HECO
1996-2003

ADEQUACY OF SUPPLY
REPORTS

(SPECIAL REPORTS – PERMANENT)

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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May 14, 2003

William A. Bonnet
Vice President
Government and Community Affairs

Department of Commerce and
Consumer Affairs
Division of Consumer Advocacy
250 S. King Street, 8th Floor
Honolulu, Hawaii 96813

Attention: Ms. Cheryl Kikuta

Subject: <u>HECO Adequacy of Supply dated January 31, 2003</u>

Dear Ms. Kikuta:

Attached are HECO's responses to the Consumer Advocate's information requests submitted by letter dated March 17, 2003.

CA-IR-1 <u>Ref: Adequacy of Supply report, dated January 31, 2003.</u>

Footnote 3, page 2 of HECO's Adequacy of Supply report, dated January 31, 2003, states that:

> Also included in HECO's capacity planning criteria is a reliability guideline. The guideline states: *"Capacity planning analysis will include a calculation of risk (Loss of Load Probability) in years per day for each year of each plan of the long-range expansion study. In cases where risk is calculated to be less than 4.5 years per day, the plan will be reviewed by the Vice President of Power Supply and the President for approval of use of the plan in the study."*

a. Please provide a discussion on the following aspects of the Company's use of "loss of load probability":

   1. Please confirm that HECO's use of a 4.5 years per day factor for loss of load probability represents the threshold of an allowable instance of at least one day every 4.5 years where system peak exceeds the system generation capacity.

2. Please confirm that HECO's criteria means that, if the resulting loss of load probability is less than 4.5 years per day, the Vice President of Power Supply and President of HECO must approve the plan before it is used because that lower factor (which translates into higher reliability) would probably entail greater capital investment costs or capital investments being spent sooner than under HECO's other generation planning criteria.

3. Please provide examples using actual or hypothetical examples of HECO's loss of load probability calculations.

b. Please explain how the Company determined the threshold for the loss of load probability of 4.5 years per day. Please include the workpapers and/or documentation used to determine the threshold as well as industry standards relied upon, if any.

c. Please explain why HECO has included this reliability guideline in its capacity planning criteria.

d. In response to TGC-RIR-1001e. in Docket No. 99-0207, HELCO stated that:

> A Loss of Load Probability (LOLP) guideline would be expected to result in generating units being added sooner than with [HELCO's] current criterion. Sooner unit additions, while increasing the reliability of the generating system by reducing the probability of loss of load, would result in higher costs for customers. HELCO has not made a determination that the cost to its customers of adding generation based on an LOLP guideline is necessary at this time, or that the benefits would outweigh the cost.

1. Please confirm that HECO's Loss of Load Probability guideline is still not part of HELCO's capacity planning criteria for the reasons discussed in the response to TGC-RIR-1001e., in Docket No. 99-0207.

2. Please confirm that HECO's Loss of Load Probability guideline is not part of MECO's capacity planning criteria and, if so, please explain why HECO's Loss of Load Probability guideline is not part of MECO's capacity planning criteria.

3. HECO's 2002 Evaluation Report Regarding Integrated Resource Planning, dated December 2002 filed in Docket No. 95-0347 concluded that the next generating unit is still projected to be required in 2009.

(a) Please confirm that the Loss of Load Probability guideline was used in HECO's capacity planning criteria to determine that the next generating unit is projected to be required in 2009.

(b) Please confirm that HECO's generation planning criteria consists of the factors listed in response to TGC-RIR-1007a. If HECO's generation planning criteria have been revised, please provide the revised criteria.

(c) Please identify when the next generating unit would be required in HECO's system if the Loss of Load Probability guideline was excluded from HECO's generation planning criteria.

4. Please identify when the Company included the reliability guideline listed above in its capacity planning criteria.

Response: a. 1. HECO's use of 4.5 years per day loss of load probability represents the threshold of an allowable instance of a maximum of one day every 4.5 years where the system peak exceeds available generation.

2. A loss of load probability (LOLP) value lower than 4.5 years per day would mean that the system is less reliable than it would be if the LOLP were at 4.5 years per day. For example, if the LOLP value is 2.0 instead of 4.5 years per day, there is a probability that the system peak would exceed available generation (due to forced outages of multiple units) once every 2.0 years instead of once every 4.5 years. Therefore, the system is less reliable.

If the LOLP value is forecasted to be less than 4.5 years per day, the Vice President of Power Supply and President of HECO must approve the plan before it is used because there is a higher risk that customers may experience an interruption in service compared to when the LOLP is at 4.5 years per day.

3. Please see Attachment 1 for a numerical example.

b. In the late 1950s and early 1960s, the electric utility industry began using probability methods in generation planning, in addition to providing for the loss of largest unit and a minimum amount of margin. In 1962, HECO commissioned Commonwealth Associates, Inc., to conduct a study of the HECO system and to recommend the criteria to be used for planning generating unit additions. In its report, Commonwealth Associates recommended the Company work toward an index of reliability of seven to ten years per one day loss of load but not less than two in any year. This was considered acceptable by much of the utility industry on the mainland.

In 1965, the probability criterion for HECO generation planning was added, which specified a minimum risk of two years per day. In 1968, in an effort to move toward the recommended reliability level of seven to ten years per one day loss of load, the reliability level was increased to 4.5 years per day.

Increasing the reliability level from 4.5 years per day to seven to ten years per day would require that generation capacity be added to the system sooner such that reserve margins could be increased. Doing so would require a higher commitment of financial resources and would result in higher rates for consumers.

Since 1968, the HECO generation planning reliability threshold has remained at 4.5 years per day.

Please see attached reference materials for more detailed information:

i) Generation Planning Criteria History, Presentation to PUC Staff, May 19, 1972. (See Attachment 2.)
ii) Testimony of J. F. Richardson, Jr., Public Utilities Commission Hearing, 1975 Hawaiian Electric Company, Inc. Capital Budget, March 18, 1975. (See Attachment 3.)
iii) Commonwealth Associates, Inc., System Generation Reserve Study, Hawaiian Electric Company, Limited, Engineering Report R-920, July 1962. (See Attachment 4.)

c. HECO included a reliability guideline in its capacity planning criteria because (1) probabilistic analyses provided a more comprehensive means of assessing generation system reliability and (2) probabilistic planning methodologies for capacity planning were commonly being used in the electric utility industry on the mainland.

d. 1. Yes, HECO's Loss of Load Probability guideline is still not part of HELCO's capacity planning criteria for the reasons discussed in the response to TGC-RIR-1001, subpart e, in Docket No. 99-0207.

   2. Yes, HECO's Loss of Load Probability guideline is not part of MECO's capacity planning criteria for the reasons discussed in the response to TGC-RIR-1001, subpart e, in Docket No. 99-0207.

3. (a) Yes, the Loss of Load Probability guideline of 4.5 years per day in HECO's capacity planning criteria was used to determine that the next generating unit is projected to be required in 2009.

   (b) HELCO's response to TGC-RIR-1007, subpart a, indicated that HECO's capacity planning criteria included a Load Service Capability Criterion, a Quick Load Pickup Criterion and a Reliability Guideline. These components are still included in HECO's capacity planning criteria.

   (c) If the Loss of Load Probability guideline were excluded from HECO's generation planning criteria, it is estimated that the next generating unit would be needed in 2012.

4. Please refer to the response to subpart b above.

Sincerely,

William A. Bonnet

Attachments

cc: Public Utilities Commission

HECO Response to CA-IR-1, subpart a.3.
HECO Adequacy of Supply, Dated January 31, 2003

Sample Calculation of Loss of Load Probability for HECO

The Loss of Load Probability (LOLP) calculation quantifies the probability that a particular generating system will be unable to serve a given demand. The calculation uses the following inputs:

- normal capability rating of each generating unit;
- equivalent force outage rate (EFOR) for each generating unit;
- maintenance schedule for each generating unit and
- peak demand in each day.

The calculation treats the forced outages of generating units as random and independent events.

To illustrate the calculation, consider a system consisting of three generating units (for simplicity, maintenance schedules are not considered):

Table 1
Characteristics of Generating Units in a Hypothetical System

	Capacity, MW	Equivalent Forced Outage Rate (EFOR)	In-Service Rate (1 – EFOR)
Unit A	50	0.05	0.95
Unit B	100	0.07	0.93
Unit C	200	0.10	0.90
Total	350		

Table 2
All Possible Forced Outage States on the System

Units on Forced Outage			MW on Forced Outage	Units in Service			Probability of Particular State	
A	B	C		A	B	C		
None			0	X	X	X	0.95 x 0.93 x 0.90 =	0.7952
X			50		X	X	0.05 x 0.93 x 0.90 =	0.0419
	X		100	X		X	0.95 x 0.07 x 0.90 =	0.0599
		X	200	X	X		0.95 x 0.93 x 0.10 =	0.0884
X	X		150			X	0.05 x 0.07 x 0.90 =	0.0032
X		X	250		X		0.05 x 0.93 x 0.10 =	0.0047
	X	X	300	X			0.95 x 0.07 x 0.10 =	0.0067
X	X	X	350	None			0.05 x 0.07 x 0.10 =	0.0004
							Sum =	1.0000

Suppose a determination must be made of the probability that a 220 MW peak demand could not be served with the given system on a particular day. First, all states in which there are less than 220 MW in service must be identified. Then the probabilities of those states must be summed.

Table 3
Probability that a 220 MW Peak Demand Could Not Be Served

MW on Forced Outage	MW in Service	Probability of State	220 MW in Service?	Probability
0	350	0.7952	Yes	
50	300	0.0419	Yes	
100	250	0.0599	Yes	
200	150	0.0884	No	0.0884
150	200	0.0032	No	0.0032
250	100	0.0047	No	0.0047
300	50	0.0067	No	0.0067
350	0	0.0004	No	0.0004
		1.0000	Total =	0.1032

Therefore, there is a probability of 0.1032, or about a 10% chance, that a 220 MW peak demand on a particular day could not be served.

The above example illustrates the calculation for a particular day. The resulting probability value can be interpreted to mean 0.1032 days per day that a 220 MW demand could not be served. The concept can be expanded to cover a series of days.

Suppose a series of days, each with a particular peak demand is considered, as shown in Table 4. The calculation would be as follows:

Table 4
Probability that Peak Demand Could Not Be Served

Day	Peak Demand, MW	Probability of State												
Sunday	140							0.0047	+	0.0067	+	0.0004	=	0.0117
Monday	280	0.0599	+	0.0884	+	0.0032	+	0.0047	+	0.0067	+	0.0004	=	0.1630
Tuesday	240			0.0884	+	0.0032	+	0.0047	+	0.0067	+	0.0004	=	0.1032
Wednesday	220			0.0884	+	0.0032	+	0.0047	+	0.0067	+	0.0004	=	0.1032
Thursday	260	0.0599	+	0.0884	+	0.0032	+	0.0047	+	0.0067	+	0.0004	=	0.1630
Friday	290	0.0599	+	0.0884	+	0.0032	+	0.0047	+	0.0067	+	0.0004	=	0.1630
Saturday	130							0.0047	+	0.0067	+	0.0004	=	0.0117
	Total =													0.7186

The calculation indicates there is probability of about 0.72 days over a period of seven days (or 0.72 days per week) that the demand will not be served. This is about equal to 0.72 / 7 = 0.103 or about a 10% chance over the seven-day period.

If the peak demand for every day of an entire year is known, then the calculation can be performed for the entire year. The result would be expressed in terms of days per year.

HECO uses a program, called PREL, to perform this type of LOLP calculations for its system. PREL is a module of PMONTH, which is a production simulation computer model used by HECO, HELCO and MECO, and which was developed by PPlus Corporation.

Typical values resulting from the LOLP calculations are fractions of a day per year. HECO long ago adopted a convention of taking the inverse of the result such that the units would be in years per day. This is primarily because greater reliability values resulted in higher values so that people could more easily understand the reliability numbers in terms of "bigger is better." For example, a system may have an LOLP of 10.0 years per day under a given set of conditions and an LOLP of 5.0 years per day under another set of conditions. The system with an LOLP of 10.0 years per day is more reliable than the system with an LOLP of 5.0 years per day.

System Planning Department

Generation Planning Criteria History
Presentation to PUC Staff May 19, 1972

The criteria used for planning the generating capability to serve the predicted load has varied considerably over the years. With each change the system was planned to have greater reliability. Each of these changes instituted additional capital cost to the company.

During World War II some of the company's load was served by Pearl Harbor Naval Shipyard and by a power barge, the Jacona. From 1947 until about 1955, generation capability of the system was adequate only to serve the peak load and provide for maintenance or overhaul of each generating unit two to six weeks each year. This does not provided for a very reliable system because at any time one of the generating units may have a forced outage.

Beginning in 1956 we began to add capability to the system such that with the forced outage of a unit in service at the time of the evening peak we would still be able to carry system load. At the beginning of this period we provided for the loss of about 25 mw, or the capability of our smallest unit, and gradually increased this so that by 1964 we were providing for the loss of 83 mw, the maximum capability of any unit at that time. During this period the system load grew from 204 mw to 426 mw.

The criterion of providing for the loss of the largest unit was used by mainland utilities of comparable size (1957 EEI publication on system planning practices). Small utilities tended to use a loss of largest unit while large companies tended to use a percentage margin.

In the late 1950's and early '60's the industry began using probability methods in generation planning, in addition to providing for the loss of the largest unit and a minimum amount of margin. Utilizing probability mathematics, the probability of simultaneous combinations of units being out of service due to forced outage such that insufficient generating capability will be available to meet the system peak load is computed to give the Reliability Index. The Index is stated in years per day.

In 1962 we requested the consulting firm, Commonwealth Associates, Inc., of Jackson, Michigan, to make a study of the Hawaiian Electric system and recommend the criteria to be used for planning generating unit additions. In their report, Commonwealth Associates recommended the company work toward an index of reliability of seven to ten years per one day loss of load but not less than two in any year.

In 1965 the probability criterion for generation planning was added, which specified a minimum risk of two years per day. This meant that multiple outages of generating units might necessitate interruption of load one day every two years. Or, the chances of having to drop load were one in 520 on any week day.

Since 1968, generation planning has been at a level of reliability of 4.5 years per day. We planned (in 1972) to increase the level of reliability to between 7.0 and 10.0, as recommended by Commonwealth Associates, and as considered acceptable by much of the utility industry on the mainland, as our company financing and earnings will permit us to do so.

TESTIMONY OF J. F. RICHARDSON, Jr.
PUBLIC UTILITIES COMMISSION HEARING
1975 HAWAIIAN ELECTRIC COMPANY, INC. CAPITAL BUDGET
MARCH 18, 1975

At the end of 1974, the total generating capacity on the Hawaiian Electric Company system was 1,209,400 kw. Approximately 15% of this capacity is installed at the Honolulu plant, 41% at the Kahe plant, and 44% at the Waiau plant. With the present predicted system peaks through 1979, as discussed by Ken Stretch, we will not require additional generating capacity until 1979.

Over the years, Hawaiian Electric has developed criteria for determining when new generation should be added to the system. These criteria have been changed periodically as the total system load has grown and as it has become more critical that a higher degree of reliability of service should be maintained. Because of the isolation of our system from neighboring utilities for interconnection purposes, it has been necessary to maintain considerably more generation margin than mainland utilities.

The two basic criteria now being used for planning the installation of additional generating capacity on the Hawaiian Electric system are as follows:

1. Total system capacity must be equal to or greater than the sum of the peak load, the capacity of units scheduled for maintenance, and the capacity lost by the forced outage of the largest operating unit.

2. Total system capacity must be sufficient to provide an Index of Reliability of at least 4.5 years per day.

The Index of Reliability is derived from probability mathematics and gives an indication of the relative probability that there will be insufficient generating capability to meet the system peak load due to the simultaneous combination of units being out of service due to forced outage. The Index is stated in years per day. An Index of Reliability of 4.5 years per day means that there is a probability that there will be insufficient generation to meet system peak load once in 4.5 years.

F

In 1962 we requested the consulting firm of Commonwealth Associates, Inc., of Jackson, Michigan, to make a study of the Hawaiian Electric system and recommend the criteria to be used for planning generating unit additions. In their report, a copy of which was made available to the Commission, Commonwealth Associates recommended the company work toward an Index of Reliability of seven to ten years per one day loss of load but not less than two in any year.

Generation planning has two basic objectives. The first is to determine how much generation will be needed in future years, and this is where the generation criteria come into play. This objective is largely a matter of establishing sufficient future generation reserve capacity to give adequate system reliability.

The second objective is to establish what kinds of generation should be added, the mix of different kinds, and the sizes of individual units. The choice is a matter of economics, the combination resulting in the lowest cost of electricity to the customer being the plan followed.

Generation planning methods revolve around three basic processes: first, capacity and probability calculations by which the reliability of a system can be measured and planned; second, production costing simulation techniques which allow an estimate to be made of future fuel, operation, and maintenance costs; and third, a calculation of the fixed carrying charges on investment in new generation. These methods have been developed to a high degree of sophistication within the industry, and Hawaiian Electric has developed its own computer program models to take into account the uniqueness of an isolated system.

During the next five years the generation margin will decrease from 34% in 1975 to 15% in 1978, and increase to 22% in 1979 when Kahe 6 is included. During this period it is anticipated that our index of reliability will stay above the 4.5 years per day we have been able to maintain beginning in 1970.

SYSTEM GENERATION RESERVE STUDY

HAWAIIAN ELECTRIC COMPANY, LIMITED

Engineering Report R-920

COMMONWEALTH
ASSOCIATES · INC.

209 E. WASHINGTON AVE.
JACKSON, MICHIGAN
STATE 4-6111

July 20, 1962

Mr. Ralph B. Johnson, President
The Hawaiian Electric Company
Box 2750
Honolulu 3, Hawaii, USA

Dear Mr. Johnson:

In response to your letter of April 24, 1962, to Mr. W. B. Tippy, we have made a study of your generating reserves in accordance with the scope which was discussed with Mr. C. H. Williams and confirmed in my letter to him on May 1, 1962. It was also agreed that we should use the computer programs and services of the Westinghouse Manufacturing Company. Attached are five copies of Report R-920 covering the results of this study.

The use of probability methods for studying plans of generation additions results in an index of reliability which must be compared with costs to evaluate the various plans. While this is the most comprehensive approach to the problem and the method which is gaining greater acceptance, there is still a great deal of judgment left to determine the critical value of a satisfactory reliability index. A review of experience and practice indicates a rather wide range of index values from 2 to 30 (years for one-day loss of load) being used by various utilities. A range of 7 to 10 appears to be the mode and this has been used as a reference in the report.

The conclusions given in the report are as follows:

1. The Hawaiian Electric Company has experienced forced outage rates which are much lower than the national average.

2. Forced outage rates over the long term for The Hawaiian Electric Company are not expected to be significantly different from the national averages on the United States mainland for oil-fired units of similar design. Therefore, higher forced outage rates should be anticipated and generation planning should be based on these rates.

3. The Hawaiian Electric Company index of reliability for the 1956-1961 period based on the expected forced outage rates as derived in this report was lower than that normally considered adequate. Likewise, the reliability based on the lower experienced forced outage rates was also inadequate.

4. Based on the expected outage rates, Budget Plans 1 and 2 for the 1962-1970 period yield a higher index of reliability than has been experienced in the past; however, the system reliability provided by all plans is below the index generally considered acceptable.

5. If generating units that are large with respect to system load are installed as proposed in the four budget plans, a low index of reliability must be anticipated unless additional reserve capacity is installed.

It is our understanding that this report may be considered preliminary or Phase 1 to be followed by studies of alternate plans, depending on your decision as to whether the reserves provided by any of the plans are considered as satisfactory. As a result of this study it appears that the system reliability may be improved by the installation of peaking capacity. It may even be possible to reduce the capital expenditures during this period while increasing the system reliability. This would involve a study comparing the economics and index of reliability of alternate plans of generation expansion.

We should be glad to discuss this with you further at your convenience.

Yours very truly,

M. C. Westrate

M. C. Westrate

MCW/mhn

SYSTEM GENERATION RESERVE STUDY

THE HAWAIIAN ELECTRIC COMPANY, LIMITED

Prepared by
Commonwealth Associates Inc.
Jackson, Michigan
July 1962
mhn

Engineering Report R-920

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EXHIBIT 1 - 1962 GENERATING CAPABILITY
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SYSTEM GENERATION RESERVE STUDY

A study has been made comparing The Hawaiian Electric Company generating reserves and system characteristics with mainland utility reserve criteria. Generation reserves for a 15-year period from 1956 through 1970 were analyzed utilizing the four proposed budget plans of generator additions in the future years.

SCOPE

The Scope of this study includes the following:

1. Discussion of current system planning practices used on the United States mainland for determining required generation reserves.

2. Determination of expected forced outage rates for The Hawaiian Electric Company's present and future generators.

3. Determination of loss of load probabilities for a 15-year period from 1956 through 1970, using the Westinghouse Powercasting Program, for each of the four budget plans of future generator additions.

4. Preparation of a report analyzing the results of the study and including conclusions.

SITUATION

The Hawaiian Electric Company supplies power to the Island of Oahu. In 1961, the system peak load was 341 megawatts. The system generation is located at the Honolulu and Waiau Stations. Following the 1961 installation of Waiau Unit 6, a 50 megawatt unit, the system net generating capability was 457 megawatts, as shown on Exhibit 1. With the exception of ties to several plantations which have small turbine-generators and to the generating station which supplies a portion of the Pearl Harbor load (the remaining requirements are purchased from The Hawaiian Electric Company), there are no interconnections with outside sources of power.

The annual peak loads that occurred during the 1956-1961 portion of the study period are shown on Exhibit 2. During this period, 50 megawatt units were installed in 1957, 1959 and 1961, and the generation reserves at the time of system peak varied from 28 percent to 50 percent as shown on Exhibit 3.

CORRECTION

THE PRECEDING DOCUMENT(S) HAS BEEN REPHOTOGRAPHED TO ASSURE LEGIBILITY
SEE FRAME(S)
IMMEDIATELY FOLLOWING

SYSTEM GENERATION RESERVE STUDY

A study has been made comparing The Hawaiian Electric Company generating reserves and system characteristics with mainland utility reserve criteria. Generation reserves for a 15-year period from 1956 through 1970 were analyzed utilizing the four proposed budget plans of generator additions in the future years.

SCOPE

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SITUATION

The Hawaiian Electric Company supplies power to the Island of Oahu. In 1961, the system peak load was 341 megawatts. The system generation is located at the Honolulu and Waiau Stations. Following the 1961 installation of Waiau Unit 6, a 50 megawatt unit, the system net generating capability was 457 megawatts, as shown on Exhibit 1. With the exception of ties to several plantations which have small turbine-generators and to the generating station which supplies a portion of the Pearl Harbor load (the remaining requirements are purchased from The Hawaiian Electric Company), there are no interconnections with outside sources of power.

The annual peak loads that occurred during the 1956-1961 portion of the study period are shown on Exhibit 2. During this period, 50 megawatt units were installed in 1957, 1959 and 1961, and the generation reserves at the time of system peak varied from 28 percent to 50 percent as shown on Exhibit 2.

BASIS OF STUDY

The predicted peak loads, four budget plans of generator additions, and maintenance schedule for this study were supplied by The Hawaiian Electric Company.

PREDICTED PEAK LOADS

The predicted peak loads for the years 1962 through 1970 are as follows:

Year	Predicted Peak Load - Mw
1962	369
1963	399
1964	430
1965	465
1966	502
1967	542
1968	585
1969	632
1970	683

BUDGET PLANS OF GENERATOR ADDITIONS

All of the budget plans schedule commercial operation of Kahe Unit 1, a 75 megawatt unit, March 1, 1963. Following the installation of this unit, the various plans install three additional 75 megawatt units or a second 75 megawatt unit and two 100 megawatt units. The 75 megawatt and 100 megawatt units are expected to have a maximum net capability of 82.5 megawatts and 110 megawatts, respectively.

Budget Plan 1, as shown on Exhibit 3, places a second 75 megawatt unit, Kahe 2, in commercial operation November 1, 1964. Kahe Units 3 and 4 are rated 100 megawatts each and are scheduled for commercial operation November 1, 1966, and November 1, 1968, respectively. Exhibit 3 indicates that generation reserves increase from about 24 percent in 1962 to 46 percent following the installation of Kahe 3 in 1966 and subsequently decrease to about 23 percent in 1970.

Budget Plan 2, shown on Exhibit 4, is based on Kahe Units 2, 3 and 4 being 75 megawatt units placed in commercial operation November 1, 1964, 1966 and 1968, respectively. During the period 1962-1970, see

Exhibit 4, generation reserves increase to a maximum of about 45 percent, following the installation of Kahe Unit 2 in 1964. In succeeding years, this plan's generation reserves decrease to about 15 percent in 1970 if no generation is installed in that year.

Budget Plan 3, as shown on Exhibit 5, places a second 75 megawatt Kahe Unit 2 in commercial operation March 1, 1965. Kahe Units 3 and 4 are scheduled for commercial operation March 1, 1967, and March 1, 1969, respectively, and are 100 megawatt units. In this plan, generation reserves for the 1962-1970 period vary from a maximum of about 35 percent, following the installation of Kahe Unit 1, to a minimum of 23 percent in 1970.

Budget Plan 4 is based on the installation of 75 megawatt generators for Kahe Units 2, 3 and 4. These units are to be placed in commercial operation March 1, 1965, 1967 and 1969. As shown on Exhibit 6, the maximum reserve at the time of system peak is 35 percent, following the installation of Kahe Unit 1 in 1963, and subsequently decreases to a minimum reserve of about 15 percent if no generation is installed in 1970.

MAINTENANCE SCHEDULE

In the determination of the loss of load probabilities for the four budget plans of generator additions, using the Westinghouse Powercasting Program, maintenance can be based on a fixed schedule, or the computer program can develop a maintenance schedule on a constant or minimum risk basis. After considering these methods of handling maintenance, it was decided to use a fixed maintenance schedule because it eliminated any variation in the comparison and would not penalize any of the plans. Therefore the fixed maintenance schedule shown on Exhibit 7 was used in this study.

GENERATION RESERVE PLANNING PRACTICES

On electric utility systems, it is generally the practice to provide sufficient generation to supply the system load with an adequate margin to allow for scheduled and reasonable unscheduled generator outages. In system planning, one of the fundamental problems is the determination of the amount of reserve capacity that is required to yield an acceptable index of reliability. On the U. S. mainland, several criteria are used by the major utilities to determine the required system generation reserves. The three basic methods used for this purpose are (1) largest unit, (2) percentage reserve and (3) probability.

LARGEST UNIT METHOD

One criterion for determining the proper generation reserve is based on maintaining sufficient generating capacity to provide for the loss of some multiple of the largest unit at any time. Historically, this is perhaps the oldest criterion used for generation planning purposes. At first, all companies were isolated or loosely interconnected and had to supply their own generation reserves to provide backup for forced and scheduled maintenance outages. At that time, it was not economically feasible for an individual company to supply backup for units that were large in relation to the total installed capacity. Therefore, small units were installed to hold reserves to a minimum while providing for the loss of some multiple of the largest unit. Also, as long as the largest units available were moderately sized and the dollars per kilowatt savings were not appreciable, it was economical for many companies to utilize smaller units. However, with the dollar per kilowatt savings now available, there appears to be a trend toward installing larger units and reducing the multiple of the largest unit planned for as reserve capacity. This has been made possible by many of the companies becoming interconnected or by strengthening existing interconnections to permit sharing installed reserves.

A survey of a number of the major utilities indicated that about 15 percent still use some multiple of the largest unit for determining reserve requirements. In some cases, planning is based on a multiple of the largest unit plus a fixed percentage (2 to 3 percent) of the estimated peak load. Approximately 9 percent consider the largest unit out of service, and about 4 percent utilize 1-1/2 times the largest unit. Most of these companies are well interconnected with neighboring utilities. Only 2 percent plan system generation on the basis of the two largest units out of service, and in these cases they are not as well interconnected.

PERCENTAGE RESERVE METHOD

In the percentage reserve method the determination of the proper generation reserve is based on maintaining a certain minimum percentage of the estimated peak load as reserve capacity. As companies became more closely interconnected to permit sharing of reserve capacity, it became feasible to utilize the percentage method. This sharing allowed companies to install larger units without the inherent disadvantage of increasing their installed reserves.

The percentage reserve method provides a means for determining the relative reserves for all companies in an interconnected group or pool where the size of new units will greatly exceed the reserve of the individual companies. The actual percentage selected is based on the number and size of units, load diversity and experience of the interconnected companies. The percentage is generally between 10 and 15 percent for well interconnected systems. The survey shows that approximately 55 percent of the utilities on the U.S. mainland use the percentage reserve method for capacity planning purposes.

PROBABILITY METHOD

The complexity of the generation reserve problem has resulted in the development of methods of analysis which permit a systematic evaluation of all important factors. Probability mathematics allow the system planner to acknowledge forced outages of generation to evaluate the relationship between system reliability and such factors as the size and timing of generation additions, the accuracy of load forecasts, load duration characteristics and maintenance schedules.

The survey indicated that about 30 percent of the utilities use probability methods to determine system capacity requirements. Some of these use probability in combination with some type of percentage reserve method as the basis of capacity planning. It appears that probability methods have obtained wide acceptance in the industry, and that the trend is toward the application of this method to system planning problems.

In the survey, the standard of service reliability used to determine the required reserves varies from 2 years to 30 years for one-day loss of load. At the present time the most generally accepted range appears to be from 7 to 10 years for one-day loss of load. However, on utility systems that have a relatively small number of generating units, with the largest unit being about 20 to 30 percent of the annual peak load, the index of reliability can be expected to vary considerably from year to year. In this case, an average reliability of 7 to 10 years per one-day loss of load is considered adequate, provided that the minimum index in any one year is no lower than 2 years per day.

COMPARISON OF METHODS

Of the three criteria described, the largest unit and percentage reserve methods of generation planning are based on rules of thumb and experience, which have been found to yield an acceptable level of service reliability. While these methods provide a straightforward approach, they do not permit evaluation of the important factors in the complex generation reserve problem.

Probability methods allow the system planner to systematically analyze various plans of generator additions to determine which plan will yield an acceptable standard of service most economically. The application of this relatively new technique should lead to generation planning that is better than can be expected by the application of rule of thumb methods.

APPLICATION TO THE HAWAIIAN ELECTRIC COMPANY

In the past, The Hawaiian Electric Company generation planning has been based on the largest unit method. Generation additions were installed to maintain sufficient generating capacity to supply the system load with an adequate margin of reserve to allow for one unit on scheduled maintenance and the loss of the largest remaining unit. This method does not permit analysis of the relationship between system reliability and such factors as the size and timing of generator additions.

The use of probability methods will allow The Hawaiian Electric Company to evaluate the effect of system variables on the required reserves. Probability analysis will also facilitate investigation of the economic balance between installed reserves and system reliability.

FORCED OUTAGE RATES

The value of probability calculations depends materially on the reliability of the forced outage rates used. The forced outage rate is the fundamental quantity on which predictions of the future performance of the equipment are based and must necessarily be obtained from previous experience with similar equipment. Therefore, it is important that sufficient data is available to obtain stable forced outage values so that the inclusion of additional unit data would not result in a significant change in the forced outage rate.

PAST EXPERIENCE

The average forced outage experience for The Hawaiian Electric Company units is shown on Exhibit 8. This data has been accumulated for a seven-year period from 1955 through 1961, for all units installed prior to 1954, and for shorter periods for all subsequent units. As indicated on Exhibit 8, The Hawaiian Electric Company has experienced very low forced outage rates.

Several of the present units have experienced forced outages due to stator coil failures and the manufacturer indicates that these failures can be expected to continue. Thus far, the failures have occurred in the top coils which are relatively easily repaired. However, failure of a bottom coil would result in a forced outage of considerable duration. Also, all units have integral steam chests and nozzle chambers. The manufacturer has indicated that units of this design and operating at steam temperatures of 850 F and higher are subject to cylinder cracking. Mainland experience indicates that cylinder cracking can be expected to occur regardless of whether the unit is operated as a base load unit or is cycled frequently. While no forced outages have been experienced due to cylinder cracking, approximately 80 percent of the total system generating capability is susceptible to this type of outage.

In view of the relatively short historical record and the above possible causes of forced outages, the forced outage record in the future will undoubtedly be higher than past experience. In fact, over the life of the units, the forced outage rates for The Hawaiian Electric Company units should not be expected to be significantly different from the industry experience on the U. S. mainland for oil-fired units of similar design.

EXPECTED FORCED OUTAGE RATES

The expected forced outage rates for the turbine-generator-condenser portion of The Hawaiian Electric Company units were derived from outage data compiled by EEI for the period 1956 through 1960.

The boiler outage data that is readily available does not distinguish between the various methods of firing. Therefore, data from a recent EEI survey of oil-fired units was obtained and used to determine the expected forced outage rates. Also utilities in New England, Florida and Southern California were contacted to obtain additional outage data for oil-fired boilers.

The expected outage rates for the present and future generating units shown on Exhibit 9 were developed from the data for turbine-generator-condenser group and oil-fired boilers. Exhibit 10 graphically compares the expected outage rates with the 1955-1961 Hawaiian Electric Company experience and the experience of the industry regardless of the type of fuel.

It is understood that Honolulu 1 and 5 are multiple turbine and boiler installations, but were considered to be unit type installations when the probability portion of the Powercasting Program for The Hawaiian Electric Company was developed. Correspondingly, the forced outage rates shown on Exhibit 9 for Honolulu 1 and 5 were derived by considering the various capacity outage factors for each plant. While the unit approach for these plants is not correct, it does not appear that this will materially affect the results of the study since this capacity represents a small and ever-decreasing percentage of the total installed capacity and is presumably operated as peaking capacity.

IMMATURE OUTAGE RATES

The application of probability methods to power system problems is an analytical approach based on best available statistical data. It must be realized that forced outages of system components are assumed to be random events independent from one another and governed by the laws of chance. Also, probability theory only predicts the average performance of system components over a long period of time. It cannot predict the performance of a given unit in a specific year.

Previous studies that have been made for The Hawaiian Electric Company by Westinghouse, using the Powercasting Program, considered that new units were immature for one year after installation. During this period the outage rates were considered to be twice the mature outage rate.

In this study only average outage rates were used. This was done since the period of the study is short compared to the life of the units, and the expected forced outage rates were derived based on the average experience during their life. Therefore, the reduced reliability of the units during their early life is reflected in the average outage rate selected.

SYSTEM RELIABILITY

In this study, the system reliability was calculated using the probability portion of the Westinghouse Powercasting Program. In this program, the determination of the system reliability is based on the probability of the available installed capacity being adequate to meet the system load requirements. The measure of reliability is expressed in years per day or the average interval in years per one-day loss of load.

1956-1961 RELIABILITY

The system reliability for the historical period was calculated using the actual forced outage rates that were experienced during the period (see Exhibit 8) and the expected forced outage rates derived in this report and shown on Exhibit 9. The results of these probability calculations are tabulated on Exhibit 11 and shown graphically on Exhibit 13. The system reliability during these years can be summarized as follows:

	Reliability - Years Per One-Day Loss of Load	
	Using Experienced Forced Outage Rates	Using Expected Forced Outage Rates
Minimum	0.51	0.23
Maximum	7.65	2.88
Average	2.87	1.01

Based on the expected forced outage rates derived in this report, the probability study indicated that the system reliability would have been very low and a loss of load would have been expected to occur on the average of once each year. The experienced forced outage rates during this relatively short period were lower than the national average and correspondingly the index of reliability was higher. However, the index was still lower than normally considered adequate.

1962-1970 RELIABILITY

The system reliability provided by the four budget plans of generator additions during this period is tabulated on Exhibit 12 and shown graphically on Exhibit 13. The following is a summary of the data shown on these exhibits:

	Reliability - Years Per One-Day Loss of Load			
	Plan 1	Plan 2	Plan 3	Plan 4
Minimum	2.12	1.88	0.96	0.75
Maximum	8.02	5.90	4.22	3.55
Average	4.13	3.43	2.45	2.11

The system reliability in 1970 is not included in the above summary, since it appears that additional generating capacity may be required in that year.

Based on the outage rates derived in this report, the results of the probability study indicate that none of the four plans yields an index of reliability that would normally be considered adequate. Only Plans 1 and 2 yield a higher average index of reliability than has been actually experienced in the past. However, each of the four budget plans yields a higher index of reliability based on national averages than would have been expected during the 1956-1961 period.

DISCUSSION

The primary factors which influence system reliability in addition to the forced outage rates are (1) number and size of generating units, (2) amount of reserve generating capacity, and (3) scheduled maintenance time. On The Hawaiian Electric Company system a large portion of the generating capacity is concentrated in a few large units which tends to decrease the system reliability. At the present time, 65 percent of the generation consists of units that range in size from 15 to 18 percent of the system peak. This can be compared to the practices of isolated mainland systems where the largest unit is only about 10 percent of the peak load and only a few units this large are installed.

The Hawaiian Electric Company generation planning has been based on maintaining reserves equal to a maintenance outage of 25 megawatts plus the largest unit at the time of system peak. Isolated mainland systems generally plan reserves equal to twice the largest unit at the time of system peak which will increase the relative reliability of these systems. Also, The Hawaiian Electric Company's peak load variation curve is relatively flat compared to similar winter or summer peaking systems on the mainland. If the annual valley were more pronounced the reliability would be improved because of higher reserves during the maintenance period.

In view of the relatively low reliability provided by each of the budget plans, an additional case was run for comparison purposes and to demonstrate the effect of increasing generation reserves. Plan 4 was rerun and increased reserves were simulated by reducing the annual peak loads by 10 percent. In this case designated Plan 5, the reliability during the 1962-1970 period as shown on Exhibit 12 varied from a minimum of 8.25 to a maximum of 64.81 years per one-day loss of load. The average reliability during the period was about 24 years per day which indicates that the additional reserves were greater than required to provide an average reliability of 7 to 10 years per one-day loss of load.

CONCLUSIONS

As a result of this study, it is concluded that:

1. The Hawaiian Electric Company has experienced forced outage rates which are much lower than the national average.

2. Forced outage rates over the long term for The Hawaiian Electric Company are not expected to be significantly different from the national averages on the U.S. mainland for oil-fired units of similar design. Therefore, higher forced outage rates should be anticipated and generation planning should be based on these rates.

3. The Hawaiian Electric Company index of reliability for the 1956-1961 period based on the expected forced outage rates as derived in this report was lower than that normally considered adequate. Likewise, the reliability based on the lower experienced forced outage rates was also inadequate.

4. Based on expected forced outage rates Budget Plans 1 and 2 for the 1962-1970 period yield a higher index of reliability than has been experienced in the past. However, the system reliability provided by all plans is below the index generally considered acceptable.

5. If generating units that are large with respect to system load are installed as proposed in the four budget plans, a low index of reliability must be anticipated unless additional reserve capacity is installed.

CORRECTION

THE PRECEDING DOCUMENT(S) HAS BEEN REPHOTOGRAPHED TO ASSURE LEGIBILITY
SEE FRAME(S) IMMEDIATELY FOLLOWING

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3. The Hawaiian Electric Company index of reliability for the 1956-1961 period based on the expected forced outage rates as derived in this report was lower than that normally considered adequate. Likewise, the reliability based on the lower experienced forced outage rates was also inadequate.

4. Based on expected forced outage rates Budget Plans 1 and 2 for the 1962-1970 period yield a higher index of reliability than has been experienced in the past. However, the system reliability provided by all plans is below the index generally considered acceptable.

5. If generating units that are large with respect to system load are installed as proposed in the four budget plans, a low index of reliability must be anticipated unless additional reserve capacity is installed.

APPENDIX

CORRECTION

THE PRECEDING DOCUMENT(S) HAS
BEEN REPHOTOGRAPHED TO ASSURE
LEGIBILITY
SEE FRAME(S)
IMMEDIATELY FOLLOWING

APPENDIX

Exhibit 1

1962 GENERATING CAPABILITY
Megawatts

Plant	Unit	Throttle Temperature And Pressure Degrees F	Psig	Turbine Name Plate Rating	Net Capability
Honolulu	1	651.4	265	40(a).	30
	5	700	430	20	23
	7	900	650	35	42
	8	950	1250	40	55
	9	950	1250	50	60
Plant Total					210
Waiau	1	825	650	7.5	8
	2	825	650	15	18
	3	900	850	40	52
	4	900	850	40	52
	5	950	1250	50	60
	6	950	1250	50	57
Plant Total					247
Total System Capability					457

(a) 4 - 10 megawatt turbines (Units 1, 2, 3 and 6)

Exhibit 2

1956 - 1961
GENERATION, LOAD AND RESERVE CAPACITY

Year	Unit Addition				System Net Capability Mw	Peak Load Mw	Reserve Capacity	
	Unit	Date	Rating Mw	Capability Mw			Mw	% of Peak
1956					280	204	76	37.2
1957	Honolulu 9	12/9	50	60	340	227	113	49.8
1958					340	248	92	37.1
1959	Waiau 5	10/9	50	60	400	287	113	39.4
1960					400	313	87	27.8
1961	Waiau 6	7/28	50	57	457	341	116	34.0

Exhibit 3

BUDGET PLAN 1
Generation Expansion Pattern

Year	Unit Addition: Unit	Date	Rating Mw	Capability Mw	System Net Capability Mw	Peak Load Mw	Reserve Capacity: Mw	% of Peak
1962					457	369	88	23.8
1963	Kahe 1	3/1	75	82.5	539.5	399	140.5	35.2
1964	Kahe 2	11/1	75	82.5	622	430	192	44.6
1965					622	465	157	33.8
1966	Kahe 3	11/1	100	110	732	502	230	45.8
1967					732	542	190	35.1
1968	Kahe 4	11/1	100	110	842	585	257	43.9
1969					842	632	210	33.2
1970					842	683	159	23.3

Exhibit 4

BUDGET PLAN 2
Generation Expansion Pattern

	Unit Addition				System Net	Peak	Reserve Capacity	
Year	Unit	Date	Rating Mw	Capability Mw	Capability Mw	Load Mw	Mw	% of Peak
1962					457	369	88	23.8
1963	Kahe 1	3/1	75	82.5	539.5	399	140.5	35.2
1964	Kahe 2	11/1	75	82.5	622	430	192	44.6
1965					622	465	157	33.8
1966	Kahe 3	11/1	75	82.5	704.5	502	202.5	40.3
1967					704.5	542	162.5	30.0
1968	Kahe 4	11/1	75	82.5	787	585	202	34.5
1969					787	632	155	24.5
1970					787	683	104	15.2

Exhibit 5

BUDGET PLAN 3
Generation Expansion Pattern

Year	Unit Addition: Unit	Date	Rating Mw	Capability Mw	System Net Capability Mw	Peak Load Mw	Reserve Capacity Mw	Reserve Capacity % of Peak
1962					457	369	88	23.8
1963	Kahe 1	3/1	75	82.5	539.5	399	140.5	35.2
1964					539.5	430	109.5	25.4
1965	Kahe 2	3/1	75	82.5	622	465	157	33.8
1966					622	502	120	23.9
1967	Kahe 3	3/1	100	110	732	542	190	35.1
1968					732	585	147	25.1
1969	Kahe 4	3/1	100	110	842	632	210	33.2
1970					842	683	159	23.3

Exhibit 6

BUDGET PLAN 4
Generation Expansion Pattern

Year	Unit Addition: Unit	Unit Addition: Date	Unit Addition: Rating Mw	Unit Addition: Capability Mw	System Net Capability Mw	Peak Load Mw	Reserve Capacity: Mw	Reserve Capacity: % of Peak
1962					457	369	88	23.8
1963	Kahe 1	3/1	75	82.5	539.5	399	140.5	35.2
1964					539.5	430	109.5	25.4
1965	Kahe 2	3/1	75	82.5	622	465	157	33.8
1966					622	502	120	23.9
1967	Kahe 3	3/1	75	82.5	704.5	542	162.5	30.0
1968					704.5	585	119.5	20.4
1969	Kahe 4	3/1	75	82.5	787	632	155	24.5
1970					787	683	104	15.2

Exhibit 7
Sheet 1 of 2

1956 - 1961
MAINTENANCE SCHEDULE
Week Numbers (a)

Plant	Unit	1956	1957	1958	1959	1960	1961
Honolulu	1	29-32	33-34	33-34 42-43	0	1-4	9-11
	5	34-36	30-32	37-40	0	5-8	6-8 12
	7	22-27	24-29	9-16	0	25-30	30 49-52
	8	15-20	23	17-19	8-12	9-10	31
	9	-	0	0	3-6	11-14	0
Waiau	1	41-42	11-13	33	30-31	48-50	0
	2	38-39	14-15	31-32	30-31	36-40	0
	3	10-13	19-21	26-30	13-20	16-19	41-45
	4	5-8	16-18	6-8 20-25	22-28	20-23	35-40
	5	-	-	-	0	31-35	33-34
	6	-	-	-	-	-	0

(a) For example Honolulu Unit 1 is on scheduled maintenance for the period starting the 29th week and extending through the 32nd week in 1956.

Exhibit 7
Sheet 2 of 2

1962 - 1970
MAINTENANCE SCHEDULE
Week Numbers

Plant	Unit	1962	1963	1964	1965	1966	1967	1968	1969	1970
Honolulu	1	0	6-9	6-9	5-8	5-8	5-8	5-8	5-8	4-6
	5	32-37	1-5	1-5	1-4	1-4	1-4	1-4	1-4	1-3
	7	0	10-13	48-52	41-46	47-52	41-46	49-52	45-48	37-39
	8	8-13	14-18	10-14	9-13	9-12	9-12	9-12	9-12	7-10
	9	14-17	25-31	20-23	20-23	17-20	17-20	17-20	17-20	15-18
Waiau	1	3-7	49-52	40-43	47-52	40-46	47-52	40-43	49-52	40-44
	2	3-7	49-52	36-39	47-52	40-46	47-52	40-43	49-52	40-44
	3	0	39-43	32-35	33-36	33-36	33-36	37-39	37-40	45-48
	4	0	44-48	44-47	37-40	37-39	37-40	44-48	41-44	49-52
	5	0	32-38	28-31	29-32	29-32	29-32	33-36	33-36	34-36
	6	19-25	19-24	15-19	14-19	13-16	13-16	13-16	13-16	11-14
Kahe	1	-	0	24-27	24-28	21-24	21-24	21-24	21-24	19-22
	2	-	-	-	-	25-28	25-28	25-28	25-28	23-26
	3	-	-	-	-	-	-	29-32	29-32	27-30
	4	-	-	-	-	-	-	-	-	31-33

Exhibit 8

1955 - 1961
EXPERIENCED FORCED OUTAGE RATES
PERCENT

Plant	Unit	Annual Outage Rate 1955	1956	1957	1958	1959	1960	1961	Average Outage Rate
Honolulu	1	10.00	6.75	0	0	0	72.05	0	12.70
	5	0	0.82	0	2.62	0	0	0	0.49
	7	0	0.86	0	0.92	8.53	0	0.83	1.59
	8	-	0	0.77	0	1.27	0	0	0.34
	9	-	-	-	-	0	1.22	1.15	0.79
Waiau	1	0	0	0	0	0	1.10	0	0.16
	2	0.48	0	2.86	0	0.41	0	0	0.54
	3	0	0	0.41	0.44	0.90	0.41	3.00	0.74
	4	0	0	0.83	0.94	0	0.82	0	0.37
	5	-	-	-	-	-	-	0.40	0.40

Exhibit 9

EXPECTED FORCED OUTAGE RATES

Plant	Unit	Turbine Name Plate Rating - Mw	Net Capability Mw	Forced Outage Rate - %
Honolulu	1	40	30	1.6
	5	20	23	1.6
	7	35	42	1.5
	8	40	55	1.4
	9	50	60	1.4
Waiau	1	7.5	8	1.5
	2	15	18	1.5
	3	40	52	1.3
	4	40	52	1.3
	5	50	60	1.4
	6	50	57	1.4
Kahe	1	75	83	1.6
	2	75	83	1.6
	3	75	83	1.6
	3	100	110	1.8
	4	75	83	1.6
	4	100	110	1.8

Exhibit .10

COMPARISON OF FORCED OUTAGE RATES

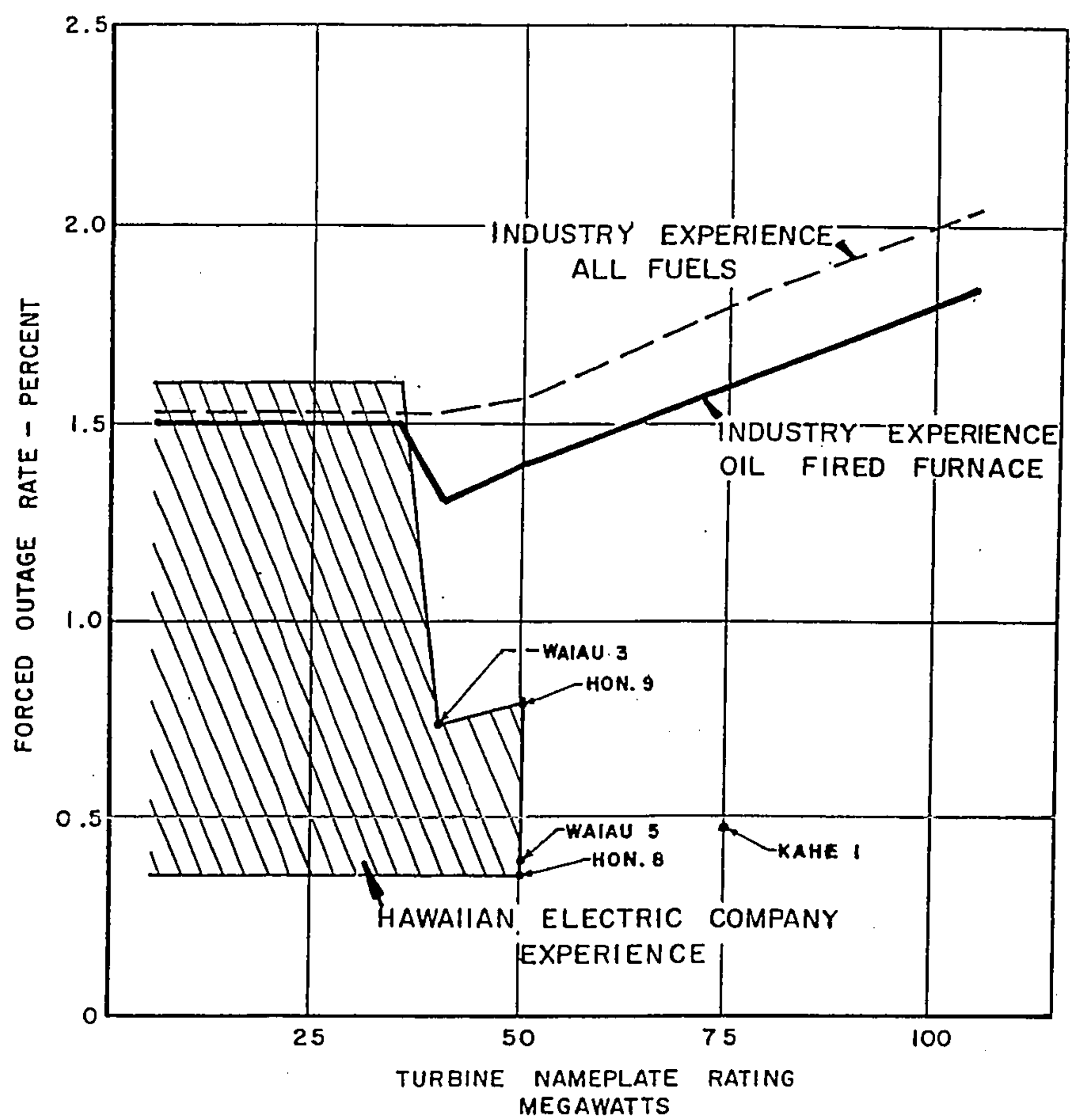


Exhibit 11

1956 - 1961
SYSTEM RELIABILITY

Year	Years Per One Day Loss of Load: Experienced Outage Rates	Years Per One Day Loss of Load: Expected Outage Rates
1956	1.70	0.63
1957	0.97	0.37
1958	7.65	2.88
1959	0.59	0.23
1960	5.82	1.63
1961	0.51	0.30

Exhibit 12

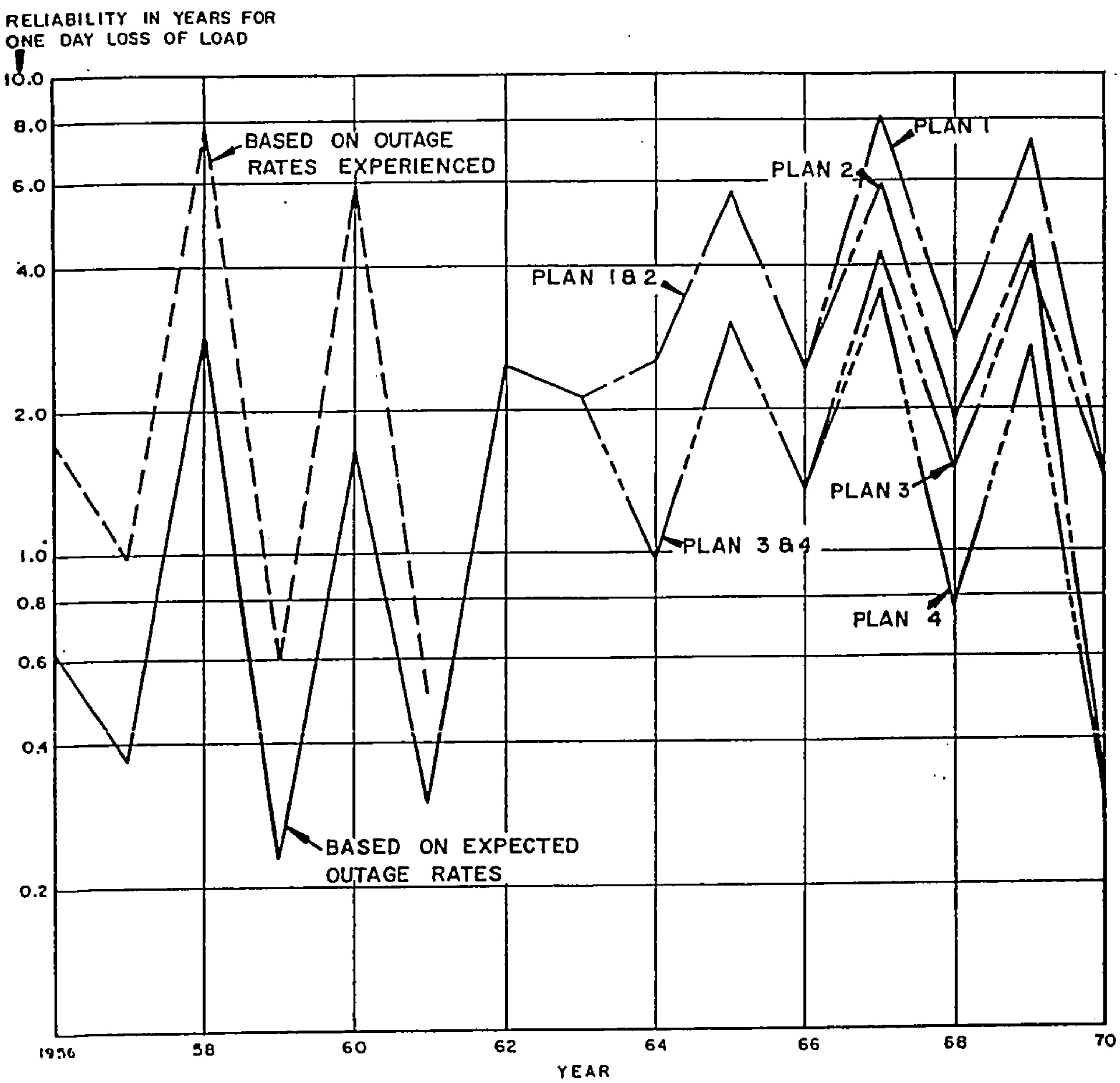
1962 - 1970
SYSTEM RELIABILITY

Year	Years Per One Day Loss of Load				
	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5 (a)
1962	2.48	2.48	2.48	2.48	17.57
1963	2.12	2.12	2.12	2.12	13.20
1964	2.51	2.51	0.96	0.96	11.12
1965	5.62	5.62	3.02	3.02	29.87
1966	2.42	2.41	1.33	1.33	11.22
1967	8.02	5.90	4.22	3.55	64.81
1968	2.73	1.88	1.49	0.75	9.44
1969	7.13	4.50	3.99	2.68	50.25
1970	1.35	0.29	1.35	0.29	8.25

(a) Plan 5 is the same as Plan 4 except that peaking capacity equal to ten percent of the annual peak load has been installed.

Exhibit 13

1956 - 1970
SYSTEM RELIABILITY



C A Inc R - 920

LINDA LINGLE
GOVERNOR

JAMES R. AIONA, JR.
LT. GOVERNOR

MARK E. RECKTENWALD
DIRECTOR

CHERYL S. KIKUTA
ACTING EXECUTIVE DIRECTOR

STATE OF HAWAII
DIVISION OF CONSUMER ADVOCACY
DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS
P. O. BOX 541
HONOLULU, HAWAII 96809

FILED
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PUBLIC UTILITIES COMMISSION

March 17, 2003

Mr. William A. Bonnet
Vice President-Government and Community Affairs
Hawaiian Electric Company, Incorporated
P.O. Box 2750
Honolulu, Hawaii 96840-0001

Dear Mr. Bonnet:

RE: Hawaiian Electric Company, Inc. – Adequacy of Supply Report, dated January 31, 2003.

We would appreciate receiving responses to the attached submission of information requests to facilitate our review in the above matter. In order to complete our review, we would appreciate receiving your responses by April 7, 2003.

In you are unable to respond by this date or if there are any questions or concerns regarding the information requests, please call Cheryl Kikuta at (808) 586-2765. Your prompt attention to this matter will be greatly appreciated.

Sincerely yours,

Cheryl S. Kikuta

Cheryl S. Kikuta
Acting Executive Director

CSK:mc
Enclosure

c: Public Utilities Commission

HAWAIIAN ELECTRIC COMPANY, INC.

FIRST SUBMISSION OF INFORMATION REQUESTS

INSTRUCTIONS

In order to expedite and facilitate the Consumer Advocate's review and analysis in the above matter, the following is requested:

1. For each response, the Company should identify the person who is responsible for preparing the response as well as the witness who will be responsible for sponsoring the response should there be an evidentiary hearing;
2. Unless otherwise specifically requested, for applicable schedules or workpapers, the Company should provide hard copies of each schedule or workpaper together with one copy of each such schedule or workpaper on electronic media in a mutually agreeable format (e.g., Excel and Quattro Pro, to name two examples); and
3. When an information request makes reference to specific documentation used by the Company to support its response, it is not intended that the response be limited to just the specific document referenced in the request. The response should include any non-privileged memoranda, internal or external studies, assumptions, Company instructions, or any other relevant authoritative source which the Company used.
4. Should the Company claim that any information is not discoverable for any reason:
   a. State all claimed privileges and objections to disclosure;

b. State all facts and reasons supporting each claimed privilege and objection;

c. State under what conditions the Company is willing to permit disclosure to the Consumer Advocate (e.g., protective agreement, review at business offices, etc.); and

d. If the Company claims that a written document or electronic file is not discoverable, besides complying with subparagraphs 4(a-c), identify each document or electronic file, or portions thereof, that the Company claims are privileged or will not be disclosed, including the title or subject matter, the date, the author(s) and the addressee(s).

HAWAIIAN ELECTRIC COMPANY, INC.

FIRST SUBMISSION OF INFORMATION REQUESTS

CA-IR-1 **Ref: *Adequacy of Supply* report, dated January 31, 2003.**

Footnote 3, page 2 of HECO's *Adequacy of Supply* report, dated January 31, 2003, states that:

> Also included in HECO's capacity planning criteria is a reliability guideline. The guideline states: *"Capacity planning analysis will include a calculation of risk (Loss of Load Probability) in years per day for each year of each plan of the long-range expansion study. In cases where risk is calculated to be less than 4.5 years per day, the plan will be reviewed by the Vice President of Power Supply and the President for approval of use of the plan in the study."*

a. Please provide a discussion on the following aspects of the Company's use of "loss of load probability":

  1. Please confirm that HECO's use of a 4.5 years per day factor for loss of load probability represents the threshold of an allowable instance of at least one day every 4.5 years where system peak exceeds the system generation capacity.

2. Please confirm that HECO's criteria means that, if the resulting loss of load probability is less than 4.5 years per day, the Vice President of Power Supply and President of HECO must approve the plan before it is used because that lower factor (which translates into higher reliability) would probably entail greater capital investment costs or capital investments being spent sooner than under HECO's other generation planning criteria.

3. Please provide examples using actual or hypothetical examples of HECO's loss of load probability calculations.

b. Please explain how the Company determined the threshold for the loss of load probability of 4.5 years per day. Please include the workpapers and/or documentation used to determine the threshold as well as industry standards relied upon, if any.

c. Please explain why HECO has included this reliability guideline in its capacity planning criteria.

d. In response to TGC-RIR-1001e. in Docket No. 99-0207, HELCO stated that:

> A Loss of Load Probability (LOLP) guideline would be expected to result in generating units being added sooner than with [HELCO's] current criterion. Sooner unit additions, while increasing the reliability of the generating system by reducing the probability of loss of load, would result in higher costs for customers. HELCO has not made a determination that the cost to its customers of adding generation based on an LOLP guideline is necessary at this time, or that the benefits would outweigh the cost.

1. Please confirm that HECO's Loss of Load Probability guideline is still not part of HELCO's capacity planning criteria for the reasons discussed in the response to TGC-RIR-1001e., in Docket No. 99-0207.

2. Please confirm that HECO's Loss of Load Probability guideline is not part of MECO's capacity planning criteria and, if so, please explain why HECO's Loss of Load Probability guideline is not part of MECO's capacity planning criteria.

3. HECO's 2002 Evaluation Report Regarding Integrated Resource Planning, dated December 2002 filed in Docket No. 95-0347 concluded that the next generating unit is still projected to be required in 2009.

(a) Please confirm that the Loss of Load Probability guideline was used in HECO's capacity planning criteria to determine that the next generating unit is projected to be required in 2009.

(b) Please confirm that HECO's generation planning criteria consists of the factors listed in response to TGC-RIR-1007a. If HECO's generation planning criteria have been revised, please provide the revised criteria.

(c) Please identify when the next generating unit would be required in HECO's system if the Loss of Load Probability guideline was excluded from HECO's generation planning criteria.

4. Please identify when the Company included the reliability guideline listed above in its capacity planning criteria.

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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PUBLIC UTILITIES COMMISSION

January 31, 2003

William A. Bonnet
Vice President
Government and Community Affairs

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Adequacy of Supply
Hawaiian Electric Company, Inc.

In accordance with paragraph 5.3a. of General Order No. 7, the following information is respectfully submitted.

HECO's 2002 system peak occurred on Thursday, October 3, 2002 and was 1,250,000 kW-gross or 1,204,000 kW-net based on net HECO generation, net purchased power generation, the peak reduction benefits of energy efficiency demand-side management programs implemented in mid-1996, and with several cogenerators[1] operating at the time. Had these cogenerating units not been operating, the 2002 system peak would have been 1,270,000 kW-gross or 1,224,000 kW-net. Oahu had a reserve margin of approximately 32% over the 2002 system net peak.[2]

HECO's 2002 total generating capability of 1,615,000 kW-net includes 406,000 kW-net of firm power purchased from (1) Kalaeloa Partners, L.P.; (2) AES Hawaii, Inc.; and (3) H-POWER.

HECO also has power purchase contracts with two as-available energy producers. Since these contracts are not for firm capacity, they are not reflected in HECO's total generating capability.

Attachment 1 shows the expected reserve margin over the next three years, based on HECO's Sales and Peak Forecast, dated August 2002, and on HECO's latest estimate of forecasted DSM impacts for 2002. Attachment 2 details the gross and net ratings of HECO units IPP units.

1 At the time of the peak, Tesoro, Chevron, and Pearl Harbor were generating an estimated 20,000 kW of power.
2 The reserve margin calculation takes into account the 5,000 kW interruptible load served by HECO.

The following method is used to determine the timing of an additional generation unit:

> *The total capability of the system plus the total amount of interruptible loads must at all times be equal to or greater than the summation of the following:*
>
> a. *the capacity needed to serve the estimated system peak load;*
>
> b. *the capacity of the unit scheduled for maintenance; and*
>
> c. *the capacity that would be lost by the forced outage of the largest unit in service.*[3]

The method used to determine the timing of an additional generation unit accounts for interruptible loads. HECO will not build reserve capacity to serve interruptible loads.

HECO's generation capacity for Oahu for the next three years is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies.

Very truly yours,

Attachment

cc: Division of Consumer Advocacy

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[3] Also included in HECO's capacity planning criteria is a reliability guideline. The guideline states: "*Capacity planning analysis will include a calculation of risk (Loss of Load Probability) in years per day for each year of each plan of the long-range expansion study. In cases where risk is calculated to be less than 4.5 years per day, the plan will be reviewed by the Vice President of Power Supply and the President for approval of use of the plan in the study.*"

ADEQUACY OF SUPPLY
Hawaiian Electric Company, Inc.
January 31, 2003

			Without Future DSM (Includes Acquired DSM) [1]		With Future DSM (Includes Acquired DSM) [2]	
Year	**System Net Capability at the Peak, kW [3] (A)**	**Interruptible Load, kW[4] (B)**	**System Net Peak, kW (C)**	**Reserve Margin, % (A+B-C) / C**	**System Net Peak, kW (D)**	**Reserve Margin, % (A+B-D) / D**
Recorded						
2002	1,615,000	5,000	1,224,000	32%	N/A	N/A
Forecasted						
2003	1,615,000	5,000	1,255,700	29%	1,248,000	30%
2004	1,615,000	11,900	1,283,900	27%	1,273,000	28%
2005	1,615,000	22,300	1,308,800	25%	1,294,000	27%

Notes:

(1) System Peaks (Without Future Peak Reduction Benefits of 20-Yr DSM Programs):

- Implementation of full-scale DSM programs began in the second half of 1996 following Commission approval of the programs. The forecasted system peaks values for the years 2003-2005 include the actual peak reduction benefits acquired in 1996 - 2001 and also include the estimated peak reduction benefits acquired in 2002.
- Peaks include 20,000 kW of standby load for the following cogenerators:

Tesoro	18.0
Chevron	0.0
Pearl Harbor	2.0
	20.0 MW

- In 2002, the estimated peak reduction benefit of the DSM programs was 3,300 net-kW (net of free riders). Without this peak reduction benefit, the recorded system net peak of 1,224,000 kW in 2002, which includes 20,000 kW of standby load, would have been 1,227,300 kW.
- The forecasted system peaks (2003-2005) are evening peaks based on the peak forecast dated August 2002.

(2) System Peak (With Peak Reduction Benefits of the DSM Programs):

- The forecasted peaks for 2003-2005 include the estimated DSM peak reduction benefits filed with the Public Utilities Commission in May 2000. Peaks include 20,000 kW of standby load. See Note 1, bullet 2.

(3) System Capability includes:

- HECO units at a total normal capability of 1,209,000 kW-net or 1,263,000 kW-gross.
- Firm power purchase contracts have a combined net total of 406,000 kW from Kalaeloa (180,000 kW), AES Hawaii (180,000 kW), and H-POWER (46,000 kW).

(4) Interruptible Loads:

- Includes existing Rider I interruptible loads of 5,000 kW
- HECO plans to implement a dispatchable commercial & industrial load program and a residential direct load control program beginning in 2004, and the estimated interruptible peak loads under these new programs are included beginning in 2004.

ADEQUACY OF SUPPLY
Hawaiian Electric Company, Inc.
January 31, 2003
2002 Through 2005 Unit Ratings (Firm Capacity)

Unit	NTL Rating (Gross MW)	NTL Rating (Net MW)
Honolulu 8	56.0	52.9
Honolulu 9	57.0	54.4
Waiau 3	49.0	46.2
Waiau 4	49.0	46.4
Waiau 5	57.0	54.6
Waiau 6	58.0	55.6
Waiau 7	92.0	88.1
Waiau 8	92.0	88.1
Waiau 9	52.0	51.9
Waiau 10	50.0	49.9
Kahe 1	92.0	88.2
Kahe 2	90.0	86.3
Kahe 3	92.0	88.2
Kahe 4	93.0	89.2
Kahe 5	142.0	134.7
Kahe 6	142.0	133.9
HECO Total	1,263.0	1,208.6
Kalaeloa Partners LP	180.0 (1)	180.0
H-POWER	46.0 (1)	46.0
AES	180.0 (1)	180.0
IPP Total	406.0	406.0
System Total	1,669.0	1,614.6

Notes
(1) IPP ratings in Net MWs only

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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2002 JAN 31 P 4: 05
PUBLIC UTILITIES COMMISSION

William A. Bonnet
Vice President
Government and Community Affairs

January 31, 2002

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Adequacy of Supply
Hawaiian Electric Company, Inc.

In accordance with paragraph 5.3a. of General Order No. 7, the following information is respectfully submitted.

HECO's 2001 system peak occurred on Thursday, October 25, 2001 and was 1,233,000 kW-gross or 1,191,000 kW-net based on net HECO generation, net purchased power generation, the peak reduction benefits of energy efficiency demand-side management programs implemented in mid-1996, and with several cogenerators[1] operating at the time. Had these cogenerating units not been operating, the 2001 system peak would have been 1,255,000 kW-gross or 1,213,000 kW-net. Oahu had a reserve margin of approximately 34% over the 2001 system net peak.[2]

HECO's 2001 total generating capability of 1,615,000 kW-net includes 406,000 kW-net of firm power purchased from (1) Kalaeloa Partners, L.P.; (2) AES Hawaii, Inc.; and (3) H-POWER.

HECO also has power purchase contracts with several as-available energy producers. Since these contracts are not for firm capacity, they are not reflected in HECO's total generating capability.

The attached table shows the expected reserve margin over the next three years, based on HECO's Sales and Peak Forecast, dated November 2001, and on HECO's latest estimate of forecasted DSM impacts for 2001.

[1] At the time of the peak, Tesoro, Chevron, and Pearl Harbor were capable of generating 22,500 kW of power.

[2] The reserve margin calculation takes into account the 5,000 kW interruptible load served by HECO.

The following method is used to determine the timing of an additional generation unit:

> *The total capability of the system plus the total amount of interruptible loads must at all times be equal to or greater than the summation of the following:*
>
> a. *the capacity needed to serve the estimated system peak load;*
>
> b. *the capacity of the unit scheduled for maintenance; and*
>
> c. *the capacity that would be lost by the forced outage of the largest unit in service.*[3]

The method used to determine the timing of an additional generation unit accounts for interruptible loads. HECO will not build reserve capacity to serve interruptible loads.

HECO's generation capacity for Oahu for the next three years is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies.

Very truly yours,

Attachment

cc: Division of Consumer Advocacy

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3 Also included in HECO's capacity planning criteria is a reliability guideline. The guideline states:

> *"Capacity planning analysis will include a calculation of risk (Loss of Load Probability) in years per day for each year of each plan of the long-range expansion study. In cases where risk is calculated to be less than 4.5 years per day, the plan will be reviewed by the Vice President of Power Supply and the President for approval of use of the plan in the study."*

ADEQUACY OF SUPPLY
Hawaiian Electric Company, Inc.
January 31, 2002

			Without Future DSM (Includes Acquired DSM) [1]		With Future DSM (Includes Acquired DSM) [2]	
Year	**System Net Capability at the Peak, kW [3] (A)**	**Interruptible Load, kW[4] (B)**	**System Net Peak, KW (C)**	**Reserve Margin, % (A+B-C) / C**	**System Net Peak, kW (D)**	**Reserve Margin, % (A+B-D) / D**
Recorded						
2001	1,615,000	5,000	1,213,000	34%	N/A	N/A
Forecasted						
2002	1,615,000	5,000	1,241,000	31%	1,231,000	32%
2003	1,615,000	5,000	1,256,000	29%	1,241,000	31%
2004	1,615,000	5,000	1,287,000	26%	1,267,000	28%

Notes:

(1) System Peaks (Without Future Peak Reduction Benefits of DSM Programs):

- Implementation of full-scale DSM programs began in the second half of 1996 following Commission approval of the programs. The forecasted system peaks values for the years 2002-2004 include the actual peak reduction benefits acquired in 1996 - 2000 and also include the estimated impacts acquired in 2001.
- Peaks include 22,500 kW of standby load for the following cogenerators:

Tesoro	18.2
Chevron	2.3
Pearl Harbor	2.0
	22.5 MW

- In 2001, the estimated peak reduction benefit of the DSM programs was 3,900 net-kW (net of free riders). Without this peak reduction benefit, the recorded system net peak of 1,213,000 kW in 2001, which includes 22,500 kW of standby load, would have been 1,216,900 kW.
- The forecasted system peaks (2002-2004) are evening peaks based on the peak forecast dated November 2001.

(2) System Peak (With Peak Reduction Benefits of the DSM Programs):

- The forecasted peaks of 2002-2004 include the estimated DSM peak reduction benefits filed with the Public Utilities Commission in May 2000. Peaks include 22,500 kW of standby load. See Note 1, bullet 2.

(3) System Capability includes:

- HECO units at a total normal capability of 1,209,000 kW-net or 1,263,000 kW-gross.
- Firm power purchase contracts have a combined net total of 406,000 kW from Kalaeloa (180,000 kW), AES Hawaii (180,000 kW), and H-POWER (46,000 kW).

(4) Interruptible Loads:

- Includes existing Rider I interruptible loads.
- On November 13, 2001, HECO withdrew its application for approval of its commercial and industrial capacity buyback program. HECO will evaluate load management DSM programs in its next cycle of IRP and in its next rate case proceeding.

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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2001 JAN 31 P 3:45

PUBLIC UTILITIES
COMMISSION

January 31, 2001

Edward Y. Hirata
Vice President
Regulatory Affairs
Government Relations

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Adequacy of Supply
Hawaiian Electric Company, Inc.

In accordance with paragraph 5.3a. of General Order No. 7, the following information is respectfully submitted.

HECO's 2000 system peak occurred on Wednesday, November 1, 2000 and was 1,203,000 kW-gross or 1,164,000 kW-net based on net HECO generation, net purchased power generation, the peak reduction benefits of energy efficiency demand-side management programs implemented in mid-1996, and with several cogenerators[1] operating at the time. Had these cogenerating units not been operating, the 2000 system peak would have been 1,224,300 kW-gross or 1,185,300 kW-net. Oahu had a reserve margin of approximately 37% over the 2000 system net peak.

HECO's 2000 total generating capability of 1,615,000 kW-net includes 406,000 kW-net of firm power purchased from (1) Kalaeloa Partners, L.P.; (2) AES-Hawaii, Inc.; and (3) HPOWER.

HECO also has power purchase contracts with several cogenerators. Since these contracts are not for firm capacity, they are not reflected in HECO's total generating capability.

The attached table shows the expected reserve margin over the next three years, based on HECO's Sales and Peak Forecast, dated May 2000, and on HECO's latest estimate of forecasted DSM impacts for 2000.

1 At the time of the peak, Tesoro, Chevron, and Pearl Harbor were self-generating 21,300 kW of power.

The following method is used to determine the timing of an additional generation unit:

The total capability of the system plus the total amount of interruptible loads must at all times be equal to or greater than the summation of the following:

a. *the capacity needed to serve the estimated system peak load;*

b. *the capacity of the unit scheduled for maintenance; and*

c. *the capacity that would be lost by the forced outage of the largest unit in service.*

The method used to determine the timing of an additional generation unit accounts for interruptible loads. HECO will not build reserve capacity to serve interruptible loads.

HECO's generation capacity for Oahu for the next three years is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies.

Very truly yours,

Attachment

cc: Division of Consumer Advocacy

ADEQUACY OF SUPPLY
Hawaiian Electric Company, Inc.
January 31, 2001

			Without Future DSM (Includes Acquired DSM) (2)		With Future DSM (Includes Acquired DSM) (3)	
Year	System Net Capability at the Peak, kW (1) (A)	Interruptible Load, kW(4) (B)	System Net Peak, KW (C)	Reserve Margin, % (A+B-C) / C	System Net Peak, kW (D)	Reserve Margin, % (A+B-D) / D
Recorded						
2000	1,615,000	5,000	1,185,300	37%	N/A	N/A
Forecasted						
2001	1,615,000	5,000	1,197,000	35%	1,190,000	36%
2002	1,615,000	5,000	1,220,000	33%	1,208,000	34%
2003	1,615,000	5,900	1,244,000	30%	1,228,000	32%

Notes:

(1) System Capability includes:
- HECO units at a total normal capability of 1,209,000 kW-net or 1,263,000 kW-gross.
- Firm power purchase contracts have a combined net total of 406,000 kW from Kalaeloa (180,000 kW), AES-Hawaii (180,000 kW), and HPOWER (46,000 kW).

(2) System Peaks (Without Future Peak Reduction Benefits of 20-Yr DSM Programs):
- Implementation of full-scale DSM programs began in the second half of 1996 following Commission approval of the programs. The forecasted system peaks include the peak reduction benefits acquired in 1996 - 1999 and embedded in the base peak forecast, but exclude the peak reduction benefits acquired in 2000 and to be acquired in the future.
- Peaks include 22,000 kW of standby load for the following cogenerators:

Tesoro	18.2
Chevron	1.3 (1MW of 2.3 MW total was assumed in the peak forecast)
Pearl Harbor	2.5
	22.0 MW

- In 2000, the estimated peak reduction benefit of the DSM programs was 4,300 net-kW (net of free riders). Without this peak reduction benefit, the recorded system net peak of 1,185,300 kW in 2000, which includes 22,000 kW of standby load, would have been 1,189,600 kW.

- The forecasted system peaks (2001-2003) are evening peaks based on the peak forecast dated May 2000.
- System Peak values for the years 2001-2003 include Acquired DSM through the year 1999. System Peak recorded values for the year 2000 include Acquired DSM through the year 2000.

(3) System Peak (With Peak Reduction Benefits of the DSM Programs):

- The forecasted peaks of 2001-2003 include the estimated peak reduction benefits from the continuation of the current DSM programs.
- Peaks include 22,000 kW of standby load. See Note 2.

(4) Interruptible Loads:

- Includes existing Rider I interruptible loads and forecasted Capacity Buy-Back loads.
- Impacts for the Capacity Buy-Back Program are assumed to begin in 2003.

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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2000 JAN 31 P 4: 13

PUBLIC UTILITIES COMMISSION

January 31, 2000

Edward Y. Hirata
Vice President
Regulatory Affairs
Government Relations

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Adequacy of Supply
Hawaiian Electric Company, Inc.

In accordance with paragraph 5.3a. of General Order No. 7, the following information is respectfully submitted.

HECO's 1999 system peak occurred on Tuesday, December 14, 1999 and was 1,161,000 kW-gross or 1,120,000 kW-net based on net HECO generation, net purchased power generation, the peak reduction benefits of energy efficiency demand-side management programs implemented in mid-1996, and with the Tesoro cogenerating unit operating at the time. Had the Tesoro unit not been operating, the 1999 system peak would have been 1,178,000 kW-gross or 1,137,000 kW-net. Oahu had a reserve margin of approximately 43% over the 1999 system net peak.

HECO's 1999 total generating capability of 1,615,000 kW-net includes 406,000 kW-net of firm power purchased from (1) Kalaeloa Partners, L.P.; (2) AES-Hawaii, Inc.; and (3) HPOWER.

HECO also has power purchase contracts with several cogenerators. Since these contracts are not for firm capacity, they are not reflected in HECO's total generating capability.

The attached table shows the expected reserve margin over the next three years, based on HECO's Sales and Peak Forecast, dated April 1999, and on HECO's latest estimate of forecasted DSM impacts for 1999.

The following method is used to determine the timing of an additional generation unit:

The total capability of the system plus the total amount of interruptible loads must at all times be equal to or greater than the summation of the following:

a. *the capacity needed to serve the estimated system peak load;*

b. *the capacity of the unit scheduled for maintenance; and*

c. *the capacity that would be lost by the forced outage of the largest unit in service.*

The method used to determine the timing of an additional generation unit accounts for interruptible loads. HECO will not build reserve capacity to serve interruptible loads.

HECO's generation capacity for Oahu for the next three years is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies.

Very truly yours,

Edward [signature]

Attachment

cc: Division of Consumer Advocacy

ADEQUACY OF SUPPLY
Hawaiian Electric Company, Inc.
January 31, 2000

			Without Peak Reduction Benefits of 20-Yr Energy Efficiency DSM Programs[2] (Includes Acquired DSM)		With Peak Reduction Benefits of 20-Yr Energy Efficiency DSM Programs[3] (Includes Acquired DSM)	
Year	**System Net Capability at the Peak, kW [1] (A)**	**Interruptible Load, kW[4] (B)**	**System Net Peak, KW (C)**	**Reserve Margin, % (A+B-C) / C**	**System Net Peak, kW (D)**	**Reserve Margin, % (A+B-D) / D**
Recorded						
1999	1,615,000	N/A	1,137,000	43%	N/A	N/A
Forecasted						
2000	1,615,000	6,000	1,172,000	38%	1,158,000	40%
2001	1,615,000	6,000	1,183,000	37%	1,161,000	40%
2002	1,615,000	6,900	1,201,000	35%	1,172,000	38%

Notes:

(1) System Capability includes:
- HECO units at a total normal capability of 1,209,000 kW-net or 1,263,000 kW-gross.
- Firm power purchase contracts have a combined net total of 406,000 kW from Kalaeloa (180,000 kW), AES-Hawaii (180,000 kW), and HPOWER (46,000 kW).

(2) System Peaks (Without Future Peak Reduction Benefits of 20-Yr DSM Programs):
- Implementation of full-scale DSM programs began in the second half of 1996 following Commission approval of the programs. The forecasted system peaks include the peak reduction benefits acquired in 1996 - 1998 and embedded in the base peak forecast but exclude the peak reduction benefits acquired in 1999 and to be acquired in the future.
- Peaks include 17,000 kW for Tesoro load.
- In 1999, the estimated peak reduction benefit of the DSM programs was approximately 4,700 net-kW (net of free riders). Without this peak reduction benefit, the recorded system net peak of 1,137,000 kW in 1999, which includes 17,000 kW of Tesoro load, would have been 1,141,700 kW.
- The forecasted system peaks (2000-2002) are evening peaks based on the peak forecast dated April 1999 and do not include the peak reduction benefits of 20-Yr

DSM programs from 1999 and on, but do include the peak reduction benefits acquired from DSM programs implemented in 1996 - 1998.

- Forecasted peaks not reduced by existing Rider I interruptible loads and forecasted Capacity Buy-Back loads.

(3) System Peak (With Peak Reduction Benefits of 20-Yr DSM Programs):

- The forecasted peaks of 2000-2002 include the peak reduction benefits of the 20-Yr DSM programs.
- Peaks include 17,000 kW for Tesoro load.
- Forecasted peaks not reduced by existing Rider I interruptible loads and forecasted Capacity Buy-Back loads.

(4) Interruptible Loads:

- Includes existing Rider I interruptible loads and forecasted Capacity Buy-Back loads.
- Impacts for the Capacity Buy-Back Program are assumed to begin in 2002.

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

File

January 29, 1999

Edward Y. Hirata
Vice President
Regulatory Affairs
Government Relations

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99 JAN 29 P 3:59
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Adequacy of Supply
<u>Hawaiian Electric Company, Inc.</u>

In accordance with paragraph 5.3a. of General Order No. 7, the following information is respectfully submitted.

HECO's 1998 system peak occurred on Monday, November 9, 1998 and was 1,175,000 kW-gross or 1,131,000 kW-net based on net HECO generation, net purchased power generation, the peak reduction benefits of energy efficiency demand-side management programs implemented in mid-1996, and with the Tesoro cogenerating unit operating at the time. Had the Tesoro unit not been operating, the 1998 system peak would have been 1,192,000 kW-gross or 1,148,000 kW-net. Oahu had a reserve margin of approximately 41% over the 1998 system net peak.

HECO's 1998 total generating capability of 1,615,000 kW-net includes 406,000 kW-net of firm power purchased from: (1) Kalaeloa Partners, L.P.; (2) AES-Hawaii, Inc.; and (3) HPOWER.

HECO also has power purchase contracts with several cogenerators. Since these contracts are not for firm capacity, they are not reflected in HECO's total generating capability.

The attached table shows the expected reserve margin over the next three years, based on HECO's Sales and Peak Forecast, dated April 1998, and on HECO's latest estimate of forecasted DSM impacts for 1999.

The following method is used to determine the timing of an additional generation unit:

> *The total capability of the system plus the total amount of interruptible loads must at all times be equal to or greater than the summation of the following:*
>
> *a. the capacity needed to serve the estimated system peak load;*
>
> *b. the capacity of the unit scheduled for maintenance; and*
>
> *c. the capacity that would be lost by the forced outage of the largest unit in service.*

The method used to determine the timing of an additional generation unit accounts for interruptible loads. HECO will not build reserve capacity to serve interruptible loads.

Very truly yours,

Edward G. Hee

Attachment

cc: Division of Consumer Advocacy

ADEQUACY OF SUPPLY
Hawaiian Electric Company, Inc.
January 29, 1999

			Without Peak Reduction Benefits of 20-Yr Energy Efficiency DSM Programs[2]		With Peak Reduction Benefits of 20-Yr Energy Efficiency DSM Programs[3]	
Year	System Net Capability at the Peak, kW [1] (A)	Interruptible Load, kW[4] (B)	System Net Peak, kW (C)	Reserve Margin, % (A+B-C) / C	System Net Peak, kW (D)	Reserve Margin, % (A+B-D) / D
Recorded						
1998	1,615,000	6,000	1,153,500	41%	1,148,000	41%
Forecasted						
1999	1,615,000	6,000	1,201,000	35%	1,191,000	36%
2000	1,615,000	8,500	1,218,000	33%	1,195,000	36%
2001	1,615,000	20,800	1,242,000	32%	1,213,000	35%

Notes:

(1) System Capability includes:
- HECO units at a total normal capability of 1,209,000 kW-net or 1,263,000 kW-gross.
- Firm power purchase contracts have a combined net total of 406,000 kW from Kalaeloa (180,000 kW), AES-Hawaii (180,000 kW), and HPOWER (46,000 kW).

(2) System Peaks (Without Future Peak Reduction Benefits of 20-Yr DSM Programs):
- Implementation of full-scale DSM programs began in the second half of 1996 following Commission approval of the programs. The forecasted system peaks include the peak reduction benefits acquired in 1996 and 1997 and embedded in the base peak forecast but exclude the peak reduction benefits acquired in 1998 and to be acquired in the future.
- Peaks are adjusted for 17,000 kW of Tesoro load.
- In 1998, the estimated peak reduction benefit of the DSM programs was 5,500 net-kW (net of free riders). Without this peak reduction benefit, the recorded system net peak of 1,148,000 kW in 1998, which includes 17,000 kW of Tesoro load, would have been 1,153,500 kW.
- The forecasted system peaks (1999-2001) are evening peaks based on the peak forecast dated April 1998 and do not include the peak reduction benefits of 20-Yr DSM programs from 1998 and on, but do include the peak reduction benefits acquired from DSM programs implemented in 1996 and 1997 .

(3) System Peak (With Peak Reduction Benefits of 20-Yr DSM Programs):

- The forecasted peaks of 1999-2001 include the peak reduction benefits of the 20-Yr DSM programs.
- Peaks are adjusted for 17,000 kW of Tesoro load.

(4) Interruptible Loads:

- Includes existing Rider I interruptible loads and forecasted Capacity Buy-Back and Residential Load Control Program loads.
- Impacts for the Capacity Buy-Back and Residential Load Control Programs are assumed to begin in 2000.

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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March 9, 1998

Edward Y. Hirata
Vice President
Regulatory Affairs

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PUBLIC UTILITIES
COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Revision to 1998 Adequacy of Supply
Hawaiian Electric Company, Inc.

This is to correct HECO's 1998 Adequacy of Supply report, which was submitted by transmittal letter dated January 30, 1998.

HECO terminated its wind energy power purchase contracts in 1997[1]. Therefore, the first sentence of the fourth paragraph of the January 30, 1998 letter should be revised as follows:

"HECO also has power purchase contracts with several cogenerators."

For the Commission's convenience, attached is a red-lined copy of the previously submitted first page of HECO's January 30, 1998 transmittal.

Very truly yours,

Edward Y. Hirata

cc: Division of Consumer Advocacy

[1] See HECO's letter to the Commission dated August 25, 1997 in Docket Nos. 5239 (Makani Uwila Purchase Power Contract) and 5281 (Makani Uwila Purchase Power Contract).

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

Red-lined
for correction

January 30, 1998

Edward Y. Hirata
Vice President
Regulatory Affairs

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Adequacy of Supply
Hawaiian Electric Company, Inc.

In accordance with paragraph 5.3a. of General Order No. 7, the following information is respectfully submitted.

HECO's 1997 system peak occurred on Tuesday, September 2, 1997 and was 1,220,000 kW-gross or 1,193,000 kW-net based on net HECO generation, net purchased power generation, and the peak reduction benefits of energy efficiency demand-side management programs implemented in mid-1996. Oahu had a reserve margin of approximately 36% over the 1997 system net peak.

HECO's 1997 total generating capability of 1,615,000 kW-net includes 406,000 kW-net of firm power purchased from (1) Kalaeloa Partners, L.P.; (2) AES Hawaii Inc. (formerly known as AES-Barbers Point, Inc).; and (3) HPOWER.

HECO also has power purchase contracts with ~~a wind energy provider and~~ several cogenerators. Since these contracts are not for firm capacity, they are not reflected in HECO's total generating capability.

The attached table shows the expected reserve margin over the next three years, based on the Forecast Work Group's HECO Sales and Peak Forecast, dated April, 1997 and on HECO's latest estimate of forecasted DSM impacts.

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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January 30, 1998

Edward Y. Hirata
Vice President
Regulatory Affairs

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PUBLIC UTILITIES
COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Adequacy of Supply
Hawaiian Electric Company, Inc.

In accordance with paragraph 5.3a. of General Order No. 7, the following information is respectfully submitted.

HECO's 1997 system peak occurred on Tuesday, September 2, 1997 and was 1,220,000 kW-gross or 1,193,000 kW-net based on net HECO generation, net purchased power generation, and the peak reduction benefits of energy efficiency demand-side management programs implemented in mid-1996. Oahu had a reserve margin of approximately 36% over the 1997 system net peak.

HECO's 1997 total generating capability of 1,615,000 kW-net includes 406,000 kW-net of firm power purchased from (1) Kalaeloa Partners, L.P.; (2) AES Hawaii Inc. (formerly known as AES-Barbers Point, Inc).; and (3) HPOWER.

HECO also has power purchase contracts with a wind energy provider and several cogenerators. Since these contracts are not for firm capacity, they are not reflected in HECO's total generating capability.

The attached table shows the expected reserve margin over the next three years, based on the Forecast Work Group's HECO Sales and Peak Forecast, dated April, 1997 and on HECO's latest estimate of forecasted DSM impacts.

The following method is used to determine the timing of an additional generation unit:

> *The total capability of our system plus the total amount of interruptible loads must at all times be equal to or greater than the summation of the following:*
>
> *a. the capacity needed to serve the estimated system peak load;*
>
> *b. the capacity of the unit scheduled for maintenance; and*
>
> *c. the capacity that would be lost by the forced outage of the largest unit in service.*

The method used to determine the timing of an additional generation unit now accounts for interruptible loads. HECO will not build reserve capacity to serve interruptible loads.

Very truly yours,

Edward J H

Attachment

cc: Division of Consumer Advocacy

ADEQUACY OF SUPPLY
Hawaiian Electric Company, Inc.
January 30, 1998

			Without Peak Reduction Benefits of 20-Yr Energy Efficiency DSM Programs[2]		With Peak Reduction Benefits of 20-Yr Energy Efficiency DSM Programs[3]	
Year	**System Net Capability at the Peak, kW [1] (A)**	**Interruptible Load, kW (B)**	**System Net Peak, kW (C)**	**Reserve Margin, % (A+B-C) / C**	**System Net Peak, kW (D)**	**Reserve Margin, % (A+B-D) / D**
Recorded						
1997	1,615,000	6,000	1,198,000	35%	1,193,000	36%
Forecasted						
1998	1,615,000	6,900	1,219,000	33%	1,210,000	34%
1999	1,615,000	16,000	1,247,000	31%	1,231,000	33%
2000	1,615,000	26,700	1,276,000	29%	1,251,000	31%

Notes:

(1) System Capability includes:

- HECO units at a total normal capability of 1,209,000 kW-net or 1,263,000 kW-gross.
- Firm power purchase contracts have a combined net total of 406,000 kW from Kalaeloa (180,000 kW), AES Hawaii (180,000 kW), and HPOWER (46,000 kW).

(2) System Peaks (Without Peak Reduction Benefits of 20-Yr DSM Programs):

- Implementation of full-scale DSM programs began in the second half of 1996 following Commission approval of the programs. The forecasted system peaks exclude the peak reduction benefits of the 20-Yr DSM programs.
- Peaks are adjusted for 17,000 kW of BHP load.
- In 1997, the estimated peak reduction benefit of the DSM programs was 5,000 net-kW. Without this peak reduction benefit, the recorded system net peak of 1,193,000 kW in 1997 would have been 1,198,000 kW.
- The forecasted system peaks (1998-2000) are evening peaks based on the peak forecast dated April, 1997 and do not include the peak reduction benefits of 20-Yr DSM programs.

(3) System Peak (With Peak Reduction Benefits of 20-Yr DSM Programs):

- The forecasted peaks of 1998-2000 include the peak reduction benefits of the 20-Yr DSM programs.
- Peaks are adjusted for 17 MW of BHP load.

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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January 31, 1997

Edward Y. Hirata
Vice President
Regulatory Affairs

PUBLIC UTILITIES COMMISSION
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The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Adequacy of Supply
Hawaiian Electric Company, Inc.

In accordance with paragraph 5.3a. of General Order No. 7, the following information is respectfully submitted.

HECO's 1996 system peak occurred on Thursday, August 29, 1996, and was 1,166,000 KW-net, or 1,209,000 KW based on gross HECO generation and net purchased power generation. Oahu had a reserve margin of approximately 39% over the 1996 system net peak.

HECO's 1996 total generating capability of 1,614,600 KW-net includes 406,000 KW-net of firm power purchased from (1) Kalaeloa Partners, L.P.; (2) AES-Barbers Point, Inc.; and (3) HPOWER.

HECO also has power purchase contracts with a wind energy provider and several cogenerators. Since these contracts are not for firm capacity, they are not reflected in HECO's total generating capability.

The attached table shows the expected reserve margin over the next three years, based on the Forecast Work Group's HECO 1996-2001 Sales, Peak and Purchased Power Forecast, dated March, 1996, and on HECO's latest estimate of forecasted DSM impacts.

The following method is used to determine the timing of an additional generation unit:

> *The total capability of our system plus the total amount of interruptible loads must at all times be equal to or greater than the summation of the following:*
>
> *a. the capacity needed to serve the estimated system peak load;*
>
> *b. the capacity of the unit scheduled for maintenance; and*
>
> *c. the capacity that would be lost by the forced outage of the largest unit in service.*

The method used to determine the timing of an additional generation unit now accounts for interruptible loads. HECO will not build reserve capacity to serve interruptible loads.

Very truly yours,

Attachment

cc: C. W. Totto

ADEQUACY OF SUPPLY
Hawaiian Electric Company, Inc.

January 31, 1997

			Without Full-Scale 20-Yr DSM Impacts		With Full-Scale 20-Yr DSM Impacts	
Year	System Net Capability at the Peak, KW [1] (A)	Interruptible Load, KW (B)	System Net Peak, KW [2] (C)	Reserve Margin, % (A+B-C) / C	System Net Peak, KW [3] (D)	Reserve Margin, % (A+B-D) / D
Recorded 1996	1,614,600	6,000	1,166,000	39%	N/A	N/A
Forecasted 1997	1,614,600	6,000	1,214,000	33%	1,203,300	35%
1998	1,614,600	6,900	1,243,000	30%	1,226,000	32%
1999	1,614,600	17,590	1,266,000	29%	1,231,900	32%

Notes:

1) System Capability includes:
- HECO units at a total normal capability of 1,208,600 KW-net or 1,263,000 KW-gross. (HECO has changed its reporting basis from "gross" to "net".)
- Firm power purchase contracts have a combined net total of 406,000 KW from Kalaeloa (180,000 KW), AES-Barbers Point (180,000 KW), and HPOWER (46,000 KW).

2) System Peaks (Without Full-Scale 20-Yr DSM Impacts):
- Implementation of full-scale DSM programs began in the second half of 1996 following Commission approval of the programs. The forecasted system peaks without full-scale 20-year DSM impacts excludes the impacts of these programs.
- The forecasted system peaks (1997-1999) are evening peaks based on the peak forecast dated March, 1996 and do not include full-scale 20-Yr DSM program impacts.

3) System Peak (With Full-Scale 20-Yr DSM Impacts):
- The forecasted peaks of 1997-1999 reflect the full-scale 20-Yr DSM program impacts.

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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January 31, 1996

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Edward Y. Hirata
Vice President
Regulatory Affairs

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Adequacy of Supply
Hawaiian Electric Company, Inc.

In accordance with paragraph 5.3a. of General Order No. 7, the following information is respectfully submitted.

HECO's 1995 system peak occurred on Monday, December 11, 1995 and was 1,190,000 KW. Oahu had a reserve margin of approximately 40% over the 1995 system peak.

HECO's 1995 total generating capability of 1,669,000 KW includes 406,000 KW of firm power purchased from (1) Kalaeloa Partners, L.P.; (2) AES-Barbers Point, Inc.; and (3) HPOWER.

HECO also has power purchase contracts with several sugar, wind, and other cogenerators. Since these contracts are not for firm capacity, they are not reflected in HECO's total generating capability.

The attached table shows the expected reserve margin over the next three years, based on the Forecast Planning Committee's 1995-2015 HECO Sales and Peak Forecast dated March 31, 1995, and revised May 1, 1995.

The following method is used to determine the timing of an additional generation unit:

> *The total capability of our system must at all times be equal to or greater than the summation of the following:*
>
> *a. the capacity needed to serve the estimated system peak load;*
>
> *b. the capacity of the unit scheduled for maintenance; and*
>
> *c. the capacity that would be lost by the forced outage of the largest unit in service.*

Very truly yours,

Edward J Ito

Attachment

cc: C. W. Totto

ADEQUACY OF SUPPLY
Hawaiian Electric Company, Inc.

January 31, 1996

		With Pilot DSM Without Full-Scale 20-Yr DSM Impacts		With Full Scale 20-Yr DSM Impacts	
Year	**System Capability at the Peak KW (1) (A)**	**System Peak KW (2) (B)**	**Reserve Margin % ((A - B) / B)**	**System Peak KW (3) (C)**	**Reserve Margin % ((A - C) / C)**
Recorded					
1995	1,669,000	1,190,000	40%	N/A	N/A
Forecasted					
1996	1,669,000	1,226,000	36%	1,219,000	37%
1997	1,669,000	1,239,000	35%	1,228,000	36%
1998	1,669,000	1,265,000	32%	1,245,000	34%

Notes:

1) System Capability includes:
- HECO units at a total normal capability (gross) of 1,263,000 KW.
- Firm power purchase contracts have a combined total of 406,000 KW from Kalaeloa (180,000 KW), AES-Barbers Point (180,000 KW), and HPOWER (46,000 KW).

2) System Peaks (Without Full-Scale 20-Year DSM Impacts):
- Recorded and forecasted peaks include impacts attributed to the pilot DSM programs.
- The forecasted system peaks (1996-1998) are evening peaks based on the peak forecast dated March 31, 1995, and revised May 1, 1995, and include the impact of the pilot DSM programs, but do not include future full-scale 20-Year DSM program impacts.

3) System Peak (With Full-Scale 20-Year DSM Impacts):
- The 1995 peak includes impacts attributed to the pilot DSM programs.
- The forecasted peaks of 1996-1998 reflect the impacts of both pilot and full-scale 20-Year DSM program impacts.