads and Construction Costs

Of the five potential WECS sites discussed, only Honouliuli would have a considerable road access problem. The crestline of the Waianae Range is sharp and rugged in this area, and the only access points are at Kolekole Pass and through the naval reservation road to Mauna Kapu. The five miles of ridgeline between these two points are of narrow crest and rapidly varying height, which will probably make a difficult situation for building a road or construction pads.

However, even this observation of road building difficulty does not assure that the cost of road access would be excessive for a good mountain wind resource. Typical mainland construction costs of very rugged roads carved up the side of hard rock mountains are perhaps \$250,000/mile. If a crestline road for the construction and maintenance of a row of ridgetop wind machines cost this much it should still be a small cost compared to the \$15 to \$25 million per mile cost of a few miles of WTGs placed at minimum spacing. It is hard to imagine terrain conditions where the combination of mountain climbing access roads and ridgetop interconnections would exceed 10 percent of the cost of the WTGs installed in the system unless the access road served a WECS consisting of only a very few units. For example, it is likely that a single WECS installed on a mountain peak requiring an access road would be uneconomical. But, if a few dozen machines are involved, the road and construction access costs fade to insignificance in the total.

Although it is considered a small factor, the access situation is summarized in Table 5-3.

5.1.2.5 Summary of Scenario Site Selection

The WECS site selection criteria judged significant for Oahu are thus summarized in Table 5-3. Koko Head and Kolekole Pass, because of their high mean wind speeds, offer the lowest wind energy costs among the sites considered. Since the mean wind speeds are so high, they might be even more economical if a WTG of slightly higher rated speed than 22.7 mph (10.15 m/s) became available. Unfortunately, because of the small size and concentrated nature of the resource at the two locations, neither would supply a substantial part of the HECO total generation needs. Also, the strong esthetic impact of an installation at Koko Head probably rules it out for WECS development in the near future. If the early public reaction to the esthetics of wind turbine installations elsewhere on Oahu is very favorable and the public concern for energy self-sufficiency rises, as it might after possible future oil boycotts, then Koko Head might receive favorable consideration for the far future.

In the meantime, it would seem wise to survey further inland from Koko Head in regions that are much less accessible but also practically invisible to the public. There are probably larger WECS resources unfound in this region.

Kolekole Pass should probably be developed. Further survey is needed to determine the extent of the resource. It appears that it should yield profitable wind generation, but a very small fraction of HECOs needs.

Kahuku Point is the best of the three remaining WECS resource possibilities. Using the Mod 1 WTG design, it offers the possibility of up to 40 percent penetration of the present HECO generating capacity. The resource survey has not gone far enough to establish the distribution between higher and lower wind energies over the site, but at least a reasonable part of this large area is available at above 18 mph mean annual wind speed. Access to the land can probably be negotiated and the esthetic impact is moderate because of the primarily agricultural and undeveloped nature of the region. It should be relatively easy to avoid adverse interaction with the major communication antennas in the area. Interference with the present Army use of the area for maneuvers is a potential problem that needs further exploration.

The WECS resource on Kaena Point looks slightly less attractive because of the lower mean wind speed and the estimate of a moderate total WECS capacity. Both the capacity and the maximum available mean wind speeds are quite uncertain, since only one point at the lower end of the ridge has been surveyed to date.

The Honouliuli region is less attractive as a potential WECS site. Its total capacity is small, and because of its more moderate wind speeds, the energy cost will be significantly higher. It does not seem likely that switching to a lower-rated speed machine will help the cost problem. With moderate concern over the esthetic impact, and probably the toughest road and construction job of the sites considered, this site is discarded from consideration.

The Kahuku Point wind resource was selected for the scenario site design effort of this study. It is reasonably economical, large enough to show an effect on HECO operations, and is probably available for WECS development.

5.2 WTG SUBSYSTEM DESCRIPTION

The WTG performance assumed throughout this study is closely related to the preliminary design definitions of the DOE/NASA Mod 1 WTG. At the time of this study the final design was not crystallized, so the performance assumed will probably not coincide exactly with the eventual Mod 1 design.

5.2.1 General WTG Description

The general characteristics of the Mod 1 preliminary design are described in Reference 5-4. Its key design features, as described in the Reference, are given in Table 5-5. The WTG system characteristics used in this study were obtained from this Reference and are given in Table 5-6.

Strictly speaking, the listed annual energy and capacity factor are not system characteristics, but performance projections for the design when operated on a site having the NASA specified wind speed duration distribution for an 18 mph (8.0 m/s) mean annual wind speed. The preliminary design was developed in an economic optimization for operation in that wind regime.

TABLE 5-5

DOE/NASA MOD 1 DESIGN FEATURES

- Constant rotor speed
- Variable pitch control
- Single rotor per tower, placed downwind
- Propeller-type blades
- 2 blades per rotor
- Fixed ratio gearbox transmission
- Synchronous generator
- Truss or concrete tower
- Microcomputer based control system

TABLE 5-6

DOE MOD 1 SYSTEM CHARACTERISTICS USED IN THIS STUDY

Power Rating, kWe	1500	
Annual Energy, kWh	6.62×10^6	
Capacity Factor	0.51	
Rotor Diameter, m (ft)	57.9	(190)
Rotor Speed, rpm	40	
Rated Velocity, m/s (mph)	10.15	(22.7)
λ Rated (λ Design = 10)	9.5	
Tip Speed, m/s (ft/sec)	121	(398)
Cut-in Velocity, m/s (mph)	5.11	(11.4)
λ Cut-in	18.4	
Cut-out Velocity, m/s (mph)	22.3	(50)
λ Cut-out	4.18	
Hours Above V_{ci}	6568	
Hours at Rated	2718	

5.2.2 Assumed WTG Performance

Most of the above particulars of the WTG design do not affect the calculations of this report. The performance computations in this Study are based on the WTG performance curves developed in Reference 5-1 (see Figure 4-4 of that Reference) in conjunction with the following numbers:

Rated Power, $P_R = 1500 \text{ kW}$

Rated Velocity, $V_R = 10.15 \text{ m/s (22.7 mph)}$ at Sea Level

Cut-In Velocity, $V_{ci} = 5.11 \text{ m/s (11.4 mph)}$ at Sea Level

Cut-Out Velocity, $V_{co} = 22.35 \text{ m/s (50 mph)}$

Rotor Diameter, $D = 57.9 \text{ m (190 ft)}$

The first four factors determine the sea level performance curve. The diameter affects only the minimum WTG array spacing and wake interference correction.

5.3 SCENARIO WECS DESIGN

A strong wind energy field is located at the north tip of Oahu (Figure 5-1), which coincides with the northwest end of the Koolau Range. Because of the constricting effect of the tropical inversion layer in the area, it was expected that the highest wind velocities would not be found at the crest of the range, which rises to somewhat over 3000 ft, but at lower elevations on the ends of the range where the constricted flow accelerates around the obstruction. There is no theory to specify the altitude of maximum surface wind speed. Initially it was expected by both the analytical and experimental teams to occur at elevations of 1000 to 1600 ft. However, biological indicators in the area strongly suggest that the high wind is confined to the altitude range between 500 and 900 ft. No examples of significant biological distortion of trees have been seen outside of this narrow range.

In this elevation range, the end of the Koolau Mountains is no longer a single ridgeline, but splays out into a number of small ridges that taper down into the oceanside flatland. The conformation of these ridges in the area of interest is shown by the geological survey map of Figure 5-2.

The wind instrument locations in the Kahuku field are shown in Figure 5-2. The three lower stations labeled Upper, Field, and Lower, have been operated by the UoH. The highest station, labeled Hill, was installed by LLL as part of their analytical modeling program. The Kahuku Lower station has been abandoned since 1 May 1976.

The distribution of wind energy over the Kahuku field is highly variable over short distances. The data available at the Upper and Field stations are substantially different, although the two stations are only 3000 ft (.9 kilometer) apart

Figure 5-2. Wind Survey Instrument Locations for Kahuku WECS

horizontally and 480 ft (150 meters) vertically, different. Biological indicators on the hilltops strongly indicate that the differences go down to much smaller scale, perhaps as little as one or two WTG diameters. Data taken over short time periods by the UoH team using mobile vans appear to confirm this suspicion.

5.3.1 Phased Implementation

The Kahuku WECS field layout was done in a series of four Phases, starting with 45 MW rated power in the first Phase and building to a total (four phases) of 450 MW at completion of Phase 4. This sequence of consecutively larger WECS fields was selected to (1) parametrically describe the varying cost and performance of the WECS with increasing field size and decreasing resource quality and (2) show a logical plan for growth from the first installation to the much larger investment of full field development. This phased approach using the most valuable resource first is probably the wisest and most likely pattern for development of a WECS in mountainous terrain.

The Phase 1 development of the WECS should use the most energetic spots in the field (subject to the constraint that other things being equal, upstream sites should be developed first—see Section 4.9.3.2) with larger field development spreading to lower resource value locations. Because of the present lack of knowledge of the details of the wind resource field, this growth sequence can only be estimated. In a real field design, unlike this scenario exercise, each stage of expansion would be done only after careful instrumentation to document the hierarchy of wind energy values of the remaining possible locations in the field to determine which are economical.

5.3.2 Field Layout

Phase 1

Using real wind data where available, and interpolating and extrapolating from biological indicators where possible, the indicated regions in Figure 5-3 were chosen as containing the most energetic sites. Using the biological indicator scale developed in Reference 5-5 (Putnam), the contours of mean annual wind velocity along the three ridges were estimated as shown in Figure 5-3.

The areas within these contours was exploited in Phase 1 of the Kahuku field development. Phase 1 will be sized at 45 MW rated power (30 WTGs). This sizing is based on an estimate of the power that can be carried away in both directions along the 46 kV transmission line paralleling Route 83 along the Kahuku coast. It is estimated that this line can handle about 20 to 25 MW in each direction. Since both ends are tied back to the main grid, 40 to 50 MW is the total capacity. The location of the 30 WTGs in the Phase 1 field development are shown in Figure 5-4.

Spacing of 400 ft is selected. This keeps a large number of machines within the high energy portion of the wind field without entailing excessive losses due to interference between the WTGs. The losses are kept minimal because the three rows are more or less normal to the prevailing wind. Two hundred foot spacing would reduce

Figure 5-4. Kahuku WECS Field Layout
Phase 1; 45 MW (30 WTGs)

the energy collected because (even with the favorable array orientation to the prevailing wind), energy losses would increase significantly for some portions of the array. On the other hand, larger spacings of the WTGs would require use of lower energy sites to obtain the same 45 MW of installed rated power. The portions of the ridges developed are those separated by more than approximately 10 WTG diameters, or 1900 ft. Four-thousand volt power collector circuits are shown connecting each group of 10 WTGs to a central transformer station where the voltage is jumped to 46 kV for transmission down the hill. Here it connects with the existing transmission line of the HECO network. In addition to the transformer, the usual switching and protection equipment will be necessary and these are included in the transmission cost estimate of a later Section.

An alternative exists for the transmission hookup of the Phase 1 system. There is a switchyard on the west side of the town of Kahuku, just beyond the east edge of the map in Figure 5-4. Connecting to this switchyard might allow a larger WECS installation without major new transmission lines, since the town of Kahuku could take its loads separately in addition to the transmission of power away in both directions along the main transmission line.

Phase 2

The Phase 2 WECS is based on Phase 1 as shown in Figure 5-5. Two new lines of WTGs are added, labeled 2 and 4, and the existing lines 1, 3 and 5 are extended up and down the ridges to poorer energy resources. In addition, it is found that in a few of the higher energy locations of the original Phase 1 installation new WTGs may be economically inserted at 200 ft spacing between the 400 ft spacings of the original layout. The losses due to mutual interference of these WTGs, and those already installed, still leave a greater energy capture per WTG than would be obtained by going to lower energy portions of the wind field. The two new rows, 2 and 4, are interrupted when they extend within approximately 10 WTG diameters of the existing rows. However, an exception is made at the south end of row 4 where the row crosses into a gulch that appears to have a very strong venturi conformation. It is assumed that this conformation will make up for the loss of energy from the upstream row. Incidentally, there are strong biological indicators in this gulch of extreme wind concentration to confirm this assumption.

At the lower end of row 2 a gap is made to avoid close approach to the COMSAT antenna which shares this ridge. Row 3 is also interrupted about 1000 ft short of the Naval Communication Antennas at Opana. The exact size of these clearances would have to be examined more carefully when an actual design is undertaken.

Since the total power of Phase 2 greatly exceeds what can be carried by the local transmission line, a new transmission line is required to connect to a major trunk of the utility system. The connection chosen is the switchyard in Wahiawa where 138 kV lines are available to carry larger power. The transmission line assumed is shown in Figure 5-6. It is assumed that installation along the coast, or substantial upgrading of the existing coastal transmission line, would meet environmental and esthetic objections. Transmission directly over the mountains, on the other hand, would probably be excessively expensive. The projected line skirts the foothills of

Figure 5-5. Kahuku WECS Field Layout
Phase 1+2; 150 MW (100 WTGs)

Figure 5-6. Kahuku WECS Field Layout
Transmission System for Phases 1, 2, 3 and 4

the mountains at a distance inland corresponding to the ends of a number of local roads which should ease the construction problems. The line also skirts far enough inland to be out of view of Waimea Falls, a local scenic spot.

Assuming that expansion to Phases 3 and 4 is intended, the transmission poles of this line should possibly be designed to be capable of handling three or more circuits in later expansions. The 46 kV connection to the local line on the coast remains in place, taking out a small amount of the power. It is estimated that only one 138 kV line to Wahiawa would be required for Phase 2. Appropriate additions are made to the collection lines, transformer system, and protection equipment to supply the power to both the 46 kV and 138 kV power lines. Although single lines are shown, the 4000 kV collectors for long rows, such as 1 and 5, would become multiple parallel lines in order to carry the current without excessive losses.

Phase 3

The Phase 3 expansion contemplates building up the entire mountain field to what may be its economic limiting size at near-term projected costs of WTGs and fuel. The resulting layout of Phases 1, 2 and 3 combined is shown in Figure 5-7. A little more doubling is done in the new rows where the energy may be high enough to justify it. Another substation is added in row 8 and tied to the one in row 3. The transmission line from Wahiawa goes to triple circuits to carry the additional peak load. The total WECS size contemplated at the completion of Phase 3 for the three phases is about 200 WTGs or 300 MW of rated power. Since there is practically no wind data available to indicate the value of the resource in Rows 6 through 9, they represent a considerable extrapolation in the scenario design.

Phase 4

It is not clear whether further development of the Kahuku WECS field is practical or not. For the sake of analysis, an additional expansion of 100 WTGs for a total of 300 WTGs (450 MW rated power) was assumed as a Phase 4 development of the Kahuku field. In this Phase the WTG lines would run down the headland slopes and across the flatlands toward the sea in arrays roughly normal to the prevailing wind with appropriate clearing gaps for the highway, habitations, and a resort hotel. Another substation would have to be added north of the highway and connected to the transmission net. The transmission line to Wahiawa would have to go to about five 138 kV circuits on parallel rows of towers or be upgraded to a higher voltage.

It is not anticipated that the Phase 4 development would be viable in the near future for the following reasons:

1. The esthetic impact would become substantial as machines were installed on the ocean side of the highway and in close view of habitations.
2. Substantial farming land would either be put completely out of use or require diminished cultivation beneath the WTGs. The economic value of these lands will be shown to be much less than the value of the energy harvested from them, but a reduction of agricultural land would still result.

Figure 5-7. Kahuku WECS Field Layout for Phases 1, 2 and 3; 300 MW (200 WTGs)

3. The wind data available at present at Kahuku Lower (see Figure 5-2) indicate a wind resource that will be shown to be uneconomical at present projections of WTG costs.

Despite these objections, a Phase 4 WECS was laid out and carried into the study for its comparison value. The design philosophy of the four consecutive Phases is summarized in Table 5-7. A key guideline throughout the hypothetical design process was to not make design decisions in one Phase that would prejudice later expansion. For example, spacings of WTGs greater than two diameters are chosen so that later Phases can interpolate WTGs at closer spacing, wherever profitable. An attempt is made to design rows so that they do not preclude using a valuable adjoining row at a later time. The transmission system to Wahiawa is designed with future expansion in mind. Of course, this implies that at the beginning of the Phase 1 design, the designer has at least moderate knowledge of the full extent and energy distribution of the wind field and some idea of how future economics of fuel cost and WTG cost are likely to progress.

5.3.3 Collection and Transmission Cost Estimates

An estimate was made of the cost of the electrical power collection and transmission systems. The costs were based on similar items in Reference 5-1. The items and totals (coordinated with HECO) are shown in Table 5-8.

5.3.4 Access Roads and Construction Problems

The network of access roads is required for the initial construction of the wind machines and collection network and for continuing operations and maintenance. The actual construction work may also require off-the-road pads large enough to store material and provide a platform for a crane to be used during erection. The cost of these provisions is included in the economic analysis.

The preferred road type is that which will minimize the combined road and access vehicle cost and should ultimately be determined by a careful planning study. In the absence of such a study it has been assumed that a simple dirt road similar to the access roads used by utilities for maintaining transmission lines will be the best choice. On flat ground these roads are normally constructed by clearing the right of way with a bulldozer and grading the roadway with a standard grader. Drainage provisions are kept to the minimum necessary to avoid excessive washouts and prevent erosion downhill from the road.

Based on previous studies and consultation with the Hawaiian subcontractors, it is estimated that construction of such roads may run as low as \$10,000/mile on level terrain or ridgetop construction. The cost can run much higher for hillside slope construction which requires extensive cut and fill and expensive drainage and slope stabilization provisions. In the Kahuku region very little such construction will be required. An average cost of \$20,000/mile was therefore used for estimating the road costs. To minimize the cost, maximum use should be made of ridgetop routes and sideslope connections to the ridgetop should be carefully located for minimum cost.

TABLE 5-7

WECS IMPLEMENTATION PHASES

PHASE 1: 30 WTGs, 45 MW_R

- Develop spots of highest economic value first
- Adequate Kahuku transmission loop carrying capacity
- No design decisions that prejudice later expansion
- Minimal interference
 - Spacing 400'
 - N-S Rows

PHASE 2: 70 WTGs, 105 MW_R (150 MW TOTAL)

- Develop next echelon of economic value sites
- First transmission line to Wahiawa
- Design transmission for easy expansion
- Expand length and number of rows
- Introduce 200' spacing where profitable

PHASE 3: 100 WTGs, 150 MW_R (300 MW TOTAL)

- Develop sites of lower economic value
- Expand transmission capacity to Wahiawa
- Expand length and number of strings
- Interpolate more 200' spacing where profitable

PHASE 4: ≈100 WTGs, 150 MW_R (450 MW TOTAL)

- Develop sites of marginal economic value, including:
 - Flatland locations to safety and esthetic limits
 - More 200' spacing
 - Search further to East and West
 - Weigh carefully against other regions
- Expand transmission capacity, possibly beyond Wahiawa

TABLE 5-8

WECS TRANSMISSION SYSTEM COSTS
(1977 dollars)

<u>PHASE 1</u> (45 MVA); Transmission by Local 46 kV Line	
3.25 mi 4 kV T.L. @ \$54 K/mi	\$ 173,000
1.4 mi 46 kV T.L. (double circuit) @ \$100 K/mi	\$ 140,000
4 kV/46 46 kV Substation @ \$250 K	<u>\$ 250,000</u>
Subtotal \$12.51/kW =	\$ 563,000
<u>PHASE 2</u> (105 MVA); Transmission to Wahiawa at 138 kV + local line	
10.55 addl. mi 4 kV T.L. @ \$53 K/mi	\$ 559,000
12 mi 138 kV T.L. @ \$126 K/mi	\$ 1,512,000
2 - 138/4 kV Transformers @ \$415 K	\$ 830,000
2 - 138 circuit breakers @ \$65 K	<u>\$ 130,000</u>
\$23.97/kW =	\$ 3,594,000
<u>PHASE 3</u> (150 MVA); Transmission to Wahiawa on Triple 138 kV Circuit + local	
11.6 addl. mi 4 kV T.L. @ \$53 K/mi	\$ 615,000
12 mi triple circuit increment 138 kV @ \$126 K/mi	\$ 1,512,000
1.5 mi double circuit 138 kV @ \$189 K/mi	\$ 284,000
3 - 138 kV transformers @ \$415 K	<u>\$ 1,245,000</u>
\$23.81/kW =	\$ 7,250,000
<u>PHASE 4</u> (150 MVA); Transmission to Wahiawa on Five 138 kV Circuits & local	
<u>ROWS K-3</u>	
5.4 addl. mi 4 kV T.L. @ \$53 K/mi	\$ 286,000
1.7 mi 138 kV T.L. @ \$126 K/mi	\$ 309,000
1 - 138/4 kV transformer @ \$415 K	\$ 415,000
1 - 138 kV circuit breaker @ \$65 K	<u>\$ 65,000</u>
	\$ 8,325,000
<u>LINE EXTENSIONS AND WTG DOUBLING</u>	
2.1 addl. mi 4 kV T.L. @ \$53 K/mi	\$ 111,000
5 - 138/4 kV transformers @ \$415 K	<u>\$ 2,075,000</u>
	\$10,511,000
<u>MAIN LINE INCREMENT</u>	
12 mi double circuit 138 kV @ \$189 K/mi	\$ 1,008,000
1 - 138 kV circuit breaker @ \$65 K	<u>\$ 65,000</u>
	\$11,584,000

Because of existing military and communication uses, the basic road network in the Kahuku area is already reasonably adequate. Paved feeder roads used to access the Comsat antenna, the Opana Navy antennas, the military command post and the military retreat provide a reasonable set of access paths to the top of all the significant ridges. The terrain is such that simple ridgetop roads can serve most of the remaining needs.

There will be no snow and ice problems in the area but the rainfall is in the vicinity of 400 in/yr with rain almost every afternoon. The volcanic soil is porous and reasonably stable when wet.

5.3.5 Site Resource Survey and WECS Design Costs

The WECS site survey and WECS design procedure outlined in Section 4.0 seems an expensive and time-consuming process. An attempt has been made to summarize the total cost and time schedule for the entire three-stage resource search procedure and four phase WECS construction for a Kahuku WECS in the HECO utility system. The results are summarized in Table 5-9.

Numerous assumptions were necessary to create the Table. Each step of the site survey procedure is assumed carried out with conventional meteorological instruments, using some newly developed system to record data on tape. This is being done by the UoH and LLL teams now, with custom-built equipment. Adequate numbers of survey sites are assumed at each stage of survey and for supporting the detailed design of each Phase. The strategy relative to tower heights required for vertical survey is as described in Section 8.0. The instruments, recorders and towers are costed at \$10,000/site for two years' operation. This includes installation, eventual removal, data collection, calibration correction, editing, collating of data on tapes, and simple statistical summaries of data for each site. This cost estimate is probably low for the first stages of survey, but is not unreasonable for the later stages when economies of scale, and retrieval and reuse of instruments, may cut costs somewhat.

The allowance for correlation or modeling analyses connected with detailed WECS Phase design is somewhat uncertain, because the tasks have not been undertaken. It has been assumed that site-to-site correlation and interpolation techniques conceptually similar to those described in Section 5.4.2, but somewhat more complex, will be used. Also, interference loss tradeoff computations or estimates for various WTG spacings in the more energetic parts of the field are assumed.

The amount of both survey and analysis will be dictated by their cost and time delay balanced against the economic risks of installing WTGs on less than optimum sites. This tradeoff will be addressed in Section 9.0, where the risk is shown to be very high compared to the costs in Table 5-9.

In the Table, estimates are included for a low level of utility inhouse evaluation of the wind alternative and a larger allowance for the WECS Engineering Design. The WTG cost is then listed at a nominal \$1000/kW to give a basis of cost comparison. The conclusion is that these survey, analysis and design costs will not be a significant cost penalty to the WECS if they are charged against a successful installation of at least several dozen WTGs.

TABLE 5-9

ILLUSTRATIVE WECS EXPENDITURE AND STATUS SCENARIO
(1977 Dollars)

Utility Application Studies Sites Instrumented (Approx)	\$0.2M 20	\$0.2M 30	\$0.5M 50	150	200	200	
Instrumentation and Data Reduction	\$0.2M	\$0.3M	\$0.5M	\$1.5M	\$ 2.0M	\$ 2.0M	
Correlation or Modeling Analysis	<u>\$0.3M</u>	<u>\$0.4M</u>	<u>\$0.5M</u>	<u>\$1.5M</u>	<u>\$ 2.0M</u>	<u>\$ 2.0M</u>	
Subtotal	<u>\$0.7M</u>	<u>\$0.9M</u>	<u>\$1.5M</u>	<u>\$3.0M</u>	<u>\$ 4.0M</u>	<u>\$ 4.0M</u>	
Cumulative Expense	\$0.7M	\$1.6M	\$3.1M	\$6.1M	\$10.1M	\$14.1M	
Utility Design			<u>\$ 2M</u>	<u>\$ 1M</u>	<u>\$ 1M</u>	<u>\$ 1M</u>	
Cumulative Expense			\$ 2M	\$ 3M	\$ 4M	\$ 5M	
Total WECS Cost (including land and interface costs) assumed to be \$1000/kW				<u>\$ 45M</u>	<u>\$ 105M</u>	<u>\$ 150M</u>	<u>\$150M</u>
Cumulative Expense				\$ 45M	\$ 150M	\$ 300M	\$450M
Total Cumulative Expense	\$0.7M	\$1.6M	\$5.1M	\$ 54M	\$ 164M	\$ 319M	\$469M
Cumulative Rated Capacity				45MW	105MW	300MW	450MW
Status	Utility- Specific Feasibility	WECS Area(s) Selection	WECS Detail Design	Phase 1	Phase 2	Phase 3	Phase 4
Nominal Year	1977	1979	1981	1983	1984	1985	1986

However, the Table does highlight one serious impact of a careful survey and design effort. The survey lead times are several years, compared to the one year or less required to accept delivery of a WTG from a going production line and install it. Unless a way is found to safely shorten this survey time, it will set the schedule for WECS exploitation. This schedule will be set by the utilities' confidence in wind power, the availability of capital, WTG production rates, and the progressive economic justification of exploitation of successively poorer wind resources as WTG costs and fuel price projections change.

5.3.6 Land Requirements and Costs

It is assumed that the land occupied by the WECS consists of a strip along each WTG row 2000 ft wide, to provide a fenced area 1000 ft wide on each side to keep the public beyond the possible range of a thrown blade. A value of \$3000/acre was assigned to this area, or alternatively a rental of 10 percent or \$300/acre/yr. These values were used in the economic analyses of Section 7.0.

5.4 WECS OUTPUT SYNTHESIS

In Section 6.0, a classical Loss-of-Load Probability (LOLP) analysis was undertaken for HECO including the WECS contribution. In addition, the impact of the WECS on HECO spinning reserve requirements and the consequent economics of operating with a WECS in the generation mix was investigated. An essential input to these computations is a representation of WECS output over a long period of time (≥ 1 yr) on time intervals corresponding to the demand data.

Variations in WECS value with penetration because of its interaction with the utility are expected. Variations are also expected to be related to the decreasing wind resource quality and increasing geographic diversity as the penetration of the WECS increases. Another source of effective diversity within the WECS field springs from the effect of various array geometries on WTG wake interference as portions of the array with different alignments show different responses to different wind approach directions. Yet another source stems from the interaction of WTG cut-in and rated velocities with the varying wind speed at various locations. The WECS output synthesis must retain this diversity information for the LOLP computations.

The WECS output synthesis task can be attempted at several different levels of complexity. The simplest representation is to calculate the output of a single WTG at the location of a given wind instrument on an hourly basis or whatever frequency the wind data allows. This WTG output is then simply multiplied by the assumed number of units in the WECS to obtain the total WECS output.

This method is adequate if it is clear that the winds over the entire WECS area are essentially identical on an hour-by-hour basis. It will also suffice if it is clear that only the total energy gathered by the WECS is important, not its time distribution, and that the total annual energy at each WTG site is the same.

None of these conditions apply in the present case. The energy convertible by a given WTG at the four surveyed locations in the Kahuku field is substantially

different. The hour-to-hour variation of the total WECS output is critical to the calculations in Section 6.0 of this report. A brief examination of the data from the four instrumented sites shows that any one site can show an hourly average wind speed high enough to give full-rated WTG power (~ 22.7 mph (10.15 m/s)) for several consecutive hours during which any other is below WTG cut-in speed. This finding indicates substantial geographic diversity within the local wind resource, in a circle of less than three miles (5 km) diameter.

This was unexpected. It should affect the credit for displacement of conventional capacity so it must be preserved in the method for synthesizing the WECS output. At the same time, the method must be firmly based on the actual data and must not create diversity by careless introduction of random variables.

5.4.1 Data Gaps

The coverage in time available with the data from the four Kahuku sites is shown in Figure 5-8. The Lower site was installed as shown in Figure 5-3 near an RCA naval communications site in November 1975. The velocities were surprisingly low, perhaps partly because it was located over dense trees. Poor results and electromagnetic interference problems with the RCA station led to its abandonment in late April of 1976.

Meanwhile, a very successful site was located at Opana, a promontory overlooking the ocean and the bordering low land. This site, labeled Kahuku Upper, has run with few outages, as indicated in Figure 5-8, down to the time of this study.

At the end of May the Field site was set up on flatland near the foot of the next promontory as indicated in Figure 5-3. The wind resource was good, but there are numerous gaps in the record. Recording problems were caused by line power surges when an irrigation pump on the same line started or stopped.

The Kahuku Hill site was established by LLL in August 1976. LLL was unable to provide more than four months of data due to priority problems. These data also have gaps as noted. The Hill resource is the best found to date on Kahuku Point.

The length of record at several other sites is indicated. The three permanent sites shown (Honolulu, Kaneohe Bay, and Barker's Point) have long time records. However, the records for a given year do not become available from the NCC until many months after the year's end.

5.4.2 Regression Analysis to Support Data Fill-In

A statistically adequate fill-in of missing data at the four sites is possible if an adequate correlation can be developed between the wind speed and direction at pairs of sites at a given time. Such correlations were developed, using Kahuku Upper as a baseline. Kahuku Upper was chosen because it has the best coverage over a year of data and good overlap of the recording times of all the other sites except Kahuku Lower.

Scatter plots were made of wind speed at the other three sites against wind speed at Kahuku Upper disregarding wind direction. The correlation was very poor. It was determined that the correlation was strongly dependent on the wind direction.

Figure 5-8. Hawaiian Wind Data Time Lines

Accordingly, the data were grouped into 10° bins of wind direction at Kahuku Upper. This correlation was reasonably successful. The wind speed scatter plots for Kahuku Hill vs. Kahuku Upper are shown for several representative wind directions in Figures 5-9 through 5-16. (The complete wind speed correlations for the three sites are presented in Appendix A.) The range of wind directions included in the scatter plot is given at the top left margin of each diagram, followed by the equation of the straight line obtained by least squares regression of the site data against Kahuku Upper.

Figure 5-17 shows the difference between the wind directions at the two sites plotted against the wind direction at Kahuku Upper. Most of the data show correlation within a direction variance of $\pm 30^\circ$. The wider excursions as straight line correlations at the higher azimuths result from instrument errors (see Appendix A, page A-1).

For the wind directions represented by a large number of wind data points, from about 0° to 120° ; the wind speed correlation is good. It becomes a little erratic from about 200° to 350° (see Figures 5-14 and 5-15, for example) because there are too few points of wind data from these directions to accurately define the correlation. The intervals of 240° to 250° and 320° to 330° contain only one point of data each for the entire year. Fortunately, where the lack of data results in a poor correlation, there are also few points requiring data reconstruction.

The coefficients a and b of the linear regression fits are plotted in Figure 5-18. The coefficient, a , representing the zero shift of the regression is small and erratic, contributing very little to the trends. The coefficient, b , defining the slope of the regression is of particular interest. In the range from 0° to 180° it appears to go through a complete cycle, rising to about 1.4 at 80° and dropping to about 0.6 at 170° . This means that for winds from near 80° the wind speed at Kahuku Hill approaches 1.4 times that at Kahuku Upper, giving energy approaching three times. If the wind always blew from this direction, Kahuku Hill would always be a much more attractive resource than Kahuku Upper. However, the preference reverses when the wind is from about 160° . Then, Kahuku Hill winds are closer to 0.6 times those at Kahuku Upper and have about a quarter the energy.

This geographic variation of energy distribution with wind flow direction in a mountain resource is a very significant finding. It is sometimes proposed (see Reference 5-6 and 5-7) to smooth the output and reduce the outage of multiple WECS by interconnecting several systems widely enough spaced to experience different weather and different wind energies at the same time. It is generally assumed that to obtain significant geographic diversity the WECS must be separated by hundreds of miles, or an appreciable fraction of the spacing between weather storm centers. References 5-6 and 5-7 prove this diversity to be significant for interconnection of several WECS spread over a geographic dimension of the order of 1000 miles. The four Kahuku Point stations contained within a circle three miles (5 km) in diameter show a degree of geographical diversity within one mountain resource.

Standard Deviations of Residuals

Standard deviations of the data residuals taken with respect to the straight-line regressions were calculated for 10° wind direction intervals for various wind speed

Figures 5-9 to 5-14. Wind Speed Scatter Plots; Representative Wind Directions
Kahuku Hill versus Kahuku Upper

Figure 5-15
Figure 5-16
Wind Speed Scatter Plots; Representative Wind Directions
Kahuku Hill versus Kahuku Upper

Figure 5-17. Wind Direction Variation
Kahuku Hill versus Kahuku Upper

Figure 5-18. Correlation Equation Trends with Wind Direction

intervals. The results for the wind speed intervals 5.0 to 7.5 and 7.5 to 10.0 m/s (Kahuku Upper) are given in Figure 5-19. These are the intervals that primarily affect variations in WTG power output. Results below 5.0 m/s generally contribute no WTG power. Results above 10.0 m/s generally give full-rated WTG power, regardless of wind speed, but these points are included in the Figure for interest. The numbers indicate the number of points included in a wind direction and speed bracket. The flagged points represent more than 100 data points.

Many wind direction and speed brackets are unrepresented because there were not enough data points in the interval to provide a standard deviation. There are not enough data pairs to provide a reliable data base outside the direction range of 40° to 120° because the wind blew too seldom from those directions. The data for well represented points group around a mean value of 0.9 to 1.0 m/s standard deviation and represent a total of nearly 2000 data points. A standard deviation of 0.95 m/s was selected for data reconstruction work, based on this chart.

Similar correlations were run from Kahuku Upper against Kahuku Field and Kahuku Lower, with almost identical results for the well represented points. Therefore, the standard deviation of 0.95 m/s was chosen to represent all three correlations.

Consideration was given to using a standard deviation varying with wind direction, but the data were too sparse for most wind directions. The above value was therefore used for all wind directions.

Figure 5-19. Standard Deviations of Residuals

An attempt to further refine the standard deviation by speed range also seemed futile for the 5.0 to 7.5 and 7.5 to 10.0 m/s speed ranges. They look very similar in Figure 5-19.

The speed range greater than 10.0 m/s does show a slightly lower standard deviation in Figure 5-19. However, including this in the data reconstruction was judged not worthwhile. Most data points reconstructed in this range will result in full-rated power regardless of the standard deviation used. The interval would be more significant if a higher rated wind speed WTG were considered.

This completes the necessary groundwork for adequate reconstruction of the missing data in the wind records.

5.4.3 Wind Data Reconstruction

The wind data regressions and standard deviations were used to reconstruct gaps in the wind data for the period 1 April 1976 to 31 March 1977 using the method described below.

First, the wind speed and direction at Kahuku Upper and the straight-line regression equations were used to calculate a nominal value for each missing Kahuku Hill point for which there was a Kahuku Upper datum available. Then, the calculated standard

deviation of 0.95 m/s was used with a random number generator to add appropriate random dispersion to the number assuming a Gaussian distribution. The resulting wind speed datum and the Kahuku Upper wind direction were then inserted into the Kahuku Hill data at the corresponding point in time. The process (Figure 5-4) was used to fill in the missing months of Kahuku Hill data and a few missing hours within the record when the instruments broke down.

The process was then reversed by computing the regression and standard deviations for Kahuku Upper regressed against Kahuku Hill. By the same reconstruction technique, missing Kahuku Upper points were filled in wherever Kahuku Hill data were available.

At the end of this process, about four days of data were still missing where both records were blank simultaneously. Filling this in with averaged values was considered but rejected because it would tend to slightly reduce the wind record variability. Instead, the Kahuku Upper record was completed by lifting blocks of data from the same hours of the previous and following days. The Kahuku Hill data were then completed by cross-correlation. The 12 months of Kahuku Upper data now being complete, only forward correlation was needed to reconstruct corresponding 12-month records of Kahuku Field and Kahuku Lower. The result of this cross-correlation technique was a set of four simultaneous and complete 12-month hourly wind records. The statistics of wind variability at the four sites should have suffered minimum alteration, so that infield diversity was correctly represented.

Of the four reconstructions, it was assumed that the reconstruction of the Kahuku Lower data was of significantly lower quality because there were only five weeks of data overlap with Kahuku Upper. As a result, the regressions were based on less data than desired and most of the Kahuku Lower record had to be fabricated. This is probably not particularly important because it was found (Section 6.0) that this Section of the WECS (Phase 4) was not economic.

In the case of Kahuku Hill, more than four months of data were available, including substantial variable wind directions in the fall, giving reasonably adequate correlations. A large amount of data still had to be reconstructed, but the technique should be valid.

The Kahuku Field intersection of data with Kahuku Upper was more than adequate and very little reconstruction was required.

5.4.4 Construction of WECS Output Model

The four simultaneous wind records were used to construct an hourly history of the WECS power output for each of the four installation Phases for one year (8760 hours). This history was used in the LOLP and Cost-of-Production analyses of Section 6.0.

5.4.4.1 Model Requirements

The requirements of the WECS output model are that it (1) be based entirely on the data from the four sites, reconstructed where necessary as described in Section 5.4.3, and (2) retain all "diversity" characteristics of the data, including:

- (a) Wind speed diversity of four site records.
- (b) Power output diversity created by the directionality of WTG array wake interference out of wind direction diversity.
- (c) Power output diversity created by the directionality of wake interference interaction with WTG array angle diversity.
- (d) Effect of nonlinearity of WTG power conversion curve.

5.4.4.2 Characterization of Individual WTGs

For the construction of a WECS power output; it was necessary to characterize each WTG in each of the four Phases of WECS development. The analytical model of Reference 5-1 was used to correct WTG performance for wake interference losses in the array. The analytically defined losses of the model are for a WTG in an infinite straight-line array. But the end WTG of a finite array sees no wake interference from half of the wind approach angles. And the WTG at the opposite end of the array sees no interference from the opposite half of the wind approach angles. Therefore, the total array performance can be adequately described by adding the performance of one WTG without interference and the remainder of the array with infinite array losses. This does assume that the wind regime is the same at the two ends of the array, which was considered a reasonable approximation.

The array performance calculation is set up by assigning to each WTG in a straight array of uniform spacing the array angle and spacing to the next WTG. The last WTG in the line is then assigned a noninterference status.

For changes in array angle and spacing along the array, the same reasoning applies. Each WTG sees for half of the wind approach angles the infinite array loss associated with the array angle and spacing on one side of it, and for the other half of the wind approach angles the loss associated with the array angle and spacing on the other side. This analytical result is most easily accomplished by starting at one end of the array and assigning to each WTG the array angle and spacing between it and the next unit. The last machine in the line is then assigned noninterference. The performance of each machine is calculated from the infinite array performance for the array angle and spacing assigned to that machine.

Tables 5-10 (a through d) describe the WECS array for each of the four Phases in the prescribed manner. The number in the first column identifies the Row. The Group number in the second column identifies a Group of WTGs having constant array angles and spacing. The following columns identify the number of WTGs in the Group, the spacing, and the array angle to the next WTG. The angles were measured on the large scale maps from which Figures 5-5, 5-6 and 5-8 were copied. The columns really describe the width and array direction of the gap between each pair of WTGs. The undefined direction and spacing for the last WTG in the row are signified by an X.

The next column identifies the wind resource assumed for each "group" of WTGs. One of the four available records was identified for each group (K_H , K_Y , K_F , K_L). The selection was based primarily on which data site is closest to the WTG site, and

TABLE 5-10a
WECS OUTPUT SYNTHESIS DATA
PHASE 1

Row	Group	Number	Spacing S, Ft	Array Angle β Deg	Winds	Annual Energy kWh/yr $\times 10^{-7}$
1	1	2	400	350	1.1 K _H	.8467
	2	7	400	327	K _H	.7552
	3	1	X	X	K _H	.7679
3	1	3	400	357	1.1 K _H	.8430
	2	6	400	335	K _H	.7553
	3	1	X	X	K _H	.7679
5	1	3	400	23	1.2 K _H	.8966
	2	6	400	18	K _H	.7377
	3	1	X	X	K _H	.7679

secondarily on corresponding altitude and exposure. Since, in some cases, the nearest data site is over a mile away and on a different ridgetop with somewhat different exposure, considerable license was exercised in this part of the modeling.

An attempt was made to incorporate the energy variability along a ridge, as postulated in Figure 5-3. This was accomplished by assigning an appropriate multiplier to each record given in the next to last column of Tables 5-10. This means that all wind speeds on the selected record are multiplied by this number before calculating the WTG output on the site(s).

The multipliers assigned in Phase 1 were based on the careful reasoning that led to Figure 5-3. Multipliers for the other Phases were assigned on a more arbitrary basis. No useful biological evidence was available to guide the assignments for Phases 2, 3, and 4. They were made on judgments of the exposure of the sites, based on U.S. Geological Survey maps of the terrain and photographs made during field trips to the area. Note that when additional WTGs are inserted between or at the end of existing rows, the wake interference losses on the existing machines change and their performance must be recomputed. Therefore, the additional power output of Phase 2 includes a decrement to the output of WTGs in Phase 1 because of the interaction. In the design of a real WECS system, these tradeoffs would be worked very carefully in terms of each site's local resource data to balance increased utilization of the highest energy locations against wake interference losses to machines in the closely packed regions.

TABLE 5-10b
WECS OUTPUT SYNTHESIS DATA
PHASE 1+2

Row	Group	Number	Spacing S, Ft	Array Angle β Deg	Winds	Annual Energy kWh/yr $\times 10^{-7}$
1	1	4	200	350	1.1 K _H	.8179
	2	9	400	327	K _H	.7552
	3	10	400	336	K _H	.5106
	4	2	200	298	K _u	.6196
	5	1	400	56	K _H	.6403
	6	1	200	303	K _H	.6433
	7	2	400	328	K _H	.7553
	8	1	X	X	K _u	.5280
2	1	3	400	336	K _u	.5106
	2	3	400	327	K _u	.5096
	3	1	X	X	K _u	.5280
	4	1	X	X	K _u	.5280
3	1	6	400	330	K _H	.7553
	2	6	200	358	1.1 K _H	.8130
	3	2	200	319	K _H	.6986
	4	2	200	330	1.1 K _H	.6050
	5	6	400	357	1.1 K _u	.6437
	6	1	X	X	K _u	.5280
4	1	2	200	332	K _H	.7211
	2	4	400	332	0.9 K _H	.6322
	3	3	400	12	K _u	.4970
	4	1	X	X	K _u	.5280
5	1	1	400	36	K _H	.7255
	2	6	200	19	1.2 K _H	.8557
	3	6	200	19	1.1 K _H	.7832
	4	1	400	2	K _H	.7451
	5	1	400	329	K _H	.7553
	6	12	400	5	K _H	.5009
	7	1	200	8	K _u	.4442
	8	1	X	X	K _u	.5280

TABLE 5-10c
WECS OUTPUT SYNTHESIS DATA
PHASE 3

Row	Group	Number	Spacing S, Ft	Array Angle β Deg	Winds	Annual Energy kWh/yr $\times 10^{-7}$
3	7	2	400	325	K _U	.5090
	8	1	400	330	K _U	.7553
	9	1	400	285	K _H	.6702
	10	2	200	338	K _H	.7258
	11	1	200	305	K _H	.6519
	12	1	400	18	0.9 K _H	.6165
	13	3	400	335	0.9 K _H	.6321
4		1	400	290	K _U	.4608
		6	400	355	K _U	.5064
6	1	4	400	25	0.9 K _H	.6142
	2	1	X	X	0.9 K _H	.6417
	3	2	400	5	0.9 K _H	.6210
	4	5	400	20	0.8 K _H	.4733
	5	3	400	350	0.8 K _H	.4828
	6	1	400	30	0.8 K _H	.4666
	7	1	X	X	0.8 K _H	.4916
7	1	1	400	280	0.9 K _U	.2914
	2	4	400	0	0.9 K _U	.3625
	3	3	400	340	0.9 K _U	.3709
	4	4	400	5	K _U	.5009
	5	1	X	X	K _U	.5280
8		3	400	320	0.8 K _H	.4836
		1	400	30	0.8 K _H	.4666
		2	400	350	0.8 K _H	.4828
		2	400	310	0.9 K _H	.6257
		1	400	280	0.9 K _H	.5117
		1	X	X	0.8 K _H	.4916
		3	400	335	0.85 K _H	.5612
		3	400	0	0.85 K _H	.5538
		3	400	345	0.85 K _H	.5599
		2	400	290	0.85 K _H	.5112
		1	400	330	0.85 K _H	.5611
		1	400	340	0.9 K _H	.6317
		1	400	0	0.9 K _H	.6238
		3	400	320	0.8 K _H	.4836
		1	X	X	0.8 K _H	.4916
9		3	400	0	0.8 K _H	.4789
		1	200	0	0.8 K _H	.4561
		5	200	315	0.9 K _H	.5663
		5	400	320	0.9 K _U	.3704
		2	400	340	0.9 K _U	.3709
		5	400	355	0.95 K _U	.4357
		2	400	15	0.95 K _U	.4243
		1	X	X	0.9 K _U	.3874

TABLE 5-10d
WECS OUTPUT SYNTHESIS DATA
PHASE 4

Row	Group	Number	Spacing S, Ft	Array Angle β Deg	Winds	Annual Energy kWh/yr $\times 10^{-7}$
10	1	5	200	340	1.1 K_F	.4884
11	1 2	5 3	200 400	350 350	K_U 1.1 K_F	.4736 .5107
12	1 2	4 2	200 400	340 10	K_U K_F	.4772 .3892
13	1 2 3	4 6 1	400 200 X	10 330 X	K_F 1.2 K_L 1.2 K_L	.3892 .4066 .4426
14	1 2 3 4	3 3 3 1	200 400 400 X	10 10 345 X	1.1 K_U K_F 1.1 K_L 1.1 K_L	.5733 .3892 .3371 .3442
15	1 2 3 4 5 6 7 8 9	1 8 1 1 3 2 8 4 1	X 200 400 400 200 400 400 200 X	X 315 340 5 15 0 355 350 X	K_U K_U K_U K_U K_U K_U 1.1 K_L 1.2 K_L 1.1 K_L	.5280 .4431 .5130 .5009 .4248 .2353 .3299 .3991 .3442
16	1 2 3 4	2 2 10 1	200 400 400 X	350 10 355 X	0.9 K_U 1.1 K_L K_L 1.1 K_L	.3367 .3138 .2397 .3442
17	1 2	15 1	400 X	5 X	1.1 K_L 1.1 K_L	.3190 .3442

5.4.4.3 Synthesis of WECS Power Output

The calculation of WECS output proceeded as indicated in Figure 5-20 and described below:

Figure 5-20. WECS Power Output Computational Flow

- (1) A one-year time history of WTG power output was calculated for each WTG (or unit in a group of identical WTGs) listed in Tables 5-10.
- (2) The inputs were the time history of wind velocity and direction defined by the site and number designation, the array spacing, array angle, wind instrument height above ground level, and WECS altitude. (A single mean altitude was used.)
- (3) The hour-by-hour power output of each WTG was summed for each Phase, giving a time history of total power output for each Phase. Careful accounting must be done so that reductions of performance to WTGs of a new Phase when they are spaced between units of the previous phase are properly charged against the new Phase. Strictly speaking, the power history of a Phase is not the power of the specific newly installed WTGs, but the power output increment for all of the installed Phases taken together which includes interference changes.
- (4) The same output statistics of diurnal, seasonal, and directional power distributions, power duration curves, and capacity factor that are run for single WTGs were run for each Phase. These runs were vital for cross-checking and give a better understanding of diversity effects. They are summarized in Section 8.0.

The resulting power output time histories were used as inputs to the LOLP and Cost-of-Production calculations described in Section 6.0.

The annual energy output for each WTG is shown in the last column of Tables 5-10. Of course, the wind resource values are smoothed and simplified compared to a real design exercise, where a different resource would be assigned to each WTG, assuming the survey found significant site-to-site variations.

Table 5-11 compares the overall capacity factors and annual energy outputs of the various WECS Phases with the results for single WTGs at the four surveyed sites. The capacity factor for the four sites ranges from 0.646 at Kahuku Hill to 0.247 at Kahuku Lower, with no wake interference losses. The groups of WTGs in Phases show a capacity factor spread from 0.595 for Phase 1 to 0.291 for Phase 4. The summations are affected by both the mix of WTGs with varying resource level and by the varying interference losses due to array geometry. Interference losses imposed on Phase 1 WTGs by addition of Phase 2 WTGs are deducted from the output credited to Phase 2. The same applies to Phases 3 and 4. Therefore, the total WECS output, as Phases are added, is a simple running summation of the increasing Phases, as shown in the Table.

TABLE 5-11
SUMMARY OF WECS OUTPUT RESULTS

<u>Site or Phase</u>	<u>Capacity Factor C_F</u>	<u>Annual Energy Output $\text{kWh} \times 10^{-9}$</u>
Kahuku Hill	.646	.00849
Kahuku Upper	.485	.00637
Kahuku Field	.378	.00497
Kahuku Lower	.247	.00325
Phase 1	.595	0.235
Phase 2	.455	0.418
Phases 1 & 2	.497	0.653
Phase 3	.386	0.507
Phases 1, 2 & 3	.441	1.160
Phase 4	.291	0.383
Phases 1, 2, 3 & 4	.391	1.543

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UTILITY IMPACT ANALYSIS

6.1 INTRODUCTION

The main motivation for installing wind turbine generators in a utility grid will be to save conventional fuels (oil, coal, uranium, etc). The main detraction will be capital expense. It is expected that the capital requirements for a WECS will in most implementations be over and above the capital requirements for conventional equipment being installed in the same time frame.

The extent to which the WECS can displace or postpone the installation of conventional equipment is very important because that capital will then be free to support the WECS installation. The factor which dominates decisions to install new generating units is the reserve margin between available capacity and expected customer demand. The calculation of reserve margin for the HECO system integrated with the four development Phases for the Point Kahuku WECS is presented next in Section 6.2.

Although it might be expected that a WECS will save some amount of capital expense associated with conventional units, by far the greatest savings will be in fuel cost. A detailed analysis of fuel savings is presented in Section 6.3.

6.2 RESERVE MARGIN ANALYSIS

In the consideration of the integration of a large scale WECS into an electric utility, it is immediately observed that a WECS is not committed and dispatched in the manner of a conventional generating unit. Because the WECS fuel is free and O&M is only weakly dependent on operating time, it is obviously most economic to let the WECS produce as much electricity as it can--not start it up and shut it down like a conventional cycling unit which is meeting the variable component of daily demand. However, if the WECS is operated to produce as much electricity as possible, its output will generally vary up and down and there will be randomly distributed several day periods where the power produced is nil due to a lack of wind. This characteristic is not typical of a conventional baseload unit. Because of the lack of control over the resource, the WECS cannot be committed to meet a rising demand or a crisis due to the failure of another unit, nor can it be counted on to meet the baseload demand component at a steady output level.

As a consequence of the above, the net conclusion in discussions of WECS implementations has often been that the installation of a WECS will not displace the installation of any amount of conventional capacity. However, using the same generating system reliability indices that utility planners rely on, it can be shown that typical WECS installations will indeed increase the overall system reliability and, therefore, that there is some conventional capacity displacement due to WECS.

To do this credibly requires that the index be an hourly index and that the WECS forced outage rate depend on both time of day and time of year. In this Section, a method of calculating the capacity equivalency of a WECS using Loss-of-Load Probability (LOLP) as the index is explained and applied to the Oahu system of the Hawaiian Electric Company.

6.2.1 LOLP Calculations for Systems of Conventional Units

Most electric utilities have a variety of reserve margin criteria which they impose when planning the maintenance of existing capacity and the addition of new capacity. The following are examples of typical criteria for the required amount of available (installed and not on maintenance) capacity:

- The available capacity exceeds the expected demand by X percent.
- The available capacity exceeds the demand by Y percent + the capacity of the largest committed (operating) unit.
- The available capacity exceeds the demand by the sum of the capacities of the two largest committed units.

These are simple criteria which are ordinarily only critical at the time of the daily peak demand, and most critical at the time of the annual peak. Criteria such as these do not require complex calculations and are still used rigidly by some utilities and as rules of thumb by others.

In recent years, more complex criteria based on reliability information on the generating units have been adopted by many utilities. Sometimes these criteria are used in conjunction with one or several of the simpler criteria like those mentioned above, and sometimes they stand alone. The most widely used probability criterion is the LOLP.

If for some short period of time, say one hour, the demand will be at a given level (MW), LOLP is the probability that there will not be enough operable units to meet that demand. The LOLP calculation does not reveal probabilistic information on the duration of a capacity short fall, nor does it provide information on the magnitude of the short fall. Such information is of importance to a utility, but is generally too complex for use in generation planning. LOLP is regarded as a reliability "index" for use in planning generation installation and maintenance schedules. It is a calculated number which responds to important basic parameters of a generating system: the number of units in the system and their individual capacities and reliabilities.

For LOLP calculations, the reliability of a generating unit is described by its forced outage rate, which is simply the fraction of time the unit was not available because it was inoperable (not including the time it was unavailable because of scheduled preventive maintenance). In some very large units, it is possible for the unit to fail partially. One of several boilers may go out, for example. For such units, the mutually exclusive states are individually associated with a probability of occurrence and the capacity corresponding to that occurrence. This more complex description of outage probabilities can be readily accommodated in a typical LOLP algorithm.

To calculate LOLP, every possible combination of units in a forced outage condition is identified and the corresponding probability of that occurrence is calculated. The resulting probabilities are ordered in terms of ascending magnitude of capacity in a forced outage condition, and the running sum of the probabilities is calculated from the bottom (zero capacity out) up. This running sum as a function of the outage capacity is the cumulative distribution function for system outage which can then be used to calculate LOLP. The actual calculation of the distribution function is more efficiently organized than that described above, but it is the same calculation in principle and produces exactly the same results. A short description of the algorithm used in this study is presented in Appendix D. A table of the probability that capacity D or greater is not available is formed from this distribution function. For every i^{th} hour, the argument of the table is the current demand D_i . The probability that capacity D_i or greater is not available for the i^{th} hour is the Loss-of-Load Probability for that hour, $LOLP_i$. The monthly or annual LOLP is then simply the sum of $LOLP_i$ over all of the hours of the period of interest. In this process, it is assumed that the demand and outage probability function are unrelated.

If the LOLP calculation is repeated for every hour of the year and the results for each hour are all summed together, the result is the probable number of outage "events" per year. The probable number of outage events per year can also be calculated using only that particular hour of each day corresponding to peak demand. If only daily peaks are used, the calculated number of events per year will be smaller because 23 hours of each day are ignored. Some utilities calculate the annual LOLP using every hour of the year and others calculate it using only the daily peaks. Because of the different bases for the calculation, and because of different levels of emphasis on the importance of LOLP, there is no generally agreed upon criteria for an acceptable level of LOLP. It should be noted in this connection that the units of LOLP (and the quoted LOLP criterion) are often given to be hours per year (usually when the quoted annual LOLP was calculated using every hour of the year) and just as often said to be in days per year (usually when the calculation is based on daily peaks, but sometimes when every hour of the year is used and the results are divided by 24). There can get to be no end of confusion and debate about this, and it appears to be best to quote the number in terms of events per year while simultaneously indicating the basis for the calculation.

For a system using all conventional generation, there is some merit to basing the calculation on daily peaks only, because the computational load is significantly reduced. This mode of calculation is often accurate enough because the peak hours tend to dominate LOLP and the general effect of changes in unit schedules, capacities and reliabilities is adequately reflected in the results. The LOLP criterion quoted for the system should reflect that the calculation is based only on daily peaks, of course. A fundamental requirement for an LOLP calculation based on daily peaks is that the magnitude of daily peak be identified, which usually requires identification of the time of the peak in order to determine the magnitude. When the daily load duration curve is fairly flat, or where there is some uncertainty (a priori) about the time of the peak and the demand level in hours adjacent to the peak, an hourly calculation is preferred. This leads to the requirement for calculating LOLP on an hourly basis when a significant amount of WECS capacity is contemplated.

6.2.2 Sample LOLP Results for HECO Without WECS

The monthly distribution of LOLP for HECO conventional generation without a WECS is shown in Figure 6-1. These results were computed on an hourly basis whereas HECO ordinarily computes LOLP using daily peaks only. Because these monthly distributions of LOLP were computed without a WECS in the system, they indicate the monthly potential for increasing system reliability by adding a WECS. The demand time history used to compute the LOLP distributions of Figure 6-1 was constructed by scaling the 1976 HECO demand record to match HECO's forecast of the monthly peaks over the 15-year period (described in Section 3.0). HECO's annual peak always occurs in October. Even though the normalized annual time history is the same for each year, always peaking in October, the months with the greatest LOLP vary from year to year. That is, the months with the greatest potential for system reliability improvement do not necessarily correspond to the annual demand peak. This example leads to a general result that is often not recognized: for a WECS to have the potential for increasing system reliability, it is not necessary that the WECS seasonal performance match the seasonal variation of customer demand.

There are several reasons for the HECO year-to-year variation of monthly LOLP. Although the demand pattern repeats every year (while growing at a rate estimated in 1976 to be approximately 4.6 percent per year), the installation of new units is discrete and unevenly spaced in time, depending on the capacity of the new unit. Thus the difference between demand and installed capacity varies from year to year. The initial operating times for the new units (corresponding to this generation plan which was under consideration by HECO in March, 1977) are indicated by the callouts (K6, G3, G4, . . .) in Figure 6-1. Over the 15-year period of the study, the generation system increased from 19 to 28 units, a total of 1002 MW.

In addition to the uneven growth of installed capacity, the system maintenance schedule for the units already installed varies from year to year because of year-to-year variations in maintenance requirements for individual units. HECO maintains their units on a two-, five-, or seven-year cycle, as discussed in Section 3.0. The calendar phase of the cycle for each unit depends on its year of installation, of course. In addition to the maintenance cycle constraints for each unit, constraints on maintenance crew scheduling must be observed. The sum effect of year-to-year variations in installation pattern and maintenance schedule patterns is to produce year-to-year variations in the distribution of monthly LOLP.

6.2.3 LOLP Calculations for Utilities Using WECS

There are two basic ways in which the LOLP can be calculated for a utility using a WECS in conjunction with conventional generation. Both approaches require hourly calculations and the synthesis of WECS hourly power output based on as much historical wind data as can be obtained (either directly or indirectly through correlation means). The synthesis of the output of the four implementation Phases for the Point Kahuku WECS was discussed earlier in Section 5.0. The two approaches are:

Figure 6-1. Monthly HECO LOLP Distribution for Baseline Study Plan

- (1) Subtract the synthesized WECS output from the demand, and calculate LOLP using the outage rate data for the conventional units meeting the residual demand.
- (2) Synthesize forced outage rates (dominated by wind outage) for the WECS using the hourly WECS power output data, and then calculate LOLP using the outage rate data for both the WECS and conventional units meeting the total demand.

Done correctly, the two approaches will give essentially the same results, but the first requires averaging to remove the effects of arbitrary phasing between society (as reflected in demand time histories) and wind system output which has no dependence on the day of the week. Note in the first approach that the hour of the day corresponding to the peak residual cannot be identified a priori (unless the WECS capacity is small relative to the peak demand), suggesting that it is most appropriate to calculate LOLP on an hourly basis when including a WECS in the generation mix. In addition to the averaging problem, the first approach requires treating supply as a negative demand which confuses the bookkeeping and implementation of other demand-dependent criteria. It is more straightforward to use the second approach as was done in this study.

In analyzing the time history of a WECS output for a WECS comprised of wind turbine generators which were selected to minimize the capital cost per annual energy output (rather than maximize capacity factor, for example), it will be found for most WECS locations that the power output has a significant diurnal variation as well as a significant seasonal variation. The diurnal wind variation can be adequately represented on an hourly basis which is consistent with the usual diurnal representation of demand. Climatological statistics are seldom prepared over averaging periods of less than one month—implying that seasonal variations can be adequately represented on a monthly basis.

For a WECS comprised of WTGs sized to minimize capital cost per annual energy output, the power output will vary from zero to nameplate rating with a significant fraction of the time (greater than 50 percent) spent somewhere between the two extremes. This implies that a partial availability (where availability is the complement of outage) description is required in the same manner as with very large conventional units designed with paralleled subsystems. In the numerical results presented for Oahu in the next Section, a partial availability description using five percent increments of nameplate rating was used.

It is expected that forced outage due to mechanical failure combined with scheduled maintenance will average out to about three percent for an individual WTG (which is very small compared to expected wind outage). Because a WECS will be typically comprised of a large number of identical WTGs, a statistically acceptable method for accounting for this component of outage is to simply derate the machines by the amount of expected mechanical outage. The availability density function (forced outage + maintenance) is shown in Figure 6-2 for the 30-unit Phase I WECS. The expected availability of 29.1 ($=30 \times .97$) is obviously a reasonable approximation for the density function shown. The approximation improves further as the number of units (N) is increased, as seen from the formula for the standard deviation expressed as a percentage of the expected availability.

Figure 6-2. Availability Density Function for 30-Unit Binomial Distribution

In summary then, the forced outage rate for a WECS can be adequately represented for LOLP calculations by:

- (1) Derating the WECS nameplate rating by the amount of expected mechanical outage and scheduled maintenance.
- (2) Describing the WECS availability at discrete steps of from five to 10 percent of maximum output, calling the result a WECS availability vector.
- (3) Calculating the WECS availability vector for each hour of the day for each month of the year. A total of $12 \times 24 = 288$ vectors would be required to completely describe forced outage probabilities for a WECS.

The probabilities are calculated as above from the synthesized WECS time histories. The probabilities are simply computed as the percentage of possible time that the WECS output falls in a bin centered about each of the capacity levels defined for the vector of partial availability probabilities.

A typical availability probability array is shown in Table 6-1 for the month of March for a WECS located at Point Kahuku on the north side of Oahu. This array

corresponds to an installation of 150 MW_e nameplate rating (Phases 1 and 2 taken together). In Table 6-1, there are 22 rows corresponding to the indicated capacities beginning at the top with 145.5 MW (nameplate rating 150 MW x (1 - .03) = 145.5) and running down to exactly zero output. Each of the 24 columns corresponds to the hour of the day. The first column gives the probability of the output averaged over 12 midnight to 1AM being at the indicated power level. The second column corresponds to time averages over the interval 1AM to 2AM, and so on.

Specifically, the matrix in Table 6-1 was calculated as follows:

- (a) A simulation of WECS operation (as developed in Section 5.0) was driven with historical hourly wind speed data to obtain an hourly WTG power output time history. The hour of the day and month of the year for each hourly output value was preserved in generating the WECS output history.
- (b) The output time history was then multiplied by .97 to account for a mechanical outage rate (forced + scheduled) of .03.
- (c) Each item of output for a given hour of the day for the month of March (for example) was sorted into one of 22 bins:
 - (1) $P = \text{exactly } 145.5 \text{ MW}$ ($145.5 = .97 \times \text{nameplate rating}$)
 - (2) $138.225 \leq P < 145.5$ ($138.225 = .95 \times .97 \times 150$)
 - (3) $130.95 \leq P < 138.225$ ($130.95 = .90 \times .97 \times 150$)
 - .
 - .
 - .
 - .
 - (20) $7.27 \leq P < 14.55$
 - (21) $0 < P < 7.275$
 - (22) $P = \text{exactly } 0$
- (d) It was assumed that (for example) those output levels that were between 138.225 and 145.5 (item (b) above) corresponded to an output of exactly 141.8625 MW; and so on for the subsequent 19 levels. That is, what is really a smooth function was fitted with a staircase function discretized at five percent intervals.
- (e) The value that appears in the matrix is then the number of times that that output power level occurred divided by the possible number of times that it could have occurred.

TABLE 6-1

HOUR OF THE DAY

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
145.50	.548	.548	.516	.484	.484	.677	.581	.581	.548	.581	.581	.484	.548	.516	.548	.516	.484	.484	.387	.581	.387	.419	.484	.548
141.86	.032	.065	.0650.000	.065	.032	.097	.032	.065	.032	.032	.129	.129	.065	.065	.065	.097	.194	.129	.129	.032	.032	.032	.065	
134.59	.129	.065	.194	.194	.0970.000	.032	.129	.097	.129	.065	.1290.000	.097	.129	.065	.097	.065	.129	.032	.194	.097	.065	.097	.065	
127.31	0.0000.0000.000	.032	.0650.000	.0320.000	.0650.000	.065	.0320.000	.0320.0000.0000.000	.0320.000	.0320.0000.0000.000	.0320.000	.0320.0000.0000.000	.0320.000	.0320.0000.0000.000	.0320.000	.0320.0000.0000.000	.0320.000	.0320.0000.0000.000	.0320.000	.0320.0000.0000.000	.0320.000	.0320.0000.0000.000	.0320.000	.0320.0000.0000.000
120.04	.0650.000	.0320.000	.0320.000	.032	.0650.000	.032	.032	.0320.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000
112.76	0.0000.0000.0000.0000.0000.0000.000	.032	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000	.0320.0000.000
105.49	.065	.0320.0000.0000.000	.032	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000
98.21	0.0000.0000.0000.000	.0320.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000
90.94	0.000	.0650.0000.0000.0000.0000.0000.0000.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000
83.66	0.0000.0000.0000.000	.065	.0320.0000.0000.0000.0000.0000.0000.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000
76.39	0.000	.0320.000	.0650.000	.0320.0000.000	.0320.0000.000	.0320.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000
69.11	0.0000.0000.000	.0650.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000
61.84	0.0000.0000.0000.000	.0650.0000.0000.0000.0000.0000.0000.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000
54.56	0.0000.0000.0000.000	.0650.0000.0000.0000.0000.0000.0000.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000
47.29	.0320.0000.0000.000	.0650.0000.0000.0000.0000.0000.0000.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000
40.01	.0320.0000.0000.000	.0650.0000.0000.0000.0000.0000.0000.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000
32.74	0.000	.0320.0000.0000.000	.0650.0000.0000.0000.0000.0000.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000
25.46	0.0000.000	.0320.0000.0000.0000.0000.0000.0000.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000
18.19	.032	.0320.0000.0000.000	.0650.0000.0000.0000.0000.0000.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000
10.91	0.000	.032	.0320.0000.0000.0000.0000.0000.0000.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000	.0320.0000.0000.000
3.64	.065	.065	.097	.032	.097	.065	.065	.032	.065	.032	.065	.065	.032	.0970.000	.065	.097	.032	.097	.032	.129	.065	.097	.097	.097
0.00	0.000	.032	.032	.097	.065	.097	.065	.065	.032	.065	.0320.000	.0320.000	.032	.065	.097	.194	.129	.194	.065	.097	.097	.097	.097	.097

- (f) Each element is then interpreted to be the probability of that power level occurring at that hour of the day in that particular month for the WECS design reported in Section 5.0.

The variation of probabilities with output level for each column is not smooth because it is based on data for only one March (March of 1977). A matrix based on many years of wind data would show a smooth variation, of course. The process of convolving the WECS availability probability vectors into the conventional generation vector is a smoothing process, making it unnecessary to artificially smooth the WECS vector.

Twelve such matrices, one for each month, were developed for the four WECS installation Phases described in Section 5.0. Given that the WECS power output (used to derive the matrices) is statistically independent of the customer demand (approximated for HECO by gross demand) on an hour-specific basis, these matrices can be used in the same manner as conventional unit availability probability vectors to compute LOLP. In the case of HECO, the demand is statistically independent of wind conditions at Kahuku as discussed in Section 6.2.4. The matrices were then used to compute the LOLP for HECO for each hour of a 12-year period using the baseline generation installation schedules, maintenance schedules and hourly demand which were defined in Section 3.0; and the four WECS Phases defined in Section 5.0. The results of those calculations are presented in Sections 6.2.5 and 6.2.6.

6.2.4 Correlation of HECO Demand with Winds

Implicit in the LOLP procedure described in Sections 6.2.1 and 6.2.3 is the requirement that generating unit forced outages be independent of customer demand. This is clearly the case for conventional units but not necessarily so for WECS.

The annual peak demand for the HECO system occurs in October. No firm reason for the peak being in October has been identified, but it has been theorized by HECO personnel that the reason is that October tends to be quite still, i.e., without winds. It is theorized that even though the temperatures are quite ordinary in October, the lack of breezes causes a greater air-conditioning load. These comments relate to a possible correlation between winds and demand at the predominant HECO load center, Honolulu.

If HECO demand depends on Honolulu winds and Honolulu winds are related to Kahuku winds, the LOLP calculation procedure must be modified to reflect that dependency. The question can be resolved by a direct comparison of HECO demand to Kahuku winds without considering any intermediate relationship with Honolulu winds or winds at other load centers.

Historical HECO demand data for 1976 were compared with Kahuku Upper wind data for the months of April through December. Kahuku Upper wind data prior to April 1976 are not available. The comparisons were made on both an hour-specific basis and a daily basis.

For the hour-specific comparison, the average hourly profiles for the four or five Mondays of a given month, the four or five Tuesdays of that same month and so on for the remaining five types of days (holidays were discarded) were calculated from the historical demand data. Residuals were formed by subtracting the average demand from the actual demand for each specific day of the week. The demand residuals were then scatter plotted against the Kahuku Upper wind for each particular hour. There was no discernible correlation between the residuals and the Kahuku Upper winds for any of the nine months investigated. The results for October (1976) shown in Figure 6-3 are typical. The sign convention for the residuals in this and the following figures is that the residual is positive when the actual demand exceeds the average demand.

The business day hours of (roughly) 8AM to 11PM are most important from a system generation reliability point of view. These same hours undoubtedly have more discretionary air-conditioning load (i.e., air-conditioning load that is not routinely left on on a 24-hour basis) than do the nighttime hours of 11PM to 8AM. To be sure that a distinct wind demand correlation for the daylight hours was not being masked by uncorrelated nighttime data, separate scatter plots were made only retaining the data pairs for the hours of 8AM to 11PM. Again, there was no discernible correlation. Figure 6-4 shows a scatter plot for this restricted set of data for the month of October, which is typical of the other eight months investigated.

It is possible that the demand response to wind (or lack of wind) might be smoothed over a number of hours regardless of the rise and fall of the wind for each specific hour. It may take more than several hours of stillness to trigger discretionary air-conditioning, and then some persistence in the stillness to motivate the maintenance of the increased air-conditioning expense. To investigate this possibility, the daily demand for each of the seven types of days were averaged for each month and subtracted from the actual daily demand. Again, there was no discernible correlation. The scatter diagram for the month of October shown in Figure 6-5 is typical.

It was concluded that there is negligible correlation between winds at Kahuku point and HECO system customer demand, and that it is legitimate to assume that HECO demand is independent of the WECS availability probability in calculating LOLP.

6.2.5 LOLP Improvement Due to WECS

If the baseline HECO generation plan is unaltered (in terms of both maintenance schedule and installation plans) and the four Phases of the Kahuku WECS are installed and declared operational as described in Section 5.0, there is a substantial improvement in the overall HECO system LOLP. The results are shown in Table 6-2 for LOLP computed as outlined in Section 6.2.3. The substantial decrease in LOLP due to the installation of the WECS suggests that a modification of the installation schedule for the new conventional generation might be possible without compromising the system reliability as measured by LOLP. The modification should lead to a savings or postponement of capital expenditures for conventional units, of course.

The real problem in a WECS planning study is to determine how much the previously planned installation date for each future conventional unit can be postponed due to

Figure 6-3. Scatter Plot of Hourly Demand Residuals
versus Kahuku Upper Wind Speed for
All Hours of the Day
Month of October, 1976

Figure 6-4. Scatter Plot of Hourly Demand Residuals
versus Kahuku Upper Wind Speed for Hours
Between 8:00 AM and 11:00 PM
Month of October, 1976

Figure 6-5. Scatter Plot of Daily Demand Residuals versus Average Daily Kahuku Upper Wind Speed for Month of October, 1976

TABLE 6-2

LOLP FOR BASELINE HECO SYSTEM WITH WECS

Year	Baseline LOLP (Events/year)	Baseline + Phase 1 LOLP (Events/year)	Baseline + Phases 1&2 LOLP (Events/year)	Baseline + Phases 1,2&3 LOLP (Events/year)	Baseline + Phases 1,2,3&4 LOLP (Events/year)
1980	.033	---	---	---	---
81	.157	---	---	---	---
82	.370	---	---	---	---
83	.098	.044	---	---	---
84	.437	.213	.122	---	---
1985	.257	.130	.078	.062	---
86	.542	.253	.131	.101	.080
87	.815	.458	.285	.233	.186
88	.593	.308	.176	.139	.110
89	1.198	.621	.342	.258	.203
1990	.949	.532	.294	.225	.180
91	.640	.342	.189	.146	.115
92	.942	.555	.327	.256	.204
93	1.250	.758	.458	.357	.287
94	1.589	.952	.557	.431	.347

the installation of a WECS. The extent to which they are postponed reflects the capacity credit attributable to the WECS. The extent to which the different types of conventional units leapfrog each other in the postponement reflects a change in generating mix--a variable that depends on cost of production and capital cost considerations as well as reliability. The problem is very complicated as well as peculiar to the particular utility under consideration.

These complicated aspects of a WECS implementation on Oahu for HECO are discussed in Section 6.2.6. A more direct method of exposing the equivalent WECS capacity credit was developed here to gain a more general understanding of the problem. This approach described below facilitates a calculated understanding of the reliability of a WECS without all of the peculiar encumbrances of the real problem.

A hypothetical conventional unit with a forced outage rate of .05 which required no maintenance was added to the baseline generation plan described in Section 3.0. The capacity of this single unit was varied incrementally up to 120 MW and the HECO system LOLP recalculated for each of the 15 years in the span 1980-94. The resulting annual LOLP variation with the capacity of the added unit is shown in Figure 6-6. The curves show, in terms of annual LOLP, how much the addition of a single highly reliable conventional unit will improve the system reliability.

The hypothetical conventional unit was then removed from the system and a WECS described by 288 availability vectors as discussed in Section 6.2.3 was added to the HECO system. The annual LOLP was then recalculated with the WECS in the system. A distinct single value of LOLP is obtained for each year of the 15-year span studied. Figure 6-6 can be entered for the year of interest at the ordinate value of LOLP calculated including the WECS, and the corresponding capacity of a single conventional unit can be read from the horizontal scale. The results for each of the 12 years beginning in 1983 are spotted on Figure 6-7 for Phase 1 of the Kahuku WECS.

The Phase 1 WECS installation is comprised of 30 WTGs with a total nameplate rating of 45 MW. Note that the equivalent capacity of the Phase 1 WECS varies year to year from 20 to 28 MW. This variation is due entirely to the variation in monthly distribution of the baseline LOLP as discussed earlier in Section 6.2.2. There will be a year-to-year variation in actual WECS output, of course, but there will not be a variation in expected output (or its complement, expected outage). In the same sense, there is no variation in forced outage rate for a mature conventional unit.

The 20 to 28 MW range in equivalent conventional capacity corresponds to a WECS capacity credit of from 44.4 to 62.2 percent. This is a lower-bound estimate because the maintenance schedule for the conventional units was not replanned for the addition of the WECS. The results therefore correspond to a suboptimal schedule and can only improve with rescheduling. The results for Phases 1 and 2 (150 MW nameplate rating), Phases 1, 2 and 3 (300 MW) and Phases 1, 2, 3 and 4

(450 MW) are shown in Figures 6-8, 6-9, and 6-10. The percentage capacity displacement decreases successively for these additional Phases because the quality of the wind was successively poorer as discussed in Section 5.0. A lower quality wind is reflected in the WECS availability vector, of course. In fact, the availability vector and its effect on system LOLP is a measure of wind quality.

Figures 6-11 through 6-15 show the reduction in LOLP associated with the addition of a single hypothetical unit with a forced outage rate of .10 rather than .05. Note that there is a substantial increase in WECS capacity credit when the forced outage rate of the competition is increased.

It should be reemphasized that the capacity credit results presented above are hypothetical in that the LOLP improvement due to the WECS is compared to the improvement due to the hypothetical introduction of a conventional plant with a rubber capacity. The real situation calls for analyzing the possible displacement of one of the presently planned HECO conventional units. This problem is discussed next in Section 6.2.6.

6.2.6 Effect of WECS on LOLP for Planned HECO Generation

The HECO plan for the installation of new equipment used in this Study (called here the "baseline plan") was one of several under consideration in March of 1977. It was provided to Aerospace specifically for use in this Study but it has not been adopted by HECO as a firm plan. Such plans are always in a continual state of reappraisal and revision. The following analysis is therefore realistic but not definitive for HECO.

Figure 6-16 shows the scheduled increase of HECO installed capacity (in terms of second contingency ratings--see Section 3.5.3). The indicated installation dates are the same as those provided in Table 3-5. Units G3, G4, G5 and K7 are clear candidates for displacement or postponement by a WECS installed in the middle 1980s.

In considering either the displacement or remixing of different types of conventional units by wind energy, both system generation reliability and cost-of-production optimization must be considered. The reliability aspects were pursued to the point of identifying viable possibilities but the apparent value of these possibilities did not warrant further investigation under the cost limitations of the present study.

HECO bases their generation risk analysis on an LOLP index computed with daily peaks only and have therefore not defined a risk criterion consistent with hourly LOLP calculations. The approach taken here was to calculate the hourly LOLP for the baseline HECO installation and maintenance plan and use the results as a guide (the term criterion is too strong) for adequate reliability in the evaluation of the WECS. The annual LOLP for the baseline plan is charted in Figure 6-17 (also presented in Table 6-2). It was considered acceptable if the displacement of one or several of the planned installations by one or several of the Kahuku WECS Phases did not produce an annual LOLP significantly exceeding the highest baseline value (which occurred in 1994).

Figure 6-6. Variation of HECO Annual LOLP with Capacity of an Additional Unit with .05 Forced Outage Rate

Figure 6-7. Equivalent Conventional Unit Capacity of Kahuku WECS Phase 1 (Conventional Unit Forced Outage Rate = .05)

Figure 6-8. Equivalent Conventional Unit Capacity
of Kahuku WECS Phases 1 and 2
(Conventional Unit Forced Outage Rate = .05)

Figure 6-9. Equivalent Conventional Unit Capacity
of Kahuku WECS Phases 1, 2 and 3
(Conventional Unit Forced Outage Rate = .05)

Figure 6-10. Equivalent Conventional Unit Capacity
of Kahuku WECS Phases 1, 2, 3 and 4
(Conventional Unit Forced Outage Rate = .05)

Figure 6-11. Variation of HECO Annual LOLP
with Capacity of an Additional Unit
with .10 Forced Outage Rate

Figure 6-12. Equivalent Conventional Unit Capacity of Kahuku WECS Phase 1
(Conventional Unit Forced Outage Rate = .10)

Figure 6-13. Equivalent Conventional Unit Capacity of Kahuku WECS Phases 1 and 2
(Conventional Unit Forced Outage Rate = .10)

Figure 6-14. Equivalent Conventional Unit Capacity
of Kahuku WECS Phases 1, 2 and 3
(Conventional Unit Forced Outage Rate = .10)

Figure 6-15. Equivalent Conventional Unit Capacity
of Kahuku WECS Phases 1, 2, 3 and 4
(Conventional Unit Forced Outage Rate = .10)

Figure 6-16. HECO Baseline Study Plan for Installed Conventional Capacity

Figure 6-17. Annual LOLP for HECO Baseline Study Plan Conventional Unit Availability Schedule

Figures 6-18, 6-19, and 6-20 chart the annual LOLP corresponding to the displacement of G3 (a 70 MW gas turbine scheduled for initial operation in 1984) with the Kahuku WECS Phase 1, Phases 1 & 2, and Phases 1, 2 & 3, respectively. Phase 1 alone and Phases 1 & 2 do not produce acceptable LOLPs. However, Phases 1, 2 & 3 taken together with the removal of G3 produce annual LOLPs as good as the worst year (1994) for the baseline case. It is concluded therefore that the installation of WECS Phases 1, 2 & 3 will displace G3. That is, the installation of 200 WTGs with a nameplate rating of 300 MW displaces 70 MW of conventional generation for a capacity credit of 23.3 percent. The capacity credit is slightly more than shown in Figure 6-9 (64 MW) because the hypothetical unit of Figure 6-9 required no scheduled maintenance and was added to the existing system rather than subtracted from the existing system.

Figure 6-18. Annual LOLP for HECO Baseline Study Plan with Kahuku WECS Phase 1 and Without G3

As an alternative to displacing G3, the possibility of adding a WECS plus two new 70 MW gas turbines to displace K7 was investigated. K7 is a 178 MW (second contingency rating) oil-fired thermal unit. Consistent with HECO gas turbine experience, the gas turbines were assumed to have forced outage rates of .05. They were to become operational at the same time K7 would have in 1989. The LOLP for the two turbines replacing K7 without help from a WECS is charted in Figure 6-21. The LOLP is very high in both 1993 and 1994. Adding the Phase 1 WECS into the picture brings the LOLP within reason as shown in Figure 6-22. It is concluded that from a generation reliability standpoint Phase 1 plus two gas turbines can displace K7.

Figure 6-19. Annual LOLP for HECO Baseline Study Plan with Kahuku WECS Phases 1 and 2 and Without G3

Figure 6-20. Annual LOLP for HECO Baseline Study Plan with Kahuku WECS Phases 1, 2 and 3 and Without G3

Figure 6-21. Annual LOLP for HECO Baseline Study Plan with Two 70 MW Gas Turbines Replacing K7

Figure 6-22. Annual LOLP for HECO Baseline Study Plan with Kahuku WECS Phase 1 and Two 70 MW Gas Turbines Replacing K7

The displacement of G3, a unit costing approximately \$10M (1977 dollars) by Phases 1, 2 & 3 would add about \$33/kW to the value of the first 200 WTGs installed on Kahuku. This was not deemed significant enough to carry through the financial analysis. The replacement of K7 with two gas turbines would save approximately \$35M (1977 dollars) in capital expenses but (in the presence of Phase 1 WECS generation) would impact the cost of production on the order of \$10M/year (1977 dollars) in the time frame immediately after installation in 1989. In both cases, the savings associated with these capital displacements were dwarfed by the savings associated with fuel displacement. Therefore it was decided to completely discount the capital value of the WECS and figure the WECS value solely on the basis of operational savings. That is, the WECS was treated as fuel saver in calculating break-even costs. The calculation of fuel savings is covered next in Section 6.3.

6.3 GENERATION COST OF PRODUCTION

6.3.1 Objectives

The main economic benefit of a WECS on Oahu will be due to the displacement of oil energy (or possibly, coal energy). The measure of that benefit is the cost of the additional oil that would have been consumed had the WECS not been installed. A first order estimate of this savings can be obtained by simply assuming an average HECO generating system efficiency (net heat rate) and then calculating the oil dollar equivalent of the electric energy produced by the WECS. Such an analysis was performed in this study and reported earlier (Reference 6-1). However, the actual system heat rate will depend on the serial characteristics of the WECS output relative to the customer demand, which requires a simulation of utility production operations.

The most efficient and least efficient generating units in a typical utility will have annual production cost rates (as measured for each unit in terms of mills/kWh) which bare in a 2:1 ratio (not including fixed charges). The least efficient units, often called "peakers," are generally used only for a short period at the time of peak loads. The economic value of wind energy will obviously be greatest for a WECS output at the time of peak loads thereby displacing the fuel burned by the relatively less efficient peakers. The quantitative assessment of this effect can only be established with a determination of the displaced oil on an hourly basis. Such a calculation is called a cost-of-production calculation in the industry and it ordinarily includes the various operating constraints and dispatching rules that the subject utility observes in its actual operations. These rules are addressed in detail for HECO in Section 6.3.3.

In accurately assessing the cost-of-production differential due to wind, a variety of operating rules must be observed. One of the most important class of rules in terms of their effect on production costs are the Spinning Reserve Criteria. Hawaiian Electric Company operations on Oahu are completely isolated from any backup outside of their own system. They consequently have (1) a somewhat larger amount of installed capacity relative to expected demand and (2) a greater number of units turned on and producing electricity at a level less than their individual capacity limits than would be expected of a utility of the same size that is interconnected

with other systems in a reliability pool. A major consideration in the cost-of-production analysis is the determination of the effect of the variability and lack of predictability of wind on the cost of production. The answer to this question lies in the way in which the Spinning Reserve Criteria are applied in providing backup for a WECS wind power outage. Thus, a second objective of the cost-of-production analysis which is closely related to the first is to assess the economic effect of wind variability (on production cost).

6.3.2 Analysis Assumptions

With the exception of the description of hourly demand (explained below), the basic modeling assumptions, imposition of HECO operating rules, power demand book-keeping conventions and other matters pertaining to cost-of-production analyses used in this study are exactly the same as those used by HECO in their own studies. Some of the more important assumptions are discussed below. The HECO operating policies and rules for the production of electricity are described in Section 6.3.3.

Hourly Dispatching

As implied in earlier discussions, the cost-of-production simulation is driven by a time history of hourly demand data. The demand datum for a particular hour is actually the average power over the preceeding hour. An hourly basis is standard for economic calculations of this type although two-hour intervals are sometimes used. The hourly time history of demand used in the cost-of-production analyses was synthesized for the 1980-94 time frame as described in Section 3.3.2. The cost-of-production calculations performed by HECO for their own studies use average weekdays and average weekend days for each of 12 periods in a year.

Quadratic Performance Curves

The following form is used by HECO to describe the heat rate curve for each unit:

$$\text{Heat Rate} = \frac{A}{P} + B + CP, \text{ Btu/kWh}$$

where P is the gross power output for the unit. The input/output curve is obtained by multiplying the heat rate curve by P:

$$\text{Heat Rate} \times P = A + BP + CP^2, \text{ Btu/hr}$$

and the incremental heat rate curve obtained by differentiating the input/output curve with respect to P is a straight line:

$$\text{Incremental Heat Rate} = B + 2 CP, \text{ Btu/kWh}$$

The incremental cost rate is obtained by multiplying the incremental heat rate by the dollar value of a Btu of the type fuel used by the unit being considered. The use of straight line segments for the incremental cost rate facilitates the dispatching optimization calculations.

Forced Outage Rates

Consistent with HECO practice in their own cost-of-production studies, the forced outage of units was not considered in these cost-of-production calculations. Because HECO units have very low forced outage rates, the results will only be slightly optimistic (lower cost). Note that because the actual production cost for conventional electricity will be slightly higher than that calculated here under this assumption, the consequent value of wind energy will be slightly higher than computed here. That is, this assumption produces a conservative result from the standpoint of wind energy advocacy.

Gross Demand and Supply

The demand data used in this study include the demand due to generating unit auxiliary equipment. Consistently, all generating unit output operating limits, performance curve information, etc., are for gross output. This is standard practice for HECO, but leads to some error because the percentage of gross output which is parasitic is not the same for all units nor necessarily a constant independent of unit loading. The net result of this assumption is that there is small unknown error in the computed results.

Normal Maximum Operating Limit

HECO does not operate their units above the normal operating limit (see Table 3-6 in Section 3.0) unless there is an emergency where a unit has been forced out. Only in the event of a forced outage emergency will a temporary over-limit condition be permitted with the operating units (while a cold unit is fired up and brought on line). Consistent with this practice and the above assumption regarding forced outages, the cost-of-production calculations are based on all units operating at or below their normal maximum limit.

6.3.3 HECO Unit Commitment Rules

There are a variety of operating policies and rules governing the commitment (decision to fire up and operate) of units. These rules are observed by HECO to ensure an acceptable quality of service and level of system integrity. At this point, these rules should be studied and understood in the context of a purely conventional mix of generation; the application of the rules in the context of a mix of conventional and wind turbine generators is discussed later in Sections 6.3.5 and 6.3.6.

In applying the rules, the objective of producing electricity as cheaply as possible must not be overlooked. The unit commitment rules are thus properly regarded as constraints in an optimization problem--the problem of producing a given amount of electric power at a minimum cost rate (\$/hr).

The HECO unit commitment rules are defined below. They must be satisfied for every hour.

6.3.3.1 Unit Commitment Priority

When the system demand is rising and the unit commitment rules require that an additional unit be committed (started), that unit is selected from those which are available (installed and not on maintenance status) according to a unit commitment priority ranking. That is, if another unit is required, the unit with the highest priority number is started. Consistently, if it is required or permitted to shutdown a unit, the unit to be shutdown is that operating unit with the lowest priority number. The HECO unit commitment priority numbers are listed in Table 6-3 along with the unit heat rate at the normal maximum rating and the normal maximum rating. Note that generally the heat rate increases with decreasing priority. However, there are considerations other than efficiency in establishing commitment priority rankings like, for example, the stress associated with firing up a very old unit.

TABLE 6-3

HECO UNIT COMMITMENT PRIORITY NUMBERS

<u>Unit</u>	<u>Priority Number</u>	<u>Gross Heat Rate at Normal Rating</u>	<u>Normal Rating</u>	
X1	28	9030 Btu/kWh	223 MW	Must-Run Unit
K8	27	9141	170	"
K7	26	9141	170	"
K6	25	8985	141	"
K5	24	8985	141	"
K4	23	9100	90	"
K3	22	9100	90	"
K2	21	9150	88	"
K1	20	9150	88	"
W8	19	9472	90	"
W7	18	9472	90	"
W6	17	10575	57	
W5	16	10586	60	
H9	15	11047	60	
H8	14	11024	55	
W4	13	11882	52	
W3	12	11882	52	
H7	11	12645	42	
G7	10	12864	60	
G6	9	12879	59	
G5	8	12864	60	
G4	7	12879	59	
G3	6	12864	60	
G2	5	12641	44	
G1	4	12641	44	
H5	3	15749	23	
W2	2	13174	18	
W1	1	15690	8	

6.3.3.2 Unit Operating Limits

No operating unit may be individually loaded below its minimum rating nor above its normal maximum rating (except in emergencies which are not accounted for in these cost-of-production calculations). Furthermore:

- Rule (1): The sum of the minimum ratings for all of the operating units must be less than or equal to the demand.
- Rule (2): The sum of the normal maximum ratings for all of the operating units must equal or exceed the demand.

6.3.3.3 Must-Run Units

- Rule (3): All of the available ("available" means installed and not on maintenance) must-run units must be operated unless that violates Rule (1) above. If (1) is violated, the maximum number of units (in order of commitment priority) which do not violate (1) above are to be run. A conflict in one hour does not permit relaxation of this rule in other hours.

6.3.3.4 Spinning Reserve Criteria

The following two rules are imposed to ensure that at all times there are enough units currently operating (spinning) and that between them there is enough additional generating capability that they could make up for the sudden failure of the largest unit then operating. These two criteria are the system Spinning Reserve Criteria which are of particular importance in the application of wind power because of the possibility of a relatively sudden fall off of power output across an entire WECS field of WTGs. These two criteria should be studied here in the context of conventional generation only; their application in the context of a mix of conventional and wind generators is discussed later in Sections 6.3.5 and 6.3.6.

- Rule (4): The sum of the first contingency ratings of all operating units excluding the largest operating unit must equal or exceed the demand. If this rule cannot be met by running every available unit or if this rule causes a conflict with Rule (1), then as many units as possible are to be run. A conflict in one hour does not permit relaxation of this rule in other hours.
- Rule (5): The total quick load pickup capability of all operating units taken together but excluding the most heavily loaded unit must equal or exceed the load on the most heavily loaded unit minus five percent of the demand. This criterion is designed to keep the system frequency from falling below 58.5 Hz assuming a two percent reduction in effective system demand for each one percent reduction in frequency. If this rule cannot be met by running every available unit or if this rule

causes a conflict with Rule (1), then as many units as possible are to be run. A conflict in one hour does not permit relaxation of this rule in other hours.

6.3.3.5 Minimum Down Time

As a general rule to prevent excessive thermal and mechanical stressing of their units due to too numerous startups and shutdowns, HECO imposes a requirement that no unit will be shutdown if it is expected that rising demand will again require its operation within five hours. That is:

Rule (6): If Rules (2), (3), (4), and (5) permit the shutdown of any particular unit, that unit will not be shutdown if its operation will be required again within five hours. If Rule (1) requires that a particular unit be shutdown, that unit will be shutdown regardless of this rule. That is, Rule (1) takes precedence over Rule (6).

6.3.3.6 Application of Unit Commitment Rules

The six unit commitment rules defined in Sections 6.3.3.2 through 6.3.3.5 are incomplete without the logic by which they interact. That logic is supplied below in Table 6-4. To prevent circumlocution, the logic is supplied with a minimal amount of comment. The purpose of each step is generally self-explanatory. In Table 6-4, N is the number of units to be committed and the units are committed strictly in the order of the unit commitment priority discussed in Section 6.3.3.1. The logic is applied for each hour in succession without exception.

6.3.4 Baseline System Cost of Production

The Baseline system cost of production was computed to establish the basis for evaluating the economic worth of the four different Phases of WECS implementation. These computations were based on the baseline maintenance and installation schedules, unit performance data, hourly demand data, and fuel costs, all described in detail in Section 3.0. The units were committed and dispatched according to the rules and policies discussed above in Section 6.3.3.

The computed system performance for each of the 15 years in the 1980-94 time frame is shown in Table 6-5. The gross energy is the energy at the busbar including that required to run generating unit auxiliary equipment and is the same (of course) as the gross demand energy discussed in Section 3.0. The capacity factor is figured by multiplying the normal maximum rating of each unit by the number of hours in the corresponding year (subsequent to installation, if the unit was installed in the same year), summing over all the units, and dividing the result into the total gross energy generated. The number of hot starts is the total number of times units were started up within 12 hours of when they were shutdown. The number of cold starts is the number of starts for which the preceeding downtime had exceeded 12 hours. The gross heat rate is the heat rate figured on the basis of total power output from the generator including that required to run generating unit auxiliary equipment.

TABLE 6-4

HECO UNIT COMMITMENT LOGIC

Step NumberAction or Criteria

1	Set N = number of available must-run units.	Go to Step 2.
2	Check Rule (1). If satisfied,	go to Step 4.
3	Set N = N - 1.	Go to Step 2.
4	Check Rule (4). If satisfied,	go to Step 9.
5	If more units are available,	go to Step 6.
6	Set N = N + 1.	Go to Step 7.
7	Check Rule (1). If satisfied,	go to Step 4.
8	Set N = N - 1.	Go to Step 9.
9	Check Rule (2). If satisfied,	go to Step 12.
10	If more units are available,	go to Step 11.
11	Set N = N + 1.	Go to Step 9.
12	Dispatch N units (min cost).	Go to Step 13.
13	Check Rule (5). If satisfied,	go to Step 18.
14	If more units are available,	go to Step 15.
15	Set N = N + 1.	Go to Step 16.
16	Check Rule (1). If satisfied,	go to Step 12.
17	Set N = N - 1.	Go to Step 18.
18	Rule (6) {	go to Step 24.
19		If not, go to Step 19.
20		go to Step 20.
21		If not, go to Step 24.
22	Set N = N for preceeding hour.	Go to Step 21.
23	Check Rule (1). If satisfied,	go to Step 23.
24	Set N = N - 1.	Go to Step 21.
	Dispatch N units (min cost).	Go to Step 24.
	Units are dispatched.	Go to next hour.

* Requires purchase of electricity from outside source which will never happen for a valid unit availability schedule.

TABLE 6-5

BASELINE SYSTEM OPERATING PERFORMANCE 1980-94
(Current Dollars)

Year	Gross Energy (1000 MWh)	Capacity Factor	Number of Starts		Gross Heat Rate (Btu/kWh)	Fuel Cost (mills/kWh)	Total Cost (mills/kWh)	Total Cost (millions \$)
			Hot	Cold				
1980	5811	.579	1608	891	9518	33.63	35.20	204.63
81	6047	.592	1833	919	9595	37.07	38.57	234.14
82	6310	.544	1903	951	9406	39.69	41.40	261.28
83	6597	.586	1471	960	9394	43.19	44.96	296.71
84	6907	.568	1926	1018	9519	47.88	49.73	343.54
1985	7206	.594	2005	1006	9525	52.33	54.27	391.01
86	7536	.596	2255	1021	9567	56.59	58.60	441.63
87	7882	.595	2508	1035	9709	61.88	63.98	504.28
88	8261	.625	2601	1024	9761	67.01	69.06	571.46
89	8628	.588	2699	1093	9549	70.40	72.68	627.10
1990	9041	.596	2602	1106	9626	76.11	78.49	709.64
91	9472	.600	2859	1131	9778	83.62	86.10	815.52
92	9955	.629	3060	1190	9856	90.94	93.52	930.98
93	10404	.605	3105	1231	9766	96.49	99.16	1031.69
94	10905	.569	3132	1285	9711	102.86	105.64	1151.95
Total	120.961	---	35,567	15,861	9639	---	---	8515.56

The fuel cost is the cost of fuel required to economically dispatch the units based on the fuel costs in Table 3-12 of Section 3.0. The fuel costs include the Hawaii tax revenue requirements factor; i.e., to get pure fuel costs, divide the tabulated numbers by 1.1142. The total cost is the fuel cost plus operations and maintenance costs associated with generation (exclusive of transmission, distribution and other O&M costs). The cost rates (per kWh) are figured on the basis of gross busbar energy output.

The data in Table 6-5 are simply presented for reference purposes--no significant findings can be deduced from the data. Some considerable year-to-year variation in capacity factor and hot and cold starts and heat rate might be noted in Table 6-5. This variation is due to the variation of available installed units and can be correlated with the installation and maintenance schedule data presented in Section 3.0. To provide more understanding of these annual data, performance information for individual units is provided in Table 6-6 for the arbitrarily selected year 1986. The definitions of these variables are the same as, or consistent with, those of Table 6-5. The units in Table 6-6 are listed in the order of their commitment priority.

6.3.5 Cost-of-Production Savings with WECS and Full Spinning Reserve

The Kahuku WECS was treated as a must-run unit which supplied a time history of electric energy synthesized as described in Section 5.0. The WECS supply was subtracted from the HECO demand (synthesized as described in Section 3.0) on an hourly basis and the conventional HECO generation was then optimally dispatched against the resulting residual demand. All of the unit commitment rules described earlier for the all conventional baseline system were followed exactly. The WECS was treated as the top priority must-run unit. In the determination of the spinning reserve required to protect the system, the WECS was treated as a single unit that could suddenly be forced out in its entirety. The WECS first contingency rating (see Rule (4), Section 6.3.3.4) was taken to be the actual WECS output for the particular hour under consideration. Consistent with this, of course, zero quick load pickup capability was attributed to the WECS. Such an operating policy would be consistent with a total inability to predict wind levels thus requiring spinning protection for the sudden disappearance of wind energy. This is a conservative assumption, as pointed out later (Section 8.1.4) in the discussion of geographic diversity within a WECS. For a gradual wind fall-off occurring over a period of several minutes but less than an hour, HECO's oil-fired units need not be spinning but can be rapidly brought up from a hot or cold condition to meet the load. However, this policy is not so conservative as to require spinning reserve for protection against the simultaneous failure of the largest conventional unit and the WECS.

The change in various performance parameters due to the WECS production of electricity is presented in Tables 6-7 through 6-10 for the four WECS installation Phases. The heat rates and costs per kWh are based on just the electricity produced by the conventional generation.

TABLE 6-6

BASELINE UNIT OPERATING PERFORMANCE - 1986

Unit	Rating (MW)	Average Output (MW)	On Time (Hrs)	Number of Starts		Capacity Factor	Gross Heat Rate (Btu/kWh)	Fuel Cost (mills/kWh)
				Hot	Cold			
X1	223	Not yet installed						
K8	170	Not yet installed						
K7	170	Not yet installed						
K6	141	130.9	8256	0	1	.875	8905	52.43
K5	141	130.4	7416	0	1	.783	8897	52.38
K4	90	84.5	8424	0	1	.903	9034	53.18
K3	90	84.5	8424	0	1	.903	9034	53.18
K2	88	84.6	8424	0	1	.924	9094	53.54
K1	88	84.6	8424	0	1	.924	9094	53.54
W8	90	77.4	7584	0	1	.745	9420	55.46
W7	90	77.4	8760	0	0	.861	9429	55.51
W6	57	36.9	7096	216	1	.524	10688	62.92
W5	60	39.5	6726	305	0	.506	10670	62.81
H9	60	32.6	6074	362	0	.376	11206	65.97
H8	55	33.6	5616	348	19	.392	11197	65.92
W4	52	22.6	5158	318	49	.256	12542	73.84
W3	52	23.6	4333	266	91	.224	12606	74.21
H7	42	16.5	3171	188	144	.142	13666	80.46
G7	60	Not yet installed						
G6	59	Not yet installed						
G5	60	Not yet installed						
G4	59	30.1	2007	115	75	.117	14988	99.50
G3	60	30.4	2298	107	215	.133	14915	99.01
G2	44	43.3	1060	26	231	.119	12730	84.50
G1	44	43.5	273	4	166	.031	12835	85.20
H5	23	10.0	22	0	21	.001	31634	186.24
W2	18	10.0	1	0	1	---	22196	130.67
W1	8	0	0	0	0	0	---	---
System	1452			2255	1021	.596	9567	56.59

* Includes revenue recovery factor

TABLE 6-7

IMPACT OF WECS ON CONVENTIONAL SYSTEM OPERATING PERFORMANCE
FULL SPINNING RESERVE FOR WECS OUTAGE CONTINGENCY

(Current Dollars)

PHASE 1

Year	Gross Energy (Conventional) (1000s MWh)	Capacity Factor	Change In Number of Starts		Gross Heat Rate (Btu/kWh)	Change In Gross Heat Rate (Btu/kWh)	Change In Fuel Cost Rate (mills/kWh)	Fuel Cost Savings (millions \$)	Total Cost Savings (millions \$)
			Hot	Cold					
1983	6362	.586	-190	+2	9369	-25	.12	10.88	11.06
1984	6672	.556	-133	+6	9482	-37	.23	12.77	13.01
1985	6972	.582	-135	+8	9488	-37	.24	13.98	14.20
1986	7302	.585	-101	-14	9525	-32	.32	15.60	15.83
1987	7648	.580	-56	-17	9664	-45	.39	17.42	17.69
1988	8025	.607	-44	-14	9714	-47	.44	19.33	19.61
1989	8393	.572	-75	-3	9505	-44	.45	20.32	20.61
1990	8807	.586	-102	+24	9588	-38	.42	21.55	21.82
1991	9237	.586	-9	-9	9734	-44	.57	24.92	25.24
1992	9720	.617	-13	-18	9813	-43	.64	27.60	27.96
1993	10170	.591	-65	-10	9728	-38	.61	28.81	29.14
1994	10671	.557	-78	-5	9677	-34	.61	30.63	30.96
12 Years	99979	---	-1001	-50	9623	-40	---	243.81	247.13

TABLE 6-8

IMPACT OF WECS ON CONVENTIONAL SYSTEM OPERATING PERFORMANCE
FULL SPINNING RESERVE FOR WECS OUTAGE CONTINGENCY

(Current Dollars)

PHASES 1 & 2

Year	Gross Energy (Conventional) (1000s MWh)	Capacity Factor	Change In Number of Starts		Gross Heat Rate (Btu/kWh)	Change In Gross Heat Rate (Btu/kWh)	Change In Fuel Cost Rate (mills/kWh)	Fuel Cost Savings (millions \$)	Total Cost Savings (millions \$)
			Hot	Cold					
1983	6362	.586	-190	+2	9369	-25	.12	10.88	11.06
1984	6251	.521	-410	+12	9438	-81	.47	34.33	34.92
1985	6553	.547	-408	+71	9436	-89	.57	37.92	38.54
1986	6883	.551	-313	+37	9459	-108	.78	42.33	42.97
1987	7230	.549	-287	+26	9592	-117	.96	47.37	48.07
1988	7605	.576	-222	+51	9639	-122	1.13	52.54	53.27
1989	7975	.544	-290	+34	9437	-112	1.13	54.95	55.71
1990	8388	.558	-388	+92	9526	-100	1.08	58.73	59.49
1991	8819	.559	-149	+11	9663	-115	1.46	67.44	68.28
1992	9299	.590	-112	+13	9745	-111	1.61	74.61	75.52
1993	9751	.567	-271	+20	9664	-102	1.58	78.57	79.45
1994	10252	.535	-328	+25	9616	-95	1.62	83.76	84.65
12 Years	95368	---	-3369	+394	9563	-100	---	643.43	651.93

TABLE 6-9

IMPACT OF WECS ON CONVENTIONAL SYSTEM OPERATING PERFORMANCE
FULL SPINNING RESERVE FOR WECS OUTAGE CONTINGENCY

(Current Dollars)

PHASES 1, 2 & 3

Year	Gross Energy (Conventional) (1000s MWh)	Capacity Factor	Change In Number of Starts		Gross Heat Rate (Btu/kWh)	Change In Gross Heat Rate (Btu/kWh)	Change In Fuel Cost Rate (mills/kWh)	Fuel Cost Savings (millions \$)	Total Cost Savings (millions \$)
			Hot	Cold					
1983	6362	.586	-190	+2	9369	-25	.12	10.88	11.06
1984	6251	.521	-410	+12	9438	-81	.47	34.33	34.92
1985	6046	.505	-392	+75	9436	-89	.58	64.23	65.02
1986	6376	.510	-340	+73	9444	-123	.90	71.37	72.19
1987	6722	.516	-359	+69	9574	-135	1.12	79.29	80.20
1988	7095	.537	-285	+91	9615	-146	1.35	87.68	88.60
1989	7468	.509	-402	+60	9408	-141	1.42	92.26	93.28
1990	7881	.525	-527	+144	9500	-126	1.37	99.06	100.13
1991	8311	.527	-249	+61	9626	-152	1.91	112.90	114.05
1992	8790	.558	-197	+35	9705	-151	2.17	125.04	126.29
1993	9244	.538	-392	+52	9628	-138	2.14	131.78	133.02
1994	9745	.509	-473	+71	9582	-129	2.19	140.63	141.90
12 Years	90291	---	-4216	+745	9539	-124	---	1049.45	1060.66

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TABLE 6-10

IMPACT OF WECS ON CONVENTIONAL SYSTEM OPERATING PERFORMANCE
FULL SPINNING RESERVE FOR WECS OUTAGE CONTINGENCY

(Current Dollars)

PHASES 1, 2, 3 & 4

Year	Gross Energy (Conventional) (1000s MWh)	Capacity Factor	Change In Number of Starts		Gross Heat Rate (Btu/kWh)	Change In Gross Heat Rate (Btu/kWh)	Change In Fuel Cost Rate (mills/kWh)	Fuel Cost Savings (millions \$)	Total Cost Savings (millions \$)
			Hot	Cold					
1983	6362	.586	-190	+2	9369	-25	.12	10.88	11.06
1984	6251	.521	-410	+12	9438	-81	.47	34.33	34.92
1985	6046	.505	-392	+75	9436	-89	.58	64.23	65.02
1986	5993	.480	-4	+71	9460	-107	.81	92.18	93.13
1987	6339	.487	-98	+82	9590	-119	1.03	102.01	103.05
1988	6710	.508	-115	+51	9631	-130	1.27	112.37	113.38
1989	7085	.483	-129	+52	9424	-125	1.33	118.09	119.20
1990	7498	.499	-371	+142	9507	-119	1.34	127.48	128.69
1991	7928	.503	-173	+83	9630	-148	1.92	144.27	145.52
1992	8405	.534	-142	+40	9706	-150	2.22	159.65	161.02
1993	8861	.515	-380	+66	9629	-137	2.20	168.40	169.76
1994	9362	.489	-503	+92	9580	-131	2.27	180.01	181.42
12 Years	86840	---	-2907	+768	9543	-120	---	1313.90	1326.17

The annual savings in current dollars for each of the four Phases are plotted on a semi-log scale in Figure 6-23. Straight line (semi-log) least squares curve fits are also shown. These curve fits were used to extrapolate the results for 30 years for use in calculating the WTG break-even costs presented in Section 7.0.

The variation about the straight line of the computed points in Figure 6-23 is due to the year-to-year variation of installation and maintenance schedules. The variation of installation and maintenance schedules leads to a year-to-year variation in generating efficiency which is reflected in the annual system heat rate. On years which have high system heat rates for the baseline system without a WECS, there is a greater potential for operational savings with the WECS. This correlation is shown in Figure 6-24 where the Phase 1 energy savings are plotted versus the baseline case heat rate for each of the 13 years examined. Similar effects are observed with Phases 2, 3 and 4, of course.

In the cost-of-production calculation for the system including a WECS, the hourly energy supplied by the WECS is subtracted from the hourly HECO gross demand and the conventional units are dispatched against the remainder. In performing the subtraction, the hour-for-hour reconciliation of HECO demand and WECS supply was based on the actual 1976 calendar dates corresponding to the source data. The 1976 source record of demand data was complete (8784 hours), but gaps existed in the wind data which required filling in with adjacent data and augmentation with 1977 data, as described in Section 5.0. The HECO demand is very strongly dependent on the day of the week (Monday, Tuesday, etc.) and as found in Section 6.2.4, is independent of the Kahuku winds. The Kahuku winds also have no dependence on the day of the week, of course. Therefore, it is somewhat arbitrary to assume the particular relationship between winds and demand that happened to exist in 1976. It would be most accurate to time shift the WECS supply with respect to the HECO demand by increments of one day, two days, . . . , six days and recompute the cost of production for each of the seven phasing relationships. The average of the seven results would then be the best possible estimate. This time consuming and expensive procedure was assumed to be unnecessary after a comparative examination of the results corresponding to a three-day shift.

The maximum WECS penetration analyzed in the synthesized four Phase scenario occurs with Phases 1, 2, 3 and 4 in 1986. In this year the system peak (as seen by the conventional units) is knocked down from 1261 MW to 1249 MW and the load factor is drastically reduced. The normalized load duration decomposition curve for the maximum penetration (1986; Phases 1, 2, 3 and 4) zero shift and three-day shift cases are shown in Figure 6-25 and 6-26, respectively. These two sets of curves are virtually identical (and should be compared to the load duration decomposition for the baseline case in Figure 3-2), implying little difference in cost of production for the two cases. To be sure, the cost-of-production calculations were repeated for all years from the installation of each Phase through 1994 for the three-day shift case. The resulting cost-of-production difference expressed as a percent of the savings due to the WECS is shown in Table 6-11. The differences are negligible and based on this spot check, it is assumed that the zero shift case is adequately representative and that there is no need for averaging. The zero shift assumption was checked similarly and also retained for the analysis of partial spinning reserve discussed next in Section 6.3.6.

Figure 6-23. Annual Cost Savings
Due to Kahuku WECS

KAHUKU POINT WECS ECONOMICS

Economic evaluation of alternate energy systems is often based on "levelized cost" methods of analysis. Levelized methods of analysis, however, do not show the annual cost of service or the initial impact of the early years of operation. They also ignore the utilities' cash flow problems in the first few years of the WECS investment, which may be considerably more severe than indicated by the total investment in the WECS accounted on a levelized basis.

Therefore, costs were computed on a cash flow basis to evaluate the economics of WECS application in HECO. Since tax effects can be significant to investment decisions, the analysis was done on an after-tax basis.

Costs were computed on a discounted cash flow basis, with proper account taken of inflation effects on maintenance and other costs, and the normal utility policies of loan repayment and rate of return on investment.

The significant features of cash flow economics are shown in Figures 7-1 and 7-2. In Figure 7-1 is shown the "Wind Energy System Saving" for Phase 1 of the WECS. This amounts to the net annual cash inflow to the utility as a result of the WECS. This net saving is found by totaling the system savings of fuel, conventional system O&M, local taxes, and subtracting the WECS annual costs, which consist of initial investment, operating costs, and return on investment. The example of Figure 7-1 was computed with a WTG cost of \$1220/kW, which is the Phase 1 break-even cost as discussed later.

If revenue flows are matched so as to break even after 30 years where fuel cost is escalating, the net cash flow is negative for about the first six years. During this time the interest on the debt and the uniform debt payback rate exceed the fuel savings.

Later in the system life, the money cost on the remaining debt decreases and the fuel saving increases, leading to a positive and rapidly increasing cash flow.

The integrated effect of these varying cash flows is shown in Figure 7-2 as the "Cumulative Wind System Saving." Because of the initial negative cash flows, the cumulative value drops until the total cash position in this case is 36 percent beyond the initial investment and the cumulative cash flow does not return to zero for approximately 15 years. Thereafter, it recovers to high values very rapidly.

These general results seem to be fairly universal; a substantial net cash outflow ending in about six years, followed by recovery to zero cumulative cash flow about the end of 15 years. It is this cash flow problem, as much as the initial investment, that will deter utilities from a decision to install WECS. The negative cash flow period and amount would be greatly reduced by shortening the WECS payback period, but a substantially lower WTG cost would be required to make this possible.

Figure 7-1. Wind Energy System Saving

Figure 7-2. Cumulative Wind System Saving

Break-Even Costs

Since the cost of the WTGs is not known, all computational results are presented in terms of the break-even WTG price. This is the price at which WTGs will break even economically in the HECO system at a rate of return equal to the weighted cost of (new) capital.

The cash flow analysis starts with an assumed WTG cost and finds the resulting rate of return. The specific required rate of return of 11.7 percent determines the break-even WTG cost as shown in Figure 7-3. The required rate of return of 11.7 percent equals the weighted cost of new capital consistent with the HECO financial parameters described in Section 3.2. The specific financial assumptions are given in Table 7-2.

Figure 7-3. Rate of Return versus WTG Cost for Four Phases

The cross-plot then also indicates the tradeoffs of break-even cost with rate of return.

This combination of cash flow analysis and break-even cost is the best economic evaluation technique to qualitatively assess the economic potential of each utility investment alternative. The combination of the break-even criterion with the cash flow format properly considers the time value of money, costs, and revenues over the project's operating life. With the time value of money concept, it is recognized that costs and revenues that occur during the first five to 10 years are more important than the costs and revenues that occur at a later time.

Evaluation by Phase

The four separate WECS Phases, as defined in Section 5.0, are treated separately in the economic evaluation.

Phase 1 consists of 30 WTGs being installed in 1982 and becoming operational 1 January 1983. Phase 2 consists of 70 WTGs being installed in 1983 and becoming operational 1 January 1984. Phases 3 and 4 consist of 100 WTGs each and follow by one-year increments, becoming operational on 1 January 1985 and 1986, respectively.

Each Phase is separately evaluated as to investment costs, operating costs, cost savings, cash flow balance, and break-even WTG unit costs. This mode of analysis assumes (and the results confirm) that the break-even price of a WTG will vary greatly for the different Phases because of the large difference in wind resource between Phases.

Under these circumstances, the investment decisions for the separate Phases are likely to be made one at a time with long "holds" between steps rather than the one-year delays between Phases assumed in the following analyses. This does not invalidate the analyses, however. The analysis of each Phase as presented here is intended to represent the economic decision criteria facing the utility at the earliest time for which an investment decision on each Phase could reasonably be made. At each such decision time the utility might elect to commit the construction of one Phase of the WECS or to delay the decision for another year. If the commitment is delayed, it would be reviewed each following year in the light of new WTG price levels, new fuel cost projections, changed estimates of the wind resource, the performance of new WTGs available, and other lesser factors. Eventually, major changes such as falling WTG prices as a consequence of increased production rates or increases in the long-term projected prices of oil should justify the next Phase.

7.1 ECONOMIC INPUT SUMMARY

7.1.1 Costs

The input assumptions on WECS construction and operation costs used for the four Phases in the economic analysis are summarized in Table 7-1. The output WTG break-even cost is added to the summary for comparison.

Input values for transmission construction costs and "prior costs" of resource search and planning were derived in Section 5.0.

Land costs assume an annual land rental cost of \$300/acre for a 1000 ft buffer (2000 ft wide) strip with 15 WTGs per mile. This results in an annual land rental cost of \$4848/turbine generator computed in the following manner:

$$\text{WTG Land Rental Cost} = \frac{(\text{Land Width})(\text{Acres/Sq. Mile})(\text{Cost Per Acre})}{(\text{Feet/Mile})(\text{WTG Per Mile})}$$

TABLE 7-1

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII
CONSTRUCTION & OPERATING COSTS (000)

1977 COST BASE

	<u>Phase 1</u>	<u>Phase 2</u>	<u>Phase 3</u>	<u>Phase 4</u>
Year of Construction	1982	1983	1984	1985
Number of Wind Turbine Generators	30	70	100	100
Power Generation Facilities				
Land & Land Rights	145	339	475	475
Structures & Improvements	40	93	133	133
Wind Turbine Generator*	54,900	91,350	94,500	53,550
Prior Costs				
Application Studies	530	70	100	
Instrumentation and Data Reduction		1,500	2,000	2,000
Correlation and Modeling Analysis		<u>1,500</u>	<u>2,000</u>	<u>2,000</u>
Total Prior Costs	530	3,070	4,100	4,000
Total Power Generation Facilities	55,615	94,852	99,208	58,158
Transmission Facilities	<u>563</u>	<u>3,022</u>	<u>3,656</u>	<u>4,347</u>
Total Wind Energy System Cost	56,178	97,874	102,864	62,505
Operating Cost/Year				
Power Generation Facilities				
Land Rights	145	339	485	485
WTG System	<u>483</u>	<u>1,127</u>	<u>1,610</u>	<u>1,610</u>
Total Power Generation	628	1,466	2,095	2,095
Transmission Facilities (Mills/kWh)	.15	.15	.15	.15

*Break-Even Cost

No escalation of land rental costs has been assumed. Structures and improvements consist of road costs at \$1333/WTG. This is computed by dividing the road construction cost of \$20,000/mile by 15 WTGs.

Annual operating costs for the WTG system are based on the estimate in Reference 7-1 of \$16,000/yr/generator. Annual operating costs for transmission facilities have been estimated at 0.15/kWh based on extrapolation of 1976 HECO transmission cost data.

7.1.2 Financial Assumptions

The assumptions for financing, interest rates, depreciation, inflation, etc., generally followed the practice and projections of HECO. These inputs are summarized in Table 7-2. All the inputs are reasonably typical of privately-owned utilities.

7.2 SUMMARY OF RESULTS FOR BASELINE CASE

Economic break-even results for the four Phases for the HECO baseline conditions are summarized in Table 7-3 and plotted in Figure 7-4. The break-even WTG costs vary from about \$1220/kW for Phase 1 to \$360/kW for Phase 4. This tremendous variation results primarily from the large variation of energy output per WTG at the different Phases.

The negative cash flow on each Phase ends after about six years and the cumulative cash flow is positive after about 15 years. These cash flow times are set primarily by choosing the WTG payoff times (30 years) and secondarily by the inflation rate and utility rate of return.

The break-even WTG cost is shown in Figure 7-4 plotted against the level of WECS penetration in rated megawatts and in percentage of the 1982 utility total generating capacity. Again, the rapid fall off of WTG break-even cost with WECS penetration is almost entirely a result of use of less economic wind energy resources.

7.3 ECONOMIC PERTURBATIONS - GENERIC CASES

In different circumstances than those on Oahu, the economic factors will vary significantly. The following section evaluates the effect of many of these economic perturbations on break-even WECS cost in several different circumstances.

7.3.1 Displacement Capacity Value

The LOLP computations of Section 6.0 show that the WECS has a substantial capacity displacement value. As discussed in that Section, the HECO system expansion plans, which consist mainly of one large new petroleum-fired steam plant (K6), leave no opportunity to take advantage of this WECS capacity value. There is not quite enough good wind resource located on Oahu to displace this large planned plant. Displacement of a planned gas turbine is hardly a worthwhile saving. Therefore, all of the break-even costs and analyses described above have been based on fuel (and O&M) savings only.

TABLE 7-2

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII
FINANCIAL ASSUMPTIONS

Debit Equity Ratios, %	
Long-Term Debt	
Preferred Stock	53.0
Common Stock	13.0
Equity Ratio, %	34.0
Interest Rates, %	47.0
Long-Term Debt	
Invested Earnings	9.0
Dividend Rates, %	7.0
Preferred	
Common	9.0
Financing Cost, %	15.0
Debt Funds	
Equity Funds	1.0
Income Tax Rates, %	2.0
Federal	
State	48.0
Other Taxes, %	6.4
Gross Revenue & Miscellaneous	
Investment Tax Credit, %	10.2
Investment Tax Credit Liability Rate, %	10.0
Bond Retirement, Yrs	50.0
Amortization of Financing Cost, Yrs	30.0
Book Depreciation, Yrs	20.0
Book Depreciation Method: Straight Line	30.0
Tax Depreciation, Yrs	
Tax Depreciation Method: Declining Balance/Sum of Years Digits	24.0
Material & Supplies, %	
Operating & Maintenance (Plant Cost)	
Working Capital Allowance, %	1.6
During Construction	
Plant Operation	1.0
Operating & Maintenance	
Inflation Rate, %	12.5
Plant Construction	
1978-1982	
1983-1987	9.0
1988-1992	8.0
1993-1997	7.5
Operating & Maintenance	7.0
Materials & Supplies	7.0
General Inflation	6.0
Insurance (% Plant Cost)	5.5
	0.06

TABLE 7-3
SUMMARY OF ECONOMIC RESULTS

	<u>Phase 1</u>	<u>Phase 2</u>	<u>Phase 3</u>	<u>Phase 4</u>
<u>Wind Energy System Assumptions</u>				
Number of Wind Turbine Generators	30	70	100	100
MWe Each	1.5	1.5	1.5	1.5
Installed Capacity (MWe)	45	105	150	150
Year Installed	1982	1983	1984	1985
Year Operational - 1 January	1983	1984	1985	1986
Capacity Factor, %	59.6	45.6	38.7	29.2
Annual Mean Power, MW	26.8	47.9	58.1	43.8
<u>Analysis Results</u>				
Break-Even WTG Cost (\$/kW 1977)	1,220	870	630	360
Years to Annual Positive Cash Flow	6	6	7	6
Years to Cumulative Positive Cash Flow	15	15	15	15
Weighted Average Cost of Capital, %	11.7	11.7	11.7	11.7
Internal Rate of Return, %	12.3	12.3	12.3	12.3

Figure 7-4. WTG Break-Even Costs by Phase

In a situation of the generic type where oil-fired capacity at \$550/kW total installed cost with a forced outage rate of 0.05 could be displaced, the capacity displacement value of a WECS would be approximately the WECS capacity credit times the cost per kW of the displaced conventional capacity. The savings that would result for the Kahuku WECS based on the equivalent capacity credit calculated in Section 6.2.5 is indicated in Figure 7-5.

Although the displaced capacity is substantial, its economic significance is dwarfed by the petroleum fuel savings. WECS are primarily fuel savers, not because their capacity displacement in a good wind resource is small but because the petroleum fuel saving is so large.

If the displaced generation is gas turbines, the value would be only about a third as great because of the lower initial costs of gas turbines. The higher fuel rate of the gas turbines when running would somewhat increase the fuel savings. The economic capacity value of WECS would look relatively smaller.

If the displaced capacity is coal fired, the fuel costs would be lower and the displacement capacity value about the same as in Figure 7-5.

Figure 7-5. Break-Even Cost; Effect of Displacement Capacity

7.3.2 Transmission Cost

The transmission cost should be divided into two parts for clarity; costs associated with power collection within the WECS, and costs associated with transmission of the total WECS power from the resource area to the utility consumption area or to a main transmission line able to handle the additional load.

In the Oahu case, the power collection installation costs of Table 5-8 range from \$3 to \$6/kW (1977 \$) for all four Phases of development. The transmission system costs only about \$4/kW for Phase 1 because it can be tied in to an existing 46 kV line only a little over a mile from its center. Phases 2-4 must be carried 12 miles to a major bus near the Kahe Powerplant Complex at a cost of \$20 to \$25/kW.

This total increment is shown in relation to the break-even WTG costs in Figure 7-6. Clearly for Oahu, collection and transmission costs are negligible. The collection component is too small to show in the Figure.

Figure 7-6. Break-Even Cost; Impact of Transmission Cost

7.3.3 Costs of Roads, Land, and Initial Search

The costs of roads were assumed at \$1333/WTG. This was computed by dividing the road construction cost estimate of \$20,000/mile for bulldozed dirt road with minimum cost arrangement for drainage by 15 WTGs/mile. Most of the roads would follow the crestline to minimize costs. The assumed road cost is too little to show in Figure 7-7.

The prior costs before construction of application studies, instrumentation, data reduction, data correlation, and any modeling that may be done are estimated in Section 5.3.2. The instrumentation program was assumed to be very thorough, with an instrument tower assumed at every potential WTG site, and the height of every third tower equal to WTG hub height.

These costs appear large standing alone, and may be difficult to commit several years ahead of WECS development. However, Figure 7-7 makes it clear that they

Figure 7-7. Break-Even Cost; Effect of Land Costs and Prior Costs

are very small compared to the break-even WTG costs. It also appears that the large instrumentation and survey costs assumed would be well spent if the results are moderate improvements in the resource siting of many of the WTGs.

The land costs assume an annual rental cost of \$300/acre (purchase cost of \$3000/acre). The land requirement is assumed to be a buffer strip 2000 ft (600 m) wide along each WTG row, giving a safety distance of 1000 ft (300 m) for security against thrown blades. At 15 WTGs per mile, this results in a land cost of \$3.23/kW/yr or \$3232/kW purchase cost. Figure 7-7 shows that this land cost is not a significant deterrent to WECS development. Note that the value of \$3000/acre is much greater than the \$100 to \$200/acre for mountainous resource land in California mentioned in Reference 7-2.

As a generic extension, it appears that land values set by agricultural and forestry uses will never be an economic barrier to mountain WECS development. This is doubly true because the value of such land for crops and grazing is reduced by the adverse effects of the high winds. Wind energy conversion will be the highest use of such land, as discussed in the Land Use and Zoning Criteria of Section 4.0.

Unfortunately, as with other scarce resources, the wind energy resource will set the value of such land where it is privately owned. And, it appears from Figure 7-7 that such use might support very high land prices (in excess of \$10,000/acre, for example) for a few excellent locations.

7.3.4 Public Ownership

Public versus private ownership of utilities and the relative societal costs of each, is subject to strong controversy. However, addressing only the cost accounting of each, public utility applications favor capital intensive sources, such as wind power. The chief reasons for this are the somewhat lower cost of money under public bond issues and the elimination of federal and state income taxes and local property and revenue taxes.

Although the exact numbers vary with federal and state bond rates and with state and local tax rates, public ownership will generally increase the WTG break-even costs by about one-third on a capital intensive system like WECS.

The approximate break-even WTG unit costs are shown in Figure 7-8 as a band of values for the various resource values represented by the Phases. The representation, of course, is not intended to suggest that WECS public ownership is recommended for Hawaii. The result does suggest, however, that if WTGs go into production and the prices are slowly reduced, they will show break-even economics first in public-ownership situations, other circumstances being equal.

7.4 DETAILED ECONOMIC ELEMENT BREAKDOWNS

During the time of this study a financial investment analysis program became available that is consistent with utility practices before regulatory agencies. This program can provide annual financial statements covering income and expenses, cash flow, balance sheet, and a number of supporting financial statements.

Under funding separate from this contract, the HECO and WECS data were run to produce detailed financial statements that should be of special interest to utility financial specialists examining WECS. The results are presented separately in Appendix B.

Figure 7-8. Break-Even Cost; Effect of Public Ownership

REFERENCES FOR SECTION 7.0

- 7-1. "Design Study of Wind Turbines 50 KW to 3000 kW for Electric Utility Applications, Analysis and Design," General Electric Company, Valley Forge, December 1976.
- 7-2. Lindley, C.A., "Wind Machines for the California Aqueduct," The Aerospace Corporation, February 1977.

WECS APPLICATION PARAMETRICS

In order to properly address the generic extension of results in Section 9.0, and to facilitate the interpretation and extension of the results of this study, a number of parametric relationships and trends were sorted out. These are summarized below.

8.1 INFORMATION OBTAINED FROM WECS OUTPUT SYNTHESIS

Although this is a synthetic design exercise, much understanding of WECS field design problems and economic tradeoffs can be gained by examination of the results.

8.1.1 Array Design Tradeoffs

The intent in this design is to group the developed sites in four levels of approximate economic worth for successive action as the balance of WTG cost and fuel cost projection changes. However, the spread of energy levels in the partial list of sites in Phase 3, for example, (Table 8-1) is more than 2.5 to 1 between the points noted by the arrows. This is too much to justify grouping them economically in the same Phase.

If this were a real design study, based on real wind resource data for each site, some regrouping or array redesign would occur before commitment. Several units in Row 3 with annual energy conversion above 7×10^6 kWh/yr should be developed under Phase 2. They are located physically close enough to a Phase 2 row for easy electrical connection.

On the other hand, Group 1 of Row 7 is a flagrant example of a poorly sited machine that should have been demoted to Phase 4 (and possibly to oblivion) on economic grounds. In a real design study the designer would recognize that, aside from the weak wind resource, part of the problem is a bad array angle (280°). At 400 ft spacing, this leg of the array is nearly parallel to the prevailing wind direction, resulting in excessive wake interference loss. The bad angle results from a short dogleg in the hill crestline, which the designer followed. Possible cures would be to change the angle to not quite follow the crestline, increase the spacing, drop the one WTG site from development, or drop the site upwind of it. Trades of this sort would be worked out carefully in a real mountain WECS design, because the penalty for bad judgment is loss of about half the value of the badly sited WTG. The goal would be to cull out units like this one that will pull down the economics of the whole field. Of course, such culling can only be done with adequate detailed site wind survey data.

8.1.2 Interference Versus Array Angle Tradeoffs

The typical situation for wind resources in mountainous terrain is that each resource area is limited in total extent, and the energy available falls off severely over short

TABLE 8-1

WECS SYNTHESIS INPUT
PARTIAL LISTING OF PHASE 3

Row	Group	Number	Spacing S, Ft	Array Angle β Deg	Winds	Annual Energy kWh/yr $\times 10^{-7}$
3	7	2	400	325	K_u	.5090
	8	1	400	330	K_H	.7553
	9	1	400	285	K_H	.6702
	10	2	200	338	K_H	.7258
	11	1	200	305	K_H	.6519
	12	1	400	18	0.9 K_H	.6165
	13	3	400	335	0.9 K_H	.6321
4		1	400	290	K_u	.4608
		6	400	355	K_u	.5064
6	1	4	400	25	0.9 K_H	.6142
	2	1	X	X	0.9 K_H	.6417
	3	2	400	5	0.9 K_H	.6210
	4	5	400	20	0.8 K_H	.4733
	5	3	400	350	0.8 K_H	.4828
	6	1	400	30	0.8 K_H	.4666
	7	1	X	X	0.8 K_H	.4916
7	1	1	400	280	0.9 K_u	.2914
	2	4	400	0	0.9 K_u	.3625
	3	3	400	340	0.9 K_u	.3709
	4	4	400	5	K_u	.5009
	5	1	X	X	K_u	.5280
8		3	400	320	0.8 K_H	.4836
		1	400	30	0.8 K_H	.4666
		2	400	350	0.8 K_H	.4828
		2	400	310	0.9 K_H	.6257
		1	400	280	0.9 K_H	.5117
		1	X	X	0.8 K_H	.4916
		3	400	335	0.85 K_H	.5612
		3	400	0	0.85 K_H	.5538
		3	400	345	0.85 K_H	.5599
		2	400	290	0.85 K_H	.5112
		1	400	330	0.85 K_H	.5611
		1	400	340	0.9 K_H	.6317
		1	400	0	0.9 K_H	.6238
		3	400	320	0.8 K_H	.4836
		1	X	X	0.8 K_H	.4916
9		3	400	0	0.8 K_H	.4789
		1	200	0	0.8 K_H	.4561
		5	200	315	0.9 K_H	.5663
		5	400	320	0.9 K_u	.3704
		2	400	340	0.9 K_u	.3709
		5	400	355	0.95 K_u	.4357
		2	400	15	0.95 K_u	.4243
		1	X	X	0.9 K_u	.3874

distances from the heart of the resource. If the resource is developed following the spacing rule of thumb of at least 10 diameters between WTGs, either the total power available will be severely limited or WTGs will be installed on much less energetic, and therefore, much less economically viable sites.

In most cases, a favorable tradeoff is available by closer spacing of WTGs in the more energetic locations. Conditions are especially favorable for close spacing when there is a strongly prevailing wind direction, approximately perpendicular to the array axis. An example is a row of WTGs along the crest of a ridge lying across the prevailing flow direction, or one or more rows of WTGs crossing the throat of a mountain pass where the prevailing winds flow through the pass. These situations are typical energetic mountain resource locations.

Wake Interference Theory

The losses due to wake interference between WTGs have been estimated by analytical models reported in References 8-1 and 8-2. The results were applied to specific cases reported in Reference 8-2 and this report, which are summarized below.

The analytical model is an inviscid actuator disk theory which describes the wake expansion geometry of a single WTG as shown in Figure 8-1, and its intersection with a downstream WTG disk for a given array spacing and angle. The area of the downstream rotor intersected by the wake is assigned a reduced output power, based on the reduced inflow velocity, and the same rotor conversion efficiency.

For wind speeds below the WTG rated wind speed, a uniform velocity ratio of one-third across the upstream WTG disk is assumed (Reference 8-3). The resulting power reductions for various spacings and angles between the wind direction and the normal to the array axis are shown in Figure 8-2.

For wind approach speeds greater than the WTG rated speed, the rotor pitch is increased to "spill" more energy into the wake. The increasing wake velocity calculated on a simple Betz-type model (Reference 8-3) gives the rotor exit speed ratios shown in Figure 8-3. Recalculation of the wake interference losses for various exit speeds shows greatly reduced losses, as in Figures 8-4 and 8-5.

No complete experimental confirmation of the theory exists. One set of wind tunnel tests (Reference 8-4) looked for the wake interference boundary for one model WTG operating at an angle near the downstream direction of another. The degree of correlation for these tests is shown in Figure 8-6. The models were very small. Aerodynamic scale effects or greater-than-ideal velocity drop could explain the slightly larger wake size of the experiment compared to the analytical model. A measure of the interference loss within the wake region was not made and would not be advisable without larger scale models.

Application to WECS Design

The wake interference loss model can be used to calculate the reduction in energy collected by an interior member of a WTG array of a given orientation angle in a given wind speed and direction history. This was done for specific cases in Reference 8-2.

Figure 8-1. WTG Wake Interference Geometry

Figure 8-2. WTG Wake Interference Power Correction

Figure 8-3. WTG Wind Speed Relationships

Figure 8-4. WTG Wake Interference Power Correction

Figure 8-5. WTG Wake Interference Power Correction

Figure 8-6. Experimental Check of WTG Interference Boundary

In Reference 8-2 an hourly wind speed and direction history was available from Sandberg Weather Station on Bald Mountain in Southern California. A wind energy rose for Sandberg is shown in Figure 8-7, based on the total energy in the wind from 16 compass directions for the year 1949. The assumed array angle is 45° , nearly normal to the primary wind direction, although significant energy comes from two other nonnormal directions.

Figure 8-7. Sandberg Energy Rose - 1949

The converted power was calculated for each hourly wind speed and direction reading and summed over the year for various spacings. The assumed WTG had a rated wind speed of 22.7 mph (10.15 m/s) and a diameter of 190 ft (57.9 m). The results are shown in Figure 8-8. The annual recovered energy falls off to about 88 percent at 2.1 diameters (400 ft) spacing and 76 percent at 1.05 diameters (200 ft). With the expected spread of energy between sites and the application requirement of many hundreds of WTGs, it was concluded that spacings down to 400 ft, and

possibly lower, were likely to be justified. Firm conclusions could not be drawn without a site survey of the available resource to determine the spread of resource energy over the available sites and the directionality of the wind at various locations. (The directionality must vary from location to location, as the flow is deflected around mountains and through passes.)

Figure 8-8. Effect of Spacing on Interference Losses

A more extreme example is provided by the analyses of Section 5.4.4.3. At Kahuku Point on Oahu the tropical tradewinds prevail most of the year, giving a strong prevailing direction to the energy rose, as shown in Figure 8-9. For this particular site (Kahuku Upper) the array angles for maximum and minimum wake interference loss are at array angles of 70° and 340° , as shown on the energy rose. The WTG power was calculated and summed for the recorded wind speed and direction at each hour of the year for several WTG spacings and array angles. The results for the best and worst array angle are shown in Figure 8-10.

At the 340° array angle, which is approximately normal to the prevailing wind, the percentage of the unobstructed energy collection is 90 percent at 200 ft spacing (1.05 diameters) and 97 percent at 400 ft spacing (2.1 diameters). For the worst

Figure 8-9. Wind Energy Rose and Extreme Array Angles
Kahuku Upper

Figure 8-10. Mean Annual WTG Power Output for
Best and Worst Array Angles
Kahuku Upper Winds

array angle of 70° (parallel to the prevailing wind) the corresponding percentages are only 39 percent at 1.05 diameter spacing and 58 percent at 2.1 diameter. Clearly, in this case, the losses at one or two diameter spacing and the preferred array angles are an acceptable price for increased use of a superior wind resource. The losses at the worst array angles are very severe.

The variation of energy losses over a 180° range of array angles is shown in Figure 8-11. (By geometric definition the remaining 180° is identical.) For a spacing of 400 ft (2.1 diameters) the interference loss is negligible for array angles up to 30° to 40° either side of the ideal array angle. Further deviations of the array angle rapidly lead to excessive losses. For a spacing of 200 ft (1.05 diameters), losses are about 10 percent out to 20° either side of the best angle and then increase rapidly. Most of the ridgetops of the Kahuku Point field lie between about 310° and 10° orientation, so that near-optimum ridgetop alignments are possible.

Figure 8-11. Effect of Array Angle and Spacing on Conversion

A careful consideration of the normal erosion shapes and wind-flow patterns about various mountain configurations suggests that lines of maximum wind-flow velocity will usually be approximately normal to the prevailing wind, and therefore, favorable to closely-spaced arrays. The introduction of closer WTG spacing in WECS in mountainous terrain is significant because it will allow a two- to 10-fold increase in the total exploitation of mountain wind resources, which include the most energetic, and therefore, most economic resources available.

It must be remembered that the shape of the curves in Figure 8-11 is determined by the wind speed and direction history at the site. The losses are small for close spacing where the approaching energy flow is highly directional and the array can be aligned nearly normal to it. A site where the approaching energy directional distribution has two peaks in opposite directions is equally favorable for low interference losses. Such a site is San Geronio Pass in Southern California where the high mountains on either side channel the flow into the directions along the axis of the pass.

The amount of the loss is affected by the site speed duration relations, as well as the site wind directions. As indicated by Figures 8-4 and 8-5, when the wind speed is slightly greater than the WTG rated speed, the interference losses for adverse wind directions are greatly reduced. The part of the wind data contributing most of the interference loss is that part where the wind direction is substantially parallel to the array axis and the wind speed is between cut-in and rated speed for the WTG.

8.1.3 Closer Spacing Versus Lower Energy Sites

The types of design tradeoffs that must be made in a WECS design layout are illustrated in Figure 8-12, using the WECS Output Synthesis data.

Figure 8-12. WECS Design Tradeoff; Array Spacing and Angle of Wind Energy

Suppose that in the synthetic design layout a number of sites have been established at 400 ft spacings along a ridge with a uniform wind spectrum described by $1.0 K_H$. Their capacity and annual energy output are described by the upper 400 ft curve in Figure 8-12 as a function of the array angle, which is assumed to vary along the ridge. The question is, will the next few WTG units provide more energy if they are installed along another ridgeline with a resource of only $0.9 K_H$ and array angles varying between 330° and 30° , or if they are inserted between existing machines on the first ridge?

Consider a high energy site at an array angle of 10° . The reduced energy level between 400 ft and 200 ft spacing is indicated by the upper arrow in the chart. However, insertion of the machine will also reduce the output of the two adjoining machines by a total of the same amount. The total energy decrement from the basic level for 400 ft spacing is indicated by the lower arrow and the dashed line. Since this line is still above the $0.9 K_H$ line, additional units should be inserted in the higher energy rows before developing the lower energy sites.

Now, suppose most of the first ridge has been reduced to 200 ft spacing and the only 400 ft gap left has an array angle of 315° . By the same construction described above, it would be more profitable to develop the $0.9 K_H$ ridge at most angles and spacings before inserting a machine at the bad array angle in the high energy row. However, the 315° gap should be filled in before going on to the even lower energy $0.8 K_H$ row.

In an actual WECS design, tradeoffs of this sort should be made at each Phase of design, based on the real wind data available for each site. This will result in an ordering of the value of the WTG sites, so that the best sites will be intensively developed first and only those sites economically viable at a given level of WTG cost and projected fuel cost will be developed. Other less economical sites will be held in abeyance until changes in the projected costs of alternative conventional generation may make them economically viable.

8.1.4 Geographic Diversity Within a Wind Energy Resource

The Kahuku Point wind resource is the first instance in which a single mountain resource has been surveyed for some period of time at several locations. In the course of synthesizing the WECS output power it became evident that there was a very considerable amount of geographic diversity within this wind resource field despite its small size.

The four survey sites are contained within a circle of about three miles (6 km) in diameter. The altitude of the locations varies from about 20 ft above sea level for Kahuku Lower to 980 ft above sea level for Kahuku Hill. The general exposure of the whole field would be described as a north sloping point of land, but of course, the detailed hill and valley shape surrounding each site is different. Kahuku Lower and Field are on flatland at two different distances from the ocean (see Figure 5-7), while Kahuku Upper is on the crest of a prominent headland and Kahuku Hill is further up the hill on a nearby ridge.

The wind speed duration curves for the four sites are shown in Figure 8-13. Included on the same curve are the speed duration curves for the Sandberg Weather Station on a mountain top in Southern California for the years 1948 and 1949. It is immediately evident that the slopes of the two curves from a continental location and the tradewind resource on Oahu are noticeably different. In particular, the Kahuku Upper location spends almost 70 percent of its time between wind speeds of 6 and 10 m/s. In contrast, the Sandberg 1948 record shows only about 35 percent of the time between these two readings. Although the average wind speed of the two sites is very similar, the tradewind resource, as expected, has much less variability than the continental resource.

Figure 8-13. Kahuku Site Speed Duration Curves

At the same time, the Hill location has much more variable winds, spending only about 35 percent of the time between 6 and 10 meters per second. The Lower and Field locations show only slightly more variability than Kahuku Upper.

This tradewind site shows generally less variability than a typical continental wind resource, but at the same time shows a great spread of variability between locations within the resource. As shown in a later Section, this has some noticeable effects on the capacity factor performance of the two sites.

Using the wind records of the four sites, hour-by-hour power outputs for the baseline WTG were computed. Statistical breakdowns on these power outputs were done with the results shown in Figures 8-14 and 8-15. Figure 8-14 shows the diurnal variation of the power output of a WTG at each of the four surveyed sites. All four sites show approximately the same average diurnal variation of power output. The power level or average capacity factor, of course, varies greatly because of the varying mean wind speed at the four sites. All four sites show a favorable early afternoon peaking characteristic with minima just before sunrise. There is nothing surprising in the diurnal relationships between these four sites.

Figure 8-14. Diurnal Wind Power Variation

Figure 8-15. Seasonal Wind Power Variation at Kahuku Instrument Sites

However, the seasonal variation of power output between the four locations shown in Figure 8-15 shows a great deal of diversity. It is during April to October that all the power differential between Kahuku Hill and Kahuku Upper is generated. For the remainder of the year the sites are essentially the same. Similarly, Kahuku Field delivers an excess of power over Kahuku Lower over the same months and is essentially the same during the winter season. There is a greater degree of seasonal diversity between sites within a wind resource of very limited dimensions than one would normally expect between sites hundreds of miles apart in flat land (see References 8-5 and 8-6).

Of course, when the output of the various phases of the full WECS field are summed by the synthesis method described in Section 5.4, these seasonal output variations tend to be averaged, as shown in Figure 8-16. The mixing of WTG locations described by the Hill and Upper wind records causes Phases 1 and 1+2 to have intermediate characteristics of seasonal variation between Kahuku Hill and Kahuku Upper. Similarly, the mixing of Kahuku Field and Kahuku Lower resource data as Phases 3 and 4 are added (1-3, 1-4) gives a further averaging effect as more Phases are added.

Circumstances could be visualized where the demand of a particular utility system might encourage emphasizing a desirable seasonal variation of power output rather than leveling the output in mixing portions of the various resources.

Figure 8-16. Seasonal Wind Power Variation for Kahuku WECS

Above it was seen that the various portions of the Kahuku wind resource vary greatly in their seasonal distribution of power output yet show very little variation of the diurnal distributions. Another significant measure of the geographic diversity within the field is the extent to which the hour-to-hour variation of power output

between the four instrumented sites results in a leveling of the total power output duration curves of the system. This effect is shown in Figures 8-17 and 8-18. Figure 8-17 shows the power duration curves of a WTG at each of the four sites. These curves can be derived directly from the speed duration curves of Figure 8-13 with consideration of the instrument height and density altitude correction for each site and the input-output characteristics of the DOE/NASA Mod 1 design as defined in Table 5-6. The power duration distributions are, of course, much more level than those obtained for a continental wind resource and are much flatter for Kahuku Upper than for Kahuku Hill. The total power available (area under the curve) decreases with decreasing mean velocity from Kahuku Hill through Kahuku Lower.

Figure 8-17. Power Duration Curves by Site

Figure 8-18 shows what happens to the power duration curves (per WTG) when the outputs of the WTGs (including the effects of interference losses) are summed to obtain the power duration curve of the total WECS. Mixing of the resources at the different instrument sites has accomplished some leveling of the speed duration curves. However, because the consecutive Phases add more and more of the sites described by the lower energy survey points, the reduction of the percentage of time at full system WECS output power is greater than the increase of time with powers greater than zero. The amount of leveling due to resource diversity shown here is undoubtedly less than the amount that would be shown if the computation were based upon several dozen survey sites within the resource area rather than only four.

Figure 8-18. Comparison of Power Duration Curves for Kahuku WECS and Instrument Sites

The conclusion is that the four survey sites within a circle of only about three miles (5 km) diameter show a surprising amount of geographic diversity. The degree of diversity shown is a lower limit, since the introduction of additional survey sites can increase the demonstrated diversity but cannot decrease it.

8.2 GEOGRAPHIC DIVERSITY ALONG AND ACROSS MOUNTAIN RANGES

Since a substantial amount of geographic diversity was found within the small wind resource of Kahuku at one end of a mountain range, a larger degree of geographic diversity might be expected between the two ends of the mountain range. This can be checked from the present data.

The UoH team provided data from their site at Koko Head, which is located at the opposite of the Koolau Range from Kahuku Point. The distance between the two ends of the range is about 35 miles (56 km).

A series of scatter diagrams were run comparing the wind velocity at Kahuku Upper with that at Koko Head. A typical result is shown in Figure 8-19 for the wind direction interval 70-80°. Figure 8-20 compares the corresponding scatter diagram between winds at Kahuku Hill and Kahuku Upper. There is obviously much more geographic diversity between the two ends of the Koolau Range than within the

Figure 8-19
Wind Speed Scatter Plot; 70-80°
Koko Head versus Kahuku Upper

Figure 8-20
Wind Speed Scatter Plot; 70-80°
Kahuku Hill versus Kahuku Upper

Figure 8-21
Wind Speed Scatter Plot; 70-80°
Kaena Point versus Kahuku Upper

Kahuku Point field. The full set of scatter diagrams for these two sites for all wind directions can be compared in Appendix A. It can be seen that both the degree of scatter and the regression equations vary with the prevailing wind direction.

The same correlation was run between Kaena Point and Kahuku Upper data. The results for one direction are shown in Figure 8-21, and for all directions in Appendix A. The degree of diversity is intermediate between the other two cases and the "shape" of the scatter plots is noticeably different. Kaena Point, the western-most tip of Oahu, is 21 miles (34 km) from Kahuku, and in a downwind position on the second mountain range, the Waianae.

As would be expected, the degree of geographic diversity of wind resources at the two ends of a short mountain range or on two nearby ranges is significantly greater than the diversity across a single wind field.

It is concluded that very significant geographic diversity is to be expected in a mountain resource between sites at the opposite ends or opposite sides of a single mountain range or between nearby ranges. It is possible that the degree of geographical diversity available in a mountain wind resource of a few nearby ranges and passes may rival that available by connecting typical level land sites many hundreds of miles apart. The issue needs further examination.

8.3 SIGNIFICANCE OF LOCAL RIDGETOP OVERSPEED

There has been a concern through the years that mountain crest wind surveys might give misleading results. The same flow deflections that cause locally higher wind speeds near a mountain crest can cause greater overspeed nearer the surface, resulting in a negative or significantly reduced positive wind speed gradient in the height range containing the instrument tower and later the WTG. This leads to a question of the proper height of the survey instrument tower. The problem was noted by Putnam (Reference 8-7), with negative wind speed gradients found for some wind directions at Mount Washington and significantly reduced gradients at Grandpaw's Knob. This problem was discussed earlier in Section 4.0, and experimental data from the Kaena Point Tower are introduced here to illustrate the point.

The Kaena Point data illustrates the problem of height of the survey instrument. It is the only multilevel tower in the UoH survey with instruments at 30, 90, and 180 ft. Because of problems with the instrument located at 90 ft, the intermediate level data are neglected here.

Table 8-2 shows that the mean wind speed increases with height. However, the increase is much less than the $1/6$ power relation, which would call for 8.45 m/s at 180 ft. This apparently mild deviation in the vertical gradient leads to the 48 percent difference in WTG power output projection (Mod 1) shown in the third column of Table 8-2.

This difference occurs because the WTG performance is calculated from the wind speed at 30 ft with an integration, assuming a $1/6$ power wind speed gradient over

the WTG. The performance program used in this study projects the measured wind speeds at 180 ft back to the 30 ft reference using the same 1/6 power law assumption.

TABLE 8-2
KAENA POINT MEAN DATA

<u>Instrument Height (Feet)</u>	<u>Mean Wind Speed (m/sec)</u>	<u>Projected Mod 1 WTG Average Output (kW)</u>
30	6.25	364.89
180	7.26	245.83

The calculated diurnal power distribution shown in Figure 8-22 shows greater differences in the calculated afternoon peak power than in the nighttime levels. These differences in power projections suggest that resource surveys at a height of 30 ft are insufficient for WECS design layout purposes and that they are probably insufficient for resource evaluation as well. On the other hand, construction of many high survey towers can become expensive.

The following strategy is suggested to minimize risks and still hold down survey costs:

- (1) Most of the final survey for WECS design layout should be done with 30 ft towers.
- (2) Every third or fourth tower along a ridgetop suspected of local overspeed conditions should be extended to WTG hub height.
- (3) No design survey will go above hub height unless extremely unusual vertical profiles are suspected.
- (4) The above strategy should be experimentally tested by taking a more complete survey (more and higher towers) in a number of test survey cases, to determine the errors resulting from the strategy and the safety of further reducing the survey net.

The strategy proposed in items (1) through (3) was assumed in estimating survey costs in Section 5.3.5.

8.4 CAPACITY FACTOR VERSUS WIND SPEED RATIO

Empirically or analytically derived correlations between WTG capacity factor (or other measures of energy output) and mean wind speed are useful in understanding

Figure 8-22. Calculated WTG Diurnal Power Distribution Based on Two Levels at Kaena Point

the machine resource matching problem and the variation of WTG output with resource energy level. Since the wind speed duration distribution in a tradewind resource is atypical (see Figure 8-13), these correlations may be significantly different from those of References 8-8 and 8-9. This possibility is explored below.

8.4.1 Correlations from Other Sources

There are two past references of correlations of capacity factor with wind speed ratio* available. In Reference 8-8, Justus and Hargraves obtain the two curves shown in Figure 8-23 by empirical correlation of wind power outputs calculated for many sites for which wind records were available. The sites were classified as "High" and "Low" variance of the speed duration relationships, with an "Average" value (not reproduced in the Figure) which is intermediate but closer to the "Low" value.

Figure 8-23. Available Correlations of Capacity Factor for Site Matching

* Wind speed ratio = $\bar{V}/V_R$ where $\bar{V}$ is the mean site wind speed (at a reference height) and V_R is the WTG rated wind speed (at the same reference height).

The "Low Variance" curve has a higher peak value than the "High Variance" curve at high values of the speed ratio ($V/V_R \cong 1.0$). For very low values of the speed ratio ($V/V_R \cong 0.6$), the "High Variance" resource gives higher capacity factors. The crossover occurs at approximately the site matching condition giving minimum cost of energy ($V/V_R \cong 0.7$, or capacity factor $\cong 0.45$) according to Reference 8-10. This minimum energy cost for a fixed site mean wind speed, V , is affected by the designer's estimate of the rate at which WTG cost per installed kilowatt can be reduced by increasing rated speed, V_R . Of course, with a given WTG design (specified cost and rated speed, V_R) minimum energy cost is obtained by siting the unit for maximum Capacity Factor ($V/V_R \cong 1.1$).

The second correlation available is from Reference 8-9 by Lapin. This correlation was derived analytically rather than empirically, but was based on a single empirical "typical" wind speed duration relationship. The two curves shown in Figure 8-23 describe a WTG with no cutout at high wind speed, and one shutdown three percent of the time for high winds. The Lapin relationship agrees well with the Justus relations except at the extreme ends of the curves.

8.4.2 Correlation for Extremely Low Variance

A correlation guideline for extremely low wind speed variance is desired to set a limiting case for the tradewind situation. The ultimate of low wind variability is zero variance, or a constant speed wind. In that case the constant hourly wind speed is identical to the annual mean wind speed, and the convolution leading to Lapin's relation reduces to simply the wind speed versus power curve of the WTG. The result is shown in Figure 8-24.

This curve is proposed as a limiting case for very low variability. Its chief characteristics are a much lower value of capacity factor at low speed ratios, a higher value at higher speed ratios, and a much steeper slope as the speed ratio approaches 1.0. The steeper slope should push the most economic site matching condition of Reference 8-10 to a speed ratio very nearly one.

This suggests that the most economic WTG site matching in a tradewind area is a rated velocity much nearer to the mean annual velocity of the site. The capacity factor at this economic optimal condition could be higher than that of a properly matched WTG in a temperate zone climate.

8.4.3 Correlation of Annual Energy and Mean Power for Kahuku Wind Spectra

The power output data for the 1500 kW WTG at the four instrumented sites at Kahuku can be plotted against the site mean wind speed, as shown in Figure 8-25. The power for various multiples of the basic data is used to extend the points to curves as shown in the Figure. Each curve can be regarded as the result of the particular wind speed duration pattern of a particular site. Although generally similar, it will be recalled from Figure 8-13 that the speed duration patterns varied somewhat in detailed shape.

Figure 8-24. Proposed Limit for Low Variance Winds

Figure 8-25. Energy Conversion Results for Four Kahuku Sites

The Sandberg 1948 and 1949 wind data from Figure 8-13 had more variability than the tradewind resources on Oahu. Power output data for these two input data sets from Reference 8-2 are included in Figure 8-25 to represent typical temperate climate speed duration distributions.

It appears that the Sandberg wind distributions and the Kahuku Hill distribution, which is the most variable of the four Kahuku sites, show significantly more power at a given mean wind speed than the three Kahuku sites of lower variability.

The question of whether this reduced capacity represents a reduced effectiveness of a low variability wind regime, or only a requirement of a different matching of resource to WTG rated speed in such sites, remains to be explored in this Section and Section 8-5.

8.4.4 Comparison with Kahuku Point Data

The power computation results for the four Kahuku sites and their multiples from Figure 8-25 plotted in the nondimensional format of the capacity factor correlation are shown in Figure 8-26. The results are mixed.

Figure 8-26. Comparison of Data with Proposed Low Variance Correlation

The data for the Kahuku Hill site closely parallel the temperate zone climate correlation of the two references. This fits with the observation in Section 8.1.4 that Kahuku Hill winds were much more variable than those at the three other sites.

The data for the three other sites closely matches the proposed correlation for extremely low variance. However, the slope is lower and some points are displaced to the right of the curve proposed for zero variance. All the extended curves for the four Kahuku Point sites are steeper in slope than the referenced correlations except, perhaps, the upper end of the Kahuku Hill curve.

8.4.5 Correlation Conclusions

It is concluded, tentatively, that capacity factor versus speed ratio correlation for a tradewind site has a steeper slope and generally lower values at the same speed ratio than for a conventional site. However, the machine-to-site matching for minimum energy cost shifts to a rated speed closer to the mean wind speed. The result is a higher WTG capacity factor at optimal site matching in a tradewind area.

To consolidate these conclusions additional data are needed in two areas: (1) more tropical mountainous wind resource data are needed to confirm the correlation and (2) a firm relation between WTG rated velocity and cost per rated kilowatt is needed to establish the shift of optimal economic matching of WTG rated speed to the site.

8.5 EFFECT OF VARYING WTG RATED POWER

The output of a given size WTG on a given site can be affected by changing the WTG power and rated speed. If several WTG design variants were available, the output and economy of a mountain WECS could thus be improved by individually matching the best WTG model available to each site. A well designed flatland WECS might usually be comprised of only one model of WTG if the wind resource energy does not vary greatly across the site. But a well designed mountain WECS should usually contain more than one WTG rated speed to best use the resource.

The prime variable describing the WTG site-matching problem is the WTG rated wind speed, V_R . This is the wind speed at which the machine reaches rated power. This rated speed is the denominator in the speed ratio of Figure 8-24, as used by Lapin and by Justus and Hargraves.

8.5.1 Capacity Factor

For a rotor of a given diameter and power coefficient, the rated power varies with the cube of the rated speed. Holding this relationship, the capacity factor variation at the four Kahuku data sites was computed for WTG rated power levels varying from 1200 to 2000 kW. The results are shown in Figure 8-27. The rated speed scale is retained for reference.

8.5.2 Mean Power Output

As a measure of the total annual energy recovery per site, the mean power output per WTG is also of interest. For a wind resource situation such as Oahu, WECS are

Figure 8-27. Capacity Factor Variation with Rated Power

likely to be profitable, but the wind resource is limited compared to the economically displaceable petroleum fueled generation. Unless more resources are found, there is some importance to pulling the maximum energy out of each available site. This strategy, in addition to the tactic of close WTG spacing discussed earlier, will maximize utilization of the available energetic wind resource area.

The variation of the mean power per site with the WTG rated power can readily be calculated. The result is shown in Figure 8-28. The maximum power per site is obtained by matching at the peak of each curve; that is, about 1900 kW at Kahuku Hill, 1700 kW at Kahuku Upper, 1400 kW at Kahuku Field, and less than 1200 kW at Kahuku Lower. Corresponding WTG rated speeds are about 25, 24, 22, and less than 21 mph.

Figure 8-28. Mean Annual Power Variation with Rated Power

The match point for the most economic energy production in each case is a little to the left of the power peak in Figure 8-28, because the cost of the WTG of given diameter increases slowly with increasing rated velocity and installed generator power. The exact location of the economic minimum depends on the slope of the cost per rated kilowatt versus the rated power, a tradeoff estimated in Reference 8-10, for instance, but still under evaluation.

8.5.3 Conclusion

From Figure 8-28, it appears that an increase of 10 percent or more in energy conversion per site can be obtained with the Kahuku Hill resource (K_H) by increasing rated WTG power (at fixed diameter) from 1500 to about 1800 kW. It is not clear that this increment would justify the slightly higher cost per WTG and the possible costs of multiple models. At the sites assumed to have $\approx 1.2 K_H$ resource, the gain would be more dramatic and would almost certainly exceed the increased cost.

Sites having the Kahuku Field and Kahuku Lower resource level should use a WTG having lower rated power (at the same diameter) for maximum power conversion. The economic optimum requires even lower rated powers.

If an installation like Kolekole Pass were contemplated, a somewhat higher rated speed (and rated power at a given WTG diameter) would be desirable because the site has a somewhat higher mean wind speed than Kahuku Hill. It probably also has greater wind speed variability, which as suggested in Section 8.4 might demand a higher rated speed matching for a given site mean wind speed.

It appears that a mountainous wind resource like Kahuku can be developed most economically if two or more WTGs of different rated speed are available for selective site matching installation. Differential costs for the two designs would have to be considered in making the actual installation decisions for each site, of course.

8.6 EFFECT OF VARYING WTG CUT-OUT WIND SPEED

It may be possible to save a small percentage of the unit cost of a WTG by reducing the cutout or furling speed. This is the limiting wind speed at which the WTG stops rotation and goes into a parked and feathered mode to weather a storm. The blade and tower design stresses of a maximum wind gust when the WTG is operating at cutout speed may establish the required strength, weight, and therefore, cost. The possible cost savings must be balanced against the loss of energy collection.

The results of reducing WTG cutout speed from 50 mph to 40 mph for four Oahu sites and two different years data from Sandberg Weather Station are shown in Table 8-3. The first two columns give the site mean wind speeds and mean wind energy. Note that the Hawaiian sites have less total energy for a given wind speed because of their reduced variability.

The power output for the baseline WTG is shown in the next three columns in terms of mean power, annual energy collected, and capacity factor. This baseline WTG has a 50 mph cutout wind speed.

The cutout loss of capacity factor for 50 mph cutout speed is shown in the next column, followed by the corresponding loss for 40 mph cutout speed. The last two columns show the loss increment resulting from lowering the cut-out speed from 50 to 40 mph in terms of capacity factor reduction (ΔC_F) and percent loss of mean power or energy collected.

The three Kahuku locations with low variability (Upper, Field, and Lower) show no wind speeds of 50 mph and therefore no cutout losses at those sites. At 40 mph cut outs are rare enough to cause less than $0.0005 \Delta C_F$, the threshold value of this computation. Therefore, the penalty of cutout speed reduction from 50 to 40 mph at a tradewind site of low variability is negligible.

Because of its higher wind variability, the Kahuku Hill site shows a small performance loss for cut out at 50 mph, similar to that for the two years of

TABLE 8-3

EFFECT OF VARYING WTG CUT-OUT SPEED

Wind Record	Mean Wind Speed $\bar{V}$, m/s	Mean Site Wind Energy $\bar{w}$, m^2	Mean Power $\bar{P}$, kW	Annual Energy ΣE $\text{kW} \times 10^6$	Capacity Factor C_F	Cut-Out Loss ΔC_F	Cut-Out Loss ΔC_F	Capacity Factor Change ΔC_F	Percent Energy Change %
K _H K _u K _F K _L S-49 S-48	9.12 8.06 7.35 6.03 7.51 7.16	683.5 416.3 320.5 258.7 479.8 403.1	$V_{co} = 22.35 \text{ m/s (50 mph)}$				$V_{co} = 17.88 \text{ m/s (40 mph)}$		
			876.9	7.69	0.585	-.002	-.013	-.011	-1.88
			602.7	5.28	0.402	0	0	0	0
			458.2	4.01	0.305	0	0	0	0
			287.5	2.52	0.192	0	0	0	0
			659.15	5.77	0.439	-.0015	-.0090	-.0075	-1.71
			605.21	5.30	0.404	-.0005	-.0065	-.0060	-1.49

Sandberg data at the bottom of the Table. Similarly, the loss at 40 mph cutout speed is about 1.5 percent to two percent for Kahuku Hill and the Sandberg site. This can be partly credited to the large mean velocity at Kahuku Hill, compared to Sandberg.

It appears that most tradewind sites show no output penalty for cutout speed reduction to 40 mph. However, some sites, particularly with large terrain wind amplification and mean wind speed, can show losses similar to temperate zone sites.

Of course, the above outage estimate is based on hourly average winds. Detailed intrahour variations of the wind might show more excursions above the cutout velocity. If these excursions are brief, they may not, in themselves, represent a significant total amount of outage time. However, the WTG restart control sequence may involve a significant waiting time between a cut out for a brief gust and the return to online generation. In this case, the results may not be so favorable to lowering the cutout speed, and the energy losses may be more related to the restart sequence time than to the duration of high winds.

8.7 FINDINGS ON SHORT-TERM VARIABILITY

There is a basic concern over the possible effects on the short-term (less than several minutes) control, stability and operation costs of a utility when a large portion of its power is supplied by one or more WECS. An effort was made to further define this problem in the Hawaiian scenario.

The general problem proved intractable to present theoretical approaches, and also to empirical solutions based on the data available from Oahu. A few worthwhile findings were obtained. The general problem can only be evaluated by field test of one or more WECS or by instrumentation of a WECS field to a density equivalent to the number of WTGs to be built there.

The following section reports the attempts made on the problem and the findings.

8.7.1 Wind Variability Correlations

The origin of the WECS output variability discussed here is the short-term wind speed variability at a given location due to turbulent flow, the resulting WTG output variability at that same site, and the correlation between the output variations of all of the different WTGs in the WECS which are similarly affected.

Certain correlations exist between the time and space variations of wind speed at two nearby points. These relations result from the physical fact that variations in the instantaneous speed at a point in turbulent flow result from the passage of eddies or "vorticity cells." Over the dimensions of a vorticity cell, certain correlations exist. Beyond this dimension, fluctuations are essentially uncorrelated. The correlations in the stream-wise and cross stream directions are simply related. The correlation laws have been derived empirically for turbulent flow over a flat boundary, but little is known about their application to flow over surfaces that are not flat.

Table 8-4 presents a simple statement of the time-distance correlation dimensions over a flat surface. The value of this Table is chiefly to suggest limits. It indicates that disturbances of less than a five to 10 second time constant have physical dimensions so small they will average out over the dimension of a single WTG disc. For a WECS of three to five miles dimension, disturbances for averaging times below about five minutes should be uncorrelated over the field, while longer integration times will affect the field as a unit. If two or more WECS are installed 30 miles apart (Kahuku and Kolekole Pass or Koko Head), they would be uncorrelated according to this theory for averaging times below about one hour, which is the basic time increment in which this study was done.

8.7.2 Correlation Defects

The problem with application of these correlations to the Hawaiian case, or to any situation in mountainous terrain, is that all the empirical correlations apply only to flow over a flat surface. The expert opinion is that they are not valid in a flow with strong orographic effects (Reference 8-11).

It is particularly incorrect to apply them in a crest flow situation where there are probably flow separations. Separations amount to severe local generation of large scale vorticity which is not immediately mixed back into the flow. This severely violates the basic assumption of stochastic turbulence conditions which underlie all flat plate turbulent flow correlations. It was concluded that this will invalidate any analytical modeling of extended WECS power output based on conventional time-distance correlations that would otherwise be possible.

8.7.3 Experimental Correlations

An attempt was made to confirm the basic autocorrelation of this tropical mountain flow from the UoH data to obtain some indication of the turbulence characteristics. Correlations available in the literature from Reference 8-12 are shown in Figure 8-29.

The data from Kahuku Upper was selected for three three-day periods of typical tradewind flow at near-average wind speed. Spectral analysis was run on these samples to determine if the spectra matched those of Figure 8-29. Note that even if the autocorrelation were good, it would leave large doubts about time-space correlations over distances in mountainous terrain.

The data available were taken at a height of 42.1 ft (12.8 m) and at six-minute time intervals. The results for 48 and 72 hr data intervals are shown in Appendix C. Transcription of the data to the nondimensional format of Figure 8-29 results in the data band shown in Figure 8-30. The variability spectra appears lower, but is shifted out of the regime of the References by the low value of Z , the instrument height. It is also made very uncertain by arbitrary choice of U_* , which is based on a surface roughness description of the terrain. The rule of thumb is to base it on about 1/10 the height of grass, trees or buildings on flat ground. But in mountains, should it refer to the vegetation height or the mountain height? Discussion of this ambiguity with specialists (Reference 8-11) reinforced the conclusion that the whole method was hopeless for this terrain, and blind extension of the theory would be pointless. The effort returned to simpler issues that could be answered.

TABLE 8-4

TIME-DISTANCE CORRELATION RELATIONS

<u>Correlation Time</u>	<u>Correlation Distance (ft, mi)(m, km)</u>		<u>Number of WTGs (200' Spacing)</u>	<u>Correlated Power Level (1.5 MW/unit)</u>
5 sec.	165 ft.	(5.3 m)	0.8	1.2 MW
15	495	(151)	2.5	3.8
30	990	(302)	5.0	7.5
1 min.	0.38 mi.	(.60 km)	10	15
5	1.88	(3.0)	50	75
20	7.5	(12.0)	200	300
1 hr.	22.5	(36.0)	600	900

Assumptions:

Correlation distance $d = Vt$

Rated velocity of 10.1/m/sec at 30 ft. elevation, is the relevant velocity

Lateral and windward correlation distances are identical

1.5 MW units at 200' (61.0 m) spacing

Figure 8-29. Experimental Turbulent Spectra Correlations

Figure 8-30. Comparison of Kahuku Upper Data

8.7.4 Impact of Variability on Energy Converted

One effect that can be checked from the UoH data is what Putnam (Reference 8-7) calls the "cube factor." The energy in a variable wind is always greater than that of the mean wind, because the average of the cube of a set of variable numbers is greater than the cube of the average. The difference is quoted as one to six percent in Reference 8-5. However, because of the nonlinearity of the WTG energy conversion algorithm, the converted power ratio can be either greater or less than the average.

To check the practical impact of variability, the 12-month Kahuku Upper tape of six-minute data was run through the same WTG energy conversion and power output statistical analysis as the corresponding one-hour data. Data were limited to those hours for which all 10 six-minute points were available. The overall energy results are compared in Table 8-5.

TABLE 8-5
EFFECT OF DATA INTERVAL ON CALCULATED ENERGY

<u>Interval</u>	<u>Σ WTG Output Energy</u>
6 min	3.642×10^6 kWh
1 hr	3.647×10^6 kWh

The results are almost identical, with the one-hour data giving 0.1 percent less energy. Apparently, the nonlinearity of the power conversion relation and the low variability of the data combine to eliminate the "cube factor" on energy converted in this case. One-hour data is therefore adequate for fuel savings computations. Statistical distributions of energy over diurnal, seasonal, and annual intervals were also checked, and showed negligible variability.

8.7.5 Fuel Penalty for Variability

The operating cost of maintaining spinning reserve to protect against a complete and sudden outage of WECS and conventional generation is just slightly greater than the cost of protecting against only outage of the conventional generation. This result is based on a detailed simulation using hourly averages of demand and WECS output. It turns out that the additional units required to provide the spinning reserve result in operation at only slightly higher incremental costs per kilowatt hour (higher heat rates). When the lower output per unit is considered, the overall cost of production (for the same amount of electricity) is just slightly higher than with fewer spinning reserve units. A detailed discussion is provided in Section 6.0. In addition, as can be seen from Table 8-5, the effects of short-term variability on the calculated amount of energy extracted is very low due to the steadiness of the winds at Kahuku.

8.7.6 Dispatching Impact of Variability

Because of the spinning reserve policy of HECO and the frequency of computer optimized dispatching decisions in actual practice, there is no significant impact of WECS generation on the dispatching procedure for the conventional units. The HECO units are automatically dispatched (excepting W1, W2, H5, G1, and G2 which are manually adjusted, and which are not run very often) based on an analog computer solution for the minimum cost loading. The automatic adjustments are made continuously and simultaneously for those units (excepting the above five units) which are currently operating. The analog system is damped with a complex R-C network for stability reasons, and the overall system time constant is less than a minute, i.e., considerably less than the time it would take for the wind to die across the extent of the Kahuku WECS.

8.7.7 Summary on Variability Issues

The fuel consumption and dispatching problems caused by WECS output variability down to five-minute time constants is negligible for HECO. The same would apply to most utilities. A possible exception is where WECS penetration reaches the level in the utility dispatching stack where it might penetrate nuclear generation. In this case, a decision might have to be made to waste WECS energy or dump power to another connected utility rather than to throttle back a nuclear reactor.

WECS output variability for time constants below five minutes would appear to be small based on flat plate turbulence theory, which unfortunately is not valid for fundamental reasons. The empirical turbulent-flow correlations available should not be used to project mountain WECS variability.

The only trustworthy projection of WECS output variability in mountainous terrain will come from actual mountain WECS data or from a network of many field wind instruments installed on close centers representing a mountain WECS geometry.

8.8 VALUE OF STORAGE

Energy storage is often proposed as a valuable auxiliary to a utility containing a major WECS component. The rationale usually made for this combination is the consolidation of a significant WECS capacity displacement value by bridging over WECS resource outage time. However, it was shown in Reference 8-2 that the cost of pumped hydro storage is about \$140/kW plus about \$10/kWh for storage capacity unless conveniently shaped valleys allow large storage with a small dam. Oahu does not offer such topography. It was also shown in the above reference that about six days of storage was required in the case of the California Aqueduct to cover the longest outage times of six days with only ≈ 2 percent capacity factor. Despite the persistence of the tradewinds, the Kahuku Point resource (Phases 1-3) shows periods of up to seven days with less than 10 percent capacity factor and several complete outages of two to four days within one year's data.

Because of its volcanic origin, Oahu presents a unique difficulty in the design of water storage reservoirs. The soil is composed of a mixture of lava and ash of great

porosity. Water held in a reservoir behind a dam simply percolates into the soil and flows to the sea. The only cure for this is to pave the entire reservoir bottom and sides with a waterproof coating, which leads to exorbitant reservoir cost. Corps of Engineers studies have found no locations where dams for holding large domestic water supplies could be economically built. The domestic water system relies on run-of-the-stream supplies plus a few small reservoirs and tanks. Economic hydro-pumped-storage is therefore considered impossible on Oahu. Alternatives of underground pumped storage and compressed air are subject to the same soil limitations and are therefore also not viable.

In any case, storage is not needed in the application of WECS on Oahu. The maximum WECS output is estimated at 26 to 39 percent of the 1982 generation base. The conventional generation is all petroleum-fired steam and gas turbines. As shown in Section 6.0, there is no operational difficulty in reducing the generation dispatched by the amount provided by WECS output (300 to 450 MW) at any projected utility demand rating. Therefore, the full fuel saving possible from WECS energy supplied can always be accomplished, and there is no need to store WECS energy for later use. Because all of the HECO conventional units are fired with the same type of fuel (oil) the marginal cost of production differential between units is quite small--only depending on differential heat rates. Therefore, storage would save very little operational cost to pay back its capital costs. In the context of Oahu, it would also save no planned generation capacity.

In other generically similar isolated utilities, storage is likely to be uneconomical unless the available WECS resource capacity substantially exceeds the difference between the lowest utility demand and the lowest practical generating level of the conventional capacity.

In the generic case of a nonisolated utility with a strong (mountain) wind energy resource, (Figure 7-6) the transmission of WECS output over distances up to several hundred miles from the resource will be economical. This strongly suggests that the need for storage in connection with mountain wind generation should be obviated by distributing the mountain wind resource output to large utility nets where the WECS output would never have to be dumped because of the size and diversity of the load and conventional generation. This is particularly true if the same mountain utility systems include substantial hydroelectric generation components with output that can be managed to balance the wind power availability without taking the 25 to 35 percent in-out energy losses entailed in hydropumped-storage operations.

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GENERIC EXTENSION OF RESULTS

This Section extends the results of the study to situations generically similar to Oahu in other locations. Parametric and other means of extension are used as appropriate.

9.1 PRIME CHARACTERISTICS OF THE OAHU CASE

The prime characteristics of the Oahu case that are subject to generic extension are:

- (1) Isolated utility system
- (2) Principally oil-fired conventional generation
- (3) Tradewind resource
- (4) Mountainous terrain wind resource

These characteristics are discussed separately in the following sections.

9.2 ISOLATED UTILITY SYSTEM; GENERIC EXTENSION

9.2.1 HECO Situation

The HECO utility net on Oahu is a totally isolated utility system and is likely to remain so indefinitely. Connection to the mainland systems is, of course, unthinkable. Supportive transmission connections between islands approaches the impossible by today's technical standards because of the ocean depth between Oahu and Molokai, the nearest island. Certainly, it is economically impractical.

There are also no technical or economical incentives for interconnection today. The total generating capacity of the other islands is an order of magnitude less than Oahu, so they would not be significant in a loss-of-load situation. The "neighbor islands" (all except Oahu) would not import enough energy to amortize heavy transmission costs. They would not generate and export enough energy to amortize such costs.

There is a slight hope that the last fact listed might change. Maui and Hawaii are endowed with great geothermal energies that might be exploited soon. They and Molokai all appear to have better wind resources than Oahu, which might be exploited. All presently have biowastes (sugar cane baggasse and pineapple wastes) beyond those presently being converted. The resources for ocean thermal conversion are on hand. Out of these renewable resources there could arise in the next 20 years a situation where the neighbor islands could economically export energy to

Oahu, if submarine power transmission technology improves. Even in this case, local policy would probably be to use the energy at the source to develop new energy-intensive industries to reverse the unhealthy crowding in Oahu and lure part of the population back to the "neighbor islands."

9.2.2 Consequent HECO Policies

For the near future, Oahu remains an isolated utility system. Its protection from loss of load comes from an unusually high ratio of installed generation capacity to experienced peak load (1192/887) (see Section 3.5.1), and a very aggressive maintenance and repair policy that has kept generation forced outage rates far below typical utility practice (see Table 3-9).

The unit commitment and dispatching policy used by HECO also recognizes their isolated status, at a small cost in extra fuel consumption. The question of whether this policy should be applied to the WECS system as a single generation unit was discussed with HECO at length. However, when the problem was worked with and without spinning reserve for the WECS (see Section 6.0), the issue was found to have little economic consequence.

9.2.3 Generic Extension

The impact of utility isolation on WECS integration problems appears to have been greatly overestimated in the past. Operational policy decisions are required regarding dispatching for quick load pickup. However, the economic consequences of these decisions are minimal, amounting to only a small reduction in the WECS fuel saving and minor operational restrictions on the dispatchers.

As small as they are, these penalties can be reduced if the WECS component of the utility is split up into several geographically diverse WECS. As indicated in Section 8.0, a surprising amount of diversity is obtained between two sites at opposite ends of a mountain range only 37 miles (60 km) apart. Apparently, a great deal of diversity can be obtained by merely using the opposite ends, or opposing faces, of a single mountain barrier without reference to distance between weather systems. Local mountain geometries and environmental situations will determine the availability of this diversity. In Oahu, for instance, Koko Head may be unavailable, but unexplored mountainous terrain north of it may be available.

9.3 TRADEWIND RESOURCE; GENERIC CONCLUSIONS

The basic advantage of tradewinds for wind power generation is that they are very steady in force and direction for much of the year and their outages tend to be brief. Because of their steadiness, a WTG well matched to the resource will give full-rated power 40 to 50 percent of the time and some power 80 to 90 percent of the time. Capacity factors can exceed 65 percent. Even higher availabilities can be obtained by deliberately undermatching the WTG rated speed to the resource.

The relationship between capacity factor and dimensionless rated velocity is somewhat different from that for a more variable wind resource. The optimum matching

of site to machine moves in the direction of a WTG rated velocity only slightly greater than the site mean wind speed. The WTG capacity factor is more sensitive to accurate matching of machine rated speed to site mean wind speed than for the typical resources which have greater wind variability.

The steadiness of direction of the tradewinds makes the location of sites of mountain amplification of the winds more sharply defined. It also increases the feasibility of locating wind machines in very close array spacing normal to the prevailing wind direction without taking severe wake interference losses.

Tradewinds over the open ocean are generally about 10 mph (4.5 m/s) mean speed, not strong enough for wind power utilization. It is their acceleration around and over island terrain, especially mountainous terrain, that amplifies the wind speeds to a commercially exploitable level.

Some tradewind areas are also subject to tropical hurricanes and their very destructive accompanying winds. These winds can occasionally exceed the structural design limits of large WTGs in the furled condition, which are generally set in the range of 125 to 150 mph. Other tradewind areas, like Oahu, may never have experienced a severe hurricane and can be considered fairly safe from severe winds.

9.4 MOUNTAINOUS TERRAIN RESOURCE ENHANCEMENT

The most significant generic characteristic of the Oahu utility system is that the wind resources are in mountainous terrain. This leads to certain generic characteristics that will be typical of all mountain-enhanced wind resources.

Mountainous or terrain-enhanced wind resources are concentrated in relatively small spaces, typically with dimensions ranging from a few miles to less than a mile. Within these dimensions the wind energy that can be generated annually at each WTG site varies greatly over dimensions as small as the individual WTG.

There is a significant amount of geographic diversity within such wind resources, despite their limited physical dimensions, and more diversity between mountain resources only tens of miles apart. This can probably be exploited to great profit if it is understood or carefully surveyed.

Because of the great spread of site energy within a small mountain resource, it will usually be profitable to exploit such resources with WTGs at spacings of one to two diameters in the richest locations. The greater use of high energy locations will usually compensate for wake interference losses between units. However, the detailed relationships of prevailing wind direction and wind speed are needed to rationally plan close array spacings and directions.

Anomalous vertical wind speed gradients over ridgetops can also have important effects on energy conversion and economic viability of mountainous terrain resources.

9.4.1 Special Survey Demands

Because strong variations of energy over just a few hundred feet will have severe economic impact, fiscal prudence demands a detailed and careful wind resource survey of mountain sites to locate the economic WTG sites and screen out the uneconomic ones. The effects of diversity, design for interference loss, and anomolous vertical gradients also call for careful individual WTG site surveys.

The cost of such surveys was shown in Figure 7-7 to be small relative to the total economic impact of the WECS. The value of the survey, to be weighed against the cost, can be established from the basic system economics of Figure 7-4 and the performance parametrics of Figure 8-26.

9.4.2 Survey Cost/Value Tradeoffs

The basic slope of the Capacity Factor versus Site-Matching Speed Ratio from Figure 8-26 is

$$\frac{d C_F}{d (\bar{V}/V_R)} \cong 1.5$$

for low-variance sites.

The relationship between the break-even costs (C , \$/kW) of the baseline WTG and the capacity factor (C_F) is shown in Figure 9-1, taken from the data of Section 7.0. The slope of this curve is

$$\frac{d C}{d C_F} \cong \$2930/\text{kW}$$

Combining the two

$$\frac{d C}{d (\bar{V}/V_R)} \cong \$4400/\text{kW}$$

If the rated velocity is held constant, the relation between break-even unit WTG cost and site mean wind speed for the Kahuku Point case studied is:

$$\Delta C \cong \$4400 (\Delta \bar{V}/\bar{V}) (\bar{V}/V_R)$$

where

ΔC is the change in WTG break-even cost resulting from improved site mean wind speed, \$/kW

$\bar{V}$ is the site mean wind speed

Figure 9-1. Relation Between WTG Costs and Capacity Factor
in Context of HECO Economics

ΔV is the site mean wind speed improvement resulting from survey

V_R is the WTG rated speed

Inserting typical values from this study, a site improvement of 2 mph in mean wind speed is worth

$$\Delta C = \$4400 (2/18) (.8) = \$390/\text{kW}$$

For a 1500 kW WTG this is: \$585,000/WTG. This is a substantial value for a successful survey.

The rather intensive site survey plan proposed in Table 5-8 increased costs by about \$24/kW of installed WECS. Such an intensive site survey in Oahu would pay off if it increased the mean wind speed at each site by an average of

$$\Delta V = 2 (24/390) = 0.12 \text{ mph (0.055 m/s)}$$

It appears that a rather intensive survey will be justified economically in most mountainous terrain situations.

9.4.3 Other Consequences of Survey Demands

The strong economic incentive for a careful and detailed survey of a site before committing a detailed WECS design to construction raises certain problems in planning for mountain WECS design:

- (1) The lead time of about four years from initial resource search to first Phase construction suggested in Table 5-8 is a substantial planning lead time, especially considering that the WECS Phase construction time may be only one or two years.
- (2) The tools for such a search may be conventional instruments, but the strategy and tactics of their employment have not been worked out and tested. So far, only initial resource location searches have been carried out.
- (3) Although the search is not costly in the total WECS economics, it is up-front money for an unproved energy source. This may discourage utilities from taking the initiative in Wind Energy.
- (4) There are not yet any "experienced search experts" available.
- (5) If the temptation to shortcut the search prevails, the result may well be a substantial reduction in the economic success of early WECS installations in mountains.
- (6) The whole problem may be avoided by going to more uniform sites in flatland, but this will also entail accepting reduced WECS economic success because the best mountain sites will generally be more economical.

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APPENDIX A

WIND SPEED AND DIRECTION CORRELATIONS VARIOUS SITES VERSUS KAHUKU UPPER

Data Presentation, Wind Speed Correlation

The scatter diagrams developed for the data reconstruction work on Kahuku sites, and to evaluate diversity versus Koko Head and Kaena Point, are presented in this Section. All scatter diagram comparisons were made against Kahuku Upper. The straight line correlations are least square fits of each site regressed on Kahuku Upper data in each case.

In some cases there was too little data for valid correlation (one point) or valid standard deviations (two points). This occurs because the wind angle bins into which the data are sorted are small (10°), the total data overlap between two sites may be only several weeks or months, and most of the time the tradewind blows from between North and East. Regressions lacking adequate data are presented in the Kahuku Hill figures but deleted in the remainder of the Appendix.

In all cases the data presented are original data only, not synthesized data based on the regression analysis results. The synthesized data were scatter plotted and regression analyzed again to see that the addition of random number-generated data in the synthesis process did no violence to the statistical correlation and character of the original actual data. The statistical comparison of original data and reconstructed data showed no significant changes.

Wind Direction Correlation

The correlation of wind direction between the Kahuku sites is also presented at the end of each Kahuku wind speed correlation set. Each diagram shows the difference between wind direction at the site and that at Kahuku Upper, plotted against the direction at Kahuku Upper, for each data point.

Any consistent deviation from zero shows a trend of flow deflection between the two sites for that prevailing wind. For the wind angle range of 20° to 120° for Kahuku Hill versus Kahuku Upper, for instance, a definite pattern of flow deflection between sites seems evident.

Instrument Error Checks

The wind direction chart shows a disturbing anomaly at the higher angles (160° - 340°) that showed up in several other correlations. In this angle regime, most of the data align into two 45° sloping lines. These correlations are easily explained if the Kahuku Hill wind direction indicator "stuck" (either mechanically or electronically) on a single reading for several hours (not necessarily consecutive) while the actual

wind direction wandered around at the other station. Similar correlations on a vertical line indicate that the baseline (Kahuku Upper) direction indicator stuck. It was confirmed that these problems had occurred.

In another case the velocity data appeared to have two correlation curves, suggestive of a change of calibration such as might be caused by an intermittent short in the electronics. The data from that point were not used. The direction problems noted are not considered important to the data use. However, these scatter plot techniques put on a production basis may be very useful for catching instrument problems early, if applied to the large numbers of instruments used in a wind resource survey operation.

Possible Extension to Survey Time Reduction

A more basic use of these correlations is also suggested. With correlation techniques of this type it may prove possible to obtain an adequate survey of a mountain site by putting an instrument on it only long enough to observe wind flows from all points of the compass. A correlation would then be made from several such short-term instrument sites to a nearby long-term site, and the short-term instruments would be moved on to a new survey site every few weeks or months. This technique could cut the cost and time required for survey significantly. However, it must be tested and verified in an actual mountain site survey situation before it can be trusted.

Data Presentation

The following pages give the correlation results between data from the following five sites and Kahuku Upper:

- (1) Kahuku Hill
- (2) Kahuku Field
- (3) Kahuku Lower
- (4) Koko Head
- (5) Kaena Point

Figure A-1
Wind Speed Correlation, 0-60 Degrees
Kahuku Hill vs Kahuku Upper

Figure A-2
Wind Speed Correlation, 60-120 Degrees
Kahuku Hill vs Kahuku Upper

Figure A-3
Wind Speed Correlation, 120-180 Degrees
Kahuku Hill vs Kahuku Upper

Figure A-4
Wind Speed Correlation, 180-240 Degrees
Kahuku Hill vs. Kahuku Upper

Figure A-5
Wind Speed Correlation, 240-300 Degrees
Kahuku Hill vs Kahuku Upper

Figure A-6
Wind Speed Correlation, 300-360 Degrees
Kahuku Hill vs Kahuku Upper

Figure A-7
Wind Direction Variation
Kahuku Hill vs Kahuku Upper

Figure A-8
Wind Speed Correlation, 0-60 Degrees
Kahuku Field vs Kahuku Upper

Figure A-9
Wind Speed Correlation, 60-120 Degrees
Kahuku Field vs Kahuku Upper

Figure A-10
Wind Speed Correlation, 120-180 Degrees
Kahuku Field vs Kahuku Upper

Figure A-11
Wind Speed Correlation, 180-240 Degrees
Kahuku Field vs Kahuku Upper

Figure A-12
Wind Speed Correlation, 240-300 Degrees
Kahuku Field vs Kahuku Upper

Figure A-13
Wind Speed Correlation, 300-360 Degrees
Kahuku Field vs Kahuku Upper

Figure A-14
Wind Direction Variation
Kahuku Field vs Kahuku Upper

Figure A-15
Wind Speed Correlation, 30-90 Degrees
Kahuku Lower vs Kahuku Upper

Figure A-16
Wind Speed Correlation, 90-160 Degrees
Kahuku Lower vs Kahuku Upper

Figure A-17
Wind Direction Variation
Kahuku Lower vs Kahuku Upper

Figure A-18
Wind Speed Correlation, 0-60 Degrees
Koko Head vs Kahuku Upper

Figure A-19
Wind Speed Correlation, 60-120 Degrees
Koko Head vs Kahuku Upper

Figure A-20
Wind Speed Correlation, 120-180 Degrees
Koko Head vs Kahuku Upper

Figure A-21
Wind Speed Correlation, 180-240 Degrees
Koko Head vs Kahuku Upper

Figure A-22
Wind Speed Correlation, 240-300 Degrees
Koko Head vs Kahuku Upper

Figure A-23
Wind Speed Correlation, 300-360 Degrees
Koko Head vs Kahuku Upper

Figure A-24
Wind Speed Correlation, 0-60 Degrees
Kaena Point vs Kahuku Upper

Figure A-25
Wind Speed Correlation, 60-120 Degrees
Kaena Point vs Kahuku Upper

Figure A-26
Wind Speed Correlation, 120-180 Degrees
Kaena Point vs Kahuku Upper

Figure A-27
Wind Speed Correlation, 180-240 Degrees
Kaena Point vs Kahuku Upper

Figure A-28
Wind Speed Correlation, 240-300 Degrees
Kaena Point vs Kahuku Upper

APPENDIX B

DETAILED ECONOMIC ELEMENT BREAKDOWN BY PHASE

Discounted Cash Flow Analysis Data

At the end of this study a computer program for discounted cash flow financial analysis became available from another source. As a shakedown exercise, supported on separate funding, that program was applied to the case of the four-Phase WECS development in the HECO system. The same input data was used as in Section 7.0 and the break-even WTG costs of Table 7-2 were input.

The result is a very detailed financial breakdown printout in a format conveniently understandable by those with accountant and financial analyst backgrounds. The data breakdown is presented here in four separate packages, one for each WECS Phase. Because of the standard format of each printout, some of the material is repetitive. A precise set of definitions of the key terminology is inserted at the end of the Phase 4 printout.

Although the results are too detailed for general interest, they are included in this Appendix for their possible interest to financial specialists.

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 1

WIND ENERGY SYSTEM ANNUAL COST VS HECO BASELINE SYSTEM SAVINGS

WIND TURBINE GENERATOR COST
(\$/KW 1977 COST BASE)

1220

DISCOUNTED CASH FLOW ANALYSIS

DISCOUNT RATE, %

11.7

RATE OF RETURN, %

11.7

CASH FLOW ANALYSIS

B-2

	1982	1983	1984	1985	1986	1987	1988	1992	1997	2002	2007	2012
WIND ENERGY SYSTEM ANNUAL COST	92991	23349	21883	20938	20029	19156	18327	15397	12678	11097	10855	11521
HECO BASELINE SYSTEM SAVING												
FUEL		9774	11461	12539	14010	15635	17349	24771	36968	57324	88880	137280
OPERATING & MAINTENANCE		152	215	206	197	242	251	323	355	481	651	881
OTHER TAXES		1134	1333	1455	1622	1813	2010	2866	4262	6601	10224	15778
TOTAL BASELINE SYSTEM SAVING		11060	13009	14200	15829	17690	19610	27960	41585	64406	99755	153939
WIND ENERGY SYSTEM SAVING	-92991	-12289	-8873	-6738	-4200	-1468	1283	12562	28908	53309	88900	142418
CUMULATIVE WIND SYSTEM SAVING	-92991	-105281	-114154	-120892	-125092	-126560	-125276	-95427	10877	225111	592492	1189384

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 1

FINANCIAL & PERFORMANCE ASSUMPTIONS

FINANCIAL ASSUMPTIONS

DEBT EQUITY RATIOS, %

LONG TERM DEBT	53.0
PREFERRED STOCK	13.0
COMMON STOCK	34.0

EQUITY RATIO, % 47.0

INTEREST RATES, %

LONG TERM DEBT	9.00
DIVIDENDS EARNED DURING CONSTRUCTION	
INVESTED EARNINGS	7.00

DIVIDEND RATES, %

PREFERRED	9.00
COMMON	15.00

FINANCING COST, %

DEBT FUNDS	1.00
EQUITY FUNDS	2.00

INCOME TAX RATES, %

FEDERAL	48.0
STATE	6.4

OTHER TAXES, %

PROPERTY & MISCELLANEOUS	
DURING CONSTRUCTION	
PLANT OPERATIONS	

GROSS REVENUE & MISCELLANEOUS 10.2

INVESTMENT TAX CREDIT, % 10.0

INVESTMENT TAX CREDIT LIABILITY RATE, % 50.0

BOND RETIREMENT, YRS

INITIAL FACILITIES	30.0
REPLACEMENT FACILITIES, 10 YR	0.0
REPLACEMENT FACILITIES, 5 YR	0.0

AMORTIZATION OF FINANCING COST, YRS

INITIAL FACILITIES	20.0
REPLACEMENT FACILITIES, 10 YR	0.0
REPLACEMENT FACILITIES, 5 YR	0.0

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BOOK DEPRECIATION, YRS	
30 YEAR	30.0
10 YEAR	0.0
5 YEAR	0.0
BOOK DEPRECIATION METHOD	
STRAIGHT LINE	
TAX DEPRECIATION, YRS	
30 YEAR	24.0
10 YEAR	0.0
5 YEAR	0.0
TAX DEPRECIATION METHOD	
DECLINING BALANCE/SUM OF YEARS, DIGITS	
MATERIALS & SUPPLIES, %	
OPERATING & MAINTENANCE (PLANT COST)	1.60
FUEL STOCK (YEARLY FUEL COST)	0.80
WORKING CAPITAL ALLOWANCE, %	
DURING CONSTRUCTION	1.0
PLANT OPERATION	
OPERATING & MAINTENANCE	12.5
FUEL	
INFLATION RATE, %	
PLANT CONSTRUCTION	
1978-1982	9.0
1983-1987	8.0
1988-1992	7.5
1993-1997	7.0
OPERATING & MAINTENANCE	7.0
FUEL COST	0.0
MATERIALS & SUPPLIES	6.0
GENERAL INFLATION	5.5
PERFORMANCE ASSUMPTIONS	
PLANT SIZE (MEGAWATTS)	45.0
OPERATING COST ASSUMPTIONS	
FUEL COST (¢/BTU)	0.0
INSURANCE (% PLANT COST)	0.06
HEAT RATE (BTU/KWH)	0
PLANT CAPACITY FACTOR, %	59.5

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 1

SCHEDULE 1A CONSTRUCTION COSTS 1977 COST BASE

	1982	TOTAL	\$/KW
LAND & LAND RIGHTS	145	145	3
STRUCTURES & IMPROVEMENTS	40	40	1
WIND TURBINE GENERATOR	54900	54900	1220
PRIOR COSTS			
APPLICATION STUDIES	530	530	12
INSTRUMENTATION & DATA REDUCT	0		0
CORRELATION & MODELING	0		0
TOTAL	530	530	12
POWER GENERATION FACILITIES	55615	55615	1236
TRANSMISSION FACILITIES	563	563	13
TOTAL WIND ENERGY SYSTEM COST	56178	56178	1248

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 1

	SCHEDULE 1 TOTAL CONSTRUCTION COST		
	1982	TOTAL	\$/KW
LAND & LAND RIGHTS	145	145	3
STRUCTURES & IMPROVEMENTS	62	62	1
WIND TURBINE GENERATOR	84470	84470	1377
PRIOR COSTS			
APPLICATION STUDIES	530	530	12
INSTRUMENTATION & DATA REDUCT	0		0
CORRELATION & MODELING	0		0
TOTAL	530	530	12
POWER GENERATION FACILITIES	85206	85206	1893
TRANSMISSION FACILITIES	866	866	19
TOTAL WIND ENERGY SYSTEM COST	86073	86073	1913
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	7668	7668	170
OTHER TAXES			0
TOTAL CONSTRUCTION COST	93741	93741	2083
MATERIALS & SUPPLIES	1378	1378	31
WORKING CAPITAL	861	861	19
TOTAL CAPITAL COST	95980	95980	2133

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 1

SCHEDULE 2 DISCOUNTED CASH FLOW ANALYSIS & FINANCIAL RATIOS

DISCOUNTED CASH FLOW ANALYSIS

LEVELIZED BUSBAR ENERGY COST (MILLS/KWH)

FIRST YEAR OF COMMERCIAL OPERATION	74.7
1977 COST BASE	56.6
ANNUALIZED FIXED CHARGE RATE, %	17.2
CAPITAL RECOVERY FACTOR, %	12.2
WEIGHTED AVERAGE COST OF CAPITAL, %	11.7
RATE OF RETURN, % (START OF CONSTRUCTION TO END OF PLANT OPERATION)	
INTERNAL RATE OF RETURN	12.3
RETURN ON COMMON EQUITY	18.9

PRESENT VALUE ANALYSIS

COST OF SERVICE (THOUSANDS)	144028
ENERGY PRODUCTION (MILLIONS OF KWH)	1928
COMMON DIVIDENDS (THOUSANDS)	39711
PREFERRED DIVIDENDS (THOUSANDS)	10802
OPERATING & MAINTENANCE EXPENSE	11798

FINANCIAL RATIOS

CUMULATIVE DIVIDEND PAYOUT RATE (30YRS), %	
PREFERRED STOCK	8.9
COMMON STOCK	8.6
EFFECTIVE TAX RATE, %	47.6
RATIO OF EARNINGS TO FIXED CHARGES	4.1
TANGIBLE NET WORTH, END 30 YEARS (THOUSANDS)	45198

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 1

SCHEDULE 2A
LEVELIZED BUSBAR ENERGY COST
MILLS PER KWH

OPERATION & MAINTENANCE EXPENSE	0.0
FUEL	5.9
OTHER	0.2
INSURANCE	6.1
TOTAL OPER. & MAINT. EXPENSE	13.3
DEPRECIATION EXPENSE	7.7
TAXES, OTHER THAN INCOME	14.6
PROVISION FOR INCOME TAXES	2.3
FEDERAL	18.0
STATE	30.8
TOTAL INCOME TAXES	74.7
RETURN ON RATE BASE	
TOTAL LEVELIZED BUSBAR ENERGY COST	

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 1

SCHEDULE 2B
LEVELIZED BUSBAR ENERGY COST
MILLS PER KWH
1977 COST BASE

OPERATION & MAINTENANCE EXPENSE	
FUEL	0.0
OTHER	0.0
INSURANCE	0.2
TOTAL OPER. & MAINT. EXPENSE	0.2
DEPRECIATION EXPENSE	10.2
TAXES, OTHER THAN INCOME	5.9
PROVISION FOR INCOME TAXES	
FEDERAL	11.1
STATE	1.7
TOTAL INCOME TAXES	13.8
RETURN ON RATE BASE	23.6
TOTAL LEVELIZED BUSBAR ENERGY COST	53.6

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 1

SCHEDULE 3
COST OF SERVICE
MILLS PER KWH

	1983	1984	1985	1986	1987	1988	1992	1997	2002	2012
COST OF SERVICE										
OPERATION AND MAINT EXPENSE										
FUEL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OTHER	3.8	3.9	4.1	4.4	4.6	4.8	5.9	7.7	10.1	17.6
INSURANCE	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
TOTAL OPER. & MAINT. EXPENSE	4.0	4.2	4.4	4.6	4.8	5.0	6.1	7.9	10.3	17.8
DEPRECIATION EXPENSE	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
TAXES, OTHER THAN INCOME TAX	10.2	9.5	9.2	8.8	8.4	3.0	6.7	5.5	4.9	5.0
PROVISION FOR INCOME TAXES										
FEDERAL	24.7	22.3	20.9	19.5	18.2	16.9	12.5	8.5	6.1	6.4
STATE	3.5	3.2	3.0	2.8	2.6	2.4	1.8	1.2	0.9	0.9
TOTAL INCOME TAXES	28.2	25.4	23.9	22.3	20.8	19.3	14.3	9.7	7.0	7.3
RETURN ON RATE BASE	45.1	41.9	39.8	37.7	35.6	33.5	26.3	18.8	13.1	6.8
TOTAL COST OF SERVICE	100.8	94.3	90.5	86.7	83.0	79.1	66.7	55.3	48.6	50.2
NET ANNUAL ENERGY PRODUCTION	234.4	235.2	234.4	234.4	234.4	235.2	235.2	234.4	234.4	235.2
PLANT CAPACITY FACTOR, %	59.5	59.7	59.5	59.5	59.5	59.7	59.7	59.5	59.5	59.7
AVERAGE COST OF SERVICE OVER 30 YEAR PLANT LIFE	61.8									

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 1

SCHEDULE 4
INCOME AND RETAINED EARNINGS

	1983	1984	1985	1986	1987	1992	1997	2002	2012	TOTAL
UTILITY OPERATING INCOME										
OPERATING REVENUES	23349	21883	20938	20029	19158	15397	12678	11097	11521	426350
OPERATING EXPENSES										
OPERATING AND MAINTENANCE	932	976	1023	1072	1125	1439	1859	2421	4180	64022
DEPRECIATION	3120	3120	3120	3120	3120	3120	3120	3120	3120	93595
TAXES OTHER THAN INCOME	2393	2243	2146	2053	1964	1578	1299	1137	1181	43701
PROVISION FOR INCOME TAXES										
FEDERAL	5779	5235	4900	4577	4269	2944	1991	1434	1509	75885
STATE	828	750	702	656	612	422	285	205	216	10873
INVESTMENT TAX CREDIT ADJ.	-286	-286	-286	-286	-286	-286	-286	-286	-286	-8593
TOTAL OPERATING EXPENSES	12766	12038	11604	11192	10803	9217	8268	8031	9920	279484
NET UTILITY OPERATING INCOME	10583	9845	9334	8837	8355	6181	4409	3066	1601	146866
OTHER INCOME AND DEDUCTIONS										
OTHER INCOME										
INTEREST INCOME		189	418	636	843	1714	2310	2624	2424	57904
INVESTMENT TAX CREDIT	1206	1811	1708	1611	1521					
ALLOWANCE FOR FUNDS USED										
DURING CONSTRUCTION										7668
OTHER INCOME	1206	2001	2126	2246	2363	1714	2310	2624	2424	74165
OTHER DEDUCTIONS										
INCOME TAXES-INTEREST INCOME		97	215	326	433	880	1186	1347	1245	29732
INTEREST CHARGES										
INTEREST ON LONG TERM DEBT	4399	4251	4103	3955	3807	3068	2329	1589	111	70959
AMORTIZATION OF DEBT EXPENSE	68	68	68	68	68	68	68	68		1367
TOTAL INTEREST CHARGES	4467	4319	4171	4024	3876	3136	2397	1658	111	72326
NET INCOME	7321	7429	7074	6734	6410	3878	3136	2685	2669	118974
RETAINED EARNINGS, BEG. OF YEAR	4355	1491	1491	1491	1491	1491	1491	1491	1491	
DIVIDENDS	10186	7429	7074	6734	6410	3878	3136	2685	2669	117483
RETAINED EARNINGS, END OF YEAR	1491	1491	1491	1491	1491	1491	1491	1491	1491	

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 1

SCHEDULE 5 BALANCE SHEET

	1982	1983	1984	1985	1986	1987	1992	1997	2002	2012
ASSETS AND OTHER DEBITS										
UTILITY PLANT IN SERVICE		93741	93741	93741	93741	93741	93741	93741	93741	93741
LESS: ACCUMULATED DEPRECIATION		3120	6240	9360	12479	15599	31199	46798	62397	93595
NET PLANT IN SERVICE		90621	87501	84381	81262	78142	62542	46943	31344	146
CONSTRUCTION WORK IN PROGRESS	93741									
NET UTILITY PLANT	93741	90621	87501	84381	81262	78142	62542	46943	31344	146
CURRENT ASSETS										
TEMPORARY CASH INVESTMENTS		2702	5968	9080	12037	14840	26513	34227	37883	33955
OPERATING MATERIALS & SUPPLIES	1378	1951	2068	2192	2324	2463	3296	4411	5903	10572
FUEL STOCK			124	130	136	143	182	235	305	525
OTHER WORKING CAPITAL, NET	861	118	8160	11402	14497	17446	29991	38873	44091	45052
TOTAL CURRENT ASSETS	2239	4772								
DEFERRED DEBITS										
UNAMORTIZED DEBT EXPENSE	1367	1299	1230	1162	1094	1025	684	342		
TOTAL ASSETS & OTHER DEBITS	97347	96692	96892	96945	96852	96613	93217	86158	75435	45198
LIABILITIES AND OTHER CREDITS										
PROPRIETARY CAPITAL										
PREFERRED STOCK	12089	12089	12089	12089	12089	12089	12089	12089	12089	12089
COMMON STOCK	31618	31618	31618	31618	31618	31618	31618	31618	31618	31618
RETAINED EARNINGS	4355	1491	1491	1491	1491	1491	1491	1491	1491	1491
TOTAL PROPRIETARY CAPITAL	48062	45198	45198	45198	45198	45198	45198	45198	45198	45198
LONG-TERM DEBT	49286	47644	46001	44358	42715	41072	32858	24643	16429	0
ACCUMULATED DEFERRED INCOME TAX		3851	5693	7390	8940	10343	15162	16317	13808	0
TOTAL LIABILITIES AND OTHER CREDITS	97349	96692	96892	96945	96852	96613	93217	86158	75435	45198

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 1

SCHEDULE 6 CASH FLOW

	1982	1983	1984	1985	1986	1987	1992	1997	2002	2012
CASH SOURCES										
NET INCOME	4355	7321	7429	7074	6734	6410	3878	3136	2685	2669
ADD: NON CASH CHARGES (CREDITS)										
DEPRECIATION		3120	3120	3120	3120	3120	3120	3120	3120	3120
CHANGE IN DEF. INCOME TAXES		3851	1843	1696	1550	1403	671	-62	-795	-1527
AMORTIZ. OF DEBT EXPENSE		68	68	68	68	68	68	68	68	68
EQUITY COMPONENT OF AFUDC	-4355									
CASH FLOW FROM OPERATIONS	0	14360	12461	11959	11472	11002	7737	6262	5078	4262
FUNDS FROM INVESTORS										
LONG TERM DEBT	49286									
PREFERRED STOCK	12089									
COMMON STOCK	31618									
TOTAL FUNDS FROM INVESTORS	92993									
TOTAL CASH SOURCES	92993	14360	12461	11959	11472	11002	7737	6262	5078	4262
CASH USES										
PLANT ADDITIONS	93741									
LESS: EQUITY COMP. OF AFUDC	4355									
CASH REQ FOR PLANT ADDITIONS	89386									
LONG TERM DEBT RETIREMENT		1643	1643	1643	1643	1643	1643	1643	1643	1643
COST OF ISSUING SECURITIES	1367									
DIVIDENDS										
PREFERRED		1901	1088	1088	1088	1088	1088	1088	1088	1088
COMMON		8285	6341	5986	5646	5322	2790	2048	1597	1581
TOTAL		10186	7429	7074	6734	6410	3878	3136	2685	2669
CHANGE IN NET CURRENT ASSETS	2240	2531	3388	3242	3095	2949	2216	1483	751	-50
TOTAL CASH USES	92993	14360	12461	11959	11472	11002	7737	6262	5078	4262

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 1

SCHEDULE 7 OPERATING AND MAINTENANCE

	1983	1984	1985	1986	1987	1988	1992	1997	2002	2012
OTHER OPERATING & MAINTENANCE										
LAND RIGHTS	145	145	145	145	145	145	145	145	145	145
WIND TURBINE GENERATOR	685	726	770	816	865	917	1158	1549	2073	3712
TRANSMISSION SYSTEM	50	53	56	59	63	67	85	113	151	271
TOTAL	880	925	971	1021	1073	1129	1388	1807	2369	4129
INSURANCE	52	52	52	52	52	52	52	52	52	52
OPERATING AND MAINTENANCE	932	976	1023	1072	1125	1181	1439	1859	2421	4180

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 1

SCHEDULE 8 RATE OF RETURN

	1983	1984	1985	1986	1987	1988	1992	1997	2002	2012
AVERAGE CAPITALIZATION										
AVERAGE OUTSTANDING DEBT, LESS UNAMORTIZED DEBT EXPENSE	47132	45558	43983	42409	40834	39260	32961	25089	17216	822
AVERAGE OUTSTANDING PREFERRED	12089	12089	12089	12089	12089	12089	12089	12089	12089	12089
AVERAGE OUTSTANDING COMMON INCLUDING RETAINED EARNINGS	35973	33108	33109	33109	33109	33109	33109	33109	33109	33109
TOTAL AVERAGE CAPITALIZATION	95194	90755	89181	87606	86032	84457	78159	70286	62414	46019
AVERAGE CAPITALIZATION COMPONENT (%)										
LONG TERM DEBT	49.5	50.2	49.3	48.4	47.5	46.5	42.2	35.7	27.6	1.8
PREFERRED SHARES	12.7	13.3	13.6	13.8	14.1	14.3	15.5	17.2	19.4	26.3
COMMON EQUITY	37.8	36.5	37.1	37.8	38.5	39.2	42.4	47.1	53.0	71.9
TOTAL AVERAGE CAPITALIZATION	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
COST OF CAPITAL										
TOTAL INTEREST CHARGES	4467	4319	4171	4024	3876	3728	3136	2397	1658	111
WEIGHTED AVERAGE DEBT COST, %	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.6	9.6	13.5
DIVIDEND RATE PREFERRED SHARES, %	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
RATE OF RETURN COMMON EQUITY, %	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
RATE OF RETURN PERCENTAGE COMPONENTS (%)										
LONG TERM DEBT	4.7	4.8	4.7	4.6	4.5	4.4	4.0	3.4	2.7	0.2
PREFERRED SHARES	1.1	1.2	1.2	1.2	1.3	1.3	1.4	1.5	1.7	2.4
COMMON EQUITY	5.7	5.5	5.6	5.7	5.8	5.9	6.4	7.1	8.0	10.8
RATE OF RETURN, %	11.5	11.4	11.5	11.5	11.5	11.6	11.8	12.0	12.4	13.4

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 1

SCHEDULE 9
RETURN ON RATE BASE

	1983	1984	1985	1986	1987	1988	1992	1997	2002	2012
UTILITY PLANT IN SERVICE END OF YEAR	93741	93741	93741	93741	93741	93741	93741	93741	93741	93741
AVER UTILITY PLANT IN SERVICE	93741	93741	93741	93741	93741	93741	93741	93741	93741	93741
LESS AVERAGE: ACCUMULATED DEPRECIATION	1560	4680	7800	10920	14039	17159	29639	45238	60837	92036
ACCUMULATED DEFERRED INC. TAX	1925	4772	6542	8165	9641	10971	14826	16348	14206	764
ADD: WORKING CAPITAL ALLOWANCE	1738	1844	2006	2164	2329	2503	3286	4515	6115	11006
NET INVESTMENT IN UTILITY PLANT	91994	86133	81406	76821	72390	68113	52562	36670	24813	11948
RATE OF RETURN	11.5	11.4	11.5	11.5	11.5	11.6	11.8	12.0	12.4	13.4
RETURN ON RATE BASE	10583	9845	9334	8837	8355	7889	6181	4409	3066	1601

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TOTAL PHASE 1

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

SCHEDULE 10
DEPRECIATION

	1983	1984	1985	1986	1987	1988	1992	1997	2002	2012
TOTAL CONSTRUCTION COST										
CUMULATIVE CONSTRUCTION COST AT END OF YEAR	93596	93596	93596	93596	93596	93596	93596	93596	93596	93596
LESS: CONSTRUCTION WORK IN PROGRESS AT END OF YEAR										
DEPRECIATED FACILITIES UTILITY PLANT IN SERVICE AT END OF YEAR	93596	93596	93596	93596	93596	93596	93596	93596	93596	93596
UTILITY PLANT IN SERVICE CLASSIFIED BY DEPRECIATION RATES										
30 YEAR	93596	93596	93596	93596	93596	93596	93596	93596	93596	93596
10 YEAR	0									
5 YEAR	0									
TOTAL UTILITY PLANT IN SERVICE	93596	93596	93596	93596	93596	93596	93596	93596	93596	93596
DEPRECIATION PROVISION ON AVERAGE PLANT IN SERVICE										
5.0%	3120	3120	3120	3120	3120	3120	3120	3120	3120	3120
10.0										
20.0										
TOTAL DEPRECIATION	3120	3120	3120	3120	3120	3120	3120	3120	3120	3120
ACCUM DEPRECIATION BEGIN OF YEAR		3120	6240	9360	12479	15599	28079	43678	59277	90476
ACCUM PROVISION FOR DEPRECIATION	3120	6240	9360	12479	15599	18719	31199	46798	62397	93595
AVERAGE ACCUMULATED DEPRECIATION	1560	4680	7800	10920	14039	17159	29639	45238	60837	92036

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 1

SCHEDULE 11
FEDERAL & STATE INCOME TAXES

	1983	1984	1985	1986	1987	1988	1992	1997	2002	2012
RETURN ON RATE BASE	10583	9845	9334	8837	8355	7889	6181	4409	3066	1601
LESS: INTEREST EXPENSE	4467	4319	4171	4024	3876	3728	3136	2397	1658	111
EQUITY PORTION OF RETURN	6116	5526	5163	4814	4480	4161	3044	2012	1408	1490
BOOK DEPRECIATION OF EQUITY RETURN CAPITALIZED DURING CONST	145	145	145	145	145	145	145	145	145	145
TOTAL EQUITY RETURN AFTER TAXES INCLUDED IN REVENUES	6261	5671	5308	4959	4625	4306	3189	2157	1553	1635
FEDERAL INCOME TAX	5779	5235	4900	4577	4269	3975	2944	1991	1434	1509
TAXABLE INCOME AFTER STATE INCOME TAXES	12040	10906	10208	9536	8894	8282	6134	4149	2987	3144
STATE INCOME TAX	828	750	702	656	612	570	422	285	205	216
TOTAL INCOME TAX	6607	5985	5602	5233	4881	4545	3366	2277	1639	1725
ADDITIONAL TAX ADJUSTMENTS										
TAX DEPRECIATION	-7161	-6564	-6279	-5993	-5708	-5422	-4281	-2854	-1427	
BOOK DEPRECIATION	2975	2975	2975	2975	2975	2975	2975	2975	2975	2975
TAX LOSS CARRYFORWARD		0	0	0	0	0	0	0	0	0
TAX LOSS CURRENT YEAR										
TAX LOSSES PRIOR YEARS	-3313	0	0	0	0	0	0	0	0	0
TAX LOSS CARRYOVER	0	0	0	0	0	0	0	0	0	0
TOTAL TAX ADJUSTMENTS	-7499	-3589	-3304	-3018	-2733	-2448	-1306	121	1548	2975
DEFERRED INCOME TAXES										
FEDERAL	3368	1612	1484	1356	1227	1099	587	0	0	0
STATE	483	231	213	194	176	158	84	0	0	0
TOTAL	3851	1843	1696	1550	1403	1257	671			
INCOME TAXES PAYABLE CURRENTLY										
FEDERAL	2411	3623	3416	3222	3042	2876	2358	2046	2129	2845
STATE	346	519	489	462	436	412	338	293	305	408
TOTAL	2757	4142	3905	3683	3477	3288	2695	2339	2434	3253
CHANGE IN DEFERRED INCOME TAXES	3851	1843	1696	1550	1403	1257	671	-62	-795	-1527
DEFERRED INCOME TAXES BEG. OF YR		3851	5693	7390	8940	10343	14491	16379	14603	1527
DEFERRED INCOME TAXES END OF YR	3851	5693	7390	8940	10343	11600	15162	16317	13808	0
AVER ACCUM DEFERRED INCOME TAX	1925	4772	6542	8165	9641	10971	14826	16348	14206	764

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 1

SCHEDULE 12
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

	1982	TOTAL	\$/KW
CASH FLOW			
CASH SOURCES			
DEBT	49286	49286	1095
EQUITY			
PREFERRED STOCK	12089	12089	269
COMMON STOCK	31618	31618	703
TOTAL EQUITY FUNDS	43707	43707	971
TOTAL CASH SOURCES	92993	92993	2067
CASH USES			
TOTAL PLANT COST	86073	86073	1913
INTEREST DURING CONST.	3313	3313	74
FINANCING EXPENSE:			
DEBT FUNDS	493	493	11
EQUITY FUNDS	874	874	19
TOTAL FINANCING EXPENSE	1367	1367	30
OTHER TAXES			0
MATERIALS & SUPPLIES	1378	1378	31
WORKING CAPITAL	861	861	19
TOTAL CASH USES	92991	92991	2066
TOTAL CONSTRUCTION COST			
TOTAL PLANT COST	86073	86073	1913
EQUITY PORTION OF AFUDC			
PREFERRED STOCK	813	813	18
COMMON STOCK	3542	3542	79
EQUITY PORTION OF AFUDC	4355	4355	97
INTEREST DURING CONST.	3313	3313	74
TOTAL AFUDC	7668	7668	170
OTHER TAXES			0
TOTAL CONSTRUCTION COST	93741	93741	2083
TOTAL DEPRECIABLE			
TOTAL CONSTRUCTION COST	93741	93741	2083
LESS: LAND	145	145	3
TOTAL DEPRECIABLE COST	93596	93596	2080

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 2

WIND ENERGY SYSTEM ANNUAL COST VS HECO BASELINE SYSTEM SAVINGS

WIND TURBINE GENERATOR COST
(\$/KW 1977 COST BASE) 870

DISCOUNTED CASH FLOW ANALYSIS

DISCOUNT RATE, % 11.7

RATE OF RETURN, % 11.7

CASH FLOW ANALYSIS

	1983	1984	1985	1986	1987	1989	1991	1993	1998	2003	2008	2013
WIND ENERGY SYSTEM ANNUAL COST	173275	44122	41426	39701	38044	34953	32164	29688	24936	22413	22531	24539
HECO BASELINE SYSTEM SAVING												
FUEL		19359	21495	23981	26889	31081	38171	44660	69682	108446	168749	262583
OPERATING & MAINTENANCE		306	350	377	377	422	458	494	610	783	1004	1287
OTHER TAXES		2246	2495	2782	3114	3598	4411	5157	8027	12474	19386	30134
TOTAL BASELINE SYSTEM SAVING		21911	24340	27140	30380	35101	43040	50311	78320	121702	189138	294004
WIND ENERGY SYSTEM SAVING	-173275	-22211	-17086	-12562	-7665	148	10876	20622	53383	99289	166608	269465
CUMULATIVE WIND SYSTEM SAVING	-173275	-195486	-212572	-225134	-232798	-235452	-220426	-183132	13065	411022	1098566	2222188

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 2

FINANCIAL & PERFORMANCE ASSUMPTIONS

FINANCIAL ASSUMPTIONS

DEBT EQUITY RATIOS, %	
LONG TERM DEBT	53.0
PREFERRED STOCK	13.0
COMMON STOCK	34.0
EQUITY RATIO, %	47.0
INTEREST RATES, %	
LONG TERM DEBT	9.00
DIVIDENDS EARNED DURING CONSTRUCTION	
INVESTED EARNINGS	7.00
DIVIDEND RATES, %	
PREFERRED	9.00
COMMON	15.00
FINANCING COST, %	
DEBT FUNDS	1.00
EQUITY FUNDS	2.00
INCOME TAX RATES, %	
FEDERAL	48.0
STATE	6.4
OTHER TAXES, %	
PROPERTY & MISCELLANEOUS	
DURING CONSTRUCTION	
PLANT OPERATIONS	
GROSS REVENUE & MISCELLANEOUS	10.2
INVESTMENT TAX CREDIT, %	10.0
INVESTMENT TAX CREDIT LIABILITY RATE, %	50.0
BOND RETIREMENT, YRS	
INITIAL FACILITIES	30.0
REPLACEMENT FACILITIES, 10 YR	0.0
REPLACEMENT FACILITIES, 5 YR	0.0
AMORTIZATION OF FINANCING COST, YRS	
INITIAL FACILITIES	20.0
REPLACEMENT FACILITIES, 10 YR	0.0
REPLACEMENT FACILITIES, 5 YR	0.0

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BOOK DEPRECIATION, YRS	
30 YEAR	30.0
10 YEAR	0.0
5 YEAR	0.0
BOOK DEPRECIATION METHOD	
STRAIGHT LINE	
TAX DEPRECIATION, YRS	
30 YEAR	24.0
10 YEAR	0.0
5 YEAR	0.0
TAX DEPRECIATION METHOD	
DECLINING BALANCE/SUM OF YEARS, DIGITS	
MATERIALS & SUPPLIES, %	
OPERATING & MAINTENANCE (PLANT COST)	1.60
FUEL STOCK (YEARLY FUEL COST)	0.80
WORKING CAPITAL ALLOWANCE, %	
DURING CONSTRUCTION	1.0
PLANT OPERATION	
OPERATING & MAINTENANCE	12.5
FUEL	
INFLATION RATE, %	
PLANT CONSTRUCTION	
1978-1982	9.0
1983-1987	8.0
1988-1992	7.5
1993-1997	7.0
OPERATING & MAINTENANCE	7.0
FUEL COST	0.0
MATERIALS & SUPPLIES	6.0
GENERAL INFLATION	5.5
PERFORMANCE ASSUMPTIONS	
PLANT SIZE (MEGAWATTS)	105.0
OPERATING COST ASSUMPTIONS	
FUEL COST (\$/BTU)	0.0
INSURANCE (% PLANT COST)	0.06
HEAT RATE (BTU/KWH)	0
PLANT CAPACITY FACTOR, %	45.6

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 2

SCHEDULE 1 TOTAL CONSTRUCTION COST

	1983	TOTAL	\$/KW
LAND & LAND RIGHTS	339	339	3
STRUCTURES & IMPROVEMENTS	155	155	1
WIND TURBINE GENERATOR	151798	151798	1446
PRIOR COSTS			
APPLICATION STUDIES	70	70	1
INSTRUMENTATION & DATA REDUCT	1500	1500	14
CORRELATION & MODELING	1500	1500	14
TOTAL	3070	3070	29
POWER GENERATION FACILITIES	155361	155361	1480
TRANSMISSION FACILTIES	5022	5022	48
TOTAL WIND ENERGY SYSTEM COST	160383	160383	1527
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	14289	14289	136
OTHER TAXES			0
TOTAL CONSTRUCTION COST	174672	174672	1664
MATERIALS & SUPPLIES	2567	2567	24
WORKING CAPITAL	1604	1604	15
TOTAL CAPITAL COST	178843	178843	1703

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII.

TOTAL PHASE 2

SCHEDULE 1A CONSTRUCTION COSTS 1977 COST BASE

	1983	TOTAL	\$/KW
LAND & LAND RIGHTS	339	339	3
STRUCTURES & IMPROVEMENTS	93	93	7
WIND TURBINE GENERATOR	91350	91350	870
PRIOR COSTS			
APPLICATION STUDIES	70	70	1
INSTRUMENTATION & DATA REDUCT	1500	1500	14
CORRELATION & MODELING	1500	1500	14
TOTAL	3070	3070	29
POWER GENERATION FACILITIES	94852	94852	903
TRANSMISSION FACILITIES	3022	3022	29
TOTAL WIND ENERGY SYSTEM COST	97874	97874	932

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TOTAL PHASE 2

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

SCHEDULE 2
DISCOUNTED CASH FLOW ANALYSIS & FINANCIAL RATIOS

DISCOUNTED CASH FLOW ANALYSIS

LEVELIZED BUSBAR ENERGY COST (MILLS/KWH)

FIRST YEAR OF COMMERCIAL OPERATION 80.3

1977 COST BASE 57.2

ANNUALIZED FIXED CHARGE RATE, % 17.3

CAPITAL RECOVERY FACTOR, % 12.2

WEIGHTED AVERAGE COST OF CAPITAL, % 11.7

RATE OF RETURN, %
(START OF CONSTRUCTION TO END OF PLANT OPERATION)

INTERNAL RATE OF RETURN 12.3

RETURN ON COMMON EQUITY 18.9

PRESENT VALUE ANALYSIS

COST OF SERVICE (THOUSANDS) 276541

ENERGY PRODUCTION (MILLIONS OF KWH) 3443

COMMON DIVIDENDS (THOUSANDS) 74378

PREFERRED DIVIDENDS (THOUSANDS) 20126

OPERATING & MAINTENANCE EXPENSE 28352

FINANCIAL RATIOS

CUMULATIVE DIVIDEND PAYOUT RATE (30YRS), %

PREFERRED STOCK 8.9
COMMON STOCK 8.7

EFFECTIVE TAX RATE, % 47.6

RATIO OF EARNINGS TO FIXED CHARGES 4.2

TANGIBLE NET WORTH, END 30 YEARS (THOUSANDS) 84266

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 2

SCHEDULE 2A LEVELIZED BUSBAR ENERGY COST MILLS PER KWH

OPERATION & MAINTENANCE EXPENSE	
FUEL	0.0
OTHER	8.0
INSURANCE	0.2
TOTAL OPER. & MAINT. EXPENSE	8.2
DEPRECIATION EXPENSE	13.9
TAXES, OTHER THAN INCOME	8.2
PROVISION FOR INCOME TAXES	
FEDERAL	15.3
STATE	2.4
TOTAL INCOME TAXES	19.0
RETURN ON RATE BASE	32.3
TOTAL LEVELIZED BUSBAR ENERGY COST	80.3

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 2

SCHEDULE 2B LEVELIZED BUSBAR ENERGY COST MILLS PER KWH 1977 COST BASE

OPERATION & MAINTENANCE EXPENSE	
FUEL	0.0
OTHER	0.0
INSURANCE	0.2
TOTAL OPER. & MAINT. EXPENSE	0.2
DEPRECIATION EXPENSE	10.1
TAXES, OTHER THAN INCOME	6.0
PROVISION FOR INCOME TAXES	
FEDERAL	11.1
STATE	1.7
TOTAL INCOME TAXES	13.8
RETURN ON RATE BASE	23.4
TOTAL LEVELIZED BUSBAR ENERGY COST	53.4

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 2

SCHEDULE 3
COST OF SERVICE
MILLS PER KWH

	1984	1985	1986	1987	1988	1989	1993	1998	2003	2013
COST OF SERVICE										
OPERATION AND MAINT EXPENSE										
FUEL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OTHER	5.1	5.3	5.6	5.9	6.2	6.5	8.0	10.5	13.7	24.0
INSURANCE	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
TOTAL OPER. & MAINT. EXPENSE	5.3	5.6	5.8	6.1	6.4	6.8	8.3	10.7	14.0	24.2
DEPRECIATION EXPENSE	13.8	13.9	13.9	13.9	13.8	13.9	13.9	13.9	13.9	13.9
TAXES, OTHER THAN INCOME TAX	10.8	10.1	9.7	9.3	8.9	8.6	7.3	6.1	5.5	6.0
PROVISION FOR INCOME TAXES										
FEDERAL	25.7	23.4	21.9	20.5	19.0	17.8	13.2	9.0	6.6	7.2
STATE	3.7	3.4	3.1	2.9	2.7	2.6	1.9	1.3	0.9	1.0
TOTAL INCOME TAXES	29.4	26.7	25.0	23.4	21.7	20.4	15.1	10.3	7.6	8.2
RETURN ON RATE BASE	47.0	43.9	41.7	39.4	37.1	35.2	27.7	19.8	13.9	7.6
TOTAL COST OF SERVICE	106.2	100.3	96.1	92.2	88.0	84.8	72.2	60.9	54.8	59.9
NET ANNUAL ENERGY PRODUCTION	420.5	418.5	418.5	418.5	420.5	413.5	418.5	418.5	418.5	418.5
PLANT CAPACITY FACTOR. %	45.7	45.5	45.5	45.5	45.7	45.5	45.5	45.5	45.5	45.5
AVERAGE COST OF SERVICE OVER 30 YEAR PLANT LIFE	68.1									

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 2

SCHEDULE 4 INCOME AND RETAINED EARNINGS

	1983	1984	1985	1986	1987	1993	1998	2003	2013	TOTAL
UTILITY OPERATING INCOME										
OPERATING REVENUES		44122	41426	39701	38044	29688	24936	22413	24539	840089
OPERATING EXPENSES										
OPERATING AND MAINTENANCE		2225	2332	2445	2566	3458	4480	5848	10129	154502
DEPRECIATION		5811	5811	5811	5811	5811	5811	5811	5811	174332
TAXES OTHER THAN INCOME		4523	4246	4069	3900	3043	2556	2297	2515	86109
PROVISION FOR INCOME TAXES										
FEDERAL		10798	9787	9165	8567	5540	3784	2772	3001	144017
STATE		1547	1402	1313	1227	794	542	397	430	20635
INVESTMENT TAX CREDIT ADJ.		-533	-533	-533	-533	-533	-533	-533	-533	-16004
TOTAL OPERATING EXPENSES		24371	23045	22270	21537	18113	16640	16592	21352	563591
NET UTILITY OPERATING INCOME		19752	18381	17431	16507	11576	8296	5821	3187	276497
OTHER INCOME AND DEDUCTIONS										
OTHER INCOME										
INTEREST INCOME			336	761	1165	3165	4264	4834	4419	106500
INVESTMENT TAX CREDIT		2262	3392	3201	3021					
ALLOWANCE FOR FUNDS USED										
DURING CONSTRUCTION	14289									14289
OTHER INCOME	14289	2262	3729	3961	4186	3165	4264	4834	4419	136793
OTHER DEDUCTIONS										
INCOME TAXES-INTEREST INCOME			173	391	598	1625	2190	2482	2269	54684
INTEREST CHARGES										
INTEREST ON LONG TERM DEBT	6174	8196	7921	7645	7370	5717	4339	2962	207	132220
AMORTIZATION OF DEBT EXPENSE		127	127	127	127	127	127	127		2547
TOTAL INTEREST CHARGES	6174	8324	8048	7773	7497	5844	4467	3089	207	134767
NET INCOME	8115	13690	13888	13229	12598	7271	5904	5084	5130	223839
RETAINED EARNINGS, BEG. OF YEAR		8115	2825	2825	2825	2825	2825	2825	2825	
DIVIDENDS		18980	13888	13229	12598	7271	5904	5084	5130	221014
RETAINED EARNINGS, END OF YEAR	8115	2825	2825	2825	2825	2825	2825	2825	2825	

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 2

SCHEDULE 5
BALANCE SHEET

	1983	1984	1985	1986	1987	1988	1993	1998	2003	2013
ASSETS AND OTHER DEBITS										
UTILITY PLANT IN SERVICE		174672	174672	174672	174672	174672	174672	174672	174672	174672
LESS: ACCUMULATED DEPRECIATION		5811	11622	17433	23244	29055	58111	87166	116221	174332
NET PLANT IN SERVICE		168860	163049	157238	151427	145616	116561	87505	58450	339
CONSTRUCTION WORK IN PROGRESS	174672									
NET UTILITY PLANT	174672	168860	163049	157238	151427	145616	116561	87505	58450	339
CURRENT ASSETS										
TEMPORARY CASH INVESTMENTS		4801	10867	16644	22133	27333	48953	63161	69757	61781
OPERATING MATERIALS & SUPPLIES	2567	3852	4083	4328	4588	4863	6508	8709	11655	20873
FUEL STOCK										
OTHER WORKING CAPITAL, NET	1604	281	295	309	324	340	436	564	736	1273
TOTAL CURRENT ASSETS	4171	8935	15245	21282	27045	32536	55897	72434	82148	83927
DEFERRED DEBITS										
UNAMORTIZED DEBT EXPENSE	2547	2420	2292	2165	2038	1910	1274	637		
TOTAL ASSETS & OTHER DEBITS	181390	180215	180587	180685	180510	180063	173731	160576	140598	84267
LIABILITIES AND OTHER CREDITS										
PROPRIETARY CAPITAL										
PREFERRED STOCK	22526	22526	22526	22526	22526	22526	22526	22526	22526	22526
COMMON STOCK	58915	58915	58915	58915	58915	58915	58915	58915	58915	58915
RETAINED EARNINGS	8115	2825	2825	2825	2825	2825	2825	2825	2825	2825
TOTAL PROPRIETARY CAPITAL	89556	84266	84266	84266	84266	84266	84266	84266	84266	84266
LONG-TERM DEBT	91837	88776	85715	82654	79592	76531	61225	45919	30613	1
ACCUMULATED DEFERRED INCOME TAX		7173	10606	13765	16652	19265	28240	30391	25719	0
TOTAL LIABILITIES AND OTHER CREDITS	181393	180215	180587	180685	180510	180063	173731	160576	140598	84267

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 2

SCHEDULE 6
CASH FLOW

	1983	1984	1985	1986	1987	1988	1993	1998	2003	2013
CASH SOURCES										
NET INCOME	8115	13690	13888	13229	12598	11998	7271	5904	5084	5130
ADD: NON CASH CHARGES (CREDITS)										
DEPRECIATION		5811	5811	5811	5811	5811	5811	5811	5811	5811
CHANGE IN DEF. INCOME TAXES		7173	3432	3160	2887	2614	1249	-116	-1480	-2845
AMORTIZ. OF DEBT EXPENSE		127	127	127	127	127	127	127	127	
EQUITY COMPONENT OF AFUDC	-8115									
CASH FLOW FROM OPERATIONS	0	26801	23259	22327	21423	20551	14459	11727	9542	8096
FUNDS FROM INVESTORS										
LONG TERM DEBT	91837									
PREFERRED STOCK	22526									
COMMON STOCK	58915									
TOTAL FUNDS FROM INVESTORS	173278									
TOTAL CASH SOURCES	173278	26801	23259	22327	21423	20551	14459	11727	9542	8096
CASH USES										
PLANT ADDITIONS	174672									
LESS: EQUITY COMP. OF AFUDC	8115									
CASH REQ FOR PLANT ADDITIONS	166556									
LONG TERM DEBT RETIREMENT		3061	3061	3061	3061	3061	3061	3061	3061	3061
COST OF ISSUING SECURITIES	2547									
DIVIDENDS										
PREFERRED	3542	2027	2027	2027	2027	2027	2027	2027	2027	2027
COMMON	15438	11861	11201	10570	9971	5244	3877	3057	3103	3103
TOTAL	18980	13888	13229	12598	11998	7271	5904	5084	5130	5130
CHANGE IN NET CURRENT ASSETS	4175	4761	6310	6037	5764	5491	4126	2762	1397	-95
TOTAL CASH USES	173278	26801	23259	22327	21423	20551	14459	11727	9542	8096

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 2

SCHEDULE 7 OPERATING AND MAINTENANCE

	1984	1985	1986	1987	1988	1989	1993	1998	2003	2013
OTHER OPERATING & MAINTENANCE										
LAND RIGHTS	339	339	339	339	339	339	339	339	339	339
WIND TURBINE GENERATOR	1695	1796	1904	2018	2139	2268	2863	3831	5127	9182
TRANSMISSION SYSTEM	95	100	106	112	120	126	159	213	286	511
TOTAL	2129	2236	2349	2470	2598	2733	3362	4384	5752	10033
INSURANCE	96	96	96	96	96	96	96	96	96	96
OPERATING AND MAINTENANCE	2225	2332	2445	2566	2694	2829	3458	4480	5848	10129

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 2

SCHEDULE 8 RATE OF RETURN

	1984	1985	1986	1987	1988	1989	1993	1998	2003	2013
AVERAGE CAPITALIZATION										
AVERAGE OUTSTANDING DEBT, LESS UNAMORTIZED DEBT EXPENSE	87823	84889	81956	79022	76088	73154	61418	46749	32079	1531
AVERAGE OUTSTANDING PREFERRED	22526	22526	22526	22526	22526	22526	22526	22526	22526	22526
AVERAGE OUTSTANDING COMMON INCLUDING RETAINED EARNINGS	67030	61740	61740	61740	61740	61740	61740	61740	61740	61740
TOTAL AVERAGE CAPITALIZATION	177379	169155	166222	163288	160354	157420	145684	131015	116346	85797
AVERAGE CAPITALIZATION COMPONENT (%)										
LONG TERM DEBT	49.5	50.2	49.3	48.4	47.4	46.5	42.2	35.7	27.6	1.8
PREFERRED SHARES	12.7	13.3	13.6	13.8	14.0	14.3	15.5	17.2	19.4	26.3
COMMON EQUITY	37.8	36.5	37.1	37.8	38.5	39.2	42.4	47.1	53.1	72.0
TOTAL AVERAGE CAPITALIZATION	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
COST OF CAPITAL										
TOTAL INTEREST CHARGES	8324	8048	7773	7497	7222	6946	5844	4467	3089	207
WEIGHTED AVERAGE DEBT COST, %	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.6	9.6	13.5
DIVIDEND RATE PEF. SHARES, %	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
RATE OF RETURN COMMON EQUITY, %	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
RATE OF RETURN PERCENTAGE COMPONENTS (%)										
LONG TERM DEBT	4.7	4.8	4.7	4.6	4.5	4.4	4.0	3.4	2.7	0.2
PREFERRED SHARES	1.1	1.2	1.2	1.2	1.3	1.3	1.4	1.5	1.7	2.4
COMMON EQUITY	5.7	5.5	5.6	5.7	5.9	5.9	6.4	7.1	8.0	10.8
RATE OF RETURN, %	11.5	11.4	11.5	11.5	11.5	11.6	11.8	12.0	12.4	13.4

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 2

SCHEDULE 9
RETURN ON RATE BASE

	1984	1985	1986	1987	1988	1989	1993	1998	2003	2013
UTILITY PLANT IN SERVICE END OF YEAR	174672	174672	174672	174672	174672	174672	174672	174672	174672	174672
AVER UTILITY PLANT IN SERVICE	174672	174672	174672	174672	174672	174672	174672	174672	174672	174672
LESS AVERAGE: ACCUMULATED DEPRECIATION	2906	8717	14528	20339	26150	31961	55205	84261	13316	171427
ACCUMULATED DEFERRED INC. TAX	3587	8889	12185	15208	17959	20436	27615	30449	26460	1422
ADD: WORKING CAPITAL ALLOWANCE	3514	3727	4047	4359	4686	5029	6582	9025	12211	21963
NET INVESTMENT IN UTILITY PLANT	171694	160792	152005	143483	135249	127304	98433	68987	47108	23786
RATE OF RETURN	11.5	11.4	11.5	11.5	11.5	11.6	11.8	12.0	12.4	13.4
RETURN ON RATE BASE	19752	18381	17431	16507	15612	14746	11576	8296	5821	3187

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 2

SCHEDULE 10
DEPRECIATION

	1984	1985	1986	1987	1988	1989	1993	1998	2003	2013
TOTAL CONSTRUCTION COST										
CUMULATIVE CONSTRUCTION COST AT END OF YEAR	174333	174333	174333	174333	174333	174333	174333	174333	174333	174333
LESS: CONSTRUCTION WORK IN PROGRESS AT END OF YEAR										
DEPRECIATED FACILITIES UTILITY PLANT IN SERVICE AT END OF YEAR	174333	174333	174333	174333	174333	174333	174333	174333	174333	174333
UTILITY PLANT IN SERVICE CLASSIFIED BY DEPRECIATION RATES										
30 YEAR	174333	174333	174333	174333	174333	174333	174333	174333	174333	174333
10 YEAR	0									
5 YEAR	0									
TOTAL UTILITY PLANT IN SERVICE	174333	174333	174333	174333	174333	174333	174333	174333	174333	174333
DEPRECIATION PROVISION ON AVERAGE PLANT IN SERVICE										
5.0%	5811	5811	5811	5811	5811	5811	5811	5811	5811	5811
10.0										
20.0										
TOTAL DEPRECIATION	5811	5811	5811	5811	5811	5811	5811	5811	5811	5811
ACCUM DEPRECIATION BEGIN OF YEAR		5811	11622	17433	23244	29055	52300	81355	110410	168521
ACCUM PROVISION FOR DEPRECIATION	5811	11622	17433	23244	29055	34866	58111	87166	116221	174332
AVERAGE ACCUMULATED DEPRECIATION	2906	8717	14528	20339	26150	31961	55205	84261	113316	171427

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 2

SCHEDULE 11
FEDERAL & STATE INCOME TAXES

	1984	1985	1986	1987	1988	1989	1993	1998	2003	2013
RETURN ON RATE BASE	19752	18381	17431	16507	15612	14746	11576	8296	5821	3187
LESS: INTEREST EXPENSE	8324	8048	7773	7497	7222	6946	5844	4467	3089	207
EQUITY PORTION OF RETURN	11428	10332	9658	9010	8390	7800	5731	3829	2732	2980
BOOK DEPRECIATION OF EQUITY RETURN CAPITALIZED DURING CONST	271	271	271	271	271	271	271	271	271	271
TOTAL EQUITY RETURN AFTER TAXES INCLUDED IN REVENUES	11698	10603	9929	9280	8661	8070	6002	4100	3003	3251
FEDERAL INCOME TAX	10798	9787	9165	8567	7995	7450	5540	3784	2772	3001
TAXABLE INCOME AFTER STATE INCOME TAXES	22497	20390	19093	17847	16656	15520	11542	7864	5774	6251
STATE INCOME TAX	1547	1402	1313	1227	1145	1067	794	542	397	430
TOTAL INCOME TAX	12346	11190	10478	9794	9140	8517	6334	4327	3169	3431
ADDITIONAL TAX ADJUSTMENTS										
TAX DEPRECIATION	-13337	-12226	-11694	-11162	-10631	-10099	-7973	-5315	-2658	
BOOK DEPRECIATION	5541	5541	5541	5541	5541	5541	5541	5541	5541	5541
TAX LOSS CARRYFORWARD		0	0	0	0	0	0	0	0	0
TAX LOSS CURRENT YEAR										
TAX LOSSES PRIOR YEARS	-6174									
TAX LOSS CARRYOVER	0	0	0	0	0	0	0	0	0	0
TOTAL TAX ADJUSTMENTS	-13970	-6685	-6153	-5622	-5090	-4559	-2433	225	2883	5541
DEFERRED INCOME TAXES										
FEDERAL	6274	3002	2764	2525	2286	2047	1093	0	0	0
STATE	899	430	396	362	328	293	157	0	0	0
TOTAL	7173	3432	3160	2887	2614	2341	1249			
INCOME TAXES PAYABLE CURRENTLY										
FEDERAL	4524	6785	6401	6042	5709	5402	4448	3885	4066	5489
STATE	648	972	917	866	818	774	637	557	583	786
TOTAL	5172	7757	7318	6907	6526	6176	5085	4442	4649	6275
CHANGE IN DEFERRED INCOME TAXES	7173	3432	3160	2887	2614	2341	1249	-116	-1480	-2845
DEFERRED INCOME TAXES BEG. OF YR		7173	10606	13765	16652	19265	26991	30507	27200	2845
DEFERRED INCOME TAXES END OF YR	7173	10606	13765	16652	19265	21606	28240	30391	25719	0
AVER ACCUM DEFERRED INCOME TAX	3587	8889	12185	15208	17959	20436	27615	30449	26460	1422

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 2

SCHEDULE 12 ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

	1983	TOTAL	\$/KW
CASH FLOW			
CASH SOURCES			
DEBT	91837	91837	875
EQUITY			
PREFERRED STOCK	22526	22526	215
COMMON STOCK	58915	58915	561
TOTAL EQUITY FUNDS	81441	81441	776
TOTAL CASH SOURCES	173278	173278	1650
CASH USES			
TOTAL PLANT COST	160383	160383	1527
INTEREST DURING CONST.	6174	6174	59
FINANCING EXPENSE:			
DEBT FUNDS	918	918	9
EQUITY FUNDS	1629	1629	16
TOTAL FINANCING EXPENSE	2547	2547	24
OTHER TAXES			0
MATERIALS & SUPPLIES	2567	2567	24
WORKING CAPITAL	1604	1604	15
TOTAL CASH USES	173275	173275	1650
TOTAL CONSTRUCTION COST			
TOTAL PLANT COST	160383	160383	1527
EQUITY PORTION OF AFUDC			
PREFERRED STOCK	1514	1514	14
COMMON STOCK	6601	6601	63
EQUITY PORTION OF AFUDC	8115	8115	77
INTEREST DURING CONST.	6174	6174	59
TOTAL AFUDC	14289	14289	136
OTHER TAXES			0
TOTAL CONSTRUCTION COST	174672	174672	1664
TOTAL DEPRECIABLE			
TOTAL CONSTRUCTION COST	174672	174672	1664
LESS: LAND	339	339	3
TOTAL DEPRECIABLE COST	174333	174333	1660

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 3

WIND ENERGY SYSTEM ANNUAL COST VS HECO BASELINE SYSTEM SAVINGS

WIND TURBINE GENERATOR COST
(\$/KW 1977 COST BASE)

630

DISCOUNTED CASH FLOW ANALYSIS

DISCOUNT RATE, %

11.7

RATE OF RETURN, %

11.7

CASH FLOW ANALYSIS

	1984	1985	1986	1987	1988	1989	1990	1994	1999	2004	2009	2014
WIND ENERGY SYSTEM ANNUAL COST	195516	50723	47736	45845	44034	42308	40670	35030	30154	27962	28966	32422
HECO BASELINE SYSTEM SAVING												
FUEL		23613	26073	28649	31529	33486	36197	51050	80533	124242	191662	295674
OPERATING & MAINTENANCE		153	153	188	179	233	278	331	509	783	1205	1854
OTHER TAXES		2714	2995	3293	3521	3851	4165	5868	9255	14278	22025	33978
TOTAL BASELINE SYSTEM SAVING		26480	29221	32130	35329	37570	40640	57249	90297	139303	214892	331506
WIND ENERGY SYSTEM SAVING	-195516	-24243	-18515	-13715	-8705	-4738	-30	22219	60142	111341	185926	299084
CUMULATIVE WIND SYSTEM SAVING	-195516	-219759	-238274	-251989	-260394	-265432	-265461	-206224	16735	474897	1243572	2493152

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 3

FINANCIAL & PERFORMANCE ASSUMPTIONS

FINANCIAL ASSUMPTIONS

DEBT EQUITY RATIOS, %	
LONG TERM DEBT	53.0
PREFERRED STOCK	13.0
COMMON STOCK	34.0
EQUITY RATIO, %	47.0
INTEREST RATES, %	
LONG TERM DEBT	9.00
DIVIDENDS EARNED DURING CONSTRUCTION	
INVESTED EARNINGS	7.00
DIVIDEND RATES, %	
PREFERRED	9.00
COMMON	15.00
FINANCING COST, %	
DEBT FUNDS	1.00
EQUITY FUNDS	2.00
INCOME TAX RATES, %	
FEDERAL	48.0
STATE	6.4
OTHER TAXES, %	
PROPERTY & MISCELLANEOUS	
DURING CONSTRUCTION	
PLANT OPERATIONS	
GROSS REVENUE & MISCELLANEOUS	10.2
INVESTMENT TAX CREDIT, %	10.0
INVESTMENT TAX CREDIT LIABILITY RATE, %	50.0
BOND RETIREMENT, YRS	
INITIAL FACILITIES	30.0
REPLACEMENT FACILITIES, 10 YR	0.0
REPLACEMENT FACILITIES, 5 YR	0.0
AMORTIZATION OF FINANCING COST, YRS	
INITIAL FACILITIES	20.0
REPLACEMENT FACILITIES, 10 YR	0.0
REPLACEMENT FACILITIES, 5 YR	0.0

BOOK DEPRECIATION, YRS	30.0
30 YEAR	0.0
10 YEAR	0.0
5 YEAR	
BOOK DEPRECIATION METHOD	
STRAIGHT LINE	
TAX DEPRECIATION, YRS	24.0
30 YEAR	0.0
10 YEAR	0.0
5 YEAR	
TAX DEPRECIATION METHOD	
DECLINING BALANCE/SUM OF YEARS DIGITS	
MATERIALS & SUPPLIES, %	1.60
OPERATING & MAINTENANCE (PLANT COST)	0.80
FUEL STOCK (YEARLY FUEL COST)	
WORKING CAPITAL ALLOWANCE, %	1.0
DURING CONSTRUCTION	
PLANT OPERATION	12.5
OPERATING & MAINTENANCE	
FUEL	
INFLATION RATE, %	
PLANT CONSTRUCTION	9.0
1978-1982	8.0
1983-1987	7.5
1988-1992	7.0
1993-1997	
OPERATING & MAINTENANCE	7.0
FUEL COST	0.0
MATERIALS & SUPPLIES	6.0
GENERAL INFLATION	5.5
PERFORMANCE ASSUMPTIONS	
PLANT SIZE (MEGAWATTS)	150.0
OPERATING COST ASSUMPTIONS	
FUEL COST (¢/BTU)	0.0
INSURANCE (% PLANT COST)	0.06
HEAT RATE (BTU/KWH)	0
PLANT CAPACITY FACTOR, %	38.7

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 3

SCHEDULE 1 TOTAL CONSTRUCTION COST

	1984	\$/KW
LAND & LAND RIGHTS	475	3
STRUCTURES & IMPROVEMENTS	239	2
WIND TURBINE GENERATOR	169594	1131
PRIOR COSTS		
APPLICATION STUDIES	100	1
INSTRUMENTATION & DATA REDUCT	2000	13
CORRELATION & MODELING	2000	13
TOTAL	4100	27
POWER GENERATION FACILITIES	174408	1163
TRANSMISSION FACILITIES	6561	44
TOTAL WIND ENERGY SYSTEM COST	180969	1206
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	16123	107
OTHER TAXES		0
TOTAL CONSTRUCTION COST	197092	1314
MATERIALS & SUPPLIES	2897	19
WORKING CAPITAL	1810	12
TOTAL CAPITAL COST	201799	1345

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 3

SCHEDULE 1A CONSTRUCTION COSTS 1977 COST BASE

	1984	\$/KW
LAND & LAND RIGHTS	475	3
STRUCTURES & IMPROVEMENTS	133	1
WIND TURBINE GENERATOR	94500	630
PRIOR COSTS		
APPLICATION STUDIES	100	1
INSTRUMENTATION & DATA REDUCT	2000	13
CORRELATION & MODELING	2000	13
TOTAL	4100	27
B-42 POWER GENERATION FACILITIES	99208	661
TRANSMISSION FACILTIES	3656	24
TOTAL WIND ENERGY SYSTEM COST	102864	686

TOTAL PHASE 3

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

SCHEDULE 2
DISCOUNTED CASH FLOW ANALYSIS & FINANCIAL RATIOS

DISCOUNTED CASH FLOW ANALYSIS

LEVELIZED BUSBAR ENERGY COST (MILLS/KWH)

FIRST YEAR OF COMMERCIAL OPERATION 77.8

1977 COST BASE 52.0

ANNUALIZED FIXED CHARGE RATE, % 17.5

CAPITAL RECOVERY FACTOR, % 12.2

WEIGHTED AVERAGE COST OF CAPITAL, % 11.7

RATE OF RETURN, %
(START OF CONSTRUCTION TO END OF PLANT OPERATION)

INTERNAL RATE OF RETURN 12.3

RETURN ON COMMON EQUITY 18.9

PRESENT VALUE ANALYSIS

COST OF SERVICE (THOUSANDS) 324560

ENERGY PRODUCTION (MILLIONS OF KWH) 4172

COMMON DIVIDENDS (THOUSANDS) 84415

PREFERRED DIVIDENDS (THOUSANDS) 22708

OPERATING & MAINTENANCE EXPENSE 42001

FINANCIAL RATIOS

CUMULATIVE DIVIDEND PAYOUT RATE (30YRS), %

PREFERRED STOCK 8.9

COMMON STOCK 8.8

EFFECTIVE TAX RATE, % 47.6

RATIO OF EARNINGS TO FIXED CHARGES 4.2

TANGIBLE NET WORTH, END 30 YEARS (THOUSANDS) 95143

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 3

SCHEDULE 2A
LEVELIZED BUSBAR ENERGY COST
MILLS PER KWH

OPERATION & MAINTENANCE EXPENSE	
FUEL	0.0
OTHER	9.9
INSURANCE	0.2
TOTAL OPER. & MAINT. EXPENSE	10.1
DEPRECIATION EXPENSE	12.9
TAXES, OTHER THAN INCOME	8.0
PROVISION FOR INCOME TAXES	
FEDERAL	14.4
STATE	2.2
TOTAL INCOME TAXES	17.8
RETURN ON RATE BASE	30.2
TOTAL LEVELIZED BUSBAR ENERGY COST	77.8

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TOTAL PHASE 3

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

SCHEDULE 28
LEVELIZED BUSBAR ENERGY COST
MILLS PER KWH
1977 COST BASE

OPERATION & MAINTENANCE EXPENSE	
FUEL	0.0
OTHER	0.0
INSURANCE	0.1
TOTAL OPER. & MAINT. EXPENSE	0.1
DEPRECIATION EXPENSE	8.9
TAXES, OTHER THAN INCOME	5.5
PROVISION FOR INCOME TAXES	
FEDERAL	9.9
STATE	1.5
TOTAL INCOME TAXES	12.2
RETURN ON RATE BASE	20.8
TOTAL LEVELIZED BUSBAR ENERGY COST	47.5

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 3

SCHEDULE 3
COST OF SERVICE
MILLS PER KWH

	1985	1986	1987	1988	1989	1990	1994	1999	2004	2014
COST OF SERVICE										
OPERATION AND MAINT EXPENSE										
FUEL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OTHER	6.2	6.5	6.9	7.2	7.6	8.0	9.9	12.9	16.9	29.6
INSURANCE	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
TOTAL OPER. & MAINT. EXPENSE	6.4	6.8	7.1	7.4	7.8	8.2	10.1	13.1	17.1	29.8
DEPRECIATION EXPENSE	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9
TAXES, OTHER THAN INCOME TAX	10.2	9.6	9.3	8.9	8.5	8.2	7.1	6.1	5.6	6.5
PROVISION FOR INCOME TAXES										
FEDERAL	24.1	21.8	20.5	19.1	17.9	16.7	12.5	8.6	6.4	7.1
STATE	3.5	3.1	2.9	2.7	2.6	2.4	1.8	1.2	0.9	1.0
TOTAL INCOME TAXES	27.5	25.0	23.4	21.8	20.4	19.1	14.2	9.8	7.3	8.2
RETURN ON RATE BASE	44.0	41.0	38.9	36.7	34.8	32.9	25.9	18.6	13.2	7.6
TOTAL COST OF SERVICE	101.2	95.3	91.5	87.6	84.6	81.3	70.2	60.6	56.1	65.1
NET ANNUAL ENERGY PRODUCTION	507.4	507.4	507.4	509.5	507.4	507.4	507.4	507.4	509.5	507.4
PLANT CAPACITY FACTOR, %	38.6	38.6	38.6	38.8	38.6	38.6	38.6	38.6	38.8	38.6
AVERAGE COST OF SERVICE OVER 30 YEAR PLANT LIFE	68.0									

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 3

SCHEDULE 4
INCOME AND RETAINED EARNINGS

	1984	1985	1986	1987	1988	1994	1999	2004	2014	TOTAL
UTILITY OPERATING INCOME										
OPERATING REVENUES		50723	47736	45845	44034	35030	30154	27962	32422	1018101
OPERATING EXPENSES										
OPERATING AND MAINTENANCE		3270	3432	3603	3784	5123	6659	8715	15144	229959
DEPRECIATION		6554	6554	6554	6554	6554	6554	6554	6554	196617
TAXES OTHER THAN INCOME		5199	4893	4699	4513	3591	3091	2866	3323	104355
PROVISION FOR INCOME TAXES										
FEDERAL		12222	11085	10386	9714	6321	4364	3255	3626	165846
STATE		1751	1588	1488	1392	906	625	466	520	23763
INVESTMENT TAX CREDIT ADJ.		-602	-602	-602	-602	-302	-602	-602	-602	-18049
TOTAL OPERATING EXPENSES		28395	26951	26128	25356	21893	20692	21255	28566	702491
NET UTILITY OPERATING INCOME		22328	20785	19717	18678	13137	9463	6707	3856	315610
OTHER INCOME AND DEDUCTIONS										
OTHER INCOME										
INTEREST INCOME			358	836	1290	3534	4760	5384	4861	118390
INVESTMENT TAX CREDIT		2572	3850	3635	3433					
ALLOWANCE FOR FUNDS USED										
DURING CONSTRUCTION	16123									
OTHER INCOME	16123	2572	4208	4470	4723	3534	4760	5384	4861	16123
OTHER DEDUCTIONS										
INCOME TAXES-INTEREST INCOME			184	429	662	1814	2444	2765	2496	60789
INTEREST CHARGES										
INTEREST ON LONG TERM DEBT	6966	9249	8938	8627	8316	6451	4896	3342	233	149191
AMORTIZATION OF DEBT EXPENSE		144	144	144	144	144	144	144		2874
TOTAL INTEREST CHARGES	6966	9392	9081	8771	8460	6594	5040	3486	233	152066
NET INCOME	9157	15508	15728	14988	14279	8262	6739	5841	5988	255317
RETAINED EARNINGS, BEG. OF YEAR		9157	3249	3249	3249	3249	3249	3249	3249	
DIVIDENDS		21416	15728	14988	14279	8262	6739	5841	5988	252068
RETAINED EARNINGS, END OF YEAR	9157	3249	3249	3249	3249	3249	3249	3249	3249	

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 3

SCHEDULE 5
BALANCE SHEET

	1984	1985	1986	1987	1988	1989	1994	1999	2004	2014
ASSETS AND OTHER DEBITS										
UTILITY PLANT IN SERVICE		197092	197092	197092	197092	197092	197092	197092	197092	197092
LESS: ACCUMULATED DEPRECIATION		6554	13108	19662	26216	32770	65539	98308	131078	196617
NET PLANT IN SERVICE		190538	183984	177430	170877	164323	131553	98784	66014	476
CONSTRUCTION WORK IN PROGRESS	197092									
NET UTILITY PLANT	197092	190538	183984	177430	170877	164323	131553	98784	66014	476
CURRENT ASSETS										
TEMPORARY CASH INVESTMENTS		5119	11937	18430	24595	30433	54662	70480	77648	67814
OPERATING MATERIALS & SUPPLIES	2897	4605	4881	5174	5485	5814	7780	10412	13933	24952
FUEL STOCK										
OTHER WORKING CAPITAL, NET	1810	413	433	454	477	501	644	837	1096	1901
TOTAL CURRENT ASSETS	4707	10137	17252	24058	30557	36748	63086	81729	92677	94668
DEFERRED DEBITS										
UNAMORTIZED DEBT EXPENSE	2874	2730	2587	2443	2299	2156	1437	719		
TOTAL ASSETS & OTHER DEBITS	204673	203406	203823	203932	203733	203226	196077	181232	158691	95143
LIABILITIES AND OTHER CREDITS										
PROPRIETARY CAPITAL										
PREFERRED STOCK	25418	25418	25418	25418	25418	25418	25418	25418	25418	25418
COMMON STOCK	66477	66477	66477	66477	66477	66477	66477	66477	66477	66477
RETAINED EARNINGS	9157	3249	3249	3249	3249	3249	3249	3249	3249	3249
TOTAL PROPRIETARY CAPITAL	101051	95143	95143	95143	95143	95143	95143	95143	95143	95143
LONG-TERM DEBT	103626	100171	96717	93263	89809	86355	69084	51813	34542	
ACCUMULATED DEFERRED INCOME TAX		8091	11963	15526	18781	21729	31850	34276	29007	0
TOTAL LIABILITIES AND OTHER CREDITS	204677	203406	203823	203932	203733	203226	196077	181232	158691	95143

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 3

SCHEDULE 6
CASH FLOW

	1984	1985	1986	1987	1988	1989	1994	1999	2004	2014
CASH SOURCES										
NET INCOME	9157	15508	15728	14988	14279	13607	8262	6739	5841	5988
ADD: NON CASH CHARGES (CREDITS)										
DEPRECIATION		6554	6554	6554	6554	6554	6554	6554	6554	6554
CHANGE IN DEF. INCOME TAXES		8091	3871	3563	3255	2948	1409	-130	-1669	-3208
AMORTIZ. OF DEBT EXPENSE		144	144	144	144	144	144	144	144	
EQUITY COMPONENT OF AFUDC	-9157									
CASH FLOW FROM OPERATIONS	0	30297	26297	25248	24232	23252	16368	13306	10869	9334
FUNDS FROM INVESTORS										
LONG TERM DEBT	103626									
PREFERRED STOCK	25418									
COMMON STOCK	66477									
TOTAL FUNDS FROM INVESTORS	195520									
TOTAL CASH SOURCES	195520	30297	26297	25248	24232	23252	16368	13306	10869	9334
CASH USES										
PLANT ADDITIONS	197092									
LESS: EQUITY COMP. OF AFUDC	9157									
CASH REQ FOR PLANT ADDITIONS	187935									
LONG TERM DEBT RETIREMENT		3454	3454	3454	3454	3454	3454	3454	3454	3454
COST OF ISSUING SECURITIES	2874									
DIVIDENDS										
PREFERRED		3996	2288	2288	2288	2288	2288	2288	2288	2288
COMMON		17420	13441	12700	11992	11320	5974	4451	3553	3701
TOTAL		21416	15728	14988	14279	13607	8262	6739	5841	5988
CHANGE IN NET CURRENT ASSETS	4710	5427	7114	6807	6499	6191	4652	3113	1574	-109
TOTAL CASH USES	195520	30297	26297	25248	24232	23252	16368	13306	10869	9334

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 3

SCHEDULE 7 OPERATING AND MAINTENANCE

	1985	1986	1987	1988	1989	1990	1994	1999	2004	2014
OTHER OPERATING & MAINTENANCE	475	475	475	475	475	475	475	475	475	475
LAND RIGHTS	2566	2720	2883	3056	3240	3434	4335	5802	7764	13904
WIND TURBINE GENERATOR	121	129	136	145	153	162	205	274	369	657
TRANSMISSION SYSTEM	3162	3323	3494	3676	3868	4071	5015	6551	8607	15036
TOTAL										
INSURANCE	108	108	108	108	108	108	108	108	108	108
OPERATING AND MAINTENANCE	3270	3432	3603	3784	3976	4179	5123	6659	8715	15144

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 3

SCHEDULE B RATE OF RETURN

	1985	1986	1987	1988	1989	1990	1994	1999	2004	2014
AVERAGE CAPITALIZATION										
AVERAGE OUTSTANDING DEBT, LESS UNAMORTIZED DEBT EXPENSE	99096	95786	92475	89165	85654	82544	69302	52750	36197	1727
AVERAGE OUTSTANDING PREFERRED	25418	25418	25418	25418	25418	25418	25418	25418	25418	25418
AVERAGE OUTSTANDING COMMON INCLUDING RETAINED EARNINGS	75634	69725	69725	69725	69725	69725	69725	69726	69726	69726
TOTAL AVERAGE CAPITALIZATION	200147	190929	187618	184308	180997	177687	164445	147893	131340	96870
AVERAGE CAPITALIZATION COMPONENT (%)										
LONG TERM DEBT	49.5	50.2	49.3	48.4	47.4	46.5	42.1	35.7	27.6	1.8
PREFERRED SHARES	12.7	13.3	13.5	13.8	14.0	14.3	15.5	17.2	19.4	26.2
COMMON EQUITY	37.8	36.5	37.2	37.8	38.5	39.2	42.4	47.1	53.1	72.0
TOTAL AVERAGE CAPITALIZATION	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
COST OF CAPITAL										
TOTAL INTEREST CHARGES	9392	9081	8771	8460	8149	7838	6594	5040	3486	233
WEIGHTED AVERAGE DEBT COST, %	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.6	9.6	13.5
DIVIDEND RATE PEF. SHARES, %	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
RATE OF RETURN COMMON EQUITY, %	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
RATE OF RETURN PERCENTAGE COMPONENTS (%)										
LONG TERM DEBT	4.7	4.8	4.7	4.6	4.5	4.4	4.0	3.4	2.7	0.2
PREFERRED SHARES	1.1	1.2	1.2	1.2	1.3	1.3	1.4	1.5	1.7	2.4
COMMON EQUITY	5.7	5.5	5.6	5.7	5.8	5.9	6.4	7.1	8.0	10.8
RATE OF RETURN, %	11.5	11.4	11.5	11.5	11.5	11.6	11.8	12.0	12.4	13.4

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 3

SCHEDULE 9 RETURN ON RATE BASE

	1985	1986	1987	1988	1989	1990	1994	1999	2004	2014
UTILITY PLANT IN SERVICE END OF YEAR	197092	197092	197092	197092	197092	197092	197092	197092	197092	197092
AVER UTILITY PLANT IN SERVICE	197092	197092	197092	197092	197092	197092	197092	197092	197092	197092
LESS AVERAGE: ACCUMULATED DEPRECIATION	3277	9831	16385	22939	29493	36046	62262	95032	127801	193340
ACCUMULATED DEFERRED INC. TAX	4046	10027	13744	17153	20255	23049	31145	34341	29841	1604
ADD: WORKING CAPITAL ALLOWANCE	4317	4577	4960	5335	5728	6141	8012	10963	14818	26634
NET INVESTMENT IN UTILITY PLANT	194087	181811	171923	162335	153073	144138	111697	78682	54268	28782
RATE OF RETURN	11.5	11.4	11.5	11.5	11.5	11.6	11.8	12.0	12.4	13.4
RETURN ON RATE BASE	22328	20785	19717	18678	17671	16698	13137	9463	6707	3856

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 3

SCHEDULE 10 DEPRECIATION

	1985	1986	1987	1988	1989	1990	1994	1999	2004	2014
TOTAL CONSTRUCTION COST										
CUMULATIVE CONSTRUCTION COST AT END OF YEAR	196617	196617	196617	196617	196617	196617	196617	196617	196617	196617
LESS: CONSTRUCTION WORK IN PROGRESS AT END OF YEAR										
DEPRECIATED FACILITIES										
UTILITY PLANT IN SERVICE AT END OF YEAR	196617	196617	196617	196617	196617	196617	196617	196617	196617	196617
UTILITY PLANT IN SERVICE CLASSIFIED BY DEPRECIATION RATES										
30 YEAR	196617	196617	196617	196617	196617	196617	196617	196617	196617	196617
10 YEAR	0									
5 YEAR	0									
TOTAL UTILITY PLANT IN SERVICE	196617	196617	196617	196617	196617	196617	196617	196617	196617	196617
DEPRECIATION PROVISION ON AVERAGE PLANT IN SERVICE										
5.0%	6554	6554	6554	6554	6554	6554	6554	6554	6554	6554
10.0										
20.0										
TOTAL DEPRECIATION	6554	6554	6554	6554	6554	6554	6554	6554	6554	6554
ACCUM DEPRECIATION BEGIN OF YEAR		6554	13108	19662	26216	32770	58985	91755	124524	190063
ACCUM PROVISION FOR DEPRECIATION	6554	13108	19662	26216	32770	39323	65539	98308	131078	196617
AVERAGE ACCUMULATED DEPRECIATION	3277	9831	16385	22939	29493	36046	62262	95032	127801	193340

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 3

SCHEDULE 11
FEDERAL & STATE INCOME TAXES

	1985	1986	1987	1988	1989	1990	1994	1999	2004	2014
RETURN ON RATE BASE	22328	20785	19717	18678	17671	16698	13137	9463	6707	3856
LESS: INTEREST EXPENSE	9392	9081	8771	8460	8149	7838	6594	5040	3486	233
EQUITY PORTION OF RETURN	12935	11704	10946	10218	9523	8860	6543	4423	3221	3623
BOOK DEPRECIATION OF EQUITY	305	305	305	305	305	305	305	305	305	305
RETURN CAPITALIZED DURING CONST										
TOTAL EQUITY RETURN AFTER TAXES INCLUDED IN REVENUES	13241	12009	11252	10523	9828	9165	6848	4728	3526	3929
FEDERAL INCOME TAX	12222	11085	10386	9714	9072	8460	6321	4364	3255	3626
TAXABLE INCOME AFTER STATE INCOME TAXES	25463	23095	21638	20237	18900	17625	13169	9092	6782	7555
STATE INCOME TAX	1751	1588	1488	1392	1300	1212	906	625	466	520
TOTAL INCOME TAX	13973	12674	11874	11106	10372	9672	7227	4990	3722	4146
ADDITIONAL TAX ADJUSTMENTS										
TAX DEPRECIATION	-15041	-13788	-13188	-12589	-11989	-11390	-8992	-5995	-2997	6249
BOOK DEPRECIATION	6249	6249	6249	6249	6249	6249	6249	6249	6249	0
TAX LOSS CARRYFORWARD		0	0	0	0	0	0	0	0	0
TAX LOSS CURRENT YEAR	-6966									
TAX LOSSES PRIOR YEARS	0	0	0	0	0	0	0	0	0	0
TAX LOSS CARRYOVER	-15759	-7539	-6940	-6340	-5741	-5141	-2743	254	3251	6249
TOTAL TAX ADJUSTMENTS										
DEFERRED INCOME TAXES										
FEDERAL	7077	3386	3117	2847	2578	2309	1232	0	0	0
STATE	1014	485	447	408	369	331	177	0	0	0
TOTAL	8091	3871	3563	3255	2948	2640	1409			
INCOME TAXES PAYABLE CURRENTLY										
FEDERAL	5145	7700	7269	6866	6494	6151	5089	4478	4715	6433
STATE	737	1103	1042	984	930	881	729	642	676	922
TOTAL	5882	8803	8311	7850	7424	7032	5818	5120	5391	7354
CHANGE IN DEFERRED INCOME TAXES	8091	3871	3563	3255	2948	2640	1409	-130	-1669	-3208
DEFERRED INCOME TAXES BEG. OF YR		8091	11963	15526	18781	21729	30441	34406	30676	3208
DEFERRED INCOME TAXES END OF YR	8091	11963	15526	18781	21729	24369	31850	34276	29007	0
NET ACCUM DEFERRED INCOME TAX	4046	10027	13744	17153	20255	23049	31145	34341	29841	1604

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 3

SCHEDULE 12
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

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	1984	\$/KW
CASH FLOW		
CASH SOURCES		
DEBT	103626	691
EQUITY		
PREFERRED STOCK	25418	169
COMMON STOCK	66477	443
TOTAL EQUITY FUNDS	91894	613
TOTAL CASH SOURCES	195520	1303
CASH USES		
TOTAL PLANT COST	180969	1206
INTEREST DURING CONST.	6966	46
FINANCING EXPENSE:		
DEBT FUNDS	1036	7
EQUITY FUNDS	1838	12
TOTAL FINANCING EXPENSE	2874	19
OTHER TAXES		0
MATERIALS & SUPPLIES	2897	19
WORKING CAPITAL	1810	12
TOTAL CASH USES	195516	1303
TOTAL CONSTRUCTION COST		
TOTAL PLANT COST	180969	1206
EQUITY PORTION OF AFUDC		
PREFERRED STOCK	1709	11
COMMON STOCK	7448	50
EQUITY PORTION OF AFUDC	9157	61
INTEREST DURING CONST.	6966	46
TOTAL AFUDC	16123	107
OTHER TAXES		0
TOTAL CONSTRUCTION COST	197092	1314
TOTAL DEPRECIABLE		
TOTAL CONSTRUCTION COST	197092	1314
LESS: LAND	475	3
TOTAL DEPRECIABLE COST	196617	1311

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

WIND ENERGY SYSTEM ANNUAL COST VS HECO BASELINE SYSTEM SAVINGS

WIND TURBINE GENERATOR COST
(\$/KW 1977 COST BASE) 357

DISCOUNTED CASH FLOW ANALYSIS

DISCOUNT RATE, % 11.7
RATE OF RETURN, % 11.7

CASH FLOW ANALYSIS

	1985	1986	1987	1988	1989	1990	1995	2000	2005	2015
WIND ENERGY SYSTEM ANNUAL COST	126351	34252	32406	31268	30186	29165	25023	22621	22201	28225
HECO BASELINE SYSTEM SAVING										
FUEL		18668	20391	22169	23182	25507	37749	54541	78487	160142
OPERATING & MAINTENANCE		126	117	73	81	126	126	161	205	334
OTHER TAXES		2146	2342	2540	2657	2927	4325	6247	8987	18326
TOTAL BASELINE SYSTEM SAVING		20940	22850	24782	25920	28560	42200	60949	87679	178803
WIND ENERGY SYSTEM SAVING	-126351	-13312	-9556	-6486	-4266	-605	17178	38328	65477	150578
CUMULATIVE WIND SYSTEM SAVING	-126351	-139663	-149218	-155704	-159970	-160575	-108653	38472	308680	1383314

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

FINANCIAL & PERFORMANCE ASSUMPTIONS

FINANCIAL ASSUMPTIONS

DEBT EQUITY RATIOS, %

LONG TERM DEBT	53.0
PREFERRED STOCK	13.0
COMMON STOCK	34.0

EQUITY RATIO, % 47.0

INTEREST RATES, %

LONG TERM DEBT	9.00
DIVIDENDS EARNED DURING CONSTRUCTION	
INVESTED EARNINGS	7.00

DIVIDEND RATES, %

PREFERRED	9.00
COMMON	15.00

FINANCING COST, %

DEBT FUNDS	1.00
EQUITY FUNDS	2.00

INCOME TAX RATES, %

FEDERAL	48.0
STATE	6.4

OTHER TAXES, %

PROPERTY & MISCELLANEOUS
DURING CONSTRUCTION
PLANT OPERATIONS

GROSS REVENUE & MISCELLANEOUS 10.2

INVESTMENT TAX CREDIT, % 10.0

INVESTMENT TAX CREDIT LIABILITY RATE, % 50.0

BOND RETIREMENT, YRS

INITIAL FACILITIES	30.0
REPLACEMENT FACILITIES, 10 YR	0.0
REPLACEMENT FACILITIES, 5 YR	0.0

AMORTIZATION OF FINANCING COST, YRS

INITIAL FACILITIES	20.0
REPLACEMENT FACILITIES, 10 YR	0.0
REPLACEMENT FACILITIES, 5 YR	0.0

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BOOK DEPRECIATION, YRS	30.0
30 YEAR	0.0
10 YEAR	0.0
5 YEAR	
BOOK DEPRECIATION METHOD	
STRAIGHT LINE	
TAX DEPRECIATION, YRS	24.0
30 YEAR	0.0
10 YEAR	0.0
5 YEAR	
TAX DEPRECIATION METHOD	
DECLINING BALANCE/SUM OF YEARS, DIGITS	
MATERIALS & SUPPLIES, %	1.60
OPERATING & MAINTENANCE (PLANT COST)	0.80
FUEL STOCK (YEARLY FUEL COST)	
WORKING CAPITAL ALLOWANCE, %	
DURING CONSTRUCTION	1.0
PLANT OPERATION	
OPERATING & MAINTENANCE	12.5
FUEL	
INFLATION RATE, %	
PLANT CONSTRUCTION	9.0
1978-1982	8.0
1983-1987	7.5
1988-1992	7.0
1993-1997	
OPERATING & MAINTENANCE	7.0
FUEL COST	0.0
MATERIALS & SUPPLIES	6.0
GENERAL INFLATION	5.5
PERFORMANCE ASSUMPTIONS	
PLANT SIZE (MEGAWATTS)	150.0
OPERATING COST ASSUMPTIONS	
FUEL COST (¢/BTU)	6.0
INSURANCE (% PLANT COST)	0.06
HEAT RATE (BTU/KWH)	0
PLANT CAPACITY FACTOR, %	29.2

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

SCHEDULE 1 TOTAL CONSTRUCTION COST

	1985	TOTAL	\$/KW
LAND & LAND RIGHTS	475	475	3
STRUCTURES & IMPROVEMENTS	258	258	2
WIND TURBINE GENERATOR	103792	103792	692
PRIOR COSTS			
APPLICATION STUDIES	0		0
INSTRUMENTATION & DATA REDUCT	2000	2000	13
CORRELATION & MODELING	2000	2000	13
TOTAL	4000	4000	27
POWER GENERATION FACILITIES	108525	108525	723
TRANSMISSION FACILITIES	8425	8425	56
TOTAL WIND ENERGY SYSTEM COST	116950	116950	780
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	10419	10419	69
OTHER TAXES			0
TOTAL CONSTRUCTION COST	127369	127369	849
MATERIALS & SUPPLIES	1872	1872	12
WORKING CAPITAL	1169	1169	8
TOTAL CAPITAL COST	130411	130411	869

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

SCHEDULE 1A CONSTRUCTION COSTS 1977 COST BASE

	1985	TOTAL	\$/KW
LAND & LAND RIGHTS	475	475	3
STRUCTURES & IMPROVEMENTS	133	133	1
WIND TURBINE GENERATOR	53550	53550	357
PRIOR COSTS			
APPLICATION STUDIES	0		0
INSTRUMENTATION & DATA REDUCT	2000	2000	13
CORRELATION & MODELING	2000	2000	13
TOTAL	4000	4000	27
POWER GENERATION FACILITIES	58158	58158	388
TRANSMISSION FACILITIES	4347	4347	29
TOTAL WIND ENERGY SYSTEM COST	62505	62505	417

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

SCHEDULE 2 DISCOUNTED CASH FLOW ANALYSIS & FINANCIAL RATIOS

DISCOUNTED CASH FLOW ANALYSIS

LEVELIZED BUSBAR ENERGY COST (MILLS/KWH)

FIRST YEAR OF COMMERCIAL OPERATION	72.8
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1977 COST BASE	45.1
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ANNUALIZED FIXED CHARGE RATE, %	17.8
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CAPITAL RECOVERY FACTOR, %	12.2
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WEIGHTED AVERAGE COST OF CAPITAL, %	11.7
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RATE OF RETURN, % (START OF CONSTRUCTION TO END OF PLANT OPERATION)	
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INTERNAL RATE OF RETURN	12.3
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RETURN ON COMMON EQUITY	18.9
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PRESENT VALUE ANALYSIS

COST OF SERVICE (THOUSANDS)	229250
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ENERGY PRODUCTION (MILLIONS OF KWH)	3149
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COMMON DIVIDENDS (THOUSANDS)	55024
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PREFERRED DIVIDENDS (THOUSANDS)	14673
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OPERATING & MAINTENANCE EXPENSE	43475
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FINANCIAL RATIOS

CUMULATIVE DIVIDEND PAYOUT RATE (30YRS), %	
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PREFERRED STOCK	8.9
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COMMON STOCK	9.0
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EFFECTIVE TAX RATE, %	47.7
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RATIO OF EARNINGS TO FIXED CHARGES	4.3
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TANGIBLE NET WORTH, END 30 YEARS (THOUSANDS)	61543
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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

SCHEDULE 2A LEVELIZED BUSBAR ENERGY COST MILLS PER KWH

OPERATION & MAINTENANCE EXPENSE	0.0
FUEL	13.6
OTHER	0.2
INSURANCE	13.8
TOTAL OPER. & MAINT. EXPENSE	
DEPRECIATION EXPENSE	11.0
TAXES, OTHER THAN INCOME	7.5
PROVISION FOR INCOME TAXES	
FEDERAL	12.5
STATE	1.9
TOTAL INCOME TAXES	15.4
RETURN ON RATE BASE	26.1
TOTAL LEVELIZED BUSBAR ENERGY COST	72.8

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

SCHEDULE 2B
LEVELIZED BUSBAR ENERGY COST
MILLS PER KWH
1977 COST BASE

OPERATION & MAINTENANCE EXPENSE	
FUEL	0.0
OTHER	5.9
INSURANCE	0.1
TOTAL OPER. & MAINT. EXPENSE	6.0
DEPRECIATION EXPENSE	7.2
TAXES, OTHER THAN INCOME	4.9
PROVISION FOR INCOME TAXES	
FEDERAL	8.1
STATE	1.3
TOTAL INCOME TAXES	10.1
RETURN ON RATE BASE	17.0
TOTAL LEVELIZED BUSBAR ENERGY COST	45.1

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

SCHEDULE 3 COST OF SERVICE MILLS PER KWH

	1986	1987	1988	1989	1990	1991	1995	2000	2005	2015
COST OF SERVICE										
OPERATION AND MAINT EXPENSE										
FUEL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OTHER	8.6	9.0	9.5	10.0	10.5	11.1	13.7	17.8	23.5	41.1
INSURANCE	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
TOTAL OPER. & MAINT. EXPENSE	8.8	9.2	9.6	10.2	10.7	11.3	13.9	18.0	23.7	41.3
DEPRECIATION EXPENSE	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
TAXES, OTHER THAN INCOME TAX	9.2	8.7	8.3	8.1	7.8	7.6	6.7	6.0	5.9	7.6
PROVISION FOR INCOME TAXES										
FEDERAL	20.7	18.8	17.5	16.5	15.4	14.4	10.8	7.6	5.8	6.7
STATE	3.0	2.7	2.5	2.4	2.2	2.1	1.6	1.1	0.8	1.0
TOTAL INCOME TAXES	23.7	21.5	20.1	18.9	17.7	16.5	12.4	8.7	6.7	7.7
RETURN ON RATE BASE	37.8	35.2	33.2	31.7	30.0	28.3	22.4	16.1	11.7	7.2
TOTAL COST OF SERVICE	90.5	85.6	82.2	79.8	77.2	74.7	66.4	59.8	59.0	74.7
NET ANNUAL ENERGY PRODUCTION	382.9	382.9	385.0	382.9	382.9	382.9	382.9	385.0	382.9	382.9
PLANT CAPACITY FACTOR, %	29.1	29.1	29.3	29.1	29.1	29.1	29.1	29.3	29.1	29.1
AVERAGE COST OF SERVICE OVER 30 YEAR PLANT LIFE	67.7									

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

SCHEDULE 4
INCOME AND RETAINED EARNINGS

	1985	1986	1987	1988	1989	1995	2000	2005	2015	TOTAL
UTILITY OPERATING INCOME										
OPERATING REVENUES		34252	32406	31268	30186	25023	22621	22201	28225	766579
OPERATING EXPENSES										
OPERATING AND MAINTENANCE		3362	3531	3711	3900	5304	6915	9068	15808	239059
DEPRECIATION		4230	4230	4230	4230	4230	4230	4230	4230	126893
TAXES OTHER THAN INCOME		3511	3322	3205	3094	2565	2319	2276	2893	78574
PROVISION FOR INCOME TAXES										
FEDERAL		7934	7204	6755	6324	4153	2913	2228	2573	110412
STATE		1137	1032	968	906	595	417	319	369	15820
INVESTMENT TAX CREDIT ADJ.		-388	-388	-388	-388	-388	-388	-388	-388	-11647
TOTAL OPERATING EXPENSES		19785	18930	18480	18065	16459	16406	17732	25484	559113
NET UTILITY OPERATING INCOME		14467	13476	12788	12120	8564	6216	4469	2740	207466
OTHER INCOME AND DEDUCTIONS										
OTHER INCOME										
INTEREST INCOME			212	518	810	2246	3025	3411	3022	74780
INVESTMENT TAX CREDIT		1682	2509	2372	2243					
ALLOWANCE FOR FUNDS USED										
DURING CONSTRUCTION	10419									10419
OTHER INCOME	10419	1682	2721	2890	3053	2246	3025	3411	3022	96847
OTHER DEDUCTIONS										
INCOME TAXES-INTEREST INCOME			109	266	416	1153	1553	1752	1552	38397
INTEREST CHARGES										
INTEREST ON LONG TERM DEBT	4502	5977	5776	5575	5374	4169	3164	2160	151	96414
AMORTIZATION OF DEBT EXPENSE		93	93	93	93	93	93	93		1857
TOTAL INTEREST CHARGES	4502	6070	5869	5668	5467	4262	3257	2253	151	98271
NET INCOME	5918	10080	10219	9745	9291	5395	4430	3876	4060	167644
RETAINED EARNINGS, BEG. OF YEAR		5918	2157	2157	2157	2157	2157	2157	2157	
DIVIDENDS		13840	10219	9745	9291	5395	4430	3876	4060	165487
RETAINED EARNINGS, END OF YEAR	5918	2157	2157	2157	2157	2157	2157	2157	2157	

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

SCHEDULE 5
BALANCE SHEET

	1985	1986	1987	1988	1989	1990	1995	2000	2005	2010	2015
ASSETS AND OTHER DEBITS											
UTILITY PLANT IN SERVICE		127369	127369	127369	127369	127369	127369	127369	127369	127369	127369
LESS: ACCUMULATED DEPRECIATION		4230	8460	12589	16919	21149	42298	63447	84596	105745	126893
NET PLANT IN SERVICE		123139	118910	114680	110450	106220	85071	63922	42773	21625	476
CONSTRUCTION WORK IN PROGRESS	127369										
NET UTILITY PLANT	127369	123139	118910	114680	110450	106220	85071	63922	42773	21625	476
CURRENT ASSETS											
TEMPORARY CASH INVESTMENTS		3026	7404	11571	15526	19269	34756	44772	49145	47182	42021
OPERATING MATERIALS & SUPPLIES	1872	3150	3339	3539	3752	3977	5322	7122	9531	12754	17068
FUEL STOCK											
OTHER WORKING CAPITAL, NET	1169	423	444	466	490	515	666	867	1136	1496	1978
TOTAL CURRENT ASSETS	3042	6599	11187	15577	19768	23761	40744	52761	59812	61433	61068
DEFERRED DEBITS											
UNAMORTIZED DEBT EXPENSE	1857	1765	1672	1579	1486	1393	929	464			
TOTAL ASSETS & OTHER DEBITS	132268	131503	131769	131836	131704	131374	126744	117147	102585	83058	61544
LIABILITIES AND OTHER CREDITS											
PROPRIETARY CAPITAL											
PREFERRED STOCK	16425	16426	16426	16426	16426	16426	16426	16426	16426	16426	16426
COMMON STOCK	42960	42960	42960	42960	42960	42960	42960	42960	42960	42960	42960
RETAINED EARNINGS	5918	2157	2157	2157	2157	2157	2157	2157	2157	2157	2157
TOTAL PROPRIETARY CAPITAL	65304	61543	61543	61543	61543	61543	61543	61543	61543	61543	61543
LONG-TERM DEBT	66967	64735	62503	60271	58038	55806	44645	33484	22322	11161	0
ACCUMULATED DEFERRED INCOME TAX		5225	7723	10022	12123	14025	20555	22120	18719	10353	0
TOTAL LIABILITIES AND OTHER CREDITS	132271	131503	131769	131836	131704	131374	126744	117147	102585	83058	61544

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

SCHEDULE 6
CASH FLOW

	1985	1986	1987	1988	1989	1990	1995	2000	2005	2010	2015
CASH SOURCES											
NET INCOME	5918	10080	10219	9745	9291	8861	5395	4430	3876	3852	4060
ADD: NON CASH CHARGES (CREDITS)											
DEPRECIATION		4230	4230	4230	4230	4230	4230	4230	4230	4230	4230
CHANGE IN DEF. INCOME TAXES		5225	2498	2299	2101	1902	909	-84	-1077	-2071	-2071
AMORTIZ. OF DEBT EXPENSE		93	93	93	93	93	93	93	93		
EQUITY COMPONENT OF AFUDC	-5918										
CASH FLOW FROM OPERATIONS	0	19627	17040	16367	15714	15085	10627	8669	7121	6012	6219
FUNDS FROM INVESTORS											
LONG TERM DEBT	66967										
PREFERRED STOCK	16426										
COMMON STOCK	42960										
TOTAL FUNDS FROM INVESTORS	126353										
TOTAL CASH SOURCES	126353	19627	17040	16367	15714	15085	10627	8669	7121	6012	6219
CASH USES											
PLANT ADDITIONS	127369										
LESS: EQUITY COMP. OF AFUDC	5918										
CASH REQ FOR PLANT ADDITIONS	121452										
LONG TERM DEBT RETIREMENT		2232	2232	2232	2232	2232	2232	2232	2232	2232	2232
COST OF ISSUING SECURITIES	1857										
DIVIDENDS											
PREFERRED		2583	1478	1478	1478	1478	1478	1478	1478	1478	1478
COMMON		11257	8741	8266	7812	7382	3917	2952	2398	2374	2582
TOTAL		13840	10219	9745	9291	8861	5395	4430	3876	3852	4060
CHANGE IN NET CURRENT ASSETS	3044	3555	4588	4390	4191	3992	2999	2006	1013	-73	-73
TOTAL CASH USES	126353	19627	17040	16367	15714	15085	10627	8669	7121	6012	6219

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

SCHEDULE 7 OPERATING AND MAINTENANCE

	1986	1987	1988	1989	1990	1991	1995	2000	2005	2015
OTHER OPERATING & MAINTENANCE										
LAND RIGHTS	475	475	475	475	475	475	475	475	475	475
WIND TURBINE GENERATOR	2720	2883	3056	3240	3434	3640	4595	6150	8230	14738
TRANSMISSION SYSTEM	97	103	110	116	123	130	164	221	294	526
TOTAL	3292	3461	3641	3830	4031	4245	5234	6845	8998	15739
INSURANCE	70	70	70	70	70	70	70	70	70	70
OPERATING AND MAINTENANCE	3362	3531	3711	3900	4101	4315	5304	6915	9068	15808

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

SCHEDULE 8
RATE OF RETURN

	1986	1987	1988	1989	1990	1991	1995	2000	2005	2015
AVERAGE CAPITALIZATION										
AVERAGE OUTSTANDING DEBT, LESS UNAMORTIZED DEBT EXPENSE	64040	61901	59761	57622	55483	53343	44786	34089	23392	1116
AVERAGE OUTSTANDING PREFERRED	16426	16426	16426	16426	16426	16426	16426	16426	16426	16426
AVERAGE OUTSTANDING COMMON INCLUDING RETAINED EARNINGS	48878	45117	45117	45117	45117	45117	45118	45118	45118	45118
TOTAL AVERAGE CAPITALIZATION	129344	123444	121305	119165	117026	114887	106329	95632	84936	62660
AVERAGE CAPITALIZATION COMPONENT (%)										
LONG TERM DEBT	49.5	50.1	49.3	48.4	47.4	46.4	42.1	35.6	27.5	1.8
PREFERRED SHARES	12.7	13.3	13.5	13.8	14.0	14.3	15.4	17.2	19.3	26.2
COMMON EQUITY	37.8	36.5	37.2	37.9	38.6	39.3	42.4	47.2	53.1	72.0
TOTAL AVERAGE CAPITALIZATION	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
COST OF CAPITAL										
TOTAL INTEREST CHARGES	6070	5869	5568	5467	5266	5065	4262	3257	2253	151
WEIGHTED AVERAGE DEBT COST, %	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.6	9.6	13.5
DIVIDEND RATE PREF. SHARES, %	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
RATE OF RETURN COMMON EQUITY, %	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
RATE OF RETURN PERCENTAGE COMPONENTS (%)										
LONG TERM DEBT	4.7	4.8	4.7	4.6	4.5	4.4	4.0	3.4	2.7	0.2
PREFERRED SHARES	1.1	1.2	1.2	1.2	1.3	1.3	1.4	1.5	1.7	2.4
COMMON EQUITY	5.7	5.5	5.6	5.7	5.8	5.9	6.4	7.1	8.0	10.8
RATE OF RETURN, %	11.5	11.4	11.5	11.5	11.5	11.6	11.8	12.0	12.4	13.4

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

SCHEDULE 9
RETURN ON RATE BASE

	1986	1987	1988	1989	1990	1991	1995	2000	2005	2015
UTILITY PLANT IN SERVICE END OF YEAR	127369	127369	127369	127369	127369	127369	127369	127369	127369	127369
AVER UTILITY PLANT IN SERVICE	127369	127369	127369	127369	127369	127369	127369	127369	127369	127369
LESS AVERAGE: ACCUMULATED DEPRECIATION	2115	6345	10575	14804	19034	23264	40183	61332	82481	124779
ACCUMULATED DEFERRED INC. TAX	2612	6474	8872	11072	13074	14876	20101	22162	19258	1035
ADD: WORKING CAPITAL ALLOWANCE	3118	3304	3571	3834	4110	4400	5717	7799	10525	18894
NET INVESTMENT IN UTILITY PLANT	125760	117855	111493	105327	99372	93629	72802	51674	36155	20450
RATE OF RETURN	11.5	11.4	11.5	11.5	11.5	11.6	11.8	12.0	12.4	13.4
RETURN ON RATE BASE	14467	13476	12788	12120	11474	10848	8564	6216	4469	2740

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

SCHEDULE 10
DEPRECIATION

	1986	1987	1988	1989	1990	1991	1995	2000	2005	2015
TOTAL CONSTRUCTION COST										
CUMULATIVE CONSTRUCTION COST AT END OF YEAR	126894	126894	126894	126894	126894	126894	126894	126894	126894	126894
LESS: CONSTRUCTION WORK IN PROGRESS AT END OF YEAR										
DEPRECIATED FACILITIES										
UTILITY PLANT IN SERVICE AT END OF YEAR	126894	126894	126894	126894	126894	126894	126894	126894	126894	126894
UTILITY PLANT IN SERVICE CLASSIFIED BY DEPRECIATION RATES										
30 YEAR	126894	126894	126894	126894	126894	126894	126894	126894	126894	126894
10 YEAR	0									
5 YEAR	0									
TOTAL UTILITY PLANT IN SERVICE	126894	126894	126894	126894	126894	126894	126894	126894	126894	126894
DEPRECIATION PROVISION ON AVERAGE PLANT IN SERVICE										
5.0%	4230	4230	4230	4230	4230	4230	4230	4230	4230	4230
10.0										
20.0										
TOTAL DEPRECIATION	4230	4230	4230	4230	4230	4230	4230	4230	4230	4230
ACCUM DEPRECIATION BEGIN OF YEAR		4230	8460	12689	16919	21149	38068	59217	80366	122664
ACCUM PROVISION FOR DEPRECIATION	4230	8460	12689	16919	21149	25379	42298	63447	84596	126893
AVERAGE ACCUMULATED DEPRECIATION	2115	6345	10575	14304	19034	23264	40183	61332	82481	124779

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

SCHEDULE 11
FEDERAL & STATE INCOME TAXES

	1986	1987	1988	1989	1990	1991	1995	2000	2005	2015
RETURN ON RATE BASE	14467	13476	12786	12120	11474	10848	8564	6216	4469	2740
LESS: INTEREST EXPENSE	6070	5869	5666	5467	5266	5065	4262	3257	2253	151
EQUITY PORTION OF RETURN	8398	7607	7121	6653	6208	5783	4302	2958	2216	2590
BOOK DEPRECIATION OF EQUITY RETURN CAPITALIZED DURING CONST	197	197	197	197	197	197	197	197	197	197
TOTAL EQUITY RETURN AFTER TAXES INCLUDED IN REVENUES	8595	7804	7318	6851	6405	5980	4499	3156	2414	2787
FEDERAL INCOME TAX	7934	7204	6755	6324	5912	5520	4153	2913	2228	2573
TAXABLE INCOME AFTER STATE INCOME TAXES	16529	15008	14073	13174	12317	11500	8653	6069	4642	5360
STATE INCOME TAX	1137	1032	968	906	847	791	595	417	319	369
TOTAL INCOME TAX	9071	8236	7723	7230	6759	6311	4748	3330	2547	2941
ADDITIONAL TAX ADJUSTMENTS										
TAX DEPRECIATION	-9706	-8897	-8511	-8124	-7737	-7350	-5803	-3868	-1934	
BOOK DEPRECIATION	4033	4033	4033	4033	4033	4033	4033	4033	4033	4033
TAX LOSS CARRYFORWARD		0	0	0	0	0	0	0	0	0
TAX LOSS CURRENT YEAR										
TAX LOSSES PRIOR YEARS	-4502									
TAX LOSS CARRYOVER	0	0	0	0	0	0	0	0	0	0
TOTAL TAX ADJUSTMENTS	-10176	-4865	-4478	-4091	-3704	-3317	-1770	164	2098	4033
DEFERRED INCOME TAXES										
FEDERAL	4570	2185	2011	1837	1664	1490	795	0	0	0
STATE	655	313	288	263	238	213	114	0	0	0
TOTAL	5225	2498	2299	2101	1902	1703	909			
INCOME TAXES PAYABLE CURRENTLY										
FEDERAL	3364	5019	4744	4486	4248	4030	3358	2987	3170	4384
STATE	482	719	680	643	609	577	481	428	454	628
TOTAL	3846	5738	5423	5129	4857	4608	3840	3415	3625	5012
CHANGE IN DEFERRED INCOME TAXES	5225	2498	2299	2101	1902	1703	909	-84	-1077	-2071
DEFERRED INCOME TAXES BEG. OF YR		5225	7723	10022	12123	14025	19646	22204	19797	2071
DEFERRED INCOME TAXES END OF YR	5225	7723	10022	12123	14025	15728	20555	22120	18719	0
AVER ACCUM DEFERRED INCOME TAX	2612	6474	8872	11072	13074	14876	20101	22162	192	1035

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WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

SCHEDULE 12
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

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	1985	TOTAL	\$/KW
CASH FLOW			
CASH SOURCES			
DEBT	66967	66967	446
EQUITY			
PREFERRED STOCK	16426	16426	110
COMMON STOCK	42960	42960	286
TOTAL EQUITY FUNDS	59386	59386	396
TOTAL CASH SOURCES	126353	126353	842
CASH USES			
TOTAL PLANT COST	116950	116950	780
INTEREST DURING CONST.	4502	4502	30
FINANCING EXPENSE:			
DEBT FUNDS	670	670	4
EQUITY FUNDS	1188	1188	8
TOTAL FINANCING EXPENSE	1857	1857	12
OTHER TAXES			0
MATERIALS & SUPPLIES	1872	1872	12
WORKING CAPITAL	1169	1169	8
TOTAL CASH USES	126351	126351	842
TOTAL CONSTRUCTION COST			
TOTAL PLANT COST	116950	116950	780
EQUITY PORTION OF AFUDC			
PREFERRED STOCK	1104	1104	7
COMMON STOCK	4813	4813	32
EQUITY PORTION OF AFUDC	5918	5918	39
INTEREST DURING CONST.	4502	4502	30
TOTAL AFUDC	10419	10419	69
OTHER TAXES			0
TOTAL CONSTRUCTION COST	127369	127369	849
TOTAL DEPRECIABLE			
TOTAL CONSTRUCTION COST	127369	127369	849
LESS: LAND	475	475	3
TOTAL DEPRECIABLE COST	126894	126894	846

WIND ENERGY SYSTEMS APPLICATIONS IN HAWAII

TOTAL PHASE 4

DEFINITIONS

LEVELIZED BUSBAR ENERGY COST

PRICE PER UNIT OF ENERGY (MILLS PER KWH) WHICH IF HELD CONSTANT THROUGHOUT THE LIFE OF THE PLANT WOULD PROVIDE THE REQUIRED REVENUE, ASSUMING THAT ALL CASH FLOW INTERIM REQUIREMENTS OR EXCESSES ARE BORROWED OR INVESTED AT THE RATE FOR INVESTED EARNINGS

ANNUALIZED FIXED CHARGE RATE

FACTOR BY WHICH THE PRESENT VALUE OF CAPITAL INVESTMENT MUST BE MULTIPLIED TO OBTAIN THE CONTRIBUTION OF CAPITAL INVESTMENT TO THE ANNUALIZED COST

CAPITAL RECOVERY FACTOR

THE UNIFORM PERIODIC PAYMENT, AS A FRACTION OF ORIGINAL PRINCIPAL, THAT WILL FULLY REPAY A LOAN INCLUDING ALL INTEREST

WEIGHTED AVERAGE COST OF CAPITAL

WEIGHTED AVERAGE COST OF CAPITAL OVER 30 YEAR PLANT LIFE WITH WEIGHTING PROPORTIONAL TO DISCOUNT FACTOR IN THAT YEAR

INTERNAL RATE OF RETURN

THE RATE AT WHICH THE PRESENT WORTH OF A FUTURE CASH STREAM EQUALS ZERO CALCULATED FROM THE START OF CONSTRUCTION TO THE END OF PLANT OPERATION. CASH STREAM INCLUDES CASH AVAILABLE FOR RETURN OF PROPRIETARY CAPITAL

RETURN ON COMMON EQUITY

THE RATE AT WHICH THE PRESENT WORTH OF THE CASH STREAM OF THE INVESTMENT IN COMMON STOCK, COMMON DIVIDENDS, AND THE CASH AVAILABLE FOR THE RETURN OF PROPRIETARY CAPITAL EQUALS ZERO

PRESENT VALUE

THE PRESENT VALUE OF A CASH FLOW IS ITS REAL VALUE ADJUSTED FOR THE INTEREST THAT COULD BE EARNED, OR MUST BE PAID BETWEEN THE TIME OF THE ACTUAL CASH FLOW AND THE SPECIFIED "PRESENT" TIME. THE "PRESENT" IN PRESENT VALUE CALCULATIONS IS JANUARY 1, THE FIRST YEAR OF COMMERCIAL OPERATIONS

CUMULATIVE DIVIDEND RATE

TOTAL DIVIDENDS EARNED FROM START OF CONSTRUCTION DIVIDED BY DIVIDENDS PAID

RATIO OF EARNINGS TO FIXED CHARGES

RATIO OF EARNINGS, BEFORE FIXED CHARGES AND TAXES, ON INCOME TO FIXED CHARGES

TANGIBLE NET WORTH

THE SUM OF PREFERRED & COMMON STOCKHOLDER'S EQUITY INCLUDING RETAINED EARNINGS

APPENDIX C

WIND SPEED SPECTRAL ANALYSIS KAHUKU UPPER, SIX-MINUTE AVERAGE DATA

In the course of analyzing the variability question a few spectral analyses were run. The results were interpreted to the correlation band shown in Figure 8-30, subject to the interpretation problems described in Section 8.7. The raw wind spectra results are presented here.

Data were chosen from the Kahuku Upper site. Three periods of 72 hours each with no data dropouts were selected. The periods were picked as representative of strong tradewind intervals, the type of weather in which most of Kahuku's wind energy output will occur.

The specific three-day intervals started at 0000 on the dates 1 April 1976, 2 July 1976, and 10 September 1976. The UoH magnetic tape record of six-minute averages recorded was used. A plot of the wind speed over one of the intervals is shown in Figure C-1. As an empirical observation, the data plot appears much more uniform than a typical continental U.S. wind record.

A conventional analysis of the data was done for each time interval, using both a 72-hour data base of six-minute intervals and the first 48 hours of the interval. The results are plotted in Figure C-2 through C-7 for frequency intervals from one to five cycles/hour (60 to 12 minutes/cycle).

Figure C-1. Typical 72-Hour Wind Data Sample
Six-Minute Intervals; 0000 1 April 1976 to 2400 3 April 1976

Figure C-2. 72-Hour Wind Speed Spectrum; Kahuku Upper Six-Minute Averages; 0000 1 April 1976 to 2400 3 April 1976

Figure C-3. 72-Hour Wind Speed Spectrum; Kahuku Upper Six-Minute Averages; 0000 2 July 1976 to 2400 4 July 1976

Figure C-4. 72-Hour Wind Speed Spectrum; Kahuku Upper Six-Minute Averages; 0000 10 September 1976 to 2400 12 September 1976

Figure C-5. 48-Hour Wind Speed Spectrum; Kahuku Upper Six-Minute Averages; 0000 1 April 1976 to 2400 3 April 1976

Figure C-6. 48-Hour Wind Speed Spectrum; Kahuku Upper Six-Minute Averages; 0000 2 July 1976 to 2400 4 July 1976

Figure C-7. 48-Hour Wind Speed Spectrum; Kahuku Upper Six-Minute Averages; 0000 10 September 1976 to 2400 12 September 1976

APPENDIX D

CUMULATIVE AVAILABILITY PROBABILITY ALGORITHM

It is required to compute the loss-of-load probability, $LOLP_j$, for any j^{th} hour of the year. Under the assumptions of the algorithm outlined below, $LOLP_j$ will be a function only of the availability schedules for each of the N units not on maintenance status and the power demand, D_j , for the j^{th} hour.

The probability $LOLP_j$ is calculated using the N -vector $P(k)$, $k = 1, 2, \dots, N$; where $P(k)$ is the probability that capacity $k\Delta S$ or greater is not available due to some number of units being "down" or in a forced outage condition. Then

$$LOLP_j = P([1/1 = D_j/\Delta S])$$

where by the notation $[X]$ is meant the largest integer less than or equal to the number X (i.e., truncation). ΔS is an input roundoff tolerance also used in several other equations below.

The remainder of the discussion has to do with the algorithm for calculating the vector $P(k)$. $P(k)$ must be recalculated each time the combination of units not on maintenance status is changed. However, for a given combination, the $LOLP_j$ for each hour is simply obtained by entering the same vector $P(k)$ with the appropriate argument $k = [1/2 + D_j/\Delta S]$. The value of the algorithm outlined below is in its efficiency in calculating the vector $P(k)$ for each possible combination of active units (those not on maintenance status) which might be encountered operationally.

In addition to ΔS , an "availability" schedule is input for each unit. For the i^{th} unit, the schedule is simply an array of N_α data pairs:

$$\begin{array}{l} p_i(1), S_i(1) \\ p_i(2), S_i(2) \\ \vdots \\ p_i(\alpha), S_i(\alpha) \\ \vdots \\ p_i(N_\alpha), S_i(N_\alpha) \end{array}$$

The value $p(\alpha)$ is the probability that the corresponding (exact) capacity $S(\alpha)$ MW will be available (up and running if required) for that unit. This partial-outage description is generally only required for very large baseload units or Wind Energy Conversion Systems (WECS).

A simple binary description is satisfactory for most units:

$$p_i(1), S_i(1)$$

$$p_i(2), S_i(2)$$

In either case, the values $S_i(1), S_i(2), S_i(3), \dots$ must be arranged so as to ascend monotonically starting with $S_i(1) = 0$ and ending with the upper operating limit, for the algorithm as described below to work properly. For the case where only two data pairs describe the availability, $p_i(1)$ - the forced outage rate and $p_i(2) = 1 - p_i(1)$.

For reasons of numerical stability, the calculations are performed using "unavailability" schedules $[q(\alpha), US(\alpha); \alpha = 1, 2, \dots, N_\alpha]$. These schedules are obtained by transforming the input availability schedules as follows:

$$q_i(\alpha) = p_i(N_\alpha + 1 - \alpha); \alpha = 1, 2, \dots, N_\alpha.$$

$$US_i(\alpha) = S_i(N_\alpha) - S_i(N_\alpha + 1 - \alpha); \alpha = 1, 2, \dots, N_\alpha.$$

The algorithm for computing $P(k)$ has three modes of operation:

Mode 1 - $P(k)$ is directly calculated for a given combination of units using the input availability schedules for those units.

Mode 2 - A function $P(K)$ already exists for a given combination of units and it is desired to calculate the new $P(k)$ corresponding to the addition of one particular unit. Mode 2 permits the calculation of $P(k)$ for the new combination using only the old $Q(k)$ corresponding to the old $P(k)$, and the availability schedule for the added unit.

Mode 3 - A function $P(k)$ already exists for a given combination of units and it is desired to calculate the new $P(k)$ corresponding to the deletion of one particular unit. Mode 3 permits the calculation of $P(k)$ for the new combination using only the old $Q(k)$ corresponding to the old $P(k)$, and the availability schedule for the deleted unit.

Of course, Modes 2 and 3 can be used successively to calculate the new distribution functions for the simultaneous addition or deletion of two or more units. The algorithms for the three modes are as follows:

Mode 1

Define a vector $Q(k)$, $k = 1, 2, \dots, N$ where $N = 1 + \sum [1/2 + US_i(N_\alpha)/\Delta S]$ summed over all the units for which $P(k)$ is to be computed. Set the elements of $Q(k) = 0$. Then, substitute the value $q_i(\alpha)$ for $Q(\mu)$ where $\mu = 1 + [1/2 + S_i(\alpha)/\Delta S]$ for $\alpha = 1, 2, \dots, N_\alpha$, for the i^{th} availability schedule. It makes no difference which schedule is taken first; the choice is arbitrary.

Modify this initial value of $Q(k)$ according to the following rule taking each of the availability schedules one at a time (again, the sequence of schedules may be chosen arbitrarily). Compute the matrix ϕ_i :

$$\phi_i(\alpha, k) = q_i(\alpha) Q(k); \alpha = 1, 2, \dots; k = 1, 2, \dots, N.$$

Then, but not before completing the matrix ϕ_i :

Set $Q(\mu) = 1$, all μ , then

Replace $Q(\mu)$ with $Q(\mu) + \phi_i(\alpha, k)$

where $\mu = k + [1/2 + S_i(\alpha)/\Delta S]$; $\alpha = 1, 2, \dots, N_{\alpha i}$; $k = 1, 2, \dots, N$.

Values of $\mu > N$ can be ignored -- they correspond to zero probabilities. This process is repeated in turn for each of the availability schedules until they have all been cycled into the vector $Q(k)$. The distribution function $P(k)$ is then obtained from the backward running sum of the density function $Q(k)$:

$$P(k) = \sum_{x=1}^k Q(N+1-x)$$

The vector $Q(k)$ should be saved for Mode 2 and Mode 3 operations.

Mode 2

Mode 2 simply amounts to picking up Mode 1 with an existing vector $Q(k)$ and cycling in the availability schedule for the particular unit to be added. $P(k)$ is computed from the resulting $Q(k)$ in the same way as in Mode 1, of course.

Mode 3

In this mode, a density function $Q(k)$ exists for a given combination of units; call it $Q_e(k)$. It is desired to compute $P(k)$ corresponding to the same combination less one particular unit. That is, a deconvolution process is required.

The first step is to compute the vector $\psi(k)$. Define $\psi(k)$; $k = 1, 2, \dots, N$; and set all of the elements of $\psi(k) = 1$. Then compute the matrix θ_i :

$$\theta_i = q_i(\alpha) \psi(k); \alpha = 1, 2, \dots; k = 1, 2, \dots, N.$$

This matrix is computed only once using the vector $q_i(\alpha)$ for the i^{th} unit which is the one to be deleted. Then, but not before completing the matrix θ_i :

Set $\psi(\mu) = 0$, all μ , then

Replace $\psi(\mu)$ with $\psi(\mu) + \theta_i(\alpha, k)$

where $\mu = [1/2 + S_i(\alpha)/\Delta S]$; $\alpha = 1, 2, \dots; k = 1, 2, \dots, N$.

Form the N-vector $\gamma(\mu)$;

$$\gamma(1) = \psi(1)$$

$$\gamma(\mu) = \psi(\mu) - \psi(\mu - 1); \mu = 2, 3, \dots, N.$$

Then, the following recursion formula can be used to compute the new vector $Q(k)$:

$$Q(1) = \frac{1}{\gamma(1)} Q_e(1)$$

$$Q(k) = \frac{1}{\gamma(1)} \left(Q_e(k) = \sum_{x=\ell}^{k-1} Q(x) \gamma(k+1-x) \right); k = 2, 3, \dots, N.$$

Where $\ell = 1$ or $k - [1/2 + S_i(N_\alpha)/\Delta S]$, whichever is larger. When $\ell > 1$, the test can be eliminated because ℓ will remain greater than 1 as k advances further.

The distribution function $P(k)$ is then computed from the backward running sum of $Q(k)$, as before.