CA-IR-550

Please provide copies of workpapers, or cite previously provided workpapers, supporting the derivation of Franchise Royalty Taxes "At Present Rates" as reflected on HECO-1701.

HECO Response:

See response to CA-IR-546, page 3 of 4.

CA-IR-551

<u>Ref: HECO revised response to CA-IR-251 & HECO-1310 (HEI Billings).</u>

Footnotes 12 and 15 of HECO-1310 provide additional "normal" annual costs attributable to Sarbanes-Oxley (Sections 404 and 302) compliance. Footnote 12 also indicates that "since 2004 will be the first year of implementation of Sarbanes-Oxley Section 404, the Company anticipates that the actual costs will far exceed the 2004 estimates shown." Please provide the following:

a. Referring to HECO-1310, please confirm that the "normal" costs included in the 2004 of new IRS forms, return disclosures and more documentation of tax items in order to be in compliance with SOX 404 (i.e. additional reviews and authorizations are required for all tax accruals). [Costs considered as SOX 404 costs relate to the auditor's attestation fees and management time spent testing and certifying its internal controls over financial reporting.]

b. The revised response to CA-IR-251, which reflects the 2004 actual HEI billings to HECO of

[redacted]

estimate will be at least $203,000. HEI estimated that HECO would have been allocated approximately $200,000 in 2004 instead of the $69,440 actually billed if all costs (both external and internal costs) were charged to HECO.

d. The company now expects the "normal" SOX 404 costs to be in excess of the original test

CA-IR-552

Ref: HECO revised response to CA-IR-251 & HECO-1310 (HEI Billings).

Please explain and reconcile the following variances between the amounts included in the 2005 test year forecast and the 2004 actual charges to HECO from HEI:

a. INV 006 (Group analyst meetings): $150,510 actual 2004 vs. $127,251 test year forecast.

b. INV 008 (Investor base/ stockholder monitoring): $15,851 actual 2004 vs. $29,745 test year forecast.

c. INV 009 (Investor Relations Planning): $2,221 actual 2004 vs. $43,595 test year forecast.

d. INV 13 (Other investor relations activities): $34,225 actual 2004 vs. $20,746 test year forecast.

HECO Response:

a. INV 006 (Group analyst meetings): INV 006 and INV 009 (Investor Relations Planning) were used interchangeably in 2003 (which is the basis for the 2005 test year estimate shown on HECO-1310) and 2004. The allocation percentage to HECO is the same for both investor relations charge codes INV006 and INV009. The net amount of the difference for the two charge codes is an increase of approximately $15,000 (see page 3 for the calculation of the difference). The difference is primarily due to higher investor relations planning costs of approximately $6,000 and no summer analyst meeting in 2004 of approximately $6,000. Specifically in 2004, HEI did not incur the annual costs associated with the investor relations planning trip since the Manager of Investor Relations was able to meet with the investor relations consultants while attending another conference on the mainland. However, this cost savings is specific to 2004 and is not expected to recur in 2005 and beyond. In addition, due to the Sarbanes-Oxley Section 404 compliance efforts required in 2004, additional costs anticipated for investor relations planning and the annual summer analyst meeting were not incurred in 2004 as the meetings were canceled due to scheduling conflicts. However, it is anticipated that in a "normal" year, costs would be incurred related to investor relations planning and the summer analyst meeting. The company's response to CA-IR-419 which shows the updated 2005 test year estimate should have included an additional $12,000 for these "normal" investor relations planning costs and group analyst meeting costs and will be reflected in rebuttal testimony.

b. INV 008 (Investor base/ stockholder monitoring): INV 008 and INV 013 (Other investor relations activities) were used interchangeably in 2003 (which is the basis for the 2005 test year estimate shown on HECO-1310) and 2004. The allocation percentage to HECO is the same for both charge codes. The 2004 actual charges adjusted for the 2005 inflation adjustment were $637 higher (1% higher) than the 2005 test year estimate for these charge codes (see page 3 for the calculation).

c. INV 009 (Investor Relations Planning): Please see response to CA-IR-552 a. above.

d. INV013 (Other investor relations activities): Please see response to CA-IR-552 b. above.

Support to CA-IR-552 a. and c.

INV006 2004 actual charges		150,510
INV009 2004 actual charges		2,221
		152,731
2005 inflation adjustment @ 2.1%		3,207
Estimated 2005 charges	(a)	155,938
INV006 test year forecast		127,251
INV006 test year forecast		43,595
	(b)	170,846
Difference	(a) - (b)	(14,908)

Support to CA-IR-552 b. and d.

INV008 2004 actual charges		15,851
INV013 2004 actual charges		34,225
		50,076
2005 inflation adjustment @ 2.1%		1,052
Estimated 2005 charges	(c)	51,128
INV008 test year forecast		29,745
INV013 test year forecast		20,746
	(d)	50,491
Difference	(c) - (d)	637

CA-IR-553

Ref: HECO-1310 (HEI Billings).

Please provide the following information regarding the identified charges included in the 2005 test year forecast:

a. CON 002 (Meetings) and CON 004 (Other): $43,051 of test year general consulting charges directly assigned to HECO. Please identify and describe the specific consulting services typically incurred by HEI and assigned to HECO for inclusion in the test year forecast.

b. TAX 003 (Tax and financial planning): $22,263 is included in the test year forecast. Please describe the type and nature of tax/ financial planning services, identifying any portion associated with personal advice to executives and senior management personnel.

HECO Response:

a. The $43,051 test year CON 002 (Meetings) and CON 004 (Other) general consulting charges that were directly charged to HECO are all associated with charges from the HEI President who is also HECO's Chairman of the Board. As HECO's Chairman of the Board, the HEI President has frequent meetings with HECO senior management to discuss HECO matters and to provide general consulting services to HECO. In addition, annually the HEI President attends the EEI Annual Convention as HECO's Chairman of the Board where matters related to the electric utility industry are discussed and shared with other industry members. The time and costs associated with the EEI Annual Convention represent approximately one third of the test year estimate for consulting charges. Note that the test year amount will be revised as shown in response to CA-IR-419.

b. Tax and financial planning generally includes identifying ways to comply with Federal, State and local tax regulations, satisfy financial reporting requirements and identify and evaluate tax strategies. The 2005 test year estimate shown on HECO-1310 is based on the actual experience of charges in 2003. The amount included in the test year forecast consists of several ongoing activities including general tax research on issues related to compliance and financial reporting; meetings with HECO personnel to discuss potential transactions and related tax issues; and discussions with HECO personnel involving the tax impact of transactions already incurred. There is no portion associated with personal advice to executives and senior management personnel. Note that the test year amount will be revised as shown in response to CA-IR-419.

CA-IR-554

Ref: HECO T-8, p. 18 & HECO T-13, p. 47. (OMS).

The Outage Management System is described as a major reliability initiative HECO plans to implement in 2006. Please provide the following:

a. Are any costs associated with OMS included in the 2005 test year forecast of rate base or expense?

b. Referring to item (a) above, please provide the respective amounts included in revenue requirement, along with a pinpoint reference to the forecast workpapers or other documentation supporting the quantification of such amounts.

HECO Response:

a. The costs included in the 2005 test year associated with the OMS total $152,569 and are included as part of Distribution Operations expenses. These expenses are related to specification preparation, bid evaluation and data cleanup. The accounting for such costs is consistent with Statement of Position (SOP) 98-1 and the agreement between HECO and the Consumer Advocate dated April 21, 2005 in Docket No. 04-0131.

b. The $152,569 was included in revenue requirements. Please refer to CA-IR-1 & 2, Docket No. 04-0113, Project Number P0000828, pages 1, 2 and 3 of 9 for documentation supporting the amount.

CA-IR-555

Ref: HECO T-9, p. 5-6 & 15, & HECO T-13, p. 47. (CIS).

HECO's plans to replace the current Customer Information System are generally discussed, with reference to Docket No. 04-0268. Please provide the following:

a. Are any costs associated with CIS included in the 2005 test year forecast of rate base or expense?

b. Referring to item (a) above, please provide the respective amounts included in revenue requirement, along with a pinpoint reference to the forecast workpapers or other documentation supporting the quantification of such amounts.

HECO Response:

a. The 2005 test year forecast of rate base does not include capital or deferred costs for the CIS Replacement project (P0000571) because the Project is forecasted to be completed and placed in service after the test year period. The 2005 test year forecast of expenses does include costs for the CIS project as discussed in part b. below. There are no amortization or depreciation expenses for the new CIS in the test year.

b. The amount of rate base for the CIS project included in revenue requirement is $0.

   The amount of expenses for the CIS project included in revenue requirement is $251,000.

   Workpapers and documentation supporting the quantification of $240,000 direct labor and non-labor project costs (excluding on-costs) were provided to the Consumer Advocate in CA-IR-1 and CA-IR-2 (Project No. P0000571) on January 11, 2005. Related project on-

CA-IR-556

<u>Ref: T-15, page 17, response to CA-IR-345 & HECO-1507 (Long-Term Disability).</u>

With regard to the update to HECO-1507 produced in response to CA-IR-345, please provide the following:

a. Referring to page 8 of the response to CA-IR-345, please provide support for calculation of the average merit salary ($73,284) and BU wage ($57,595) as of January 1, 2005.

b. Referring to item (a) above, how do these average compensation levels compare to the compensation levels effectively included in HECO's 2005 test year forecast? Please explain and reconcile any material differences.

<u>HECO Response:</u>

a. The average merit salary and BU wage used in HECO-1507 noted on page 8 of the response to CA-IR-345 was calculated by using a data file of actual covered employees as of January 1, 2005. The salaries/wages used is as of October 1, 2004, which is what is used to determine FlexPlan benefits for 2005. A schedule is attached and the supporting worksheets included in the electronic file labeled "CA-IR-556Attch.xls" will be provided under separate transmittal.

b. As noted above, these average compensation levels are as of October 1, 2004. Compensation levels for the test year were determined as described in HECO T-15, pages 33-34, which describes adjustments based on BU wage and merit salary increases projected in 2005.

Average Wage / Salary Statistics
as of 1/1/2005

		CO	
Class	Data	**HECO**	**Grand Total**
BU	**Average of Wage/Salary**	**$57,595**	**$57,595**
	Count of Class	682	682
MERIT	**Average of Wage/Salary**	**$73,284**	**$73,284**
	Count of Class	658	658
Total Average of Wage/Salary		**$65,299**	**$65,299**
Total Count of Class		1340	1340

CA-IR-557

a. Please identify by name and title the person within HECO's organization who has lead responsibility for monitoring generating system reliability (i.e., performance relative to the "4.5 years per day" standard).

b. Please provide copies of all memoranda, reports, or correspondence issued between January 1, 2002 and the March 31, 2005, (i) to, or (ii) by the person identified in response to part (a), above, addressing the topics of actual, historic, or projected generating system reliability.

HECO Response:

a. Ross Sakuda, Director, Generation Planning Division, Power Supply Services Department.

Mr. Sakuda is the sponsor of HECO's Direct Testimony in HECO T-4.

b. HECO objects to the request to provide "all" memoranda, reports, or correspondence issued between January 1, 2002 and the March 31, 2005, (i) to, or (ii) by the person identified in response to part (a), above, addressing the topics of actual, historic, or projected generating system reliability, on the grounds that (1) requests that HECO produce "all" documents are overly broad and unduly burdensome given the volume of documents; (2) internal communications contain information subject to the attorney-client and attorney product privileges; and (3) information produced pursuant to such requests could include preliminary and/or outdated analyses, which have been superseded by later analyses. Without waiving this objection, HECO is willing to provide the following response. All documents or relevant parts of the documents cited below were prepared under the supervision of Mr. Sakuda and have been previously filed with the Commission and Consumer Advocate.

- January 31, 2002 – HECO 2002 Adequacy of Supply Report – HECO indicated that there was a reserve margin of approximately 34% over the 2001 system net peak. HECO projected reserve margins of 32%, 31% and 28% in 2002, 2003 and 2004, respectively, with the peak reduction benefits of future DSM.

- July 1, 2002 – HECO Electric Utility System Cost Data Report – Page A-4 provides an 11-year resource plan (then-current year plus 10 future years). A simple cycle unit addition is shown in 2009. Note (4) on page A-5 states "A 106.5 MW simple cycle combustion turbine is scheduled to be added in 2009, based on the application of the reliability guideline in HECO's capacity planning criteria. The actual size and type of unit may change along with its associated costs." The timing of the unit addition in 2009 indicated that generating system reliability would be above 4.5 years per day until 2009 based on the assumptions given in the report.
- July 2002 – Waiau Fuel Pipeline Project[1] – Final Environmental Impact Statement ("FEIS")[2] – The FEIS required an analysis of a "No Action" scenario in which there would be no further delivery of fuel to the Waiau Power Plant beyond the end of the then-current contract between HECO and Chevron that expired on December 31, 2004. The FEIS stated in Section 2.4 (copy attached) that under this scenario, among other things, "HECO would have to violate the generating reserve criteria stipulated in its filings with the PUC. This would greatly increase the fragility of the electrical power supply. It could also lead to transmission bottlenecks as the grid struggles to move power from the remaining generating units to users." The FEIS further stated "HECO would have to institute drastic measures to restrict demand. While some of these would involve voluntary conservation, such measures would fall far short of the drastic cut in

capacity at Waiau. Inevitably, this means that the company would have to institute rolling blackouts. These would be of the sort occasionally needed during natural disasters and large-scale equipment failures in the past. But they would be far more widespread and prolonged. As a result, they would be much more costly to its customers and disruptive to the life and economy of the island." Mr. Sakuda provided input to this section of the FEIS.

- December 31, 2002 – HECO IRP-2 Evaluation Report – As indicated on page 68 of the report, the timing of generating unit additions was determined by the application of HECO's load service capability criterion and HECO's reliability guideline of 4.5 years per day. The integration analysis concluded on page 71 that the next generating unit is still required in 2009. In other words, generating system reliability was not expected to fall below 4.5 years per day until 2009 based on the assumptions used in the report. Table 5.3.2 on page 72 shows the timing of generating unit additions for various scenarios, where the timing of the additions was determined by the application of the 4.5 years per day reliability guideline.
- January 9, 2003 – Honolulu 9 HP/LP Turbine Blading Application – HECO submitted an application for approval to commit funds in excess of $500,000 for Item Y00035, the Honolulu 9 HP/LP Turbine Blading Project in Docket No. 03-0006. In examining the application, the Consumer Advocate submitted Information Requests ("IRs") to HECO to obtain details related to the application. One particular IR (CA-IR-9) pertained to generating system reliability. Please see HECO's response to CA-IR-9 in Docket No. 03-0006, submitted on April 4, 2003.
- April 3, 2003 – Honolulu 8 HP/LP Turbine Blading Application – HECO submitted an

application for approval to commit funds in excess of $500,000 for Item P0000773, the Honolulu 8 HP/LP Turbine Blading Project in Docket No. 03-0083. In examining the application, the Consumer Advocate submitted IRs to HECO to obtain details related to the application. One particular IR (CA-IR-7) pertained to generating system reliability. Please see HECO's response to CA-IR-7 in Docket No. 03-0083, submitted on June 12, 2003.

- <u>June 6, 2003 – Residential Direct Load Control ("RDLC") Program Application</u> – HECO submitted to the Commission an application for approval of its RDLC Program in Docket No. 03-0166. Exhibit E, page 3, of that application showed the impact of the timing of firm capacity additions with and without the RLDC and Commercial and Industrial Direct Load Control ("CIDLC") Programs[3]. In the base plan (with the RDLC and CIDLC Programs), the first unit addition was needed in 2009. Subsequent unit additions were needed in 2015, 2016 (two units), 2021 and 2022.

application of the 4.5 years per day reliability guideline. In the base plan (No Utility CHP), generating system reliability was projected to be above 4.5 years per day until 2009, when a simple cycle combustion turbine would need to be added to maintain generating system reliability above the 4.5 years per day threshold. Subsequent unit additions would need to occur in 2015, 2016 (two units) and 2021 to maintain generating system reliability above 4.5 years per day. The in the alternate plan (With Utility CHP), unit additions would need to occur in 2010, 2016 (two units), 2021 and 2022 to maintain generating system reliability above 4.5 years per day.

- <u>December 11, 2003 – Commercial and Industrial Direct Load Control ("CIDLC") Program Application</u> – HECO submitted to the Commission an application for approval of its CIDLC Program in Docket No. 03-0415. Exhibit G, page 3, of that application

showed the impact of the timing of firm capacity additions with and without the RLDC and CIDLC Programs. The resource plans with and without the programs were the same ones used in Exhibit E of the RDLC Program application.

- <u>December 26, 2003 – Opposition to CHP Program Suspension</u> – The cost-effectiveness analyses for the RDLC and CHP and CIDLC programs were based on the latest long-term base resource plan (generally, the IRP-2 plans as updated in the December 31, 2002 Evaluation report using the August 2002 Long-term Sales and Peak Load Forecast). In the response to the Consumer Advocate's proposal to suspend consideration of the CHP Program Application, which would delay HECO's ability to install CHP systems, HECO pointed out that:

" Delaying the start of the program for any significant period of time would irrevocably harm ratepayers, the Companies and CHP program customers. Load is growing faster higher than the forecasted system peak for 2003. Without the central station deferral benefits expected from their CHP programs, the need dates for new generation may well occur sooner than the forecasted need date of 2009 for HECO. The Companies are not in a position to accelerate the installation dates for new generation, and the installation of utility-owned CHP systems can help avoid reserve margin shortfalls."

Although HECO was still working on a new long-term Sales and Peak Load Forecast, which would form the basis for the 2004 Adequacy of Supply Report, HECO provided details to back up its findings that load was growing at a faster rate than forecast. See HECO's Reply to the Division of Consumer Advocacy's Statement of Position filed December 26, 2003 in Docket No. 03-0366, in which HECO requested the flexibility to report that the CHP programs be implemented on an interim basis.

- March 31, 2004 – HECO 2004 Adequacy of Supply Report – Pages 5 to 10 discuss the projection of generating system reliability based on the circumstances at that time, including the new February 2004 Long-term Sales and Peak Load Forecast. (In its January 30, 2004 request to delay filing the report until the new load forecast was completed, HECO again provided information showing that load was growing faster than previously forecast.) HECO indicated that "With the February 2004 forecast, which is higher than the August 2002 forecast as indicated in Table 1, HECO's analysis indicates that generating system reliability will fall below the 4.5 years per day reliability guideline in 2006, assuming that no new central-station generating capacity is added from 2004 to 2006, even if:

1. forecasted peak reduction benefits (estimated at 11 MW for 2004–2006) from continuation of existing energy efficiency DSM programs are acquired,

2. proposed peak reduction benefits (estimated at 28 MW for 2004–2006) from the two load management programs are acquired, as forecasted in their respective

applications [footnote 5 excluded]; and

3. proposed utility CHP impacts (estimated at 8 MW for 2004–2006) occur as forecasted in Docket No. 03-0366.

Should the forecasted peak reduction benefits from these programs not occur, then the generating system reliability is expected to fall below the 4.5 years per day reliability guideline sooner than 2006."[4]

- May 13, 2004 – Waiau CT Separation Project Application – HECO submitted an application for approval to commit funds in excess of $500,000 for Item P0000939, the Waiau CT Separation Project in Docket No. 04-0104. On pages 5 and 6 of the application, HECO included excerpts of the March 31, 2004 Adequacy of Supply report and stated "The proposed project is related to the above category of increasing output from HECO's existing units." The application further stated that the "Waiau CT Separation Project will help to increase the availability of Waiau 9 and 10 CT units." In examining the application, the Consumer Advocate submitted IRs and Supplemental Information Requests ("SIRs") to HECO to obtain details related to the application. Several of the IRs and SIRs related to generating system reliability and Loss of Load Probability. HECO filed its responses to the IRs and SIRs on July 21, 2004, and August 25, 2004, respectively. Please refer to HECO's responses to CA-IR-3, 5 and 7 and to CA-SIR-2 and 3 in Docket No. 04-0104.
- June 30, 2004 – HECO Electric Utility System Cost Data Report – Page A-4 provides an 11-year resource plan (then-current year plus 10 future years). One simple cycle unit addition is shown in 2009 and a second one is shown in 2013. Note (7) on page A-5

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[4] From pages 5 and 6 of the HECO 2004 Adequacy of Supply report.

states "For planning purposes the following future units will be added in 2004-2014: A nominal 100 MW simple cycle combustion turbine is scheduled to be added in 2009. HECO's analysis indicates that the generating system reliability will fall below the 4.5 years per day reliability guideline beginning in 2006. However, given the long lead time to install the next generating unit, HECO projects an installation date of 2009. The actual size and type of unit may change along with its associated costs."

- July 14, 2004 – Distributed Generation Docket (Docket No. 03-0371) Direct Testimony – HECO T-3, pages 7 and 8, discusses the need for firm capacity in 2006, and possibly sooner.
- August 31, 2004 – Honolulu Power Plant Retirement Scenario – HECO presented to the IRP-3 Integration Technical Committee the scenarios that HECO would be analyzing as part of the IRP-3 integration analysis. A scenario with the possible retirement of Honolulu Power Plant was included. The scenario analysis considered changes in resource timing and total resource costs based on retiring Honolulu Power Plant in 2015, maintaining generating system reliability throughout the 20-year planning period, and meeting the objectives in each IRP-3 plan concept. In essence, replacement capacity is needed before Honolulu Power Plant is retired. Please refer to HECO's response to CA-IR-450 and 451. As shown on page 6 of HECO's response to CA-IR-451, HECO communicated to the Aloha Tower Development Corporation that "The new power plant must be fully permitted, constructed and operational before the Honolulu Power Plant can be shut down."
- October 22, 2004 – Distributed Generation Docket (Docket No. 03-0371) Rebuttal Testimony – HECO RT-3, pages 1 and 2, reiterates the need for firm capacity, and

discusses the higher than forecast system peaks that occurred in October 2004.

- November 5, 2004 – HECO's Application for Approval of Amendment Nos. 5 and 6 to Power Purchase Agreement between HECO and Kalealoa – Section V.D. on pages 10 to 12 discusses the projection of generating system reliability.
- November 8, 2004 – HECO IRP-3 Integration Technical Committee Meeting #5 – HECO presented to the Integration Technical Committee ("ITC") the attributes and measures for each of the six finalist resource plans developed for IRP-3 with Advisory Group input. Generating system reliability was one of the attributes that was quantified. Slide 18 (which shows the generating system reliability) from that presentation is attached. A handout provided to the ITC provided detailed year-by-year breakdowns for certain attributes. Page 36 of 61 (which shows the generating system reliability) from that handout is attached.
- November 12, 2004 – HECO Test Year 2004 Rate Case – Mr. Sakuda submitted Direct Testimony in HECO T-4. Pages 4 and 5 discuss a projection of generating system reliability.
- March 10, 2005 – HECO 2005 Adequacy of Supply Report – The report provides an extensive assessment of current and future generating system reliability. The report was filed with the Commission with a copy to the Consumer Advocate.
- March 11, 2005 – HECO Response to CA-IR-271 in the Instant Docket – Information is provided on historical and projected generating system reliability.

2.4 NO ACTION ALTERNATIVE

In the case of HECO's proposed pipeline project, "No Action" consists of failing to arrange for continued fuel delivery to Waiau beyond the end of the current contract between HECO and Chevron. This would result in the loss of nearly a quarter of the installed electrical generating capacity for O'ahu. It cannot be emphasized too strongly that this alternative would not meet the objectives of the proposed action. Instead, "No Action" is included only because it is needed to fulfill the requirements of Chapter 343.

Implementation of the "No Action" alternative would require HECO to make a number of changes in the way it operates.

- First, it would have to drastically increase the utilization of the generating units that would remain in service. This, in turn, would entail increased fuel deliveries to those facilities, greater emissions from them, longer operating hours, and other changes.
- Second, HECO would have to violate the generating reserve criteria stipulated in its filings with the PUC. This would greatly increase the fragility of the electrical power supply. It could also to lead to transmission bottlenecks as the grid struggles to move power from the remaining generating units to users.
- Third, HECO would have to institute drastic measures to restrict demand. While some of these would involve voluntary conservation, such measures would fall far short of the drastic cut in demand that would be needed for HECO to serve all of its customers without the capacity at Waiau. Inevitably, this means that the company would have to institute rolling blackouts. These would be of the sort occasionally needed during natural disasters and large-scale equipment failures in the past. But they would be far more widespread and prolonged. As a result, they would be much more costly to its customers and disruptive to the life and economy of the island.

As noted above, HECO's contract with Chevron expires on December 31, 2004. Because of this, HECO must make new arrangements for the continued delivery of fuel to Waiau and Iwilei beyond that time. In the case of deliveries to Waiau, this fuel is needed for the continued operation of the existing LSFO-fired units at the Waiau Generating Station, which constitute about a quarter of O'ahu's generating capacity. Continued operation of the Waiau Generating Station will have no bearing on HECO's efforts to pursue meeting future energy needs with additional generation utilizing new technologies, including renewable energy and other developing technologies.

4	5	6
HECO w/contribution from HELCO/MECO to conform to SB2474 Plan	Maximize Fuel Diversity Plan	Combined Plan
21.3	24.0	25.6
+	Reference	Reference
ference	Reference	Reference
-	+	Reference
65.2	25.2	65.2
8,724	2,726	8,724
ference	Reference	Reference
ference	Reference	Reference
308	919	920
38	61	74

November 8, 2004

HECO IRP-3 Integration T...nical Committee

Attribute 3.a. Generating System Reliability

LOLE (Years/Day)	IRP-2 Evaluation Report with Utility CHP	Plan 1 Least Cost Plan	Plan 2 Meets the State RPS Law -- Oahu Only	Plan 3 Maximize Renewable Energy Plan	Plan 4 Meets the State RPS Law	Plan 5 Maximize Fuel Diversity Plan	Plan 6 Combination Plan
2006	2.6	6.9	6.9	6.9	6.9	5.6	6.9
2007	2.1	6.1	6.1	6.1	6.1	4.4	6.1
2008	1.7	6.7	6.7	6.7	6.7	4.1	6.7
2009	7.9	26.3	26.3	26.3	26.3	12.7	26.3
2010	5.3	20.8	20.8	20.8	20.8	8.2	20.8
2011	11.1	47.6	47.6	47.6	47.6	18.2	47.6
2012	7.4	47.6	47.6	47.6	47.6	17.5	47.6
2013	15.2	10.4	10.4	10.4	10.4	5.2	10.4
2014	38.5	30.3	30.3	30.3	30.3	10.8	30.3
2015	31.3	29.4	41.7	76.9	29.4	10.5	29.4
2016	13.5	11.2	16.4	29.4	11.2	41.7	11.2
2017	20.4	25.0	35.7	62.5	25.0	100.0	25.0
2018	15.9	17.2	25.0	45.5	17.2	43.5	17.2
2019	7.4	12.8	18.5	32.3	12.8	40.0	12.8
2020	4.0	9.6	8.0	8.0	9.6	41.7	9.6
2021	6.1	6.9	17.9	17.9	6.9	37.0	6.9
2022	5.9	18.2	7.9	7.9	18.2	12.2	32.3
2023	13.0	40.0	18.2	18.2	40.0	29.4	83.3
2024	10.3	40.0	16.7	16.7	40.0	27.0	55.6
2025	58.8	13.5	6.8	6.8	13.5	9.7	25.6
20-year Average	**13.9**	**21.3**	**20.8**	**26.2**	**21.3**	**24.0**	**25.6**

HECO IRP-3 Integration Technical Committee

Obj&Meas Base Scenario Graphs r14.xls, Rev 11/10/04

CA-IR-558

a. Please verify that HECO's March 31, 2004 Adequacy of Supply report ("AOS 2004") to the Commission identified a need for 40 MWs to maintain generating system reliability above the 4.5 years per day guideline to 2007 (see page 6).

b. Please verify that, as of March 31, 2004, HECO was exploring several options to address this need for additional capacity resources including:

   i. more aggressive energy and load management DSM programs;
   ii. identification and implementation of CHP projects in addition to those included in HECO's proposed CHP program;
   iii. increased output from HECO's existing units;
   iv. increased output from existing Independent Power Producers; and
   v. the installation of DG (see AOS 2004 at 9).

c. For each mitigation measure described in part (b) above (and other mitigation measures not listed), please describe the steps that HECO accomplished during the months between publication of AOS 2004 and AOS 2005.

d. For each mitigation measure discussed in part (c), above, please describe the incremental MW contributions that HECO has been able to secure for each year 2005 through 2009, based on the efforts described.

e. Please provide the "action plan," i.e., the document or documents that governed HECO's actions as it pursued the incremental MW contributions described in part (d), above.

HECO Response:

a. No, the CA's statement is incorrect. As stated on page 10 of the AOS 2004 report, "HECO anticipates seeking 40 MW (specifically 30 MW before 2007 and an additional 10 MW before 2009) of combined additional capacity and load reductions through a mix of generation alternatives and demand-side management programs that are critical to maintain HECO's generating system reliability above the reliability guideline until firm capacity from the new central-station generating unit is added in 2009." (Underlining added.)

b. HECO verifies that, as of March 31, 2004, HECO was exploring all of the options identified in Items i. to v. and as stated on page 9 of HECO's AOS 2004 report.

c. Please refer to HECO's response to CA-IR-6, in Docket No. 04-0320 (Kalaeloa PPA Amendment Nos. 5 and 6), filed on February 23, 2005, for information on the capacity and energy resources HECO is pursuing. Below is additional information covering the period after February 23, 2005.

1) Energy Efficiency DSM: On March 16, 2005, the PUC issued Order No. 21698 which separated HECO's proposed DSM projects from the on-going rate case. The proposed DSM projects will be examined in a newly established Energy Efficiency Docket (Docket No. 05-0069). Please refer to HECO's response to CA-IR-446, part a., Item 2.

2) Load Management DSM Programs: Please refer to HECO's response to CA-IR-446, part a., Item 1. As of May 31, 2005, 1,769 load control switches have been installed under the Residential Direct Load Control Program. This will provide 1,123 kW of controllable load at the net generation level. As of the same date, one customer has signed up for the Commercial & Industrial Direct Load Control Program. This will provide 1,818 kW of controllable load at the net generation level.

3) Identification and implementation of CHP projects in addition to those included in HECO's proposed CHP program: On March 4, 2005, HECO withdrew its application in Docket No. 04-0314 for approval of a CHP Agreement with Pacific Allied Products, Limited.

4) Increased output from existing Independent Power Producers: On October 12, 2004 Kalaeloa Partners L.P. ("Kalaeloa") and HECO executed two amendments to their power purchase agreement ("PPA"), subject to approval by the Commission and certain other conditions, which provide for up to 29 additional MW of firm capacity to be made available to HECO from the Kalaeloa facility. On May 13, 2005, the

Commission approved Amendments No. 5 and 6 to the PPA, in Decision and Order No. 21820, in Docket No. 04-0320. Kalaeloa has at its own initiative and sole expense, [redacted] of May 31, 2005. Please also refer to HECO's AOS 2005 report, Appendix 2, page 1, Table A2, for a projection of load management program impacts. In addition to this, HECO secured a peak reduction benefit of about 2.4 MW through a Rider I contract with Grace Pacific Corporation[2]. Please also refer to HECO's response to CA-IR-446, part a., Items 1 and 2.

ii. Identification and implementation of CHP projects in addition to those included in HECO's proposed CHP program: Please see HECO's response to CA-IR-6, in Docket No. 04-0320 (Kalaeloa PPA Amendment Nos. 5 and 6), filed on February 23, 2005. Please also refer to HECO's response to part c., in Item 3) above.

iii. Increased output from HECO's existing units: Please see HECO's response to CA-IR-6, in Docket No. 04-0320 (Kalaeloa PPA Amendment Nos. 5 and 6), filed on February 23, 2005.

iv. Increased output from existing Independent Power Producers: Please refer to HECO's response to part c., Item 4) above.

v. Installation of DG: Please refer to HECO's responses to CA-IR-446, part a., Item 7, and CA-IR-535, part a.

e. There is no document entitled the Action Plan for options listed in subpart b. Please see HECO's response to CA-IR-446, part a, Adequacy of Supply letter filed March 10, 2005, and responses to other information requests ("IRs") related thereto.

i. More aggressive energy and load management DSM programs: For the enhanced energy efficiency DSM programs please refer to HECO's testimonies, exhibits and responses to IRs in the instant rate case related to the DSM programs, including HECO

[2] Please refer to PUC D&O No. 20907, filed on April 15, 2004, in Docket No. 03-0266.

T-1 (Mr. Robert Alm), page 8, line 18, to page 9, line 25; HECO T-10 (Mr. Alan Hee), page 35, line 1, to page 63, line 2; HECO T-11 (Mr. Gregory Wikler) – Demand-Side Management Programs; and HECO T-12 (Mr. Daniel Violette) – Appropriate DSM Incentives and Alignment with Policy Objectives. For the load management programs, please refer to the testimonies, exhibits, and responses to IRs and stipulations with the CA in Docket No. 03-0166, regarding HECO's application for approval of the Residential Direct Load Control Program filed on June 6, 2003, and in Docket No. 03-0415, regarding HECO's application for approval of the Commercial and Industrial Direct Load Control Program filed on December 11, 2003.

ii. Identification and implementation of CHP projects in addition to those included in HECO's proposed CHP program: Please refer to HECO's testimonies, exhibits and responses to IRs in the Commission's docket investigating distributed generation, Docket No. 03-0371, to which the CA is a party, HECO's application for approval of a CHP Agreement with Pacific Allied Products, Limited, filed on October 28, 2004, in Docket No. 04-0314.

iii. Increased output from HECO's existing units: Please see HECO's response to CA-IR-6, in Docket No. 04-0320 (Kalaeloa PPA Amendment Nos. 5 and 6), filed on February 23, 2005.

iv. Increased output from existing Independent Power Producers: Please see part a., Item 4) above.

Nos. 5 and 6), filed on February 23, 2005. See also HECO's response to CA-IR-441, in this instant docket, filed with the Consumer Advocate and the Department of Defense on April 22, 2005, and Attachment 1A to HECO's letter updating revenue requirement inputs filed on May 5, 2005 with the Consumer Advocate, Department of Defense and the Commission. Please also refer to HECO's response to CA-IR-535, part a.

CA-IR-559

a. Please provide a copy of each contingency analysis performed relative to the "base case scenario" represented in AOS 2004.

b. Please provide a copy of the contingency plan for addressing contingencies identified in the response to part (a), above.

HECO Response:

a. HECO is unclear as to what "contingency analysis" and "base case scenario" the CA is referring to with respect to the 2004 Adequacy of Supply report since there are no such references in the report.

HECO did state the following on pages 5 and 6 of the report: "With the February 2004 forecast, which is higher than the August 2002 forecast as indicated in Table 1, HECO's generating system reliability is expected to fall below the 4.5 years per day reliability guideline threshold sooner than 2006.

[redacted]

programs do occur, it is estimated that about 30 MW of additional peak reduction benefits, or equivalent capacity additions, would be needed from 2004 through 2006, over and above these programs, to maintain generating system reliability above the 4.5 years per day guideline to 2007. It is also estimated that an additional 10 MW (over and above the 30 MW) of peak reduction benefits, or equivalent capacity additions, would be needed from 2004 through 2008 to maintain generating system reliability above the guideline to 2009.

HECO further stated in the conclusion on page 10 of the report: "HECO's generation addition, HECO anticipates seeking another 40 MW (specifically 30 MW before 2007 and an additional 10 MW before 2009) of combined additional capacity and load reductions through a mix of generation alternatives and demand-side management programs that are critical to maintain HECO's generation system reliability above the reliability guideline until firm capacity from the new central-station generating unit is added in 2009.

In summary, HECO was projecting reserve capacity shortfalls of 30 MW in 2006 and 2007 and 40 MW in 2008 based on the application of the 4.5 years per day reliability threshold, even with the forecasted peak reduction benefits of energy efficiency DSM program, load management DSM programs, and CHP program as proposed at that time.

HECO stated on page 9 of the 2004 AOS report: "Given that the next generating unit cannot be installed in 2006, HECO is exploring several other options to mitigate the effects of the higher forecast on generating system reliability. These options include, but are not limited to, more aggressive energy and load management DSM programs that acquire increased and accelerated impacts, identification and implementation of CHP projects in addition to those included in HECO's proposed CHP Program, increased output from HECO's existing units within the limits of existing permits, increased output from existing Independent Power Producers, and the installation of DG. HECO is currently evaluating the cost, permitting, schedule and regulatory requirements for these options."

At the time the 2004 AOS report was filed, assessment of the potential impacts of the options listed above was in the early stages. The options were developed and assessed in the manner discussed in applications and responses to information requests in this and other dockets. Enhanced energy efficiency DSM programs were developed in the IRP-3 process, and filed in HECO's 2005 test year rate case, as required by the approved stipulations with the CA. Stipulations were entered into with the CA in the load management DSM dockets in 2004, so that implementation of those programs could begin in 2005. HECO's efforts to implement CHP system projects were delayed by the suspension of the CHP program application, as requested by the CA. HECO's subsequent efforts to pursue CHP system projects on a "Rule 4" contract basis, pending resolution of the Commission's DG investigation, were detailed in the DG Docket, Docket No. 03-0371. The first Rule 4 contract with Pacific Allied was filed in October 2004 in Docket No. 04-0314, but was suspended pending the DG investigation and then terminated by Pacific Allied. It is not expected that further DG agreements will be negotiated until there is a determination in [redacted] into account developments with respect to the resources in HECO's base resource plan and any changes in planning assumptions and forecasts since the 2004 AOS. HECO identified additional measures to be evaluated and implemented, if assessed to be appropriate. Generally, these were measures being considered of the impacts if the planned resources were less then forecast, or if necessary regulatory approvals could not be obtained or were delayed for planned resources, or if load grew faster than was forecast. Direct load control of residential air conditioning was a measure that was evaluated, along with other measures, in the IRP-3 process. Development of a voluntary demand load response program generally was expected to follow implementation of C&I Direct Load Control, but has been moved up given the current capacity situation. Consideration of installing leased DG units at substation and other sites on an interim basis has been fast-tracked in 2005 given the delays in obtaining approvals needed to proceed with customer-sited CHP systems, which HECO considers to be a better long-term option for both HECO and its customers. The extensive efforts that HECO has taken and is continuing to take to maintain and/or improve the availability of its existing generating units have been detailed in HECO T-6 and related IR responses. The new "measures" include adding operational staff to allow for 24 hours a day, 7 days a week, operation of Honolulu 8 & 9 and Waiau 3&4, and the addition of night maintenance crews at the Kahe and Waiau power plants.

In the 2004 AOS report, HECO did not analyze an alternate scenario as it did in the 2005 AOS report. Long-term sensitivity analyses were done in 2004 as part of the IRP-3 process. The CA was provided with results as part of HECO's IRP Advisory Group process, and the detailed draft report is expected to be sent to Advisory Group members during the week of June 6th as part of the on-going IRP-3 process.

b. There is no document entitled a Contingency Plan, and the options discussed above are identified and discussed in the documents identified in part a above, and in the response to CA-IR-446.

CA-IR-560

a. Can Table 3 of AOS 2005 be interpreted to mean that, in 2006, Oahu should expect one outage per year because HECO's generation system cannot meet customer demands? Please explain.

b. Can Table 3 of AOS 2005 be interpreted to mean that, in 2005, Oahu should expect about one outage per year because HECO's generation system cannot meet customer demands? Please explain.

c. If the answer to part (a) or part (b), above is in the affirmative, please reconcile the response to the paragraph on page 25 of AOS 2005, which begins "HECO has sufficient firm generating capacity on its system to meet the forecasted load."

HECO Response:

a. Table 3 on page 17 of HECO's AOS 2005 report indicates that the projected generating system reliability in 2006 is 1.0 years per day. This can be interpreted to mean that based on the particular assumptions used in the analysis, there is a probability of one occurrence

during the year where the generating system will be unable to satisfy some part of the total load. HECO may not, at times, have sufficient capacity to cover for the loss of the largest unit or for multiple generating unit outages."

If the only unavailable generating units are those that are on planned maintenance (i.e., no units are on forced outage), then there will be sufficient capacity to meet the forecasted load. If, however, there are simultaneous forced outages of multiple units, or if the largest unit is forced out of service during a particular peak period, then there may not be sufficient capacity to meet the forecasted load. The probability of this happening is estimated in the referenced Table 3.

In other words, if only the forecasted peak load, the total system capacity and the scheduled unavailability of generating units are considered, then there will be sufficient firm generating capacity on the system to meet the forecasted load. However, if the unexpected loss of the largest unit or the unexpected loss of multiple units is considered, then there is a possibility that the forecasted load may not be satisfied. That possibility is quantified in terms of the generating system reliability projection given in the referenced Table 3.

CA-IR-561

Attachment 2 to Appendix 3 to HECO's March 10, 2005 Adequacy of Supply report ("AOS 2005") to the Commission suggests that the Company's "4.5 years per day" standard has been the Company's planning standard since 1968 (see Page 3 of 3). Please verify that this is the case.

HECO Response:

HECO's generating system reliability guideline has been 4.5 years per day since 1968.

CA-IR-562

a. Has HECO made commitments to any government leaders or agencies to preserve system reliability at or above the 4.5 years per day standard?

b. If the response to part (a) is in the affirmative, please identify:

   i. each such government leader (by office) or agency to which such commitment was made; and
   ii. provide the earliest known date on which each such commitment was made.

c. Please provide copies of documents that support the response to part (b), above.

<u>HECO Response:</u>

a. No, HECO has not made such a "commitment".

b. Not applicable.

c. Not applicable.

CA-IR-563

a. Given that the AOS 2005 base scenario includes assumed resources as described at 16-17, including an additional 29 MWs from Kalaeloa, please explain how the resource deficiency grew from 40 MWs in AOS 2004 to 60 MWs in AOS 2005.

b. Please provide a table that reconciles the shortage identified in AOS 2004 to the shortage

[illegible]

i. peak forecast values (MWs) and the change in peak forecast values from AOS 2004 to AOS 2005;
ii. load management DSM values (MWs) and the change in MW contributions under AOS

lower (as shown in Appendix 2, page 1, Table A2 of the 2005 AOS report), and the estimated impacts of utility and non-utility CHP are forecasted to be lower (as shown in Appendix 2, page 4, Table A4 of the 2005 AOS report).

b.

i. Please refer to Table 1, on page 10 of HECO's 2005 Adequacy of Supply report for a comparison of the forecasted peaks from AOS 2004 and AOS 2005.

ii. Please refer to Table A2 in Appendix 2 on page 1 of the HECO 2005 AOS report.

iii. Please refer to Table A3 in Appendix 2 on page 3 of the HECO 2005 AOS report.

CA-IR-564

Attachment 2 to Appendix 3 to HECO's AOS 2005 states that "We planned (in 1972) to increase the level of reliability to between 7.0 and 10.0, … as our company financing and earnings will permit us to do so" (see Page 3 of 3).

a. Please verify that the "7.0" and "10.0" refer to "7.0 years per day" and "10.0 years per day" planning standards, respectively.

b. Please state (i) whether and (ii) when this alternate planning standard was adopted.

c. If the 7.0 to 10.0 years per day planning standard was adopted, please explain statements in the AOS 2005 that identify 4.5 years per day as the planning standard.

d. If the 7.0 to 10.0 years per day planning standard was not adopted, please explain why not.

HECO Response:

a. Yes, the "7.0" and "10.0" refer to "7.0 years per day" and "10.0 years per day" planning standards, respectively.

b. The higher 7.0 years per day and 10.0 years per day generating system reliability guidelines were never adopted.

c. Not applicable.

d. HECO's generating system reliability has been satisfactory. No evidence has been provided to HECO that its generating system reliability is or has been unsatisfactory. In fact, as part of its currently on-going IRP-3 effort, HECO commissioned a study to review its capacity planning criteria and consider whether these criteria are appropriate for continued use in its integrated resource planning process. The study concluded as follows:

> "The current reliability guideline of 4.5 years to experience one loss of load day is reasonable for both a regulated vertically integrated utility on Oahu and for a

the U.S. The LOLE level appropriate for HECO should be based on the local situation, considering its operating environment with high load factor balanced by the costs of improving reliability with more resources. While the reliability criterion is lower than [redacted] internationally." A copy of the study is attached on pages 3 through 36 to this response.

Report No. R30-04

REVIEW OF CAPACITY PLANNING RELIABILITY CRITERIA

Prepared for
Hawaiian Electric Company, Inc.

Submitted by:

Robert Zeles
Associate Director

Consulting Services

December 13, 2004

1058690

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Section
1

Introduction

As part of the integrated resource planning (IRP) process, the various key criteria, factors, assumptions, and methodology need to be reviewed and documented at the start of the effort. One of the key items that should be reviewed early in this process is the capacity planning criteria. These criteria will be used to evaluate generation adequacy, to establish the need for additional resources to meet future demand and energy requirements, and to evaluate the impacts that different portfolios of new resources will have on the reliability of the overall electric system. The criteria should be reviewed to ensure that they are both reasonable and appropriate for the current and future conditions.

Shaw Power Technologies, Inc. ™ (PTI) was asked by Hawaiian Electric Company, Inc. (HECO) to review its capacity planning criteria and consider whether these criteria are appropriate for continued use in its integrated resource planning process.

1.1 Current HECO Capacity Planning Criteria

At the present time, there are three criteria that HECO uses to determine when additional generating facilities need to be added. HECO's planning criteria indicates that new generation would be added to prevent the violation of any one of the rules. The first rule states that:

> *"The sum of the amount net capability ratings of all available units minus the normal net capability rating of the largest available unit must be equal to or greater than the system peak load (as measured at the high-voltage side of the generator step-up transformers, i.e., before T&D losses) to be supplied at 60 Hz, minus the total amount of underfrequency relay-controlled interruptible loads."*

The second rule is an operational criterion:

> *"There must be enough net generation running in economic dispatch so that the sum of the three second quick load pickup power available from all running units, not including the most heavily loaded unit, plus the net loads of all other running units must equal or exceed 95 percent of the hourly system net load (which excludes power plant auxiliary loads but includes T&D losses). This is based on a minimum allowable system frequency of 58.5 Hz and assumes a 2 percent reduction in load for each 1 percent reduction in frequency."*

A third element in HECO's capacity planning criteria is a reliability guideline. This guideline indicates that:

"Capacity planning analysis will include a calculation of risk (Loss of Load Probability) in years per day for 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. Calculations of risk will utilize normal net capability ratings (N_1, N_2, N_3 ..., N_N)."

1.2 Defining Reliability

Reliability is a measure that indicates how well a system performs its intended function. Adequacy is a related concept that is associated with reliability. A system is considered adequate if there are sufficient resources to perform its function. To apply these terms to electric systems, the North American Electric Reliability Council (NERC) has defined power system reliability as:

"[t]he degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability must be measured by the frequency, duration and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system – adequacy and security.

Adequacy – the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security – The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements."

These definitions apply to both the generation and transmission systems, and in using these definitions, an electric system would be considered unreliable if either the generation or transmission system were inadequate. For this specific review, the focus is on the generation aspect of the HECO electric system, while recognizing that transmission system constraints could impact the amount of generating capacity that could be deliverable to meet load.

1.3 Generation Adequacy

The function of the capacity planning criteria is to establish a consistent basis for evaluating the current system and proposed expansion plans in terms of whether there will be adequate generation to meet load. Generation adequacy can be defined as the ability of all generating resources to supply the total system demand, with appropriate consideration of both scheduled and unscheduled outages of the generating facilities. It does not consider reliability issues or limits associated with the transmission system, outside of constraints on importing power through ties to other systems.

System operators can predict hourly loads for the next day with reasonable accuracy, given that some of the factors associated with load variability will have minimal effect in the short term, while others such as weather can be estimated with reasonable certainty. However, especially beyond one or two days, demand levels on a daily or hourly basis cannot be exactly predicted into the future. Therefore, it is not possible to precisely determine the amount of generating capacity that would be required to meet load levels at various points in time in the future. Similarly, sudden equipment failures can occur randomly, and repairs of outaged equipment can take longer than expected. Since there is a finite non-zero probability that each operating generation resource on the system could fail at a particular point in time, an infinite amount of generating capacity would be required to "guarantee" that the total load would always be met. As this is unrealistic and unfeasible, a probabilistic approach has often been used to evaluate generation adequacy.

As zero risk is approached, the marginal costs of incremental risk reduction (additional resources) become very large and there is no evidence to indicate a willingness of consumers to pay very high premiums for slightly higher reliability. Additionally, unexpected or unpredictable events, such as exceptionally severe weather or acts of terrorism, occasionally cause electric systems to fail, either locally or wide spread, and these events may not be preventable at all. The logical conclusion of this issue from an economic perspective is that the process of setting an adequate level for reliability needs to balance the costs associated with disruption of supply against the costs of reducing that risk.

1.4 Changing Environment

Both in the U.S. and in numerous countries throughout the world, the electric industry is undergoing a structural change that is altering the responsibility for maintaining adequate resources to meet load. Previously, utilities were generally vertically integrated and had monopoly franchises. In that environment, utilities had an obligation to serve and to provide reliable service to all customer classes at the lowest reasonable cost. To conform to those requirements, utilities added resources to meet their projected load requirements, with the timing and, to some extent, sizing of new supply-side resources based upon the generation adequacy evaluations. This process and the resulting approval procedure from regulatory bodies were meant to ensure that reliability was being maintained at a reasonable level while at the same time limiting the ability of utilities to add too much generating capacity that would result in higher rates to consumers than may be considered reasonable.

As portions of the electric industry move towards a competitive generation market, this process is no longer directly applicable. For a deregulated generation supply industry, market forces should guide the addition of new generating facilities, while generation adequacy studies would be a guide to the likely level of future reliability. In this new environment, individual power producers are focused on producing power at the lowest cost possible to maximize profits, while the issues such as reliability, the environment, and demand-side control, previously considered in a regulatory environment especially in the IRP process, need to be addressed in other arenas.

Especially from an international perspective, governments have traditionally taken a strong interest in reliability of utility supply. Some of the factors behind such an interest in security of supply include:

- the essential nature of electricity and the associated high costs of interruptions,
- the difficulty in obtaining alternative supplies other than through monopoly-based transmission line networks, and

- the difficulty of storing energy for most consumers.

Thus, it has generally been recognized that interruptions to energy supply can be both sudden and have serious consequences. At the same time that the structure of the electric utility industry is changing, there is no consistent approach being used to deal with generating resource adequacy. In certain competitive markets, capacity reserve margins have been required for customers, while other markets have taken a hands-off approach and are letting prices and resource additions be entirely market driven.

Section
2

Capacity Planning Criteria

The evaluation process that was used for this study was to review the planning criteria used by other electric utilities, reliability organizations, and regulatory bodies in the U.S operating in an interconnected basis, and utilities operating in other countries that are either isolated or interconnected and to compare those criteria with the planning criteria used by HECO. The purpose of this effort was to provide benchmarks for the evaluation of HECO criteria. The information that has been gathered for this process has been extracted from various public sources.

2.1 General

In attempting to express the reliability of an electric system, there is no single index that is universally used. The types of criteria that historically have been used by utilities for capacity planning include:

- Specified percentage reserve margin,
- Loss of largest unit,
- Loss of load expectation (LOLE),
- Dependence upon interconnections, and
- Expected unserved energy (EUE).

Of these, the percentage reserve margin and the LOLE criteria have generally been the criteria most often used.

The list of reliability indices can be broadly categorized as either deterministic or probabilistic. Deterministic indices, such as reserve margin and loss of largest unit, can be readily calculated with easily documented system parameters and can provide a snapshot of the system. These deterministic measures can be used for evaluating system adequacy for many years into the future. While they can be easily calculated, they have a deficiency in that they do not take unforeseen events into account and, hence, do not directly consider the various aspects of the system that affect overall system reliability.

The dynamic and variable nature of a power system is better analyzed through probabilistic measures. These approaches will take into account the future uncertainties in system components through statistical analyses. The resulting indices will provide a better indication of system reliability, with the tradeoff being that they are more difficult and time consuming to compute and evaluate.

2.2 Reserve Margin

The main reason for the prevalent use of a reserve margin as a reliability standard is a function of its ease of calculation and understanding. The reserve margin is a deterministic measure and represents the relative amount that installed generating resources are greater than the annual peak load. If the calculated reserve margin is above the criterion, then the system would be considered to be within the standard for the period evaluated.

The reserve margin is generally expressed as a percentage and is calculated by taking the difference between total generating system capacity and the system annual peak load and then dividing by the system annual peak load. This calculation can be readily performed for numerous years, utilizing projected annual peak loads and expected resources that would be available to meet those loads. The calculated reserve margins can then be compared with reliability criterion to determine the need to add resources. This process can be refined to consider seasonal peaks for regional analyses where diversity of loads or seasonal differences in generating capacity needs to be considered. Interruptible loads can be reflected in the analysis by either including the interruptible load as a resource, or by using system firm load in the calculations.

The capacity margin is another reliability measure that has also been used and one which is very similar to the reserve margin. It shares all of the advantages and disadvantages of the reserve margin. The capacity margin would be calculated in a comparable manner to reserve margin, with the excess capacity above annual peak demand divided by the total generating system capacity.

2.3 Loss of Largest Unit

Unlike the reserve margin criteria, this criterion recognizes the potential reliability issue if the largest resource fails or is otherwise unavailable to serve load. For systems where a large unit, relative to the other generating units and more importantly system load, is added, the loss of that unit could result in the inability to meet peak load even if the reserve margin criterion were otherwise met.

This criterion is also a deterministic measure that is easy to evaluate and interpret. The net capacity of all available resources except for the largest unit are summed and compared to the system peak load. As long as that net capacity is larger than the peak load, the criterion is satisfied. For relatively large systems where the largest unit is a small percentage of the system peak, the use of this criterion without any other indices will result in insufficient capacity available to meet load when one or more units are unexpectedly tripped while other generation is out for scheduled maintenance.

2.4 Loss of Load Expectation

Loss of load expectation (LOLE) is a reliability index that indicates the expected number of periods in a year when the peak demand would exceed the available supply resources. While it can be calculated hourly, it is typically calculated and expressed in terms of the number of days per year.

In its more common presentation, LOLE is the expected number of days in a year the available generating capacity and other resources would be less than the daily peak demand, resulting in the inability to serve some portion of the load. It is obtained by calculating the probability that the daily peak demand would exceed the available capacity for each day, under the assumption that each day is independent of all others. These daily values are then summed for all the days in a year and multiplied by the number of days in the year. The calculation for hourly LOLE is similar, with the calculations done for each hour in the year, again under the assumption that each hour is independent of all others.

Of the various methods to assess system adequacy that have been discussed thus far, LOLE provides a more complete evaluation of the expected system behavior. Unlike other measures, such as reserve margin, LOLE takes the following factors into account:

1. The peak load of every day (or the load of every hour for hourly calculations) of the year is considered to have an influence on system adequacy, not just the hour(s) of peak demand. Systems with a high load factor will tend to have a lower level of reliability, all other factors being equal.

2. Plant availability is taken into account. Generating resources with a high availability are of more benefit than generating units with low availability, from the system reliability point of view.

3. The number and relative sizes of generating units impact the LOLE calculations. A small number of large units will provide less security than a large number of small units, all other factors being equal.

The reserve margin method does not take these factors into account. Its calculation is based on an annual peak or two seasonal peaks. The number and relative sizes of the units are not considered, nor are their availability levels. The loss of the largest unit approach has usefulness for small systems such as Hawaii Electric Light Co. and Maui Electric Company where the unit size is large compared to peak load and for short-term operational planning, but otherwise suffers from the same limitations as the reserve margin.

While LOLE is typically expressed in terms of days per year or hours per year, it can also be expressed in terms of the number of years per one day loss of load. To illustrate by way of an example, a LOLE criterion of 1 day in 10 years is identical to 0.1 days per year. It is synonymous with 10 years per one day loss of load terminology used by HECO. HECO's reliability guideline is a LOLE calculation with a threshold of 4.5 years per day, or equivalently 0.22 days per year.

The LOLE values are sometimes referred to as loss of load probability (LOLP). However, the proper use of the term LOLP refers to the probability of not meeting load in any hour and thus is a unitless value. In contrast, the LOLE calculation is the result of a mathematical operation known as expected value. Because of this, the term LOLE is the proper name for this calculated value. The calculational procedure for hourly LOLP is the same as for hourly LOLE, with the result being the probability of not serving load in any hour in the year. Multiplying the hourly LOLP value by the number of hours in a year will result in the LOLE in hours per year.

There is no fixed relationship between an LOLE expressed in days per year and one expressed in hours per year. In the LOLE calculated on a daily basis, as is used in HECO's reliability guideline, only the peak demand for each day of the year is considered. For the hourly LOLP calculation, each hour of the year is considered. For systems with a high load factor on a daily basis, there would be more contribution to the LOLE value than if the daily load shape were more peaked. Similarly, energy-limited resources can contribute to a skewing of hourly LOLE values compared to daily calculations. For a "typical" utility, calculated LOLE values of 0.4 - 0.7 hours per year have been found to be comparable to 0.1 days per year for the same system and assumptions.

As previously indicated, the annual LOLE is the sum of the contributions from each day, or each hour if the analysis is so structured. In general, the daily expectations consider the peak load level for the day, the variability of that load, the units that are out on scheduled maintenance, and the probability that each of the remaining plants will be available. Typically, a plant availability distribution table is prepared, from which the probability of the available generation being less than any given load level can be found directly. These tables would then be modified for scheduled maintenance.

The calculated adequacy level is then compared to the reliability criteria standard to assess the adequacy of the system. If the calculated LOLE is greater than the standard, then the system fails to meet the adequacy standard and additional resources are needed. If the LOLE is less than or equal to the standard, then the system is within the standard. A very low LOLE value compared to the criterion is indicative of a system that has excess capacity strictly from the reliability planning criteria; this result could be expected for systems with significant amounts of hydro generation.

2.4.1 Issues Relevant to LOLE Criteria Levels

balances these interruption costs against resource addition costs will vary by utility, especially in the international arena. A more stringent LOLE criterion will generally reflect higher interruption costs; these could be associated with an increased dependence on electricity for production, and societal costs associated with widespread power outages.

Some economists that are advocating for market prices to drive resource additions have argued that the industry standard of 1 day in 10 years implies a much higher customer interruption cost than their studies have shown. Their argument suggests that the current [redacted] regions that are heavily dependent on electricity would be much greater than for underdeveloped countries where electric energy use is minimal by comparison.

2.5 Dependence Upon Interconnections

A similar reliability index is the dependence on supplemental capacity resources. One approach for this index is the determination of the number of days when the system under study would have to depend upon interconnections with other systems, curtailment of service to interruptible customers, and direct-controlled load management. Alternatively, the MW magnitude of dependence on interconnected systems can be used as the calculation approach, with the criterion being the import capability of the existing interconnections. In either of these approaches, the data requirements include forced outage rates, scheduled maintenance, and load forecasts as in the LOLE analyses.

The fundamental premise for this reliability index is that there are resources outside the utility system or planning area that could provide emergency power through one or more transmission interconnections. Thus, the utility will be dependent upon that external capability to avoid the shedding of load during supply emergencies. If there is no capacity

Section
3

Review Process

3.1 General

The review process that was used for this report was to examine the planning criteria used by other electric utilities, reliability organizations, and regulatory bodies in the U.S operating in an interconnected basis, and utilities operating in other countries that are either isolated or interconnected. The purpose of this effort was to provide benchmarks for the evaluation of HECO criteria. The information that has been gathered has been extracted from various public sources.

3.2 Isolated Systems

The transmission systems of most electric utilities in the United States are interconnected with other systems. The interconnected networks allow the utilities to call upon the resources of neighboring systems to help in meeting load during emergency conditions. In contrast, HECO operates an electric system that is isolated from other utilities or sources of power not located on the island of Oahu. As a result, HECO must depend on its own generating resources plus the resources of independent power producers located on the island to meet customer load requirements. Recognizing that in general terms electric power cannot be stored but must be generated at the time that it is demanded, there is a probability that equipment failures, scheduled maintenance, and other factors may prevent generating facilities from operating. Therefore, while the criteria of interconnected utilities can be compared with isolated systems such as HECO's, the additional resources to meet the same criteria would need to be provided by local generation or load modification, rather than transmission lines to neighboring utilities.

3.3 Market Pricing Issues

As the electricity supply industry moves from the vertically integrated regulated monopolistic structure to a competitive commodity market, volatility in prices should be expected that reflect market forces. Developers of resources will install new capacity when they perceive that the market prices will provide them with sufficient revenue to result in a profitable venture. In periods of excess capacity, prices will remain low and provide little incentive to build new capacity. In commodity markets other than electric energy, marketers, retailers, and large customers will typically use long-term bilateral contracts that limit their exposure to price volatility as well as price hedging instruments. Unlike price volatility responses in some commodity markets, the issue of inadequate investment in generation and conservation may lead to actual electricity supply shortages, with resultant interruptions and the consequential economic disruptions. This risk stems from the instantaneous balancing of supply and demand in the electricity markets, the limited storage capability for electricity, and the transition time from when demand side issues appear to the time when supply side facilities can be developed and implemented.

Electricity has become a vital element of economic activity throughout most of the world, such that shortfalls of generating capacity can have significant economic and political ramifications. Since the development time for generating plants can be relatively long, it is important to consider the impacts that may result from the various options available to moderate the price volatility and the potential demand and supply imbalances. Some of the options that have been suggested include:

- A regulatory requirement on Load Serving Entities (LSEs) to maintain certain capacity margins.

- Require some entity to construct resources to maintain certain capacity margins.

- Provide some form of capacity payment from LSEs to give added incentive for a greater level of development of new generation. This would require some entity with sufficient market presence to implement the billing and collection from electricity users and direct the financial resources to the appropriate developers.

- Let the market mechanisms develop for hedging the risk of volatility. The premiums collected could be used to support the development of resources to boost supplies, thereby moderating the price volatility.

The current approach that has been implemented in the eastern U.S. has focused on requiring LSEs to have, in some manner, sufficient capacity to meet peak load plus a specified level of reserves. There are several approaches being developed that would provide for capacity payments, but these are in a state of flux at this time. While economists advocate that the market can provide mechanisms for addressing price risk, there has been limited movement in this direction given the political response to significant spikes in prices.

Theoretically, generation adequacy can be evaluated without concern as to whether the electricity market is competitive or not. While the market will influence the price of electricity during periods of supply shortage, it should not constrain the quantity of available capacity that will be available to meet demand. This assumes that the market conditions in the future will be sufficient to attract investment for future required capacity in a timely manner and that commercial operation of the market discourages poor availability levels. However, insufficient revenue to support costly or inefficient generating resources could lead to the early retirement of those units, thereby reducing total system generating capability.

In most commodity markets, the consumers' responses to price changes serve as a mechanism to restrain price swings. As prices get too high, consumers use the product more efficiently, curtail use of the product, find substitutes, or shift use to periods when it is less expensive. In certain regards, electricity is different in that it is a relative necessity of modern life and there are few substitutes for it, although there are ways in which to reduce the use of electricity, implement efficiency improvements or change the periods of use.

Another impact associated with the movement towards competitive markets is the focus of oversight parties. In the past, the focal point was on long-term resource needs. Now the state and regional bodies are focused on the shorter-term adequacy and reliability assessments and on the performance of electricity markets. Additionally, data requirements for these efforts and the availability of that data are issues that have impeded the review process.

Market-based pricing as a means to signal the need for additional capacity is not an applicable consideration in Hawaii, as there is no competitive retail market and a limited wholesale market.

3.4 Planning Criteria in Current Practice

The discussions in the following sections present the basis and rationale of the planning criteria used in various regions of the U.S. and in a number of countries.

3.4.1 Mid-Atlantic Area Council

The Mid-Atlantic Area Council (MAAC) is a reliability council that covers the states of New Jersey, Delaware, Maryland, and the majority of Pennsylvania. This reliability council, like others throughout the U.S., has maintained its reliability principles and standards as the generation market has undergone varying aspects of deregulation and re-regulation. Initially adopted in 1968, and most recently revised in March 1990, MAAC's reliability standards provide that the installation of generating capacity needs to be sufficient in each year to ensure that the probability of load exceeding the available generating capacity shall not be greater than one day in ten years. They have indicated a number of factors that should be reflected in the reliability analysis. These include the scheduled and unscheduled outages of generating units, limited energy capability from supply-side resources, the transmission network capabilities within the individual systems within MAAC, the connections to parties outside MAAC, and the nature of the connected load. The underlying principle for these standards is that they only apply to facilities that impact the reliability of the overall MAAC system, as opposed to facilities that only affect the reliability to supply local system loads.

MAAC's focus is to ensure that the bulk electric system is planned and built so that the more likely contingencies will not result in loss of load. This allows individual participants in MAAC to adopt different criteria for their own systems where cost or other factors may limit the ability to attain the specified reliability. MAAC also recognizes that a diversity of types, sizes, and locations of all electric system facilities is needed to maintain reliability, by minimizing common mode outages. With respect to supply side resources, this means that different fuel types, fuel supply sources, or equipment types should be encouraged. If adequate diversity is not possible, then common mode outages should be considered in evaluating the overall system reliability level.

To ensure that all systems within MAAC contributed to the overall reliability, consistent with an LOLE of 1 day in 10 years, the Reliability Council of Pennsylvania New Jersey Maryland Interconnection LLC (PJM) established a 19.0% required reserve for the 2001 – 2003 planning periods. This obligatory reserve must be met by all load-serving entities in PJM as signatories to the Reliability Assurance Agreement (RAA). This reserve margin is the amount of generation that the LSE must maintain above their peak demand. Total PJM load is met through generating resources within PJM coupled with purchases from other regional markets. While generating resources can be energy-only or installed capacity resources, only the latter can be used by LSEs to meet their load and reserve responsibility.

The installed capacity resources used by a LSE within PJM can be called upon to support PJM during system emergencies. However, their output can be removed by their owner or marketer from the PJM market with as little as one day's notice, allowing their output to serve more lucrative markets. Since the installed capacity resources are important in evaluating and maintaining reliability levels, PJM is considering what approaches might be used to address this issue. An alternative to the reserve obligation would be to implement a market-based adequacy model. In this environment, a market that relies on price signals must also be designed with adequate safeguards in place to ensure that should there be a conflict between market price signals and system adequacy, that the reliability issues should not be jeopardized.

3.4.2 New York State

The New York State Reliability Council (NYSRC) was formed in 1997 to promote and preserve the reliability of electric service. The NYSRC is responsible for developing and updating reliability rules that shall be complied with by the New York Independent System Operator (NY ISO) and all entities engaged in electric power transactions in the New York State power system.

The NYSRC reliability rules as used in the December 2003 report on installed capacity requirement for 2004-2005 indicates that adequate resource capacity shall exist such that "...the probability of disconnecting firm load due to a resource deficiency will be, on the average, not more that once in ten (10) years." This NYSRC reliability rule is consistent with the Northeast Power Coordination Council (NPCC) resource adequacy standard. In this NYSRC report, the installed reserve margin for the New York Control Area (NYCA) has been set at 18% of forecasted peak load, based upon study results structured to ensure that the LOLE reliability criteria of 1 day in 10 years is met. In addition, LSEs are required to acquire [illegible]

"Resources will be planned and installed in such a manner that, after due allowance for the factors enumerated below, the probability of disconnecting non-interruptible customers due to resource deficiency, an average, will be no more than once in ten years.

a) The possibility that load forecasts may be exceeded due to weather variations.

b) Immature and mature equivalent forced outage rates appropriate for generating units of various sizes and types, recognizing partial and full outages.

c) Seasonal adjustment of resource capability.

d) Proper maintenance requirements.

e) Available operating procedures.

f) The reliability benefits of interconnections with systems that are not NEPOOL Participants.

g) Such other factors as may from time-to-time be appropriate."

As documented in a recently completed report on the NEPOOL installed capacity requirement for the 2004-2005 power year, the system operator, ISO New England (ISO-NE), is required to calculate the total installed capacity that must be available to meet projected daily loads and meet the annual LOLE reliability criterion of 1 day in 10 years. This is the capacity that must be purchased from the capacity market. The procedure utilizes current forced outage rates, maintenance schedules, and incorporates seasonal capacity changes as well as the benefits of ties to Canada and New York.

In using market prices to support a capacity market, ISO-NE has observed that the installed capacity market as currently structured may not provide sufficient capacity when needed. The market structure has not produced sufficient revenue for some of the regional generator owners who have had to turn over assets to lenders or file for bankruptcy. In addition, some of the new generation has been installed where transmission constraints limit the ability to deliver power where needed. This situation has resulted from both inadequate locational price signals and changes in the FERC minimum interconnection standards. As a result, ISO-NE is considering a location-based installed capacity market to address deficiencies in the existing capacity market.

3.4.4 Florida

Most of the members of the Florida Reliability Coordinating Council (FRCC) use a deterministic reliability criterion, namely reserve margin. As part of its overall assessment of resource adequacy, FRCC determines reserve margins for both summer and winter, based on system conditions expected at the time of the system peaks for each season. In their calculations of reserve margin, non-firm demand resources (interruptible loads and load management programs) plus supply side resources are compared to firm peak demand.

Progress Energy Florida and Florida Power & Light Company also use LOLE, with a criterion of 0.1 days per year. Effective in 2004, these two utilities and Tampa Electric Company have raised the reserve margin criterion from 15 to 20%. In addition, Seminole Electric Cooperative uses two reliability criteria, a 15% reserve margin and a 1% EUE.

3.4.5 Western Electricity Coordinating Council

The Western Electricity Coordinating Council (WECC) is the largest reliability council in the U.S. in geographical terms, covering essentially all of the western 13 contiguous states plus two Canadian provinces. While reliability criteria are prescribed by many states and regional reliability councils, neither the WECC nor the state of Washington specify an adequacy standard for resource planning. In its 2003 integrated resource plan, Puget Sound Energy, Inc. (PSE) indicated that it considered a range of planning levels for meeting both energy and capacity. With a substantial portion of their existing energy resources based on hydro generation, their planning process needs to consider economic evaluation of both the constraints during prolonged drought periods as well as periods of above average precipitation. If PSE focused only on capacity margin or LOLP, this would likely result in a shortage of energy during low water periods even though there was sufficient installed hydro generating capacity.

In their planning process and IRP analysis, PSE has considered the economic tradeoffs and risks by considering a number of planning levels. In addition, their analysis reflected the need to evaluate resource options from both a capacity and energy perspective.

In contrast, Xcel Energy Inc. (Xcel) had historically utilized WECC Power Supply Design Criteria No. 1 to establish the level of planning reserves for its system. Those criteria indicated that the needed reserve margin was equal to the largest risk (generating unit) plus 5 percent of load. Subsequent to Xcel's 1999 IRP filing, a reserve margin was determined and stipulated to by the Colorado Public Utility Commission that would equate to a LOLE of 1 day in 10 years. In this stipulation, a reserve margin of 13% to 17% was deemed appropriate, with the range designed to take into account load forecast uncertainty and resource development risks. These factors had not been reflected in the analysis to develop a basic reserve margin that would produce the target LOLE of 1 day in 10 years. In its 2004 IRP filing, Xcel has further refined its analysis of the reserve margin necessary to maintain the target LOLE and determined the appropriate value to be in the 16% to 17% range and is using this as the basis for identifying resource needs.

3.4.6 Australia

With the establishment of a national market, the National Electricity Code Administrator established the Reliability Panel to determine the appropriate reliability standards. The current structure of this market is an energy-only market. It appears the market has been successful to date, including the development of new investment in generating facilities. At the same time, the reserve trader arrangements that consider reliability levels have been continued as a backstop in the event that future market responses have the potential to reduce power system reliability.

With these standards, the National Electricity Market Management Company could intervene in the market to contract for additional resources to ensure an adequate reliability of supply in the event that there was a failure of the market to meet customer expectations. In this market, the reliability standard has been based upon unserved energy rather than capacity shortage expressed in either reserve margins or LOLE. Their rationale behind this approach is that the reliability standards in a market environment should be focused more towards individual customer reliability. While LOLE measures the number of days (or hours) of load shedding, it does not reflect the magnitude or duration of the deficiency. In contrast, unserved energy indicates the amount of overall customer energy requirements that would not be met over a period of time.

3.4.7 Ireland

Ireland has been moving to a fully competitive market and there have been concerns related to whether there would be sufficient generation added to meet demand under changing market structures. As a result, the Transmission System Operator Ireland (TSOI) is required to analyze and prepare a generation adequacy report covering the upcoming 7-year period. The reliability standard is 8 hours loss of load per year as indicated in the latest report, covering the 2004-2010 period. This means that in 8 hours during each year, the available capacity is expected to be less than unrestricted demand. The LOLE calculations used by TSOI do not reflect emergency operational procedures that are used to avoid loss of firm load, such as importing extra power from Northern Ireland or interruptible load shedding. The peak demand estimated for the winter 2004 season is 4,468 MW with available generation of 5,892 MW. Their system is relatively isolated, with ties to Northern Ireland capable of delivering about 300 MW in emergencies and contractually providing 167 MW under current normal conditions.

3.4.8 Israel

The utility in Israel, the Israel Electric Corporation (IEC), is a vertically integrated utility owned by the government. In 2003, installed capacity of 10,117 MW was available to meet the peak demand of 8,570 MW for an 18.1% reserve margin. With no ties to other countries, IEC's reliability criterion is indicative of the desire to have a reliable supply-side system, with a planning criterion of 2.0 hours per year, with long term intention to increase reliability by reducing the LOLE criterion to 0.7 hours per year.

3.4.9 Italy

The Italian power industry has been gradually restructuring since 1999. Prior to that time, ENEL, the utility that had the responsibility to maintain supply resources, used a ratio of Expected Energy Not Supplied to Demand with the criteria set at 10^{-5}. Since 1999, several approaches have been taken to provide incentives for maintaining adequate capacity, including a reserve margin payment and an operational reserve. The issue of resource adequacy appears to have played an important role in the nation-wide blackout in the fall of 2003. The European Union (EU) Commission is also concerned with security of supply and the adequacy margin of each generating system. The EU Commission issued a proposal late in 2003 that, among other things, required member states to have a published approach for ensuring a balance between supply and demand including targets for reserve generation capacity.

3.4.10 Puerto Rico

The Puerto Rico Electric Power Authority (Authority) is a government owned utility providing service to the entire island. At the present time there is no pressure for deregulation. Currently the Authority has 5,359 MW of resources to meet a peak load of 3,376 MW, yielding a reserve margin of nearly 59%. Of the Authority-owned generating facilities, there are four units with net capacity over 400 MW each, which in total supplied about 51% of the 2003 system peak. In addition, there are two cogeneration facilities, a coal-fired plant with about 450 MW net capability and a 507 MW net combined cycle plant. In recent years the Authority has made significant capital expenditures to improve reliability of its existing generating facilities. Ten years ago, the equivalent availability ratio was about 60%; with the recent improvements, it is now approaching 80%. Due to its isolated service area and minimal seasonal demand variations coupled with generating units that are large compared to system load, the Authority needs a large reserve margin to maintain reliability. The Authority's current target reserve margin is 45%, down from the 70% maintained in the early 1990s when there were more frequent forced outages.

3.4.11 Thailand

The Electricity Generating Authority of Thailand (EGAT) is the principal owner of generation and provides power to two distribution utilities and a number of large industrial sites. This government-owned utility had used reserve margin of 25-30%, but given the prolonged decline in economic activity, there are indications that this may have been reduced to 15%. Total generation in Thailand is over 21,000 MW and the transmission system has limited interconnections with neighboring countries. While there have been attempts by the government to privatize portions of EGAT, those attempts have been met with significant resistance.

3.4.12 Korea

As the Korean government has moved towards wholesale competition, the generation sector was removed from state-owned Korea Electric Power Corporation (KEPCO), which owned most of the generation, and divided into six generation subsidiaries. Shortly thereafter, the government prepared a study for an electricity resource baseline plan. In the resulting report prepared in 2002, the electric resource requirements for the 2002 – 2015 period were determined. These requirements were based on a LOLE of 0.5 days/year with an associated capacity reserve margin of 15-17%. Generation in South Korea currently totals about 56,000 MW. Demand for electricity over the past 30 years has increased at an average rate of about 12% per year, well over the 6.8% average annual growth in real GDP during the same period. Electric rates have risen minimally compared to the overall consumer price index and have contributed to the industrial competitiveness of Korea.

3.4.13 Singapore

The electricity wholesale market started operations in 2003, following years of transition from a vertically integrated government utility. The Energy Market Authority (EMA) replaced the Public Utilities Board in regulating the electric industry. In its role, the EMA uses a reserve margin for assessing generation adequacy, comparing the projected margins against a 30% target index.

Operating reserves are determined by the power system operator (PSO), and are classified as either primary, secondary, and contingency, where response time is either 8 seconds, 30 seconds, or 10 minutes, respectively. The PSO will determine the reserve capacity needed, recognizing the need to consider the unexpected outage of a scheduled plant.

3.4.14 Jamaica

The total capacity of the generating resources on the island of Jamaica that was available to meet the 589 MW peak load in 2003 was 766 MW. These generating facilities include 16 small steam, diesel, and combustion turbine units (the largest of which has a nameplate capacity of 68.5 MW), 23 MW of hydro generation, 4 independent power producer (IPP) contracts and one 120-MW combined cycle plant. Generation expansion requirements are established within the guidelines of the mandated level of reliability to customers as stipulated by Jamaica Public Service's (JPS's) operating license. The reliability criterion for capacity planning purposes is measured as LOLP. Given the current system resource configuration, the 0.55% LOLP criteria will allow the two largest units to be out of service (one on normal maintenance and the second tripped off). For JPS, the reliability requirement will result in a reserve margin of about 25%.

3.4.15 United Kingdom

National Grid Company plc (NGC) was established in 1990 as the owner and operator of the

high voltage transmission system in England and Wales and is responsible for balancing supply with demand 24 hours a day. As part of their transmission license, NGC produces a seven-year forward looking statement that presents expected changes in the transmission system, projected loads and expected generating capacity. Within the competitive electricity supply industry in England and Wales, there is no set standard or requirement for planning estimated national demand plus additional capacity to offset the potential failures of production plants and transmission lines.

The current posture of Nordel is that the market should provide a credible price for electricity and thus the necessary signal for proper decision making by the market participants. The market prices should not be influenced or capped by any intervention that harms the market-oriented approach, even when prices are high. Adequacy should be provided by the market participants so that supply will meet demand and new facilities will be built by the market participants when it is needed. From this perspective, the TSO's responsibility should be limited to the operational hour and necessary operational reserves.

Nordel's position is that if society loses confidence in the participants' ability to provide adequacy, there will be a push towards centralized control and actions. The end result of this could be to create uncertainty among the market participants and potentially have a negative impact on the incentive to invest in new resources.

3.4.17 South Africa

South Africa is in the process of restructuring its electric supply industry, moving from a vertically integrated industry dominated by Eskom, the government-owned utility, to an unbundled supply industry with competition in the generation sector. The National Energy Regulator (NER) is the regulatory authority over the electricity supply industry in South Africa.

The NER recently completed a study for the National Integrated Resource Plan (IRP). The focus of this IRP was to optimize the supply-side and demand-side resource mix while ensuring a reliable electric supply and minimizing the cost of power to consumers. The intent of this effort by the NER is to provide an independent source of information and reference for the various decision-makers and stakeholders in order to help insure security of supply. The resulting reference plan presented in the IRP reflects two constraints, a 10% reserve margin, and a maximum EUE of 0.011% of total annual energy demand, based upon Eskom's LOLE criteria of 22 hours per year.

3.5 Discussion

Within the ten reliability councils of the U.S., four of the councils, MAAC, East Central Area Reliability Coordination Agreement (ECAR), Mid-America Interconnected Network (MAIN), and Northeast Power Coordinating Council (NPCC), use LOLE as their stated planning criteria and indicate that the standard is 1 day in 10 years (or its equivalent). While Electric Reliability Council of Texas (ERCOT), Mid-Continent Area Power Pool (MAPP) and Southwest Power Pool (SPP) use a reserve margin as their stated reliability criteria, they periodically use probability analyses to evaluate if changing conditions would require a revision to that deterministic criterion. This analytical process is generally structured to establish that the values used as the benchmark reserve margin would provide for a LOLE that was equivalent to 1 day in 10 years.

There are no specific criteria that have been prescribed by the WECC. In part, this recognizes the wide diversity of resources throughout the region. With the large dependence upon hydro power in the northwest and large coal plants in other states in the western U.S., the various utilities in the WECC have established their individual criteria appropriate for their situation that are designed to maintain reliability.

In the eastern U.S. where the wholesale markets are competitive, the general thrust has been to require the LSEs to have or purchase sufficient capacity from the market to maintain a reserve margin that would functionally sustain a LOLE of 1 day in 10 years. Specifically, the Midwest ISO (MISO) uses the 1 day in 10 years LOLE target to establish reserve margins for individual LSEs. The MISO approach considers the resources within each of the LSEs in setting the different reserve margins. In contrast, the PJM market currently uses the same reserve margin for all LSEs to maintain its target LOLE. Within New York State (part of NPCC), each LSE is required to maintain a reserve margin calculated from a study to ensure that the LOLE reliability criteria of 1 day in 10 years is met.

As the wholesale markets in more regions of the U.S. become more competitive, the application of reliability criteria for long range planning will tend to become more difficult. In a competitive environment, there will be less sharing of data including the addition of new facilities and the retirement or mothballing of older units. This will introduce additional risk into the process since there will be less certainty as to the resources that will be available to meet future loads. As a result, there will be a shift to shorter-term planning perspectives, with the focus limited to perhaps three years into the future. With the general trend to requiring load serving entities to acquire sufficient reserves, there will likely be an increasing reliance on resources that can be developed quickly. The current emphasis on combined cycle units and combustion turbines with their short construction period gives the LSEs flexibility in responding to the dynamic marketplace with its changing and competitive aspects.

In summary, the industry standard for reliability criterion for the U.S. mainland has remained as a LOLE of 1 day in 10 years, even as the electric industry has transitioned from a vertically integrated and regulated environment to a competitive wholesale market. With the planning or evaluation horizon shortened due to reduced free sharing of data and other competitive factors, and the complexity associated with LOLE or other probabilistic methods, reserve

TABLE 1
Comparison of Generation Planning Criteria

Country	Organization	Criteria Used	Target Index	Comment
Australia	National Electricity Code Administrator	Unserved Energy	0.002% annual energy	
China	China Electric Power Institute	Reserve Margin	>20%	
England	NGC	Reserve Margin	20%	Reliability assessment
		LOLE	1 occasion/year	Operational Planning
India	Central Electricity Authority	LOLP	1%	
Ireland	TSO Ireland	LOLE	8 hours/year	
Israel	IEC	LOLE	2.0 hours/year	Through 2010
			0.7 hours/year	After 2011
Italy	ENEL	EUE	10^{-6}	Pre1999 industry reform
Jamaica	JPS	LOLP	0.55%	Equivalent LOLE is 48 hours/year
Korea	KERI	LOLE	0.5 days/year	Reserve Margin of 15-17%
Malaysia	TNB	LOLE	1 day/year	
Puerto Rico	Puerto Rico Electric Power Authority	Reserve Margin	45%	
Saudi Arabia	SCECO East and West	LOLE	0.2 days/year	
Singapore	Energy Market Authority	Reserve Margin	30%	Reliability assessment
South Africa	Eskom	LOLE	22 hours/year	
UAE	Sharjah Electric Company	LOLE	5 hours/year	Reserve margin of 20%
US	MAAC	LOLE	1 day/10 years	
	ECAR	LOLE	1 day/10 years	
	ERCOT	Reserve Margin	15%	
	FRCC	Reserve Margin	13.5 – 22%	Varies by utility
	MAIN	LOLE	0.1 days/year	
	MAPP	Reserve Margin	15%	
	NPCC	LOLE	1 day/10 years	

general approach that would support the development of additional resources. This process involves the requirement that load serving entities procure sufficient capacity to meet both their peak load and a pre-determined reserve margin. Those LSEs that fail to procure adequate capacity from the market would be subject to a penalty.

Other approaches that are more market-based focus on (1) ensuring that the spot market [redacted]

higher, (2) including an energy-only market that involves demand bidding and forward markets, and (3) setting rational price caps when the market can't. From pure economic theory, the inclusion of price caps represents an unpredictable intrusion into the market environment such that the economic demand and supply curves are distorted. Various aspects of these approaches have been tried in California as well as in Argentina and [redacted]

Section
4

Planning Criteria for HECO

4.1 Loss of Largest Unit

The first rule used by HECO in evaluating the adequacy of existing resources is whether there is sufficient capacity without the largest unit to meet the system peak load including transmission and distribution system losses. The AES Barber Point facility is currently the largest generating resource on Oahu and has a net capability of 180 MW. This facility represents about 14 percent of the 2003 annual system peak of 1,284 MW. Total generating resources available to HECO in 2003 provided about 1,615 MW, as shown in the following table, and resulted in a reserve margin of 25.8% assuming no interruptible loads.

TABLE 2
HECO Resources

Unit	Net Capacity (MW)
Honolulu 8	52.9
Honolulu 9	54.4
Waiau 3	46.2
Waiau 4	46.4
Waiau 5	54.6
Waiau 6	55.6
Waiau 7	88.1
Waiau 8	88.1
Waiau 9	51.9
Waiau 10	49.9
Kahe 1	88.2
Kahe 2	86.3
Kahe 3	88.2
Kahe 4	89.2
Kahe 5	134.7
Kahe 6	133.9
H-POWER	46.0
KPLP CT-1	90.0
KPLP CT-2	90.0
AES	180.0
Total	1614.6

Using the methodology of the first rule, and assuming for this discussion that relay-controlled interruptible load is zero, HECO had 1,435 MW of generating resources (excluding AES, the largest unit) to meet a peak load of 1,284 MW in 2003, indicating that the criterion was

satisfied at least during the peak period.

If the largest unit was 340 MW (rather than 180 MW) and all of the generating resources still provided the same total net capacity of 1,615 MW, the loss of that largest unit during the peak period would have resulted in a capacity deficiency of about 10 MW. This rule has the effect of discouraging the installation of a single large generating unit (relative to the existing resources) that would serve a significant portion of HECO's system load.

In the months when peak demand is a little lower, maintenance is generally scheduled for all of the units. During February 2003, when the peak demand was 1,141 MW, if Kahe 5 or Kahe 6 were on scheduled maintenance and the AES unit failed, HECO would still have had 1,300 MW available to serve the peak load.

In applying the rule during lighter load months like February, the total available capacity would likely be reduced by units that are out for maintenance. This criterion can be readily used to determine the maximum capacity that can be scheduled out for maintenance at any point in time while allowing for the unscheduled outage of the largest available unit. Given the relatively constant monthly peak loads throughout the year, the use of this criterion on a monthly basis with the maintenance schedule will help to assure that there is sufficient capacity available to meet the expected peak loads.

During system emergencies where system frequency is starting to drop due to a mismatch between generation and load, there may be minimal time for system operators to respond to the situation. While all interruptible loads can be dropped, there may be significant delays between the time that a capacity shortfall is identified, notification to interruptible customers is made, and action is taken. For load disconnection to be effective in sudden system emergencies, only those interruptible loads that can be automatically disconnected can provide an immediate benefit to system stability. The use of under-frequency relays to disconnect these interruptible loads should result in immediate benefit to the system by reducing the load versus supply imbalance. Therefore, HECO's recognition of specific interruptible loads in evaluating resource adequacy is appropriate.

Of the utilities, reliability bodies and regulatory authorities surveyed, there was no mention of the loss of the largest unit as a specific criterion. In most cases, the utilities or regions in question have a much larger peak demand compared to the largest generating unit. Thus this reliability index would not be a limiting factor for them from the reliability perspective. Even in Jamaica, where the system load is less than HECO's, the largest unit represents only 11.6% of the peak load. With their criterion of 0.55% LOLP, JPS acknowledged that this will require sufficient capacity to be installed to allow the loss of the largest unit when the second largest is out for maintenance.

While this criterion does not reflect the relative reliabilities of the generating units in the system to indicate system security, it does indicate when the supply resources are not rule is directed towards the operating procedures of HECO to minimize the loss of load due to a forced outage of an operating generator.

The issue of maintaining sufficient operating reserves and maintaining sufficient capacity reserves are closely related. Operating reserves are the first line of defense against major generation outages. Operating reserves are provided by generating units that can readily increase their output to restore balance to the system after a contingency such as the loss of a generator.

A mismatch between generation and load results in frequency deviation. To maintain nominal frequency and respond to sudden changes in supply or load, there needs to be sufficient generating capacity operating and available to meet those additional needs. The amounts of these reserves are related to the system's characteristics and frequency deviation limitations.

The specific parameters of this operational criterion are a function of the behavior of the system and the nature and capability of any interconnected utilities. While quick response reserves for some utilities or TSOs may be the capacity available 5 or 10 seconds after a system disturbance, the resources available to provide that reserve would be spread throughout the interconnected system. The review of the specific parameters, which are particular to the HECO environment, are beyond the scope of this review.

4.3 LOLP

HECO's reliability guideline is currently at 4.5 years for one day loss of load. While the mainland U.S. has a higher level of reliability at 10 years for one day loss of load, a number of the island utilities that were reviewed indicate lower reliability levels in terms of LOLE. The National Grid Company which controls about 70 GW of generation in the competitive market of the United Kingdom uses a 1 occasion per year LOLE. Ireland's electric system, which has a peak demand about 4 times that of HECO, has a LOLE reliability standard of 8 hours per year. If this were calculated in terms of days per year, the equivalent LOLE value would be about 1.5 days per year. Both England and Ireland have established industry that is dependent on electric power for their economic viability. At the same time, these countries have transitioned to a competitive power supply sector, and, in the case of Ireland, do not recognize the benefit of interruptible load in this calculation.

In certain regards, the island of Jamaica is more comparable with HECO, both in terms of size and regulatory environment. Jamaica's reliability criterion of 0.55% LOLP is equivalent to 48 hours per year. As a result, without considering interruptible loads or load management benefits, the planning process for capacity planning for the electric supply system on Jamaica would appear to result in a system that would be less reliable than HECO's. In part, the lower level of reliability reflects the lower level of economic activity on Jamaica with the associated inability or unwillingness to pay for additional generating resources to improve reserve margins.

As previously discussed, the setting of a target LOLE should be based upon or recognize the cost of increasing capacity to improve reliability against the costs associated with interruption of service. In heavily developed countries with significant industrial load that is dependent on reliable service, the cost of interruptions is likely to be high. These costs include those expenses associated with lost production or the inability to serve customers, inconvenience, and societal costs like civil disorder. Adding resources to increase system reliability will increase electric costs that will be offset by reduced interruption costs. In contrast, in less developed countries with lower industrial activity and lower dependence on electricity for normal activities, there would be a much lower level of costs associated with interruption of electric service. Thus the difference in LOLE criterion levels between Jamaica and the United Kingdom or Ireland is reasonable.

After consideration of the sizes of the generating units relative to the demand levels, the next most critical factor influencing the LOLE calculation is the reliability levels of the various generating units. A system where the equivalent forced outage rates are over 20 percent (this excludes normal scheduled maintenance) for the large units will generally have a high LOLE value unless large reserve margins exist. In Puerto Rico, the equivalent availability for the generating resources in the 1990s had been about 60%; this means that each generating unit was out of service an average of 40% of the year due to forced outages or planned maintenance. While the LOLE values are not available, the utility recognized that a large reserve margin was necessary to maintain reliability and thus had a target reserve margin of 70%. Recently, as the results of significant increases in maintenance at its power plants have been realized through improving generating unit availability, the utility has been able to reduce the target reserve margin to about 45%. In contrast, based on the observed forced outage data for the past 10-years by unit type, HECO's equivalent forced outage rates are under 10% for most units, and for many of its larger units are under 2%. The benefit of these low failure rates is a high likelihood that the generating units will be available when needed. Thus, for a given LOLE level, a lower reserve margin will be appropriate for HECO compared to systems where generating units are less reliable.

While not an island, Israel's electric system is essentially isolated from the neighboring countries. Its current planning criterion is 2 hours per year LOLE, which is roughly equivalent to 1 day in 3 years. Israel's long term objective for capacity planning is to increase the level of reliability to 0.7 hours per year, equivalent to about 1 day in 10 years. Their goal to increase the criteria level over the next several years will improve their security of supply and also will raise costs associated with the increasing generating capacity requirements. The existing electric system in Korea is also isolated and their planning process uses a 0.5 days per year or 1 day in 2 years criterion. Since the growth rate of electric demand has been high and the Korean government has been focused on maintaining low energy costs to enhance its competitive position, the reliability criteria has been maintained at a lower level than other heavily industrialized nations. While both of these are developed countries with security and industrial activity that place a value on the reliability of supply, there is recognition that there are tradeoffs that have been explicitly or implicitly accepted in terms of cost and reliability.

In reviewing the LOLE reliability criterion indicated for other developed countries like UAE and Malaysia, the criterion is for a 1 day per year LOLE. In contrast, in less developed countries where electric service is not available throughout the country, the planning criterion reflects a LOLE of over 4 days per year.

4.4 Rationale for HECO's Reliability Guideline

The interconnected nature of the mainland U.S. utilities provides benefits in terms of reserve margins that must be maintained by any utility or ISO. Historically, the reliability criteria that have generally been used for the mainland utilities are based on a LOLE of 1 day in 10 years. Some of the reliability councils are indicating reserve margins as their planning criteria, but acknowledge that the reserve levels should be adequate to provide a 1 day in 10 year LOLE level. As some supply markets, such as PJM, MISO, NE-ISO, and NY ISO, have moved to a competitive environment, the maintenance of supply reliability has been passed onto LSEs in the form of reserve margins that have been developed based on the LOLE criterion of 1 day in 10 years.

The Eastern Interconnected system in the U.S. has been planned using either directly or indirectly a LOLE of 1 day in 10 years. This standard was developed over time in a process that considered the consumers' costs of increasing reliability and the costs that interruption of service would cause. It can be argued that individual utilities would have different interruption costs, reflecting their industrial customers' needs, level of local economic activity, and other related factors. If this process was used and each individual utility was allowed to set its own LOLE criteria, then neighboring utilities could end up with significantly different reserve margins. The net result of this would be much greater dependence on neighboring utilities for systems with minimal reserves encountering the loss of a generator. With the interconnected nature of the system, this would result in uncompensated and unplanned sharing of other parties' resources; depending upon the state of the system it could also result in failures in adjacent systems or potentially cascading system failure. To ensure fairness and equitable sharing of costs, the reliability criterion is specified at the regional level and is power relative to available income, the need for basic necessities, and the way of life would all constrain the amount that consumers would pay for increasing reliability above any nominal level. Without rigorous calculations, the planning process with such low level of reliability would be similar to adding new generation when the load was greater than the installed capacity.

In developed countries with relatively isolated systems where security issues are important, economic activity is dependent on electricity and the standard of living is relatively high, the LOLE levels range from 1.0 to 5.0 years per one day loss of load. Saudi Arabia with relatively high income is at the more reliable end, with Korea and Israel in the mid range at 2.0 to 3.0 years per day, and the lower end including UAE and Ireland. As a state-owned utility, the planning criteria for Israel's utility in the near term may be guided by other government financial issues, since the long range criteria is for a much higher reliability level. The Irish and Korean reliability levels may reflect the nature of the country where heavy industrial requirements are somewhat offset by significant population in rural areas with a lower dependence on reliability of electric power. Oahu can be considered to be urbanized with greater dependence on electricity than Ireland or UAE. From this perspective, the reliability guideline used by HECO of 4.5 years per day is reasonable.

For a system that has a low load factor, the utility can strive to make all its capacity resources available during short peak period and easily perform preventative maintenance during the off-peak periods. In contrast, utilities with a high annual load factor, such as HECO's 2003 level of 73.4%, and small fluctuations in monthly peak demands can't concentrate all their maintenance to off-peak periods but must spread it throughout the year. With the relatively constant load levels, the probability of not meeting load on each day of the year would be comparable, whereas a system with a needle-peak would find most of the risk clustered around the peak with almost no chance of failure during the remainder of the year. Thus, as the reserve margin for HECO gets smaller, there is a more constant risk of failure throughout the year. Additionally, the effect of the lower reserve margin is an exponential increase in the LOLP value. In order to have the equivalent level of reliability on the system peak day for a high and low load factor utility, the high load factor utility would have to maintain a more reliable system in terms of calculated LOLE per year. Thus HECO's 4.5 years per day guideline is not unreasonable when compared to the other relatively isolated developed countries.

In the 1960's, HECO had undertaken studies to review its planning criteria. These studies recommended increasing the system reliability to a 7 to 10 year range for one day loss of load. The effect of implementing this recommendation would result in the need for additional resources above current plans. In the absence of a recent detailed study to evaluate total costs at varying reliability levels, it would be difficult to recommend that the current reliability guideline be changed. If island security costs increase significantly as a result of a less reliable power supply system, then a more in-depth review of the reliability guideline may be justifiable.

4.5 Other Criteria

While none of the surveyed organizations made reference to reliance on interconnections with other utilities, this approach is not appropriate for Hawaii. The expected unserved energy method recognizes the same factors as the LOLP method and also considers the amount of load that will be shed, but is a less utilized approach. While unserved energy does provide useful information and can be used in the IRP process to reflect dependence on other utilities or compare predicted unserved energy between resource portfolios, its use as a reliability measure has not been widely adopted.

Section
5

Conclusions

The three elements of the current planning criteria used by HECO reflect its operating environment on Oahu. The first rule is designed to ensure adequate supply in the event of a reasonably foreseeable event, the loss of the largest generator. Similarly, the second rule is intended to ensure that the remaining generators can quickly supply the lost generation without severe system imbalance, loss of system frequency, system separation and system collapse. Both are appropriate elements that are needed to ensure that the supply side is adequate to meet the system's needs.

The current reliability guideline of 4.5 years to experience one loss of load day is reasonable for both a regulated vertically integrated utility on Oahu and for a competitive environment should one evolve. While the criterion is less stringent than U.S. mainland, it is higher than most of the surveyed systems outside the U.S. The LOLE level appropriate for HECO should be based on the local situation, considering its operating environment with high load factor balanced by the costs of improving reliability with more resources.

While the reliability criterion is lower than the mainland U.S., it compares favorably with utilities and regulatory bodies internationally.

CA-IR-565

a. Has HECO made commitments to any government leaders or agencies to preserve system reliability at or above the 7.0 years per day standard?

b. If the response to part (a) is in the affirmative, please identify:

   i. each such government leader (by office) or agency to which such commitment was made; and
   ii. provide the earliest known date on which each such commitment was made.

c. Please provide copies of documents that support the response to part (b), above.

<u>HECO Response:</u>

a. No, HECO has not made such a "commitment".

b. Not applicable.

c. Not applicable.

CA-IR-566

The AOS 2005, at 3, states that "delays have resulted in reduced estimates of annual load management program impacts…."

a. Could HECO have taken steps to accelerate the marketing and installation of the Residential Direct Load Control, and Commercial and Industrial Load Control Programs? Please explain.

b. Please explain why HECO did or did not take steps to accelerate the marketing and installation of these "Load Management DSM Programs" (i.e., prior to March 10, 2005).

c. Please provide all documents that address HECO decisions regarding the timing of marketing and installing these "Load Management DSM Programs."

HECO's Response:

a. Yes. HECO did take steps to accelerate the marketing and installation of the Residential Direct Load Control (RDLC), and Commercial and Industrial Load Control (CIDLC) Programs. Prior to the Commission's approval of the RDLC and CIDLC Programs in Docket Nos. 03-0166 and 03-0415, respectively, HECO had taken the following steps:

- Stipulated with the CA, on June 30 and July 15, 2004, for the RDLC and CIDLC Programs respectively, to not recover direct labor, advertising, and miscellaneous costs of the programs through the IRP Surcharge, but to instead request recovery of these costs through base rates in the next (instant) rate case. HECO did this in order to accelerate the approval of the two load management program applications. The stipulation received PUC approval in October 2004. Under the stipulation HECO will not recover a portion of incurred program costs until a Decision and Order is issued by the PUC in this rate case.
- Issued a Request for Bid for RDLC program implementation on August 16 (see page 4)

and selected the hardware vendor and program administrator on October 12 (pages 5 to 6). Contract award was not made until after the Commission's approval of the RDLC program on October 14, 2005.

- In early October, developed a preliminary list of potential CIDLC program participants based on: 1) the presence or absence of standby generators on premise, 2) standby generator capacity, 3) expressed willingness to interrupt load, 4) the acceptable number of hours and number of interruptions, and 5) acceptable time of day to interrupt.

HECO's efforts to accelerate the marketing and installation of the RDLC and CIDLC Programs continued after the Commission's approval:

- Distributed 500 RDLC test direct mail pieces to residential customers in the Kapolei/Makakilo/ Ewa Beach/Nanakuli areas on November 30, 2004, and an additional 600 pieces on December 3 (pages 7 to 11).
- Conducted market research focus groups to determine the efficacy of the RDLC test direct mail pieces on December 14 and 15 (pages 12 to 16).
- Signed the RDLC contract on December 20 that combined the load control switch installation and administration of the program (pages 17 to 22).
- Conducted RDLC load control switch installation training on January 25, 2005.
- Conducted the first mailing of nearly 6,000 direct mail pieces to Ewa Beach on January

commercial customers began in October soon after the Commission's approval on October 19, 2004.

- Detailed CIDLC Program discussions with selected large customers by HECO's engineers in November 2004.
- Issued RFQ for CIDLC software and hardware, dated January 18, on January 20, pages 23 to 34.
- Continued discussions and, if permitted by the customer, implementation of site assessments and evaluations to determine the feasibility and extent of possible curtailable loads at the customer's premises.
- The first CIDLC Program contract was executed on May 9, 2005.

b. See response to part a. above.

c. HECO objects to providing "all documents that address HECO decisions regarding the timing and marketing and installing these "Load Management DSM Programs" as such request is overly broad and unduly burdensome to the extent that it requests "all" such documents. Without waiving any objections, please see response to subpart a.

August 16, 2004

Name
Company
Address 1
City, State Zip

Dear Name,

Enclosed you will find a Request for Bid (RFB) for equipment and services associated with Hawaiian Electric Company's (HECO) Residential Direct Load Control (RDLC) Program's load management system and an RFB for the implementation and installation of the load control receivers. HECO will consider bids for either equipment only or implementation or both. Also enclosed is a copy of HECO's Consultant Services Master Agreement. If you intend to submit a bid for the implementation of the program, please be aware you will be asked to sign and abide by this agreement.

Please review the RFB, and if you wish to submit a bid, please do so by September 10, 2004. Please include with your bid a listing and short description of key staff members. Also, please provide a list of your company's qualifications with your bid.

I look forward to hearing from you in the near future. I would appreciate it if you could confirm your intentions to bid by August 27, 2004. If you have any questions regarding this RFB, please contact Keith Block at (808) 543-4792.

Sincerely,

Alan Hee
Manager, Energy Services
Hawaiian Electric Company, Inc.

Enclosures: System Specification for Load Management
Load Control Receiver Installation Specification
Consultant Services Master Agreement

Alan K. C. Hee
Manager
Energy Services Department

October 12, 2004

Mr. Joel Cannon
Cannon Technologies, Inc.
8301 Golden Valley Road, Suite 300
Golden Valley, MN 55427

Dear Mr. Cannon:

It is our pleasure to anounce that Hawaiian Electric Company, has selected Cannon Technologies, Inc. as our supplier of load management equipment and software for our Residential Direct Load Control (RDLC) Program. After reviewing proposals from various vendors, we have decided to continue further negotiations with Cannon Technologies as the preferred contractor for this project.

This non-binding letter is our request for Cannon to work with Hawaiian Electric to develop a detailed Statement of Work (SOW) for this project. It is our desire to complete the SOW process by November 30, 2004, however, this SOW will be contingent on a satisfactory Decision and Order (D&O) from the Hawaii Public Utilities Commission (HPUC) approving the implementation of the RDLC Program. This letter is our indication that we will work with Cannon on an exclusive basis until an agreeable SOW is developed or until such time that Hawaiian Electric, at its sole option, notifies Cannon that it has decided not to continue work towards a contract with Cannon.

It is understood that this letter merely constitutes a statement of Hawaiian Electric's intentions with respect to the transactions contemplated hereby and does not contain all matters upon which agreement must be reached in order for the transactions contemplated hereby to be consummated and, therefore, that nothing herein contained will constitute a legally binding agreement of Hawaiian Electric or Cannon Technologies with respect to the potential transaction.

We look forward to working with you and your team. If you have any questions or comments regarding the RDLC Program, please contact Keith Block at (808) 543-4792.

Best regards,

AlanKCHee

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

October 12, 2004

Alan K. C. Hee
Manager
Energy Services Department

Mr. Kevin McDonough
Honeywell DMC Services, L.L.C.
999 Broadway, Suite 300
Saugus, MA 01906

Dear Mr. McDonough:

It is our pleasure to anounce that Hawaiian Electric Company, has selected Honeywell DMC Services as our implementation and installation services contractor for our Residential Direct Load Control (RDLC) Program. After reviewing proposals from various vendors, we have decided to continue further negotiations with Honeywell DMC Services as the preferred contractor for this project.

This non-binding letter is our request for Honeywell DMC Services to work with Hawaiian Electric to develop a detailed statement of work (SOW) for this project. It is our desire to complete the SOW process by November 30, 2004, however, this SOW will be contingent on a satisfactory Decision and Order (D&O) from the Hawaii Public Utilities Commission (HPUC) approving the implementation of the RDLC Program. This letter is our indication that we will work with Honeywell DMC Services on an exclusive basis until an agreeable SOW is developed or until such time that Hawaiian Electric, at its sole option, notifies Honeywell DMC Services that it has decided not to continue work towards a contract with Honeywell DMC Services.

It is understood that this letter merely constitutes a statement of Hawaiian Electric's intentions with respect to the transactions contemplated hereby and does not contain all matters upon which agreement must be reached in order for the transactions contemplated hereby to be consummated and, therefore, that nothing herein contained will constitute a legally binding agreement of Hawaiian Electric or Honeywell DMC Services with respect to the potential transaction.

We look forward to working with you and your team. If you have any questions or comments regarding the RDLC Program, please contact Keith Block at (808) 543-4792.

Best regards,

AlanKCHee

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

December 2, 2004

William A. Bonnet
Vice President
Government and Community Affairs

FILED
2004 DEC -2 P 4: 00
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: Docket No. 03-0166
Residential Direct Load Control Program

In its response to the Consumer Advocate's information request CA-IR-5, filed October 1, 2003, HECO stated it would provide the Commission and the Consumer Advocate with copies of the direct mail pieces it planned to use to promote the Residential Direct Load Control ("RDLC") Program. Attached are copies of the two separate direct mail pieces used to test the response rate from customers.

HECO mailed two separate direct mail pieces targeted to customers in the Kapolei/Makakilo/Ewa Beach/Nanakuli areas. The first direct mail piece was distributed to 500 customers on November 30, 2004 offering three free compact fluorescent lamps ("CFLs") to customers who signed up for the program by December 6, 2004. The second direct mail piece was distributed to another 600 customers on December 3, 2004 without the offer of the free CFLs and a requested response by December 9, 2004. HECO intends to conduct focus groups with these customers in order to refine its marketing program. Depending on the results of the focus groups, the direct mail pieces may be modified. Customers who sign up for the RDLC Program through these direct mail pieces will be enrolled in the program under the conditions stated in the card they return.

The cost of the CFLs distributed as part of the RDLC Program marketing effort will not be recovered through the IRP Cost Recovery Provision, Residential Demand-Side Management Adjustment, in accordance with Decision and Order No. 21415, dated October 14, 2004. Furthermore, HECO will not claim lost margin recovery for these CFLs.

Sincerely,

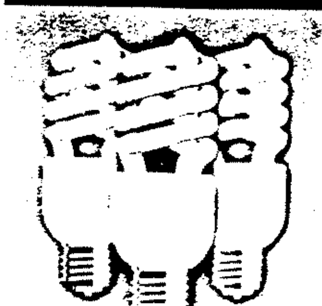
Attachments

cc: Division of Consumer Advocacy

There may come a time in the near future that Oahu's businesses and residences will require more electricity than Hawaiian Electric Company (HECO) can currently provide. You may have read in the papers recently how we, as an island of energy consumers hit a new high in electricity usage and came close to exceeding the supply of electricity that was available at the time. HECO is doing many things to ensure the lights stay on, but everyone can help. Here's one way you can pitch in AND earn a bill credit each month on your electric bill. Install an Energy Scout for your water heater. An Energy Scout is an intelligent radio device that can temporarily turn off your water heater during a system emergency.

As our island economy grows, so does electricity use. It's important to conserve energy and like a good scout, be prepared! We are focusing on water heaters because they can use up to 30% of the electricity in the home. Besides air conditioning, water heaters are the home's largest energy users.

In turn you'll receive a $3 credit every month on your electric bill. Your participation will help us manage and ensure there's enough power during system emergencies.



SIGN UP BY DEC. 6 TO RECEIVE
3 FREE
COMPACT FLUORESCENT LIGHT BULBS AND A
$3 MONTHLY BILL CREDIT

HECO reserves the right at its sole discretion to cancel, terminate, modify or suspend the Energy Scout Program.

CONDITIONS:

Who is eligible?
You are eligible if your home has an electric water heater with a capacity of at least 40 gallons. Homes with solar, heat pump, or gas water heaters are not eligible for the program.

How does the program work?
HECO will install a FREE Energy Scout near your water heater. In case of a system emergency, the Energy Scout will sense the need to reduce energy use and may temporarily turn off the electricity to your water heater. Most people will never notice when the Energy Scout is working. Even after your water heater is turned off, you can still use the hot water already in your tank.

How long will my water heater be off?
When the Energy Scout is working, it is estimated that the power to your water heater would not be interrupted for more than 1 hour at a time.

How do I save?
By participating in the program you'll earn **$3 every month as a bill credit on your electric bill, even if your water heater never gets turned off.** Your bill credit begins with the first complete billing period after your Energy Scout is installed.

How do I sign-up?
Fill out the postage paid application below, tear it out, and drop it in the mail. And just for signing up, you'll receive a gift box of 3 **energy saving compact fluorescent light bulbs** when we install your Energy Scout.

Can I cancel?
You may cancel at any time without any penalty by calling 94-POWER (947-6937).

DETACH AND MAIL

FOR MORE INFORMATION
If you have any questions, please call 94-POWER

We thank you for making a difference for a better energy future.

ENERGY **$OLUTIONS** FOR HAWAII
Hawaiian Electric · Giving you the power

Please complete the following information for your home and return the postage paid card by **December 6, 2004** in order to receive your **3 FREE CFLs**. All information must be provided to determine your eligibility to receive the Energy Scout. I (the customer and/or owner) give HECO permission to install one Energy Scout device at the address below under the conditions of the Energy Scout Program.

Daytime Ph. ______________ Evening Ph. ______________ E-mail ______________

Best time of day for contact: ☐ Morning ☐ Afternoon ☐ Evening

Do you ☐ own or ☐ rent the property at this address?

Do you have a 40 gallon or larger electric water heater? ☐ yes ☐ no (solar and heat pumps are not eligible)

Is your water heater accessible? ☐ yes ☐ no (circle all that apply) locked gate, enclosed garage, or dogs

Is your circuit breaker panel accessible? ☐ yes ☐ no (circle all that apply) inside home, locked gate, enclosed garage, or dogs

____
Signature of Customer Date

Team up your
water heater
with an
Energy Scout
and help
Hawaii's
energy future.

Hawaiian Electric Company, Inc.

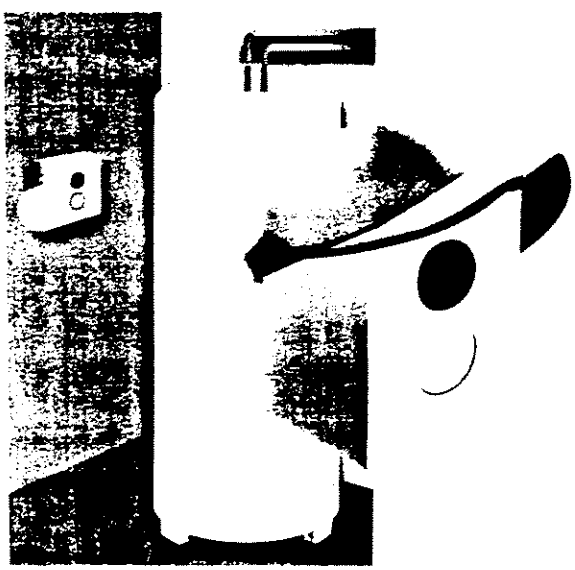
NO POSTAGE
NECESSARY
IF MAILED
IN THE
UNITED STATES

BUSINESS REPLY MAIL

FIRST-CLASS MAIL PERMIT NO. 41 HONOLULU HI

POSTAGE WILL BE PAID BY ADDRESSEE

HAWAIIAN ELECTRIC COMPANY INC
PO BOX 3920
HONOLULU HI 96812-9929



Team up your water heater with an Energy Scout and help Hawaii's energy future.

ENERGY$OLUTIONS
FOR HAWAII
Hawaiian Electric • Giving you the power

Hawaiian Electric Company, Inc.
P.O. Box 2750
Honolulu, Hawaii 96840-0001

U.S. POSTAGE
PAID
HONOLULU HI
PERMIT NO. 75

There may come a time in the near future that Oahu's businesses and residences will require more electricity than Hawaiian Electric Company (HECO) can currently provide. You may have read in the papers recently how we, as an island of energy consumers hit a new high in electricity usage and came close to exceeding the supply of electricity that was available at the time. HECO is doing many things to ensure the lights stay on, but everyone can help. Here's one way you can pitch in AND earn a bill credit each month on your electric bill. Install an Energy Scout for your water heater. An Energy Scout is an intelligent radio device that can temporarily turn off your water heater during a system emergency.

As our island economy grows, so does electricity use. It's important to conserve energy and like a good scout, be prepared! We are focusing on water heaters because they can use up to 30% of the electricity in the home. Besides air conditioning, water heaters are the home's largest energy users.

In turn you'll receive a $3 credit every month on your electric bill. Your participation will help us manage and ensure there's enough power during system emergencies.

SIGN UP BY DEC. 9 TO RECEIVE A $3 MONTHLY BILL CREDIT

AS A THANK YOU FOR PARTICIPATING IN HECO'S ENERGY MANAGEMENT PROGRAM

HECO reserves the right at its sole discretion to cancel, terminate, modify or suspend the Energy Scout Program.

FOR MORE INFORMATION

If you have any questions, please call 94-POWER

CONDITIONS:

Who is eligible?
You are eligible if your home has an electric water heater with a capacity of at least 40 gallons. Homes with solar, heat pump, or gas water heaters are not eligible for the program.

How does the program work?
HECO will install a FREE Energy Scout near your water heater. In case of a system emergency, the Energy Scout will sense the need to reduce energy use and may temporarily turn off the electricity to your water heater. Most people will never notice when the Energy Scout is working. Even after your water heater is turned off, you can still use the hot water already in your tank.

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When the Energy Scout is working, it is estimated that the power to your water heater would not be interrupted for more than 1 hour at a time.

How do I save?
By participating in the program you'll earn **$3 every month as a bill credit on your electric bill, even if your water heater never gets turned off.** Your bill credit begins with the first complete billing period after your Energy Scout is installed.

How do I sign-up?
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Can I cancel?
You may cancel at any time without any penalty by calling 94-POWER (947-6937).

DETACH AND MAIL

Please complete the following information for your home and return the postage paid card by **December 9, 2004.** All information must be provided to determine your eligibility to receive the Energy Scout. I (the customer and/or owner) give HECO permission to install one Energy Scout device

Team up your water heater with an Energy Scout and help Hawaii's energy future.

Hawaiian Electric Company, Inc.

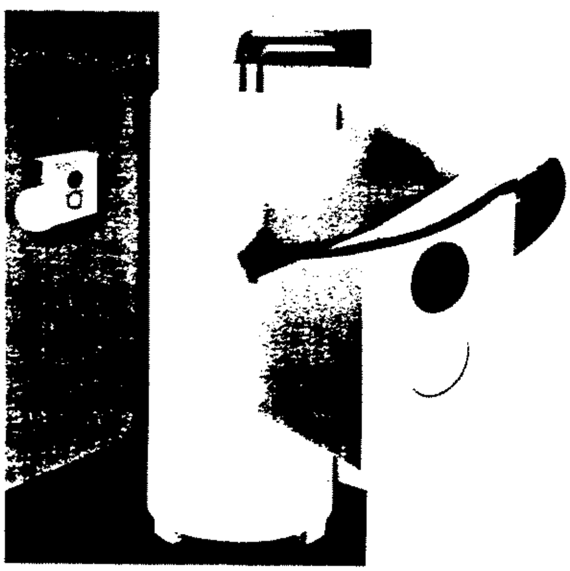
NO POSTAGE NECESSARY IF MAILED IN THE UNITED STATES

BUSINESS REPLY MAIL

FIRST-CLASS MAIL PERMIT NO. 41 HONOLULU HI

POSTAGE WILL BE PAID BY ADDRESSEE

HAWAIIAN ELECTRIC COMPANY INC
PO BOX 3920
HONOLULU HI 96812-9929



Team up your water heater with an Energy Scout and help Hawaii's energy future.

ENERGY$OLUTIONS FOR HAWAII
Hawaiian Electric • Giving you the power

U.S. POSTAGE PAID HONOLULU HI PERMIT NO. 75

Hawaiian Electric Company, Inc.
P.O. Box 2750
Honolulu, Hawaii 96840-0001

WARD RESEARCH

POSITIONING THE RESIDENTIAL LOAD CONTROL PROGRAM

Prepared for:

Hawaiian Electric Company

January 2005

Ward Research, Inc. • 828 Fort Street Mall, Suite 210 • Honolulu, Hawaii 96813 • Phone: (808) 522-5123 • Fax: (808) 522-5127

EXECUTIVE SUMMARY

This summary presents the highlights from three focus groups conducted December 14 and 15, 2004, among the following:

[redacted]

the Residential Load Control (RLC) test mailer; and

- One group of decision makers in households that *did* respond.

A total of twenty-five persons participated in the groups, seventeen non-responders and eight responders. The overall objective of the focus group study was to

Of the five direct mail pieces tested (the two existing flyers and the three mock-ups prepared for this research), the mailer with the headline, "Cold Cash for Hot Water," drew the most positive response – both relative to its ability to generate attention and the likelihood of the response. Flyers used in the market test were found to contain too much text for the broader market. At the same time, however, responders found the question and answer approach to be quite informative and to provide information they used to make their decision. An approach that uses a very direct incentive message, while incorporating more of the "need-to-know' information, will likely be most successful.

To summarize reactions to the other four pieces:

- As stated above, the two existing mailers were found to contain too much text and not enough visual interest. While some of the responders found the "Energy Scout" graphic to be engaging, most of the non-responders indicated they would glance at it then put it aside to read later or throw it out. When opening the piece, the graphic depicting the three CFLs was the strongest visual draw.

- The piece with the headline, "If we use too much energy . . . ," was described by many as using "scare tactics." At the same time, it was recognized as "attention getting" by the remainder of the participants. Most agreed, however, that the scenic shot of Hawaii inside and the reference to "Hawaii's precious resources" both reflected an important environmental consideration.

- The third mock-up, "It's What Inside That Counts," was felt by many to look like a real estate ad on the outside. This, many said, would cause them to throw out the ad before looking through it.

- Relative to the incentives tested, the monthly credit on the electric bill was clearly the strongest draw. Adding in the CFLs enhanced the offer among those familiar with the technology, but it seems that the incremental gain coming from the CFLs will be minimal. The coupon book, included in the "What's Inside" mailer, generated little interest, due to skepticism about most coupon books (*"You have to buy one to get one*

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free," "It's usually for something you don't use or a store you don't go to"). A coupon book related to energy savings, however, could be successful (e.g. coupons for dollars off the electric bill, discounts on energy-saving bulbs and appliances, household needs at Home Depot, etc.).

Relative to the preferred means of learning about the RLC program, participants in the groups identified a variety of vehicles. Bill stuffers, information on the monthly bill, direct mail, and radio ads all were mentioned with some degree of frequency. Willingness to participate in a referral program was low, whether administered via email or some other means. The RLC program will generate some word-of-mouth referrals, but likely will need marketing dollars invested in order to reach the program goals set by HECO.

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WORK AUTHORIZATION NO. 2
Contract No. SD-04-01

I. Request for Quote

Under the terms and conditions of the Consultant Services Master Agreement ("CSMA"), dated May 1, 2004, by and between Honeywell DMC Services, Inc. ("Consultant") and Hawaiian Electric Company, Inc. ("Company"), Company hereby requests Consultant perform the following Work to support the Company's Residential Direct Load Control Program (Program) as directed by the Company and in accordance with the attached price list (Attachment B):

RESIDENTIAL PROGRAM

General Information

Load control receivers will be installed on residential single-phase water heaters in order to interrupt them during peaking periods or system emergency conditions. In return, participating customers will receive a discount off their monthly electric bill.

Hawaiian Electric estimates that it will require 5,000 load control receiver installations in the first 12 months of a program beginning in the fourth quarter of 2004, 7,500 installations per year for two years thereafter, decreasing to 4,000 installations the following year and finally 1,600 installations in the final year of a five year program.

A. PROGRAM IMPLEMENTATION

1. Each year, Hawaiian Electric will use a variety of methods to offer the program to its customers. These include bill inserts and direct mail pieces. Hawaiian Electric promotions will attempt to attract customers in designated areas so as to reduce travel time between installations.

2. Consultant will be required to maintain a business office on the island of Oahu and Consultant's staff will be available during the hours of 7:30 am through 4:00 pm, Monday through Friday, to respond to inquiries from the Company's customers and employees. Consultant will provide all office space, transportation, telephones and related equipment necessary for implementation of the Programs. Consultant shall be licensed and qualified under applicable laws to perform the authorized installations. Consultant shall not subcontract any work without the prior written consent of Hawaiian Electric.

3. Consultant will respond to all inquiries from the public related to the Programs. This will include telephone calls and responses to direct mail advertising. Consultant shall maintain a toll free telephone "hotline" which will be staffed Monday through Friday from 7:30 am through 4:00 pm and which will provide recorded information during all other hours. Based upon experience gained during implementation of the programs, these hours may be modified by written agreement between the Company and the Consultant.

4. Customers who wish to participate will send in a response card or call the hotline. Customers will be told the load control receiver will be mounted near the water heater and access to their breaker panel will be necessary during installation.

5. Consultant will pre-qualify customers who wish to participate. Pre-qualification will consist of verifying:
   Customer has a HECO residential account;
   Device not already installed at location;
   Owner or landlord permission required;
   Customer has a 40 gallon or greater electric resistance water heater;
   Heat pump or solar water heating systems do not qualify.

6. Non-qualifying customers will be informed of the reason(s) they do not qualify, and their record in the database will be updated accordingly.

7. Consultant will schedule the installation and enter that data into Company's data base. The Consultant will be expected to schedule appointments during the first contact with the customer. Confirmation of the date and time of the installation will be given to the customer along with program details and specifics about the installation. Hawaiian Electric may direct Consultant to specific area within its service territory for utility operational purposes. Consultant is to abide by these directions.

8. The Consultant is required to have an answering machine or answering service available to take phone calls during non-staffed periods.

9. The Consultant will track all Program activities using the Company's tracking system. The Consultant may use other systems to track its work, as required, but it will ensure that all necessary data is entered into the Company's system on a timely basis. The Company will at its expense install all necessary computers, telephone lines, and related equipment required to provide the Consultant access to the Company's tracking system. The Company will provide the necessary training for the Consultant's employees in the use of its tracking system.

10. After initial installation, if the customer chooses to drop out of the program, they are asked to call the hotline and the Consultant will deactivate the load control receiver in the master control computer and update the tracking system.

11. Consultant may be requested to provide mailing services for all direct mail offers, communications to customers and other mailing services. Unless otherwise agreed, the Company will develop and print any necessary direct mailers and related materials. In those instances where the Consultant develops and/or prints materials at the Company's request, the Company must pre-approved any materials mailed to its customers or participating vendors.

12. Consultant will purchase, store, and inventory all load control receivers required for the Programs. The costs of the measures, plus 15% mark-up, will be billed to the Company as a separate line item in the Consultant's monthly billing. The Company will have the sole right to specify the load control receivers used for the Programs.

13. [illegible]

with a weekly program status report indicating the number of customer responses received, the name, address and serial number of each load control receiver installed and other pertinent information necessary to ensure the orderly implementation of the program.

14. Consultant will maintain hard copy files of all Program documents and provide all original documents to the Company's Program Manager upon request. The Consultant will cooperate with representatives of the Company, or with third parties approved by the Company, in any audit or review of program expenses or program documentation.

15. Consultant will be required to maintain all insurance and meet all requirements specified in the Terms and Conditions of the standard Company Master Consultant Services Agreement. To the extent that any differences between this Scope of Work and the terms and conditions of the standard Company Master Consultant Services Agreement arise, the terms and conditions of the standard Company Master Consultant Services Agreement shall prevail.

3. Installation Practices

Each Consultant crew will be required to have a portable testing unit in its possession during the installations. They can be acquired from Hawaiian Electric for a $500.00 refundable deposit. The operation of the receiver must be checked with the testing equipment after the installation. If the receiver is found to be defective, a new unit should be installed. An explanation shall accompany the defective equipment when returned to Hawaiian Electric.

Consultant must use standard electrical practices when mounting and wiring the receiver. All wiring will meet the NEC, state and local codes. Consultant will be responsible for any required permits or inspections.

Consultant assumes complete responsibility for the workmanship of the installations. Consultant will guarantee the quality of the provided materials and the workmanship for one year after the installation. The Consultant will make their best effort to resolve all customer complaints regarding the quality and/or workmanship or the parts/labor or materials provided by the Consultant within forty-eight (48) hours after being notified by Hawaiian Electric. In the event the Consultant is unable to resolve the dispute, Consultant will refer the dispute to Hawaiian Electric for resolution. Consultant will promptly re-execute its own work without expense to Hawaiian Electric or its customers.

C. Information Security

It is understood that all business and customer information (including profiles and billing history data) made available by Company to Consultant in connection with the work to be performed under this authorization is subject to the confidentiality obligations imposed by Article IX of the CSMA. Consultant shall not retain any copies of such information after the conclusion of the Project and shall promptly destroy or return to Company all copies of such information at Company's request.

Without limiting any provisions in the CSMA, it is understood that Company shall own and at all times have the right to use the Data developed or augmented as part of the Program.

It is contemplated that Company billing data and related confidential information will be stored on Consultant's server in preparation for and during the course of the Program. The security and protection of this information from unauthorized disclosure is critically important to Company. Therefore, Consultant will maintain security procedures and measures consistent with industry standards and/or considered prudent to protect such information. Without limiting the foregoing obligations, Consultant shall:

- Keep current with and apply all relevant vulnerability fixes;

- Adequately configure firewalls accessing servers housing Company data and applications;
- Protect Company's data from unauthorized access;
- Open only those firewall TCP/IP ports which are necessary to conduct business for Company customers; and
- Limit access to Customer's data to those Consultant employees working on the Project who have need to access that data.

Company shall be immediately notified in the event of a computer security breach that did or might expose any of the Company's confidential information.

Company reserves the right to randomly monitor and scan the Consultant's site for known potential vulnerabilities.

Consultant shall at all times cooperate with Company's reasonable requests to confirm and enhance the security of its information.

Dated: 12/14/04 ______________________ Company

II. Consultant's Proposal

Consultant hereby proposes to perform the Work described above in Section I, under said terms and conditions, for the following amount: Billing as proposed in Attachment B.

Total not-to-exceed cost is $3,900,000.

Work will begin no later than January 1, 2005 and be completed on or before December 31, 2006. Company may at its sole discretion extend the term of this Work Authorization for a two-year term through December 31, 2008 by providing written notice to Consultant at least thirty (30) days prior to the expiration of the then current term.

Yvette Maskrey will act as Consultant's Designated Representative during the performance of this Work.

Dated: 12/09/04 ______________________ Consultant

Kevin McDonough, General Manager
Honeywell DMC Services L.L.C.

III. Work Authorization

Consultant's foregoing Proposal is accepted. Consultant is authorized to perform the Work as proposed. Company's Designated Representative for this Work Authorization shall be Keith Block.

Dated: 12-20-04 ______________________
Company

Dated: 12-20-04 ______________________
Company

REQUEST FOR QUOTE

FROM

HAWAIIAN ELECTRIC COMPANY

FOR

PROPOSED COMMERCIAL & INDUSTRIAL DIRECT LOAD CONTROL (CIDLC) SYSTEM

ON

OAHU, HAWAII

January 18, 2005

PROPOSED COMMERCIAL & INDUSTRIAL DIRECT LOAD CONTROL (CIDLC) SYSTEM

REQUEST FOR QUOTATION (RFQ) No.
January 18, 2005

TO ALL PROSPECTIVE BIDDERS:

The Hawaiian Electric Company, Inc. (HECO), located in Honolulu, HI, is an investor owned electric utility with approximately 231,000 residential electric Customers and 16,000 Commercial and Industrial (C&I) electric Customers. HECO is interested in applying load management to reduce peak loads, manage individual circuits, and provide under frequency load control for its Commercial and Industrial Customers. It is the intent of this specification to purchase a system, which will allow HECO to automatically control loads at commercial, industrial and other electrical Customers.

HECO is interested in a system from a company with a proven history of load management capabilities and having the future additional capability of the Load Management Application being fully integrated with HECO's SCADA System. Also, the Load Management System must have the future capability of integrating the Load Management software into HECO's Customer Billing Systems.

It is the intent of HECO to purchase a System that will provide live data collection and presentation of meter data, automatically control loads, handle all of HECO to Customer communication, and calculate settlement. The System shall use existing public communication Systems. HECO is interested in complete solutions that include the load control hardware, meter data collection infrastructure, and C&I Load Control Application software. Partial solutions will not be considered. HECO will not purchase an untested technology and will give credit in the evaluation to mature Systems from suppliers who work to provide high customer satisfaction.

All proposals shall comply with the following enclosed documents.

Instruction to Bidders
HECO Proposed Contractor Bid Form
Specification
HECO Services Agreement (SA)

Any purchase resulting from this inquiry will be issued by Hawaiian Electric Company, Inc.

Your proposal is due in the possession of HECO on the enclosed proposal forms on or before **February 2, 2005, 4:00 p.m.** A proposal received later than the date and time listed above and submitted on other than the Proposal Form provided with the Enclosed Proposal Documents may be rejected.

Any questions on this RFQ shall be submitted in writing and should be faxed to Hawaiian Electric Company, Inc., attention: Todd Kanja (FAX No. 543-4690, Phone No. 543-4773); answers will be furnished to all Proposers. Please provide a FAX number to expedite our replies.

PROPOSED COMMERCIAL & INDUSTRIAL DIRECT LOAD CONTROL (CIDLC) SYSTEM

ON

OAHU, HAWAII

TABLE OF CONTENTS

INSTRUCTION TO BIDDERS

1. PROPOSALS: The original and three (3) copies of each proposal shall be prepared and submitted to HECO. Proposals, which are not prepared and submitted in accordance with these instructions, will imply that the Bidder does not intend to comply with all of the contract conditions and such proposals will be considered irregular.

If the prospective Bidder declines to propose, he shall return all proposal documents and provide written notice to HECO no later than the proposal due date.

Preparation: Each proposal shall be carefully prepared using the proposal forms provided. Entries on the proposal forms shall be typed or legibly written in black ink. All prices shall be stated in words and figures except where the forms provide for figures only.

Each Bidder shall list in the space provided on the proposal form all exceptions or conflicts between his proposal and the specification. If more space is required for this listing, additional pages may be added. If the Bidder takes no exceptions, he shall write "NONE" in the space provided. Proposals, which do not comply with this requirement, will be considered irregular. In case of conflicts not stated as directed, the specification shall govern.

The Bidder shall not alter any part of the specification in any way, except by stating his exceptions in the space provided on the proposal form.

The Bidder shall staple or otherwise bind, with each copy of the proposal submitted a signed copy of each addendum issued for the contract documents during the bidding period. The Bidder shall assemble all supplementary information necessary to thoroughly describe services covered by the proposal, and shall attach such supplemental information to the proposal.

Signatures: Each Bidder shall sign the proposal with his usual signature and shall give his full business address.

Bids by partnerships shall be signed with the partnership name followed by the signature and designation of one of the partners or other authorized representative.

Mail all proposals to the following:

Hawaiian Electric Company, Inc.
P.O. Box 2750
Honolulu, HI 96840
Attention: Todd Kanja
Sr. Technical Services Engineer

If other than Regular U.S. Mail, proposals shall be addressed as follows:

Hawaiian Electric Company, Inc.
220 S. King Street, Suite 1302
Honolulu, HI 96813
Attention: Todd Kanja
Sr. Technical Services Engineer

The proposal shall be submitted in a sealed package with the following information shown on the package:

SEALED BID PROPOSAL - RFQ
PROPOSED COMMERCIAL AND INDUSTRIAL DIRECT LOAD CONTROL (CIDLC) PROGRAM

Your company name and address shall be clearly indicated on the envelope containing the proposal.

It is the sole responsibility of the bidder to see that his bid is received in proper time. Any bid, received after the scheduled closing time for receipt, may be returned to bidder unopened at HECO's discretion. No responsibility will be attached to HECO for premature opening of, or failure to open a bid not properly identified.

2. MODIFICATIONS AND ERASURES: Changes on or additions to the Bid Form, recapitulations of the work bid upon, alternative proposals, or any other modifications of the Bid Form, which is not specifically called for in the Contract Documents, may result in HECO's rejection of the bid as not being responsive to the invitation to bid. No verbal or telephone modification of any bid submitted will be considered. The Contract Documents shall include all documents provided in the Bid Packet.

3. WITHDRAWAL OF BIDS: Any bidder may withdraw his bid either personally, or by written request, at any time prior to the scheduled closing time for receipt of bids. No bidder may withdraw a bid within 45 days after the actual date of the opening thereof.

4. DRAWINGS AND SPECIFICATIONS: All copies of the drawings and specifications are the property of HECO.

5. INTERPRETATION OF PLANS AND CONTRACT DOCUMENTS: If any person contemplating submitting a bid for the construction of the work, is in doubt as to the true meaning of any part of the Contract Documents, or finds discrepancies or omissions from any part of the Contract Documents, he may submit a written request for an interpretation or correction thereof faxed to HAWAIIAN ELECTRIC COMPANY, INC., attention Todd Kanja (FAX No. (808) 543-4690, Phone No. (808) 543-4773), no later than three (3) days before bids are opened. The person submitting the request will be responsible for its prompt delivery. Any interpretation or correction of the Contract Documents will be made only by Addendum, and will be faxed to each Bidder of record.

Bidder is solely responsible for seeking an interpretation or clarification hereunder and absent any such inquiries, HECO shall assume that Bidder understands HECO's intent, meaning and requirements and HECO shall not be responsible whatsoever for any other explanations or interpretations of the proposed documents.

It shall further be Bidder's sole responsibility to advise HECO, before the bid opening date, of any and all conflicting requirements, ambiguities, or omissions of information which require clarification. In the event that a question is not addressed in the addenda issued by HECO, Bidder shall list in the space provided in the proposal form, a statement that sets forth for each unanswered question, the exact nature and extent to which the question impact Bidder's proposal.

7. ADDENDA TO THE DOCUMENTS: HECO reserves the right to issue such addenda to the documents as it may desire at any time prior to the bid opening. A copy of all such addenda will be promptly faxed or delivered to each person receiving a set of Contract Documents. The number and date of each addendum shall be listed on the Contractor's Proposal in the space provided. Such addenda shall be covered in the bid and shall become part of the Contract.

8. LAWS AND REGULATIONS: The bidder's attention is directed to the fact that all applicable Federal laws, State laws, Codes, municipal ordinances, and rules and regulations of all authorities having jurisdiction over construction of the project shall apply to the Contract throughout and shall be deemed to be included in the Contract to the same extent as though here written out in full.

9. ACCEPTANCE AND REJECTION OF BIDS: HECO reserves the right to select other than the lower bid, or to reject any and all bids, or to reject a portion of a particular bid, or to otherwise waive irregularities and informalities in any bid that is submitted, or to amend or cancel the project after any bids are submitted.

All proposals shall become the property of the Hawaiian Electric Company, Inc.

10. TAX, FEE, DUTY, INSURANCE, AND OTHER CONSIDERATIONS: All bids shall include, but [illegible]

13. LIQUIDATED DAMAGES & SCHEDULING: HECO will require that the Direct Load Control software, excluding the Settlement software module, shall be installed and operational within 10 weeks after issuance of the contract. The Settlement software module shall be completed within 20 weeks after issuance of the contract. If the contractor fails to complete the work by the specified time without an approved time extension from HECO, the Contractor shall be subject to liquidated damages of **$20.00 per day** for each day beyond the contract completion date. Please refer to the Services Agreement, Appendix A.

Proposal for
Delivery of a Commercial and Industrial Direct Load Control System

To: __________
____
____

The undersigned being familiar with all the details, conditions, and requirements hereby proposes to furnish a load management System to __________, in strict conformance with the Specifications included in the Request for Proposal documents.

BASE BID:
HECO desires to have the bidder host the System for the first 3 months of operation and then have the System deployed and operated from HECO's IT Data Center. The bidder shall supply pricing for both situations and include all cost elements.

3 Months of System Hosting	
System Hosting	$__________
Software Application Service Provider Charges	$__________
Meter Communication Costs	$__________
Load Control Device Communication Costs	$__________
Project Options	
Settlement Calculations	$__________
Interactive Voice Response (IVR)	$__________
System License	
Load Management Hardware (Excluding Servers)	$__________
Load Management Software	$__________
Annual Maintenance and Support (per year)	$__________
Set-up, System Testing, and Training after hosting complete	$__________
Field Equipment Costs	
25 Each Load Control Receivers	$__________
Other Equipment	
Test Equipment	$__________
Recommended spare parts	$__________

Please provide terms and conditions for travel and living expense.

In support of this pricing, a detailed bill of material in the Vendor's chosen format shall be attached.

Load Management System Delivery Schedule: ______________**weeks after receipt of order.**

All materials shall be delivered F.O.B., __________.

OPTIONAL ITEMS:

Including: software options, hardware options, and spare parts options, test equipment options:
(Please describe...)

TOTAL LUMP SUM CONTRACT PRICE $ ______________

Dated this ______ day of ______________________, 20__.

Bidder ________________________

Address:

Authorized Officer:

Title:

ADDITIONAL INFORMATION

A.	Proposal Expiration Date.	____________ (Date)
B.	Bidder accepts Purchaser's Services Agreement.	____________ (Yes or No)
	If no, are specific exceptions and clarifications included?	____________ (Yes or No)
C.	Is Proposal completely in accordance with the Specification?	____________ (Yes or No)
	If no, are specific exceptions and clarifications included?	____________ (Yes or No)
D.	Bidder acknowledges receipt of and compliance with amendments through to the bidding documents.	____________ (Yes or No)
E	Bidder agrees to Purchaser's schedule	____________ (Yes or No)
	If no, list specific exceptions and / or clarifications:	____________
F.	Small Business (SB),	____________ (Yes or No)
G.	Woman Owned Small Business (WOSB)	____________ (Yes or No)
H.	Small Disadvantaged Business (SDB)	____________ (Yes or No)

I. Provide list of addendum received.

Addendum # ________ Dated ____________
Addendum # ________ Dated ____________
Addendum # ________ Dated ____________
Addendum # ________ Dated ____________

J. Bidder's representative to contact should any questions arise regarding Bidder's proposal:

Name: ________________________________

Position: ________________________________

Company: ________________________________

Address: ________________________________

Telephone: ______________________________

Fax: ______________________________

K. Bidder's designated contact for sales/commercial matters:

Name: ______________________________

Position: ______________________________

Company: ______________________________

Address: ______________________________

Telephone: ______________________________

Fax: ______________________________

L. Bidder's Corporate Officer to contact with regards to the project for executive matters:

Name: ______________________________

Position: ______________________________

Company: ______________________________

Address: ______________________________

Telephone: ______________________________

Fax: ______________________________

The undersigned, have examined the Contract Documents entitled "Proposed Commericial and Industrial Direct Load Control (CIDLC) Program," hereby proposed and agrees to furnish all labor, materials, equipment, and software, and to deliver a functional and operation System as required by said proposed Contract Documents within the schedule specified in the Instructions to Bidders for the sum(s) stipulated for the Block Bid(s).

Total Contract price shall not exceed the amount of $________________

If the undersigned is notified of the acceptance of this Proposal, he agrees to execute a HECO Services Agreement for the work within 5 business days. The under signed further agrees that the liquidated damage per calendar day for failure to complete the work on time shall be in accordance with the enclosed Instruction to Bidders. The material cost shall include all applicable freight, delivery, and storage, etc. costs. HECO will not be responsible for additional cost, which have not received prior approval.

Respectfully Submitted,

NAME OF COMPANY

By:
Its:

____
ADDRESS OF COMPANY

* Please attach evidence of the authority of this office to submit bid on behalf of Company, giving also the address.

NOTE: Fill in all blank spaces with information asked for or bid may be invalidated. Provide list of addendum received.

END OF SECTION

CA-IR-567

The AOS 2005, at 3, states that "it is assumed that the benefits from these eight programs will begin in July 2005, but this date is predicated on the assumed bifurcation of the DSM programs from the HECO rate case such that they can be reviewed and approved by the PUC on an accelerated schedule…."

a. Please explain why HECO did or did not take steps to accelerate the implementation of these DSM programs (i.e., prior to March 10, 2005).

b. Please provide copies of all documents that address HECO decisions regarding the timing of the implementation of these DSM programs.

HECO Response:

a. HECO attempted to accelerate the enhanced DSM programs as much as it could, while still complying with mandated regulatory and planning processes. The programs were developed in the on-going IRP-3 process. They were fully documented and filed with HECO's rate case, as required by HECO's PUC-approved stipulations with the CA (for the C&I DSMprograms) and with the CA and other parties (for the Residential DSM programs). By opening a new Energy Efficiency docket, the Commission has made it clear that the new programs will be submitted to full regulatory review. As a result, HECO's plan is to seek [illegible]

link to the City and County webpage is:
http://www.co.honolulu.hi.us/dcs/housingloans.htm.

- Accelerated the number and schedule for industry sector meetings in 2004 and 2005 in order to increase and reinforce awareness of our DSM program offerings (pages 4 to 6).
- Developed and implemented a "Sustainable Design Tools Workshop Series" targeted at design professionals (architects and engineers), with 6 workshops presented between January 2004 and February of 2005 (pages 7 to 12). The purpose of these full-day workshops was to provide the technical design tools allowing professionals to integrate efficiency into new and renovation projects. This series was a HECO-led initiative supported by the US Department of Energy, DBEDT, the University of Hawaii School of Architecture, Rebuild America, and Rebuild Hawaii.
- Developed an Energy Efficiency Award pullout section in the Pacific Business News in October 2004 to recognize the award recipients and to increase and reinforce awareness of our DSM programs (pages 13 to 24)

- Sponsored an energy efficiency track of workshops at the AIA/CSI Building and Trade Expo, held at the Hawaii Convention Center in November of 2004, to increase exposure to efficient design a concepts and to promote the DSM programs (pages 25 to 29).
- Created and filled an additional contract program engineer position in January 2005 to assist with the commercial and industrial energy efficiency programs.
- Transferred a regular HECO employee into the Customer Efficiency Programs Division in December 2004 (from the Customer Installations Department) to assist with the commercial and industrial energy efficiency programs. (See HECO's response to CA-IR-78.)

The entire process of developing the changes to HECO's portfolio of programs began nearly two years ago with the initiation of a DSM potential study in July 2003 and the organization of a DSM Technical Committee under IRP auspices in December 2003. The DSM Technical Committee provided valuable input into the design of the DSM programs. The last meeting of the Committee was held on April 21, 2004 and culminated in the portfolio of 10 DSM programs that was proposed in HECO's rate case filed in November 2004. The Commission must approve the modifications to these existing programs and the new DSM programs before the modifications and new programs are implemented.

b. HECO objects to providing "all" documents that address HECO decisions regarding the timing and the implementation if these DSM Programs as such request is overly broad and unduly burdensome to the extent that it requests "all" such documents. Without waiving any objections, please see response to subpart a.

2004 Customer Events

January 2004
January 29- Sustainable Design Tools Workshop Series: *Daylighting and Lighting Controls:* HEI2

February
February 5 – 2004 Business Engagement-Convention Center
February 26 – Creating High Performance Buildings: HEI2

March
3/ 9 – May 11 (10 weekly sessions): HECO/ASHRAE/TRANE HVAC Clinic: HEI2
3/17 -- Energy Efficiency for Property Managers (Institute of Real Estate Management) : Willows Restaurant
3/18 - Sustainable Design Tools Workshop Series: *Indoor Air Quality Mitigation Through Design:* HEI 2

April
4/6 – May 11 (6/10 weekly sessions remaining): HECO/ASHRAE/TRANE HVAC Clinic: HEI2

May
5/3, 5/11 – (last 2 sessions to complete 10 weekly sessions):
HECO/ASHRAE/TRANE HVAC Clinic: HEI2

5/11 – BWS/HECO/FEMP/AWWA Water Efficiency Workshop: Ilikai

5/20 – Sustainable Design Tools Workshop Series
Building Energy Simulation for Sustainable Design of Buildings: HEI2

5/21 – Energy Efficiency in City Government Buildings: HEI2

5/22 – Energy Efficiency in City and County Government Buildings: HEI2

5/24-27 – HECO/FEMP Securing Energy Saving Projects for Your Facility : HEI2

5/26 – Hawaii Green Business Program: Green Hotel Forum – Sheraton Waikiki

5/28 – Energy Saving Technologies for Industrial Customers: HEI2

June
6/1 – Implementing Energy Efficient Projects: HEI2

6/30 – Grainger / GE Lighting Seminar: Sheraton Waikiki

July

7/1 – Grainger / GE Lighting Seminar: Airport Hotel

7/8 – Sustainable Design Tools Workshop Series: *Energy Management Controls: A Guide to Understanding and Specifying Next Generation DDC Systems:* HEI2

7/20 – Kaman Industrial Equipment Seminar

October

10/26 – Building Integrated Photovoltaic Workshop: HEI2

10/26 – Energy *Cash Flow Opportunity Calculator* Workshop: Honolulu Community College

10/27-28 – Energy Expo: Sheraton Waikiki

November

11/3 – AIA/CSI Expo (w/ HECO sponsored workshop track): Hawaii Convention Center

- Three HECO Sponsored Workshops at AIA/CSI Expo:
    - Building Commissioning
    - A Model of Sustainable Design
    - High Performance Buildings

11/4 - HECO/DBEDT: Building Commissioning Procedures for City and County and State of Hawaii Facilities

11/16 – Hawaii Green Business Program: Green Hotel Forum - Hale Koa Hotel

Energy$olutions for Small Business / Light Year Presentations

7 Light Lunch Presentations

- Macy's Light Lunch
- Ogilvy's Client List
- IREM (International Real Estate Managers)
- Foodland
- Times Supermarket
- Windward Mall Presentation

36 individual company meetings for Small Business and LightYear

DSM Architect and Engineer Outreach Programs (Tom Van Liew):

- 4 local firms

2005 Customer Events (January through March)

January
1/07 – Industry Segment Meeting: City and State Government -- Commissioning Meeting

February
2/03 – Industry Segment Customer Meeting: Hospital Engineering Association
2/09 – Industry Segment Customer Meeting: Hotel Chief Engineers
2/22 – Business Engagement: Hawaii Convention Center
2/24 – Sustainable Design Tools Workshop: Advanced Daylighting

March
3/11 Maintenance Fair Energy Exhibition: Painters Warehouse

Hawaiian Electric Company and
Rebuild Hawaii Consortium present:

Sustainable Design Tools | Workshop Series

Design professionals in Hawaii are seeing an increase in client demand for energy-efficient and sustainable buildings. The Sustainable Design Tools Workshops are a series of one-day technical courses designed to equip architects and engineers with tools to meet these new demands. This series consists of four workshops on topics that are directly applicable to sustainable design:

One workshop will be held every other month from January through July 2004.

HEI Training Room
8th Floor,
American Savings
Bank Building
(Corner of S. King St. and Alakea St.)

January 29, 2004
Daylighting and Lighting Controls
Joel Loveland, BetterBricks Daylighting Lab

March 18, 2004
Indoor Air Quality Mitigation Through Design
Joe Lstiburek, Building Science Corporation

May 20, 2004
Building Energy Simulation for Sustainable Design of Buildings
Michael Hatten, SOLARC Architecture and Engineering, Inc.

Energy Management Controls:
A Guide to Understanding and Specifying

Program Hours

Sustainable Design Tools

JOEL LOVELAND
Director, BetterBricks Daylighting Lab Associate Professor, Department of Architecture, University of Washington

Sustainable Design Tools | **Workshop Series**

Building Energy Simulation for Sustainable Design of Buildings

May 20, 2004

MICHAEL HATTEN, *PE*
SOLARC Architecture and Engineering, Inc

This course will introduce architects and engineers to basic energy simulation concepts and approaches that can be used to evaluate building designs while still on the boards, or even before they are on the boards! Integration of design tools such as energy simulation into the design process can impact the design in ways that result in improved efficiency, increased comfort, and reduced costs. Concepts for design process integration, that apply to all energy simulation software, will be discussed.

This course will specifically demonstrate one of the state-of-the art energy simulation tools – eQUEST. eQUEST is a windows-version of DOE2.2 – a hour-by-hour simulation tool that can model daylighting, commercial refrigeration, detailed geometry, solar shading,, and sophisticated mechanical system concepts. The Building Creation Wizard – a feature of eQUEST that allows quick models to be generated at early design stages – will be demonstrated. In addition, more sophisticated designs involved detailed input will also be used as workshop examples. All participants will receive a CD with the current version of eQUEST, software documentation, and relevant Hawaii weather files.

MICHAEL HATTEN
PE, SOLARC Architecture and Engineering, Inc.

Michael Hatten, P.E. is a principal with the innovative Oregon consulting firm–SOLARC Architecture and Engineering inc. He is a mechanical engineer, educator, and energy analyst who is nationally recognized for his

Michael combines a design, analysis, and training background in his roles as project manager and project engineer. His reputation as a leader in energy efficiency has grown from his wide-ranging body of efficiency project experience. He has conducted analysis efforts on well over 30,000,000 square feet of residential, commercial, and industrial space.

In recognition of his contributions to furthering sustainable design excellence in the Pacific Northwest, Michael was recently recognized with the 2003 BetterBricks engineering award.

Energy Management Controls: A Guide to Understanding and Specifying Next Generation DDC Systems

July 8, 2004

JOHN J. "JACK" MC GOWAN, *CEM*

JOHN J. "JACK" MC GOWAN
CEM, Energy Control, Inc.

Mr. Mc Gowan is President of Energy Control, Inc. (ECI), a System Integration and Energy Service Company specializing in value-based real-time technologies and services. ECI was named one of the Top 100 System Integrators in North America in 2003 and

Sustainable Design Tools | **Workshop Series**

☐ YES! Please register me for the Sustainable Design Tools | **Workshop Series**.

Mr./Ms. First Name ______________________ Last Name ______________________

Title ______________________ Affiliation ______________________

Address ____

City ______________________ State ____________ Zip ____________

Phone ______________ Fax ______________ Email ______________

Occupation:
__ Architect
__ Nonprofit Organization
__ Product Manufacturer
__ Engineer
__ Energy/Sustainability
__ Developer
__ Facility Manager
__ Contractor/Builder
__ Other: ______________

What do you need most out of these workshops? ______________________________

SPACE IS LIMITED. REGISTER BY JANUARY 15, 2004

Registration Fees
Workshop Series (4 classes): $300 (Lunch included)
To qualify for Series discount price, full registration fee must be received no later than January 15, 2004.

Individual Workshops: $99/workshop

☐ **January 29, 2004**
Daylighting and Lighting Controls

☐ **March 18, 2004**
Indoor Air Quality Mitigation Through Design

☐ **May 20, 2004**
Building Energy Simulation for Sustainable Design of Buildings

☐ **July 8, 2004**
Energy Management Controls: A Guide to Understanding and Specifying Next Generation DDC Systems

Payment for individual workshops will be due 2 weeks prior to course date. Fees includes workshop, materials, lunch and break refreshments.

Payment
Make check payable to Hawaiian Electric Company, Inc.

Total Amount Enclosed: ______________

Refunds are limited to 80% and must be requested in writing no later than 1/15/04. No refunds will be made after this date. Registration attendee substitutions may be made by calling Marsha at 808/543-4743.

Send registration to: Marsha Saiki CP12-SD
Hawaiian Electric Company
P.O. Box 2750 • Honolulu, Hawaii 96840

Phone: 808/543-4743 • Fax: 808/543-4722
Email: marsha.saiki@heco.com

Rebuild Hawaii

School of Architecture
University of Hawai'i

DBEDT
STATE OF HAWAII

Rebuild America

Hawaiian Electric Company, Inc.
Giving you the power

2004 Efficient Electro-Technology Exposition & Conference Pre-Conference Workshop

Sustainable Design Tools **Workshop Series**

Tuesday, October 26, 2004

Photovoltaics in Buildings

STEVEN STRONG
Solar Design Associates, Inc., Harvard, MA

HEI Training Room 8th Floor, American Savings Bank Building
(Corner of S. King St. and Alakea St.)

Morning Session
8:00 am to 12:00 pm
Afternoon Session
1:00 pm to 5:00 pm
(select one session)

Cost: $25
Students: Free

Rebuild Hawaii

School of Architecture University of Hawai'i

DBEDT

Rebuild America

This workshop provides a world overview of building-integrated PV activity including a description of component and systems development along with many examples of Solar Electric Architecture.

Architects with vision have come to understand it is no longer the goal of good design to simply create a building that's aesthetically pleasing - buildings of the future must be environmentally responsive as well.

One of the most promising renewable energy technologies is photovoltaics. Photovoltaics (PV) is a truly elegant means of producing electricity on site, directly from the sun, without concern for energy supply or environmental harm. These solid-state devices simply make electricity out of sunlight, silently with no maintenance, no pollution and no depletion of materials. Photovoltaics are also exceedingly versatile - the same technology that can pump water, grind grain and provide communications and village electrification in the developing world can produce electricity for the buildings and distribution grids of the industrialized countries.

Building integration of photovoltaics (PV), where the PV elements actually become an integral part of the building, often serving as the exterior weathering skin, is growing worldwide. PV specialists and innovative architects in Europe, Japan and the US are now beginning to explore creative ways of incorporating solar electricity into their designs.

Workshop Speaker and Facilitator:

STEVEN STRONG
Solar Design Associates, Inc. — Harvard, MA

The program is presented by **Steven J. Strong,** president of **Solar Design Associates,** Inc., a Harvard based A&E firm dedicated to the design and integration of renewable energy systems and environmentally responsive buildings.

Over the last 25 years, he has designed dozens of homes and buildings powered by solar electricity, including the world's first PV-powered neighborhood in central Massachusetts, the natatorium complex at the 1996 Olympic Summer Games using the world's largest roof-top PV power system and 3 solar energy systems at the White House in Washington, DC. He recently designed a new "solar skin" for the US Mission to the United Nations in Geneva.

He has advised numerous government officials on energy and environmental issues, and is a highly published author of books and articles on photovolatics in buildings. Articles about him and his work have appeared in over 100 publications including TIME Architecture, Architectural Record, Environmental Design and Construction, World Architecture, Popular Science, Wired, New Age and Business Week. Mr Strong has been recognized by Time magazine as a 'Hero of the Planet" as well as by the Amercian Solar Energy Society and the Audobon Society.

Hawaiian Electric Company, Inc.
Giving you the power

Hawaiian Electric Company and
Rebuild Hawaii Consortium present:

Sustainable Design Tools | **Workshop Series**

February 24, 2005

Advanced Daylighting Design

VICTOR OLGYAY
Ensar Group, Boulder CO.

HEI Training Room
8th Floor,
American Savings
Bank Building
(Corner of S. King St.
and Alakea St.)

Program Hours
8:00 am to 4:00 pm

Light inspires us and enlivens space. Natural light in buildings can provide ambient illumination and reduce the use of electric light, and the resultant internal heat gain. This lowers energy consumption and reduces the generation of pollution. Misapplied, natural light can result in excessive heat gain, uncomfortable glare, and degradation of materials.

This seminar will teach you to avoid the pitfalls and optimize the benefits of daylight in your projects. It is a continuation of the "Sustainable Design Tools" Workshop Series targeted specifically for architects and engineers. We will focus on useable information, techniques and design tools which can be applied in you practice. We will learn how to what strategies may be best for a given project, look at available tools, resources and techniques, cover LEED requirements and issues, examine a number of case studies, address Hawaii specific concerns, and consider the elegant integration on daylight

Rebuild Hawaii

School of Architecture
University of Hawai'i

DBEDT
STATE OF HAWAII

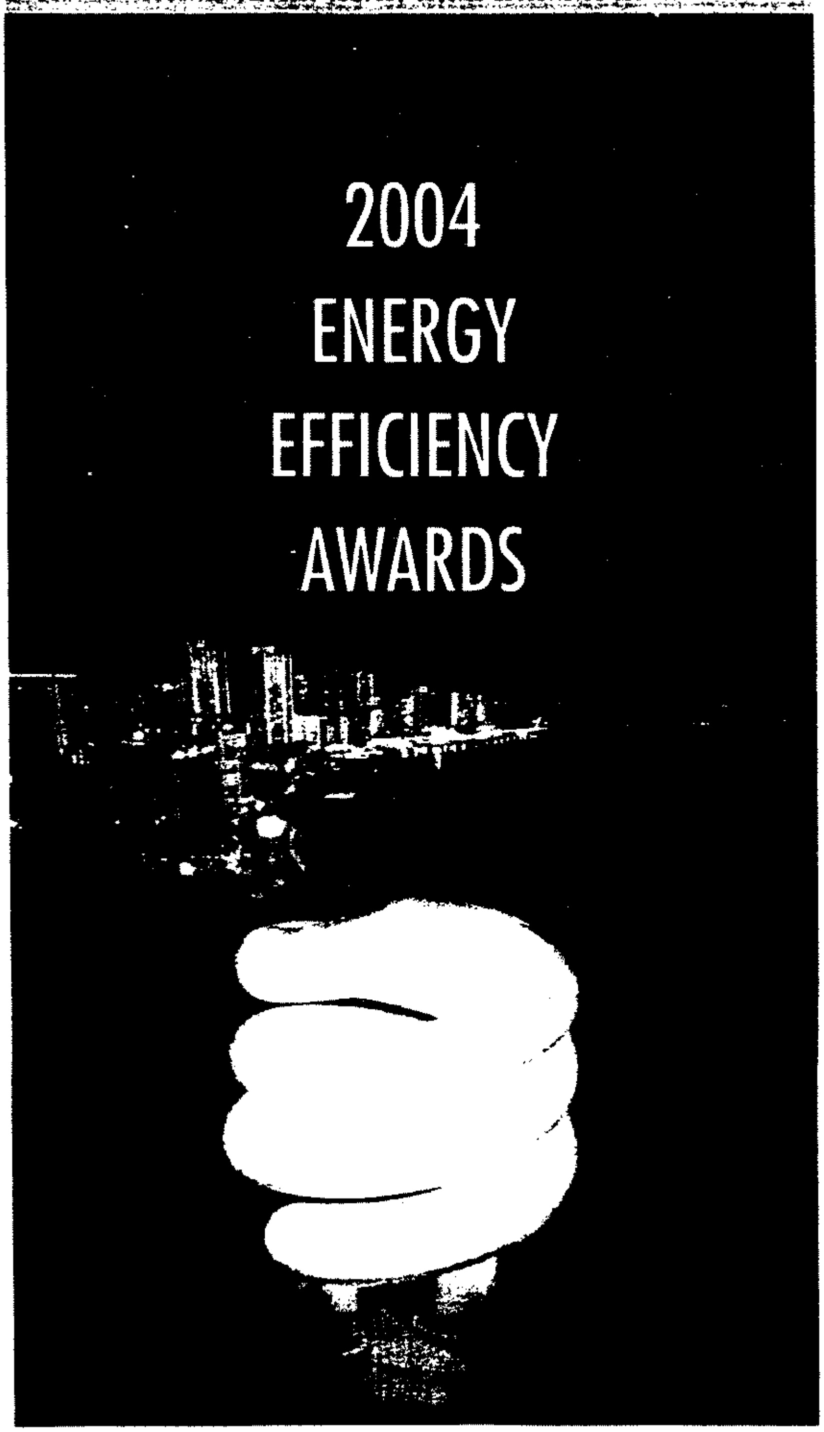
Rebuild America

Mr.Olgyay is currently a Vice President and Architect with ENSAR Group, Inc., located in Boulder, Colorado. He has performed Architectural Design, Planning, Environmental Systems design and analysis, Acoustical, Lighting and Daylighting Consultation on a wide variety of projects internationally, with an emphasis in the areas of daylighting, bioclimatic, ecologic and low energy design.

He holds architectural registrations in Massachusetts, Hawaii, and Colorado. In the last 25 years he has worked both in architectural offices and independently, and designed bioclimatic structures that have been built throughout the United States, and several other countries. He received a Master's in Architecture from MIT in 1986, and taught at the University of Hawaii from 1992 to 2000 as an Associate Professor of Architecture and Environmental Control Systems.

He was named Director of Research at the UH School of Architecture in 1993 and oversaw numerous energy, environmental and lighting research projects under contract to various state and federal agencies. He was Chairman of the AIA Honolulu Energy and Environment Committee from 1995 -2000, and in 1998 was named a Dana Fellow of the Joslyn Castle Institute for Sustainable Communities.

Mr. Olgyay is active in lecturing and has numerous published research papers as well as being a primary writer and researcher with W.M.C.Lam of Sunlighting as Formgiver for Architecture



THE HAWAIIAN ELECTRIC 2004 ENERGY EFFICIENCY AWARDS

Aloha,

All of us at HECO are pleased to congratulate the winners of the 2004 Hawaiian Electric Energy Efficiency Awards. The awards described here pay well-deserved tribute to the highest level of commitment to energy efficiency within Oahu's business and government sectors.

Now a biennial event, the Energy Awards demonstrate by good example how local businesses, institutions and government agencies are making investments to reduce operating costs by controlling their demand for electricity.

As you read about the winners in the commercial, institutional, residential and multiple-facility categories, consider the great diversity of opportunities for large energy users to save money and protect the environment at the same time. See what your business peers (and in some cases, your competitors) are doing to reduce their energy consumption. In many cases the steps are simple, and well within the resources of many more businesses and government organizations.

Of course, you have available the advice, assistance and often financial incentives available directly from the *EnergySolutions* for Business consultants of the electric utility. Also, you can enlist the support of the professional architecture, design and engineering community, as well as local service providers and trade allies.

Please join Hawaiian Electric Company in honoring the 2004 Energy Award winners.

T Michael May

T. Michael May
President and CEO
Hawaiian Electric Company

Hawaiian Electric Company, Inc.
Giving you the power

WHAT ARE THE HAWAIIAN ELECTRIC **ENERGY EFFICIENCY AWARDS?**

The Hawaiian Electric Company is pleased to honor the recipients of the 2004 Energy Efficiency Awards. In its sixth year, the awards program was established to recognize Oahu businesses, individuals and organizations that implement innovative energy efficiency projects as well as encourage all businesses and organizations to help Hawaii become more energy efficient.

This program provides an opportunity to acknowledge and congratulate those leaders in the community who are preparing for tomorrow by becoming more energy efficient consumers today.

This year winners were selected from Commercial, Residential, Institutional and Multi-Facility categories. Also this year, due to an exceptional commitment toward energy efficiency in new construction and retrofit and renovation projects, 5 branches of the military, the Army, Navy, Marines, Air Force and Coast Guard are also recognized in their own categories.

JUDGING CRITERIA

Energy Efficiency
Annual energy savings; percent reduction in annual kWH usage.

Project Description
Motivation for the efficiency

★ ENERGY EFFICIENCY AWARDS **PROJECT OF THE YEAR** ★

WINNER INSTITUTIONAL PROJECT

CITY & COUNTY OF HONOLULU
HONOLULU HALE & LED TRAFFIC LIGHTS

The City has demonstrated leader-

WINNER COMMERCIAL PROJECT

PACIFIC GUARDIAN CENTER

The Pacific Guardian Center (PGC), formerly known as the Grosvenor Center, is comprised of two 30-story office buildings encompassing over 580,000 square feet of office space.

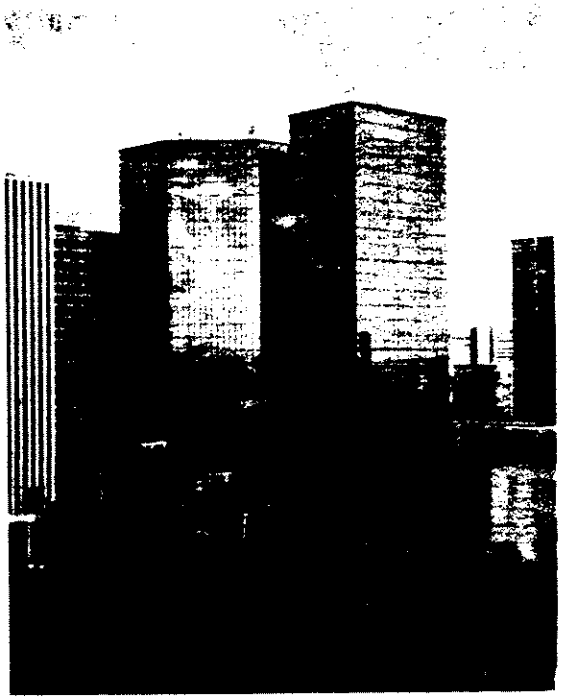
Completed in 1981, it was poised for a renovation of its building, air conditioning and ventilation systems. In 1997 a master plan to modernize the electrical and mechanical systems was developed. Several phases of the modernization culminated in 2003 when PGC installed several major components including three chillers, an energy management system (EMS), air handling units, and improvements to its chilled water loop and cooling towers.

PGC studied the load profiles of the old HVAC system and concluded that the new system would be designed to stage the chillers to match the load and lower the buildings' chilled water supply temperature from 50 to 45 degrees. This was accomplished while reducing its annual chiller plant energy use by 825,000 kWh with the new chillers, VFDs on the air handling units and upgraded chilled water valves.

The new EMS, manufactured by Alerton, allowed for more responsive VAV monitoring and control options as well as the ability to be programmed. The new direct digital control system was done at no additional cost to building operations. The new EMS has the ability to monitor air flow, room temperatures, and operation of the chillers, at the most optimal energy efficient levels.

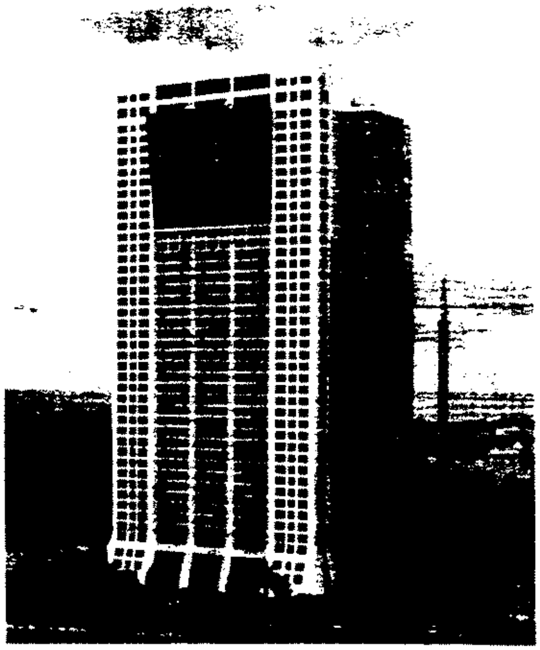
Other partners associated with this project: Trane, Hawaii Instrumentations & Control, Gellert Company, and Higa Mechanical

Annual Energy Savings	$250,000
Annual kWh reduction	15%
Payback Period	4.3 years
HECO Rebate	$118,657



WINNER RESIDENTIAL PROJECT

HAWAIKI TOWER



Opened in 1999, the Hawaiki Tower is a 46-story high-rise condominium comprised of 427 residential apartments and four commercial/retail units. Over a three-year period, the building management installed various retrofit projects, including booster pump, condenser water and hot water

The hot water retrofit uses the air-conditioning condenser water to supply water to the low zone heat pumps that generate the hot water for the lower half of the building. This change now permits the controller of the condenser water system to reduce the speed and flow of the cooling tower

CONGRATULATIONS TO THE
RECIPIENTS OF THE 2004
HECO ENERGY EFFICIENCY AWARDS

WINNER INSTITUTIONAL PROJECT

IOLANI SCHOOL

Iolani School is a private, college preparatory, co-educational school with a total enrollment of 1,800 students in grades K-12.

In Phase 1 of its 20-year master plan, the school established education program goals as well as a new architectural vocabulary for future design that includes sustainable design concepts.

The multipurpose building contains classrooms, stadium seating, a parking garage, and a central ice plant. Though initially serving the multipurpose building, the central ice plant was designed to eventually service buildings throughout the entire campus.

Architectural elements of sustainable design include aluminum light shelves and light pipes to bring natural daylight into the space. Daylight sensors monitor the natural daylight to control use of the lighting fixtures, and occupancy sensors eliminate unnecessary lighting in unoccupied spaces. High performance glazing in the facility maximizes the visible light transmittance while minimizing solar heat gain.

With a partial ice storage system, the chiller provides both ice-making at night, normal cooling during the day to take advantage of off-peak utility rates, and an improved load factor due to the reduction in the daily peak demand. The VAV and ice storage systems are controlled by a direct digital control EMS system.

Other partners associated with this project: Fukunaga & Associates, Cedric Chong & Associates, MK Engineers

Annual Energy Savings	$136,000
Annual kWh reduction	28%
Payback Period	8.9 years
HECO Rebate	$33,422

WINNER RESIDENTIAL/MILITARY PROJECT

FORD ISLAND & RADFORD TERRACE NAVAL HOUSING

At Ford Island and Radford Terrace, Actus Lend Lease LLC developed and currently manages 170 energy-efficient residential homes for the US Navy. The homes were designed to take full advantage of solar energy, efficient lighting and air-conditioning, and innovative window/ceiling construction.

In the area of solar energy, all units have solar water heating, solar tube skylights in the windowless bathrooms, and photocell-controlled lighting. All units are equipped with compact fluorescent lamps and T-8 lighting throughout. Garage and address lights are equipped with photocell and/or motion detectors. The windows are vinyl framed with high performance dual pane low-e glazing that reduces heat gain while allowing natural daylight in. Ceilings are [illegible] tively. These features significantly reduce the cooling load on the air conditioning systems.

To control mold growth, all units are equipped with moisture-sensing bathroom exhaust fans that come on when the humidity exceeds 50% and automatically go off when the humidity is less than 50%. Additionally, the entire exterior of the units is wrapped with a vapor barrier which further aids in the prevention of mold and increases the efficiency of the air-conditioning.

Other partners associated with the project: K&K Plumbing, PowerPlus Electric, Island Home Building Supplies, Atlas Mechanical, John Cool Inc., and Town and Home Architects.

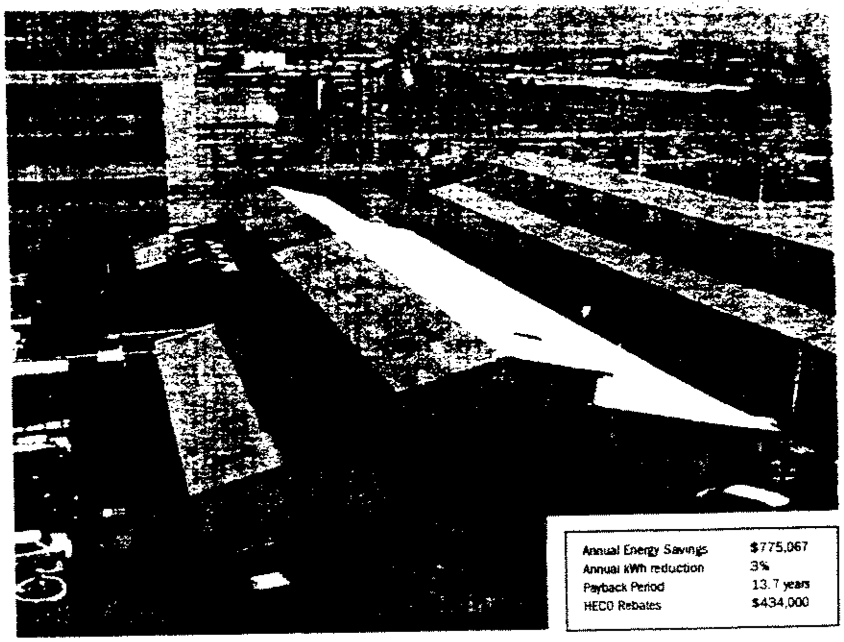
WINNER INSTITUTIONAL/MILITARY PROJECT

NAVY REGION HAWAII, PEARL HARBOR NAVAL SHIPYARD

The Navy Region Hawaii's project at Pearl Harbor Shipyard replaced multiple inefficient systems with a new 1800-ton chiller plant, two separate chilled water distribution loops, and lighting retrofits. The new chiller plant serves eight buildings with the chiller distribution loops serving various parts of the shipyard. Hawaiian Electric Company arranged for financing an internal program for requesting funding for federal government projects. The design of the project allows the Navy Region Hawaii to take advantage of technologies such as Thermal Energy Storage or Combined Heat and Power.

The new central plant replaced multiple air-cooled chillers and window air conditioners thereby improving efficiency, lowering costs, and providing improved comfort and indoor air quality within the buildings it serves. The Navy also installed direct digital controls that would provide immediate feedback on the status of the system, allowing for timely adjustments, tighter control of scheduling, minimizing run times of air-conditioning individual spaces, and significantly lowering maintenance time and costs.

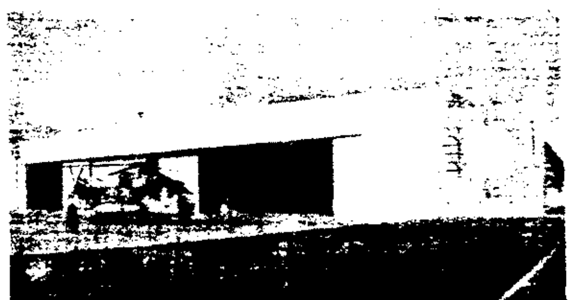
Other partners associated with this project: Economy Plumbing, Pearl Harbor Naval Shipyard, ROICC Pearl Harbor, [illegible]DIV, HECO Customer Technology Applications Division.



Annual Energy Savings	$775,067
Annual kWh reduction	3%
Payback Period	13.7 years
HECO Rebates	$434,000

WINNER MULTI-FACILITIES/MILITARY PROJECT

MARINE CORPS BASE HAWAII, KANEOHE



Marine Corps Base Hawaii (MCBH) completed several significant energy savings projects in a range of facilities.

These projects included improvements to aircraft hangar lighting; retail and warehouse facilities lighting, controls and air conditioning; and installation of energy efficient lighting and solar water heating in new housing units.

Hangars were retrofitted with new 400w adjustable dual reflector metal halide light fixtures. A daylighting control system was installed, which automatically turns off a zone of lights when not needed due to adequate sunlight through skylights and open hangar doors.

The MCBH retail Exchange was retrofitted with a new energy efficient air-conditioning system. This included a chilled water system, four air handling units, fan motors, and variable frequency drive units on the roof of the retail Exchange store. Energy efficient metal halide, adjustable dual reflector light fixtures were installed in the storage warehouse, furniture store, Toyland and outdoor living facilities.

Extending its commitment to efficiency to housing, MCBH installed T8 lamps with electronic ballasts, compact fluorescent lighting and solar water heating in 184 new housing units.

Other partners associated with this project: NORESCO, ECO-Lite, StingRay Lighting, Navy Public Works Center, Precision Air Conditioning.

Annual Energy Savings	202,450 kwh
Annual kWh reduction	42%
Payback Period	5.5 years
HECO Rebate	$195,761

HONORABLE MENTION RESIDENTIAL/MILITARY

U.S. COAST GUARD THOMPSON HALL BERTHING FACILITY

The USCG Air Station Barber's Point recently built the new Thompson Hall Berthing Facility to provide living accommodations for sixteen people.

The facility is comprised of 6,000 square feet in a two-story complex. It contains a dining area, recreation room, 11 berthing rooms, storage, and a laundry room. The windows are insulated with blue-green tinted glazing and use argon gas to reduce heat gain. The appliances in the laundry room are "Energy Star" rated. Lighting throughout the facility features both dimmable compact fluorescent lamps and LCD exit signs. Motion sensors control lights in the restrooms, laundry, janitor, and storage rooms. The attic is insulated and the roof canopy houses air-cooled condensing units. Various chaseways and catwalks were incorporated into the building design for ease of maintenance and operation.

Other partners associated with this project: ECH Edberg Christiansen Heidenreich Architecture (Seattle), CC Engineering and Construction, Inc.

Annual Energy Savings	$10,312
Annual kWh reduction	32%
Payback Period	6.5 years
HECO Rebate	$523

HONORABLE MENTION INSTITUTIONAL/MILITARY PROJECT

SCHOFIELD BARRACKS WASTE WATER MANAGEMENT

Schofield's Wastewater Treatment Plant handles all wastewater processing

CA-IR-567
DOCKET NO. 04-0113
PAGE 23 OF 29

MAHALO TO THE JUDGES OF THE 2004 ENERGY EFFICIENCY AWARDS

Mahalo to the judges for their time and efforts spent reviewing applications and visiting the sites.


Melek Yalcintas, PhD

Dr. Melek Yalcintas has more than fifteen years of experience in consulting and academia.

Her articles have appeared in several technical journals including International Journal of Energy Research and Journal of Smart Materials and Structures. Her most recent article entitled "Artificial Neural Networks Applications in Building Energy Predictions and a Case Study for Tropical Climates" was submitted for publication this year.

She is principal of AMEL Technologies and previously served as consultant with Cedric D.O. Chong & Associates in Honolulu and REE Associates in Pennsylvania. She is a member of the American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) and is registered as a LEED® Accredited Professional with the U.S. Green Building Council.

Dr. Yalcintas received her BS and MS from Middle East Technical University in Turkey followed by her PhD in Mechanical Engineering from Lehigh University in Pennsylvania. In her spare time, she enjoys gardening.


Stephen Meder, ArchD

Dr. Stephen Meder teaches design and environmental systems at the University of Hawaii-Manoa School of Architecture (SoA) and School of Earth Science and Technology. A principal of The Architecture Studio, he specializes in design, renewable energy and energy efficiency sustainable design consulting.

Dr. Meder has designed integrated photovoltaic systems for the US Navy and the United States Postal Service. He authored the energy efficient design chapters for the Hawaii Advanced Building Technology program. He was a principal author for the US Department of Energy publication on "Performance and Comfort in Hawaii Homes" and was an advisory group member for the State of Hawaii, Commercial Building Guidelines.

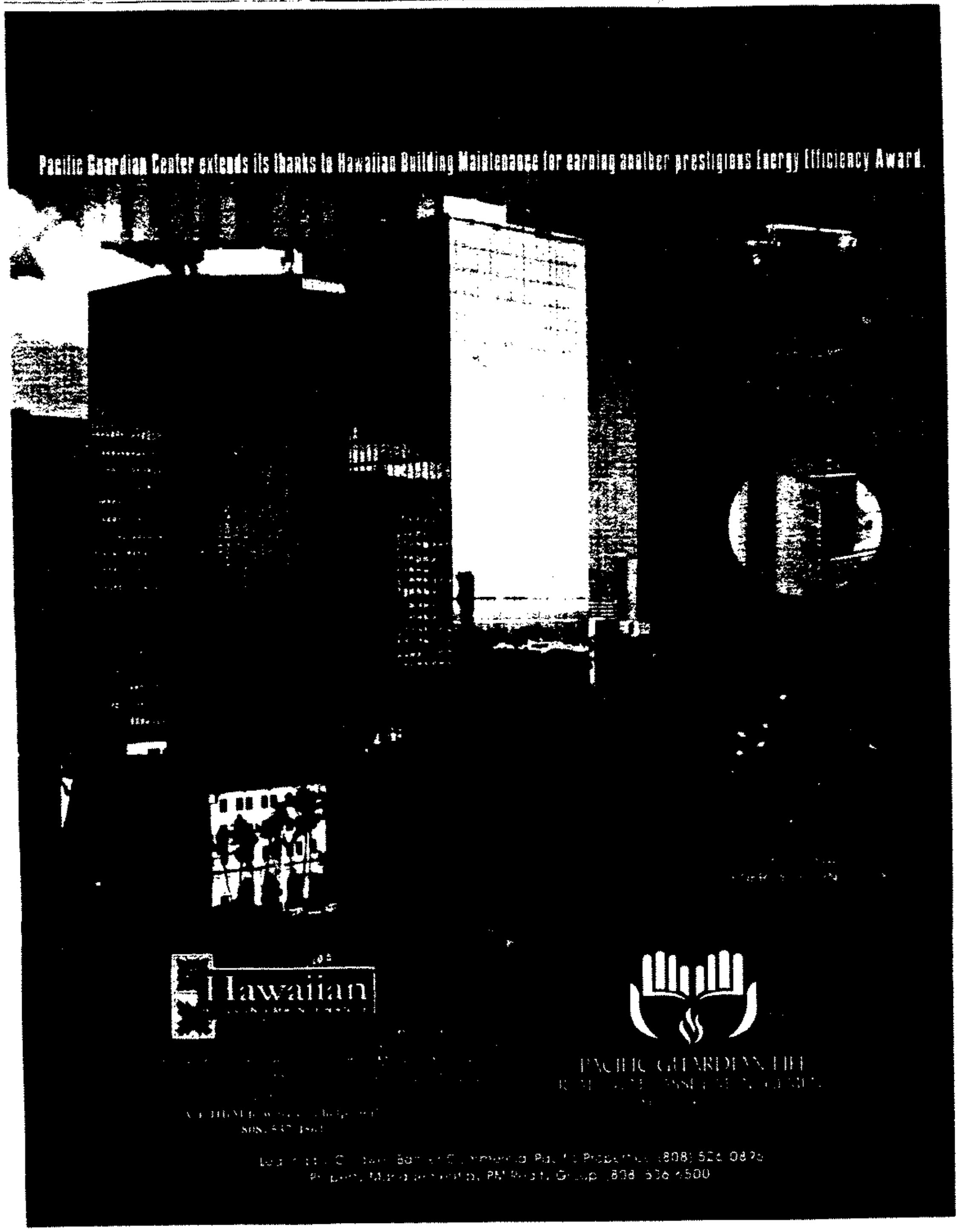
Dr. Meder received his Doctor of Architecture degree from the University of Hawaii, School of Architecture. He is also the Director of the School of Architecture's Environmental Systems Laboratory.

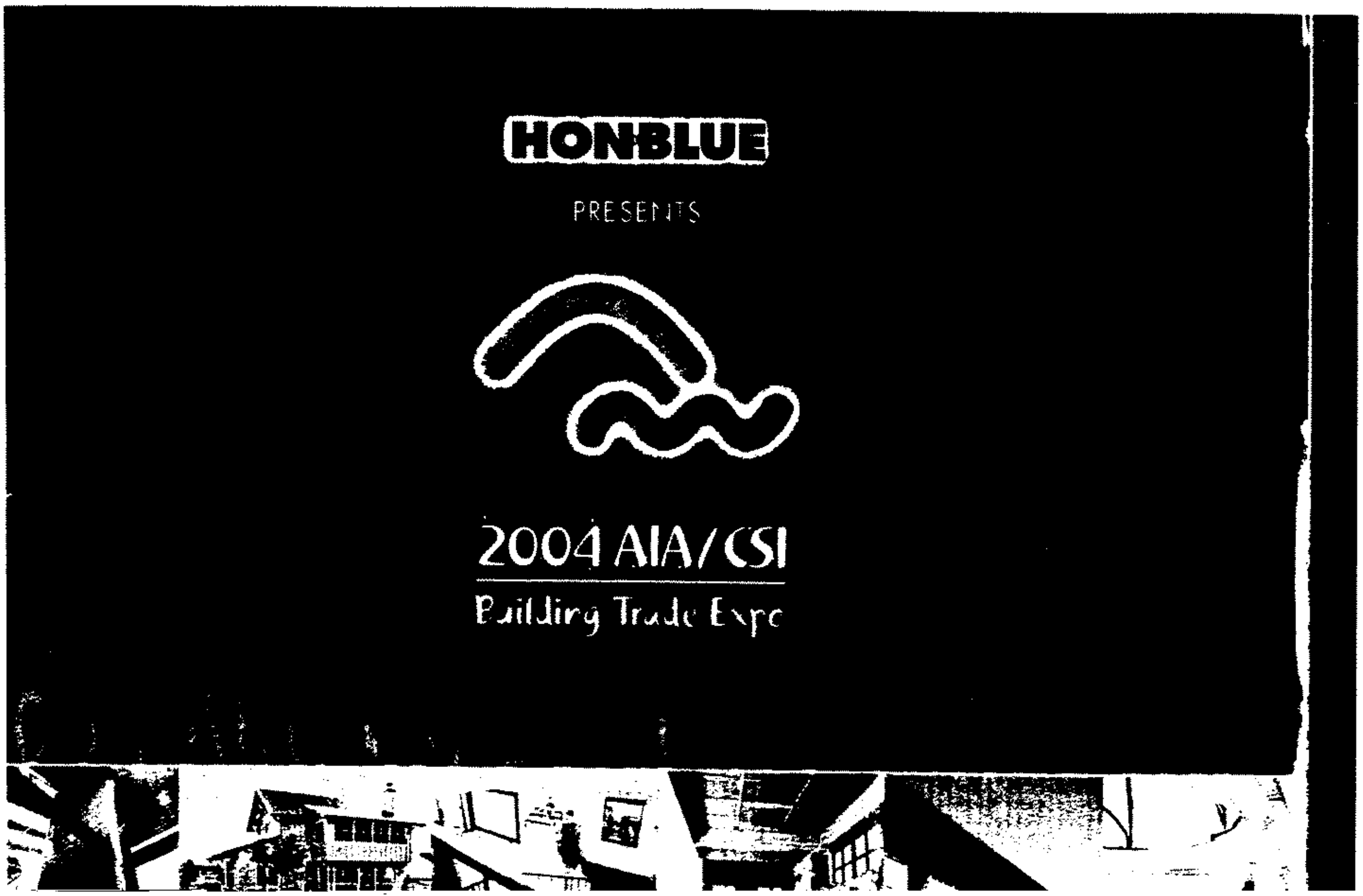

Ronald Tolleson

Ron Tolleson is the Manager of Facilities Engineering at The Queen's Medical Center (QMC). He has over 15 years of experience in facilities and building management. Over the last few years, he was instrumental in leading the renovation projects at QMC. In 2001, Queen's was the recipient of the HECO Energy Efficient "Project of the Year" Award.

Mr. Tolleson's professional memberships include the Hawaii Society of Healthcare Engineers (President), American Society of Healthcare Engineering, and the Rebuild Hawaii Energy Consortium. He is qualified as a Certified Healthcare Facility Manager, Water Distribution System Operator, Universal EPA Technician, and Certified Medical Gas Inspector. He serves as board member of both the Moiliili Neighborhood Board and the University Plaza Condominium Association.

He received his MBA from Hawaii Pacific University and BA from the University of Hawaii.


Pacific Guardian Center extends its thanks to Hawaiian Building Maintenance for earning another prestigious Energy Efficiency Award.
Hawaiian


HONBLUE
PRESENTS
2004 AIA/CSI
Building Trade Expo

HONBLUE PRESENTS
2004 AIA/CSI Building Trade Expo
Building Excellence

HECO Booth and Seminars

HECO, Hawaiian Electric Company, Inc., Kula (gold) level corporate sponsor, in addition to taking a booth presence on the floor of the expo hall, will be filling out an entire track of seminars focusing on energy conservation and sustainability. One of these seminars will look at three high performance LEED (Leadership in Energy & Environmental Design) platinum level projects, providing an overview of each project, its sustainability features and some of the challenges each presents to the owner, design team and construction team. The projects are all located in the Los Angeles area.

Speaker, Tom Lunneberg, PE, vice president of CTG Energetics, Inc. provides energy efficiency consulting, analysis and training to a variety of commercial and institutional clients. Lunneberg has provided training to a number of clients on topics of energy efficiency and energy management.


Tom Lunneberg

Rick Casault, president of Casault Engineering, will be presenting a special three-hour seminar on "Building Commissioning for High Performance Buildings." The seminar will be broken into a one-hour introductory session, which will give attendees a good overall understanding of the topic, then moves into a detailed two-hour session, which covers current topics and shows attendees how to incorporate commissioning in their next projects. All seminars will be eligible for AIA continuing education credit.


Rick Casault

ENERGY $OLUTIONS FOR BUSINESS
Hawaiian Electric • *Giving you the power*

HONBLUE
PRESENTS
2004 AIA/CSI
Building Trade Expo
Building Excellence

Expo Schedule

SEMINARS

TIME	HECO	Practice	Technical	Design	EXHIBIT HALL
8:00					
:15	Session 1A (HSW) **Triple Platinum** Room 317A	Session 1B (HSW) **Case Studies in Construction Law** Room 317B	Session 1C (HSW) **Architectural Structural Precast** Room 318A	Session 1D **Beauty in Function: Members' Choice** Room 318B	
:30					
:45					**Opening Ceremony Exhibition Opens**
9:00					
:15					
:30	Session 2A (HSW) **Advanced Buildings** Room 317A	Session 2B (HSW) **ADA/UFAS: New and Updated Standards** Room 317B	Session 2C (HSW) **Evaluating Floor Performance** Room 318A	Session 2D **Designing with Local Culture and Material** Room 318B	
:45					
10:00					
:15					
:30					
:45					
11:00					
:15					
:30					
:45					
12:00		**AIA Honolulu Chapter Annual Business Meeting Room 319A**			**Lunch Buffet in Exhibition**
:15					
:30					
:45					
1:00					
:15					
:30					
:45					
2:00	Session 3A (HSW) **Building Commissioning (Part A)** Room 317A	Session 3B **CAD Management Issues** Room 317B	Session 3C (HSW) **Building Movement Design** Room 318A	Session 3D **Why Hawaii Architects Can/Cannot Design** Room 318B	
:15					
:30					
:45					
3:00					
:15	Session 4A (HSW) **Building Commissioning (Part B)** Room 317A	Session 4B **Visions: Retooling for a Livable Honolulu** Room 317B	Session 4C **Weed Risk Assessment** Room 318A	Session 4D **Ford Island Development and Renovation** Room 318B	
:30					
:45					
4:00					
:15					
:30					
:45					
5:00					
:15					
:30					**Rocky Mountain Prestress Aloha Reception**
:45					
6:00					
:15					
:30					**Exhibits Closes**
:45					
7:00					

All seminars qualify for one AIA/CSI LU. (HSW) indicates the seminar qualifies for Health Safety and Welfare credit.

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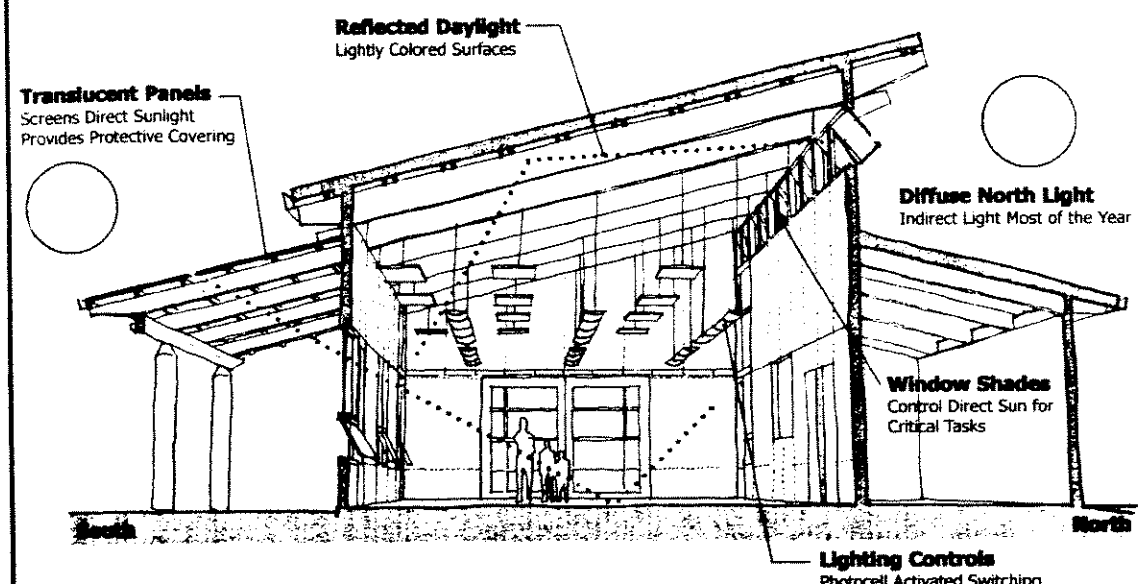

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Hawaii Lumber Products Association
Hawaii Pacific Steel Framing Alliance
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Masonry Institute of Hawaii
National Kitchen & Bath Assn (NKBA), Aloha Chapter
Plumbing & Mechanical Contractors Association of Hawaii
Sheet Metal Contractors Association
West Oahu Economic Development Association

CA-IR-568

The AOS 2005, at 4, states that "a revised forecast for CHP was developed that estimates CHP impacts, based on the assumption that HECO will be allowed to begin installing CHP systems in 2006."

a. Could HECO have taken steps to accelerate the installation of CHP systems? Please explain.

b. Please provide all documents that address HECO decisions regarding the timing of installing CHP systems.

HECO Response:

a. HECO took a number of steps to accelerate the installation of CHP systems, including filing of a utility CHP Program application in Docket No. 03-0366 in October 2003, and filing the HECO-Pacific Allied CHP Agreement in Docket No. 04-0314 in October 2004. The Commission suspended the CHP Program application as proposed by the CA in Order No. 20381, filed March 2, 2004. HECO then proceeded on the basis that review of utility CHP agreements filed in accordance with Rule 4 of its tariff, such as that for the Pacific Allied project, could be done in parallel to the generic Distributed Generation Investigative Docket No. 03-0371, especially when warranted by customer circumstances. See HECO T-1, HECO RT-1, HECO T-6, and HECO RT-6 in Docket No. 03-0371, to which the CA is a party. The Commission's January 21, 2005 suspension Order No. 21555 in Docket No. 04-0314 clearly indicated that the PUC would not consider CHP agreements under Rule 4 until it had substantially resolved the issues in Docket No. 03-0371. With this, HECO determined that it would not be prudent to execute additional CHP agreements with customers until the Commission issued a decision and order in Docket No. 03-0371.

HECO continues to review and evaluate potential CHP projects in anticipation of a favorable ruling in Docket No. 03-0371. However, given the uncertainty concerning the future ruling, HECO has limited its CHP project development efforts primarily to that which can be performed by internal HECO labor, putting on hold project development actions which would involve commitment of significant funds. In this manner, HECO is taking reasonable, but prudent, steps to accelerate installation of CHP. Considering that a final decision and order in Docket No. 03-0371 has not yet occurred and the time required to negotiate a CHP agreement, obtain permits, do final engineering, and to procure and install equipment, HECO believes that it is reasonable to forecast that no utility CHP will be placed in service until the second half of 2006.

b. HECO objects to the request to provide "all" documents pertaining to HECO decisions regarding the timing of installing CHP systems, on the grounds that the "decisions" regarding the installation of HECO-owned CHP decisions are regulatory decisions made in dockets to which the CA is a party. Moreover, as a general matter, (1) documents regarding HECO's CHP system plans contain proprietary commercial and financial information, and the disclosure of such confidential information on a public basis or to entities engaged in the sale of competing services could adversely impact the Company's transactions with customers, adversely impact the Company's costs of doing business, and result in higher costs to ratepayers; (2) the uncontrolled disclosure of proprietary information would give providers of competitive services information useful in making their own marketing decisions, without expending the time and money necessary to gather and develop the data, and would allow providers of competitive services to profit or otherwise derive benefits at the expense of the Company and its ratepayers; (3) requests that the Company produce "all" documents are overly broad and unduly burdensome given the volume of documents (including e-mails, agendas, power point presentations, etc.); (4) information produced pursuant to such requests could include preliminary and/or outdated analyses, which have been superseded by later analyses that are more relevant to the subject-matter of this proceeding; and (5) many of the documents contain information that is protected by the attorney-client privilege and/or the attorney work product privilege.

The Companies also object to the production of customer-specific information on the grounds that (1) such information is confidential and has been protected from disclosure by the Commission in other proceedings, (2) in some cases, the customer specific information is already subject to a protective order in another docket, and (3) the disclosure of such information has not been consented to by the customers.

Without waiving such objections, please refer to the extensive record in Docket Nos. 03-0371, 04-0314 and Informal Complaint No. IC-03-098, which the CA already has. Also, please see the response to CA-IR-276 which explains the key considerations on CHP timing that were taken into account in HECO's latest CHP forecast of March 2005.

CA-IR-569

a. Please state what HECO will do to ensure that system reliability returns to the 4.5 years per day standard in the event that there are further delays in proceedings before the Commission addressing DSM and CHP programs.

b. Please provide a copy of any "contingency" or "action" plan that documents HECO's planned actions under the contingency described in part (a), above.

HECO Response:

HECO cannot "ensure" that that system reliability returns to the 4.5 years per day guideline in the event that there are further delays in proceedings before the Commission addressing DSM and CHP programs. Even with the currently forecasted peak reduction benefits of energy efficiency DSM, load management DSM, and CHP, HECO estimated that generating system reliability would be between 0.9 and 1.6 years per day during the period 2005 to 2009, as shown on page 17, Table 3, of HECO's 2005 AOS report. HECO also analyzed illustrative scenarios in which the estimated reserve capacity shortfalls would be higher (i.e., the LOLP results in years/day would be lower.) In the meantime, HECO is proceeding with other actions and mitigation measures as outlined on pages 24 to 27 of the 2005 AOS report. Please also refer to

CA-IR-570

Please provide a copy of the (a) capital improvements and (b) maintenance budgets for each HECO generating facility for the years 1999 through 2004.

HECO Response:

HECO objects to providing capital and maintenance budgets for prior years 1999 through 2002 on the grounds that the request is overly broad and unduly burdensome, the budget information for prior years is voluminous and provision of such information would be time consuming and serve no productive purpose in this proceeding. Providing variance to budget explanations was raised as an issue by the Consumer Advocate in MECO's 1992-1993 test year rate case, Docket No. 7000. MECO (and essentially HECO and HELCO, or the Companies) and the Consumer Advocate reached agreement in Docket No. 7000 to separate from Docket No. 7000 the Budget Preparation Process/Budget Issues, including the type and amount of information to be provided to the Consumer Advocate between rate cases. MECO and The Consumer Advocate agreed to work together outside of Docket No. 7000 to resolve the budgeting and reporting issues. As a result of the discussions to resolve the issues, among other things, the Companies agreed to provide detailed recorded data files and forecast detailed data files for the link year as part of each subsequent rate case filing. (See transmittal letters dated December 6, 2004 and March 28, 2005 in this proceeding indicating such information was provided to the Commission, Consumer Advocate and Department of Defense. In addition, the Companies have provided as part of the direct testimonies filed in the rate case, explanations of variances by activity, above a threshold, between the budget prepared for the test year and the full year actual information. See for example HECO-WP-601, HECO-WP-805, and HECO-WP-1033 submitted in this proceeding. HECO has responded to numerous IRs regarding the variance explanations.) The Companies have provided a significant amount of information as a result of prior agreements in order for the Consumer Advocate and the Commission to determine the reasonableness of HECO's test year expenses. The Consumer Advocate should not need budget information for going back to 2000 in order to review HECO's 2005 test year expenses.

Actual historical expenditures and year-over-year comparisons have been provided in CA-IR-170 (Other Production O&M from 1986 – 2005TY), CA-IR-180 (2000 – 2005 Overhaul Projects broken down by Labor, Material, Outside Services and Overheads), and CA-IR-44, Attachments 5 - 8 (2002 – 2004 Actual Projects direct labor and non-labor by RA). Capital and O&M budget vs. actual variance explanations were provided for 2003 and 2004 in CA-IR-41, Attachments 2 and 3 (2003 O&M and Capital budget vs. actual Variance) and CA-IR-42, Attachments 2 and 3 (2004 O&M and Capital budget vs. actual variance). And lastly a revised 2005 overhauls schedule with changes to the capital and O&M budgets was provided in CA-IR-43 Revised, pages 3 - 6 (2005 O&M and Capital budgets).

Notwithstanding HECO's objection to providing historical capital and O&M budget information from 1999 through 2002, the capital improvement and O&M budgets for years 2003 and 2004 are provided. The respective budget information is voluminous, therefore one copy each will be provided to the Consumer Advocate, the Department of Defense and the Public Utilities Commission under separate transmittal.

a. The capital expenditure budget for year 2003 is provided on pages 4 to 5.

b. The capital expenditure budget for year 2004 is provided in CA-IR-203.

c. The 2003 Operation and Maintenance budget by NARUC Account and code block is provided on pages 6 to 33. The list of the 2003 Operation and Maintenance projects only is provided on page 34.

d. The 2004 Operation and Maintenance budget by NARUC Account and code block is provided on pages 35 to 80. The list of the 2004 Operation and Maintenance projects only is provided on page 81.

Due to the voluminous nature of the information, one copy (pages 4 – 81) will be provided to the Consumer Advocate, Department of Defense and the Public Utilities Commission under separate transmittal.

CA-IR-571

a. Please provide copies of all HECO documents dated between January 1998 and the present that address the lead times for permitting new generating facilities.

b. Please provide copies of all HECO documents dated between January 1998 and the present that address HECO decisions to initiate the permitting of its next major generating facility (e.g., the "Next Generating Unit Addition" discussed in the AOS 2005, at 5.

HECO Response:

HECO objects to the request to provide "all" documents dated between January 1998 and the present which address the lead times for permitting new generating facilities and HECO decisions to initiate the permitting of its next major generating facility, on the grounds that (1) requests that HECO produce "all" documents are overly broad and unduly burdensome given the volume of documents; (2) internal communications contain information subject to the attorney-client and attorney work product privileges; (3) information produced pursuant to such requests could include preliminary and/or outdated analyses, which have been superseded by later analyses; and (4) "the next major generating facility" is not the subject of this 2005 test year rate case. Without waiving this objection, HECO is willing to provide the following response.

[redacted]

Project	Permit No.	Date PSD Application Submitted	Draft Permit Issuance	Final Permit Issuance	Permit Effective Date	Total Months for Processing
MECO						
Maalaea X1 and X2	PSD HI 86-02	5/13/86	5/1/87	10/5/87	11/4/87	18
Maalaea 12 and 13	PSD HI 87-01	2/23/87	5/12/89	11/17/89	12/17/89	34
Maalaea 14	PSD HI	4/20/90	9/12/91	12/9/91	1/8/92	21

Until 2004, not all generation projects required environmental review. In 2004, however, HRS Chapter 343 was amended to require environmental review for new or expanded power generating facilities where the new fossil fuel-fired equipment's output exceeds 5 megawatts. Thus, all but the smallest fossil fuel-fired generation projects are now subject to environmental review. The time required for acceptance of an Environmental Impact Statement ("EIS") can vary, depending on the circumstances of the project. For example, for MECO's Waena Generating Station EIS, the EIS preparation notice was published on March 8, 1997, and the Final EIS was accepted by the County of Maui in November 1997 (approximately eight months). For HELCO's Keahole Generation Expansion EIS, the EIS preparation notice was published on September 8, 1992, and the Final EIS was accepted by the State Department of Land and Natural Resources in January 1994 (approximately 16 months). In addition, although not a generation project, the EIS process for the proposed Kamoku-to-Pukele Transmission Line Project took 21 months from inception to acceptance.

No specific studies have been prepared other than a general review of historic time periods for CS/PSD review and EIS approval for HECO, MECO, and HELCO projects, as indicated in the response to part a. above.

b. Within every project schedule, there are items that make up the critical path. Critical path items are those that cannot be delayed without delaying the finish time for the entire project. Typically, critical path items have dependencies upon each other and, therefore, such items often have to be done sequentially. There are currently two parallel critical paths identified for commercial operation of the next generating unit in 2009. The first path starts with the covered source permit and the second critical path starts with Commission approval to commit funds in excess of $2,500,000. Following completion of these two items, the critical paths merge and include lead time to receive the combustion turbine, and construction/start-up/testing. Other project required/regulated permits and approvals (e.g, EIS, conditional use permit, building permits, etc.) and tasks, while necessary to complete the project, have some flexibility as to when they may be completed while still allowing the estimated project service date to be met, but they could become critical path items if significantly delayed or their schedule is affected by compression of other critical path items.

HECO began efforts to obtain the Covered Source Permit ("air permit") for a nominal 100 MW simple-cycle combustion turbine in January 2003. HECO submitted an initial application for the air permit with the State of Hawaii Department of Health in October 2003. The decision to submit the application for this generating facility in October 2003 was based on the critical path items in the schedule to maintain an in-service date of 2009, consistent with HECO's IRP-2 (1998) and IRP-2 Evaluation Report (2002). As can be seen in the above table, the time to obtain a final covered source permit following submittal of the application can vary significantly between projects. At the time the covered source application was submitted for the next HECO generating unit, the schedule for the Maalaea 17 & 19 units was considered to be "typical". Therefore, it was estimated that it would take approximately 49 months to obtain a final covered source permit including appeal.

Following receipt of permits and approvals, the estimated lead time to receive the combustion turbine is 12 months. This lead time was based on feedback from the candidate combustion turbine vendors regarding standard industry delivery schedules for this size of unit.

To estimate the time to complete construction, start-up and testing following receipt of the combustion turbine, HECO received input from its engineering consultant (Sargent & Lundy), who is very experienced with developing and implementing schedules for construction of the type of facility that HECO is proposing. Through this consultation with Sargent & Lundy, the time for these tasks was estimated at 9 months.

The total time of these critical path items, which are to be accomplished in series, is 70 months. Therefore, by starting the covered source permitting process in October 2003, the estimated commercial operation date of the new unit is July 2009.

CA-IR-572

a. Please provide copies of all HECO documents dated between January 1998 and the present that address the lead times for engineering new generating facilities.

b. Please provide copies of all HECO documents dated between January 1998 and the present that address HECO decisions to initiate the engineering of its next major generating facility (e.g., the "Next Generating Unit Addition" discussed in the AOS 2005, at 5.

HECO Response:

HECO objects to the requests to provide "all" documents dated between January 1998 and the present that addresses the lead times for engineering new generating facilities and HECO decisions to initiate the engineering of its next major generating facility, on the grounds that (1) requests that HECO produce "all" documents are overly broad and unduly burdensome given the volume of documents; (2) internal communications contain information subject to the attorney-client and attorney work product privileges; (3) information produced pursuant to such requests could include preliminary and/or outdated analyses, which have been superseded by later analyses; and (4) "the next major generating facility" is not the subject of this 2005 test year rate case. Without waiving this objection, HECO provides the following responses.

a. Since engineering of new generating facilities is not typically a critical path item in a project schedule, HECO does not track the lead time for this item.

b. Some amount of preliminary engineering is required to support the permitting processes for a new generation facility. For example, to submit a complete covered source permit application a preliminary plant layout with stack location, stack size, and height of structures in vicinity of the stack is required. Preliminary engineering is also needed to produce visual renderings of the proposed project for community presentations and to estimate the total project cost for the PUC application. Therefore, the decision to initiate engineering was based on supporting the permitting and approval processes necessary to meet a commercial operation date of 2009 (see HECO's response to CA-IR-571).

CA-IR-573

The AOS 2005 states at 5-6 that HECO anticipates reserve capacity shortfalls in 2005 and projects these shortfalls to continue at least until 2009.

a. Please identify the earliest date by which HECO is projecting that it will re-attain the "4.5 years per day" reliability standard.

b. Please identify the earliest date by which HECO is projecting that it will re-attain a "7.0 years per day" reliability standard.

c. How much incremental generating capacity (i.e., relative to existing generating capacity and existing resource commitments) would be required to re-attain the "7.0 years per day" standard in the year identified in the response to part (b), above.

HECO Response:

a. The earliest date by which HECO is projecting that it will re-attain the "4.5 years per day" reliability guideline is 2009, predicated on (1) actual peak demands not exceeding the forecast provided in the 2005 AOS report; (2) acquiring the forecasted peak reduction benefits of energy efficiency DSM by 2009 (provided Commission approval is obtained to continue with the programs); (3) acquiring the forecasted peak reduction benefits of load management DSM by 2009; (4) acquiring the forecasted peak reduction benefits of utility

[illegible]

is 4.5 years per day.

The table below provides results if the reliability analysis done for the 2005 AOS is extended beyond 2009 by assuming that a combustion turbine is added in 2009. The June 2004 short-term peak forecast was used in the 2005 AOS Report for the years 2005 to 2009. In order to extend the analysis beyond 2009, the February 2004 long-term forecast (which was used for HECO IRP-3) is used for the later years, because that is the latest available long-term forecast.

The results of the generating system reliability analysis for the years 2009 through 2011, assuming either a 76 MW combustion turbine or a 107 MW combustion turbine is installed, are shown below.

	Projected Generating System Reliability, Years per Day	
Year	76 MW CT in 2009	107 MW CT in 2009
2009	4.8	4.8
2010	6.1	9.9
2011	12.8	21.3

c. As indicated in part b above, an addition of a 76 MW nominal combustion turbine in 2009 (together will all other assumptions given in HECO's 2005 AOS report) will result in an increase in generating system reliability above 7.0 years per day in 2011. Generating system reliability will be above 7.0 years per day in 2010 if a 107 MW unit is installed in 2009. HECO has not quantified the amount of capacity needed to achieve exactly 7.0 years per day in these years.

CA-IR-574

Regarding the AOS 2005 and the "Action Plan and Mitigation Measures" identified at 24:

a. Please provide a status report on each mitigation measure.

b. Please identify the incremental capacity contributions that HECO projects from each mitigation measure for each year 2005 through 2009.

HECO Response:

a. DG at HECO Sites – HECO has filed air permit applications with the State Department of Health for three of the five candidate DG sites described in the response to CA-IR-441 part b, and is in the process of preparing air permit applications for the remaining two sites. Concurrently, HECO is seeking required approvals from the City and County of Honolulu Department of Planning and Permitting. Engineering design and system interconnection studies are in progress. Please also refer to rate case updates filed with the Consumer Advocate, Department of Defense and the Commission on May 5, 2005 which describes the background to the DG mitigation measure and associated costs, and HECO's responses to CA-IR-441, CA-IR-446 and CA-IR-558, parts c., d., and e.

   Demand Load Response Program, Residential Air Conditioning Load Control Program and Public Notification Program – Please refer to HECO's response to CA-IR-446, part a., Items 8, 9 and 10.

b. DG at HECO Sites – Please refer to HECO's response to CA-IR-535, part a., for the projected incremental capacity contribution from DG at HECO sites.

   Demand Load Response Program, Residential Air Conditioning Load Control Program and Public Notification Program – At this time, HECO does not have estimates for incremental peak load reduction contributions from these mitigation measures. Please refer to HECO's response to CA-IR-535, part c.

CA-IR-575

Ref: Schedule PP – Large Power Primary HECO-WP-304, page 124.

For each month in 2004, please provide in electronic format, for each customer in the Large Power Primary Voltage Service, in rate class Schedule PP, the following:

a. KWh;

b. KVARh;

c. kW;

d. Power Factor (%), please indicate whether this amount is actual or an estimate;

e. Demand Charges ($);

f. Energy Charges ($);

g. Power Factor Adjustment Rate (%); and

h. Power Factor Adjustment ($).

HECO Response:

See the accompanying electronic file, "Response File for CA-IR-575", provided under separate transmittal. Please note that the Power Factor (%) is an actual, and the responses to (d) and (g) above are identical.

CA-IR-576

Ref: Schedule PP – Large Power Primary HECO-WP-304, page 124.

For each HECO generating unit please provide the following:

a. Rated Capacity.

b. Rated power factor (%) (at rated capacity in 1).

c. Exciter rating (kW).

d. Original cost and accumulated depreciation costs for FERC Account numbers 314 and 344 for each HECO generating unit. Breakout the cost of the generator, steam turbine (if applicable) and exciter.

e. Please provide the range of the rated power factor, from leading to lagging.

f. Please provide the range of the rated VAR capability, from leading to lagging.

g. What is the minimum generation (kW)?

HECO Response:

a. For the "rated capacity," please refer to HECO-WP-406. The values represent Normal Top Load ("NTL") ratings. Please refer to HECO's response to CA-IR-127 filed on

	Account 314 Plant Balance as of 12/31/2004
Honolulu	$13,843,791.87
Kahe	$66,868,450.69
Waiau	$34,961,558.18
Total	$115,673,800.74

Total accumulated depreciation for Account 314 as of December 31, 2004 is $84,467,999.25. The Account 314 plant account information is available only by location. HECO does not have a breakdown by individual generating unit.

The table below provides the Account 344 plant balances as of December 31, 2004.

	Account 344 Plant Balance as of 12/31/2004
Honolulu	$0.00
Kahe	$0.00
Waiau	$5,379,110.80
Total	$5,379,110.80

Total accumulated depreciation for Account 344 as of December 31, 2004 is $4,657,614.49. The Account 344 plant account information is available only by location. HECO does not have a breakdown by individual generating unit.

The requested breakouts by the cost of the generator, steam turbine and exciter are not readily available. This is because the equipment, when originally purchased, were provided by a single vendor as part of a single package for a single lump sum price without breakdowns for individual components. For example, please see pages 5 to 10 to this response, for Order No. 12950, dated February 16, 1945, to Westinghouse Electric and Manufacturing Co., for the Waiau Unit No. 3 turbine, generator and exciter. The order includes numerous items, including the turbine (page 5), generator (page 8) and exciter (page 8). The lump sum price of $639,420.00 is given on page 10.

e. The range of rated power factor, from leading to lagging, is listed in the table below. The range listed below is for the generator nameplate rated MW capacity listed in HECO's response to CA-IR-127 part b.

Hon 8	0.80 lagging to 0.99 leading
Hon 9	0.85 lagging to 0.99 leading
Waiau 3	0.87 lagging to 0.95 leading
Waiau 4	0.87 lagging to 0.95 leading
Waiau 5	0.85 lagging to 0.96 leading
Waiau 6	0.85 lagging to 0.96 leading
Waiau 7	0.85 lagging to 0.90 leading
Waiau 8	0.85 lagging to 0.90 leading
Waiau 9	0.90 lagging to 0.99 leading
Waiau 10	0.90 lagging to 0.99 leading
Kahe 1	0.85 lagging to 0.92 leading
Kahe 2	0.85 lagging to 0.90 leading
Kahe 3	0.85 lagging to 0.99 leading
Kahe 4	0.90 lagging to 1.00 leading
Kahe 5	0.85 lagging to 0.92 leading
Kahe 6	0.85 lagging to 0.95 leading

f. The range of rated VAR capability, from leading to lagging, is listed below. The range listed below is for the generator nameplate rated MW capacity listed in HECO's response to CA-IR-127 part b.

Hon 8	37.5 MVAR lagging to 6.5 MVAR leading
Hon 9	33.7 MVAR lagging to 8.5 MVAR leading
Waiau 3	28.4 MVAR lagging to 17.0 MVAR leading
Waiau 4	28.4 MVAR lagging to 17.0 MVAR leading
Waiau 5	33.7 MVAR lagging to 15.5 MVAR leading
Waiau 6	33.7 MVAR lagging to 15.5 MVAR leading
Waiau 7	50.6 MVAR lagging to 39.1 MVAR leading
Waiau 8	50.6 MVAR lagging to 39.1 MVAR leading
Waiau 9	24.8 MVAR lagging to 7.0 MVAR leading
Waiau 10	24.8 MVAR lagging to 7.0 MVAR leading
Kahe 1	50.6 MVAR lagging to 34.2 MVAR leading
Kahe 2	50.6 MVAR lagging to 39.2 MVAR leading
Kahe 3	53.2 MVAR lagging to 9.0 MVAR leading
Kahe 4	44.0 MVAR lagging to 7.0 MVAR leading

Kahe 5	83.7 MVAR lagging to 56.3 MVAR leading
Kahe 6	83.7 MVAR lagging to 45.4 MVAR leading

g. Please refer to HECO-WP-406.

STOCK REQUISITION

File No. 233.51
Eng. No. 800

Order No. 12950 Extra Copies Reese, White, Thorsen, Olsen Date February 16, 1945

Order from Westinghouse Electric & Mfg. Co.

Address No. 1 Montgomery St., San Francisco, Calif.

Ship By Matson Navigation Company

For Waiau Power Plant - Unit #3 Sales No.

Auth. 1105 Account 314-E Job No. 3C-545

Notify White - Dewey - Thorsen C. O. No.

H. E. Form 34

UANTITY	DESCRIPTION	FACTORY	
		List	Discount

DER No. 12980 PAGE No. 2

Form 34A

QUANTITY	DESCRIPTION	FACTORY List	Discour
	1 - Motor operated speed changer with hand wheel - 125 volts D.C.		
	1 - Emergency overspeed governor safety stop with testing device.		
	1 - Impeller type main oil pump mounted directly on turbine shaft.		
	1 - Turbine driven auxiliary oil pump with automatic regulator.		
	1 - Low oil pressure trip mechanism.		
	2 - Westinghouse oil coolers each of sufficient size to cool the entire quantity of oil circulated - 83° F. salt water.		
	1 - Oil reservoir with removable strainer.		
	1 - Set necessary inter-connecting oil piping including necessary gauges and thermometers in oil lines.		
	1 - Motor driven auxiliary oil pump 440 volts, 3 phase, 60 cycle, for use when the unit is on turning gear, complete with motor but exclusive of wiring and control.		
	9 - Dial thermometers, one each for thrust bearing, #1, #2, #3, #4, #5, O.S. Ped. Bearing and two for exciter bearings. Flush panel mounting type with back connection.		
	1 - Motor driven spindle turning gear complete with 440 volt, 3 phase, 60 cycle motor but exclusive of wiring and control.		
	1 - Interlocking safety device for preventing operation of turning gear without adequate oil pressure.		
	1 - Kingsbury thrust bearing.		
	1 - Set blanket type insulating material with painted steel jacket (priming coat).		
	1 - Set metal covers for giving streamlined effect to turbine and Generator.		

DER No. 12950 PAGE No. 3

Form 34A

QUANTITY	DESCRIPTION	FACTORY C List	Discoun
	1 - Hydraulically operated load limiting device.		
	1 - Spindle lifting gear.		
5	1 - Set wrenches.		
	2 - Spindle truth indicators.		
	1 - Electric type indicating and recording tachometer for Kl...		

ORDER No. 12980 PAGE No. 4

Form 84A

QUANTITY	DESCRIPTION	FACTORY C List	Discount
	1 - Governing Oil 4-1/2" Dia. Dial		
	1 - Secondary Gov. Oil 4-1/2" " "		
	1 - Steam Flow Limit Oil 4-1/2" " "		
	1 - Gen. Gland Seal Oil 4-1/2" " "		
	2 - Gland Water 4-1/2" Dia. Dial.		
	1 - Turning Gear Oil Pump Disch. 4-1/2" Dia. Dial.		
	1 - 50,000 KVA 40,000 KW alternating current hydrogen cooled generator, 3,600 RPM 80% power factor 3 phase 60 cycle 11,000 nominal voltage, 0.8 short circuit ratio. 1/2 lbs. hydrogen gas pressure for normal operation.		
	1 - Hydrogen control equipment complete including all necessary valves, fittings, pipe and tubing.		
	6 - Armature leads brought out from winding thru housing.		
	9 - 10 ohm resistance coils embedded in armature winding for hot spot temperature measurement.		
	4 - 10 ohm resistance coils for temperature measurement of hydrogen coolers.		
	1 - Field discharge resistor.		
bris/.	1 - Two section hydrogen cooler built into the generator housing, of required size, for 85° F. Salt Water.		

DER No. 12950 PAGE No. 8

Form 34A

QUANTITY	DESCRIPTION	FACTORY List	Discoun
	1 - Hand operated field rheostat for pilot exciter.		
	DRAWINGS:		
	Six copies of all drawings to be furnished the Hawaiian Electric Co., Ltd., one copy to be returned with approval signatures affixed.		
	Six Sectional drawings and performance curves to be furnished of all pumps and blowers, one copy each to be returned with approval signatures.		
	PROPOSAL:		
	Fifteen copies of the proposal to be furnished, one copy to be returned approved. These copies to be kept up to date and revised sheets furnished to cover all changes made in the original proposal.		
	SUPERVISION OF INSTALLATION:		
	The Hawaiian Electric Co., Ltd., will require the services of a Westinghouse engineer to superintend the erection of this unit, this cost not to be included as part of the contract price for the equipment but rather on a cost per day basis, this to be covered in a separate order.		
	TERMS:		
	Sixty (60%) percent of contract price to be paid in twelve equal monthly installments, the first invoice to be issued March, 1945 with corresponding payments at 30 - day intervals thereafter until 60% of the total contract price has been paid.		
	Thirty (30%) percent of the contract price 30 days from date		

)ER No. 12850 PAGE No. 6

H.E. Form 84A

QUANTITY	DESCRIPTION	FACTORY (	
		List	Discoun
	TERMS: (Cont'd.)		
	completion of erection and starting is delayed due to no fault of the		
	Westinghouse Electric & Mfg. Co., this payment shall be due 150 days		
	from date of Bill of Lading.		
	All for the sum of $830,420.00 f.o.b. Factory.		
	(Subject to regular Agency discount of 5%)		
	Priority Rating AA2X, Form W.P.B. 2774, Serial No. 81943, dated October 3, 1944		

ISSUED BY:

APPROVED BY

CA-IR-577

Ref: Schedule PP – Large Power Primary HECO-WP-304, page 124.

Please provide the original cost and accumulated depreciation costs for all generator step-up transformers.

HECO Response:

The original cost of generator step-up transformers which could be specifically identified in our property records (Account No. 353 – Transmission Plant, Station Equipment) as of December 31, 2004 totaled $5,307,910 and included costs for Waiau 3, 5, 6, and 7, Kahe 1, 2, 3, 4, 5, 6, 1 Spare, and 3 Spare and an estimate for the Waiau 8 step-up transformer of $222,119. The estimate for the Waiau 8 step-up transformer was based on the installed cost of the Waiau 7 step-up transformer multiplied by a factor of 8.5% (percentage increase in the invoice cost between the Waiau 8 transformer placed in service in 1968 and the Waiau 7 transformer placed in service in 1966).

The original cost of Waiau 4 (placed in service 1950), Honolulu 8 (placed in service 1954), Honolulu 9 (placed in service 1957), and Waiau 3 Spare (purchased in 1947) generator step-up transformers could not be determined because these units were acquired prior to HECO maintaining property records details, and were recorded as lump sums in plant Account No. 353. Also, since the cost for Waiau 9 and 10 generator step-up transformers were included in the installation cost of the generators and were not broken out the cost of these units could also not be determined.

Accumulated depreciation is available only by plant account. HECO does not have a breakdown of accumulated depreciation by property units.

CA-IR-578

Ref: Schedule PP – Large Power Primary HECO-WP-304, page 124.

Please provide the original cost and accumulated depreciation cost for all capacitors on the HECO system (HECO owned).

HECO Response:

The original cost of substation power "capacitor banks" in substations for reactive support of the power system and to improve the overall system power factor as of December 31, 2004 is $4,747,566. Accumulated depreciation is available only by plant account. HECO does not have a breakdown of accumulated depreciation by property units.

CA-IR-579

Ref: Schedule PP – Large Power Primary HECO-WP-304, page 124.

a. Please provide the actual system VAR flow at the time of the annual peak load in 2003 and 2004.

b. Please provide the annual peak demands in 2003 and 2004 (including date and time of peak).

HECO Response:

a. The actual VAR flow on the HECO transmission system at the instantaneous peak megawatt demand for 2003 was 613 MVAR. For 2004, VAR flow on the HECO transmission system at the instantaneous peak megawatt demand was 596 MVAR. The MVAR value provided is the sum of the "gross" MVAR output from the HECO generators plus the "net" MVAR output from the IPP generators. Note, the VAR flow on the HECO subtransmission system and distribution system will be different due to VAR losses, VAR injection by line and cable charging, VAR injection by capacitors, customer VAR loads served at higher voltage levels, etc.

b. The following are annual system peak demands for 2003 and 2004:

Year	System Peak (MW, Gross Generation)	Date	Time
2003	1284	10/27/03	18:42
2004	1327	10/12/04	18:49

CA-IR-580

Ref: Schedule PP – Large Power Primary HECO-WP-304, page 124.

a. Please provide the actual MW and MVAR output of all HECO generating units at the time of the annual peak load for 2003 and 2004.

b. Please provide an hourly actual MW and MVAR output of all HECO generating units for a recent 24-hour period.

HECO Response:

a. The annual peak load for 2003 occurred on October 27, 2003. Please refer to the attached report, pages 2 through 6. The individual units are grouped by columns, identified by the headings (e.g., "Waiau 6" on page 2). Provided for each unit are columns for "GROSS MW" and "GROSS MVAR". Refer to the row under "SYSTEM PEAKS" labeled "18:42", to locate the MW and MVAR value for each HECO unit at the time of the 2003 peak. The annual peak load for 2004 occurred on October 12, 2004. Please refer to the attached report, pages 7 through 11. The individual units are grouped by columns, identified by the headings (e.g., "Waiau 6" on page 7). Provided for each unit are columns for "GROSS MW" and "GROSS MVAR". Refer to the row under "SYSTEM PEAKS" labeled "18:49", to locate the MW and MVAR value for each HECO unit at the time of the 2004 peak.

b. The report for a recent 24-hour period (4/12/05) is attached on pages 12 through 16, and provides the same information as requested in part a.

CA-IR-580
DOCKET NO. 04-0113
PAGE 2 OF 16

WAIA … POWER PLANT
FOR … 27/03

	WAIAU 3				WAIAU 4			WAIAU 5				WAIAU 6			
TIME	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY
01:00	0.0	0.0	0	0	0.0	0.0	0	0.0	0.0	0	0	0.0	0.0	0	0
02:00	0.0	0.0	0	0	0.0	0.0	0	0.0	0.0	0	0	0.0	0.0	0	0
03:00	0.0	0.0	0	0	0.0	0.0	0	0.0	0.0	0	0	0.0	0.0	0	0
04:00	0.0	0.0	0	0	0.0	0.0	0	0.0	0.0	0	0	0.0	0.0	0	0
05:00	0.0	0.0	0	0	0.0	0.0	0	0.0	0.6	1	0	0.0	0.0	0	0
06:00	0.0	0.0	0	0	4.5	2.7	5	22.1	14.1	26	22	0.0	0.0	0	0
07:00	0.0	0.0	0	0	22.0	11.6	25	25.9	18.2	32	57	2.7	4.2	5	3
08:00	0.0	0.0	0	0	26.0	12.8	29	25.7	25.3	36	57	20.2	11.4	23	20
09:00	0.0	0.0	0	0	25.7	15.7	30	25.8	30.3	40	57	29.1	29.6	42	56
10:00	0.0	0.0	0	0	25.5	31.3	40	25.4	40.2	48	57	34.7	39.2	52	56
11:00	0.0	0.0	0	0	25.3	32.5	41	25.4	40.4	48	57	42.3	39.5	58	56
12:00	0.0	0.0	0	0	30.3	33.9	45	30.9	40.9	51	57	43.4	39.6	59	56
13:00	0.0	0.0	0	0	30.9	33.8	46	34.6	40.2	53	57	44.3	39.1	59	56
14:00	0.0	0.0	0	0	25.0	33.3	42	25.5	40.5	48	57	43.0	39.3	58	56
15:00	0.0	0.0	0	0	24.6	34.0	42	25.5	42.7	50	57	34.8	42.1	55	56
16:00	0.0	0.0	0	0	24.9	33.4	42	25.5	38.9	46	57	33.0	38.2	51	56
17:00	0.0	0.0	0	0	24.4	31.2	40	25.4	37.5	45	57	30.5	36.2	47	56
18:00	0.0	0.0	0	0	27.0	31.6	42	26.2	38.2	46	57	39.0	36.3	53	56
19:00	0.0	0.0	0	0	35.1	30.1	46	39.3	40.2	56	57	37.9	39.2	55	56
20:00	0.0	0.0	0	0	24.6	29.7	39	35.6	37.8	52	57	34.1	35.3	49	56
21:00	0.0	0.0	0	0	24.6	29.6	38	25.5	37.0	45	57	26.8	35.0	44	56
22:00	0.0	0.0	0	0	0.0	0.0	0	25.2	38.2	46	25	25.4	36.2	44	56
23:00	0.0	0.0	0	0	0.0	0.0	0	0.0	0.0	0	0	0.0	0.0	0	0
24:00	0.0	0.0	0	0	0.0	0.0	0	0.0	0.0	0	0	0.0	0.0	0	0
SYSTEM PEAKS															
13:22	0.0	0.0	0	0	30.3	33.3	45	34.3	40.7	53	57	44.6	39.3	59	56
18:42	0.0	0.0	0	0	35.1	30.1	46	39.3	41.0	57	57	41.1	40.0	57	56
MINLOAD															
03:22	0.0	0.0	0I	0	0.0	0.0	0I	0.0	0.0	0	0	0.0	0.0	0I	0

WAIAU POWER PLANT
FOR 10/27/03

TIME	WAIAU 7 GROSS MW	WAIAU 7 GROSS MVR	WAIAU 7 MVA	WAIAU 7 CAPY	WAIAU 8 GROSS MW	WAIAU 8 GROSS MVR	WAIAU 8 MVA	WAIAU 8 CAPY	WAIAU 9 GROSS MW	WAIAU 9 GROSS MVR	WAIAU 9 MVA	WAIAU 9 CAPY	WAIAU 10 GROSS MW	WAIAU 10 GROSS MVR	WAIAU 10 MVA	WAIAU 10 CAPY	WAIAU TOTALS GROSS MW	WAIAU TOTALS GROSS MVR	WAIAU TOTALS CAPY
01:00	0.0	-0.1	0	0	34.9	13.9	38	80	0.0	0.0	0	0	0.0	0.0	0	0	34.9	13.8	80
02:00	0.0	-0.1	0	0	35.5	12.7	38	80	0.0	0.0	0	0	0.0	0.0	0	0	35.5	12.6	80
03:00	0.0	0.0	0	0	35.3	11.3	37	80	0.0	0.0	0	0	0.0	0.0	0	0	35.3	11.3	80
04:00	0.0	0.0	0	0	37.0	12.2	39	80	0.0	0.0	0	0	0.0	0.0	0	0	37.0	12.2	80
05:00	0.0	0.0	0	0	42.8	14.8	45	90	0.0	0.0	0	0	0.0	0.0	0	0	42.8	15.4	90
06:00	0.0	-0.1	0	0	53.7	17.8	57	90	0.0	0.0	0	0	0.0	0.0	0	0	80.3	34.5	117
07:00	0.0	-0.1	0	0	58.7	11.4	60	90	13.4	3.1	14	53	0.0	0.0	0	0	122.6	48.5	225
08:00	0.0	-0.1	0	0	61.1	21.7	65	90	13.6	8.6	16	53	0.0	0.0	0	0	146.5	79.8	269
09:00	0.0	-0.1	0	0	64.7	32.5	72	90	13.3	14.4	20	53	0.0	0.0	0	0	158.6	122.6	305
10:00	0.0	-0.1	0	0	68.8	27.4	74	90	13.4	7.9	16	53	14.1	9.6	17	50	182.0	155.6	355
11:00	0.0	-0.1	0	0	76.3	40.8	87	90	13.5	17.7	22	53	16.5	19.0	25	50	199.4	189.9	355
12:00	0.0	0.0	0	0	77.8	40.0	87	90	15.0	17.8	23	53	17.4	19.1	26	50	214.8	191.3	355
13:00	0.0	-0.1	0	0	77.6	39.1	87	90	14.5	17.5	23	53	18.0	18.6	26	50	219.8	188.1	355
14:00	0.0	0.0	0	0	78.8	39.1	88	90	14.7	17.4	23	53	17.2	18.6	25	50	204.2	188.1	355
15:00	0.0	-0.1	0	0	71.3	43.4	83	90	14.4	19.8	24	53	14.2	21.0	25	50	184.7	203.0	355
16:00	0.0	-0.1	0	0	69.5	36.9	79	90	14.5	16.5	22	53	14.5	17.7	23	50	182.0	181.4	355
17:00	0.0	-0.1	0	0	67.3	35.2	76	90	14.4	15.8	21	53	14.4	16.8	22	50	176.4	172.6	355
18:00	0.0	0.0	0	0	75.6	36.9	84	90	15.5	16.6	23	53	16.3	17.7	24	50	199.6	177.2	355
19:00	0.0	0.0	0	0	72.1	38.0	82	90	14.5	17.2	22	53	14.2	18.3	23	50	213.1	182.9	355
20:00	0.0	0.0	0	0	68.2	34.6	76	90	14.3	15.6	21	53	0.0	0.0	0	0	176.8	152.9	305
21:00	0.0	-0.1	0	0	63.7	34.6	72	90	0.0	0.0	0	0	0.0	0.0	0	0	140.5	136.1	252
22:00	0.0	0.0	0	0	60.9	35.3	70	90	0.0	0.0	0	0	0.0	0.0	0	0	111.5	109.6	171
23:00	0.0	-0.1	0	0	58.4	36.7	69	90	0.0	0.0	0	0	0.0	0.0	0	0	58.4	36.7	90
24:00	0.0	0.0	0	0	34.7	35.4	50	90	0.0	0.0	0	0	0.0	0.0	0	0	34.7	35.4	90
SYSTEM PEAKS																			
13:22	0.0	-0.1	0	0	78.6	39.3	88	90	14.4	17.6	23	53	18.0	18.7	26	50	220.2	188.8	355
18:42	0.0	0.0	0	0	76.4	39.4	86	90	14.8	17.9	23	53	16.4	19.1	25	50	223.1	187.3	355
MINLOAD																			
03:22	0.0	0.0	0I	0	35.7	11.3	37I	80	0.0	0.0	0	0	0.0	0.0	0	0	35.7	11.3	0

KAHE POWER PLANT
FOR 10/27/03

	KAHE 1				KAHE 2				KAHE 3				KAHE 4			
TIME	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY
01:00	33.0	11.5	35	80	32.9	11.5	35	85	46.9	12.7	49	85	31.5	8.6	33	89
02:00	32.9	12.2	35	80	32.8	12.0	35	85	32.8	13.9	36	85	31.7	8.8	33	89
03:00	33.9	11.5	36	86	32.9	11.2	35	85	32.7	13.2	35	85	30.8	7.6	32	80
04:00	32.7	11.9	35	86	33.0	11.5	35	85	32.8	13.6	35	85	31.1	8.0	32	80
05:00	33.0	15.8	37	86	32.8	14.6	36	85	47.1	14.2	49	85	39.1	10.7	41	89
06:00	43.4	19.5	48	86	50.0	18.5	53	85	62.5	26.0	68	85	63.0	27.9	69	89
07:00	61.7	35.3	71	86	59.2	34.7	69	85	66.9	25.8	72	85	72.8	25.5	77	89
08:00	68.8	39.5	79	86	63.0	39.1	74	85	68.8	35.3	77	85	77.0	34.2	84	89
09:00	84.1	40.8	94	86	73.5	41.5	84	85	74.6	36.9	83	85	86.5	38.0	95	89
10:00	84.1	36.9	92	86	83.7	37.6	92	85	80.9	32.5	87	85	89.3	31.9	95	89
11:00	84.1	34.5	91	86	84.4	35.3	91	85	85.1	34.7	92	85	89.2	36.1	96	89
12:00	84.1	33.4	91	86	84.0	34.8	91	85	85.0	33.5	91	85	88.8	35.7	96	89
13:00	84.4	35.3	92	86	84.3	35.1	91	85	85.1	32.8	91	85	89.3	34.0	96	89
14:00	84.4	34.9	91	86	84.0	38.6	92	85	85.1	32.7	91	85	89.4	33.8	96	89
15:00	84.3	37.1	92	86	83.6	40.8	93	85	82.1	37.2	90	85	89.2	38.4	97	89
16:00	84.4	35.9	92	86	81.1	36.8	89	85	79.8	37.5	88	85	88.9	36.6	96	89
17:00	84.6	35.1	92	86	76.4	35.8	84	85	77.0	37.5	86	85	88.7	34.6	95	89
18:00	85.5	35.9	93	86	84.0	36.4	92	85	82.0	36.3	90	85	85.2	35.4	92	89
19:00	85.7	36.8	93	86	85.1	37.3	93	85	82.0	37.4	90	85	85.4	36.4	93	89
20:00	85.8	34.5	92	86	81.7	35.3	89	85	81.3	34.8	88	85	83.0	33.5	90	89
21:00	78.3	33.4	85	86	69.2	34.7	77	85	72.5	37.1	81	85	83.8	33.2	90	89
22:00	73.2	33.0	80	86	64.6	34.3	73	85	71.5	31.8	78	85	59.6	32.7	68	89
23:00	57.6	29.4	65	86	57.8	29.4	65	85	67.3	33.3	75	85	30.1	34.9	46	80
24:00	33.4	23.7	41	86	42.2	24.3	49	85	58.1	18.6	61	85	30.9	17.8	36	80
SYSTEM PEAKS																
													89.2	34.2	96	89
13:22	84.6	35.4	92	86	84.2	35.3	91	85	85.1	32.9	91	85	85.4	37.4	93	89
18:42	85.8	37.7	94	86	85.0	38.2	93	85	82.2	37.6	90	85				
MINLOAD																
03:22	33.2	11.4	35I	86	32.9	11.1	35I	85	32.7	13.2	35I	85	30.7	7.5	32	80

KAHE POWER PLANT
FOR 10/27/03

	KAHE 5				KAHE 6				KAHE TOTALS		
TIME	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	CAPY
01:00	73.9	29.1	79	142	75.3	29.8	81	75	293.5	103.3	556
02:00	55.2	14.7	57	142	75.8	14.4	77	76	261.1	76.1	557
03:00	54.9	13.5	57	142	75.9	13.6	77	76	261.1	70.6	554
04:00	55.8	13.9	58	142	76.3	13.8	78	76	261.7	72.8	554
05:00	75.7	15.6	77	142	76.3	15.2	78	76	304.0	86.1	563
06:00	105.9	19.4	108	142	78.5	18.6	81	79	403.4	129.9	566
07:00	118.2	21.5	120	142	80.1	16.3	82	80	458.9	159.1	567
08:00	122.0	25.8	125	142	96.9	19.7	99	97	496.5	193.6	584
09:00	134.5	31.4	138	142	96.5	24.6	100	97	549.7	213.2	584
10:00	136.1	34.4	140	142	96.4	35.7	103	96	570.5	209.0	583
11:00	136.5	35.3	141	142	96.2	36.5	103	96	575.5	212.3	583
12:00	135.8	44.2	143	142	95.7	43.2	105	96	573.4	224.8	583
13:00	136.5	43.7	143	142	96.5	42.9	106	97	576.1	223.9	584
14:00	138.1	43.7	145	142	106.3	42.5	114	142	587.3	226.2	629
15:00	138.2	46.1	146	142	133.8	44.0	141	142	611.1	243.6	629
16:00	138.7	44.9	146	142	128.0	42.9	135	142	600.9	234.6	629
17:00	138.3	43.9	145	142	121.4	42.1	128	142	586.4	229.0	629
18:00	140.3	45.1	147	142	122.6	43.2	130	142	599.5	232.4	629
19:00	140.3	46.1	148	142	131.5	43.7	139	142	610.1	237.6	629
20:00	137.9	43.3	145	142	131.9	41.1	138	142	601.6	222.5	629
21:00	131.1	42.2	138	142	131.6	40.3	138	142	566.6	221.0	629
22:00	123.5	41.7	130	142	128.6	40.2	135	142	521.1	213.8	629
23:00	117.5	41.9	125	142	118.7	41.0	126	142	448.9	209.9	620
24:00	99.6	36.8	106	142	103.5	35.0	109	142	367.7	156.2	620
SYSTEM PEAKS											
13:22	137.0	43.9	144	142	96.9	43.0	106	97	577.0	224.7	584
18:42	140.6	47.0	148	142	132.2	44.7	139	142	611.2	242.6	629
MINLOAD											
03:22	55.2	13.3	57I	142	76.0	13.4	77I	76	260.7	69.9	554

HONOLULU POWER PLANT
FOR 10/27/03

	HONOLULU 8				HONOLULU 9				HONOLULU TOTALS		
TIME	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAP	GROSS MW	GROSS MVR	CAPY
01:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0
02:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0
03:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0
04:00	0.0	0.0	0	0	0.0	0.1	0	0	0.0	0.1	0
05:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0
06:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0
07:00	0.0	0.0	0	0	17.3	22.8	29	17	17.3	22.8	17
08:00	0.0	0.0	0	0	26.5	25.3	37	57	26.5	25.3	57
09:00	0.0	0.0	0	0	26.6	28.6	39	57	26.6	28.6	57
10:00	0.0	0.0	0	0	26.8	28.2	39	57	26.8	28.2	57
11:00	0.0	0.0	0	0	28.7	25.0	38	57	28.7	25.0	57
12:00	0.0	0.0	0	0	28.7	24.6	38	57	28.7	24.6	57
13:00	0.0	0.0	0	0	29.5	23.8	38	57	29.5	23.8	57
14:00	0.0	0.0	0	0	28.8	23.6	37	57	28.8	23.6	57
15:00	0.0	0.0	0	0	26.8	26.6	38	57	26.8	26.6	57
16:00	0.0	0.0	0	0	26.8	22.3	35	57	26.8	22.3	57
17:00	0.0	0.0	0	0	26.7	20.0	33	57	26.7	20.0	57
18:00	0.0	0.0	0	0	27.0	21.4	34	57	27.0	21.4	57
19:00	0.0	0.0	0	0	40.7	20.9	46	57	40.7	20.9	57
20:00	0.0	0.0	0	0	25.0	20.4	32	57	25.0	20.4	57
21:00	0.0	0.0	0	0	25.0	19.1	31	25	25.0	19.1	25
22:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0
23:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0
24:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0
SYSTEM PEAKS											
13:22	0.0	0.0	0	0	30.4	24.4	39	57	30.4	24.4	57
18:42	0.0	0.0	0	0	41.1	20.8	46	57	41.1	20.8	57
MINLOAD											
03:22	0.0	0.0	0	0	0.0	0.1	0	0	0.0	0.1	0

WAIAU POWER PLANT
FOR 10/12/04

	WAIAU 3				WAIAU 4				WAIAU 5				WAIAU 6			
TIME	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY
01:00	0.0	0.1	0	0	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0
02:00	0.0	0.1	0	0	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0
03:00	0.0	0.1	0	0	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0
04:00	0.0	0.1	0	0	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0
05:00	0.0	0.1	0	0	0.0	0.0	0	0	0.0	0.0	0	0	10.1	6.0	12	10
06:00	0.0	0.1	0	0	14.9	9.2	17	15	0.0	0.0	0	0	26.5	8.3	28	56
07:00	0.0	0.1	0	0	24.5	8.4	26	49	9.2	3.4	10	9	26.8	7.4	28	56
08:00	0.0	0.1	0	0	24.7	8.4	26	49	25.6	13.6	29	57	32.2	12.4	35	56
09:00	11.4	5.0	12	11	25.1	15.1	29	49	25.3	34.3	43	57	38.8	35.9	53	56
10:00	29.7	16.0	34	30	24.7	34.8	43	49	25.5	32.3	41	57	33.1	32.3	46	56
11:00	42.4	9.1	43	42	25.2	36.0	44	49	25.6	33.1	42	57	29.6	32.1	44	56
12:00	42.7	8.6	44	43	24.6	36.3	44	49	25.7	32.6	42	57	32.5	31.5	45	56
13:00	43.0	8.2	44	43	24.7	36.2	44	49	34.8	33.9	49	57	35.5	32.9	48	56
14:00	43.1	15.8	46	43	24.9	32.3	41	49	34.7	34.0	49	57	32.4	33.1	46	56
15:00	43.2	15.7	46	43	25.0	32.2	41	49	34.8	33.5	48	57	31.2	32.7	45	56
16:00	43.4	15.5	46	46	27.3	31.1	41	49	35.8	32.7	48	57	46.2	31.3	56	56
17:00	43.1	15.5	46	46	25.0	29.6	39	49	35.6	30.3	47	57	38.8	29.1	49	56
18:00	43.4	15.2	46	46	25.4	29.8	39	49	25.9	28.9	39	57	32.3	27.6	43	56
19:00	43.3	15.6	46	46	24.8	31.7	40	49	41.9	30.8	52	57	46.6	29.5	55	56
20:00	43.6	15.4	46	46	24.5	30.1	39	49	25.1	29.1	38	57	32.6	26.4	42	56
21:00	33.7	19.8	39	46	24.9	20.5	32	49	25.5	28.1	38	57	37.7	25.9	46	56
22:00	33.6	20.5	39	46	11.3	7.8	14	11	25.7	27.9	38	57	27.4	27.3	39	56
23:00	0.0	0.1	0	0	0.0	0.0	0	0	25.4	29.1	39	57	24.4	28.6	38	56
24:00	0.0	0.0	0	0	0.0	0.0	0	0	25.0	30.1	39	57	0.0	0.0	0	0
SYSTEM PEAKS																
14:51	43.1	15.8	46	43	24.9	32.1	41	49	34.8	33.6	48	57	33.6	32.5	47	56
18:49	43.4	15.8	46	46	31.8	29.5	43	49	39.3	31.1	50	57	44.6	29.5	54	56
MINLOAD																
03:18	0.0	0.1	0I	0	0.0	0.0	0I	0	0.0	0.0	0	0	0.0	0.0	0I	0

WAIAU POWER PLANT
FOR 10/12/04

	WAIAU 7				WAIAU 8				WAIAU 9				WAIAU 10				WAIAU TOTALS		
TIME	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	CAPY
01:00	26.0	23.8	35	80	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0	26.0	23.9	80
02:00	26.8	23.2	35	80	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0	26.8	23.2	80
03:00	26.8	27.9	39	80	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0	26.8	27.9	80
04:00	27.0	29.6	40	80	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0	27.0	29.6	80
05:00	39.8	28.3	49	87	0.0	-0.1	0	0	0.0	0.0	0	0	0.0	0.0	0	0	49.9	34.3	97
06:00	51.3	24.2	57	87	0.0	-0.1	0	0	0.0	0.0	0	0	0.0	0.0	0	0	92.6	41.7	158
07:00	62.4	21.2	66	87	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0	122.9	40.5	201
08:00	78.3	26.1	83	87	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0	160.8	60.6	249
09:00	85.1	30.8	90	87	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0	185.7	121.0	260
10:00	79.1	28.2	84	87	0.0	0.0	0	0	3.0	0.2	3	3	14.9	2.8	15	50	210.2	146.6	332
11:00	70.4	29.0	76	87	0.0	0.0	0	0	0.0	0.0	0	0	14.4	3.2	15	50	207.6	142.5	341
12:00	79.1	30.0	85	87	0.0	-0.1	0	0	0.0	0.0	0	0	15.6	28.6	33	50	220.3	167.6	342
13:00	83.7	32.1	90	87	0.0	0.0	0	0	0.0	0.0	0	0	15.0	29.2	33	50	236.7	172.6	342
14:00	84.1	31.8	90	87	0.0	0.0	0	0	0.0	0.0	0	0	14.9	29.0	33	50	234.1	176.0	342
15:00	70.0	31.2	77	87	0.0	0.0	0	0	0.0	0.0	0	0	19.5	28.8	35	50	223.7	174.0	342
16:00	36.8	28.5	47	87	0.0	0.0	0	0	0.0	0.0	0	0	20.8	28.2	35	50	210.2	167.3	345
17:00	52.0	25.5	58	87	0.0	0.0	0	0	0.0	0.0	0	0	19.7	26.6	33	50	214.2	156.7	345
18:00	78.3	24.6	82	87	0.0	-0.1	0	0	0.0	0.0	0	0	15.0	26.1	30	50	220.3	152.0	345
19:00	82.6	27.5	87	87	0.0	-0.1	0	0	0.0	0.0	0	0	25.2	26.7	37	50	264.3	161.7	345
20:00	78.9	24.7	83	87	0.0	-0.1	0	0	0.0	0.0	0	0	15.2	25.5	30	50	219.9	151.1	345
21:00	85.1	24.3	88	87	0.0	-0.1	0	0	0.0	0.0	0	0	15.1	8.6	17	50	222.0	127.1	345
22:00	65.7	23.4	70	87	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0	163.8	106.9	257
23:00	54.7	24.8	60	87	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0	104.6	82.7	200
24:00	48.8	26.3	55	87	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0	73.8	56.3	144
SYSTEM PEAKS																			
14:51	69.8	31.2	77	87	0.0	-0.1	0	0	0.0	0.0	0	0	19.8	28.8	35	50	226.0	174.1	342
18:49	82.1	27.9	87	87	0.0	-0.1	0	0	0.0	0.0	0	0	25.0	27.0	37	50	266.3	160.7	345
MINLOAD																			
03:18	26.5	28.4	39I	80	0.0	0.0	0I	0	0.0	0.0	0	0	0.0	0.0	0	0	26.5	28.4	80

KAHE POWER PLANT
FOR 10/12/04

TIME	KAHE 1 GROSS MW	KAHE 1 GROSS MVR	KAHE 1 MVA	KAHE 1 CAPY	KAHE 2 GROSS MW	KAHE 2 GROSS MVR	KAHE 2 MVA	KAHE 2 CAPY	KAHE 3 GROSS MW	KAHE 3 GROSS MVR	KAHE 3 MVA	KAHE 3 CAPY	KAHE 4 GROSS MW	KAHE 4 GROSS MVR	KAHE 4 MVA	KAHE 4 CAPY
01:00	47.8	20.8	52	86	50.7	22.6	56	85	63.4	25.3	68	83	67.6	20.3	71	89
02:00	36.1	20.4	41	86	41.1	22.4	47	85	57.9	18.6	61	83	56.7	13.5	58	89
03:00	36.3	25.5	44	86	39.9	24.9	47	85	51.6	16.1	54	83	45.4	15.2	48	89
04:00	35.3	23.2	42	86	39.2	16.6	43	85	52.7	17.6	56	83	47.5	17.5	51	89
05:00	39.4	22.5	45	86	46.7	15.5	49	85	60.5	19.0	63	83	62.1	17.4	65	89
06:00	58.3	19.6	61	86	57.3	15.7	59	85	65.9	12.9	67	83	71.9	17.6	74	89
07:00	75.2	28.6	80	86	66.2	27.5	72	85	70.8	26.4	76	83	79.6	26.6	84	89
08:00	83.4	33.2	90	86	79.3	33.8	86	85	77.6	29.5	83	83	86.7	29.7	92	89
09:00	80.8	36.3	89	86	75.8	37.0	84	85	77.5	35.1	85	83	87.0	33.0	93	89
10:00	83.1	28.0	88	86	81.2	28.2	86	85	77.3	33.0	84	83	86.8	32.1	93	89
11:00	83.0	32.9	89	86	74.4	32.3	81	85	77.3	34.5	85	83	86.5	32.6	92	89
12:00	82.7	32.9	89	86	80.6	32.6	87	85	77.3	33.8	84	83	86.6	32.6	93	89
13:00	83.1	33.9	90	86	81.4	33.8	88	85	77.3	35.6	85	83	87.1	33.7	93	89
14:00	83.1	33.3	90	86	79.7	33.0	86	85	77.2	34.7	85	83	88.1	33.2	94	89
15:00	83.0	35.1	90	86	77.5	35.2	85	85	77.3	33.8	84	83	87.0	32.6	93	89
16:00	83.4	34.2	90	86	82.1	34.2	89	85	76.1	33.2	83	83	85.0	31.4	91	89
17:00	83.5	32.0	89	86	72.1	32.8	79	85	75.9	31.2	82	83	85.4	29.3	90	89
18:00	82.8	31.2	88	86	79.6	31.2	86	85	76.0	30.5	82	83	87.7	28.5	92	89
19:00	84.2	32.6	90	86	82.8	32.5	89	85	75.9	33.1	83	83	87.0	29.9	92	89
20:00	83.6	29.1	89	86	80.6	29.7	86	85	76.1	30.2	82	83	88.2	28.2	93	89
21:00	83.4	28.5	88	86	82.1	29.2	87	85	75.9	28.5	81	83	88.8	27.5	93	89
22:00	78.9	27.8	84	86	69.5	28.7	75	85	72.9	29.7	79	83	83.4	26.5	88	89
23:00	61.9	28.7	68	86	58.0	29.8	65	85	68.0	32.9	76	83	73.2	27.0	78	89
24:00	53.6	27.9	60	86	55.2	21.4	59	85	66.1	26.8	71	83	69.9	21.9	73	89
SYSTEM PEAKS																
													87.0	32.7	93	89
14:51	82.8	35.2	90	86	79.3	35.2	87	85	77.3	34.2	84	83	85.5	30.1	91	89
18:49	84.1	32.9	90	86	83.1	32.7	89	85	76.0	33.4	83	83				
MINLOAD																
03:18	35.7	22.5	42I	86	39.3	15.9	42I	85	50.4	17.9	53I	83	43.5	16.6	47	89

KAHE POWER PLANT
FOR 10/12/04

	KAHE 5				KAHE 6				KAHE TOTALS		
TIME	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	CAPY
01:00	90.8	54.6	106	142	60.4	16.0	62	142	380.6	159.5	627
02:00	90.8	54.7	106	142	60.6	15.9	63	142	343.2	145.6	627
03:00	90.7	60.3	109	142	60.5	21.2	64	142	324.4	163.2	627
04:00	91.6	62.2	111	142	61.5	23.3	66	142	327.8	160.4	627
05:00	91.3	61.4	110	142	61.0	22.4	65	142	361.0	158.2	627
06:00	91.3	58.0	108	142	87.7	31.0	93	142	432.4	154.7	627
07:00	92.8	50.8	106	142	98.3	35.7	105	142	483.0	195.5	627
08:00	91.7	53.1	106	142	96.8	43.2	106	142	515.6	222.4	627
09:00	110.3	57.0	124	142	117.8	46.0	126	142	549.1	244.4	627
10:00	115.3	56.1	128	142	124.8	44.8	133	142	568.5	222.1	627
11:00	131.7	57.3	144	142	138.4	45.1	146	142	591.3	234.7	627
12:00	134.5	57.3	146	142	137.7	44.9	145	142	599.4	234.1	627
13:00	133.4	58.4	146	142	136.8	46.1	144	142	599.2	241.6	627
14:00	133.5	57.7	145	142	137.4	54.7	148	142	599.1	246.6	627
15:00	140.0	57.5	151	142	136.9	54.1	147	142	601.6	248.2	627
16:00	133.3	56.4	145	142	137.1	53.2	147	142	596.9	242.7	627
17:00	133.4	54.2	144	142	137.0	51.2	146	142	587.2	230.6	627
18:00	134.0	53.4	144	142	137.8	50.4	147	142	597.9	225.2	627
19:00	132.7	54.9	144	142	137.2	51.9	147	142	599.8	234.9	627
20:00	133.9	53.0	144	142	137.9	49.9	147	142	600.3	220.1	627
21:00	134.6	52.4	144	142	138.6	49.4	147	142	603.5	215.6	627
22:00	133.8	51.9	144	142	137.6	48.9	146	142	576.2	213.5	627
23:00	133.4	53.0	144	142	137.0	29.3	140	142	531.5	200.6	627
24:00	132.9	54.6	144	142	101.9	31.7	107	142	479.5	184.4	627
SYSTEM PEAKS											
14:51	138.2	57.6	150	142	136.9	54.3	147	142	601.4	249.1	627
18:49	132.5	55.3	144	142	136.6	52.2	146	142	597.8	236.6	627
MINLOAD											
03:18	90.6	61.5	110I	142	60.3	22.5	64I	142	319.8	156.9	627

HONOLULU POWER PLANT
FOR 10/12/04

TIME	HONOLULU 8 GROSS MW	HONOLULU 8 GROSS MVR	HONOLULU 8 MVA	HONOLULU 8 CAPY	HONOLULU 9 GROSS MW	HONOLULU 9 GROSS MVR	HONOLULU 9 MVA	HONOLULU 9 CAPY	HONOLU GROSS MW	HONOLU GRO MV	TOTALS CAPY
01:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0	0
02:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0	0
03:00	0.0	0.1	0	0	0.0	0.0	0	0	0.0	0	0
04:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0	0
05:00	0.0	0.1	0	0	0.0	0.0	0	0	0.0	0	0
06:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0	0
07:00	0.0	0.0	0	0	25.7	17.0	31	57	25.7	16	57
08:00	0.0	0.0	0	0	25.4	28.8	38	57	25.4	28	57
09:00	19.3	15.4	25	19	26.7	16.4	31	57	46.0	31	76
10:00	25.6	18.6	32	56	25.9	19.8	33	57	51.5	38	113
11:00	25.7	25.2	36	56	26.3	27.1	38	57	52.0	52	113
12:00	25.8	24.6	36	56	26.1	27.0	38	57	51.8	51	113
13:00	25.9	24.5	36	56	25.8	27.3	38	57	51.7	51	113
14:00	25.9	24.3	36	56	25.9	27.5	38	57	51.8	51	113
15:00	31.3	23.2	39	56	31.1	25.5	40	57	62.4	48	113
16:00	38.3	22.2	44	56	34.4	24.1	42	57	72.7	46	113
17:00	30.4	20.7	37	56	31.6	19.4	37	57	62.0	40	113
18:00	26.3	20.1	33	56	26.0	17.4	31	57	52.3	37	113
19:00	26.9	21.5	34	56	34.1	19.3	39	57	61.0	40	113
20:00	26.6	20.8	34	56	26.5	18.8	32	57	53.1	39	113
21:00	26.8	21.1	34	56	27.4	19.9	34	57	54.2	41	113
22:00	26.3	20.8	33	56	26.4	18.0	32	57	52.7	38	113
23:00	0.0	0.0	0	0	25.9	24.1	35	26	25.9	24	26
24:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0	0
SYSTEM PEAKS											
14:51	31.0	23.4	39	56	31.1	25.7	40	57	62.1	49	113
18:49	35.5	21.5	42	56	33.5	20.4	39	57	69.0	41	113
MINLOAD											
03:18	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0	0

WAIAU POWER PLANT
FOR 04/12/05

	WAIAU 3				WAIAU 4				WAIAU 5				WAIAU 6			
TIME	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY
01:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0
02:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.1	0	0	0.0	0.0	0	0
03:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.1	0	0	0.0	0.0	0	0
04:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.1	0	0	0.0	0.0	0	0
05:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.1	0	0	0.0	0.0	0	0
06:00	0.0	0.0	0	0	0.0	0.0	0	0	12.5	7.0	14	12	0.0	0.0	0	0
07:00	0.0	0.0	0	0	14.3	5.7	15	14	23.9	7.2	25	57	0.0	0.0	0	0
08:00	0.0	0.0	0	0	25.5	9.7	27	49	25.1	11.9	28	57	0.0	0.0	0	0
09:00	0.0	0.0	0	0	25.3	12.5	28	49	25.4	13.8	29	57	0.0	0.0	0	0
10:00	0.0	0.0	0	0	25.6	12.8	29	49	25.6	15.7	30	57	0.0	0.0	0	0
11:00	0.0	0.0	0	0	25.6	13.3	29	49	25.8	15.7	30	57	0.0	0.0	0	0
12:00	0.0	0.0	0	0	25.6	13.1	29	49	25.7	16.0	30	57	0.0	0.0	0	0
13:00	0.0	0.0	0	0	25.5	14.0	29	49	25.8	16.0	30	57	0.0	0.0	0	0
14:00	0.0	0.0	0	0	25.3	13.8	29	49	25.5	15.5	30	57	0.0	0.0	0	0
15:00	0.0	0.0	0	0	25.5	13.1	29	49	26.8	14.7	31	57	0.0	0.0	0	0
16:00	0.0	0.0	0	0	25.5	13.5	29	49	25.5	16.9	31	57	0.0	0.0	0	0
17:00	0.0	0.0	0	0	25.4	13.4	29	49	25.6	15.2	30	57	0.0	0.0	0	0
18:00	0.0	0.0	0	0	25.5	11.0	28	49	25.5	13.3	29	57	0.0	0.0	0	0
19:00	0.0	0.0	0	0	25.9	12.2	29	49	25.5	17.4	31	57	0.0	0.0	0	0
20:00	0.0	0.0	0	0	29.6	14.7	33	49	25.6	16.2	30	57	0.0	0.0	0	0
21:00	0.0	0.0	0	0	25.3	12.8	28	49	25.6	15.6	30	57	0.0	0.0	0	0
22:00	0.0	0.0	0	0	0.0	0.0	0	0	25.3	15.9	30	57	0.0	0.0	0	0
23:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0
24:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0	0
SYSTEM PEAKS																
12:31	0.0	0.0	0	0	25.4	14.1	29	49	25.7	16.5	31	57	0.0	0.0	0	0
19:24	0.0	0.0	0	0	27.9	16.2	32	49	25.6	18.2	31	57	0.0	0.0	0	0
MINLOAD 03:12	0.0	0.0	0I	0	0.0	0.0	0	0	0.0	0.1	0	0	0.0	0.0	0I	0

WAIAU POWER PLANT
FOR 04/12/05

	WAIAU 7				WAIAU 8				WAIAU 9				WAIAU 10				WAIAU TOTALS		
TIME	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	CAPY
01:00	0.0	-0.1	0	0	34.2	30.2	46	90	0.0	0.0	0	0	0.0	0.0	0	0	34.2	30.0	90
02:00	0.0	-0.1	0	0	34.0	26.5	43	90	0.0	0.0	0	0	0.0	0.0	0	0	34.0	26.5	90
03:00	0.0	-0.1	0	0	35.5	24.4	43	90	0.0	0.0	0	0	0.0	0.0	0	0	35.5	24.4	90
04:00	0.0	-0.1	0	0	35.1	24.1	43	90	0.0	0.0	0	0	0.0	0.0	0	0	35.1	24.1	90
05:00	0.0	0.0	0	0	36.0	25.4	44	90	0.0	0.0	0	0	0.0	0.0	0	0	36.0	25.4	90
06:00	0.0	-0.1	0	0	58.3	29.0	65	90	0.0	0.0	0	0	0.0	0.0	0	0	70.8	35.9	102
07:00	0.0	0.0	0	0	60.2	23.0	64	90	0.0	0.0	0	0	10.1	4.6	11	10	108.5	40.5	171
08:00	0.0	-0.1	0	0	62.4	30.2	69	90	0.0	0.0	0	0	15.2	8.3	17	50	128.3	60.0	246
09:00	0.0	0.0	0	0	69.1	33.0	77	90	0.0	0.0	0	0	14.7	9.6	18	50	134.5	68.8	246
10:00	0.0	-0.1	0	0	66.5	36.0	76	90	0.0	0.0	0	0	0.0	0.0	0	0	117.7	64.4	196
11:00	0.0	0.0	0	0	66.7	36.0	76	90	0.0	0.0	0	0	0.0	0.0	0	0	118.1	65.0	196
12:00	0.0	-0.1	0	0	67.3	36.9	77	90	0.0	0.0	0	0	0.0	0.0	0	0	118.6	66.0	196
13:00	0.0	-0.1	0	0	67.7	36.9	77	90	0.0	0.0	0	0	0.0	0.0	0	0	119.0	66.8	196
14:00	0.0	-0.1	0	0	68.0	36.2	77	90	0.0	0.0	0	0	0.0	0.0	0	0	118.8	65.4	196
15:00	0.0	-0.1	0	0	67.1	34.9	76	90	0.0	0.0	0	0	0.0	0.0	0	0	119.5	62.6	196
16:00	0.0	-0.1	0	0	66.9	38.0	77	90	0.0	0.0	0	0	0.0	0.0	0	0	118.0	68.3	196
17:00	0.0	0.0	0	0	66.3	37.3	76	90	0.0	0.0	0	0	0.0	0.0	0	0	117.3	65.9	196
18:00	0.0	0.0	0	0	65.4	34.5	74	90	0.0	0.0	0	0	0.0	0.0	0	0	116.5	58.8	196
19:00	0.0	0.0	0	0	67.7	40.8	79	90	0.0	0.0	0	0	0.0	0.0	0	0	119.2	70.4	196
20:00	0.0	0.0	0	0	66.8	38.8	77	90	0.0	0.0	0	0	0.0	0.0	0	0	122.0	69.7	196
21:00	0.0	0.0	0	0	64.6	37.8	75	90	0.0	0.0	0	0	0.0	0.0	0	0	115.5	66.2	196
22:00	0.0	-0.1	0	0	59.5	38.2	71	90	0.0	0.0	0	0	0.0	0.0	0	0	84.8	53.9	147
23:00	0.0	-0.1	0	0	54.8	36.6	66	90	0.0	0.0	0	0	0.0	0.0	0	0	54.8	36.4	90
24:00	0.0	0.0	0	0	40.9	33.3	53	90	0.0	0.0	0	0	0.0	0.0	0	0	40.9	33.3	90
SYSTEM PEAKS																			
12:31	0.0	-0.1	0	0	67.7	37.4	77	90	0.0	0.0	0	0	0.0	0.0	0	0	118.9	67.9	196
19:24	0.0	0.0	0	0	69.4	41.9	81	90	0.0	0.0	0	0	0.0	0.0	0	0	122.9	76.2	196
MINLOAD 03:12	0.0	-0.1	0I	0	35.7	23.6	43I	90	0.0	0.0	0	0	0.0	0.0	0	0	35.7	23.5	0

KAHE POWER PLANT
FOR 04/12/05

	KAHE 1				KAHE 2				KAHE 3				KAHE 4			
TIME	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY
01:00	35.7	10.1	37	85	35.1	11.0	37	86	33.5	18.6	38	84	35.6	12.8	38	80
02:00	35.3	9.5	37	85	35.2	9.3	36	86	33.1	13.5	36	84	34.8	10.5	36	80
03:00	34.9	9.6	36	85	35.3	9.7	37	86	33.0	13.4	36	84	36.0	9.0	37	80
04:00	34.6	9.9	36	85	35.0	10.9	37	86	33.0	13.3	36	84	36.3	8.7	37	89
05:00	34.7	11.0	36	85	35.0	12.3	37	86	33.0	13.1	35	84	36.2	9.8	37	89
06:00	50.6	13.4	52	85	35.8	14.0	38	86	53.0	15.2	55	84	69.6	18.5	72	89
07:00	54.3	10.6	55	85	48.1	12.7	50	86	57.7	30.1	65	84	77.3	24.4	81	89
08:00	55.8	26.5	62	85	47.4	26.4	54	86	62.4	27.4	68	84	76.7	29.2	82	89
09:00	61.1	28.9	68	85	68.2	29.3	74	86	73.5	28.1	79	84	87.2	32.3	93	89
10:00	58.9	29.9	66	85	63.5	30.4	70	86	68.3	32.4	76	84	86.4	36.5	94	89
11:00	59.2	28.2	66	85	59.2	28.9	66	86	67.6	32.8	75	84	83.8	34.4	91	89
12:00	59.8	28.7	66	85	61.9	29.0	68	86	69.5	31.8	76	84	85.1	35.1	92	89
13:00	59.9	29.4	67	85	61.8	29.7	69	86	70.0	31.6	77	84	84.7	35.0	92	89
14:00	60.2	29.1	67	85	59.2	28.8	66	86	68.0	31.5	75	84	84.1	34.6	91	89
15:00	58.9	30.8	67	85	60.4	30.5	68	86	69.6	31.8	77	84	83.0	33.2	89	89
16:00	59.2	32.3	67	85	58.2	32.1	67	86	66.5	33.8	75	84	83.8	34.9	91	89
17:00	58.7	30.3	66	85	53.1	30.5	61	86	65.1	33.3	73	84	81.4	32.5	88	89
18:00	58.8	28.1	65	85	56.5	28.2	63	86	66.7	33.3	75	84	81.4	30.4	87	89
19:00	59.3	32.4	68	85	62.9	32.5	71	86	70.5	31.2	77	84	86.6	35.6	94	89
20:00	58.5	31.0	66	85	55.9	31.3	64	86	66.7	38.0	77	84	82.1	33.3	89	89
21:00	56.9	30.0	64	85	48.0	30.4	57	86	62.3	40.5	74	84	79.2	32.1	85	89
22:00	53.1	29.8	61	85	37.0	30.6	48	86	55.0	34.5	65	84	72.1	28.4	77	89
23:00	45.8	23.6	51	85	35.3	17.9	40	86	41.7	24.6	48	84	61.8	18.9	65	89
24:00	35.9	18.9	41	85	35.2	16.1	39	86	34.6	13.8	37	84	52.1	12.3	54	89
SYSTEM PEAKS																
12:31	60.0	29.3	67	85	63.6	27.8	69	86	69.8	31.6	77	84	84.8	35.6	92	89
19:24	62.3	33.6	71	85	69.5	33.9	77	86	74.8	32.2	81	84	87.9	36.4	95	89
MINLOAD																
03:12	35.0	9.7	36I	85	35.3	10.7	37I	86	33.0	13.4	36I	84	36.2	8.4	37	80

KAHE POWER PLANT
FOR 04/12/05

	KAHE 5				KAHE 6				KAHE TOTALS		
TIME	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	MVA	CAPY	GROSS MW	GROSS MVR	CAPY
01:00	56.8	9.3	58	142	60.4	9.7	61	129	257.0	71.5	606
02:00	55.1	7.2	56	142	60.4	7.5	61	129	253.9	57.4	606
03:00	54.9	5.5	55	142	60.5	6.2	61	129	254.8	53.4	606
04:00	54.8	6.8	55	142	60.4	7.9	61	129	254.2	57.6	615
05:00	54.6	7.9	55	142	60.0	9.0	61	129	253.4	63.1	615
06:00	70.8	12.3	72	70	68.2	12.7	69	129	347.9	86.1	543
07:00	74.5	26.9	79	70	88.3	26.6	92	129	400.2	131.4	543
08:00	76.9	31.7	83	70	105.7	30.5	110	129	424.8	171.7	543
09:00	76.1	33.9	83	142	105.5	32.6	110	129	471.6	185.0	615
10:00	113.0	36.2	119	142	105.4	33.7	111	129	495.6	199.0	615
11:00	137.2	52.7	147	142	105.5	51.4	117	129	512.5	228.4	615
12:00	140.1	53.2	150	142	104.9	52.0	117	129	521.3	229.9	615
13:00	140.4	53.0	150	142	105.5	51.8	118	129	522.2	230.5	615
14:00	137.9	52.6	148	142	105.0	51.4	117	129	514.3	227.9	615
15:00	138.5	51.3	148	142	105.3	50.2	117	129	515.8	227.8	615
16:00	135.8	52.7	146	142	106.0	51.8	118	129	509.6	237.6	615
17:00	132.0	50.5	141	142	105.3	49.6	116	129	495.6	226.6	615
18:00	135.0	48.4	143	142	105.5	47.7	116	129	503.9	216.2	615
19:00	140.2	53.5	150	142	105.3	52.2	118	129	524.7	237.5	615
20:00	135.3	51.5	145	142	105.3	50.5	117	129	503.8	235.6	615
21:00	126.1	50.1	136	142	104.9	49.5	116	129	477.4	232.6	615
22:00	113.0	49.6	123	142	105.8	49.5	117	129	436.0	222.3	615
23:00	85.2	22.2	88	142	74.2	21.6	77	129	343.9	128.8	615
24:00	56.5	10.8	58	142	60.3	11.3	61	129	274.6	83.2	615
SYSTEM PEAKS											
12:31	140.6	53.7	151	142	105.3	52.3	118	129	524.1	230.4	615
19:24	141.1	54.4	151	142	105.4	53.0	118	129	541.0	243.3	615
MINLOAD											
03:12	55.1	6.5	55I	142	60.6	7.6	61I	129	255.2	56.2	606

HONOLULU POWER PLANT
FOR 04/12/05

TIME	HONOLULU 8 GROSS MW	HONOLULU 8 GROSS MVR	HONOLULU 8 MVA	HONOLULU 8 CAPY	HONOLULU 9 GROSS MW	HONOLULU 9 GROSS MVR	HONOLULU 9 MVA	HONOLULU 9 CAPY	HONOLULU TOTALS GROSS MW	HONOLULU TOTALS GROSS MVR	HONOLULU TOTALS CAPY
01:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0
02:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0
03:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0
04:00	0.0	0.1	0	0	0.0	0.0	0	0	0.0	0.1	0
05:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0
06:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0
07:00	19.6	11.1	23	20	0.0	0.0	0	0	19.6	11.1	20
08:00	26.3	14.5	30	56	0.0	0.0	0	0	26.3	14.5	56
09:00	26.8	15.2	31	56	0.0	0.0	0	0	26.8	15.2	56
10:00	26.6	14.4	30	56	25.3	9.1	27	55	51.9	23.5	111
11:00	26.7	14.6	30	56	26.1	7.6	27	55	52.8	22.3	111
12:00	26.7	14.9	31	56	26.2	14.4	30	55	52.9	29.3	111
13:00	26.8	15.4	31	56	26.2	16.4	31	55	53.0	31.8	111
14:00	26.8	15.4	31	56	26.4	16.1	31	55	53.2	31.5	111
15:00	26.6	14.6	30	56	26.4	15.9	31	55	53.0	30.5	111
16:00	26.3	15.0	30	56	26.4	16.3	31	55	52.7	31.3	111
17:00	26.3	14.6	30	56	26.4	16.2	31	55	52.7	30.8	111
18:00	26.1	9.9	28	56	26.3	16.0	31	55	52.3	25.9	111
19:00	25.8	11.3	28	56	26.5	14.3	30	55	52.3	25.7	111
20:00	25.5	9.7	27	56	26.3	14.2	30	55	51.8	23.9	111
21:00	0.0	0.0	0	0	26.3	14.7	30	55	26.3	14.7	55
22:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0
23:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0
24:00	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0
SYSTEM PEAKS											
12:31	26.8	15.0	31	56	26.3	14.3	30	55	53.1	29.3	111
19:24	25.5	11.4	28	56	26.3	14.5	30	55	51.8	26.0	111
MINLOAD											
03:12	0.0	0.0	0	0	0.0	0.0	0	0	0.0	0.0	0

CA-IR-581

<u>Ref: T-1, page 28, Revenue Increase Allocation.</u>

level of base rate system increase" cannot be provided as this would entail changes in the revenue requirements such as the system rate of return corresponding to the hypothetical $50.0 million increase, which is required in applying the HECO criteria.

c. HECO does not have an updated revenue requirements calculation to reflect the known changes to its filing including the removal of DSM costs that would be recovered through a surcharge. HECO will be providing an updated revenue requirements calculation with its rebuttal testimonies. Thus, HECO will provide its proposed class distribution of its revised overall increase with its rebuttal testimonies.

d. See part c above.

e. Consideration of how the total rate increase will impact each customer class should be weighed in comparison to the impact on the total electric bills for the customers.

f. The Commission's orders that are responsive to HECO's criteria for the rate increase allocation to customer classes include the following:

   1. PUC Decision & Order No. 11317, Docket No. 6531, issued October 17, 1991, pages 179-193.
   2. PUC Decision & Order No. 13704, Docket No. 7700, issued December 28, 1994, pages 99-101.
   3. PUC Decision & Order No. 11699, Docket No. 6998, issued June 30, 1992, pages 175-181.
   4. PUC Decision & Order No. 11893, Docket No. 6999, issued October 2, 1992, pages 98-102.
   5. PUC Decision & Order No. 7553. Docket No. 4393, issued May 27, 1983, pages70-71
   6. PUC Decision & Order No. 8179, Docket No. 4833, issued November 23, 1984, pages

63-64.

7. PUC Decision & Order No. 7678, Docket No. 4536, issued September 16, 1983, pages137-141.

	At Present Rates		At Full Cost-To-Serve				At Equal Percent Increase				At Proposed Increase - Illustration Only			
Rate Class	Sales Revenues @Present Rates	ROR @Present Rates	Sales Revenues Increase	Total Sales Rev Reqrmt	Percent Rate Increase	Rate of Return	Sales Revenues Increase	Total Sales Rev Reqrmt	Percent Rate Increase	Rate of Return	Sales Revenues Increase	Total Sales Rev Reqrmt	Percent Rate Increase	Rate of Return
	($000s)	(%)	($000s)	($000s)	(%)		($000s)	($000s)	(%)	(%)	($000s)	($000s)	(%)	(%)
Schedule R/E	$317,901.1	1.30%	$64,877.0	$382,778.1	20.4%	9.11%	$31,293.5	$349,194.6	9.84%	5.07%	$48,085.3	$365,986.4	15.13%	7.08%
Schedule G	$60,702.9	7.60%	$2,284.0	$62,986.9	3.8%	9.11%	$5,975.6	$66,678.5	9.84%	11.49%	$4,129.8	$64,832.7	6.80%	10.30%
Schedule J	$255,035.3	7.15%	$8,365.0	$263,400.3	3.3%	9.11%	$25,105.2	$280,140.5	9.84%	13.07%	$16,735.1	$271,770.4	6.56%	11.08%
Schedule H	$6,913.7	5.39%	$553.0	$7,466.7	8.0%	9.11%	$680.6	$7,594.3	9.84%	9.97%	$616.8	$7,530.5	8.92%	9.54%
Schedule PS	$99,113.9	4.36%	$7,218.0	$106,331.9	7.3%	9.11%	$9,756.8	$108,870.7	9.84%	10.81%	$8,487.4	$107,601.3	8.56%	9.96%
Schedule PP	$230,924.5	4.67%	$14,346.0	$245,270.5	6.2%	9.11%	$22,731.7	$253,656.2	9.84%	11.76%	$18,538.9	$249,463.4	8.03%	10.43%
Schedule PT	$18,142.7	13.04%	($719.0)	$17,423.7	-4.0%	9.11%	$1,786.0	$19,928.7	9.84%	23.09%	$533.5	$18,676.2	2.94%	15.99%
Schedule F	$5,298.0	1.36%	$927.0	$6,225.0	17.5%	9.11%	$521.6	$5,819.6	9.84%	5.69%	$724.3	$6,022.3	13.67%	7.40%
Total	$994,032.1	4.04%	$97,851.0	$1,091,883.1	9.84%	9.11%	$97,851.0	$1,091,883.1	9.84%	9.11%	$97,851.0	$1,091,883.1	9.84%	9.11%
%ROR Boundary: +/- 50%						4.56%				7.38%				
%Rate Incr Boundary, +/- 25%						13.67%				12.30%				

CA-IR-582

Ref: HECO web at http://www.heco.com/CDA/JVN/JVN_Shell/.

According to the Company's internet postings, the following positions were open as of April 7, 2005: Control Technician, Director of Internal Audit, Financial Systems Analyst, Industrial (Power Plant) Journey Electrician, Insulator, Machinist, Operations & Maintenance Engineer, Pipefitter/Boiler Mechanic, Planning Engineer, Power Plant Mechanical Engineer, Sr. Resource Planning Analyst, Structural Engineer, Transmission & Distribution Standards Engineer, Welder.

a. Please state whether each such position was included within test year expenses.

b. If yes, was the position filled throughout the year 2005.

c. Provide the approximate test year wage and benefits expense by NARUC account attributable to each such budgeted position.

HECO Response:

a. All positions except for the Power Plant Mechanical Engineer were included in the test year.

b. Positions were included in the test year as if filled throughout 2005.

c. When test year wage and benefit information was available by labor class only, approximate amounts for the budgeted positions were determined by dividing the labor class information by the number of employees included in the respective labor classes. Approximate test year wage and benefits expense by NARUC account attributable to each budgeted position except the Sr. Resource Planning Analyst position is provided on page 2. HECO's response for the Sr. Resource Planning Analyst position is provided in CA-IR-601.

tter/ er anic	Planning Engineer	Structural Engineer	T&D Standards Engineer	Welder
.24	1,473.58	58,523.27	276.34	1,456.24
.27				2,307.27
		1,698.00	28,483.33	
.38		12,253.90	72,222.57	3,170.38
	37,897.35	15,475.80	3,190.13	
	36,867.74			
	5,148.07			
		1,132.23		
.28		6,480.70		8,323.28
.46				49,159.46
.73				19,402.73
.21				5,782.21
	1,889.20			
		135.84	341.80	
			7,747.47	
			131.02	
	4,533.76			
	1,511.68			
.57	89,321.38	95,699.74	112,392.66	89,601.57

CA-IR-583

Ref: HECO-WP-303 and CA-IR-167, page 4, Field Collection Visits.

The workpaper indicates estimated field collection visits under proposed rates of 16,608. However, CA-IR-167 appears to support a "Total Attempts" volume that is somewhat higher in each of the years 2002 and 2003. Please explain this difference and provide support for the 16,608 value that was used, or admit that some other stated volume is more appropriate.

HECO Response:

The support for the estimated field collection visits under proposed rates of 16,608, is shown on HECO's response to CA-IR-167, pages 3 and 4. The transactions shown for successful field collections on HECO's response to CA-IR-167, page 3, are based on actual transactions billed over the five years, 1999-2003. The 40% amount, which is based on two years of data shown on HECO's response to CA-IR-167, page 4, is used to adjust the billed field collections transactions of 6,643 to the estimated field collection attempts at proposed rates, 16,608. This method of estimation makes a linkage between the billing transactions for field collections at present rates and the billing transactions for field collections at proposed rates.

CA-IR-584

Ref: Response to CA-IR-374 and CA-IR-375: "Potential" rider customers

Several of the referenced Rider customers are indicated to be "potential" customers anticipated to be added in 2005 for which the Company does not presently have contracts for rider service discounts. Other CHP and EDR customers are similarly "potential" discount recipients and expected to be removed from the Company's filing. Please provide the following information:

a. Identify each rider discount customer within each rate schedule in HECO-WP-2223 where the Company cannot presently document the existence of a Rider service arrangement.

b. Explain whether or not the calculated revenue discount for each customer identified in response to part (a) is, or is not, properly removed from the test year revenue calculations.

c. For each test year Rider customer identified in response to part (a) that HECO proposes to <u>not</u> eliminate from the revenue discount calculations in HECO-WP-2223, please provide an explanation of all reasons why a full year of discounted service remains a reasonable assumption for the customer.

d. Provide complete copies of all documents associated with your response to part (c).

<u>HECO Response:</u>

a. There is no HECO-WP-2223. There are 14 potential rider customers. The Schedule J potential rider customers are shown on HECO-WP-304, page 55. There are three potential Rider M customers - Rider Mh J11, Rider Mh J12, Rider Mh J13; one Rider EDR customer -

Rider EDR J1; and one CHP customer - CHP J1. The Schedule PS potential rider customers are shown on HECO-WP-304, page 111. There is one potential Rider revenue estimates, as indicated in HECO's response to CA-IR-375. The other potential rider customers identified in subpart (a) of this response, three Rider M customers and three Rider I customers, and their associated revenue impacts, will continue to be reflected in the estimate of test year revenues.

c. Potential rider customers are appropriately included in the test year estimates to anticipate the growth in participation in existing rider programs and in proposed rider programs (such as the proposed modification to Rider I). There were 28 rider customers included in the 1995 test year estimates in HECO's last rate case, Docket No. 7766. There are 63 rider customers included in the original 2005 test year estimates (after removing the EDR and CHP customers), including 57 existing rider customers. There is an additional Rider M customer (Schedule J), acquired in April 2005, that will also be included in the revised 2005 test year estimates. There is no estimate of Rider M savings for this customer at this time. Rider M savings are dependent on the customer's performance, the ability to curtail demand during the priority peak hours. The test year estimate of Rider M savings for this additional customer will be based on the available actual monthly bills (first Rider M bill for this customer is expected in May 2005).

d. There are no other documents associated with the response to subpart (c) above.

CA-IR-585

Ref: Response to CA-IR-332, HECO-WP-303 and HECO-1320, Six Properties Gain on Sale.

In Decision and Order 16935 in Docket No. 98-0314, the Commission approved the sale of several properties, four of which are reflected within test year amortization revenues. Please provide the following information regarding these properties:

a. Current status of efforts to sell the "old" Waianae Substation Site and all known sale price, gain on sale and amortization amounts associated with any such sale.

b. Current status of efforts to sell the Kahaluu Transmission Corridor and all known sale price, gain on sale and amortization amounts associated with any such sale.

HECO Response:

a. HECO has not yet sold the "old" Waianae Substation site. Earlier efforts to market the property failed to find a buyer. A new plan to market this property is being considered.

b. HECO has not yet sold the Kahaluu Transmission Corridor property. Earlier efforts to market the property failed to find a buyer. A new plan to market this property is being considered.

CA-IR-586

Ref: HECO-619 AND HECO-623, Production Staffing Changes.

According to the referenced Exhibits, HECO intends to add 62 employee positions, relative to actual staffing levels at year-end 2003. Please respond to the following regarding these positions:

a. State whether HECO human resources personnel maintain standardized position description (or comparable) forms in the normal course of business.

b. If standardized forms are maintained, please provide a complete copy of such forms for each of the following positions where staffing is to be increased:

   1. Operators.

   2. Maintenance Supervisor.

   3. Day Crew.

   4. Night Maintenance Supervisor.

   5. Night Crew.

   6. Crew.

c. If standardized position description forms are not maintained in the normal course of business by HECO, provide the most detailed existing description of the skills,

1. "Operators" comprised of the following positions. Specific counts of each position are not provided due to the closed line of progression (i.e., each Station has its own line of operator progression) where operators from the bottom fill higher level operator positions based on seniority. Eventually vacancies are created at the lowest operator position which is the Equipment Operator.
   - Shift Supervisor. Refer to pages 4-6.
   - Control Operator. Refer to page 7.
   - Junior Control Operator. Refer to page 8.
   - Equipment Operator. Refer to page 9.
   - Utility Operator. Refer to page 10.
2. "Maintenance Supervisor" (1) for the Honolulu Station. Refer to Position Description on pages 11-13.
3. "Day Crew" is comprised of the following trades and crafts positions.
   - Kahe – Pipefitter Mechanics (2). Refer to Position Description on page 19.
   - Waiau – Sr. Electrician (1) and Control Technicians (3). Refer to Position Descriptions on pages 15 and 20, respectively.
4. "Night Shift Supervisor" (2). Refer to pages 11-13.
5. "Night Crew" for Kahe and Waiau Stations comprised of the following trades and crafts:
   - Electrical Working Foreman (2). Refer to page 14.
   - Boiler Working Foreman (2). Refer to page 16.
   - Machinist Working Foreman (2). Refer to page 16.
   - Machinist (2). Refer to page 17.

- Sr. Electrician (2). Refer to page 15.
- Pipefitter Mechanic (2). Refer to page 19.
- Certified Combination Welder (2). Refer to page 18.
- Control Technician (4). Refer to page 20.

6. "Crew" refers to vacancies in the Travel Crew. The 12 positions in HECO-623 are comprised of:

- Machinist Working Foreman (1). Refer to page 16.
- Senior Electrician (1). Refer to page 15.
- Machinist (1). Refer to page 17.
- Certified Combination Welder (1). Refer to page 18.
- Control Technician (1). Refer to page 20.
- Helper (1). Refer to page 22.
- Insulator (2). Refer to page 21.
- Condenser Cleaner (4). Refer to page 23.

c. Position descriptions were provided in b. above.

HAWAIIAN ELECTRIC COMPANY
MERIT
POSITION DESCRIPTION

Position Title:	**Supervisor, Shift**
Department:	**Operations & Maintenance**
Reports to:	**Sr. Supervisor**

Job Code:	S2081	***FLSA:***	E
Role:	TS	***Date:***	04-21-99

Primary Role/Function

Supervises and directs the operation of the power generating station to ensure safe, reliable, and cost effective generation of electricity to meet system demands while complying with all applicable safety and environmental regulations and laws.

Honolulu S/S - Two steam units
Waiau S/S - Six steam units and two CTs
Kahe S/S - Six steam units

Job Responsibilities

*	25%	Directs and supervises the shift operating personnel (including performance appraisal, teamwork and self-directed workforce, two-way communication, training and development, safety, and discipline) at the generating plant during normal and abnormal operating conditions, starting, and shutting down of units and equipment.
*	20%	Responsible for isolating of mechanical and electrical equipment for safety and maintenance repairs.
*	20%	Investigates, evaluates and makes verbal reports and written work requests to locate and define malfunctioning equipment, controls, systems and instruments.
*	15%	- Coordinates and supports activities with system operations, maintenance, technical- personnel for operating, maintaining, testing and overhauling the generating units.
*	5%	Maintains accurate and complete log of all events occurring on the station during shift concerning equipment or personnel.
*	5%	Enforces operating policies and procedures; administers shift and overtime schedules; coordinates and complete timecards.
*	10%	Ensures plant operations are in compliance with all federal and state regulations.
		Interacts with all employees and other internal and external suppliers and customers in a positive, supportive, and collaborative manner, to ensure the fulfillment of Company strategic objectives.
		Supports two-way communications to ensure a focused and well-informed workforce.
		Promotes teamwork and self-directed workforce to support quality initiatives and Company vision and values.

*** Denotes a "Fundamental Responsibility"**

This position description in no way states or implies that these are the only duties/functions to be performed by the incumbent. Employee will be required to follow any other job-related duties/functions assigned by the supervisor

Supervisor, Shift S2081

Minimum Qualifications

Knowledge Requirements:

- Thorough working knowledge in the operation of generating units and systems, electrical system, operating policies and operating emergency corrective procedures.
- Good working knowledge in the area of maintenance of the generating units and systems.
- Working knowledge of personal computers and/or mainframe systems and related software applications.
- Knowledge of the requirements for compliance with State and Federal environmental regulations.
- Completion of the ICS Generating Station Operator curriculum (or Company approved equivalent).

Skills Requirements

- Ability to effectively communicate with all levels of internal and external customers - both verbally and in written communication.
- Able to read, comprehend and utilize technical publications such as manufacturer's instruction manuals, unit data books, blueprints and piping and instrument diagrams.
- Supervisory/leadership skills and abilities to work with a variety of individuals dealing with sensitive, difficult or confrontational issues.
- Troubleshooting skills to determine operating and maintenance problems with the units and equipment.
- Ability to remain flexible in a demanding work environment and adapt to rapidly changing priorities.
- Ability to handle difficult or sensitive issues while using tact, courtesy, and discretion.

Experience Requirements

Several years (3-5) of operational experience as a control room operator or equivalent.

Requirements are representative of minimum levels of knowledge, skills, and abilities. To perform the position successfully, the incumbent will need to demonstrate the use of these knowledge, skills, and abilities at an "Effective" level.

Positions Supervised

Supervisor, Shift S2081

Physical Requirements

Only items that are necessary to perform the "fundamental" responsibilities of the position are indicated.
"F" for Frequently: Daily, several times a week, weekly
"O" for Occasionally: Monthly, Couple times a year

F	Standing	F	Lifting/Carrying below 25 lbs.
F	Walking		26 to 50 lbs.
F	Sitting		above 50 lbs.
F	Climbing Ascending or descending ladders, stairs, or other objects.	F	Vision acuity the ability to see clearly 20 feet or more
O	Balancing on narrow, slippery, or erratically moving surfaces.	F	Color vision the ability to identify and distinguish different colors.
F	Stooping, kneeling, crouching, crawling, and/or squatting	F	Night vision the ability to perform work at night with the use of portable lighting.
F	Handling Working with hands, arms or fingers.	F	Talking
O	Feeling Perceiving attributes such as size, share, temperature or texture.	F	Hearing
F	Ability to follow written/oral instructions		Ability to perform simple, repetitive tasks for an extended period of time
			Ability to perform complex and varied tasks for an extended period

Environmental Conditions

The employee will be exposed to the following environmental conditions in performing the "fundamental" responsibilities of the position.

	Extreme Cold cold temperatures for an hour or more	F	Working Outdoors may be during prevailing weather/climate conditions
F	Extreme Heat warm/hot temperatures for an hour or more	O	Hazardous Conditions potentially life-threatening situations
O	Wetness	F	Work above 5 feet
F	Use of personal protective equipment (hard hats, respirator, leather gloves, rubber glove, safety shoes, nomex clothing)	O	Work above 70 feet
O	Work in emergency/potentially "high stress" situations		Work on mountain trails/cliff sides
F	Noise At least 80 decibels		

Job responsibilities are subject to possible modification to reasonably accommodate individuals with disabilities.

Some job requirements may exclude individuals who pose a direct threat or significant risk to the health and safety of themselves or other individuals.

This position description in no way states or implies that these are the only duties/functions to be performed by the incumbent. Employee will be required to follow any other job-related duties/functions assigned by the supervisor

WAGE FILE CODE:	T154JD
FOR WAGE ADM. USE:	
PAY SCHEDULE:	SINGLE RATE

SHIFT

HAWAIIAN ELECTRIC COMPANY, INC.
BARGAINING UNIT JOB DESCRIPTION

JOB CODE:	T154	STATUS:	ADA Revision
POSITION:	**CONTROL OPERATOR**		
DEPARTMENT:	Power Supply Operations & Maintenance	REPLACES:	T154 appr. 1/30/64
SUPERVISED BY:	Shift Supervisor		

FUNCTION:

Operates high pressure steam generator automatically and/or manually. Operates turbo-generator, main and auxiliary controls. Supervises the Jr. Control Operator and Equipment Operator. Cooperates with the Load Dispatcher.

JOB CONTENT:

FUNDAMENTAL RESPONSIBILITIES:

Must have sufficient knowledge of generating units to which assigned and of the proper operation to carry out the following duties:

WAGE FILE CODE:	T149-JD
FOR WAGE ADM. USE:	
PAY SCHEDULE:	SINGLE RATE

SHIFT

HAWAIIAN ELECTRIC COMPANY, INC.
BARGAINING UNIT JOB DESCRIPTION

JOB CODE:	T149	STATUS:	
POSITION:	**JUNIOR CONTROL OPERATOR**		
DEPARTMENT:	~~Generation~~ Power Supply Ops & Maint	REPLACES:	
SUPERVISED BY:	Shift Supervisor		

FUNCTION:

Assists the Control Operator. Trains to perform as Control Operator. Performs any assigned task on outside the control room level and at burner stations.

JOB CONTENT:

FUNDAMENTAL RESPONSIBILITIES:

- Attends instruction classes, when scheduled, on company time to prepare to qualify for Control Operator.
- Assists the Control Operator and acquires sufficient knowledge to relieve Control Operator when necessary.
- Performs the following additional tasks:
  - Performs all mechanical and electrical operations as directed by the Control Operator.
  - Cuts-in and cuts-out burners when required.
  - Cleans fuel oil strainer. Makes flue-gas and water analyses. Takes turbine thrust and pedestal micrometer readings when required.
  - Adjusts turbine gland water, steam seal and air ejector pressures. Makes routine external inspection and takes all field instruments readings on turbo-generator. Logs necessary readings.
  - Feeds chemicals to boilers as needed. Checks reboiler operation. Cleans externally all standby burners.
  - Makes operating inspection of all soot blowers. Inspects boiler air preheating operation. Blows soot. Does auxiliary plan switching up to and including 2.3 kv as directed.
- Maintains proper housekeeping.
- Reports any abnormal conditions.
- Maintains shift until properly relieved.

OTHER RESPONSIBILITIES:

- Performs similar and incidental duties as required.

APPROVED:

/S/FRANK HICKS	04/01/1963	/S/J. R. ZEIGLER	04/09/1963
DEPARTMENT MANAGER	DATE	VICE PRESIDENT	DATE

WAGE FILE CODE:	T114-JD
FOR WAGE ADM. USE:	
PAY SCHEDULE:	SINGLE RATE

SHIFT

HAWAIIAN ELECTRIC COMPANY, INC.
BARGAINING UNIT JOB DESCRIPTION

JOB CODE:	T114	STATUS:	ADA Revision
POSITION:	**EQUIPMENT OPERATOR**		
DEPARTMENT:	Power Supply Operations & Maintenance	REPLACES:	T114 appr. 1/11/73
SUPERVISED BY:	Shift Supervisor		

FUNCTION:

Tends and operates the hydrogen and seal oil system and the auxiliary equipment on units as assigned. Tends and operates turbines and accessories. Trains to perform duties of other classifications in Operating Division as assigned.

JOB CONTENT:

FUNDAMENTAL RESPONSIBILITIES:

- Attends instruction classes, when scheduled, on company time to prepare to pass examination to qualify for next higher job.
- Determines operating status of equipment from previous shift personnel and log book entries.
- Watches carefully all equipment for normal operation; reports any unusual conditions to the Shift Supervisor.
- Operates C.W. pumps, feed pumps, auxiliary cooling water pumps, condensate pumps, condensate booster pump, vapor extractor pump, distilled water make-up pumps, generator air cooler pumps, sump pumps and evaporator.
- Operates the hydrogen and seal oil systems; the feed water heaters, controls, traps and

WAGE FILE CODE:	T135-JD
FOR WAGE ADM. USE:	
PAY SCHEDULE:	SINGLE RATE

SHIFT

HAWAIIAN ELECTRIC COMPANY, INC.
BARGAINING UNIT JOB DESCRIPTION

JOB CODE:	T135	STATUS:	ADA Revision
POSITION:	**UTILITY OPERATOR**		
DEPARTMENT:	Power Supply Operations & Maintenance	REPLACES:	T135 appr. 3/4/76
SUPERVISED BY:	Shift Supervisor		

FUNCTION:

Performs various tasks in starting up and shutting down of units. Performs various tasks as assigned by Shift Supervisor during normal operation of units. May be assigned to replace employees due to absence. Observes operation in control room and assists during emergencies or abnormal operations as required.

JOB CONTENT:

FUNDAMENTAL RESPONSIBILITIES:

- During startup and shutdown of units, performs various tasks as required.
- May be required to man various stations on units during intermittent operation.
- Performs various tasks, as assigned by the Shift Supervisor, in maintaining operation of generating equipment and related plant auxiliaries. Reports any abnormal conditions to Shift Supervisor.
- Operates fuel oil heaters, transfers pumps, controls, and other related equipment as directed. Takes fuel oil tank soundings as directed. Takes various readings, soundings and operating data as required. Maintains recording charts; checks plant for proper lighting.
- Maintains watch until relieved.
- Starts and stops combustion turbines and monitors operations as required.
- Operates and maintains wastewater treatment facilities.
- Maintains proper housekeeping.

OTHER RESPONSIBILITIES:

- Performs similar and incidental duties as required.

APPROVED:

/S/THOMAS JOAQUIN	1/3/94	/S/HARRY H.K. KAMEENUI	12/2/94
DEPARTMENT MANAGER	DATE	UNION	DATE

HAWAIIAN ELECTRIC COMPANY
MERIT
POSITION DESCRIPTION

Position Title:	**Supervisor, Maintenance**
Department:	**Operations & Maintenance**
Reports to:	**Superintendent, Maintenance**

Job Code:	S2414	***FLSA:***	E
Role:	TS	***Date:***	5/16/99

Primary Role Function

Provides quality maintenance, repair, and construction services to the power generating station while complying with applicable safety, environmental, and code regulations and laws.

Job Responsibilities

*	50%	Provides leadership, supervision (including performance appraisal, teamwork and self-directed workforce, two-way communication, training and development, recognition, safety, and discipline) and technical direction, to develop and maintain a highly competent, flexible and motivated workforce.
*	30%	Provides safe, reliable, timely, and competitive maintenance services to meet or exceed operational expectations through effective job planning, coordination, scheduling, monitoring and controlling. May conduct on-site maintenance inspections.
*	10%	Prepares and manages section's O&M forecast and adjusts as necessary to meet year-end targets. Approves material requisitions up to authorization amount

Supervisor, Maintenance S2414

Minimum Qualifications

Knowledge Requirements:

Thorough knowledge of union contract, Company policies, and Department policies/practices.

Thorough familiarity with applicable state and federal regulations /permits, laws and codes.

Knowledge of equipment operation and maintenance in a power generating facility.

Working knowledge of personal computers and/or mainframe systems and related software applications (including maintenance and materials management).

Skills Requirements

Supervisory/leadership skills and abilities to work with a variety of individuals dealing with sensitive, difficult or confrontational issues.

Ability to effectively communicate with all levels of personnel, both verbally and in written communications.

Must have or be able to qualify for Hawaii driver's license and HECO driver's license to conduct on-site boiler maintenance inspections.

Ability to remain flexible in a demanding work environment and adapt to changing priorities.

In-depth equipment troubleshooting and testing skills.

Ability to utilize reference materials, drawings, instruction manuals, and historical information.

Experience Requirements

Extensive experience (7 or more years) as a journeyperson in a maintenance (boiler, electrical, technical or turbine) trade.

Requirements are representative of minimum levels of knowledge, skills, and abilities. To perform the position successfully, the incumbent will need to demonstrate the use of these knowledge, skills, and abilities at an "Effective" level.

Positions Supervised [illegible]

Resource Planner
Working Foremen
Condenser Group Leader
Journeypersons
Equipment Operators
Equipment Mechanics
Insulators
Condenser Cleaner
Groundskeeper
Apprentices
Helpers

Physical Requirements

Only items that are necessary to perform the "fundamental" responsibilities of the position are indicated.

"F" for Frequently:	Daily, several times a week, weekly
"O" for Occasionally:	Monthly, Couple times a year

F	Standing	F	Lifting/Carrying below 25 lbs.
F	Walking	O	26 to 50 lbs.
F	Sitting		above 50 lbs.
F	Climbing Ascending or descending ladders, stairs, or other objects.	F	Vision acuity the ability to see clearly 20 feet or more
	Balancing [illegible]		Color vision [illegible]

WAGE FILE CODE:	F155-JD
FOR WAGE ADM. USE:	
PAY SCHEDULE:	SINGLE RATE

HAWAIIAN ELECTRIC COMPANY, INC.
BARGAINING UNIT JOB DESCRIPTION

JOB CODE:	F155	STATUS:	ADA Revision
POSITION:	**WORKING FOREMAN (ELECTRICAL)**		
DEPARTMENT:	Power Supply Ops & Maint	REPLACES:	F155 appr. 12/3/85
SUPERVISED BY:	Maintenance Superintendent		

FUNCTION

Directs personnel engaged in the maintenance of generating station electrical equipment.

JOB CONTENT

FUNDAMENTAL RESPONSIBILITIES:

- Assigns work and material and directs crews who overhaul, repair, modify, troubleshoot, and/or install power plant electrical equipment.
- Makes final tests on electrical equipment installed or repaired.
- Requisitions spare parts and materials for jobs under direction.
- Allocates charges for labor and materials and keeps time for personnel assigned.
- Reviews completed Maintenance Work Requests for accuracy and completeness.
- Reports equipment problems which may be observed.
- Is responsible for the safety and training of personnel under direction; includes tagging equipment to be worked on.
- Conducts safety meetings.
- Assumes portions of the duties of Supervisor when required.
- Performs the work of lower classifications as required.

OTHER RESPONSIBILITIES:

- Assists the supervisors in evaluating performance of subordinates.
- Performs similar and incidental duties as required.

APPROVED:

/S/TOM JOAQUIN	03/01/1994	/S/HARRY H.K. KAMEENUI	03/23/1994
DEPARTMENT MANAGER	DATE	UNION	DATE

WAGE FILE CODE:	T174JD
FOR WAGE ADM. USE:	
PAY SCHEDULE:	SINGLE RATE

HAWAIIAN ELECTRIC COMPANY, INC.
BARGAINING UNIT JOB DESCRIPTION

JOB CODE:	T174	STATUS:	ADA Revision
POSITION:	**SENIOR ELECTRICIAN**		
DEPARTMENT:	Power Supply Operations & Maintenance	REPLACES:	T174 appr. 2/12/86
SUPERVISED BY:	Maintenance Supervisor		

FUNCTION:

Installs and maintains generating station electrical equipment.

JOB CONTENT:

WAGE FILE CODE:	F155-JD
FOR WAGE ADM. USE:	
PAY SCHEDULE:	SINGLE RATE

HAWAIIAN ELECTRIC COMPANY, INC.
BARGAINING UNIT JOB DESCRIPTION

JOB CODE:	F155	STATUS:	ADA Revision
POSITION:	WORKING FOREMAN (TURBINE & AUXILIARY)		
DEPARTMENT:	Power Supply Ops & Maint	REPLACES:	F155 appr. 12/3/85
SUPERVISED BY:	Maintenance Superintendent		

FUNCTION

Directs personnel engaged in the maintenance of generating station mechanical equipment.

JOB CONTENT

FUNDAMENTAL RESPONSIBILITIES:

- Assigns work and material and directs crews who overhaul, repair, modify, troubleshoot, and/or install turbines and related equipment.
- Requisitions spare parts and materials for jobs under direction.
- Allocates charges for labor and materials and keeps time for personnel assigned.
- Reviews completed Maintenance Work Requests for accuracy and completeness.
- Reports equipment problems which may be observed.
- Is responsible for the safety and training of personnel under direction; includes tagging equipment to be worked on.
- Conducts safety meetings.
- Assumes portions of the duties of Supervisor when required.
- Performs the work of lower classifications as required.

OTHER RESPONSIBILITIES:

- Assists the supervisors in evaluating performance of subordinates.
- Performs similar and incidental duties as required.

APPROVED:

/S/TOM JOAQUIN	03/01/1994	/S/HARRY H.K. KAMEENUI	03/23/1994
DEPARTMENT MANAGER	DATE	UNION	DATE

WAGE FILE CODE:	T125JD
FOR WAGE ADM. USE:	
PAY SCHEDULE:	SINGLE RATE

HAWAIIAN ELECTRIC COMPANY, INC.
BARGAINING UNIT JOB DESCRIPTION

JOB CODE:	T125	STATUS:	ADA Revision
POSITION:	**MACHINIST**		
DEPARTMENT:	Power Supply Operations & Maintenance	REPLACES:	T125 appr. 2/12/86
SUPERVISED BY:	Maintenance Supevisor		

FUNCTION:

Installs and maintains power plant mechanical equipment.

JOB CONTENT:

FUNDAMENTAL RESPONSIBILITIES:

- Performs mechanical maintenance and machining on all power plant equipment.
- Troubleshoots and repairs rotating equipment problems.
- Sets up and operates machine tools such as lathes, boring mills, shapers, milling machines, drill presses, metal disintegrator, large diameter pipe prepping tools, etc.
- Devises, sets up and operates field machining tools as required.
- Performs precision machining work.
- Aligns and balances all types of rotating equipment.
- Demonstrates knowledge of properties and use of metals.
- Directs the work of and trains personnel of lower classifications on any or all of the above operations.
- Works from blueprints, sketches, instruction manuals and written or oral instructions.
- Performs necessary rigging for assigned work.
- Works with electricians in dismantling, inspecting and repairing generators, exciter and motors.
- Services and repairs lubricating oil systems.
- Operates material handling and other equipment as required.
- Records a description of work completed.
- Uses and repairs all precision hand tools and power operator tools.
- Reports equipment problems that may be observed.

OTHER RESPONSIBILITIES:

- Performs minor non-asbestos insulation removal incidental to the performance of maintenance tasks.
- Performs similar and incidental duties as required.

APPROVED:

/S/THOMAS JOAQUIN	3/9/93	/S/HARRY H.K. KAMEENUI	9/23/93
DEPARTMENT MANAGER	DATE	UNION	DATE

WAGE FILE CODE:	T137JD
FOR WAGE ADM. USE:	
PAY SCHEDULE:	SINGLE RATE

HAWAIIAN ELECTRIC COMPANY, INC.
BARGAINING UNIT JOB DESCRIPTION

JOB CODE:	T137	STATUS:	ADA Revision
POSITION:	CERTIFIED COMBINATION WELDER		
DEPARTMENT:	Power Supply Operations & Maintenance	REPLACES:	T137 appr. 12/3/85
SUPERVISED BY:	Roving Maintenance Supervisor or Welding Maintenace Engineer or Boiler Maintenance Supervisor		

FUNCTION:

Arc and gas welds any materials involved in the installation and maintenance of generating station equipment in accordance with the applicable sections of the ASME Boiler and Pressure Vessel Code. Installs and maintains generating station mechanical and structural equipment.

JOB CONTENT:

FUNDAMENTAL RESPONSIBILITIES:

- Recognizes properties and weldability of materials commonly used in power plant apparatus.
- Arc and gas welds with and without backing rings in all positions on boilers, piping, turbines and structural steel.
- Arc and gas cuts steel and non-ferrous alloys.
- Arc and gas brazes and silver-solders steel and non-ferrous alloys.
- Performs the work of lower classifications as required.
- Directs the work of and trains personnel of lower classifications on any or all of the above operations.
- Maintains proficiency in various welding procedures as demonstrated by annual recertification.

OTHER RESPONSIBILITIES:

- Performs similar and incidental duties as required.

APPROVED:

/S/THOMAS JOAQUIN	1/5/94	/S/HARRY H.K. KAMEENUI	2/16/94
DEPARTMENT MANAGER	DATE	UNION	DATE

WAGE FILE CODE:	T175JD
FOR WAGE ADM. USE:	
PAY SCHEDULE:	SINGLE RATE

HAWAIIAN ELECTRIC COMPANY, INC.
BARGAINING UNIT JOB DESCRIPTION

JOB CODE:	T175	STATUS:	ADA Revision
POSITION:	**PIPEFITTER MECHANIC**		
DEPARTMENT:	Power Supply Operations & Maintenance	REPLACES:	T175 appr. 1/22/85
SUPERVISED BY:	Maintenance Supervisor		

FUNCTION:

Installs and maintains generating station piping, mechanical and structural equipment.

JOB CONTENT:

FUNDAMENTAL RESPONSIBILITIES:

- Performs mechanical maintenance on power plant equipment, such as boilers, air heaters, sootblowers, fans, heat exchangers, travelling screens, valves and piping.
- Sets and/or repairs safety valves.
- Lays out, installs or repairs all types of power plant piping and valves including hangers, supports, etc. Bends, installs, removes or repairs boiler and other heat exchanger tubes.
- Lays out and performs structural steel erection.
- Performs tube/piping welding prep cuts by hand or utilizing available power tools.
- Performs the work of lower classifications as required.
- Directs the work of and trains personnel of lower classifications on any or all of the above operations.

OTHER RESPONSIBILITIES:

- Performs similar and incidental duties as required.

APPROVED:

/S/R.K.MCQUAIN	11/29/85	/S/V.E. CRONKHITE	12/3/85
DEPARTMENT MANAGER	DATE	VICE PRESIDENT	DATE

WAGE FILE CODE:	T1006-JD
FOR WAGE ADM. USE:	
PAY SCHEDULE:	STEP PROG.

HAWAIIAN ELECTRIC COMPANY, INC.
BARGAINING UNIT JOB DESCRIPTION

JOB CODE:	T1006	STATUS:	ADA Revision
POSITION:	**CONTROL TECHNICIAN**		
DEPARTMENT:	Power Supply Operations & Maintenance	REPLACES:	T1006 appr. 6/23/87
SUPERVISED BY:	Technical Superintendent		

FUNCTION:

Performs all necessary work on instruments and control systems in generating stations.

JOB CONTENT:

FUNDAMENTAL RESPONSIBILITIES:

- Installs, tests, maintains, troubleshoots, adjusts and repairs all instruments and control systems including complex multiple loop and other interacting systems.
- Plans and coordinates test plans with required supervisory personnel; conducts control system tests, test data analysis and equipment/control system calibration as required to optimize generating station control systems.
- Performs modifications as necessary to improve or update control systems and equipment.
- With minimum assistance from supervision, troubleshoots all equipment and control system problems.
- Performs the work of lower classifications as required.
- Makes corrections of drawings and notifies supervisors of any discrepancies.
- Directs the work of and trains personnel of lower classifications on any or all of the above operations.

OTHER RESPONSIBILITIES:

- Performs similar and incidental duties as required.

APPROVED:

/S/THOMAS JOAQUIN	3/9/93	/S/HARRY H.K. KAMEENUI	6/24/93
DEPARTMENT MANAGER	DATE	UNION	DATE

WAGE FILE CODE:	T131JD
FOR WAGE ADM. USE:	
PAY SCHEDULE:	STEP PROG.

HAWAIIAN ELECTRIC COMPANY, INC.
BARGAINING UNIT JOB DESCRIPTION

JOB CODE:	T131	STATUS:	ADA Revision
POSITION:	**INSULATOR**		
DEPARTMENT:	Power Supply Operations & Maintenance	REPLACES:	T131 appr. 12/3/85
SUPERVISED BY:	Maintenance Supervisor		

FUNCTION:

Installs and maintains refractories and insulations. Does concrete work.

JOB CONTENT:

FUNDAMENTAL RESPONSIBILITIES:

As an Insulator at the maximum level, performs the following duties at times in confined spaces and/or at elevations of 80 feet. As an Insulator at lower levels, performs the following duties under direction or direct supervision in accordance with the various stages of training attained.

- Works from blueprints, sketches and written or oral instructions.
- Fabricates, installs, or removes all boiler, turbine, pipe and duct insulation, including pads, finish coats and canvas or sheet metal coverings. Includes installing insulation pin studs with an insulpin type gun.
- Fabricates, installs or removes plastic and castable refractories; installation methods including gunniting. Lays and repairs firebrick, burner tiles and baffles.
- Does concrete work including the constructing of forms (without use of a transit), installation of steel, cement finishing of new capital construction projects, in addition to modifications or additions to existing plants.
- At the Journeyman level, directs the work of personnel in lower classification on any or all of the above operations.
- Operates material handling and other equipment as required.

OTHER RESPONSIBILITIES:

- Does general roofing repairs.
- Records a description of work completed.
- Performs similar and incidental duties as required.

APPROVED:

/S/THOMAS JOAQUIN	10/13/93	/S/HARRY H.K. KAMEENUI	10/21/93
DEPARTMENT MANAGER	DATE	UNION	DATE

WAGE FILE CODE:	TL17-JD
FOR WAGE ADM. USE:	
PAY SCHEDULE:	STEP PROG.

HAWAIIAN ELECTRIC COMPANY, INC.
BARGAINING UNIT JOB DESCRIPTION

JOB CODE:	TL17	STATUS:	New Job
POSITION:	**MAINTENANCE HELPER**		
DEPARTMENT:	Power Supply Operations & Maintenance	REPLACES:	None
SUPERVISED BY:	Various Supervisors		

FUNCTION:

Performs unskilled and semi-skilled work under direct or indirect supervision. Assists various trades & crafts personnel of higher classifications in the construction, installation, maintenance, and operations of Company facilities.

JOB CONTENT:

FUNDAMENTAL RESPONSIBILITIES:

- Performs routine tasks such as sandblasting, parts cleaning, painting, building/grounds relamping, high-pressure washing, etc. under direct or indirect supervision.
- Assists various trades & crafts personnel of higher classifications with their regularly assigned tasks including but not limited to the following:
  - Lead and asbestos abatement work including removal of lead paint by hand or mechanical equipment, setup of containments to perform the work, and containment of asbestos material for removal.
  - Installation of wiring and cabling.
  - Repair/replacement of piping and/or replacement of leaking water valves/fittings.
  - Fuel oil pipeline repair work.
  - Plumbing repairs, concrete work, temporary roof repairs, and other miscellaneous duties as required.
- Uses hand, power, hydraulic & pneumatic tools such as hammers, saws, screwdrivers, pliers, punches, wrenches, drills, impact guns/wrenches, sandblaster, etc.
- Drives Company vehicles. May drive a truck carrying personnel and/or materials. If qualified, operates trucks or equipment of a higher classification.
- Lifts and carries materials, tools, and equipment required to perform assigned tasks.
- Services company vehicles (fills with gas, checks oil and water, and washes exterior)

OTHER RESPONSIBILITIES:

- Performs similar and incidental duties as required.

APPROVED:

/S/RONALD W. MULLANEY FOR HAROLD K. KAGEURA	11/2/98	/S/BRIAN F. AHAKUELO	11/6/98
DEPARTMENT MANAGER	DATE	UNION	DATE

WAGE FILE CODE:	TL180JD
FOR WAGE ADM. USE:	
PAY SCHEDULE:	STEP PROG.

HAWAIIAN ELECTRIC COMPANY, INC.
BARGAINING UNIT JOB DESCRIPTION

JOB CODE:	TL180	STATUS:	Conversion & Revision
POSITION:	**CONDENSER CLEANER**		
DEPARTMENT:	Production	REPLACES:	T180 approved 7/13/79
SUPERVISED BY:	Boiler Maintenance Supervisor		

FUNCTION:

As directed and instructed: Cleans and maintains power plant heat exchangers. Performs unskilled work under direct or indirect supervision. Assists personnel of higher classification in the construction, installation, maintenance and operations of Company facilities.

JOB CONTENT:

FUNDAMENTAL RESPONSIBILITIES:

- Performs routine cleaning, servicing and repairing of condenser tubes, tube sheets and water boxes, and other heat exchangers. Locates and plugs tube/tube sheet leaks upon completion of cleaning operation. Performs minor repairs to condenser and other heat exchanger equipment such as drain valve replacements, gasket replacements, cathodic protection equipment servicing, etc.
- Performs routine tasks under direct or indirect supervision. Assists personnel of higher classifications in their regularly assigned tasks.
- Works from written or oral instructions.
- Uses hand tools such as hammer, saw, screwdrivers, pliers, punches, wrenches, etc.
- Uses power tools such as electric/pneumatic drills, high pressure air and water guns, impact wrenches, tube rollers, etc.
- Lifts and carries materials, tools, and equipment.
- Does cleaning and painting.
- Does record keeping.
- Drives company vehicles including fork lifts, and material handling equipment. May drive a truck carrying personnel and/or materials. If qualified, operates trucks or equipment of a higher classification.
- Transports stores materials, spare parts, and tools.

OTHER RESPONSIBILITIES:

- Directs the work of lower classifications as required.
- Performs similar and incidental duties as required.

APPROVED:

/S/HAROLD K. KAGEURA	7/18/01	/S/JOHN B. JUMALON	8/13/01
DEPARTMENT MANAGER	DATE	UNION	DATE

CA-IR-587

Ref: HECO's responses to CA-IR-360 and CA-IR-340; Employee Service Discounts.

According to part (c) of this response, "...the employee discount is a contractual obligation between HECO and its bargaining unit employees." The Agreement with Local 1260 at page 38 states, "The employee's electric light and power discount will be equal to one third of the employee's monthly KWH usage up to a cap of 275 KWH." Please respond to the following:

a. Please explain whether billings to employees reflect removal of the first 275 KWH from billed KWH, or whether some other billing algorithm is actually employed.

b. Please state whether any of the customer charge is actually discounted for employees.

c. Please explain whether retirees are provided with the employee discount and provide [illegible]

d. Provide a breakdown of test year numbers of employees, retirees and any other persons who are included in the employee discount calculations at HECO-WP-304, page 5.

e. Provide information needed to reconcile the employee and retiree numbers in your response to part d into the projected test year 1,493 employees contained within HECO-1612.

b. Yes. The customer charge is discounted by one-third for employees/retirees.

c. The employee discount applies to retirees per contractual agreement. Please see HECO-WP-1553, page 1.

d. The breakdown of the test-year number of employees and kWh included in the calculation of the employee discount in HECO-WP-304, page 5 is provided below:

	No. of Employees/Others	kWh for TY 2005
Employees	1,211	12,659,000
Retirees	773	8,154,000
Total, Schedule E	1,984	20,813,000

e. The information provided in part d. above is based on the recorded number of customers served under Schedule E and does not include employees and retirees who live in master-metered dwellings, employees and retirees whose electric bills are included in their rent/lease and/or maintenance fees, temporary and probationary employees, employees who work less than 40 hours per week, and retirees who reside outside of Hawaii. Additionally, when both spouses (husband and wife) are employees of the company (or both retired from the Company) and they live together, these husband/wife employees/retirees get only one employee discount applied to their primary residence. In comparison, the 1,493 employees provided in HECO-1612 reflect the total average number of employees for test-year 2005, as defined in HECO T-16, page 25, lines 21-23.

f. The electric discount trust is used to reimburse the company for the amount of the electric discount applicable to retirees. Expenses related to the electric discount are included in the FAS 106 OPEB cost for the test year. The FAS 105 OPEB cost for the test year is $7,014,500 without the amortization of the regulatory asset (see HECO-1504 Updated

4/7/05 attached to the response to CA-IR-337). The electric discount portion of this amount is $816,500.

g. The $297,000 referenced in HECO T-15, page 11, is based on the average discount per month per retiree recorded for January 2003 through June 2003. It was derived as follows:

(Total recorded retirees discount for Jan-June 03) ÷ 6 months x 12 months

h. No further adjustment calculations are required to reconcile costs associated with employee discount with the employee levels included in the test-year.

CA-IR-588

<u>Ref: HECO's responses to CA-IR-219; page 3.</u>

According to part (e) of this response, "The referenced workpaper, HECO-WP-2217, page 85 location of the customer relative to the system facilities, so that a portion of these costs should be classified as customer-related, and a portion as demand-related. The distribution facilities costs provided in HECO-WP-2217, page 61 are the costs of connecting the homes in 4 subdivisions, and dividing the total costs by the number of homes provided in the table provides the distribution facilities cost per home or cost per customer. These costs can also be expressed on a per kW basis based on an assumed kW load of 4 kW per home as used in HECO-2217.

c. The marginal distribution cost of $4.23/month provided in HECO-2211, is based on the annual distribution substation cost at secondary voltage of $29.78 and the distribution facilities cost of $21.00 provided in HECO-2217, expressed on a per month basis, and derived as follows: [($29.78 + $21.00) ÷ 12 months = $4.23/month].

d. The marginal customer costs provided in HECO-2211 are simply one twelfth of the total annual marginal customer costs shown in HECO-WP-2217, page 85. The marginal metering costs and marginal service drops costs do not reflect the entire marginal costs of connecting a customer to the system. Connecting the customers to the system requires distribution facilities such as substations, poles, lines, and transformers – in addition to the service drops and meters.

e. HECO-WP-2217, page 61, provides the estimate of the distribution facilities costs. It is based on the costs of connecting 4 subdivisions, and provides the number of homes (or customer) per subdivision. The estimated distribution facilities cost translates to $692 per home or per customer, or $173/kW assuming 4 kW load per home.

CA-IR-589

Ref: HECO T-15, pages 11-12, response to CA-IR-340 and HECO-1504 (FAS106 OPEB Costs).

The cited testimony refers to HPUC Decision No. 13659 in support of the FAS106 regulatory asset deferral and 18-year amortization beginning January 1, 1995. The historical comparison of benefit costs presented on HECO-1504 includes an OPEB-Regulatory Asset Amortization of $1,301,839. According to pages 2 and 7 of the response to CA-IR-340, the OPEB-FAS 106 budget amounts for 2004 and 2005 set forth on HECO-1504 include $2,400,379 for the amortization of the transition obligation (i.e., TBO Amortization). Please provide the following:

a. Ordering paragraph 2 of Decision No. 13659 adopted a 20 year TBO amortization period. Is HECO amortizing the TBO over a 20-year period? Please explain the basis for any amortization period less than 20 years.

b. Please provide the amount of the original Transition Benefit Obligation being amortized and the term (i.e., 20 years) of the amortization period, indicating the effective date the amortization commenced.

c. Please provide a detailed breakdown of the components of the regulatory asset (by year of deferral) which forms the basis for the $1,301,839 OPEB-Regulatory Asset Amortization.

HECO Response:

a. Per Decision No. 13659, HECO amortizes the transition obligation over a 20-year period beginning January 1, 1993.

b. The original Transition Benefit Obligation was $93,914,980. See response of part a. above.

c. The regulatory asset represents the difference between the OPEB costs determined under SFAS 106 and the pay-as-you-go amount. The breakdown is as follows:

	1993	1994	
Service Cost	3,656,431	3,254,749	
Interest Cost	7,807,126	6,980,359	
Asset Return	0	0	
Amort of Transition Obligation	4,695,749	4,695,749	
Amort of Prior Service Cost	0	0	
Amort (Gain)/Loss	0	0	
Total SFAS 106 cost per actuary's records	16,159,306	14,930,857	
Total SFAS 106 recorded cost	16,159,306	14,930,657*	
Pay-As-You-Go Amounts	(3,109,152)	(3,098,547)	
Balance	13,050,154 +	11,832,110 =	24,882,264
1995 write-off of Reg Asset relating to Executive Life			(1,449,162)
Adjusted Reg Asset			23,433,102
Amortization beginning 1/1/95 (18 years)			1,301,839

* We are unable to identify the reason for the $200 difference between the SFAS 106 cost per the actuary's records and HECO recorded amounts.

CA-IR-590

Ref: HECO response to CA-IR-341 (FAS106 OPEB Costs).

The referenced response provides a comparison of FAS106 cost data by year since adoption in 1995. Please explain why the TBO Amortization has not remained constant, particularly referring to the BU VEBA, NBU VEBA, and the 401(h) Account.

HECO Response:

Since the adoption of SFAS 106, the Postretirement Welfare Benefits Plan for Employees of Hawaiian Electric Company, Inc. and Participating Employers has been amended several times, resulting in reductions in the postretirement benefit obligation. As instructed by paragraph 55 of SFAS 106, the reductions in the obligation were used to reduce the remaining unrecognized transition obligation. In each case, the smaller unrecognized transition obligation was amortized over the remaining amortization period, resulting in a smaller amortization amount.

CA-IR-591

Ref: HECO response to CA-IR-340 & HECO-1504 (FAS106 OPEB Costs).

The response to CA-IR-340(c) indicates that the reforecast of the 2005 FAS106 projection, based on employee demographics and assumptions as of January 1, 2005, will be completed by June 2005 and provided to the parties as soon as it is available. Even though the study is not yet complete, certain data should be currently available. Please provide the following:

a. Referring to pages 7-11 of the response to CA-IR-340, please provide the actual value of plan assets, by trust, as of 12/31/2004.

b. Please provide the distribution of the 12/31/2004 plan asset balances, supplied in response to part (a) above, between HECO, HELCO, MECO and HEI.

c. Referring to pages 8-11 of the response to CA-IR-340, the estimated gain/(loss) on plan assets for 2004 was $0. Please provide the actual gain/(loss) on plan assets, by trust, for 2004.

HECO Response:

a. See page 2.

b. See page 2.

c. See page 2.

HEI FAS 106
Disclosure
12/31/2004

ASSET RETURN RATE: **9.00%**

ASSET (GAIN)/LOSS

ELEC DISC	HECO	HELCO	MECO	HEI	TOTAL
MV EOY	13,552	38,522	31,416	0	83,490
Actual Distributions	325,172	89,263	60,729	0	475,164
Actual Non-Invst Expenses	164	109	85	0	358
Actual Contributions	325,000	100,000	75,000	0	500,000
Transfers	1,910	2,603	(4,513)	0	0
MV BOY	16,790	27,912	17,142	0	61,844
Actual Return	(4,812)	(2,621)	4,601	0	(2,832)

BU VEBA	HECO	HELCO	MECO	HEI	TOTAL
MV EOY	51,771,405	11,177,714	10,275,648	0	73,224,767
Actual Distributions	2,822,946	718,904	432,002	0	3,973,852
Actual Non-Invst Expenses	11,782	2,459	2,264	0	16,505
Actual Contributions	1,161,737	682,245	511,017	0	2,354,999
Transfers	(45,869)	73,979	(28,110)	0	0
MV BOY	48,568,400	10,183,572	9,244,866	0	67,996,838
Actual Return	4,921,865	959,281	982,141	0	6,863,287

NBU VEBA	HECO	HELCO	MECO	HEI	TOTAL
MV EOY	8,661,324	1,863,454	1,799,261	841,952	13,165,991
Actual Distributions	1,916,177	287,738	270,437	37,803	2,512,155
Actual Non-Invst Expenses	43,713	10,719	9,811	5,153	69,396
Actual Contributions	4,004,378	475,011	558,070	79,090	5,116,549
Transfers	(4,549)	387	(7,897)	12,059	0
MV BOY	5,927,995	1,525,519	1,369,747	728,319	9,551,580
Actual Return	693,390	160,994	159,589	65,440	1,079,413

401(h)	HECO	HELCO	MECO	HEI	TOTAL
MV EOY	14,403,743	4,379,271	3,132,056	1,094,250	23,009,320
Actual Distributions	770,016	89,396	116,142	10,345	985,899
Actual Non-Invst Expenses	9,363	2,964	2,132	728	15,187
Actual Contributions	1,188,816	72,427	73,075	44,161	1,378,479
Transfers	(8,701)	714	(12,482)	20,469	0
MV BOY	12,718,542	4,003,225	2,894,062	962,561	20,578,390
Actual Return	1,284,465	395,265	295,675	78,132	2,053,537

TOTAL	HECO	HELCO	MECO	HEI	TOTAL
MV EOY	74,850,024	17,458,961	15,238,381	1,936,202	109,483,568
Actual Distributions	5,834,311	1,185,301	879,310	48,148	7,947,070
Actual Non-Invst Expenses	65,022	16,251	14,292	5,881	101,446
Actual Contributions	6,679,931	1,329,683	1,217,162	123,251	9,350,027
Transfers	(57,209)	77,683	(53,002)	32,528	0
MV BOY	67,231,727	15,740,228	13,525,817	1,690,880	98,188,652
Actual Return	6,894,908	1,512,919	1,442,006	143,572	9,993,405
EXP RETURN	6,663,285	1,551,774	1,337,998	137,830	9,690,887
(GAIN)/LOSS	(231,623)	38,855	(104,008)	(5,742)	(302,518)

CA-IR-592

<u>Ref: HECO T-15, page 11 & response to CA-IR-340 (FAS106 OPEB Costs)</u>.

The cited testimony indicates that the 2005 OPEB costs were reduced by $297,000, representing the electric discount (ED) for retirees, in order to avoid duplication with the lower test year revenues resulting from these discounts. Please provide the following:

a. Please provide a copy of the supporting documentation and calculations associated with the derivation of the $297,000 cited at HECO T-15, page 11.

b. Page 7 of the response to CA-IR-340 identifies an expense distribution of the electric discount in the amount of $295,549. How does this amount related to the $297,000? Please explain.

c. At page 7 of CA-IR-340, the $128.1 million beginning APBO includes $7.1 million related to the electric discount. The interest cost of $7.8 million includes about $436,000 of ED related interest cost associated with the $7.1 million ED APBO, reduced by ½ of the expense distribution. Please confirm that test year OPEB costs include this ED interest component. If this cannot be confirmed, please explain.

d. Referring to part (c) above, please explain why test year OPEB costs should include this ED interest component, since test year revenues have already been reduced for the full electric discounts provided to employees and ...

HECO Response:

(Consolidated) for the Generic Investigation of Accrual Accounting and Ratemaking Treatment of Post-Retirement Benefits Other Than Pension. Per D&O No. 13659, "The utilities in this docket may adopt, for ratemaking purposes, SFAS 106 in its entirety and include in their rates the full cost of postretirement benefits other than pensions calculated on an accrual basis pursuant to SFAS 106, effective January 1, 1993." Therefore, the ED interest component, which is part of the OPEB costs determined under Statement of Financial Accounting Standards No. 106 ("SFAS 106") should be included in the test year OPEB costs. The OPEB cost for the test year was reduced to exclude the estimated discount in the test year for retirees, since the electric discount adjustment to the test year revenues includes the retirees (see HECO T-15, page 11).

CA-IR-593

<u>Ref: HECO-1504 & response to CA-IR-340 (FAS106 OPEB Costs).</u>

HECO-1504 identifies an $886,000 adjustment reducing test year OPEB costs for executive life insurance so as to limit issues. Please provide the following:

a. Please provide a copy of the supporting documentation and calculations associated with the derivation of the $886,000.

b. Page 7 of the response to CA-IR-340 identifies an expense distribution of executive life insurance in the amount of $407,929. How does this amount related to the $886,000 cited at HECO-1504? Please explain.

c. At page 7 of CA-IR-340, the $128.1 million beginning APBO includes $7.3 million related to executive life. The interest cost of $7.8 million includes about $443,000 of executive life related interest cost based on the $7.3 million APBO, reduced by ½ of the expense distribution. Was the interest cost associated with executive life included or excluded from test year OPEB costs? Please explain.

<u>HECO Response:</u>

a. The OPEB costs for the executive life insurance was calculated by the actuary using data provided by the company on individuals and coverage amounts. The components of the

CA-IR-594

Ref: HECO response to CA-IR-340 (FAS106 OPEB Costs).

Pages 2 and 7 of the referenced response recaps the input data and OPEB cost components supporting the 2004 and 2005 budget amounts set forth on HECO-1504. The four pages immediately following these two "recap" pages provide additional detail regarding the plan assets in each of the four identified trusts. However, the sum of the individual trust asset balances do not appear to tie to the recap asset balances of $111,806,169 (2004) and $115,459,602 (2005). Please explain and reconcile these amounts into the supporting asset trust detail.

HECO Response:

The total asset balance of $111,806,169 for 2004 on the recap sheet (page 2 of the response to CA-IR-340) includes $282,503 attributable to the value of an insurance contingency fund ("ICF") with Prudential. This ICF is used to fund postretirement benefits for eight retired managers and executives from a prior contract with Prudential.

The total asset balance for 2005 on the recap sheet (page 7 of the response to CA-IR-340) does not include the ICF. The totals for the four trusts (see pages 8-11) add up to the $115,459,602 on page 7.

CA-IR-595

Ref: HECO response to CA-IR-343 (FAS106 OPEB Costs).

Please provide a copy of all correspondence and other documentation between HECO/HEI and the Company's actuary (Watson Wyatt) concerning the Medicare Reform Act (MRA) and any related estimates of the impact of MRA on FAS106 costs.

HECO Response:

See attached pages.

Watson Wyatt
Worldwide

April 1, 2005

Ms. Julie Price
Manager, Employee Benefits & Health Services
Hawaiian Electric Company, Inc.
P.O. Box 2750
Honolulu, HI 96840-0001

Re: Proposal for Medicare Rx Reform Analysis and Support

Dear Julie:

We appreciate the opportunity to work with you in crafting HEI's response to the Medicare Reform Act. We think this Act provides a great opportunity for employers to reevaluate the prescription drug benefits they offer to their retirees, and look forward to helping HEI achieve its objectives for this plan.

In this letter we summarize briefly your current situation, describe two alternative approaches for HEI to take advantage of the new Medicare Part D benefits, describe the scope of the services, and provide a budget for the work.

HEI's Current Situation

HEI provides employees who retire after 1998 with the opportunity to participate in the senior drug plan. Retirees may not elect to participate if they have earlier waived coverage.

HEI pays a portion of the premiums for the drug benefits, depending upon whether the participant was hired before or after January 1, 1999 and depending upon the participant's years of service. For those hired after that date, the maximum company-paid premium for the drug plan is coordinated with the premiums for the retiree's health care benefits.

Recent regulations clarified the provisions of the Act, including actuarial equivalence to determine whether HEI would be eligible for the federal subsidy provided to certain employers who sponsor retiree drug plans. This letter describes two approaches to assisting HEI take advantage of the new Act:

1. Analysis of available alternatives for HEI to benefit from the new legislation and recommendation of the best fit alternative for HEI and its retirees.

2. Analysis of federal subsidy only and the impact on the plan's liabilities and net benefit cost.

In addition, if the federal subsidy is the best fit or only approach being considered by HEI, Watson Wyatt will provide the actuarial attestation necessary for the federal subsidy and would be available to assist HEI to apply for the subsidy.

Alternative Approaches and Fees

1. ***Medicare Reform Analysis*** – $20,000 - $25,000

   We will review the range of alternatives with HEI and present our recommendation of the best fit alternative. Our analyses will focus on those alternatives that would best meet your objectives and will include the impact on the financial liability of the plan. .

2. ***Analysis of Federal Subsidy Only*** – -$10,000 - $15,000

   If HEI wants to pursue the federal subsidy without considering other options, we will determine at a high level that HEI's plan is actuarial equivalent to Medicare Part D benefits and analyze the impact on the financial liability of the plan.

3. ***Actuarial Attestation*** – $5,000 (plus $3,000 per plan if HEI decides to add or segment plans).

   We will perform and certify to the actuarial equivalence testing necessary for HEI to be eligible for the subsidy (assuming the plan is actuarially equivalent to the Medicare Part D benefits). The study will include both the gross test necessary to establish creditable coverage for enrollees as well as the net test showing that HEI is eligible for the federal subsidy.

The fees shown above include our standard 7% technology charge. In addition, we will add the 4.166% Hawaii excise tax to the above fees.

Alternatives 1 and 2 would require that HEI gather claims information from the health case insurers. We would provide a list of specific data elements needed to perform the analyses.

Project Team

The study and actuarial equivalence review would be headed up by Steve Carlson, FSA. Steve is a group health actuary and heads up Watson Wyatt's group health practice in Seattle. Steve's biography is shown below. He will be assisted by Douglas Lum and Betty Berni, from our Honolulu office.

Any meeting time with Steve would be conducted by video or teleconference. Th

Steve Carlson

Steve Carlson is Group & Health Care Benefits Practice Leader for Watson Wyatt in the Northwest. He is a consulting actuary with 19 years experience working with clients on the development of benefits strategies, assessment of program competitiveness, health care and disability plan design, vendor management, and the design and valuation of retiree health benefits. Steve also has experience assisting clients with benefits issues in the environment of labor contract negotiations.

Steve's clients have included many public and private organizations such as Amazon.com, Esterline Technologies, Fluor Hanford, Nordstrom, Alderwoods, PACCAR, The Oregon Education Association, State of Alaska, and Virginia Mason Medical Center.

Prior to joining Watson Wyatt, Steve was an actuary with Blue Cross of Washington and Alaska. While at Blue Cross, he was involved in the redesign and pricing of Blue Cross' medical and dental products as well as analysis of Blue Cross' provider payment approaches. Steve also has prior consulting experience with Milliman USA where he was involved in the analysis of physician and hospital reimbursement methods, HMO pricing, and the pricing of medical and dental benefit plans.

Steve received a Bachelor's Degree in Mathematics and English from Pacific Lutheran University in Tacoma, Washington. He is a Fellow of the Society of Actuaries, a member of the American Academy of Actuaries, and a member of the Western Pension & Benefits Conference. Steve is a published author on health care and health insurance issues.

* * * * * * * *

Julie, we look forward to working with you on this project. Please let us know if you would like to discuss this proposal or have any questions. Also, we would like to arrange a conference call with Steve if that would be helpful to you.

Sincerely,

Betty Berni

Betty Berni, F.S.A.
Actuary and Managing Consultant

BB:fik
J:\hei\db\coRR\2005\B4015he1.doc

Lum, Douglas (Honolulu)

From:	Lum, Douglas (Honolulu)
Sent:	February 25, 2005 2:14 PM
To:	Loo, Jennifer
Cc:	Berni, Betty (Honolulu); Smothermon, Leonard (Honolulu); FILEHON (Honolulu)
Subject:	Medicare Prescription Drug

Hi Jennifer,

Here is the Word document with suggested revisions.

Please call if you have any questions.

Doug

Medicare
escription Drug1.do

Douglas Lum
Consultant
Watson Wyatt Worldwide
737 Bishop Street, Suite 2340
Honolulu, HI 96813
Telephone: (808)535-0511
Fax: (808)531-1853
douglas.lum@watsonwyatt.com
www.watsonwyatt.com

Medicare Prescription Drug, Improvement and Modernization Act of 2003. The Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law on December 8, 2003. The Act expanded Medicare to include for the first time coverage for prescription drugs. The Act provides that persons eligible for Medicare benefits can enroll in Part D, prescription drug coverage, for a monthly premium. Alternatively, if an employer sponsors a retiree health plan that provides benefits determined to be actuarially equivalent to those covered under the Medicare standard prescription drug benefit, the employer will be paid a subsidy of 28 percent of a participant's drug costs between $250 and $5,000 if the participant waives coverage under Medicare Part D.

In May 2004, the FASB issued FSP No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." When an employer is able to determine that benefits provided by its plan are actuarially equivalent to the Medicare Part D benefits, the FSP requires (a) treatment of the effects of the federal subsidy as an actuarial gain like similar gains and losses, and (b) certain financial statement disclosures related to the impact of the Act for employers that sponsor postretirement health care plans providing prescription drug benefits. The FASB's related initial guidance, FSP No. 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," was superseded upon the effective date of FSP No. 106-2, which was the first interim or annual period beginning after June 15, 2004.

In the Company's current disclosure, the accumulated postretirement benefit obligation and net periodic postretirement benefit cost do not reflect any amount associated with the federal subsidy

because, although the Company has concluded that the benefits the plan provides are actuarially equivalent to Medicare Part D benefits under the Act, the Company may not be eligible for any employer sponsored qualified plan subsidy, partly due to caps on the Company costs for these benefits and the sharing of premiums between the Company and retirees. If the Company is eligible, it expects the impact to be immaterial. The new Medicare legislation could impact the Company's future measures of accumulated postretirement benefit obligation and net periodic postretirement benefit cost in three ways: (1) as described above, the subsidy would reduce the obligation for benefits provided by the postretirement health plan, (2) to the extent election into Medicare Part D coverage causes retirees to elect out of the Company's plan, such measures will be lower, and (3) the employer will review the plan design for alternative ways to capture savings from the Medicare prescription drug act.

Lum, Douglas (Honolulu)

From: Lum, Douglas (Honolulu)
Sent: September 09, 2004 1:01 PM
To: 'Loo, Jennifer'
Cc: Berni, Betty (Honolulu); Lee, Brenda; Horita, Sandra; FILEHON (Honolulu)
Subject: RE: Disclosure-Medicare Prescription Drug, Improvement and Modernization Act of 2003

Hi Jennifer,

Yes, to the best of our knowledge, we confirm the three items described below.

Doug & Betty

R: BB

Douglas Lum
Consultant
Watson Wyatt Worldwide
737 Bishop Street, Suite 2340
Honolulu, HI 96813
Telephone: (808)535-0511
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douglas.lum@watsonwyatt.com
www.watsonwyatt.com

-----Original Message-----
From: Loo, Jennifer [mailto:jloo@hei.com]
Sent: September 07, 2004 11:14 AM
To: Lum, Douglas (Honolulu)
Cc: Berni, Betty (Honolulu); Lee, Brenda; Horita, Sandra
Subject: Disclosure-Medicare Prescription Drug, Improvement and Modernization Act of 2003

Doug,

Can you confirm to the best of your knowledge the following?:

(1) Hawaiian Electric Industries, Inc. and its subsidiaries (the Company) have not determined that benefits provided by its postretirement benefit plans are actuarially equivalent to the Medicare Part D benefits (based on the guidance provided to date),
(2) should the federal subsidy apply, the impact on costs associated with the subsidy is expected to be immaterial, and
(3) the disclosure in the Company's Form 10-Q for the quarterly period ended June 30, 2004 (copied below) is accurate.

(Note: We are in the process of determining how best to document various processes/disclosures with KPMG LLP.)

Let me know, thanks much, Jennifer

From the Company's SEC Form 10-Q for the quarterly period ended June 30, 2004:

Medicare Prescription Drug, Improvement and Modernization Act of 2003

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law on December 8, 2003. The Act expanded Medicare to include for the first time coverage for prescription drugs. The Act provides that persons eligible for Medicare benefits can enroll in Part D, prescription drug coverage, for a monthly premium. Alternatively, if an employer sponsors a retiree health plan that provides benefits determined to be actuarially equivalent to those covered under the Medicare standard prescription drug benefit, the employer will be paid a subsidy of 28 percent of a participant's drug costs between $250 and $5,000 if the participant does not elect to be covered under Medicare Part D.

In May 2004, the FASB issued FASB Staff Position (FSP) No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." When an employer is able to determine that benefits provided by its plan are actuarially equivalent to the Medicare Part D benefits, the FSP requires (a) treatment of the effects of the federal subsidy as an actuarial gain like similar gains and losses, and (b) certain financial statement disclosures related to the impact of the Act for employers that sponsor postretirement health care plans providing prescription drug benefits. The FASB's related initial guidance, FSP No. 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," is superseded upon the effective date of FSP No. 106-2. The effective date of the new FSP for public companies is the first interim or annual period beginning after June 15, 2004.

In the Company's current disclosure, the accumulated postretirement benefit obligation and net periodic postretirement benefit cost do not reflect any amount associated with the federal subsidy because the Company is unable to conclude whether the benefits it provides are actuarially equivalent to Medicare Part D benefits under the Act. Currently there is no guidance on how actuarial equivalence is to be determined. Should the federal subsidy apply, the Company expects the impact on costs associated with the subsidy to be immaterial.

The new Medicare legislation could impact the Company's measures of accumulated postretirement benefit obligation and net periodic postretirement benefit cost in two ways: (1) as described above, the subsidy would reduce the obligation for benefits provided by the postretirement health plan, and (2) to the extent election into Medicare Part D coverage causes retirees to elect out of the Company's plan, such measures will be lower. The Company does expect that fewer retirees will opt for drug coverage in the future because (1) the premiums retirees pay to participate in the plan has increased substantially, and (2) retirees may opt for coverage under Medicare Part D instead of the Company's plan. The Company's measures of accumulated postretirement benefit obligation and net periodic postretirement benefit cost reflect lower participation rates than in prior years, based on a study of current participation. The measures are expected to decrease in the future if experience unfolds showing further evidence of lower participation rates.

Price, Julie

From: O'Brien, Myra
Sent: Monday, February 09, 2004 11:59 AM
To: Betty Berni (E-mail)
Cc: Price, Julie
Subject: Medicare / HECO Senior Drug Plan info

This is a follow-up to our Medicare Drug / HECO Senior Drug Plan information:

As of 1/31/2004, there are only 39 retirees /spouses in the Senior Drug Plan.
12 retirees(10)/spouses(2) waived coverage to date.
7 BU (bargaining unit) and 5 NBU (non-bargaining)

2003 out-of-pocket cost per person (for 20 years and over):
$116.60
Total premium: $249.93
Max. employer contribution: $133.33

2004 out-of-pocket cost per person:
$158.84
Total premium per person: $292.17
Max. employer contribution: $133.33

Phyllis/Doug will be providing you with the number of retirees after 12/31/1998 and retirees that will eventually be eligible for participation in the Sr. Drug Plan.

If you need anything else, let me know.

HMSA is looking into Medicare Part D and wrap arounds if any. Still in the reviewing stages.

Myra O'Brien
Compensation & Benefits Division
HECO - 543-4674

Price, Julie

From: Berni, Betty (Honolulu) [Betty.Berni@WatsonWyatt.com]
Sent: Saturday, February 07, 2004 6:23 PM
To: Price, Julie
Cc: Lum, Douglas (Honolulu)
Subject: Proposal for Retiree Drug Plan

Julie, at our last meeting you asked for a quote on fees for determining whether HEI's post-65 drug plan is a qualified plan for the Federal subsidy available from the new Medicare legislation and, if it qualifies, a broad estimate of the amount of subsidy and the impact on FAS 106 net periodic benefit cost.

Because HEI's cost varies from retiree to retiree based on service and hire date, the plan could qualify for one participant and not for another. We don't know yet what, if any, aggregation rules will be allowed in determining actuarial equivalence. Further, since HEI's percentage of the contribution decreases as premiums increase, very soon the plan would not qualify for any participants. Thus, the subsidy (if there is any) would be available only in the early years when [redacted] small. One other point: the rules on how to determine actuarial equivalence to Medicare Part D benefits are not yet available, which makes any calculation difficult at this time. For these reasons, we don't think it makes sense to determine when and for which participants the plan would qualify. One further consideration: Because of the variation from participant to participant and changes each year, HMSA would have a very difficult time administering any calculation of the subsidy.

So for now, we think the immediate next steps are:

1. determine impact on FAS 106 net periodic benefit cost based on a realistic assumption of the percentage of retirees who will participate in the drug plan. The current assumption is 100%, so there will be a cost reduction.

2. check with HMSA to see if they are planning to offer a product that carves out Medicare drug.

We can help with all of the above and would work with our group/health actuaries and consultants, who specialize in drug and other medical plans, on any such project.

Please call to discuss. Thanks.

Betty

Betty Berni
Managing Consultant and Actuary
Watson Wyatt Worldwide
737 Bishop Street, Suite 2340
Honolulu, Hawaii 96813
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betty.berni@watsonwyatt.com
www.watsonwyatt.com

Price, Julie

From: Berni, Betty (Honolulu) [Betty.Berni@WatsonWyatt.com]
Sent: Monday, January 12, 2004 3:36 PM
To: Yeaman, Eric; Lee, Brenda
Cc: Price, Julie; Lum, Douglas (Honolulu)
Subject: Quick Survey on Medicare Drug

I did a quick survey to see how many clients nationwide intend to reflect the Medicare drug subsidy in 2003 income. Results so far are that only 1 out of more than 10 will reflect the subsidy in 2003 income. Thought you might be interested. Regarding the one who will, the comment was:

"Only 1 out of 4 major clients will reflect. The 1 is looking for any possible expense reduction; even if it will end up being reversed in part later this year."

(I don't have the exact number because one response was just that 100% will not take subsidy into account.)

Betty

Betty Berni
Managing Consultant and Actuary
Watson Wyatt Worldwide
737 Bishop Street, Suite 2340
Honolulu, Hawaii 96813
Telephone: (808)535-0516
Fax: (808)531-1853
betty.berni@watsonwyatt.com
www.watsonwyatt.com

Price, Julie

From: Lum, Douglas (Honolulu)
Sent: Friday, January 9, 2004 7:17 PM
To: Yeaman, Eric
Cc: Lee, Brenda; Berni, Betty (Honolulu); FILEHON (Honolulu)
Subject: Medicare Drug Reform
Importance: High

Hi Eric,

As requested, we have reviewed the currently available information regarding the potential drug subsidies provided under recently enacted Medicare Drug Reform legislation. Very shortly, HEI will need to decide whether to account for the effects of the legislation immediately or to wait until the FASB issues guidance. Shown below is a memo from our research center summarizing the main issues surrounding this decision. As the memo points out, there could be disadvantages to early adoption.

Brenda asked us to estimate the impact on 2003 income of recognizing the legislation. The legislation would reduce plan costs in one of several ways. The first would be through plan changes reducing benefits because a portion would be provided by Medicare. This alternative would not reduce 2003 income because the benefits are negotiated and HEI cannot unilaterally amend the plan. Secondly, some employers would terminate their plans or pay just Medicare Part D premiums. A third alternative would be to recognize the Medicare subsidy for providing an employer-sponsored drug plan. This alternative would impact 2003 income if so elected by the plan sponsor.

In order to adopt the third alternative, HEI's plan would have to qualify for the subsidy by providing benefits that are actuarially equivalent to Medicare Part D. Because the employees pay a large portion of the drug premiums, it is not clear that the plan qualifies.

The calculation of the impact on 2003 income would involve three steps:

1) Determine whether or not HEI's plan is actuarially equivalent to Medicare Part D. Guidance on the determination of actuarial equivalence is not yet available.

2) Assuming the plan qualifies, determine projected claims costs. (Currently, we use premiums rather than claims to

instead.

In addition, over the next year, HEI will probably want to consider plan changes to coordinate benefits with Medicare drug benefits. These changes could lead to higher plan costs after the changes are adopted.

Another issue that needs to be addressed is the possible effect of reversing some of these gains or restatement of prior earnings if it should turn out that the 2003 gain recognition was too aggressive.

HEI may want to defer accounting for the legislation until after FASB guidance is issued because of the many uncertainties and possible disadvantages with respect to early adoption. In any case, additional guidance is expected from the FASB on Monday, 1/12/04. We will review this guidance and call Brenda to discuss how to proceed.

Please call if you have any questions.

Doug & Betty

Douglas Lum
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The FASB met this morning to discuss comments received on the proposed FASB Staff Position (FSP) No. 106-a, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. The Staff received 14 comment letters in response to the proposed FSP, including one from Watson Wyatt encouraging the Board to permit earlier recognition of the effect of the new law for plans that anticipate they will be eligible for the Medicare subsidy. Bruce Monte attended this morning's meeting and his notes are attached. The highlights of the decisions made at the meeting are as follows:

- Employers are permitted, but not required, to account for the effects of the Act in the first measurement date after December 8, 2003.
- If they do not account for the Act immediately, they must elect to defer accounting until the FASB issues guidance. (Exception: the adoption of any plan amendment affecting the retiree medical plan would

accordingly.

Issues:

- There is an opportunity to realize a reduction in liability disclosed at year-end. In addition, reductions in expense may be taken beginning in the first quarter, and may be reflected in guidance given to investors.
- There may be disadvantages in adopting early. If the method chosen is conservative, and a more advantageous approach is available under FASB guidance, has the opportunity been lost to take advantage of more favorable accounting? (Note that if a more advantageous method is prescribed, it

Price, Julie

From: Corporate Marketing & PR [CorporateMarketing@WatsonWyatt.com]

Sent: Thursday, December 18, 2003 7:51 AM

Subject: Follow-up: Watson Wyatt Web Conference -- Medicare Reform: How It Will Affect Employer-sponsored Health Care

Thank you for joining yesterday's web conference, "Medicare Reform: How It Will Affect Employer-sponsored Health Care." A PDF version of the presentation slides and very brief online evaluation form is available at http://www.watsonwyatt.com/us/research/webconferences/medicarerx/eval.asp. Your feedback is important to us to help plan for future web conferences.

Additional information is also available at http://www.watsonwyatt.com/medicare. If you have further questions on Medicare reform including Health Savings Accounts, please contact your local Watson Wyatt consultant.

Happy Holidays.

CA-IR-596

<u>Ref: HECO response to CA-IR-341 (FAS106 OPEB Costs).</u>

The response to CA-IR-341(c) states: "The asset method for the funding valuation has been changed effective January 1, 2004. Consequently, the value shown on the updated HECO-1504 for column q (2003) in the row labeled 'Actual Returns for Valuation' was changed from 22.13% to 2.29%." [Note: Although CA-IR-341 refers to information supplied in response to CA-IR-337, the response to CA-IR-337 has not been filed and is still outstanding as of 4/8/05.] Please provide the following:

a. Please provide a detailed explanation of the change in "the asset method for funding valuation" that was implemented 1/1/04.

b. Referring to part (a) above, please explain how the referenced "change" impacts the quantification of the actual return on assets.

c. Please provide a side by side comparison of the change in "the asset method for funding valuation" and show the impact on achieved returns.

d. In general terms, would this change in "the asset method for funding valuation" have the [illegible] asset return is significantly smaller under the new method because the ending asset value is much smaller under the new method.

c. See pages 3-5 attached to this response.

d. No. Generally, the new method could have produced lower returns in certain years and higher returns in other years. Both methods use the same market value gains and losses, but spread the recognition of those gains and losses in a different pattern. Neither method would always produce higher or lower returns than the other.

Retirement Plan for Employees of Hawaiian Electric Industries, Inc. and Participating Subsidiaries

Derivation of Valuation Value of Assets as of 1/1/2004 - Old Method

Gain or Loss 2003

	Actual	Weighted	
(1) Market Value on 12/31/2002	560,257,888		
(2) Contributions	22,651,446	3,132,267	weight calculated
(3) Benefit Payments	(35,994,987)	(17,997,494)	0.5000
(4) Admin Expenses	(351,927)	(175,964)	0.5000
(5) Expected Income at 8.5%	46,343,419		
(6) Expected Asset Value	592,905,839		
(7) Market Value on 12/31/2003	673,689,289		
(8) Gain/(Loss) for Year	80,783,450		
Actual Return:	127,126,869	23.32%	

Unrecognized Portion of Gains and Losses

Year Ended December 31	Gain/(Loss)	Recognized	Unrecognized	Gain/(Loss)
1999	144,984,387	100.00%	0.00%	0
2000	(99,775,393)	75.00%	25.00%	(24,943,848)
2001	(147,176,096)	50.00%	50.00%	(73,588,048)
2002	(150,284,891)	25.00%	75.00%	(112,713,668)
2003	80,783,450	0.00%	100.00%	80,783,450
		Unrecognized Gain/(Loss):		(130,462,114)

Adjusted Assets

	Heco	Helco	Meco	Hei	Total
(1) Market Value on December 31, 2003	490,309,770	93,546,744	77,824,403	12,008,372	673,689,289
(2) Unrecognized Gain/(Loss)	(94,950,076)	(18,115,630)	(15,070,948)	(2,325,460)	(130,462,114)
(3) Adjusted Assets (1)-(2)	585,259,846	111,662,374	92,895,351	14,333,832	804,151,403
(4) Accrued Contribution	9,686,494	2,618,450	2,330,816	1,744,669	16,380,429
(5) Total Adjusted Assets: (3)+(4)	594,946,340	114,280,824	95,226,167	16,078,501	820,531,832
(6) Corridor Test: 80%	399,997,011	76,932,155	64,124,175	11,002,433	552,055,774
120%	599,995,517	115,398,233	96,186,263	16,503,649	828,083,662
(7) Actuarial Value of Assets	594,946,340	114,280,824	95,226,167	16,078,501	820,531,832
Market Value incl/accrued	499,996,264	96,165,194	80,155,219	13,753,041	690,069,718

Retirement Plan for Employees of Hawaiian Electric Industries, Inc. and Participating Subsidiaries

Derivation of Valuation Value of Assets as of 1/1/2004 - New Method

Gain or Loss 2003

	Actual	Weighted	
(1) Market Value on 12/31/2002	N/A		
(2) Contributions	N/A	N/A	weight calculated
(3) Benefit Payments	N/A	N/A	0.5000
(4) Admin Expenses	N/A	N/A	0.5000
(5) Expected Income at 8.5%	N/A		
(6) Expected Asset Value	N/A		
(7) Market Value on 12/31/2003	N/A		
(8) Gain/(Loss) for Year	N/A		
Actual Return:	N/A	N/A	

Unrecognized Portion of Gains and Losses

Year Ended December 31	Gain/(Loss)	Recognized	Unrecognized	Gain/(Loss)
1999	N/A	100.00%	0.00%	N/A
2000	N/A	80.00%	20.00%	N/A
2001	N/A	60.00%	40.00%	N/A
2002	N/A	40.00%	60.00%	N/A
2003	N/A	20.00%	80.00%	N/A
		Unrecognized Gain/(Loss):		N/A

Adjusted Assets

	Heco	Helco	Meco	Hei	Total
(1) Market Value on December 31, 2003	490,309,770	93,546,744	77,824,403	12,008,372	673,689,289
(2) Unrecognized Gain/(Loss)	0	0	0	0	0
(3) Adjusted Assets (1)-(2)	490,309,770	93,546,744	77,824,403	12,008,372	673,689,289
(4) Accrued Contribution	9,686,494	2,618,450	2,330,816	1,744,669	16,380,429
(5) Total Adjusted Assets: (3)+(4)	499,996,264	96,165,194	80,155,219	13,753,041	690,069,718
(6) Corridor Test: 80%	399,997,011	76,932,155	64,124,175	11,002,433	552,055,774
120%	599,995,517	115,398,233	96,186,263	16,503,649	828,083,662
(7) Actuarial Value of Assets	499,996,264	96,165,194	80,155,219	13,753,041	690,069,718
Market Value incl/accrued	499,996,264	96,165,194	80,155,219	13,753,041	690,069,718

In the year of the change in asset method, the actuarial value of assets is set equal to the market value plus accrued contributions.

Retirement Plan for Employees of Hawaiian Electric Industries, Inc. and Participating Subsidiaries

2003 Investment Return

	Market	Funding Valuation	
	Value	Old Method	New Method
@ 1/1/2003	560,257,888	672,309,466	672,309,466
@ 12/31/2003	673,689,289	820,531,832	690,069,718
Benefit Payments	(35,994,987)	(35,994,987)	(35,994,987)
Payment (weighted - .489804)	(17,630,489)	(17,630,489)	(17,630,489)
Contributions (weighted)	3,132,267	3,132,267	3,132,267
Contributions	22,651,446	22,651,446	22,651,446
Accrued Contributions	n/a	16,380,429	16,380,429
Admin Expenses	(351,927)	(351,927)	(351,927)
Admin Exp (weighted - .489804)	(172,375)	(172,375)	(172,375)
Earnings - New Method	127,126,869	145,537,405	15,075,291
Investment Base - New	545,587,291	657,638,869	657,638,869
Actual Rate of Return - New	23.30%	22.13%	2.29%

Note: .489804 = (1.085^.5-1)/.085

CA-IR-597

Ref: HECO T-19, page 12 (FAS106 OPEB Costs).

In explaining why the unamortized OPEB regulatory asset should be included in rate base, the referenced testimony states at line 20: "The unamortized OPEB regulatory assets represents costs associated with services provided in 1993 and 1994, net of amounts that ratepayers have paid." Do the amounts recorded as regulatory assets in 1993 or 1994 represent accrued costs or actual out-of-pocket cash payments? Please explain.

HECO Response:

The amounts recorded as OPEB regulatory asset in 1993 and 1994 represent the difference between the OPEB costs determined under Statement of Financial Accounting Standards No. 106 ("SFAS 106") and the pay-as-you-go amount for OPEB costs, including the electric discount to retirees.

CA-IR-598

Ref: HECO T-19, pages 13 & 35 (FAS106 OPEB Costs & FAS87 Pension Costs).

In explaining who provides the OPEB liability, the referenced testimony at page 35 states: "Ratepayers provide the funds to support the OPEB NPBC and investors provide the funds contributed to the OPEB trusts. The OPEB liability is the net of the offset to the OPEB regulatory asset plus the NPBC and less the funds contributed to the trusts." Please provide the following with regard to HECO's pension accounting:

a. Does HECO record a pension liability in its books and records?

b. If no, please explain why it is appropriate to record an OPEB liability but not a pension liability.

c. If the response to part (a) is affirmative, please provide the monthly balance of such liability account in 2004 and 2005 to date and provide the amounts used to reduce rate base in the 2005 test year forecast. If none, please explain

HECO Response:

Prepaid Pension Asset
Month End Balance in $'s

2004	Jan	64,437,865
	Feb	64,524,032
	Mar	64,610,199
	Apr	64,696,366
	May	64,782,533
	Jun	65,125,159
	Jul	65,254,069
	Aug	65,382,979
	Sep	75,198,383
	Oct	75,327,293
	Nov	75,456,203
	Dec	81,085,113
2005	Jan	80,717,113
	Feb	80,349,113
	Mar	79,981,113

CA-IR-599

Ref: HECO Response to CA-IR-92; General Inflation Factor.

a. Does HECO possess any information supportive of the premise that its non-labor expenses that were not projected based upon "specific prices, inflation rates, or cost indices" do, in fact, tend to increase in direct correlation with CPI?

b. If affirmative, please provide complete copies of all such information.

HECO Response:

a. The Company does not have any specific analysis. A general inflation index, such as CPI, tracks changes in the prices of the general goods and services included in the index. In the absence of a specific price or index, it makes sense to use a general index.

b. Not applicable.

CA-IR-600

Ref: HECO response to CA-IR-331 & HECO website at http://www.heco.com/CDA/JVN/JVN_Shell/ (T&D Employees).

According to the Company's internet postings, the positions open as of April 7, 2005, were primarily in Power Supply. Comparing the actual employee counts as of February 2005 (see CA-IR-331, pages 12-20) with the Company's 2005 test year forecast (HECO-1612), the Energy Delivery department was still down 8 "Project Management" and 10 "System Operation" employees. Please provide the following:

a. "Project Management" positions:

1. Since February 2005, please state whether each "Project Management" position open as of February 28, 2005, has since been filled.

2. For those "Project Management" positions still open, please describe HECO's current plans and expected hire dates to fill those positions.

3. Please indicate whether the 2005 test year forecast was prepared in a manner that treated those open "Project Management" positions as if filled throughout 2005 and provide the approximate test year wage and benefits expense by NARUC account attributable to each such budgeted but unfilled position.

b. "System Operation" positions:

1. Since February 2005, please state whether each "System Operation" position open as of February 28, 2005, has since been filled.

2. For those "System Operation" positions still open, please describe HECO's current plans and expected hire dates to fill those positions.

3. Please indicate whether the 2005 test year forecast was prepared in a manner that treated those open "System Operation" positions as if filled throughout 2005 and provide the approximate test year wage and benefits expense

HECO Response:

a. 1. On HECO-1612, Project Management is listed under Energy Delivery as a separate entity with a 2003 recorded employee count of 6 and 2005 budget employee count of 8. During September 2004, the Project Management Division was merged into the Engineering Department. Please refer to CA-IR-331, page 14 of 28 where Project

Management (PBP) can be found listed under Engineering and has maintained their current employee count of 6. The two vacancies remain unfilled at this time.

2. Of the two vacancies, as a result of the merger, one position was eliminated. The other position is currently in the process of being filled within the Engineering Department.

3. The 2005 test year forecast was prepared in a manner that treated the eliminated position as if filled throughout 2005. The approximate test year wage and benefits expense for the eliminated position is $139,198. The breakdown of these costs by NARUC is $682, $123,707, $7,515 and $7,294 to accounts 1861, 184, 107 and 186, respectively. For the remaining vacancy, the 2005 test year forecast was prepared in a manner that treated this position as if filled beginning in March 2005. The approximate test year wage and benefits expense of this position is $115,998. The breakdown of these costs by NARUC is $568, $103,090, $6,262 and $6,078 to accounts 1861, 184, 107 and 186, respectively. The wages portion of the amounts was forecasted primarily to Energy Delivery clearing.

b. 1. Since February 28, 2005 the department has filled 6 positions, bringing the current employee count to 105.

2. System Operation intends to fill the remaining positions by the end of June 2005.

3. Yes, in the 2005 test year forecast, these positions were treated as if filled throughout 2005. The approximate test year wage and benefits expense of the 10 positions is $1,352,000. This estimate for the 2005 test year forecast includes O&M, capital and clearing costs associated with the positions. As noted in part b.1. above, 6 positions have been filled.

CA-IR-601

Ref: HECO response to CA-IR-331 & HECO website at http://www.heco.com/CDA/JVN/JVN_Shell/ (Energy Solutions Employees).

According to the Company's internet postings, the positions open as of April 7, 2005, were primarily in Power Supply. Comparing the actual employee counts as of February 2005 (see CA-IR-331, pages 12-20) with the Company's 2005 test year forecast (HECO-1612), the Energy Solutions department was still down 59 "Energy Services" and 4 "Integrated Resource Planning" employees. Please provide the following:

a. "Energy Services" positions:

1. Since February 2005, please state whether each "Energy Services" position open as of February 28, 2005, has since been filled.

2. For those "Energy Services" positions still open, please describe HECO's current plans and expected hire dates to fill those positions.

3. Please indicate whether the 2005 test year forecast was prepared in a manner that treated those open "Energy Services" positions as if filled throughout 2005 and provide the approximate test year wage and benefits expense by NARUC account attributable to each such budgeted but unfilled position.

b. "Integrated Resource Planning" positions:

1. Since February 2005, please state whether each "Integrated Resource Planning" position open as of February 28, 2005, has since been filled.

2. For those "Integrated Resource Planning" positions still open, please describe HECO's current plans and expected hire dates to fill those positions.

3. Please indicate whether the 2005 test year forecast was prepared in a manner that treated those open "Integrated Resource Planning" positions as if filled throughout 2005 and provide the approximate test year wage and benefits expense by NARUC account attributable to each such budgeted but unfilled position.

HECO Response:

a. "Energy Services" positions:

1. Effective June 28, 2004, the Energy Solutions process area was reorganized. Refer to response to CA-IR-510 (a) for explanation of the Energy Solutions process area reorganization. Effective with this reorganization the Energy Services Department and

the Integrated Resources Planning ("IRP") Division became part of the Customer Solutions process area. Because of this reorganization, the Energy Services Department and IRP Division actual employee counts as of February 2005 no longer show up under "SR VP Energy Solutions" (see CA-IR-331 page 19 of 28) but are reflected instead under "Customer Solutions" (see CA-IR-331 page 13 of 28).

Refer to CA-IR-510 (b).1 for discussion regarding "open" positions now covered under this Docket and hirings made during the March 1, 2005 through May 18, 2005 period. As of May 18, 2005, there were three Energy Services "open" positions covered under this Docket.

2. The following represents HECO's current plans and expected hire dates to fill these three "open" positions.

   a. One Customer Technology Applications Senior Technical Engineer position is still open. Efforts to fill this position are on-going. This position is envisioned to be filled by 3rd quarter 2005.

   b. The DSM C&I Direct Load Control Program Manager position remains open. This position is envisioned to be filled by the end of the year.

   c. One DSM Program Engineer who will support both the RDLC and CIDLC DSM programs remains open. However, since the approval of the programs in October 2004 the engineering and technical work associated with the load management programs has been performed by a Senior Technical Engineer "on-loan" from the Customer Technology Applications Division.

3. The 2005 test year forecast was prepared on the basis that the three "open" positions were filled on January 1, 2005. See pages 5 and 6 for approximate test year wage and

benefit expenses by NARUC account for these budgeted but unfilled three positions. Total 2005 wage and benefit expenses impact for these three "open" positions approximates $242,646 – $197,007 in wages and $45,639 in benefits.

b. "Integrated Resource Planning " positions:

1. In October 2004, the Integrated Resources Planning ("IRP") Division had filled all open positions and had an actual employee count of 5. One person resigned from HECO in December 2004 reducing the employee count to 4 and creating an open position. As of February 28, 2005, a replacement for this vacant position had not yet been found and hence the Division's actual employee count remained [redacted]

2. HECO is currently actively recruiting to find a replacement for the open Senior Resource Planning Analyst position and anticipates filling the vacancy in June 2005. This open position was unforecasted and not included in the 2005 O&M Expense Budget.

3. As indicated per HECO-1612, the 2005 test year forecast was based on budgeting for 4 IRP Division employees as follows:

   a. The impact of three forecasted positions were included in the 2005 test

In addition, the open Senior Resource Planning Analyst position referred to in (2) above is considered an HECO IRP Incremental position that was also not included in the 2005 O&M Expense Budget.

The O&M impact of both the IRP Administrative Aide and the Senior Resource Planning Analyst have been incorporated into the 2005 Test Year O&M amounts through the normalization test year adjustment of recovering HECO's incremental IRP-related costs through base rates. Refer to HECO T-10 pages 64-67 for further discussion. The 2005 wage impact of both incremental IRP positions, which is based on both positions being filled as of the beginning of the year, is an increase of $58,000 to the O&M Expense Budget Account 920 (Administrative and General Expenses – Labor). Refer to HECO-1029 for derivation of this labor adjustment. This labor adjustment is incorporated as part of the adjustment in HECO-1301 page 1.

The estimated benefits impact of both positions (on-costs approximating $16.3K) is included as part of the 2005 IRP non-labor forecast amount ($669.3K) per HECO-1029. This amount was used to compute the $560K IRP non-labor normalization adjustment which resulted in an increase to Account 921 (Administrative and General Expenses – Nonlabor). This nonlabor adjustment was incorporated as part of the adjustment in HECO-1301 page 1.

CUSTOMER SOLUTIONS
ESTIMATED 2005 NARUC WAGE/BENEFIT IMPACT SUMMARY
"OPEN" POSITIONS AS OF MAY 18, 2005

"OPEN" POSITIONS AS OF MAY 18, 2005
(3 Positions)

NARUC ACCOUNT RECAP:

NARUC	Description	2005 O&M Impact
910	Customer Assistance Expense	$197,007
921	Admin & General Expense - Nonlabor	$45,639
	TOTAL	**$242,646**

5/21/2005 CA-IR-601_a_3re ✓.xls

CUSTOMER SOLUTIONS
ESTIMATED 2005 NARUC O and M IMPACT
"OPEN" POSITIONS AS OF MAY 18, 2005

Labor [3]

Positions	Impact on Employee Count	Labor Class	Hourly Rate [1]	DSM Load Control Engineer		DSM CIDLC Program Manager		CTAD Sr. Technical Engineer		TOTAL: Estimated 2005 O&M $$$ Impact
Open as of 05/18/05, To Be Filled										
DSM Load Control Engineer	1	_TC	$30.67	$58,396	1,904					$58,396
DSM CIDLC Program Manager	1	_TC	$30.67			$58,396	1,904			$58,396
CTAD Sr. Technical Engineer	1	_TC	$30.67					$58,396	1,904	$58,396
	3			**$58,396**	**1,904**	**$58,396**	**1,904**	**$58,396**	**1,904**	**$175,188**

On-Costs [2]

EE #	On - Costs Description	2005 Final Budget Rate		DSM Load Control Engineer	DSM CIDLC Program Manager	CTAD Sr. Technical Engineer	TOTAL: Estimated 2005 O&M $$$ Impact
421	Non-Prod. Wages	$3.82	Per Productive Hour	$7,273	$7,273	$7,273	$21,819
422	Employee Benefits	$7.99	Per Productive Hour	$15,213	$15,213	$15,213	$45,639
			TOTAL ON-COSTS	**$22,486**	**$22,486**	**$22,486**	**$67,458**
			TOTAL LABOR & ON-COSTS	**$80,882**	**$80,882**	**$80,882**	**$242,646**

[1] Standard 2005 Hourly Rate taken from Rate Case Pillar Budget File (VIEWBUD05RA1_RateCaseO&M-ABM.pln)
[2] Source: On-Costs & Vehicle Rate Summary
[3] Hours shown represent estimated productive hours only. Vacation and holidays are factored in as part of EE #421.

NARUC ACCOUNT RECAP (UNFILLE POSITIONS A/O 04/05)	
NARUC 910	
Labor	$175,188
On-Costs (EE #421)	$21,819
	$197,007
NARUC 921	
Benefits	
On-Costs (EE#422)	$45,639
	$45,639
TOTAL	$242,646

CA-IR-602

<u>Ref: HECO response to CA-IR-331 & HECO website at http://www.heco.com/CDA/JVN/JVN_Shell/ (Customer Service Employees).</u>

According to the Company's internet postings, the positions open as of April 7, 2005, were primarily in Power Supply. Comparing the actual employee counts as of February 2005 (see CA-IR-331, pages 12-20) with the Company's 2005 test year forecast (HECO-1612), the <u>Customer Service</u> department was still down 10 "Customer Service" employees. Please provide the following:

a. Since February 2005, please state whether each "Customer Service" position open as of February 28, 2005, has since been filled.

b. For those "Customer Service" positions still open, please describe HECO's current plans and expected hire dates to fill those positions.

c. Please indicate whether the 2005 test year forecast was prepared in a manner that treated those open "Customer Service" positions as if filled throughout 2005 and provide the approximate test year wage and benefits expense by NARUC account attributable to each such budgeted but unfilled position.

<u>HECO Response:</u>

a. No. As of April 7, 2005 all 10 "Customer Service" positions have not been filled.

b. Customer Service Department is currently in the process of hiring the 10 positions that were vacant as of February 2005. Nine of the positions should be filled by June 2005, and the remaining positions should be filled by the end of the year.

c. The open positions were put into the 2005 test year forecast as if those positions were filled throughout the 2005 test year.

ESTIMATED WAGES

903 NARUC account, $23.00 base hourly rate * 2080 Hrs. * 10 Staff = $ 478,400

ESTIMATED BENEFITS

926 NARUC account, $7.99 benefit * 1904 (Productive Hours) * 10 Staff = $152,130

CA-IR-603

Ref: HECO responses to CA-IR-1 and CA-IR-2 (Labor & Nonlabor Expense Forecasts).

The referenced interrogatories sought detailed support underlying HECO's 2005 test year forecast. Item (b) of both interrogatories sought "copies of all calculations, spreadsheet files, 'pencil' workpapers, surveys and other analyses performed by each of the employees identified in response to part (a), documenting all work done to determine required staffing levels and overtime hours by Department, RA, Activity and NARUC Account." In response, HECO provided a significant volume of hard copy documentation. However, the information provided directly to Utilitech did not contain any "spreadsheet files." Please provide the spreadsheet files, as originally requested, in an Excel format with all cell references and formulae intact.

HECO Response:

The electronic files will be provided on a CD in a folder labeled "1st Submission – IR - 1 & 2".

CA-IR-604

Ref: HECO responses to CA-IR-1 and CA-IR-249 (Labor Hour Forecasts & Standard Labor Rates).

In response to the referenced requests, HECO separately provided hard copies of documentation showing employee work hours (CA-IR-1) and the standard labor rates used by HECO to translate those work hours into labor costs. Please provide the following:

a. For each HECO witness, please provide a recap of the work hours contained on the various "labor input sheets" that are used by Pillar in compiling the 2005 test year labor forecast. Such information should be provided in an Excel spreadsheet file format organized by labor class, such that the hours for each employee can be tied into the response to CA-IR-1.

b. Using the 2005 standard labor rates provided in the response to CA-IR-249 and the employee hours provided in response to item (a) above, please provide a "proof" of the labor costs included in the 2005 test year forecast in an Excel spreadsheet file format.

c. If the responses to items (a) and (b) above indicate that the requested information is either not available or cannot be provided in an Excel spreadsheet file format because HECO chose to prepare its 2005 forecast using software that is either not compatible with or is unable to download detailed forecast data into an Excel spreadsheet file, please provide a detailed explanation indicating how HECO considers its labor cost forecast (i.e., based on employee forecasts, which are then translated into labor hours and labor expense) to be auditable and verifiable.

d. If the responses to items (a) and (b) above do not contain the requested data in an Excel spreadsheet file format, please provide a detailed explanation as to how HECO would recommend that the Consumer Advocate quantify any ratemaking adjustments to the Company's forecasted increase in employee levels.

e. If the responses to items (a) and (b) above do not contain the requested data in an Excel spreadsheet file format, please provide a detailed explanation as to how HECO would recommend that the Consumer Advocate quantify any ratemaking adjustments to the Company's forecasted labor hours.

f. If the responses to items (a) and (b) above do not contain the requested data in an Excel spreadsheet file format, please provide a detailed explanation as to how HECO would recommend that the Consumer Advocate quantify any ratemaking adjustments resulting from revisions to the Company's forecasted standard labor rates.

HECO Response:

a. The hours, rates and amounts for the budget used to develop the 2005 test year estimate were extracted into an Excel file which will be transmitted under separate transmittal. The printed version of this file is voluminous. One copy each will be provided to the Consumer Advocate and the Public Utilities Commission under separate transmittal.

b. The amounts provided in response to part a above are the result of multiplying the respective hours by the respective labor rate. The total labor amount ($59,175,646) and labor hours (1,814,583) for 2005 provided in response to part a above ties to the direct labor dollars and hours for the 2005 budget provided in the response to CA-IR-13.

c. Not applicable.

d. Not applicable.

e. Not applicable.

f. Not applicable.

Due to the voluminous nature of the information, one copy (pages 3-82) will be provided to the Consumer Advocate and the Public Utilities Commission under separate transmittal.

CA-IR-605

Ref: HECO-2301 (Overall Revenue Requirement).

The spreadsheet files supporting HECO T-23 that have been previously provided to Utilitech do not include HECO-2301 or the referenced "Pbase.xls" or "Pdsmrev.xls" spreadsheet files. Please provide the following:

a. Please provide a copy of the referenced Excel spreadsheet files, with cell formulae, algorithms and links to other spreadsheet files intact and not converted to values.

b. If not contained in the spreadsheet files produced in response to item (a) above, please provide the algorithms used by HECO to translate the operating income and rate base, under current rates, and the proposed weighted cost of capital (i.e., 9.11%) into the amounts set forth in the "Additional Amount" column (pro forma revenue increase and related effects on other operating income and rate base elements) of HECO-2301 and HECO-2302.

HECO Response:

a. The following electronic files will be provided:

- Pbase.xls
- INPUT.xls
- Pdsmrev.xls

b. Not applicable.

CA-IR-606

<u>Ref: HECO T-8 and responses to CA-IR-2 & CA-IR-13 (T&D Outside Services).</u>

CA-IR-2 sought detailed budget information for non-labor items exceeding $50,000. None of the attachments to CA-IR-2 appear to contain any documentation supporting the development of the following forecast amounts.

normalization treatment in the context of historical levels of expense.

4. If the identified outside service amounts are included in the quantification of overall revenue requirement, what assurances can HECO provide that comparable amounts will be regularly incurred on a recurring basis in future years?

c. Wood Poles.

1. Referring to the non-labor spreadsheet provided in response to CA-IR-13, the amount forecast for wooden distribution poles ($400,000) appears to significantly exceed the average expenditures during 2000-2004.

   (a) Does the following table accurately compare historical levels of expenditures for wooden pole outside services with the test year forecast?

   (b) If not, please explain and provide any necessary corrections, including reliance on internal employees in lieu of external resources.

Year	A/C 593 Act. 471
2000 Actual	0
2001 Actual	0
2002 Actual	0
2003 Actual	486
2004 Actual	260,946
2005 FCST	400,000

2. Referring to the table in item (c) (1) above, please discuss and describe the discretionary nature of HECO's wood pole maintenance efforts and requirements.

3. In quantifying the 2005 test year forecast, please explain and describe any efforts or methods employed by HECO to normalize the cost of outside contractors for maintaining and treating wood poles. If none, please so state and explain the absence of any normalization treatment in the context of historical levels of expense.

4. If the identified outside service amount is included in the quantification of overall revenue requirement, what assurances can HECO provide that comparable amounts will be regularly incurred on a recurring basis in future years?

HECO Response:

a. Please refer to CA-IR-1, Project: Various C&M Programs Attachment A, page 8 for Vegetation Management and page 9 for Test & Treat for a breakdown of costs. The 2005 test year forecast for outside service costs for vegetation management was based on maintaining historical expenditures, as noted in item b. 2-4. The 2005 test year forecast for test and treat of wooden poles was also derived on maintaining historical expenditures, as noted in response to part c. 2-4 below.

b. 1. (a) No, the attached table above does not accurately compare historical levels of expenditures for outside vegetation management services with the test year forecast. Please refer to b. 1. (b) for the revised tables.

(b) During the period 2000 – 2004, Vegetation Management outside services was charged to EE 501 and 505. The tables below illustrate the breakdown between the EE and the totals. Please also refer to response to CA-IR-66, which was filed with the Consumer Advocate and the Department of Defense on April 12, 2005, which discusses the use of EE 501 and 505.

Transmission - (Outside Contractors- Tree-trimming)

Year	A/C 571 RA PDV Act. 355 EE 501	A/C 571 RA PDV Act. 355 EE 505	A/C 571 Act. 355 Other RA's	Total
2000 Actual	$525,504	$196,591	$61	$722,156
2001 Actual	2,282	487,240	0	489,522
2002 Actual	4,723	500,714	3,980	509,418
2003 Actual	354	419,938	375	420,667
2004 Actual	184,260	318,271	0	502,531
2005 FCST	500,004	0	5,000	505,004

Distribution (Outside Contractors – Tree-trimming)

Year	A/C 593 RA PDV Act. 494 EE 501	A/C 593 RA PDV Act. 494 EE 505	A/C 593 Act. 494 Other RA's	Total
2000 Actual	$1,339,735	$21,413	$18,348	$1,381,079
2001 Actual	480	1,349,372	426	1,350,278
2002 Actual	(7,227)	1,236,868	0	1,229,641
2003 Actual	3,816	1,724,155	(5,925)	1,722,046
2004 Actual	1,470,359	27,505	0	1,497,864
2005 FCST	1,360,004	0	0	1,360,004

Total

Year	A/C 571 RA PDV Act. 355 Total	A/C 593 RA PDV Act. 494 Total	Total
2000 Actual	$722,156	$1,381,079	$2,103,235
2001 Actual	489,522	1,350,278	1,839,800
2002 Actual	509,418	1,229,641	1,739,059
2003 Actual	420,667	1,722,046	2,142,713
2004 Actual	502,531	1,497,864	2,000,395
2005 FCST	505,004	1,360,004	1,865,008

2-4. The revised tables in b. 1. (b) illustrate that the program is not operated in a "discretionary" manner. Also, please note that although amounts are budgeted for transmission and distribution, during the year the focus may shift between the two areas, and therefore the budget is viewed in total. The vegetation management program is designed such that the entire island is divided into 26 regions. Based on the location and type of growth a "return" cycle of between 12 and 15 months is assigned to each region. Outside contractors are assigned to perform the trimming work on these 26 regions. For several years we had a starting budget of approximately $1.8 million for outside contractors roughly based on historical expenditure levels. Based on this starting budget and considering work schedules, "return" cycles and HECO Arborists' and contractors' experience with actual vegetation growth rates in these regions, additional work is done if necessary. For the 2000 to 2004 period, the average amount of outside contractor expenditures was $1,965 million. Based on recent experience it appears the 2005 forecast understates actual expenditures by approximately $100,000.

c. 1. (a) No, the attached table above does not accurately compare historical levels of expenditures for wooden pole outside services with the test year forecast. Please refer to response to c. 1. (b) below for revised tables.

(b) During the period 2000 – 2004, Test & Treat outside services were charged to EE 501 and 505. The tables below illustrate the breakdown between the EE and the totals. Please also refer to response to CA-IR-66 (filed with the CA and the DOD on April 12, 2005) which discusses the use of EE 501 and 505.

Year	A/C 593 Act. 471 EE 501	A/C 593 Act. 471 EE 505	Total
2000 Actual	$0	$571,236	$571,236
2001 Actual	0	179,285	179,285
2002 Actual	0	146,676	146,676
2003 Actual	486	383,864	384,350
2004 Actual	260,946	38,457	299,403
2005 FCST	400,000	0	400,000

2-4. The program is not operated in a "discretionary" manner. The 2005 test year forecast was based on maintaining the same level of expenditures as 2003 and 2004. The actual costs in 2004 are lower than 2003 actual and 2005 estimated amounts due to approximately $100,000 of 2004 invoices that were not processed until 2005. Taking this into account, the 2003 ($384,350) and 2004 ($399,403) actual costs are comparable to the 2005 test year forecast. During 2001 and 2002, the work performed was lower as the scope of the program was being revised. The program now includes additional data collection, including, but not limited to, Global Position System (GPS) data, field pictures and the ability to access data electronically.

CA-IR-607

Ref: HECO T-9 and responses to CA-IR-2 & CA-IR-13 (Customer Accounts – Outside Services).

CA-IR-2 sought detailed budget information for non-labor items exceeding $50,000. None of the attachments to CA-IR-2 appear to contain any documentation supporting the development of the following forecast amounts.

A/C	RA	Act.	EE	2005 $	
901	PCA	720	501	$100,000	Improve Bus. Process
903	PCA	600	501	485,035	Cust. Inquiries
903	PCA	614	501	100,000	Proc. Verify Mail Bills

Please provide the following:

a. For each of these items, please explain and provide a copy of all related workpapers and analyses showing how the forecast amounts were determined.

b. Referring to the non-labor spreadsheet supplied in response to CA-IR-13, the amounts forecast for each of these items appear to significantly exceed the average actual expenditures during 2000-2004.

1. Does the following table accurately compare historical levels of expenditures for these items with the test year forecast?

2. If not, please explain and provide any necessary corrections, including reliance on internal employees in lieu of external resources.

Year	A/C 901 RA PCA Act. 720 EE 501	A/C 903 RA PCA Act. 600 EE 501	A/C 903 RA PCA Act. 614 EE 501
2000 Actual	$3,155	$7,918	$17,026
2001 Actual	616	90,706	24,258
2002 Actual	247	335,717	4,521
2003 Actual	0	252,462	26
2004 Actual	13,620	-116,231	177,342
2005 FCST	100,000	485,035	100,000

c. Referring to the table in item (b) above, please discuss and describe the discretionary nature of HECO's reliance on outside contractors in these customer service areas.

d. In quantifying the 2005 test year forecast, please explain and describe any efforts or methods employed by HECO to normalize the cost of outside contractors for customer accounting purposes. If none, please so state and explain the absence of any normalization treatment in the context of historical levels of expense.

e. If the identified outside service amounts are included in the quantification of overall revenue requirement, what assurances can HECO provide that comparable amounts will be regularly incurred on a recurring basis in future years?

HECO Response:

a. A/C	RA	Act.	EE	2005$	Act. Description
901	PCA	720	501	$100,000	Improve. Bus. Process - See Page 4
901	PCA	600	501	$485,035	Cust. Inquiries – Refer to CA-IR-2 Project No. P0000571 CIS for $167,353 of this total. See Pages 5-9 for $313,500 of this total. The balance of $4,182 is for miscellaneous expenses for the Department.
901	PCA	614	501	$100,000	Proc. Verify Mail Bills – See Page 10

b. 1. Yes

2. Not Applicable

c. This is explained in the testimony HECO T-9, page 10, and lines 12 – 5. "Ongoing use of various experts and consultants enable us to get the benefit of expert assistance as needed on specialized areas. We utilize exert and specialist help on a part time basis in order to balance the high cost of outside experts with the value and benefit of such resources. We believe that this is an effective way to utilize expert assistance without having to maintain a staff of experts/specialists."

d. There were no efforts or methods employed by HECO to normalize the cost of outside contractors for customer accounting purposes. As explained in the testimony HECO T-9, page 10, lines 2-5. "The increase in the non-labor expense is primarily due to operational initiatives including technical improvements, support, customer initiatives and other related customer operations projects."

e. HECO will need to spend comparable amounts on a recurring basis in the future. This is explained in the testimony HECO T-9, page 5, and lines 6-14. "Significant advances in customer technology and widespread increases in the use of costly and sensitive electronic consumer products and appliances have created a more sophisticated class of customers, with growing needs and expectations. To keep abreast of evolving customer demands and to better serve its customers, HECO has continued to evaluate and pursue new or improved initiatives, systems and tools. As these have grown to meet customer and operating needs, so has the Customer Service Department's need for additional and/or different staffing, skills and resources to develop, implement, operate and maintain these system and tools."

PROJECT IDENTIFICATION FORM

Project Title: CSD Continuous Improvement

Perm Project Number: P0000694
Code Block **PCA720**PHEP0000694**501**

Purpose/Objectives:
To insure that CSD continues to initiate new process improvement initiatives and sustains and increases performance of implemented initiatives.

Scope Description:
On going program to identify, implement and sustain process improvements.

Resource Needs:

Labor
None

Materials and Supplies
none

Outside Services
Consultant Estimate $100,000.00

Justification:
[redacted]

PROJECT IDENTIFICATION FORM

Project Title: Promote e-Customer Service

Perm Project Number: P0000984
Code Block **PCA600**OAHP0000984**501**

Purpose/Objectives:

1. To encourage customers to use electronic channels, when it makes sense, to conduct business with HECO.
2. To provide our technically inclined customers more "frictionless" means of conducting business with HECO.

Scope Description:

Primary:
1. complete assessment of current infrastructure supporting e-customer services
2. strengthen current infrastructure, where needed, to deliver excellent e-customer services
3. inform, educate, and assist customers in using e-customer services

Secondary:
1. complete assessment of what customers want
2. complete assessment of what we have
3. prioritized list of what we can and will provide
4. assessment of whether to build or buy services in item 3
5. deliver services identified in item 3

Resource Needs:

Labor
assess current infrastructure, improve current infrastructure, manage promotional campaigns, identify new e-services to provide, deliver and support new e-services. Estimate $14,721.00

Other
bill inserts, postage, printing materials and IT support. Estimate $62,000.00.

Outside Services
customer assessment of what they want, campaign development, designer services, printing services, mailing services, possible e-service provider fees, training to upgrade current workforce skills. Estimate $100,000.00.

Justification:

Useful and reliable e-services will enhance HECO's corporate image as a proactive company and, ultimately, gain the trust and confidence of our customers. We have seen the positive effect of leading edge technology applied to our commercial customers' needs.

Project Title:	Bill Payment System
Perm Project Number:	P0000985
Code Block	**PCA600**OAHP0000985**501**

Purpose/Objectives:
To determine the costs and benefits of offering credit card payment options to our residential customers.

Scope Description:
1. Pilot offering credit card payment to a small, targeted segment of our residential customer base. Target a group of customers such that net cost to HECO is limited to $100,000 annually.
2. Assess financial impact to HECO, and utlimately, its customr base.
3. Assess customer satisfaction with new payment option.
4. Perform cost-benefit analysis of this payment option.

Resource Needs:
Labor
project oversight and subject matter experts. Estimate $7,833.00

Matrials and Supplies
none

Outside Services
management of project and credit card fees. Estimate - Managment $24,000; Credit Card fees $100,000 based on a rate of 2 1/2 %.

Justification:
As credit cards increase in popularity as the preferred payment option, the demands for HECO to directly offer this option increases.

PROJECT IDENTIFICATION FORM

Project Title: Global Positioning System

Perm Project Number: P0000986
Code Block **PCA600**OAHP0000986**501**

Purpose/Objectives:
Upgrade the current GPS system to improve coverage.

Scope Description:
1. Evaluate and compare various vendors and networks to identify best fit.
2. Install new system and subscribe to new network service.
3. Test and implement features of new system.

Resource Needs:
Labor
project oversight and subject matter experts. Estimate $3.977.00

Materials and Supplies
none

Outside Services
Global Positioning System technology and network service subscription. Estimate $18,000.00 annually

Justification:
There currently exists blank spots on the island where communication and monitoring capabilities are lost. An upgraded system would also allow for the potential of enhanced navigational capabilities which could help the field people complete their work more efficiently.

PROJECT IDENTIFICATION FORM

Project Title: 3rd Party Pay Solutions

Perm Project Number: P0000987
Code Block **PCA600**OAHP0000987**501**

Purpose/Objectives:
Expand current locations where customers can make a walk-in payment.

Scope Description:
1. analyze current walk-in payments to identify best locations for new walk-in sites
2. work with American Payment Systems to implement walk-in locations where our customers can make a payment

Resource Needs:
Labor
project oversight and subject matter experts. Estimate $2,410.00

Materials and Supplies
none

Outside Services
Consulting and setup fees. Estimate $22,000.00

Other
IT support. Estimate $4,000.00

Justification:
Partnering with 3rd party payment providers offloads the higher cost of walk-in payments. Studies and experience show that customers who walk-in to make payment sare usually not too sensitive to the minimal fee. Their main concern is paying their bill and preventing a disconnect.

PROJECT IDENTIFICATION FORM

Project Title: Access-Solutions to Issues

Perm Project Number: P0000988
Code Block **PCA600**OAHP0000988**501**

Purpose/Objectives:

1. Understand current issues and situations that prevent HECO from accessing customer meters safely and timely.
2. Develop systems and processes that allow HECO to access meters on customer property safely.

Scope Description:

1. Analyze existing access issues.
2. Categorize and prioritize issues.
3. Identify issues with greatest cost and risk to HECO.
4. Develop solutions for high-cost, high-risk situations.

Resource Needs:

Labor
project oversight and subject matter experts. Estimate $11,996.00

Materials and Supplies
none

Outside Services
analyze current issues; develop solutions. Estimate $49,500.00

Justification:

Access issues are situation where HECO personnel are unable to access company meters for: readings, disconnects, repairs, and reconnects. It is to the customer and HECO's benefit to complete any of these functions on the first visit.

PROJECT IDENTIFICATION FORM

Project Title: Competitive Pricing/Billing

Perm Project Number: P0000686
Code Block **PCA614**OAHP0000686**501**

Purpose/Objectives:
To offer new competitive pricing options to customers as determined by customer and regulatory strategy, or as required by legislation. To further insure that the Company is able to bill all new competitive rate options to all customers when needed.

Scope Description:
Feasibility assessment for competitive rate offerings.

Resource Needs:
Labor
None

Materials and Supplies
none

Outside Services
Consultant Estimate $100,000.00

Justification:
Competitive rate options will be initiated by the Company or may otherwise be required in the near future.

CA-IR-608

Ref: HECO T-10 and responses to CA-IR-2 & CA-IR-13 (Customer Service – Outside Services).

CA-IR-2 sought detailed budget information for non-labor items exceeding $50,000. None of the attachments to CA-IR-2 appear to contain any documentation supporting the development of the following forecast amounts.

A/C	RA	Act.	EE	2005 $	
910	PNR	750	501	$250,000	Maint. Cust. Relations
910	PSA	105	501	100,000	Dev. Marketing Prog.

Please provide the following:

a. For each of these items, please explain and provide a copy of all related workpapers and analyses showing how the forecast amounts were determined.

b. Referring to the non-labor spreadsheet supplied in response to CA-IR-13, the amounts forecast for each of these items appear to significantly exceed the average actual expenditures during 2000-2004.

   1. Does the following table accurately compare historical levels of expenditures for these items with the test year forecast?
   2. If not, please explain and provide any necessary corrections, including

HECO Response:

a. There are no workpapers that develop the program estimates for the two forecast amounts identified above. The $250,000 under RA PNR (Technology Division) represents an estimate for development and implementation costs of a Green Power program. As indicated in HECO T-10 page 4, this expense was eliminated from the O&M Expense Budget, and therefore from Test Year expenses, because the O&M Expense Budget for the Administrative Division of the Energy Services Department included $100,000 for this same program.

b. 1. Yes, with respect to A/C 910 RA PNR items. However, with respect to A/C 910 RA PSA items the historical levels do not appropriately reflect the expenditures related to the proposed test year program.

2. 2000-2004 charges for PSA Act. 102 EE 501 relate primarily to PCEA conference

c. 2002 and 2004 expenditures of $27 and $12 respectively represent miscellaneous non-labor charges.

d. 2003 expenditures of $189 represent PCEA registration fee for the Energy Services Department Manager. In 2003, the Marketing Services (PSN) Division of the Energy Services Department conducted the PCEA conference; therefore, PCEA conference expenditures were coded to the PSN Division.

Revisions to the table that reflect Green Power program activity only are shown in the table below.

Revised Table:

Year	A/C 910 RA PNR Act. 750 EE 501	A/C 910 RA PSA Act. 102 EE 501
2000 Actual	$0	$0
2001 Actual	0	0
2002 Actual	0	0
2003 Actual	0	0
2004 Actual	0	0
2005 FCST	250,000	100,000

c. At this time, it is not the intention of HECO to hire an outside contractor to develop or implement the Green Power program, although that remains an option depending on the discretion of HECO's management. Instead, HECO intends to hire a consultant to assist in the development of the program and to use regular HECO staff to implement and administer the program.

d. Yes. Please see HECO's response to part a. above.

e.. Please refer to HECO's response to CA-IR-79.

CA-IR-609

<u>Ref: HECO T-13 and responses to CA-IR-2 & CA-IR-13 (A&G Expense – Outside Services).</u>

CA-IR-2 sought detailed budget information for non-labor items exceeding $50,000. None of the attachments to CA-IR-2 appear to contain any documentation supporting the quantification of the following forecast amounts.

A/C	RA	Act.	EE	2005 $	
921	P3V	753	501	$120,000	Maint. relat. w/commun.
921	P9S	730	501	480,000	Dev. & Adm. Bus. Plan
921	P9V	700	501	606,400	Research New Technol.

Please provide the following:

a. For <u>each</u> of these items, please explain and provide a copy of all related workpapers and analyses showing how the forecast amounts were determined.

b. Referring to the non-labor spreadsheet supplied in response to CA-IR-13, the amounts forecast for each of these items appear to significantly exceed the average actual expenditures during 2000-2004.

1. Does the following table accurately compare historical levels of expenditures for these items with the test year forecast?

d. In quantifying the 2005 test year forecast, please explain and describe any efforts or methods employed by HECO to normalize the cost of outside contractors in these areas. If none, please so state and explain the absence of any normalization treatment in the context of historical levels of expense.

e. Referring to the $120,000 item (maintain relations with the community), CA-IR-2, Attachment 26 (pages 2-10) discusses government relations, community affairs,

increasing the Community Service fund by $20,000 to "enhance goodwill and maintain active relations." Please provide the following:

1. According to the referenced materials, the $20,000 was added to a base forecast

1. Please describe the specific work undertaken by or expected to be assigned to Communications-Pacific and Alani Apio, providing the amounts associated with each.

2. Please provide specific planning details regarding the nature of the specific work to be undertaken that is described as "an additional amount for specific services" for which examples were given on Attachment 23, page 2.

3. Please elaborate on the "community process," specifically discussing the ratepayer benefits of assisting high school film programs, target message paths, and emergency grants to high school programs (Searider Productions).

4. Please provide a detailed explanation of the projects undertaken by Searider Productions and what facilitated HECO's decision to provide the emergency grant.

HECO Response:

Please note that the descriptions for activities 700 and 730 in the first chart above are reversed and should be corrected as follows:

A/C	RA	Act.	EE	2005 $	
921	P3V	753	501	$120,000	Maint. relat. w/commun.
921	P9S	730	501	480,000	Research New Technol.
921	P9V	700	501	606,400	Dev. & Adm. Bus. Plan

a. P3V. The Test Year 2005 amount was determined by a review of past expenditures and recognition of future community relations opportunities related to known projects in the leeward coast area.

P9S. See HECO's response to CA-IR 2, at HECO T-13 Attachment 21 page 5 for an explanation on the P9S test year budget.

P9V. The Test Year 2005 amount was determined by looking at past expenditures in the area and looking at the upcoming public affairs challenges, most particularly the new generating unit at Campbell Industrial Park and the Wind Farm at Kahe.

b. 1. P3V. No, the table does not accurately compare historical expenditures with the Test

[redacted]

are charged to various activities depending on the work being performed. The recorded outside service costs for Public Affairs are as follows:

2000	0
2001	450,000
2002	100,058
2003	155,342
2004	397,448

1. P3V. See response to part b1 for P3V.

   P9S. There are no corrections to be made on the P9S Test Year 2005 amount. Internal [redacted]

   However, since the renewable energy activities in the P9S test year budget will focus outsider perspective is maintained at all times.

d. P3V. As shown in response to part b1 for P3V, the historical expenditures are in line with the Test Year 2005 estimate.

P9S. As discussed in response to part b1 for P9S, since the Energy Solution & Technology Department is new and growing, the comparison of historical expenses to normalize outside contractors would be inappropriate.

P9V. The Test Year 2005 estimate is the level expected to be spent for the foreseeable future. It has taken a couple of years to calibrate the amount and to some extent, it remains project dependent, but this amount is appropriate based on our experience.

e. 1. The Test Year 2005 amount is to fund community related activities, to enhance goodwill and maintain active relations with communities and civic groups where utility facilities selectively impact a community.

2. The $100,000 was considered to be an appropriate estimate based on past experience, adjusted upward for additional community relations challenges to enhance goodwill.

f. 1. The Renewable Portfolio Standard ("RPS") law is a requirement that a certain percentage of an electric utility's energy be generated by using renewable resources. Hawaii's original RPS statute was enacted in 2001 (Act 272) and later modified in 2004 (Act 95).

2. The $180,000 for consultants and outside legal counsel and $300,000 for outside services is based on experience we have had to date in defining and implementing new technology within the Company.

3. HECO will be evaluating new technology to meet the RPS. This would include market studies and limited demonstrations of fuel cells, advanced wind technology, advanced

photovoltaic technology and in the long term, wave energy.

4. HECO remains committed to the maintenance of a reliable and affordable electric system and full integration of renewable energy, conservation, energy efficiency and demand side management in our mix of energy options. These new tools will stand beside the more traditional thermal generation of electricity with oil and coal in bringing HECO into its new energy future.

g. 1. Communications Pacific (CommPac) provides a variety of services to the Company. These include advising us on, and assisting us in executing, good community process; advising us on the consistency and quality of our messages to the community; connecting us with other companies and agencies so that we can take maximum advantage of shared expenses and shared challenges. On this final point, it should be noted that among CommPac's clients, are the Board of Water Supply, Kamehameha Schools and Chevron, each of whom has faced similar challenges to ours.

One of the choices the Company had to face in light of the Wa'ahila Ridge and Keahole controversies was how to dramatically improve our work with impacted communities. It was obvious to everyone that not only were these controversies very challenging in terms of getting our job done, they were also very expensive, an expense for which the Company would clearly seek compensation from the ratepayer.

Part of the Company's response was to create the Public Affairs process area including its Community Relations area. There are, however, two solid reasons for supplementing that hiring: First, we get the services of dozens of experts at CommPac and we get those services in specialty areas only to the extent we need them; and second, it provides an ongoing outside perspective to our work. That outside look, to be on our side but still to be somewhat detached as an observer, is critical to keeping our efforts on track.

We meet with CommPac every two weeks to go over all major public activities of [redacted]

profile in the community, they connect us with partners in the community, and at times, they have even represented us. Without their involvement, we would not have successfully negotiated a settlement in the Keahole controversy or moved the East Oahu Transmission Project to the state it is in. The amount expected to be spent on both are currently in the negotiation phase and represent the types of items which must be funded as part of open and transparent public process.

And again, the principle at work here is that an open and transparent community process will allow for better decisions on key projects, made at earlier stages (thus reducing costs), and avoiding protracted disputes with their very heavy costs to all involved.

3. One of the keys to communicating successfully with communities is to find out how the communities themselves want the communication to occur. In the case of West Oahu and Waianae, we were specifically asked, for example, to work with the school film programs, with media in the area such as West Side Stories, and with programs such as Ma'o Farms and Ka'ala Farms. We believe that the messages will be both received in a factual sense and also received in a content sense if we follow this advice.

   The key is who people go to for leadership and what those people say about the project. And to repeat, the goal is to have project decisions made quickly and for the right reasons. That makes sense for the ratepayer and for us, both from a system side and from a cost side.

4. Searider Productions (Searider) has engaged in numerous projects for both not-for-profit causes and for commercial clients. They have expressed an interest in becoming involved in our conservation education plans. Last fall, however, we received information that Searider was in financial distress. In order to continue working with Searider, HECO provided them a grant.

CA-IR-610

<u>Ref: HECO T-16 and responses to CA-IR-2 & CA-IR-13 (Miscellaneous General Expense – Outside Services).</u>

[redacted]

to a $616,500 technology item (Account 9302, RA PNR, Act. 730, EE 501), CA-IR-2 (Attachment 1, p. 2) refers to Attachment 9 for support. Attachment 9 discusses three renewable energy R&D, Development and Demonstration areas: local EPRI matching funds, recurring renewable seed money, and a wind initiative. Please provide the following:

a. Please compare and contrast the nature of the work included within the $616,500 technology items included in Account 9302 with the $480,000 included in Account 921 by HECO T-13 for similar endeavors.

The renewable energy activities in Account 921 will concentrate on the long-term—technologies and policy issues. These activities would include, but would not be limited to, hydrogen energy, fuel cells, advanced energy storage systems, and other emerging technologies that could have a place in Hawaii's generation mix in the future. Renewable energy activities in Account 921 will also address the revolving and evolving energy policies. Some of the state and federal energy policies are renewable portfolio standards, net energy metering, system benefit charges, protecting the environment, reducing impact on customer rates, energy security, carbon emissions, energy credit trading, tax credits, and other energy policies. HECO is taking steps to be even more proactive in the renewable energy field by looking at the next steps and next technology that will help increase renewable energy on Oahu.

b. See response in a.

c. Comparable actual local EPRI matching funds for HECO in calendar years 2000-2004 are provided below:

- 2000: $452,049
- 2001: $225,720
- 2002: $155,000
- 2003: $303,479
- 2004: $243,300

CA-IR-611

<u>Ref: HECO Response to CA-IR-449 EFOR Rates.</u>

According to the response, "...a substantial amount of boiler, turbine, generator and other work was done to Honolulu Unit 8 to restore its condition." Please respond to the following regarding this statement:

a. Explain the degree of deterioration in the condition of each major system within Honolulu Unit 8 and how long HECO had been aware of such deterioration.

b. Describe what incremental work, above and beyond recent typical unit overhaul scoping, was required to restore the condition of the Unit.

c. Provide HECO's best estimate of the incremental capital and expensed costs incurred in connection with the incremental work described in your response to part b.

d. Which of the incremental work elements identified and quantified in your responses to parts b and c, respectively, will <u>not</u> be recurring in future overhauls of the unit?

e. What has been the historical overhaul interval/schedule for the Unit?

f. What will be the ongoing future overhaul interval/schedule for the Unit?

<u>HECO Response:</u>

a. As shown in HECO-601, Honolulu 8 is 50 years old (in 2004), and operates daily as a cycling unit. The unit was available and operated in daily cycling mode up until the planned outage that started on April 12, 2003. Based on the age of H8, daily cycling operation, and unanticipated problems found on its sister unit, Honolulu 9, during its overhaul in 2002-2003, similar problems were anticipated on H8. A description of the scope of repairs [illegible] material was required to repair the H9 turbine cylinder, and 1400 pounds of weld material was required to repair the H8 turbine cylinder. The weld preparation procedures and repairs were developed using in-house expertise and, to HECO's knowledge, was never before performed in the utility industry. The benefit to the ratepayer is the avoidance of purchasing a new cylinder with approximately 2 years lead time. The results, as experienced on the H9 repairs, were very successful.

The generator rotor was rewound after inspection of the end turns revealed fractures in the coil caused by cyclic fatigue due to daily starting and stopping (cycling duty). The rewind was unanticipated.

The boiler underwent replacement of all tube connections to the front and rear waterwall headers based on previous tube leak repairs.

b. The incremental work performed beyond recent overhaul scope included the following:

- Capital projects identified in CA-IR-41, Attachment 2, page 2.
- Turbine cylinder crack repairs
- Boiler front and rear waterwall header tube connections

c. Capital projects and costs for the Honolulu 8 planned outage are provided in CA-IR-41, Attachment 2, page 2. It is not possible to estimate the O&M incremental cost impact due to the age of the unit, and the uncertainty of the longevity of the extensive repairs on the turbine cylinder and boiler waterwalls. The boiler waterwall header connections will be inspected during the next boiler planned outage in three years. The turbine cylinder will be inspected during the next turbine planned outage in six to nine years.

d. All of the repairs and capital improvements can be expected to recur in future overhauls. The longevity of repairs and capital improvements depends on many factors as described throughout HECO T-6. Also, the repairs and capital improvements included in the scope of [redacted] unit, and will require repairs and/or replacement at some point into the future. Of the repairs and improvements completed during the 2003 planned outage, the generator rewind and boiler waterwall front and rear header tube connections are expected to last well into the future. While extensive weld repairs were completed on the turbine cylinder, cracking in

CA-IR-612

<u>Ref: HECO Response to CA-IR-449 EFOR Rates.</u>

According to the response, "Another example is Waiau Unit 9. It has a five-year (2000-2004) average EFOR of 26.2%. The unit suffered a major force outage in October 2004 due to considerable blade damage in the compressor. (See HECO's response to CA-IR-129). A substantial amount of work is being done on the unit to restore its condition." Please respond to the following regarding this statement:

a. Explain the degree of deterioration in the condition of each major system within Waiau Unit 9 and how long HECO had been aware of such deterioration.

b. Describe what incremental work, above and beyond recent typical unit overhaul scoping, was required to restore the condition of the Unit.

c. Provide HECO's best estimate of the incremental capital and expensed costs incurred in connection with the incremental work described in your response to part b.

d. Which of the incremental work elements identified and quantified in your responses to parts b and c, respectively, will <u>not</u> be recurring in future overhauls of the unit?

e. What has been the historical overhaul interval/schedule for the Unit?

f. What will be the ongoing future overhaul interval/schedule for the Unit?

<u>HECO Response:</u>

a. All systems on Waiau Unit 9 operated normally until the catastrophic failure of the

b. In addition to the exhaust duct replacement, the inlet duct was inspected and a decision was made to replace the inlet duct material to mitigate any future source of erosion, i.e., rust particles, to the compressor blade. Other items included compressor and turbine water washing capability; replacement of the original electrostatic precipitator with a lube oil mist eliminator, and an upgrade of the Bentley Nevada turbine supervisory instrumentation.

c. The capital and O&M cost for the items in b. above are broken down as follows:

- Exhaust duct - $1,213,000 Capital

[redacted]

- Water washing - $117,015 Capital
- Inlet duct repairs - $499,522 O&M (as of 6/2/05)
- Lube oil mist eliminator - $ 72,072 O&M (as of 6/2/05).

d. The items listed above are not expected to recur in the near term.

e. Overhaul type and interval for the peaking units based on 2-year combustor inspections, 4-

maintenance outages will be scheduled to perform visual borescopic examinations of accessible sections of the compressor, turbine, generator and combustor.

CA-IR-613

<u>Ref: HECO Response to CA-IR-449 EFOR Rates.</u>

According to the response, "Waiau Unit 10 has a five-year EFOR of 14.5%, but that unit is scheduled for a lengthy planned outage in 2005 to restore its condition." Please respond to the following regarding this statement:

a. Explain the degree of deterioration in the condition of each major system within Waiau Unit 10 and how long HECO had been aware of such deterioration.

b. Describe what incremental work, above and beyond recent typical unit overhaul scoping, is required during the 2005 outage to restore the condition of the Unit.

c. Provide HECO's best estimate of the incremental capital and expensed costs to be incurred in connection with the incremental work described in your response to part b.

d. Which of the incremental work elements identified and quantified in your responses to parts b and c, respectively, will <u>not</u> be recurring in future overhauls of the unit beyond 2005?

e. What has been the historical overhaul interval/schedule for the Unit?

f. What will be the ongoing future overhaul interval/schedule for the Unit?

<u>HECO Response:</u>

a. Waiau Unit 10 has been operating reliably as indicated by the level of service hours in CA-

c. Please refer to CA-IR-612, c. As mentioned in b. above, in addition to the similar scope performed on W9, a controls upgrade (capital) is planned for W10 at a cost of $439,600.

d. Please refer to CA-IR-612, d.

e. Please refer to CA-IR-612, e.

f. Please refer to CA-IR-612, f.

CA-IR-614

Ref: HECO Response to CA-IR-451 Honolulu Power Plant Retirement.

Please provide a complete copy of the "Study completed by Sargent & Lundy" that has "shown that Honolulu Units 8 and 9 can operate reliably and cost-effectively until at least 2024."

HECO Response:

The referenced study contains confidential information. HECO will provide the study on Honolulu 8 and 9 to the Commission, Consumer Advocate and Department of Defense under a protective order when a protective order is issued.

As an alternative, please see HECO's response to CA-IR-32 (attached) in Docket No. 95-0347 (HECO IRP-2). The response provides summary conclusions from each of the remaining useful life assessments performed on all of HECO's generating units, except for Kahe 5 and 6, which are the newest units on HECO's system.

CA-IR-32

<u>Ref: IRP (1/30/98) p. 3-5; Remaining Useful Life (RUL) Assessments.</u>

HECO cites several RUL assessments used in determining the retirement dates assumed in its Annual Evaluation and IRP-97 plans. Please provide the cover pages and document the conclusions of these reports. Alternatively, provide citations to these reports if they have previously been filed with the Commission and the Consumer Advocate.

HECO Response: The cover pages for each of the Remaining Useful Life Assessment Reports are attached. The conclusions of each of the reports are summarized below:

some components, especially the electrical components. The limit of the useful life will probably be economic and the commercial development of less costly technologies."

Waiau Units 3, 4, 5, & 6: " In conclusion, there were no significant technical reasons found that will limit the operational life of the units to less than 25 additional years. However, there is relatively little available data for some components, especially the electrical components. The limit of the useful life will probably be economic and the commercial development of less costly technologies."

Waiau Units 7 & 8, Kahe Units 1 & 2: " In conclusion, there were no significant technical reasons found that will limit the operational life of the units to less than 25 additional years. However, there is relatively little available data for some components, especially the electrical components. The limit of the useful life will probably be economic and the commercial development of less costly technologies."

<u>Kahe Units 3 & 4</u>: " In conclusion, there were no significant technical reasons found that will limit the operational life of the units to less than 25 additional years. However, there is relatively little available data for some components, especially the electrical components. The limit of the

useful life will probably be economic and the commercial development of less costly technologies."

<u>Waiau Units 9 & 10</u>: " The Waiau units have operated less than 10,000 hours and are forecast to operate less than 25,000 total hours by the year 2030. Based on the above it is predicted that Waiau 9 & 10 to operate economically until 2030 at the forecast

loading. It is possible that the units may be able to operate significantly past the year 2030 but it is not practical to predict further. Therefore the scheduled retirement dates for Waiau 9 & 10 should be revised to 2030. The remaining life should be reevaluated in about 10 years or if there is a major change in HECO's needs."

Honolulu Units 8 & 9

Condition Assessment and Remaining Useful Life

Prepared for
Hawaiian Electric Company

SL-5120
June 26, 1997

Sargent & Lundy LLC

55 East Monroe Street
Chicago, IL 60603-5780 USA

Waiau Units 7 & 8 and Kahe Units 1 & 2
Condition Assessment and Remaining Useful Life

Prepared for
Hawaiian Electric Company

SL-5100
February 10, 1997

Sargent & Lundy LLC

55 East Monroe Street
Chicago, IL 60603-5780 USA

Kahe Units 3 & 4
Condition Assessment and Remaining Useful Life

Prepared for
Hawaiian Electric Company

SL-5101
March 18, 1997

Sargent & Lundy LLC

55 East Monroe Street
Chicago, IL 60603-5780 USA

Hawaiian Electric Company

Waiau Units 9 & 10

Condition Assessment and Life Extension Study

SL-5074
July 1996

Sargent & Lundy LLC

CA-IR-615

Ref: HECO response to CA-IR-260 & HECO-1605 (Rent Expense).

In response to CA-IR-260, the Company updated HECO-1605 to reflect revised lease rates, including the proposed capital lease treatment of the renegotiated King Street lease. Please provide the following:

a. In response to CA-IR-260(a), HECO summarizes its proposed ratemaking treatment of the King Street lease, as follows: $521,315 in amortization expense; $9.948 million in rate base; $10.115 million lease obligation; and a $301,365 HEI rent credit (see revised HECO-1605). Please compare the revenue requirement effect of the proposed capital lease treatment to an operating lease treatment, showing all calculations.

b. Referring to item (a) above, does HECO plan on including the long-term lease obligation in the capital structure or using it as a rate base reduction to offset the lease asset? Please explain, indicating the cost rate to be applied to any lease obligation included in the capital structure.

c. In renegotiating the King Street lease, were any economic or financial studies/analyses conducted by or for HECO/HEI for purposes of analyzing the relative costs and benefits of the renegotiated lease terms?

1. [illegible]

relevant guidance from FAS 71 is attached on page 4. The impact of the financial statement treatment is that the capital structure is impacted by the lease obligation even if the lease is treated as an operating lease for ratemaking purposes.

b. HECO proposes to include the lease obligation in its capital structure and incorporate the embedded interest rate of ~~5.789%~~ 5.75%* in its cost of capital.

c. Yes, numerous comparisons of options were prepared based on the offers as they were being considered by the Company. The comparisons are voluminous, please contact Irene Sekiya at 543-4778 to arrange for viewing.

d. Key features of the new lease are:

1. Fixed monthly payments for the twenty-year term as follows:

Effective Date to November 30, 2009	\$64,583.34
December 1, 2009 to November 30, 2014	\$71,041.67
December 1, 2014 to November 30, 2019	\$78,145.84
December 1, 2019 to November 30, 2024	\$85,960.42

2. KSBE to pay for building improvements as follows:

Effective Date to 4th anniversary	up to \$5 million
4th anniversary	additional \$2 million
11th anniversary	additional \$2 million

In the prior King Street lease dated April 18, 1980, annual payments were fixed for the first two years and eight months at \$67,000 and for the next five years at \$134,000. Thereafter, the payments were subject to renegotiation every five years. The lease was first amended on March 6, 1990 to reflect annual rent of \$385,000 for the period December 1, 1987 to November 30, 1992. On April 20, 1998, the lease was further amended to reflect annual

* INTEREST RATE CHANGED DUE TO UPDATED ASSUMPTION OF THE NEW LEASE BEGINNING JULY 1, 2005. THIS RESULTED IN A CHANGE TO THE VALUE OF THE LEASE PAYMENTS OVER THE TERM OF THE LEASE.

relevant guidance from FAS 71 is attached on page 4. The impact of the financial statement treatment is that the capital structure is impacted by the lease obligation even if the lease is treated as an operating lease for ratemaking purposes.

b. HECO proposes to include the lease obligation in its capital structure and incorporate the embedded interest rate of 5.789% in its cost of capital.

c. Yes, numerous comparisons of options were prepared based on the offers as they were being

[redacted]

rent payments of $750,000 for the period December 1, 1992 to November 30, 1997 and $775,000 for the period December 1, 1997 to November 30, 2004. HECO was responsible for all building improvements.

Per Financial Accounting Standard No. 71 "Accounting for Certain Types of Regulation"

Accounting for Leases

40. Statement 13, as amended, specifies criteria for classification of leases and the method of accounting for each type of lease. For rate-making purposes, a lease may be treated as an operating lease even though the lease would be classified as a capital lease under the criteria of Statement 13. In effect, the amount of the lease payment is included in allowable costs as rental

expense in the period it covers.

41. For financial reporting purposes, the classification of the lease is not affected by the

King St. Lease

	Capital Lease for Book and Ratemaking		Capital Lease With Recovery based on Lease Payments	
Year	Revenue Requirements	Net Income	Revenue Requirements	Net Income
2005	1,993,000	649,000	1,643,000	655,000
2006	1,933,000	623,000	1,626,000	643,000
2007	1,873,000	597,000	1,608,000	629,000
2008	1,811,000	571,000	1,588,000	615,000
2009	1,745,000	544,000	1,597,000	599,000
2010	1,672,000	516,000	1,614,000	580,000
2011	1,603,000	487,000	1,583,000	557,000
2012	1,533,000	457,000	1,551,000	534,000
2013	1,462,000	427,000	1,517,000	509,000
2014	1,384,000	395,000	1,513,000	481,000
2015	1,299,000	362,000	1,516,000	449,000
2016	1,218,000	328,000	1,467,000	413,000
2017	1,135,000	292,000	1,415,000	375,000
2018	1,050,000	256,000	1,360,000	335,000
2019	956,000	218,000	1,338,000	292,000
2020	854,000	179,000	1,323,000	242,000
2021	756,000	137,000	1,248,000	188,000
2022	655,000	94,000	1,169,000	130,000
2023	550,000	49,000	1,086,000	70,000
2024	277,000	13,000	604,000	19,000
	25,759,000	7,194,000	28,366,000	8,315,000

Assumptions Input

Cost of Capital Assumptions:	Weight	Rate	Weighted Average	After-tax Weighted Average	Weighted Average Revenue Requirement	Rev Req
ST Debt	3.00%	6.00%	0.180%	0.110%	0.198%	
Taxable Debt **	36.00%	5.63%	2.027%	1.238%	2.224%	6.179%
Preferred Stock	7.00%	8.00%	0.560%	0.560%	1.006%	
Common Stock	54.00%	12.00%	6.480%	6.480%	11.642%	
			9.247%	8.388%	15.070%	

Tax Assumptions:		
Federal	35.00%	32.89%
State	6.40%	6.02%
		38.91%

Public Service Company Tax	5.885%	(on gross receipts)
PUC Fee	0.500%	(on gross receipts)
Franchise Tax	2.500%	(on electricity sales)
Revenue Tax Rate	8.885%	

	Annual	Monthly
Incremental Borrowing Rate	5.630%	0.469%

	Total	GET	Total Including GET
Appraisal	3,470,000		
		4.0000%	
Monthly Lease Payments		4.1670%	
Effective Date to 11/30/2009	64,583.34	2,691.19	67,274.53
12/1/2009 to 11/30/2014	71,041.67	2,960.31	74,001.98
12/1/2014 to 11/30/2019	78,145.84	3,256.34	81,402.18
12/1/2019 to 11/30/2024	85,960.42	3,581.97	89,542.39
Annual Lease Payments			
Effective Date to 11/30/2009	775,000	32,294	807,294
12/1/2009 to 11/30/2014	852,500	35,524	888,024
12/1/2014 to 11/30/2019	937,750	39,076	976,826
12/1/2019 to 11/30/2024	1,031,525	42,984	1,074,509

HEI sq. ft.	8,874
Total building sq. ft.	58,313
HEI %	15%
Capitalized Leased Property	10,209,077

** Assumed "taxable debt" as theoretical quantification of the impact to HECO to simplify the analysis.
(Eliminates the need to adjust income tax deferral for adjustment to tax depreciation if revenue bond financing is assumed.)

Assumptions Input

Cost of Capital Assumptions:	Weight	Rate	Weighted Average	After-tax Weighted Average	Weighted Average Revenue Requirement	Rev Req
ST Debt	3.00%	6.00%	0.180%	0.110%	0.198%	
Taxable Debt **	36.00%	5.63%	2.027%	1.238%	2.224%	6.179%
Preferred Stock	7.00%	8.00%	0.560%	0.560%	1.006%	
Common Stock	54.00%	12.00%	6.480%	6.480%	11.642%	
			9.247%	8.388%	15.070%	

Tax Assumptions:		
Federal	35.00%	32.89%
State	6.40%	6.02%
		38.91%

Public Service Company Tax	5.885%	(on gross receipts)
PUC Fee	0.500%	(on gross receipts)
Franchise Tax	2.500%	(on electricity sales)
Revenue Tax Rate	8.885%	

	Annual	Monthly
Incremental Borrowing Rate	5.630%	0.469%

	Total	GET	Total including GET
Appraisal	3,470,000		
		[illegible].0000%	
Monthly Lease Payments		[illegible].1670%	
Effective Date to 11/30/2009	64,583.34	2,691.19	67,274.53
12/1/2009 to 11/30/2014	71,041.67	2,960.31	74,001.98
12/1/2014 to 11/30/2019	78,145.84	3,256.34	81,402.18
12/1/2019 to 11/30/2024	85,960.42	3,581.97	89,542.39
Annual Lease Payments			
Effective Date to 11/30/2009	775,000	32,294	807,294
12/1/2009 to 11/30/2014	852,500	35,524	888,024
12/1/2014 to 11/30/2019	937,750	39,076	976,826
12/1/2019 to 11/30/2024	1,031,[illegible]25	42,984	1,074,509
HEI sq. ft.	[illegible],874		
Total building sq. ft.	[illegible]8,313		
HEI %	15%		
Capitalized Leased Property	10,209,077		

** Assumed "taxable debt" as theoretical quantification of the impact to HECO to simplify the analysis.
(Eliminates the need to adjust income tax deferral for adjustment to tax depreciation if revenue bond financing is assumed.)

King Street Lease

Year			1	2	3	4	5	6
Number of Months in Year			12	12	12	12	12	12
Total Payments		(10,209,077)	807,294	807,294	807,294	807,294	854,386	888,024
Excise Tax Pmt			32,294	32,294	32,294	32,294	34,178	35,524
Lease Pmt			775,000	775,000	775,000	775,000	820,208	852,500
HEI Payments			129,353	129,353	129,353	129,353	136,899	142,289
Capital Lease Treatment								
Cash Flow								
Lease Payment			807,294	807,294	807,294	807,294	854,386	888,024
Excise Tax Expense			32,294	32,294	32,294	32,294	34,178	35,524
Interest Expense on Lease Obligation			582,315	570,932	558,878	546,111	531,934	513,484
Principal Repayment			192,685	204,068	216,122	228,889	288,274	339,016
Total Debits			807,294	807,294	807,294	807,294	854,386	888,024
Current Tax Deduction			807,294	807,294	807,294	807,294	854,386	888,024
Book Expense			1,140,399	1,129,016	1,116,961	1,104,194	1,091,901	1,074,797
Deferred Tax Base			(333,104)	(321,722)	(309,667)	(296,900)	(237,515)	(186,773)
Deferred Tax			(129,610)	(125,181)	(120,491)	(115,523)	(92,417)	(72,673)
Accumulated Deferred Tax			(129,610)	(254,791)	(375,282)	(490,805)	(583,222)	(655,895)
Leased Property			10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077
Amortization Expense			525,789	525,789	525,789	525,789	525,789	525,789
Accumulated Amortization			525,789	1,051,579	1,577,368	2,103,157	2,628,947	3,154,736
Net Leased Property		10,209,077	9,683,288	9,157,498	8,631,709	8,105,920	7,580,130	7,054,341
Ending Rate Base		10,209,077	9,812,898	9,412,290	9,006,991	8,596,725	8,163,352	7,710,235
Average Rate Base			10,010,987	9,612,594	9,209,640	8,801,858	8,380,038	7,936,794
Beginning Lease Obligation			10,209,077	10,016,392	9,812,324	9,596,202	9,367,313	9,079,038
Lease Interest Expense			582,315	570,932	558,878	546,111	531,934	513,484
Principal Repayments			192,685	204,068	216,122	228,889	288,274	339,016
Ending Lease Obligation		10,209,077	10,016,392	9,812,324	9,596,202	9,367,313	9,079,038	8,740,022
ST Debt	3.0%	306,272	294,387	282,369	270,210	257,902	244,901	231,307
Taxable Debt	36.0%	(6,533,809)	(6,483,749)	(6,423,900)	(6,353,685)	(6,272,492)	(6,140,232)	(5,964,337)
Preferred Stock	7.0%	714,635	686,903	658,860	630,489	601,771	571,435	539,716
Common Stock	54.0%	5,512,902	5,298,965	5,082,636	4,863,775	4,642,231	4,408,210	4,163,527
Total Ending Capitalization		10,209,077	9,812,898	9,412,290	9,006,991	8,596,725	8,163,352	7,710,235
Average ST Debt			300,330	288,378	276,289	264,056	251,401	238,104
Average Taxable Debt			(6,508,779)	(6,453,824)	(6,388,793)	(6,313,088)	(6,206,362)	(6,052,284)
Average Preferred Stock			700,769	672,882	644,675	616,130	586,603	555,576
Average Common Stock			5,405,933	5,190,801	4,973,206	4,753,003	4,525,221	4,285,869
Average Capitalization			10,010,987	9,612,594	9,209,640	8,801,858	8,380,038	7,936,794
ST Interest Expense	6.00%		18,020	17,303	16,577	15,843	15,084	14,286
Taxable Debt Interest Expense	5.63%		(366,444)	(363,350)	(359,689)	(355,427)	(349,418)	(340,744)
Preferred Dividends	8.00%		56,062	53,831	51,574	49,290	46,928	44,446
Return on Common	12.00%		648,712	622,896	596,785	570,360	543,026	514,304
Revenue Requirements			1,993,394	1,933,122	1,872,150	1,810,435	1,741,073	1,668,970
Revenue Taxes			177,113	171,758	166,341	160,857	154,694	148,288
Amortization Expense			525,789	525,789	525,789	525,789	525,789	525,789
Excise Tax Expense			32,294	32,294	32,294	32,294	34,178	35,524
HEI Rent Payments			(129,353)	(129,353)	(129,353)	(129,353)	(136,899)	(142,289)
Interest Expense			233,890	224,885	215,766	206,527	197,600	187,026
Income Before Taxes			1,153,660	1,107,749	1,061,313	1,014,321	965,710	914,631
Income Taxes			448,887	431,023	412,955	394,670	375,756	355,881
Preferred Dividends			56,062	53,831	51,574	49,290	46,928	44,446
Net Income			648,712	622,896	596,785	570,360	543,026	514,304

HECO:
Ending lease obligation changed due to a change in the obligation reduction as a result of the updated assumption of the new lease beginning July 1, 2005.

HECO:
Ending rate base changed due to a change in amortization expense as a result of the updated assumption of the new lease beginning July 1, 2005.

King Street Lease

Year		1	2	3	4	5	6
Number of Months in Year		12	12	12	12	12	12
Total Payments	(10,209,077)	807,294	807,294	807,294	807,294	840,932	888,024
Excise Tax Pmt		32,294	32,294	32,294	32,294	33,640	35,524
Lease Pmt		775,000	775,000	775,000	775,000	807,292	852,500
HEI Payments		129,353	129,353	129,353	129,353	134,743	142,289
Capital Lease Treatment							
Cash Flow							
Lease Payment		807,294	807,294	807,294	807,294	840,932	888,024
Excise Tax Expense		32,294	32,294	32,294	32,294	33,640	35,524
Interest Expense on Lease Obligation		586,010	574,775	562,872	550,262	536,589	518,719
Principal Repayment		188,990	200,225	212,128	224,738	270,703	333,781
Total Debits		807,294	807,294	807,294	807,294	840,932	888,024
Current Tax Deduction		807,294	807,294	807,294	807,294	840,932	888,024
Book Expense		1,139,619	1,128,364	1,116,481	1,103,871	1,091,543	1,075,558
[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

King Street Lease

Year	7	8	9	10	11	12	13	14
Number of Months in Year	12	12	12	12	12	12	12	12
Total Payments	888,024	888,024	888,024	939,825	976,826	976,826	976,826	976,826
Excise Tax Pmt	35,524	35,524	35,524	37,596	39,076	39,076	39,076	39,076
Lease Pmt	852,500	852,500	852,500	902,229	937,750	937,750	937,750	937,750
HEI Payments	142,289	142,289	142,289	150,589	156,518	156,518	156,518	156,518
Capital Lease Treatment								
Cash Flow								
Lease Payment	888,024	888,024	888,024	939,825	976,826	976,826	976,826	976,826
Excise Tax Expense	35,524	35,524	35,524	37,596	39,076	39,076	39,076	39,076
Interest Expense on Lease Obligati	493,457	472,247	449,784	425,274	395,535	363,505	329,583	293,657
Principal Repayment	359,043	380,253	402,716	476,955	542,215	574,245	608,167	644,093
Total Debits	888,024	888,024	888,024	939,825	976,826	976,826	976,826	976,826
Current Tax Deduction	888,024	888,024	888,024	939,825	976,826	976,826	976,826	976,826
Book Expense	1,054,770	1,033,560	1,011,097	988,659	960,401	928,371	894,448	858,522
Deferred Tax Base	(166,746)	(145,536)	(123,074)	(48,834)	16,425	48,455	82,378	118,304
Deferred Tax	(64,881)	(56,628)	(47,888)	(19,001)	6,391	18,854	32,053	46,032
Accumulated Deferred Tax	(720,775)	(777,403)	(825,291)	(844,292)	(837,901)	(819,047)	(786,994)	(740,962)
Leased Property	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077
Amortization Expense	525,789	525,789	525,789	525,789	525,789	525,789	525,789	525,789
Accumulated Amortization	3,680,526	4,206,315	4,732,104	5,257,894	5,783,683	6,309,472	6,835,262	7,361,051
Net Leased Property	6,528,551	6,002,762	5,476,973	4,951,183	4,425,394	3,899,605	3,373,815	2,848,026
Ending Rate Base	7,249,327	6,780,165	6,302,264	5,795,475	5,263,295	4,718,652	4,160,809	3,588,988
Average Rate Base	7,479,781	7,014,746	6,541,214	6,048,870	5,529,385	4,990,973	4,439,731	3,874,899
Beginning Lease Obligation	8,740,022	8,380,979	8,000,726	7,598,010	7,121,055	6,578,840	6,004,596	5,396,428
Lease Interest Expense	493,457	472,247	449,784	425,274	395,535	363,505	329,583	293,657
Principal Repayments	359,043	380,253	402,716	476,955	542,215	574,245	608,167	644,093
Ending Lease Obligation	8,380,979	8,000,726	7,598,010	7,121,055	6,578,840	6,004,596	5,396,428	4,752,335
ST Debt	217,480	203,405	189,068	173,864	157,899	141,560	124,824	107,670
Taxable Debt	(5,771,221)	(5,559,866)	(5,329,195)	(5,034,684)	(4,684,054)	(4,305,881)	(3,898,537)	(3,460,299)
Preferred Stock	507,453	474,612	441,158	405,683	368,431	330,306	291,257	251,229
Common Stock	3,914,636	3,661,289	3,403,222	3,129,557	2,842,179	2,548,072	2,246,837	1,938,054
Total Ending Capitalization	7,249,327	6,780,165	6,302,264	5,795,475	5,263,295	4,718,652	4,160,809	3,588,988
Average ST Debt	224,393	210,442	196,236	181,466	165,882	149,729	133,192	116,247
Average Taxable Debt	(5,867,779)	(5,665,544)	(5,444,531)	(5,181,940)	(4,859,369)	(4,494,968)	(4,102,209)	(3,679,418)
Average Preferred Stock	523,585	491,032	457,885	423,421	387,057	349,368	310,781	271,243
Average Common Stock	4,039,082	3,787,963	3,532,256	3,266,390	2,985,868	2,695,126	2,397,455	2,092,445
Average Capitalization	7,479,781	7,014,746	6,541,214	6,048,870	5,529,385	4,990,973	4,439,731	3,874,899
ST Interest Expense	13,464	12,627	11,774	10,888	9,953	8,984	7,992	6,975
Taxable Debt Interest Expense	(330,356)	(318,970)	(306,527)	(291,743)	(273,582)	(253,067)	(230,954)	(207,151)
Preferred Dividends	41,887	39,283	36,631	33,874	30,965	27,949	24,862	21,699
Return on Common	484,690	454,556	423,871	391,967	358,304	323,415	287,695	251,093
Revenue Requirements	1,599,686	1,529,170	1,457,347	1,376,593	1,292,275	1,210,478	1,126,708	1,040,848
Revenue Taxes	142,132	135,867	129,485	122,310	114,819	107,551	100,108	92,479
Amortization Expense	525,789	525,789	525,789	525,789	525,789	525,789	525,789	525,789
Excise Tax Expense	35,524	35,524	35,524	37,596	39,076	39,076	39,076	39,076
HEI Rent Payments	(142,289)	(142,289)	(142,289)	(150,589)	(156,518)	(156,518)	(156,518)	(156,518)
Interest Expense	176,565	165,904	155,032	144,419	131,906	119,422	106,620	93,480
Income Before Taxes	861,965	808,375	753,806	697,068	637,203	575,157	511,632	446,541
Income Taxes	335,389	314,537	293,304	271,228	247,934	223,792	199,075	173,748
Preferred Dividends	41,887	39,283	36,631	33,874	30,965	27,949	24,862	21,699
Net Income	484,690	454,556	423,871	391,967	358,304	323,415	287,695	251,093

King Street Lease

Year	7	8	9	10	11	12	13	14
Number of Months in Year	12	12	12	12	12	12	12	12
Total Payments	888,024	888,024	888,024	925,025	976,826	976,826	976,826	976,826
Excise Tax Pmt	35,524	35,524	35,524	37,004	39,076	39,076	39,076	39,076
Lease Pmt	852,500	852,500	852,500	888,021	937,750	937,750	937,750	937,750
HEI Payments	142,289	142,289	142,289	148,217	156,518	156,518	156,518	156,518
Capital Lease Treatment								
Cash Flow								
Lease Payment	888,024	888,024	888,024	925,025	976,826	976,826	976,826	976,826
Excise Tax Expense	35,524	35,524	35,524	37,004	39,076	39,076	39,076	39,076
Interest Expense on Lease Obligati	498,877	477,855	455,583	431,643	402,558	370,742	337,035	301,324
Principal Repayment	353,623	374,645	396,917	456,378	535,192	567,008	600,715	636,426
Total Debits	888,024	888,024	888,024	925,025	976,826	976,826	976,826	976,826
Current Tax Deduction	888,024	888,024	888,024	925,025	976,826	976,826	976,826	976,826
Book Expense	1,055,715	1,034,693	1,012,421	989,961	962,949	931,133	897,425	861,714
Deferred Tax Base	(167,691)	(146,669)	(124,398)	(64,937)	13,877	45,693	79,401	115,112
Deferred Tax	(65,248)	(57,069)	(48,403)	(25,267)	5,400	17,779	30,895	44,790
Accumulated Deferred Tax	(725,673)	(782,742)	(831,145)	(856,411)	(851,012)	(833,232)	(802,338)	(757,548)
Leased Property	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077
Amortization Expense	521,315	521,315	521,315	521,315	521,315	521,315	521,315	521,315
Accumulated Amortization	3,649,202	4,170,517	4,691,831	5,213,146	5,734,460	6,255,775	6,777,089	7,298,404
Net Leased Property	6,559,875	6,038,560	5,517,246	4,995,931	4,474,617	3,953,302	3,431,988	2,910,673
Ending Rate Base	7,285,548	6,821,302	6,348,391	5,852,343	5,325,628	4,786,535	4,234,325	3,668,221
Average Rate Base	7,513,581	7,053,425	6,584,846	6,100,367	5,588,985	5,056,081	4,510,430	3,951,273
Beginning Lease Obligation	8,778,513	8,424,890	8,050,245	7,653,328	7,196,950	6,661,758	6,094,750	5,494,034
Lease Interest Expense	498,877	477,855	455,583	431,643	402,558	370,742	337,035	301,324
Principal Repayments	353,623	374,645	396,917	456,378	535,192	567,008	600,715	636,426
Ending Lease Obligation	8,424,890	8,050,245	7,653,328	7,196,950	6,661,758	6,094,750	5,494,034	4,857,608
ST Debt	218,566	204,639	190,452	175,570	159,769	143,596	127,030	110,047
Taxable Debt	(5,802,093)	(5,594,576)	(5,367,907)	(5,090,106)	(4,744,531)	(4,371,597)	(3,969,677)	(3,537,048)
Preferred Stock	509,988	477,491	444,387	409,664	372,794	335,057	296,403	256,775
Common Stock	3,934,196	3,683,503	3,428,131	3,160,265	2,875,839	2,584,729	2,286,536	1,980,839
Total Ending Capitalization	7,285,548	6,821,302	6,348,391	5,852,343	5,325,628	4,786,535	4,234,325	3,668,221
Average ST Debt	225,407	211,603	197,545	183,011	167,670	151,682	135,313	118,538
Average Taxable Debt	(5,896,812)	(5,698,334)	(5,481,242)	(5,229,007)	(4,917,319)	(4,558,064)	(4,170,637)	(3,753,363)
Average Preferred Stock	525,951	493,740	460,939	427,026	391,229	353,926	315,730	276,589
Average Common Stock	4,057,334	3,808,850	3,555,817	3,294,198	3,018,052	2,730,284	2,435,632	2,133,688
Average Capitalization	7,513,581	7,053,425	6,584,846	6,100,367	5,588,985	5,056,081	4,510,430	3,951,273
ST Interest Expense	13,524	12,696	11,853	10,981	10,060	9,101	8,119	7,112
Taxable Debt Interest Expense	(331,991)	(320,816)	(308,594)	(294,393)	(276,845)	(256,619)	(234,807)	(211,314)
Preferred Dividends	42,076	39,499	36,875	34,162	31,298	28,314	25,258	22,127
Return on Common	486,880	457,062	426,698	395,304	362,166	327,634	292,276	256,043
Revenue Requirements	1,603,272	1,533,355	1,462,136	1,384,332	1,299,147	1,217,974	1,134,828	1,049,593
Revenue Taxes	142,459	136,239	129,911	122,998	115,429	108,217	100,829	93,256
Amortization Expense	521,315	521,315	521,315	521,315	521,315	521,315	521,315	521,315
Excise Tax Expense	35,524	35,524	35,524	37,004	39,076	39,076	39,076	39,076
HEI Rent Payments	(142,289)	(142,289)	(142,289)	(148,217)	(156,518)	(156,518)	(156,518)	(156,518)
Interest Expense	180,411	169,735	158,842	148,230	135,773	123,224	110,347	97,121
Income Before Taxes	865,860	812,832	758,834	703,002	644,071	582,660	519,779	455,342
Income Taxes	336,904	316,271	295,260	273,537	250,607	226,712	202,245	177,173
Preferred Dividends	42,076	39,499	36,875	34,162	31,298	28,314	25,258	22,127
Net Income	486,880	457,062	426,698	395,304	362,166	327,634	292,276	256,043

King Street Lease

Year	15	16	17	18	19	20	Total
Number of Months in Year	12	12	12	12	12	5	233
Total Payments	1,033,808	1,074,509	1,074,509	1,074,509	1,074,509	447,712	18,262,341
Excise Tax Pmt	41,355	42,984	42,984	42,984	42,984	17,910	730,550
Lease Pmt	992,452	1,031,525	1,031,525	1,031,525	1,031,525	429,802	17,531,792
HEI Payments	165,648	172,169	172,169	172,169	172,169	71,737	2,926,188
Capital Lease Treatment							
Cash Flow							
Lease Payment	1,033,808	1,074,509	1,074,509	1,074,509	1,074,509	447,712	18,262,341
Excise Tax Expense	41,355	42,984	42,984	42,984	42,984	17,910	730,550
Interest Expense on Lease Obligati	254,815	209,521	160,963	109,536	55,071	6,113	7,322,715
Principal Repayment	737,637	822,004	870,562	921,989	976,454	423,689	10,209,077
Total Debits	1,033,808	1,074,509	1,074,509	1,074,509	1,074,509	447,712	18,262,341
Current Tax Deduction	1,033,808	1,074,509	1,074,509	1,074,509	1,074,509	447,712	18,262,341
Book Expense	821,960	778,294	729,736	678,309	623,844	243,102	18,262,341
Deferred Tax Base	211,848	296,215	344,773	396,200	450,664	204,610	
Deferred Tax	82,429	115,256	134,150	154,160	175,352	79,613	
Accumulated Deferred Tax	(658,533)	(543,276)	(409,126)	(254,966)	(79,613)	(0)	
Leased Property	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	
Amortization Expense	525,789	525,789	525,789	525,789	525,789	219,079	10,209,077
Accumulated Amortization	7,886,841	8,412,630	8,938,419	9,464,209	9,989,998	10,209,077	
Net Leased Property	2,322,236	1,796,447	1,270,658	744,868	219,079	(0)	
Ending Rate Base	2,980,769	2,339,723	1,679,784	999,834	298,692	(0)	
Average Rate Base	3,284,879	2,660,246	2,009,754	1,339,809	649,263	149,346	
Beginning Lease Obligation	4,752,335	4,014,698	3,192,694	2,322,131	1,400,142	423,689	
Lease Interest Expense	254,815	209,521	160,963	109,536	55,071	6,113	7,322,715
Principal Repayments	737,637	822,004	870,562	921,989	976,454	423,689	10,209,077
Ending Lease Obligation	4,014,698	3,192,694	2,322,131	1,400,142	423,689	0	
ST Debt	89,423	70,192	50,394	29,995	8,961	(0)	
Taxable Debt	(2,941,621)	(2,350,393)	(1,717,409)	(1,040,202)	(316,160)	(0)	
Preferred Stock	208,654	163,781	117,585	69,988	20,908	(0)	
Common Stock	1,609,615	1,263,451	907,083	539,910	161,294	(0)	
Total Ending Capitalization	2,980,769	2,339,723	1,679,784	999,834	298,692	(0)	
Average ST Debt	98,546	79,807	60,293	40,194	19,478	4,480	
Average Taxable Debt	(3,200,960)	(2,646,007)	(2,033,901)	(1,378,806)	(678,181)	(158,080)	
Average Preferred Stock	229,942	186,217	140,683	93,787	45,448	10,454	
Average Common Stock	1,773,835	1,436,533	1,085,267	723,497	350,602	80,647	
Average Capitalization	3,284,879	2,660,246	2,009,754	1,339,809	649,263	149,346	
ST Interest Expense	5,913	4,788	3,618	2,412	1,169	269	197,937
Taxable Debt Interest Expense	(180,214)	(148,970)	(114,509)	(77,627)	(38,182)	(8,900)	(4,915,824)
Preferred Dividends	18,395	14,897	11,255	7,503	3,636	836	615,803
Return on Common	212,860	172,384	130,232	86,820	42,072	9,678	7,125,719
Revenue Requirements	944,475	843,448	744,420	642,401	537,214	197,491	25,561,699
Revenue Taxes	83,917	74,940	66,142	57,077	47,731	17,547	2,271,157
Amortization Expense	525,789	525,789	525,789	525,789	525,789	219,079	10,209,077
Excise Tax Expense	41,355	42,984	42,984	42,984	42,984	17,910	730,550
HEI Rent Payments	(165,648)	(172,169)	(172,169)	(172,169)	(172,169)	(71,737)	(2,926,188)
Interest Expense	80,514	65,339	50,072	34,321	18,058	(2,518)	2,604,827
Income Before Taxes	378,547	306,565	231,603	154,399	74,821	17,211	12,672,277
Income Taxes	147,292	119,284	90,116	60,076	29,113	6,697	4,930,754
Preferred Dividends	18,395	14,897	11,255	7,503	3,636	836	615,803
Net Income	212,860	172,384	130,232	86,820	42,072	9,678	7,125,719

King Street Lease

Year	15	16	17	18	19	20	Total
Number of Months in Year	12	12	12	12	12	7	235
Total Payments	1,017,527	1,074,509	1,074,509	1,074,509	1,074,509	626,797	18,396,890
Excise Tax Pmt	40,704	42,984	42,984	42,984	42,984	25,074	735,932
Lease Pmt	976,823	1,031,525	1,031,525	1,031,525	1,031,525	601,723	17,660,958
HEI Payments	163,039	172,169	172,169	172,169	172,169	100,432	2,947,747
Capital Lease Treatment							
Cash Flow							
Lease Payment	1,017,527	1,074,509	1,074,509	1,074,509	1,074,509	626,797	18,396,890
Excise Tax Expense	40,704	42,984	42,984	42,984	42,984	25,074	735,932
Interest Expense on Lease Obligati	263,111	218,532	170,202	118,998	64,750	11,445	7,451,881
Principal Repayment	713,712	812,993	861,323	912,527	966,775	590,278	10,209,077
Total Debits	1,017,527	1,074,509	1,074,509	1,074,509	1,074,509	626,797	18,396,890
Current Tax Deduction	1,017,527	1,074,509	1,074,509	1,074,509	1,074,509	626,797	18,396,890
Book Expense	825,129	782,831	734,500	683,296	629,049	340,619	18,396,890
Deferred Tax Base	192,398	291,678	340,009	391,212	445,460	286,178	
Deferred Tax	74,862	113,491	132,297	152,220	173,327	111,351	
Accumulated Deferred Tax	(682,686)	(569,195)	(436,899)	(284,679)	(111,351)	(0)	
Leased Property	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	
Amortization Expense	521,315	521,315	521,315	521,315	521,315	304,100	10,209,077
Accumulated Amortization	7,819,719	8,341,033	8,862,348	9,383,662	9,904,977	10,209,077	
Net Leased Property	2,389,358	1,868,044	1,346,729	825,415	304,100	-	
Ending Rate Base	3,072,045	2,437,239	1,783,628	1,110,093	415,451	0	
Average Rate Base	3,370,133	2,754,642	2,110,433	1,446,861	762,772	207,726	
Beginning Lease Obligation	4,857,608	4,143,896	3,330,903	2,469,580	1,557,053	590,278	
Lease Interest Expense	263,111	218,532	170,202	118,998	64,750	11,445	7,451,881
Principal Repayments	713,712	812,993	861,323	912,527	966,775	590,278	10,209,077
Ending Lease Obligation	4,143,896	3,330,903	2,469,580	1,557,053	590,278	0	
ST Debt	92,161	73,117	53,509	33,303	12,464	0	
Taxable Debt	(3,037,959)	(2,453,497)	(1,827,474)	(1,157,419)	(440,716)	(0)	
Preferred Stock	215,043	170,607	124,854	77,707	29,082	0	
Common Stock	1,658,904	1,316,109	963,159	599,450	224,344	0	
Total Ending Capitalization	3,072,045	2,437,239	1,783,628	1,110,093	415,451	0	
Average ST Debt	101,104	82,639	63,313	43,406	22,883	6,232	
Average Taxable Debt	(3,287,504)	(2,745,728)	(2,140,485)	(1,492,446)	(799,067)	(220,358)	
Average Preferred Stock	235,909	192,825	147,730	101,280	53,394	14,541	
Average Common Stock	1,819,872	1,487,507	1,139,634	781,305	411,897	112,172	
Average Capitalization	3,370,133	2,754,642	2,110,433	1,446,861	762,772	207,726	
ST Interest Expense	6,066	4,958	3,799	2,604	1,373	374	199,887
Taxable Debt Interest Expense	(185,086)	(154,584)	(120,509)	(84,025)	(44,987)	(12,406)	(4,975,456)
Preferred Dividends	18,873	15,426	11,818	8,102	4,272	1,163	621,869
Return on Common	218,385	178,501	136,756	93,757	49,428	13,461	7,195,914
Revenue Requirements	956,420	854,391	755,995	654,603	550,037	276,675	25,759,408
Revenue Taxes	84,978	75,913	67,170	58,162	48,871	24,583	2,288,723
Amortization Expense	521,315	521,315	521,315	521,315	521,315	304,100	10,209,077
Excise Tax Expense	40,704	42,984	42,984	42,984	42,984	25,074	735,932
HEI Rent Payments	(163,039)	(172,169)	(172,169)	(172,169)	(172,169)	(100,432)	(2,947,747)
Interest Expense	84,090	68,906	53,491	37,578	21,136	(588)	2,676,312
Income Before Taxes	388,372	317,443	243,205	166,735	87,901	23,938	12,797,110
Income Taxes	151,115	123,516	94,631	64,876	34,202	9,314	4,979,327
Preferred Dividends	18,873	15,426	11,818	8,102	4,272	1,163	621,869
Net Income	218,385	178,501	136,756	93,757	49,428	13,461	7,195,914

King Street Lease

Year			1	2	3	4	5	6
Capital Lease for Books with Rates based on Lease Payments								
Cash Flow								
Lease Payment			807,294	807,294	807,294	807,294	854,386	888,024
Excise Tax Expense			32,294	32,294	32,294	32,294	34,178	35,524
Interest Expense on Lease Obligation			582,315	570,932	558,878	546,111	531,934	513,484
Principal Repayment			192,685	204,068	216,122	228,889	288,274	339,016
Total Debits			807,294	807,294	807,294	807,294	854,386	888,024
Current Tax Deduction			807,294	807,294	807,294	807,294	854,386	888,024
Book Expense			807,294	807,294	807,294	807,294	854,386	888,024
Deferred Tax Base			-	-	-	-	-	-
Deferred Tax			-	-	-	-	-	-
Accumulated Deferred Tax			-	-	-	-	-	-
Financial Statements Adjusted to Reflect Ratemaking based on Lease Payments								
Leased Property			10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077
Adjusted Amortization Expense			192,685	204,068	216,122	228,889	288,274	339,016
Accumulated Amortization			192,685	396,753	612,875	841,764	1,130,039	1,469,055
Net Leased Plant		10,209,077	10,016,392	9,812,324	9,596,202	9,367,313	9,079,038	8,740,022
Ending Net Assets		10,209,077	10,016,392	9,812,324	9,596,202	9,367,313	9,079,038	8,740,022
Average Rate Base			10,112,734	9,914,358	9,704,263	9,481,757	9,223,175	8,909,530
Beginning Lease Obligation			10,209,077	10,016,392	9,812,324	9,596,202	9,367,313	9,079,038
Lease Interest Expense			582,315	570,932	558,878	546,111	531,934	513,484
Principal Repayments			192,685	204,068	216,122	228,889	288,274	339,016
Ending Lease Obligation		10,209,077	10,016,392	9,812,324	9,596,202	9,367,313	9,079,038	8,740,022
ST Debt	3%	306,272	300,492	294,370	287,886	281,019	272,371	262,201
Taxable Debt	36%	(6,533,809)	(6,410,491)	(6,279,888)	(6,141,569)	(5,995,080)	(5,810,584)	(5,593,614)
Preferred Stock	7%	714,635	701,147	686,863	671,734	655,712	635,533	611,802
Common Stock	54%	5,512,902	5,408,852	5,298,655	5,181,949	5,058,349	4,902,681	4,719,612
Total Ending Capitalization		10,209,077	10,016,392	9,812,324	9,596,202	9,367,313	9,079,038	8,740,022
Average ST Debt			303,382	297,431	291,128	284,453	276,695	267,286
Average Taxable Debt			(6,472,150)	(6,345,189)	(6,210,728)	(6,068,325)	(5,902,832)	(5,702,099)
Average Preferred Stock			707,891	694,005	679,298	663,723	645,622	623,667
Average Common Stock			5,460,877	5,353,753	5,240,302	5,120,149	4,980,515	4,811,146
Average Capitalization			10,112,734	9,914,358	9,704,263	9,481,757	9,223,175	8,909,530
ST Interest Expense	6.00%		18,203	17,846	17,468	17,067	16,602	16,037
Taxable Debt Interest Expense	5.63%		(364,382)	(357,234)	(349,664)	(341,647)	(332,329)	(321,028)
Preferred Dividends	8.00%		56,631	55,520	54,344	53,098	51,650	49,893
Return on Common	12.00%		655,305	642,450	628,836	614,418	597,662	577,338
Revenue Requirements (with Capital Structure Rebalancing in Rates)								
Revenue Requirement			1,643,140	1,625,503	1,606,824	1,587,042	1,607,455	1,610,572
Revenue Taxes			145,993	144,426	142,766	141,009	142,822	143,099
Lease Payments			807,294	807,294	807,294	807,294	854,386	888,024
HEI Rent Payments			(129,353)	(129,353)	(129,353)	(129,353)	(136,899)	(142,289)
Interest Expense			(346,179)	(339,388)	(332,196)	(324,580)	(315,728)	(304,991)
Income Before Taxes			1,165,385	1,142,525	1,118,313	1,092,672	1,062,873	1,026,729
Income Taxes			453,449	444,554	435,133	425,156	413,562	399,498
Preferred Dividends			56,631	55,520	54,344	53,098	51,650	49,893
Net Income (Ratemaking)			655,305	642,450	628,836	614,418	597,662	577,338
Book Returns								
Revenues			1,643,140	1,625,503	1,606,824	1,587,042	1,607,455	1,610,572
Revenue Taxes			145,993	144,426	142,766	141,009	142,822	143,099
Amortization Expense			192,685	204,068	216,122	228,889	288,274	339,016
Excise Tax Expense			32,294	32,294	32,294	32,294	34,178	35,524
HEI Rent Payments			(129,353)	(129,353)	(129,353)	(129,353)	(136,899)	(142,289)
			[illegible]	[illegible]	[illegible]	[illegible]	216,206	208,493

King Street Lease

Year			1	2	3	4	5	6
Capital Lease for Books with Rates based on Lease Payments								
Cash Flow								
Lease Payment			807,294	807,294	807,294	807,294	840,932	888,024
Excise Tax Expense			32,294	32,294	32,294	32,294	33,640	35,524
Interest Expense on Lease Obligation			586,010	574,775	562,872	550,262	536,589	518,719
Principal Repayment			188,990	200,225	212,128	224,738	270,703	333,781
Total Debits			807,294	807,294	807,294	807,294	840,932	888,024
Current Tax Deduction			807,294	807,294	807,294	807,294	840,932	888,024
Book Expense			807,294	807,294	807,294	807,294	840,932	888,024
Deferred Tax Base			-	-	-	-	-	-
Deferred Tax			-	-	-	-	-	-
Accumulated Deferred Tax			-	-	-	-	-	-
Financial Statements Adjusted to Reflect Ratemaking based on Lease Payments								
Leased Property			10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077
Adjusted Amortization Expense			188,990	200,225	212,128	224,738	270,703	333,781
Accumulated Amortization			188,990	389,214	601,342	826,080	1,096,783	1,430,564
Net Leased Plant		10,209,077	10,020,087	9,819,863	9,607,735	9,382,997	9,112,294	8,778,513
Ending Net Assets		10,209,077	10,020,087	9,819,863	9,607,735	9,382,997	9,112,294	8,778,513
Average Rate Base			10,114,582	9,919,975	9,713,799	9,495,366	9,247,645	8,945,403
Beginning Lease Obligation			10,209,077	10,020,087	9,819,863	9,607,735	9,382,997	9,112,294
Lease Interest Expense			586,010	574,775	562,872	550,262	536,589	518,719
Principal Repayments			188,990	200,225	212,128	224,738	270,703	333,781
Ending Lease Obligation		10,209,077	10,020,087	9,819,863	9,607,735	9,382,997	9,112,294	8,778,513
ST Debt	3%	306,272	300,603	294,596	288,232	281,490	273,369	263,355
Taxable Debt	36%	(6,533,809)	(6,412,856)	(6,284,712)	(6,148,950)	(6,005,118)	(5,831,868)	(5,618,248)
Preferred Stock	7%	714,635	701,406	687,390	672,541	656,810	637,861	614,496
Common Stock	54%	5,512,902	5,410,847	5,302,726	5,188,177	5,066,818	4,920,639	4,740,397
Total Ending Capitalization		10,209,077	10,020,087	9,819,863	9,607,735	9,382,997	9,112,294	8,778,513
Average ST Debt			303,437	297,599	291,414	284,861	277,429	268,362
Average Taxable Debt			(6,473,333)	(6,348,784)	(6,216,831)	(6,077,034)	(5,918,493)	(5,725,058)
Average Preferred Stock			708,021	694,398	679,966	664,676	647,335	626,178
Average Common Stock			5,461,874	5,356,786	5,245,451	5,127,498	4,993,728	4,830,518
Average Capitalization			10,114,582	9,919,975	9,713,799	9,495,366	9,247,645	8,945,403
ST Interest Expense	6.00%		18,206	17,856	17,485	17,092	16,646	16,102
Taxable Debt Interest Expense	5.63%		(364,449)	(357,437)	(350,008)	(342,137)	(333,211)	(322,321)
Preferred Dividends	8.00%		56,642	55,552	54,397	53,174	51,787	50,094
Return on Common	12.00%		655,425	642,814	629,454	615,300	599,247	579,662
Revenue Requirements (with Capital Structure Rebalancing in Rates)								
Revenue Requirement			1,643,304	1,626,002	1,607,672	1,588,252	1,597,230	1,613,761
Revenue Taxes			146,008	144,470	142,842	141,116	141,914	143,383
Lease Payments			807,294	807,294	807,294	807,294	840,932	888,024
HEI Rent Payments			(129,353)	(129,353)	(129,353)	(129,353)	(134,743)	(142,289)
Interest Expense			(346,242)	(339,581)	(332,523)	(325,045)	(316,565)	(306,219)
Income Before Taxes			1,165,598	1,143,172	1,119,412	1,094,240	1,065,693	1,030,863
Income Taxes			453,532	444,806	435,561	425,766	414,659	401,106
Preferred Dividends			56,642	55,552	54,397	53,174	51,787	50,094

King Street Lease

Year	7	8	9	10	11	12	13	14
Capital Lease for Books with Rat								
Cash Flow								
Lease Payment	888,024	888,024	888,024	939,825	976,826	976,826	976,826	976,826
Excise Tax Expense	35,524	35,524	35,524	37,596	39,076	39,076	39,076	39,076
Interest Expense on Lease Obligati	493,457	472,247	449,784	425,274	395,535	363,505	329,583	293,657
Principal Repayment	359,043	380,253	402,716	476,955	542,215	574,245	608,167	644,093
Total Debits	888,024	888,024	888,024	939,825	976,826	976,826	976,826	976,826
Current Tax Deduction	888,024	888,024	888,024	939,825	976,826	976,826	976,826	976,826
Book Expense	888,024	888,024	888,024	939,825	976,826	976,826	976,826	976,826
Deferred Tax Base	-	-	-	-	-	-	-	-
Deferred Tax	-	-	-	-	-	-	-	-
Accumulated Deferred Tax	-	-	-	-	-	-	-	-
Financial Statements Adjusted to R								
Leased Property	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077
Adjusted Amortization Expense	359,043	380,253	402,716	476,955	542,215	574,245	608,167	644,093
Accumulated Amortization	1,828,098	2,208,351	2,611,067	3,088,022	3,630,237	4,204,481	4,812,649	5,456,742
Net Leased Plant	8,380,979	8,000,726	7,598,010	7,121,055	6,578,840	6,004,596	5,396,428	4,752,335
Ending Net Assets	8,380,979	8,000,726	7,598,010	7,121,055	6,578,840	6,004,596	5,396,428	4,752,335
Average Rate Base	8,560,500	8,190,852	7,799,368	7,359,533	6,849,948	6,291,718	5,700,512	5,074,382
Beginning Lease Obligation	8,740,022	8,380,979	8,000,726	7,598,010	7,121,055	6,578,840	6,004,596	5,396,428
Lease Interest Expense	493,457	472,247	449,784	425,274	395,535	363,505	329,583	293,657
Principal Repayments	359,043	380,253	402,716	476,955	542,215	574,245	608,167	644,093
Ending Lease Obligation	8,380,979	8,000,726	7,598,010	7,121,055	6,578,840	6,004,596	5,396,428	4,752,335
ST Debt	251,429	240,022	227,940	213,632	197,365	180,138	161,893	142,570
Taxable Debt	(5,363,826)	(5,120,465)	(4,862,727)	(4,557,475)	(4,210,458)	(3,842,941)	(3,453,714)	(3,041,494)
Preferred Stock	586,669	560,051	531,861	498,474	460,519	420,322	377,750	332,663
Common Stock	4,525,728	4,320,392	4,102,926	3,845,370	3,552,574	3,242,482	2,914,071	2,566,261
Total Ending Capitalization	8,380,979	8,000,726	7,598,010	7,121,055	6,578,840	6,004,596	5,396,428	4,752,335
Average ST Debt	256,815	245,726	233,981	220,786	205,498	188,752	171,015	152,231
Average Taxable Debt	(5,478,720)	(5,242,145)	(4,991,596)	(4,710,101)	(4,383,966)	(4,026,699)	(3,648,328)	(3,247,604)
Average Preferred Stock	599,235	573,360	545,956	515,167	479,496	440,420	399,036	355,207
Average Common Stock	4,622,670	4,423,060	4,211,659	3,974,148	3,698,972	3,397,528	3,078,276	2,740,166
Average Capitalization	8,560,500	8,190,852	7,799,368	7,359,533	6,849,948	6,291,718	5,700,512	5,074,382
ST Interest Expense	15,409	14,744	14,039	13,247	12,330	11,325	10,261	9,134
Taxable Debt Interest Expense	(308,452)	(295,133)	(281,027)	(265,179)	(246,817)	(226,703)	(205,401)	(182,840)
Preferred Dividends	47,939	45,869	43,676	41,213	38,360	35,234	31,923	28,417
Return on Common	554,720	530,767	505,399	476,898	443,877	407,703	369,393	328,820
Revenue Requirements (with Cap								
Revenue Requirement	1,579,541	1,546,677	1,511,871	1,520,510	1,509,307	1,459,676	1,407,114	1,351,447
Revenue Taxes	140,342	137,422	134,330	135,097	134,102	129,692	125,022	120,076
Lease Payments	888,024	888,024	888,024	939,825	976,826	976,826	976,826	976,826
HEI Rent Payments	(142,289)	(142,289)	(142,289)	(150,589)	(156,518)	(156,518)	(156,518)	(156,518)
Interest Expense	(293,043)	(280,389)	(266,988)	(251,932)	(234,487)	(215,378)	(195,140)	(173,706)
Income Before Taxes	986,507	943,909	898,794	848,108	789,384	725,054	656,923	584,769
Income Taxes	383,848	367,273	349,719	329,997	307,147	282,117	255,607	227,532
Preferred Dividends	47,939	45,869	43,676	41,213	38,360	35,234	31,923	28,417
Net Income (Ratemaking)	554,720	530,767	505,399	476,898	443,877	407,703	369,393	328,820
Book Returns								
Revenues	1,579,541	1,546,677	1,511,871	1,520,510	1,509,307	1,459,676	1,407,114	1,351,447
Revenue Taxes	140,342	137,422	134,330	135,097	134,102	129,692	125,022	120,076
Amortization Expense	359,043	380,253	402,716	476,955	542,215	574,245	608,167	644,093
Excise Tax Expense	35,524	35,524	35,524	37,596	39,076	39,076	39,076	39,076
HEI Rent Payments	(142,289)	(142,289)	(142,289)	(150,589)	(156,518)	(156,518)	(156,518)	(156,518)
Interest Expense	200,414	191,858	182,796	173,342	161,048	148,127	134,443	119,950
Income Before Taxes	986,507	943,909	898,794	848,108	789,384	725,054	656,923	584,769
Income Taxes	383,848	367,273	349,719	329,997	307,147	282,117	255,607	227,532
Preferred Dividends	47,939	45,869	43,676	41,213	38,360	35,234	31,923	28,417
Net Income	554,720	530,767	505,399	476,898	443,877	407,703	369,393	328,820

King Street Lease

Year	7	8	9	10	11	12	13	14
Capital Lease for Books with Rat								
Cash Flow								
Lease Payment	888,024	888,024	888,024	925,025	976,826	976,826	976,826	976,826
Excise Tax Expense	35,524	35,524	35,524	37,004	39,076	39,076	39,076	39,076
Interest Expense on Lease Obligati	498,877	477,855	455,583	431,643	402,558	370,742	337,035	301,324
Principal Repayment	353,623	374,645	396,917	456,378	535,192	567,008	600,715	636,426
Total Debits	888,024	888,024	888,024	925,025	976,826	976,826	976,826	976,826
Current Tax Deduction	888,024	888,024	888,024	925,025	976,826	976,826	976,826	976,826
Book Expense	888,024	888,024	888,024	925,025	976,826	976,826	976,826	976,826
Deferred Tax Base	-	-	-	-	-	-	-	-
Deferred Tax	-	-	-	-	-	-	-	-
Accumulated Deferred Tax	-	-	-	-	-	-	-	-
Financial Statements Adjusted to R								
Leased Property	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077
Adjusted Amortization Expense	353,623	374,645	396,917	456,378	535,192	567,008	600,715	636,426
Accumulated Amortization	1,784,187	2,158,832	2,555,749	3,012,127	3,547,319	4,114,327	4,715,043	5,351,469
Net Leased Plant	8,424,890	8,050,245	7,653,328	7,196,950	6,661,758	6,094,750	5,494,034	4,857,608
Ending Net Assets	8,424,890	8,050,245	7,653,328	7,196,950	6,661,758	6,094,750	5,494,034	4,857,608
Average Rate Base	8,601,702	8,237,567	7,851,786	7,425,139	6,929,354	6,378,254	5,794,392	5,175,821
Beginning Lease Obligation	8,778,513	8,424,890	8,050,245	7,653,328	7,196,950	6,661,758	6,094,750	5,494,034
Lease Interest Expense	498,877	477,855	455,583	431,643	402,558	370,742	337,035	301,324
Principal Repayments	353,623	374,645	396,917	456,378	535,192	567,008	600,715	636,426
Ending Lease Obligation	8,424,890	8,050,245	7,653,328	7,196,950	6,661,758	6,094,750	5,494,034	4,857,608
ST Debt	252,747	241,507	229,600	215,908	199,853	182,842	164,821	145,728
Taxable Debt	(5,391,930)	(5,152,157)	(4,898,130)	(4,606,048)	(4,263,525)	(3,900,640)	(3,516,182)	(3,108,869)
Preferred Stock	589,742	563,517	535,733	503,786	466,323	426,632	384,582	340,033
Common Stock	4,549,441	4,347,132	4,132,797	3,886,353	3,597,349	3,291,165	2,966,779	2,623,108
Total Ending Capitalization	8,424,890	8,050,245	7,653,328	7,196,950	6,661,758	6,094,750	5,494,034	4,857,608
Average ST Debt	258,051	247,127	235,554	222,754	207,881	191,348	173,832	155,275
Average Taxable Debt	(5,505,089)	(5,272,043)	(5,025,143)	(4,752,089)	(4,434,786)	(4,082,082)	(3,708,411)	(3,312,526)
Average Preferred Stock	602,119	576,630	549,625	519,760	485,055	446,478	405,607	362,307
Average Common Stock	4,644,919	4,448,286	4,239,965	4,009,575	3,741,851	3,444,257	[illegible]	[illegible]

King Street Lease

Year	15	16	17	18	19	20	Total
Capital Lease for Books with Rat							
Cash Flow							
Lease Payment	1,033,808	1,074,509	1,074,509	1,074,509	1,074,509	447,712	18,262,341
Excise Tax Expense	41,355	42,984	42,984	42,984	42,984	17,910	730,550
Interest Expense on Lease Obligati	254,815	209,521	160,963	109,536	55,071	6,113	7,322,715
Principal Repayment	737,637	822,004	870,562	921,989	976,454	423,689	10,209,077
Total Debits	1,033,808	1,074,509	1,074,509	1,074,509	1,074,509	447,712	18,262,341
Current Tax Deduction	1,033,808	1,074,509	1,074,509	1,074,509	1,074,509	447,712	18,262,341
Book Expense	1,033,808	1,074,509	1,074,509	1,074,509	1,074,509	447,712	18,262,341
Deferred Tax Base	-	-	-	-	-	-	
Deferred Tax	-	-	-	-	-	-	
Accumulated Deferred Tax	-	-	-	-	-	-	
Financial Statements Adjusted to R							
Leased Property	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	
Adjusted Amortization Expense	737,637	822,004	870,562	921,989	976,454	423,689	10,209,077
Accumulated Amortization	6,194,379	7,016,383	7,886,946	8,808,935	9,785,388	10,209,077	
Net Leased Plant	4,014,698	3,192,694	2,322,131	1,400,142	423,689	0	
Ending Net Assets	4,014,698	3,192,694	2,322,131	1,400,142	423,689	0	
Average Rate Base	4,383,516	3,603,696	2,757,413	1,861,137	911,916	211,844	
Beginning Lease Obligation	4,752,335	4,014,698	3,192,694	2,322,131	1,400,142	423,689	

King Street Lease

Year	15	16	17	18	19	20	Total
Capital Lease for Books with Rat							
Cash Flow							
Lease Payment	1,017,527	1,074,509	1,074,509	1,074,509	1,074,509	626,797	18,396,890
Excise Tax Expense	40,704	42,984	42,984	42,984	42,984	25,074	735,932
Interest Expense on Lease Obligati	263,111	218,532	170,202	118,998	64,750	11,445	7,451,881
Principal Repayment	713,712	812,993	861,323	912,527	966,775	590,278	10,209,077
Total Debits	1,017,527	1,074,509	1,074,509	1,074,509	1,074,509	626,797	18,396,890
Current Tax Deduction	1,017,527	1,074,509	1,074,509	1,074,509	1,074,509	626,797	18,396,890
Book Expense	1,017,527	1,074,509	1,074,509	1,074,509	1,074,509	626,797	18,396,890
Deferred Tax Base	-	-	-	-	-	-	
Deferred Tax	-	-	-	-	-	-	
Accumulated Deferred Tax	-	-	-	-	-	-	
Financial Statements Adjusted to R							
Leased Property	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	10,209,077	
Adjusted Amortization Expense	713,712	812,993	861,323	912,527	966,775	590,278	10,209,077
Accumulated Amortization	6,065,181	6,878,174	7,739,497	8,652,024	9,618,799	10,209,077	
Net Leased Plant	4,143,896	3,330,903	2,469,580	1,557,053	590,278	0	
Ending Net Assets	4,143,896	3,330,903	2,469,580	1,557,053	590,278	0	
Average Rate Base	4,500,752	3,737,399	2,900,241	2,013,316	1,073,666	295,139	
Beginning Lease Obligation	4,857,608	4,143,896	3,330,903	2,469,580	1,557,053	590,278	
Lease Interest Expense	263,111	218,532	170,202	118,998	64,750	11,445	7,451,881
Principal Repayments	713,712	812,993	861,323	912,527	966,775	590,278	10,209,077
Ending Lease Obligation	4,143,896	3,330,903	2,469,580	1,557,053	590,278	0	
ST Debt	124,317	99,927	74,087	46,712	17,708	0	
Taxable Debt	(2,652,093)	(2,131,778)	(1,580,531)	(996,514)	(377,778)	(0)	
Preferred Stock	290,073	233,163	172,871	108,994	41,319	0	
Common Stock	2,237,704	1,798,688	1,333,573	840,809	318,750	0	
Total Ending Capitalization	4,143,896	3,330,903	2,469,580	1,557,053	590,278	0	
Average ST Debt	135,023	112,122	87,007	60,399	32,210	8,854	
Average Taxable Debt	(2,880,481)	(2,391,936)	(1,856,154)	(1,288,522)	(687,146)	(188,889)	
Average Preferred Stock	315,053	261,618	203,017	140,932	75,157	20,660	
Average Common Stock	2,430,406	2,018,196	1,566,130	1,087,191	579,779	159,375	
Average Capitalization	4,500,752	3,737,399	2,900,241	2,013,316	1,073,666	295,139	
ST Interest Expense	8,101	6,727	5,220	3,624	1,933	531	231,032
Taxable Debt Interest Expense	(162,171)	(134,666)	(104,501)	(72,544)	(38,686)	(10,634)	(4,624,754)
Preferred Dividends	25,204	20,929	16,241	11,275	6,013	1,653	718,767
Return on Common	291,649	242,183	187,936	130,463	69,574	19,125	8,317,164
Revenue Requirements (with Cap							
Revenue Requirement	1,337,960	1,322,610	1,248,181	1,169,328	1,085,786	603,932	28,366,950
Revenue Taxes	118,878	117,514	110,901	103,895	96,472	53,659	2,520,403
Lease Payments	1,017,527	1,074,509	1,074,509	1,074,509	1,074,509	626,797	18,396,890
HEI Rent Payments	(163,039)	(172,169)	(172,169)	(172,169)	(172,169)	(100,432)	(2,947,747)
Interest Expense	(154,070)	(127,939)	(99,281)	(68,920)	(36,754)	(10,103)	(4,393,722)
Income Before Taxes	518,664	430,696	334,222	232,013	123,729	34,012	14,791,125
Income Taxes	201,811	167,583	130,045	90,276	48,143	13,234	5,755,193
Preferred Dividends	25,204	20,929	16,241	11,275	6,013	1,653	718,767
Net Income (Ratemaking)	291,649	242,183	187,936	130,463	69,574	19,125	8,317,164
Book Returns							
Revenues	1,337,960	1,322,610	1,248,181	1,169,328	1,085,786	603,932	28,366,950
Revenue Taxes	118,878	117,514	110,901	103,895	96,472	53,659	2,520,403
Amortization Expense	713,712	812,993	861,323	912,527	966,775	590,278	10,209,077
Excise Tax Expense	40,704	42,984	42,984	42,984	42,984	25,074	735,932
HEI Rent Payments	(163,039)	(172,169)	(172,169)	(172,169)	(172,169)	(100,432)	(2,947,747)
Interest Expense	109,041	90,594	70,921	50,078	27,997	1,341	3,058,160
Income Before Taxes	518,664	430,696	334,222	232,013	123,729	34,012	14,791,125
Income Taxes	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

CA-IR-616

Ref: HECO response to CA-IR-260 & HECO-1605 (Rent Expense).

In response to CA-IR-260, the Company updated HECO-1605 to reflect revised lease rates, including the proposed capital lease treatment of the renegotiated King Street lease. On April 6, 2005, the Company filed a Petition with the HPUC (Docket No. 05-0084) seeking a declaratory order approving HECO's renegotiated "capital lease agreement" with the Trustees of the Estate of Bernice Pauahi Bishop. Attachment B of the referenced Petition represents the Company's detailed analysis of the applicability of capital lease Criteria d of FAS13. Please provide the following:

a. Please provide a copy of the "2005 Braig appraisal" referenced as the data source for the land and building estimates on Petition Attachment B, including all supporting documents such as comparable property sales or other analyses.

b. Petition Attachment B indicates that HECO's estimated incremental borrowing rate is 5.63%, citing to a 20-year uninsured taxable bond quote provided by Goldman Sachs. Page 4 of the Company's response to CA-IR-260 uses a monthly discount rate of 0.4824% (i.e., annual rate of 5.789%). Please explain and reconcile the difference between these discount rates.

c. Page 4 of the response to CA-IR-260 calculates HECO's proposed monthly amortization by dividing the estimated FMV of the leased property of $10.209 million (see HECO Petition, Attachment B) by 235 months. Since the renegotiated lease is for a 20-year term, please explain why HECO used a 235-month appropriate amortization period, rather than 240 months.

HECO Response:

a. See attached pages 3 to 26.

b. 5.63% is an estimate of HECO's incremental borrowing rate based on information provided by Goldman Sachs. 5.75%* ~~5.789%~~ is the interest rate that is embedded in the lease pricing. The embedded rate was derived based on the monthly lease payments in the lease and assuming fair market value of $10,209,077. The rates are from different sources and do not "reconcile."

c. The lease term is from "Effective Date" to November 30, 2024. "Effective Date" is defined

* INTEREST RATE CHANGED DUE TO UPDATED ASSUMPTION OF THE NEW LEASE BEGINNING JULY 1, 2005. THIS RESULTED IN A CHANGE TO THE VALUE OF THE LEASE PAYMENTS OVER THE TERM OF THE LEASE.

CA-IR-616

Ref: HECO response to CA-IR-260 & HECO-1605 (Rent Expense).

In response to CA-IR-260, the Company updated HECO-1605 to reflect revised lease rates, including the proposed capital lease treatment of the renegotiated King Street lease. On April 6, 2005, the Company filed a Petition with the HPUC (Docket No. 05-0084) seeking a declaratory order approving HECO's renegotiated "capital lease agreement" with the Trustees of the Estate of Bernice Pauahi Bishop. Attachment B of the referenced Petition represents the Company's detailed analysis of the applicability of capital lease Criteria d of FAS13. Please provide the following:

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c. The lease term is from "Effective Date" to November 30, 2024. "Effective Date" is defined in the lease as December 1, 2004; however, the lease will not be recorded on HECO's books until the lease is executed. The response to CA-IR-260 assumed that the lease would be executed on May 1, 2005 and would be amortized over the period May 1, 2005 to November 30, 2024.

Robert C. Hastings, Jr., MAI, CRE
Alan J. Conboy, MAI, SRA
Robert R. Braig, MAI, SRA
Ricky P. Minn
Don H. Konno, MAI
Robert C. Hastings, III, MAI
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HASTINGS, CONBOY, BRAIG & ASSOCIATES, LTD.

Real Estate Appraisers, Counselors and Economists

February 3, 2005

Mr. Philip Hauret
Senior Land Agent
Land & Rights of Way
Hawaiian Electric Company, Inc.
P.O. Box 2750
Honolulu, Hawaii 96840

RE: Phase I Analysis – Building Improvement Value, HECO Downtown Property

Dear Mr. Hauret:

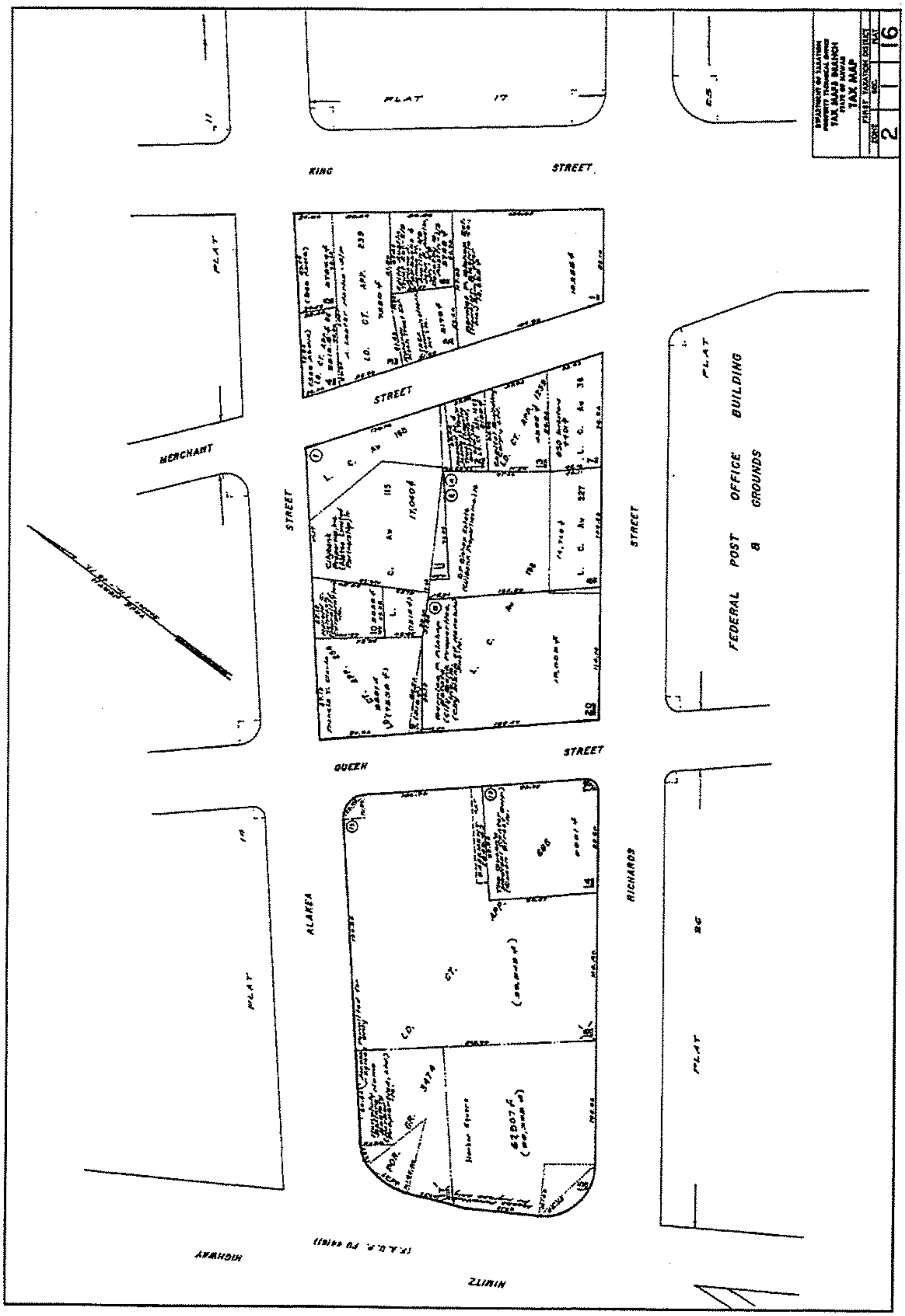
We are pleased to transmit the results of our PRELIMINARY, PHASE I ANALYSIS of the Hawaiian Electric Company, Inc. (HECO) Downtown Property located at 233 South King Street, Honolulu, Hawaii. The subject property is further identified on State of Hawaii Tax Maps as First Division, Tax Map Key 2-1-16, Parcel 1.

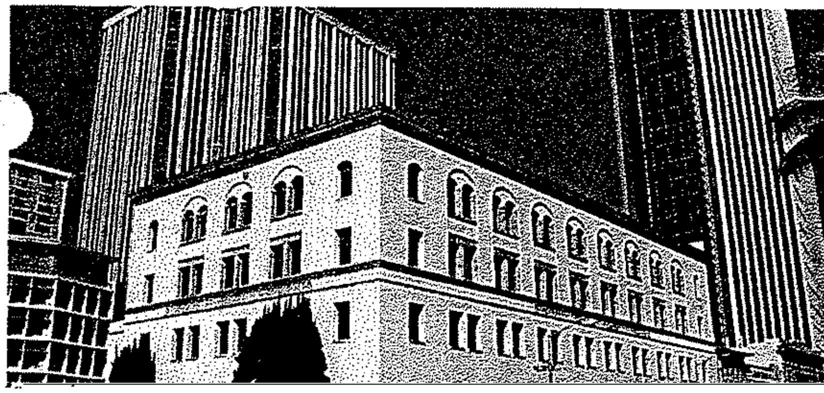
The subject property has a gross land area of 13,255 square feet and is zoned BMX-4, Central Business Mixed Use District, by the City and County of Honolulu. The property is presently leased and occupied by Hawaiian Electric Company, Inc. under a month-to-month agreement with the fee simple land owner, the Trustees of the Estate of Bernice Pauahi Bishop (Bishop Estate). Existing building improvements located on the property consist of a four-story masonry office building, with basement level, originally built in 1927.

ASSIGNMENT

Our assignment is to estimate the "as is" value of Bishop Estate's leased fee interest in the existing building improvements located on the subject property. Due to the existing

PROPERTY LOCATION MAP
Hawaiian Electric Company
Honolulu, Oahu, Hawaii





View of subject looking west across King Street.

CA-IR-616

PROPERTY BACKGROUND

Rentable Floor Areas

The following information regarding rentable floor areas associated with the subject building has been provided to the appraiser by the client.

Floor Level	Gross Interior Square Footage	Non-Rentable Square Footage	Rentable Square Footage
Basement	11,733	2,086	9,647
First/Ground	11,760	1,951	9,809
Second	11,760	1,070	10,690
Third	11,530	910	10,620
Fourth	11,530	1,069	10,461
Total	58,313	7,086	51,227

Estimated Building Renovation Costs, Exhibit D (Revised)

A schedule of estimated building renovation costs, referred to herein as Exhibit D (Revised), is included with this letter. Exhibit D (Revised) has been provided to the appraiser by the client.

PRELIMINARY VALUATION ANALYSIS

Fee Simple Land Value (Sales Comparison Analysis) -- Our valuation analysis of the fee simple interest in land associated with the subject property is presented in Table 1. The three selected comparables are as follows. Transaction Number 1 is the recent sale of a 13,246 square-foot site located along Queen Emma Street, adjacent to the "Block J" development site. This site was formerly owned by HECO. Transaction Number 2 is the sale of the 2.386-acre, "Block J" development site, itself, from the City and County of Honolulu to the Pflueger group. Transaction Number 3 is the sale of a 38,177 square-foot site located at the intersection of Nuuanu Avenue and Nimitz Highway in the Chinatown area. This site was purchased by Hawaii National Bank from Bank of Hawaii.

The unadjusted sale prices of the three selected comparables range from $1.5 to $10.5 million. Their unadjusted average unit land prices range from approximately $100.00 to $150.00 per square foot of gross land area. From a comparative standpoint, each of the selected comparable properties is considered either similar or relatively inferior to the subject property with respect to market conditions (i.e., time of sale), property location, and street frontage/access. Conversely, all three selected comparables are considered substantially superior to the subject property with respect to the category of zoning/building height limit. The subject property has a significantly more restrictive height limit of 65 feet and is also listed on the National Register of Historic Sites.

After adjustments, the fee simple unit land value indications for the subject property range from $61.08 to 88.01 per square foot of gross land area. The mean average unit land value

Table 1

FEE SIMPLE LAND VALUE ANALYSIS
First Division, Tax Map Key 2-1-16, Parcel 1
233 South King Street, Honolulu, Hawaii

Transaction Number	Subject	1	2	3
First Division, Tax Map Key	2-1-16-01	2-1-09-11	2-1-09-18	1-7-02-02
Street Address	233 S. King St.	1240 Queen Emma St.	1212 Queen Emma St.	800 Nuuanu Ave.
Land Area (Sq. Ft.)	13,255	13,246	103,139	38,177
City & County Zoning (LUO)	BMX-4	BMX-4	BMX-4	BMX-4
Special District	Hawaii Capital	Hawaii Capital	Hawaii Capital	Chinatown
Historic Site Register	National Register	None	None	None
Building Height Limit (Feet)	65	350	350	250
Transaction Date		1/05	6/04	4/04
Instrument/Financing		Deed	Deed	Deed
Sale Price/Indicated Fee Simple Value		$1,500,000	$10,500,000	$5,600,000
Unit Land Value Indication ($ Per Sq. Ft.)		$113.24	$101.80	$146.69
Market Conditions/Time Factor		1.00	1.00	1.00
Time Adjusted Unit Value		$113.24	$101.80	$146.69
Adjustments (%)				
Location		10%	10%	10%
Zoning and Height Limit		-50%	-50%	-50%
Street Frontage and Access		0%	0%	0%
Net Adjustment (%)		-40%	-40%	-40%
Adjusted Unit Value Before Size		$67.94	$61.08	$88.01
Size Adjustment Factor		1.00	1.00	1.00
Indicated Unit Land Value ($ Per Sq. Ft.)		$67.94	$61.08	$88.01

Range of Indicated Unit Land Values	**$61.08 to $88.01 per sq. ft.**
Mean Unit Land Value Indication	**$72.34 per sq. ft.**
Concluded Unit Land Value	**$75.00 per sq. ft.**
Concluded Fee Simple Land Value	**$75.00 x 13,255 sq. ft. = $994,125**
	Rounded = $1,000,000

Source: Hastings, Conboy, Braig & Associates, Ltd., February 2005.

/6947.LTA

indication is $72.34 per square foot. Based on these indications, we estimate an average fee simple unit land value of $75.00 per square foot for the 13,255 square-foot subject property. This results in an estimated fee simple land value of $1,000,000 as indicated by our sales comparison analysis.

Leased Fee Property Value, As Improved (Discounted Cash Flow Analysis) – Our valuation analysis of the leased fee value of the subject property, as improved, is summarized in Tables 2 and 3. For this Phase I portion of the assignment, two alternative discounted cash flow schedules are presented, each based on a different leasing forecast. Table 2 presents Leasing Scenario No. 1, and Table 3 presents Leasing Scenario No. 2. The primary differences among these two forecasted leasing scenarios are outlined in the following paragraphs, which summarize the various assumptions and forecasts utilized to derive our valuation estimates.

Revenues/Income – Forecasted Potential Gross Income consists of a combination of Base Rents, Common Area Maintenance (CAM) Expense Recovery, and General Excise Tax (GET) Expense Recovery. Forecasted Effective Gross Income is equal to Potential Gross Income less Vacancy and Credit Loss.

- Potential Base Rents are forecast as follows. In both Scenario Nos. 1 and 2, Base Rents in Year 1 are forecast at: $1.00 per square foot of rentable floor area per month for the Basement; $3.00 per square foot of rentable floor area for the Ground Floor; and $1.50 per square foot of rentable floor area per month for Floors 2, 3, and 4. Also, in both scenarios, Base Rents are forecast to increase at a constant rate of three percent (3.0%) annually throughout a projected, ten-year investment holding period.

- Potential CAM Recovery is equal to one hundred percent (100.0%) of the forecasted CAM Expenses, based on the assumption of an absolute net lease(s).

- Potential GET Recovery is forecast at 4.166 percent of all other sources of Potential Gross Income.

- Vacancy and Credit Loss is forecast as follows. In Scenario No. 1, the annual Vacancy and Credit Loss factor is forecast at fifty percent (50.0%) in Year 1, twenty-five percent (25.0%) in Year 2, and stabilized at ten percent (10.0%) starting in Year 3. In Scenario No. 2, the annual Vacancy and Credit Loss factor is forecast at thirty-three percent (33.0%) in Year 1, fifteen percent (15.0%) in Year 2, and stabilized at ten percent (10.0%) starting in Year 3.

Operating Expenses – Annual Operating Expenses consists of a combination of Building Renovation Costs, CAM Expenses, General Excise Tax (GET), Tenant Improvement Allowances, Leasing Commissions, and Reserves for Repairs and Replacements.

- Building Renovation Costs are forecast as follows. In Year 1, $3,505,000. In Year 2, $2,060,000 (equal to $2,000,000 escalated at three percent annually for one year). In Year 5, $1,069,200 (equal to $950,000 escalated at three percent annually for four

Table 2

DISCOUNTED CASH FLOW ANALYSIS NO. 1 (Leasing Scenario No. 1)
HECO Downtown Property
233 South King Street, Honolulu, Hawaii

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
REVENUES/INCOME											
Base Rent Income, Basement Level	$115,760	$119,240	$122,810	$126,500	$130,290	$134,200	$138,230	$142,380	$146,650	$151,050	$155,580
Base Rent Income, Ground Floor Retail	353,120	363,720	374,630	385,870	397,440	409,370	421,650	434,300	447,330	460,750	474,570
Base Rent Income, Floors 2, 3 & 4, Office	571,880	589,030	606,710	624,910	643,650	662,960	682,850	703,340	724,440	746,170	768,560
CAM Expense Recovery	522,520	538,200	554,350	570,980	588,110	605,750	623,920	642,640	661,920	681,780	702,230
General Excise Tax Recovery	65,130	67,080	69,090	71,170	73,300	75,500	77,760	80,100	82,500	84,980	87,530
POTENTIAL GROSS INCOME	$1,628,410	$1,677,270	$1,727,590	$1,779,430	$1,832,790	$1,887,780	$1,944,410	$2,002,760	$2,062,840	$2,124,730	$2,188,470
Vacancy and Credit Loss	814,210	419,320	172,760	177,940	183,280	188,780	194,440	200,280	206,280	212,470	218,850
EFFECTIVE GROSS INCOME	$814,200	$1,257,950	$1,554,830	$1,601,490	$1,649,510	$1,699,000	$1,749,970	$1,802,480	$1,856,560	$1,912,260	$1,969,620
EXPENSES											
Building Renovation Costs	$3,505,000	$2,060,000	$0	$0	$1,069,200	$0	$0	$0	$0	$0	$0
CAM Expenses	522,520	538,200	554,350	570,980	588,110	605,750	623,920	642,640	661,920	681,780	702,230
General Excise Tax	32,570	50,320	62,190	64,060	65,980	67,960	70,000	72,100	74,260	76,490	78,780
Tenant Improvements Allowances	130,000	65,000	37,500	0	0	0	0	0	0	0	0
Leasing Commissions	78,000	39,000	22,500	16,010	16,500	16,990	17,500	18,020	18,570	19,120	19,700
Reserves for Repairs and Replacements	16,280	25,160	31,100	32,030	32,990	33,980	35,000	36,050	37,130	38,250	39,390
TOTAL EXPENSES	4,284,370	2,777,680	707,640	683,080	1,772,780	724,680	746,420	768,810	791,880	815,640	840,100
NET OPERATING INCOME	($3,470,170)	($1,519,730)	$847,190	$918,410	($123,270)	$974,320	$1,003,550	$1,033,670	$1,064,680	$1,096,620	$1,129,520
Present Value Factor	0.8969	0.8044	0.7214	0.6470	0.5803	0.5204	0.4667	0.4186	0.3754	0.3367	
Net Present Value	($3,112,400)	($1,222,500)	$611,200	$594,200	($71,500)	$507,000	$468,400	$432,700	$399,700	$369,200	
CUMULATIVE NET PRESENT VALUE	($3,112,400)	($4,334,900)	($3,723,700)	($3,129,500)	($3,201,000)	($2,694,000)	($2,225,600)	($1,792,900)	($1,393,200)	($1,024,000)	

PRESENT VALUE OF CASH FLOW		($1,024,000)
Eleventh Year Net Cash Flow	$1,129,520	
Capitalization Rate	0.090	
Estimated Sales Price Year 11	$12,550,200	
Less Disposition Costs at 2.0%	251,000	
Net Sales Proceeds	$12,299,200	
Present Value Factor	0.3367	
PRESENT VALUE OF REVERSION		$4,141,100
INDICATED PROPERTY VALUE		$3,117,100
	ROUNDED	$3,120,000

Source: Hastings, Conboy, Braig, & Associates, Ltd., February 2005.

/6947.DCF-1

Table 3

DISCOUNTED CASH FLOW ANALYSIS NO. 2 (Leasing Scenario No. 2)
HECO Downtown Property
233 South King Street, Honolulu, Hawaii

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
REVENUES/INCOME											
Base Rent Income, Basement Level	$115,760	$119,240	$122,810	$126,500	$130,290	$134,200	$138,230	$142,380	$146,650	$151,050	$155,580
Base Rent Income, Ground Floor Retail	353,120	363,720	374,630	385,870	397,440	409,370	421,650	434,300	447,330	460,750	474,570
Base Rent Income, Floors 2, 3 & 4, Office	571,880	589,030	606,710	624,910	643,650	662,960	682,850	703,340	724,440	746,170	768,560
CAM Expense Recovery	522,520	538,200	554,350	570,980	588,110	605,750	623,920	642,640	661,920	681,780	702,230
General Excise Tax Recovery	65,130	67,080	69,090	71,170	73,300	75,500	77,760	80,100	82,500	84,980	87,530
POTENTIAL GROSS INCOME	$1,628,410	$1,677,270	$1,727,590	$1,779,430	$1,832,790	$1,887,780	$1,944,410	$2,002,760	$2,062,840	$2,124,730	$2,188,470
Vacancy and Credit Loss	537,380	251,590	172,760	177,940	183,280	188,780	194,440	200,280	206,280	212,470	218,850
EFFECTIVE GROSS INCOME	$1,091,030	$1,425,680	$1,554,830	$1,601,490	$1,649,510	$1,699,000	$1,749,970	$1,802,480	$1,856,560	$1,912,260	$1,969,620
EXPENSES											
Building Renovation Costs	$3,505,000	$2,060,000	$0	$0	$1,069,200	$0	$0	$0	$0	$0	$0
CAM Expenses	522,520	538,200	554,350	570,980	588,110	605,750	623,920	642,640	661,920	681,780	702,230
General Excise Tax	43,640	57,030	62,190	64,060	65,980	67,960	70,000	72,100	74,260	76,490	78,780
Tenant Improvements Allowances	170,000	45,000	12,500	0	0	0	0	0	0	0	0
Leasing Commissions	102,000	27,000	15,550	16,010	16,500	16,990	17,500	18,020	18,570	19,120	19,700
Reserves for Repairs and Replacements	21,820	28,510	31,100	32,030	32,990	33,980	35,000	36,050	37,130	38,250	39,390
TOTAL EXPENSES	4,364,980	2,755,740	675,690	683,080	1,772,780	724,680	746,420	768,810	791,880	815,640	840,100
NET OPERATING INCOME	($3,273,950)	($1,330,060)	$879,140	$918,410	($123,270)	$974,320	$1,003,550	$1,033,670	$1,064,680	$1,096,620	$1,129,520
Present Value Factor	0.8969	0.8044	0.7214	0.6470	0.5803	0.5204	0.4667	0.4186	0.3754	0.3367	
Net Present Value	($2,936,400)	($1,069,900)	$634,200	$594,200	($71,500)	$507,000	$468,400	$432,700	$399,700	$369,200	
CUMULATIVE NET PRESENT VALUE	($2,936,400)	($4,006,300)	($3,372,100)	($2,777,900)	($2,849,400)	($2,342,400)	($1,874,000)	($1,441,300)	($1,041,600)	($672,400)	

PRESENT VALUE OF CASH FLOW		($672,400)
Eleventh Year Net Cash Flow	$1,129,520	
Capitalization Rate	0.090	
Estimated Sales Price Year 11	$12,550,200	
Less Disposition Costs at 2.0%	251,000	
Net Sales Proceeds	$12,299,200	
Present Value Factor	0.3367	
PRESENT VALUE OF REVERSION		$4,141,100
INDICATED PROPERTY VALUE		$3,468,700
	ROUNDED	$3,470,000

Source: Hastings, Conboy, Braig, & Associates, Ltd., February 2005.

/6947.DCF-2

Initial Improvements **EXHIBIT D**

Project Name/Description	Start Year*	Estimated Cost	Contractor
~~Chillwater Pipe/Reinsulate Pipes (attic) Note 1~~	~~2004~~	~~$82,000~~	~~Heidi & Cooke~~
~~Downspout Replacement Note 2~~	~~2004~~	~~$75,000~~	~~Heidi & Cooke~~
Replace or Refurbish Passenger Elevators Note 3	2004-2005	$300,000	ThyssenKrupp Elevator
Attic Project-Relocate Chillers Outside of Building	2005	$155,000	TBD
Electrical Improvements to comply w/code (part 1) **Note 4**	2005	$250,000	Bennett Engineers Inc.
Window Replacement **Note 5**	2005	$1,125,000	TBD
HVAC Replacement - **Note 6**	2005-2006	$3,300,000	See below**
~~Fire Sprinkler Installation~~	~~2006~~	~~$250,000~~	~~TBD~~
Basement Leak Repairs	2004	$25,000	TBD
Thermal/Moisture Protection of Exterior Walls	2006	$350,000	TBD
Electrical Improvements to comply w/code (part 2) **Note 4**	2009	$500,000	TBD
Roof Restoration/Reroof Building	2009	$300,000	TBD
~~Building Sewer Improvements~~	~~2009~~	~~$1,000,000~~	~~TBD~~
Assessment/Repair Exterior Walls***		$150,000	TBD
Freight Elevator Restoration	2016	$250,000	TBD
Electrical Upgrades (Emergency power, UPS, electric rooms)	2016	$1,000,000	TBD
TOTAL		$9,122,000	

* Anticipated
** Engineering Consultant: Miyashiro & Associates Inc.
Electrical Consultant: Bennett Engineers Inc.
Architectural Consultant: Richard Matsunaga & Associates Architects Inc.
A/C Contractor: Bids will be requested from Heidi & Cooke, Continental Mechanic, Oahu Plumbing & Economy Plumbing
*** May need to do the work sooner

Note 1 - Work on attic pipes in progress; anticipate completion in December 2004; non-attic chillwater pipes work will be done as part of HVAC project.
Note 2 - (corroded interior spouts) Work completed, except for wall touch-up. HECO has paid $47,968 to date.
Note 3 - HECO payment of $84,128 already made as partial payment for major parts; installation planned for January 2005.
Note 4 - Electrical retrofit
Note 5 - Replacement of all windows, frames and perimeter frames
Note 6 - Includes replacement of chillerplant, pumps, cooling towers, chillwater pipes, condenser water piping, air handlers and air distribution ducts.

years). In all other years. Building Renovation Costs are forecast at zero dollars. All

proposed renovation costs scheduled to occur after calendar year 2015 are disregarded for purposes of this analysis.

- CAM Expenses are forecast at $0.85 per square foot of rentable floor are per month in Year 1 and escalated at three percent (3.0%) annually thereafter.

- GET is forecast at four percent (4.0%) of Effective Gross Income.

- Tenant Improvement Allowances are forecast as follows. In Scenario No. 1, at $5.00 per square foot of rentable floor area multiplied by 26,000 square feet in Year 1; 13,000 square feet in Year 2; and 7,500 square feet in Year 3. In Scenario No. 2, at $5.00 per square foot of rentable floor area multiplied by 34,000 square feet in Year 1; 9,000 square feet in Year 2; and 2,500 square feet in Year 3.

- Leasing Commissions are forecast as follows. In Scenario No. 1, at $3.00 per square foot of rentable floor multiplied by 26,000 square feet in Year 1; 13,000 square feet in Year 2; 7,500 square feet in Year 3; and at one percent (1.0%) of Effective Gross Income thereafter starting in Year 4. In Scenario No. 2, at $3.00 per square foot of rentable floor multiplied by 34,000 square feet in Year 1; 9,000 square feet in Year 2; and at one percent (1.0%) of Effective Gross Income thereafter starting in Year 3.

- Reserves for Repairs and Replacement are forecast at two percent (2.0%) of Effective Gross Income.

Net Operating Income – Deducting Operating Expenses from Effective Gross Income results in the annual Net Operating Income forecast for the subject property. This future net income stream is discounted to a corresponding net present value based on an annual Internal Rate of Return (IRR) requirement (i.e., Discount Rate) of 11.5 percent. The selected discount rate is supported by recent published results of the Korpacz Real Estate Investor Survey and information gathered from interviews with local commercial investment firms.

Reversionary Interest in the Property -- The reversionary interest in the subject property is based on the assumption that the property is sold at the end of the tenth year of the cash flow analysis. This anticipated future disposition value is adjusted downward for selected marketing costs and then discounted to a corresponding net present value indication.

In this analysis, the subject property's forecasted Net Operating Income in Year 11 is converted into a forecasted future sale price based on an overall, Terminal Capitalization Rate of 9.0 percent. This terminal capitalization rate is supported by the results of the Korpacz Survey. After deducting a two percent allowance for sale disposition and marketing costs, the resulting net sale proceeds are discounted to a present value indication at an 11.5 percent internal rate of return.

Leased Fee Property Value Estimates -- The sum of the net present value indications corresponding to the forecasted ten-year Net Operating Income stream and the anticipated

[redacted]

property, as improved. For the two alternative scenarios, the value estimates indicated by our ten-year, discounted cash flow analysis of the subject property are as follows:

result, or the occurrence of a subsequent event directly related to the intended use of this appraisal.

- The reported analyses, opinions, and conclusions were developed, and this report has been prepared, in conformity with the requirements of the Code of Professional Ethics and Standards of Professional Appraisal Practice of the Appraisal Institute, which include the Uniform Standards of Professional Appraisal Practice.

- Robert R. Braig, MAI, SRA and Ricky P. Minn have made a personal inspection of the property that is the subject of this report.

- No one provided significant real property appraisal assistance to the person signing this certification.

- As of the date of this report Robert R. Braig, MAI, SRA has completed the [illegible]

requirements of the continuing education program of the Appraisal Institute.

- The use of this report is subject to the requirements of the Appraisal Institute relating [illegible]

CONTRACT OF

APPRAISAL SERVICES

Robert C. Hastings, Jr., MAI, CRE
Alan J. Conboy, MAI, SRA
Robert R. Braig, MAI, SRA
Ricky P. Minn
Don H. Konno, MAI
Robert C. Hastings, III, MAI
Liza F. Hamada
Elsie R. Rose, CCIM

HASTINGS, CONBOY, BRAIG & ASSOCIATES, LTD.

Real Estate Appraisers, Counselors and Economists

December 30, 2004

Mr. Phil Hauret
Hawaiian Electric Company
PO Box 2750
Honolulu, Hawaii 96840

Dear Mr. Hauret:

Assignment

This letter will serve as our proposal to provide you with a counseling report addressing the value of the improvements in the Hawaiian Electric Building located at 233 South King Street, Honolulu, Hawaii. The property is further identified on Hawaii Tax Maps as First Division, Tax Map Key 2-1-16, Parcel 1 containing a gross land area of 13,255 square feet.

The function of this analysis is for internal decision making purposes. This analysis will be performed in conformance with and will be subject to the requirements of the Uniform Standards of Professional Appraisal Practice (USPAP) of the Appraisal Foundation, and Code of Professional Ethics and Standards of Professional Conduct of the Appraisal Institute. The use of the report is subject to the requirements relating to review by duly authorized representatives of the Appraisal Institute.

Proposed Scope of Services

Per your request, this analysis will be limited to valuing the "as is" leased fee interest in the subject improvements assuming HECO vacates the building. Our analysis will consider any improvements which will be required for deferred maintenance plus tenant improvement. Furthermore, we will project market rents, absorption and marketing costs for an assumed lease-up of the property on a multi-tenant basis. The estimated value of the land will be deducted from the leased fee value to estimate the value of the improvements. This assignment will be completed in two phases. Phase One will consist of reporting our preliminary value conclusions. Phase Two will be completion of the report. The results of this analysis will be communicated in the form of a brief summary report.

Our report will be subject to various conditions and assumptions appropriate to our analysis and conclusions. Typical assumptions and conditions are in the attached Addendum.

Required Items for This Assignment

To complete this assignment, we will require the following:

1. Copy of and/or summary of the building improvements.
2. Gross and net leasable areas of the subject building and floor plans, if available.

1067 Alakea Street • Honolulu, Hawaii 96813 • Telephone (808) 524-1700 • Fax (808) 538-1337

Proposed Fees and Timing

Based on our present staff availability, we anticipate that we can complete Phase One of our analysis within five to six weeks from the receipt of your written authorization and retainer. Phase Two will require an additional two weeks.

Professional fees charged by our firm are computed on the basis of the complexity of the problem and the time spent by members of our staff at their established billing rates, plus reimbursement of out-of-pocket expenses. We estimate that the first phase of this assignment can be completed for a fee ranging from $5,500 to $6,000 plus gross excise tax. Should you wish to complete this assignment, the second phase can be completed for additional fee ranging from $1,000 to $1,500.

It is our standard practice to require a 60 percent retainer at the commencement of an assignment; the balance upon delivery of the report. If the balance is not received within 15 days, a one percent per month interest fee will be charged. If the terms of this letter are satisfactory, please acknowledge your authorization by signing and dating a copy of this letter and returning it together with your check in the amount of $3,300.

The terms and conditions of this proposal are based on present and anticipated staff availability. If the executed copy of this proposal and retainer are not received before January 10, 2004, we reserve the right to reschedule the anticipated date of delivery and revise the estimated fee.

If you have any questions regarding the scope of the assignment or wish to clarify this proposal, please contact us at your earliest convenience. We look forward to working with you on this assignment.

Sincerely,
HASTINGS, CONBOY, BRAIG
& ASSOCIATES, LTD.

Robert R. Braig, MAI, SRA
Executive Vice President

Ricky Minn
Senior Vice President

APPROVED:
HAWAIIAN ELECTRIC COMPANY
By: ______________________
(Authorized Signature)
Date: January 4, 2005

CONTRACT ADDENDUM REGARDING APPRAISAL ASSUMPTIONS AND CONDITIONS

Our report will be subject to the following conditions and assumptions which will constitute the primary framework of our analysis and conclusions. Various other assumptions and limiting conditions may be required to complete the assignment.

1. The appraisal will be based upon the present condition of the national economy and the present purchasing power of the dollar.

2. The report will express the opinion of the signer(s) on a specified date; in no way will it be contingent upon the reporting of specified values or findings.

3. It will be assumed that the subject property is free and clear of any and all encumbrances other than those referred to in the report, and no responsibility will be assumed for matters of a legal nature. The report will not be construed as rendering any opinion of title, which will be assumed to be good and marketable.

4. Any maps or plot plans reproduced and included in the report will be intended only for the purpose of showing special relationships. They are not necessarily measured surveys or measured maps, and we will not be responsible for topographic or surveying errors. No liability will be assumed for soil conditions, bearing capacity of the subsoil or for engineering matters relating to proposed or existing structures.

5. The appraiser will not give testimony or appear in court because of having made this appraisal unless arrangements for the appearance and the fee for such appearance have been agreed upon by the person or corporation requiring such testimony.

6. The value conclusions reported will assume completion of any proposed improvements in accordance with furnished architectural plans.

7. When the appraisal report contains an allocation of the total valuation between land and improvements such allocation applies only under the existing program of utilization. The separate valuations for land and building can not be used in conjunction with any other appraisal and will be invalid if so used.

8. When the appraisal report contains a valuation relating to a geographical portion or tract of real estate, the value reported for such geographical portion relates to such portion only and should not be construed as applying with equal validity to other portions of the larger parcel or tract, and, the value reported for such geographical portion plus the value of all other [illegible]

ADDENDUM
(Page 2)

9. When the appraisal report contains a valuation relating to an estate in land that is less than the whole fee simple estate, the value reported for such estate relates to a fractional interest only in the real estate involved and, the value of this fractional interest plus the value of all other fractional interests may or may not equal the value of the entire fee simple estate considered as a whole.

10. Information provided by informed local sources such as governmental agencies, financial institutions, Realtors, buyers, sellers and others, will be weighed in the light in which it was

supplied and checked by secondary means where possible; however, no responsibility will be assumed for possible misinformation.

11. Possession of the report, or a copy thereof, does not carry with it the right of publication

and the report may not be used by any person or organization except the client without the previous written consent of the appraiser, and then only in its entirety.

12. Disclosure of the contents of the report is governed by the Bylaws and Regulations of the Appraisal Institute. The contents of the report (especially any conclusions as to value, the identity of the appraiser, or the firm with which he or she is connected, or any reference to the Appraisal Institute, or the MAI or SRA designation) shall not be disseminated to the public through advertising, public relations, news, sales, or any public means of communication without prior written consent and approval.

HASTINGS, CONBOY, BRAIG & ASSOCIATES, LTD.
Real Estate Appraisers, Counselors and Economists
1067 Alakea Street / Honolulu, Hawaii 96813 / Telephone (808) 524-1700 / Fax (808) 538-1337

GENERAL

Hastings, Conboy, Braig & Associates, Ltd. (HCBA) is one of the largest real estate counseling firms headquartered in the State of Hawaii. The firm has a staff of professional real estate counselors, appraisers, economists and market analysts, and investment analysts. Its staff has extensive experience analyzing and appraising South and West Pacific real estate; three members hold designations from the American Institute of Real Estate Appraisers (MAI) and from the Society of Real Estate Appraisers (SRPA). Associated companies offer development management, real estate brokerage, and investment services.

The firm assists clients with solutions to real estate problems. Its purpose is to provide sound and objective analysis directed toward reducing the financial risks inherent in the real estate decision-making process. This is accomplished by the application of intensive research and analysis to interpreting the dynamics influencing real estate markets and real estate investments, and the subsequent identification of opportunities and courses of action which can be profitably employed.

In executing its assignments, HCBA utilizes the broad experience of its highly qualified staff to identify specific problem areas associated with client programs and to structure and implement effective solutions.

Hastings, Conboy, Braig & Associates, Ltd. maintains an extensive technical library of books, monographs, journals and special statistical compilations in the fields of land use, recreation, investment analysis, urban planning and development. Surveys of market conditions for a variety of land use are maintained in our library and updated constantly. In conjunction with being headquartered in Hawaii, these library resources allow HCBA to closely monitor local real estate developments and activity. On an annual basis, HCBA receives the operating statistics from approximately 60 office buildings, and 26 shopping centers, which are compiled into the Hawaii version of the BOMA, and ICSC annual exchange reports.

Our clients include builders and developers, financial institutions and advisors, corporations, private individuals, estates, and governmental agencies at all levels.

PROFESSIONAL SERVICES

Problem solving is a major function of HCBA. Although specific services and approaches to problems differ from case to case, they may be generally described by the following basic types of studies. Study results can be evaluated utilizing the computerized analysis program to determine financial feasibility and to calculate measurements of project performance.

Real Estate Investment Counseling — Determination and evaluation of effective real estate investment strategies including project selection, analysis of highest and best use, and determination of optimum development strategy based upon an iterative process of conceptualizing and evaluating alternative development schemes.

Market Value Appraisal — Valuations for mortgage loans, investment counseling, lease negotiations, condemnation, assessment appeal and policy decisions. Appraisals extend to a variety of properties, including income properties, existing and proposed resort and residential developments, industrial properties, high-rise office buildings and condominiums, hotels and apartments, sugar plantations and large vacant acreage ownerships.

Negotiation/Arbitration — Counseling on space and ground lease rents for original negotiation or reporting and availability as arbitors when agreement between principals cannot be reached.

Special Valuation Assignments — Estimates of value diminution or enhancement caused by public policy decisions, analysis and quantification of cost-benefit effects, future value projections, portfolio reviews, corporate planning and disposition strategy studies, and analysis and [illegible]ation of air rights, easements and water rights.

Resort and Recreation Projects — Application of travel, recreation and leisure trends to determination of demand for transient and recreation accommodations and services, including determination of sources of patronage and consumer preferences, in addition to marketing strategies for sale of recreation properties.

Housing Marketing Studies — Analysis of housing marketing conditions, determination of consumer housing preferences, and identification of housing market opportunity areas; including analysis of single family and multiple family projects regarding pricing, sizing and marketing strategies.

Retail Analysis — Determination of market area sales potential and penetration estimates for specific sites based upon locational attributes and relationship to competitive facilities, including on-site analysis to coordinate functional uses to facilitate merchandising space and maximizing overall return.

Office Space Analysis — Measurement of office space supply including tenancy, vacancy, rental patterns; evaluation of demand factors leading to forecasts of office space demand for whole communities, specific subareas, and individual sites; and translation of supply and demand factors into prospects for particular projects.

Industrial Studies — Analysis of local labor markets and economic conditions to determine industrial space requirements, including site analysis to evaluate competitive positions within the market structure.

Commercial Banks and Thrift Institutions
Bancorp Finance
Bank of America
Bank of Hawaii
Bank of Honolulu
Bank of Maui
Central Pacific Bank
City Bank of Honolulu
Crocker National Bank
First Hawaiian Bank
First Hawaiian Credit Corp.
First National Bank - Seattle
GECC Financial Corp.
Honfed Bank
Pioneer Savings Bank
Westpac Banking

Savings Institutions
American Savings & Loan Association
Citizens Federal Savings & Loan
Coast Savings & Loan
Continental Savings & Loan
First Federal Savings & Loan Association
Pacific Coast Mortgage
Provident Federal Savings
State Savings & Loan Association
Territorial Savings & Loan Association

Insurance Companies and Pension Funds
American National Life Insurance Co.
Bankers Life of Nebraska
Equitable Life Assurance Co.
John Hancock
Mutual of Omaha

Trusts and Estates
American Trust Company
Bernice Pauahi Bishop Estate
Bishop Trust Company
Harold K.L. Castle Estate
Hawaiian Trust Company
James B. Campbell Estate
Liliuokalani Trust
Magoon Estate
McCandless Properties
Moody Estate

Builders, Developers and Industrial Firms
Alcoa
Alexander & Baldwin
Amelco Corp.
Amfac, Inc.
Asahi Development
Aston Hotels & Resorts
Blackfield Hawaii Corp.
Bedford Properties
Boise Cascade
Campbell Industrial Park
Castle & Cooke, Inc.
Charles Pankow Builders
Chevron U.S.A.
Cooke Land Company, Inc.
C. Brewer & Co., Ltd.
Dillingham Land Corporation
Dow Chemical
Frito-Lay of Hawaii
Gentry Pacific, Ltd.
GO Financial Group

Government Agencies (continued)
Marianas Public Land Corporation,
Commonwealth of the Marianas
Maui Redevelopment Agency
National Park Service
State of Hawaii—
Department of Planning & Economic Development
U.S. Department of Commerce—
Economic Development Administration
U.S. Department of Interior
U.S. Department of Transportation
U.S. Fish and Wildlife Service

Others
Belt, Collins & Associates
Brewer Chemical Co.
Hawaiian Electric Co.
Hawaiian Telephone Co.
Holiday Inns, Inc.
Honolulu International Airport
MCI Telecommunications
Northwest Airlines
Pacific International
Public Storage, Inc.
Rosewood Properties, Inc.
Safeway Stores, Inc.
Texaco, Inc.
The Nature Conservancy
United Airlines
Westin Hotels

Foreign Corporations and Banks

PROFESSIONAL QUALIFICATIONS OF
ROBERT R. BRAIG, MAI, SRA

Professional Affiliations
Appraisal Institute - MAI and SRA designations
Qualified Instructor for Course 201 - Principles of Income Property Appraising (1983) and
Course 202 - Applied Income Property Valuation (1984)
President of Hawaii Chapter 15 - American Institute of Real Estate Appraisers (1989)

Licensing and Certification
State of Hawaii - Certified General Appraiser (CGA-149)
Certificate Expires December 31, 2005
Real Estate Brokers License - State of Hawaii

Education
M.B.A. (Finance) University of Nebraska
B.S. (Business Administration) University of Nebraska

Employment Experience
Mr. Braig is presently Executive Vice President and Director of Hastings, Conboy, Braig & Associates, Ltd. (HCBA) and its subsidiary real estate brokerage company Pacific Area Realty. He has been associated with this firm since 1973 and is one of three principals. HCBA was founded in 1973 and is one of the largest real estate counseling firms in the State of Hawaii. This committed team of professional real estate appraisers, counselors, economists and market analysts provide assistance involving all forms of commercial real estate. This company has extensive experience throughout the State of Hawaii, Micronesia and the U.S. mainland. Included among its staff of professionals are five individuals who hold the MAI designation; three of these also hold the SRA designation and one holds the CRE designation.

Mr. Braig's area of expertise spans the entire spectrum of commercial real estate ranging from commercial, industrial, shopping centers, office buildings, residential development (apartments, condominiums and subdivisions), golf course, tax appeal and mixed use land development.

Over the last fifteen years Mr. Braig has served on numerous arbitration panels throughout the State of Hawaii involving ground rent renegotiations and commercial space lease reopenings. His involvement has ranged from witness, appointed panel member, appointment as third person and sole arbitrator.

Selected clients include:

Financial Institutions – Bank of Hawaii, First Hawaiian Bank, G.E. Capital, First Federal Savings and Loan, Central Pacific Bank, American Savings Bank, Construction Lending Corporation of America, Nipon Credit Bank, Territorial Savings and Loan, First Hawaiian Credit Corporation, Nomura Credit Corporation, Bank of Tokyo – Mitsubishi, Metzler North America, City Bank, Hawaii National Bank, Bank of Honolulu, Finance Factors, Trans Pacific Mortgage and

Robert R. Braig, MAI, SRA
(Page 2)

Developers -- The Gentry Companies, Schuler Homes, Grove Farm Land Corp., Seibu Hawaii, Haseko Hawaii, C. Brewer Homes, John D. Lusk & Sons, The Petty Corporation, Sports Shinko (Hawaii), Waikoloa Properties, Pacific Construction, The McNaughton Group, Maui Lani Partners, Alexander & Baldwin, Inc., Servco Pacific, GTE Hawaiian Telephone, K.H. Properties, Aloha Petroleum, Ltd., Duty Free Shoppers.

Trusts, Estates and Consultants -- The Nature Conservancy, The Estate of James Campbell, C. Brewer & Company, Queen Emma Foundation, Realty Investment, Co., McCandless Estate, Hawaiian Trust Company, Pacific Century Trust, Damon Estate, Deloitte & Touche LLP, Arthur Anderson, Koll, Cushman & Wakefield.

Selected Assignments include:

Commercial Properties -- Kahala Mall, Kukui Grove Shopping Center, Stadium Mall Shopping Center, Liliha Square Shopping Center, Pearl City Plaza, Kaimuki Shopping Center, Hilo Shopping Center, Salt Lake Shopping Center, Kings Shops (Waikoloa Beach Resort), Manoa Shopping Center, Hawaii Kai Towne Center, Kihei Longs Shopping Center, Maui Marketplace, Kauai Kmart, Kona Kmart, Ewa Beach Shopping Center, Kapolei Shopping Center, Aina Haina Shopping Center, Kapolei State Office Building, Micronesia Mall (Guam), Windward City Shopping Center, Waianae Mall, Gentry Shopping Center, Coconut Grove Marketplace, Kuakini Physician's Tower, Pearl Kai Shopping Center, Gentry Marina, Duty Free Shoppers – Waikiki, Royal Hawaiian Shopping Center.

Master Planned Communities -- Ewa by Gentry, Waikele, Gentry Waipio, Waikoloa (Hawaii), Mililani Town, Makenna Resort (Maui), Wailuna, Ko'Olina Resort, City of Kapolei, Waiawa, Kehalani (Maui), Wailea Golf Courses.

Subdivisions -- The Lofts by Gentry (305), Kula Lei (193), Maui Lani (268), Summerhill (84), Villages at Leialii, Sunrise Estates (143), Sun Terra, West Loch Fairways (73), Westcliff (39), Waialae Iki, Soda Creek, Heights at Wailuna, Wailuku Heights, 49 Black Sand Beach (49) Kohala Waterfront (50), Westhills, Lombard Way, Islands at Maui Lani, Greens at Maui Lani, The Carriages.

Condominiums -- [illegible]

PROFESSIONAL QUALIFICATIONS OF RICKY P. MINN

BUSINESS BACKGROUND

Hastings, Conboy, Braig & Associates, Ltd., Senior Vice President.
Employed with Hastings, Conboy, Braig & Associates, Ltd. since November 1977.

EDUCATIONAL BACKGROUND

University of Hawaii at Manoa, Bachelor of Arts Degree in Economics, Awarded 1977.
Appraisal Institute, Credit for the following Educational Courses:
Standards of Professional Practice, Parts A, B, and C.
Capitalization Theory and Techniques, Parts A and B.

PROFESSIONAL AFFILIATIONS

Appraisal Institute, Affiliate Member.

LIST OF SELECTED CLIENTS AND STUDIES

Island of Kauai:

U.S. Department of the Navy	Port Allen Pier Rental Rates
Central Pacific Bank	Old Koloa Town Shopping Center
State of Hawaii Department of Agriculture	Kekaha Agricultural Park
Art and Elizabeth Charitable Remainder Unitrust	Kalapaki Villas Condominium

Island of Oahu:

Hawaii Carpenter's Financial Security Fund	Waimalu Shopping Paza
Pacific Century Trust	Alexander Gardens Condominium
Roscha Woodwork, Inc.	Roscha Woodwork Industrial Building
Condiotti Enterprises, Inc.	Queen Emma Office Building
First Hawaiian Bank	Mililani Shopping Center
First Hawaiian Bank	SJS Office Building
A & B Properties, Inc.	Mill Town Center Business Park
Hotels In Paradise	Waikiki Whaler Apartments
City Bank	Lee & Young Building
Bank of Hawaii	SunPoint Condominium
The Bank of Tokyo-Mitsubishi, Ltd.	Royal Kunia Gardens Condominium
Bank of Hawaii	377 Keahole Street Building
Woodmen of the World Life Insurance Society	4400 Kalanianaole Highway
First Hawaiian Bank	Westhills Subdivision, Phases II and III
GE Capital Hawaii, Inc.	1450 Young Street Condominium

LIST OF SELECTED CLIENTS AND STUDIES

Island of Maui:

Baldwin*Malama	Piilani Village Development Sites
The Trust for Public Land	Nu'u and Waiu Properties
U.S. National Park Service	Kaupo Ranch Trail Easement
First Hawaiian Bank	Kihei Longs Shopping Center
First Hawaiian Bank	Proposed Napilihau Townhomes

Island of Hawaii:

First Hawaiian Bank	Nani Mau Gardens
[illegible]	[illegible]
Owens Financial Group, Inc.	Waiakea Village
Raymond K. Hasegawa, Attorney At Law	Dodo Mortuary
Carlsmith Ball	MacFarms of Hawaii
Farm Credit Bank of Texas	IASCO Macadamia Nut Orchards
Banc One Commercial Loan Origination Corp.	Liliha Healthcare Center
Bank of Hawaii	Kilauea Plaza
Bank of Hawaii	BFS Hilo Center
Central Pacific Bank	Suisan Company Jumbo and Super Jumbo
Bank of Hawaii	Big Island Toyota Suzuki Hyundai
Bank of Hawaii	Ka Waena Lapa'au, Hilo Radiologic Offices
American Savings Bank	Aloha Building
State of California Department of Insurance	Bayview Banyan Apartments
Pacific Century Trust	Kamuela Ace Hardware
Trans-Pacific Mortgage Group	Coconut Grove Marketplace
Housing & Community Develop. Corp. of Hawaii	Kamaaina Hale Leased Fee
Metzler North American Corporation	Kohala Waterfront Subdivision
The Stewart Living Trust	Hoomau Ranch
Marcus & Associates, Inc.	Kealakekua Business Plaza
First Hawaiian Bank	Hualalai Center
Puuanui Partnership	Puuanui Partnership Properties
Hillwood/Mills Big Island Development LLC	49 Black Sand Beach Subdivision

CA-IR-617

<u>Ref: HECO response to CA-IR-260 & HECO-1605 (Rent Expense).</u>

Please provide the following:

a. Original HECO-1605 took into account the rent that had been waived for January and February for CPP Suites 700, 1520 and 1530. Revised HECO-1605 (CA-IR-260) does not recognize this waiver. Please explain and reconcile this change in position.

b. Revised HECO-1605 (CA-IR-260) reflects updated monthly rental rates and monthly CAM rates for the CPP suites. Please provide a copy of the negotiated lease amendments supporting these rates.

c. Referring to item (b) above, please provide a copy of any related correspondence or other documentation regarding the determination of fair market value rental rates used for the CPP suites.

d. Please confirm that the Annual Property Tax Credit arises from the fact that the property owner is able to avoid property taxes on spaced used by the utility. If this cannot be confirmed, please explain.

e. Referring to revised HECO-1605 (CA-IR-260), please explain and provide support for the property tax credit amounts reflected in column (f).

f. Footnote 1 on the original and revised HECO-1605 indicates that the monthly CAM rate is for common area maintenance. The CAM rate in column (d) declined from $0.992 (original) to $0.975 (revised) per square foot per month. Please identify and describe the specific recurring and nonrecurring maintenance covered by this rate.

g. Column (g) of both the original and revised HECO-1605 is identified as "Op Exp Recon." Please provide the following:
   1. Please describe the purpose of this apparent reconciliation of operating expense.
   2. Please explain how the amounts in column (g) were determined.
   3. Discuss the process associated with any delays in the apparent expense true-up mechanism.

waiver of rent for January and February did not include the waiver of CAM charges for those months.)

b. Due to its voluminous nature, one copy each of the negotiated lease amendments and agreements will be provided to the Consumer Advocate and the Commission under separate transmittal. Final amendments for Suites 1010, 1480, and 1515 have not yet been received and Suites 700, 1300, 1520 & 1530 are still awaiting landlord approval.

   Monthly CAM charges for all CPP Suites except for Suites 1020, 1025 & 1075, 1250 & 1270 and the HEIPC lease are provided on pages 4-13. Suites 1020, 1025 & 1075 and 1250&1270 are new leases that reflect the new CAM rates. The HEIPC Sublease amounts are included as part of HEI's inter-company billing.

c. A copy of available correspondence regarding the determination of fair market value rental rates used for the CPP Suites is provided on page 14.

d. Yes, the annual real property tax credit arises from the fact that HECO is exempt from paying real property taxes on space used by the utility.

e. CPP's Estimated 2005 Operating Expenses Report, which itemizes the building operation expenses, is provided on page 15. The real property tax shown on this report was used to determine the property tax credit amounts reflected on the revised HECO-1605.

f. See page 15 for items included in the monthly CAM rate.

g. 1. The Common Area Maintenance (CAM) charged during the year is based on CPP's operating budget. A reconciliation of operating expenses is done on an annual basis to adjust the CAM charged during the year to the CAM based on the actual expenses for the year.

2. The amounts in column (g) were estimated using a 3% escalation of the 2003 operating expense reconciliation amount per square foot.

3. The financial statements will reflect estimated rent amounts until the true-up is completed.

4. The CAM rate set forth in column (d) represents the estimated CAM per square foot for 2005. As explained in g.1., the operating expense reconciliation represents a true-up of the estimated CAM charged to each Suite during the year to their respective portion of the actual building operating expenses for the year.

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CENTRAL PACIFIC PLAZA
2005 Common Area Maintenance (CAM) Charge

We have completed the 2005 operating budget for Central Pacific Plaza. Detailed below is the breakdown of your new CAM charge for the 2005 calendar year based on the operating budget. The new CAM charge is reflected on your February billing statement as well as an adjustment to the amount billed in January.

TENANT: **Hawaiian Electric Co., Inc.**

SUITE: **700**

Operating Expense Pro-rata Share: 7,598 square feet of 232,959 total square feet = 3.2615%

1.	Annual Share of Operating Expenses: $2,726,406 * 3.2615%	= $	88,922.00
2.	Monthly Share of Operating Expenses: (divide line 1 by 12 months)	= $	6,001.27

January CAM Adjustment

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CENTRAL PACIFIC PLAZA
2005 Common Area Maintenance (CAM) Charge

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TENANT: Hawaiian Electric Co., Inc.

SUITE: 1010

Operating Expense Pro-rata Share: 4,509 square feet of 232,959 total square feet = 1.9355%

1.	Annual Share of Operating Expenses: $2,726,406 * 1.9355%	= $	52,771.00
2.	Monthly Share of Operating Expenses: (divide line 1 by 12 months)	= $	3,561.46

<u>January CAM Adjustment</u>

3.	New 2005 Monthly CAM	= $	3,561.46
4.	CAM billed in January	= $	(3,736.33)
5.	January CAM adjustment	= $	(174.87)

Should you have any questions, please contact Carmen L. Magno at 521-6024.

* *Please note that these amounts are rounded to the nearest whole cent.*

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CENTRAL PACIFIC PLAZA
2005 Common Area Maintenance (CAM) Charge

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TENANT: **Hawaiian Electric Co., Inc.**

SUITE: **1212**

Operating Expense Pro-rata Share: 813 square feet of 232,959 total square feet = 0.3490%

1.	Annual Share of Operating Expenses: $2,726,406 * 0.3490%	= $	9,515.00
2.	Monthly Share of Operating Expenses: (divide line 1 by 12 months)	= $	642.15

January CAM Adjustment

3.	New 2005 Monthly CAM	= $	642.15
4.	CAM billed in January	= $	(673.69)
5.	January CAM adjustment	= $	(31.54)

Should you have any questions, please contact Carmen L. Magno at 521-6024.

* *Please note that these amounts are rounded to the nearest whole cent.*

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TENANT: Hawaiian Electric Co., Inc.

SUITE: 1300

Operating Expense Pro-rata Share: 9,601 square feet of 232,959 total square feet = 4.1213%

1.	Annual Share of Operating Expenses: $2,726,406 * 4.1213%	= $	112,364.00
2.	Monthly Share of Operating Expenses: (divide line 1 by 12 months)	= $	7,583.42

January CAM Adjustment

3.	New 2005 Monthly CAM	= $	7,583.42
4.	CAM billed in January	= $	(7,955.76)
5.	January CAM adjustment	= $	(372.34)

Should you have any questions, please contact Carmen L. Magno at 521-6024.

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CENTRAL PACIFIC PLAZA
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TENANT: **Hawaiian Electric Co., Inc.**

SUITE: **1425**

Operating Expense Pro-rata Share: 2,742 square feet of 232,959 total square feet = 1.1770%

1. Annual Share of Operating Expenses: = $ 32,091.00

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CENTRAL PACIFIC PLAZA
2005 Common Area Maintenance (CAM) Charge

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TENANT: **Hawaiian Electric Co., Inc.**

SUITE: **1480**

Operating Expense Pro-rata Share: 1,242 square feet of 232,959 total square feet = 0.5331%

1.	Annual Share of Operating Expenses: $2,726,406 * 0.5331%	= $	14,536.00
2.	Monthly Share of Operating Expenses: (divide line 1 by 12 months)	= $	980.97

January CAM Adjustment			
3.	New 2005 Monthly CAM	= $	980.97
4.	CAM billed in January	= $	(1,029.17)
5.	January CAM adjustment	= $	(48.20)

Should you have any questions, please contact Carmen L. Magno at 521-6024.

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CENTRAL PACIFIC PLAZA
2005 Common Area Maintenance (CAM) Charge

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TENANT: **Hawaiian Electric Co., Inc.**

SUITE: **1515**

Operating Expense Pro-rata Share: 732 square feet of 232,959 total square feet = 0.3142%

1.	Annual Share of Operating Expenses: $2,726,406 * 0.3142%	= $	8,567.00
2.	Monthly Share of Operating Expenses: (divide line 1 by 12 months)	= $	578.16

January CAM Adjustment			
3.	New 2005 Monthly CAM	= $	578.16
4.	CAM billed in January	= $	(606.57)
5.	January CAM adjustment	= $	(28.41)

Should you have any questions, please contact Carmen L. Magno at 521-6024.

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CENTRAL PACIFIC PLAZA
2005 Common Area Maintenance (CAM) Charge

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TENANT: **Hawaiian Electric Co., Inc.**

SUITE: **1530**

Operating Expense Pro-rata Share: 2,451 square feet of 232,959 total square feet = 1.0521%

1. Annual Share of Operating Expenses: = $ 28,685.00

$2,726,406 * 1. 0521%

2. Monthly Share of Operating Expenses: = $ 1,935.91
(divide line 1 by 12 months)

January CAM Adjustment

3.	New 2005 Monthly CAM	= $	1,935.91
4.	CAM billed in January	= $	(2,031.00)
5.	January CAM adjustment	= $	(95.09)

Should you have any questions, please contact Carmen L. Magno at 521-6024.

* *Please note that these amounts are rounded to the nearest whole cent.*

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CENTRAL PACIFIC PLAZA
2005 Common Area Maintenance (CAM) Charge

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TENANT: **Hawaiian Electric Co., Inc.**

SUITE: **1570**

Operating Expense Pro-rata Share: 2,969 square feet of 232,959 total square feet = 1.2745%

1.	Annual Share of Operating Expenses: $2,726,406 * 1.2745%	= $	34,747.00
2.	Monthly Share of Operating Expenses: (divide line 1 by 12 months)	= $	2,345.11

<u>January CAM Adjustment</u>

3.	New 2005 Monthly CAM	= $	2,345.11
4.	CAM billed in January	= $	(2,460.23)
5.	January CAM adjustment	= $	(115.12)

Should you have any questions, please contact Carmen L. Magno at 521-6024.

* *Please note that these amounts are rounded to the nearest whole cent.*

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

March 2, 2004

Ms. Arlene P. Reis
Property Manager
Colliers Monroe Friedlander Mgmt., Inc.
220 South King Street, Suite 1800
Honolulu, Hawaii 96813

Re: Central Pacific Plaza – Suite 1515 & 1570
Second Amendment of Lease – Base Rent Renewal

Dear Ms. Reis:

Our rents for Suites 1515 & 1570 are up for renegotiation effective for March 1, 2004 through November 30, 2006. However, we had not received a letter proposing new base rents as we had in the past.

We just received the rental statements for March 2004 and noted that the base rents remained the same at $1.48 per rentable square foot per month.

However, we do not agree that the proposed rent of $1.48 per rentable square foot per month is reflective of the fair market rent in the downtown area. We feel that the market rate is still in line with what we negotiated for suites 1480 and 1010, and that our rents for Suites 1515 & 1570 should be consistent with that at $1.25 per rentable square foot per month. Thus, we feel that it is reasonable to set our base rent for the period March 1, 2004 through November 30, 2006 at $1.25 per rentable square foot per month.

If acceptable, please acknowledge by signing below and returning a copy to our office. We look forward to hearing from you.

Sincerely,

Cheryl K. Fujiwara

Cheryl K. Fujiwara
Director
Facilities Operations & Planning

Agreed & Accepted:

By_______________________________
Its

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CENTRAL PACIFIC PLAZA
2005 Operating Expenses

CAM Expenses	2005 Budget
A/C Maintenance	38,404
Depreciation	152,401
Electrical Maintenance	3,750
Electricity	622,983
Elevator Maintenance	[illegible]

Due to the voluminous nature of the information, one copy (pages 16-184) will be provided to the Consumer Advocate, Department of Defense, and the Public Utilities Commission under separate transmittal.

CA-IR-618

Ref: HECO response to CA-IR-260 & HECO-1605 (Rent Expense).

Revised HECO-1605 (CA-IR-260) contains a new line for Pauahi Tower with annual rent in the amount of $453,000 – occupied by Information Technology & Services. Please provide the following:

a. The referenced rent amount represents an input into revised HECO-1605. Please provide a copy of any lease agreements that document the terms and conditions of the rental, including square footage occupied, term, rental rates and CAM factors.

b. Please provide the following information regarding the newly leased space in Pauahi Tower, occupied by Information Technology & Services:

1. How many employees occupy this space?
2. Where were these employees located prior to the move to Pauahi Tower?
3. Regarding the space previously occupied by these employees, which department(s) now occupy the former office location?
4. Please describe and explain the basis of the decision to obtain additional space for Information Technology and Services.

HECO Response:

a. Due its voluminous nature, one copy each of the Pauahi Tower lease agreement will be provided to the Consumer Advocate, Department of Defense, and the Commission under separate transmittal.

b. 1) The newly renovated space at Pauahi Tower will house 72 open workstations for the staff and four enclosed offices for the directors and the manager.

2) These employees are being relocated from Ward II 3rd and 2nd Floors, and Ward I 2nd Floor.

3) There is a small group of staff that will remain at Ward II 3rd floor to support the Data Center operations, and Infrastructure & Operations functions. In addition, there are several satellite workstations being created to house staff who must work from both locations. The balance of the space is being proposed for use by the non-public

operations of the Customer Service Department currently working out of the 900 Richards Street offices (King St Building).

4) The decision to relocate the Information Technology Services ("ITS") Department was due to the significant staff/operational growth in departments operating at the Ward Avenue facilities. ITS has staff scattered within Ward II 3rd Floor and 2nd Floor and the Ward I 2nd Floor. Other engineering departments also have staffing growth which required additional space within the areas currently (temporarily) occupied by ITS.

ITS was the best choice for relocation as they support internal customers throughout the company (both downtown and Ward Avenue, etc). The other engineering departments work closely together, making it difficult to relocate only one group.

Also, the area ITS is vacating is adjacent to the proposed area for Customer Services' Field Services Division, which enables all of Customer Service's non-public operations to be consolidated.

Due to the voluminous nature of the information requested in part a., one copy (pages 3 to 65) will be provided to the Consumer Advocate, Department of Defense, and the Public Utilities Commission under separate transmittal.

CA-IR-619

Ref: HECO response to CA-IR-248 (T&D O&M).

The referenced response provides historical levels (2000-2004 and 2005 test year forecast) of transmission and distribution contract labor by expense element (EE). Please provide the following:

a. For both Transmission and Distribution, please explain the shift in emphasis between EE 505 to EE 501 beginning in 2004, describing any special projects or new initiatives.

b. EE 505 is described as including charges from outside contractors for the construction of facilities, such as breaking and repairing concrete sidewalks to expose buried cables and digging of pole holes.

   1. Is this "construction" work typically capitalized to plant in service by HECO?

   2. If not, why not? Please explain.

HECO Response:

a. Please refer to HECO's response to CA-IR-66, filed with the Consumer Advocate and the Department of Defense on April 12, 2005, for information on the shift between EE 505 and EE 501.

b. Costs with EE 505 that are construction in nature (i.e., construction of new line, installation of new line, etc.) are capitalized to plant in service. However, they are expensed in cases when associated with the repair of equipment (e.g. concrete sidewalks are broken to expose buried cables for repair).