HECO RT-15
DOCKET NO. 04-0113

REBUTTAL TESTIMONY OF
JULIE K. PRICE

MANAGER
COMPENSATION & BENEFITS
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: A&G Expenses
Employee Benefits

INTRODUCTION

Q. Please state your name and business address.

A. My name is Julie K. Price. My business address is 220 South King Street, Honolulu, Hawaii. I am the Manager of Compensation and Benefits at Hawaiian Electric Company, Inc.("HECO").

Q. What is your area of responsibility in this proceeding?

A. My testimony will cover HECO's test year estimates of employee benefit expenses (Account 926000 and Account 926010) as included in total Administrative and General ("A&G") expenses addressed by Ms. Faye Yamauchi in HECO RT-13. The employee benefit expenses charged to operations and maintenance ("O&M"), is the net amount resulting from the total cost of employee benefits (Accounts 926000 and 926010), and the amount transferred to construction and other (Account 926020). The amount transferred to construction and other (Account 926020) is covered by Ms. Faye Yamauchi in HECO RT-13. I will also cover the wage and salary increases projected for the test year, the Human Resources Suite Project and provide information on an additional position in the Compensation and Benefits division.

Q. How will your rebuttal testimony be presented?

A. My rebuttal testimony will:

1) present the Company's revised test year estimates for employee benefit expenses;
2) discuss issues raised by the Consumer Advocate ("CA") and the Department of Defense ("DOD") on the Company's employee benefit expenses;
3) review the wage and salary increases projected for the test year;
4) update the status of the Human Resources Suite Project, and,

5) provide information regarding an additional position in the Compensation and Benefits division.

TEST YEAR EMPLOYEE BENEFIT EXPENSES

Q. Please describe what is included in employee benefit expenses.

A. HECO's employee benefit expenses were broken down into general categories in HECO-1502 of HECO T-15 as follows:

Account 926000 Employee Pensions and Benefits

- Qualified Pension Plan
- Non-Qualified Pension Plans
- Other Postretirement Benefits
- Long-Term Disability Benefits
- Other Benefits/Administration

Account 926010 Employee Benefits – Flex Credits

- Flex Credits Less Prices
- Group Medical Plan
- Group Dental Plan
- Group Vision Plan
- Group Life Insurance Plan
- Other/Administration

Q. How were employee benefit expenses estimated for the test year?

A. Expenses related to insurance premiums such as medical, dental, vision, life insurance, and long term disability were estimated using an average level of employees projected for the test year, and employee elections, wages and salaries and premium rates as of January 1, 2005. Pension and postretirement benefit

costs were determined by the actuary for the plans, Watson Wyatt Worldwide, under the applicable accounting standards and using January 1, 2005 employee demographics.

Q. How were employee benefit expenses updated from HECO's direct testimony?

A. The amount charged to O&M for employee benefit expenses in direct testimony was $15,843,000. The updated employee benefit expenses charged to O&M in this rebuttal testimony are $16,152,000, an increase of $309,000 (see HECO-R-1501, columns a, e, line 19).

Employee benefit expenses in Account 926000 and Account 926010 were updated from direct testimony to include:

1) enrollment data and premium rates as of January 1, 2005,
2) adjustments to delete administrative expenses related to the 401(k) plan per HECO T-1, pg. 26,
3) updated pension and postretirement plan costs, and
4) a correction to reverse a prior adjustment.

Q. Why were these updates necessary?

A. Updates using January 1, 2005, employee enrollment data and actual premium rates provide better estimates of costs for the test year. Pension and postretirement costs for 2005 were received in June, 2005.

Q. Were these updates previously provided to the CA and the DOD?

A. Updates in items 1-3 above were provided to the CA and the DOD in response to various information requests and in Attachment 8 of HECO's June 15, 2005 submission to the CA and the DOD.

Q. Please explain the correction listed as item 4 above.

A. A correction of $65,000 was made in Account 926000 to reverse a prior

adjustment. This correction is necessary to reverse a portion of the ($52,000) adjustment previously included in Attachment 8, page 1, note c. The ($52,000) is the net amount resulting from ($65,000) for HEI Executive Incentive Compensation Plan ("EICP") charges and $13,000 of additional HEI charges. The ($65,000) adjustment was included in error since HEI EICP charges were previously excluded in total for all A&G accounts in Mr. Ernest Shiraki's direct testimony, HECO T-13, page 26.

Q. How were pension and postretirement costs updated?

A. Pension plan costs increased by $239,000 and postretirement benefit costs increased by $311,000 from direct testimony. Pension costs included in A&G expenses are the net periodic pension cost as determined by the actuary, Watson Wyatt Worldwide, under the provisions of the Statement of Financial Accounting Standards No. ("SFAS") 87. Postretirement costs included in A&G expenses are the net periodic postretirement benefits cost of $7,033,000 as determined by the actuary, Watson Wyatt Worldwide, under the provisions of SFAS 106, reduced by $900,000 related to executive life insurance benefits, plus $1,302,000 which is the amortization of the regulatory asset established in accordance with the Decision and Order ("D&O") 13659, issued on November 29, 1994, and letter dated December 28, 1994, in Docket Nos. 7243 and 7233 (consolidated), less $297,000 which represents the electric discount for retirees.

Q. What are the reasons for the increase in costs from direct testimony?

A. Updated net period pension and postretirement benefit costs are greater than prior estimates due to a decrease in the discount rate assumption from 6.25% to 6%, and an increase in the number of covered employees beyond the actuary's prior estimate. In addition, the increase in pension costs was offset by the effect of a

contribution of $15,186,494 made in December, 2004. Postretirement costs also increased due to changes in the graded trend rates for medical costs from 10% grading down to 5% (previously 10% grading down to 4.5%), dental costs from 4.25% to 5% and vision costs from 3.25% to 4%.

Q. What accounts for these increasing costs?

A. Pension and postretirement costs have been increasing since 2004 and will continue to increase under current estimates. The reasons for these increasing costs include a trend of decreasing long term interest rates used to discount pension liabilities and the recognition of deferred asset losses due to investment performance below expected returns in recent years.

ISSUES RAISED BY THE CA AND THE DOD

Q. What is the level of employee benefit expenses proposed by the CA and the DOD for Account 926000?

A. The CA and the DOD propose a total of $13,023,000 in Account 926000 compared to HECO's revised estimate of $13,671,000 (see HECO-R-1501, column f and g, line 8). The difference is attributable to 1) HECO's $65,000 correction as explained above, and 2) a $583,000 reduction described as the employee benefits adjustment for the "Even Hiring Lag" approach for "open positions" (see CA-101, Schedule C-21, DOD-118).

Q. What is HECO's position on this adjustment?

A. HECO does not agree with the labor adjustment and associated adjustment for employee benefits to the test year estimates. Ms. Tayne Sekimura discusses the Company's position in detail in HECO RT-16.

1 WAGE AND SALARY INCREASES

2 Q. What were the estimates of wages and salaries for the test year?

3 A. As covered by my direct testimony, test year expenses included a general wage
4 increase for bargaining unit positions of 1.5% effective May 1, 2005, and 1.5%
5 effective November 1, 2005 calculated as a percentage of wages as of November
6 1, 2002. A budget of 3.50% for merit salary increases effective May 1, 2005, and
7 .25% equity increase effective September 1, 2005, calculated as a percentage of
8 salaries as of April 30, 2005, was included for nonunion positions.

9 Q. Were any issues raised by the CA and DOD regarding the wage and salary
10 increase assumptions?

11 A. No issues were raised on the wage and salary increases.

12

13 HUMAN RESOURCES SUITE

14 Q. What is the status of the Human Resources Suite project?

15 A. Due to the delay in implementation of this project, expenses related to the Human
16 Resources Suite project were removed from the test year, which include the
17 removal of the annual amortization of Phase 1 costs from A&G expenses and the
18 average balance of unamortized system development costs from rate base (see the
19 response to CA-IR-661 and CA-IR-352). The CA and the DOD have
20 incorporated these changes in their test year estimates.

21

22 ADDITIONAL POSITION

23 Q. How have staffing levels changed in the compensation and benefits division?

24 A. One position was added to the division that was not included in the test year
25 staffing level as discussed by Ms. Tayne Sekimura in HECO RT-16.

Q. Please describe the position.

A. The position is for a Benefits Administrator/Analyst that was filled in May, 2005.

Q. Why was this position created?

A. An additional position was required due to the need for expanded oversight of data maintenance and monitoring of current processes to meet the requirements of the Sarbanes-Oxley Act of 2002 ("SOX") for the pension and postretirement plans. This resulted from our review of our internal controls over financial reporting for our pension and postretirement sub-processes. Additional controls were required and additional support to the systems administrator was necessary.

Q. How are labor costs for this position charged?

A. Currently 6% of labor costs are being charged to other companies with remaining costs charged to Account 926.

SUMMARY

Q. Please summarize your rebuttal testimony.

A. HECO's estimated employee benefit expenses charged to O&M as revised in this rebuttal are $16,152,000 which is $309,000 greater than the estimates included in direct testimony. Updates were made to incorporate more recent information and corrections. The CA's and the DOD's proposed level of employee benefits is $15,524,000 which includes an adjustment of ($583,000), to reflect a "hiring lag". HECO does not agree to the "hiring lag" adjustment.

Pension and postretirement benefit costs have also been updated to reflect changes in assumptions and the number of participants as of January 1, 2005. These costs are projected to continue to increase under current conditions.

Wage and salary increases as included in direct testimony were not contested and

amounts related to the Human Resources Suite Project were removed due to the delay in implementation of this project.

Finally, an additional position was created and has been filled to support SOX compliance.

Q. Does this conclude your testimony?

A. Yes.

HAWAIIAN ELECTRIC COMPANY, INC.
Administrative & General Expenses - Employee Benefits
($Thousands)

Line	Account Description	a Direct TY Est.	b Adj	c Rev TY Est per Attach 8	d Adj.	e Rev TY Est TY Est	f CA	g DOD
	926000 Employee Pensions and Benefits							
1	Qualified Pension Plan	4,349	239	4,588		4,588	4,588	4,588
2	Non-Qualified Pension Plans	0	0	0		0	0	-
3	Other Postretirement Benefits	6,827	311	7,138		7,138	7,138	7,138
4	Long-Term Disability Benefits	684	-86	598		598	598	598
5	Other Benefits/Administration	849	-129	720	65	785	137	137
6	Subtotals: Non-Labor	12,709	335	13,044		13,109	12,461	12,461
7	Labor	562	0	562		562	562	562
8	Total 926000	13,271	335	13,606	65	13,671	13,023	13,023
	926010 Employee Benefits-Flex Credits							
9	Flex Credits Less Prices	-1,289	168	-1,121		-1,121	-1,121	-1,121
10	Group Medical Plan	8,310	-319	7,991		7,991	7,991	7,991
11	Group Dental Plan	1,183	39	1,222		1,222	1,222	1,222
12	Group Vision Plan	190	-5	185		185	185	185
13	Group Life Insurance Plan	1,111	112	1,223		1,223	1,223	1,223
14	Other/Administration	245	55	300		300	300	300
15	Subtotals: Non-Labor	9,750	50	9,800		9,800	9,800	9,800
16	Labor	61	0	61		61	61	61
17	Total 926010	9,811	50	9,861		9,861	9,861	9,861
18	926020 Employee Benefits Transfer	-7,239	-121	-7360	-20	-7,380	-7,360	-7,360
19	Grand Total Charged to O&M	15,843	264	16,107	45	16,152	15,524	15,524

Col
a HECO-1502
c Attachment 8, submitted 6/15/05
d Correction to Attachment 8 to reverse EICP for HEI charges previously deleted per CA-IR-346, pg. 2, note 1.
f Exhibit CA-101, Schedule C-22, HECO/CA-IR-202, Schedule C-16, Schedule C-21
g Exhibits DOD-123 and DOD-118

HAWAIIAN ELECTRIC COMPANY, INC.
Administrative & General Expenses - Employee Benefits
($Thousands)

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3	Other Postretirement Benefits	6,827	311	7,138		7,138	7,138	7,138
4	Long-Term Disability Benefits	684	-86	598		598	598	598
5	Other Benefits/Administration	849	-129	720	65	785	137	137
6	Subtotals: Non-Labor	12,709	335	13,044		13,109	12,461	12,461
7	Labor	562	0	562		562	562	562
8	Total 926000	13,271	335	13,606	65	13,671	13,023	13,023
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9	Flex Credits Less Prices	-1,289	168	-1,121		-1,121	-1,121	-1,121
10	Group Medical Plan	8,310	-319	7,991		7,991	7,991	7,991
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12	Group Vision Plan	190	-5	185		185	185	185
13	Group Life Insurance Plan	1,111	112	1,223		1,223	1,223	1,223
14	Other/Administration	245	55	300		300	300	300
15	Subtotals: Non-Labor	9,750	50	9,800		9,800	9,800	9,800
16	Labor	61	0	61		61	61	61
17	Total 926010	9,811	50	9,861		9,861	9,861	9,861
18	926020 Employee Benefits Transfer	-7,239	-121	-7360	-20	-7,380	-7,360	-7,360
19	Grand Total Charged to O&M	15,843	264	16,107	45	16,152	15,524	15,524

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f Exhibit CA-101, Schedule C-22, HECO/CA-IR-202, Schedule C-16, Schedule C-21
g Exhibits DOD-123 and DOD-118

HECO RT-16
DOCKET NO. 04-0113

REBUTTAL TESTIMONY OF
TAYNE S. Y. SEKIMURA

FINANCIAL VICE PRESIDENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Depreciation Expense and Accumulated Depreciation; Total Average Number of Employees; King Street Office Building Lease; Prepaid Pension Asset; Gains on Sale of Land and Iolani Court Plaza Lease Premium; Accounting for Computer Software Development Costs; Abandoned Capital Project Costs; Maintaining Financial Integrity

INTRODUCTION

Q. Please state your name and business address.

A. My name is Tayne S. Y. Sekimura and I am the Financial Vice President at Hawaiian Electric Company, Inc. ("HECO"). My business address is 900 Richards Street, Honolulu, Hawaii, 96813.

Q. Have you previously submitted testimony in this docket?

A. Yes. I submitted written direct testimony, exhibits, and supporting workpapers as HECO T-16.

Q. What will you present in this testimony?

A. In this testimony, I will:

1) Present the Company's rebuttal position related to depreciation expense and accumulated depreciation;
2) Present the Company's average employee count for the test year, and address the Consumer Advocate's and Department of Defense's proposed adjustment related to the average employee count for the test year;
3) Present the Company's position regarding the King Street Office Building Lease;
4) Present the Company's position regarding its Prepaid Pension Asset;
5) Address the Company's ratemaking treatment for computer software development costs, abandoned capital project costs, and gain on the sale of land and Iolani Court Plaza lease premium; and
6) Address the Company's latest discussions with rating agencies and the need to maintain financial integrity.

Q. Did you present testimony in other areas in direct testimony?

A. Yes, I addressed the overall normalized test year 2005 estimates for Miscellaneous

Administrative and General ("A&G") expenses, which include account numbers 928-932, in my direct testimony filing. However, Ms. Faye Yamauchi, in HECO RT-13, has been assigned the rate case responsibilities for the Miscellaneous A&G expenses in rebuttal testimony and has adopted my direct testimony in that area.

DEPRECIATION EXPENSE AND ACCUMULATED DEPRECIATION

Q. What is the Company's rebuttal position with respect to depreciation expense and accumulated depreciation?

A. The Company's rebuttal test year 2005 estimates for depreciation expense and accumulated depreciation are as follows:

1) Depreciation expense: $70,730,000

2) Accumulated depreciation: $1,053,599,000

Q. Do the rebuttal estimates shown above reflect adjustments to the Company's direct testimony estimates?

A. Yes. The Company's direct testimony estimates for depreciation expense and accumulated depreciation shown on HECO-R-1601 were adjusted.

Q. In general, why did the Company adjust its direct testimony estimates?

A. The adjustments were made to reflect actual balances as of 12/31/2004 and updates to the test year 2005 plant additions, covered in Ms. Nagata's testimony at HECO-RT-18. The adjustments also reflect updates to the historical 5-year averages for retirements, cost of removal, and salvage which are used to calculate HECO's 2005 test year estimates for retirements, cost of removal, and salvage. See HECO-R-1601.

Q. Are there any differences between the Company and the CA and/or DOD with respect to the 2005 test year estimates for depreciation expense and accumulated

depreciation?

A. The DOD's 2005 test year depreciation expense estimate of $70,730,000 per DOD's Exhibit DOD-104 agrees with HECO's rebuttal test year 2005 estimate. With respect to the 2005 test year accumulated depreciation estimate, prior to the adjustments noted on Column 4 at HECO-R-1601, the DOD was in agreement with HECO's 2005 test year estimate for net plant in service (which includes the accumulated depreciation estimate) per DOD's Exhibit DOD-103. The adjustments noted on Column 4 at HECO-R-1601 are the results of updates to the 2005 test year plant additions and updates to the historical 5-year averages for retirements, cost of removal, and salvage which are used to calculate HECO's 2005 test year estimates for retirements, cost of removal, and salvage.

The CA's 2005 test year estimate for depreciation expense does not agree with HECO's 2005 test year estimate. Per the CA's Exhibit CA-101 Schedule C, page 1, the CA's proposed depreciation expense of $70,690,000 is $40,000 lower than HECO's 2005 test year estimate of $70,730,000.

Additionally, the CA's 2005 test year accumulated depreciation estimate does not agree with HECO's 2005 test year estimate.

Q. Please explain the reasons for the differences in the 2005 test year depreciation expense estimates proposed by HECO and the CA.

A. The CA's 2005 test year depreciation expense is $40,000 lower than HECO's 2005 test year estimate because while the CA accepted HECO's updated depreciation accrual amount, the CA did not include the $36,000 adjustment resulting from the reduction of depreciation expense on vehicles which related to the updated depreciation accrual (i.e. reflecting lower depreciation expense on vehicles) which is reclassified from depreciation expense and charged to a

clearing account. Additionally, the CA's proposed 2005 test year depreciation expense includes an adjustment of $4,000 for the combined heat and power projects which was already taken into account in HECO's 2005 test year depreciation expense.

Q. Why is the annual vehicle depreciation accrual subtracted from the total depreciation accrual in deriving the amount of depreciation expense included in operating expense?

A. As described in my direct testimony at HECO-T-16, page 20, the annual vehicle depreciation accrual is excluded because it is cleared (i.e. charged) to either capital or operation ("O&M") projects for which the vehicles are used.

This clearing process results in the inclusion of the vehicle depreciation accrual in either the O&M expenses for that particular O&M project or in the subsequent depreciation expense of the assets resulting from the capital projects to which the vehicle depreciation is charged. Thus, it is necessary to exclude the vehicle depreciation accrual from the total depreciation accrual to avoid double-counting the expense.

Q. Please explain the reason for the differences in the 2005 test year accumulated depreciation estimates proposed by HECO and the CA.

A. In response to HECO/CA-IR-122, the CA indicated that after reflecting revisions to their 2005 test year accumulated depreciation estimate, the results would match the updated results proposed by HECO in it response to DOD-IR-9-3. Since providing information in response to DOD-IR-9-3, HECO again revised its 2005 test year accumulated depreciation estimate to reflect updates to the test year 2005 plant additions and updates to the historical 5-year averages for retirements, cost of removal, and salvage which are used to calculate HECO's 2005 test year

1 estimates for retirements, cost of removal, and salvage.

2 TOTAL AVERAGE NUMBER OF EMPLOYEES

3 Q. What was the Company's test year 2005 total average number of employees
4 presented with the Company's direct testimonies?

5 A. The Company's test year 2005 total average number of employees presented with
6 direct testimonies was 1,493. (See HECO T-16, page 25; HECO-1612; response
7 to CA-IR-508.)

8 Q. Has the Company since revised its test year 2005 total average number of
9 employees?

10 A. Yes. The Company's revised test year 2005 total average number of employees is
11 1,485, as shown in HECO-R-1602. Like the average number of employees figure
12 presented with direct testimonies, this revised employee count includes regular,
13 temporary and probationary employees, but excludes temporary agency help hired
14 on a contractual basis. The average number of employees was determined using a
15 13-month average based on the total number of employees at the end of each
16 month.

17 Q. Why is the Company presenting a revised test year 2005 total average number of
18 employees?

19 A. As explained by Mr. Hee in HECO RT-10 (and also in response to CA-IR-78),
20 there was a net decrease of eight positions in the Energy Solutions area as a result
21 of (a) a reduction of twelve positions in Energy Services to reflect that the costs
22 for these twelve positions have been removed from the test year results of
23 operations because new DSM Programs will be considered in the Energy
24 Efficiency Docket No. 05-0069, and the cost for existing DSM Programs that are
25 currently recovered through a surcharge will continue to be recovered in that

1 manner at this time and (b) an increase of four positions to reflect the addition of
2 three Energy Services positions and one IRP position.
3 Q. Was the revised test year estimate of the number of employees developed in the
4 same manner as discussed on page 26 of your direct testimony (HECO T-16)?
5 A. Yes.
6 Actual Employee Count
7 Q. Do you have updated information on the Company's actual employee count?
8 A. Yes. The actual monthly employee count for December 2004 through July 27,
9 2005 is provided in HECO-R-1604.
10 Q. What is the Company's actual employee count as of July 27, 2005?
11 A. The actual employee count as of July 27, 2005 is 1,454. See HECO-R-1604.
12 Q. Who updates the Company's efforts to fill unfilled positions?
13 A. The individual O&M witnesses whose areas have unfilled positions.
14 Additional Unforecasted Positions
15 Q. Were there additional positions approved subsequent to the development of the
16 Company's 2005 test year employment count forecast that are not included in the
17 revised estimate?
18 A. Yes. There are additional positions that were approved subsequent to the
19 development of the Company's 2005 test year forecasted employee count, in
20 addition to the four positions already discussed. These additional positions have
21 not been included in the Company's 2005 test year employee count. I will refer to
22 these positions as "additional unforecasted positions". These positions have not
23 been included because the Company has not adjusted its labor cost estimates to
24 reflect these new positions. However, if an adjustment is made to test year labor
25 expenses based on differences between the test year employee count and the

actual employee count for 2005, as proposed by the CA and DOD, then the expected 2005 actual employee count should be considered.

Q. How many of these additional unforecasted positions are expected to be filled by the end of 2005?

A. As of June 30, 2005, 41 of these additional unforecasted positions had been filled as set forth in HECO-R-1606. Another 11 positions are expected to be filled as of the end of this year with one remaining position forecast to be filled shortly after the end of this year. Thus, while some of the originally estimated test year positions may be unfilled by the end of 2005, the total employee count at the end of 2005 will probably exceed the revised test year year-end count of 1,490.

The breakdown of these 53 additional unforecasted positions, along with the number of these positions that have been filled as of June 30, 2005, is shown below by Department area. There is also a designation of the witness that will address these additional unforecasted positions in their rebuttal testimony.

VP	# Additional Unforecast/# Filled	Reference
Corporate Excellence	5/5	(HECO RT-13, RT-15)
Energy Delivery	12/1	(HECO RT-8)
Energy Solutions	7/6	(HECO RT-7, RT-10, RT-13)
Financial VP	5/5	(HECO RT-13)
Government & Community Affairs	4/4	(HECO RT-13)
President's Office	8/8	(HECO RT-13, RT-16)
Power Supply	10/10	(HECO RT-6)
VP – Special Projects	2/2	(HECO RT-16)

The impact of the additional unforecasted positions that were filled was reflected in the actual employee count figures provided in a number of IR responses.

Q. Please provide an example of where the impact of the additional unforecasted positions that were filled was reflected in the actual employee count figures.

A. In the Company's response to DOD-IR-8-8 on pages 3 and 4, the Company provided its end of 2004 actual employee count of 1,415. The 1,415 positions includes 17 additional unforecasted positions that had been filled. See HECO-R-1606.

Wages And Benefits Of The Additional Unforecasted Positions

Q. Has the Company calculated the wages and benefits for the 53 additional unforecasted positions?

A. Yes, please see HECO-R-1606. This exhibit shows the annual wages and benefits estimates for the 41 positions already filled (as of June 30, 2005), which totals $3,502,000. The wages component totals $2,878,000 and the benefits component totals $624,000. Of the total wages and benefits component, $2,511,000 is charged to O&M expense, $502,000 goes to capital costs, $232,000 is billable (which means charges are billed to others [i.e., HELCO or MECO]), and $257,000 goes to clearing (a portion of the clearing charges will end up going to O&M expense). As noted in HECO-R-1606, the wages and benefits estimates were calculated based on the standard labor rate for the labor class of the respective positions and the benefits rate of $7.99/hour was applied to 1904 productive hours.

This exhibit also shows the wages and benefits for the 53 positions, which totals $4,495,000. The wages component totals $3,689,000 and the benefits component totals $806,000. Of the total wages and benefits component,

$2,987,000 is charged to O&M expense, $815,000 goes to capital costs, $232,000 is billable, and $461,000 goes to clearing (a portion of the clearing charges will end up going to O&M expense).

Additional Unforecasted Positions In the Strategic Initiatives And Special Projects Areas

Q. Please describe the additional unforecasted positions that fall under the President.

A. As shown on HECO-R-1603, there are two additional unforecasted positions that fall under the President. These two positions are in the Strategic Initiatives Division. The Strategic Initiatives Division facilitates the Company's long-term strategic planning process and continuous improvement initiatives. The two additional unforecasted positions in this Division are the Director, Strategic Initiatives and an Administrative Assistant. The Director, Strategic Initiatives position was filled in November 2004. Prior to filling this position, the previous Director, Strategic Initiatives was performing some of the work of the Director, Strategic Initiatives on an interim basis while also fulfilling her new position's responsibilities. The Director's responsibilities include assessing, guiding and tracking the Company's long-term strategic direction by facilitating the strategic planning process and continuous improvement initiatives as well as assisting the Chief Executive Officer with internal and external communications, handling protocol responsibilities, and coordinating executive functions and activities as required. The Administrative Assistant's position is a newly created position which was filled in January 2005. The Administrative Assistant's responsibilities include providing administrative and clerical support to the Chief Executive Officer, Director of Strategic Initiatives, and the Chief Executive Officer's Office Administrator.

Q. Are there additional unforecasted positions in the Special Projects area?

A. Yes, as shown on HECO-R-1603 there are two additional unforecasted positions in the Special Projects area. The positions are the Vice-President, Special Projects and Executive Secretary. These positions have been filled since September 2004. As stated in the response to CA-IR-512, the Vice President, Special Projects' responsibilities include overseeing special projects and assignments that need executive oversight, and overseeing the development and implementation of the Energy Management System ("EMS") and Outage Management System ("OMS"), the construction of the new Dispatch Office, and the overall integration of the Customer Information System ("CIS"). As stated in the response to CA-IR-512, the Executive Secretary's responsibilities include providing secretarial and administrative support to the Vice President, Special Projects. These two positions will continue for the duration of the EMS and OMS projects, currently scheduled to be completed by mid-2007. At that point, if there are no major systems projects to oversee (interoperability will continue until the completion of the CIS project around the middle of 2008), these positions will be phased out.

<u>Proposed Labor Expense Adjustments Of The CA And DOD</u>

Q. What is the CA's position on the Company's 2005 test year average number of employees?

A. The CA did not propose an adjustment to the Company's 2005 test year average number of employees. Instead, the CA proposed labor expense adjustments. The CA proposed adjustments to Non-Production O&M labor expense, Production operations labor expense and Production maintenance labor expense.

Q. What is the CA' proposed Non-Production O&M labor expense adjustment?

A. The CA proposed an adjustment of $1,599,000 (which includes the employee benefits as well). CA-T-2, pages 81-82; Exhibit CA-101, Schedule C-21.

Q. What is the CA's proposed Production operations labor expense adjustment?

A. The CA proposed an adjustment of $218,000. CA-T-1, page 61; CA-101, Schedule C-8; CA-WP-101-C8/9.

Q. What is the CA's proposed Production maintenance labor expense adjustment?

A. The CA proposed an adjustment of $1,194,000. CA-T-1, page 82; CA-101, Schedule C-9; CA-WP-101-C8/9.

Q. What is the total of the CA's proposed labor expense adjustments?

A. The CA's total proposed labor expense adjustment is $3,011,000. This total includes wages and benefits.

Q. Please describe how the CA came up with its proposed labor expense adjustments.

A. For the CA's proposed Non-Production O&M labor expense adjustment, the CA took the Company's estimate of the wages and benefits of the "open" positions included in the 2005 test year estimate (as provided in the Company's response to DOD-IR-8-8) and removed one-half of the wages and benefits the Company estimated for the "open" Non-production positions and the benefits of the "open" Production positions. CA-T-2, page 81; Exhibit CA-101, Schedule C-21.

For the CA's proposed Production O&M labor expense adjustments, the CA calculated a test year average number of employees by averaging the December 31, 2004 actual employee count and the average of the 2005 "actual beginning-of-year and projected end-of-year headcounts". From there, a "percentage adjustment factor was then derived from the calculated test year employee staffing levels, compared to HECO's forecasted test year staffing levels, to adjust HECO's proposed direct labor expense amounts for each RA proportionately to reflect an

average test year projection. The Direct Labor by RA expense amounts were input from the response to CA-IR-1, HECO T-6, Attachment 3 and Attachment 4." CA-T-1, page 62, 82; CA-WP-101-C8/9.

Q. Please describe the CA's rationale underlying its proposed labor expense adjustment.

A. The CA claimed that the Company's labor expense estimate was erroneous because it assumed that each employee position was filled throughout the entire test year and that no vacancies existed throughout the year. The CA contended that an "Even Hiring Lag" should have been recognized in the Company's labor expense forecast for budget purposes, which would have recognized that positions would be filled throughout 2005 and not all positions would be filled from the beginning of 2005. See CA-T-1, pages 57-59; CA-T-2, page 79.

Q. Did the DOD propose a labor expense adjustment?

A. Yes. While the DOD did not propose an adjustment of the average test year employee level, the DOD proposed a labor expense adjustment in the amount of $3,340,000. This proposed adjustment is comprised of proposed adjustments of $2,561,000 to payroll expense, $583,000 to employee benefits, and $196,000 to payroll tax expense. See DOD T-1, page 23-24, DOD-118.

Q. How did the DOD derive these proposed adjustments?

A. The DOD used the information provided on page 5 of the response to DOD-IR-8-8. The DOD took the information from DOD-IR-8-8 concerning payroll expense and "calculated an adjustment for average test year employees by removing one-half of the payroll expense, or $2.561 million." The DOD also took the employee benefits information presented in DOD-IR-8-8 and "removed one-half of that amount, for an adjustment to decrease expense by $583,000." The DOD then

"applied a rate of 7.65% to the payroll expense adjustment to determine the adjustment to payroll tax expense of $196,000." See DOD T-1, pages 25-26; DOD-118.

Q. Why did the DOD propose its labor expense adjustment?

A. The DOD contends that the Company's proposed ratemaking treatment for the 2005 test year "open" positions, which assumed that the "open" positions were filled throughout the test year, is not consistent with the use of an average test year. The DOD proposed its adjustment to address this matter. See DOD T-1, page 28.

Q. What is the Company's response to the proposed labor expense adjustments of the CA and DOD?

A. The Company does not agree with the labor expense adjustments proposed by the CA and DOD. First, the CA erroneously assumes that employee vacancies directly translate into a reduction in labor expenses, when some vacancies may be offset by unforecasted overtime (in the case of bargaining unit employees) and a significant percentage of employee costs are charged to capital projects rather than expenses.

In addition, the Company has added and expects to fill additional positions beyond those included in the test year estimate, which means that the year-end employee count, and/or the employee count in future years, should exceed the test year average.

Moreover, the CA treats vacancies arising out of new staffing positions created to enable the Company to perform new or substantially increased work that will carry over into future years in the same manner that it treats "structural vacancies" due to retirements and/or terminations that periodically occur.

1 Also, some of the "vacant" positions relate to the Company's proposals to
2 expand its DSM programs and to include DSM program costs in base rates. The
3 expenses related to these programs have separately been removed from the rate
4 case, and the CA double counts the reduction when it separately reduces labor
5 expenses due to these "vacancies".
6 Q. As a general matter, does the CA contest the need for the staffing increase?
7 A. No it does not, although it contends that it "has probably erred in the Company's
8 favor and overstated labor costs somewhat for the 2005 test year," at least with
9 respect to production department staffing. See CA T-1, page 59 and response to
10 HECO/CA-IR-107.b.
11 Q. Did the Company justify the need for the staffing increases?
12 A. The Company fully justified the need for the staffing increases in the direct
13 testimonies of our expense witnesses, who generally are the ones with first-hand
14 knowledge of the needs in their areas of operation and in numerous responses to
15 information requests.
16 Q. Many of the staffing vacancies are in the Production area. In its response to
17 HECO/CA-IR-117, the CA claims that "it has proposed staffing and expense
18 levels sufficient to perform all scheduled unit overhauls and to perform other
19 routine corrective, predictive and preventive maintenance required to maintain
20 long-term reliability of generating units." Is this a fair conclusion?
21 A. No. The CA has assumed production maintenance staffing of 128 at the end of
22 2004 and 160 at the end of 2005. In effect, the CA has included "funding" for
23 144, not 160, maintenance staff, because 32 positions (including the 20 new night
24 maintenance staff positions) were vacant at the end of 2004.
25 Q. What is the stated basis for the CA's approach?

A. The CA bases its approach on the use of an "average" test year. However, for purposes of this rate case, there are at least three fundamental problems in the CA's approach. These problems are also applicable to the DOD's approach.

First, most of the staffing increase is for new positions, and is not just to fill previously authorized but unfilled positions. In Production, the Company needs to add 20 employees to establish night maintenance crews. The CA has included the annual costs for only one-half the new positions (by including one-half the full year's cost for all of the positions). Allowing the costs for only 10 new employees (by including only one-half the annual cost for 20 new employees) is not going to provide funding for 20 new employees. Sales growth from 2005 to 2006 is not going to pay for the other one-half of this new cost.

In addition, new rates are not being set at the beginning of 2005. If rates were reset at the beginning of the year, and it was assumed that full staffing was in place at the beginning of the year even though staffing increases occurred gradually over the course of the year, then the amount included for staffing in rates for 2005 (looked at in isolation) might be too high. In this case, however, rates are not expected to be reset until at least October (for the interim increase) and until next year (for the final increase). The Company will not have received any rate increase during the first 9 months of 2005, even though significant staff increases have been made.

Moreover, staffing expenses should not be viewed in isolation, particularly in the Production area where the CA proposes the largest adjustment. As shown in HECO RT-6, and numerous IR responses, the Production expenses are expected to exceed the 2005 rate case amounts, even though there has been a

"lag" in filling some of the new positions, and even though there have been some vacancies in existing positions.

Q. With respect to the CA's and DOD's treatment of vacancies, what is the Company's position with respect to the CA's contention that there will be "structural" vacancies due to retirements and/or terminations, and that the Company will incur less expenses than forecast based on the assumption that all authorized positions will be filled?

A. There may or may not be merit to the CA's and DOD's general proposition, depending on the specific circumstances faced by the Company. For example, in prior rate cases, the Company has shown that test year expenses should <u>not</u> be less than forecasted, even if there are vacancies, because labor expense savings due to vacancies will be offset by increased labor expenses for unforecasted overtime and increased non-labor expense for contracted services (and/or because the vacancies are in positions that charge to capital and not to expense).

Q. What is the situation in this case?

A. In this case, the number of vacancies with respect to the positions included in the test year estimates is misleading, because (1) there are additional positions that were not included in the test year estimates that have been and are being filled (i.e., the additional unforecasted positions), (2) some of the vacant positions relate to expanded DSM programs, for which the expenses have been removed from the test year, (3) some of the vacancies are not "structural" vacancies, but are new positions that should be filled by the end of the test year, and (4) the Company is incurring additional, unforecasted overtime in some areas as a result of some of the vacancies.

Q. Does the CA distinguish between structural vacancies and vacancies due to the establishment of new positions?

A. The CA's proposed labor expense adjustment does not distinguish between these two types of vacancies.

Q. Why should structural vacancies be treated differently from vacancies due to a lag in filling new positions in setting rates for the future?

A. A number of the increases in the Company's permanent organizational staffing were included in test year expenses for 12 months as a normalized expenditure because the positions are in addition to the organizational structure as opposed to an existing position in the organizational structure that is vacated. This is a very important distinction for ratemaking purposes. For example, as Mr. Fujinaka discusses in HECO RT-6, a number of the additions to the organizational structure in the Production Department were due to increasing the maintenance staffing level to establish off-peak maintenance. These type of positions created additional vacancies that are not the same as vacancies created due to normal turnover caused by voluntary (e.g., retirements, transfers, resignations, military deployment) and involuntary (e.g., terminations) separation from the position or the Company. As previously discussed, the CA's proposed labor expense adjustment does not provide for funding for all of the new positions (i.e., the positions that are in addition to the organizational structure), and sales growth is not going to pay for the portion of the new costs that the CA has proposed not be recovered.

Q. Please discuss how the Company has added and expects to fill positions in addition to those included in the forecasted test year employee count estimate.

A. As previously discussed, as of June 30, 2005, the Company had filled 41 additional unforecasted positions. Another 11 are expected to be filled as of the end of this year with one remaining position forecast to be filled shortly after the end of this year. These positions were not included in the forecasted test year employee count and the test year revenue requirements. This means that the year end employee count, and/or the employee count in future years, should exceed the test year average. The 53 additional unforecasted positions have annual wages and benefits that total $4.5 million, of which over $3.0 million is charged to O&M expense (a portion of the clearing charges will end up going to O&M expense).

Q. Please discuss how the proposed labor expense adjustments of the CA and DOD double count some labor expenses which results in overstating the amount of the adjustment.

A. As discussed by Mr. Alan Hee in HECO RT-10, the proposed labor expense adjustments of the CA and DOD for 4 "open" DSM positions reduces the Company's labor expense for positions that the CA and DOD already removed from the rate case because of the Energy Efficiency Docket. Thus, the CA and DOD have in effect removed the 4 DSM positions twice. In order to remove this double counting, the proposed adjustment of the CA and DOD must be reduced by $125,000.

KING STREET OFFICE BUILDING LEASE

Q. What is the King Street office building lease?

A. The Company leases its King Street office building in downtown Honolulu from the Estate of Bernice Pauahi Bishop ("Bishop Estate"). Bishop Estate owns the HECO King Street building and underlying land (collectively referred to as "leased property"). The previous lease agreement between HECO and Bishop

1 Estate expired on November 30, 2004, and the Company was on a month-to-
2 month lease term at the same monthly rate of $64,583.34 per month just prior to
3 the expiration of the previous lease agreement. HECO uses the building primarily
4 for office and business-related purposes. HECO executives, as well as executives
5 of its parent company, Hawaiian Electric Industries, Inc. ("HEI"), and portions of
6 the Customer Service Department, the Corporate Communications Division, the
7 Education and Consumer Affairs Division, the General Accounting Department,
8 the Management Accounting and Financial Services Department, and Mailing
9 Services and Records Management currently occupy the King Street office
10 building.
11 Q. Has the Company and Bishop Estate negotiated a new lease?
12 A. Yes, as will be discussed later in this testimony. The Company and Bishop Estate
13 initially negotiated but did not execute a new 20-year agreement in 2004, which
14 would have been classified as a capital lease for accounting and financial
15 reporting purposes. Based on the negotiated (but not executed) new agreement, in
16 April 2005, HECO requested a declaratory order from the Commission to
17 determine that Commission approval of HECO's negotiated capital lease
18 arrangement would not be required under Hawaii Revised Statutes ("HRS")
19 Section 269-17 in Docket No. 05-0084. In Decision and Order No. 21821 issued
20 on May 13, 2005, the Commission determined that HRS Section 269-17 would
21 not apply. In its request for a declaratory ruling, HECO indicated the ratemaking
22 treatment of the capital lease would be addressed in the current rate case.
23 Q. Did HECO provide the proposed ratemaking treatment of the capital lease in the
24 current rate case?
25 A. Yes, HECO provided the ratemaking treatment for the initially negotiated (but not

executed) King Street office building lease, which reflected the lease being treated as a capital lease for accounting and financial reporting purposes, in responses to CA-IR-260, CA-IR-615 and CA-IR-616. In addition, HECO modified its responses to CA-IR-260, CA-IR-615 and CA-IR-616 on June 15, 2005 to reflect a capital lease for financial reporting purposes, with electric rates based on the lease payments.

Q. Is HECO's revenue requirements based on the revised responses to the Consumer Advocate's information requests?

A. No. Given the complexity of the ratemaking treatment of a capital lease arrangement, the fact that the revenue requirements of a capital lease inherently decline over time (which requires a higher revenue requirement in the earlier years of the lease), and informal discussions with the Consumer Advocate's consultant which indicated some concerns regarding the capital lease treatment of the negotiated lease, HECO decided to discuss the negotiated lease with Bishop Estate. After a couple of months of discussions, in July 2005, HECO and Bishop Estate, agreed to modifications to the initially negotiated lease, and executed a modified agreement effective July 1, 2005. Based on the modified terms of the lease, the executed lease agreement is now deemed to be an operating lease, under Statement of Financial Accounting Standards ("SFAS") No. 13. The term of the executed lease is from July 1, 2005 through November 30, 2021 with fixed monthly rent throughout. Rental payments through November 30, 2009 are $775,000 annually ($64,583.34 per month, the same amount as under the previous lease agreement just prior to expiration), and the lease contains fixed rent escalations of 10% every five years thereafter. The lease also grants HECO a three-year extension option at a rent to be negotiated by the parties.

Q. What is included in the test year rent expense related to the King Street office building lease?

A. As discussed in HECO-RT-13, HECO rebuttal testimony estimate for the King Street office building rent is a net $549,000 [after reimbursements from Hawaiian Electric Industries, Inc. ("HEI")], compared to the direct testimony estimate of a net $506,000, an increase of $43,000.

Q. How did the Company calculate its revised annual King Street office building lease amount?

A. The calculation is shown in HECO-R-1307. To summarize the calculation, the Company's test year rent expense for the King Street office building is based on six months of month-to-month rent incurred under the previous lease agreement (i.e. $387,000 total from January to June 2005), six months of operating lease expense under the new lease agreement (i.e. $440,000 from July to December 2005), general excise tax of $32,000, and rent reimbursements from HEI of $310,000. See HECO-R-1307 for the calculation of the rent reimbursement.

Q. Why is the rent for July to December 2005 not the same as for the first six months of the year, if the month-to-month lease payment and the first five years of the lease payment are based on the same previous lease arrangement?

A. Under SFAS No. 13, for financial reporting purposes, lease payments for the fixed term of the lease must be recorded on a straight-line basis over the fixed term of the lease, even if the rental payments are not made on a straight-line basis. Since the lease payments escalate over time, a straight-line lease payment amount for the fixed term was calculated. HECO proposes that the ratemaking treatment and the financial accounting treatment to be the same.

Q. Why should the rate making treatment of the lease be consistent with the financial

accounting treatment of the operating lease?

A. The rate making and financial accounting treatment should be the same for the following reasons:

1) The new lease agreement is in the best interests of ratepayers;
2) The resulting difference in test year rent expense is not significant;
3) Differences in rate making and financial accounting treatment could have negative financial implications for the Company.

<u>The new lease agreement is in the best interests of ratepayers</u>

Q. Why is the new lease agreement in the best interests of ratepayers?

A. HECO has occupied the King Street building since 1927 and its location is well-known to the community. HECO negotiated with Bishop Estate to continue to lease the King Street building to be able to continue to provide service to its customers without interruption or disruption. The location in downtown Honolulu is near the bus routes, and nearby municipal parking, which makes it convenient for customers who require meeting with Customer Service representatives. In addition, a number of customers prefer to physically make payments for their electric service and the current location is very convenient for such customers. Further, relocating from the King Street building will cause disruption in operations and reduce productivity. Since HECO expects its need for downtown office accommodations to continue for a very long time, HECO sought a long-term contract. Bishop Estate was willing to renegotiate a new long-term lease for the building and it was appropriate for HECO to continue to occupy the King Street building.

HECO negotiated fixed lease rent escalations in the lease terms because subjecting the lease rent to periodic market adjustments could potentially be

costly. The escalations of 10% every five years, equivalent to less than a 2% annual escalation rate, are reasonable and eliminate the Company's exposure to potentially volatile market conditions. Thus, negotiating a long-term lease with a fixed escalation is in the best interests of rate payers.

The resulting difference in test year rent expense is not significant

Q. What is the difference between the ratemaking and financial accounting treatment of the new lease agreement?

A. With respect to the amount of rent expense for the King Street office building included in Account No. 931 – Rents Expense, discussed by Ms. Faye Yamauchi in HECO RT-13, the Consumer Advocate included HECO's direct testimony estimate of $506,000 in its determination of the Company's revenue requirements. See CA-101, Schedule C-15. The Department of Defense at DOD T-1, pages 38 to 40 indicated it did not agree with the capital lease treatment for the King Street lease provided in response to CA-IR-260 and did not make any adjustment to HECO's direct testimony estimate for rent expense. Thus the difference between HECO's rebuttal test year estimate and the CA's and DOD's test year estimate is the $43,000 increase in annual rent expense HECO has presented in rebuttal testimony. As described above, the lease rent expense is higher because the lease rent expense since the inception of the new lease is recorded on a straight-line basis over the fixed term of the lease in accordance with SFAS No. 13, rather than based on the lease payments. The fact that SFAS No. 13 requires that the lease rent be recorded on a straight-line basis over the fixed term of the lease, results in a slightly higher rent expense in the 2005 test year. However, in later years, the rent expense for ratemaking purposes will be lower than the lease payments. In addition, the difference between the actual payments and the straight-line rent

1 expense will be recorded as a deferred rent expense (a liability) for financial
2 statement purposes. For ratemaking purposes, the deferred rent expense is
3 reflected as a reduction to rate base in the test year, as described by Ms. Ohashi in
4 HECO RT-19. For income tax purposes, the tax deduction is based on actual
5 payments rather than the book expense; therefore, there is also a corresponding
6 accumulated deferred income tax impact which is included in the accumulated
7 deferred income tax calculation presented in HECO-RWP-1704.
8 Differences in rate making and financial accounting treatment could have negative
9 financial implications for the Company.
10 Q. What are the possible financial implications if the ratemaking treatment of the
11 new King Street office building differs from the financial accounting treatment
12 required by SFAS No. 13?
13 A. For financial statement purposes, HECO is required to account for the new King
14 Street office building lease in accordance with SFAS No. 13. Specifically, if for
15 ratemaking purposes, the Commission decides to use the lower Consumer
16 Advocate and DOD proposed actual lease payment amount in setting rates in this
17 case, HECO must still record as an expense the higher levelized amount required
18 by SFAS No. 13, unless in its Decision and Order in this case, the Commission
19 gives sufficient assurances that it will allow higher rates in the future to recover
20 the accumulated difference between the ratemaking and financial accounting
21 treatment of the new lease agreement. If the Commission provides such
22 assurances, the Company will record the difference between the ratemaking and
23 SFAS No. 13 treatment as a regulatory asset rather than as an expense, and there
24 would be no earnings impact as a result of the difference. If, however, the
25 Commission does not provide the required assurances, the Company will have to

1 record the higher SFAS No. 13 required expense, and to that extent, the Company
2 will not have a fair chance to earn the rate of return determined to be reasonable
3 by the Commission in this case.
4 Q. Do you have any comments with respect to the possibility of a regulatory asset
5 should there be a difference between the ratemaking and financial accounting
6 treatment of the new King Street office building lease agreement?
7 A. Yes, the Company would have concerns, even if a regulatory asset resulted from
8 any difference between the ratemaking and financial accounting treatment of the
9 new lease agreement. In general, a regulatory asset represents a receivable from
10 ratepayers. If the receivable becomes a long-term receivable (i.e. the receivable
11 will not be recovered through rates for a long period of time) the regulatory asset
12 will not be viewed favorably by the financial markets. In general, the higher the
13 amount of the regulatory asset and the longer the period for the recovery, the more
14 concerned investors would be about the ultimate collection of revenue to cover the
15 regulatory asset. Thus, regulatory asset treatment, while perhaps may appear to be
16 better than immediate expense treatment, is not necessarily an ideal solution to the
17 difference between the parties with respect to the test year estimate for King Street
18 building rent expense. As stated earlier in this testimony, HECO proposes that the
19 ratemaking treatment and the financial accounting treatment be the same.
20 Q. How is the lease rent reimbursement from HEI determined?
21 A. The lease rent reimbursement from HEI is determined based on the lease rent
22 expense that would be reflected for financial reporting. HEI's rent allocation is
23 based on the square footage of space occupied by HEI personnel, and a prorated
24 share, based on square footage, of the costs incurred by HECO to maintain the
25 building. The allocation percentage to HEI is consistent with the percentage

1 provided in direct testimony and accepted by the Consumer Advocate and the
2 Department of Defense in determining HECO's rent expense for the test year.
3 Q. Do you have any final comments regarding the $43,000 difference between
4 HECO and the CA and DOD with respect to the test year rent expense for the
5 King Street building?
6 A. Yes. HECO has not previously disclosed that HECO would need to record the
7 lease rent on a straight-line basis over the fixed term of the lease. However, as
8 described earlier, HECO will need to record the lease expense for financial
9 reporting in accordance with SFAS No. 13. The phenomenon arises due to the
10 long-term nature of the agreement and the fixed escalation in the agreement. As
11 discussed earlier, it is in the ratepayers interest to have a long-term lease with
12 fixed payments. Thus, it is reasonable to include the lease expense as required by
13 SFAS No. 13 in HECO's revenue requirements.
14 Q. Does the King Street lease impact the Company in any other way?
15 A. Yes. Because the new lease is a long-term obligation with fixed lease payments,
16 we expect that credit rating agencies will treat the obligation as debt in calculation
17 HECO's financial ratios for their financial evaluation of the Company. So
18 although the lease will be an operating lease for financial statement purposes, we
19 expect that the credit rating agencies will impute debt as a result of the operating
20 lease. Mr. von Gnechten discusses the imputed debt associated with the new lease
21 and the impact of the imputed debt on HECO's capital structure in HECO RT-21.
22 PREPAID PENSION ASSET
23 Q. What will you discuss in this section of your testimony?
24 A. This section of my testimony will address the ratemaking treatment of the
25 Company's qualified pension plan and will address the inclusion of prepaid

1 pension asset in rate base.

2 Q. How is your testimony organized?

3 A. My testimony is structured as follows:

4 1) First, I will provide a brief overview of the Company's qualified pension plan
5 and describe the accounting and regulatory treatment of the Company's
6 pension plan. I will explain the generally accepted accounting principles on
7 which the treatment is based. I will explain the importance of consistently
8 applying the methodology and summarize this Commission's past decisions
9 relating to the Company's pension costs.

10 2) Next, I will discuss the specifics of the Company's prepaid pension asset. I
11 will provide pension fund and pension obligation balances. I will discuss the
12 situation that gave rise to the prepaid pension asset and explain why it was
13 prudent to create the asset. I will also explain how ratepayers have benefited
14 in the past and will continue to benefit in the future from this asset.

15 3) Then, I will discuss treatment of the prepaid pension asset proposed by the
16 Consumer Advocates' ("CA") and Department of Defense ("DOD"). I will
17 explain how the lack of consistency in the CA's proposed treatment will be
18 detrimental to the Company and its ratepayers.

19 4) I will close with a summary of why this Commission should continue the use
20 of SFAS 87 for ratemaking treatment of the pension plan and should allow the
21 inclusion of the prepaid pension asset in HECO's rate base.

22 Pension Background

23 Q. Please briefly explain the Company's qualified pension plan.

24 A. As described by Ms. Price in HECO T-15, the Company provides pension benefits
25 to its employees by participating in the Retirement Plan for Employees of

1 Hawaiian Electric Industries, Inc. and Participating Subsidiaries, a qualified
2 defined benefit pension plan.
3 Although assets of the HEI Retirement Plan are commingled for all
4 participating employers, assets and liabilities of each participating employer are
5 separated for purposes of determining each participating employer's pension
6 costs. The amounts provided in this testimony and in this rate case are the portion
7 that applies to HECO only. The plan assets are held by its trustee, The Bank of
8 New York.
9 Q. What regulations apply to the pension plan?
10 A. The Employee Retirement Income Security Act of 1974 ("ERISA") is the primary
11 source of regulation that applies to the pension plan. ERISA is a federal law that
12 sets minimum standards for pension participation, vesting, benefit accrual and
13 funding. ERISA also requires plans to provide participants and government with
14 information about the plan including plan features and funding.
15 In addition, the Internal Revenue Code ("IRC") establishes rules for
16 operating a tax-qualified pension plan, including pension plan funding and vesting
17 requirements.
18 Q. What accounting pronouncements provide guidance on the accounting and
19 financial reporting for pensions?
20 A. Financial Accounting Standards Board ("FASB") Statement of Financial
21 Accounting Standards No. 87 ("SFAS 87"), "Employers' Accounting for Pension"
22 is the primary source of guidance in the accounting for pensions.
23 Q. Please provide a brief description of SFAS 87.
24 A. Prior to the adoption of SFAS 87 in December 1985, measuring cost and reporting
25 liabilities resulting from defined benefit pension plans were sources of accounting

controversy. There was a lack of consistency in accounting treatment between different companies and between periods for the same company. Under SFAS 87, FASB standardized the method for measuring pension costs, expanded the financial statement disclosures related to pensions, and changed accounting treatment under specific circumstances. FASB reaffirmed the usefulness of information based on accrual accounting; however, SFAS 87 retained the following aspects of past pension accounting, which are in some respects in conflict with other accounting principles: delayed recognition of certain events, reporting net cost, and offsetting liabilities and assets. The delayed recognition feature means that changes in the pension obligation and changes in the value of pension assets are not recognized as they occur, but are recognized systematically and gradually over subsequent periods. All changes are ultimately recognized, but at any point changes that have been identified and quantified await subsequent accounting recognition. The net cost feature means that the changes affecting the plan are aggregated on the income statement, rather than appearing as separate items. The offsetting feature means that fund contributions and liabilities for pensions are offset and presented net on a company's balance sheet.[1]

Pensions are reflected on the financial statements as follows:

- Income Statement

  The pension costs allocated to a reporting period are called net periodic pension costs ("NPPC"). "NPPC" includes: service costs, interest costs, return on plan assets, effects of changes in actuarial assumptions and amortization of prior changes.[2]

[1] SFAS 87 Summary section
[2] HECO-RT-1608 provides definitions of the components of the NPPC.

- Balance Sheet

  A liability (unfunded accrued pension cost) is recognized if the cumulative NPPC exceeds the cumulative amounts the employer has contributed to the plan. An asset (prepaid pension cost) is recognized if the cumulative NPPC recognized is less than cumulative amounts contributed to the pension plan. This situation may change, however, when the pension obligation exceeds the pension fund as I will explain later in my testimony.

- Financial Statement Footnote

  The value of the pension fund assets and the pension obligation are included in the footnotes to the financial statements. Footnote disclosure also includes descriptions of the plan and items which have in the past or can in the future impact the cost of the pension.

SFAS 87 is explained in greater detail on Exhibit HECO-R-1608.

Q. How has the pension been treated for ratemaking purposes?

A. For ratemaking purposes, the Company incorporates the NPPC in its forecast of employee benefits, which is included in the administration and general ("A&G") expense.[3] If the Company forecasts a prepaid pension asset, the Company includes the prepaid pension assets in rate base. If the Company forecasts a pension liability, the pension liability would be treated as a deduction in the rate base calculation. The Company's forecast of working cash is based on the accrual method of accounting for the pension, consistent with the other pension components.

Q. Has the Company consistently applied this ratemaking treatment to its pension?

[3] Approximately 25% to 30% of the NPPC is allocated to corporate overhead and is capitalized annually as plant in service.

A. Yes, the Company has consistently used this ratemaking treatment for its pension throughout this case, in all prior rate cases since the adoption of SFAS 87, and in its periodic reporting to the Commission. In addition, the Company's subsidiaries, HELCO and MECO, have also consistently applied this treatment.

In this case, the methodologies and guidance in SFAS 87 were used in determining all of HECO's pension-related estimates. HECO forecasts a test year NPPC of approximately $5 million as discussed by Ms. Price in HECO RT-15 which is incorporated in the administrative and general expense (a portion of which is then allocated to overhead and capitalized). HECO forecasts a test year average prepaid pension asset of $79 million as discussed by Ms. Ohashi in HECO RT-19, which is included in rate base. Further, as discussed by Ms. Ohashi in HECO RT-19, the Company's forecast of working cash is based on the accounting treatment of pensions prescribed by SFAS 87.

Since the adoption of SFAS 87 by the Company in 1987, the Company has consistently based its pension expense forecast on the NPPC calculation prescribed in SFAS 87 in all of its rate cases (Docket No. 7766, HECO 1995 test year, HECO-T-11; Docket No. 7700, HECO 1994 test year, HECO-T-11; Docket No. 6998, HECO 1992 test year, HECO-T-7; and Docket No. 6531, HECO 1990 test year, HECO-T-7). Prior to 2000, HECO's prepaid pension asset was not significant and HECO did not have any test year in which there was an estimated prepaid pension asset. Since January 2000, the prepaid pension asset has grown significantly and has been recognized in the Company's calculation of rate base in its semi-annual reporting to the PUC.

Both HELCO and MECO have also used SFAS 87 as the basis for their ratemaking treatment of pension. Both companies have used the forecast NPPC

as the basis for the pension portion of their respective A&G expenses and have incorporated the balance sheet impact of the respective pension balance in their respective rate bases.

In its 2000 test year rate case (Docket No. 99-0207), HELCO incorporated a negative NPPC of $3 million in A&G expense and included a prepaid pension asset in rate base of $1.4 million.

In its 1999 test year rate case (Docket No. 97-0346), MECO incorporated an NPPC of approximately $900,000 in A&G expense and deducted a pension liability of approximately $1.2 million from rate base.

Q. Has the Commission accepted the Company's ratemaking treatment of pension in the past?

A. Yes, this Commission has accepted the treatment of pension consistent with SFAS 87 in prior rate cases.

The Commission has consistently based ratemaking decisions on the Company's NPPC forecast in all of the Company's rate cases since the adoption of SFAS 87 (Docket No. 7766, HECO 1995 test year, D&O 14412; Docket No. 7700, HECO 1994 test year, D&O 13704; Docket No. 6998, HECO 1992 test year, D&O 11699; and Docket No. 6531, HECO 1990 test year, D&O 11317).

In D&O 18365, Docket No. 99-0207, HELCO 2000 test year rate case the Commission accepted the negative NPPC of $3 million in A&G expense and included a prepaid pension asset in rate base of $1.4 million as presented by HELCO.

In Docket No. 97-0346, MECO 1999 test year, MECO and the CA reached a settlement agreement which incorporated MECO's treatment of the pension (NPPC of approximately $900,000 in A&G expense and deducting pension

liability of approximately $1.2 million from rate base). The Commission accepted these items from the settlement agreement.

Prepaid Pension Asset

Q. Please provide an accounting overview of the pension as of the end of 2004.

A. A financial overview of HECO's pension at December 31, 2004 is presented on Exhibit HECO-R-1609, page 2. HECO's balance sheet reflected:

Prepaid pension asset	$81,085,000

The following items relating to HECO's qualified pension plan were incorporated in the pension footnote to the Company's audited financial statements (HECO's audited financial statements aggregate HECO's qualified plan with the non-qualified pension):

Fair value of the pension fund assets	$523,000,000
Projected benefit obligation ("PBO")	$584,000,000
Accumulated benefit obligation ("ABO")	$498,000,000

Q. What did the fair value of the pension fund assets of $523 million represent?

A. The fair value of the pension fund assets was the estimated market value as of December 31, 2004.

Q. Who determined the fair value of the pension fund?

A. The pension plan's trustee, The Bank of New York, determined the fair value of the pension fund.

Q. What does the projected benefit obligation represent?

A. In lay terms, the PBO is an estimate of the pension promise as of a specified date, but based on the expectation that a company and its pension plan will continue.

Q. How was the projected benefit obligation determined?

A. The PBO was the actuarial present value of all benefits attributed by the plan's

1 benefit formula to employee service rendered prior to December 31, 2004. The
2 PBO is measured using an assumption as to future compensation levels since
3 HECO's pension benefit formula is based on future compensation levels.
4 Q. Who determined the PBO?
5 A. Watson Wyatt Worldwide, the consulting enrolled actuary, determined the PBO.
6 Q. What does the accumulated benefit obligation represent?
7 A. The ABO approximates the value of benefits that would be payable if a company
8 were to terminate the plan as of a specified date. Note however, that if the plan
9 were to actually terminate, it would need to purchase annuities from an insurance
10 company to cover the ABO. Because insurance companies would use more
11 conservative assumptions in determining the price for the annuities, the actual
12 termination cost would be higher. Therefore, ABO is an optimistic (i.e. low)
13 estimate of the termination cost.
14 Q. How was the accumulated benefit obligation determined?
15 A. The ABO was the actuarial present value of benefits (whether vested or
16 nonvested) attributed by the pension benefit formula to employee service rendered
17 before December 31, 2004 and based on employee service and compensation prior
18 to December 31, 2004. The ABO differs from the PBO in that it includes no
19 assumption about future compensation levels.
20 Q. Who determined the ABO?
21 A. Watson Wyatt Worldwide, the consulting enrolled actuary, determined the ABO.
22 Q. Who administers HECO's pension plan?
23 A. The Pension Investment Committee ("PIC") is the named fiduciary for the
24 pension plan and is responsible for overseeing the administration of the plan and
25 management of all plan assets.

Q. How does the PIC determine how much to contribute to the pension fund?

A. The PIC's funding policy is to contribute amounts to the plan in accordance with the funding requirements of ERISA and the IRC.

ERISA has a specific methodology for determining the required funding for the pension. HECO relies on its actuary, Watson Wyatt Worldwide, for the annual calculation of minimum funding under ERISA. In 2003 and 2004, HECO had no minimum fund contribution required to comply with ERISA.

The IRC also specifies minimum and maximum fund contributions to avoid adverse tax consequences. HECO also relies on its actuary, Watson Wyatt Worldwide for the annual calculation of minimum and maximum funding under the IRC. In 2003, the maximum deductible contribution under the IRC was approximately $23 million. In 2004, the maximum deductible contribution under the IRC was approximately $67 million.

Within the minimum funding requirements of ERISA and the maximum deductible funding allowed under the IRC, the PIC considers the financial reporting of the plan. There are no specific regulations in financial reporting as to how a company should fund its pension. Generally, it has been the practice of the PIC to fund the NPPC; however, in 2003 and 2004, the PIC based its funding decision largely on the adequacy of funding relative to the ABO. SFAS 87 provides two measures of pension obligation that can be used to assess the adequacy of the pension funding. One is a comparison between the fair value of the plan assets to the PBO and the other is a comparison between the fair value of the plan assets to the ABO.

Q. What is the significance of comparing the fair value of the pension fund assets to the PBO?

A. Since the PBO is based on what the company expects to incur in pension costs over time, the comparison of the fair value of the pension fund assets to the PBO is an estimate of how well the pension fund supports what is projected to be the cost of the pension.

Q. How did the fair value of HECO's pension fund compare to its PBO at December 31, 2004?

A. At December 31, 2004, the fair value of the pension fund assets was $523 million compared to the PBO of $584 million; therefore the PBO exceeded the pension fund by approximately $61 million. By this measure, the pension fund was underfunded by $61 million.

Q. How was the underfunded status of the fair value of the plan assets compared to its PBO shown on HECO's financial statements?

A. It was disclosed in the footnotes to the financial statements. This measure of pension "underfunding" is not reflected on HECO's balance sheet. As I mentioned earlier, SFAS 87 allows deferred recognition of changes in the PBO and changes in the fair value of the pension assets; therefore, not all changes are immediately recognized in the NPPC. Ignoring gains and losses which are unrecognized, changes in the fair value of the pension fund (excluding the pension contribution), changes in the PBO, and changes in the unrecognized deferred charges for the period, are aggregated and constitute the NPPC. A reconciliation of the changes in HECO's pension in 2004 is shown on Exhibit HECO-R-1609, page 2.

Q. What is the significance of comparing the fair value of the pension fund assets to the ABO?

A. As I mentioned, the ABO can be viewed as an optimistic proxy for the pension

obligation if the pension were terminated on the valuation date; therefore, the comparison of the ABO to the fair value of the plan assets on the valuation date roughly provides an optimistic measure of the sufficiency of the pension fund to meet the pension obligation if the plan were terminated. Again, I would note that if the plan were to actually terminate, the plan assets would likely not be sufficient to cover its obligations since insurance companies would likely use more conservative assumptions in determining the cost of annuities to cover the plan obligations than the assumptions that are used in determining the ABO.

Q. How did the fair value of HECO's pension fund compare to its ABO at December 31, 2004?

A. At December 31, 2004, the fair value of the pension fund assets was $523 million compared to the ABO of $498 million; therefore the pension funds exceeded the ABO by approximately $25 million. Although the fair value of the pension fund assets exceeded the ABO by approximately 5% at the valuation date (December 31, 2004), there have been periods over the last several years when the fair value of the pension was in jeopardy of being insufficient to cover the ABO.

Q. How is the pension funding compared to its ABO shown on HECO's financial statements?

A. ABO is not used in calculating the NPPC, therefore there is no direct impact of the ABO on the financial statements, as long as the fair value of the pension fund assets exceeds the ABO. If the fair value of the pension fund assets exceeds the ABO either: (1) an asset (prepaid pension asset) is recognized when the cumulative NPPC recognized is less than cumulative amounts contributed to the pension plan, or (2) a liability (unfunded accrued pension cost) is recognized if the cumulative NPPC exceeds the cumulative amounts the employer has contributed

to the plan. The fair value of HECO's pension plan has exceeded its ABO since it adopted SFAS 87. At December 31, 2004, the cumulative NPPC recognized was less than the cumulative amounts contributed to the pension fund, therefore the Company reflected a prepaid pension asset on its balance sheet.

Q. If the pension is underfunded compared to its ABO (ie. the ABO is greater than the fair value of the fund assets), how would HECO's financial statements change?

A. As I mentioned earlier in my testimony, under SFAS 87, the accounting treatment of the pension changes when the ABO exceeds the fair value of the pension fund assets. If the fair value of the pension fund assets is less than the ABO, SFAS 87 prescribes the following changes in accounting treatment: (1) a liability is recognized equal to the amount of unfunded ABO (i.e., the difference between the ABO and the fair value of the pension fund assets is immediately recognized as a liability), (2) the prepaid pension asset is eliminated and (3) the liability recognized and the prepaid pension asset eliminated, net of income taxes, are both charged directly to a separate component of equity, called accumulated other comprehensive income ("AOCI charge"). The fund contributions in 2003 and 2004 were intended to reduce the possibility of an AOCI charge. The Company was not required to make any contributions to the plan to meet minimum funding requirements under ERISA or the IRC in 2003 or 2004.

Q. What is the prepaid pension asset?

A. As I mentioned earlier in my testimony, SFAS 87 states that fund contributions and liabilities for pensions should be offset and presented net on a company's balance sheet. The prepaid pension asset is the net of the cumulative fund contributions and the recognized pension liability.

Fund contributions are the cash payments the Company has made to the pension fund over the years. Pension liability is the accumulated NPPC that the Company has already recognized on its income statement. Fund contributions are analogous to any other investment, such as gross plant. Pension liability is analogous to accumulated depreciation. Just as the pension liability increases as NPPC is recognized, accumulated depreciation increases as the Company recognizes depreciation expense on its income statement. Net plant, gross plant net of accumulated depreciation, is the corresponding analogy to the prepaid pension asset (i.e., fund contributions net of pension liability).

Q. How was the prepaid pension asset created?

A. Under SFAS 87, a prepaid pension asset is created when fund contributions exceed the NPPC. Exhibit HECO-R-1609, page 1 summarizes the annual activity in HECO's prepaid pension asset account since the inception of SFAS 87. The historical activity in the prepaid pension asset account shows that in the period from 1987 through 1994, in general, the NPPC was rising annually and HECO funded the NPPC. Beginning in 1995, the NPPC begins showing greater volatility, primarily declines. The declining NPPC resulted primarily from higher stock prices increasing the fair value of plan assets and the lower interest rate environment, which resulted in a lower discount rate used to calculate the net present value of the pension obligation. As discussed earlier, under SFAS 87, the increase in plan asset returns (due to the higher fair value of the plan assets) and the decrease in pension obligation (due to the lower discount rate and lower net present value of the plan obligation) are not immediately recognized. Rather the recognition of the change is deferred in order to smooth the NPPC (as compared to the volatility that would be experienced if the changes were entirely recognized

in the year they occur). From 1995 through 1998, because HECO generally funded the NPPC, the prepaid pension asset was not significant. In the late 1990's, high stock prices and low interest rates continued to drive the NPPC down. Beginning in 1999, HECO began experiencing negative NPPC accruals. Therefore although no fund contributions were made, the prepaid pension asset grew significantly in this period. Then, HECO experienced a low NPPC in 2003 and a negative NPPC in 2004. In addition, HECO made fund contributions in 2003 and 2004, further increasing the prepaid pension asset balance.

Q. Can HECO demonstrate that investors made the fund contributions?

A. Yes. Fund contributions were made by cash disbursements from the Company to the pension fund over the life of the pension fund. Details supporting the cash contributions made in 2004 of $15 million and 2003 of $13 million are provided on HECO-RT-1905 page 4 of 5. Fund contributions can also be verified by examination of the pension fund's audited financial statements filed annually with the federal government.

Q. How can you demonstrate that these were <u>investor</u> funds?

A. Payments made to the pension fund were from the same sources of funds that HECO would use to make any investment. There were no special contributions from any source, therefore the funds could only have come from investor funds. Ratepayers, on the other hand, provide the Company with revenues. The Company uses the revenues to pay expenses and to pay investors a return on and of their investment. Going back to my gross plant analogy, investor funds are used to fund the pension plan just as investor funds are used to construct or purchase the gross plant assets.

Q. Why was the prepaid pension asset created?

A. In the period 1999 through 2002, the negative NPPC accruals increased the prepaid pension asset significantly. Under ERISA, HECO cannot take cash refunds from the pension fund. Further, there is a tax on revision of qualified plan assets to the employer. Under Section 4980 of the IRC, a 20% tax on the amount of reversion is imposed. Funds contributed to the pension fund must stay in the pension fund (except under special circumstances such as plan termination). Whereas in the past, HECO had generally made contributions to match the NPPC, HECO could not take cash from the pension fund to match the negative NPPC accruals. Further, from 1999 through 2002, HECO was not required to make a minimum contribution under ERISA and could not make deductible fund contributions under the IRC. Contributions in excess of the IRC maximum contribution would be subject to a 10% non-deductible excise tax, effectively a 10% penalty for contributions, under Section 4972 of the IRC. As a result, in the period 1999 through 2002, the increase in the prepaid pension asset was solely a function of the negative NPPC. As I discussed earlier, the negative NPPC in this period was a result of high stock prices, low interest rates, and the deferred recognition requirements under SFAS 87.

Q. Why did HECO increase the prepaid pension asset in 2003 and 2004?

A. In 2003, HECO had a relatively low NPPC, but was potentially facing a situation at the measurement date (December 31, 2003) at which the fair value of the pension assets may not have been sufficient to cover the ABO. As I discussed earlier, funding the pension to sufficiently cover the ABO is significant because it is a rough, optimistic measure of whether the funds are sufficient to cover the plan if the plan were terminated. If the fair value of the pension assets is less than the ABO, it also results in a change in the accounting treatment under SFAS 87.

Therefore, HECO resumed fund contributions by making a $13 million contribution to the pension fund in 2003. The maximum deductible contribution for 2003 was $23 million. There was no minimum fund contribution required in 2003.

HECO faced a similar situation again in 2004, when it had a negative NPPC and was facing a situation at measurement date (December 31, 2004) at which the ABO could potentially have exceeded the fair value of the pension assets. As a result, HECO made contributions totaling $15 million to the pension fund in 2004. The maximum deductible contribution for 2004 was $67 million. There was no minimum contribution required in 2004.

The low NPPC in 2003 and negative NPPC in 2004 together with the fund contributions in those years increased the prepaid pension asset by $24 million (from $57 million at the end of 2002 to $81 million at the end of 2004 as shown on HECO-R-1608, page 1).

Q. Does the fact that HECO had a prepaid pension asset balance of $81 million at December 31, 2004 indicate that it had overfunded its pension plan?

A. No, in fact, the situation is generally the opposite. As I mentioned earlier, by some measures, HECO's pension plan is underfunded. At December 31, 2004, the PBO exceeded the pension fund by approximately $61 million. By this measure, the pension fund was underfunded by $61 million. In addition, as I mentioned earlier in my testimony, at December 31, 2004, the pension fund exceeded the ABO by only 5%, or $25 million.

Q. Did the prepaid pension asset result from prudent business decisions made by the Company?

A. Yes. As I described, in the period 1999 through 2002, the activity in the prepaid

1 pension asset was solely a function of the negative NPPC. The negative NPPC
2 resulted from the performance of the pension fund, the actuarial valuations, and
3 the accounting treatment prescribed under SFAS 87. The cumulative
4 contributions by the Company to the pension fund trust in excess of the
5 cumulative NPPC recognized increased the prepaid pension asset. The
6 contributions to the fund were critical for the Company to maintain a funded
7 pension fund. The funded pension trust that at least meets the ABO helps to
8 preserve the financial integrity of the Company as well as the pension plan.
9 An adequately funded pension trust reduces the risk that, in the future, the
10 pension fund will be required to make a fund contribution at a time when the
11 Company may not have funds available or access to capital markets to contribute
12 to the fund. If the pension is not adequately funded, the Company may be
13 required under ERISA or under IRC to make fund contributions. Minimum fund
14 contribution requirements may come at a time when the Company has other
15 significant capital requirements or when capital markets are constrained.
16 Maintaining an adequately funded pension plan preserves financial flexibility of
17 having discretion over the timing of fund contributions.
18 Q. How do the credit rating agencies evaluate the funding status of the pension fund
19 on a company's creditworthiness?
20 A. In published articles on the subject, both S&P and Moody's have indicated that
21 they evaluate the funding status of the pension plan by comparison to the PBO.[4]
22 They adjust the financial ratios to reflect any underfunded status relative to the
23 PBO as debt. See attached Exhibits HECO-R-1610 and HECO-R-1611. In early

[4] Standard & Poor's Corporate Ratings Criteria 2005 "Postretirement Obligations"; Moody's Investors Service Rating Methodology "Analytical Observations Related To U.S. Pension Obligations" dated January 2003.

2003, both S&P and Moody's issued articles warning that pension obligations were putting downward pressure on credit ratings.[5] See HECO-R-1612 and HECO-R-1613. HECO's PBO has been underfunded, however, I am not aware of any specific adjustment made to HECO's financial ratios by either S&P or Moody's.

Q. Have the credit rating agencies raised any concerns about HECO's pension fund?

A. No, neither S&P nor Moody's have raised any specific concerns relating to HECO's pension fund. In my opinion, the measures that the Company has taken to contribute to the pension fund in the past two years have helped reduce the potential for concerns that might have been raised by credit rating analysts and generally have had a positive impact on the Company's credit quality.

Q. How do ratepayers benefit from the prepaid pension asset?

A. Ratepayers benefit from the prepaid pension asset because the funding of the pension fund that creates the asset also results in lower NPPC. In this rate case the NPPC is $5 million compared to the NPPC in the 1995 test year case which was $10 million. Earlier in my testimony, I explained that return on plan assets was included in the NPPC. The return on plan assets is normally a credit which reduces the NPPC. The higher the level of funds in the pension fund, the greater the fund earnings will be to offset other pension costs and result in a lower NPPC.

Ratepayers also benefit from the financial stability of a funded pension plan. To the extent HECO contributes to the pension fund, it reduces the risk of being required to raise capital in the future, potentially in a constrained capital market, to fund the pension. Conversely, inadequate funding of the pension fund

[5] Standard & Poor's "Pension Liabilities Latest Red Flag For U.S. Utility Credit Ratings" dated June 5, 2003; Moody's "Moody's Reports: U.S. Pension Obligations May Increase Pressure on Credit Ratings" dated February 3, 2003

would adversely impact the Company's credit quality, which would ultimately result in higher financing costs.

CA and DOD Proposed Treatment

Q. Are the positions of the CA and the DOD with respect to the prepaid pension asset similar?

A. Yes. The DOD essentially mirrors the CA's arguments and recommendations. In this section, I will specifically address the CA's arguments and recommendations but my remarks will apply equally to the DOD's position on the prepaid pension asset.

Q. What is the CA's proposed treatment of the Company's pension?

A. CA witness, Mr. Carver, makes no adjustment to the Company's NPPC forecast (CA-T-2, page 82). However, Mr. Carver proposes to eliminate the prepaid pension asset of $79 million from rate base and correspondingly adjust the related accumulated deferred income taxes by $28 million (CA-T-2, pages 7-8).

Q. What is the basis for the CA's proposed treatment?

A. Mr. Carver mischaracterizes HECO's position on inclusion of the prepaid pension asset in rate base. He presents a flawed analysis of the impact of non-rate case years on ratepayers and on the Company. He proposes that the prepaid pension asset meet criteria for inclusion in rate base that is inappropriate. Mr. Carver then attempts to quantify an adjustment to reflect exclusion of the prepaid pension asset from rate base.

Q. In his direct testimony, Mr. Carver states "....HECO claims that the prepaid pension asset should be included in rate base since recorded pension costs are less than pension contributions – investors having advanced more funds than provided by ratepayers." (CA-T-2 page 13) Is Mr. Carver's depiction of the Company's

position accurate?

A. No. First, let me clarify the following statement on page 11 of HECO T-19:

> In theory, ratepayers provide the funds based on the NPPC and investors provide the funds contributed to the pension fund. The prepaid pension asset is the net of the NPPC and the funds contributed to the pension fund. Since the test year estimates forecast that the NPPC and fund contributions will result in a net asset, investors are providing the net amount. Since investors are entitled to earn a return on these funds, this asset is appropriately included as an addition to rate base. This was the result in HELCO's 2000 test year rate case. See D&O No. 18365 (dated February 8, 2001) in Docket No. 99-0207.

What this statement attempted to point out is that contributions to the pension fund and ultimately the prepaid pension asset are essentially investments. I have shown this to be the case earlier in my testimony. Company investments are funded through the issuance of debt or stock or through retained earnings.

Where the statement in HECO T-19 requires correction is that ratepayers do not actually "provide the funds based on the NPPC." Ratepayers do not fund Company investments. Rather, they pay for services and those payments are recorded as revenues. The statement in HECO T-19 was alluding to the utility ratemaking formula that revenue requirements equal the utility's expenses plus a return on rate base. Revenues from ratepayers' payments for services contribute to the recovery of the utility's revenue requirement. However, it is not true that ratepayers actually pay for or fund any particular expense. They pay for electric service, not particular Company expenses or investments.

With regard to Mr. Carver's statement, the rationale supporting the inclusion of the prepaid pension asset in rate base has nothing to do with investors having advanced more funds than ratepayers. Rather, the prepaid pension asset should be

included in rate base because, under SFAS 87, it is the recognized pension funding in excess of the pension obligation.[6] It reflects an investment that the Company has made in the pension plan. The pension plan is an integral part of the Company's compensation to its employees and is one of the elements necessary to attract and retain quality employees that are engaged in the provision of electric service to the public. As discussed earlier in my testimony, the Company makes contributions to the pension fund according to and in consideration of the provisions of ERISA, the IRC, and SFAS 87. In doing so, the Company has been in compliance with the law, avoided negative tax consequences, reduced the possibility of an AOCI charge at the measurement date, and at the same time provided more than the minimum required pension funding. Adequate funding of the pension trust provides security for the Company, its employees, and its ratepayers.

Q. On page 16 of his testimony, Mr. Carver states: "In general terms, the utility is considered to have recovered all costs incurred between rate cases and achieved a reasonable return on its rate base investment." Do you agree with this statement?

A. No. This is the first of a string of unsupported presumptions that Mr. Carver lays out to rationalize his recommendation to disallow the prepaid pension asset from rate base. Mr. Carver's statement implies that utilities are guaranteed their authorized rate of return when in fact they are unable to make up for past revenue deficiencies through rates. There is no true-up mechanism that will ensure that a utility will recover all costs incurred between rate cases and achieve a reasonable, let alone "authorized", rate of return on its rate base investment. There are

[6] Another financial measure of the pension plan is the NPPC which both the CA and the DOD have each included in their respective revenue requirement calculation.

1 numerous factors that impact a utility's decision on whether to apply for a general
2 rate increase. A utility may endure a number of years of substandard earnings
3 before initiating a rate case.
4 Q. Since its last rate case, has the Company generally earned less than the returns
5 used to establish rates?
6 A. Yes. In Docket No. 7766, the Commission based rates on a return on rate base of
7 9.16% and return on equity of 11.4%. In eight of the last ten years, the Company
8 earned less than the 9.16% return on rate base and in six of the last ten years the
9 Company earned less than the 11.4% return on common equity.
10 Q. Has the Company ever earned more than the returns used to establish rates in its
11 last rate case?
12 A. Yes. In 1995 and 1996, the Company earned a return on rate base based on
13 simple average of 9.84% and 9.70%, respectively. The Company earned a return
14 on common equity of 11.84%, 11.93%, 11.51%, and 11.46% in 1995, 1996, 2000,
15 and 2001, respectively. Theoretically, in order to actually have an opportunity to
16 earn the return found to be fair in a rate case, the utility must sometimes earn more
17 than the so-called "authorized" return, since it will sometimes earn less than the
18 "authorized" return.
19 Q. Mr. Carver proposes that "...the question in the current proceeding should focus
20 on whether HECO's ratepayers have benefited from the reduced pension costs, in
21 comparison to pension contributions, to support rate base inclusion of the pension
22 asset" He clarifies by posing the following question: "In other words, have
23 negative pension costs (or pension costs below pension contribution levels) been
24 reflected in the cost of service or somehow separately flowed through to
25 customers 'as recorded' each year since the adoption of FAS87?" Is this a

reasonable standard to determine whether the prepaid pension asset should be included in rate base?

A. Mr. Carver has actually posed two different standards. It is reasonable to expect a utility to show some benefit that a rate base item will accrue to ratepayers. I do NOT agree, however, that the benefit must be reflected in the current cost of service or separately flowed through to customers as recorded each year.[7] There is no other rate base item that is required to clear this kind of hurdle in order to achieve inclusion in rate base. For example, a utility would not have to show that savings from a new generating unit are reflected in current rates or have already flowed through to customers before it can be included in rate base.

Q. Mr. Carver states on page 17 of CA-T-2 that "...While the Company has proposed to include the pension asset in rate base, HECO has provided no factual support that utility rates have been materially understated or that ratepayers have somehow improperly been advantaged to the detriment of HECO's investors." Are these proper criteria to determine whether the prepaid pension asset should be included in rate base?

A. Absolutely not. Mr. Carver's criteria have no practical application to the issue at hand. With respect to his first criterion, there is no existing rate specifically for the recovery of the pension asset. Further, there is no way to determine whether the Company's existing rates are understated due to the inclusion or exclusion of a single rate base item. Rather, a rate case is utilized to examine the Company's total rate base and expenses to determine whether rates need to be raised.

With respect to the second criteria, the Company should not need to

[7] Although Mr. Carver seems to believe that pension credits should be flowed through to the ratepayer, it is noteworthy that the Company receives no cash for those credits. The Company's pension is held in trust and has no access to the funds in the pension.

demonstrate that ratepayers have been improperly advantaged to the detriment of HECO's investors to include an asset in rate base. Mr. Carver would have you believe that ratepayers can only be advantaged at the expense of the Company and vice versa. I do not believe this to be true. I believe that the Company can provide reliable and high quality service and earn a fair and reasonable return on its investments such that both the ratepayer and the Company are advantaged.

Q. Please describe Mr. Carver's quantitative analysis on NPPC.

A. Mr. Carver attempts to compare the level of pension costs included in rates from the last rate case with the contributions to the pension plan recorded over the same period. He reasons that since about $10.6 million[8] of NPPC was included in the revenue requirement in HECO's last rate case, that in the 10-year period from 1996 through 2005, ratepayers have "paid" $106 million for pension. He compares the $106 million to investor contributions of $44 million and concludes that ratepayers have received no tangible "benefit" from HECO having recorded cumulative pension costs at levels less than pension contributions; consequently the pension asset should be excluded from rate base.

Q. Is Mr. Carver's analysis valid?

A. No, it is not. First, Mr. Carver concedes at the outset that it is not possible to precisely quantify the amount of accumulated net pension recoveries from or benefits provided to ratepayers following the adoption of FAS87 (CA-T-2, pages 19, 21). More importantly, Mr. Carver's analysis is a form of retroactive

[8] Mr. Carver gets his 1995 test year forecast NPPC from HECO's response to CA-IR-355. CA-IR-355 (b) asked "Please provide the amount of NPPC included in the test year forecast in HECO's last rate proceeding." HECO's response was "The NPPC included in the test year estimates in HECO's last rate case (1995 test year) was $11,100,000 in Direct Testimony, and $10,604,000 in Rebuttal Testimony." HECO should have also stated that subsequent to rebuttal testimony, HECO revised its NPPC estimate to $9.5 million. Rates in the 1995 test year were based on NPPC of $9.5 million (Docket No. 7766 D&O 14412 dated December 11, 1995)

ratemaking. It is erroneous to effectively reduce rates based on an alleged over-recovery of a single expense item incurred in the past. Mr. Carver acknowledges that the Commission should not engage in retroactive ratemaking, but would have us believe that his analysis does not constitute retroactive ratemaking because he contends that he does not recommend that the Company should pay any money back to ratepayers (CA-T-2, page 22). The fact remains, however, that he seeks to make up for what he perceives to be an over recovery of NPPC in years prior to the test year by disallowing the prepaid pension asset from rate base. Because this disallowance would reduce revenue requirement and ultimately decrease the Company's rates, it would in effect pay money back to ratepayers and would thus constitute retroactive ratemaking.

Q. Is Mr. Carver's analysis consistent with the Consumer Advocate's theory of the test year concept.

A. No. Mr. Brosch states the following on pages 9 and 10 of CA-T-1:

> ... The test year is not intended to accurately predict the future results of a utility. Each data element used to determine the revenue requirement is dynamic through time and can be expected to vary throughout the period the newly set utility rates remain in effect....The use of a test year to quantify ratemaking values for these variables is intended to determine a revenue requirement based upon <u>the relationship between</u> revenue and cost levels at a common point in time, rather than the absolute values of test year revenues and costs.

Given this concept, it is entirely inconsistent for Mr. Carver to fashion an argument that HECO should be held to the $10.6 million per year (or $106 million in the last ten years) for NPPC recovery that he contends was included in the 1995 rate case revenue requirement and is currently embedded in rates. There

are numerous expenses and rate base items that can be shown to have exceeded, and/or to have never been included in, the theoretical amount included in the revenue requirement of the last rate case. However, I do not believe Mr. Carver is ready to concede that HECO's revenue requirement in this proceeding should be adjusted upward for shortfalls in the recovery of these items over the last ten years.

Instead attention should properly focus on the test year amounts for the prepaid pension asset as is done for all other components of the Company's revenue requirement.

Q. Do you have any other concerns with Mr. Carver's recommendation?

A. Yes. I find it troubling that he would make a proposal that is contrary to the proper matching of the NPPC and the prepaid pension asset as specified by generally accepted accounting principles ("GAAP"). As is evident from my testimony, the accounting of the NPPC and prepaid pension asset as prescribed by SFAS 87 is interrelated and both must be considered to properly reflect the financial condition of a company's pension plan.

Q. In summary, why should the Commission reject the CA's and DOD's argument and proposed treatment of the prepaid pension asset?

A. First, the CA's and DOD's argument constitutes retroactive ratemaking. It is erroneous to assess whether a particular investment should be included in rate base based on an alleged over-recovery of a single expense item incurred in the past. Mr. Carver is clearly aware of this and acknowledges that the Commission should not engage in retroactive ratemaking (CA-T-2, page 22).

Second, their argument that HECO should be held to the $10.6 million per year for NPPC recovery is entirely inconsistent with the CA's own, stated test

year concept that data elements used to determine the revenue requirement are dynamic and can be expected to vary in time.

Third, as I discussed earlier, ratepayers have benefited from the prepaid pension asset. Funding of the pension is part of what resulted in lower NPPC. This contributed to a lower revenue requirement, which negated the need to request a general rate increase in the last ten years. If the Company had had a rate case during the last ten years, and its rates had stayed the same (based on the results of operations that reflected a negative pension expense), Mr. Carver would not even be able to make his argument. The fact that rates were able to stay the same without a rate case should not change the result. In addition, the funding of the pension fund will contribute to a lower NPPC than what would otherwise be realized.

Finally, the CA's and DOD's proposal would result in a completely arbitrary adjustment. Ratepayers will enjoy the benefits of pension funding without paying the full costs of funding. Note that under their proposed treatment of pension, they accept the NPPC of $5 million, which is only a portion of the full cost of the pension. The cost of providing the prepaid pension asset is the other portion of the total pension cost picture. In HECO's 1995 test year rate case, the Commission found that NPPC of $9.5 million was reasonable with no prepaid pension asset in rate base. (Docket No. 7766 D&O No. 14412 dated December 11, 1995 p. 30) The NPPC of $5 million in this rate case is only reasonable in conjunction with a fair return on rate base of the $79 million prepaid pension asset.

Q. Does HECO agree with any portion of the CA's and DOD's proposed treatment of pension?

A. All parties have agreed on the NPPC forecast based on SFAS 87 presented by HECO.

Q. Mr. Carver cites eight cases in which he proposed disallowance of the prepaid pension asset. Please comment on the cases.

A. In response to HECO/CA-IR-204(d), Mr. Carver acknowledges that four of the eight cases cited were settled without litigation addressing the prepaid pension issue. One case is ongoing. He cites the three cases in which pension asset was excluded from rate base. Based on the information provided by Mr. Carver, the rulings in those three cases do not apply to this situation. The following summarizes and addresses the applicability of those rulings:

- Arizona Corporation Commission Case E-1051-93-183 (U. S. West Communications, Inc. rate case)

  The Arizona Corporation Commission ("Arizona Commission") ruled that U. S. West Communications, Inc. had not presented sufficient evidence to clearly demonstrate that the shareholders had advanced the pension amounts for inclusion in rate base. My testimony explains how HECO's prepaid pension asset is funded and provides the reasons why is should be allowed into rate base.

- Utah Public Service Commission Docket No. 97-049-08 (U. S. West Communication, Inc. rate case)

  The Public Service Commission of Utah ("Utah Commission") rejected the use of SFAS 87 for regulatory accounting for pension costs primarily on the basis that the potential impact it could have on the changing regulations relating to telecommunications in Utah. The Utah Commission's concerns related primarily to the changes specific to the

telecommunications industry in the state of Utah. Those concerns would clearly not apply to this case.

- Washington Utilities & Transportation Commission Docket No. UT-930074 (U. S. West Communications, Inc. request to include pension asset in rate base effective with 1992 sharing year)

  The Washington Utilities and Transportation Commission ruled that if otherwise appropriate, inclusion should be part of working capital analysis. No working capital calculation was presented in the proceeding. Ms. Ohashi addresses the working capital aspects of the pension in RT-19.

Q. Are you aware of any other jurisdictions that have approved a recovery mechanism for the prepaid pension asset?

A. Yes. Although HECO has not conducted an exhaustive search of state commission orders, it is aware that state regulatory commissions in Massachusetts, Kentucky and Washington have issued orders enabling some form of recovery of the prepaid pension asset. I have summarized these orders below:

- Massachusetts - On October 31, 2003, the Department of Telecommunications and Energy of the Commonwealth of Massachusetts issued an Order in D.T.E. 03-47-A approving a recovery mechanism for pensions and post retirement benefits other than pensions ("PBOP") for the Commonwealth Electric Company, Cambridge Electric Light Company and Boston Edison Company (dba NSTAR Gas Company). Among other things, the mechanism allowed carrying costs on the "average annual prepaid pension balance expense" to be collected (or refunded) from customers.

- Kentucky - On September 30, 1997, the Kentucky Public Service Commission issued an Order in Case No. 97-034 for the Kentucky-American Water Company. In this case the State Attorney General recommended that Kentucky-American's rate base be reduced by the balance in an accrued pension account which recorded the difference between annual SFAS 87 pension expenses and annual ERISA pension plan contributions. The Commission agreed with the adjustment but also agreed with Kentucky-American's recommendation that, if the accrued balance reverses in the future and a pension asset is created, the asset should be included in rate base.
- Washington – On April 11, 1996, the Washington Utilities and Transportation Commission issued its 15th Supplemental Order in Docket No. UT-950200 accepting US West Communications, Inc.'s proposal to include the prepaid pension asset as a discrete item in rate base.

In addition, in its response to HECO/CA-IR-204 (Attachment A, pages 36-40), the CA provided testimony from a Qwest Corporation witness in Docket No. T-0105B-99-0105 in Arizona that identifies several jurisdictions in which regulators have included a pension asset in rate base through either an order or settlement. These jurisdictions include the Federal Communications Commission, Colorado, Iowa, Minnesota and Oregon.

Q. Has this Commission approved the inclusion of the prepaid pension asset into rate base in any other proceeding?

A. Yes. As I mentioned earlier, in Decision and Order No. 18365 in Docket No. 99-0207, the Commission allowed HELCO to include a prepaid pension asset of $1.4

1 million in rate base.

2 Q. In Docket No. 99-0207, did the CA object to inclusion of the prepaid pension
3 asset into HELCO's rate base?

4 A. No, it did not. The CA accepted HELCO's year-end test year estimate of the
5 prepaid pension asset and reflected it in its proposed rate base (Exhibits CA-921,
6 HELCO-R-1501).

7 Q. Has this Commission approved any settlement agreements that have resulted in
8 inclusion of some amount for prepaid pension asset?

9 A. Yes. In Docket No. 94-0298, the Commission approved a stipulated agreement
10 between GTE Hawaiian Telephone Company Incorporated ("GTE") and the CA
11 which resulted in a prepaid pension asset of $16.3 million being included in
12 GTE's rate base (Exhibit B of Decision and Order No. 15345).

13 Hence, although the CA has identified in its response to CA-IR-204 certain
14 decisions that have excluded the pension asset from rate base, there are clearly
15 others that have ruled for inclusion or approved settlement agreements that have
16 resulted in inclusion of a pension asset in rate base.

17 Q. What are the potential consequences of adopting the CA and DOD's proposed
18 disallowance of the prepaid pension asset?

19 A. If the prepaid pension asset is not included in rate base, investors will not be
20 compensated for cash they contribute to the pension fund. This would be a
21 disincentive to adequately fund HECO's pension and would increase the
22 Company's financial risk as it could result in minimum funding requirements in
23 the future when HECO may not have adequate sources of funds.

24 <u>Summary</u>

25 Q. Should the Commission continue to accept the use of SFAS 87 for ratemaking

1 purposes?

2 A. Yes. The Company and its subsidiaries have consistently applied SFAS 87 in
3 prior rate cases and in each company's respective PUC reports. SFAS 87 is fair to
4 both the ratepayer and to the Company's shareholders. It is based on widely-
5 accepted and independent sources of guidance. The accounting standards have
6 been established by the FASB.

7 As I indicated, this treatment has been accepted in a number of other
8 jurisdictions.

9 Ratemaking treatment for pension under SFAS 87 is also consistent with the
10 ratemaking treatment for other post-retirement employee benefits ("OPEB")
11 under Statement of Financial Accounting Standards 106 ("SFAS 106"),
12 "Employer's Accounting for Postretirement Benefits Other Than Pensions" which
13 the Commission approved in Docket No. 7243 and 7233 (consolidated) D&O No.
14 13659 dated November 29, 1994. The ratemaking treatment of OPEB is similar
15 to the ratemaking treatment for pensions in that the cumulative contributions to
16 the trusts which exceed the benefit liability are included as additions to rate base
17 (prepaid pension asset and prepaid OPEB asset) and cumulative contributions to
18 the trust which are less than the benefit liability are included as deductions to rate
19 base (pension liability and OPEB liability).

20 Q. Should the prepaid pension asset be included in rate base?

21 A. Yes. Inclusion of the prepaid pension asset in rate base is consistent with the
22 application of SFAS 87 for ratemaking purposes.

23 I have demonstrated in my testimony that investors have provided the cash
24 to the pension fund and that it was prudent to do so. Inclusion of the prepaid
25 pension asset in rate base will fairly compensate investors for the funds they have

advanced for the funding of the pension plan.

GAINS ON SALE OF LAND AND IOLANI COURT PLAZA LEASE PREMIUM

Q. What is the Company's rebuttal position with respect to the unamortized Gains on Sale of Land and unamortized Iolani Court Plaza Lease Premium?

A. The Company's normalized test year 2005 estimates for the unamortized Gains on Sale of Land and unamortized Iolani Court Plaza Lease Premium are as follows:

1) Unamortized Gains on Sale of Land
   a) 12/31/04 balance $470,000
   b) 12/31/05 balance $1,503,000
2) Unamortized Iolani Court Plaza Lease Premium
   a) 12/31/04 balance $19,000
   b) 12/31/05 balance $15,000
3) Total
   a) 12/31/04 balance: $ 489,000
   b) 12/31/05 balance: $1,518,000
   c) Average ([a+b]/2): $1,004,000

Q. Do the rebuttal estimates shown above reflect adjustments to the Company's direct testimony estimates?

A. Yes, the Company's direct testimony estimates for the unamortized Gains on Sale of Land and unamortized Iolani Court Plaza Lease Premium shown on HECO-1320 were adjusted as described in the Company's response to DOD/HECO-IR-10-4.

Q. In general, why did the Company adjust its direct testimony estimates?

A. The adjustments were made to reflect actual balances as of 12/31/2004 and to update some of the estimated 12/31/2005 balances, including updates for transactions occurring subsequent to the filing of the Company's direct testimony.

Q. Are there any differences between the Company and the Consumer Advocate and/or Department of Defense with respect to the test year estimates for the unamortized Gains on Sale of Land and unamortized Iolani Court Plaza Lease Premium?

A. No, all parties are in agreement with respect to the unamortized balances for the test year. The Consumer Advocate accepted the Company's updated estimates (see CA-T-1, page 98, Schedule B, line 18 and Schedule B-2, lines 48-50) as did the Department of Defense (see DOD T-1, page 10 and Exhibit DOD-108, line 13).

Q. Are there any differences between the Company and the Consumer Advocate with respect to the amount of Gains on Sale of Land to be amortized in the test year?

A. Yes, the Company and Consumer Advocate do not agree on the amount of amortization to be included in test year Other Operating Revenues - Miscellaneous Revenues for the Lilipuna property. The Company's position with respect to this issue is addressed by Mr. Peter Young (see HECO RT-3). The Consumer Advocate's position regarding the Unamortized Gain related to the Lilipuna property is not consistent with its position related to the amortization of the gain on sale of land with respect to the property. If the Consumer Advocate's proposal to exclude the amortization of the gain in Other Operating Revenues is adopted, the unamortized gain related to the property, while small, should also be excluded from the unamortized gain balance in rate base.

1 ACCOUNTING FOR COMPUTER SOFTWARE DEVELOPMENT COSTS

2 Q. Are there any issues between the HECO and the Consumer Advocate and
3 Department of Defense related to the Accounting for Computer Software
4 Development Costs?

5 A. With the exception of costs related to the Company's Ellipse software upgrade,
6 which is discussed by Ms. Faye Yamauchi in HECO RT-13, there appears to be
7 agreement with respect to the test year estimates related to computer software
8 development project costs. There are no expense amounts in the test year for the
9 amortization of previously deferred software development project costs and there
10 are no unamortized deferred project costs included in rate base. There are,
11 however, certain software development project costs included as expense in the
12 test year, in accordance with the Company's accounting procedures for such costs,
13 which are consistent with Generally Accepted Accounting Principles. The
14 Consumer Advocate and the Department of Defense has not raised any issues
15 regarding the Company's accounting policy for computer software development
16 costs.

17 Q. Is there additional support for HECO's accounting for computer software
18 development costs?

19 A. Yes, HECO's accounting for computer software development costs were
20 presented in Docket No. 04-0131 (Outage Management System docket) and in
21 Docket No. 04-0268 (Customer Information System docket). The Commission in
22 approving the Company's CIS project in Decision and Order No. 21798 found
23 HECO's proposed accounting treatment to be consistent with generally accepted
24 accounting principles and reasonable.

25

1 ABANDONED CAPITAL PROJECT COSTS

2 Q. What are the positions of the parties with respect to abandoned capital project
3 costs?

4 A. As discussed in HECO T-13, pages 50 and 51, the Company's test year expense
5 estimates include a total of $264,000 for abandoned capital project costs. The
6 Consumer Advocate and Department of Defense have accepted the Company's
7 estimates in developing their estimate of HECO's revenue requirements.

8

9 MAINTAINING FINANCIAL INTEGRITY

10 Recent Discussions with and Feedback from Rating Agencies

11 Q. What has been the state of recent discussions with and feedback from the rating
12 agencies regarding HECO's corporate credit ratings and outlook?

13 A. On April 22, 2005, Standard and Poor's Ratings Services ("S&P") affirmed
14 HECO's BBB+ corporate credit ratings. At the same time, S&P revised its
15 outlook from stable to negative. See HECO's response to DOD-IR-3-5 for a copy
16 of the report from S&P dated April 22, 2005: Hawaiian Electric Industries and
17 Utility Units Ratings Affirmed; Outlook Revised to Negative.

18 Q. Why did S&P revise HECO's outlook from stable to negative?

19 A. According to S&P, the outlook revision reflects a declining trend in HECO's
20 financial metrics which have been pressured by:

21 1) rising operating expenses;
22 2) yet to be recovered investments and
23 3) the long-term lack of rate relief.

24 S&P also cited that absent a supportive rate decision in HECO's pending rate case,
25 prospective key financial metrics may not support a financial profile that is

1 commensurate for the current ratings.

2 Q. Did the Company engage in further discussions with S&P, in light of the revised
3 outlook?

4 A. As part of the Company's annual visit, on May 17, 2005, Company management
5 met with S&P to review HECO's key financial results and business plans,
6 including the status of its rate case proceeding. S&P indicated that they would be
7 evaluating HECO's business profile of "6" and would consider changing HECO's
8 business profile to "5".

9 Q. Please describe the business profile scores assigned by S&P.

10 A. S&P assigns business profile scores to all rated companies. S&P uses a 10-point
11 scale, where "1" represents the lowest risk and "10" represents the highest risk.
12 Companies with a strong business profile are generally scored "1" to "4", while
13 companies facing greater threats would generally be rated with a business profile
14 score of "7" to "10".

15 Q. Did S&P proceed with changing HECO's business profile from "6" to "5"?

16 A. Yes. On May 31, 2005, S&P changed HECO's business profile from "6" to "5".
17 There was, however, no change to the Company's outlook, which remained at
18 negative. S&P reiterated that a responsive rate order from the PUC regarding
19 HECO's pending rate case is crucial and absent a supportive rate decision,
20 prospective key financial metrics may not support a financial profile that is
21 commensurate with the current ratings. Additionally, S&P indicated that ...
22 "Failure to strengthen key financial parameters, especially cash flow coverage of
23 debt, ... a punitive rate order, ... could lead to lower ratings." A copy of S&P's
24 publication related to HECO's business profile is shown at HECO-R-1614.

25 Q. Does the change in business position from "6" to "5" signal a decrease in HECO's

1 risk?

2 A. No. As noted in the S&P's May 31, 2005 report, business profiles "5" and "6" are
3 considered satisfactory business profiles. Again, S&P did not change the
4 company's outlook, which remained at negative. It's our understanding that
5 S&P's change in business profile from "6" to "5" would allow HECO's financial
6 ratios to more easily fall within the guidelines of a BBB+ corporate credit rating.

7 Q. Is there any evidence to support S&P's statement that a change in business profile
8 from "6" to "5" would allow HECO to maintain its BBB+ corporate credit rating?

9 A. On page 4 of HECO-R-1614, S&P states that HECO's adjusted funds from
10 operations ("FFO") to total debt ratio is weak at approximately 20.

11 Q. Why did S&P conclude that HECO's FFO to total debt ratio is weak?

12 A. The following are ranges that S&P uses to determine the strength of the FFO to
13 total debt ratio to assist with their determination of a company's corporate credit
14 rating: (Note that S&P publishes a range for a BBB rating only. Ratios that fall
15 on the high end of the range are considered for a BBB+ rating, while ratios that
16 fall on the low end of the range are considered for a BBB- rating, with ratios that
17 fall in the middle of the range are considered for a BBB rating.)

18

19 HECO's FFO/total debt ratio as of 12/31/04: 20
20 Business Profile 5: 22-15
21 Business Profile 6: 28-18

22 Under business profile "5", HECO's ratio is closer to the upper end of the range
23 (supporting a BBB+ rating). In constrast, under business profile "6", HECO's
24 ratio is closer to the lower end of the range (supporting a BBB- rating).

25 Q. Did the Company engage in discussions with its other rating agency, Moody's

1 Investors Service ("Moody's")?

2 A. Yes. Also as part of the Company's annual visit, HECO management met with
3 Moody's on May 16, 2005.

4 Q. What information was shared with Moody's on May 16, 2005?

5 A. Company management reviewed HECO's key financial results and business plans,
6 including the status of its rate case proceeding.

7 Q. As a result of the meeting, did Moody's take any ratings actions?

8 A. No. Moody's did not take any ratings actions. However, they did indicate that
9 they would be monitoring the results of the HECO rate case.

10 Q. Why is it important for HECO to maintain good corporate credit ratings?

11 A. Maintaining good credit ratings helps to minimize electric rates by lowering the
12 cost of capital to the Company. It also gives the Company the ability to
13 consistently attract new capital on reasonable terms, whatever the current state of
14 the financial markets. These points were discussed in detail in Mr. von
15 Gnechten's direct testimony on page 7 at HECO T-21.

16 Q. What would be the impact on HECO's financial ratios if the CA's and DOD's
17 recommendations regarding the fair rate of return on common equity were
18 adopted?

19 A. As addressed in by Mr. von Gnechten in HECO RT-21, using Mr. Parcell's
20 proposed return on equity, the funds from operations over total debt ratio would
21 be indicative of only a low BBB credit rating. A low BBB rating would mean at
22 least one and possibly two notch downgrade from HECO's current BBB+ rating.

23 <u>Need for Meaningful Rate Relief</u>

24 Q. Why is it important for HECO to obtain a meaningful rate relief?

25 A. It's important for HECO to obtain a meaningful rate relief in order for HECO to

1 maintain its financial integrity.

2 Q. What is meant by financial integrity?

3 A. Financial integrity refers to the financial health of the Company. This means
4 having sufficient funds to fulfill the electrical needs of its customers and prudently
5 planning for future needs, while providing a reasonable rate of return for its
6 shareholders and the ability to attract new capital at reasonable terms.

7 Q. Are there any concerns regarding HECO's ability to maintain its financial
8 integrity?

9 A. Yes. First of all, in 2005, HECO will not have the opportunity to earn the return
10 found to be reasonable by the Commission because by the time the evidentiary
11 hearings are held, three-fourths of the year would have gone by. Under the test
12 year concept, the amount of the rate increase approved by the Commission in a
13 general rate case, which uses an average rate base, generally is the increase in
14 revenue necessary at the beginning of the test year. Unless a rate increase is
15 effective at the beginning of a test year, the Company will not have the
16 opportunity to earn the fair rate of return on rate base determined to be fair and
17 reasonable by the Commission, based on the estimated results of operations for
18 the normalized test year.

19 HECO acknowledges that the timing of a rate case application is clearly its
20 own responsibility. However, as can be seen by the positions taken by the
21 Consumer Advocate and DOD with respect to test year expenses, there is a
22 reluctance to accept representations that expenses will increase without a showing
23 that expenses already have increased.

24 Additionally, due to unanticipated changes in schedules, the estimated plant
25 additions for two large projects, the Ford Island and Mamala substations, were

removed from the 2005 test year plant additions estimate. These projects are now estimated to be completed in 2006, falling outside our 2005 test year rate case. HECO will not have the opportunity to recover its investment in these projects, nor will it have the opportunity to earn a fair rate of return on these projects until its next rate case. (Even for the 2005 test year plant additions, only one-half the investment is included in an average rate base and none of the additional depreciation expense is included in test year expenses because depreciation starts in the year following the addition.)

Finally, over the coming years, HECO will be implementing a number of system-related projects, including the Energy Management System, the Outage Management System, and the Customer Information System, all which fall outside the 2005 test year rate case.

Sales growth has the potential to offset normal increases in expenses and rate base, but it is difficult for sales growth to make up for substantial expense and rate base increases. In order for HECO to maintain its financial integrity, it will be important for HECO to obtain a meaningful rate relief in this proceeding. It will be difficult enough to address the pension cost and rate base additions without another rate case if the Commission recognizes the full cost of staffing additions in this rate case. It will be much more difficult to manage the situation if only part of the staffing cost increase is recognized.

SUMMARY

Q. Please summarize HECO's rebuttal position in this case with respect to the subject areas for which you are responsible.

1) I have presented the Company's rebuttal position related to depreciation

expense and accumulated depreciation;

2) Presented the Company's average employee count for the test year and address the Consumer Advocate's and Department of Defense's proposed adjustment related to the average employee count for the test year;

3) Presented the Company's position regarding the King Street Office Building Lease;

4) Presented the Company's position regarding its Prepaid Pension Asset;

5) Addressed the Company's ratemaking treatment for computer software development costs, abandoned capital project costs, and gain on the sale of land and Iolani Court Plaza lease premium; and

6) Addressed the Company's latest discussions with rating agencies and the need to maintain financial integrity.

As discussed in my testimony, significant pressure will be place on HECO's financial situation in the near term. In order to maintain its financial integrity, meaningful rate relief needs to be granted in this proceeding.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaiian Electric Company, Inc.
Summary of Changes to Plant, Depreciation Reserves, and Depreciation Expense
For Test Year 2005
($ in Thousands)

	(1) Direct Testimony	(2) Adjustments	(3) Response to IR	(4) Adjustments	(5) HECO Rebuttal
Plant Balance	HECO-WP-1601		DOD-IR-10-2 DOD-IR-10-3		(A)
Plant Balance @ 12/31/04	2,227,400	2,569	2,229,969	-	2,229,969
Additions	133,204	(29,017)	104,187	5,636	109,823
Retirements	(9,954)	-	(9,954)	74	(9,880)
Plant Balance @ 12/31/05	2,350,650	(26,448)	2,324,202	5,710	2,329,912
Depreciation Reserve	HECO-1609		DOD-IR-10-3		(A)
Depreciation Reserve @ 12/31/04	991,611	(3,550)	988,061	-	988,061
Depreciation Accrual	81,474	(1,394)	80,080	-	80,080
Retirements	(9,954)	-	(9,954)	74	(9,880)
Removal Cost	(5,176)	-	(5,176)	309	(4,867)
Gross Salvage	179	-	179	26	205
Depreciation Reserve @ 12/31/05	1,058,134	(4,944)	1,053,190	409	1,053,599
Depreciation Expense	HECO-1608		DOD-IR-9-2 HECO-1608 **		Exhibit DOD-104
Depreciation Accrual	81,474	(1,394)	80,080	-	80,080
Amortization of King Street Lease	-	193	193	(193)	-
Less: Depreciation on Vehicles	(1,810)	36	(1,774)	-	(1,774)
Amortization of CIAC	(7,510)	26	(7,484)	-	(7,484)
Amortization of Federal ITC *	(905)	-	(905)	-	(905)
Amortization of SFAS109 reg asset	808	6	814	-	814
Depreciation Expense	72,056	(1,133)	70,924	(193)	70,730

* Amortization of Federal ITC is included in Depreciation Expense in accordance with the SFAS 109 method of accounting for income taxes as described in testimony at HECO T-17.

** Revised 6/17/05

(A) Retirements, removal cost, and gross salvage revised to reflect actual 12/31/04 plant balances and updated 5 year historical percentages to include 2004 actuals.

HECO
Revised TY 2005 Average Employee Count [1]
Adjusted for Energy Services & IRP employee counts per CA-IR-510

VP	Dept	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Total	13 Mo Ave
Corp Exc	Comp & Ben	14	14	14	14	14	14	14	14	14	14	14	14	14	182	14
Corp Exc	Ind Rel	9	9	9	9	9	9	9	9	9	9	9	9	9	117	9
Corp Exc	SSF	42	43	43	43	43	43	43	43	43	43	43	43	43	558	43
Corp Exc	VP-Corp Exc	2	2	2	2	2	2	2	2	2	2	2	2	2	26	2
Corp Exc	WFSD	16	16	16	16	16	16	16	16	16	16	16	16	16	208	16
Corp Exc Total		83	84	84	84	84	84	84	84	84	84	84	84	84	1091	84
Corp Rel	Corp Comm	11	11	11	11	11	11	11	11	11	11	11	11	11	143	11
Corp Rel	VP-Corp Rel	2	2	2	2	2	2	2	2	2	2	2	2	2	26	2
Corp Rel Total		13	13	13	13	13	13	13	13	13	13	13	13	13	169	13
En Del	C&M	210	221	221	221	221	221	221	221	221	221	221	221	221	2862	220
En Del	Engineering	78	78	78	79	79	79	79	79	79	79	79	79	79	1024	79
En Del	Proj Mgmt	7	7	7	8	8	8	8	8	8	8	8	8	8	101	8
En Del	Supp Svcs	80	81	81	81	81	81	81	81	81	81	81	81	81	1052	81
En Del	Sys Op	106	109	109	109	109	109	109	109	109	109	109	109	109	1414	109
En Del	VP-En Del	3	3	3	3	3	3	3	3	3	3	3	3	3	39	3
En Del Total		484	499	499	501	501	501	501	501	501	501	501	501	501	6492	500
EnSol	CID	46	47	47	47	47	47	48	48	48	48	47	47	47	614	47
EnSol	Engy Proj	5	8	8	8	8	8	8	8	8	8	8	8	8	101	8
EnSol	Engy Svcs **	41	51	51	51	51	51	51	51	51	51	51	51	51	653	50
EnSol	IRP	3	5	5	5	5	5	5	5	5	5	5	5	5	63	5
EnSol	SVP-EnSol	3	4	4	4	4	4	4	4	4	4	4	4	4	51	4
EnSol	Tech	2	2	2	2	2	2	2	2	2	2	2	2	2	26	2
EnSol Total		100	117	117	117	117	117	118	118	118	118	117	117	117	1508	116
FinVP	Financial VP	3	3	3	3	3	3	3	3	3	3	3	3	3	39	3
FinVP	Gen Acctg	25	26	26	26	26	26	26	26	26	26	26	26	26	337	26
FinVP	InfoTech	94	94	94	94	94	94	94	94	94	94	94	94	94	1222	94
FinVP	MAFS	22	22	22	22	22	22	22	22	22	22	22	22	22	286	22
FinVP	RiskMgt	9	9	9	9	9	9	9	9	9	9	9	9	9	117	9
FinVP Total		153	154	154	154	154	154	154	154	154	154	154	154	154	2001	154
GenCounsel	Legal	16	16	16	16	16	16	16	16	16	16	16	16	16	208	16
GenCounsel	VPGen	2	2	2	2	2	2	2	2	2	2	2	2	2	26	2
GenCounsel Total		18	18	18	18	18	18	18	18	18	18	18	18	18	234	18
Govt&Comr	Ed & Cons Aff	7	7	7	7	7	7	7	7	7	7	7	7	7	91	7
Govt&Comr	Gov Rel	2	3	3	3	3	2	2	2	2	2	2	2	2	30	2
Govt&Comr	Reg Affairs	7	7	7	7	7	7	7	7	7	7	7	7	7	91	7
Govt&Comr	VP-Gov & Com	5	5	5	5	5	5	5	5	5	5	5	5	5	65	5
Govt&Comm Total		21	22	22	22	22	21	21	21	21	21	21	21	21	277	21
Operations	Cust Svc	131	134	134	134	134	134	134	134	134	134	134	134	134	1739	134
Operations	SVP-Oper	2	2	2	2	2	2	2	2	2	2	2	2	2	26	2
Operations Total		133	136	136	136	136	136	136	136	136	136	136	136	136	1765	136
Pres	Int Audit	6	6	6	6	6	6	6	6	6	6	6	6	6	78	6
Pres	President	3	3	3	3	3	3	3	3	3	3	3	3	3	39	3
Pres Total		9	9	9	9	9	9	9	9	9	9	9	9	9	117	9
PubAffairs	SVP-Pub Aff	2	2	2	2	2	2	2	2	2	2	2	2	2	26	2
PubAffairs Total		2	2	2	2	2	2	2	2	2	2	2	2	2	26	2
Pwr Sup	Environ	24	24	24	24	24	24	24	24	24	24	24	24	24	312	24
Pwr Sup	Plng & Eng	50	55	55	55	55	55	55	55	55	55	55	55	55	710	55
Pwr Sup	Production	315	354	354	354	354	354	354	354	354	354	354	354	354	4563	351
Pwr Sup	VP-Pwr Sup	2	2	2	2	2	2	2	2	2	2	2	2	2	26	2
Pwr Sup Total		391	435	435	435	435	435	435	435	435	435	435	435	435	5611	432
VP-Special Projects															0	0
Revised Grand Total		**1407**	**1489**	**1489**	**1491**	**1491**	**1490**	**1491**	**1491**	**1491**	**1491**	**1490**	**1490**	**1490**	**19291**	**1485**
Per CA-IR-508, page 2 *		1408	1497	1497	1499	1499	1498	1499	1499	1499	1499	1498	1498	1498		
Difference **		-1	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8		

Adjustment to Monthly 2005 Customer Solutions Employee Count	Energy Services	IRP	Total
Revised 2005 Monthly Employee Count	51	5	56
Monthly Count per CA-IR-508, page 2 *	60	4	64
Difference	-9	1	-8
Additional Positions due to Reorganization per CA-IR-78	3	1	4
Positions Moved to the Energy Efficiency Docket No. 05-0069	-12		-12
Difference per CA-IR-510, page 6	-9	1	-8

* Provided monthly employee counts supporting the 2005 test year average included in T-16 direct testimony.
** One position, included in the December 2004 count, was moved to the Energy Efficiency Docket No. 05-0069.

[1] Monthly amounts represent the employee count at month end

HECO
Total Positions Approved for Hiring in 2005
As of 7/26/05

VP	Dept	Revised TY December 2005 Employee Count	Additional Approved Positions Unforecasted in TY 2005	Positions Approved for Hiring in 2005 as of 7/26/05	Rebuttal Testimony Reference
Corp Exc	Comp & Ben	14	1	15	RT-15
Corp Exc	Ind Rel	9		9	
Corp Exc	SSF	43	3	46	RT-13
Corp Exc	VP-Corp Exc	2		2	
Corp Exc	WFSD	16	1	17	RT-13
Corp Exc Total		84	5	89	
Corp Rel	Corp Comm [1]	11	-1	10	
Corp Rel	VP-Corp Rel	2		2	
Corp Rel Total		13	-1	12	
En Del	C&M	221		221	
En Del	Engineering	79	3	82	RT-8
En Del	Proj Mgmt	8		8	
En Del	Supp Svcs	81	2	83	RT-8
En Del	Sys Op	109	7	116	RT-8
En Del	VP-En Del	3		3	
En Del Total		501	12	513	
EnSol	CID	47	5	52	RT-10
EnSol	Engy Proj	8	1	9	RT-7
EnSol	Engy Svcs	51		51	
EnSol	IRP	5		5	
EnSol	SVP-EnSol	4		4	
EnSol	Tech	2	1	3	RT-13
EnSol Total		117	7	124	
FinVP	Financial VP	3		3	
FinVP	Gen Acctg	26		26	
FinVP	InfoTech	94	5	99	RT-13
FinVP	MAFS	22		22	
FinVP	RiskMgt	9		9	
FinVP Total		154	5	159	
GenCounsel	Legal	16		16	
GenCounsel	VPGen	2		2	
GenCounsel Total		18	0	18	
Govt&Comm	Ed & Cons Aff	7	1	8	RT-13
Govt&Comm	Gov Rel	2	1	3	RT-13
Govt&Comm	Reg Affairs	7	1	8	RT-13
Govt&Comm	VP-Gov & Com [1]	5	2	7	RT-13
Govt&Comm Total		21	5	26	
Operations	Cust Svc	134		134	
Operations	SVP-Oper	2		2	
Operations Total		136	0	136	
Pres	Int Audit	6	6	12	RT-13
Pres	President	3	2	5	RT-16
Pres Total		9	8	17	
PubAffairs	SVP-Pub Aff	2		2	
PubAffairs Total		2	0	2	
Pwr Sup	Environ	24		24	
Pwr Sup	Plng & Eng	55	8	63	RT-6
Pwr Sup	Production	354	2	356	RT-6
Pwr Sup	VP-Pwr Sup	2		2	
Pwr Sup Total		435	10	445	
VP-Special Projects			2	2	RT-16
Grand Total		1490	53	1543	

[1] VP-Gov&Comm received an approval to fill an unforecasted Public Affairs Specialist in their department.
However, Corp Comm forecasted for a similar position which they will not be filling due to the hiring of the Public Affairs Specialist.

HECO
Actual Employee Counts
For December 2004-July 27, 2005

VP	Dept	12/31/04	01/31/05	02/28/05	03/31/05	04/30/05	05/31/05	06/30/05	07/27/05
Corp Exc	Comp & Ben	14	13	14	14	14	14	14	14
Corp Exc	Ind Rel	9	9	9	9	9	9	9	9
Corp Exc	SSF	52	52	52	51	50	48	49	50
Corp Exc	VP-Corp Exc	2	2	2	2	2	2	2	3
Corp Exc	WFSD	17	17	17	17	16	16	16	16
Corp Exc Total		94	93	94	93	91	89	90	92
Corp Rel	Corp Comm	9	9	9	9	10	10	10	10
Corp Rel	VP-Corp Rel	2	2	2	2	2	2	2	2
Corp Rel Total		11	11	11	11	12	12	12	12
En Del	C&M	219	219	219	217	216	217	217	216
En Del	Engineering	74	76	76	76	76	76	75	82
En Del	Proj Mgmt	5	6	6	6	6	6	6	**
En Del	Supp Svcs	81	81	81	81	79	80	80	80
En Del	Sys Op	100	97	99	99	105	105	107	108
En Del	VP-En Del	2	2	2	2	2	2	2	2
En Del Total		481	481	483	481	484	486	487	488
EnSol	CID	43	46	46	46	46	45	45	45
EnSol	Engy Proj	8	8	8	8	9	9	9	9
EnSol	Engy Svcs *	44	45	45	48	48	48	48	48
EnSol	IRP	4	4	4	4	4	4	3	4
EnSol	SVP-EnSol	4	4	4	4	4	4	4	4
EnSol	Tech	2	2	2	3	3	3	3	3
EnSol Total		105	109	109	113	114	113	112	113
FinVP	Financial VP	3	3	4	4	3	3	3	3
FinVP	Gen Acctg	25	23	24	25	25	24	24	24
FinVP	InfoTech	90	88	90	92	93	90	95	95
FinVP	MAFS	20	21	22	21	21	22	22	22
FinVP	RiskMgt	9	9	9	9	9	9	9	9
FinVP Total		147	144	149	151	151	148	153	153
GenCounsel	Legal	16	16	16	16	16	16	16	16
GenCounsel	VPGen	2	2	2	2	2	2	2	2
GenCounsel Total		18	18	18	18	18	18	18	18
Govt&Comn	Ed & Cons Aff	6	6	6	6	6	8	8	8
Govt&Comn	Gov Rel	3	3	3	3	3	3	3	3
Govt&Comn	Reg Affairs	5	6	5	6	6	7	8	7
Govt&Comn	VP-Gov & Com	7	7	7	6	6	6	6	7
Govt&Comm Total		21	22	21	21	21	24	25	25
Operations	Cust Svc	126	124	124	124	127	132	132	132
Operations	SVP-Oper	2	2	2	2	2	2	2	2
Operations Total		128	126	126	126	129	134	134	134
Pres	Int Audit	6	7	8	8	8	9	9	8
Pres	President	4	5	5	5	5	5	5	5
Pres Total		10	12	13	13	13	14	14	13
PubAffairs	SVP-Pub Aff	2	2	2	2	2	2	2	2
PubAffairs Total		2	2	2	2	2	2	2	2
Pwr Sup	Environ	24	24	24	24	24	24	24	24
Pwr Sup	Plng & Eng	59	59	56	57	60	62	61	60
Pwr Sup	Production	310	310	310	311	309	309	307	315
Pwr Sup	VP-Pwr Sup	2	2	2	2	2	2	2	2
Pwr Sup Total		395	395	392	394	395	397	394	401
VP-Special Projects		3	3	4	4	3	3	3	3
Grand Total		1415	1416	1422	1427	1433	1440	1444	1454

* Excludes employees moved to the Energy Efficiency Docket No. 05-0069.
** Project Management employee count included with Engineering.

HECO
Comparison of June 30, 2005 Actual Employee Count with Revised TY December 2005 Forecast

VP	Dept	Employee Count as of June 30, 2005	Revised Test Year December 2005	Difference
Corp Exc	Comp & Ben	14	14	0
Corp Exc	Ind Rel	9	9	0
Corp Exc	SSF	49	43	6
Corp Exc	VP-Corp Exc	2	2	0
Corp Exc	WFSD	16	16	0
Corp Exc Total		90	84	6
Corp Rel	Corp Comm	10	11	-1
Corp Rel	VP-Corp Rel	2	2	0
Corp Rel Total		12	13	-1
En Del	C&M	217	221	-4
En Del	Engineering	81	87	-6
En Del	Supp Svcs	80	81	-1
En Del	Sys Op	107	109	-2
En Del	VP-En Del	2	3	-1
En Del Total		487	501	-14
EnSol	CID	45	47	-2
EnSol	Engy Proj	9	8	1
EnSol	Engy Svcs *	48	51	-3
EnSol	IRP	3	5	-2
EnSol	SVP-EnSol	4	4	0
EnSol	Tech	3	2	1
EnSol Total		112	117	-5
FinVP	Financial VP	3	3	0
FinVP	Gen Acctg	24	26	-2
FinVP	InfoTech	95	94	1
FinVP	MAFS	22	22	0
FinVP	RiskMgt	9	9	0
FinVP Total		153	154	-1
GenCounsel	Legal	16	16	0
GenCounsel	VPGen	2	2	0
GenCounsel Total		18	18	0
Govt&Comm	Ed & Cons Aff	8	7	1
Govt&Comm	Gov Rel	3	2	1
Govt&Comm	Reg Affairs	8	7	1
Govt&Comm	VP-Gov & Com	6	5	1
Govt&Comm Total		25	21	4
Operations	Cust Svc	132	134	-2
Operations	SVP-Oper	2	2	0
Operations Total		134	136	-2
Pres	Int Audit	9	6	3
Pres	President	5	3	2
Pres Total		14	9	5
PubAffairs	SVP-Pub Aff	2	2	0
PubAffairs Total		2	2	0
Pwr Sup	Environ	24	24	0
Pwr Sup	Plng & Eng	61	55	6
Pwr Sup	Production	307	354	-47
Pwr Sup	VP-Pwr Sup	2	2	0
Pwr Sup Total		394	435	-41
VP-Special Projects		3	0	3
Grand Total		1444	1490	-46

* Excludes employees moved to the Energy Efficiency Docket No. 05-0069

HECO
Estimated Annual Wages & Benefits of Additional Approved Positions Not Included in TY 2005 Forecast

	# Positions	Estimated Annual Wages $ [1]	Estimated Annual Benefits [2]	Estimated Annual Wages & Benefits	Estimated Annual Wages & Benefits Charged to: O&M	Capital	Billables	Clearing
Positions Filled Prior to 1/1/05	17	1,378,416.00	258,620.32	1,637,036.32	1,206,515.45	234,806.68	30,141.09	165,573.10
Positions Filled in:								
January 2005	7	436,488.00	106,490.72	542,978.72	457,734.84	85,243.88	0.00	0.00
February 2005	3	191,380.80	45,638.88	237,019.68	230,699.16	6,320.52	0.00	0.00
March 2005	4	239,532.80	60,851.84	300,384.64	216,243.16	45,231.00	0.00	38,910.48
April 2005	5	329,929.60	76,064.80	405,994.40	79,006.56	80,857.76	196,904.06	49,226.02
May 2005	3	191,380.80	45,638.88	237,019.68	232,279.29	0.00	4,740.39	0.00
June 2005	2	110,843.20	30,425.92	141,269.12	88,345.94	49,810.05	0.00	3,113.13
Positions Filled as of June 30, 2005	41	2,877,971.20	623,731.36	3,501,702.56	2,510,824.39	502,269.90	231,785.55	256,822.73
Unfilled Positions	12	811,324.80	182,555.52	993,880.32	476,164.23	313,176.97	0.00	204,539.11
TOTAL	53	3,689,296.00	806,286.88	4,495,582.88	2,986,988.62	815,446.87	231,785.55	461,361.84

[1] Based on 2080 hours

[2] Based on 1904 productive hours @ $7.99 per productive hour

Hawaiian Electric Company, Inc.
King Street Office Building

		SL Lease Expense A	Excise Tax Paid B	Total Lease Expense A + B	
1	January 1, 2005	64,583	2,691	67,275	*
2	February 1, 2005	64,583	2,691	67,275	*
3	March 1, 2005	64,583	2,691	67,275	*
4	April 1, 2005	64,583	2,691	67,275	*
5	May 1, 2005	64,583	2,691	67,275	*
6	June 1, 2005	64,583	2,691	67,275	*
7	July 1, 2005	73,285	2,691	75,977	
8	August 1, 2005	73,285	2,691	75,977	
9	September 1, 2005	73,285	2,691	75,977	
10	October 1, 2005	73,285	2,691	75,977	
11	November 1, 2005	73,285	2,691	75,977	
12	December 1, 2005	73,285	2,691	75,977	
	Total	827,212	32,294	859,506	**

Monthly Lease Payments ***	Months (a)		Lease Payment (b)	Totals (a) x (b)	
7/1/2005 to 11/30/2009	53		64,583	3,422,917	
12/1/2009 to 11/30/2014	60		71,042	4,262,500	
12/1/2014 to 11/30/2019	60		78,146	4,688,750	
12/1/2019 to 11/30/2021	24		85,960	2,063,050	
	197	E		14,437,218	F
Straight-Line Expense (F/E)	73,285	G			

Deferred Rent Calculation (7/1/05-12/1/05)		
SL Lease Expense	G * 6 months	439,712
Actual Lease Payment	64,583 * 6 months	387,500
Deferred Rent		52,212

* Month-to-Month lease from 1/1/05 - 6/1/05

** See HECO-R-1303 for total test year rent expense

*** Per modified agreement. See discussion in RT-16

Accounting for Pensions

The primary source of guidance for generally accepted accounting for pensions is found in Statement of Accounting Standards No. 87, "Employers' Accounting for Pensions" ("FAS 87"). Three significant accounting concepts embodied in FAS 87[1] are somewhat unique to pension accounting:

1. Delayed recognition of changes in pension obligation and changes in plan assets
   The *delayed recognition* feature means that changes in the pension obligation (including those resulting from plan amendments) and changes in the value of assets set aside to meet those obligations are not recognized as they occur but are recognized systematically and gradually over subsequent periods. All changes are ultimately recognized except to the extent they may be offset by subsequent changes, but at any point changes that have been identified and quantified await subsequent accounting recognition as net cost components and as liabilities or assets.

2. Certain costs are aggregated and presented as net cost
   The *net cost* feature means that the recognized consequences of events and transactions affecting a pension plan are reported as a single net amount on the income statement.

3. Certain liabilities and assets are presented net on the balance sheet
   The *offsetting* feature means that recognized values of assets contributed to a plan and liabilities for pensions recognized as net pension cost of past periods are shown net in the balance sheet.

The following is a general overview of HECO's pension as reflected in the following financial statements:

- Income Statement
  In general, the **net periodic pension costs** ("NPPC") is reflected in the income statement.[2]

- Balance Sheet
  A liability (**unfunded accrued pension cost**) is recognized if net periodic pension cost exceeds amounts contributed to the plan. An asset (**prepaid pension cost**) is recognized if **net periodic pension cost** is less than amounts the employer has contributed to the plan.[3]

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[1] FAS 87 Summary
[2] A portion of the NPPC is taken off the income statement and is capitalized through an overhead allocation to capital projects; however, in order to simplify this discussion, that component is not addressed.
[3] FAS 87, paragraph 35.

However, if the **accumulated benefit obligation** exceeds the **fair value of plan assets**, certain other tests must be applied which may result in a change to the balance sheet presentation described above.

- Footnote Disclosure
  In addition to other required disclosures, the financial statement footnotes provide a reconciliation of the following:
  1. The fair value of plan assets
  2. The projected benefit obligation
  3. The amount of unrecognized prior service cost
  4. The amount of unrecognized net gain or loss (including asset gains and losses not yet reflected in market-related value)
  5. The amount of any remaining unrecognized net obligation or net asset existing at the date of initial application of FAS 87
  6. The amount of any additional liability recognized (see "Additional Tests" discussion below)
  7. The amount of net pension asset or liability recognized

The financial statement treatment is more fully described below.

Net Periodic Pension Cost

The NPPC is comprised of the following (See Attachment A):

a. Service cost
   The service cost component recognized in a period is determined as the actuarial present value of benefits attributed by the pension benefit formula to employee service during that period.

b. Interest cost
   The interest cost component recognized in a period is determined as the increase in the projected benefit obligation due to the passage of time.

c. Actual return on plan assets, if any
   The actual return on plan assets shall be determined based on the **fair value** of plan assets at the beginning and the end of the period, adjusted for contributions and benefit payments.[4]

d. Amortization of unrecognized prior service cost (gain), if any
   Plan amendments often include provisions that grant increased benefits based on services rendered in prior periods. Because plan amendments are granted with the

[4] FAS 87, footnote 13 regarding disclosure requirements. "The net asset gain or loss during the period deferred for later recognition (in effect, an offset or a supplement to the actual return on assets"

expectation that the employer will realize economic benefits in future periods, FAS 87 does not require the cost of providing such retroactive benefits (that is, prior service cost) to be included in net periodic pension cost entirely in the year of the amendment but provides for recognition during the future service periods of those employees active at the date of the amendment who are expected to receive benefits under the plan.

e. Gain or loss (including the effects of changes in assumptions) to the extent recognized
The gain or loss component of net periodic pension cost shall consist of (a) the difference between the actual return on plan assets and the expected return on plan assets and (b) amortization of the unrecognized net gain or loss from previous periods. The gain or loss component is the net effect of delayed recognition of gains and losses (the net change in the unrecognized net gain or loss) except that it does not include changes in the projected benefit obligation occurring during the period and deferred for later recognition.

Gains and losses are changes in the amount of either the projected benefit obligation or plan assets resulting from experience different from that assumed and from changes in assumptions. Gains and losses include amounts that have been realized, as well as amounts that are unrealized. Because gains and losses may reflect refinements in estimates as well as real changes in economic values and because some gains in one period may be offset by losses in another or vice versa, FAS 87 does not require immediate recognition of gains and losses as components of net pension cost of the period in which they arise.

Asset gains and losses are differences between the actual return on assets during a period and the expected return on assets for that period. Asset gains and losses include both (a) changes reflected in the market-related value of assets and (b) changes not yet reflected in the market-related value (that is, the difference between the fair value of assets and the market-related value). Asset gains and losses not yet reflected in market-related value are not required to be amortized.

f. Amortization of the unrecognized net obligation (and loss or cost) or unrecognized net asset (and gain) existing at the date of initial application of FAS 87

Accumulated Benefit Obligation

The **accumulated benefit obligation** is the actuarial present value of benefits (whether vested or nonvested) attributed by the pension benefit formula to employee service rendered before a specified date and based on employee service and compensation (if applicable) prior to that date. The accumulated benefit obligation differs from the projected benefit obligation in that it includes no assumption about future compensation levels.

Projected Benefit Obligation
The **projected benefit obligation** as of a date is the actuarial present value of all benefits attributed by the plan's benefit formula to employee service rendered prior to that date. The projected benefit obligation is measured using an assumption as to future compensation levels if the pension benefit formula is based on those future compensation levels.

Fair Value of Plan Assets
Fair value of plan assets is the amount that the pension plan could reasonably expect to receive for an investment in a current sale between a willing buyer and a willing seller, that is, other than in a forced or liquidation sale.

Expected Return on Plan Assets
An amount calculated as a basis for determining the extent of delayed recognition of the effects of changes in the fair value of assets. The expected return on plan assets is determined based on the expected long-term rate of return on plan assets and the market-related value of plan assets.

Market-Related Value of Plan Assets
A balance used to calculate the expected return on plan assets. Market-related value can be either fair market value or a calculated value that recognizes changes in fair value in a systematic and rational manner over not more than five years. Different ways of calculating market-related value may be used for different classes of assets, but the manner of determining market-related value shall be applied consistently from year to year for each asset class.

Additional Tests
If the accumulated benefit obligation exceeds the fair value of plan assets, the employer shall recognize in the statement of financial position a liability (including unfunded accrued pension cost) that is at least equal to the **unfunded accumulated benefit obligation**.

Recognition of an additional minimum liability is required if an unfunded accumulated benefit obligation exists and (a) an asset has been recognized as prepaid pension cost, (b) the liability already recognized as unfunded accrued pension cost is less than the unfunded accumulated benefit obligation, or (c) no accrued or prepaid pension cost has been recognized.

If an additional minimum liability is recognized, an equal amount shall be recognized as an intangible asset, provided that the asset recognized shall not exceed the amount of unrecognized prior service cost. If an additional liability required to be recognized exceeds unrecognized prior service cost, the excess (which would represent a net loss not yet recognized as net periodic pension cost) shall be reported as a separate component (that is, a reduction) of equity, net of any tax benefits.

When a new determination of the amount of additional liability is made to prepare a statement of financial position, the related intangible asset and separate component of equity shall be eliminated or adjusted as necessary.

Hawaiian Electric Company, Inc.
Prepaid Pension Asset Balances
1987-2005
($ in thousands)

Year	Beginning Pension Asset Balance	Contributions to Trust	NPPC Accrual	Ending Pension Asset Balance	
	A Prior Year Col. D	B	C	D A+B-C	
1987	$ 480	$ 8,736	$ 9,216	$ -	
1988	-	8,308	8,308	-	
1989	-	9,007	9,007	-	
1990	-	9,740	9,740	-	
1991	-	10,618	10,618	-	
1992	-	11,382	11,382	-	
1993	-	10,940	10,940	-	
1994	-	10,925	10,925	-	
1995	-	9,058	6,408	2,650	
1996	2,650	6,972	8,381	1,241	
1997	1,241	5,876	7,117	-	
1998	-	2,206	1,871	335	
1999	335	0	(1,074)	1,409	
2000	1,409	0	(19,322)	20,731	
2001	20,731	0	(20,465)	41,196	
2002	41,196	0	(15,656)	56,852	
2003	56,852	13,394	5,894	64,352	
2004	64,352	15,186	(1,547)	81,085	[1]
2005 (Est.)	81,085	0 [1]	4,588 [1]	76,497	[2]
Total		$ 132,348	$ 56,331		

Rate Base Calculation:

Recorded Balance, 12/31/04	$	81,085	[1]
Estimated Balance, 12/31/05	$	76,497	[2]
Average 2005 Balance	**$**	**78,791**	([1]+[2])/2

Recorded balances, except as noted in footnote 1 below.

[1] Per June 2005 update of HECO-1504

Hawaiian Electric Company, Inc.

2004 Reconciliation of Pension Balances

	12/31/2003 Balance Sheet a	1/1/2004 Recon Gain/(loss) b	1/1/2004 Balance Sheet c = a+b	2004 NPPC d	2004 Cash Flow e	12/31/2004 Expected Balance Sheet f = c+d+e	Assumption Change g	12/31/2004 Remeasurement Gain/(Loss) h	12/31/2004 Balance Sheet j = f+g+h
				(14,776) 1					
				(33,485) 2	248 4				
				137 3	29,281 5				
[1] **Projected Benefit Obligation (PBO)**	(548,620)	(2,371)	(550,991)	(48,124)	29,529	(569,586)	(14,768)	30	(584,324)
					15,186 8				
				47,513 6	(248) 9				
				(42) 7	(29,281) 10				
[2] **Fair Value of Plan Assets**	490,310		490,310	47,471	(14,343)	523,438			523,438
[3] **Funded Status**	(58,310)	(2,371)	(60,681)	(653)	15,186	(46,148)	(14,768)	30	(60,886)
[4] **Unrecognized Loss**	127,257	2,371	129,628	1,721		131,349	14,768	(30)	146,087
[5] **Unrecognized Prior Service Cost**	(4,595)		(4,595)	479		(4,116)			(4,116)
[6] **Net Amount Recognized (Prepaid Pension Cost)**	**64,352**	**-**	**64,352**	**1,547**	**15,186**	**81,085**	**-**	**-**	**81,085**
[7] **Fair Value of Plan Assets**	490,310								523,439
[8] **Accumulated Benefit Obligation (ABO)**	465,007								498,098
[9] **Funded ABO**	25,303								25,341

[1]+[2]=[3]
[3]+[4]+[5]=[6]
[7]-[8]=9

1 Service Cost
2 Interest Cost
3 Transfers
4 Admin Expenses
5 Benefit Payments
6 Actual Return on Plan Assets
7 Transfers
8 Employer Cost
9 Admin Expenses
10 Benefit Payments

NOTE: Totals may not add exactly due to rounding.

Postretirement Obligations

Standard & Poor's Ratings Services views unfunded liabilities relating to defined benefit pension plans and retiree medical plans as debt-like in nature. This also is the case with deferred lump-sum payment schemes, such as termination programs for employees in Italy. By accepting a portion of their compensation on a deferred basis, the employees essentially become creditors of the company. As with conventional debt, these liabilities pose risks to their corporate sponsors from the call on future cash flow they represent. (Defined contribution plans generally are not problematic because they must be funded on a current basis, and the corporate sponsor does not bear ongoing investment performance risk.)

A company's postretirement obligations affect its financial position, and also may be germane to its competitive position. Most problematic is when peers face different retiree costs. Companies that have been relatively generous, have an older workforce, or have a comparatively large number of retirees, cannot raise their own selling prices more than those of their competitors'. Likewise, competitors in different countries often are not saddled with similar costs because of differences in pension and health care systems in their respective countries. Any company more burdened with such retiree costs than its competitors will be penalized in the assessment of its overall cost position. The implications for its competitiveness are no less than if it had older, less efficient manufacturing facilities. Such a competitive advantage—or disadvantage—is an important rating consideration.

Distinguishing Characteristics

Various characteristics distinguish unfunded postretirement liabilities from debt obligations. One is the difficulty of measuring their value. Because of the prospective and variable nature of postretirement obligations, their quantification relies on numerous assumptions, including:

- Employee turnover rates and length of service, whereby the length of time the worker is employed by the company determines eligibility for and the size of the retiree benefit;
- Mortality rates, given that the employee's lifespan determines how long he or she receives the benefit;
- Dependency status, if the plan covers surviving dependents;
- Compensation levels, if the employee's wages or salary prior to retirement is a factor in determining the amount of the benefit;
- Discount rate, which is required to calculate a present value of the future required cash outflows; and
- Return on benefit plan investments. To the extent that the benefit is prefunded with investment assets, if positive, the returns realized on those assets will help defray the cost of the benefit.

Because retiree medical benefits are not monetary in nature, but rather are in-kind benefits—i.e., the employee is promised future health care services—there is additional uncertainty. Assumptions must be made about future changes in health care inflation and in health care use and delivery patterns. Not simple matters.

Because of these difficulties, the analytical exercise does not try to quantify a precise amount to represent the postretirement obligation. As discussed below, sensitivity analysis is a better way to capture a company's exposure than by focusing on a single figure.

Further, management's actions to modify plan benefits or regulatory changes could alter the value of the liability over time. Standard & Poor's pays close attention to management's strategies for reducing the cost of the burden and assesses these strategies in the context of the company's labor relations; however, we naturally are reluctant to prejudge the success of any such strategies, particularly if the workforce is tightly unionized, and determined to resist such cost-cutting efforts. Similarly, in theory, there always is the potential that some significant change in the regulatory framework could enable a corporation to shift some portion of its postretirement benefits, burden to the government, but it hardly is prudent to assume such a solution would emerge. Indeed, there also is the risk governments could tighten funding requirements, as recently did Spain and the Netherlands.

National/Regulatory Differences

Analysis of postretirement benefit obligations must take into account the differences among countries' regulatory systems. In some countries (e.g., France, Italy, and Spain), corporations do not bear such obligations directly to any material extent; pension and other postretirement benefits are provided largely under governmental, rather than corporate, schemes. Corporations generally must support these schemes indirectly through taxes. Obviously, a company's overall tax burden must be considered in the analysis of its cash flow.

In other cases, the benefit is provided directly by corporations. Furthermore, strict regulations require the company to prefund the benefit by making contributions to dedicated trusts well in advance of the ultimate disbursal of funds to retirees or third-party insurers. This insulates retirees from the risk that the company might become unable to honor its commitments. Under such regulations, however, the company typically retains some discretion to decide how much to contribute in a given year. This is the case with defined-benefit plans in the U.S., governed by the Employee Retirement and Income Security Act (ERISA) of 1974 and by the tax code, and with such plans in the U.K. and the Netherlands.

In still other cases (e.g., defined-benefit pensions in Germany and retiree medical benefits in the U.S.), the benefit is provided directly by companies, but there is no regulatory requirement to prefund and, typically, no tax incentive for doing so. In such pay-as-you-go systems, the cash burden on the company may be light for many years if the company has a young workforce and few retirees. On the other hand, if the company has a high ratio of retirees to active employees, the ongoing cash outlays may be onerous. Moreover, under this system, there is virtually no flexibility in the timing of payments: the retirees are owed their benefits.

If a company does business in more than one country, Standard & Poor's pays close attention to the geographic profile of its postretirement benefits obligations and the relevant regulatory requirements.

Assessing the Liability

As a practical matter, the company's financial reporting is the best starting point because of the accessible, timely, and comprehensive nature of financial reporting information compared with other sources. Analysts must be wary, however, of the relatively uncertain nature of accounting for postretirement obligations, given all the assumptions necessary for their measurement, discussed above.

Moreover, in virtually all national accounting systems, as well as under International Accounting Standards (IAS), those setting the accounting standards have sought to avoid volatile swings in earnings and liability values; hence, the extensive use of various smoothing techniques, in which underlying net liability changes and variations in actual performance—rather than assumptions—are recognized on a deferred basis over an extended period. *(See "Pitfalls of U.S. Pension Accounting and Disclosure.")*

The first step in analyzing postretirement obligations is to examine key assumptions used to quantify the obligations and determine expense accrual for financial reporting purposes. The discount rate, wage appreciation, expected investment return, and medical inflation rate are all disclosed under U.S. GAAP. The use of actuarial assumptions regarding mortality, dependency status, and turnover can lead to more or less conservative estimations, but these assumptions are not disclosed directly in financial reporting; however, unrecognized losses or gains relating to changes in actuarial assumptions indicate further investigation is warranted.

When assessing assumptions, we focus on differences among companies. Assumptions are considered in light of an issuer's individual characteristics, but also are compared with those of industry peers and general industrial norms. In addition, assumptions are assessed in terms of their internal consistency. For example, both the discount rate and rate of future compensation increases should be closely linked to the rate of inflation. If the discount rate assumption significantly exceeds the assumed rate of compensation increases, this may reflect overoptimism by management about its ability to contain wage and salary increases.

Quantitative adjustments may be made to normalize assumptions. For example, one rough rule of thumb is that for each percentage point increase or decrease in the discount rate, the liability decreases or increases by 10% to 15%. At the very least, any liberal or conservative bias is taken into account when looking at the reported plan obligations and assets.

The next step is to compare the current value of a company's plan assets to the projected benefit obligation (PBO) for pensions, or to the accumulated postretirement benefit obligations (APBO) for retiree medical benefit obligations. In the case of flat-benefit pension plans (i.e., the pension benefit is a fixed amount per year of service, rather than pay-related plans, in which the benefit for each retiree is derived from a formula tied to compensation over a specified period), the PBO likely understates the true economic liability. This is because the PBO does not take account of future benefit improvements for these plans, even if probable, unless provided for in the current labor agreement. In such cases, the analyst estimates the additional economic liability based on the company's pattern of granting benefit improvements and management's current strategies with respect to compensation.

A company's plan assets as a percentage of the PBO or APBO is a simple, basic measure of plan solvency, referred to here as the funding ratio. Companies with the same funding ratios in their benefit plans do not, however, necessarily bear the same risks related to their plans. The size of the gross liability is also important because, where the gross liability is large relative to the company's assets, any given percentage change in the liability or related plan assets will have a much more significant effect than if the gross liability had been less substantial.

To bring the depiction of postretirement-related items in the financial statements more in line with its own analytical perspec-

tive, Standard & Poor's has devised certain ratio adjustments *(see "Adjusting Financials for Postretirement Liabilities")*. These adjustments are intended to undo the smoothing of the accounting treatment and reallocate certain accounting effects in the statements while integrating the analysis of postretirement obligations with other aspects of the financial analysis. This last point is particularly important because of the different funding approaches and regulations that pertain to different plans. For example, as noted earlier, pension plans in Germany largely are unfunded; however, major German industrial companies commonly hold large cash balances and long-term financial assets on the balance sheet to provide for future pension-related cash requirements. Analytically, as long as Standard & Poor's is comfortable that these assets will be retained over the long term to satisfy the pension-related obligations, the arrangement might well be viewed as if the pension plan had been funded. If, however, such a company's capitalization were analyzed without factoring in the pension liability, one could make the mistake of netting the surplus cash against debt, thereby double-counting the cash position and underestimating the company's financial leverage.

Beyond determining the plan's current level of funding, the analyst must also consider the likelihood of significant changes made in the liability or assets in the future. As an example, workforce downsizing through early retirement programs is a major issue in the current economic environment. The potential for changes in benefits largely is a function of the labor climate and the level of benefits relative to those of direct competitors and other regional employers. Similarly, to take a prospective view of plan assets requires the sponsor's input regarding its funding strategies and asset allocation guidelines. Regarding the latter, we do not have a preferred strategy: heavy weighting toward equities heightens near-term volatility, but—if experience holds true—should enhance long-range returns. Conversely, heavy weighting toward fixed-income holdings should minimize near-term volatility, but may well limit long-range returns.

Although Standard & Poor's views unfunded postretirement obligations as debt-like, the surplus relating to overfunded plans generally cannot be viewed as a cash equivalent. Having a significantly overfunded postretirement benefit plan is, of course, a positive from a credit perspective. If nothing else, it generally means the company can curtail future contributions to the plan, barring changes in asset or liability levels. Companies can use the surplus to enrich the retiree benefits (possibly in lieu of raising wages) or sometimes to fund special workforce reduction programs. In the U.S., a portion of the surplus can also be used to fund retiree medical benefits in some circumstances. But in the U.S.—as in most other countries—companies with overfunded pension plans may have little practical ability to revert the surplus: In the U.S., there are harsh tax consequences for doing so. (Amounts recaptured are subject to ordinary income tax, plus a punitive excise tax.)

Cash-Flow Implications

The level of necessary future cash outlays has the most immediate effect on a company's financial health. Standard & Poor's focuses on prospective outlays. Information about the regulatory funding status of the plan, a company's workforce, the makeup of its retiree population, its benefit plan characteristics, and management's cost-cutting and funding strategies helps the analyst understand the likely direction of future cash outlays.

For plans in which prefunding is mandated by regulations, the degree of discretion over payments is critical. The cash requirements for U.S. corporate sponsors are significantly shorter term than the underlying disbursals to retirees, but ERISA usually grants considerable flexibility in the year-to-year timing of contributions, except when the plan is severely underfunded. Near-term minimum funding requirements often are low enough that companies can sharply curtail contributions temporarily if needed to maintain liquidity. (In Japan, pension regulations grant companies significantly greater flexibility to defer contributions over an extended period than the U.S.) When funding is required in the near term to comply with ERISA guidelines, the amounts

involved are viewed in a different, more severe, light.

The calculation of minimum pension plan contributions under ERISA is a highly complex matter. Although the ERISA framework has some similarities to the financial reporting framework, ERISA uses its own distinct methodologies and assumptions for valuing the assets and liabilities of the plan. Funding requirements are not just a function of the current funded status of the plan, but also take into account the past funded status, the level of past contributions relative to requirements, and the nature of the events that gave rise to any underfunding, among other factors.

In theory, it is possible to arrive at a rough estimate of the company's minimum future contribution levels by using the publicly available Annual Return/Report of Employee Benefit Plan on Form 5500, filed by the corporate plan sponsor; however, one such form is filed for each qualified U.S. plan of a company, and large companies may have dozens of separate plans. Moreover, the timeliness of Form 5500 is problematic: it must be filed 210 days after the end of the plan year or after the sponsor has filed its federal income tax form, whichever is later. As a practical matter, then, Standard & Poor's relies on management for information regarding the company's future minimum pension contributions to meet regulatory requirements.

Other factors besides funding regulations can influence funding decisions. For example, in the U.S., benefits provided under qualified, defined-benefit pension plans are guaranteed by a quasi-governmental entity, the Pension Benefit Guaranty Corp. (PBGC), which, in turn, charges plan sponsors an annual premium, currently $19 per plan participant. If a plan's assets are less than the vested portion of the liability (as measured under the very conservative methodology stipulated by the PBGC, which is different from the ERISA approach), an additional, variable annual premium is assessed of $9 for each $1,000 of unfunded liability. Moreover, the plan sponsor must notify plan participants of the plan's underfunded status. Companies often make sufficient contributions to their pension plans to avoid these consequences, even if they are not required to do so under ERISA.

Perversely, perhaps, financial reporting can also drive funding decisions. For example, under U.S. GAAP, if the value of plan assets falls below that of the APBO, a large charge to equity can result ("Pitfalls of U.S. Pension Accounting and Disclosure," again). Companies sometimes make contributions to avoid this reporting effect, particularly if financial covenants might thereby be violated.

In the U.S., there are some tax-effective means of prefunding retiree medical benefits. One funding vehicle is the so-called Voluntary Employees' Beneficiary Association (VEBA) trust. As with pensions, contributions to a VEBA trust generally are tax-deductible up to a certain limit, and earnings on trust investments are tax-exempt. VEBA trusts are more flexible than pension trusts: Although VEBA funds cannot be reverted directly by the corporate sponsor, they can be used to pay for a variety of current benefits-related expenses, thereby freeing up other cash. For this reason, though, if a company is at all inclined to use its VEBA assets in this way, Standard & Poor's tends to view the asset as an extension of the company's ready liquidity position, rather than as offsetting a portion of the retiree medical liability.

In some cases, companies issue debt to finance their benefit plan contributions. In assessing the effect on credit quality, Standard & Poor's considers:

- Any loss of payment-timing flexibility. For example, if the company issues debt with a five-year term to satisfy funding contributions that could otherwise be spread over up to 10 years, this could well be viewed negatively;
- The maturity of the new obligation compared with the terms of the obligations it replaces. For example, if the company is able to eliminate looming, near-term funding requirements with a long-term debt issue, this could be a positive development;
- Tax consequences, such as the cash flow benefit of accelerating a tax-deductible contribution; and
- The implications for the company's debt issuance capacity, to the extent the company might have other borrowing requirements.

In most countries, companies are permitted to contribute limited amounts of their own stock to their benefit plans, substituting for or supplementing cash contributions. Standard & Poor's views such transactions as similar—in their beneficial effect—to the company's issuing common stock and using the proceeds to reduce financial obligations. One difference, however, is the correlation risk that results: If the company encounters significant setbacks, this would presumably be reflected in a weaker share price, which could cause deterioration in benefit-funding levels and precipitate accelerated funding requirements. (For this reason, funding regulations generally set some limit on contributions of so-called employer securities. For example, under ERISA, such contributions cannot exceed 10% of the fair value of plan assets, as determined through a closely scrutinized valuation process.)

Ultimate Recovery Considerations

For companies with significant unfunded postretirement benefit obligations, the standing of such obligations in bankruptcy can be an important consideration for creditors. It may affect their willingness to lend, as it obviously has a bearing on ultimate recovery in a reorganization or liquidation. Analysis of this matter is highly specific to the legal system and type of benefit in question, as well as to the legal structure of the corporation. In the U.S., unfunded pension liabilities typically have the standing of general unsecured claims. (The PBGC or the company generally terminates the plan, and then the PBGC pursues a claim against the company for the funding shortfall.) Companies in financial distress could have been granted funding waivers by government regulators in return for liens on assets in advance of a bankruptcy filing, but this is rare among rated companies.

The standing of retiree medical liabilities in the U.S. is less clear-cut because these do not enjoy the same degree of protection under ERISA. If, however, the benefits are owed under the terms of a labor contract, the company's voiding of the contract in bankruptcy would give rise to a general unsecured claim by employees and retirees. If the company were to reorganize rather than liquidate, this claim would most likely be settled through the continuation of the benefit, albeit perhaps in a reduced form, rather than a monetary payout. This would—at least, in theory—still dilute the recovery of other senior unsecured claims, because the liability in its new capital structure would limit the reorganized company's debt capacity.

Pitfalls of U.S. Pension Accounting and Disclosure

All areas of financial reporting require management to make estimates and judgments, but this is particularly true of accounting for defined-benefit pension plans. Given the prospective and variable nature of the promise companies make to provide pension benefits to retirees, pension accounting relies on numerous subjective assumptions (e.g., employee turnover, mortality rates, compensation levels, discount rates, and investment returns). Moreover, the standards that currently govern pension accounting under U.S. GAAP—Statement of Financial Accounting Standards No. 87, "Employers' Accounting for Pensions" (SFAS 87)—were issued in 1985, despite intense opposition from many companies. The Financial Accounting Standards Board (FASB) responded with various compromise provisions to smooth the effect on earnings and on the balance sheet of pension-related factors. Consequently, some aspects of the financial reporting for pensions are incongruent with the analytical perspective.

Aspects of the current accounting framework that represent potential pitfalls for analysts include the following.

Balance-Sheet Aspects

SFAS 87 defines the pension liability two ways:

- The accumulated benefit obligation (ABO) is a measure of the present value of all benefits earned to date and includes nonvested and vested benefits attributable to services rendered through the balance sheet date. It approximates the value of benefits that would be payable if the company were to terminate the plan, so it represents a shutdown perspective.

- The projected benefit obligation (PBO) also is a measure of the liability for accumulated service, but, unlike the ABO, it also accounts for the effect of salary and wage increases on benefit payouts that are linked to future compensation levels by some formula (for example, where the benefits are based on a fixed percentage of the average annual compensation over the five years prior to the employee's retirement). The PBO thus values the pension promise at the amount for which it will ultimately be settled as the company continues as a going concern.

Measurement of the ABO and PBO requires the company to make many assumptions. Most important, because the liability is calculated as the present value of estimated future payments to plan beneficiaries, the liability valuation is highly sensitive to the discount rate used. (The lower the discount rate, the higher the liability, and vice versa.) SFAS 87 directs companies to "...look to available information about rates implicit in current prices of annuity contracts that could be used to effect settlement of the obligation [and] also...to rates of return on high-quality fixed-income instruments currently available and expected to be available during the period to maturity of the pension benefits."

The discount rate therefore should differ among companies, to the extent they operate in regions with different prevailing interest rates and have different workforce demographics. In actuality, though, as many observers have noted, discount rate assumptions vary significantly more widely among companies than underlying differences in these variables would justify. If the ultimate pension benefit payout is linked to compensation levels, the assumption regarding salary or wage increases also is crucial. In theory, this assumption should bear a close correlation to the discount rate because both reflect, at least partly, the expected inflation rate. If the discount rate is significantly higher than the rate of compensation increases, this may well reflect an overly optimistic view by management about its ability to contain salary and wage cost increases.

Under the framework of SFAS 87, the PBO is the basis for expense recognition—i.e., the accounting seeks to spread the total cost reflected in the PBO over the working careers of the employees earning pension benefits. In the pension footnote, the PBO is compared with the fair value of plan assets to derive the funded status of the plan. (Note: companies can use a measurement date up to 90 days earlier than the balance sheet date to facilitate preparation of the financial statements. This can distort comparisons between the funded status of different companies.) This PBO-related funded status is the best measure of a company's pension-related liability or surplus, and therefore is the one upon which Standard & Poor's focuses.

However, the ABO, not the PBO, serves as the basis for balance-sheet recognition of any unfunded liability. Under the rules of SFAS 87, the relationship of different balance-sheet accounts to the underlying economic reality of the plan is sometimes tenuous. In the normal course of affairs, a company records a liability on the balance sheet to the extent that its pension expense exceeds its plan contributions. To the extent that a company's plan contributions exceed its accrued expense, the company records a prepaid pension asset on the balance sheet.

Strangely, an asset also can be created as a result of benefits enhancements that increase the value of the liability: This intangible asset reflects the presumed economic benefit the employer derives from the plan improvement—for example, better labor productivity from a happier workforce. From an analyst's perspective, the increase in the amount of the liability is more prudently interpreted as a sunk cost. However, if at the end of a fiscal year the fair value of plan assets is less than the ABO, the company must record a so-called minimum liability by increasing any existing balance sheet liability to the level of the unfunded ABO and eliminating any existing asset accounts, with the offset being an after-tax charge to equity (which flows through "other comprehensive earnings," rather than net income). In other words, the additional liability is ABO less (the market value of plan assets plus already accrued liabilities less already accrued assets).

As Table 1 illustrates, this requirement means a nominal change in the funding status

Table 1—Quirks of Liability and Asset Recognition

Under SFAS 87*

Example 1

(Mil. $)	—Year ended Dec. 31— 2001	2002
Accumulated benefit obligation (ABO)	80	100
Plan assets	80	80
Unamortized prior service cost	0	15
Pension-related assets	—	—
Prepaid pension assets	0	0
Intangible assets	0	15
Pension-related liability	0	20
Change in net worth	0	(5)

At year-end 2001, the company's pension plan was fully funded relative to the ABO. During 2002, the ABO increased by $20 million: $15 million because of plan amendments and $5 million because of variances from actuarial assumptions. Thus, at year-end 2002, the company recorded a liability of $20 million. Offsets: the $15 million of the $20 million increase in the ABO resulting from plan amendments gives rise to a $15 million intangible asset, and the balance reduces net worth.

Example 2

(Mil. $)	—Year ended Dec. 31— 2001	2002
Accumulated benefit obligation (ABO)	100	—
Plan assets	80	80
Unamortized prior service cost	0	—
Pension-related assets	—	—
Prepaid pension assets	0	0
Intangible assets	0	0
Pension-related liability	0	20
Change in net worth	0	(20)

In this example, there also was a $20 million increase in the ABO. The entire increase results from actuarial losses, however. Thus, net worth is reduced by the entire $20 million.

Example 3

(Mil. $)	—Year ended Dec. 31— 2001	2002
Accumulated benefit obligation (ABO)	80	100
Plan assets	80	80
Unamortized prior service cost	0	0
Pension-related assets	—	—
Prepaid pension assets	0	0
Intangible assets	0	0
Pension-related liability	15	20
Change in net worth	0	(5)

In this example, the facts are exactly the same as in Example 2, except that the company already had accrued expense on the balance sheet of $15 million. Thus, it is necessary to record only another $5 million to increase the balance sheet liability to a total of $20 million.

Table 1—Quirks of Liability and Asset Recognition (continued)

Example 4

(Mil. $)	—Year ended Dec. 31— 2001	2002
Accumulated benefit obligation (ABO)	80	100
Plan assets	100	100
Unamortized prior service cost	0	0
Pension-related assets	—	—
Prepaid pension assets	30	30
Intangible assets	0	0
Pension-related liability	0	0
Change in net worth	0	0

In this example, the company had a $20 million pension funding surplus at Dec. 31, 2001, and a $30 million prepaid pension asset account because, historically, its plan contributions had exceeded its accrued expense. (Under SFAS 87, there is no direct connection between the actual size of the surplus and the amount of the prepaid asset account.) During 2002, the ABO increased to $100 million (because of actuarial losses), eliminating the funding surplus. Because the plan was still fully funded at Dec. 31, 2002, however, there was no write-down of the prepaid asset account. A $30 million prepaid asset account remains, even though there is no pension funding surplus. (Had this been a $30 million intangible asset, the treatment would have been the same.)

Example 5

(Mil. $)	—Year ended Dec. 31— 2001	2002
Accumulated benefit obligation (ABO)	80	100
Plan assets	100	99
Unamortized prior service cost	0	0
Pension-related assets	—	—
Prepaid pension assets	30	30
Intangible assets	0	0
Pension-related liability	0	31
Change in net worth	0	(31)

In this example, the facts are same as in Example 4. However, apart from the increase in the ABO, there was a $1 million decrease in the value of plan assets. Thus, the plan was underfunded by $1 million at Dec. 31, 2002, relative to the ABO. The company's balance sheet must now show a $1 million net liability, the shortfall of plan assets compared with the ABO. Thus, the company must record a $31 million liability to offset the $30 million prepayment. Had the $30 million prepaid asset been an intangible asset instead, this would have been written off against equity, and only a $1 million liability would have been recorded. *All examples ignore tax effects.

could result in a huge reduction in equity. Analysts must be especially alert to the potential for a charge to equity in cases where companies have financial covenants tied to book equity levels. Yet, although the ABO is the crucial benchmark for triggering such a charge, companies are not required to disclose the ABO (except, indirectly, if a company has already had to book a minimum liability)—only the PBO.

Income-Statement Aspects

Although the PBO and ABO are subject to volatile year-to-year fluctuations, SFAS 87 was structured to minimize earnings volatility. Pension expense consists of a number of components, which can be grouped into four categories:

- Service cost. This is the value of benefits earned by active employees during the period. From an analytical perspective, this is akin to a normal operating expense;
- Interest cost. This results from the "aging" of the liability within the present-value framework. The discount rate is applied to the PBO at the beginning of the period. From an analytical perspective, this is akin to a financing charge;

- *Expected return on plan assets.* This is management's long-range expectation about the performance of the investment portfolio, rather than the actual return generated during the reporting period, based on planned asset allocations. Companies are given little guidance in the accounting literature for setting this assumption, and the assumptions used vary widely. From an analytical perspective, this is a dubious proposition at best. (Imagine if plain vanilla operating earnings were reported based on management's long-range expectations.) Moreover, as an alternative to being based on the fair value of assets at the beginning of the period, the assumed return rate can be applied instead to the market-related value of plan assets—i.e., on a basis that smoothes out market fluctuations over a period of up to five years; and
- *Amortization cost.* Any changes in the liability resulting from plan amendments are generally amortized over the expected average future service of employees who are active at the date of the amendment. In addition, any changes in the liability resulting from actual experience that is different from the assumption—beyond a threshold (i.e., 10% of either the PBO or the market-related value of plan assets, whichever is larger)— also are amortized over an extended period. Examples include shortfalls in investment performance, the effect of unanticipated early retirement programs, variances in mortality, and changes in the discount rate. From an analytical perspective, these all represent items without economic substance: all are losses or gains that have already been realized in economic—if not accounting—terms.

The reliance on expected investment returns is the element of SFAS 87 that has drawn the harshest criticism of late, as companies have clung to return assumptions that seem aggressive after three years of negative actual returns. For one thing, although these assumptions may be justifiable based on a very long-range view, minimum funding requirements under the Employee Retirement Income Security Act (ERISA) will in some instances necessitate substantial funding over much a shorter timeframe, barring a dramatic rebound in the stock market.

Separately, even without making aggressive investment return assumptions, some companies are reporting sizable net pension credits (that is, the expected return on plan assets more than offsets the other cost components), generally reflecting the significant overfunding of their pension plans. Overfunded benefits plans are a positive factor from a credit perspective. Yet, the advantages this provides may well be overstated by the credits (given, for example, the practical inability of most companies to directly revert the surplus), and Standard & Poor's takes this into account when arriving at a rating.

Under SFAS 87, all the cost components are aggregated, although from an analytical perspective, as mentioned above, the interest cost and investment returns are more appropriately viewed as financing items. In addition, the accounting literature contains no definitive guidance on how to display the pension cost on the income statement, so it is variously classified with cost of goods sold, SG&A, R&D, etc. Companies are not required to disclose how they have allocated pension cost among these accounts.

Cash-Flow Aspects

The elements of accrual accounting that make the balance sheet and income statement aspects of SFAS 87 problematic do not have the same effect on the statement of cash flows, which reverses noncash accruals and reflects only the cash flows related to the pension plan. There is no standardization regarding where pension plan contributions should be presented on the statement of cash flows, however, nor any requirement that these be identified separately. As discussed in the related article mentioned above, funding that significantly exceeds or falls short of the normal period pension cost (net of financing costs) is most appropriately viewed from an analytical perspective as a financing item, but adjusting for the distortions that otherwise can result is greatly complicated by the lack of better disclosure.

Ultimately, if a company has a significant unfunded pension liability and faces material required pension fund contributions, its funding position as defined under ERISA—rather than SFAS 87—is the most relevant

analytical consideration. Yet, companies are not specifically required by the SEC to disclose their ERISA funding positions or their expected future minimum contributions as determined under ERISA. Likewise, the contributions necessary to avoid Pension Benefit Guaranty Corp. (PBGC) variable-rate premiums, even though avoiding these can also be a powerful incentive for companies to make plan contributions.

Adjusting Financials for Postretirement Liabilities

Standard & Poor's uses certain financial adjustments and ratio definitions to help ensure that ratings on industrial companies fully reflect unfunded, defined benefit pension and other postretirement obligations, including health care obligations, retiree lump-sum payment schemes, and other forms of deferred compensation, whether partially funded or completely unfunded. If benefits-related matters are material, Standard & Poor's we will calculate capitalization and cash flow protection measures that fully reflect such unfunded benefits obligations. Also, in its analysis of profitability, Standard & Poor's will undo certain distortions that result from current accounting standards and their application.

Given the intricacies of benefits-related regulations and financial reporting, Standard & Poor's must strike a balance between what, on one hand, might seem like the most correct approach and, on the other hand, what is feasible in light of the practical limitations of the analytic process.

In any event, if benefits obligations constitute a major rating consideration, ratio analysis will not substitute for a close consideration of the issuer's particular circumstances and its benefits plans. Note: Funding and liquidity considerations may well be much more important than the financial-statement analysis matters covered here.

In approaching benefits-related adjustments and ratio calculations, the following guiding assumptions are made:

- Standard & Poor's treats unfunded pension liabilities, health care obligations, and all other forms of deferred compensation as debt-like;
- To simplify the analysis, Standard & Poor's combines all benefits plan assets and liabilities, netting a company's overfunded plans against its underfunded plans. In theory, companies with multiple plans can curtail over the long term funding of overfunded plans and direct contributions to underfunded plans. In actuality, there is often little tax incentive to fund certain plans. Also, companies have very limited practical ability to tap funding surpluses; it is even possible for companies to face onerous near-term cash contribution requirements related to certain plans while other plans are overfunded. When near-term cash requirements are the central focus, though, ratio analysis is likely to be of secondary importance; and
- Standard & Poor's emphasizes the fullest measure of the unfunded liability available. Generally, for pensions, this is the so-called projected benefit obligation (PBO) under U.S. GAAP, which takes account of the value at which the liability ultimately will be settled (including the effect of expected wage increases if the benefit is tied to employee compensation according to some formula) and views the company as a going concern. It should be noted, however, that for collectively bargained labor contracts, the PBO does not take account of expected wage increases beyond the term of the existing contract. The PBO is a broader measure than the accumulated benefit obligation (ABO) or vested benefit obligation, which instead reflects a shutdown value perspective. For postretirement medical liabilities, the measure equivalent to the pension PBO under U.S. GAAP is the accumulated postretirement benefit obligation (APBO).

Capital Structure Analysis

Standard & Poor's emphasizes the following as an important measure of capitalization:

- (total debt + unfunded benefits obligations) ÷ (total debt + unfunded benefits obligations + adjusted equity)

Unfunded benefits obligations are factored in as debt equivalents.

Given the point made above, our benefits-adjusted capitalization ratio is based on the

unfunded PBO rather than on the amount recognized on the balance sheet. There often is a substantial gap between the two, given the accounting approach of amortizing the effects of variances in investment or actuarial performance compared with assumptions, or of changes in plan benefits, over an extended period. For companies with net underfunded plans, Standard & Poor's increases or reduces the balance sheet liability to equal the unfunded PBO, with the offsets to the incremental change in the liability being to deferred tax assets (where applicable) and equity *(see table 2)*. Any transition assets, intangible assets stemming from benefits enhancements, or prepaid asset amounts are deducted from equity because Standard & Poor's believes such assets lack economic substance.

We factor benefits liabilities in on an after-tax basis, using the marginal tax rate, in countries where plan contributions—or direct payments to retirees or third-party insurers—are tax-deductible. This distinguishes benefits liabilities from debt, repayment of which does not generate tax credits. Again, the emphasis assumes the company is a going concern and can pay its taxes.

If a company is experiencing financial distress, the tax benefits related to required plan contributions are unlikely to be realized, and the analyst may then choose to exclude a tax benefit from the calculations. (In such cases, liquidity—rather than capitalization—normally would be the main area of emphasis in Standard & Poor's analysis.)

Table 2—Capitalization Adjustments

XYZ Co.*

Debt totals $1.0 billion and equity $600 million at Dec. 31, 200X. Tax rate: 33%-1/3%. Projected benefits obligation (PBO) exceeds fair value of plan assets by $1.1 billion at year-end 200X, up from $700 million at the previous year-end.

Change in benefits obligation (Mil. $)	
PBO, beginning of year	2,000.0
Current service cost	60.0
Interest cost (7% x 2,000)	140.0
Actuarial adjustments	100.0
Benefits paid	(300.0)
PBO, end of year	2,000.0
Change in plan assets	
Fair value of plan assets, beginning of year	1,300.0
Actual return on plan assets	(100.0)
Benefits paid	(300.0)
Fair value of plan assets, end of year	900.0
Unfunded PBO	1,100.0

Assuming only $800 million of the $1.1 billion unfunded accumulated benefits obligation was recognized on the balance sheet at Dec. 31, 200X, adjusted debt leverage is computed as follows:

Adjusted debt and debt-like liabilities =	Total debt + [(1 - tax rate) x (unfunded PBO)]	$1.0 bil. + (66-2/3% x $1.1 bil.) = $1.733 bil.
Adjusted equity =	Book equity - [(1 - tax rate) x (unfunded PBO - liability already recognized on balance sheet)]	$600 mil. - [66-2/3% x ($1.1 bil. - $800 mil.)] = $400 mil.
Adjusted debt and debt-like liabilities/total capitalization =		$1.733 bil./($1.733 bil. + $400 mil.) = 81.2%
This compares with unadjusted total debt to capitalization of:		$1.0 bil./($1.0 bil. + $600 mil.) = 62.5%

*XYZ Co. operates in a country where benefits plans are prefunded and plan contributions are tax-deductible. Any intangible pension asset account relating to previous service cost would be eliminated against equity. This would also be tax-effected.

Note: Given the latitude companies have under some accounting systems to choose the discount rate, and the significant sensitivity of the liability measurement to the rate used, it would in theory be desirable to normalize for different discount rate assumptions, putting all companies in the same region, with the same workforce demographics, on the same basis. This is, however, as a practical matter extremely difficult to do with any accuracy, without knowing the underlying cash flow assumptions on which the company's liability measurement are based. Standard & Poor's periodically will survey companies' disclosures to help ascertain which discount rate constitutes the norm. Where companies vary materially from the norm, Standard & Poor's will seek sensitivity information from management to facilitate the analysis.

Cash-Flow Analysis

Where benefits obligations are material, Standard & Poor's calculates the following ratio:

- Funds from operations ÷ (Total debt + unfunded benefits obligations)

The denominator is adjusted as described above. Funds from operations (FFO) is defined as net income from continuing operations plus D&A, deferred income taxes, and other non-cash items.

Standard & Poor's makes an additional adjustment to FFO for companies with unfunded benefits obligations that make

Table 3—Cash Flow Adjustment

ABC Co.*

The company makes "catch-up" plan contributions that significantly exceed period expense. Tax rate: 33-1/3%. The company had a sizable unfunded PBO at the previous year-end and contributes $400 million to benefits plan during 200X. The actual return on plan assets is $30 million.

Pension expense for 200X	**(Mil. $)**
Service cost	50
Interest cost	150
Expected return on plan assets	(140)
Amortization of previous service cost, other unrecognized gains or losses	40
Net periodic benefits cost	100

By contributing more than the combined service cost and net interest cost ($50 million + $150 million - $30 million), ABC Co. is viewed as retiring a portion of its unfunded benefits obligation. The amount of cash needed to satisfy the combined service and net interest cost is treated as a normal cash operating expense. The balance of the cash flow effect of the $400 million contribution is reclassified as a financing item.

Reported 200X statement of cash flows	
Net income	100
Adjustments for items not affecting cash from operating activities	
Depreciation	200
Deferred income taxes	50
Other	100
Funds from operations§	450

Adjustments: The $400 million contribution depressed reported FFO by $266 million: $400 million - (33-1/3% x $400 million). The tax-effected overage: [($400 million - ($50 million + $150 million - $30 million)] x (1 - 33-1/3%) = $153 million, is added back to FFO and subtracted from financing sources/uses:

Reported FFO	450
Adjustment	153
Adjusted FFO	603

*ABC Co. operates in a country where benefits plans are prefunded and plan contributions are tax-deductible. Includes ($266 million) after-tax effect of $400 million contribution. §Management input may be required to differentiate FFO effects of the contribution from the working capital effects.

"catch-up" contributions to reduce their unfunded liabilities. Otherwise, FFO would appear depressed as a result of a cash outflow that Standard & Poor's would view as a finance item (akin to debt amortization) rather than a cash operating expense. Specifically, as shown below, plan contributions that are materially greater than benefits-related service and net interest cost accrued during the period (that is, net of actual pension investment returns) are added back to FFO. (Note that this adjustment is capped at zero, given what would otherwise be the distorting effect of net positive cash inflows.)

Conversely, if the company is funding its postretirement obligations at a level substantially below its accrued expense, this may be interpreted as a form of borrowing that artificially bolsters reported cash flow from operations. Standard & Poor's also adjusts cash flow to normalize for investment return performance viewed as nonrecurring in nature, whether abnormally high or low *(see table 3)*.

Table 4—Application/Expansion of Core Earnings Framework

UVW Co.

The company used 10% in 200X as its expected return on plan assets assumption. Plan assets totaled $3.5 billion at the beginning of the year. Actual return was 2% ($70 million).

200X income statement	**(Mil. $)**
Net sales	2,000
Operating expenses	—
Pension expense	200
D&A	1,000
All other operating expenses	600
Oper. income (after D&A)	200
Interest expense	120
Pretax income	80
Pension expense for 200X	
Current service cost	50
Interest cost	300
Expected return on plan assets (10% x $3.5 bil.)	(350)
Amortization of unrecognized gains or losses	200
Net pension expense	200

The income statement would be adjusted as follows:

	As reported	**Adjustments**	**Adjusted**
Net sales	2,000		2,000
Operating expenses			
Pension expense*	200	(150)	50
D&A	1,000		1,000
All other operating expenses	600		600
EBIT	200		350
Interest expense	120	230	350
Pretax income	80		0
EBIT fixed-charge interest coverage (x)	200/120 = 1.7		350/350 = 1.0

*All but the current service cost ($50 million) are eliminated from benefits expense. Benefits-related interest cost, less the actual return on plan assets ($300 million - $70 million) is combined with other interest expense.

Profitability Analysis

In analyzing profitability (including EBITDA), as illustrated below, it is appropriate to disaggregate the benefits cost components that are combined in financial reporting and eliminate those with no economic substance, in accordance with the approach of Standard & Poor's Core Earnings framework. The so-called "service cost"—reflecting the present value of future benefits earned by employees for services rendered during the period—is viewed as an operating expense, and treated as such.

The components that represent accounting artifacts and stem from the smoothing approach of the accounting rules—e.g., amortization of variations from previous expectations regarding plan benefits, investment performance, and actuarial experience—are eliminated (consistent with the

Table 5—Profitability Adjustment for Overly Optimistic Expected Return on Plan Assets

UVW Co.

The company used 10% in 200X as its expected return on plan assets assumption. Standard & Poor's views 8% as a more realistic long-range expected annual return. Plan assets totaled $3.5 billion at the previous year-end.

200X income statement	**(Mil. $)**
Net sales	2,000
Operating expenses	—
Pension expense	200
D&A	1,000
All other operating expenses	600
Oper. income (after D&A)	200
Interest expense	120
Pretax income	80
Pension expense for 200X	
Current service cost	50
Interest cost	300
Expected return on plan assets	
(10% x $3.5 billion)*	(350)
Amortization of unrecognized gains and losses	200
Net pension expense	200

The income statement would be adjusted as follows:

	As reported	**Adjustments**	**Adjusted**
Net sales	2,000		2,000
Operating expenses			
Pension expense	200	70	270
D&A	1,000		1,000
All other operating expenses	600		600
EBIT	200		130
Interest expense	120		120
Pretax income	80		10
EBIT fixed-charge interest coverage (x)	200/120 = 1.7		130/120 = 1.1

*Under U.S. GAAP, the expected return on plan assets may not be based on the fair value of plan assets at the previous year-end, but on a "market-based value," i.e., a smoothed value averaging values of several previous years. The adjustment should always be based on the fair value of plan assets at the previous year-end. The expected return on plan assets is reduced by (10% - 8%) x $3.5 billion = $70 million, thereby increasing pension expense by $70 million.

immediate recognition of these unamortized amounts in the treatment of capitalization discussed above).

Any increase or decrease in the plan liability resulting from plan benefit changes is recognized immediately as an operating expense/credit. Interest expense, which is the result of the application of the discount rate to the PBO to "age" the liability with the passage of time, is essentially a finance charge and is reclassified as such. (As discussed above, sensitivity analysis taking account of different discount rates is appropriate.)

The expected return on plan assets also is eliminated and replaced by a much more meaningful amount: the actual return on plan assets during the reporting period. The actual return on plan assets is netted against interest expense up to the amount of the interest expense reported, but not beyond in the case of fully funded plans, as the economic benefits to be derived from such overage are limited. If the actual return is negative, though, the full amount in excess of interest expense is treated as an addition to interest expense because, unfortunately, the resulting economic detriment to the company is quite tangible *(see table 4)*.

In practice, however, the profitability measures that result from the use of this approach can be extremely volatile, with benefits-related effects often obscuring operating results. For this reason, we view such measures as supplementary. Just as in other aspects of its analysis, we look beyond changes considered temporary in nature. In approaching its conventional profitability ratios, we adjust for the effects of expected investment return assumptions that are significantly higher than the norm, where this has a material effect on reported earnings *(see table 5)*.

Moreover, we are alert to cases where companies have net pension credits that are a material source of overall earnings. Net pension credits generally reflect a healthy benefits funding picture, but such credits exaggerate the economic advantage to the company of this overfunding status and can distort period-to-period and peer comparisons.

At this time, we do not intend to recalculate its published key industrial and utility financial ratios as described here. Because most U.S. companies' pension plans were fully funded through the latter half of the 1990s, we believe such adjustments would not make a substantial difference to the published medians. If, however, current, broadly depleted funding levels persist, we will reassess the basis for statistical data. ■

Rating Methodology

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Analytical Observations Related To U.S. Pension Obligations

Summary And Conclusions

The precipitous decline in worldwide stock markets has reduced defined benefit pension plan assets and caused many pension trusts to become underfunded. Moody's is closely watching this development but expects no rating downgrades in the US at this stage based solely on pension-related issues. However, if equity values continue to decline from year-end 2002 levels, causing further deterioration of pension plan assets, there could be significant pressure on companies' cash flows and weakening of their balance sheets and profits. Under such a scenario, the decline in credit quality could lead to rating downgrades.

- In its credit analysis of pension obligations, Moody's places greatest emphasis on assessing the future cash flow requirements to fund a company's defined benefit pension plan. Through conversations with company management and our own estimates derived from available information, we seek to assess the range of probable contributions. When these required contributions appear likely to exceed a company's internal funding capabilities, or could impair the company's ability to make other critical business investments, a reassessment of the rating may be warranted.
- Statement of Financial Accounting Standards No. 87, as amended by No. 132, (collectively referred to herein as SFAS 87) governs pension accounting and disclosure for companies reporting in the US. SFAS 87 incorporates various assumptions that can lead to significant variability, year to year, in a company's reported funded status. Because these assumptions vary between companies, they can also make comparisons between companies less meaningful. In the current economic environment of very low interest rates and weak stock market performance, Moody's is now placing greater emphasis on understanding the economic realities and burden related to a company's pension liabilities.
- The most critical assumptions in pension accounting often relate to the assumed returns on pension assets and the discount rate used to assess the present value of future payments. Where assumptions appear unsustainable, Moody's analysts may require companies to undertake a sensitivity analysis using different assumptions.
- When assessing the quality of a company's earnings, Moody's continues to adjust reported profits to exclude net periodic pension income, if any. In those cases, Moody's considers the best estimate of the operating cost of the pension plan to be the service cost component.
- Moody's views underfunded pension liabilities as debt-like and incorporates them into certain adjusted leverage measurements as debt equivalents. The variability caused by changes in market values leads us to conclude that we should evaluate adjusted leverage measurements over a period of time.
- Similarly, companies taking large non-cash charges to Other Comprehensive Income (OCI) due to the severity of their underfunded pensions dramatically affects reported equity and causes large variations in leverage calculations. Moody's believes that this accounting treatment is rendering traditional balance sheet leverage analysis less meaningful, particularly on a point-in-time basis. However, such adjustments become very important if they endanger compliance with financial covenants.
- It is critical to understand how pensions can affect a company's overall credit quality, including minimum future funding requirements, alternative strategies available to meet these requirements, implications for labor relations, potential risks in maintaining covenant compliance, and potential issues affecting priority of claims.

Introduction

The funding requirements of defined benefit pension plans, as well as the accounting for them, are complex subjects that require the expertise of both actuaries and accountants. Moody's understands that the economic life of a pension plan is long-term, while changes in interest rates and return on plan assets can be volatile. Nevertheless, pension liabilities can place significant pressure on cash flows. Also, net pension liabilities generally rank equal to unsecured debt in bankruptcy, and therefore could dilute the claims of debtholders. For these reasons, Moody's considers pension liabilities to be debt-like, and failure to fully understand the nature of a company's pension obligations can result in an inaccurate assessment of credit risk.

The most readily available information on pension plan performance is disclosed in the notes to financial statements pursuant to the requirements of SFAS 87. However, this information is generally only disclosed annually, and may not be sufficiently informative. To enrich our understanding of pension obligations, Moody's relies heavily on communication with company management, other pension-related filings (e.g., Form 5500), and modeling using alternate assumptions where appropriate.

Many companies' pension plans were overfunded in the late 1990s, which meant companies were able to enjoy using more operating cash flow for investing in growth initiatives. (Contributions to overfunded plans are not tax deductible and, in fact, may be subject to an excise tax.) By the fall of 2002, the capital markets were at their lowest level in five years, and bond yields and interest rates were also at record lows. Consequently, many plans are now underfunded, and companies may soon be required to contribute cash into their plans to satisfy Employee Retirement Income Security Act of 1974 (ERISA) requirements.

Some companies are not required to make pension contributions at this time, but have announced that they will be making significant voluntary contributions in the near future. Sometimes companies make this election to accelerate a tax deduction or to avoid recognizing a pension liability with a corresponding non-cash charge to equity — required by SFAS 87 when plans are underfunded below certain levels. While such voluntary contributions may have the benefit of protecting against charges to equity and the need to make even larger payments in the future, excessive contributions could actually limit financial flexibility and be viewed negatively in the rating process.

This report summarizes Moody's observations about the credit implications of defined benefit pension plan obligations and the methodology that we use in considering those obligations into our ratings. While on a stand-alone basis underfunded pension plans will not drive the rating process, it does raise red flags as to future funding requirements and their potential impact on company cash flow. Moody's rating methodology considers the magnitude and timing of these cash requirements.

This report does not address defined contribution pension plans (such as 401(k) plans) and other postretirement employee benefit (OPEB) liabilities.

Defined Benefit Pension Obligations – Navigating The Funding Requirements

The funded status of a pension plan can be measured in several different ways. One measure is contained in the financial statements of companies sponsoring pension plans pursuant to the requirements of SFAS 87. Pension plans themselves also prepare separate financial statements as required under ERISA, and the funded status using these financial statements and the accompanying notes thereto will most likely differ from that disclosed by the employer under SFAS 87 due to differences in the assumptions used in making calculations. Last, but certainly not least, ERISA also has a "minimum funding standard for pension plans" and some "additional funding" requirements that require employers to make contributions to their pension plans depending on the funded status as calculated in the Annual Return/Report of Employee Benefit Plan on Form 5500 (Form 5500). This joint report is filed annually with ERISA, the Internal Revenue Service (IRS), and the Pension Benefit Guaranty Corporation (PBGC) for defined benefit pension plans in the US. The cash contributions are also subject to a maximum limit under the Internal Revenue Code (IRC). For purposes of credit analysis the SFAS 87 and Form 5500 information is the most available and useful.

Plan Sponsor's Financial Statements

The funded status of a pension plan as defined by SFAS 87 is derived by comparing the fair value of plan assets (FVA) to the plan's projected benefit obligation (PBO), an actuarially determined liability. If the FVA exceeds the PBO, the plan is overfunded. If the PBO exceeds the FVA, the plan is underfunded. Neither the FVA nor the PBO are recorded on the face of the financial statements of the plan sponsor, but they are disclosed in the notes to these statements.

Plan sponsors also have actuaries calculate an accumulated benefit obligation (ABO). Unlike the PBO, the ABO excludes any assumption about future compensation increases. However, when assessing a company as a going concern it is more appropriate to consider the PBO. SFAS 87 requires that employers compare the ABO to the FVA. To the extent that the ABO exceeds the FVA, employers must report the difference as a liability on their balance sheets (referred to as the "minimum liability"), often with a corresponding reduction in shareholders' equity.

Contribution Requirements Under ERISA

Plan sponsors' cash flows are impacted by their pension plans in two ways; (1) ERISA funding requirements and (2) the PBGC's "insurance" premiums.

The ERISA funding requirement has two components, (1) a minimum contribution amount that represents a "smoothed" approximation of the employer's cost of providing pension benefits to its employees, and (2) a catch-up additional funding requirement that is mandated when the pension plan's funded status falls below certain levels.

While the ERISA and IRC calculations of funded status are similar to those used for SFAS 87, ERISA uses different actuarial tables, models and assumptions. Additionally, ERISA funding requirements are calculated using data as of the beginning of the pension plan's fiscal year. For purposes of calculating the minimum contribution, actuaries measure the "current liability" (defined by the IRC) and the value of the assets in the pension plan. For the assets, either a market value or actuarial value may be used. The primary difference is that the actuarial value of the assets considers recent investment experience and allows some smoothing of the value (versus a fair market value as of one specific point in time). If the FVA is greater than the current liability, the plan is overfunded and the employer is prohibited from making contributions to the pension plan. If the plan is underfunded, then the rules become complex and the employer must not only make a minimum contribution but also determine if it has an additional funding requirement. The most common ERISA rules affecting the calculation of the pension contribution are summarized below.

- The minimum contribution required is generally equal to the "normal cost" for the year, which approximates the service cost (a component of net periodic pension cost) as disclosed under SFAS 87, plus certain adjustments related to the amortization of actuarial gains and losses, plan amendments, and credit balances or prior year funding deficiencies. Interest for the year is also included. A credit balance can exist if the employer has made excess contributions over the minimum required contribution in previous years. Credit balances can offset and defer cash contributions by the employer.
- To determine whether an additional funding requirement exists, actuaries assess the severity of underfunding. Generally, if a plan maintains assets equal to or greater than 90% of the current liability in the current year, no additional funding requirement exists. Further, if the ratio in the current year is in the 80% to 89% range, and the ratio was at least 90% in each of the two preceding years, then there is no current additional funding requirement. However, if the plan does not pass this test, referred to as the "gateway percentage", employers must make deficit reduction contributions pursuant to a formula prescribed by Section 412 of the IRC.
- Employers can choose to contribute more than the minimum, subject to the ceiling imposed by Section 412 of the IRC which establishes the maximum deduction available to employers on their tax return. Any contribution that exceeds the maximum is subject to a 10% excise tax, which for all practical purposes precludes such contributions. There is no allowable tax deduction if plans are overfunded.
- Sponsors can contribute to their plans in cash, plan sponsor stock (limited to 10% of the fair value of plan assets), or other "reasonable" investments such as stock in other companies.

Timing Of Contributions

Generally, contributions to meet the minimum funding requirements are due within 8½ months after the end of the plan year. For example, assume a plan's year-end was December 31, 2002. As previously mentioned, actuaries are required to calculate the funding requirement as of the beginning of a plan year (i.e., January 1, 2002). Once the amount of the 2002 funding is determined, the plan sponsor has until September 15, 2003 to make the contribution using an extension.

Additionally, for plans that have a funded ratio (using the current liability as defined by ERISA and the IRC) for the preceding plan year of less than 100%, ERISA accelerates the payment requirement to a quarterly basis. In general, these quarterly contributions will be based upon 90% of the amount required to be contributed for the plan year.

Pension Benefit Guaranty Corporation

Established by Title IV of ERISA, the PBGC is a federal agency formed to insure employee benefits in the event a pension plan cannot meet its obligations. When an employer sponsoring a pension plan files for bankruptcy under Chapter 7 or Chapter 11 of the US Bankruptcy Code, the debtor may seek to terminate any underfunded defined benefit plans. Therefore, the PBGC, through its insurance program, assumes an unconditional obligation to pay plan participants and beneficiaries lifetime benefits once a plan is terminated. Consequently, the PBGC may have claims against the debtor for (1) underfunding (i.e., plan asset insufficiency); and (2) unpaid contributions (i.e., sponsor's failure to fund the plan on an ongoing basis prior to termination). For purposes of credit analysis it is important to understand the potential claim of the PBGC in a bankruptcy filing as it can affect the recovery for other creditors. Generally, PBGC claims rank equal to other unsecured creditors, but in some situations can hold a priority claim.

Under ERISA, sponsors of tax qualified single-employer defined benefit pension plans must pay fixed annual premiums to the PBGC of $19 for each plan participant. Employers must pay an additional variable premium of $9 for each $1,000 of unfunded vested benefits. There is no maximum on the additional variable premium. Thus, depending on the severity of a plan's underfunded status and the number of participants, an employer could be obligated to pay a significant additional premium.

Moody's Pension Analysis Methodology

In this presentation of our methodology, we first explain how we use the SFAS 87 information along with the ERISA and IRC funding rules to estimate pension contribution requirements. Then we discuss our methodology for adjusting the balance sheet (because pension obligations are debt-like) and the income statement (to reverse much of the SFAS 87 smoothing) in our credit analysis.

Estimating Pension Contribution Requirements

Understanding a company's cash flow requirements related to their pension plan is paramount to Moody's analysis. However, the cash funding requirements are driven by ERISA and IRC rules and regulations and are actuarially determined. Since Moody's analysts usually do not have access to the company's actuaries, Moody's uses an alternative methodology that helps analysts flag large future funding requirements and the need for further analysis and discussion with management.

Although imperfect, Moody's methodology begins with the data disclosed in the notes to a plan sponsor's annual financial statements. We use this data because it is both readily available and somewhat current compared to the data in other publicly available sources.

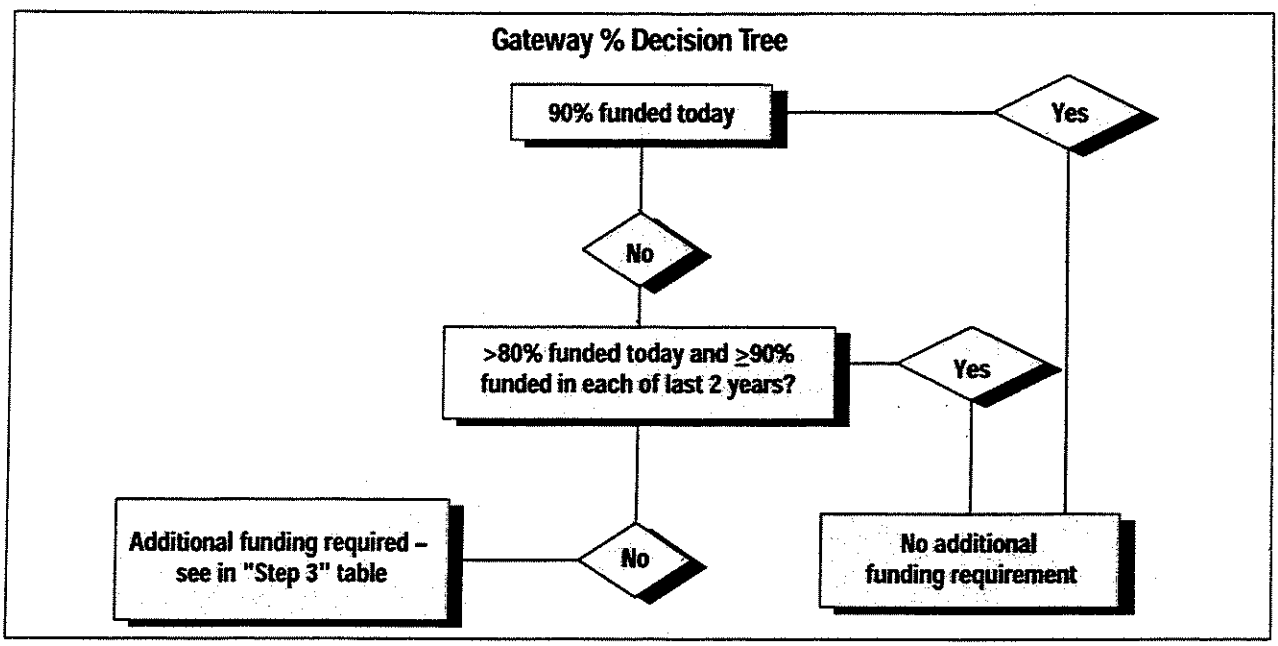
The following example demonstrates the steps analysts will take in estimating a range of possible funding requirements based on the SFAS 87 information found in a company's 10-K. The data provided is for illustrative purposes only.

Pension Data (In Millions):

	1999	2000	2001	2002
FVA	$430	$450	$440	$420
PBO	$450	$500	$550	$600
Over (under) funded:	$(20)	$(50)	$(110)	$(180)
Funded ratio (FVA/PBO)	96%	90%	80%	70%
Service Cost	$15	$17	$18	$19

Step 1 – Determine the minimum funding requirement using the SFAS 87 service cost, which will approximate the normal cost defined by ERISA and the IRC. In this case this amount would be $19 million for 2003.

Step 2 – Determine if an additional funding requirement is possible using the gateway % decision tree:



Step 3 – Determine the contribution % required to be used to calculate the additional funding requirement using the table below (created using the formula in Section 412 of the IRC):

Funding Ratio	Contribution %
90% or greater	Not required
80% to 89%	Not required if plan was funded at least 90% for each of the last two plan years
85%	20% (assume preceding year was < 90%)
80%	22% (assume preceding year was < 90%)
75%	24%
70%	26%
65%	28%
60% or less	30%

Step 4 – Calculate the additional funding requirement and the low end of the funding range by multiplying the contribution % obtained in Step 3 by the amount of the funding deficiency. The sum of the service cost and the additional funding requirement, if any, would be the estimated minimum contribution a plan sponsor would have to make.

Step 5 – The highest end of the funding range would be if the company elected to fully fund the pension plan (subject to the IRC's maximum deductible amount). Use the PBO-FVA to determine this amount.

Illustration

		Estimated funding to be paid in: 2003	2004
Data for January 1, 2002 determined from notes to the December 31, 2001 financial statements?		Yes	—
Data for January 1, 2003 determined from notes to the December 31, 2002 financial statements?		—	Yes
Step 1:	Estimated minimum funding	$18	$19
Step 2:	Additional funding		
	a) Current year at 90% or more?	No	No
	b) Current year 80 – 89 % ?	Yes	No
	c) Each of past 2 years ≥ 90%?	Yes	No
	d) Additional funding required?	No	Yes
Step 3:	What is the funding ratio? (see table above)	—	70%
	What is the required contribution %?	—	26%
Step 4:	Calculate the additional contribution (26% * $180)	—	$ 47
	What is the low end of the range?	$ 18	$ 66 ($19 + $47)
Step 5:	What is the high end of the range (assuming full funding)?	$ 110	$180

In this illustration, it is assumed that the maximum contribution (high end of the range) allowed for tax purposes is the equivalent of fully funding the plan. As demonstrated, the estimated range for possible funding requirements for 2003, based upon the December 31, 2002 SFAS 87 disclosures, could be between $66 million ($19 + $47) and the maximum of $180 million. As discussed earlier in this report under "Timing of Contributions," the actual contribution for 2003 will not have to be made by the plan sponsor until 2004 (within 8 ½ months after the end of the plan year).

However, we stress that the illustration above only gives analysts an idea of possible contribution requirements (i.e., raises red flags). Analysts will not have the actuarial information and must depend on the company to explain why ERISA or the IRC funding might be deferred. For example, if the company has a credit balance carryforward from prior years (which is not disclosed in the financial statements), it can be used to offset the contribution calculated for the current year. Additionally, Form 5500 may provide additional information to an analyst to assist them in understanding a company's funding requirements.

Form 5500

Schedule B of Form 5500 must be filed by the plan sponsor for each of its defined benefit plans subject to the minimum funding standards under ERISA. The reason we note this is that Schedule B, while somewhat complex due to the many IRC rules, is the schedule by which plan sponsors calculate their funding requirements (cash contributions). An enrolled actuary must sign and certify Schedule B.

Without going into great detail, the information that a user can obtain from reviewing Part I of Schedule B includes:

- Current value of plan assets (fair value at the beginning of the plan year)
- Actuarial value of plan assets for funding purposes; actuarial methods and assumptions used
- Information on the current liability and the expected increase due to benefits accruing during the year
- Contributions made by the employer throughout the plan year
- Amortization bases related to plan amendments, changes in actuarial assumptions, and plan experience gains or losses
- Charges and credits to the funding account
- Funded status and percentages
- Calculation of contribution necessary to avoid an accumulated funding deficiency

The information on Schedule B is useful but generally stale. Given that an employer has up to 9½ months (due 7 months after end of plan year and can be extended up to 2½ months) after the end of a plan year to file Form 5500, and that all calculations are based upon information at the *beginning* of the plan year, the information in Schedule B can be over 21 months old. The other challenge we see in using Form 5500 is that there is one form filed for each plan. Thus, analyzing the data for a company with multiple plans is not a simple process.

Adjusting The Balance Sheet

Discount Rate

The discount rate assumption has a large effect on reported pension plan funded status as it is used to compute the present value of future benefit payments. Lowering the discount rate increases the PBO. In practice, US pension plan sponsors often set the discount rate based on the yield of Moody's Aa bond index. This establishes a fairly narrow range for the discount rate. For example, in 1999, 2000, and 2001, 74%, 78%, and 86% of all companies in the Fortune 500 used discount rates within a 75 basis point range. Differences can be caused by timing, i.e., different fiscal year ends, or by the company's mix of US and foreign pension plans, since foreign plans often use a discount rate consistent with the cost of issuing debt in those countries.

When reviewing a company's pension obligation, Moody's analysts will utilize the company's sensitivity analyses when the discount rate is higher than industry averages and there is no apparent reason for the difference. An often-used rule of thumb is that a 1% change in the discount rate results in an 8 to 12% change in the PBO.

Adjustments To Debt

As discussed earlier, Moody's views the underfunded amount of the pension plan as debt-like, and thus debt will be adjusted to include the difference between the PBO and the FVA when assessing pension adjusted leverage ratios. This is broken down into two components. First, SFAS 87 requires companies to record a minimum liability on the balance sheet, which is equal to the difference between the ABO and the FVA. The second component would be the difference between the PBO and the ABO. Thus, debt will be adjusted as follows:

	Recorded Debt Per Balance Sheet
Add:	Off-balance sheet liabilities (e.g., lease obligations, guarantees)
Add:	Recorded Minimum Liability (ABO – FVA; see explanation below)
Add:	Underfunded PBO in excess of the recorded Minimum Liability (PBO – ABO)
	= Adjusted Debt

As discussed above, if the discount rate is not within a reasonable range, then sensitivity analyses using different assumptions should be made to the PBO, which would in turn change the total Adjusted Debt amount.

When the Minimum Liability is recorded, generally a charge is recorded in OCI, net of tax (assuming there is no unrecognized prior service or transition cost, in which case an intangible asset could be recorded). The charge will be increased by an existing prepaid pension asset or decreased by an existing accrued pension liability. A prepaid asset represents the excess of accumulated cash contributions made by a company over the accumulated net periodic pension expense, while an accrued pension liability is recorded when the opposite is true and the accumulated net periodic pension expense exceeds the accumulated cash contributions.

For example, if during a year a company contributed $10 million in cash to the pension plan and its net periodic pension expense was $9 million, the difference of $1 million would create a prepaid pension asset or reduce an accrued pension liability. Assume that the market performed poorly and by the end of the year the company's ABO exceeded FVA by $5 million. At this point in time, the company would have to record an adjustment to the pension liability account of $6 million which, when netted against the $1 million prepaid pension asset, would reflect a net minimum pension liability of $5 million on the balance sheet. The corresponding charge of the $6 million would go to OCI and reduce equity (again assuming no unrecognized prior service cost).

Companies can elect to have a pension valuation date (referred to as the measurement date) that is up to three months prior to their year-end. Typically, a company with a calendar year-end will use September 30 as the valuation date. This measurement date is when the FVA, ABO and PBO and funded status are determined under SFAS 87.

When a company records a minimum liability both the liability recorded and the reduction to OCI impact its leverage ratios. Therefore, companies should be prepared to discuss with analysts the impact this charge to equity has on their debt covenants or if it has any negative effects on a company's operations or cash flows (including rating triggers). Analysts recognize that the OCI charge is a non-cash charge and can be temporary; thus, analysts may evaluate their adjusted leverage ratios over time (e.g., three year average) to take into consideration the swings in equity caused by applying SFAS 87.

Adjusting The Income Statement

Expected Return On Plan Assets

Under SFAS 87, the plan sponsor chooses a rate of return on plan assets that it believes is an appropriate long-term average return. The assumed return will reflect the pension plan's investment strategy and risk tolerance as well as historical experience to some extent. Influencing asset allocation decisions, in turn, are the age and income level of the plan sponsor's workforce, the historical volatility of the company's earnings and cash flow (i.e., plan sponsors with greater variability of earnings should invest more conservatively than a more stable sponsor), and, possibly, contractual limits imposed by the company's collective bargaining agreements.

The plan sponsor should not justify its choice of an expected return based solely on historical performance. While historical investment returns are useful for predicting future results, the expected return on plan assets should take into account *prospective* portfolio management decisions and estimated future investment returns among various asset classes.

When using the expected return on assets in the analysis of future results, analysts must assess the reasonableness of the sponsor's return-on-plan-assets assumption. When a company's assumed plan asset returns appear to be too high, it should provide a sensitivity analysis of its pension expense using a range of lower rates of return. The following may indicate that the company's rate of return assumption is too high:

- The assumed rate of return is more than 200 basis points higher than the discount rate.
- The company's assumed rate of return is significantly higher than the average for other companies in its industry.
- The rate of return the company is using in the most recent year, when compared to previous years, moved in a direction contrary to its actual investment returns or overall market returns.

Adjustments To The Income Statement

Smoothing techniques and other mechanics of SFAS 87 render the net periodic pension expense less reflective of a pension plan's real economic cost. As a result, Moody's analysts adjust the pension expense number to derive a better assessment of what the true pension costs are to a company.

The following table reflects Moody's adjustments to reported pension costs:

Reported Under SFAS 87:	As Adjusted By Moody's:
Service Cost	Service cost (no adjustments)
Interest Cost	Interest cost (adjusted only if Moody's disagrees with discount rate)
Amortization of prior service cost	Not used
Recognized net actuarial gains	Not used
Amortization of transition asset	Not used
Expected return on plan assets	Actual losses on plan assets, or Actual gains up to the amount of interest cost
= Net periodic pension cost	**= Adjusted pension cost**

Service cost represents the present value of projected benefits earned by employees during the year, which Moody's considers to be an operating cost. Interest cost represents a financing cost – it is the accretion of interest (using the discount rate) on the PBO. Moody's adjusts interest cost only if we disagree with the discount rate used by the company.

Moody's believes that a company's expected return on plan assets is not relevant in measuring the actual cost related to its pension plans. Instead, pension cost should include actual gains or losses on the plan's assets due to changes in their market values during the year. However, we limit actual gains included in adjusted pension costs to the amount of interest cost, for two reasons. First, in general, plan sponsors cannot utilize the excess assets in a pension plan to satisfy non-pension related obligations (and the monetization of overfunded plan assets may give rise to significant tax penalties). Second, Moody's believes that adjusted pension cost should be no less than the service cost component as this represents the amount of benefits attributed to the employees' service in the current year.

Disclosure

SFAS 87's complexity can be a stumbling block for investors. In many ways, a company's pension plan is similar to an off-balance sheet special purpose entity (SPE). Just as an SPE may not be well understood because of a lack of disclosure, the same may apply to a company's pension plan. The lack of disclosure, or lack of understanding of how the plan truly impacts the plan sponsor, becomes an obstacle to insightful credit analysis

Moody's supports quarterly reporting and increased disclosure related to pensions in both management's discussion and analysis and in the notes to the company's financial statements, especially in the case of employers whose plans are underfunded or who have multiple plans. Examples of helpful additional disclosures include:

- Anticipated funding requirements to the pension plan and PBGC
- Separate disclosure of PBO, ABO and FVA between US and non-US defined benefit plans
- Sensitivity analysis for asset return and discount rate scenarios
- Possible contribution requirements to avoid PBGC variable rate premiums or to avoid recognizing minimum liabilities and non-cash charges to equity
- Additional trend information related to historical returns on plan assets
- Investment mix

Other Credit Rating Implications

Moody's analysts are frequently asked about the credit implications of various alternatives that issuers might elect with respect to pension funding. Because of the analytic complexity of pension issues, the rating implications of a specific action for any given company can only be assessed on a case-by-case basis. Nevertheless, the following outlines our response to common issues:

Discretionary Excess Contributions

Companies commonly accelerate contributions or make discretionary contributions of amounts ranging between the minimum requirement and the maximum amount deductible for tax purposes. Reasons for these decisions include avoiding recording minimum liabilities (with corresponding charges to equity in the balance sheet), efficient use of excess cash balances,

and ensuring that contributions are kept at a level that avoids the buildup of a severely underfunded position (and the associated unfavorable press coverage risk). Moody's views discretionary contributions favorably, especially when companies have adequate liquidity and cash flow. The magnitude of such discretionary contributions is likely to be influenced by tax law and ERISA guidelines. Nevertheless, the degree to which a company makes contributions above minimums must be considered relative to other cash flow requirements of the business. Moody's recognizes that by making discretionary contributions in the current period companies may avoid the necessity of having to make larger minimum funding requirements in future periods. In so doing, companies may preserve or even enhance financial flexibility. While such flexibility in future pension funding needs could be viewed favorably in the rating process, it would be unlikely, on its own, to warrant a higher rating outcome.

Incurring Debt To Make Discretionary Contributions

In the current low interest rate environment, companies might consider incurring debt to make discretionary contributions to their pension plans. While, as a general rule, discretionary contributions can be viewed favorably if they enhance future financial flexibility, this viewpoint would likely be tempered if the source of funds for the contribution were from new borrowings. Done in moderate amounts, such borrowings to fund discretionary pension contributions would likely be viewed as neutral to the rating — merely exchanging one form of liability for another. If done in larger amounts, Moody's would assess the degree to which an issuer's financial flexibility, debt protection measurements, and remaining borrowing capacity might be adversely affected. Such implications can only be assessed on a case-by-case basis. One of the immediate drawbacks of borrowing for this purpose is that once cash is contributed to a plan the company relinquishes it. Arguably, if in the future the plan were to be in an overfunded status, the company would be able to regain the funds to the extent it is not required to make further contributions, but this will only occur over a period of time. Thus, an excessive level of borrowing to fund pension obligations could actually limit financial flexibility. The funded status of a plan is clearly volatile — the difference between the PBO and FVA is viewed as contingent debt. Borrowing replaces the contingent debt with contractual debt and related interest charges. Consequently, we believe that while in the current economic environment borrowing to fund pension obligations may be appropriate for some companies, it could be viewed less favorably for rating purposes if done in large amounts. Companies will need to perform a thorough analysis to achieve an appropriate balance between their funding requirement and the amount to be borrowed.

Contribution Of Shares To Pension Plans

Companies can contribute their stock in lieu of cash or combined with cash to meet their funding requirement, as long as the fair value of company shares in the plan does not exceed 10% of the fair value of plan assets. Generally, the use of shares to fund pension liabilities would be viewed favorably. Indeed, to the extent the value of a company's shares appreciate after contribution, this can be a highly effective funding strategy. However, Moody's examines this issue on a case-by-case basis, with particular focus on the likely future implications for shareholder enhancement strategies. In certain situations, large pension plan holdings, outstanding stock options, and other forms of equity could lead to more aggressive share repurchase activity in the future, and would temper the ratings benefit of this funding strategy.

Seeking Deferrals Of Minimum Funding Payments

In certain circumstances, companies might elect to seek a deferral of even the minimum pension funding requirement from the appropriate regulatory authority (i.e., ERISA or the PBGC). Generally, Moody's would view deferral of minimum funding requirements negatively for rating purposes. Indeed, any company whose cash flows were insufficient to meet minimum pension needs would likely already be under rating pressure. While potentially conserving cash, the act of deferring pension contributions can involve material consequences including the need to notify workforce members (which can affect company morale), granting of security to the PBGC, or implications for other borrowing agreements. In situations where a company finds it necessary to actually defer pension contributions, Moody's would generally view the deferral as a sign of significant liquidity stress.

Other Considerations

Legislation

Pension funding pressure has been temporarily eased this year by a provision included in the government's stimulus package, the Job Creation and Worker Assistance Act of 2002. The ERISA funding requirements rely on the current liability as discussed previously. This liability is calculated using a weighted average 30-year US Treasury Bond yield to determine the discount rate. That weighted average as of January 1, 2003, was 5.1%. Prior to the passage of the temporary rules described in the next paragraph, plans could use 105% of this rate, or 5.36%, to determine their current liability. (We note that this is approximately 1.4% below an estimated 6.75% discount rate some companies may use for reporting pension results under GAAP.)

To illustrate, consider a pension plan with a $1 billion liability measured at a 6.75% discount rate for financial disclosure purposes, with $1 billion in plan assets. Using a 5.36% discount rate, the ERISA-based liability could be as much as $1.14 billion, in which case the plan would be $140 million underfunded. However, the change in the law provided by this Act allows plan sponsors to use 120% of the weighted average Treasury rate to determine the current liability for 2002 and 2003.

This increases the discount rate to 6.12% (1.2 x 5.1%) and lowers the liability to around $1.06 billion. So, using our example, this change in the law helped the company lower its ERISA underfunding by $80 million ($1.14 billion less 1.06 billion). In this example, the company's funded status is 94% under the more liberal rules of the Act rather than 88% under the old rules. This is beneficial because, as discussed earlier, ERISA's additional funding requirements are unlikely to be triggered if the funded ratio remains above 90%.

Evolving Accounting Standards

In October 2002, the FASB and the International Accounting Standards Board (IASB) announced that they were committed to converging US and international accounting standards to eliminate or reduce differences between the two, producing high-quality global reporting standards supporting the global capital markets. One of the topics identified for convergence is accounting for employee benefits.

The IASB is considering amending the international standard on pensions to eliminate some of the smoothing features, such as those found in SFAS 87, and enhancing the quality of reporting by plan sponsors. The FASB is considering whether to amend SFAS 87. Changes in reporting standards related to accounting for pensions could affect Moody's rating methodology.

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On April 15, 2003, Standard & Poor's Ratings Services placed ratings of various U.S. companies on CreditWatch with negative implications, reflecting growing concerns about increased exposure to unfunded post-retirement benefit liabilities, including defined benefit pension and retiree medical liabilities. Standard & Poor's [redacted] The companies identified had a broad decline in funding levels over the past three years, particularly in 2002.

Although utility companies were not included in the list of companies placed on CreditWatch due to unfunded post-retirement obligations, Standard & Poor's believes that the existing ratings of many utility companies have lost some flexibility due to deterioration in benefit-plan funding levels.

Capturing Pension Expenses in Rates

Regulated utility companies, unlike industrial companies operating in the competitive marketplace, usually have the luxury of collecting pension expenses in rates. These expenses are addressed when a utility files a new rate case. Among other items factored into rates, the utility assesses the level of pension expense that must be collected. If there are no variations in the pension expenses determined by the actuaries on an annual basis, then a utility's return requirement is not affected. If, however, pension expense as determined by the actuaries differs from the level collected in rates, then one of two things may happen:

- If actual pension expense is higher than the amount included in rates, then the utility may be required to expense the difference, leading to lower net income and thus a lower ROE. However, under this scenario, public utility commissions often allow utilities to defer the difference between actual pension expense and the amounts collected in rates, implying future recovery of these costs; or
- If actual pension expense is less than the amount collected in rates, then the utility may be viewed as over-earning. Under this scenario, the utility may be required to defer any overcollections, creating a regulatory liability, and return them to ratepayers over time. However, unless the utility files for new rates to reflect the pension expense overcollection, it would normally hold on to the cash collected under the assumption that it must be returned to ratepayers over time.

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Higher Pension Expense and Additional Funding

Requirements

Utility companies' benefit-plan funding levels have deteriorated over the past year from the decline in the stock market and declining interest rates. A pension's annual cost equals the current year's portion of the plan's ove obligation minus what the assets earn for the year. The plan's return equ an assumed rate of return multiplied by the multiyear rolling average value of the plan's assets. The higher an assumed return, the lower overall pension costs will be. Conversely, as assumed rates come down, costs go up. Many companies have been using assumed rates of 10%. Now, the SEC and auditors are pressing firms to reduce assumed rates to more realistic levels.

It is important to focus on how a company's revised assumed return rate level will affect various aspects of a corporation's financial profile when assessing credit quality. An additional drag on earnings comes from the gap between hypothetical and real-world investment results. Eventually, actual and assumed plan returns are reconciled through a gain or loss that is rolled into the pension cost. When the stock market was soaring and plans were assuming 10% returns, hefty windfalls resulted. Now the reverse is happening. The discount rate for pension obligations is also coming down, requiring companies to put aside more money today to cover future pension payments. Companies estimate their total future pension obligation and discount that amount back to present dollars and compare this with assets currently available. The balance is the funded status of the plan. As the discount rate drops, the current obligation total increases. The net effect of lower assumed returns and discount rates is higher pension expense and additional funding requirements.

Required new contributions to plans affect free cash flows, diverting funds otherwise spent on capital spending, debt reduction, or higher dividends. If the shortfalls and new funding requirements are significant enough, companies could face ratings downgrades. Many companies are implementing new funding requirements. Avista Corp., for example, made a $12 million contribution to its pension this year. This will ensure that the company's plan is amply funded to cover payouts of about $12 million annually.

It is important to understand the size of the overall pension obligation and funding deficit in relation to total debt and cash flows. These measures help determine how easily a company can fund the shortfall without a cash flow crisis or need for new external capital. Standard & Poor's adjusts credit ratios, such as debt to total capital and funds from operations (FFO) to total debt to reflect pension underfundings. This is because any pension shortfall is assumed to be funded with debt, thus affecting the capitalization and FFO to total debt and FFO to interest ratios. Therefore, companies facing large underfunded pension liabilities are at a significant disadvantage when compared with similar companies with better-funded retiree obligations.

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Effects on Cash Flow

Certain regulators, such as the New York Public Service Commission (NYPSC), have established policies to allow the difference between pension expense and post-retirement benefits collected in rates to be deferred in the

form of a regulatory asset. This deferral account will track all undercollections and, therefore, net income will not be affected. In addition, the regulatory asset provides the utility with a degree of certainty that costs incurred today and funded with operating cash flow will be recovered in the future. However, from a cash flow perspective, the under-collections from ratepayers will appear as reductions in operating cash flow. The utility could still file for new rates to recover the regulatory asset. Central Hudson Gas & Electric Corp., for example, has an agreement with the NYPSC to set up a deferral account to capture undercollections. The agreement runs from July 2001 through June 2003, with an option to extend the agreement by two years. Under the agreement, Central Hudson cannot raise rates until August 2004. Until then, however, the pension and post-retirement undercollections will continue to accrue with carrying charges in the deferral account.

As utility companies face increasing pension liabilities, they may face weaker financial profiles resulting from the effect of the method of collecting pension expense through rates. Weaker financial profiles may lead to revisions in a company's corporate credit rating and outlook. For example, Central Hudson Gas & Electric's outlook was revised to stable from positive to reflect a weaker-than-expected financial profile in light of, among other factors, the company's pension undercollection and its result on operating cash flow (i.e. cash from operations after changes in working capital).

For companies operating under long-term plans, or for companies that do not plan to file rate cases soon, the inability to collect the appropriate amount of pension expense in rates may lead to diminished credit-protection measures. While ROEs may appear unaffected, cash flow may suffer. However, while filing for a new rate case may be tempting, utilities must balance cash flow needs against the additional scrutiny that is often involved in full-fledged rate cases. As a result, utilities may decide to weather the current pension environment as long as they can.

When pension expenses and post-retirement benefits increase to amounts greater than what is captured in rates, utilities will end up expensing these undercollections from ratepayers. In contrast, in the case of pension expense overcollection, cash flow could appear to increase. Although increased cash flow is a positive development, more often than not, in today's environment utility companies are undercollecting pension expense. The concern in these situations is not the undercollection per se, but the need to make material and consistent cash contributions to the pension fund assets. These cash flow contributions, which are not recovered in rates, may divert cash flow intended for other purposes, necessitating borrowing to meet obligations expected to be paid through operating cash flows. For utilities with substantial capital spending needs, the problem may be compounded, leading to higher debt leverage and weakening financial profiles. Under this scenario, the utility companies have little meaningful recourse with the regulators.

Under all circumstances, Standard & Poor's computes the adjusted ratios mentioned above, especially total debt to total capital and FFO to total debt However, Standard & Poor's probes further to determine if utilities face material cash pension contributions that may affect their ongoing cash generating capacity and may lead to weakening credit-protection measures.

In addition, information about the companies' benefit plans and funding strategies, as well as the degree of conservatism used in measuring benefit plan liabilities for financial reporting purposes and management's strategies for containing benefit costs will be assessed when reviewing a company's existing rating.

Because pension accounting conventions smooth results, the underfunding problems at utility companies will persist beyond this year. Profits for many utilities will come under pressure as income from formerly overfunded pension plans falls off. Large funding deficits are negative factors for credit quality. Standard & Poor's will continue to analyze the structural nature of the pension shortfall time frame and the period over which it must be funded to fully assess the effect on a utility's credit rating.

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Standard & Poor's
Setting the Standard

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Moody's Investors Service

Global Credit Research
Rating Action
3 FEB 2003

Rating Action:

MOODY'S REPORTS: U.S. PENSION OBLIGATIONS MAY INCREASE PRESSURE ON CREDIT RATINGS

New York, February 03, 2003 -- Low interest rates accompanied by a continuing drop in U.S. defined benefit pension plan asset values due to stock market declines are increasing pension funding requirements and could pressure U.S. company cash flows to a point where downgrades are necessary, says Moody's Investors Service. However, no rating downgrades based solely on pension-related issues are expected at this time.

Moody's says that the current economic environment and underfunded status of many defined benefit pension plans demand increased scrutiny of a company's pension liabilities and costs, and funding requirements. Specifically, understanding a company's current and future cash contributions to these plans is key to Moody's analysis.

"Moody's places its greatest emphasis on assessing future cash flow requirements needed to fund companies' defined benefit pension plans," says Moody's Senior Vice President Steve Oman in a new rating methodology report on pension obligations. "When required contributions appear likely to exceed a company's internal funding capabilities, or could impair the company's ability to make critical business investments, a reassessment of the rating may be warranted."

Moody's notes that pension disclosure for U.S. companies under Statement of Financial Standards (SFAS) No. 87, as amended by SFAS No. 132, incorporates various assumptions that can lead to significant variability, year to year, in a company's funded status. SFAS 87 also contains other smoothing mechanisms that delay immediate recognition of changes in the value of a plan's net assets or liabilities and systematically recognizes these changes over time.

"While short-term volatility is prevented, the smoothing mechanisms prevent users of financial information from understanding the plan sponsor's true assets, liabilities, and costs related to its defined benefit pension plans," says Moody's Vice President/Senior Accounting Analyst Gregory D. Clifton.

When assessing the quality of a company's earnings, Moody's continues to adjust reported profits to exclude net periodic pension income, if any. Additionally, Moody's considers the best estimate of the operating cost of the pension plan to be the service cost component.

Moody's views underfunded pension liabilities as debt-like and incorporates them into certain adjusted leverage measurements as debt equivalents. Net pension liabilities generally rank equal to unsecured debt in bankruptcy, and therefore could dilute the claims of existing debt holders.

"It is critical to understand how pensions can affect a company's overall credit quality, including minimum future funding requirements, alternative strategies available to meet these requirements, implications for labor relations, potential risks in maintaining covenant compliance, and potential issues affecting priority of claims," says Clifton. "While on a stand-alone basis an underfunded status will not drive the rating process, it does raise red flags as to future funding requirements and their potential impact on company cash flow."

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STANDARD & POOR'S UTILITIES

Publication date: 31-May-2005Primary Credit Analyst(s): Barbara A Eiseman, New York (1) 212-438-7666; barbara_eiseman@standardandpoors.com
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Hawaiian Electric Company, Inc.

Major Rating Factors
Rationale
Outlook
Accounting

Corporate Credit Rating

BBB+/Negative/A-2

Business Profile

1 2 3 4 5 6 7 8 9

Financial policy:
Moderate

Debt maturities:
Hawaiian Electric Co. Inc. has no maturing long-term debt until 2012. Scheduled maturities are $57.5 million in 2012, $11.4 million in 2014, and $50 million in 2018. Remaining maturities of $636.5 million occur in 2020 and beyond.
Hawaiian Electric Industries Inc. (parent company of Hawaiian Electric Co.) has scheduled maturities of long-term debt of $37 million in 2005, $110 million in 2006, $10 million in 2007 and $50 million in 2008. Remaining maturities of $207 million occur in 2011 and beyond.

Outstanding Rating(s)

Hawaiian Electric Company, Inc.	
Sr unsecd debt	
Local currency	BBB+
CP	
Local currency	A-2
Pfd stk	
Local currency	BBB-
Hawaiian Electric Industries Inc.	
Corporate Credit Rating	BBB/Negative/A-2
Sr unsecd debt	
Local currency	BBB
CP	
Local currency	A-2
Pfd stk	
Local currency	BB+
American Savings Bank, FSB, Honolulu HI	
Corporate Credit Rating	BBB-/Stable/A-3
Certificate Of Deposit	
Local currency	BBB-/A-3
Hawaii Electric Light Company, Inc.	
Corporate Credit Rating	BBB+/Negative/--
Sr unsecd debt	
Local currency	BBB+

Maui Electric Company, Ltd.	
Corporate Credit Rating	BBB+/Negative/--
Sr unsecd debt	
Local currency	BBB+
ASB Realty Corp.	
Pfd stk	
Local currency	BB

Corporate Credit Rating History	
Nov. 16, 1990	A-/A-2
Feb. 9, 1993	BBB+/A-1

Major Rating Factors

Strengths:

- Generally responsive regulatory climate with an excellent fuel clause,
- Limited competitive threats due to the lack of interconnections and wheeling capability,
- Cultivation of strong customer relationships, with emphasis on the military,
- Little asset concentration risk, and
- Exemption from acid rain provisions of the Clean Air Act.

Weaknesses:

- Dependence on a supportive rate decision to strengthen financial condition,
- An undiversified economy, heavily reliant on the federal government, military, and tourism, which can be significantly affected by world events,
- Large purchased-power obligations,
- Dependence on imported fuel oil,
- High electric rates,
- Parent's ownership of somewhat riskier banking operations, and
- Subpar financial metrics.

Rationale

The ratings on Hawaiian Electric Co. Inc. are based on the consolidated credit profile of Hawaiian Electric Industries Inc. (HEI), which includes Hawaiian Electric's utility operations and its two island utility subsidiaries (81% of core revenues and 64% of operating income as of Dec. 31, 2004) and the riskier financial services operations of American Savings Bank FSB, which contributed 19% of core revenues and 39% of operating income as of Dec. 31, 2004. Standard & Poor's does not accord any credit uplift to ASB as a result of its affiliation with HEI.

HEI's consolidated financial condition has declined despite the strong Hawaii economy and the company's efforts in recent years to strengthen its capital structure. Consolidated financial metrics have been pressured owing to the long-term lack of rate relief and rising operating expenses. Absent a supportive rate decision in Hawaiian Electric's pending rate case, prospective key financial metrics may not support a financial profile that is commensurate with the current ratings.

HEI and Hawaiian Electric have satisfactory business profiles of '6' and '5', respectively,

(business profiles are ranked from '1' (strong) to '10' (weak)) and weak financial measures. HEI's business position is characterized by limited competitive threats due to the utility's geographic isolation, nominal stranded-asset risk, an excellent fuel clause, and steady banking operations. American Savings Bank's consistent earnings are driven by net interest income from its low-cost deposit funding and low-risk earning-asset base. These strengths are tempered by Hawaii's undiversified economy, dependence on fuel oil, significant purchased-power obligations, and support of the somewhat riskier banking businesses. Hawaiian Electric is spared the competitive threat of wholesale competition, but its market share for direct kilowatt-hour sales could contract over time because of inroads from demand-side management (currently recovered through a surcharge on customer bills), competitive bidding, and nonutility generators, including distributed generation. Hawaiian Electric's business profile is slightly stronger than that of the parent due to the absence of nonutility operations.

A responsive rate order from the Hawaii Public Utilities Commission with regard to Hawaiian Electric's pending rate case for a $98.6 million (9.9%) gross rate hike is crucial to help lift the company's key financial measures to more appropriate levels for the ratings. Although there are no time restrictions for the commission to issue a final order, an interim decision is expected by the fourth quarter of 2005. Rate relief is needed to recover the costs of reliability investments made since 1995, which have included a number of transmission upgrades, the costs associated with an additional 29 MW of firm capacity from a purchased-power contract, a new fuel oil pipeline, and energy efficiency and conservation programs.

Hawaii's economy has been growing modestly during the past several years and is expected to grow by 3.1% after inflation in 2005 and 2.7% in 2006. Military and federal government spending remains strong as the U.S. Department of Defense has moved military assets to Hawaii. The visitor industry is also a significant component of the Hawaii economy, second only to the federal government. In 2004, visitor days exceeded 2003 by 7% and the record set in 2000 by 2%. Domestic arrivals were well above record levels set in 2000 and international arrivals are starting to increase as the Japanese economy has improved. Strength in key nontourism sectors, particularly real estate and the growing military commitment, coupled with low interest rates, have resulted in solid construction and real estate sales activity although future growth in real estate may slow with rising interest rates. Hawaii's economic growth is expected to be tied primarily to the rate of expansion in the mainland U.S. and Japan economies and increased military spending, yet remains vulnerable to uncertainties in the world's geopolitical environment.

Internal cash covered nearly 70% of HEI's consolidated capital program in 2004. Assuming no new unplanned capacity additions, which may eventually be necessary to meet load growth on Oahu, internally generated funds should satisfy the bulk of construction expenditures for the next five years. Prospective construction outlays will focus predominantly on additions and improvements to transmission facilities and, to a lesser extent, on generation projects as well as energy solutions and customer-choice technologies.

HEI's bondholder protection metrics are subpar for the current ratings. Although total debt to capital (adjusted for off-balance-sheet obligations, such as purchased-power contracts, and Hawaiian Electric's $50 million trust-originated preferred securities) declined to roughly 56% as of Dec. 31, 2004 from about 58% at the end of 2003, it is still liberal for a mid 'BBB' rating. Adjusted funds from operations (FFO) interest coverage is only 3.1x, which is at the lower end of the 'BBB' category benchmark. Adjusted FFO to total debt is just 16.1%, which is commensurate with noninvestment-grade guideposts. However, with rate relief, tight cost controls, improved earnings from continued expansion of Hawaii's

economy, and HEI's other credit supportive actions, the company's overall financial condition should improve.

Hawaiian Electric's standalone financial condition is stronger than that of the parent with total debt to total capital at about 52%, including its hybrid preferred securities and adjustments for purchased-power contracts. Although the utility's adjusted FFO interest coverage is suitable for current ratings at about 3.8x, adjusted FFO to total debt is weak somewhat at approximately 20%.

In most circumstances, Standard & Poor's will not rate the debt of a wholly owned subsidiary higher than the rating of the parent. However, exceptions can be made on the basis of structural protections and/or regulatory insulation, assuming the entity has a financial profile that supports a higher rating. In Hawaiian Electric's case, Standard & Poor's believes that there are adequate insulating conditions in Hawaii's statutory and regulatory framework, including orders issued by the Hawaii Public Utilities Commission (PUC) regarding the formation of the HEI holding company structure, to separate the corporate credit ratings of HEI and Hawaiian Electric by one notch.

Short-term credit factors

The short-term corporate credit and commercial paper ratings on HEI and Hawaiian Electric are 'A-2', incorporating solid liquidity and the ability to internally fund the bulk of dividends and capital expenditures in nearby years. HEI faces a manageable maturity schedule, with $37 million due in 2005, the bulk of which matures in December. Hawaiian Electric has no maturing long-term debt until 2012. As of March 31, 2005, HEI had $14 million of cash and cash equivalents (excluding American Savings Bank's cash and cash equivalents). HEI and Hawaiian Electric had bank lines totaling $80 million and $140 million, respectively, at the end of March 2005.

Covenants in HEI's and Hawaiian Electric's lines require Hawaiian Electric to maintain a consolidated equity capitalization ratio (exclusive of short-term debt) of at least 35%. As of March 31, 2005, Hawaiian Electric's consolidated common equity to capitalization ratio was 56%. Certain HEI lines of credit totaling $20 million and $45 million require the company to maintain a consolidated net worth, exclusive of intangible assets, of at least $900 million and $850 million, respectively, which at the end of March 2005 was $1.1 billion. The line of credit agreements do not contain interest coverage ratio requirements. None of HEI's or Hawaiian Electric's lines contains material adverse change clauses or rating triggers that affect access to the facilities.

Consolidated capital outlays are expected to decline to about $193 million in 2005 from around $215 million in 2004. Roughly 75% of the 2005 construction program is expected to be internally funded. Importantly, ongoing growth in the Hawaii economy should allow the electric utility to generate relatively stable cash flows and the bank to maintain normal cash dividend levels (50% of its earnings) while still supporting its own business growth.

HEI has $150 million of debt capacity remaining under a Rule 415 shelf registration. As of March 31, 2005, proceeds of approximately $11 million from a previous sale of special purpose revenue bonds issued by the State of Hawaii's Department of Budget and Finance for the benefit of Hawaiian Electric remained undrawn.

Outlook

The negative outlook on Hawaiian Electric mirrors that of parent HEI and reflects its declining consolidated financial performance. Failure to strengthen key financial parameters, especially cash flow coverage of debt, a slump in the Hawaii economy, a

punitive rate order, and/or an erosion in American Savings Bank's creditworthiness could lead to lower ratings. Conversely, credit supportive actions by the company as well as responsive rate treatment that would enable the company to produce consolidated FFO to total debt in the lower to mid-20% range would lead to ratings stability.

Accounting

HEI reports its financial statements in accordance with U.S. GAAP. Recently adopted or pending adoption of new accounting standards did not nor are expected to have a material effect on the company's financial statements. Importantly, there was no material weakness identified by the management in its internal control over financial reporting as of Dec. 31, 2004, under Section 404 of the Sarbanes-Oxley Act.

A few of the independent power producers (IPPs) that supply power to Hawaiian Electric have declined to provide the information necessary for the company to determine the applicability of FIN 46R related to the consolidation of variable interest entities (VIES). Hence, Hawaiian Electric was unable to apply FIN 46R to these IPPs. The company's other IPPs are either not VIES or outside the purview of FIN 46R.

Standard & Poor's has made certain analytical adjustments to HEI's reported financial information to reflect off-balance-sheet obligations (OBS), such as purchased power commitments and operating leases, when calculating its adjusted financial ratios.

As of Dec. 31, 2004, Hawaiian Electric had purchased power arrangements for 529.6 MW of firm capacity. To analyze the financial impact of purchased power contracts, Standard & Poor's employs the following methodology: the net present value of future annual capacity payments (discounted at 10%) represents a potential debt equivalent—the OBS obligation that a utility incurs when it enters into an intermediate- to long-term purchased power agreement. Standard & Poor's adds to the balance sheet only a portion of this amount, recognizing that such contractual arrangements are not entirely the equivalent of debt. The percentage that is added (the risk factor) is a function of Standard & Poor's qualitative analysis of the specific contracts and the extent to which market, operating, and regulatory risks are borne by the utility. Standard & Poor's has assigned a risk factor of 30% to the company's take-and-pay contracts, which translates into a debt equivalent of $290.9 million.

The present value of the company's operating leases is determined using a 6% discount rate and is treated as a debt equivalent. Operating lease interest expense and depreciation expense are also computed. The amounts relating to operating leases that were included in HEI's adjusted ratios for 2004 were $59.8 million for OBS debt, $3.6 million for imputed interest, and $15.4 million for depreciation.

Standard & Poor's also makes an analytical adjustment for allowance for funds used during construction (AFUDC) charges capitalized by the company and treats the charges as a part of operating expenses. The AFUDC charge is backed out to arrive at cash flows from operations. Adjustments for AFUDC debt and equity in 2004 were nominal at about $2.5 million and $5.8 million, respectively.

Table 1 Hawaiian Electric Industries Inc. Peer Comparison

	--Average of past three fiscal years--			
	Hawaiian Electric Industries Inc.	Portland General Electric Co.	El Paso Electric Co.	PNM Resources Inc.

Hawaiian Electric Company, Inc.

Rating	BBB/Negative/A-2	BBB+/Developing/A-2	BBB/Stable/--	BBB/Stable/A-2
(Mil. $)				
Sales	1,786.4	1,687.0	687.7	1,409.8
Net income from cont. oper.	114.7	71.3	28.3	70.0
Funds from oper. (FFO)	270.1	296.3	146.5	266.2
Capital expenditures	167.7	175.3	87.9	184.9
Total debt	1,271.3	974.7	633.3	1,108.6
Preferred stock	34.4	9.0	0.0	12.4
Common equity	1,115.4	1,195.0	494.9	1,050.3
Total capital	2,421.2	2,178.7	1,128.2	2,175.2
Ratios				
Adj. EBIT interest coverage (x)	2.6	2.4	1.9	2.4
Adj. FFO interest coverage (x)	3.3	4.1	3.7	4.2
Adj. FFO/avg. total debt (%)	17.6	24.5	22.5	19.8
Net cash flow/capital expenditures (%)	112.9	162.5	169.8	127.9
Adj. total debt/capital (%)	58.1	49.8	56.3	57.3
Return on common equity (%)	10.1	6.0	5.1	6.4
Common dividend payout (%)	70.5	0	0	52.0

Table 2 Hawaiian Electric Industries Inc. Financial Summary

	--Years ended Dec. 31--				
	2004	2003	2002	2001	2000
Rating	BBB/Stable/A-2	BBB/Stable/A-2	BBB/Stable/A-2	BBB/Negative/A-2	BBB/Negative/A-2
(Mil. $)					
Sales	1,924.1	1,781.3	1,653.7	1,727.3	1732.3

Hawaiian Electric Company, Inc.

Net income from cont. oper.	107.7	118.0	118.2	107.7	109.3
Funds from oper. (FFO)	239.3	268.2	302.8	258.5	245.9
Capital expenditures	212.1	162.9	128.1	126.3	134.6
Total debt	1,243.3	1,264.4	1,306.3	1,345.8	1393.1
Preferred stock	34.4	34.4	34.4	34.4	34.4
Common equity	1,210.9	1,089.0	1,046.3	929.7	839.1
Total capital	2,488.7	2,387.9	2,387.0	2,309.8	2267.4
Ratios					
Adj. EBIT interest coverage (x)	2.8	2.5	2.5	2.3	2.4
Adj. FFO interest coverage (x)	3.2	3.3	3.6	3.0	2.9
Adj. FFO/avg. total debt (%)	16.0	17.8	19.0	15.9	15.1
Net cash flow/capital expenditures (%)	68.6	118.5	179.1	151.6	113.6
Adj. total debt/capital (%)	56.1	58.7	59.6	62.4	65.4
Return on common equity (%)	8.6	10.5	11.4	11.4	9.1
Common dividend payout (%)	87.1	63.6	62.1	62.2	80.8

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Hawaiian Electric Company, Inc.

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HECO RT-17
DOCKET NO. 04-0113

REBUTTAL TESTIMONY OF
LON K. OKADA

MANAGER
CORPORATE TAXES
HAWAIIAN ELECTRIC INDUSTRIES, INC.

Subject: Taxes Other Than Income Taxes
Income Tax Expense
Unamortized net SFAS 109 Regulatory Asset
Unamortized Investment Tax Credit
Accumulated Deferred Income Taxes

INTRODUCTION

Q. Please state your name and business address.

A. My name is Lon K. Okada and my business address is 900 Richards Street, Honolulu, Hawaii.

Q. Have you previously testified in these proceedings?

A. Yes, I submitted written direct testimony, exhibits and supporting workpapers as HECO T-17.

Q. What is the scope of your rebuttal testimony?

A. My rebuttal testimony will cover revisions to my original 2005 test year estimates. It will also cover the Company's rebuttal to the Consumer Advocate's ("CA") testimony CA-T-2 and the Department of Defense's ("DOD") testimony DOD-T-1 in the areas of taxes other than income taxes, income tax expense and accumulated deferred income taxes.

HECO REBUTTAL POSITION

Q. What revisions have you made to the 2005 test year estimates presented in your direct testimony?

A. My rebuttal testimony presents revised estimates in the following areas:

1) Taxes Other Than Income Taxes—The Company's estimate of taxes other than income taxes was revised due to a) an updated FICA tax as a percentage of total wages, b) an updated SUTA tax rate and c) changes in revenue taxes which were revised for test year estimates of revenues at present and proposed rates.

2) Income taxes—The Company's estimate of income taxes for the test year was revised due to a) revisions in the test year estimates of revenues and

expenses at present and proposed rates, b) revisions to the interest expense adjustment for changes in the cost of debt securities and the AFUDC adjustment and c) revisions to the State ITC amortization estimate.

3) Unamortized Investment Tax Credits—The Company revised its estimate of the Hawaii Capital Goods Excise Tax Credit to reflect changes to the 2005 test year estimate of plant additions.

4) Accumulated Deferred Income Taxes—The Company revised its estimate of deferred taxes to reflect recorded balances as of December 31, 2004 and to reflect changes in the 2005 test year estimates affecting deferred taxes. In addition, certain deferred income tax accounts were excluded in rebuttal pursuant to the inquiry and response to DOD-IR-4-4.

5) SFAS 109 Regulatory Assets and Liabilities—The Company revised its estimate of net SFAS 109 Regulatory Asset balance to reflect recorded balances as of December 31, 2004.

AREAS OF AGREEMENT

Q. In what areas of your direct testimony are the CA and DOD in agreement with the Company?

A. We agree on the following items or issues:

1) The methodology and rates used in calculating taxes other than income taxes,

2) The methodology and rates used in calculating income taxes,

3) The methodology and rates used to calculate tax credit estimates, and

4) The methodology and rates used in calculating the SFAS 109 net

regulatory asset and deferred income taxes.

MAJOR DIFFERENCES

Q. What are the major differences between the Company and the CA and DOD in the areas of your testimony?

A. The only major difference is with the DOD in its proposal to use "interest synchronization" methodology for calculating the interest expense adjustment in the income tax calculation.

TAXES OTHER THAN INCOME TAXES

Q. What is the Company's revised estimate of 2005 test year taxes other than income taxes?

A. Under present rates, the revised 2005 test year estimate of taxes other than income taxes is $113,917,000. Under proposed rates, the revised 2005 test year estimate of taxes other than income taxes is $119,498,000. See HECO-R-1701.

Q. Why has the Company revised its estimate of 2005 test year taxes other than income taxes?

A. HECO has revised its estimate due to a change in payroll tax expense for the test year and to reflect revisions to the estimated revenues for the test year.

Q. What is the revised payroll tax estimate for the 2005 test year?

A. The revised 2005 test year estimate for payroll taxes is $5,513,000, which represents a $258,000 decrease from direct testimony. The decrease is primarily attributable to a correction of the SUTA tax rate to 0% for the test year, eliminating $202,000 of payroll taxes. This correction was noted and described in my direct testimony on page 4 of HECO-T-17. Both the CA and the DOD

agree with this adjustment. The remaining decrease is for a net reduction of FICA and FUTA taxes due to a net reduction in estimated labor costs. This net reduction is comprised of 1) the removal of labor related to the DSM program, as described in HECO-RT-10, 2) the increase in labor costs related to the reorganization of the energy services organization, as described in HECO-RT-10 and 3) a reduction of labor costs due to the Standard Labor Rate Adustment, as described in HECO-RT-13.

Q. Why does the revised payroll tax expense differ from the CA's estimate at CA-T-2?

A. Although the methodology is identical, HECO's estimate is $37,000 less than the CA's estimate, which does not include the reduction in payroll tax expense related to the HECO adjustments to remove DSM labor costs and to account for increase in labor costs related to the energy services reorganization, as mentioned above. The CA made separate payroll tax expense adjustments related to its proposed labor cost adjustments, which are addressed in HECO RT-16.

Q. Why does the revised payroll tax expense differ from the DOD's estimate at DOD-T-1?

A. Although the methodology is identical, HECO's payroll tax expense is $140,000 more than the DOD's estimate due primarily to differences in the estimates of average test year employees.

Q. Why did the estimated 2005 test year revenues change?

A. Changes to test year revenues are covered in HECO-RT-3.

Q. What is the difference between HECO's revised estimate of revenue taxes and the CA's and DOD's estimates?

A. The Company's revised estimate of $108,404,000 at present rates is less than the

CA's estimate by $2,626,000 and less than the DOD's estimate by $2,638,000. The Company's revised estimate of $113,985,000 at proposed rates is greater than the CA's estimate by $870,000 and greater than the DOD's estimate by $1,232,000.

Q. Why is there a difference between the Company's and the CA's/DOD's estimates of test year revenue taxes?

A. The difference between the HECO's estimate of revenue taxes and the CA's/DOD's estimates is primarily attributable to differences in the estimated gross revenue base used to calculate revenue taxes.

INCOME TAXES

Q. What are the Company's revised 2005 test year estimates of income tax expense at present and proposed rates?

A. Under present rates, the revised 2005 test year estimate of income tax expense is $21,207,000. Under proposed rates, the revised 2005 test year estimate of income tax expense is $43,539,000. See HECO-R-1702.

Q. Why did the Company revise its estimate of income tax expense for the test year?

A. HECO revised its estimate of 2000 test year income tax expense to reflect changes in the estimated revenues and expenses used to determine operating income before taxes as discussed by the various witnesses. The Company also revised its estimate of interest expense, which is used in the calculation of income tax expense. In addition, the adjustment to income tax expense for the amortization of state ITC has been revised.

Q. Why did the HECO revise its estimate of interest expense?

A. The Company revised its estimate of interest expense to reflect changes in the estimated cost of debt securities as discussed in HECO RT-21.

Q. What is the CA's position on the interest expense adjustment in the income tax calculation?

A. The CA has adopted HECO's interest expense estimate used in rebuttal, and consequently, there is no difference between the Company and CA's interest expense estimate. The calculation is consistent with prior PUC rulings in HECO test year 1995 Docket No.7766, D & O. No.14412 issued on December 11, 1995, and HELCO test year 2000 Docket No. 99-0207, D & O. No 18365 issued on February 8, 2001.

Q. What is the DOD's position on the 2005 test year interest adjustment in the income tax calculation?

A. The DOD uses the interest synchronization method of calculating the interest expense related to operations for the income tax expense calculation. The methodology is explained in DOD-T-1, starting on page 35.

Q. What has been the PUC's position on interest synchronization?

A. As referenced above, the PUC has considered interest synchronization in the past and has consistently ruled against the adoption of this method for calculating the interest deduction for income tax calculation purposes. In D & O No.11699, Docket No. 6998, the PUC stated:

> ...the synchronization method is an imputed amount based on various components that make up the rate base. These components include both investor and noninvestor funds. The effect of any significant changes in the components or their make-up over time is unclear. Since the interest is imputed, such changes may

1 detrimentally affect the utility or its ratepayers.
2 The reasons provided by HECO for not adopting interest synchronization were
3 detailed in my rebuttal testimonies in Docket Nos. 6531 and 6998. The
4 Commission concluded that the Company's method of computing its interest
5 expense was reasonable and should be adopted. HECO asserts its methodology
6 should be adopted as was done in the past.
7 Q. Why did the Company revise its estimate for the amortization of the state capital
8 goods excise tax credit?
9 A. The Company revised its estimate to reflect differences between the estimated
10 and the actual 2004 year end balance of unamortized state capital goods excise
11 tax credit, which is the amortized base. See HECO-R-1703.
12 Q. Why are the CA's and DOD's estimates of the amortization of state capital
13 goods excise tax credit different from the Company's revised estimate?
14 A. The CA and DOD adopted the same methodology and the amount presented by
15 HECO in the direct testimony. As explained above, HECO revised its 2005 test
16 year estimate for actual 2004 year end balances, increasing amortization by
17 $8,000.
18 Q. What is the difference between the Company's estimate of income tax expense
19 for the 2005 test year and the CA's and DOD's estimates?
20 A. The Company's estimate of income tax expense under present rates for the test
21 year of $21,207,000 is $4,892,000 less than the CA's estimate of $26,099,000
22 and $5,568,000 less than the DOD's estimate of $26,775,000. The Company's
23 estimated income tax expense under proposed rates for the test year of
24 $43,539,000 is greater than the CA's estimate by $9,117,000 and greater than the
25 DOD's estimate by $9,926,000.

Q. Why are there differences between the Company's estimate of income tax expense and the CA's and DOD's estimates of income tax expense for the 2005 test year?

A. The differences for the 2005 test year are primarily due to differences in estimated revenues and expenses used to determine pre-tax operating income and interest expense which is a deduction in the calculation of income tax expense.

UNAMORTIZED NET SFAS 109 REGULATORY ASSET

Q. What is the revised estimated beginning and ending balances of the unamortized net SFAS 109 regulatory asset for the 2005 test year?

A. The revised estimated balances for the net unamortized SFAS 109 regulatory asset at the beginning and ending of the test year are $50,082,000 and $52,341,000, respectively. See HECO-R-1705.

Q. Why did HECO revise its 2005 test year estimates?

A. The balances were revised to reflect the recorded balance as of the end of 2004 and to reflect updated estimated balances for ongoing CWIP equity for the 2005 test year.

Q. What is the CA's and DOD's position on unamortized net SFAS 109 regulatory asset balances for the 2005 test year?

A. Both the CA and DOD have adopted the Company's revised estimates.

ACCUMULATED DEFERRED INCOME TAXES

Q, What is the revised estimated 2005 test year accumulated deferred income tax balances?

A. The revised beginning and ending estimated accumulated deferred income tax

("ADIT") balances for the 2005 test year are $162,290,000 and $166,863,000, respectively. See HECO-R-1704.

Q. Why did the Company revise its 2005 test year estimate of ADIT?

A. The Company revised its estimate of ADIT--1) to reflect actual recorded balances as of December 31, 2004, 2) to adjust for revisions to 2005 additions, net, and 3) to exclude certain ADIT accounts, which the Company conceded to be properly excluded as presented in our response to DOD-IR-4-4.

Q. What differences exist between the Company's revised estimate of ADIT and the CA's estimate?

A. HECO's ADIT balance at the beginning of the 2005 test year of $162,290,000 is $29,351,000 greater than the CA's estimate and the ADIT balance at the end of the 2005 test year of $166,863,000 is $35,246,000 greater than the CA's estimate.

Q. Please explain the difference at the beginning of the 2005 test year.

A. The difference between HECO's and the CA's estimates at the beginning of 2005 is the net of the following two items: 1) the ADIT related to the prepaid pension asset of $29,375,000, which the CA excluded from rate base, consistent with their treatment of the related asset and 2) the ADIT related to e-business hardware of $24,000, which HECO excluded in rebuttal but had included in the response to DOD-IR-4-4. HECO has included the ADIT on the prepaid pension asset consistent with its treatment of this asset as explained in HECO RT-16.

Q. Please explain the difference at the end of the 2005 test year.

A. The difference between HECO's and the CA's estimates at the end of the test year is again primarily due to the CA's exclusion of the ADIT on the prepaid pension asset in the amount of $27,590,000. In addition, although the CA had

adopted the Company's direct testimony estimate of ADIT on accelerated depreciation over straight line, HECO revised its estimate on rebuttal for actual 2004 balances and revised tax depreciation on estimated 2005 plant additions for a net difference of $4,864,000.

Q. What differences exist between the Company's revised estimate of ADIT and the DOD's estimate?

A. HECO's revised ADIT balance at the beginning of the 2005 test year of $162,290,000 is $29,351,000 greater than the DOD's estimate and the ADIT balance at the end of the 2005 test year of $166,863,000 is $33,431,000 greater than the DOD's estimate. The DOD's estimate for the beginning of the test year is the same as the CA's, and therefore the CA explanation above is applicable to the DOD difference.

Q. Please explain the DOD's difference at the end of the 2005 test year.

A. The difference between HECO's and the DOD's estimates at the end of the test year is again primarily due to the ADIT related to the prepaid pension asset of $27,590,000, less the e-business adjustment of $24,000, plus the ADIT related to accelerated depreciation over straight line of $4,864,000 and plus HECO's changes to All Other Items from direct to rebuttal of $1,001,000. The last difference was because the DOD used HECO's direct estimates for the ADIT related to All Other Items, excluding the prepaid pension asset.

Q. What is the significance of these differences?

A. Except for the prepaid pension asset issue, HECO, the CA and the DOD are conceptually in agreement with the calculation of ADIT, and the differences are due to the timing of receiving updated information. With respect to the prepaid pension asset, the resolution of whether it will be included in rate base will

determine the treatment of the related ADIT.

Potential ADIT Adjustment for a Change in Accounting Method

Q. What is the CA's and DOD's position regarding the potential adjustment for the change in accounting method for determining the deduction for mixed service costs?

A. Both the CA and the DOD did not propose an adjustment because the approval by the Internal Revenue Service ("IRS") and the ultimate amount of the adjustment was not determinable at the time of filing testimony.

Q. What additional information has been received by HECO regarding the status of its application for approval by the IRS?

A. The Company has not received approval for its change to the simplified service cost method, but on August 2, 2005, the IRS issued guidance interpreting the meaning of "routine and repetitive" for purposes of the simplified service cost method under the uniform capitalization rules of Sec. 263A.

Q. Why is the definition of "routine and repetitive" the focus of the IRS guidance?

A. This definition is crucial in determining the scope of applicability of the simplified service cost method. Under this tax accounting method, the mixed service costs (overhead costs), previously capitalized to eligible self-constructed property, can be reallocated between deductible operating costs and the depreciable "eligible property." As it relates to utilities, the simplified service cost method may be used only with respect to "eligible property" that is self-constructed assets produced by the taxpayer on a "routine and repetitive" basis. If interpreted broadly, the population of eligible property is larger and more mixed service costs can be reallocated from capitalized costs to deductible

1 expense. Conversely, if interpreted narrowly, less mixed service costs can be
2 reallocated to deductible expense for tax purposes.
3 Q. How did the IRS provide guidance in defining routine and repetitive?
4 A. The guidance comprises proposed and temporary regulations (T.D. 9217)
5 effective for taxable years ending on or after August 2, 2005 and Revenue Ruling
6 2005-53 that applies for all prior open years. There are some differences in the
7 guidance in the revenue ruling and the regulations, but essentially both narrowly
8 defined "routine and repetitive" in the context of utility business, and effectively
9 carve out all generation, transmission and distribution property from the eligible
10 property base.
11 Q. What criteria were used by the IRS in formulating its definition?
12 A. In its ruling, the IRS states, "For purposes of the simplified methods under Secs.
13 1.263A-1(h)(2)(i)(D) and 1.263A-2(b)(2)(i)(D), a taxpayer's self-constructed
14 assets are produced on a routine and repetitive basis in the ordinary course of
15 business if the assets are either mass-produced ...or have a high degree of
16 turnover." The mass production requirement contemplates actual equipment
17 manufacturing activity, as opposed to the installation of equipment purchased
18 from third parties. The IRS further explains that a "high degree of turnover"
19 means that the costs of production are recovered (i.e., depreciated) over a
20 relatively short period of time. They have designated three years or less to be the
21 acceptable range for this "short period of time."
22 Q. How does this definition of routine and repetitive affect HECO?
23 A. HECO does not engage in any significant manufacturing activity, as defined by
24 the IRS, and HECO's utility assets all have estimated useful lives of greater than
25 three years. Consequently, HECO would have virtually no property eligible for

1 the simplified service cost method.
2 Q. How does this impact the 2005 test year ADIT?
3 A. Based on the IRS guidance to date, 2005 test year ADIT should not include any
4 adjustment for the potential change in accounting method described above
5 because the chances of receiving a favorable adjustment and refund for prior tax
6 return liabilities is remote.
7 Q. What recourse does HECO have in terms of salvaging any benefit from this
8 change in accounting method?
9 A. The Company has not discussed the details of HECO's specific situation with its
10 consultant, but in general, there is a comment period for the proposed
11 regulations, where taxpayers and industry groups can voice their opinions on the
12 regulations. It is also conceivable that some taxpayers, who took the deduction
13 on filed returns, may appeal and eventually litigate the issue. In any case, issue
14 resolution will be an uphill battle and far into the future.
15 Q. What has the CA proposed with respect to the potential benefits of this tax
16 accounting method change?
17 A. The CA has recommended that any benefits of this method change should be
18 considered in this proceeding. However, in the event no IRS determination is
19 received prior to a decision and order in this case, the CA proposes to defer any
20 savings realized in the form of additional cost-free ADIT reserves. This would
21 be accomplished through the capitalization of a negative carrying cost, or the
22 mirror image of AFUDC.
23 Q. What is the Company's position on the CA's recommendation?
24 A. In light of the recent IRS guidance, the Company asserts that the potential for
25 any kind of adjustment to ADIT in 2005 is remote, and it is not appropriate to

1 attempt to estimate any adjustment since the amount is not determinable and the
2 probability is remote.
3 In any case, HECO does not believe that an IRS determination outside of the
4 test year should impact this proceeding. We do not know the magnitude of this
5 potential adjustment at this time, and if this status does not change, determining
6 the accounting for this item is premature. In any event, this controversy may be
7 moot in light of the IRS regulations and revenue ruling just issued.
8
9 THE AMERICAN JOBS CREATION ACT OF 2004
10 Q. Has the CA or DOD proposed any revenue requirement impact for the American
11 Jobs Creation Act of 2004?
12 A. Neither the CA nor the DOD has included any impacts of the new law. This is
13 consistent with HECO's position in this proceeding since the guidance on new
14 Section 199 has not yet been issued. As disclosed in CA-IR-690, HECO projects
15 that it would not be entitled to any deduction benefit in the test year.
16 Q. What is the CA's position on potential savings from the new Section 199?
17 A. Similar to its position on the potential ADIT reserve adjustment, the CA
18 proposes that any savings that become available between rate cases be deferred
19 for future return to ratepayers.
20 Q. What is the Company's view regarding the CA's recommendation?
21 A. The Company does not agree with the CA. The CA states that consistent and
22 symmetrical approach in granting deferral accounting authority should be
23 followed. HECO asserts that deferral accounting is neither appropriate nor
24 applicable to the "potential" tax savings from this Section 199 deduction.
25 Q. Why is deferral accounting not applicable in this case?

A. In the normal deferral situation, a cost is known and quantifiable, and it is determined that the cost benefits the Company over a period of time, or it is determined that it should be normalized to spread the impact over a period of years.

In the case of the Section 199 deduction, each tax year stands alone, depending on the annual financial results. It is an expense element of taxable income like any other expense in the test year. Therefore, deferral accounting is not appropriate in this case. Similarly, any deduction benefit in a year subsequent to the 2005 test year is not an issue for this proceeding and should be considered in future rate proceedings.

Q. Does this conclude your rebuttal testimony?

A. Yes.

HAWAIIAN ELECTRIC COMPANY, INC.
TAXES OTHER THAN INCOME TAXES CHARGED TO OPERATIONS
2005

($ Thousands)

		At present rates			
		HECO Direct	CA	DOD	HECO Rebuttal
	PAYROLL TAXES				
1	F.I.C.A. Taxes	5,511	5,492	5,315	5,456
2	Federal Unemployment Taxes	58	58	58	57
3	State Unemployment Taxes	202	0	0	0
4	Total Payroll Taxes	5,771	5,550	5,373	5,513
	REVENUE TAXES				
5	Public Service Company Taxes	58,660	73,608	73,615	71,870
6	Public Utility Fees	4,984	6,254	6,255	6,106
7	Franchise Royalty Taxes	24,818	31,168	31,172	30,428
8	Total Revenue Taxes	88,462	111,030	111,042	108,404
9	Total Taxes Other Than Income Taxes	94,233	116,580	116,415	113,917

		At proposed rates			
		HECO Direct	CA	DOD	HECO Rebuttal
	PAYROLL TAXES				
1	F.I.C.A. Taxes	5,511	5,492	5,315	5,456
2	Federal Unemployment Taxes	58	58	58	57
3	State Unemployment Taxes	202	0	0	0
4	Total Payroll Taxes	5,771	5,550	5,373	5,513
	REVENUE TAXES				
5	Public Service Company Taxes	64,463	74,990	74,751	75,580
6	Public Utility Fees	5,477	6,371	6,352	6,421
7	Franchise Royalty Taxes	27,261	31,754	31,650	31,984
8	Total Revenue Taxes	97,201	113,115	112,753	113,985
9	Total Taxes Other Than Income Taxes	102,972	118,665	118,126	119,498

HAWAIIAN ELECTRIC COMPANY, INC.
COMPUTATION OF INCOME TAX EXPENSE
2005

(In Thousands)

		At present rates				
		HECO Direct	CA	DOD	HECO Rebuttal	References
1	Total Operating Revenues	997,107	1,251,142	1,251,282	1,221,602	
	Operating Expenses:					
2	Fuel Oil and Purchased Power	591,268	817,984	817,312	794,880	
3	Other Operation & Maint Exp	183,889	148,854	148,527	157,594	
4	Depreciation & Amortization	72,056	70,690	70,730	70,731	
5	Taxes Other Than Income Taxes	94,233	116,581	116,415	113,917	HECO-R-1701
6	Other Interest, Net	378	378	378	378	
7	Total Operating Expenses	941,824	1,154,487	1,153,362	1,137,500	
8	Operating Income Before Taxes	55,283	96,655	97,920	84,102	
	Tax Adjustments:					
9	Interest Expense	(26,224)	(27,911)	(27,438)	(27,911)	HECO-RWP-1702
10	Meals & Entertainment	66	66	66	66	HECO-WP-1702, page 3
11	Total Tax Adjustments	(26,158)	(27,845)	(27,372)	(27,845)	
12	Taxable Income for Rate-Making	29,125	68,810	70,548	56,257	
13	Income Tax Expense Before Adjustments					
	(At Composite Rate of 38.9097744%)	11,332	26,774	27,450	21,889	
14	Less: State ITC Amort (Net of Taxes)	(674)	(675)	(675)	(682)	HECO-R-1703
15	TOTAL INCOME TAX EXPENSE	10,658	26,099	26,775	21,207	

		At proposed rates				
		HECO Direct	CA	DOD	HECO Rebuttal	References
16	Total Operating Revenues	1,095,721	1,274,618	1,270,592	1,284,637	
	Operating Expenses:					
17	Fuel Oil and Purchased Power	591,268	817,984	817,312	794,880	
18	Other Operation & Maint Exp	184,016	148,854	148,552	157,653	
19	Depreciation & Amortization	72,056	70,690	70,730	70,731	
20	Taxes Other Than Income Taxes	102,972	118,666	118,126	119,498	HECO-R-1701
21	Other Interest, Net	378	378	378	378	
22	Total Operating Expenses	950,690	1,156,572	1,155,098	1,143,140	
23	Operating Income Before Taxes	145,031	118,046	115,494	141,497	
	Tax Adjustments:					
24	Interest Expense	(26,224)	(27,911)	(27,438)	(27,911)	HECO-RWP-1702
25	Meals & Entertainment	66	66	66	66	HECO-WP-1702, page 3
26	Total Tax Adjustments	(26,158)	(27,845)	(27,372)	(27,845)	
27	Taxable Income for Rate-Making	118,873	90,201	88,122	113,652	
28	Income Tax Expense Before Adjustments					
	(At Composite Rate of 38.9097744%)	46,253	35,097	34,288	44,221	
29	Less: State ITC Amort (Net of Taxes)	(674)	(675)	(675)	(682)	HECO-R-1703
30	TOTAL INCOME TAX EXPENSE	45,579	34,422	33,613	43,539	

HAWAIIAN ELECTRIC COMPANY, INC.
STATE CAPITAL GOODS EXCISE TAX CREDIT
TEST YEAR 2005

(In Thousands)

			TEST YEAR 2005			
		Actual 2004	HECO Direct	CA	DOD	HECO Rebuttal
1	Beginning Balance	22,444	24,759	24,759	24,759	24,759
2	Amortizations	(996)	(1,103)	(1,103)	(1,103)	(1,117)
3	Additions	3,311	3,053	3,053	3,053	2,991
4	Ending Balance	24,759	26,709	26,709	26,709	26,633
	Net Of Tax Amounts:					
5	Amortization Before Taxes	996	1,103	1,103	1,103	1,117
6	x 100% - 37.9699% (Composite Rate)					
7	x 100% - 38.9098% (Composite Rate)	x 61.0902%	x 61.0902%	x 61.0902%	x 61.0902%	x 61.0902%
8	Amortization Of STC (Net Of Taxes)	608	674	674	674	682
9	Ending Balance Before Taxes	24,759	26,709	26,709	26,709	26,633
10	x 100% - 37.9699% (Composite Rate)					
11	x 100% - 38.9098% (Composite Rate)	**	**	**	**	**
12	Ending Balance (Net Of Taxes)	15,166	16,356	16,356	16,356	16,309
13	Average Balance (Net Of Taxes)		15,761	15,761	15,761	15,738

** Ending Balance is a blend of both 62.0301% (100%-37.9699%) and 61.0902% (100%-38.9098%)

HAWAIIAN ELECTRIC COMPANY, INC.
DEFERRED INCOME TAX BY INDIVIDUAL ITEMS
AND YEAR END BALANCES
TEST YEAR 2005

(In Thousands)

		HECO Direct	CA	DOD	HECO Rebuttal
	BALANCE AT 12/31/04				
	Accelerated Depreciation over Straight Line				
1	Federal	55,503	59,565	59,565	59,565
2	State	6,819	7,029	7,029	7,029
3	Subtotal	62,322	66,594	66,594	66,594
	All Other Items				
4	Federal	77,740	56,319	56,319	81,131
5	State	13,899	10,026	10,026	14,565
6	Subtotal	91,639	66,345	66,345	95,696
7	Total	153,961	132,939	132,939	162,290
	2005 ADDITIONS, NET				
	Accelerated Depreciation over Straight Line				
8	Federal	(4,600)	(4,600)	(4,600)	(978)
9	State	(1,134)	(1,134)	(1,134)	108
10	Subtotal	(5,734)	(5,734)	(5,734)	(870)
	All Other Items				
11	Federal	3,772	3,746	5,281	4,611
12	State	670	666	946	832
13	Subtotal	4,442	4,412	6,227	5,443
14	Total	(1,292)	(1,322)	493	4,573
	ESTIMATED BALANCE AT 12/31/05				
	Accelerated Depreciation over Straight Line				
15	Federal	50,903	54,965	54,965	58,587
16	State	5,685	5,895	5,895	7,137
17	Subtotal	56,588	60,860	60,860	65,724
	All Other Items				
18	Federal	81,512	60,065	61,600	85,742
19	State	14,569	10,692	10,972	15,397
20	Subtotal	96,081	70,757	72,572	101,139
21	Total	152,669	131,617	133,432	166,863
	AVERAGE BALANCE	**153,315**	**132,278**	**133,186**	**164,577**

Source: HECO-RWP-1704

HAWAIIAN ELECTRIC COMPANY, INC.
SFAS 109 RECONCILIATION
REGULATORY ASSETS AND LIABILITIES

(In Thousands)

	BALANCES AT 12/31/04	A HECO Direct	B CA	C DOD	D HECO Rebuttal
1	CWIP Equity Transition	1,940	1,940	1,940	1,940
2	SFAS 109 Flow Through	3,590	3,590	3,590	3,590
3	Plant Transition	21,482	21,482	21,482	21,482
4	CWIP Equity Ongoing	28,549	28,553	28,553	28,553
5	Federal ITC	(3,588)	(3,588)	(3,588)	(3,588)
6	Excess Def'd Taxes	(4,185)	(4,185)	(4,185)	(4,185)
7	Deficit Def'd Taxes	2,290	2,290	2,290	2,290
8	Total	50,078	50,082	50,082	50,082

	ESTIMATED BALANCES AT 12/31/05	E HECO Direct	F CA	G DOD	H HECO Rebuttal
9	CWIP Equity Transition	1,850	1,850	1,850	1,850
10	SFAS 109 Flow Through	3,264	3,264	3,264	3,264
11	Plant Transition	20,459	20,459	20,459	20,459
12	CWIP Equity Ongoing	31,262	30,786	30,786	30,786
13	Federal ITC	(3,006)	(3,011)	(3,011)	(3,011)
14	Excess Def'd Taxes	(3,223)	(3,223)	(3,223)	(3,223)
15	Deficit Def'd Taxes	2,218	2,216	2,216	2,216
16	Total	52,824	52,341	52,341	52,341
17	**AVERAGE BALANCE**	**51,451**	**51,212**	**51,212**	**51,212**

HECO RT-18
DOCKET NO. 04-0113

REBUTTAL TESTIMONY OF
LORIE ANN NAGATA

TREASURER
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Plant Additions, Underground Cost-sharing, Property Held for Future Use, Contributions in Aid of Construction, and Customer Advances

INTRODUCTION

Q. Please state your name and business address.

A. My name is Lorie Ann Nagata and my business address is 900 Richards Street, Honolulu, Hawaii 96813.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted written direct testimony, exhibits, and supporting workpapers as HECO T-18.

Q. What is the purpose of your rebuttal testimony?

A. In this rebuttal testimony, I will present:

1) Updated estimates for test year 2005 for:
   a) Plant Additions
   b) Cash Contributions in Aid of Construction ("CIAC")
   c) Customer Advances
2) Differences between HECO and the Consumer Advocate ("CA") and the Department of Defense ("DOD") with respect to Plant Additions, Cash CIAC, and Property Held for Future Use ("PHFFU").
3) Explanations for the Company's positions where they differ from those of the CA and DOD.

The CA uses the Company's Cash CIAC, In-Kind CIAC, Transfers from Customer Advances to CIAC, Customer Advance Receipts, and Customer Advance Refunds by incorporating the Company's estimates from its direct testimony and response to CA-IR-95 in calculating its 2005 average balances for Unamortized CIAC and Customer Advances, as shown on Exhibit CA-101, Schedule B-2.

The DOD uses the Company's updated test year 2005 average balances for

Customer Advances and Unamortized CIAC by incorporating the Company's response to DOD-IR-10-4, as shown on Exhibit DOD-108.

With respect to the Company's Underground Cost-sharing policy, the CA does not, at this time, oppose rate recovery of the additional costs incurred and included in rate base that would not have been incurred under tariff Rule 13 procedures.

PLANT ADDITIONS

Q. What is HECO's rebuttal estimate with respect to Plant Additions for the 2005 test year?

A. HECO's rebuttal estimate for Plant Additions for the 2005 test year is $109,823,000, as shown on HECO-R-1801. This is $23,380,000 lower than the direct testimony estimate of $133,203,000, as shown on HECO-1801, and $5,636,000 higher than the updated estimate provided in Attachment 6 to HECO's 2005 Test Year Rate Case – Updates filed with the CA, DOD, and the Commission on June 15, 2005 ("June 15, 2005 Transmittal").

Q. Why has HECO revised its estimate of plant additions?

A. The Company updated its capital expenditures estimates, and resulting plant addition estimates, to reflect recorded 2004 expenditures and to reflect more current information about the projects. For example, some projects are now expected to be completed earlier or later than previously scheduled, some projects have been delayed due to changes in customers' (e.g., developers, local, state, and federal government agencies) schedules, new projects have been identified, and in some cases, more recent information has led to changes in cost estimates. HECO adjusts project schedules and costs estimates to reflect this information as it

becomes available. These updated plant addition estimates were initially reflected in Attachment 6 to HECO's 2005 Test Year Rate Case – Updates filed with the CA, DOD, and the Commission on May 5, 2005 ("May 5, 2005 Transmittal").

Q. Was Attachment 6 to the May 5, 2005 Transmittal updated?

A. Yes. The following changes were made to Attachment 6 to the May 5, 2005 Transmittal and reflected in Attachment 6 to the June 15, 2005 Transmittal.

- W6 Annunciator Upgrade project (Project No. P0000682) – the estimated 2005 amount reported in the May 5, 2005 Transmittal was in error. The amount should be $499,821 instead of $49,291. This resulted in an increase in 2005 plant additions of $450,530.
- Mamala Substation project (Grandparent Y00039: Project Nos. P0000833, P0000834, and P0000835) – the in-service date was changed from 2005 to 2006, resulting in a decrease in 2005 plant additions of $3,213,279.

The impact of the W6 Annunciator Upgrade and the Mamala Substation adjustments on 2005 test year plant additions was a net reduction of $2,763,000.

Q. Has HECO updated its plant addition estimates subsequent to the June 15, 2005 Transmittal?

A. Yes. HECO's rebuttal plant addition estimate has been updated to reflect a correction for the New Kuahua Substation project (Grandparent Y00021: Projects Nos: P0000277, P0000278, P0000279, P0000280, P0000281, and P0000282). Attachment 6 to the June 15, 2005 Transmittal did not accurately reflect the expenditures for 2005, 2006, and 2007, resulting in an understatement of 2005 expenditures of $5,635,891 and an overstatement of 2006 and 2007 expenditures of $5,589,806 and $29,850, respectively. The impact of the New Kuahua Substation adjustment on the 2005 plant addition estimate for the project and the

2005 test year is an increase of $5,636,000.

Q. Is there a difference in plant addition estimates between the Company and the CA?

A. Yes. With respect to plant additions, the CA made adjustments for CHP projects and DG Substation investments which were already reflected in HECO's updated plant addition estimate provided in Attachment 6 to the June 15, 2005 Transmittal. In response to HECO/CA-IR-120, the CA confirmed that Attachment 6 excluded the CHP projects and included the DG Substation investments and will incorporate those changes in Exhibit CA-101.

Incorporating the CA's response to HECO/CA-IR-120, the CA's estimate agrees with the Company's estimate up through the estimates provided in Attachment 6 to the June 15, 2005 Transmittal. However, HECO has since updated its plant addition estimate to correct the plant addition amount for the New Kuahua Substation Project, as described above.

Q. Is there a difference in plant addition estimates between the Company and the DOD?

A. Yes, the DOD used the updated plant addition estimate HECO provided in Attachment 6 to the June 15, 2005 Transmittal by incorporating the Company's responses to DOD-IR-9-3 and DOD-IR-10-4 to calculate its December 31, 2005 year-end plant in service balance, as shown on Exhibit DOD-107. However, as described above, HECO has since updated its plant addition estimate.

Q. Does HECO's plant additions estimate take into account the settlement agreement between HECO and the Consumer Advocate concerning betterment accounting practice?

A. Yes. As discussed in the response to CA-IR-416, HECO's plant additions

estimate takes into account the settlement agreement between HECO and the Consumer Advocate in Docket No. 03-0206 to modify HECO's betterment accounting practice to be fully consistent with the NARUC Instructions (i.e., only the difference between the cost of replacement with betterment and the cost of replacement without betterment is capitalized) beginning with betterment projects commencing in 2004, which was approved by the Commission in Decision and Order No. 21738. As discussed in the response to CA-IR-416, prior to the settlement agreement, HECO had forecast to capitalize the replacement of a minor item of property that would have been expensed pursuant to Utility Plant Instructions contained in the NARUC Uniform System of Accounts, but for the fact the replacement purportedly resulted in a substantial betterment for the projects listed in the IR response. As part of the settlement agreement with the Consumer Advocate, the plant additions for the test year were reduced to reflect the portion of the projects that were expensed, and the test year production maintenance expense was increased for the portion of the costs that were expensed. As stated in the response to CA-IR-641, the Production O&M expense was increased by $490,000 for changes in betterment accounting. As discussed in the rebuttal testimony of Mr. Aaron Fujinaka, HECO RT-6, the CA agreed with the $490,000 increase to Production O&M expense in accordance with the settlement agreement, and the DOD did not include the $490,000 increase in its proposed Production O&M expense estimate. In response to HECO/DOD-IR-101, the DOD has indicated it has not taken a position on the betterment accounting change that HECO has discussed in the IR responses.

1 CASH CONTRIBUTIONS IN AID OF CONSTRUCTION

2 Q. What is HECO's revised estimate of Cash CIAC?

3 A. The revised estimate of Cash CIAC for the 2005 test year is $9,790,000, as shown
4 on HECO-R-1802, which is $4,158,000 lower than the direct testimony estimate
5 of $13,948,000, as shown on HECO-1807.

6 Q. Why has HECO revised its estimate of Cash CIAC?

7 A. The estimate was updated to reflect more current information with respect to the
8 timing of Cash CIAC for the Ford Island Substation project to be consistent with
9 the change in in-service date for the project from 2005 to 2006, as specified in the
10 response to DOD-IR-4-5. The Company now expects to receive $3,034,000 of
11 Cash CIAC for the Ford Island Substation project in 2005, with the $4,158,000
12 difference (direct testimony estimate of $7,192,000, as shown on HECO-WP-
13 1807, less rebuttal testimony estimate of $3,034,000, as shown on HECO-RWP-
14 1802) expected to be received in 2006.

15 Q. Is there a difference in Cash CIAC between the Company and the CA and DOD?

16 A. Yes. Both the CA and DOD used the Cash CIAC estimates HECO provided in
17 direct testimony and in response to DOD-IR-10-4. However, HECO has since
18 revised its Cash CIAC estimate for the Ford Island Substation Project, as
19 described above.

20

21 CUSTOMER ADVANCES

22 Q. What is HECO's revised estimate for the average balance for Customer Advances
23 for the 2005 test year?

24 A. HECO's revised estimate for the average balance for Customer Advances is
25 $1,498,000, as shown on HECO-R-1803, which is $141,000 higher than the direct

1 testimony estimate of $1,357,000, as shown on HECO-1808.

2 Q. Why has HECO revised its estimate for Customer Advances?

3 A. The estimate has been updated to only incorporate the December 31, 2004
4 recorded balance, as specified in the response to CA-IR-95 and DOD-IR-10-4.
5 The estimates for the components of Customer Advances: Receipts, Refunds, and
6 Transfers to CIAC, did not change.

7 Q. Did the CA and DOD agree with the Company's revised estimate for the average
8 balance for Customer Advances for the 2005 test year?

9 A. Yes, the CA and DOD agreed with the Company's revised estimate for Customer
10 Advances and have incorporated the revised estimate in their revenue
11 requirements as shown at Exhibit CA-101, Schedule B-2 and Exhibit DOD-103,
12 respectively.

13 AREAS OF AGREEMENT

14 Q. In what areas are the CA and DOD in agreement with the Company?

15 A. The CA and DOD agree with the Company's estimates of the following:

16 1) 2005 In-Kind CIAC: $4,729,000, as shown on HECO-R-1802;
17 2) 2005 Transfers from Customer Advances to CIAC: $48,000, as shown on
18 HECO-R-1802; and
19 3) 2005 Average Balance for Customer Advances: $1,498,000, as shown on
20 HECO-R-1803.

21 The CA and DOD have not raised any concerns with these estimates and
22 have incorporated these estimates in their revenue requirements.

23

24 UNDERGROUND COST-SHARING POLICY

25 Q. What was the CA's position with respect to rate recovery of additional costs

1 associated with HECO's underground cost-sharing policy?

2 A. At CA-T-1, pages 102-103, the CA states "Because of the current magnitude of
3 the costs (i.e., approximately $2 million) and the fact that the costs have been
4 incurred in good faith by HECO in an effort to resolve difficult issues of public
5 policy, the Consumer Advocate does not oppose rate recovery of these amounts at
6 this time. However, as such incremental facilities undergrounding costs continue
7 to accumulate under the HECO policy in the future, consideration of capping such
8 costs or refining the policy may be required to avoid excessive subsidization of
9 certain customers receiving direct benefit from HECO's sharing policy at the
10 "expense" of the general body of ratepayers." It was also noted that "...the
11 Consumer Advocate is presently in discussions with HECO to develop criteria
12 that will allow for a means by which parties can independently review the
13 application of the criteria and better assess the reasonableness of the costs
14 associated with the implementation of the new policy for future rate proceedings."
15

16 AREA OF DISAGREEMENT

17 Q. What is HECO's rebuttal estimate with respect to Property Held for Future Use?

18 A. HECO's rebuttal estimate for PHFFU for the test year 2005 is $599,000, as shown
19 on HECO-R-1804.

20 Q. What are the positions of the CA and DOD with respect to the inclusion of the
21 costs for the Kalaeloa-Barbers Point Harbor Pipeline ("Pipeline") in Property Held
22 for Future Use?

23 A. Both the CA and DOD do not agree with the Company's inclusion of $517,000
24 for the Kalaeloa-Barbers Point Harbor Pipeline in PHFFU.

25 Q. Why do the CA and DOD propose to exclude the costs for the Pipeline from

PHFFU?

A. Both the CA and DOD argue that the costs for the Pipeline should be excluded from PHFFU because the Company has no defined plan for the use or commercial operation of the property and because it has been more than ten years since the facility has been installed which is beyond the ten-year use requirement established for inclusion in PHFFU.

Q. Why should the costs for the Pipeline be included in PHFFU?

A. It is reasonable for HECO to include the costs for the Pipeline in PHFFU even though HECO does not have a defined plan for the use or commercial operation of the property and even though it has been more than ten years since the facility was installed because:

- it was constructed and installed under unique circumstances,
- it provides the Company with the opportunity to minimize future higher costs, and
- it is a minimal investment to preserve the Company's options.

Q. Please explain the unique circumstances under which the Pipeline was constructed and installed.

A. The Pipeline is different from the types of assets that are generally included in PHFFU, such as land for future substation sites. As noted in HECO T-18, page 10, and in response to CA-IR-206, the Company installed in 1991 valve hatches and the Pipeline within the Barbers Point Harbor area in conjunction with the State of Hawaii's ("State") project to place a 15-inch thick concrete slab in the laydown area adjacent to the piers. The Company recognized that unless it took steps to install the valve hatches and Pipeline at the time the State was installing the 15-inch thick concrete slab, the Company could be denied future access to the

harbor or alternatively, faced with higher costs to install future pipelines after the concrete slabs were poured.

Undertaking the project back then provided for a more economical and feasible option for the future as it will be easier and less costly to interconnect to the Pipeline than to reacquire permission from the State to access the harbor and build new pipelines now that the State has completed its work in the Barbers Point Harbor area. This minimizes future higher costs which would ultimately be absorbed by the general ratepayer. The cost to install a pipeline after the 15-inch concrete slab in the laydown area adjacent to the piers was completed would have been much higher.

Q. What are some of the options that may be available to the Company for its use of the Pipeline?

A. The Pipeline continues to be a possible gateway for imported fuel to HECO's Barbers Point Tank Farm ("BPTF") location. This option has become more attractive given the BPTF dedicated intra-system fuel transfer infrastructure which interconnects the Kahe and Waiau generating stations and Iwilei Tank Farm into a stand-alone fuel distribution system. This is enhanced with the BPTF being the site for HECO's next generating unit. HECO will then have the ability to increase the number of fuel grades or types which it can receive, store, and consume within the BPTF. In addition, the existence of the Pipeline is used in negotiations for fuel contracts with Oahu-based refineries to provide credence to the option of importing fuel oil.

Q. Should the Pipeline continue to be included in PHFFU even though it has been more than ten years since the facility has been installed, which is beyond the ten-year use requirement for inclusion in PHFFU?

A. Yes, the Pipeline should continue to be included in PHFFU. The 10-year limit on property included in PHFFU set forth in Decision and Order No. 11699 (Docket No. 6998) addressed parcels of land for future substation sites. The Pipeline is different from the parcels of land that HECO generally acquires for future substation sites which are included in PHFFU. Parcels of land where future substations may be sited are generally easier to acquire than the Pipeline which is at issue here. The Company cannot simply 'dispose' of the Pipeline and reacquire it at a later date. The ten-year period should not be applicable to the Pipeline due to the unique circumstances under which the Pipeline was constructed and installed, as described above, and because the longer-term options that it provides the Company could benefit the ratepayer.

Q. Did the CA provide an alternative ratemaking treatment for the Pipeline?

A. Yes. Even though the CA recommends that the Pipeline should be excluded from PHFFU, the CA states at CA-T-1, page 101, "Ultimately, if and when HECO may one day find a use for the facility, the Commission could hear evidence regarding equitable treatment of carrying costs that may include recovery of a deferred return on investment for any periods when the asset was excluded from rate base."

Q. Does the Company agree with this alternative ratemaking treatment for the Pipeline?

A. No. The Company believes that the Pipeline should continue to be included in PHFFU as it is a minimal investment ($517,000) that will benefit the ratepayer and, therefore, HECO's investors should be allowed to continue to earn a return on that investment.

1 SUMMARY

2 Q. Please summarize your testimony.

3 A. HECO's forecast of Plant Additions is $109,823,000 for test year 2005. The
4 average balance of Property Held for Future Use is $599,000 for the test year.
5 Estimated Cash CIAC, In-Kind CIAC, and Transfers from Customer Advances to
6 CIAC are $9,790,000, $4,729,000 (HECO-R-1802), and $48,000 (HECO-R-
7 1803), respectively for 2005. The average balance of Customer Advances is
8 $1,498,000 for the test year.

9 The Company's estimates for Plant Additions, Property Held for Future
10 Use, Contribution in Aid of Construction, and Customer Advances are reasonable
11 for test year ratemaking purposes. In addition, the Company's underground cost-
12 sharing is reasonable.

13 Q. Does this conclude your testimony?

14 A. Yes, it does.

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Hawaiian Electric Company, Inc.

2005

PLANT ADDITIONS

($ Thousands)

	2005	Reference
Projects	$60,449	HECO-RWP-1801
Programs	49,374	HECO-RWP-1801
Total	$109,823	

Hawaiian Electric Company, Inc.

2005

CONTRIBUTIONS IN AID OF CONSTRUCTION

($ Thousands)

	2005	Reference
Contributions in aid of construction:		
Cash	$ 9,790	HECO-RWP-1802
In-Kind	4,729	HECO-WP-1807
Transfers from Customer Advances	48	HECO-WP-1808

Hawaiian Electric Company, Inc.

2005

CUSTOMER ADVANCES

($ Thousands)

			Reference
Recorded balance - 12/31/04	$	1,519	DOD/HECO-IR-10-4
2005:			
Receipts		115	HECO-WP-1808
Refunds		(110)	HECO-WP-1808
Transfers to CIAC		(48)	HECO-WP-1808
Estimated balance - 12/31/05	$	1,476	DOD/HECO-IR-10-4
Average 2005 balance	$	1,498	DOD/HECO-IR-10-4

Hawaiian Electric Company, Inc.

2005

PROPERTY HELD FOR FUTURE USE

($ Thousands)

		Reference
Recorded balance - 12/31/04	$599	HECO-1806
No Estimated Changes in 2005		
Estimated balance - 12/31/05	$599	HECO-1806
2005 Average Balance	$599	DOD/HECO-IR-10-4

Hawaiian Electric Company, Inc.

2005

PROPERTY HELD FOR FUTURE USE

($ Thousands)

Name of Site	Size (Sq Ft)	Tax Map Key	Year Acquired	Proposed Service Date	Purchase Price
Kalaeloa-Barbers Point Harbor Pipeline	----	----	1991	----	$517
Waianae Substation	28,719	8-5-019:049	1997	----	$81

Reference: HECO-1806

HECO RT-19
DOCKET NO. 04-0113

REBUTTAL TESTIMONY OF
GAYLE OHASHI

DIRECTOR, FINANCIAL ANALYSIS
MANAGEMENT ACCOUNTING AND FINANCIAL SERVICES
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Rate Base

INTRODUCTION

Q. Please state your name and business address.

A. My name is Gayle T. Ohashi and I am the Director of the Financial Analysis Division at Hawaiian Electric Company, Inc. ("HECO"). My business address is 900 Richards Street, Honolulu, HI 96813.

Q. Have you previously submitted testimony in this docket?

A. Yes. I submitted written direct testimony, exhibits, and supporting workpapers as HECO T-19.

Q. What will be presented in this testimony?

A. I will present the Company's rebuttal position related to the estimated average rate base for the test year 2005 and the revised working cash calculation included in the estimated average rate base. I will also compare the Company's position to those of the Department of Defense ("DOD") and the Consumer Advocate ("CA").

HECO's REBUTTAL POSITION

Q. Has HECO made any changes to the rate base estimates presented in direct testimony?

A. Yes. The estimated average rate base for the test year 2005 is $1,109,372,000 as shown in HECO-R-1901.

Q. How does the revised estimated average rate base compare with the estimate provided in direct testimony?

A. The revised average rate base estimate is $17,695,000 more than the estimate provided in direct testimony.

CHANGES IN RATE BASE

Q. Why did the average rate base change since direct testimony?

A. The rate base estimate required adjustments to reflect recorded 2004 balances, to reflect changes in estimates of its components, and/or to correct errors.

Q. Who explains the changes in rate base components?

A. The following is a list of the witnesses who discuss rate base components in their areas.

Rate Base Component	Witness
Cost of removal Salvage Depreciation accrual	Ms. Tayne Sekimura HECO RT-16
Plant additions Property held for future use	Ms. Lorie Nagata HECO RT-18
Fuel inventory	Mr. Ross Sakuda HECO RT-4
Production inventory	Mr. Aaron Fujinaka HECO RT-6
Transmission & Distribution ("T&D") inventory	Mr. Stephen Yoshida HECO RT-8
Unamortized net Statement of Financial Accounting Standards 109 ("SFAS 109") regulatory asset	Mr. Lon Okada HECO RT-17
Prepaid pension asset	Ms. Tayne Sekimura HECO RT-16
Unamortized other postretirement employee benefits ("OPEB") regulatory asset	Ms. Gayle Ohashi HECO RT-19
Unamortized system development cost	Ms. Julie Price HECO RT-15
Unamortized contributions in aid of construction ("CIAC") Customer advances	Ms. Lorie Nagata HECO RT-18
Customer deposits	Mr. Darren Yamamoto HECO RT-9
Accumulated deferred income taxes Unamortized investment tax credits ("ITC")	Mr. Lon Okada HECO RT-17
Unamortized gain on sales	Ms. Tayne Sekimura HECO RT-16
OPEB liability	Ms. Gayle Ohashi HECO RT-19
Deferred rent expense (office building lease)	Ms. Tayne Sekimura HECO RT-16
Working cash	Ms. Gayle Ohashi HECO RT-19

NET COST OF PLANT IN SERVICE

Q. What is the revised test year estimate of the average net cost of plant in service?

A. The revised estimated average net cost of plant in service for the test year 2005 is $1, 259,111,000 as shown on HECO-R-1902.

Q. Why did the estimate of the average net cost of plant in service change?

A. The decrease in the average net cost of plant in service reflects adjustments that were made to reflect actual balances as of 12/31/04 (as presented in response to CA-IR-96) and to update some of the estimated 12/31/05 balances.

PROPERTY HELD FOR FUTURE USE

Q. What is the revised test year estimate of the average property held for future use?

A. The estimated average property held for future use for the test year 2005 is $599,000, as shown on HECO-R-1901. This estimate did not change from the estimate provided in direct testimony.

FUEL INVENTORY

Q. What is the revised test year estimate of the average fuel inventory?

A. The revised estimated average fuel inventory for the test year 2005 is $44,484,000, as shown on HECO-R-1901.

Q. Why did the estimate of the average fuel inventory change?

A. The increase in the average fuel inventory is explained by Mr. Ross Sakuda in HECO RT-4.

MATERIALS AND SUPPLIES INVENTORY

Q. What is the revised test year estimate of the average materials and supplies inventories?

A. The revised estimated average materials and supplies inventories for both production and T&D for the test year 2005 is $10,107,000, as shown on HECO-R-1901. The test year estimate includes an adjustment for the payment lag associated with the investment in inventory.

Q. Why did the estimate of the average materials and supplies inventories change?

A. The slight increase in the average materials and supplies inventories reflects the

adjustment for actual balances as of 12/31/04 (as presented in response to CA-IR-95). The estimated balances as of 12/31/05 remains the same as presented in direct testimony.

UNAMORTIZED NET SFAS 109 REGULATORY ASSET

Q. What is the revised test year estimate of the average net regulatory asset?

A. The revised estimated average unamortized net SFAS 109 regulatory asset for the test year 2005 is $51,212,000, as shown on HECO-R-1901.

Q. Why did the estimate of the average unamortized net SFAS 109 regulatory asset change?

A. The slight decrease in the average unamortized net SFAS 109 regulatory asset reflects adjustments that were made to reflect actual balances as of 12/31/04 (as presented in response to CA-IR-95) and to update some of the estimated 12/31/05 balances (as presented in response to DOD-IR-9-7).

PREPAID PENSION ASSET

Q. What is the revised test year estimate of the average prepaid pension asset?

A. The revised estimated average prepaid pension asset for the test year 2005 is $78,791,000, as shown on HECO-R-1901.

Q. Why did the estimate of the average prepaid pension asset change?

A. The increase in the average prepaid pension asset reflects adjustments that were made to reflect actual balances as of 12/31/04 (as presented in response to CA-IR-98) and to update for the revised 2005 pension estimates (as presented in response to DOD-IR-10-4).

Q. Do the CA and DOD agree with the Company regarding the inclusion of the prepaid pension asset in rate base?

A. No. Both the CA's and DOD's rate base calculations exclude the prepaid pension

asset and its related accumulated deferred income taxes from rate base.

Q. Who addresses the inclusion of the prepaid pension asset in rate base?

A. Ms. Tayne Sekimura addresses the inclusion of prepaid pension asset in rate base in HECO RT-16.

UNAMORTIZED OPEB REGULATORY ASSET

Q. What is the revised test year estimate of the average unamortized OPEB regulatory asset?

A. The estimated average unamortized OPEB regulatory asset for the test year 2005 is $9,764,000, as shown on HECO-R-1901. This estimate is the same as the estimate presented in direct testimony.

Q. Do the CA and DOD agree to the average unamortized OPEB regulatory asset balance?

A. Yes. Both the CA's and DOD's proposed rate base includes the unamortized OPEB regulatory asset balance of $9,764,000.

UNAMORTIZED SYSTEM DEVELOPMENT COSTS

Q. What is the revised test year estimate of the average unamortized system development costs?

A. There is no unamortized system development costs for the test year 2005, as shown on HECO-R-1901. In direct testimony, the estimate of unamortized system development costs related to the Human Resources Suite project. As discussed by Ms. Price in HECO RT-15, as a result of the delay in implementation of the Human Resources Suite project, this item has been removed from the test year estimates.

UNAMORTIZED CIAC

Q. What is the revised test year estimate of the average unamortized CIAC?

A. The revised estimated average unamortized CIAC for the test year 2005 is $147,864,000, as shown on HECO-R-1901.

Q. Why did the estimate of the average unamortized CIAC change?

A. The average unamortized CIAC decreased as a result of reflecting actual balances as of 12/31/04 (as presented in response to CA-IR-99), updating the 2005 amortization based on 2004 actual balances (presented in response to CA-IR-515) and updating the estimate of 2005 cash CIAC receipts. The calculation supporting the revised estimate of unamortized CIAC is shown on HECO-R-1903. The change in estimate of 2005 cash receipts is discussed by Ms. Nagata in HECO RT-18.

CUSTOMER ADVANCES

Q. What is the revised test year estimate of the average customer advances?

A. The revised estimated average customer advances for the test year 2005 is $1,498,000, as shown on HECO-R-1901.

Q. Why did the estimate of the average customer advances change?

A. The increase in the average customer advances reflects adjustments that were made to reflect actual balances as of 12/31/04 (as presented in response to CA-IR-95) and to update the estimated 12/31/05 balance as a result of the change in the 12/31/04 balance (as presented in response to DOD-IR-10-4).

CUSTOMER DEPOSITS

Q. What is the revised test year estimate of the average customer deposits?

A. The revised estimated average customer deposits for the test year 2005 is $5,901,000, as shown on HECO-R-1901.

Q. Why did the estimate of the average customer deposits change?

A. The decrease in the average customer deposits reflects the adjustment for actual

balance as of 12/31/04 (as presented in response to CA-IR-95). The estimated balance as of 12/31/05 remains the same as presented in direct testimony.

ACCUMULATED DEFERRED INCOME TAXES

Q. What is the revised test year estimate of the average accumulated deferred income taxes?

A. The revised estimated average accumulated deferred income taxes for the test year 2005 is $164,577,000, as shown on HECO-R-1901.

Q. Why did the estimate of the average accumulated deferred income taxes change?

A. The increase in the average accumulated deferred income taxes reflects adjustments that were made to reflect actual balances as of 12/31/04 and to update some of the estimated 12/31/05 balances, as discussed by Mr. Lon Okada in HECO RT-17.

UNAMORTIZED INVESTMENT TAX CREDITS

Q. What is revised test year estimate of the average unamortized investment tax credits?

A. The revised estimated average unamortized ITC for the test year 2005 is $15,738,000, as shown on HECO-R-1901.

Q. Why did the estimate of the average unamortized ITC change?

A. The slight decrease in the average unamortized ITC reflects adjustments that were made to reflect actual balances as of 12/31/04 and to update some of the estimated 12/31/05 balances, as discussed by Mr. Lon Okada in HECO RT-17.

UNAMORTIZED GAIN ON SALES

Q. What is the revised test year estimate of the average unamortized gain on sales?

A. The revised estimated average unamortized gain on sales for the test year 2005 is $1,004,000, as shown on HECO-R-1901.

Q. Why did the estimate of the average unamortized gain on sales change?

A. The increase in the average unamortized gain on sales reflects adjustments that were made to reflect actual balances as of 12/31/04 (as presented in response to CA-IR-95) and to update some of the estimated 12/31/05 balances (as presented in response to DOD-IR-10-4).

OPEB LIABILITY

Q. What is the revised test year estimate of the average OPEB Liability?

A. The revised estimated average OPEB Liability for the test year 2005 is $9,737,000, as shown on HECO-R-1901.

Q. Has HECO made any changes to the OPEB liability estimate presented in direct testimony?

A. Yes. The estimated average OPEB liability for the test year 2005 is $9,737,000 as shown in HECO-R-1901.

Q. How does the revised estimated average OPEB liability compare with the estimate provided in direct testimony?

A. The revised estimated average OPEB liability estimate is $2,000 less than the estimate provided in direct testimony.

Q. Please explain this difference.

A. The 2005 year end balance of $9,084,000 and average balance of $9,737,000 as presented in HECO-R-1901 was originally submitted in response to DOD-IR-8-5 on DOD/HECO-IR-8-5, page 6. These amounts were carried forward and used in preparing the Company rebuttal average rate base for use in the revenue requirement calculation. Subsequent to finalization of the revenue requirements and during preparation of rebuttal testimony and related exhibits, an error was discovered in the amounts presented in DOD/HECO-IR-8-5, page 6.

Q. Please describe the error.

A. In determining the ending per book balance on DOD/HECO-IR-8-5, page 6 the electric discount to retirees was erroneously included in the calculation. As described in Ms. Price's direct testimony at HECO T-15, page 11 the electric discount for retirees is not included in the test year estimate for Other Postretirement Benefits therefore, the related amount impacting OPEB liability should not be included. As a result the OPEB liability amount presented to the DOD and used in the average rate base calculation was understated by $2,000.

Q. What is the correct OPEB liability?

A. The correct 2005 year end balance should be $9,088,000 with an average estimated balance of $9,739,000. It represents no change from the amounts presented in direct testimony and shown on HECO-1901. The Company will incorporate the corrected OPEB liability estimate at the next available opportunity to determine revenue requirements.

Q. Do the CA and DOD agree to the treatment of the OPEB Liability as a deduction in the calculation of rate base?

A. Yes. Both the CA's and DOD's rate base calculation includes the OPEB Liability as a deduction to rate base. However, the CA reflects an average OPEB Liability balance of $9,739,000 as presented in HECO's direct testimony (HECO-1901), and the DOD reflects $9,737,000 as presented in HECO's response to DOD-IR-10-4.

<u>DEFERRED RENT EXPENSE</u>

Q. What is test year estimate of the average deferred rent expense?

A. The estimated average deferred rent expense for the test year 2005 is $26,000, as shown on HECO-R-1901.

Q. What is the deferred rent expense?

A. As explained by Ms. Sekimura in HECO RT-16, HECO recently executed a new operating lease agreement for the King Street office building. Under Statement of Financial Accounting Standards No. 13, "Accounting for Leases", the Company must recognize lease expense based on a straight-line calculation derived from the fixed, escalating lease payments over the term of the lease. The supporting calculation is provided on HECO-R-1607. The deferred rent expense is an obligation that results from the net impact of the straight-line lease expense related to the King Street office building lease for July to December of 2005 and the lease payments for July to December of 2005. HECO proposes to use the straight-line lease expense for ratemaking purposes, therefore to be consistent, the deferred rent expense is shown as a deduction in the rate base calculation. For income tax purposes, the tax deduction is based on actual payments rather than the book expense, therefore there is also a corresponding accumulated deferred income tax impact which is included in the accumulated deferred income tax calculation presented in HECO-RWP-1704.

Q. Was the deferred rent expense relating to rate base presented in direct testimony?

A. No. The deferred rent expense was not presented in direct testimony due to the assumptions made regarding the treatment of the King Street office building lease at the time direct testimony was prepared. However, since then, the assumptions regarding the treatment of the King Street office building lease have been revised and are further discussed by Ms. Tayne Sekimura in HECO RT-16.

POSITIONS OF THE PARTIES

Q. Are the DOD and CA in agreement with the Company on rate base in this docket?

A. No. The rate bases are different because the parties differ on:

1) the estimates of balances for the various components of rate base other than working cash;

2) the estimates of the expenses included in the working cash calculations;

3) the treatment of the prepaid pension asset in rate base; and

4) the treatment of pension and OPEB in the working cash calculation.

Q. Who addresses the differences between the DOD, CA, and HECO with respect to the estimates of balances for the various rate base components?

A. The various witnesses listed earlier in my testimony describe HECO's position and address the CA's and DOD's positions on any differing estimates of the various components of rate base.

Q. Who addresses the differences between the DOD, CA, and HECO with respect to the estimates of expenses for the working cash items?

A. The expense estimates are addressed by the HECO witnesses who present the Company's estimates of operating expenses.

Q. Who addresses the inclusion of prepaid pension asset in rate base?

A. Ms. Tayne Sekimura addresses the inclusion of prepaid pension asset in rate base in HECO-RT-19.

Q. Who addresses the treatment of pension and OPEB in the working cash calculation?

A. I will address the treatment of pension and OPEB in working cash.

<u>WORKING CASH</u>

Q. What will you address in this section of your testimony?

A. This section of my testimony will address the following:

- First, I will provide background on the working cash calculation.
- Second, I will address the treatment of pension costs in the working cash

calculation.

- Next, I will address the treatment of OPEB costs in the working cash calculation.
- Finally, I will address other changes made to the working cash calculation since the filing of my direct testimony.

Working Cash Background

Q. What is working cash?

A. Working cash is the net cash paid for expenses in advance of cash collections of revenue. Working cash can be thought of as two separate items: 1) revenue collection lag and 2) payment lag.

The Company's revised calculation of working cash for the test year is presented on HECO-R-1905, page1. This presentation format is identical to direct testimony and is the format which the Company has used in numerous rate applications. This format was used because the Company presents data in the format necessary for use in certain revenue requirement computer models.

HECO-R-1905, page 2 is a reformatted presentation of the Company's calculation of working cash presented on HECO-R-1905, page 1. The presentation on page 2 more clearly shows the revenue collection lag and payment lag components of working cash.

Q. What is the revenue collection lag?

A. The revenue collection lag is comprised of electric service provided before customers pay for services. It is representative of an average accounts receivable for billed and unbilled revenues found on the Company's balance sheet. (See line [1] on HECO-R-1905, page 2.)

Q. What is the payment lag?

A. The payment lag is comprised of goods and services received before its costs are paid. It is representative of an average accounts payable or other accrued payables that are not otherwise reflected in the determination of rate base. (See lines [2] to [13] on HECO-R-1905, page 2.) Costs can be divided into three categories:

- Items that are expensed when incurred
- Items that are recorded as assets
- Items that offset liabilities

In doing a lead-lag study, care must be taken not to overlap what is considered in the working cash study with what is considered in rate base. Careful consideration must be given to items that are recorded as assets and items that offset liabilities. If an item is captured in rate base, it does not need to be captured in working cash and visa versa, if an item is captured in working cash, it does not need to be captured in rate base. In general, assets and liabilities with expected lives over one year are captured in rate base and lags for the periods under 365 days are covered in the working cash study.

Q. Please explain how items that are expensed are handled in the working cash study.

A. These items are immediately reflected on the income statement. The accounting journal entries ("JE") would be:

JE #1	Debit	Expense
	Credit	Accounts Payable
		To record expense.
JE #2	Debit	Accounts Payable
	Credit	Cash
		To record payment.

Many operations and maintenance and administrative and general expenses will fall in this category. The payment lag would be the days between the first

transaction and the second transaction.

Q. Please explain items that are assets.

A. These items are capitalized as assets when the goods or services are received. The JEs would be:

JE #1	Debit	Asset
	Credit	Accounts Payable
		To recognize the receipt of an asset.
JE #2	Debit	Accounts Payable
	Credit	Cash
		To record payment.
JE #3	Debit	Expense
	Credit	Asset
		To record expense.

Fuel inventory is an example of an item that falls in this category. The payment lag is comprised of the period from when the fuel is received (JE #1) to when it is paid (JE #2). The asset exists in the period between JE #1 and JE #3 is recognized as a separate component of rate base.

Q. Please explain items that offset liabilities.

A. These are payments to relieve liabilities. These items have already been expensed, but have not yet been paid. Simplified accounting journal entries would be:

JE # 1	Debit	Liability
	Credit	Cash
	To record the payment of a liability.	
JE #2	Debit	Expense
	Credit	Liability
	To record a liability being incurred.	

The liability is relieved when it is paid. The payment lag is measured from the payment date to the date the liability is incurred. An example of an item in

this category is deferred income taxes. In the case of the working cash associated with income taxes, in this application, HECO assumed that the income tax expense balance was sufficiently representative of the estimate of tax payments (as evidenced by the fact that there was not much change in the beginning of year and end of year accumulated deferred tax balance). HECO based its lead-lag study of income tax payments on the fact that income tax payments are specifically identified with the tax year and we assumed that the tax expense and the tax payments were both incurred ratably over the entire year (ie. that there was no significant fluctuation in the accumulated deferred income tax balance throughout the year).

Pension Costs in Working Cash

Q. How did HECO treat pension costs in its lead-lag study?

A. HECO included its net periodic pension cost ("NPPC") estimate in the lead-lag study with a revenue collection lag days consistent with all other items (38 days in direct testimony, subsequently reduced to 37 days in rebuttal testimony) and a payment lag of zero.

Q. Why did HECO include NPPC in the revenue collection lag calculation?

A. HECO's position is that the revenues associated with NPPC are subject to the same revenue collection lag as any other item forming the basis for its revenue estimate. All revenues are subject to the revenue collection lag and pension expense should be included in the estimate of revenue collection lag. HECO does acknowledge that in the past, the Commission has disallowed the revenue collection for certain other non-cash items. However, the Company still maintains its position that all revenue should be included in the revenue collection lag; therefore HECO included the NPPC in the revenue collection lag.

1 Q. How does HECO determine its pension fund payments?
2 A. Funding policy relating to the pension fund is discussed by Ms. Price in T-15 and
3 Ms. Sekimura in RT-16. Basically, pension funding requirements under the
4 Employee Retirement Income Security Act of 1974 and the Internal Revenue
5 Code provide minimum and maximum guidelines for funding. Within the
6 minimum and maximum guidelines for funding, the Pension Investment
7 Committee of the pension plan considers other financial impacts.
8 Q. How does HECO determine its net periodic pension costs ("NPPC")?
9 A. As discussed by Ms. Price in T-15 and Ms. Sekimura in RT-16, the NPPC is
10 calculated by the actuaries in accordance with Statement of Financial Accounting
11 Standards No. 87, "Employers' Accounting for Pensions".
12 Q. How did HECO determine the payment lag of zero associated with the pension
13 fund contributions?
14 A. HECO captured all prior actual and estimated future net periodic pension costs
15 ("NPPC") and pension payments in its calculation of the beginning of test year
16 and end of test year prepaid pension asset; therefore HECO's position is that there
17 is no positive or negative payment lag associated with pension payments in the
18 working cash. As such, the lead-lag study for pension reflected a zero payment
19 lag day. Although the NPPC estimate was presented in the workpaper supporting
20 the pension payment lag, there is no expected pension contribution, therefore there
21 is actually no expected pension payment and no pension payment lag.
22 Q. What is the CA's position with respect to the pension payment in working cash?
23 A. CA witness, Mr. Brosch in CA-T-1, page 111 takes the position that HECO did
24 not conduct a cash flow study and that a study should be conducted. The CA's
25 calculations of working cash, as presented in CA-WP-101-B9, assume a 30 day

lag for pension, the same lag days as other non-labor O&M. A 30 day payment lag for pension, applied to the NPPC, decreases working cash by approximately $300,000.

Q. Did HECO conduct a study of pension cash flows?

A. Yes, we analyzed all pension payments for the period 1999 through 2004. They are shown on HECO-R-1905, page 4. The five years of pension cost and pension payment activity clearly shows that pension payments are not directly linked to any specific NPPC nor are they directly linked to costs of any specific year. It is not necessary to link the payments to specific costs, since all cash payments for the pension are properly captured by inclusion of the prepaid pension asset in rate base. It would also not be meaningful to try to directly link each payment to a specific cost, since the payments do not correspond to expenses in any particular year.

Q. What is the DOD's position with respect to the pension payment in working cash?

A. The DOD witness, Mr. Smith in DOD T-1, revised the payment lag days for O&M non-labor to apply the 30 day payment lag to pension, resulting in an increase of the O&M non-labor lag days from 29 to 30 days. In response to HECO/DOD-IR-102, Mr. Smith discusses pension as an "accrued but unpaid" expense.

Q. In this rate case, is pension an "accrued but unpaid" expense?

A. No. In this rate case, the NPPC is recognizing expense which has been prepaid. It is offsetting the prepaid pension asset. As shown on HECO-R-1905, page 5, as of the beginning of the test year, cash payments have exceeded the NPPC recognized. In the test year estimates, the NPPC accrual is properly taken into account in the prepaid pension asset calculation and the fact that there are no

anticipated payments to the pension fund have also been taken into account in the prepaid pension asset calculation. Again, by including the prepaid pension asset in rate base, all the working cash aspects of pension funding are properly accounted for.

Q. Should the cash flow impacts of the pension be captured in working cash for ratemaking purposes?

A. No, based on the current pension activity, it is not appropriate to do a working cash study for pension. The basic problem with doing a quantification through a working cash study is that working cash studies typically use historical or projected one-year periods. For pension, both the expense and the cash contributions are extremely volatile; therefore the results will be skewed depending on the period that is examined. Further, the "lag" between the expense and the cash flow can be extremely long, such that expenses and cash flow cannot be "matched", as is typically done in a working cash study. In fact, in this case, they do not match, since there are cumulative payments in excess of cumulative cost recognition (as evidenced by the prepaid pension asset balance). This would require a projection of when the net payments (or negative costs) will be matched by cost recognition, which may be many years in the future. By incorporating the prepaid pension asset (or liability if the pension had a liability balance) in rate base, the cumulative cash flow and cumulative cost recognition is properly reflected in rate base.

Q. How should the "lag" between when cash is paid to the pension trust and when NPPC is recognized be treated for ratemaking purposes?

A. Cash paid to the pension fund in advance of the recognition of pension expenses has appropriately and completely been captured by the inclusion of prepaid

1 pension asset in rate base. The inclusion of the prepaid pension asset in rate base
2 properly captures the cash flow of pension payments.
3 OPEB Costs in Working Cash
4 Q. How did HECO treat OPEB costs in its lead-lag study?
5 A. HECO included its OPEB net periodic postretirement benefit cost ("NPPBC")
6 estimate in the lead-lag study with a revenue collection lag days consistent with
7 all other items (38 days in direct testimony, subsequently reduced to 37 days in
8 rebuttal testimony) and a payment lag of zero.
9 Q. Why did HECO include OPEB NPPBC in the revenue collection lag calculation?
10 A. HECO's position is that the revenues associated with NPBC are subject to the
11 same revenue collection lag as any other item forming the basis for its revenue
12 estimate. All revenues are subject to the revenue collection lag and NPPBC
13 should be included in the estimate of revenue collection lag. As with the pension
14 expense, HECO acknowledges that in the past, the Commission has disallowed
15 the revenue collection for certain other non-cash items. However, the Company
16 still maintains its position that all revenue should be included in the revenue
17 collection lag; therefore HECO included in the NPPBC in the revenue collection
18 lag.
19 Q. How does HECO determine its OPEB trust fund payments?
20 A. As discussed by Ms. Price in T-15, as directed by the Commission in D&O No.
21 13659, HECO funds the entire postretirement costs to the maximum extent
22 possible using tax advantaged funding vehicles. Also, as indicated in response to
23 CA-IR-519, there are no mandatory contribution dates for OPEB plans.
24 Q. How does HECO determine its OPEB NPPBC?
25 A. As discussed by Ms. Price in T-15, the NPPBC is calculated by the actuaries in

accordance with Statement of Financial Accounting Standards No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions".

Q. How did HECO determine the payment lag associated with the OPEB contributions to the OPEB trust?

A. HECO captured all prior actual and estimated future OPEB NPPBC and OPEB contributions in its calculation of the OPEB liability, which is a deduction in the rate base calculation; therefore there is no payment lag associated with OPEB payments in the working cash. As such, the lead-lag study for OPEB reflected a zero payment lag day.

Q. What is the CA's position with respect to the OPEB contribution in working cash?

A. Similar to pension, CA witness, Mr. Brosch in CA-T-1, page 111 takes the position that HECO did not conduct a cash flow study and that a study should be conducted. The CA's calculations of working cash, as presented in CA-WP-101-B9, assume a 30 day lag for OPEB payments, the same lag days as other non-labor O&M. A 30 day payment lag for OPEB, applied to the test year NPPBC, decreases working cash by approximately $400,000.

Q. Did HECO conduct a study of OPEB cash flows?

A. Yes, we analyzed OPEB payments for 2003 and 2004. They are shown on HECO-R-1905, page 5. However, as I discussed, since all the cash flow impacts of OPEB payments are captured in the adjustment to rate base for the OPEB liability, the correct payment lag for OPEB payments in the working cash study is zero.

Q. What is the DOD's position with respect to the OPEB contribution in working cash?

A. Similar to his proposed treatment of pension payments, DOD witness, Mr. Smith

in DOD T-1, revised the payment lag days for O&M non-labor to apply the 30 day payment lag to OPEB, resulting in an increase of the O&M non-labor lag days from 29 to 30 days. In response to HECO/DOD-IR-102, Mr. Smith discusses OPEB as an "accrued but unpaid" expense.

Q. Is OPEB an "accrued but unpaid" expense?

A. Yes. In this case, OPEB is an accrued but unpaid expense as shown by the fact that it is a liability, "OPEB Liability". In the test year, costs of $6.1 million ($7 million NPBC less executive life of $900,000) are less than expected payments of $7.4 million; therefore the OPEB Liability balance will decline in the test year.

Q. How should the "lag" between when OPEB NPPBC is recognized and when cash paid to the OPEB trust be treated for ratemaking purposes?

A. Cash paid to the OPEB trust has appropriately and completely been captured in the Company's estimate of OPEB Liability. By deducting the OPEB Liability in the calculation of rate base, there is no need to include any payment lag in working cash.

<u>Changes in Working Cash</u>

Q. Was there any change in HECO's estimate of working cash?

A. Yes. The revised estimate of working cash is $10,107,000 at present rates and $1,648,000 at proposed rates as shown on HECO-R-1905, page 1.

Q. Why did the estimated working cash change?

A. The change to the working cash estimate was due to a change in the revenue collection lag days, a change in the fuel payment lag days, a change in the O&M labor payment lag days, and changes in the estimates of annual expense amounts.

Q. Why did the revenue collection lag days change?

A. The revenue collection lag day change from 38 days in direct testimony to 37 days

in rebuttal is discussed by Mr. Darren Yamamoto in HECO RT-9.

Q. Do the CA and DOD agree to the change in the revenue collection lag days?

A. Yes. Both the CA's and DOD's working cash calculation in their testimony utilized the 37 days for the revenue collection lag.

Q. Why was there a change to the fuel payment lag days?

A. The fuel payment lag days was revised from 12 days in direct testimony to 16 days in rebuttal, as shown on HECO-R-1905, page 1, column B. The fuel payment lag revision was previously identified in HECO's response to CA-IR-524.

Q. Do the CA and DOD agree to the change in the fuel payment lag days?

A. Yes. Both the CA's and DOD's working cash calculation in their testimony utilized the 16 days for the fuel payment lag.

Q. Why did the O&M labor payment lag days change?

A. The O&M labor payment lag days was revised from 12 days in direct testimony to 11 days in rebuttal, as shown on HECO-R-1905, page 1, column B. The O&M labor payment lag revision was previously identified in HECO's response to DOD-IR-9-8.

Q. Do the CA and DOD agree to the change in the O&M labor payment lag days?

A. Yes. Both the CA's and DOD's working cash calculation in their testimony utilized the 11 days for the O&M labor payment lag.

Q. What are the revised estimates of the working cash annual expense amounts?

A. The revised test year estimates of the expense amounts for the working cash items are shown in HECO-R-1905, page 1, column D, "Annual Amount".

Q. Who estimates these revised working cash item expense amounts?

A. Changes to the test year estimates of the expense amounts for the working cash

items are provided by the HECO witnesses who present the Company's estimates of operating expenses.

SUMMARY

Q. What is your conclusion as to the rate base proposed by the Company?

A. HECO proposes that the Commission allow the use of an average rate base of $1,117,830,000 at present rates and $1,109,372,000 at proposed rates for the calculation of revenue requirements in this docket.

Q. Does this conclude your testimony?

A. Yes.

Hawaiian Electric Company, Inc.
2005 Average Rate Base
($ in thousands)

Investment in Assets Serving Customers	Beginning of Year 2005	End of Year 2005	Average for 2005	HECO Reference
Net Cost of Plant in Service	1,241,908	1,276,313	1,259,111	R-1902
Property Held for Future Use	599	599	599	CA-IR-95 & 1804
Fuel Inventory	44,484	44,484	44,484	R-408
Materials & Supplies Inventories	10,425	9,789	10,107	CA-IR-95 & 1903
Unamortized Net SFAS 109 Regulatory Asset	50,082	52,341	51,212	R-1705
Prepaid Pension Asset	81,085	76,497	78,791	CA-IR-98 & DOD-IR-10-4, p.4
Unamortized OPEB Regulatory Asset	10,415	9,113	9,764	CA-IR-95 & 1905
Unamortized System Development Costs	0	0	0	CA-IR-95 & CA-IR-352
Working Cash at Present Rates	10,107	10,107	10,107	R-1905
Total Investments in Assets	1,449,105	1,479,243	1,464,175	
Funds from Non-Investors				
Unamortized CIAC	144,322	151,405	147,864	R-1903
Customer Advances	1,519	1,476	1,498	R-1803
Customer Deposits	5,066	6,735	5,901	CA-IR-95 & R-902
Accumulated Deferred Income Taxes	162,290	166,863	164,577	R-1704
Unamortized ITC	15,166	16,309	15,738	R-1703
Unamortized Gain on Sales	489	1,518	1,004	CA-IR-95 & DOD-IR-10-4, p.6
OPEB Liability	10,390	9,084	9,737	CA-IR-95 & DOD-IR-8-5, p. 6
Deferred Rent Expense (King St Lease)	0	52	26	R-1607
Total Deductions	339,242	353,442	346,345	
Average Rate Base at Present Rates			1,117,830	
Change in Working Cash			(8,458)	R-1905
Average Rate Base at Proposed Rate			**1,109,372**	

Hawaiian Electric Company, Inc.
Net Cost of Plant in Service
($ in thousands)

	Original Cost	Accum Deprec	Removal Reg Liability	Net Plant In Service	HECO Reference
Recorded Balances - 12/31/03	2,108,795	(821,485)	(118,110)	1,169,200	
CHANGES in 2004:					
Net Plant Additions	146,577			146,577	CA-IR-96
Cost of Removal			4,773	4,773	CA-IR-96
Salvage			(279)	(279)	CA-IR-96
Depreciation Accrual		(78,315)		(78,315)	CA-IR-96
Deprec Accrual Reclass related to Cost of Removal [1]		18,299	(18,299)	0	CA-IR-96
Retirements [2]	(25,355)	25,355		0	CA-IR-96
Net adjustments	(48)			(48)	CA-IR-96
Recorded Balances - 12/31/04	2,229,969	(856,146)	(131,915)	1,241,908	
ESTIMATED CHANGES in 2005:					
Net Plant Additions	109,823			109,823	R-1801
Cost of Removal			4,867	4,867	R-1601
Salvage			(205)	(205)	R-1601
Depreciation Accrual [3]		(80,080)		(80,080)	R-1601
Deprec Accrual Reclass related to Cost of Removal [1]		21,457	(21,457)	0	
Retirements [2]	(9,880)	9,880		0	R-1601
Estimated Balances - 12/31/05	2,329,912	(904,889)	(148,710)	1,276,313	
AVERAGE 2005 BALANCE				**1,259,111**	

[1] Represents the amount of removal costs that has been included in the depreciation expense that will be reclassified as a liability for financial statement purposes. The 2005 TY reclass amount was calculated based on the depreciable plant balance @ 1/1/05 multiplied by the net salvage rate approved by the PUC in Docket No. 02-0391, Decision and Order No. 21331 dated September 3, 2004.

[2] Original cost of estimated retirements for the respective year.

[3] The amount does not include the amortization of the King Street lease.

Hawaiian Electric Company, Inc.
Unamortized Contributions In Aid of Construction
($ in thousands)

		HECO Reference
RECORDED BALANCES - 12/31/03	143,814	
CHANGES in 2004:		
Cash Receipts	4,135	CA-IR-99
In-Kind Receipts	3,608	CA-IR-99
Transfer from Advances	52	CA-IR-99
Amortization	(7,287)	CA-IR-99
RECORDED BALANCE - 12/31/04	144,322	
ESTIMATED CHANGES in 2005:		
Cash Receipts	9,790	R-1802
In-Kind Receipts	4,729	R-1802
Transfer from Advances	48	R-1802
Amortization	(7,484)	CA-IR-515
ESTIMATED BALANCE - 12/31/05	151,405	
AVERAGE 2005 BALANCE	147,864	

NOTE: Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.
OPEB Liability
($ in thousands)

		HECO Reference
RECORDED BALANCE - 12/31/03	18,210	
Less: Executive Life Exp for 1993-2003	(6,937)	
Add: Deferred Comp Payments for 1993-2003	419	
ADJUSTED BALANCE as of 12/31/03	11,692	
Add: FAS 106 Cost	6,233	1504
Less: Executive Life Expense	(855)	1504
Less: Contributions	(6,680)	Per instructions from HEI.
RECORDED BALANCE - 12/31/04	10,390	CA-IR-95
Add: FAS 106 Cost	7,034	Per June 15, 2005 update, Attachment 8, p. 3
Less: Executive Life Expense	(900)	
Less: Contributions	(7,435)	
ESTIMATED BALANCE - 12/31/05	9,088 *	HECO-R-1905, p.5
AVERAGE 2005 BALANCE	9,739	

NOTE: Totals may not add exactly due to rounding.

* The 2005 year end estimate of the OPEB Liability should have reflected $9,088K, which results in a test year average of $9,739K, vs. the $9,084K year end and $9,737K average balance shown in HECO-R-1901.

Hawaiian Electric Company, Inc.

WORKING CASH ITEMS, 2005

($ in thousands)

	(A) Revenue Collection Lag (Days)	Payment Lag Workpaper Reference	(B) Payment Lag (Days)	(C) Net Collection Lag (Days) (A) - (B)	Annual Amount Workpaper Reference	(D) Annual Amount	(E) Average Daily Amount - Present (D) / 365	(F) Working Cash Required (Provided) under Present Rates (C) x (E)	(G) Average Daily Amount - Proposed (D) / 365	(H) Working Cash Required (Provided) under Proposed Rates (C) x (G)
	per HECO - RT - 9				HECO RWP-2301					
ITEMS REQUIRING WORKING CASH:										
Fuel Purchases	37	CA-IR-524, p.2	16	21	p. 8	444,802	1,219	25,591	1,219	25,591
O&M Labor	37	DOD-IR-9-8, p.3	11	26	p. 9	77,097	211	5,492	211	5,492
O&M Nonlabor	37	WP-1907, p. 28	29	8	p. 9	89,503	245	1,962	245	1,962
ITEMS PROVIDING WORKING CASH:										
Purchased Power	37	WP-1907, p. 33	39	(2)	p. 8	345,433	946	(1,893)	946	(1,893)
Revenue Taxes - Present Rates	37	WP-1907, p. 39	90	(53)	p. 10	108,404	297	(15,741)		
Revenue Taxes - Proposed Rates	37	WP-1907, p. 39	90	(53)	p. 7	113,985			312	(16,551)
Income Taxes - Present Rates	37	WP-1907, p. 43	162	(125)	p. 7	15,489	42	(5,304)		
Income Taxes - Proposed Rates	37	WP-1907, p. 43	162	(125)	p. 7	37,821			104	(12,952)
Total WORKING CASH								10,107		1,648
Change in WORKING CASH										(8,458)

Hawaiian Electric Company, Inc.
WORKING CASH ITEMS, 2005
($ in thousands)

Line Ref.		At Present Rates				At Proposed Rates		
		Annual Amount A	Daily Amount B A/365	Lag Days C	Working Cash D B * C	Annual Amount E	Daily Amount F E/365	Working Cash G C * F
[1]	Revenue Collection Lag	1,080,728	2,960.9	37.0	109,553	1,108,641	3,037.4	112,383
	Payment Lag							
[2]	Fuel Purchases	444,802	1,218.6	16.0	19,498	444,802	1,218.6	19,498
[3]	O&M Labor	77,097	211.2	11.0	2,323	77,097	211.2	2,323
	O&M Non-Labor							
[4]	Pension[1]	3,303	9.0	-	-	3,303	9.0	-
[5]	OPEB[2]	5,139	14.1	-	-	5,139	14.1	-
[6]	Emission Fees[3]	574	1.6	322	506	574	1.6	506
[7]	EPRI Dues[4]	1,531	4.2	(6)	(27)	1,531	4.2	(27)
[8]	Other Non-Labor O&M[5]	78,956	216.3	30	6,559	78,956	216.3	6,559
[9]	Subtotal O&M Non-Labor	89,503	245.2		7,038.5 *	89,503	245.2	7,038.5 *
[10]	Purchased Power	345,433	946.4	39.0	36,909	345,433	946.4	36,909
[11]	Revenue Taxes	108,404	297.0	90.0	26,730	113,985	312.3	28,106
[12]	Income Taxes	15,489	42.4	162.0	6,875	37,821	103.6	16,786
[13]	Total Payment Lag	1,080,728	2,960.9		99,374	1,108,641	3,037.4	110,662
[14]	Net Working Cash				10,179			1,721
	Net Working Cash per p. 1				10,107			1,648
	Difference due to rounding				73 *			73 *

[9] = [4] + [5] + [6] + [7] + [8]
[13] = [2] + [3] + [9] + [10] + [11] + [12]
[14] = [1] - [13]

[1] Pension expense estimate based on 2005 Pension Accrual of $4,588k (per HECO-R-1501) x 72% (based on 2003 % of Employee Benefits charged to O&M expense).

[2] OPEB expense estimate based on 2005 OPEB expense of $7,138k (per HECO-R-1501) x 72% (based on 2003 % of Employee Benefits charged to O&M expense).

[3] Emission Fees per HECO T-6. No change from estimate presented in Direct Testimony.

[4] EPRI Dues per HECO-1604, page 2. No change from estimate presented in Direct Testimony.

[5] Other Non-Labor O&M = Total O&M Non-Labor expense of $89,503k (HECO-RWP-2301, p.9), less other items noted above.

* Difference due to rounding in the calculation of the weighted average payment lag for O&M Non-Labor.

Hawaiian Electric Company, Inc.
Working Cash Study
O&M Non-Labor Payment Lag

File: S:_Company\RegulatoryAffairs\HECOTY2005RateCase\RebuttalTestimonies\RT-19GOhashi\[RT-19 Exhibits.xls]Rate Base
Source: Per Supporting Worksheets

	Test Year Expense ($000's)	% of Total	Total Payment Lag Days	Weighted Average
	Note A		HECO-WP-1907, p. 29-32	
Pension [1]	$3,303	4%	0	days
OPEB [2]	$5,139	6%	0	days
Emission Fees [3]	$574	1%	322	2 days
EPRI Dues [4]	$1,531	2%	-6	days
Other Non-Labor O&M [5]	$78,956	88%	30	27 days
	$89,503	100%		
O&M Non-Labor Payment Lag				**29 days**

Note A

[1] Pension expense estimate based on 2005 Pension Accrual of $4,588k (per HECO-R-1501) x 72% (based on 2003 % of Employee Benefits charged to O&M expense).

[2] OPEB expense estimate based on 2005 OPEB expense of $7,138k (per HECO-R-1501) x 72% (based on 2003 % of Employee Benefits charged to O&M expense).

[3] Emission Fees per HECO T-6. No change from estimate presented in Direct Testimony.

[4] EPRI Dues per HECO-1604, page 2. No change from estimate presented in Direct Testimony.

[5] Other Non-Labor O&M = Total O&M Non-Labor expense of $89,503k (HECO-RWP-2301, p.9), less other items noted above.

Hawaiian Electric Company, Inc.
Prepaid Pension Asset Balance

Date	NPPC Accrual A	Trust Contribution B	Actual Pmt Date [1] C	Ending Prepaid Asset Balance [2] D Prior D - A + B
12/31/1998				335,274
1999	(1,073,259)	-		1,408,533
2000	(19,322,692)	-		20,731,225
2001	(20,465,117)	-		41,196,342
2002	(15,655,436)	-		56,851,778
Jan-03	511,833			56,339,945
Feb-03	511,833			55,828,112
Mar-03	511,833			55,316,279
Apr-03	511,666			54,804,613
May-03	511,833			54,292,780
Jun-03	511,833	2,914,000	6/30/03	56,694,947
Jul-03	470,583			56,224,364
Aug-03	470,583			55,753,781
Sep-03	470,583	1,490,248	9/30/03	56,773,446
Oct-03	470,583			56,302,863
Nov-03	470,583			55,832,280
Dec-03	470,582	8,990,000	12/30/03	64,351,698
Total 2003	5,894,328	13,394,248		
Jan-04	(86,167)			64,437,865
Feb-04	(86,167)			64,524,032
Mar-04	(86,167)			64,610,199
Apr-04	(86,167)			64,696,366
May-04	(86,167)			64,782,533
Jun-04	(342,626)			65,125,159
Jul-04	(128,910)			65,254,069
Aug-04	(128,910)			65,382,979
Sep-04	(128,910)	9,686,494	9/15/04	75,198,383
Oct-04	(128,910)			75,327,293
Nov-04	(128,910)			75,456,203
Dec-04	(128,910)	5,500,000	12/29/04	**81,085,113**
Total 2004	(1,546,921)	15,186,494		
Jan-05	368,000			80,717,113
Feb-05	368,000			80,349,113
Mar-05	368,000			79,981,113
Apr-05	368,000			79,613,113
May-05	368,000			79,245,113
Jun-05	453,831			78,791,282
Jul-05	382,305			78,408,977
Aug-05	382,305			78,026,672
Sep-05	382,305			77,644,367
Oct-05	382,305			77,262,062
Nov-05	382,305			76,879,757
Dec-05	382,306			**76,497,451**
Total 2005	4,587,662	-		

[1] Payment date reflects the day an internal Bank of Hawaii transfer was made from HECO's Bank of Hawaii account to HEI's Bank of Hawaii account. On this same day, funds were wired from the HEI account to the Bank of NY.

[2] Ending Prepaid Pension Asset balances tie to account # 24206900 per General Ledger Summary Report as of June 30, 2005.

Source:
2003 data per "2003 Revised Pension Contribution Amount for HECO" dated 12/26/03 from B. Lee.
2004 data per "2004 Final Pension and OPEB Cost and Contribution Amounts for HECO - Revised" dated 12/29/04 from B. Lee.

Hawaiian Electric Company, Inc.
Other Post-retirement Benefits Other Than Pension

Date	NPPC Accrual A	Exec Life Adjustment B	Trust Contribution C	Actual Pmt Date [1] D	Ending Liability [2] E Prior E+A-B-C
12/31/2002					12,993,642
Jan-03	562,583	70,338	75,000	1/30/03	13,410,888
Feb-03	562,583	70,338			13,903,133
Mar-03	562,583	70,338	1,727,960	3/31/03	12,667,419
Apr-03	562,583	70,338			13,159,664
May-03	562,583	70,338			13,651,910
Jun-03	562,583	70,338	1,727,960	6/30/03	12,416,195
Jul-03	588,378	70,338			12,934,236
Aug-03	588,378	70,338			13,452,276
Sep-03	588,378	70,338	1,953,818	9/30/03	12,016,499
Oct-03	588,378	70,338			12,534,539
Nov-03	588,378	70,338			13,052,580
Dec-03	588,378	70,338	1,878,817	12/30/03	11,691,803
Total 2003	6,905,766	844,050	7,363,555		
Jan-04	631,583	71,283	75,000	1/30/04	12,177,103
Feb-04	631,583	71,283			12,737,403
Mar-04	631,583	71,283	2,005,710	3/31/04	11,291,993
Apr-04	631,583	71,283			11,852,293
May-04	631,583	71,283			12,412,593
Jun-04	(41,171)	71,283	1,825,597	6/30/04	10,474,543
Jul-04	519,457	71,283			10,922,717
Aug-04	519,457	71,283			11,370,891
Sep-04	519,457	71,283	1,385,799	9/30/04	10,433,266
Oct-04	519,457	71,283			10,881,440
Nov-04	519,457	71,283			11,329,614
Dec-04	519,458	71,283	1,387,825	12/29/04	10,389,964
Total 2004	6,233,487	855,395	6,679,931		
Jan-05	584,542	75,019	87,500	1/31/05	10,811,987
Feb-05	584,542	75,019			11,321,511
Mar-05	584,542	75,019	1,857,585	3/31/05	9,973,449
Apr-05	584,542	75,019			10,482,972
May-05	584,542	75,019			10,992,495
Jun-05	594,133	75,019	1,860,065	6/30/05	9,651,545
Jul-05	586,140	75,019			10,162,666
Aug-05	586,140	75,019			10,673,787
Sep-05	586,140	75,019	1,871,324	Forecast 9/30/05	9,313,584
Oct-05	586,140	75,019			9,824,706
Nov-05	586,140	75,019			10,335,827
Dec-05	586,144	75,019	1,758,827	Forecast 12/29/05	9,088,125
Total 2005	7,033,687	900,225	7,435,301		

[1] Payment date reflects the day an internal Bank of Hawaii transfer was made from HECO's Bank of Hawaii account to HEI's Bank of Hawaii account. On this same day, funds were wired from the HEI account to the Bank of New York.

[2] Ending Liabiltiy balance reconciles to the OPEB Liability GL account #2532 per Trial Balance as of June 30, 2005.

Source:

2003 data per "2003 Final Pension and OPEB Cost and Contribution Amounts for HECO" dated 7/11/03 from B. Lee.

2004 data per "2004 Final Pension and OPEB Cost and Contribution Amounts for HECO - Revised" dated 12/29/04 from B. Lee.

HECO RT-20
DOCKET NO. 04-0113

REBUTTAL TESTIMONY OF
ROGER A. MORIN, PH.D.

CONSULTANT

HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Rate of Return on Common Equity

INTRODUCTION

Q. Please state your name, address, and occupation.

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Professor of Finance at the College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government.

Q. Are you the same Dr. Morin who previously filed testimony in this proceeding?

A. Yes.

Q. Please describe the purpose of your rebuttal testimony.

A. I have been asked to rebut Mr. Hill's (U.S. Department of Defense) and Mr. Parcell's (Division of Consumer Advocacy) cost of capital testimony.

Q. Please describe how your rebuttal testimony is organized.

A. My rebuttal testimony is organized in two sections, corresponding to each of the aforementioned individuals. I am also providing the Commission with an updated recommendation in view of the appreciable changes that have occurred in capital markets since I prepared my direct testimony, almost one year ago.

Q. Please summarize the rate of return recommendations of the witnesses you are rebutting in this case.

A. The rate of return on common equity capital recommended by each witness I am rebutting in this case is as follows:

Mr. Hill	9.0%
Mr. Parcell	8.5% -10.00%

I. REBUTTAL TO MR. HILL'S TESTIMONY

Q. Please summarize Mr. Hill's rate of return recommendation.

A. Mr. Hill recommends a common equity return ("ROE") allowance of only 9.0%, which is in the lower portion of a range of 8.75% - 9.50%. In determining the cost of equity, Mr. Hill applies a DCF analysis to a group of 10 electric utilities. This study, summarized on page 38 of his testimony, produces a result of 9.21%. Mr. Hill performs three checks on his DCF result, based on the Modified Earnings/Price, Market-to-Book, and Capital Asset Pricing Model (CAPM) methodologies, respectively, and concludes that Hawaiian Electric Company's ("HECO" or the "Company") cost of equity lies in the lower part of a range of 8.75% to 9.50%. Mr. Hill recommends that the lower point of his range be used to account for HECO's stronger than average capital structure.

Q. What is your general reaction to Mr. Hill's cost of common equity recommendation?

A. My general reaction to his testimony, before I engage in a more technical critique, is that there are two major infirmities in Mr. Hill's testimony. First, I find that Mr. Hill's recommended 9.0% ROE for HECO lies completely outside the zone of reasonableness and well outside the zone of currently authorized rates of return for major electric utilities in the United States. Mr. Hill's recommended drastic reduction in the Company's ROE down to only 9.0%, if ever adopted, would result in one of the lowest rate of return awards for a major electric utility in the country. I hesitate to think of its adverse consequences on the Company's credit ratings, the stock of its parent company, the Company's capital raising ability, and ratepayers. Moreover, Mr. Hill's single-digit recommended ROE lies well outside the zone of his own comparable companies' authorized ROEs. These are clear

indications that his return on equity recommendation for HECO is too low.

The second structural flaw of Mr. Hill's testimony is that his recommendation of 9.0% rests very heavily, if not exclusively, on the questionable results of the sustainable growth version of the DCF model. Essentially, that method requires Mr. Hill to assume the investor's expected return on book equity (ROE). But the latter is precisely what we are trying to determine in this proceeding. It is therefore profoundly illogical and circular to assume an ROE in order to determine an ROE. Unfortunately, Mr. Hill has put all of his eggs in the fragile sustainable growth version of the DCF basket which causes him to recommend returns that are well below investors' required returns. Moreover, his checks on the DCF result are redundant and flawed, as I discuss later.

Q. What are the basic conclusions of your rebuttal to Mr. Hill's cost of equity testimony?

A. Mr. Hill seriously understates HECO's cost of common equity. A proper application of cost of capital methodologies would give results substantially higher than those that he obtained.

Q. Please summarize your specific criticisms of Mr. Hill's testimony.

A. I have sixteen specific comments:

1) **Return Recommendation Far Out of The Mainstream.** Mr. Hill's recommended return is completely outside the zone of currently allowed rates of return for major electric utilities in the United States and for his own sample of companies. The average allowed return on equity for electric utilities in the years 2002, 2003, and 2004 was 11.2%, 11.0%, and 10.7%, respectively. These authorized returns exceed by a significant margin Mr. Hill's weak 9.0%

recommended return for HECO. Also, the currently authorized ROE for Mr. Hill's own comparable companies is much higher than his recommended ROE for HECO.

2) **The DCF model Understates the Cost of Equity.** It is well-known that application of the standard DCF model to utility stocks understates the investor's expected return when the Market-to-Book ratio exceeds unity. This is particularly relevant in the current capital market environment where utility stocks, including Mr. Hill's sample companies, are trading at M/B ratios well above unity.

3) **DCF Dividend Yield and Flotation Costs.** Mr. Hill's dividend yield component is understated by 30 basis points because it does not allow for flotation costs, and, as a result, a legitimate expense is left unrecovered.

4) **Sustainable Growth Method.** Mr. Hill's principal, and in fact only, technique for estimating the growth component of the DCF model is the sustainable growth technique. There are logical inconsistencies in the sustainable growth technique employed by Mr. Hill in deriving his growth estimates because he is forced to assume the answer to implement the method. From Mr. Hill's own evidence, investors expect substantially higher returns for utilities than what Mr. Hill recommends. Moreover, Mr. Hill's selection of a sustainable growth rate for each company in his comparable group is ambiguous and extremely arbitrary.

5) **DCF Historical Growth Rates.** Mr. Hill examines short-term historical data despite substantial changes occurring in the energy utility industry. Moreover, the historical growth rates that Mr. Hill examines in his DCF analysis are somewhat redundant since historical growth patterns are already

reflected in analysts' growth forecasts, which he also uses. Also, the stock price Mr. Hill uses in his DCF analysis is predicated on analysts' growth forecasts and not on historical growth rates.

6) **DCF Dividend Growth Rates**. Mr. Hill examines historical and projected dividend growth in his DCF analysis even though electric utilities are reducing dividend payouts. Because energy utilities are expected to lower their dividend payout ratio over the next several years in response to heightened business risk, the use of dividend growth projections is inappropriate in the DCF model. Earnings growth projections are far more relevant at this point.

7) **Unreliable DCF Estimates**. A test of the statistical relationship between growth and expected yield for Mr. Hill's DCF analysis shows that the hypothesis that the sample is truly risk-comparable must be rejected for the DCF estimates.

8) **MEPR and M/B Checks**. Mr. Hill's Modified Earnings Price Ratio (MEPR) and Market-to-Book Ratio (MBR) checks are merely two disguised versions of the DCF model, and do not, therefore, constitute independent stand-alone checks.

9) **The MEPR Method.** The MEPR method is antiquated, is fraught with conceptual blemishes, and has disappeared from use.

10) **The M/B Method.** The second check used by Mr. Hill, namely, the M/B ratio, is largely irrelevant. Moreover, Mr. Hill's views on the role of the M/B ratio in regulation are unjustly severe, illogical, and inconsistent.

11) **CAPM Market Risk Premium.** Mr. Hill's estimate of the market risk premium is too low because he has erroneously employed geometric means instead of the correct arithmetic means. Use of the correct market risk

premium increases Mr. Hill's CAPM estimate of HECO's cost of equity by 120 basis points.

12) **CAPM and the Empirical CAPM (ECAPM).** The plain vanilla version of the CAPM used by Mr. Hill understates the Company's cost of equity for low-beta securities.

13) **Higher Projected Long-term Interest Rates.** Mr. Hill's recommended ROE is not reflective of the forecast increase in capital costs.

14) **Capital Structure Adjustment.** Mr. Hill's downward ROE adjustment in order to account for HECO's stronger capital structure relative to its peers is unwarranted.

15) **Logical Inconsistencies.** There are several logical inconsistencies and contradictions in Mr. Hill's testimony.

16) **Unfounded criticisms**. Mr. Hill's criticisms of my testimony are unfounded.

I shall now discuss each criticism in turn.

1. ALLOWED RETURNS

Q. Is Mr. Hill's rate of return recommendation compatible with currently allowed returns in the electric utility industry?

A. No, it is not. Allowed returns, while certainly not a precise indication of a company's cost of equity capital, are nevertheless important determinants of investor growth perceptions and investor expected returns. They also serve to provide some perspective on the validity and reasonableness of Mr. Hill's recommendation.

The average allowed return in the electric utility industry in the years 2002, 2003, and 2004 as reported by Regulatory Research Associates was 11.2%,

11.0%, and 10.7%, respectively. These ROE awards exceed by a substantial margin Mr. Hill's recommended ROE of 9.0% for HECO.

I have also examined the range of returns currently allowed on common equity for the ten electric utilities in Mr. Hill's barometer group as reported in AUS Utility Reports survey for July 2005. The currently authorized ROEs for Mr. Hill's sample, shown in the table below, average 11.03%:

Company	**Allowed ROE**
Cen. Vermont Pub. Serv.	10.0%
Cinergy Corp.	11.0%
Cleco Corp.	12.3%
Empire Dist. Elec.	11.0%
Entergy Corp.	11.0%
FirstEnergy Corp.	9.8%
Hawaiian Elec.	11.2%
Pinnacle West Capital	10.3%
PNM Resources	10.3%
Progress Energy	12.8%
Cen. Vermont Pub. Serv.	10.0%
AVERAGE	**11.0%**

Source: AUS Utility Reports 7/2005

In short, Mr. Hill's recommendation is outside the mainstream of the allowed rates of return that were current during the period in which Mr. Hill performed his analysis and lies outside the zone of recently authorized returns for electric utilities and for his own sample of companies.

2. DCF MODEL UNDERSTATES THE COST OF EQUITY

Q. Does Mr. Hill's DCF result understate the cost of equity?

A. Yes, it does, and so does my own DCF result for that matter. Application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar, that is, when the Market-to-Book (M/B) ratio is close to unity. As shown

below, application of the standard DCF model to utility stocks understates the investor's expected return when the M/B ratio of a given stock exceeds unity. This is particularly relevant in the current capital market environment where utility stocks are trading at M/B ratios well above unity and have been for two decades. The converse is also true, that is, the DCF model overstates the investor's return when the stock's M/B ratio is less than unity. The reason for the distortion is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.

Q. Can you illustrate the effect of the market-to-book ratio on the DCF model by means of a simple example?

A. Yes. The simple numerical illustration shown in the table below demonstrates the result of applying a market value cost rate to book value rate base under three different M/B scenarios. The three columns correspond to three M/B situations: the stock trades below, equal to, and above book value, respectively. The last situation (shaded portion of the table) is noteworthy and representative of the current capital market environment. The DCF cost rate of 10%, made up of a 5% dividend yield and a 5% growth rate, is applied to the book value rate base of $50 to produce $5.00 of earnings. Of the $5.00 of earnings, the full $5.00 are required for dividends to produce a dividend yield of 5% on a stock price of $100.00, and no dollars are available for growth. The investor's return is therefore only 5% versus his required return of 10%. A DCF cost rate of 10%, which implies $10.00 of earnings, translates to only $5.00 of earnings on book value, a 5% return.

The situation is reversed in the first column when the stock trades below book value. The $5.00 of earnings are more than enough to satisfy the investor's

dividend requirements of $1.25, leaving $3.75 for growth, for a total return of 20%. This is because the DCF cost rate is applied to a book value rate base well above the market price.

Therefore, the DCF cost rate understates the investor's required return when stock prices are well above book, as is the case presently, and Mr. Hill's DCF results, the crux of his recommended ROE, understate HECO's cost of common equity capital.

EFFECT OF MARKET-TO-BOOK RATIO ON MARKET RETURN

		Situation 1	*Situation 2*	*Situation 3*
1	Initial purchase price	$25.00	$50.00	$100.00
2	Initial book value	$50.00	$50.00	$50.00
3	**Initial M/B**	**0.50**	**1.00**	**2.00**
4	**DCF Return 10% = 5% + 5%**	**10.00%**	**10.00%**	**10.00%**
5	Dollar Return	$5.00	$5.00	$5.00
6	Dollar Dividends 5% Yield	$1.25	$2.50	$5.00
7	Dollar Growth 5% Growth	$3.75	$2.50	$0.00
8	***Market Return***	**20.00%**	**10.00%**	**5.00%**

Q. Do regulators share these reservations on the reliability of the DCF model?

A. Yes, I believe they do. My sentiments on the DCF model were echoed in a decision by the Indiana Utility Regulatory Commission (IURC). The IURC recognized its concerns with the DCF model and that the model understates the cost of equity. In Cause No. 39871 Final Order, the IURC states on page 24:

> *"....the DCF model, heavily relied upon by the Public, understates the cost of common equity. The Commission has recognized this fact before. In Indiana Mich. Power Co. (IURC 8/24/90), Cause No. 38728, 116 PUR4th 1, 17-18, we found:*
>
> *[T]he unadjusted DCF result is almost always well below what any informed financial analyst would regard as defensible, and therefore*

requires an upward adjustment based largely on the expert witness's judgment."

The Commission also expressed its concern with a witness relying solely on one methodology:

".....the Commission has had concerns in our past orders with a witness relying solely on one methodology in reaching an opinion on a proper return on equity figure."

(page 25)

Q. Is the Indiana Commission unique in that regard?

A. No, it is not. Contrary to Mr. Hill's assertion on page 44 of his testimony, a vast majority of regulatory commissions do not rely solely on the DCF in setting the allowed rate of return on common equity. Instead, they utilize a variety of methods, as evidenced by the results posted in a survey conducted by the National Association of Regulatory Utility Commissioners (NARUC).

Mr. Hill does not properly represent the results of this study in referring to that same survey. The principal finding of this survey is that the vast majority of regulators rely on all the evidence presented and do not necessarily subscribe to any one methodology.

3. DCF DIVIDEND YIELD AND FLOTATION COSTS

Q. In your direct testimony, you stated that the return on equity should be adjusted to include an allowance for flotation costs. Please comment on flotation costs.

A. Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component represents monetary compensation to the

security underwriter for marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (printing, legal, prospectus, etc.). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure".

Flotation costs for common stock is analogous to the flotation costs associated with past bond issues which, as a matter of routine regulatory policy, continue to be amortized over the life of the bond, even though no new bond issues are contemplated. In the case of common stock, which has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity.

As demonstrated in my original testimony, the expected dividend yield component of the DCF model must be adjusted for flotation cost by dividing it by (1 - f), where f is the flotation cost factor.

Q. What flotation cost treatment did Mr. Hill recommend in this case?

A. Mr. Hill's common equity return recommendation does not include any allowance for issuance expense. Because Mr. Hill fails to include any allowance for flotation costs, his DCF estimates of equity costs are downward-biased by approximately 30 basis points as a result of that omission alone.

I am surprised by Mr. Hill's reluctance to accept flotation costs. The flotation cost allowance to the cost of common equity capital is routinely discussed and applied in most corporate finance textbooks.

Moreover, Mr. Hill's testimony contains an obvious inconsistency with regard to flotation costs. In his discussion of sustainable growth in the DCF

model, he recognizes that "investor expectations regarding growth from external source (sales of stock) must be considered and examined" (page 34 lines 25-26). Also, he employs a version of the DCF model that explicitly accounts for continuous external common stock issues over time and even quantifies the effect of such issues on company growth on his exhibit DOD-207 under the heading "external growth." Yet, he completely ignores the flotation costs that are associated with such common stock issues.

Moreover, Mr. Hill's position concerning flotation costs is inconsistent with the Value Line forecasts that show that electric utilities will be issuing new common stock in the future. According to Mr. Hill's own data, the industry is scheduled to issue considerable amounts of new equity as per exhibit DOD-207 pages 1-4 under the label "external growth" for 2006 and 2008-2010.

Q. How does Mr. Hill rationalize the omission of flotation costs?

A. Mr. Hill offers five reasons as to why a flotation cost allowance is unwarranted. As I show below, all five reasons are not valid.

Mr. Hill's first two arguments (page 41 lines 9-14, and page 41 lines 16-21) are that when new stock is issued above book value there is no need to compensate stockholders for a hypothetical dilution of book value that does not exist. I disagree. The simple fact of the matter is that in issuing common stock, the company's common equity account is credited by an amount less than the market value of the issue, so that the company must earn slightly more on its reduced rate base in order to produce a return equal to that required by shareholders. The stock's M/B value is irrelevant. The costs are there irrespective of whether the stock trades above, below, or at book value. I shall comment on Mr. Hill's fixation on M/B ratios later in my rebuttal.

Mr. Hill's third argument (page 40 lines 14-19) is that the majority of the flotation costs are underwriter fees and that the latter are not out-of-pocket expenses incurred by the issuing utility and, as such, should not be recovered. This argument is erroneous. In theory, flotation costs could be expensed and recovered through rates as they are incurred. This procedure is not considered appropriate, however, because the equity capital raised in a given stock issue remains on the utility's common equity account and continues to provide benefits to ratepayers indefinitely. It would be unfair to burden the current generation of ratepayers with the full costs of raising capital when the benefits of that capital extend indefinitely. Although flotation costs are not expensed, they must nevertheless be recovered. As I indicated in my initial testimony, unlike the case of bonds, common stock has no finite life so that flotation costs cannot be amortized and must therefore be recovered via an upward adjustment to the allowed return on equity.

Mr. Hill's third argument (page 40 lines 20-27) is that the stock price already reflects any accretion or dilution resulting from new issuances of securities. The simple fact of the matter is that, whatever stock price is set by the market, the company issuing stock will always net an amount less than the stock price due to the presence of intermediation and flotation costs. As a result, the company must earn slightly more on its reduced rate base in order to produce a return equal to that required by shareholders.

Mr. Hill's suggestion that the flotation cost allowance is unwarranted because investors factor this shortcoming in the stock price implies that it is appropriate to use a deficient model because such a deficiency is reflected in stock prices. In other words, it would be appropriate to use a deficient model because

investors would be aware of this. Such circular reasoning could be used to justify any regulatory policy. For example, under Mr. Hill's reasoning, it would be appropriate to authorize a return on equity of 1% because investors would reflect this fact in the stock price. Put somewhat differently, Mr. Hill's approach suggests that because the cost (or risk) of a particular event – in this case flotation costs – is merely reflected in the stock price investors do not require compensation for that risk in the allowed rate of return on equity. This is clearly illogical and erroneous. Any regulatory policy, as irrational as it may be, could be justified using this argument.

Mr. Hill's fourth argument is a disguised variation of his first argument. That is, the growth component of the DCF model already contains an upward adjustment for selling stock above book value, and thus the flotation allowance is unwarranted. I have already commented on the fragility of that argument. My own recommendation is that investors be compensated for flotation costs on an on-going basis because such costs were not expensed in the past, and therefore that the adjustment must continue for the entire time that these initial funds are retained in the firm. My direct testimony provided numerical illustrations which clearly show that, even if a utility does not contemplate any further common stock offerings, a flotation cost adjustment is still permanently required. This is analogous to the flotation costs associated with past bond issues, which continue to be amortized over the life of the bond, even though no new bond issues are contemplated.

In short, because Mr. Hill does not recognize flotation costs, his DCF estimates of equity costs are downward-biased by approximately 30 basis points,

as shown in my direct testimony. His criticisms of the flotation cost treatment in my direct testimony are unfounded as well.

4. SUSTAINABLE GROWTH METHOD

Q. What specific DCF methodology did Mr. Hill employ to determine the cost of equity?

A. Mr. Hill applied a DCF analysis to a sample of 10 electric utilities, using an expected dividend yield component based on a 6-week average stock price. For the growth component, Mr. Hill examined numerous growth rates, including sustainable growth rates, historical growth in book value, earnings, and dividends, Value Line growth forecasts, and the consensus growth reported in First Call, as shown on the various columns of his exhibit DOD-208 page 2. After reading his discussion of each company's growth rates in exhibit DOD-202, I was unable to reconstruct the logic of Mr. Hill's growth computation from the vast array of growth rates presented by Mr. Hill. In his final DCF analysis (exhibit DOD-210 third column), Mr. Hill ends up choosing the sustainable growth rate estimates found on the first column of exhibit DOD-208 page 2, that in turn are found again in the last column of exhibit DOD-208 page 1, as his final DCF growth rate proxy. The other ten proxies for growth shown on that same schedule are ignored. It is not clear to me as to why Mr. Hill estimates a vast compendium of historical and projected growth rates and, then uses only the sustainable growth proxy which, as I show below, is the most fragile proxy and is conceptually invalid. Adding the dividend yield component to the arbitrary growth component he selected for each company produced a cost of equity estimate of 9.21% reported on his exhibit DOD-210.

Q. Please comment on Mr. Hill's growth estimate in the DCF model?

A. Mr. Hill relies exclusively on the so-called sustainable growth method, where the growth rate is based on the equation g = b(ROE), where b is the percentage of earnings retained and ROE is the expected rate of return on book equity (ROE). He also accounts for the impact of external stock financing on growth by adding an external growth term (g = sv).

I disagree with sustainable growth technique for five reasons: 1) the method is logically circular, for it required Mr. Hill to assume the ROE answer to begin with, 2) inconsistency with the academic empirical evidence, 3) the potential lack of representativeness of Value Line's forecasts as proxies for the market consensus, 4) a technical error, and 5) the arbitrary nature of Mr. Hill's sustainable growth estimates. I will now discuss each of these points in turn.

Q. Are the growth rates used by Mr. Hill consistent with his rate of return recommendation?

A. No, they are not. Mr. Hill's sustainable growth methodology contains a puzzling logical contradiction. This is because the method requires an explicit assumption on the ROE expected from the retained earnings that drive future growth. Mr. Hill bases his ROE estimate on achieved ROEs in the past five years 2000 – 2004 and on Value Line's forecast ROE for 2005, 2006, and for the 2008-2010 period. But the ROEs used by Mr. Hill in calculating his sustainable growth rate do not match Mr. Hill's ROE recommendation. The table below replicates the ROE forecasts used by Mr. Hill in deriving his sustainable growth rates.

Mr. Hill's Forecast ROE
Sustainable Growth Estimates

	Company	2006 Expected ROE	2008-2010 Expected ROE
1	Cen. Vermont Pub. Serv.	8.5%	9.5%
2	First Energy	11.5%	11.5%
3	Progress Energy	10.0%	9.0%
4	Cinergy Corp	12.0%	11.0%
5	Cleco Corp	12.5%	11.5%
6	Empire Dist. Elec.	10.0%	10.5%
7	Entergy Corp.	11.5%	11.0%
8	Hawaiian Elec.	11.0%	11.5%
9	PNM Resources	7.5%	7.0%
10	Pinnacle West Capital	9.5%	9.0%
	Average	**10.4%**	**10.2%**

Source: Mr. Hill exhibit DOD-207 pages 1-4

The average expected ROE range of 10.2% - 10.4% used in Mr. Hill's sustainable growth computation and reported on his exhibit DOD-207 exceeds his recommended 9.0%. Mr. Hill is assuming in effect that his sample companies will earn a ROE exceeding what he has determined to be their cost of equity forever. That is, **he is assuming that these companies will earn a ROE higher than that granted by their regulators and reflected in their rates**. While this scenario implicit in Mr. Hill's sustainable growth method may be imaginable for an unregulated company with substantial market power, **it is implausible for a regulated company whose rates are set by its regulator at a level designated to permit the company to earn a return equal to its cost of capital**. I consider this logical flaw extremely damaging to the integrity of Mr. Hill's analysis, and consider it to be a sufficient basis for rejecting Mr. Hill's results produced by this method, which constitute the cornerstone of his testimony, as I discuss further below. In essence, Mr. Hill is using an ROE that differs from his final recommended cost of equity, and is requesting the Commission to make two

1 inconsistent findings regarding ROE. I am perplexed as to why Mr. Hill assumes
2 that his group of comparable electric utilities is expected to earn 10.2% - 10.4%
3 forever, while at the same time he recommends an ROE of only 9.0%. The only
4 way that these electric utilities can earn an ROE of 10.8% - 11.4% is if rates are
5 set so that they will in fact earn 10.2% - 10.4%. The only logical conclusion to be
6 drawn from the data is that the group's cost of equity is 10.2% - 10.4%, since
7 these are the returns implied in Mr. Hill's sustainable growth analysis. So, how
8 can the cost of equity be any different from 10.2% - 10.4%?
9 In short, Mr. Hill's implementation of the sustainable growth method is
10 circular, for he is using an assumed ROE that exceeds his own recommended
11 ROE. He is in effect using a growth forecast which implies that the companies
12 will earn at a return rate exceeding his recommended equity range forever, while
13 at the same time recommending that a different rate be authorized by the
14 Commission.
15 Q. Is the sustainable growth rate technique consistent with the empirical evidence?
16 A. No, it is not. The second difficulty with the sustainable growth rate approach is
17 that the empirical finance literature demonstrates this particular method of
18 determining growth is a very poor explanatory variable of market value, and is not
19 as significantly correlated to measures of value, such as stock price and
20 price/earnings ratios.
21 Q. Are value line's roe and retention ratio estimates representative of the market
22 consensus?
23 A. No. The third difficulty with Mr. Hill's sustainable growth rates is that exclusive
24 reliance on Value Line forecasts of ROE and retention ratio runs the risk that such
25 forecasts are not representative of investors' consensus forecast.

Q. Please discuss the fourth problem with Mr. Hill's sustainable growth estimates.

A. The fourth difficulty with Mr. Hill's sustainable growth approach is that the forecasts of the expected return on equity published by Value Line are based on end-of-period book equity rather than on average book equity. The following formula, discussed and derived in Chapter 5 of my book, Regulatory Finance, adjusts the reported end-of-year values so that they are based on average common equity, which is the common regulatory practice:

$$r_a = r_t \frac{2\,B_t}{B_t + B_{t-1}}$$

Where: r_a = return on average equity

r_t = return on year-end equity as reported

B_t = reported year-end book equity of the current year

B_{t-1} = reported year-end book equity of the previous year

The result of this error is that Mr. Hill's DCF estimates are understated by some 10-20 basis points, depending on the magnitude of the book value growth rate.

Q. Dr. Morin, were you or anyone on your staff able to scientifically replicate Mr. Hill's sustainable growth rate estimates?

A. No, we were not. The last difficulty with Mr. Hill's sustainable growth rate estimates is that they are arbitrary, unreliable, and impossible to replicate scientifically. Let me illustrate my difficulty with one example. From his exhibit DOD-207 page 3, the table below directly replicates Mr. Hill's sustainable growth rate estimates for Hawaiian Electric Industries ("HE").

	Retention Ratio	Equity Return	G
2000	0.1448	11.00%	1.59%
2001	0.0236	9.80%	0.23%
2002	0.2250	11.80%	2.66%
2003	0.2346	11.30%	2.65%
2004	0.2152	10.80%	2.32%
		AVG HIST br	**1.89%**
2005	0.1448	10.00%	1.45%
2006	0.2706	11.00%	2.98%
2008-2010	0.3500	11.50%	4.03%
		AVG PROJ br	**2.26%**
		Mr. Hill picks	**3.50%**

Source: Mr. Hill exhibit DOD-207 page 3

The first column of numbers shows the historical and forecast retention ratios for various years, the second column shows the historical and forecast ROE, and the third column shows the product of the two columns, that is, the sustainable growth estimates for each year. From the various estimate shown in the last column, Mr. Hill picks 3.5% as his estimate of HE's sustainable growth rate. This estimate bears little, if any, resemblance to any of the growth proxies shown in the last column, including the average growth from all his proxies. After trying every permutation and combination of historical and projected growth rates, including averages, truncated averages, and medians, I was completely unable to replicate Mr. Hill's final choice of 3.5% from estimates shown in the last column.

The same is true for every company in his sample. I tried to match Mr. Hill's final estimate of "br" shown in the first column of exhibit DOD-208 page 1 with the various estimate of "br" shown on exhibit DOD-207 for each company. There is little, if any, correspondence between Mr. Hill's final sustainable growth

estimates ("br") and the growth data from which they were derived. The estimates simply appear without any solid scientific foundation or derivation.

5. DCF HISTORICAL GROWTH RATES

Q. Please discuss the use of historical growth rates in applying the DCF model to energy utilities.

A. In arriving at his proxies for the DCF growth component, Mr. Hill considers historical growth rates as reported by Value Line. Although he reports and discusses such growth rates on exhibit DOD-208, page 2, it is difficult to tell from his discussion of each company's growth rate to what extent he places reliance, if any, on historical growth rates. To the extent that he did, I disagree.

Under circumstances of stability, it is reasonable to assume that historical growth rates in dividends/earnings influence investors' assessment of the long-run growth rate of future dividends/earnings. However, because of sea changes in the energy industry, historical growth rates have little relevance as proxies for future long-term growth. They are downward-biased by the sluggish earnings performance in the last decade, due to the structural transformation of the energy utility business from a regulated monopoly to a competitive environment.

Moreover, historical growth rates are largely redundant because such historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model. I therefore recommend that the Commission reject historical growth rates as proxies for expected growth in the DCF calculation. In fairness to Mr. Hill, however, he did not rely on historical growth rates in deriving his DCF estimates but instead relied solely on his sustainable growth estimates, as I discussed earlier.

6. DCF DIVIDEND GROWTH RATES

Q. Should value line's dividend growth forecast be considered in applying the DCF model to electric utilities?

A. No, they should not. In arriving at his proxies for the DCF growth component, Mr. Hill considers historical and projected dividend growth rates as reported by Value Line (exhibit DOD-208, page 2). Although he reports such growth rates, it is difficult to tell from his discussion of each company's growth rate to what extent he places reliance, if any, on dividend growth rates. To the extent that he did, I disagree.

There are two serious problems with the use of Value Line's dividend growth forecasts. First, heavy reliance on Value Line's in-house growth forecasts runs the risk that such forecasts are not representative of investors' consensus forecast. One would expect that averages of analysts' growth forecasts such as those contained in First Call or Zacks, rather than one particular firm's forecast, are more reliable estimates of the investors' consensus expectations likely to be reflected in stock prices. As discussed in my direct testimony, the empirical finance literature has shown that such consensus analysts' growth forecasts are reflected in stock prices, possess a high explanatory power of equity values, and are used by investors. Besides, as a practical matter, it is necessary to use earnings forecasts rather than dividend forecasts due to the extreme scarcity of dividend forecasts compared to the availability of earnings forecast. Given the paucity and variability of dividend forecasts, using dividend forecasts produces unreliable DCF results.

Second, and more importantly, it is inappropriate to use the projected dividend growth of energy utilities at this time in the DCF model. The problem

with the use of Value Line's dividend growth forecasts, besides the fact that these forecasts are only one individual firm's forecasts, is that they are largely dominated by the anticipated dividend performance over the next few years, a period of transition to competition and higher business risk. But again, in fairness to Mr. Hill, he did not rely on dividend growth forecasts in deriving his DCF estimates but instead relied solely on his sustainable growth estimates. I am not sure why Mr. Hill included a large amount of historical and forecast growth data in his testimony only to place no reliance on such data. I suspect that the reason is that the DCF estimates that would result from historical and projected dividend growth proxies are unreasonably low.

7. DCF RELIABILITY

Q. Is there any statistical evidence that Mr. Hill's DCF estimates are unreliable?

A. Yes, there is. In order for a group of companies to be truly risk-comparable, their costs of common equity should be identical. Alternatively, there must be a one-to-one correspondence between variations among the companies in the group with respect to growth (g) and variations with respect to expected yield (D_1/P). If one runs a statistical regression of growth on expected yield for a group of truly risk-comparable firms, one should obtain an estimated slope coefficient of dividend yield of -1.0. Otherwise, the sample is not risk comparable.

A test of the statistical relationship between growth and expected yield for Mr. Hill's DCF analysis shows that Mr. Hill's DCF cost of common equity estimates resulted in slope terms that are statistically significantly different from -1.0. Therefore, the hypothesis that the sample is truly risk-comparable must be rejected for the DCF estimates.

8. DCF CHECKS

Q. Are Mr. Hill's checks on his DCF results appropriate?

A. No, I do not believe they are. Mr. Hill's Modified Earnings Price Ratio (MEPR) and Market-to-Book Ratio (MBR) checks are merely two disguised versions of the DCF model, and do not constitute independent stand-alone checks. It is not surprising, therefore, that the results from these two "checks" are similar to the results produced by the DCF model. In other words, the MEPR and MBR methods he has employed are redundant, as they are merely variations of the DCF method as Mr. Hill's derivations of these two approaches in exhibit DOD-203 make abundantly clear.

9. DCF CHECKS: EARNING-PRICE RATIO

Q. Please comment on Mr. Hill's earnings-price ratio method as a check on his DCF result.

A. As one of three checks on his DCF results, Mr. Hill employs the MEPR method. According to this method, the return of earnings to shareholders is the cost to the company of equity funds, and the same rate of return must be earned on equity-financed assets to equal the cost rate.

The MEPR was discussed extensively in the corporate finance literature in the 1960's, and enjoyed some brief notoriety in regulatory hearings in that period. Today, the method has almost vanished from use because it produces unreliable results. In fact there are only two very limited cases in which the MEPR constitutes an accurate measure of the cost of equity and reduces to the standard constant-growth DCF model. The specific circumstances under which the MEPR ratio collapses to the standard DCF model are two-fold: (1) the case where all earnings are paid out in dividends, and (2) the case of an "ordinary" firm, that is, a

company without profitable opportunities earning a return on its new investments that is just equal to the cost of equity. Neither of these cases is present here. The former case lacks realism since most companies, including regulated utilities, do in fact retain earnings. The latter case is equally unrealistic since most utilities do face profitable opportunities.

The MEPR is rarely, if ever, used in rate cases. If it is, extreme care and caution must be exercised that the assumptions underlying its use are not violated. One practical difficulty is to obtain an estimate of anticipated earnings, especially if earnings are subject to substantial seasonal fluctuation. Extrapolating historical earnings would pose additional problems if unrepresentative growth rates have distorted past earnings. In conclusion, Mr. Hill's MEPR results should be discarded by the Commission.

10. DCF CHECKS: MARKET-TO-BOOK RATIO METHOD

Q. Please discuss Mr. Hill's views on market-to-book ratios.

A. As a second check on his DCF result, Mr. Hill refers to market-to-book (M/B) ratios. His testimony contains numerous and lengthy references to M/B ratios. On page 15 and pages 16-19 and again on page 35 of his testimony, Mr. Hill argues that it is reasonable to assume that investors would expect the M/B ratio to have a tendency toward unity (line 22 page 35). He also argues that when a regulated utility has a M/B ratio greater than one, the earned return exceeds the cost of common equity (page 17 lines 7-9, page 20 lines 1-2, page 35 lines 4-7), implying that the regulating authority should lower the allowed return on equity, so that the stock price will decline to book value. I presume from his statements that Mr. Hill would find it plausible that stock prices drop from the current M/B value of well above 1.0 for most electric utilities, to the desired M/B ratio range of

1.0.

There are several reasons why M/B ratios are largely irrelevant and why I disagree with Mr. Hill's views of the role of M/B in regulation.

i) Mr. Hill's testimony strongly implies that regulators should set an ROE so as to produce a M/B of 1.0. This is erroneous. The stock price is set by the market, not by regulators. The M/B ratio is the result of regulation, not its starting point. The regime of regulation envisioned by Mr. Hill, that is, that the regulator will set an allowed rate of return so as to produce a M/B of close to 1.0, presumes that investors commit capital to a utility with a M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. Such behavior on the part of investors is certainly not a realistic or accurate view of investment or regulation. To employ an analogy from Mr. Hill's pages 50-51, imagine a broker trying to sell to an investor with a return requirement of 10% a utility stock priced at $100 per share and whose M/B ratio is 2.0. "I've got a stock for you that's going to pay a 10% return on a $50 book value – in other words one share will get you $5 but each share has to drop from $100 to $50 in order for the price to drop to book value. Are you interested?" No investor in his (her) right mind would pay $100 for a stock that is going to drop to $50. Mr. Hill's position on M/B ratios defies logic.

ii) While it is true that if investors expect a utility to earn an ROE equal to its cost of equity in each period, then its M/B ratio would be approximately 1.0, this is only true in a long-run sense and is only applicable to a utility 1) whose assets are all 100% regulated, 2) whose

rate base equals invested capital and 3) when there is no inflation. None of these situations prevail, given that utility stocks have been trading well above book value for two decades.

Clearly, a company's achieved earnings in any given year are likely to exceed or be less than their long-run average. Depressed or inflated M/B ratios are to a considerable degree a function of forces outside the control of regulators, such as the general state of the economy, or general economic or financial circumstances which may affect the yields on securities of unregulated as well as regulated enterprises. I regard the achievement of a 1.0 M/B ratio as appropriate, but only in a very long-run sense, for utilities with no unregulated assets, and in a world where historical costs of assets mirror replacement costs. For utilities to exhibit a long-run M/B ratio of 1.0, it is clear that during economic upturns and more favorable capital market conditions, the M/B ratio must exceed its long-run average of 1.0 to compensate for the periods during which the M/B ratio is less than its long-run average under less favorable economic and capital market conditions.

iii) The traditional M/B does not reflect the replacement cost of a company's assets. The fundamental goal of regulation should be to set the expected economic profit for a public utility equal to the level of profits expected to be earned by firms of comparable risk, in short, to emulate the competitive result. For unregulated firms, the natural forces of competition will ensure that in the long-run the ratio of the market value of these firm's securities equals the replacement cost of

their assets. This suggests that a fair and reasonable price for a public utility's common stock is one that produces equality between the market price of its common equity and the replacement cost of its physical assets. The latter circumstance will not necessarily occur when the M/B is 1.0. Only when the book value of the firm's common equity equals the value of the firm's equity at replacement cost will equality hold.

In an inflationary period, the replacement cost of a firm's assets may increase more rapidly than its book equity. To avoid the resulting economic confiscation of shareholders' investment in real terms, the allowed rate of return should produce a M/B ratio which provides a Q-ratio of 1 or a Q-ratio equal to that of comparable firms. It is quite plausible and likely that M/B ratios will exceed one if inflation increases the replacement cost of a firm's assets at a faster pace than historical cost (book equity). Perhaps this explains in part why utility M/B ratios have remained well above 1.0 over the past two decades.

Q. Are Mr. Hill's views on the market-to-book ratio consistent with his DCF analysis?

A. No, they are not. In his implementation of the sustainable growth DCF model shown on his exhibit DOD-207, Mr. Hill uses assumed equity returns (ROE) which are considerably higher than his recommended cost of equity of 9.0% for HECO. In other words, he assumes that his sample of utilities will earn forever a return in excess of their cost of equity, or, in other words, that the M/B ratios of these companies will exceed 1.00 forever. This is inconsistent with Mr. Hill's view that investors expect M/B ratios to converge towards 1.00.

Q. Do you have any more comments on Mr. Hill's market-to-book views?

A. Yes, I do. Mr. Hill argues that utility stocks should trade at or near book value. It is highly unusual for utility stock prices to equal book value. Stock prices above book value are common for utility stocks, and indeed for all of the major market indexes. It is obvious that regulators, through their rate case decisions, and investors do not subscribe to Mr. Hill's position that utilities that have market prices above book value are over-earning. Otherwise, regulators would not grant rate increases for any utility whose stock price was above book value, and investors would never bid up the price of stock above book value. It is very difficult to accept Mr. Hill's notion that, in a free-market economy with rampant competition, the vast majority of all publicly-traded stocks are earning well in excess of their cost of capital.

Mr. Hill's views on the role of M/B are certainly not corroborated by the historical facts. Utility M/B ratios have been consistently above 1.00 for almost two decades. Are we to conclude that regulators have been systematically misguided all across the United States for all these years? Or are we to conclude that M/B ratios are largely irrelevant, and that Mr. Hill's views on the role of M/B ratios are erroneous? I subscribe to the latter view, and I conclude that Mr. Hill's M/B-based cost of equity estimates should be dismissed by the Commission along with his views on the M/B ratio.

Finally, Mr. Hill's discussion in his exhibit DOD-203 (pages 8-9) implies that, when stock prices and book values diverge, as they do now and have been for two decades, both the EPR and forecast ROE will misspecify the cost of equity. Nevertheless, he averages the results of these two methods as an indicator of investors' expected cost of equity. It is indeed disconcerting to assume that an

average of two inaccurate measures of the cost of equity will provide a reasonable result.

11. CAPM MARKET RISK PREMIUM

Q. Does Mr. Hill employ a CAPM estimate?

A. Yes, he does. As a third check on his DCF estimate, Mr. Hill performs a CAPM analysis of the cost of common equity. In his exhibit DOD-203, Mr. Hill first points out some of the theoretical blemishes of the CAPM and focuses selectively and unfairly on the 1992 Fama and French critique of the theory. It is interesting that Mr. Hill chooses to critique CAPM theory, yet devotes no such criticism to the DCF model. Had Mr. Hill conducted a theoretical assessment of the DCF method, he would have found the theoretical foundations of the DCF model even more fragile. Later in my rebuttal, I discuss the numerous assumptions that underlie the DCF model and their lack of realism, and contrast these assumptions with those underlying the CAPM. It is also interesting that Mr. Hill relies on the CAPM in order to estimate the appropriate return adjustment for HECO's stronger capital structure, relative to its peers.

Q. Do you agree with Mr. Hill's CAPM analysis?

A. No, I do not. Mr. Hill's CAPM check is flawed for two reasons. First, the use of geometric average of realized returns is erroneous. Second, the use of the plain vanilla CAPM understates the cost of capital.

Q. Please comment on the use of arithmetic averages versus geometric averages in measuring expected return.

A. One major issue relating to the use of realized returns is whether to use the ordinary average (arithmetic mean) or the geometric mean return. Mr. Hill uses both the geometric mean return and the arithmetic mean return in his CAPM

analysis (see exhibit DOD-211). Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital. As demonstrated formally in Chapter 11 of my book, Regulatory Finance, and in Brealy & Myers' best-selling corporate finance textbook, Principles of Corporate Finance, only arithmetic averages can be used as estimates of cost of capital, and the geometric mean is not an appropriate measure of the cost of capital. I also note that the widely-cited Ibbotson Associates publication from which Mr. Hill's market return estimate is derived contains a detailed and rigorous discussion of the impropriety of using geometric averages in estimating the cost of capital. There is no theoretical or empirical justification for the use of geometric mean rates of returns. I know of no textbook on finance or scientific journal article which advocates the use of the geometric mean as a measure of the appropriate discount rate in computing the cost of capital or in computing present values.

The net effect of Mr. Hill's use of the geometric mean market risk premium of 5.0% rather than the arithmetic mean of 6.6% is to decrease his estimates of the required market return by 1.60%, that is, the difference between the arithmetic and geometric mean reported in the aforementioned Ibbotson Associates publication. This in turn translates into an understatement of HECO's cost of equity by approximately 1.25% (125 basis points). The latter estimate is derived by assuming that HECO's beta is 0.78 from Mr. Hill's exhibit DOD-211 and multiplying that beta by 1.6%, the difference between the arithmetic and geometric mean risk premiums for stocks over government bonds.

Q. Can you provide a brief explanation as to why the arithmetic mean is preferable to the geometric mean when estimating the cost of capital?

A. The use of the arithmetic mean appears counter-intuitive at first glance, because

we commonly use the geometric mean return to measure the average annual achieved return over some time period. For example, the long-term performance of a portfolio is frequently assessed using the geometric mean return.

But performance appraisal is one thing, and cost of capital estimation is another matter entirely. In estimating the cost of capital, the goal is to obtain the rate of return that investors expect, that is, a target rate of return. On average, investors expect to achieve their target return. This target expected return is in effect an arithmetic average. The achieved or retrospective return is the geometric average. In statistical parlance, the arithmetic average is the unbiased measure of the expected value of repeated observations of a random variable, not the geometric mean.

The geometric mean answers the question of what constant return you would have had to achieve in each year to have your investment growth match the return achieved by the stock market. The arithmetic mean answers the question of what growth rate is the best estimate of the future amount of money that will be produced by continually reinvesting in the stock market. It is the rate of return which, compounded over multiple periods, gives the mean of the probability distribution of ending wealth.

While the geometric mean is the best estimate of performance over a long period of time, this does not contradict the statement that the arithmetic mean compounded over the number of years that an investment is held provides the best estimate of the ending wealth value of the investment. The reason is that an investment with uncertain returns will have a higher ending wealth value than an investment which simply earns (with certainty) its compound or geometric rate of return every year. In other words, more money, or terminal wealth, is gained by

the occurrence of higher than expected returns than is lost by lower than expected returns.

In capital markets, where returns are a probability distribution, the answer that takes account of uncertainty, the arithmetic mean, is the correct one for estimating discount rates and the cost of capital. In conclusion, Mr. Hill commits a serious error in logic by relying on geometric averages rather than on the conceptually correct arithmetic averages of historical returns. I know of no valid textbook, article, or professional journal that advocates discounting cash flows (estimating cost of capital) using the geometric rate of return.

While it is true that a geometric mean is correct and indeed appropriate when measuring performance over a long time period, it is incorrect when estimating a risk premium to compute the cost of capital.

Q. Are there theoretical reasons why the arithmetic mean is the correct one?

A. Yes, there are. The geometric mean measures the magnitude of the returns, as the investor starts with one portfolio and ends with another. It does not measure the variability of the journey, as does the arithmetic mean. The geometric mean is backward looking. There is no difference in the geometric mean of two stocks or portfolios, one of which is highly volatile and the other of which is absolutely stable. The arithmetic mean, on the other hand, is forward looking in that it does impound the volatility of the stocks.

To illustrate, the table below shows the historical returns of two stocks, the first one is highly volatile with a standard deviation of returns of 65% while the second one has a zero standard deviation and is therefore riskless. It makes no sense intuitively that the geometric mean is the correct measure of return, one that implies that both stocks are equally risky since they have the same geometric

mean. No rational investor would consider the first stock equally as risky as the second stock. Every financial model to calculate the cost of capital recognizes that investors are risk averse and avoid risk unless they are adequately compensated for undertaking it. It is more consistent to use the mean that fully impounds risk (arithmetic mean) than the one from which risk has been removed (geometric mean).

Table 1 Geometric vs. Arithmetic Returns

	Stock A	Stock B
1995	50.0%	11.61%
1996	-54.7%	11.61%
1997	98.5%	11.61%
1998	42.2%	11.61%
1999	-32.3%	11.61%
2000	-39.2%	11.61%
2001	153.2%	11.61%
2002	-10.0%	11.61%
2003	38.9%	11.61%
2004	20.0%	11.61%
Standard Deviation	64.9%	0.0%
Arithmetic Mean	26.7%	11.6%
Geometric Mean	11.6%	11.6%

Q. Are there empirical reasons why the arithmetic mean is the correct one?

A. Yes, there are. If both the geometric and arithmetic means for the Ibbotson deciles for 1926-2004 data are regressed against the standard deviation of returns for the firms in the deciles, the arithmetic mean outperforms the geometric mean in this statistical regression. Moreover the constant of arithmetic mean regression matches the average Treasury bond rate and therefore makes economic sense while the constant for the geometric mean matches nothing in particular. This is simply because the geometric mean is stripped of volatility information and, as a

result, does a poor job of forecasting returns based on volatility.

Q. Can you comment on the viewpoints offered by leading corporate finance textbooks on the issue of the arithmetic mean?

A. Yes. In their widely-used investment management textbook, Bodie, Kane, and Marcus, (Investments, McGraw Hill, 5th Edition) strongly advocate the use of the arithmetic mean in estimating the cost of capital. The authors offer the following example in Chapter 24. As shown in the table below, consider a stock that will either double in value (return = 100%) with a probability of 0.5, or halve in value (return = -50%) with probability of 0.5.

Outcome	Final value of $1 invested	1-yr return
Double	$2.00	100%
Halve	$0.50	-50%

Suppose that the stock's performance over a two-year period is representative of the probability distribution, doubling in one year (r1 = 100%) and halving in the next (r2 = -50%). The stock's price ends up exactly where it started, and the geometric average annual return over the two-year period, rg, is zero:

$$1 + r_g = [(1 + r_1)(1 + r_2)]^{1/2}$$

$$= [(1 + 1)(1 - .50)]^{1/2} = 1$$

$$r_g = 0$$

confirming that a zero year-by-year return would have replicated the total return earned on the stock. The expected annual future rate of return on the stock is not zero, however. It is the arithmetic average of 100% and -50%, (100-50)/2 = 25%. There are two equally likely outcomes per dollar invested: either a gain of $1 when r = 100% or a loss of $0.50 when r = -50%. The expected profit is ($1-

$.50)/2 = $.25 for a 25% expected rate of return. The profit in the good year more than offsets the loss in the bad year, despite the fact that the geometric return is zero. The arithmetic average return thus provides the best guide to expected future returns. In conclusion, Mr. Hill should have heeded professors Bodie, Kane, and Marcus' advice, and commits a serious logical error by relying on geometric averages rather than on the conceptually correct arithmetic averages of historical returns.

The following extract from a widely utilized corporate finance textbook illustrates the distinction between arithmetic and geometric averages and concludes that arithmetic averages are appropriate when estimating the cost of capital.

> *"The proper uses of arithmetic and compound rates of return from past investments are often misunderstood. Therefore, we call a brief time-out for a clarifying example.*
>
> *Suppose that the price of Big Oil's common stock is $100. There is an equal chance that at the end of the year the stock will be worth $90, $110, or $130. Therefore, the return could be –10 percent, +10 percent or +30 percent (we assume that Big Oil does not pay a dividend). The expected return is 1/3(-10+10+30)= +10 percent.*
>
> *If we run the process in reverse and discount the expected cash flow by the expected rate of return, we obtain the value of Big Oil's stock:*

$$PV = \frac{110}{1.10} = \$100$$

The expected return of 10 percent is therefore the correct rate at which to discount the expected cash flow from Big Oil's stock. It is also the opportunity cost of capital for investments which have the same degree of risk as Big Oil.

Now suppose that we observe the returns on Big Oil stock over a large number of years. If the odds are unchanged, the return will be –10 percent in a third of the years, +10 percent in a further third, and +30 percent in the remaining years. The arithmetic average of these yearly returns is

$$\frac{-10 + 10 + 30}{3} = +10\%$$

Thus the arithmetic average of the returns correctly measures the opportunity cost of capital for investments of similar risk to Big Oil stock.

The average compound annual return on Big Oil stock would be

$$(.9 \times 1.1 \times 1.3)1/3 - 1 = .088, \text{ or } 8.8\%$$

less than the opportunity cost of capital. Investors would not be willing to invest in a project that offered an 8.8 percent expected return if they could get an expected return of 10 percent in the capital markets. The net present value of such a project would be

$$NPV = -100 + \frac{108.8}{1.1} = -1.1$$

Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound

annual rates of return." (Richard A. Brealey and Stewart C. Myers, Principles of Corporate Finance, 7th Edition, Irwin McGraw-Hill, 2003, page 156-7.) [1]

12. CAPM AND THE EMPIRICAL CAPM

Q. Do you agree with the use of the raw form of the CAPM used by Mr. Hill to estimate the cost of capital?

A. No, I do not. I believe that the plain vanilla version of the CAPM should be supplemented by the more refined version of the CAPM. There have been countless empirical tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. This is one of the most well-known results in finance. A CAPM-based estimate of the cost of capital underestimates the return required from low-beta securities and overstates the return from high-beta securities, based on the empirical evidence.

The downward-bias is particularly significant for low-beta securities, such as the electric utilities used by Mr. Hill. Mr. Hill's CAPM estimates of equity costs are understated by about 50 basis points from this bias alone.

[1] A survey published in 1998 found that 71% of textbooks/tradebooks used a historical arithmetic mean as the market risk premium and 60% of financial advisors used either a market risk premium of 7.0-7.4% (similar to the arithmetic mean) or a long-term arithmetic mean. For corporations, there was no single method that represented a consensus. Robert F. Bruner, Kenneth M. Eades, Robert S. Harris, and Robert C. Higgins, "Best Practices in Estimating the Cost of Capital: Survey and Synthesis", *Financial Practice and Education,* Vol. 8, Number 1, Spring/Summer 1998, page 18.

13. INTEREST RATE FORECASTS

Q. Does Mr. Hill's roe recommendation take into account interest rate forecasts?

A. No, it does not. Mr. Hill refers to selected interest rate data on exhibit DOD-204 and makes the point that the decline in interest rates in recent periods justifies a significant reduction in ROE. However, on page 13 of his testimony, Mr. Hill points to Value Line's projected increase in the long-term Treasury bond yield to 5.1% in 2005 and 5.7% in 2006. Nowhere in his testimony does he formally factor in the projected increase in interest rates. To the extent that interest rates rise from their current levels, the cost of equity determined from recent data will understate future capital costs.

The prospect of higher interest rates rather than lower interest rates looms much larger at this time. Already, we have witnessed several increases in the Fed Funds rate by the Federal Reserve in the past twelve months. Coupled with record-high federal deficits and balance-of-payments deficits, these policy actions are indicative of rising long-term interest rates. Indeed, forecasts of long-term interest rates indicate that interest rates are expected to increase from their current levels. Thus, the 9.0% ROE recommended by Mr. Hill is certainly not reflective of the forecast increase in capital costs.

14. CAPITAL STRUCTURE

Q. Do you agree with Mr. Hill's capital structure recommendation?

Q. No, I do not. On page 27 of his testimony, Mr. Hill recommends that the ROE allowed the Company should be below the midpoint of his range of returns on the grounds that his comparable firms possess weaker capital structures (more debt) and that HECO possesses a high common equity ratio relative to its peers. I would agree with Mr. Hill if the comparable companies indeed had similar

business risks as HECO. However, as I showed in my direct testimony, HECO's business risks exceed the industry average. It is only normal and prudent management practice to lower financial risk when facing higher business risks as is the case with HECO. As a matter of fact, the Commission's decisions in past proceedings have recognized HECO's higher business risk and have added an adjustment to the cost of equity for comparison companies, the opposite of what Mr. Hill recommends. There is no basis for a downward ROE adjustment as Mr. Hill recommends. On the contrary, an upward adjustment is warranted.

The Company's projected 2005 capital structure should be employed for ratemaking purposes as the three ROE witnesses in this case recommend.

15. LOGICAL INCONSISTENCIES

EXPECTED RETURN: EQUITY MARKET VS. UTILITY

Q. Did you detect any logical inconsistency in Mr. Hill's roe recommendation?

A. Yes, I detected many. On page 8 lines 8-12 of his direct testimony, Mr. Hill tests the reasonableness of his 9.0% recommended ROE by comparing it to expected stock market returns of 8.0% - 10.0% that he claims are implied in the most recent academic research and in investment reports such as A.G. Edwards. Mr. Hill concludes that his proposed cost of equity of 9.0% is consistent with such forecasts. This is incorrect. The return figures cited by Mr. Hill are for the total equity market. HECO and utilities generally are less risky than the overall market (HECO's beta is 0.78 according to Mr. Hill) and, therefore, should have a lower expected return than the overall market. Yet, Mr. Hill's recommended ROE for HECO is the same as the aforementioned expected return for the market as a whole. This is illogical. In order to be consistent with his own view of stock market returns of 8.0% - 10.0% and HECO's beta of 0.78 (meaning that HECO is

78% as risky as the overall stock market), Mr. Hill should have recommended a ROE of 6.2% - 7.8%, that is 0.78 times 8.0% - 10.0%. That result is not reasonable.

Q. Did you detect any logical inconsistency in Mr. Hill's CAPM market risk premium?

A. Yes, I did. On pages 8 lines 1-3 of his testimony, Mr. Hill concludes that "the new research .....indicates that Ibbotson data is skewed upward and the actual market risk premium is much, much lower – in the range of 3% to 4.5%." Yet, he uses a market risk premium ("MRP") range of 5.0% - 6.6% in implementing the CAPM on exhibit DOD-211! Mr. Hill does not explain this contradiction. On pages 60-61 of his testimony, Mr. Hill chastises my use of the 7.2% historical MRP from the well-known Ibbotson publication and argues that I should have used 6% instead according to a more recent paper published by Ibbotson.

Q. Is Mr. Hill's assessment of the "new research" on the market risk premium of 3.0% to 4.5% accurate?

A. No, it is not. Leaving aside the issue that Mr. Hill did not use his own assessment of the MRP of 3.0% - 4.5%, his assessment of the state of research in this area is quite inaccurate and incomplete.

Ibbotson's Stocks, Bonds, Bills, and Inflation 2004 Yearbook is a primary source of data on U.S. capital market returns. This annual publication compiles monthly returns to various asset classes from 1926 to date. From Ibbotson 2005, a broad market sample of U.S. common stocks outperformed long-term U.S. government bonds by 6.6%. The historical market risk premium over the income component of long-term Treasury bonds rather than over the total return is 7.2%. It has been common practice to assume that this historical result provides an

adequate basis for the expected Market Risk Premium (MRP). In their widely-used aforementioned textbook, Brealey & Myers state:

> *"We have no official position on the exact market risk premium, but we believe a range of 6 to 8.5 percent is reasonable for the United States. We are most comfortable with figures toward the upper end of the range."*

Because they are referring to the premium over Treasury Bills which is about 1.5% greater than the premium over bonds (Ibbotson 2005), this implies that Brealey & Myers would look to the upper end of a range of 4.5% to 7% for the MRP, again a long way from Mr. Hill's 3.0% - 4.5% "assessment". In fact, the Ibbotson-Chen study estimates a MRP of 5.90% on an arithmetic basis. It is noteworthy that the authors conclude their paper by stating that their estimate of the equity risk premium is "far closer to the historical premium than being zero or negative."

Published work by Dimson, Marsh, and Staunton[2] report on returns over the period 1900 to 2000 for twelve countries, representing 90% of today's world market capitalization. They report an average risk premium over long bond returns over all countries of 5.6%, with the U.S. at 7.0%. The premium was generally higher for the second half century than for the first. For example, the U.S. had 5% in the first half, compared to 7.5% in the second half, again a long way from Mr. Hill's 3.0% - 4.5% estimate (which he did not use).

A second approach to estimate the MRP is prospective in nature and consists of applying the DCF model to an aggregate equity index as I did in my

[2] Dimson, Elroy, Paul Marsh and Mike Staunton (2000) "Risk and Return in the 20th and 21st centuries." Business Strategy Review 11(2): 1-18.

direct testimony. Mr. Hill cherry picks a similar prospective study by Ibbotson and Chen, the basis for his 3.0% - 4.5% MRP, although he did not use it. A recent 2003 comprehensive article published in Financial Management by Harris, Marston, Mishra, and O'Brien ("HMMO") provides estimates of the ex ante expected returns for S&P 500 companies over the period 1983-1998[3]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. The prevailing risk-free rate for each year is then subtracted from the expected rate of return for the overall market to arrive at the MRP for that year. From that study, the average MRP estimate for the overall period is 7.2%, again a long way from Mr. Hill's 3.0% - 4.5%.

Surveys of academics and investment professionals, for example the Welch surveys[4], provide another technique of estimating the MRP. While this technique has the benefit of being forward-looking, it is subject to the well-known shortcomings of survey techniques. There are several reasons to place little weight on survey results relative to the results from other approaches. First, return definitions and risk premium definitions differ widely. Second, survey responses are subject to bias. Thirdly, subjective assessments about long-term market behavior may well place undue weight on recent events and immediate prospects.

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[3] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

[4] Welch, Ivo (2000, 2001), "Views of Financial Economists on the Equity Premium and on Professional Controversies," Journal of Business 73(4): 501-537.

Keeping these limitations in mind, Welch surveyed finance professors on their views about the long-term equity premium in 1998 and again in 2001. The arithmetic mean long-term expected risk premium of respondents in the 2001 survey for the U.S. was 7.1% in 1998 and 5.5% in 2001, again a long way from Mr. Hill's 3.0% - 4.5%. Given the deplorable behavior of equity markets in the 2000-2002 period, it would not be surprising to see an upward reassessment of those risk premiums.

Q. Is Mr. Hill's market risk premium estimate of 3.0% - 4.5% consistent with regulatory decisions?

A. No, it is not. It is useful to examine the MRP estimates implicit in regulatory ROE decisions. The CAPM framework can be used to quantify the MRP implicit in the allowed risk premiums for regulated utilities. According to the CAPM, the risk premium is equal to beta times the market risk premium:

$$\text{Risk Premium} = \beta\,(R_M - R_F)$$

$$\text{Risk Premium} = \beta \times \text{MRP}$$

Solving for MRP, we obtain:

$$\text{MRP} = \text{Risk Premium} / \beta$$

I examined the MRPs implied in nearly 200 regulatory decisions for electric utilities in the United States over the period 1996-2005. Using the allowed average risk premium of 5.5% in these decisions over the last decade and a beta of 0.78 for U.S. electric utilities, the implied market risk premium is 7.0%, again a long way from Mr. Hill's 3.0% - 4.5%. Similar results are obtained when using regulatory decisions for natural gas utilities.

16. RESPONSES TO MR. HILL'S CRITICISMS

HISTORICAL RISK PREMIUM METHOD

Q. How do you respond to Mr. Hill's criticism of your risk premium method?

A. On pages 64-67 of his testimony, especially on page 64 lines 5-12, Mr. Hill critiques the risk premium method on two grounds: 1) the method looks backward in time and assumes that "past is prologue", and 2) the method assumes that the risk premium is constant over time. Mr. Hill argues that neither of these two assumptions is true.

The first criticism is unwarranted. I employed returns realized over long time periods rather than returns realized over more recent time periods. Realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods as Mr. Hill does on page 65 of his testimony by cherry-picking sub-periods in order to demonstrate the behavior of the risk premium over time. A risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge, or else, investors would never commit any funds.

I have ignored realized risk premiums measured over short time periods, since they are heavily dependent on short-term market movements. Instead, I have relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate market risk premium

minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

Mr. Hill's second concern is unwarranted as well. To the extent that the historical equity risk premium estimated follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. The best estimate of the future risk premium is the historical mean. As I explained in my direct testimony, since I found no evidence that the market price of risk or the amount of risk in common stocks has changed over time, that is, no significant serial correlation in the successive market risk premiums from year to year, it is reasonable to assume that these quantities will remain stable in the future.

In trying to support his critique of the Risk Premium method, Mr. Hill quotes a 1985 Brigham article on page 64 of his testimony. I direct Mr. Hill's attention to Professor Brigham's best-selling corporate finance textbook (Financial Management: Theory and Practice, 11th ed., South-Western, 2004), now in its 11th edition, and not its 5th edition as cited by Mr. Hill on page 52 of his testimony, where Professor Brigham strongly recommends the use of risk premium studies as I have done in my direct testimony and as I recommend in my own textbook, Regulatory Finance. Professor Brigham goes on to describe the Risk Premium approach in much the same way in which I have applied it in my own testimony.

Risk Premium analyses are widely used by analysts, investors, and expert witnesses. Most college-level corporate finance and/or investment management texts including Investments by Bodie, Kane, and Marcus, McGraw-Hill Irwin, 2002, which is a recommended textbook for CFA (Chartered Financial Analyst)

1 certification and examination, contain detailed conceptual and empirical
2 discussion of the risk premium approach. The latter is typically recommended as
3 one of the three leading methods of estimating the cost of capital (see for example
4 the best-selling finance textbook Brigham, E.F. and Gapenski, L.C., Financial
5 Management: Theory and Practice, 11th ed., South-Western, 2004). Techniques
6 of risk premium analysis are widespread in investment community reports.
7 Professional certified financial analysts are certainly well versed in the use of this
8 method. Thus, Mr. Hill's critique of the Risk Premium methodology is
9 unwarranted.

10 **RISK PREMIUM VS INTEREST RATES**

11 Q. Please discuss the relationship between the level of interest rates and utility risk
12 premiums.

13 A. On pages 67-69 of his testimony, Mr. Hill criticizes my allowed risk premium
14 study and questions the notion of an inverse relationship between the level of
15 interest rates and risk premiums. I disagree. It is transparently clear from the data
16 reported in my direct testimony that allowed risk premiums vary inversely with
17 the levels of interest rates. Regulators have systematically increased the
18 authorized risk premium when interest rates declined, and decreased the
19 authorized risk premium when interest rates increased. The relationship, depicted
20 graphically on page 32 of my direct testimony, is highly significant from a
21 statistical perspective.

22 Published studies by Brigham, Shome, and Vinson (1985), Harris (1986),
23 Harris and Marston (1992), Maddox, Pippert and Sullivan (1995), and others

demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates, rising when rates fell and declining when interest rates rose. [5]

The reason for this relationship is that when interest rates rise, bondholders, whose interest rates are fixed, often suffer a decrease in the market value of their bonds, experiencing a capital loss. This is referred to as interest rate risk. Stockholders, on the other hand, are more concerned with the firm's earning power. In order to avoid interest rate risk in an environment of rising interest rates, investors tend to become more willing to undertake equity investments which, although subject to some fear of loss of earning power, are less sensitive to the fear of interest rate risk. The resulting increase in the supply of funds available for such equity investments causes a downward pressure on the market price for equity. So, generally it is observed that if bondholders' fear of interest rate risk exceeds shareholders' fear of loss of earning power, the risk differential will narrow and hence the risk premium will shrink. This is particularly true in high inflation environments. Interest rates rise as a result of accelerating inflation, and the interest rate risk of bonds intensifies more than the earnings risk of common stocks, which are partially hedged from the ravages of inflation. This phenomenon has been termed as a "lock-in" premium. Conversely in low interest rate environments, as is the case currently, when bondholders' interest rate fears

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[5] Brigham, E.F., Shome, D.K., and Vinson, S. R. "The Risk Premium Approach to Measuring a Utility's Cost of Equity." *Financial Management,* Spring 1985, 33-45. ("BSV") Harris, R.S. "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return." *Financial Management,* Spring 1986, 58-67. Harris, R.S. and Marston, F.C. "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts." *Financial Management,* Summer 1992, 63-70. ("HM") Maddox, F.M., Pippert, D. T., and Sullivan, R.N. "An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry" *Financial Management,* Autumn 1995, 89-95. ("MPS")

subside and shareholders' loss of earning power dominate, the risk differential will widen and hence the risk premium will increase. This in fact occurred since 1998.

In short, the empirical evidence from the published academic literature demonstrates that the risk premium varies inversely with the level of interest rates, contrary to Mr. Hill's position.

CAPM VALIDATION

Q. Do you agree with Mr. Hill's criticism of your CAPM analysis?

A. No, I do not. On page 3 of exhibit DOD-203, Mr. Hill selectively picks a study by Fama & French published in 1992 which questions the importance of beta in explaining observed returns. Generally speaking, financial theory has shown that beta is a sufficient risk measure for diversified investors and most of the empirical literature has confirmed its importance in determining expected return. There is a notable exception, namely the one selectively picked by Mr. Hill. In the Fama & French (1992) article, selectively referenced by Mr. Hill, the authors found little explanatory power in beta. However, as the subsequent literature has indicated, the autopsy of beta is premature, and "reports of beta's death are greatly exaggerated." For one thing, the CAPM specifies a relationship between expected returns and beta, whereas Fama & French employ realized returns. Moreover, Mr. Hill did not reference a subsequent 1993 research paper by Kothari, Shanken, & Sloan (1993) who find significant return compensation for beta risk and little relation to M/B ratios, unlike Fama & French. They also find that market risk premiums are much larger when betas are estimated using annual rather than monthly data.

There is a fertile academic literature published in scientific journals on this subject since the publication of the Fama-French results in 1992. Since the

1 publication of the Fama & French 1992 paper, the CAPM and its primary risk
2 measure, beta, have received renewed support with the addition to the literature of
3 several more recently published papers. In a 1993 paper, Chan and Lakonishok[6]
4 found a strong relationship between beta and return for the years of their study.
5 In a prominent paper in the same journal, Fischer Black[7] also refuted the
6 conclusions of Fama and French and stated that "beta is alive and well." In
7 March 1995, Kothari, Shanken, and Sloan[8] showed that when betas are estimated
8 from time-series regressions of annual portfolio returns on the annual return on an
9 equally weighted market index, beta receives statistically significant return
10 compensation. In a December 1995 paper, Kim[9] found that, once corrected for
11 the errors in variables problem, there was more support for the role of beta. In yet
12 another 1996 paper, Jagannathan & Wang[10] showed that when betas are allowed
13 to vary over the business cycle, the empirical support of the CAPM is very strong.
14 Fama and French themselves revisited the issue in 1994 and proposed a three-
15 factor model for security returns that included beta as a factor.
16 Ibbotson Associates in their annual survey of capital market returns
17 ("Stocks, Bonds, Bills, and Inflation: 2005 Yearbook, Valuation Edition", page
18 146-147) compare the Fama-French results with the CAPM results. For large

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[6] Chan, L.K.C. and Lakonishok, J., "Are Reports of Beta's Death Premature?" Journal of Portfolio Management, Summer 1993.

[7] Black, F., "Beta and Return," Journal of Portfolio Management, Summer 1993.

[8] Kothari, S.P., Shanken, J., and Sloan, R.G., "Another Look at the Cross-Section of Expected Stock Returns," Journal of Finance, Vol. 50, No. 1.

[9] Kim, D., "The Errors in the Variables Problem in the Cross-Section of Expected Stock Returns," Journal of Finance, December 1995, Vol. 50, No. 5

[10] Jagannathan, R. and Wang. Z., "The Conditional CAPM and the Cross-Section of Expected Returns," Journal of Finance, March 1996, Vol. 51, No. 1

capitalization companies, the results are virtually indistinguishable. Finally, William Sharpe, the Nobel Prize winning author of the CAPM refutes the Fama-French criticism in a May-June 1998 article from Dow Jones Asset Manager entitled "Revisiting the CAPM". This article is available on Professor Sharpe's Web site at Stanford University.

As is the case for most of the research published in prestigious academic finance journals, the extensive literature published following the Fama-French research on beta was extremely influential, as evidenced by the continuing popularity of the CAPM in determining the cost of capital in practice.

EMPIRICAL CAPM

Q. Please comment on Mr. Hill's assessment of the empirical CAPM used in your testimony.

A. On pages 62-63, Mr. Hill argues that my ECAPM constitutes a double beta adjustment because the use of adjusted betas already allows for the biases inherent in the plain vanilla CAPM. I do not share the view that the ECAPM is equivalent to a beta adjustment.

There are two distinct and separate issues involved when implementing the CAPM. First, given the validity of the standard CAPM, what is the best proxy for expected beta? Second, and more fundamentally, does the standard CAPM provide the best explanation of the risk-return relationship observed on capital markets?

With respect to the appropriate measurement for beta, unadjusted raw betas are inappropriate to use in a CAPM analysis. Current stock prices reflect expected risk, that is, expected beta, rather than historical risk or historical beta. Historical betas, whether raw or adjusted, are only surrogates for expected beta.

The best of the two surrogates is adjusted beta. This is why Value Line and other investment information services report adjusted betas, regardless of whether one subscribes to the validity of the orthodox CAPM or not.

Another reason for relying on adjusted betas is that raw betas do not capture the extra sensitivity of utility company returns to changes in interest rates, understating the risk of utility stocks. Adjusted betas compensate for the interest sensitivity of utility stocks. Also, the betas implied in regulatory decisions are virtually identical to the adjusted beta estimates reported by Value Line for electric utilities and are inconsistent with raw beta estimates. To conclude, historical betas, whether raw or adjusted, are only surrogates for expected beta. The best of the two surrogates is clearly adjusted beta. It is quite clear that reliance on adjusted betas – widely used in the financial community – provides a more accurate perspective of the utility risk/return relationship than the raw unadjusted beta.

With respect to the empirical validity of the plain vanilla CAPM, there have been countless empirical tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM, and that result holds true even when Value Line (adjusted) betas are used. That is, empirical research has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high-

beta securities, based on the empirical evidence. This is one of the most well-known results in finance. A number of variations on the original CAPM theory have been proposed to explain this finding. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \alpha + \beta \times (MRP - \alpha)$$

where α is the "alpha" of the risk-return line, a constant, and the other symbols are defined as usual. Inserting the long-term risk-free rate as a proxy for the risk-free rate, an alpha in the range of 1% - 2%, and reasonable values of beta and the MRP in the above equation produces results that are indistinguishable from the ECAPM used in my testimony:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$

I point out that an alpha range of 1% - 2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. This is also because the use of adjusted betas rather than raw betas also incorporate some of the desired effect of using the ECAPM. Thus, it is reasonable to apply a conservative alpha adjustment.

In short, I do not share Mr. Hill's view that the ECAPM is equivalent to a beta adjustment. The ECAPM is a return adjustment and not a beta adjustment. For utility stocks with betas less than one, the CAPM understates the return. The downward-bias is particularly significant for low-beta securities such as the

sample electric utilities used by Mr. Hill. Not only has Mr. Hill misstated the basis for the Empirical CAPM which I employ in my testimony, but his own CAPM analysis also understates the rate of return on equity by approximately 50 basis points, the difference between the CAPM and ECAPM estimates in my Direct Testimony.

CAPM VS. DCF ASSUMPTIONS

Q. On page 52 of his testimony, Mr. Hill claims that the assumption underlying the CAPM are far more restrictive than those that support the DCF. Do you agree?

A. No, I do not. On pages 52-54 of his testimony, Mr. Hill attempts to denigrate the CAPM paradigm of modern finance by describing the assumptions that enable the existence of the CAPM analysis as far more restrictive than those that support the DCF. I disagree. Theoretically, the DCF model is at least as fragile, if not more, as the CAPM in view of the lack of realism of the assumptions underlying the DCF model relative to those underlying the CAPM.

The crucial assumptions of the general DCF model are:

i) That investors, in fact, evaluate common stocks in the classical valuation framework, and trade securities rationally at prices reflecting their perceptions of value.

ii) That investors discount the expected cash flows at the same rate of return ("K") in every future period. In other words, a flat yield curve is assumed.

iii) That the K obtained from the fundamental DCF equation corresponds to that specific stream of future cash flows alone, and no other. There may be alternate company policies that would generate the same future cash flows, but these policies may alter the risk of the cash flow

stream, and hence modify the investor's required return, K.

The assumptions of the standard constant growth variation of the DCF model are as follows:

Assumption #1. The 3 assumptions discussed in conjunction with the general DCF model still remain in force.

Assumption #2. The discount rate, K, must exceed the growth rate, g. In other words, the standard DCF model does not apply to growth stocks.

Assumption #3. The same growth rate applies to dividend, earnings, and book value, and is constant in every year to infinity.

Some of these assumptions can be quite unrealistic in a given capital market environment. For example, the standard constant growth DCF model assumes a constant market valuation multiple, that is, a constant price/earnings (P/E) ratio. In other words, the model assumes that investors expect the ratio of market price to dividends (or earnings) in any given year to be the same as the current price/dividend (or earnings) ratio. This is unrealistic under current conditions. The inability of the standard DCF model to account for changes in relative market valuation and the questionable applicability of the model when M/B ratios deviate substantially from 1.00 (discussed earlier in my rebuttal testimony) are additional vivid examples of the potential shortcomings of the DCF model. The DCF model is simply not equipped to deal with sudden surges in M/B and P/E ratios, as was experienced by several utility stocks in recent years.

The realism of the DCF assumptions is discussed fully in Chapter 9 of Dr. Morin's book, Regulatory Finance, Public Utility Reports Inc., Arlington, Va.,

1994. The assumptions underlying the CAPM are discussed in Chapters 12 and 15 of the same book.

Many of the assumptions that must be made to utilize the DCF model are simply not realistic. According to the theory of the constant growth form of the DCF, future earnings per share, dividends per share, book value per share, and price per share will all grow at the same constant rate. There is no evidence that these conditions actually prevail in the equity market. Indeed, a casual examination of Mr. Hill's exhibit DOD-207 clearly demonstrates that these steady-state growth conditions represent unrealistic assumptions. As Mr. Hill himself acknowledges, the constant growth assumptions of the DCF do not "track" reality. Despite this admission, he nevertheless relies exclusively on the sustainable growth version of the DCF methodology which rests on the assumption of constant growth.

In addition, the DCF method can produce returns that are severely distorted when a utility's stock price and book value diverge significantly, as I discussed earlier. While the DCF method may provide an estimate of investor expected returns on the market value of a company's stock, that estimate cannot be applied to a utility's book value when market value exceeds book value.

In contrast to the DCF model, the assumptions underlying the CAPM are far less stringent than the assumptions required for the DCF model to obtain, as I discuss below.

Q. Are the CAPM assumptions restrictive relative to those that underlie the DCF model?

A. No, I do not believe so. The CAPM can be considered a special case of the broader Arbitrage Pricing Model (APM) which has far less restrictive assumptions

than the CAPM. If we view the CAPM as a special case of the APM where the market portfolio is the only factor affecting security prices, it is clear that the assumptions underlying the APM are far less stringent than the assumptions required for the DCF model to obtain. The APM derives from two major assumptions: that security returns are linear functions of several economic factors, and that no profitable arbitrage opportunities exist since investors are able to eliminate such opportunities through riskless arbitrage transactions. The other assumptions required by the APM are that investors are greedy and risk averse, that they can diversify company-specific risks by holding large portfolios, and that enough investors possess similar expectations to trigger the arbitrage process.

The APM relationship asserts that the return on any risky security is equal to the risk-free rate plus a linear combination of risk premiums. Each risk premium is the expected return in excess of the risk-free rate associated with an asset that has a systematic risk with respect to that factor only. The CAPM is a special case of the APM if one factor influences security prices and if that factor happens to be the market portfolio. Under this circumstance, the APM collapses into the CAPM, and the APM reduces to the CAPM with the beta coefficient transformed into the traditional security beta.

In conclusion, Mr. Hill's discussion of the list of assumptions that underlie the CAPM on pages 52-55 is greatly overstated and should be dismissed.

Q. Please comment on Mr. Hill's views concerning tax effects.

A. On pages 13-14 of his testimony, Mr. Hill argues that following the passage of President Bush's tax reduction on dividend income from U.S. stocks, investor return requirements have decreased in response to the lower tax burden. Mr. Hill's argument assumes that all investors are taxable. This ignores the fact that

1 several institutional investors are not taxable, such as pension funds and mutual
2 funds, and they engage in very large amounts of trading on security markets. It is
3 quite plausible that taxable retail investors are relatively inactive traders and that
4 large non-taxable investors have a substantial influence on capital markets.
5 **EXPECTED DIVIDEND YIELD**
6 Q. Dr. Morin, can you respond to Mr. Hill's criticism of the dividend yield
7 component of your DCF analysis?
8 A. Yes. I disagree with Mr. Hill's contention on page 56 lines 15-17 that the
9 dividend yield calculation in my DCF analysis is overstated because I have
10 multiplied the spot dividend yield by one plus the expected growth rate (1 + g).
11 He himself performs exactly the same calculation, as shown clearly in the footnote
12 to exhibit DOD-209. Both my and Mr. Hill's dividend yield adjustment are
13 correct. The fundamental assumption of the annual DCF model used both by Mr.
14 Hill and by myself is that dividends are received annually at the end of each year
15 and that the first dividend is to be received one year from now. Since the
16 appropriate dividend to use in a DCF model is the prospective dividend for which
17 all companies have a positive growth rate, the dividend for all companies should
18 be increased by the (1 + g) factor.
19 In fact, the plain vanilla annual DCF model ignores the time value of
20 quarterly dividend payments and assumes dividends are paid once a year at the
21 end of the year. Multiplying the spot dividend yield by (1 + g) is actually a
22 conservative attempt to capture the reality of quarterly dividend payments and
23 understates the expected return on equity. I say "conservative" because the
24 annual DCF model ignores the more frequent compounding of quarterly
25 dividends.

By analogy, a bank rate on deposits which does not take into consideration the timing of the interest payments understates the true yield if you receive the interest payments more than once a year. The actual yield will exceed the stated nominal rate. To illustrate, if an investor has a choice between investing $1,000 in a bank account which promises a return of 10% compounded annually and another bank account which promises a return of 10% but compounded quarterly, he will clearly select the latter. Due to the quarterly compounding of interest, the investor earns an effective return of 10.38% on the latter bank account versus 10% on the former. The same is true for the return on common stocks.

RISK-FREE RATE

Q. Dr. Morin, do you agree with Mr. Hill's risk-free rate in the CAPM analysis?

A. It is hard to say since Mr. Hill is not consistent on this issue. Mr. Hill chastises my use of long-term Treasury bond yields as proxies for the risk-free rate in the CAPM, and yet that is exactly what he himself uses in his own CAPM analysis (See exhibit DOD-203 page 5).

Mr. Hill argues that long-term Treasury bonds are afflicted with interest rate risk and, therefore, are not adequate proxies for the risk-free rate. While I agree that long-term Treasury bonds possess a higher degree of interest rate risk than Treasury bills, this is only true if the bonds are sold prior to maturity. A substantial fraction of bond market participants, usually institutional investors with long-term liabilities (pension funds, insurance companies), in fact hold bonds until they mature, and therefore are not subject to interest rate risk. Even if institutional investors in long-term bonds do not hold bonds until they mature, it is well known that institutional bondholders neutralize the impact of interest rate changes by engaging in hedging transactions in the financial futures markets.

Mr. Hill also refers to a "maturity premium" inherent in long-term interest rates that should be subtracted from long-term rates in order to arrive at the real risk-free rate. More specifically, on page 58 lines 15-27, Mr. Hill refers to the Brealy & Myers textbook that recommends subtracting this "maturity premium" from long-term interest rates. Yet he himself applies no such adjustment to his risk-free rate. He did not explain this anomaly.

DCF GROWTH RATES

Q. Please comment on Mr. Hill's criticism of your DCF analysis.

A. On page 70 of his testimony, Mr. Hill maligns my use of the analyst's earning growth forecast as a proxy for the growth component, and that I have ignored historical and projected growth rates in dividends and book value. I have previously discussed the impropriety of relying on "near-term" dividend growth because it is widely expected that energy utilities will continue to lower their dividend payout ratio over the next several years in response to increased business risk, and that earnings and dividends are not expected to grow at the same rate in the future. This is evident in Mr. Hill's own table on page 71 where the projected dividend growth rates of 2.5% are far less than the earnings growth rate of 5.8%. Whenever the dividend payout ratio is expected to change, the intermediate growth rate in dividends cannot equal the long-term growth rate, because dividend/earnings growth must adjust to the changing payout ratio. In my direct testimony, I discussed the merits of using consensus analysts' earnings growth forecasts in the DCF model and the supportive empirical literature.

I find Mr. Hill's criticism surprising, given that he himself ends up relying on the sustainable growth approach to specifying the growth component of the DCF model and ignores the historical and projected growth rates in dividends and

book value. Mr. Hill goes so far as redoing my DCF analysis with the latter growth rates, although he himself chose not to rely on such growth rates.

Q. Dr. Morin, can you comment on Mr. Hill's references to your published works?

A. Yes, on page 43 of his testimony, Mr. Hill complains that my published work regarding estimating the cost of capital focuses more on the DCF model and less on risk premium analyses and that there are more chapters on DCF than on risk premium techniques. While I am flattered with Mr. Hill's frequent references to my published work, this comment is incorrect. The number of chapters or number of pages devoted to any one given methodology are certainly not indicative of the weight to be accorded to any one given method. However, it turns out that my regulatory finance textbook does devote a reasonably equal amount of space to DCF (four chapters) and to Risk Premium methods, including the CAPM (five chapters). I also note that most, if not all, college-level corporate finance textbooks devote the vast majority of their cost of capital coverage to asset pricing models, such as the CAPM, Fama-French version of the CAPM, and the Arbitrage Pricing Model. Considerably less attention is devoted to the DCF model in view of its limitations. I also refer Mr. Hill to my comments on the DCF model in Chapter 9 of my textbook "Reflections on Cost of Capital Methodology."

On page 47 of his testimony, Mr. Hill asserts that there is not one word in my published work regarding the ability of the DCF to accurately estimate the cost of equity depending on the M/B ratio of the utility. This is an incorrect statement on the part of Mr. Hill. A few pages later (pages 49-50), Mr. Hill liberally quotes entire portions of my published work dealing with the M/B issue along with a table extracted from my publications.

1 **CONCLUSIONS**

2 Q. What do you conclude from Mr. Hill's cost of capital testimony?

3 A. My general conclusions are:

4 1) Mr. Hill's recommended return is outside the zone of currently allowed rates
5 of return for utilities in the United States and for his own sample of
6 companies.

7 2) Application of the standard DCF model to utility stocks understates the
8 investor's expected return when the Market-to-Book (M/B) ratio exceeds unity
9 as is the case in the current capital market environment where utility stocks,
10 including Mr. Hill's sample companies, are trading at M/B ratios well above
11 unity.

12 3) Mr. Hill's dividend yield component is understated by 30 basis points because
13 it does not allow for flotation costs, and, as a result, a legitimate expense is left
14 unrecovered.

15 4) Mr. Hill's selection of a growth rate for each company in his comparable
16 group is ambiguous and extremely arbitrary. Moreover, there are some
17 serious errors associated with Mr. Hill's sustainable growth DCF analysis.
18 Not only is there a serious element of logical circularity in his approach
19 because he is forced to assume the answer before he conducts the analysis, but
20 the academic literature frowns on the approach.

21 5) Historical growth rates have little relevance as proxies for future long-term
22 growth in the DCF model because they are not representative of long-term
23 earning power and because they produce unreasonably low DCF estimates.
24 Moreover, historical growth rates are largely redundant because such historical
25 growth patterns are already incorporated in analysts' growth forecasts.

6) Because energy utilities are expected to lower their dividend payout ratio over the next several years in response to the gradual penetration of competition in the revenue stream, the use of dividend growth projections is inappropriate in the DCF model. Earnings growth projections are far more relevant.

7) A test of the statistical relationship between growth and expected yield for Mr. Hill's DCF analysis shows that the hypothesis that the sample is truly risk-comparable must be rejected for the DCF estimates.

8) Mr. Hill's Modified Earnings Price Ratio (MEPR) and Market-to-Book Ratio (MBR) checks are merely two disguised versions of the DCF model, and do not constitute independent stand-alone checks.

9) The EPR method used by Mr. Hill is antiquated, is fraught with conceptual blemishes, and has disappeared from use.

10) Mr. Hill's views on the role of the M/B ratio in regulation are illogical and inconsistent.

11) Mr. Hill's estimate of the market risk premium is too low because he has erroneously employed geometric means instead of the correct arithmetic means. Use of the correct market risk premium increases Mr. Hill's CAPM estimate of HECO's cost of equity by at least 125 basis points.

12) The plain vanilla version of the CAPM used by Mr. Hill understates the Company's cost of equity by about 50 basis points.

13) Mr. Hill's recommended ROE is not reflective of the forecast increase in capital costs.

14) Mr. Hill's downward ROE adjustment in order to account for HECO's stronger capital structure relative to its peers is unwarranted.

15) There are several logical inconsistencies and contradictions in Mr. Hill's

1 testimony.

2 16) Mr. Hill's criticisms of my testimony are unfounded.

3 **II. MR. PARCELL'S COST OF EQUITY TESTIMONY**

4 Q. Please summarize Mr. Parcell's rate of return recommendation.

5 A. Mr. Parcell recommends that a return allowance of 8.5% - 10.0% be employed on
6 the common equity capital of HECO. In determining HECO's cost of equity, Mr.
7 Parcell applies a DCF analysis to two groups of electric utilities. For the growth
8 component of his DCF analysis, he uses a blend of analysts' growth forecasts,
9 historical growth rates, and the earnings retention method. Mr. Parcell concludes
10 from his DCF estimates summarized on pages 35 of his testimony that the DCF
11 estimate of HECO's cost of equity is 8.5%.

12 Mr. Parcell also applies a CAPM analysis to the same groups of companies,
13 using long-term Treasury bond yields as proxies for the risk-free rate and Value
14 Line beta estimates. Lastly, Mr. Parcell performs a Comparable Earnings
15 analysis on a sample of utilities and a sample of unregulated industrial companies.
16 From his three analyses, Mr. Parcell concludes that HECO's cost of common
17 equity capital lies in the range of 8.5% - 10.0%

18 Q. Do you agree with Mr. Parcell's capital structure recommendation?

19 A. Yes, I do. On page 26 of his testimony, Mr. Parcell adopts the Company's
20 projected 2005 capital structure for ratemaking purposes with one minor change
21 on the lease obligation component. I agree with Mr. Parcell's capital structure
22 recommendation.

23 Q. Please summarize your specific criticisms of Mr. Parcell's testimony.

24 A. I have nine specific comments:

1. **Allowed return out of the mainstream**. Mr. Parcell's recommended return is outside the zone of currently allowed rates of return for major electric utilities in the United States and for his two samples of companies.

2. **The DCF Model Understates the Cost of Equity**. It is well-known that application of the DCF model to utility stocks understates the investor's expected return when the M/B ratio exceeds unity. This is particularly relevant in the current capital market environment where utility stocks are trading at M/B ratios well above unity.

3. **Understated Dividend Yield**. Mr. Parcell's dividend yield component is understated because it is not consistent with the annual form of the DCF model. It is inappropriate to increase the dividend yield by adding one-half of the future growth rate ($1 + \frac{1}{2}$ g) to the spot dividend yield. The appropriate manner of computing the expected dividend yield when using the plain vanilla annual DCF model is to add the full growth rate rather than one-quarter of the growth rate. This error understates the DCF results by some 20 basis points. Mr. Parcell's dividend yield component is also understated by 20 basis points because it ignores the time value of quarterly dividend payments.

4. **DCF Dividend Yield and Flotation Costs**. Mr. Parcell's dividend yield component is understated by 30 basis points because it does not sufficiently allow for flotation costs, and, as a result, a legitimate expense is left unrecovered.

5. **DCF Growth Rates**. The retention growth method contains a logical inconsistency because one is forced to assume the answer to implement the method. Moreover, whenever the dividend payout ratio is expected to change, the implementation of the standard DCF model is of questionable relevance.

6. **DCF Reliability**. The huge variability in the DCF results demonstrates the lack of reliability of the DCF approach and the importance of selecting relatively large sample sizes as opposed to small sample sizes consisting of a handful of companies when using the DCF model.

7. **CAPM Risk-Free Rate**. The correct proxy for the risk-free rate in the CAPM is the return on very long-term Treasury bonds.

8. **CAPM Market Risk Premium**. One of Mr. Parcell's two proxies for the market risk premium is understated by 50 basis points because it relies on the total return component of bond return instead of the income component.

9. **Comparable Earnings Test**. The ROE results from the Comparable Earnings test all exceed Mr. Parcell's recommended 8.5% - 10.0% ROE.

I also find that Mr. Parcell's criticisms of my testimony are largely unfounded.

1. ALLOWED RETURNS

Q. Is Mr. Parcell's rate of return recommendation compatible with currently allowed returns in the electric utility industry?

A. No, it is not. As I discussed earlier in my rebuttal of Mr. Hill, ROE awards in the industry exceed by a substantial margin Mr. Parcell's recommended ROE of 8.5% - 10.0% for HECO.

The currently allowed ROEs for the eight electric utilities in both of Mr. Parcell's comparable groups as reported in AUS Utility Reports survey for July 2005 average 11.0%, as shown in the two tables below, well above his recommended ROE.

AUTHORIZED RETURNS
Mr. Parcell's First Comparable Group

Company	Allowed ROE
CH Energy	10.30%
Great Plains Energy	N/A
NSTAR	11.63%
Otter Tail	12.00%
Pinnacle West	10.25%
PNM Resources	10.25%
SCANA	11.05%
Wisconsin Energy	12.20%
AVERAGE:	**11.1%**

Source: AUS Utility Reports 7/2005

AUTHORIZED RETURNS
Mr. Parcell's Second Comparable Group

Company	Allowed ROE
Avista	10.8%
Cleco	12.5%
Empire District	11.0%
IDACORP	10.3%
NSTAR	11.6%
Puget Energy	10.3%
UIL Holdings	10.5%
Vectren	11.0%
AVERAGE:	**11.0%**

Source: AUS Utility Reports 7/2005

2. DCF MODEL UNDERSTATEMENT

Q. Does the DCF model understate the cost of equity?

A. Yes, I believe it does. As I discussed earlier, application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar. The DCF cost rate understates the investor's required return when stock prices are well above book, as is the case presently. Mr. Parcell's comment on page 35-36 of his

testimony is well-taken: "*current financial conditions (low interest rates and high market-to-book ratios for utilities) have the effect of driving DCF results to low levels by historic standards.*"

3. DIVIDEND YIELD

Q. Please discuss Mr. Parcell's dividend yield component in the DCF model.

A. I believe that the dividend yield component used in Mr. Parcell's DCF analysis is downward-biased. Mr. Parcell uses a spot dividend yield inflated by one-half of the expected dividend growth $D_o(1 + 1/2\ g)$ rather than the correct expected dividend yield which is inflated by one full year of growth, $D_o(1 + g)$. This procedure fails to measure the full dividend flows expected by the investor, contrary to the spirit and fundamental nature of the DCF model.

The annual DCF model states very clearly that the expected rate of return on a stock is equal to the expected dividend at the end of the year divided by the current price of the stock, plus the expected growth rate.

Since the appropriate dividend to use in a DCF model is the prospective dividend to be received at the end of the year rather than one half of that dividend, Mr. Parcell's approach understates the proper dividend yield. This creates a downward bias in his dividend yield component, and underestimates the cost of equity by approximately 20 basis points. For example, for a spot dividend yield of 5% and a growth rate of 5%, Mr. Parcell's estimated dividend yield is 5%(1 + .05/2) = 5.1%. The correct dividend yield to employ is 5%(1 + .05) = 5.3%, which is about 20 basis points higher.

4. FLOTATION COSTS

Q. Please discuss Mr. Parcell's testimony with regard to flotation costs.

A. Mr. Parcell does not include any allowance whatsoever for flotation costs, and his

DCF methodology therefore understates the expected return on equity by approximately 30 basis points. As a result, a legitimate stockholder expense is left unrecovered. His justifications for this omission are that: 1) the Company has no plans for a public offering of common equity in the near future, and that therefore no adjustment for flotation costs is required, and 2) common equity is provided by the parent company, HEI.

I presume from his discussion that Mr. Parcell supports the notion that flotation costs should be recognized as a cost of service item at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made only in the year in which the sale of securities occurs, with no need for continuing compensation in future years. Mr. Parcell's argument implies that the Company has already been compensated for these costs. If the flotation costs of past stock issues have been fully recovered, the argument has merit. If that assumption is not met, the argument is without merit.

As for his second argument, the parent-subsidiary relationship does not eliminate the costs of a new issue, but merely transfers them to the parent. It would be unfair and discriminatory to subject parent shareholders to dilution while individual shareholders are absolved from such dilution. Fair treatment must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred.

5. DCF GROWTH RATES

Q. Please describe Mr. Parcell's methodology for specifying the growth component of the DCF model.

A. As a proxy for expected growth, Mr. Parcell employs five proxies: 1) historical

earnings retention ratio, 2) projected earnings retention ratio, 3) five-year historical growth rates in dividends, earnings, and book value, 4) projected growth rates in dividends, earnings, and book value, and 5) analysts' forecasts.

Q. Can you comment on Mr. Parcell's earnings retention growth estimate in the DCF model?

A. The earnings retention technique of specifying growth is beleaguered with serious conceptual and empirical difficulties and results from its use should be dismissed. As discussed earlier, the retention growth method contains a logical flaw when applied to a regulated utility: the method requires an estimate of ROE to be implemented. But if the ROE input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Mr. Parcell's recommended return of 8.5% - 10.0% is less than the 10% - 11% realized and expected ROEs he is assuming the companies will earn forever. Moreover, the empirical finance literature demonstrates that the retention growth method of determining growth is a poor explanatory variable of market value, and is not as significantly correlated to measures of value, such as stock price and price/earnings ratios.

In conclusion, Mr. Parcell's retention growth rates should be viewed with caution.

Q. Are the historical growth rates of electric utilities reliable?

A. No, they are not. Mr. Parcell uses historical growth rates in dividends, earnings, and book value as proxies for expected growth, as shown on CA-406 page 3. If historical growth rates are to be representative of long-term future growth rates, they must not be biased by non-recurring events. This was certainly the case for electric utilities, where growing competition, diversification programs,

1 acquisitions, restructurings and write-off activities exerted a dilutive effect on
2 historical earnings and dividends. In such cases, it is obvious that analysts' growth
3 forecasts provide a more realistic and representative growth proxy for what is
4 likely to happen in the future than historical growth. In any event, historical
5 growth rates are somewhat redundant given that analysts formulate their growth
6 expectations based in part on historical patterns.
7 In conclusion, Mr. Parcell's historical growth rates should be given
8 considerably less weight than the analysts' growth forecasts.
9 Q. What does the published academic literature say on the subject of growth rates in
10 the DCF model?
11 A. As discussed earlier, published studies in the academic literature demonstrate that
12 growth forecasts made by security analysts are reasonable indicators of investor
13 expectations, and that investors rely on analysts' forecasts.
14 Q. Do you see any dangers in relying on value line as an exclusive source of
15 forecasts in applying the DCF model?
16 A. Yes, I do. Mr. Parcell places equal weight on the Value Line forecast and the
17 market consensus forecast. As one surrogate for growth in the DCF model, Mr.
18 Parcell used an average of the three Value Line growth forecasts for earnings,
19 dividend, and book value. Mr. Parcell's heavy reliance on Value Line growth
20 forecasts runs the risk that such forecasts are not representative of investors'
21 consensus forecast. One would expect that averages of analysts' growth forecasts
22 such as those contained in First Call and/or Zacks, rather than one particular firm's
23 forecast, are more reliable estimates of the investors' consensus expectations likely
24 to be impounded in stock prices.
25 Q. Are investors expecting growth rates equal to Mr. Parcell's range?

A. No. The best evidence shows that investors are expecting growth rates higher than Mr. Parcell has found. For his first group of electric utilities, Mr. Parcell has found (see his exhibit CA-406 page 4 of 4) growth rates ranging from 2.4% to 4.6%, with a mean of 3.7%, from all the proxies he used. As indicated earlier, the retention growth estimate should be discarded from the analysis, historical growth rates should be given considerably less weight, and Value Line forecasts are somewhat unrepresentative, which leaves us with the consensus analyst forecast of 4.6%. This is almost one full percentage point above Mr. Parcell's mean estimate, and therefore Mr. Parcell's DCF cost of equity estimates are downward-biased by about 100 basis points from this understatement alone.

6. DCF RELIABILITY

Q. Is there any evidence that Mr. Parcell's DCF results are unreliable?

A. Yes, there is. The two tables below reproduce Mr. Parcell's DCF estimates (dividend yield plus growth) for both of his samples of electric utilities using each of the five proxies for growth.

Mr. Parcell's First Group of Electric Utilities
DCF Results

Company	Using Historic Retention (1)	Using Projected Retention (2)	Using Historic Per Share (3)	Using Projected Per Share (4)	Using Analysts Forecast (5)
CH Energy	6.8%	6.6%	4.5%	6.5%	4.8%
Great Plains Energy	8.4%	8.7%	9.0%	7.2%	8.5%
NSTAR	9.2%	8.7%	7.2%	7.7%	9.2%
Otter Tail	9.2%	8.3%	8.9%	7.8%	8.6%
Pinnacle West	8.9%	7.2%	7.2%	8.5%	9.0%
PNM Resources	8.6%	6.4%	5.2%	7.9%	8.7%
SCANA	9.2%	9.2%	6.8%	9.3%	8.5%
Wisconsin Energy	7.9%	8.9%	2.9%	7.6%	7.6%

Source: Mr. Parcell exhibit CA-406 page 4

Mr. Parcell's Second Group of Electric Utilities
DCF Results

Company	Using Historic Retention (1)	Using Projected Retention (2)	Using Historic Per Share (3)	Using Projected Per Share (4)	Using Analysts Forecast (5)
Avista	7.0%	7.0%	-1.1%	10.2%	7.7%
Cleco	9.6%	8.9%	8.4%	5.7%	8.4%
Empire District	5.7%	7.1%	5.1%	8.9%	7.6%
IDACORP	7.7%	7.4%	3.6%	5.9%	8.9%
NSTAR	9.2%	8.7%	7.2%	7.7%	9.2%
Puget Energy	6.6%	7.6%	-0.6%	7.6%	8.6%
UIL Holdings	7.3%	5.6%	4.1%	5.8%	6.6%
Vectren	6.8%	8.2%	4.5%	8.5%	8.5%

Source: Mr. Parcell exhibit CA-406 page 4

In the first table, the DCF results are scattered all over, ranging from a low of 2.9% for Wisconsin Energy to a high of 9.3% for SCANA. The situation is even worse in the second table with the DCF results ranging from a low of -1.1% to a high of 10.2% for Avista. Some estimates are negative, several estimates are barely above the cost of debt. The huge variability in the results demonstrates the lack of reliability of the DCF approach.

This is precisely why it is important to select relatively large sample sizes as opposed to small sample sizes consisting of a handful of companies when using the DCF model. Samples consisting of only eight companies are simply too small. This is because the electric utility industry capital market data is highly unstable and fluid at this time. Confidence in the reliability of the DCF model result is considerably enhanced when applying the DCF model to a large group of companies. Utilizing a large portfolio of companies reduces the chance of either overestimating or underestimating the cost of equity for an individual company.

I reiterate an important message from my direct testimony. A far superior approach to defining small narrowly-defined company samples is to apply cost of capital estimation techniques to a large group of electric utilities representative of the electric utility industry average and then make adjustments to account for any difference in investment risk between the Company and the industry average. In the current unstable industry environment, the composition of small groups of companies is very fluid, with companies exiting the sample due to dividend suspensions or reductions, insufficient or unrepresentative historical data due to recent mergers, impending merger or acquisition, and changing corporate identities due to restructuring activities. We can see this instability by comparing Mr. Parcell's first preferred group of electric utilities to his second group of electric utilities defined as per the Commission's past screening criteria. The groups are totally different, with only one company in common. The same is true for Mr. Hill's sample of ten companies, only four of which appear in Mr. Parcell's two samples.

Q. Please comment on Mr. Parcell's criticism of your DCF analysis.

A. On page 63 of his testimony, Mr. Parcell takes issue with the fact that I have used only one indicator of growth in the DCF analysis, namely, analyst growth projections and that I have ignored historical and projected growth rates in dividends and book value. I have previously discussed the impropriety of relying on "near-term" dividend growth because it is widely expected that energy utilities will continue to lower their dividend payout ratio over the next several years in response to increased business risk, and that earnings and dividends are not expected to grow at the same rate in the future. In my direct testimony and earlier in my rebuttal, I discussed the merits of using consensus analysts' earnings growth

1 forecasts in the DCF model and the supportive empirical literature.
2 Q. Please discuss the use of analysts' forecasts in applying the DCF model to
3 utilities.
4 A. The best proxy for the growth component of the DCF model is analysts' long-term
5 earnings growth forecasts. These forecasts are made by large reputable
6 organizations, and the data are readily available to investors and are representative
7 of the consensus view of investors.
8 Q. What does the published academic literature say on the subject of growth rates in
9 the DCF model?
10 A. Published studies in the academic literature demonstrate that growth forecasts
11 made by security analysts are reasonable indicators of investor expectations, and
12 that investors rely on analysts' forecasts. Cragg and Malkiel ["Expectations and
13 the Structure of Share Prices," Chicago: University of Chicago Press, 1982]
14 present detailed empirical evidence that the average analysts' expectation is more
15 similar to expectations being reflected in the marketplace than are historical
16 growth rates, and represents the best possible source of DCF growth rates. Cragg
17 and Malkiel show that historical growth rates do not contain any information that
18 is not already impounded in analysts' growth forecasts. A study by Professors
19 Vander Weide and Carleton, "Investor Growth Expectations: Analysts vs.
20 History" (*The Journal of Portfolio Management*, Spring 1988), also confirms the
21 superiority of analysts' forecasts over historical growth extrapolations. Another
22 study by Timme & Eiseman, "On the Use of Consensus Forecasts of Growth in
23 the Constant Growth Model: The Case of Electric Utilities," *Financial*
24 *Management,* Winter 1989, produces similar results.
25

7. CAPM RISK-FREE RATE

Q. Do you agree with Mr. Parcell's comments on your choice of risk-free rate in the CAPM analysis?

A. No, I do not. Mr. Parcell uses a risk-free rate based on the prevailing yield on 20-year Treasury bonds rather than my yield based on 30-year Treasury bonds. The appropriate proxy for the risk-free rate in the CAPM is the return on very long-term Treasury bonds. This is simply because common stocks are very long-term instruments more akin to very long-term bonds. The ideal estimate for the risk-free rate has a term to maturity equal to the security being analyzed. Because common equity has an infinite life-span, the inflation expectations embodied in its market-required rate of return will be equal to the inflation rate anticipated to prevail over the long-term. Among U.S. Treasury securities, 30-year U.S. Treasury bonds have the longest term to maturity. Therefore, 30-year U.S. Treasury bonds will most closely incorporate within their yield the inflation expectations that influence the prices of common stocks.

On page 56 of his testimony, Mr. Parcell objects to the use of 30-year bonds because the U.S. Treasury no longer issues such bonds. That is immaterial. In the same way that we can use stock prices in the application of the DCF model to a given company even though that company has not issued stock in the recent past, we can rely on bond prices of 30-year Treasury bonds and the implied yields. 30-year Treasury bonds are actively traded on secondary markets and provide useful price/yield signals.

8. CAPM MARKET RISK PREMIUM

Q. How does Mr. Parcell estimate the market risk premium component of the CAPM?

A. In order to determine the market risk premium (MRP) component of his first CAPM analysis, Mr. Parcell examines the returns on the S&P 500 and derives a MRP of 8.5%, that is, a market return of 13.2% less the risk-free rate of 4.75%. I agree with that estimate. In his second CAPM analysis, he relies on the long-term 6.6% historical market risk premium reported in the Ibbotson Associates Valuation 2005 Yearbook for the 1926 – 2004 period. I disagree with this estimate because only the income component of bond returns is relevant, and not the total return component, in calculating a MRP that serves as a proxy for the expected MRP.

Q. Should the historical market risk premium be estimated using the income component of bond returns or the total return component?

A. I response to Mr. Parcell's criticism on page 57 that I have improperly used income returns rather than total returns on bonds. The historical MRP should be computed using the income component of bond returns because the intent, even using historical data, is to identify an expected MRP. Ibbotson Associates recommend the use of the latter as a more reliable estimate of the historical MRP because the income component of total bond return (i.e., the coupon rate) is a far better estimate of expected return than the total return (i.e., the coupon rate plus capital gains), because realized capital gains/losses are largely unanticipated by investors. This particular CAPM estimate of the cost of common equity is therefore downward-biased by close to 80 basis points as a result of this omission alone (the difference between 7.2% and 6.6% times Mr. Parcell's beta estimate of 0.76).

Q. Please respond to Mr. Parcell' criticism of your second estimate of the market risk premium.

1 A. On page 58, Mr. Parcell disagrees with my estimate of 13.3% for the return on the
2 aggregate market. This is a surprising criticism given that this estimate is
3 virtually identical to his estimate of 13.2%.
4 Q. Mr. Parcell claims that the empirical CAPM inflates the CAPM result for the
5 selected company or industry. Is he correct?
6 A. No, I do not believe so. For companies with betas less than one, the CAPM
7 understates the return while for companies with betas greater than one, the CAPM
8 overstates the return. I discussed the conceptual and empirical foundations earlier
9 in my rebuttal. I should also point out that in the case of utility stocks, the CAPM
10 understates the rate of return on equity by approximately 50 basis points.
11 Q. Mr. Parcell disagrees with the risk premium methodology because economic
12 conditions today are different and that risk premiums are unstable from year to
13 year. How do you respond?
14 A. I refer back to my earlier discussion of historical risk premium in my rebuttal of
15 Mr. Hill.
16 **9. COMPARABLE EARNINGS TEST.**
17 Q. Please discuss Mr. Parcell's comparable earnings test.
18 A. In his implementation of the comparable earnings test, Mr. Parcell looks to the
19 realized returns on book equity (ROE) achieved by his group of comparable
20 utilities and by a broad group of industrials, namely the S&P 500, as a proper
21 guide for setting HECO's cost of common equity. His results are summarized in
22 table form on page 45 of his testimony. Strangely, the ROE results for the two
23 comparable groups, historic or prospective, all exceed Mr. Parcell's recommended
24 8.5% - 10.0% ROE. In other words, the ROE indicated by the Comparable
25 Earnings results is well in excess of Mr. Parcell's recommended ROE. Mr.

Parcell explains this paradox by referring to the M/B ratios of electric utilities that are well above 1.0.

Mr. Parcell seems to suggest that since current M/B ratios for utilities are in excess of 1.0, these companies are expected by investors to be able to earn more than their cost of capital, and that the regulating authority should lower the authorized return on equity. Mr. Parcell would therefore find it plausible that stock prices drop from the current 1.6 - 1.7 times book to the desired M/B ratio range of 1.00 to 1.05 times book.

If, indeed, that is Mr. Parcell's suggestion, I disagree. I discussed this issue at length earlier in rebutting Mr. Hill's testimony. M/B ratios are determined by the marketplace, and utilities cannot be expected to attract capital in an environment where industrials are commanding M/B ratios well in excess of 1.00. Moreover, if regulators were to currently set rates so as to produce a M/B ratio of 1.0, not only would the long-run target M/B ratio of 1.0 be violated, but more importantly, the inevitable consequence would be to inflict severe capital losses on shareholders. Investors have not committed capital to utilities with the expectation of incurring capital losses from a misguided regulatory process.

Q. What are the basic conclusions of your rebuttal to Mr. Parcell's return on equity testimony?

A. Mr. Parcell understates HECO's required return on common equity. A proper application of cost of capital methodologies would give results higher than those that he obtained.

III. UPDATED RECOMMENDATION

Q. What is the purpose of this section of your rebuttal testimony?

A. The purpose of this section of my rebuttal testimony is to update my ROE

1 recommendation in view of the changes that have occurred in capital market
2 conditions since I prepared my direct testimony more than one year ago in May
3 2004.
4 Q. Can you briefly describe the behavior of interest rates since you prepared your
5 rebuttal testimony?
6 A. Yes. Appreciable changes have occurred in capital market conditions since I
7 prepared my rebuttal testimony almost one year ago. The current level of U.S.
8 Treasury 30-year long-term bond yield is 4.5%, versus 5.5% when I prepared my
9 direct testimony. Moreover, long-term yields are projected to rise by
10 approximately 50 basis points (0.5%) over the year. The forecast increase in long-
11 term yields is not surprising in view of the Federal Reserve Bank's numerous
12 increases in administered short-term rates in an attempt to prevent inflationary
13 excesses, high federal deficits, high international balance of payments deficits,
14 declining unemployment, and rising core inflation. It is therefore reasonable to
15 rely on a range of 4.5% - 5.0% as an estimate of the risk-free rate. This compares
16 to a range of 5.5% - 6.0% in my direct testimony.
17 Q. Dr. Morin, what has happened to electric utility betas since you prepared your
18 direct testimony?
19 A. As shown in HECO-R-2001, they have increased from 0.78 to 0.84 in response to
20 greater risk perceptions of the electric utility industry by investors.
21 Q. Dr. Morin, has the market risk premium changed since you prepared your direct
22 testimony?
23 A. Yes, it has increased slightly from 7.5% to 7.8%.
24 Q. Dr. Morin please describe what has happened to the DCF results since you
25 prepared your direct testimony.

A. As seen from HECO-R-2003 to HECO-R-2008, the DCF results for the energy utilities have decreased in response to higher stock prices (lower dividend yields).

Q. Dr. Morin, please summarize your revised results from the various methodologies.

A. The net result of these capital market changes is a net decrease in the cost of common equity for the average risk electric utility. Alongside the original results, the revised cost of common equity estimates for the average risk electric utility are summarized in the table below.

STUDY	ROE	
	Old	New
CAPM Risk-free rate 4.5%	11.7%	11.4%
CAPM Risk-free rate 5.0%	12.2%	11.9%
Empirical CAPM Risk-free rate 4.5%	12.1%	11.7%
Empirical CAPM Risk-free rate 5.0%	12.6%	12.2%
Risk Premium Electric Utility at 4.5%	11.4%	10.4%
Risk Premium Electric Utility at 5.0%	11.9%	10.9%
Risk Premium Natural Gas at 4.5%	11.5%	10.5%
Risk Premium Natural Gas at 5.0%	12.0%	11.0%
Allowed Risk Premium at 4.5%	11.2%	10.7%
Allowed Risk Premium at 5.0%	11.3%	10.9%
DCF Moody's Electrics Zacks Growth	9.6%	9.1%
DCF Moody's Electrics Value Line Growth	9.5%	9.8%
DCF Vert Int Electrics Zacks Growth	9.9%	9.1%
DCF Vert Int Electrics Value Line Growth	10.6%	9.7%
DCF Natural Gas Zacks Growth	9.7%	8.9%
DCF Natural Gas Value Line	10.5%	10.3%

The central result from the various updated tests is 10.6% for the average risk electric utility as indicated by the average of 10.5%, the median of 10.6%, and the midpoint of the range of 10.6%. Yet another way of characterizing the results is on a methodological basis. The average result from the three principal methodologies is as follows:

CAPM	11.8%
Risk Premium	10.7%
DCF	9.3%
AVERAGE	10.6%

Again, the overall average result is 10.6% for the average risk electric utility.

Q. Did you adjust these results to account for the fact that HECO is riskier than the average electric utility?

A. Yes. As was the case in my original testimony, I increased my recommendation of 10.6% for the average risk utility by 40 basis points to 11.0% in order to account for HECO's higher relative risks and smaller size.

Q. Dr. Morin, what is your final conclusion regarding HECO's cost of common equity capital?

A. Based on current capital market conditions and the application of my professional judgment, it is my opinion that a just and reasonable return on the common equity capital of HECO's electric utility operations in the State of Hawaii is 11.0%. This represents a substantial decrease of 50 basis points from my original recommendation of 11.5%.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

MOODY'S ELECTRIC UTILITIES
BETA ESTIMATES

	Company Name	Beta
1	Amer. Elec. Power	1.15
2	CH Energy Group	0.80
3	Cinergy Corp.	0.85
4	Consol. Edison	0.60
5	Constellation Energy	0.90
6	Dominion Resources	0.90
7	DPL Inc.	0.95
8	Duquesne Light Hldgs	0.80
9	Duke Energy	1.15
10	Energy East Corp.	0.85
11	Exelon Corp.	0.75
12	FirstEnergy Corp.	0.75
13	IDACORP Inc.	0.90
14	NiSource Inc.	0.80
15	OGE Energy	0.70
16	PPL Corp.	0.95
17	Progress Energy	0.85
18	Public Serv. Enterprise	0.85
19	Southern Co.	0.65
20	TECO Energy	0.95
21	Xcel Energy Inc.	0.80
	AVERAGE	**0.85**

Source: VLIA 7/2005

ELECTRIC UTILITY INDUSTRY BETA ESTIMATES

	Company Name	Beta
1	Allegheny Energy	1.70
2	ALLETE	
3	Alliant Energy	0.85
4	Amer. Elec. Power	1.15
5	Ameren Corp.	0.75
6	Aquila Inc.	1.35
7	Avista Corp.	0.90
8	Black Hills	1.00
9	Cen. Vermont Pub. Serv.	0.50
10	CenterPoint Energy	0.60
11	CH Energy Group	0.80
12	Cinergy Corp.	0.85
13	Cleco Corp.	1.15
14	CMS Energy Corp.	1.40
15	Consol. Edison	0.60
16	Constellation Energy	0.90
17	Dominion Resources	0.90
18	DPL Inc.	0.95
19	DTE Energy	0.70
20	Duke Energy	1.15
21	Duquesne Light Hldgs	0.80
22	Edison Int'l	1.05
23	El Paso Electric	0.65
24	Empire Dist. Elec.	0.70
25	Energy East Corp.	0.85
26	Entergy Corp.	0.75
27	Exelon Corp.	0.75
28	FirstEnergy Corp.	0.75
29	Florida Public Utilities	0.65
30	FPL Group	0.75
31	Green Mountain Pwr.	0.60
32	G't Plains Energy	0.85
33	Hawaiian Elec.	0.70
34	IDACORP Inc.	0.90
35	Maine & Maritimes Corp	0.45
36	MDU Resources	0.90

ELECTRIC UTILITY INDUSTRY BETA ESTIMATES

	Company Name	Beta
37	MGE Energy	0.65
38	NiSource Inc.	0.80
39	Northeast Utilities	0.80
40	NorthWestern Corporation	1.15
41	NSTAR	0.70
42	OGE Energy	0.70
43	Otter Tail Corp.	0.55
44	Pepco Holdings	0.90
45	PG&E Corp.	1.10
46	Pinnacle West Capital	0.85
47	PNM Resources	0.90
48	PPL Corp.	0.95
49	Progress Energy	0.85
50	Public Serv. Enterprise	0.85
51	Puget Energy Inc.	0.80
52	SCANA Corp.	0.75
53	Sempra Energy	1.00
54	Sierra Pacific Res.	1.10
55	Southern Co.	0.65
56	TECO Energy	0.95
57	TXU Corp.	1.00
58	UIL Holdings	0.80
59	UniSource Energy	0.65
60	UNITIL Corp.	0.40
61	Vectren Corp.	0.80
62	Westar Energy	0.85
63	Wisconsin Energy	0.70
64	WPS Resources	0.75
65	Xcel Energy Inc.	0.80
	AVERAGE	**0.84**

Source: VLIA 7/2005

COMBINATION GAS & ELEC UTILITY BETA ESTIMATES

	Company Name	Beta
1	Alliant Energy	0.85
2	Ameren Corp.	0.75
3	CenterPoint Energy	0.60
4	CH Energy Group	0.80
5	Cinergy Corp.	0.85
6	CMS Energy Corp.	1.40
7	Consol. Edison	0.60
8	Constellation Energy	0.90
9	Dominion Resources	0.90
10	DTE Energy	0.70
11	Duke Energy	1.15
12	Energy East Corp.	0.85
13	Entergy Corp.	0.75
14	Exelon Corp.	0.75
15	Florida Public Utilities	0.65
16	MDU Resources	0.90
17	MGE Energy	0.65
18	NiSource Inc.	0.80
19	Northeast Utilities	0.80
20	NSTAR	0.70
21	Pepco Holdings	0.90
22	PG&E Corp.	1.10
23	PNM Resources	0.90
24	PPL Corp.	0.95
25	Public Serv. Enterprise	0.85
26	Puget Energy Inc.	0.80
27	SCANA Corp.	0.75
28	Sempra Energy	1.00
29	TECO Energy	0.95
30	TXU Corp.	1.00
31	Vectren Corp.	0.80
32	Wisconsin Energy	0.70
33	WPS Resources	0.75
34	Xcel Energy Inc.	0.80
	AVERAGE	**0.85**

Source: VLIA 7/2005

ELECTRIC UTILITIES
HISTORICAL GROWTH RATES

	Company Name	Earnings Growth 5-Year	Dividend Growth 5-Year	Book Value Growth 5-Year
1	Allegheny Energy			-6.0
2	ALLETE			
3	Alliant Energy	-3.0	-7.5	-1.5
4	Amer. Elec. Power	-2.0	-5.5	-4.0
5	Ameren Corp.	1.5		4.0
6	Aquila Inc.			-15.5
7	Avista Corp.	-6.5	-11.5	5.0
8	Black Hills	4.5	4.0	17.0
9	Cen. Vermont Pub. Serv.	8.5	0.5	2.0
10	CenterPoint Energy			
11	CH Energy Group	-3.0		2.0
12	Cinergy Corp.	1.5	0.5	5.0
13	Cleco Corp.	4.0	2.0	4.0
14	CMS Energy Corp.			-14.5
15	Consol. Edison	-2.0	1.0	2.0
16	Constellation Energy	6.0	-9.0	4.5
17	Dominion Resources	11.0		4.5
18	DPL Inc.	-1.0	0.5	-3.5
19	DTE Energy			3.5
20	Duke Energy	-4.5		7.5
21	Duquesne Light Hldgs	-14.5	-5.5	-17.5
22	Edison Int'l	-3.0		2.0
23	El Paso Electric	-2.5		8.5
24	Empire Dist. Elec.	-3.5		2.0
25	Energy East Corp.	-0.5	5.5	5.5
26	Entergy Corp.	11.0	1.5	5.5
27	Exelon Corp.	6.5		
28	FirstEnergy Corp.	1.0	2.0	6.0
29	Florida Public Utilities	-0.5	4.5	8.0
30	FPL Group			2.0
31	Green Mountain Pwr.	37.5	-6.5	-0.5
32	G't Plains Energy	7.0		
33	Hawaiian Elec.	1.0		2.5
34	IDACORP Inc.	-3.0	-0.5	4.0
35	Maine & Maritimes Corp	20.0	5.5	6.0
36	MDU Resources	10.5	5.0	13.0

ELECTRIC UTILITIES
HISTORICAL GROWTH RATES

	Company Name	Earnings Growth 5-Year	Dividend Growth 5-Year	Book Value Growth 5-Year
37	MGE Energy	4.0	1.0	5.0
38	NiSource Inc.	3.0	1.5	10.5
39	Northeast Utilities		37.5	2.0
40	NorthWestern Corporation		-15.5	
41	NSTAR	5.0	2.5	1.5
42	OGE Energy	-2.5		1.0
43	Otter Tail Corp.	3.5	2.5	7.0
44	Pepco Holdings			
45	PG&E Corp.	-20.5		-8.0
46	Pinnacle West Capital	-3.0	7.0	4.0
47	PNM Resources	-2.0	4.5	5.0
48	PPL Corp.	11.0	3.0	6.5
49	Progress Energy	5.5	3.0	8.5
50	Public Serv. Enterprise	5.0		0.5
51	Puget Energy Inc.	-5.5	-10.5	0.5
52	SCANA Corp.	6.5	-1.0	3.0
53	Sempra Energy	14.0	-8.5	6.0
54	Sierra Pacific Res.			-6.0
55	Southern Co.	2.5	1.0	-1.5
56	TECO Energy		-3.5	-1.5
57	TXU Corp.	-13.0	-13.0	-16.0
58	UIL Holdings	-5.0		2.0
59	UniSource Energy	-4.0		13.5
60	UNITIL Corp.	-4.0	0.5	0.5
61	Vectren Corp.	1.0	3.0	3.5
62	Westar Energy	-15.0	-12.5	-9.0
63	Wisconsin Energy	9.5	-12.0	3.5
64	WPS Resources	9.5	2.0	6.5
65	Xcel Energy Inc.	-9.5	-9.0	-5.0
	AVERAGE	**1.5**	**-0.7**	**1.8**

Source: Value Line Investment Analyzer 5/2004

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Amer. Elec. Power	3.7	3.2	3.8	7.0	7.2
2	CH Energy Group	4.4		4.4	4.4	4.6
3	Cinergy Corp.	4.3	4.5	4.5	9.0	9.2
4	Consol. Edison	4.7	3.1	4.9	8.0	8.3
5	Constellation Energy	2.4	9.8	2.6	12.4	12.5
6	Dominion Resources	3.6	6.3	3.8	10.1	10.3
7	DPL Inc.	3.5	5.0	3.6	8.6	8.8
8	Duquesne Light Hldgs	5.2	5.0	5.5	10.5	10.8
9	Duke Energy	4.1	6.1	4.3	10.4	10.7
10	Energy East Corp.	4.1	3.7	4.2	7.9	8.1
11	Exelon Corp.	3.0	6.1	3.2	9.3	9.4
12	FirstEnergy Corp.	3.4	4.3	3.6	7.9	8.1
13	IDACORP Inc.	3.8	4.3	3.9	8.2	8.4
14	NiSource Inc.	3.7	4.1	3.9	8.0	8.2
15	OGE Energy	4.6	3.0	4.7	7.7	7.9
16	PPL Corp.	3.2	5.4	3.3	8.8	8.9
17	Progress Energy	5.2	4.1	5.4	9.5	9.8
18	Public Serv. Enterprise	3.6	4.2	3.7	7.9	8.1
19	Southern Co.	4.2	4.5	4.4	8.9	9.1
20	TECO Energy	4.1	4.4	4.3	8.7	8.9
21	Xcel Energy Inc.	4.4	4.2	4.6	8.8	9.0
	AVERAGE	**3.9**	**4.8**	**4.1**	**8.7**	**8.9**

Notes:
Column 1: Value Line Investment Analyzer, 7/2007
Column 2: Zacks long-term earnings growth forecast, 7/2005
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

INVESTMENT-GRADE VERTICALLY INTEGRATED ELEC. UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Ameren Corp.	4.5	4.9	4.8	9.7	9.9
2	Cinergy Corp.	4.3	4.5	4.5	9.0	9.2
3	Cleco Corp.	4.0	4.0	4.2	8.2	8.4
4	Dominion Resources	3.6	6.3	3.8	10.1	10.3
5	DPL Inc.	3.5	5.0	3.6	8.6	8.8
6	Energy East Corp.	4.1	3.7	4.2	7.9	8.1
7	Empire Dist. Elec.	5.2	5.0	5.5	10.5	10.8
8	Entergy Corp.	3.0	7.0	3.2	10.2	10.4
9	FirstEnergy Corp.	3.4	4.3	3.6	7.9	8.1
10	FPL Group	3.2	5.4	3.4	8.8	9.0
12	G't Plains Energy	5.1	3.0	5.2	8.2	8.5
13	Hawaiian Elec.	4.5	3.5	4.7	8.2	8.4
14	IDACORP Inc.	3.8	4.3	3.9	8.2	8.4
15	Alliant Energy	3.8	4.0	4.0	8.0	8.2
16	Northeast Utilities	3.3	4.5	3.4	7.9	8.1
17	Progress Energy	5.2	4.1	5.4	9.5	9.8
18	Pinnacle West Capital	4.3	5.2	4.5	9.7	9.9
19	Puget Energy Inc.	4.2	4.8	4.3	9.1	9.4
20	Southern Co.	4.2	4.0	4.3	8.3	8.6
21	TECO Energy	4.1	4.4	4.3	8.7	8.9
22	Xcel Energy Inc.	4.4	4.2	4.6	8.8	9.0
	AVERAGE	4.1	4.6	4.3	8.8	9.1

Notes:
Column 1: Value Line Investment Analyzer, 7/2005
Column 2: Zacks long-term earnings growth forecast, 7/2005
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2
No growth forecast for Green Mountain Power

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Amer. Elec. Power	3.7	2.0	3.7	5.7	5.9
2	CH Energy Group	4.4	3.0	4.5	7.5	7.8
3	Cinergy Corp.	4.3	5.5	4.5	10.0	10.2
4	Consol. Edison	4.7	1.5	4.8	6.3	6.5
5	Constellation Energy	2.4	13.0	2.7	15.7	15.8
6	Dominion Resources	3.6	9.0	3.9	12.9	13.1
7	DPL Inc.	3.5	2.5	3.5	6.0	6.2
8	Duquesne Light Hldgs	5.2	3.0	5.4	8.4	8.7
9	Duke Energy	4.1	8.0	4.4	12.4	12.6
10	Energy East Corp.	4.1	4.5	4.3	8.8	9.0
11	Exelon Corp.	3.0	6.5	3.2	9.7	9.9
12	FirstEnergy Corp.	3.4	10.0	3.8	13.8	13.9
13	IDACORP Inc.	3.8	6.0	4.0	10.0	10.2
14	NiSource Inc.	3.7	2.5	3.8	6.3	6.5
15	OGE Energy	4.6	5.5	4.8	10.3	10.6
16	PPL Corp.	3.2	5.5	3.3	8.8	9.0
17	Progress Energy					
18	Public Serv. Enterprise	3.6	1.0	3.6	4.6	4.8
19	Southern Co.	4.2	4.0	4.3	8.3	8.6
20	TECO Energy					
21	Xcel Energy Inc.	4.4	7.5	4.7	12.2	12.5
	AVERAGE	3.9	5.3	4.1	9.4	9.6

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 7/2005
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2
No Value Line growth forecasts available for Progress Energy, TECO

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Amer. Elec. Power	3.7	2.0	3.7	5.7	5.9
2	CH Energy Group	4.4	3.0	4.5	7.5	7.8
3	Cinergy Corp.	4.3	5.5	4.5	10.0	10.2
4	Consol. Edison	4.7	1.5	4.8	6.3	6.5
5	Constellation Energy	2.4	13.0	2.7	15.7	15.8
6	Dominion Resources	3.6	9.0	3.9	12.9	13.1
7	DPL Inc.	3.5	2.5	3.5	6.0	6.2
8	Duquesne Light Hldgs	5.2	3.0	5.4	8.4	8.7
9	Duke Energy	4.1	8.0	4.4	12.4	12.6
10	Energy East Corp.	4.1	4.5	4.3	8.8	9.0
11	Exelon Corp.	3.0	6.5	3.2	9.7	9.9
12	FirstEnergy Corp.	3.4	10.0	3.8	13.8	13.9
13	IDACORP Inc.	3.8	6.0	4.0	10.0	10.2
14	NiSource Inc.	3.7	2.5	3.8	6.3	6.5
15	OGE Energy	4.6	5.5	4.8	10.3	10.6
16	PPL Corp.	3.2	5.5	3.3	8.8	9.0
17	Southern Co.	4.2	4.0	4.3	8.3	8.6
18	Xcel Energy Inc.	4.4	7.5	4.7	12.2	12.5
	AVERAGE	3.9	5.5	4.1	9.6	9.8

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 7/2005
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2
No Value Line growth forecasts available for Progress Energy, TECO
Public Service Enterprise eliminated: ongoing merger, estimate less than cost of debt

INVESTMENT-GRADE VERTICALLY INTEGRATED ELEC. UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Ameren Corp.	4.5	4.9	4.8	9.7	9.9
2	Cinergy Corp.	4.3	4.5	4.5	9.0	9.2
3	Cleco Corp.	4.0	4.0	4.2	8.2	8.4
4	Dominion Resources	3.6	6.3	3.8	10.1	10.3
5	DPL Inc.	3.5	5.0	3.6	8.6	8.8
6	Energy East Corp.	4.1	3.7	4.2	7.9	8.1
7	Empire Dist. Elec.	5.2	5.0	5.5	10.5	10.8
8	Entergy Corp.	3.0	7.0	3.2	10.2	10.4
9	FirstEnergy Corp.	3.4	4.3	3.6	7.9	8.1
10	FPL Group	3.2	5.4	3.4	8.8	9.0
11	Green Mountain Pwr.	3.4		3.4	3.4	3.6
12	G't Plains Energy	5.1	3.0	5.2	8.2	8.5
13	Hawaiian Elec.	4.5	3.5	4.7	8.2	8.4
14	IDACORP Inc.	3.8	4.3	3.9	8.2	8.4
15	Alliant Energy	3.8	4.0	4.0	8.0	8.2
16	Northeast Utilities	3.3	4.5	3.4	7.9	8.1
17	Progress Energy	5.2	4.1	5.4	9.5	9.8
18	Pinnacle West Capital	4.3	5.2	4.5	9.7	9.9
19	Puget Energy Inc.	4.2	4.8	4.3	9.1	9.4
20	Southern Co.	4.2	4.0	4.3	8.3	8.6
21	TECO Energy	4.1	4.4	4.3	8.7	8.9
22	Xcel Energy Inc.	4.4	4.2	4.6	8.8	9.0
	AVERAGE	4.0	4.6	4.2	8.6	8.8

Notes:
Column 1: Value Line Investment Analyzer, 7/2005
Column 2: Zacks long-term earnings growth forecast, 7/2005
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2
No growth forecast for Green Mountain Power

INVESTMENT-GRADE VERTICALLY INTEGRATED ELEC. UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Ameren Corp.	4.5	4.9	4.8	9.7	9.9
2	Cinergy Corp.	4.3	4.5	4.5	9.0	9.2
3	Cleco Corp.	4.0	4.0	4.2	8.2	8.4
4	Dominion Resources	3.6	6.3	3.8	10.1	10.3
5	DPL Inc.	3.5	5.0	3.6	8.6	8.8
6	Energy East Corp.	4.1	3.7	4.2	7.9	8.1
7	Empire Dist. Elec.	5.2	5.0	5.5	10.5	10.8
8	Entergy Corp.	3.0	7.0	3.2	10.2	10.4
9	FirstEnergy Corp.	3.4	4.3	3.6	7.9	8.1
10	FPL Group	3.2	5.4	3.4	8.8	9.0
12	G't Plains Energy	5.1	3.0	5.2	8.2	8.5
13	Hawaiian Elec.	4.5	3.5	4.7	8.2	8.4
14	IDACORP Inc.	3.8	4.3	3.9	8.2	8.4
15	Alliant Energy	3.8	4.0	4.0	8.0	8.2
16	Northeast Utilities	3.3	4.5	3.4	7.9	8.1
17	Progress Energy	5.2	4.1	5.4	9.5	9.8
18	Pinnacle West Capital	4.3	5.2	4.5	9.7	9.9
19	Puget Energy Inc.	4.2	4.8	4.3	9.1	9.4
20	Southern Co.	4.2	4.0	4.3	8.3	8.6
21	TECO Energy	4.1	4.4	4.3	8.7	8.9
22	Xcel Energy Inc.	4.4	4.2	4.6	8.8	9.0
	AVERAGE	4.1	4.6	4.3	8.8	9.1

Notes:
Column 1: Value Line Investment Analyzer, 7/2005
Column 2: Zacks long-term earnings growth forecast, 7/2005
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2
No growth forecast for Green Mountain Power

INVESTMENT-GRADE VERTICALLY INTEGRATED ELEC. UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Ameren Corp.	4.5	2.0	4.6	6.6	6.9
2	Cinergy Corp.	4.3	5.5	4.5	10.0	10.2
3	Cleco Corp.	4.0	1.5	4.1	5.6	5.8
4	Dominion Resources	3.6	9.0	3.9	12.9	13.1
5	DPL Inc.	3.5	2.5	3.5	6.0	6.2
6	Energy East Corp.	4.1	4.5	4.3	8.8	9.0
7	Empire Dist. Elec.	5.2	8.0	5.6	13.6	13.9
8	Entergy Corp.	3.0	6.5	3.2	9.7	9.9
9	FirstEnergy Corp.	3.4	10.0	3.8	13.8	13.9
10	FPL Group	3.2	7.5	3.5	11.0	11.1
11	Green Mountain Pwr.	3.4	3.0	3.5	6.5	6.7
12	Great Plains Energy	5.1	-1.0	5.0	4.0	4.3
13	Hawaiian Elec.	4.5	2.5	4.6	7.1	7.4
14	IDACORP Inc.	3.8	6.0	4.0	10.0	10.2
15	Alliant Energy	3.8	1.5	3.9	5.4	5.6
16	Northeast Utilities	3.3	11.0	3.6	14.6	14.8
17	Progress Energy	5.2		5.2	5.2	5.5
18	Pinnacle West Capital	4.3	3.5	4.4	7.9	8.2
19	Puget Energy Inc.	4.2	5.5	4.4	9.9	10.1
20	Southern Co.	4.2	4.0	4.3	8.3	8.6
21	TECO Energy	4.1		4.1	4.1	4.3
22	Xcel Energy Inc.	4.4	7.5	4.7	12.2	12.5
	AVERAGE	4.0	5.0	4.2	8.8	9.0

Notes:
Column 1, 2: Value Line Investment Analyzer, 7/2007
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2
No growth projections for Progress Energy, TECO
Negative growth projection for Great Plains Energy

INVESTMENT-GRADE VERTICALLY INTEGRATED ELEC. UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Ameren Corp.	4.5	2.0	4.6	6.6	6.9
2	Cinergy Corp.	4.3	5.5	4.5	10.0	10.2
3	Cleco Corp.	4.0	1.5	4.1	5.6	5.8
4	Dominion Resources	3.6	9.0	3.9	12.9	13.1
5	DPL Inc.	3.5	2.5	3.5	6.0	6.2
6	Energy East Corp.	4.1	4.5	4.3	8.8	9.0
7	Empire Dist. Elec.	5.2	8.0	5.6	13.6	13.9
8	Entergy Corp.	3.0	6.5	3.2	9.7	9.9
9	FirstEnergy Corp.	3.4	10.0	3.8	13.8	13.9
10	FPL Group	3.2	7.5	3.5	11.0	11.1
11	Green Mountain Pwr.	3.4	3.0	3.5	6.5	6.7
12	Hawaiian Elec.	4.5	2.5	4.6	7.1	7.4
13	IDACORP Inc.	3.8	6.0	4.0	10.0	10.2
14	Alliant Energy	3.8	1.5	3.9	5.4	5.6
15	Northeast Utilities	3.3	11.0	3.6	14.6	14.8
16	Pinnacle West Capital	4.3	3.5	4.4	7.9	8.2
17	Puget Energy Inc.	4.2	5.5	4.4	9.9	10.1
18	Southern Co.	4.2	4.0	4.3	8.3	8.6
19	Xcel Energy Inc.	4.4	7.5	4.7	12.2	12.5
	AVERAGE	3.9	5.3	4.1	9.5	9.7

Notes:
Column 1, 2: Value Line Investment Analyzer, 7/2007
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2
No growth projections for Progress Energy, TECO
Negative growth projection for Great Plains Energy

NATURAL GAS UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	Industry	% Current Divid Yield	Analysts Growth Forecast	Expected Divid Yield	Cost of Equity	ROE
		(1)	(2)	(3)	(4)	(5)	(6)
1	AGL Resources	GASDISTR	3.2	4.8	3.4	8.1	8.3
2	Atmos Energy	GASDISTR	4.3	5.3	4.5	9.8	10.1
3	Energen Corp.	GASDISTR	1.1	7.1	1.2	8.3	8.3
4	KeySpan Corp.	GASDISTR	4.6	2.8	4.7	7.4	7.7
5	Laclede Group	GASDISTR	4.2	5.0	4.5	9.5	9.7
6	New Jersey Resources	GASDISTR	2.8	6.0	3.0	9.0	9.1
7	NICOR Inc.	GASDISTR	4.5	2.3	4.6	6.8	7.1
8	Northwest Nat. Gas	GASDISTR	3.5	5.5	3.6	9.1	9.3
9	Peoples Energy	GASDISTR	4.9	4.0	5.1	9.1	9.3
10	Piedmont Natural Gas	GASDISTR	3.7	5.1	3.9	9.0	9.2
11	South Jersey Inds.	GASDISTR	2.8	6.0	3.0	9.0	9.2
12	Southwest Gas	GASDISTR	3.1	6.0	3.3	9.3	9.5
13	UGI Corp.	GASDISTR	2.4	7.3	2.6	9.8	9.9
14	WGL Holdings Inc.	GASDISTR	3.9	4.0	4.0	8.0	8.2
	AVERAGE		**3.5**	**5.1**	**3.7**	**8.7**	**8.9**

Notes:

Column 1, 2: Value Line Investment Analyzer, 7/2005

Column 3: Zacks long-term earnings growth forecast, 7/2005

Column 4 = Column 2 times (1 + Column 3/100)

Column 5 = Column 4 + Column 3

Column 6 = (Column 4 /0.95) + Column 3

NATURAL GAS UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH FORECASTS

	Company	Industry	% Current Divid Yield	Value Line Proj Growth	Expected Divid Yield	Cost of Equity	ROE
		(1)	(2)	(3)	(4)	(5)	(6)
1	AGL Resources	GASDISTR	3.2	5.0	3.4	8.4	8.5
2	Atmos Energy	GASDISTR	4.3	6.5	4.6	11.1	11.3
3	Energen Corp.	GASDISTR	1.1	14.5	1.3	15.8	15.8
4	KeySpan Corp.	GASDISTR	4.6	1.0	4.6	5.6	5.8
5	Laclede Group	GASDISTR	4.2	6.0	4.5	10.5	10.7
6	New Jersey Resources	GASDISTR	2.8	5.5	2.9	8.4	8.6
7	NICOR Inc.	GASDISTR	4.5	1.0	4.5	5.5	5.8
8	Northwest Nat. Gas	GASDISTR	3.5	7.5	3.7	11.2	11.4
9	Peoples Energy	GASDISTR	4.9	3.5	5.0	8.5	8.8
10	Piedmont Natural Gas	GASDISTR	3.7	6.5	4.0	10.5	10.7
11	South Jersey Inds.	GASDISTR	2.8	6.5	3.0	9.5	9.7
12	Southwest Gas	GASDISTR	3.1	10.0	3.4	13.4	13.6
13	UGI Corp.	GASDISTR	2.4	9.5	2.6	12.1	12.2
14	WGL Holdings Inc.	GASDISTR	3.9	6.5	4.1	10.6	10.8
	AVERAGE		**3.5**	**6.4**	**3.7**	**10.1**	**10.3**

Notes:
Column 1, 2, 3: Value Line Investment Analyzer, 7/2005
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3

HECO RT-21
DOCKET NO. 04-0013

REBUTTAL TESTIMONY OF
RICHARD A. VON GNECHTEN

HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Rate of Return on Rate Base

INTRODUCTION

Q. Please state your name and business address.

A. My name is Richard A. von Gnechten. My business address is 9213 Fairchild Lane, Charlotte, North Carolina, 28277.

Q. Have you previously testified in this proceeding on the return on rate base?

A. Yes, I have presented direct testimony as HECO T-21 and supporting exhibits and workpapers.

Q. What is the purpose of your rebuttal testimony?

A. The primary purposes of this testimony are as follows:

1. Update Hawaiian Electric Company, Inc. ("HECO" or the "Company") for the composite cost of capital for the average 2005 test year based on a new recommended return on common equity, issuance of the Refunding Series 2005A Special Purpose Revenue Bonds, redemption of the Series 1995A Special Purpose Revenue Bonds, and the King Street office building lease treatment;
2. Update the financial ratio calculations;
3. Discuss the importance of maintaining the Company's financial integrity in order to ensure that ratepayers have a financially sound utility, as well as to maintain trust in the financial markets; and
4. Comment on the DOD's and CA's testimonies.

I have also prepared an updated estimate of the savings to customers resulting from the use of special purpose revenue bond financing, which is shown on HECO-R-2107. This estimate has been updated to include the Refunding Series 2005A and remove the Series 1995A. Further explanation of the calculation was presented in direct testimony in HECO-2119.

1 UPDATED COMPOSITE COST OF CAPITAL

2 Q. What is HECO's updated composite cost of capital for test year 2005?

3 A. HECO's updated composite cost of capital is 8.83% as shown in HECO-R-2101.

4 Q. What updates have you made to the cost of capital calculation?

5 A. I updated the cost of capital to reflect the following changes:

6 1. Issuance of the Refunding Series 2005A Special Purpose Revenue
7 Bonds and redemption of the Series 1995A Special Purpose Revenue
8 Bonds on January 1, 2005;

9 2. Rebalancing of the capital structure to take into consideration the
10 pending lease agreement between the Company and the Trustees of the
11 Estate of Bernice Pauahi Bishop ("Bishop Estate"), for the lease of the
12 King Street office building, and

13 3. Updated the rate of return on common equity to 11.00%, from 11.50%
14 in direct testimony, to reflect Dr. Morin's updated recommendation (see
15 HECO RT-20).

16 These changes are shown in HECO-R-2101, HECO-R-2103, HECO-R-2105 and
17 the related workpapers.

18 Long-Term Borrowing

19 Q. Please describe the purpose of the issuance of the Refunding 2005A Series and
20 the redemption of the 1995A Series.

21 A. On January 1, 2005, $47 million of 4.80% Special Purpose Revenue Bonds
22 Refunding Series 2005A was issued with the proceeds to be used toward the early
23 redemption of $47 million of 6.60% Special Purpose Revenue Bonds Series
24 1995A in February 2005. The replacement of the 1995A series with the 2005A
25 series resulted in cost savings as the 1995A series bore a higher rate of interest.

Q. What is the revised average long-term borrowing balance for test year 2005?

A. The result of the new issuance and early redemption is a forecast average long-term borrowing balance of $424 million, which is slightly lower than what was presented in direct testimony. The detailed list of revenue bond issuances and other adjustments comprising the average balance is shown on HECO-R-2103.

Q. What adjustments contributed to the change in the long-term borrowing balance?

A. Changes to the long-term borrowing balance are attributable to the issuance of the Refunding Series 2005A and related unamortized issuance and insurance costs, and the early redemption of the 1995A Series and change in the unamortized issuance costs primarily due to the incurrence of $400,000 of redemption costs. The unamortized balances and calculations are shown on HECO-RWP-2103 p. 3.

Q. What is the revised estimated effective cost of long-term borrowings for test year 2005?

A. The Company has revised the estimated effective cost of long-term borrowings for the test year 2005 to 6.25% from 6.30%.

Q. Why did the effective cost of long-term borrowings decrease?

A. The decrease in the effective cost of long-term borrowings is due to a decrease in the annual requirement resulting from a lower annual interest expense as a result of the early redemption of the 1995A Series and the issuance of the Refunding Series 2005A which bears a lower interest rate. See calculation of effective rate at HECO-R-2103.

<u>King Street Office Building Lease</u>

Q. What is the King Street office building lease?

A. The Company leases its King Street office building in downtown Honolulu from the Bishop Estate. The previous lease agreement expired on November 30, 2004.

In 2004, HECO and Bishop Estate negotiated, but did not execute, a lease agreement which would have been classified as a capital lease. Subsequently, the lease agreement was renegotiated and executed. The new lease arrangement is an operating lease. Ms. Sekimura provides details of the transaction in HECO RT-16.

Q. Does the capital structure in this rebuttal testimony include a lease obligation relating to the King Street office building lease?

A. No, it does not. The revised cost of capital exhibits filed May 5, 2005 and June 15, 2005 included a capital lease obligation in the capital structure. At the time, a capital lease agreement had been negotiated between the Company and Bishop Estate.

Subsequent to the filing of those updates, further negotiations with Bishop Estate resulted in an operating lease agreement. An operating lease does not require the recording of a capital lease obligation on the balance sheet. Therefore, the Company has removed the lease obligation from its capital structure.

Q. Does the King Street office building lease have any impact on the Company's capital structure?

A. Yes. The operating lease results in approximately $7 million in imputed debt, which indirectly impacts the capital structure.

Q. What is imputed debt?

A. Although the operating lease is not shown on the Company's balance sheet, credit rating agencies consider the obligation a debt equivalent in calculating financial ratios used to evaluate the Company's financial performance.

Q. How is the imputed debt calculated?

A. The imputed debt is the net present value of the fixed minimum lease payments

discounted at 10%.

Q. How does the imputed debt impact the capital structure?

A. The imputed debt increases the Company's debt to total capital ratio. Therefore, in order to maintain its debt to total capital ratio, the Company must eliminate other debt and increase its equity balance to restore its debt to total capital ratio.

Q. What will the Company do to compensate for the imputed debt?

A. HECO estimates that it will increase common equity by $2.5 million and correspondingly decrease its estimate of short term borrowings by $2.5 million to compensate for the imputed debt related to the King Street office building lease.

Revised Capital Structure

Q. What is the revised capital structure?

A. As a result of the changes just described, the Company believes a capital structure comprised of 3.25% short-tem debt, 36.81% long-term debt, 2.37% hybrid securities, 1.78% cumulative preferred stock, and 55.79% common equity is appropriate.

UPDATED FINANCIAL RATIOS

Q. Have you updated the projected financial ratios for the test year as presented in direct testimony?

A. Yes. We have updated the financial ratio calculations in HECO-R-2106. There are two sets of ratios. One set is based on HECO receiving rate relief and earning an 11.0% return on common equity, which is optimistic since the Company is usually not actually able to achieve the level of earnings found fair and reasonable by the Commission. The other set is based on no rate relief.

Q. What are the implications of the updated ratios?

A. A comparison of HECO's projected ratios to the financial guidelines applicable to HECO is shown on HECO-R-2106. Based on HECO's current S&P business profile of "5", without rate relief:

- the funds from operations/interest coverage ratio is indicative of a BBB rating (3.0 in BBB range of 2.8-3.8),
- the funds from operations/total debt ratio is indicative of a BB rating (14.7 in BB range of 10-15), and
- the total debt/total capital ratio is indicative of a BBB rating (52.9 in BBB range of 60-50).

With rate relief:

- the funds from operations/interest coverage ratio is indicative of a BBB rating (3.7 in BBB range of 2.8-3.8),
- the funds from operations/total debt ratio is indicative of a BBB rating (19.3 in BBB range of 15-22), and
- there is no change to the total debt/total capital ratio, which is indicative of a BBB rating (52.9 in BBB range of 60-50).

HECO currently has a BBB+ corporate senior unsecured debt credit rating from Standard and Poor's. The BBB+ rating is reflective of financial ratios that would be in the upper portion of the range for each measure shown, otherwise the credit rating would not achieve the required threshold for a BBB+ and would instead be viewed as a BBB or BBB- by S&P. This would result in a downgrade for the Company and related consequences, ultimately translating into higher costs for ratepayers.

Q. Has HECO always had a BBB+ S&P credit rating?

A. No. For many years, HECO had higher credit ratings. In the 1990's, the

Company was downgraded to BBB+ by S&P. In prior rate proceedings the Company has advocated that it "believes it is prudent to work towards bringing the total risk of the Company back to a level commensurate with a strong "A" or weak "AA" rating." (Docket No. 7766, T-17, page 19) While we still believe this is the case in the long term, we believe at minimum it is essential that the Company at least maintain its current credit rating by actually earning a fair and reasonable return on equity that would support this level.

Q. What is the significance of the earned return versus the allowed return in determining credit ratings?

A. The allowed return is a very important measure for the Company and for external entities such as credit rating agencies and financial analysts to gauge what the company can achieve. Ultimately, however, the actual earned return and projected future results are what credit rating agencies use to determine a company's financial performance and credit-worthiness. For purposes of justifying a proposed return on equity in this proceeding, financial ratios are provided using the allowed return, which means the ratios are the maximum the Company could achieve if it actually earned at its allowed level. This is an important distinction, because the Company typically cannot earn its allowed return on equity, which means its financial performance usually will be lower than its allowed return.

Thus its financial ratios would be lower than projected in this proceeding. This is very important to consider since the rating agencies will look at and weigh heavily the actual financial ratios the Company achieves in addition to considering projected future results in determining its credit rating for the Company. If the potential ratios are weak then the actual ratios will be weaker and may well result

in a downgrade.

I believe this is why it's so important for the Company to have a sufficient allowed return and be able to actually earn such a return so that the Company can at least try to maintain its current credit rating.

The timing of the rate relief also impacts the Company's ability to earn its allowed return. If all items are as estimated in the test year, the only way the Company can earn its allowed return in the test year is if the Company is granted its rate relief at the beginning of the test year. This puts more pressure on the Company and is a particular reason that Standard and Poor's is waiting to see what final decision is made in this rate proceeding. S&P recently gave the Company a negative outlook in light of this situation. See rebuttal testimony of Ms. Sekimura, RT-16 for additional information.

Q. Do you have any other comments on the financial ratios?

A. Yes. While direct testimonies by Mr. Hill for the DOD and Mr. Parcell for the CA look at the interest coverage ratio in evaluating financial ratios, it is important to note that there are several other ratios that also are evaluated in determining a credit rating. In the past, the Company has had difficulty with its funds from operations to average total debt ratio ("FFO/total debt"). As you can see, the funds from operations to average total debt ratio, even with the Company's proposed rate relief, remains quite weak. Without rate relief this measure drops to the BB category given a business profile of "5". Thus, even with the requested rate relief, the Company will struggle to maintain this measure, which is why it is so important that the Company be able to earn a fair and reasonable return on equity. This is also where the impact of the imputed debt has been significant. So even though the Company has increased its equity and decreased its debt to

1 strengthen some of its financial ratios, the FFO/total debt ratio remains a
2 challenge and is dependent on the funds from operations (principally earnings)
3 that the company can achieve.
4 Q. Do you have any more comments on imputed debt?
5 A. Yes. While this issue was mentioned in my direct testimony, I want to emphasize
6 a couple points regarding imputed debt. In HECO's last rate proceeding in 1995
7 (Docket No. 7766), a 20% factor for imputed debt was used versus 30% in the
8 current case for purposes of determining the Company's capital structure and
9 financial ratios including total debt over total capital. Thus, while at first glance it
10 appears the Company's equity percentage of its capital structure has increased,
11 when you view the company's capital structure from the credit rating agencies'
12 point of view, the Company's equity percentage has actually not changed
13 significantly (53% debt/total capital means 47% equity versus 48% in the
14 Company's last rate case). Furthermore, when you look at the coverage ratios for
15 the Company, the rating agencies factor in a 10% interest cost for the
16 $243,404,000 in imputed debt versus the 6.25% earnings requirement proposed in
17 this proceeding. This puts additional pressure on the Company to meet its
18 financial coverage ratios from the rating agencies' point of view. This higher
19 interest rate means the Company must cover an additional $9,127,650 (10%
20 minus 6.25% equals 3.75% difference times $243,404,000 in debt) in interest
21 associated with the imputed debt versus what the Company could obtain in the
22 market for this same amount of debt. The total interest impact of the imputed
23 debt is $24,340,400 in interest, which is used by the rating agencies in
24 determining the Company's financial ratios. The Company has not asked for this
25 additional $24,340,400 in interest expense on the imputed debt in this rate

proceeding, because it is not a direct cost to the Company. However, it is important to note that it remains a factor in evaluating the Company's financial ratios, and is one of the reasons that the Company's ratios are weak and the Company must be able to earn a fair and reasonable rate of return on equity in order to cover these costs. This is not something that the CA and DOD have factored into their calculations, which overstates the financial ratios associated with Mr. Hill's and Mr. Parcell's proposed return on equity.

MAINTAINING FINANCIAL INTEGRITY & STRENGTH

Q. What is financial strength?

A. "Financial strength" is the ability to sell the types of securities the Company needs to sell on reasonable terms, no matter what the conditions of the financial markets. It also represents the ability of the Company to continue to meet its obligations, even under adverse conditions.

Q. How important is it to maintain financial integrity?

A. Extremely important. The Company raises its capital in competitive markets. The supply and demand for investor's funds change in those markets as economic conditions change. Under ideal conditions, financing is available for most companies. Under adverse economic conditions, however, companies with less financial strength may find it difficult, if not impossible, to raise new capital. Continued access to capital markets is critical for a company, such as HECO, that has an obligation to provide utility services, no matter what the economic conditions.

Q. How important is it for ratepayers to have a financially sound utility?

A. Again, it is very important. Investors are very sensitive to financial strength

1 considerations when they decide where to invest their own, or their client's,
2 money. If HECO's financial strength is not maintained, more and more risk
3 adverse investors will invest their money elsewhere. This, in turn, is not
4 favorable for HECO's customers because it will reduce the demand for the
5 Company's securities and will increase its cost of capital. Further, under adverse
6 market conditions, it may be difficult to attract capital. It is imperative from a
7 customer standpoint, therefore, that HECO at least maintain its financial strength.
8 Q. Are there additional reasons this is particularly important to the Company and its
9 customers?
10 A. Yes. HECO is an island utility and cannot depend on anyone else to provide
11 power to its customers. Clearly this is a burden that the Company and its
12 community carry. In the event of a financial downturn, the Company cannot turn
13 to a neighboring utility to get needed power delivered to its grid. This means the
14 Company has to build the power and delivery systems necessary to meet the
15 customer demand when it is needed. The Company has to have the financial
16 capability to raise funds to build such systems under all financial conditions.
17 Therefore, it is important for the Company to maintain financial strength so that it
18 can continue to obtain adequate capital to finance its operations to provide power
19 to its customers.
20 Q. What is a key consideration in managing the Company's capital structure?
21 A. A key consideration in formulating the financing plan that led to this capital
22 structure is the need to at least maintain and, hopefully strengthen the Company's
23 credit standing. In order for the Company to be able to attract funds in the future
24 on reasonable terms, we need to demonstrate to the investment community that
25 the Company is financially sound. One element of this process is to show that the

1 Company is managing the capital structure so as to keep the overall costs of funds
2 to a minimum, consistent with the need to insure that all classes of investors are
3 adequately compensated for the risks they are taking by entrusting their funds to
4 the Company.
5 Q. In addition to what was stated in your direct testimony on page 7 of 49, are there
6 any other reasons it is important for the Company to maintain good credit ratings?
7 A. Yes. Maintaining good credit ratings are indicative of the Company's ability to
8 withstand adverse conditions. A company with a good credit rating is usually
9 able to continue to meet its obligations despite an earnings downturn, such as
10 might occur in a recession if the company could not adjust its rates in a timely
11 manner.
12 Q. What has been the Commission's position on financial integrity in the past?
13 A. The Commission has previously said that it needs to provide a return sufficient to
14 assure confidence in the financial integrity of the enterprise to maintain its credit
15 and capital attracting ability. A return on rate base equal to the Company's
16 composite cost of capital would allow the Company to cover the capital costs of
17 the business; it would provide a return on investment commensurate with returns
18 on other investments having corresponding risks; and it would provide assurances
19 to the financial community of the Company's financial integrity.
20 Q. Is there already evidence to be concerned about the Company's financial
21 integrity?
22 A. Yes. On April 22, 2005 Standard and Poor's revised its outlook for HECO to
23 negative from stable. See Ms. Sekimura's rebuttal testimony RT-16 for further
24 information on this topic.
25 Q. How would the markets and rating agencies view dramatic changes in the

1 regulatory climate in Hawaii (such as a significant drop in the allowed rate of
2 return on equity)?
3 A. The market and rating agencies do not like adverse change. The very measure of
4 what return should be given is based on risk and uncertainty. If there was a
5 dramatic deterioration in the regulatory climate in Hawaii, including a significant
6 drop in the allowed rate of return on equity, this would likely have a very negative
7 effect on the Company's credit rating. The Company is already at the low end of
8 the investment grade credit rating. As stated in Ms. Sekimura's testimony,
9 referring to HECO-R-1614, Standard & Poor's has indicated that a "punitive rate
10 order,...could lead to lower ratings." A downgrade by S&P would have an
11 impact on the Company's ability to raise funds in the marketplace, which would
12 ultimately impact the ratepayers.
13 The current allowed return for HECO is already the lowest it has had over
14 the past 40 years and this occurred before the current drop in interest rates.
15 Q. Do you have any comments regarding interest rates and their impact on allowed
16 returns on equity?
17 A. Yes, I do. It is evident from financial literature that each of the equity models has
18 its own short-comings and experts differ as to the relative merits of each. The
19 Discounted Cash Flow or DCF approach has exhibited a downward bias and even
20 provided equity returns lower then debt levels in some cases. It is clear from
21 financial literature that lower interest rate environments result in derived equity
22 calculations to understate equity results. This has caused a number of entities to
23 pursue alternative measures that more fairly reflect the risks born by utility
24 shareholders. One illustration is provided by Rudden Associates for the Edison
25 Electric Institute in which they suggest that the current market does not

adequately reflect the risks taken by shareholders.

There is evidence that regulatory commissions are concerned about the inability of investors in regulated utilities to have an opportunity to earn their required returns when the DCF, risk premium and capital asset pricing models are used to determine the investor-required-market-returns. Mr. Parcell admits this problem with the DCF model has driven the DCF results to the lowest level by historic standards (line 1-2, page 36 of CA-T-4). This Commission has explicitly recognized that the DCF model can produce results that are too low. (D&O 13762 at 77, D&O 13704 at 94) In fact, in HELCO's 1994 rate case, the Commission found the result of the CA's standard DCF test to be an anomaly and discarded it from consideration (D&O 13762 at 76). Other Commissions also have lessened their reliance on this test. For instance, the Indiana Regulatory Commission has stated that there are "three principal reasons for [its] unwillingness to place a great deal of weight on the results of any DCF analysis" – (1) "the failure of the DCF model to conform to empirical reality," (2) "the undeniable fact that rarely if ever do two expert witnesses agree on the terms of a DCF equation for the same utility," and (3) "the unadjusted DCF result is almost always well below what any informed financial analyst would regard as defensible, and therefore requires an upward adjustment based largely on the expert witness' judgment." (Re Indiana Michigan Power Co., 116 P.U.R. 4th 1, 17-18 (Ind. U.R.C. 1990); Re Inter-State Water Co., P.U.R. 4th 535, 588 (Ill. Comm. Comm'n 1995).

In the past, this Commission has recognized this aberration and has not increased allowed return on equity levels to the extent that it could during higher interest rate environments and has not lowered allowed return on equity levels to the extent that the DOD and CA suggest current interest rates would indicate.

This is particularly important, given that the allowed return on equity is a forward looking instrument that has to be sufficient for the Company to raise capital and maintain its financial integrity for the foreseeable future, including during a higher than normal capital program such as that it is currently pursuing. This is also critical given the Company's island operating environment.

Q. In determining the fair rate of return on common equity, is it appropriate to consider the economic conditions that will prevail during the period that the rates set in the rate case are in effect?

A. Yes. The need for a longer range view was clearly stated in HECO Docket No. 3705, Decision and Order No. 6275 when interest rates were temporarily high and the Commission decided not to establish a high rate of return on equity that would be justified by the high interest rates (and the corresponding high dividend yields) at the time:

> "The Commission is cognizant of HECO's large construction and financing program which is necessary for it to meet its obligation to serve the public, and that to execute its plans at minimum cost requires that it maintain its earning power and financial integrity. The Commission is also aware that there is a need to seek rates that will remain reasonably stable for a period of time in the future. Ratemaking should not be guided solely by the point in the business cycle the economy happens to be at when new rates are being set, nor should rates fluctuate with the vicissitudes of the money market." (D&O 6275 at 87)

The Commission should apply its policy on this matter consistently, and not place undue emphasis on current market conditions when interest rates are low. It adds confidence to the regulatory process when the investment community perceives there is reasonable stability with respect to the rate of return.

Q. How hard is it to reestablish trust in the financial markets if it is lost?

A. It is often said that a person is only as good as his or her reputation. The same is

true for a corporation that has to raise capital in the financial markets. HECO has worked very hard over the years to earn a strong reputation for financial integrity. This could only be done through the support of the Commission. If the Company were to lose this reputation, it would be extremely difficult and time-consuming to reestablish that trust in the financial markets. That is even more reason why it is important during this current environment (with the Company having a negative outlook) for the Company to maintain its financial strength. One only needs to look at the time and effort it has taken for the major electric utilities in California to recover from difficult financial circumstances and the resulting political turmoil. Unfortunately, it is the entire community that suffers in such a situation.

Q. What has been the state of on-going discussions with investment analysts and rating agencies as to how they view HECO?

A. Traditionally, investment analysts and rating agencies have looked favorably upon HECO as a reflection of the Hawaii market. Given the changes in the operating environment and political landscape there is much uncertainty about what will happen to the Company going forward. S&P's negative outlook is an illustration of that uncertainty. Investment analysts have asked the same questions.

CREDIT EVALUATION

Q. Why did you spend so much time talking about business and financial risks in your direct testimony?

A. Business and financial risks are the underpinnings of how credit rating agencies evaluate the Company and determine its credit rating. As articulated in my direct testimony, the Company faces numerous business and financial risks, many of which are different than it has faced in the past and which contribute to the

1 Company's current situation. For example, the imputed debt issue has added
2 $239 million to HECO's balance sheet as viewed by the rating agencies at a 10%
3 interest rate or $23.9 million in annual interest, which is much higher than the last
4 time the Company applied for rate relief. This does not appear on our balance
5 sheet or income statement, and thus not directly covered in our rate request.
6 However, it must be considered in providing adequate rate relief for the Company
7 in order for it to try to maintain its credit rating.
8 Q. How do rating agencies evaluate the Company's business risks?
9 A. To assess the business risks of a company, the rating agencies examine a number
10 of business factors, including the company's market environment, fuel and
11 purchase power supplies, operating efficiency, regulatory environment, and
12 quality of management, among other things. For the most part, the business risks
13 are present regardless of the capital structure a company employs. The financial
14 risks, on the other hand, are directly affected by the Company's capital structure.
15 In our determination of what the Company's capital structure should be, we
16 concentrated primarily on maintaining the interest coverage and debt to capital
17 ratios because these two measures are most affected by the Company's capital
18 structure decisions. Of equal importance, however, is ensuring adequacy of the
19 Company's fund from operations to average total debt ratio, which is driven by
20 the profitability of the company compared to its interest expense. In this case, this
21 is impacted by the imputed debt the rating agencies add as well as the Company's
22 allowed rate of return and its ability to earn that return.
23 Q. Do the Commission's actions affect potential investor's perception of the amount
24 of risk there is in investing in the Company?
25 A. Yes. The investment community is very concerned about the stability of a

1 Company's earnings. Anything that can negatively affect that stability will be
2 seen as increasing the risk of the investment. The Commission plays a vital role
3 in that stability by providing both adequate and timely rate relief. The investing
4 public is quite concerned about a regulatory commission's ability and willingness
5 to provide that kind of rate relief, as evidenced by Standard and Poor's recent
6 change in outlook for the Company to negative from stable. Doubts about the
7 adequacy or timeliness of rate relief raises the risk of unstable earnings and the
8 returns required to induce the investor to invest his money in the Company. This
9 was a problem in the early 1990's when the Company had a large capital program
10 and initially was not able to obtain adequate and timely rate relief. The
11 Commission recognized this issue and subsequently has provided timely rate
12 relief.
13 Q. Are there unique business risks during a heavy construction period?
14 A. Yes. The Company is projecting a heavy construction program for the next
15 several years. Due to increases in customer demands for electricity in the past
16 several years and the forecast for the next few years, the Company finds itself in
17 need of additional generation and transmission facilities. A large construction
18 program will require both substantial amounts of external financing and also
19 timely, adequate rate relief in order to avoid attrition, which results when the
20 Company has to invest necessary capital for its facilities faster than it can get
21 recovery of such expenditures. These factors contribute to higher uncertainties
22 for investors in the Company during a heavy construction period similar to the
23 Company's near term requirements.
24 Q. Do you have any comments on purchase power obligations?
25 A. Yes. I previously discussed the impact of the imputed debt associated with these

long-term fixed obligations and the challenges HECO faces given its island utility operating environment. The principal reason this has such an impact is that HECO must sign long-term fixed obligations (which are more like debt and treated as such by the rating agencies) in order to meet its peak obligations, whereas mainland utilities can engage spot market, as-available and short-term fixed obligations to fulfill its customer power needs. This again means that HECO has unique risks versus its mainland counterparts.

Q. Are there other business risks which are of concern to HECO?

A. Yes. HECO has no interconnections with other utilities. This increases the generation planning risks faced by the Company. Likewise, business interruption insurance coverage is not available to HECO based on the lack of replacement power to mitigate the interruption.

Increasing reliance on power purchased from third parties, while somewhat mitigating HECO's reliance on fuel oil, has increased the business risks of the Company. Business risks have increased because the Company does not have as much control over the generation of its power as it would have if it owned and operated enough generation facilities to meet customer needs.

Given events of the past, there has been a realization that the potential for severe wind damage to the Company's property is much higher than previously thought. With HECO's hurricane wind exposures, insurance underwriters do not offer coverage, or if coverage is made available, reasonable pricing for Transmission & Distribution property insurance is not offered. In addition to this significant uninsured exposure, HECO's insured property deductible for hurricane exposures is extremely high. For each scheduled location, the deductible is 2% of replacement values with a minimum deductible of $1 million. HECO's exposure

would be capped at the aggregate wind deductible of $25 million for any one occurrence. For example, Kahe Power Plant has a wind deductible of $13.4 million and Waiau Power Plant has a deductible of $11 million. If the two plants were struck by a hurricane, HECO would have to cover as much as the first $24.4 million in damage costs before insurance would contribute. If additional locations were damaged, HECO's exposure would be another $.6 million before reaching the maximum aggregate wind deductible of $25 million for that occurrence.

This has increased the perceived business risks of the Company. The investors have expected all along that the Company's property was either insured or that the Commission would provide the revenue to pay for the repair of uninsured damages.

Given the experience of Kauai Electric, many feel we are in an area prone to very high winds. Investors will be concerned about the remote possibility that the damage could be so severe that the Commission at that time might find it difficult to provide the revenues with which to pay for the repairs. This possibility will cause investors generally to require either a greater return to induce them to invest their money in the Company given that the Company has not received an allowance for recovery of future costs from property damage in previous proceedings.

CA AND DOD POSITIONS

Q. Upon which of the elements of the cost of capital calculation are the parties in agreement?

A. The CA, the DOD and the Company have agreed on most of the cost of capital calculation issues, including a capital structure of 3.25% short-term debt, 36.81%

long-term debt, 2.37% hybrid securities, 1.78% preferred stock and 55.79% common equity. The parties have also agreed on the cost of short-term debt of 3.50%, long-term debt of 6.25%, cost of hybrid securities of 7.55% and cost of preferred stock of 5.54%.

Q. Are the parties in agreement regarding the cost of common equity?

A. No. In direct testimony the Company requested a cost of common equity of 11.50% as presented by Dr. Morin in HECO-T-20. Dr. Morin has revised his cost of equity for his rebuttal testimony to 11.00%. The CA's witness, Mr. Parcell, recommends a cost of equity of 9.25% within a range of 8.5% to 10.0%. The DOD's witness, Mr. Hill, recommends a cost of equity of 9.00% within a range of 8.75% to 9.50%.

Dr. Morin's revised cost of equity rebuttal testimony and supporting exhibits are presented at HECO-RT-20.

Q. Do you have any comments on Mr. Parcell's and Mr. Hill's contention that HECO's financial risk is somewhat lower because its equity ratio is higher?

A. Mr. Parcell and Mr. Hill make an erroneous contention based on the Companies' unadjusted debt to equity ratio, which does not account for the impact of purchased power obligations on the Companies' financial risk. Financial risk cannot be determined by looking solely at the equity ratio. As discussed previously, and as the Commission has recognized in previous rate case decisions, purchased power obligations have an impact on how the rating agencies view the Company's debt leverage and financial risk, and rating agencies impute part of the capacity payments as fixed charges for the Company. Thus, the Company's purchased power obligations create an element of financial risk, and the effect of purchased power commitments must be factored in to assess debt leverage. The

1 financial risk associated with their purchased power obligations has not been
2 factored into Mr. Parcell's and Mr. Hill's assessments that HECO has less
3 financial risk.
4 Q. Do you have any comments on Mr. Parcell's statement on pages 50-51, CA-T-4
5 that current circumstances do not warrant an upward adjustment to the rate of
6 return on equity for HECO?
7 A. Yes. I strongly disagree. The circumstances that HECO currently encounters
8 have not improved in comparison to the situation in the 1990's and, in fact, they
9 have gotten worse. HECO has already been given a negative outlook by one
10 rating agency, has poor financial ratios relative to its current rating, has
11 confronted all the additional business risks presented in my direct testimony,
12 including substantially higher debt from a rating agency point of view given the
13 imputed debt burden, a substantially higher construction program to meet the
14 generation and transmission needs of its customers (contrary to Mr. Parcell's
15 statements on line 15-16 of page 51 CA-T-4 that suggest a reduction in its
16 construction program), and high regulatory uncertainty given the new
17 composition of the Commission and uncertainty on how it will address key
18 decisions, including this rate case proceeding.
19 Mr. Parcell suggests HECO's financial status has improved, but it
20 currently is not strong enough to support its current credit rating (as evidenced by
21 S&P's change in outlook from stable to negative).
22 HECO's construction program has increased and is expected to continue to
23 be substantial given the need for a new power plant on Oahu and new
24 transmission. It is true that in recent times the Hawaii Commission has been
25 given good marks for its responsiveness to providing timely rate relief. In fact,

1 the Commission's desire to insulate HECO from its parent company, Hawaiian
2 Electric Industries, Inc. ("HEI"), is the chief reason HECO still gets credit for
3 regulatory insulation and is thus able to obtain a credit rating one notch higher
4 than its parent company if its financial ratios support such a rating. The
5 Commission achieved its good marks following a time period when the Company
6 did not get timely and adequate rate relief and the Company was downgraded in
7 the early 1990's. That said, there is uncertainty on the part of the rating agencies
8 and financial community as to whether the Hawaii Commission will continue to
9 provide for timely and adequate rate relief.
10 As Mr. Parcell indicates, the Commission has historically recognized that
11 HECO and its subsidiaries have higher risk than proxy groups and therefore there
12 should be an upward adjustment to the return on common equity to compensate
13 for HECO's higher risk as indicated by Dr. Morin. The Commission has
14 consistently recognized that adjustments, based on judgment, must be made to the
15 rate of return on common equity for the proxy companies to account for the
16 differences between the financial and business characteristics of the comparable
17 companies and those of HECO (D&O 15480 at 35). The Commission in prior
18 Decisions and Orders (including D&O's in Docket Nos. 7000,7700, 7764, 7766,
19 94-0140, 97-0346, 99-0207) has recognized that HECO and subsidiaries have
20 greater risks than the proxy groups and made adjustments to the Company's
21 allowed return on equity in each instance. Mr. Parcell, however, recommends that
22 the Commission discontinue this practice, but fails to account for the impact if his
23 recommendation is followed.
24 Reducing the "allowed" cost of common equity results in lower rates, at
25 least in the short-term. However, HECO's customers cannot afford for HECO's

1 cost of common equity to be understated. Hindering the ability of HECO to
2 attract capital could be harmful to the economic infrastructure of Oahu, and would
3 be contrary to the best interests of HECO's customers. HECO, unlike many other
4 companies, cannot stop necessary investments in plant, or legislated
5 environmental investment, when the availability of capital is constrained in the
6 market, as it is from time to time. Customers expect service to occur on demand.
7 Therefore, HECO, which provides customers with indispensable energy services,
8 must be sufficiently strong financially to cope with unforeseen events, and its
9 securities must be attractive enough to access capital during adverse, as well as
10 more normal, market conditions.
11 Q. On page 53 of CA-T-4, Mr. Parcell suggests that his cost of capital
12 recommendation provides the Company a sufficient level of earnings to maintain
13 its financial integrity. What is your response?
14 A. Mr. Parcell indicates that his proposal would result in a coverage level within the
15 benchmark range for a BBB rate utility. HECO is currently rated BBB+, which
16 means that it would have to have financial ratios at the top of the BBB benchmark
17 range in order to actually maintain its current rating. Mr. Parcell's proposal
18 would only meet a low BBB credit rating (line 15-17, page 53, CA-T-4), which he
19 suggests is adequate. Using Mr. Parcell's proposed return on equity, we have
20 calculated the resulting funds from operations to average total debt ratio which
21 would be 16.6 (as shown by HECO-RWP-2106 page 11 of 11). This would also
22 be on the lower end of the BBB range for this ratio of 15 to 22. A low BBB
23 rating would mean at least a one notch and possibly a two notch downgrade from
24 HECO's current BBB+ rating. And given that the utility cannot normally earn its
25 allowed return on equity, Mr. Parcell's proposal would almost ensure a

1 downgrade.

2 Ultimately, the determination of a reasonable cost of equity is a matter of
3 informed judgment, as the Commission has recognized. It is necessary to
4 ascertain whether the end result of the cost of equity determination is reasonable.
5 The return recommended by the experts must meet the standards enumerated in
6 the Bluefield and Hope cases—it must be sufficient to assure confidence in the
7 financial integrity of HECO so as to maintain its credit and capital-attracting
8 ability.

9 HECO's corporate and senior unsecured debt ratings of BBB+ by S&P are
10 already at a level where utility companies have experienced problems in attracting
11 capital in the past. Even with an earned 11.00% rate of return on equity, the S&P
12 financial ratio benchmarks for the Company will be weak. A cost of equity of
13 11.00% is necessary to maintain the Company's credit quality, and to recognize
14 the Company's higher risk.

15 Regulatory Process—Risk of Rate Base Disallowances of Construction Costs

16 Q. On page 21 of his testimony, as part of his discussion regarding the regulatory
17 climate in Hawaii, Mr. Parcell asserts that the regulatory process in Hawaii serves
18 to minimize the risk of rate base disallowances—in that the Commission's prior
19 review of construction projects (prior to their appearance in a rate case
20 proceeding) reduces the likelihood of disallowances and thus reduces the
21 Company's business risks. Do you have any comments on this?

22 A. Yes. It is the case that the Commission's prior approval of construction projects
23 helps to reduce the Company's business risk. The Commission has permitted the
24 Company's capital expenditures to be included in rate base and has not been quick
25 to disallow items because of changed circumstances. This is helpful in reducing

1 regulatory risk, but does not eliminate it completely. There have been cases
2 where the Companies have had to make substantial commitments of funds prior to
3 Commission approval under paragraph 2.3(g)(2) of General Order No. 7 in order
4 to maintain the schedule for a project essential to reliable service, since the
5 Company is not interconnected with other utilities and cannot import power as
6 other utilities can. Furthermore, in recent years the D&O for capital expenditures
7 greater than $500,000 and now $2,500,00 have included language that make it
8 less certain such projects will not be disallowed in a rate proceeding. If the
9 Company were to have an asset or capital expenditure disallowed in a rate
10 proceeding, this would eliminate the risk mitigation that Mr. Parcell suggests
11 exists and has been factored into his return on equity calculations.
12 CA and DOD Proposed Disallowance—Prepaid Pension Asset
13 Q. Do the CA and DOD raise any issues in this rate case that may be of particular
14 concern to credit rating agencies if accepted by the Commission?
15 A. Yes. I believe that it would be of particular concern to credit rating agencies if the
16 Commission were to adopt the CA's and DOD's position that the prepaid pension
17 asset should be disallowed.
18 Q. Please briefly summarize the positions of the parties on this issue.
19 A. As discussed by Ms. Price in HECO T-15 and RT-15 and Ms. Sekimura in HECO
20 RT-16, the Company has consistently based its accounting and ratemaking
21 treatment of its pension on Statement of Financial Accounting Standards No. 87
22 ("SFAS 87"), "Employers' Accounting for Pensions" since it was adopted by the
23 Company in 1986. In this rate case, the Company has included net periodic
24 pension costs ("NPPC") of approximately $5 million in administrative and
25 general expense and prepaid pension asset of approximately $79 million in rate

1 base. In HECO RT-16, Ms. Sekimura discusses in detail the Company's position
2 that the prepaid pension asset is investor-funded investment in the Company's
3 pension fund.
4 Both the CA and the DOD accept HECO's estimate of $5 million in
5 NPPC, but propose disallowance of the $79 million prepaid pension asset. The
6 CA and DOD do not dispute the validity or value of the prepaid pension asset, but
7 take the position that ratepayers have provided the funds which create the asset,
8 therefore investors should not allow a return on the asset and that it should be
9 disallowed for ratemaking purposes.
10 Q. What are the financial implications of any disallowance of the prepaid pension
11 asset?
12 A. First, in this case, the prepaid pension asset is nearly $80 million of investor-
13 provided funds. Investors clearly expect to earn a return on that investment. If it
14 is not included in rate base, revenues will not be provided to provide a return on
15 this investment which will have negative financial consequences to investors.
16 Debt-holders will still likely earn their interest income; therefore shareholders will
17 most likely suffer lower returns as a result of any disallowance.
18 In addition, any disallowance of the prepaid pension asset will also be a
19 disincentive to fund the pension plan in the future. If the prepaid pension asset is
20 not included in rate base, investors will not be earning their fair return on
21 investment and will not have incentive to provide further funding. An
22 inadequately funded pension plan will increase the business risks faced by the
23 Company. As discussed by Ms. Sekimura in HECO RT-16, when the pension
24 plan is reasonably funded, the Company has greater discretion in how much it
25 decides to contribute each year. If the pension plan is not reasonably funded, it

may be required under the Employee Retirement Income Security Act of 1974 ("ERISA") or the Internal Revenue Code ("IRC") to make minimum contributions to the pension plan, thus reducing the Company's financing flexibility. The Company may find itself required to make minimum fund contributions at a time when sources of capital are limited.

Q. Why is this proposed disallowance by the CA unreasonable?

A. Costs that are prudently incurred by HECO to provide electric service should be recovered from ratepayers. The CA's proposal is unfair and unreasonable because it would cause HECO and its investors to be unable to have a real opportunity to earn a fair rate of return on their investment.

Q. If the above CA proposal was adopted by the Commission, how would this impact investors in HECO?

A. Investors in an electric utility, such as HECO, need to have a realistic chance to earn the return determined fair and reasonable on their total investment in the electric utility business of the Company.

If the investment is not in the rate base or in construction work in progress (where the investors are compensated through allowance for funds used during construction "AFUDC"), there is currently no mechanism to earn a return on that investment. It takes the rate of return on rate base and AFUDC to cover all the costs of capital invested in the electric utility business. The inability to earn a return on part of the money invested would make it impossible (without offsetting circumstances of some sort) for the investors to earn the overall rate of return determined fair and reasonable by the Commission. This will ultimately lead to investors requiring higher returns as a result of the risk of earning lower returns due to disallowances.

Investors expect the Company to be able to recover from its customers its prudently incurred costs and return of and on investment. If such investments are excluded from rate base, this would unfairly reduce income and diminish the ability of the Company and its investors to earn the fair rate of return on equity.

Ms. Sekimura has discussed the accounting treatment of this matter in her rebuttal testimony, HECO RT-16. As evidenced in the articles accompanying HECO RT-16 testimony, the rating agencies have indicated that they would impute debt associated with any under-funding of a pension obligation. While it does not yet appear that this under-funding is included in our rating calculations, it is likely that this will be done going forward in the event the prepaid pension asset is not allowed into the rate making calculation.

Q. Do you have any further comments on Mr. Hill's suggestion that HECO's purchase power is similar to his peer group?

A. I believe Mr. Hill has potentially made two errors in suggesting the purchase power percentages are similar for HCO and his peer group. First, Mr. Hill has used a HECO consolidated percentage in calculating HECO's 28% purchase power percentage versus HECO only results. Second, HECO's risk relative to purchaser power is based on the amount of long-term fixed obligations which the rating agencies treat as debt like obligations versus similar risks for the comparable companies. While I do not know for certain the percentages for Mr. Hill's comparable group, I do know that HECO's purchase power obligations represent 40% of HECO's base-load generation, which is substantially higher then the 30% figure Mr. Hill suggested for the other utilities in his peer group.

CONCLUSION

Q. What is your conclusion as to the appropriate rate of return on rate base to use in calculating revenue requirements in this docket?

A. The rate of return on its full rate base should not be less than the Company's composite cost of capital, and the Company's composite cost of capital in 2005 is expected to be at least 8.83%, including a rate of return on common equity of at least 11.00%.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Hawaiian Electric Company, Inc.

Composite Embedded Cost of Capital
Test Year 2005 Average
($ Thousands)

		(A)	(B) = (A)/Total(A)	(C)	(D) = (B)*(C)
		Capitalization			
	WP Reference	Amount	Percent of Total	Earnings Requirement	Weighted Earnings Requirements
Short-Term Debt	R-2102	$ 37,429	3.25%	3.50%	0.11%
Long-Term Debt	R-2103	423,565	36.81%	6.25%	2.30%
Hybrid Securities	WP-2104	27,303	2.37%	7.55%	0.18%
Preferred Stock	WP-2105	20,476	1.78%	5.54%	0.10%
Common Equity	R-2104	641,955	55.79%	11.00%	6.14%
Total Capitalization		$1,150,726	100.00%		8.83%
Estimated 2005 Test Year Composite Cost of Capital					**8.83%**

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Short-Term Borrowings
Test Year 2005 Average
($ Thousands)

	WP Reference	Total	
Short-Term Borrowings as of December 31, 2003	WP-2102, p.1	$ 20,700	
2004 Estimated Net Change in Short-Term Borrowings	HECO-2107	27,085	
Short-Term Borrowings as of December 31, 2004		47,785	(A)
2005 Estimated Net Change in Short-Term Borrowings	HECO-R-2105	(20,713)	
Short-Term Borrowings as of December 31, 2005		$ 27,072	(B)
Test Year 2005 Average = [(A)+(B)]/2		**$ 37,429**	

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Embedded Cost of Long-Term Debt
Test Year 2005 Average
($ Thousands)

Long-Term Debt	(A) Rate	(B) Net Proceeds	(C) = (A)*(B) Annual Interest	(D) = RWP-2103, p.4 Annual Amortization	(E) = (C)+(D) Annual Requirement
Special Purpose Revenue Bonds (Refunded Issue):					
Series 1993	5.45%	$ 50,000	$ 2,725	$ 89	$ 2,814
Series 1995A ****	6.60%	20,000	1,320	102	1,422
Series 1996A	6.20%	48,000	2,976	79	3,055
Series 1996B	5 7/8%	14,000	823	19	842
Series 1997A	5.65%	50,000	2,825	71	2,896
Refunding Series 1998A (1987)	4.95%	42,580	2,108	254	2,362
Refunding Series 1999B (1988)	5.75%	30,000	1,725	118	1,843
Series 1999C	6.20%	35,000	2,170	63	2,233
Refunding Series 1999D (1990A)	6.15%	16,000	984	49	1,033
Refunding Series 2000 (1990B&C)	5.70%	46,000	2,622	181	2,803
Series 2002A ***	5.10%	33,644	1,716	106	1,822
Refunding Series 2003B (1992)	5.00%	40,000	2,000	195	2,195
Refunding Series 2005A (1995A) ****	4.80%	20,000	960	81	1,041
Unamortized Costs, Revenue Bonds *		(20,881)			
Unamortized Costs, First Mtg Bonds **		(779)		103	103
Test Year 2005 Average		**$ 423,565**	**$ 24,953**	**$ 1,511**	**$ 26,464**
Effective Rate = Total(E)/Total(B)					**6.25%**

* Issuance costs, redemption costs, issuance discounts, and investment income differentials are included in this amount. Refer to RWP-2103, p.3 for detail.

** Unamortized costs relate to HECO's First Mortgage Bonds which were redeemed prior to December 31, 2003. Refer to WP-2103, p.14 for First Mortgage Bonds unamortized costs.

*** Series 2002A is not fully drawn until 2005. Refer to WP-2103, p.1 for calculation of 2005 average balance.

**** Refer to RWP-2103 p.1 and p. 2 for test year average balances.

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Common Equity
Test Year 2005 Average
($ Thousands)

	WP Reference	Total	
Book Common Equity as of December 31, 2003	WP-2106, p.1	$ 582,563	
Restoration	WP-2106 p.2	3,580	
Common Equity Investment as of December 31, 2003		586,143	
2004 Estimated Net Change in Retained Earnings	HECO-2107	52,861	
Common Equity as of December 31, 2004		639,004	(A)
2005 Estimated Net Change in Retained Earnings	HECO-R-2105	5,902	
Common Equity as of December 31, 2005		$ 644,906	(B)
Test Year 2005 Average = [(A)+(B)]/2		**$ 641,955**	

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Sources and Applications of Funds
($ Thousands)

	Recorded 2003	Forecast 2004	Forecast 2005
Application of Funds:			
Capital Expenditures	$ 94,885	$ 128,681	$ 112,959
Less: CIAC & Advances	6,071	8,237	14,745
Less: AFUDC	5,311	7,545	8,010
Net Capital Expenditures	$ 83,503	$ 112,899	$ 90,204
Debt Redemption	$ 40,000	$ -	$ -
Hybrid Redemption	-	60,000	-
Total Applications	$ 123,503	$ 172,899	$ 90,204
Sources of Funds:			
Internal Sources:			
Retained Earnings	$ 12,113	$ 52,861	$ 5,902
Depreciation & Amortization	72,285	71,259	75,460
Deferred Taxes & ITC	6,095	4,650	(4,272)
Other (Misc. Net Changes in Working Capital)	(16,217)	(14,258)	21,116
Total Internal Sources	$ 74,276	$ 114,512	$ 98,206
External Sources:			
Increase (Decrease) in Short-Term Borrowings	$ 7,000	$ 27,085	$ (20,713)
Drawdown of Revenue Bond Proceeds	42,227	1,302	12,711
Sale of Hybrid Securities	-	30,000	-
Total External Financing	$ 49,227	$ 58,387	$ (8,002)
Total Sources	$ 123,503	$ 172,899	$ 90,204

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.
Financial Ratios

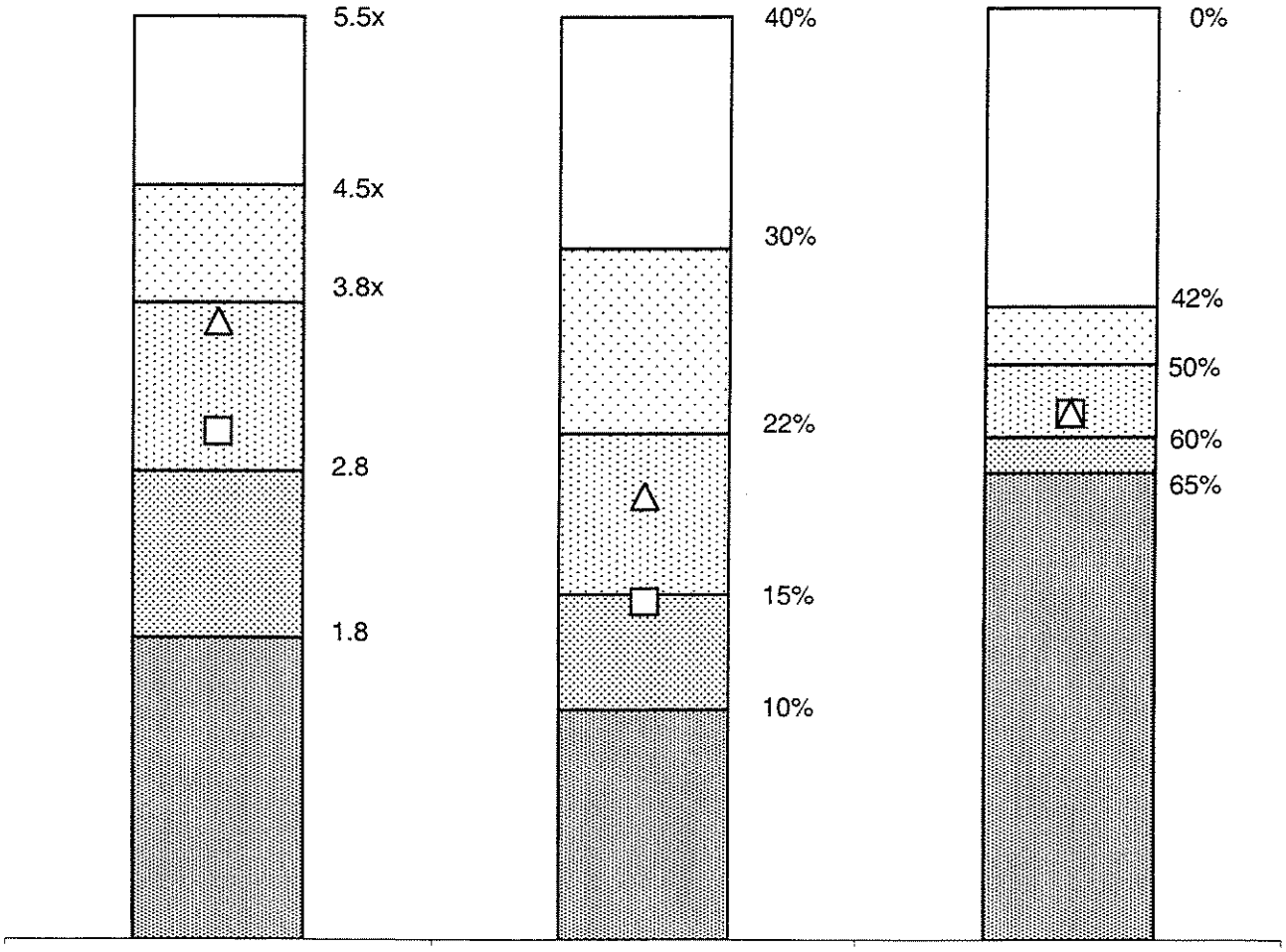
Test Year 2005	NO Rate Increase	WITH Rate Increase
Funds from Operations Interest Coverage *	3.036 x	3.688 x
Funds from Operations / Average Total Debt *	14.7%	19.3%
Total Debt / Total Capital *	52.9%	52.9%
Total Debt / Total Capital without Debt Equivalent	43.3%	43.3%

2004 Actual	
Total Debt / Total Capital *	55%
Total Debt / Total Capital without Debt Equivalent	44%

* These ratios take into account the debt equivalent (off-balance sheet purchased power obligations).

Financial Ratios in Comparison to S&P Rating Guidelines

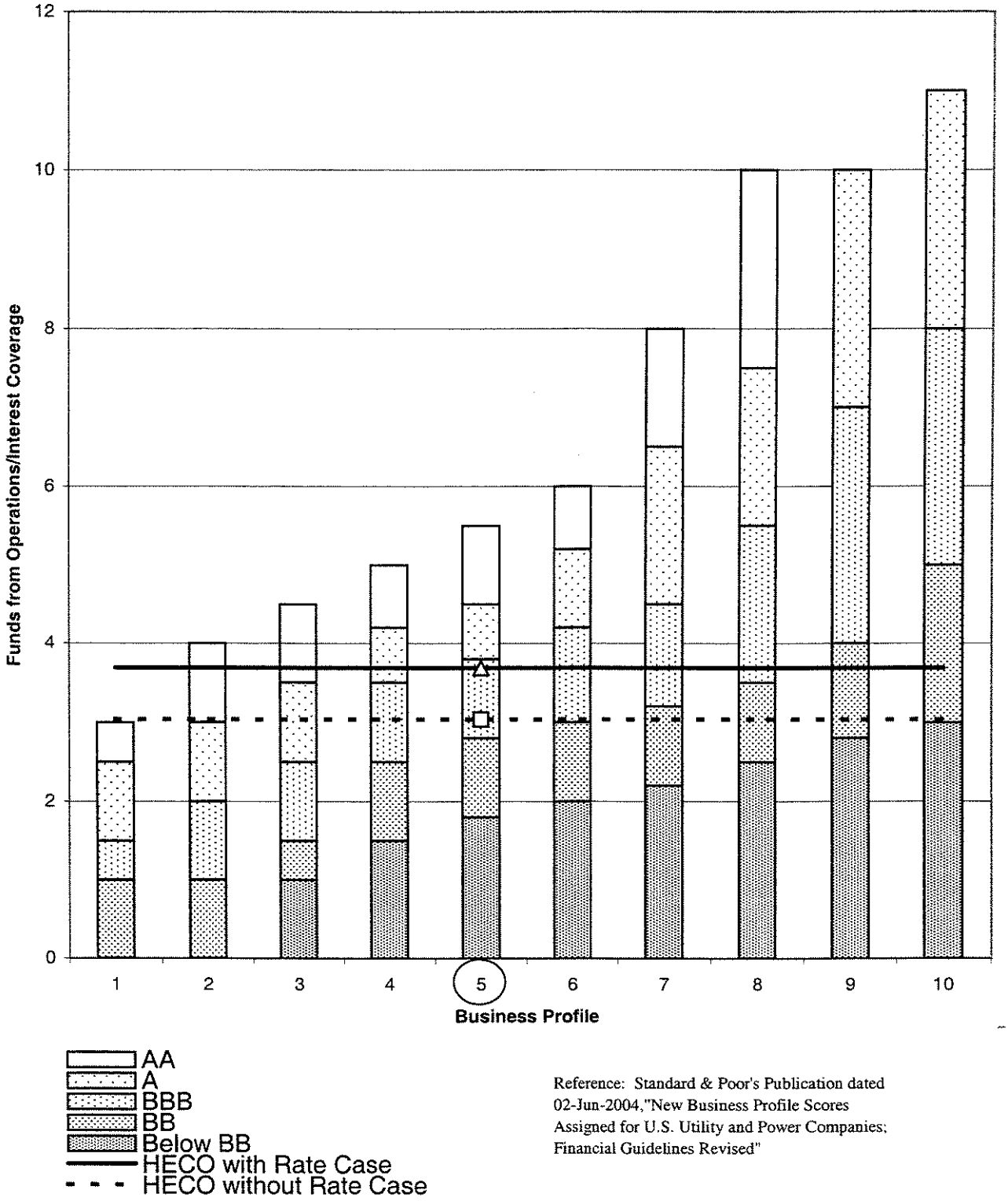
Business Profile = 5



	Funds from Operations Interest Coverage	Funds from Operations / Total Debt	Total Debt / Total Capital
HECO w/ Rate Case	3.688 x	19.3%	52.9%
HECO w/out Rate Case	3.036 x	14.7%	52.9%

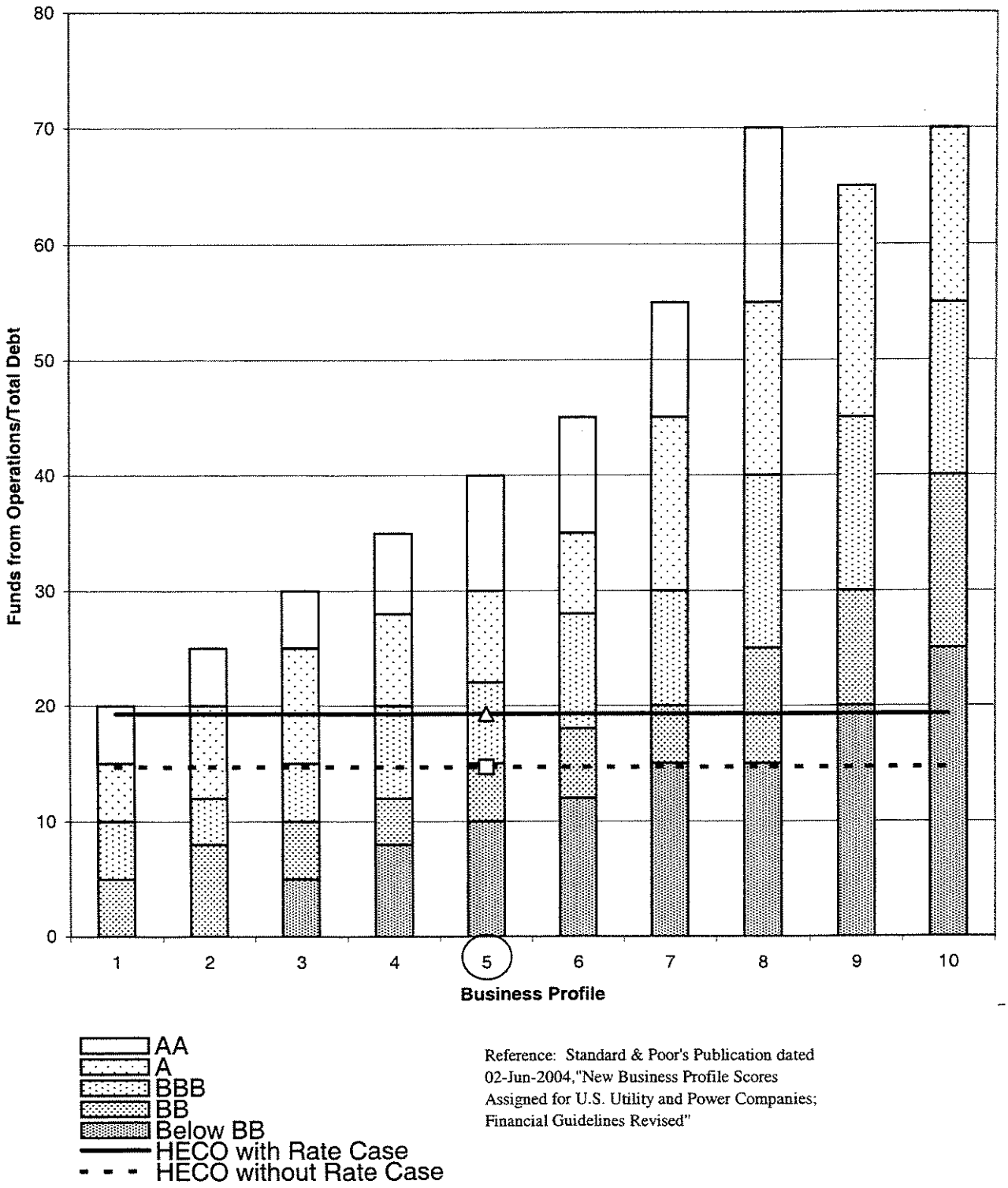
- AA
- A
- BBB
- BB
- Below BB
- △ HECO with Rate Case
- □ HECO without Rate Case

Funds from Operations/Interest Coverage



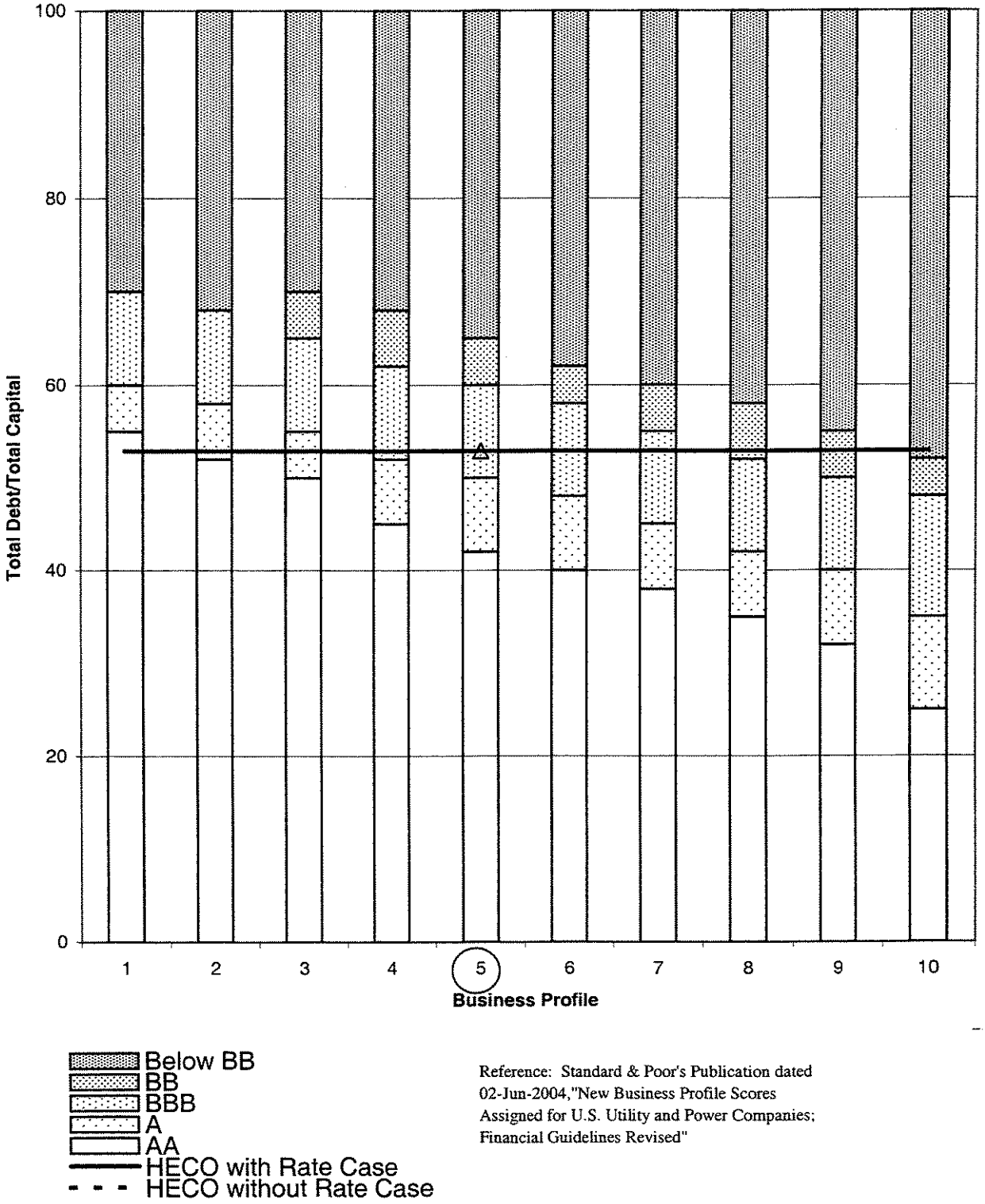
Reference: Standard & Poor's Publication dated 02-Jun-2004,"New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised"

Funds from Operations/Total Debt



Reference: Standard & Poor's Publication dated 02-Jun-2004,"New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised"

Total Debt/Total Capital



Reference: Standard & Poor's Publication dated 02-Jun-2004,"New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised"

Hawaiian Electric Company, Inc.

Estimated Savings Due to Special Purpose Revenue Bond Financing
($ in Thousands)

Series **	(A) Interest Rate	(B) Forecast Outstanding as of 12/31/05	(C) Original Life (in years)	(D) = [(A)*(B)/(1-R)]*C Revenue Requirements Over Original Life of Security * Interest	(E) Amortized Costs and Trustee Fees	(F) Average Accumulated Deferred Taxes	(G) = (D)+(E)+(F) Total
Costs of Financing with TAXABLE DEBT:							
Series 1993	7.30%	$ 50,000	30	$ 120,178	$ 672	$ (17,620)	$ 103,230
Series 1996A	8.40%	48,000	30	132,755	702	(16,915)	116,542
Series 1996B	7.75%	14,000	30	35,724	230	(4,934)	31,021
Series 1997A	7.76%	50,000	30	127,751	599	(17,620)	110,730
Refunding Series 1998A (1987)	6.75%	42,580	14	44,162	615	(8,452)	36,325
Refunding Series 1999B (1988)	7.40%	30,000	19	46,293	872	(543)	46,622
Series 1999C	7.85%	35,000	30	90,463	1,237	(12,334)	79,366
Refunding Series 1999D (1990A)	7.80%	16,000	20	27,394	523	(304)	27,613
Refunding Series 2000 (1990B&C)	7.75%	46,000	20	78,253	1,362	(874)	78,741
Series 2002A	6.35%	40,000	30	83,631	12,232	(14,096)	81,767
Refunding Series 2003B (1992)	5.65%	40,000	20	49,608	2,346	(761)	51,193
Refunding Series 2005A (1995)	5.25%	40,000	20	46,096	2,648	(761)	47,983
		$ 451,580		$ 882,306	$ 24,039	$ (95,214)	**$ 811,131** (H)
Costs of Financing with REVENUE BONDS:							
Series 1993	5.45%	$ 50,000	30	$ 89,722	$ 1,481	$ (1,391)	$ 89,812
Series 1996A	6.20%	48,000	30	97,986	2,690	(1,336)	99,340
Series 1996B	5 7/8%	14,000	30	27,081	691	(390)	27,383
Series 1997A	5.65%	50,000	30	93,014	1,896	(1,392)	93,518
Refunding Series 1998A (1987)	4.95%	42,580	14	32,385	998	(5,561)	27,822
Refunding Series 1999B (1988)	5.75%	30,000	19	35,971	1,253	(543)	36,681
Series 1999C	6.20%	35,000	30	71,448	1,278	(974)	71,752
Refunding Series 1999D (1990A)	6.15%	16,000	20	21,599	523	(304)	21,818
Refunding Series 2000 (1990B&C)	5.70%	46,000	20	57,554	1,488	(874)	58,168
Series 2002A	5.10%	40,000	30	67,168	5,851	(1,113)	71,906
Refunding Series 2003B (1992)	5.00%	40,000	20	43,901	1,764	(761)	44,904
Refunding Series 2005A (1995)	4.80%	40,000	20	42,145	2,051	(761)	43,435
		$ 451,580		$ 679,974	$ 21,965	$ (15,399)	**$ 686,539** (I)
Estimated Savings to Customers (over original life of revenue bonds) = (H)-(I)							**$ 124,592**

* Revenue requirements = nontaxable expenses grossed up for revenue taxes (R), and taxable expenses grossed up for revenue taxes and income taxes. Refer to RWP-2107, p.1 and p.4 for Amortized Costs/Trustee Fees and Average Accumulated Deferred Taxes calculations, respectively, for Series 1993 - 1996B. Revenue Requirements information for other Series are contained in the "Estimated Savings From Special Purpose Revenue Bond Financing" document filed with the Commission for the respective Series.

** See reports on savings on file with the Commission.

Note: Totals may not add exactly due to rounding.

HECO RT-22
DOCKET NO. 04-0113

TESTIMONY OF
PETER C. YOUNG

RATE ANALYST, PRICING DIVISION
ENERGY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Cost-of-Service Study and Rate Design

INTRODUCTION

Q. Please state your name and business address.

A. My name is Peter C. Young and my business address is 220 South King Street, Suite 1201, Honolulu, Hawaii.

Q. Have you sponsored other written testimony in this docket?

A. Yes. I submitted direct testimony HECO T-3 and rebuttal testimony HECO RT-3 on Electric Revenues and Other Operating Revenues. I am providing testimony on cost-of-service and rate design in rebuttal and I am adopting Ms. Seese's direct testimony, HECO T-22, in these areas.

Q. Have you testified before the Commission in prior Company proceedings?

A. Yes. My experience and background are listed in HECO-300. I have previously testified as the cost-of-service witness for the utility in Docket No. 97-0346 (Maui Electric Company, Ltd.) and Docket No. 99-0207 (Hawaii Electric Light Company, Inc.).

Q. What will you cover in HECO RT-22?

A. My testimony in HECO RT-22 will cover the following:

1) HECO's revised cost-of-service study for rebuttal testimony;
2) HECO's revised marginal cost study for rebuttal testimony;
3) The allocation of the proposed revenue increase;
4) HECO's proposed rate design and rates; and
5) HECO's rebuttal response to the testimonies of the Consumer Advocate (CA) and the Department of Defense (DOD) on cost-of-service, allocation of revenue increase, and rate design.

1 REVISED COST-OF-SERVICE STUDY

2 Q. What are the results of HECO's embedded cost-of-service study for rebuttal
3 testimony?

4 A. The results of the cost-of-service study for rebuttal are summarized in the
5 following exhibits:

6 1. HECO-R-2201 – Summary of Class Revenue Requirements and Class
7 Rates of Return at Present Rates and at Proposed Rates;
8 2. HECO-R-2202 – Summary of Class Rates of Return on Rate Base at
9 Present Rates;
10 3. HECO-R-2203 – Summary of Class Rates of Return on Rate Base at
11 Proposed Rates;
12 4. HECO-R-2204 – Proposed Allocation of Rate Increase by Rate Class;
13 5. HECO-R-2205 – Allocation of Rate Increase Based on Equal Class Rates
14 of Return;
15 6. HECO-R-2206 – Comparison of Class Revenue Requirements at Present
16 Rates, at Proposed Rates, and at Equal Rates of Return;
17 7. HECO-R-2207 – Summary of Cost Components by Rate Class at Proposed
18 Rates;
19 8. HECO-R-2208 – Summary of Unit Cost Components by Rate Class at
20 Proposed Rates;
21 9. HECO-R-2209 – Summary of Cost Components by Rate Class at Equal
22 Rates of Return;
23 10. HECO-R-2210 – Summary of Unit Cost Components by Rate Class at
24 Equal Rates of Return;
25 11. HECO-R-2211 – Summary of Allocation Factors; and

12. HECO-R-2212 – Energy Loss Analysis by Rate Class.

Q. How do the results of the embedded cost-of-service study for this rebuttal testimony compare with those presented in HECO's direct testimony?

A. A comparison of rate class revenue requirements and class rates of return between the rebuttal cost-of-service study and the study results presented in direct testimony is shown in HECO-R-2213. HECO's rebuttal total revenues at present rates are higher than the total in direct testimony primarily due to a revision in the fuel oil adjustment factor that reflects an assumption of higher fuel oil prices, as well as revised assumptions for sales, Schedule PP power factor percentage, and potential Rider customers. HECO's rebuttal total revenues at proposed rates are higher than the total in direct testimony, and are impacted by a combination of the assumption of higher fuel oil prices, lower DSM costs, and lower rate of return. The relative magnitude of the class rates of return at present rates from the rebuttal cost-of-service study are generally similar to the class rates of return at present rates presented in direct testimony. In HECO's rebuttal testimony, the Schedule R, Schedule H, and Schedule F class rates of return at present rates are less than the system average rate of return, while in HECO's direct testimony, the Schedule R and Schedule F class rates of return at present rates were below the system average. In HECO's rebuttal testimony, Schedule H's higher sales revenues are more than offset by increases in fuel expense, other taxes, and an increased allocation of administration and general costs. In both HECO's rebuttal and direct testimonies, the Schedule PT class rate of return at present rates exceeds the system average and is the highest of all the class rates of return.

Q. Are there any changes to HECO's embedded cost-of-service methodology?

A. No, the embedded cost-of service methodology remains the same as employed in

direct testimony. Two assumptions were modified in accordance with HECO's responses to CA-IR-531 and CA-IR-464.

Q. What is the first assumption that has been modified?

A. In HECO's response to CA-IR-531, HECO indicated that its rebuttal testimony embedded cost-of-service study will reflect a more appropriate classification of DSM costs, depending on the availability of data that would allow a breakdown of DSM costs. HECO has been able to analyze and develop data that provides a basis for classification of the DSM costs included in customer service expense as partially demand-related and partially energy-related, instead of the 100% customer-related classification used in direct testimony. Separate demand-related and energy-related classifications were developed for each DSM program, and the details are presented in HECO-RWP-2201. The remaining, non-DSM costs in customer service expense continue to be classified as 100% customer-related costs in rebuttal testimony. The Company believes that these are reasonable bases for the classification of DSM-related costs.

Q. What is the second assumption that has been modified?

A. HECO has revised the energy losses in the embedded cost study to reflect Kalaeloa capacity of 209 MW as indicated in HECO's response to CA-IR-464.

Q. What are the bases for the revisions to the embedded cost study in rebuttal testimony?

A. The updated embedded cost-of-service study for rebuttal testimony reflects the following:

1. Revised test year forecasts of sales discussed in HECO RT-2;
2. Revised test year revenues at present rates presented in HECO RT-3;
3. Revised test year estimates of O&M expenses, taxes, and rate base

presented by the different Company witnesses; and

4. Revised test year total revenue requirements presented in HECO RT-1 and HECO RT-23.

REVISED MARGINAL COST STUDY

Q. Are there any changes to HECO's marginal cost study?

A. Yes. The Company has revised the marginal energy cost study to align the marginal energy costs with the revised test year fuel cost assumptions. The revised marginal energy costs by time-of-use rating period are presented in HECO-R-2214. A comparison between the revised unit embedded costs and the revised unit marginal costs by function (only marginal energy costs are revised) is presented in HECO-R-2215. The Company has not revised any other elements of the marginal cost study.

Q. Are there any changes to HECO's marginal cost study methodology?

A. No. The Company has not changed its methodology in the calculation of the marginal energy costs.

ALLOCATION OF PROPOSED REVENUE INCREASE

Q. What is HECO's proposed allocation of revenue increase?

A. HECO's proposed allocation of revenue increase is presented in HECO-R-2204. HECO's revised proposed allocation follows the guidelines applied in previous dockets, to allocate the proposed revenue increase to rate classes such that each class would move closer to cost of service, as reflected by each class's rate of return moving closer to the system average rate of return. The guidelines are subject to two constraints: First, each rate class is allocated a revenue increase in

a reasonable range, which is ± 25% of the proposed Company average sales revenue increase; and second, each rate class is allocated a revenue increase such that the class rate of return is ± 50% of the Company average rate of return. If the proposed revenue allocation cannot satisfy both guidelines, then the revenue increase guideline at ± 25% of the proposed Company average sales revenue increase takes priority. These guidelines were used to propose revenue allocation among rate classes in prior rate cases, most recently HELCO's Docket No. 99-0207, and were approved by the Commission in Decision and Order No. 18365, at page 84 (February 8, 2001).

Q. How were the guidelines applied in HECO's current case?

A. In implementing the guidelines, HECO proposes to increase Schedule R, Schedule H, and Schedule F class revenues by 6.39%, which is 125% of the system average increase of 5.11%. These classes still would earn less than the system average rate of return as shown in HECO-R-2201. HECO proposes to increase Schedule J and Schedule PT class revenue by 3.84%, which is 75% of the system average increase of 5.11%, since these two classes have the highest rates of return at present rates. HECO proposes that the remaining three rate classes, Schedules G, PS, and PP receive the same 4.96% revenue increase. All commercial classes meet the rate of return guideline of ± 50% of the system average at the rebuttal revenue allocation proposal except Schedule PT. In HECO-R-2213, page 2, we see that this proposed allocation following the established guidelines moves each rate class closer to cost-of-service than the equal percentage increase proposal in direct testimony, as measured by the rate of return index, with the exception of Schedule F.

Q. Why does HECO propose to change the method of revenue increase allocation

1 from what was proposed in direct testimony?
2 A. In direct testimony, HECO proposed an equal percentage revenue increase among
3 rates classes because the Company was concerned about the significant rate
4 impact to customers, particularly to residential customers. The direct testimony
5 proposal shared the burden among all rate payers. However, the Company also
6 stated that if the amount of HECO's final revenue increase approved by the
7 Commission is less than the amount requested in the direct application, the
8 Commission should consider HECO's past criteria for the revenue increase
9 allocation in making its final revenue allocation (HECO T-1, page 28). Since the
10 rebuttal proposed increase in revenues is significantly lower than the proposed
11 increase indirect testimony ($63.0 million vs. $98.6 million), it is reasonable for
12 HECO to return to a proposed revenue increase allocation that more closely aligns
13 class revenues and class costs.
14 Q. Is there support from the DOD to align class revenues and class costs?
15 A. Yes, it appears that there is support from the DOD to more closely align class
16 revenues and class costs. The DOD recommends that the Commission direct
17 HECO to implement any approved rate increase by allocating the revenue increase
18 with the objective of reducing the interclass subsidies by at least 50%. The DOD
19 further suggests that if the Commission finds that the impacts are too large on
20 customers who are below cost, the Commission could direct HECO to phase-in
21 the adjustment over a period of not more than two years (DOD-T-3, page 20).
22 Q. Does HECO support the DOD's position?
23 A. HECO supports the DOD's position to move class rates of return to align more
24 closely with the cost-to-serve. The Company also supports, but is not proposing, a
25 phase-in rate adjustment over two years if the second part of the phased

adjustment continues to make meaningful progress towards aligning revenues and cost-to-serve among the rate classes.

Q. What is the CA's position on revenue allocation?

A. The CA's position on revenue allocation will be discussed in detail in a subsequent section.

RATE DESIGN AND PROPOSED RATES

Q. Why are changes made to HECO's proposed rates in rebuttal testimony?

A. HECO's rebuttal revisions to proposed rates reflect the changes in revenue requirements made in the Company's rebuttal testimony.

Q. Are there changes proposed for HECO's structure of rates and rules in rebuttal?

A. The proposed changes to the structure of HECO's rates and rules, including the proposed changes to terms and conditions in rates and riders, the proposed changes to Rule No. 4, Standard Customer Retention Rate, and the proposed changes to the non-sales related charges such as the Returned Checks Charge, Field Collection Charge, and Service Establishment Charge, remain the same as proposed in direct testimony, HECO T-22, pages 18 to 64. HECO proposes one modification to the proposed Schedule U demand charge which will be discussed below.

Q. How does HECO propose to reflect the changes to the proposed class revenue requirements in rebuttal testimony?

A. HECO proposes to reflect the rebuttal changes in class revenue requirements in the proposed rate class and rate rider energy charges to the extent possible. Summaries of the allocation of proposed revenue requirements among rate elements by rate class are presented in HECO-R-2216 through HECO-R-2223. The revised proposed rate and rule sheets are presented in HECO-R-2224.

Sample bill comparisons under present and proposed rates by rate schedule are presented in HECO-R-2225 through HECO-R-2236.

Q. What are the revisions to HECO's proposed rates?

A. The rebuttal revisions to HECO's proposed rates are summarized as follows:

1. Schedule R – Residential Service:

   a. Increase the Non-Fuel Energy Charge from 7.7814 ¢/kWh to 8.4415 ¢/kWh; and

   b. Increase the Base Fuel Energy Charge from 3.5140 ¢/kWh to 8.8903 ¢/kWh, as shown in HECO-R-2216.

   The changes to the customer charge, minimum charges, and the Apartment House Collection Arrangement remain as proposed in direct testimony. There are no changes proposed to Schedule E in rebuttal. The proposed Base Fuel Energy Charge is based on the Company's estimates cost of fuel and cost of purchased power, as discussed in HECO RT-10. The proposed Non-Fuel Energy Charge recovers the customer costs and demand costs that are not recovered by the customer and minimum charges.

2. Schedule G – General Service Non-Demand:

   a. Increase the Customer Charge from $20.00 to $35.00 per month for Single-Phase service;

   b. Increase the Energy Charge from 11.1570 ¢/kWh to 16.2616 ¢/kWh; and

   c. Increase the Minimum Charge from $25.00 to $40.00 per month for Single-Phase service, as shown in HECO-R-2217.

   The changes to Three-Phase service customer charge, Three-Phase

service minimum charges, and primary voltage service remain as proposed in direct testimony. The proposal for unmetered service is withdrawn, as previously indicated in HECO's response to CA-IR-365. The proposed Customer Charge of $35.00 per month for Single-Phase service aligns the revenue from customer charges at approximately 35% of the class's total fixed cost, which includes the customer-related and demand-related costs. The proposed Energy Charge recovers the customer costs and demand costs that are not recovered by the customer and minimum charges. The proposed Minimum Charge of $40.00 per month for Single-Phase service is designed to maintain the same relationship between the customer charge and the minimum charge as reflected in the present rate, for rate continuity and stability.

3. Schedule J – General Service Demand:

   a. Increase the Energy Charge for the three load factor blocks from 8.6900 ¢/kWh, 7.5419 ¢/kWh, and 6.5130 ¢/kWh, to 13.6400 ¢/kWh, 12.4919 ¢/kWh, and 11.4629 ¢/kWh, respectively, as shown in HECO-R-2218.

   The changes proposed to the customer charge, the demand charge, the availability clause, the demand ratchet, the Supply Voltage Delivery provision, the supply voltage adjustments, and the minimum term of contract remain as proposed in direct testimony. The proposed Energy Charges recover the customer costs and demand costs that are not recovered by the customer, demand, and minimum charges, net of power factor, service voltage, and rider adjustments.

4. Schedule H – Commercial Cooking and Water Heating Service:
   a. Increase the Energy Charge from 7.7422 ¢/kWh to 13.8583 ¢/kWh, as shown in HECO-R-2219.

   The proposed changes to the customer charges and demand charge remain the same as in direct testimony. The proposed Energy Charge recovers the customer costs and demand costs that are not recovered by the customer and demand charges.

5. Schedule PS – Large Power Secondary Voltage Service:
   a. Increase the Energy Charge for the three load factor blocks from 7.2087 ¢/kWh, 6.4104 ¢/kWh, and 6.1010 ¢/kWh, to 11.9578 ¢/kWh, 11.1595 ¢/kWh, and 10.8503 ¢/kWh, respectively, as shown in HECO-R-2220.

   The proposed changes to the customer charge, the demand charges, the minimum billing provision, and the term of contract remain the same as proposed in direct testimony. The proposed Energy Charges recover the customer costs and demand costs that are not recovered by the customer and demand charges, net of the power factor, network service, and rider adjustments.

6. Schedule PP – Large Power Primary Voltage Service:
   a. Increase the Energy Charge for the three load factor blocks from 7.0715 ¢/kWh, 6.2884 ¢/kWh, and 5.9849 ¢/kWh, to 11.9604 ¢/kWh, 11.1772 ¢/kWh, and 10.8737 ¢/kWh, respectively; and
   b. Change the Secondary Metering Adjustment from the current 0.1081 ¢/kWh to 0.2168 ¢/kWh, as shown in HECO-R-2221.

   The proposed changes to the customer charge, demand charges,

minimum billing provision, and term of contract remain the same as proposed in direct testimony. The proposed Energy Charges recover the customer costs and demand costs that are not recovered by the customer and demand charges, net of the power factor, secondary metering, and rider adjustments.

7. Schedule PT – Large Power Transmission Voltage Service:

   a. Increase the Energy Charge for the three load factor blocks from 6.9708 ¢/kWh, 6.1989 ¢/kWh, and 5.8997 ¢/kWh, to 11.7511 ¢/kWh, 10.9792 ¢/kWh, and 10.6800 ¢/kWh, respectively, as shown in HECO-R-2222.

   The changes to the customer charge, demand charges, Secondary Metering Adjustment, minimum billing provision, and term of contract remain the same as proposed in direct testimony. The proposed Energy Charges recover the customer costs and demand costs that are not recovered by the customer and demand charges, net of the power factor and secondary metering adjustments.

8. Schedule F – Public Street Lighting, Highway Lighting, and Park and Playground Floodlighting Service:

   a. Increase the Energy Charge for the two load factor blocks from 12.7049 ¢/kWh and 8.7309 ¢/kWh, to 18.8659 ¢/kWh and 14.8920 ¢/kWh, respectively, as shown in HECO-R-2223.

   The proposed changes to customer charge, secondary metering adjustment, and loss factor remain the same as proposed in direct testimony. The proposed Energy Charges recover the customer costs and demand costs that are not recovered by the customer charge and

the minimum charge, net of the secondary metering adjustment.

9. Schedule U – Time-of-Use Service:

   a. Increase the Energy Charge from the current 7.8230 ¢/kWh for the on-peak period to 13.4400 ¢/kWh, and from 3.0000 ¢/kWh for the off-peak period, to 10.0000 ¢/kWh; and

   b. Change the Demand Charge from $17.00 per kW to $18.00 per kW if the customer's maximum demand occurs during the priority peak period and $16.00 per kW if the customer's maximum demand occurs during the mid-peak period.

The changes to the customer charge and the service voltage adjustment remain as proposed in direct testimony. The proposed On-Peak Energy Rate of 13.4400 ¢/kWh is based on the proposed average energy charge for Schedule PS plus 2.0 ¢/kWh, which is about 20% of the marginal energy cost during the priority peak hours. The proposed Off-Peak Energy Rate of 10.0000 ¢/kWh is based on the kWh unit energy cost for Schedule PS. The proposed demand charge if peak is during the priority peak period is based on about 75% of the Schedule PS full unit demand cost. The proposed demand charge if peak is during the mid-peak period is based on the estimated average revenue per kW of the proposed Schedule PS. The structure of the proposed demand charge has been modified to be consistent with the proposed Schedule TOU-C. Commercial customers who elect service under a time-of-use rate schedule (demand customers with loads < 300 kW on Schedule TOU-C and demand customers with loads > 300 kW on Schedule U) have the

opportunity to lower their demand charges by managing their peak loads into the mid-peak hours instead of the priority peak period.

10. Schedule Q – Purchases from Qualifying Facilities 100kW or Less:

a. Change the Energy Rate for energy delivered to the Company by the customer from 3.67 ¢/kWh to 10.63 ¢/kWh;

b. Change the generation base fuel cost from the 287.83 ¢/mbtu to 870.43 ¢/mbtu; and

c. Modify the language to recognize the inclusion of the cost of fuel for the Company's Distributed Generation resources in the composite generation base fuel cost.

The proposed metering charge remains the same. The proposed energy rate of 10.63 ¢/kWh for energy delivered to the Company by the customer is based on the revised test year estimates of the Company's generation cost, DG fuel price and efficiency factors discussed in HECO RT-4.

11. Energy Cost Adjustment Clause:

a. Change the base fuel cost for Company generation from 287.83 ¢/mbtu to 869.64 ¢/mbtu;

b. Change the Company generation efficiency factor from the 0.011170 mbtu/kWh to 0.011140 mbtu/kWh;

c. Change the base purchased energy cost from 3.005 ¢/kWh to 5.568 ¢/kWh; and

d. Include a Distributed Generation (DG) Energy Component Cost in the Clause at 14.076 ¢/kWh.

The proposed changes to the base fuel and purchased power costs,

efficiency factor, and the inclusion of the DG energy component are discussed in HECO RT-4.

12. Schedule TOU-R – Residential Time-of-Use Service:

a. The proposed time-of-use energy rates are Priority Peak Period – 22.3318 ¢/kWh, Mid-Peak Period – 19.3318 ¢/kWh, and Off-Peak Period - 13.8318 ¢/kWh.

The customer charges and minimum charges remain as proposed in direct testimony. The proposed time-of-use energy rates aim to maintain the same rate differential between periods as reflected in Option 2 Energy Rates of the current Schedule TOU-R pilot program, as well as the differences between the total energy rate (non-fuel and base fuel energy rates) for Schedule R and the time-of-use energy rates. The proposed energy rate for the priority peak period of 22.3318 ¢/kWh is based on the proposed total energy rate for Schedule R of 17.3318 ¢/kWh plus 5.0 ¢/kWh which reflects about 45% of the estimated priority peak marginal energy cost. The proposed energy rate for the mid-peak period of 19.3318 ¢/kWh is based on the proposed total energy rate for Schedule R plus 2.0 ¢/kWh, which is based on about 20% of the mid-peak marginal energy cost. The proposed off-peak energy rate of 13.8318 ¢/kWh is based on the proposed total energy rate for Schedule R minus 3.5 ¢/kWh, which reflects about 33% of the off-peak marginal energy cost.

13. Schedule TOU-C– Commercial Time-of-Use Service:

a. For Non-Demand Service, the proposed time-of-use energy rates

are Priority Peak Period – 21.2616 ¢/kWh, Mid-Peak Period – 18.2616 ¢/kWh, and Off-Peak Period - 11.2616 ¢/kWh.

b. For Demand Service, the proposed time-of-use energy rates are Priority Peak Period – 18.0944 ¢/kWh, Mid-Peak Period – 15.0944 ¢/kWh, and Off-Peak Period - 10.0000 ¢/kWh.

The customer charges, demand charge, and minimum charges remain as proposed in direct testimony. For Non-Demand service, the proposed energy rate for the priority peak period of 21.2616 ¢/kWh is based on the proposed energy rate for Schedule G of 16.2616 ¢/kWh plus 5.0 ¢/kWh which reflects about 45% of the estimated priority peak marginal energy cost. The proposed energy rate for the mid-peak period of 18.2616 ¢/kWh is based on the proposed energy rate for Schedule G plus 2.0 ¢/kWh, which is based on about 20% of the mid-peak marginal energy cost. The proposed off-peak energy rate of 11.2616 ¢/kWh is based on recovering the allocated energy cost for Schedule G plus about 15% of the estimated off-peak marginal energy cost. The proposed Energy Rates for Schedule TOU-C Demand Service are derived in the same manner as the proposed Energy Rates for Schedule TOU-C Non-Demand Service except for the proposed off-peak energy rate of 10.0000 ¢/kWh, which is set to recover the allocated energy cost for Schedule J.

Q. Has the Company modified its position on the Integrated Resource Planning Cost Recovery Provision ("IRP Clause")?

A. The Company will retain the IRP clause for use in reconciling the recovery of IRP costs and for recovering DSM program costs, including lost margin and shareholders incentives, not otherwise recovered in base rates. Since HECO is no longer proposing to recover all IRP-related and DSM-related costs in the base rates, HECO no longer proposes to eliminate the IRP Cost Recovery Provision.

Q. Is the Company withdrawing the proposal for the DSM Reconciliation Clause Provision?

A. Yes, the Company withdraws the proposal for the DSM Reconciliation Clause Provision, for reasons discussed in HECO RT-10.

CA'S COST-OF-SERVICE ISSUES

Q. What are the cost-of-service issue differences raised by the Consumer Advocate?

A. In CA-T-5, pages 9-11, the CA raises the following issues with which the Company does not agree:

1. Distribution poles, lines, and transformers are improperly classified as "customer" costs;
2. HECO's classification of DSM costs as "customer-related" overstates the customer unit costs; and
3. Production O&M expenses other than fuel are classified entirely as fixed or "demand" costs, when a portion of such expenses vary with the level of generation.

Q. What are the CA's contentions about the classification of distribution poles, lines and transformers?

A. The CA says that the distribution network of poles, lines, and transformers do not vary directly with the number of customers served and should be classified

entirely as demand costs, rather than partially as customer costs, as HECO proposes (CA-T-5, page 9). The CA also contends that HECO's use of the minimum system method is flawed because it double counts cost responsibility. The CA argues that the minimum-sized distribution system is capable of serving a large percentage of customer demand, but no credit is given for this demand serving capability when allocation factors are devised and applied to the "demand" component of distribution network costs (CA-T-5, page 15).

Q. Has the Commission approved the Company's cost-of-service methodology in prior rate cases?

A. The Commission has found reasonable the Company's classification of distribution plant costs as demand-related and customer-related and the Company's use of the minimum system method as consistent with NARUC cost allocation guidelines in previous rate cases (Decision and Order No. 11699 in HECO's Docket No. 6998, Decision and Order No. 18365 in HELCO's Docket No. 99-0207, and Amended Decision and Order No. 16922 in MECO's Docket No. 97-0346) and has rejected the CA's position.

Q. Are the CA's arguments different from what has been argued in the past?

A. No. The CA has not presented any new substantive arguments to support its proposal.

Q. What is the Company's position on the CA's alleged issue of double-counting by the minimum system method?

A. The Company continues to believe the CA's position is without merit:

1) The Minimum System Method is one of the methodologies specifically approved by the NARUC Cost Allocation Manual;

2) In Docket No. 6998, HECO argued that the distribution costs that

are classified as demand-related only reflect the costs of the distribution plant required to meet the customers' expected kW demand. The distribution costs that are classified as demand-related are allocated to the customer only once, based on the composite class non-coincident peak demand. To the extent that an individual customer's expected kW demand is small or close to the minimum system load, such low demand is reflected a class composite non-coincident demand, and a class is accordingly allocated a smaller share of the distribution demand costs proportionate to the class' non-coincident peak demand. In the same manner, the distribution costs that are classified as customer-related only reflect the distribution plant costs required to connect the customer to the utility system whether or not the customer's kW demand is equal to or different from the minimum load size. The customer-related component is also allocated to the rate classes only once, proportionate to the number of customers by rate class (Docket No. 6998, HECO RT-14, pages 38-39); and

3) In Docket No. 97-0346, MECO argued that the CA's proposal to adjust the demand included in the demand allocation factors (D2 and D3) understates the actual demand that is required of the distribution substations, distribution lines, and transformers, and results in inappropriate and inaccurate demand allocation factors (Docket No. 97-0346, MECO RT-17, page 27).

These arguments were accepted by the Commission in their decisions in these dockets.

Q. Does the CA recognize that the Company's classification method is reasonable?

A. Yes. The CA recognizes that HECO's classification of distribution network costs, including poles, lines, and transformers, as customer-related is "consistent with alternatives documented within the NARUC Cost Allocation Manual . . . "(CA-T-5, page 12).

Q. What is HECO's recommendation on this issue?

A. HECO recommends that the Commission reject the CA's arguments and continue to find HECO's classification of distribution plant costs as demand-related and customer-related and the Company's use of the minimum system method, consistent with NARUC cost allocation guidelines, as reasonable.

Q. What is the CA's concern regarding DSM costs?

A. The CA is concerned that the Company has included approximately $30 million of estimated annual DSM-related costs in its revenue requirement, with more than half of such costs assigned to the Residential class, which in turn serves to depress the Residential customer class' earnings and reported rate of return (CA-T-5, page 18).

Q. Does the CA's concern remain based on HECO's rebuttal position?

A. No, the CA's concern is no longer relevant in this case. HECO's proposed revised DSM costs are $1,016,000, as discussed by Mr. Hee in HECO RT-10. These DSM costs are now classified as either demand-related costs or energy-related costs, as indicated above, based on a change in assumption used for the embedded cost-of-service study.

Q. Does the CA propose a change in classification of production O&M expenses in the current HECO rate case?

A. No. The CA does not propose to change HECO's classification of 100% of non-

fuel production O&M costs as demand-related in the current rate case.

Q. Does HECO need to undertake a cost study of production O&M expenses?

A. No. HECO's classification of non-fuel production O&M costs as 100% demand-related is reasonable, has been approved in previous rate cases, and should be accepted by the Commission. HECO recognizes that if there are variable O&M non-fuel production costs, they should be minimal.

CA'S REVENUE ALLOCATION AND RATE DESIGN ISSUES

Q. What is the CA's proposed revenue allocation?

A. The CA's proposed revenue allocation is described at CA-T-5, page 27:

1. Terminate AES credits;
2. Eliminate Power Factor Adjustment Credits;
3. Adopt HECO's proposed service establishment charge, field collection charge, and returned payment charge changes;
4. For remaining revenues, no rate increases to Schedule G and Schedule PT; Equal percentage increases to all other rate classes.

Q. What are the problems with eliminating power factor adjustment credits?

A. The CA's proposal to eliminate power factor adjustment credits is inconsistent with the CA's proposal to have equal percentage increases to all rate classes (except Schedule G and Schedule PT). The CA allocates the elimination of the power factor adjustment credits to the rate classes (Schedules J, PS, PP, and PT) prior to assigning rate increases to classes. This effectively implies a higher overall percentage rate increase to Schedules PS and PP than to Schedules R, G, H, and F, the rate schedules that do not have power factor adjustments.

Q. What other problems are there with the CA's proposed rate allocation proposal?

A. The CA's proposal does not move to align class revenues with the cost to serve each class. The CA's rate allocation proposal does not assign a rate increase to Schedule G or Schedule PT, but does assign an increase to Schedule J. The CA's position is that all three of these rate classes are earning more than the system average rate of return, as shown in CA-500. The CA's proposal would move the Schedule J rate class revenues further from the cost to serve the class.

Q. What is the CA's proposed rate design?

A. The CA proposed that the existing structure of customer charges, minimum charges, energy charges, and demand charges within all rate schedules be retained. The CA further recommends that these elements be adjusted in equal percentages, after adjusting the existing energy rate to reflect the Commission's approved base fuel energy cost, to achieve the overall revenue target (CA-T-5, page 35).

Q. What are the problems with the CA's proposed rate design?

A. There are two problems with the CA's proposed rate design. First, a simple equal percentage increase to all the existing charges does not guarantee that the target class revenues will be achieved. Changes in the number of customers subject to minimum bills and changes in rider adjustments in the commercial rate schedules will affect the revenue calculations. Second, and more importantly, the CA's proposal to adjust the existing structure of customer charges, minimum charges, energy charges, and demand charges in equal percentages is inconsistent with aligning charges closer to the cost to serve. For example, the existing Schedule R single phase service customer charge of $7.00 per customer per month recovers only about 50% of the $14.12 unit customer cost (Final Rates filed December 21, 1995 in Docket No. 7766, Exhibit 6, page 25). The Schedule R unit customer cost at proposed rates is $19.41 per customer per month (HECO-R-2208). In

order for the proposed customer charge to maintain its existing relationship of about 50% of the customer cost, the Schedule R customer charge would have to rise to $9.70, an increase of over 38%. The CA does not contemplate such a percentage increase for Schedule R's pricing elements. A simple equal percentage increase to all the existing charges will likely assure that some elements of customer, energy, or demand charges move farther away from their cost basis. The Company has two opportunities to better align revenues and the cost to serve: first, the Company can allocate revenues to rate classes such that each rate class earns a rate of return that is close to the system average return; and second, within a particular rate class, the Company can align customer charges with customer costs, energy charges with energy costs, and demand charges with demand costs more closely in order to improve efficiency and send the proper pricing signal to customers. The Company needs to seek positive progress from both opportunities to align revenues with costs.

Q. Does the CA address HECO's rate design proposals made in direct testimony?

A. Yes. At CA-T-5, pages 39-40, the CA agrees with the following proposals:

1. The Schedule R Apartment House collection arrangement;
2. The Schedule G revisions to primary service availability and supply voltage adjustment;
3. The Schedule J qualification limit of loads less than 300 kW;
4. The Schedule PS, PP, and PT qualification limit of loads greater than 300 kW;
5. The revision to the Schedule J determination of demand (demand ratchet);
6. The addition of the network adjustment to Schedule J;

7. The increase in the contract term provisions in Schedules J, PS, PP, and PT with the proposed termination charges for service discontinuation within five years;
8. The secondary metering adjustment revision to Schedules PP and PT; and
9. The elimination of the closed Minimum Billing Demand provision on Schedule PT.

The CA also did not object to implementation of the Schedules TOU-R and TOU-C at their proposed terms and conditions (CA-T-5, page 41). The CA proposes that the rates for Schedule U, Rider T, Rider M, Schedule TOU-R, and Schedule TOU-C be developed in conformance with the CA's proposed equal percentage adjustment approach (CA-T-5, pages 40-41). The CA also proposes the continuation of the IRP/DSM Surcharge, subject to reconciliation of costs and revenues and review of programs in the Energy Efficiency Docket (CA-T-5, page 27).

Q. Are there HECO proposed changes to existing rates and rules that the CA did not address in testimony?

A. Yes. The CA did not address the following HECO proposals in their testimony:

1. Reduce the Rider I minimum qualifying interruptible load from 500 kW to 100 kW;
2. Add terms and conditions to Rider T that would allow customers to perform emergency maintenance on equipment without considering its impact on the customer's maximum on-peak demand in the determination of their billing demand;
3. Terminate Rider EV-R – Residential Electric Vehicle Charging

Service and Rider EV-C – Commercial Electric Vehicle Charging Service; and

4. Eliminate Rule No. 4. Section D, the Standard Form Customer Retention Rates.

These HECO proposals are reasonable and should be adopted.

Q. Did the CA propose any modifications to HECO's rate design structure?

A. Yes. The CA proposes that HECO customers be charged when power factor is less than 95%, and no credits would apply for power factors greater than 95% (CA-T-3, page 65). The CA also proposes that Schedule H be closed to new customers (CA-T-5, page 42).

Q. Is the CA's proposal to modify the power factor base currently used in HECO's power factor adjustment reasonable?

A. No. The CA's proposal is not reasonable and should be rejected. The power factor base currently used in the power factor adjustment section in HECO's Schedules J, PS, PP, PT, and U should remain at 85%. The CA provides no cost basis for its recommended change. The CA contends that the information needed to estimate reactive power costs and subsequent power factor penalties was requested in CA-IR-576, but the requested breakouts of the generators, turbines, and exciter costs were not readily available, as indicated in HECO's response to CA-IR-576, subpart d, so the CA is not able to calculate reactive power cost (CA's response to HECO/CA-IR-507). However, it is not readily apparent that the CA could in fact calculate a reactive power cost, even if the data requested in CA-IR-576, subpart d were available, and there is nothing that suggests that 95% is a reasonable base for calculating power factor adjustment.

Q. Why does HECO have a power factor adjustment?

A. HECO's power factor adjustment encourages customers to achieve and maintain good power factor levels. This lowers overall system operating costs and benefits all customers in the long run.

Q. Are there HECO customers that would be impacted by a change in the base for calculating power factor adjustment?

A. Yes. Since HECO's base for power factor adjustment has been at 85% for many years, some customers who are subject to power factor adjustment have made investments in capacitors to improve power factor, with the expectation that the investments would pay for themselves over time through power factor adjustment credits based on the 85% power factor base. These customers who made a reasonable investment based on a reasonable assessment of the stability of the power factor adjustment would be most impacted by a change in the base for power factor adjustment.

Q. What does HECO recommend regarding power factor and power factor adjustment?

A. HECO recommends that the existing power factor adjustment base and power factor adjustment clauses in Schedules J, PS, PP, PT, and U be maintained.

Q. What does the CA recommend regarding HECO's Schedule H?

A. The CA recommends that Schedule H be closed to new customers because HECO has demonstrated no need to maintain any end-use rate schedules of this type (CA-T-5, page 42).

Q. What is HECO's position on the status of Schedule H?

A. The Company recommends that Schedule H be maintained in its present form until overall revisions to the rate can be proposed in HECO's next rate case that will address the issues of on-site inspection costs and the applicability of billing

demand exclusions for specific equipment. The Company agrees with the CA that there are significant on-site inspection efforts required to administer Schedule H (CA-T-5, pages 42-43; HECO's response to CA-IR-376). However, even if Schedule H is closed to new customers, the need for inspection of existing accounts is not eliminated, and that function may in fact approach the labor hour requirement identified in HECO's response to CA-IR-376. In addition, closing Schedule H to new customers may cause new tenants in sites with existing Schedule H service to incur extra wiring or electric bill costs, and may require clarification in order to administer (CA-T-5, page 43 and HECO's response to CA-IR-376). These are costs that can be avoided. Any transition of Schedule H should be planned to minimize administrative costs, minimize impacts on existing Schedule H customers, and establish applicability that aligns appropriately with other Company rates. HECO's Schedule H should be maintained in its current form while a transition for the rate is structured.

DOD'S COST-OF-SERVICE ISSUES

Q. What are the cost-of-service issues raised by the DOD?

A. The DOD does not raise cost-of-service issues in their testimony. The DOD agrees that the embedded cost methodology employed by the Company is generally consistent with industry practice and is suitable for use in this docket (DOD T-3, page 3). The DOD also testifies that the embedded cost-of-service study is the appropriate approach to the determination of the class cost-of-service (DOD T-3, page 7). And the DOD recommends that the Commission use HECO's class cost-of-service study as a basis for the determination of revenue requirements assigned to each customer class (DOD T-3, page 8). Finally, the

DOD agrees that the AED allocation method used for allocating generation and transmission costs continues to be appropriate for the HECO system (DOD T-3, page 9).

DOD'S REVENUE ALLOCATION AND RATE DESIGN ISSUES

Q. What is the DOD's position on revenue allocation?

A. The DOD proposes to allocate the revenue increase among classes with the objective of reducing existing interclass subsidies by at least 50%. The DOD also proposed to allocate revenue such that Schedule PS, Schedule PP, and Schedule PT rate classes all earn the same rate of return.

Q. Is there an inconsistency in the DOD's revenue allocation proposal?

A. The revenue allocation proposal for Schedules PS, PP, and PT rate classes to earn the same rate of return perpetuates interclass subsidies and appears to benefit primarily military accounts. The re-allocation of revenue between Schedules PS, PP, and PT would move Schedules PS and PP farther from their cost-of-service and increase the subsidy that each is providing. Clearly this is not efficient or equitable and should be rejected.

Q. What is the DOD's proposed rate design?

A. The DOD did not propose a rate design for all rates; the DOD did make a specific proposal for a single value demand charge for Schedule PP customers with a credit for those customers taking dedicated substation service, and an adder applicable to all others (DOD T-3, page 23).

Q. Is the DOD's proposal to create a credit and adder to the Schedule PP demand charge reasonable?

A. No. The DOD's proposal to create a credit and adder in the Schedule PP demand

charge is not cost-based; there is no supporting study of specific customers and the facilities used to serve those customers. The DOD makes an assumption that HECO customers served by a dedicated substation do not use primary lines, but provides no evidence. In fact, it appears that the DOD does not exclude the possibility that HECO's investment to serve these customers includes investment in primary lines ("HECO will own metering equipment and may own switches and a short service line to the customer. The investment would not include primary lines in the sense of the typical distribution network" Response to HECO/DOD-IR-312, subpart a). The proposed demand charge credit has no cost basis, but is simply a guess: "The one-half of the cost was established as a conservative initial value so as not to overstate the applicable credit." (Response to HECO/DOD-IR-312, subpart b). Further more, the Company does not agree that a subgroup within Schedule PP be created based on the length of the primary line used to serve customers. At an extreme, perhaps hundreds of subgroups could be created based on different customer attributes. However, creating such subgroups reduces rate simplicity and calls into question the fairness of its establishment. The DOD's proposal for a separate adder/credit to the Schedule PP demand charge should be rejected.

SUMMARY

Q. Please summarize your testimony.

A. My rebuttal testimony presents the Company's revised cost-of-service study, revised marginal energy cost study, proposed allocation of revenues, proposed rate design, and rebuttal to the CA's and the DOD's testimony on the cost-of-service and rate design.

The embedded cost-of-service study, the main basis of HECO's proposed rates, uses the embedded cost-of-service study methodology that has been used, found reasonable, and approved by the Commission in prior HECO, HELCO, and MECO rate cases.

HECO recommends that the Commission continue to find HECO's classification of distribution plant costs as demand-related and customer-related and the Company's use of the minimum system method, consistent with NARUC cost allocation guidelines, as reasonable, and reject the CA's arguments. The CA has not presented any new arguments in this case. The Commission has found the Company's classification of distribution plant costs as demand-related and customer-related to be reasonable in previous rate cases. The Commission has also adopted the Company's use of the minimum system method as consistent with NARUC cost allocation guidelines in previous rate cases.

HECO's classification of non-fuel production O&M costs as 100% demand-related is reasonable and should be accepted by the Commission.

HECO recommends that the existing power factor adjustment base and power factor adjustment clauses in Schedules J, PS, PP, PT, and U be maintained.

The Company recommends that Schedule H be maintained in its present form until overall revisions to the rate can be proposed in HECO's next rate case that will address the issues of on-site inspection costs and the applicability of billing demand exclusions for specific equipment.

The DOD's proposal to re-allocate revenue between Schedules PS, PP, and PT such that all three classes earn the same rate of return is inconsistent with reducing interclass subsidies and is self-serving.

The DOD's proposal for a separate adder/credit to the Schedule PP demand

charge has no cost basis and should be rejected.

HECO proposes a revenue allocation to classes that aligns class revenues closer to the class cost-of-service. HECO's proposal is based on revenue allocation guidelines that have been approved by the Commission in the past. HECO asks that the proposed revenue allocation based on the HECO guidelines be approved.

The Company's proposed rate design moves to align more closely customer charges with customer costs, demand charges with demand costs, and energy charges with energy costs. The Company recommends that the Commission adopt the Company's proposed rate design.

Q. Does this conclude your testimony?

A. Yes, this concludes my direct testimony.

HAWAIIAN ELECTRIC COMPANY, INC.
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SUMMARY OF CLASS REVENUE REQUIREMENTS AND CLASS RATES OF RETURN
AT PRESENT RATES AND AT PROPOSED RATES

	Present Rates			Proposed Rates			Proposed Increase	
Rate Class	Sales Revenues ($000s)	Rate of Return (%)	ROR Index (%)	Sales Revenues ($000s)	Rate of Return (%)	ROR Index (%)	Amount ($000s)	Percent (%)
Schedule R	$379,853.7	3.46%	61.54%	$404,126.4	6.39%	72.37%	$24,272.7	6.39%
Schedule G	$71,429.0	7.27%	129.15%	$74,969.6	9.55%	108.15%	$3,540.6	4.96%
Schedule J	$311,441.9	8.10%	143.86%	$323,401.3	10.87%	123.10%	$11,959.4	3.84%
Schedule H	$8,424.0	4.92%	87.45%	$8,962.3	8.49%	96.15%	$538.3	6.39%
Schedule PS	$124,046.2	6.02%	107.06%	$130,194.9	10.02%	113.48%	$6,148.7	4.96%
Schedule PP	$293,533.4	6.76%	120.05%	$308,083.3	11.21%	126.95%	$14,549.9	4.96%
Schedule PT	$23,101.4	12.67%	225.09%	$23,988.5	17.44%	197.51%	$887.1	3.84%
Schedule F	$6,437.2	1.03%	18.31%	$6,848.5	4.39%	49.72%	$411.3	6.39%
Total Sales Revenues	$1,218,266.8			$1,280,574.8			$62,308.0	5.11%
Other Operating Revenues	$3,334.9			$4,062.3			$727.4	21.81%
Total Revenues	$1,221,601.7	5.63%	100.00%	$1,284,637.1	8.83%	100.00%	$63,035.4	5.16%

HAWAIIAN ELECTRIC COMPANY, INC.
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SUMMARY OF CLASS RATES OF RETURN ON RATE BASE AT PRESENT RATES

Rate Class	Total Operating Revenues ($000s)	Total Operating Expenses ($000s)	Total Operating Income ($000s)	Rate base ($000s)	Return on Rate Base (%)
Schedule R	$382,057.5	$365,416.2	$16,641.3	$480,538.9	3.46%
Schedule G	$71,697.2	$65,150.8	$6,546.4	$90,084.0	7.27%
Schedule J	$311,920.3	$291,973.1	$19,947.2	$246,425.2	8.10%
Schedule H	$8,448.6	$8,024.9	$423.7	$8,610.2	4.92%
Schedule PS	$124,156.9	$118,873.1	$5,283.8	$87,705.9	6.02%
Schedule PP	$293,753.1	$281,135.5	$12,617.6	$186,798.0	6.76%
Schedule PT	$23,111.0	$21,747.3	$1,363.7	$10,766.4	12.67%
Schedule F	$6,457.1	$6,386.0	$71.1	$6,902.1	1.03%
TOTAL	$1,221,601.7	$1,158,706.9	$62,894.8	$1,117,830.7	5.63%

HAWAIIAN ELECTRIC COMPANY, INC.
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SUMMARY OF CLASS RATES OF RETURN ON RATE BASE AT PROPOSED RATES

Rate Class	Total Operating Revenues ($000s)	Total Operating Expenses ($000s)	Total Operating Income ($000s)	Rate base ($000s)	Return on Rate Base (%)
Schedule R	$406,956.3	$376,469.0	$30,487.3	$477,189.3	6.39%
Schedule G	$75,307.1	$66,754.1	$8,553.0	$89,596.3	9.55%
Schedule J	$323,903.4	$297,291.4	$26,612.0	$244,815.9	10.87%
Schedule H	$8,990.7	$8,265.6	$725.1	$8,537.2	8.49%
Schedule PS	$130,307.1	$121,601.8	$8,705.3	$86,881.6	10.02%
Schedule PP	$308,305.3	$287,588.3	$20,717.0	$184,857.5	11.21%
Schedule PT	$23,998.1	$22,140.6	$1,857.5	$10,648.4	17.44%
Schedule F	$6,869.1	$6,568.7	$300.4	$6,846.9	4.39%
TOTAL	$1,284,637.1	$1,186,679.5	$97,957.6	$1,109,373.1	8.83%

HAWAIIAN ELECTRIC COMPANY, INC.
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PROPOSED ALLOCATION OF RATE INCREASE BY RATE CLASS

Rate Class	Sales Revenues at Present Rates ($000s)	Sales Revenues at Proposed Rates ($000s)	PROPOSED INCREASE ($000s)	% Increase	% of Total
Schedule R	$379,853.7	$404,126.4	$24,272.7	6.39%	38.96%
Schedule G	$71,429.0	$74,969.6	$3,540.6	4.96%	5.68%
Schedule J	$311,441.9	$323,401.3	$11,959.4	3.84%	19.19%
Schedule H	$8,424.0	$8,962.3	$538.3	6.39%	0.86%
Schedule PS	$124,046.2	$130,194.9	$6,148.7	4.96%	9.87%
Schedule PP	$293,533.4	$308,083.3	$14,549.9	4.96%	23.35%
Schedule PT	$23,101.4	$23,988.5	$887.1	3.84%	1.42%
Schedule F	$6,437.2	$6,848.5	$411.3	6.39%	0.66%
Total Sales Revenues	$1,218,266.8	$1,280,574.8	$62,308.0	5.11%	99.99%
Other Operating Revenues	$3,334.9	$4,062.3	$727.4	21.81%	
Total Revenues	$1,221,601.7	$1,284,637.1	$63,035.4	5.16%	

HAWAIIAN ELECTRIC COMPANY, INC.
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ALLOCATION OF RATE INCREASE BASED ON EQUAL CLASS ROR

Rate Class	Sales Revenues at Present Rates	Rev Requirements at Equal ROR	REVENUE INCREASE			CLASS RATES OF RETURN	
	($000s)	($000s)	($000s)	% increase	% of Total	At Present Rates (%)	At Equal ROR (%)
Schedule R	$379,853.7	$424,614.8	$44,761.1	11.78%	71.8%	3.46%	8.83%
Schedule G	$71,429.0	$73,838.8	$2,409.8	3.37%	3.9%	7.27%	8.83%
Schedule J	$311,441.9	$314,613.4	$3,171.5	1.02%	5.1%	8.10%	8.83%
Schedule H	$8,424.0	$9,012.6	$588.6	6.99%	0.9%	4.92%	8.83%
Schedule PS	$124,046.2	$128,376.5	$4,330.3	3.49%	6.9%	6.02%	8.83%
Schedule PP	$293,533.4	$300,358.5	$6,825.1	2.33%	11.0%	6.76%	8.83%
Schedule PT	$23,101.4	$22,375.3	($726.1)	-3.14%	-1.2%	12.67%	8.84%
Schedule F	$6,437.2	$7,383.8	$946.6	14.71%	1.5%	1.03%	8.83%
Total Sales Revenues	$1,218,266.8	$1,280,573.7	$62,306.9	5.11%	100.0%		
Other Operating Revenues	$3,334.9	$4,062.3	$727.4	21.81%			
TOTAL SYSTEM	$1,221,601.7	$1,284,636.0	$63,034.3	5.16%		5.63%	8.83%

HAWAIIAN ELECTRIC COMPANY, INC.
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COMPARISON OF CLASS REVENUE REQUIREMENTS AT PRESENT RATES, AT PROPOSED RATES AND AT EQUAL RATES OF RETURN

				CLASS RATES OF RETURN		
Rate Class	Sales Revenues at Present Rates ($000s)	Sales Revenues at Proposed Rates ($000s)	Sales Revenues at Equal ROR ($000s)	At Present Rates (%)	At Proposed Rates (%)	At Equal ROR (%)
Schedule R	$379,853.7	$404,126.4	$424,614.8	3.46%	6.39%	8.83%
Schedule G	$71,429.0	$74,969.6	$73,838.8	7.27%	9.55%	8.83%
Schedule J	$311,441.9	$323,401.3	$314,613.4	8.10%	10.87%	8.83%
Schedule H	$8,424.0	$8,962.3	$9,012.6	4.92%	8.49%	8.83%
Schedule PS	$124,046.2	$130,194.9	$128,376.5	6.02%	10.02%	8.83%
Schedule PP	$293,533.4	$308,083.3	$300,358.5	6.76%	11.21%	8.83%
Schedule PT	$23,101.4	$23,988.5	$22,375.3	12.67%	17.44%	8.84%
Schedule F	$6,437.2	$6,848.5	$7,383.8	1.03%	4.39%	8.83%
Total Sales Revenues	$1,218,266.8	$1,280,574.8 [1]	$1,280,573.7 [1]			
Other Operating Revenues	$3,334.9	$4,062.3	$4,062.3			
				5.63%	8.83%	8.83%
TOTAL SYSTEM	$1,221,601.7	$1,284,637.1 [1]	$1,284,636.0 [1]			

[1] The totals may not exactly equal due to rounding.

HAWAIIAN ELECTRIC COMPANY, INC.
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SUMMARY OF COST COMPONENTS BY RATE CLASS AT PROPOSED RATES

Rate Class	COST COMPONENTS AT PROPOSED RATES							
	DEMAND COSTS		ENERGY COSTS		CUSTOMER COSTS		TOTAL COSTS	
	($000s)	(%)	($000s)	(%)	($000s)	(%)	($000s)	(%)
Schedule R	$135,191.3	30.82%	$208,979.1	27.62%	$59,955.6	70.24%	$404,126.0	31.56%
Schedule G	$25,289.3	5.76%	$36,759.9	4.86%	$12,920.3	15.14%	$74,969.5	5.85%
Schedule J	$118,505.5	27.01%	$195,714.0	25.87%	$9,181.6	10.76%	$323,401.1	25.25%
Schedule H	$3,109.0	0.71%	$5,197.1	0.69%	$656.1	0.77%	$8,962.2	0.70%
Schedule PS	$44,490.0	10.14%	$84,658.4	11.19%	$1,046.5	1.23%	$130,194.9	10.17%
Schedule PP	$101,600.6	23.16%	$205,025.3	27.10%	$1,457.5	1.71%	$308,083.4	24.06%
Schedule PT	$7,556.4	1.72%	$16,397.5	2.17%	$34.5	0.04%	$23,988.4	1.87%
Schedule F	$2,941.8	0.67%	$3,803.6	0.50%	$103.3	0.12%	$6,848.7	0.53%
TOTAL	$438,683.9	99.99%	$756,534.9	100.00%	$85,355.4	100.01%	$1,280,574.2	99.99%
PERCENT OF TOTAL	34.26%		59.08%		6.67%		100.01%	

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SUMMARY OF UNIT COST COMPONENTS BY RATE CLASS AT PROPOSED RATES

	Unit Cost Components At Proposed Rates			
Rate Class	Unit Demand Cost ($/kW/mo.)	Unit Energy Cost (¢/kWh)	Unit Customer Cost ($/Customer/mo.)	Total Unit Cost (¢/kWh)
Schedule R	$8.78	9.700	$19.41	18.758
Schedule G	$14.44	9.738	$42.02	19.859
Schedule J	$19.11	9.723	$114.54	16.066
Schedule H	$18.55	9.732	$52.47	16.783
Schedule PS	$24.21	9.674	$458.99	14.877
Schedule PP	$24.24	9.455	$731.67	14.207
Schedule PT	$24.55	9.438	$718.75	13.807
Schedule F	$24.29	9.438	$21.20	16.994
TOTAL	$14.63	9.630	$24.38	16.301

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SUMMARY OF COST COMPONENTS BY RATE CLASS AT EQUAL ROR

	COST COMPONENTS AT PROPOSED RATES							
Rate Class	DEMAND COSTS		ENERGY COSTS		CUSTOMER COSTS		TOTAL COSTS	
	($000s)	(%)	($000s)	(%)	($000s)	(%)	($000s)	(%)
Schedule R	$147,307.8	34.02%	$209,594.6	27.73%	$67,711.8	73.72%	$424,614.2	33.16%
Schedule G	$24,696.8	5.70%	$36,728.0	4.86%	$12,413.6	13.51%	$73,838.4	5.77%
Schedule J	$111,020.2	27.08%	$195,227.9	25.83%	$8,364.9	9.11%	$314,613.0	24.57%
Schedule H	$3,144.0	0.73%	$5,199.2	0.69%	$669.3	0.73%	$9,012.5	0.70%
Schedule PS	$42,790.3	9.88%	$84,533.9	11.19%	$1,052.3	1.15%	$128,376.5	10.02%
Schedule PP	$94,442.5	21.81%	$204,431.6	27.05%	$1,484.5	1.62%	$300,358.6	23.46%
Schedule PT	$6,122.7	1.41%	$16,228.9	2.15%	$23.8	0.03%	$22,375.4	1.75%
Schedule F	$3,426.3	0.79%	$3,824.2	0.51%	$133.4	0.15%	$7,383.9	0.58%
TOTAL	$432,950.6	101.42%	$755,768.3	100.01%	$91,853.6	100.02%	$1,280,572.5	100.01%
PERCENT OF TOTAL	33.81%		59.02%		7.17%		100.00%	

HAWAIIAN ELECTRIC COMPANY, INC.
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SUMMARY OF UNIT COST COMPONENTS BY RATE CLASS AT EQUAL ROR

	Unit Cost Components At Equalized Rates of Return			
Rate Class	Unit Demand Cost ($/kW/mo.)	Unit Energy Cost (¢/kWh)	Unit Customer Cost ($/Customer/mo.)	Total Unit Cost (¢/kWh)
Schedule R	$9.56	9.729	$21.90	19.709
Schedule G	$14.09	9.729	$40.37	19.560
Schedule J	$17.90	9.698	$104.36	15.629
Schedule H	$18.75	9.736	$53.53	16.877
Schedule PS	$23.28	9.660	$461.54	14.669
Schedule PP	$22.51	9.427	$745.22	13.851
Schedule PT	$19.89	9.341	$495.84	12.879
Schedule F	$28.30	9.489	$27.38	18.322
TOTAL	$14.59	9.620	$26.25	16.301

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SUMMARY OF ALLOCATION FACTORS

ALLOCATION BASIS		Schedule R	Schedule G	Schedule J	Schedule H	Schedule PS	Schedule PP	Schedule PT	Schedule F	Total
Demand Allocation Factors:										
Average-Excess Demand	D1	33.22%	5.62%	25.56%	0.72%	9.86%	22.51%	1.70%	0.81%	100.00%
Class Peak Demand	D2	34.81%	5.85%	25.93%	0.74%	9.77%	22.01%		0.89%	100.00%
Composite NCD	D3	50.23%	6.98%	25.06%	0.79%	9.75%	7.07%		0.13%	100.00%
Energy Allocation Factors:										
Gross Input	E1	27.74%	4.86%	25.83%	0.69%	11.18%	27.05%	2.15%	0.51%	100.00%
Customer Allocation Factors:										
Primary Lines	C1	83.62%	11.40%	4.16%	0.57%	0.07%	0.05%		0.13%	100.00%
Secondary Lines	C2	86.96%	9.69%	2.86%	0.43%	0.06%				100.00%
Transformers	C3	32.95%	39.72%	22.88%	2.66%	1.63%			0.16%	100.00%
Services	C4	83.96%	8.94%	6.14%	0.38%	0.13%	0.19%	0.05%	0.22%	100.00%
Meter	C5	62.44%	9.44%	24.41%	0.49%	0.55%	1.99%	0.32%	0.36%	100.00%
Cust Acct Fct	C6	85.28%	10.52%	3.49%	0.37%	0.09%	0.09%	0.00%	0.16%	100.00%
Bad Debt	C7	64.63%	10.74%	15.71%	1.31%	5.48%	2.03%	0.00%	0.10%	100.00%
Cust Serv Fct	C8	53.56%	0.89%	18.70%	0.04%	9.24%	17.52%	0.04%	0.01%	100.00%
Avg Cust	C10	88.31%	8.78%	2.29%	0.36%	0.07%	0.06%	0.00%	0.14%	100.00%

Hawaiian Electric Company, Inc.
Docket No. 04-0113, Test-Year 2005
Energy Loss Analysis By Rate Class

		Total System	Total R/E	G	J-DP	J-DS	J-Sec	J-Nwk	Total J	H	P-TP	P-DP	P-DS	P-SEC	P-Nwk	F-DP	F-Sec	Total F
1	Energy Sales, Mwh	7,656,000	2,154,400	377,500	205,930	22,344	1,725,745	56,565	2,013,000	53,400	173,740	2,146,006	22,522	707,627	167,305	33,652	6,448	40,300
	Line, Transformer Losses:																	
2	Generation Step Up	16,139	4,426	775	423	46	3,545	116	4,135	110	357	4,409	46	1,454	344	70	13	82
3	Transm Line Loss 138 kv	94,784	25,994	4,554	2,484	269	20,821	682	24,287	645	2,097	25,892	272	8,540	2,019	409	78	486
4	T 138 to T 46 Transf	33,137	9,087	1,592	869	94	7,279	239	8,491	225	733	9,052	95	2,986	706	143	27	170
5	Transm Line Loss 46 Kv	30,770	8,438	1,478	806	87	6,759	222	7,884	209	681	8,405	88	2,772	655	133	25	158
6	Transm To Pri Transf	47,339	13,276	2,326	1,269	138	10,634	348	12,403	329	-	13,224	139	4,362	1,031	209	40	249
7	Pri Line Loss	23,884	6,698	1,174	640	70	5,365	176	6,258	166	-	6,672	70	2,201	520	105	20	125
8	Pri to Sec Transf	125,766	51,187	8,963	-	528	40,978	1,343	42,849	1,268	-	-	535	16,807	3,974	-	153	183
9	Sec Line Loss	44,325	21,010	3,683	-	-	16,835	552	17,387	521	-	-	-	-	1,640	-	63	64
10	Total Line and Trsf Loss	416,144	140,116	24,545	6,491	1,232	112,216	3,678	123,694	3,473	3,868	67,654	1,245	39,122	10,889	1,069	419	1,537
11	Company Use	15,400	4,223	740	404	44	3,383	111	3,946	105	341	4,207	44	1,388	328	66	13	78
12	Unaccounted For	(32,244)	(8,843)	(1,549)	(845)	(92)	(7,083)	(232)	(8,262)	(219)	(713)	(8,808)	(93)	(2,905)	(687)	(139)	(26)	(165)
13	Net Input	8,255,300	2,280,896	401,236	211,980	23,528	1,834,261	60,122	2,132,378	56,759	177,236	2,209,059	23,718	745,432	177,835	34,848	6,854	41,750
14	Purchased Power	3,426,300	950,387	166,518	87,987	9,765	761,290	24,943	885,013	23,573	73,563	916,844	9,833	309,395	73,803	14,459	2,844	17,337
15	*Net Generation*	4,829,000	1,339,509	234,718	123,993	13,763	1,072,971	35,179	1,247,365	33,186	103,673	1,292,215	13,885	436,037	104,032	20,389	4,010	24,413
16	Station Use	307,800	85,381	14,962	7,904	877	68,390	2,241	79,508	2,115	6,608	82,364	886	27,794	6,630	1,299	255	1,552
17	Gross Generation	5,136,800	1,424,890	249,680	131,897	14,640	1,141,361	37,420	1,326,873	35,301	110,281	1,374,579	14,771	463,831	110,662	21,688	4,265	25,965
	Gross Input By Voltage:																	
18	Gross I	8,563,100	2,375,277	416,198	219,884	24,405	1,902,651	62,363	2,211,886	58,874	183,844	2,291,423	24,604	773,226	184,465	36,147	7,109	43,302
19	Gross II	8,376,673	2,375,277	416,198	219,884	24,405	1,902,651	62,363	2,211,886	58,874	0	2,291,423	24,604	773,226	184,465	36,147	7,109	43,302
20	Gross III	5,780,163	2,375,277	416,198	0	0	1,902,651	62,363	1,965,014	58,874	0	0	0	773,226	184,465	0	7,109	7,109
21	Gross To Sales Ratio	1.09	1.1025	1.1025	1.0678	1.0922	1.1025	1.1025	1.0988	1.1025	1.0582	1.0678	1.0924	1.0924	1.1026	1.0678	1.1025	1.0745
22	Net To Sales Ratio	1.0508	1.0629	1.0629	1.0294	1.053	1.0629	1.0629	1.0593	1.0629	1.0201	1.0294	1.0531	1.0531	1.0629	1.0294	1.063	1.0360

Derivation and Allocation Basis:
L1: Test-Year Sales Forecasts
L2: .0033 x Net Gen x % Sales
L3: .0185 x Net Gen x % Sales
L4: .0066 x Net Gen x % Sales
L5: .0061 x Net Gen x % Sales
L6: .0094 x Net Gen x % Sales Excl TP
L7: .0047 x Net Gen x % Sales Excl TP, TS
L8: .0250 x Net Gen x % Sales Excl TP, TS, DP
L9: .0088 x Net Gen x % Sales Excl TP, TS, DP, DS, PSEC
L10: Sum(L2:L9)
L11: % Sales
L12: % Sales

L13: Sum(L1, L10, L11, L12)
L14: % Net Input
L15: (L13 - L14)
L16: % Net Generation
L17: Sum(L15:L16)
L18: Sum(L14, L17)
L19: L18 Excl Transmission
L20: L18 Excl Transmission, Primary
L21: L18 ÷ L1
L22: L13 ÷ L1

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HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2005 DOCKET NO. 04-01133

COMPARISON OF CLASS REVENUES AND CLASS RATES OF RETURN
AT PRESENT RATES

	DIRECT TESTIMONY			REBUTTAL TESTIMONY		
Rate Class	Sales Revenue @Present Rates ($000s)	Class Rate of Return (%)	Rate of Return Index (%)	Sales Revenue @Present Rates ($000s)	Class Rate of Return (%)	Rate of Return Index (%)
R	$317,901.1	1.30%	32%	$379,853.7	3.46%	62%
G	$60,702.9	7.60%	188%	$71,429.0	7.27%	129%
J	$255,035.3	7.15%	177%	$311,441.9	8.10%	144%
H	$6,913.7	5.39%	133%	$8,424.0	4.92%	87%
PS	$99,113.9	4.36%	108%	$124,046.2	6.02%	107%
PP	$230,924.5	4.67%	116%	$293,533.4	6.76%	120%
PT	$18,142.7	13.04%	323%	$23,101.4	12.67%	225%
F	$5,298.0	1.36%	34%	$6,437.2	1.03%	18%
Total Sales Rev.	$994,032.1			$1,218,266.8		
Other Oper. Rev.	$3,075.0			$3,334.9		
Total Revenues	$997,107.1	4.04%	100%	$1,221,601.7	5.63%	100%

Source: HECO-2201; HECO-R-2201.

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2005 DOCKET NO. 04-01133

COMPARISON OF CLASS REVENUES AND CLASS RATES OF RETURN
AT PROPOSED RATES

	DIRECT TESTIMONY			REBUTTAL TESTIMONY		
Rate Class	Sales Revenue @Proposed Rates ($000s)	Class Rate of Return (%)	Rate of Return Index (%)	Sales Revenue @Proposed Rates ($000s)	Class Rate of Return (%)	Rate of Return Index (%)
R	$349,194.6	5.07%	56%	$404,126.4	6.39%	72%
G	$66,678.5	11.49%	126%	$74,969.6	9.55%	108%
J	$280,140.5	13.07%	143%	$323,401.3	10.87%	123%
H	$7,594.3	9.97%	109%	$8,962.3	8.49%	96%
PS	$108,870.7	10.81%	119%	$130,194.9	10.02%	113%
PP	$253,656.2	11.76%	129%	$308,083.3	11.21%	127%
PT	$19,928.7	23.09%	253%	$23,988.5	17.44%	198%
F	$5,819.6	5.69%	62%	$6,848.5	4.39%	50%
Total Sales Rev.	$1,091,883.1			$1,280,574.8		
Other Oper. Rev.	$3,838.0			$4,062.3		
Total Revenues	$1,095,721.1	9.11%	100%	$1,284,637.1	8.83%	100%

Source: HECO-2201; HECO-R-2201.

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113, TEST-YEAR 2005
MARGINAL COST STUDY

MARGINAL ENERGY COSTS BY TIME-OF-USE RATING PERIOD

YEAR	Priority Peak	Mid-Peak	Off-Peak	TOTAL
	(A)	(B)	(C)	(D)
		Transmission Voltage Service (¢/kWh)		
2005	11.16	11.09	10.24	10.64
2006	11.23	11.19	10.27	10.70
2007	11.11	11.03	10.17	10.57
2008	11.00	10.92	10.10	10.49
2009	11.02	10.96	10.08	10.49
		Primary Voltage Service (¢/kWh)		
2005	11.56	11.49	10.61	11.02
2006	11.64	11.59	10.65	11.08
2007	11.51	11.43	10.53	10.95
2008	11.40	11.31	10.46	10.87
2009	11.42	11.36	10.45	10.87
		Secondary Voltage Service (¢/kWh)		
2005	11.69	11.62	10.73	11.14
2006	11.77	11.72	10.76	11.21
2007	11.64	11.56	10.65	11.08
2008	11.53	11.44	10.58	10.99
2009	11.54	11.48	10.56	10.99
Average	11.63	11.56	10.66	11.08

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113, TEST-YEAR 2005

COMPARISON BETWEEN UNIT EMBEDDED COSTS[1] AND UNIT MARGINAL COSTS BY FUNCTION

Cost Components	Unit Embedded Costs At Equal ROR	Unit Marginal Cost
Demand Costs:	($/kW/mo.)	($/kW/mo.)
Production	$10.00	$12.67
Transmission	$2.11	$4.29
Distribution	$2.48	$4.23
TOTAL	$14.59	$21.19
Energy Costs:	(¢/kWh)	(¢/kWh)[2]
Priority Peak		11.63
Mid-Peak		11.56
Off-Peak		10.66
TOTAL	9.62	11.08
Customer Costs:	($/Customer/mo.)	($/Customer/mo.)
Schedule R	$21.90	$10.33
Schedule G	$40.37	$12.67
Schedule J	$104.36	$42.50
Schedule H	$53.53	$13.50
Schedule PS	$461.54	$34.42
Schedule PP	$745.22	$99.92
Schedule PT	$495.84	$668.42
Schedule F	$27.38	$18.00
TOTAL SYSTEM	$26.25	

[1] At proposed rates.
[2] Average for 2005-2009.

HAWAIIAN ELECTRIC COMPANY, INC.
Docket No. 04-0113, Test-Year 2005 REBUTTAL TESTIMONY
SCHEDULE R - RESIDENTIAL SERVICE

ESTIMATE OF TEST YEAR REVENUES

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS	UNIT PRICE	REVENUES $1000S	UNIT PRICE	REVENUES $1000S
ENERGY CHARGE:	(MWH)	¢/kWh		¢/kWh	
NON-FUEL ENERGY CHARGE	2,154,400	7.7814	$167,642.5	8.4415	$181,863.7
BASE FUEL ENERGY CHARGE	2,154,400	3.5140	$75,705.6	8.8903	$191,532.6
SUBTOTAL			$243,348.1		$373,396.3
CUSTOMER CHARGE:	BILLS	$/MONTH		$/MONTH	
1 PHASE CHARGE	3,090,230	7.00	$21,631.6	10.00	$30,902.3
3 PHASE CHARGE	1,546	15.00	$23.2	20.00	$30.9
SUBTOTAL	3,091,776		$21,654.8		$30,933.2
ADJUSTMENTS:					
SCHEDULE E ADJ.			($949.0)		($451.0)
MINIMUM BILL ADJ. - 1 PHASE			$281.8		$324.0
MINIMUM BILL ADJ. - 3 PHASE			$0.1		$0.2
RESIDENTIAL TOU			$0.0		($9.4)
APARTMENT HOUSE:			($64.0)		($66.3)
SUBTOTAL			($731.1)		($202.5)
TOTAL BASE REVENUE			$264,271.8		$404,127.0
BILL ADJUSTMENTS:					
FUEL OIL ADJUSTMENT:	¢/KWH	5.414	$116,639.2	-	$0.0
RATE ADJUSTMENT (AES REFUND):	(%)	-0.400%	($1,057.3)	-	$0.0
TOTAL REVENUES			$379,853.7		$404,127.0

HAWAIIAN ELECTRIC COMPANY, INC.
Docket No. 04-0113, Test-Year 2005
SCHEDULE G - GENERAL SERVICE NON-DEMAND

ESTIMATE OF TEST YEAR REVENUES

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS	UNIT PRICE	REVENUES $1000S	UNIT PRICE	REVENUES $1000S
CUSTOMER CHARGE:	BILLS	$/month		$/month	
1 PHASE - Regular	193,448	20.00	$3,869.0	35.00	$6,770.7
3 PHASE - Regular	114,100	45.00	$5,134.5	60.00	$6,846.0
SUBTOTAL	307,548		$9,003.5		$13,616.7
ENERGY CHARGE:	(MWH)	¢/kWh		¢/kWh	
G: Regular NON-DEMAND	377,500	11.1570	$42,117.7	16.2616	$61,387.5
Total	377,500		$42,117.7		$61,387.5
BASE REVENUE ADJUSTMENTS:					
DP VOLTAGE ADJUSTMENT			($0.2)		($0.2)
DS VOLTAGE ADJUSTMENT			$0.0		$0.0
MINIMUM BILL ADJUSTMENT			$74.9		$75.5
SCHEDULE E ADJUSTMENT			$0.0		($67.0)
TOU-C ADJUSTMENT					($43.0)
SUBTOTAL			$74.7		($34.7)
TOTAL BASE REVENUE			$51,195.9		$74,969.5
Other Adjustments:		Rate		Rate	
FUEL OIL ADJUSTMENT:		5.414 ¢/KWH	$20,437.9	- ¢/KWH	$0.0
RATE ADJUSTMENT (AES REFUND):		(0.400) (%)	($204.8)	- (%)	$0.0
TOTAL REVENUES			$71,429.0		$74,969.5

HAWAIIAN ELECTRIC COMPANY, INC.
Docket No. 04-0113, Test-Year 2005
Schedule J - General Service Demand

Estimate of Test Year Revenues

	PRESENT RATES			PROPOSED RATES		
	BILLING UNITS	UNIT PRICE	REVENUES $000s	BILLING UNITS	UNIT PRICE	REVENUES $000s
ENERGY CHARGE:	(MWH)	¢/kWh		(MWH)	¢/kWh	
0 - 200 KWH/KW	1,164,831	8.6900	$101,223.8	1,206,650	13.6400	$164,587.1
201 - 400 KWH/KW	674,369	7.5419	$50,860.2	638,667	12.4919	$79,781.6
> 400 KWH/KW	173,800	6.5130	$11,319.6	167,683	11.4629	$19,221.3
TOTAL	2,013,000		$163,403.6	2,013,000		$263,590.0
DEMAND CHARGE:	kW	$/kW		kW	$/kW	
ALL BILLING KW	6,471,648	5.75	$37,212.0	6,741,296	8.50	$57,301.0
CUSTOMER CHARGE:	BILLS	$/month		BILLS	$/month	
1 PHASE	6,629	35.00	$232.0	6,629	50.00	$331.5
3 PHASE	73,531	60.00	$4,411.9	73,531	70.00	$5,147.2
SUBTOTAL	80,160		$4,643.9	80,160		$5,478.7
ADJUSTMENTS:						
POWER FACTOR ADJ.			($368.5)			($589.0)
TP VOLT. ADJ.			($29.7)			($41.6)
TS VOLT. ADJ.			($1.8)			($2.8)
DP VOLT. ADJ.			($400.3)			($709.9)
DS VOLT. ADJ.			($15.5)			($21.2)
NETWORK ADJ.			$0.0			$80.7
Schedule E Adjustment			$0.0			($213.6)
Schedule J - TOU Adjustment						($73.2)
SUBTOTAL			($815.8)			($1,570.6)
UNADJUSTED BASE REVENUE			$204,443.7			$324,799.1
RATE RIDER & OTHER REVENUE ADJ.						
RIDER M(B)			($169.6)			($214.3)
RIDER I			($47.3)			($104.2)
RIDER T			($388.4)			($450.4)
MULTIPLE RIDERS			($227.9)			($327.8)
SCHEDULE U			($339.3)			($301.1)
RIDER EDR			$0.0			$0.0
RULE 4 CHP CONTRACTS ADJ.			$0.0			$0.0
Total Rate Rider & Other Revenue Adjustments			($1,172.5)			($1,397.8)
Total Base Revenue			$203,271.2			$323,401.3
Fuel Oil Adjustment	¢/kWh	5.414	$108,983.8		-	$0.0
Rate Adjustment (AES Refund)	%	-0.400%	($813.1)		-	$0.0
TOTAL REVENUE			$311,441.9			$323,401.3

HAWAIIAN ELECTRIC COMPANY, INC.
Docket No. 04-0113, Test-Year 2005
SCHEDULE H - COMMERCIAL COOKING, HEATING, AIR CONDITIONING AND REFRIGERATION SERVICE

ESTIMATE OF TEST YEAR REVENUES

		PRESENT RATES			PROPOSED RATES		
	BILLING UNITS	UNIT PRICE		REVENUES $1000S	UNIT PRICE		REVENUES $1000S
	MWH	¢/kWh			¢/kWh		
ENERGY CHARGE:	53,400	7.7422		$4,134.3	13.8583		$7,400.3
	kW	$/kW			$/KW		
DEMAND CHARGE:	106,419	9.00		$957.8	9.00		$957.8
CUSTOMER CHARGE:	BILLS	$/month			$/month		
1 PHASE	3,989	20.00		$79.8	25.00		$99.7
3 PHASE	8,515	45.00		$383.2	60.00		$510.9
SUBTOTAL	12,504			$463.0			$610.6
SCHEDULE E ADJUSTMENT				$0.0			($6.4)
TOTAL BASE REVENUE				$5,555.1			$8,962.3
ADJUSTMENTS		Rate			Rate		
FUEL OIL ADJUSTMENT:		5.414	¢/KWH	$2,891.1	-	¢/KWH	$0.0
RATE ADJUSTMENT (AES REFUND):		(0.400)	(%)	($22.2)	-	(%)	$0.0
UNADJUSTED TOTAL REVENUE				$8,424.0			$8,962.3
RIDER ADJUSTMENTS				$0.0			$0.0
TOTAL REVENUES				$8,424.0			$8,962.3

HAWAIIAN ELECTRIC COMPANY, INC.
SCHEDULE PS - LARGE POWER SECONDARY VOLTAGE SERVICE
DOCKET NO. 04-0113 TEST-YEAR: 2005

ESTIMATE OF TEST YEAR REVENUES

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS	UNIT PRICE	REVENUES $1000S	UNIT PRICE	REVENUES $1000S
ENERGY CHARGE:	(MWH)	¢/kWh		¢/kWh	
0 - 200 KWH/KW	370,793	7.2087	$26,729.4	11.9578	$44,338.7
201 - 400 KWH/KW	340,776	6.4104	$21,845.1	11.1595	$38,028.9
> 400 KWH/KW	163,563	6.1010	$9,979.0	10.8503	$17,747.1
SUBTOTAL	875,132		$58,553.5		$100,114.7
DEMAND CHARGE:	(kW)	$/kW		$/kW	
0 - 500 KW	1,044,370	10.00	$10,443.7	16.35	$17,075.4
501 - 1500 KW	563,395	9.50	$5,352.3	15.85	$8,929.8
> 1500 KW	300,108	8.50	$2,550.9	14.85	$4,456.6
SUBTOTAL	1,907,873		$18,346.9		$30,461.8
	BILLS	$/month		$/month	
CUSTOMER CHARGE:	2,281	320.00	$729.9	350.00	$798.4
ADJUSTMENTS:					
POWER FACTOR ADJ.			($692.1)		($1,175.2)
NETWORK ADJ.			$135.5		$230.5
Schedule E Adjustment			$0.0		($78.7)
SUBTOTAL			($556.6)		($1,023.4)
UNADJUSTED BASE REVENUE			$77,073.7		$130,351.5
RATE RIDER & OTHER REVENUE ADJ.					
RIDER M (B)			($82.4)		($124.9)
RIDER I			($13.1)		($28.0)
RIDER T			($3.7)		($3.7)
RULE 4 CHP CONTRACTS ADJ.			$0.0		$0.0
Total Rate Rider & Other Revenue Adjustments			($99.2)		($156.6)
TOTAL BASE REVENUE			$76,974.5		$130,194.9
Fuel Oil Adjustment	¢/kWh	5.414	$47,379.6	-	$0.0
Rate Adjustment (AES Refund)	%	-0.400%	($307.9)	-	$0.0
TOTAL REVENUE			$124,046.2		$130,194.9

HAWAIIAN ELECTRIC COMPANY, INC.
SCHEDULE PP - LARGE POWER PRIMARY VOLTAGE SERVICE
DOCKET NO. 04-0113 TEST-YEAR: 2005

ESTIMATE OF TEST YEAR REVENUES

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS	UNIT PRICE	REVENUES $1000S	UNIT PRICE	REVENUES $1000S
ENERGY CHARGE:	(MWH)	¢/kWh		¢/kWh	
0 - 200 KWH/KW	808,210	7.0715	$57,152.6	11.9604	$96,665.1
201 - 400 KWH/KW	748,793	6.2884	$47,087.1	11.1772	$83,694.1
> 400 KWH/KW	611,525	5.9849	$36,599.2	10.8737	$66,495.4
SUBTOTAL	2,168,528		$140,838.9		$246,854.6
DEMAND CHARGE:	(kW)	$/kW		$/kW	
0 - 500 KW	953,027	9.81	$9,349.2	16.15	$15,391.4
501 - 1500 KW	959,481	9.32	$8,942.4	15.65	$15,015.9
> 1500 KW	2,390,098	8.34	$19,933.4	14.65	$35,014.9
SUBTOTAL	4,302,606		$38,225.0		$65,422.2
	BILLS	$/month		$/month	
CUSTOMER CHARGE:	1,991	320.00	$637.1	400.00	$796.4
ADJUSTMENTS:	(MWH)	¢/kWh		¢/kWh	
POWER FACTOR ADJ.			($1,790.6)		($3,122.8)
SECONDARY METERING ADJ.	22,522	0.1081	$24.3	0.2168	$48.8
Schedule E Adjustment			$0.0		($173.8)
SUBTOTAL			($1,766.3)		($3,247.8)
UNADJUSTED BASE REVENUE			$177,934.7		$309,825.4
RATE RIDER & OTHER REVENUE ADJ.					
RIDER M (B)			($861.5)		($1,349.4)
RIDER I			($164.6)		($280.5)
MULTIPLE RIDERS			($72.0)		($112.3)
RULE 4 CHP CONTRACTS ADJ.			$0.0		$0.0
Total Rate Rider & Other Revenue Adjustments			($1,098.1)		($1,742.2)
Total Base Revenue			$176,836.6		$308,083.2
Fuel Oil Adjustment	¢/kWh	5.414	$117,404.1	-	$0.0
Rate Adjustment (AES Refund)	%	-0.400%	($707.3)	-	$0.0
TOTAL REVENUE			$293,533.4		$308,083.2

HAWAIIAN ELECTRIC COMPANY, INC.
SCHEDULE PT - LARGE POWER TRANSMISSION VOLTAGE SERVICE
DOCKET NO. 04-0113 TEST-YEAR: 2005

ESTIMATE OF TEST-YEAR REVENUES

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS	UNIT PRICE	REVENUES $1000S	UNIT PRICE	REVENUES $1000S
ENERGY CHARGE:	(MWH)	¢/kWH		¢/kWH	
0 - 200 KWH/KW	63,629	6.9708	$4,435.5	11.7511	$7,477.1
201 - 400 KWH/KW	62,717	6.1989	$3,887.8	10.9792	$6,885.8
> 400 KWH/KW	47,394	5.8997	$2,796.1	10.6800	$5,061.7
SUBTOTAL	173,740		$11,119.4		$19,424.6
DEMAND CHARGE:	(kW)	$/kW		$/kW	
0 - 500 KW	24,003	9.67	$232.1	16.00	$384.0
501 - 1500 KW	48,006	9.19	$441.2	15.50	$744.1
> 1500 KW	246,335	8.22	$2,024.9	14.50	$3,571.9
SUBTOTAL	318,344		$2,698.2		$4,700.0
	BILLS	$/month		$/month	
CUSTOMER CHARGE:	48	320.00	$15.4	400.00	$19.2
ADJUSTMENTS:					
POWER FACTOR ADJ.			($82.9)		($144.7)
SECONDARY METERING ADJ.			$0.0		$0.0
Schedule E Adjustment			$0.0		($10.6)
SUBTOTAL			($82.9)		($155.3)
UNADJUSTED BASE REVENUE			$13,750.1		$23,988.5
Fuel Oil Adjustment	¢/kWH	5.414	$9,406.3	-	$0.0
Rate Adjustment (AES Refund):	%	-0.400%	($55.0)	-	$0.0
UNADJUSTED TOTAL REVENUE			$23,101.4		$23,988.5
RATE RIDER & OTHER REVENUE ADJ.					
RIDER M (B)			$0.0		$0.0
RIDER I			$0.0		$0.0
RIDER T			$0.0		$0.0
MULTIPLE RIDERS			$0.0		$0.0
RIDER EDR			$0.0		$0.0
SCHEDULE CHP			$0.0		$0.0
Total Rate Rider & Other Revenue Adjustments			$0.0		$0.0
TOTAL REVENUES			$23,101.4		$23,988.5

HAWAIIAN ELECTRIC COMPANY, INC.
Docket No. 04-0113, Test-Year 2005
SCHEDULE F - PUBLIC STREET LIGHTING SERVICE
HIGHWAY LIGHTING, & PARK & PLAYGROUND FLOODLIGHTING

ESTIMATE OF TEST-YEAR REVENUES

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS	UNIT PRICE	REVENUES $1000S	UNIT PRICE	REVENUES $1000S
CUSTOMER CHARGE:	Bills	$/month		$/month	
Customers	4,872	0.00	$0.0	20.00	$97.4
ENERGY CHARGE:	MWH	¢/kWh		¢/kWh	
0 - 150 KWH/KW	18,619	12.7049	$2,365.5	18.8659	$3,512.6
> 150 KWH/KW	21,681	8.7309	$1,892.9	14.8920	$3,228.7
SUBTOTAL	40,300		$4,258.4		$6,741.3
ADJUSTMENTS:					
MINIMUM BILL			$0.6		$0.0
SCHEDULE E ADJUSTMENT			$0.0		($6.3)
SECONDARY METERING ADJUSTMENT:			$13.5		$16.1
SUBTOTAL			$14.1		$9.8
UNADJUSTED BASE REVENUE:			$4,272.5		$6,848.5
FUEL OIL ADJUSTMENT:		5.414 ¢/kWh	$2,181.8	- ¢/kWh	$0.0
RATE ADJUSTMENT (AES REFUND):		(0.400) (%)	($17.1)	- (%)	$0.0
UNADJUSTED TOTAL REVENUE			$6,437.2		$6,848.5
RIDER ADJUSTMENTS			$0.0		$0.0
TOTAL REVENUES			$6,437.2		$6,848.5

Superseding Revised Sheet No. 50
Effective January 1, 2005

REVISED SHEET No. 50
Effective

RATE SCHEDULES

The following listed sheets contain all rates in effect on and after the date indicated thereon subject to the Rules and Regulations of the Company applicable thereto:

Sheet	Schedule	Date Effective	Character of Service
		(PAGE 50.1 - NOT ASSIGNED)	
51	R		Residential Service
51A	R		Residential Service
52	G		General Service Non-Demand
53	G		General Service Non-Demand
54	J		General Service Demand
54A	J		General Service Demand
54B	J		General Service Demand
54C	J		General Service Demand
55	H		Commercial Cooking, Heating, Air Conditioning & Refrigeration Service
56	H		Commercial Cooking, Heating, Air Conditioning & Refrigeration Service
57	PS		Large Power Secondary Voltage Service
58	PS		Large Power Secondary Voltage Service
58A	PS		Large Power Secondary Voltage Service
58B	PP		Large Power Primary Voltage Service
58C	PP		Large Power Primary Voltage Service
58D	PP		Large Power Primary Voltage Service
58E	PT		Large Power Transmission Voltage Service
58F	PT		Large Power Transmission Voltage Service
58G	PT		Large Power Transmission Voltage Service

Superseding Revised Sheet No. 50A
Effective June 1, 2001

REVISED SHEET NO. 50A
Effective

RATE SCHEDULES - (continued)

Sheet	Schedule	Date Effective	Character of Service
59	F		Public Street Lighting, Highway Lighting, & Park & Playground Floodlighting
60	F		Public Street Lighting, Highway Lighting, & Park & Playground Floodlighting
61	U		Time-of-Use Service
61A	U		Time-of-Use Service
61B	U		Time-of-Use Service
62	E		Electric Service for Employees
63	Energy Cost Adjustment Clause		All Schedules Except Schedule Q
63A	Energy Cost Adjustment Clause		All Schedules Except Schedule Q
63B	Energy Cost Adjustment Clause		All Schedules Except Schedule Q
64	Rider I		Interruptible Contract Service
65	Rider M		Off-Peak and Curtailable Service
65A	Rider M		Off-Peak and Curtailable Service
65B	Rider M		Off-Peak and Curtailable Service
65C	Rider M		Off-Peak and Curtailable Service
65D	Rider M		Off-Peak and Curtailable Service

(PAGE 66 - NOT ASSIGNED)

Superseding Sheet No. 50B
Effective June 1, 2005

REVISED SHEET NO. 50B
Effective

RATE SCHEDULES (continued)

Sheet	Schedule	Date Effective	Character of Service
67	Rider T		Time-of-Day Service
67A	Rider T		Time-of-Day Service
67B	Rider T		Time-of-Day Service
68	IRP Cost Recovery Provision		All Schedules Except Schedule Q
68A	IRP Cost Recovery Provision		All Schedules Except Schedule Q
		(PAGES 69-80 - NOT ASSIGNED)	
81	Q		Purchases From Qualifying Facilities -100 kW or Less
81A	Q		Purchases From Qualifying Facilities -100 kW or Less
81B	Q		Purchases From Qualifying Facilities -100 kW or Less
82	Green Pricing Program Provision		Green Pricing
82A	Green Pricing Program Provision		Green Pricing
83	Schedule TOU-C		Commercial Time-of-Use Service
84	Schedule TOU-C		Commercial Time-of-Use Service
85	Schedule TOU-C		Commercial Time-of-Use Service
85A	Schedule TOU-C		Commercial Time-of-Use Service

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113, D&O No. _____.

Superseding Sheet No. 50C
Effective January 1, 2004

REVISED SHEET NO. 50C
Effective

RATE SCHEDULES (continued)

Sheet	Schedule	Date Effective	Character of Service
86	Schedule TOU-R		Residential Time-of-Use Service
87	Schedule TOU-R		Residential Time-of-Use Service
88	Schedule TOU-R		Residential Time-of-Use Service

Superseding Revised Sheet No. 51
Effective January 1, 1997

REVISED SHEET NO. 51
Effective

SCHEDULE R

Residential Service

Availability:

Applicable to residential lighting, heating, cooking, air conditioning and power in a single family dwelling unit metered and billed separately by the Company. This Schedule does not apply where a residence and business are combined.

Service will be delivered at secondary voltages as specified by the Company.

Rate:

CUSTOMER CHARGE:

Single-Phase Service - per month	$10.00/month
Three-Phase Service - per month	$20.00/month

NON-FUEL ENERGY CHARGE (To be added to Customer Charge)

All kWhr per month - per kWhr	8.4415 ¢/kWhr

BASE FUEL/ENERGY CHARGE (To be added to Customer Charge and Non-Fuel Energy Charge)

All kWhr per month - per kWhr	8.8903 ¢/kWhr

Minimum Charge:

Single-Phase Service - per month	$20.00/month
Three-Phase Service - per month	$25.00/month

Apartment House Collection Arrangement:

Any apartment owner having three or more apartments at one location, each apartment being separately metered and billed on the above rate, may elect to accept a discount of ten percent (10%) of the amount of the total bills rendered for each apartment for each billing period, but not to exceed $5.00 per month for each apartment, upon entering into the following collection agreement with the Company under the following terms and conditions:

Superseding Revised Sheet No. 51A
Effective September 1, 1992

REVISED SHEET NO. 51A
Effective

SCHEDULE R - (continued)

1) All accounts shall be kept in the name of the apartment house owner who shall assume the responsibility for the prompt payment of all bills.

2) All accounts shall remain active at all times and, though vacant, shall be subject to the minimum charge. Individual apartments cannot be added or deleted from this agreement more often than once in twelve months.

3) The Company will render individual bills for each apartment on a regular billing period basis and will also furnish a statement showing gross and net billings.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 52
Effective January 1, 1997

REVISED SHEET NO. 52
Effective

SCHEDULE G

General Service Non-Demand

Availability:

Applicable to general light and/or power loads less than or equal to 5000 kilowatthours per month, and less than or equal to 25 kilowatts, and supplied through a single meter.

If a customer's usage exceeds 5000 kilowatthours per month or in the opinion of the Company exceeds 25 kilowatt of demand three times in a twelve-month period, a demand meter will be installed and the customer's billing will be transferred to Schedule "J" beginning with the next convenient billing period.

Service will be delivered at secondary voltages as specified by the Company, except where the nature or location of the customer's load makes delivery at secondary voltage impractical, the Company may, at its option, deliver the service at a nominal primary voltage as specified by the Company. Service supplied at primary voltage shall be subject to the special terms and conditions set forth below.

Rate:

CUSTOMER CHARGE:

Single-Phase Service - per month	$35.00/month
Three-Phase Service - per month	$60.00/month

ENERGY CHARGE: (To be added to Customer Charge)

All kWhr per month - per kWhr	16.2616 ¢/kWhr

Minimum Charge:

Single-Phase Service - per month	$40.00/month
Three-Phase Service - per month	$60.00/month

Primary Supply Voltage Service:

Where, at the option of the Company, service is delivered and metered at the primary supply line voltage, the above energy charges will be decreased by 2.1%. When customers' transformers are adjacent to the delivery point, the Company may permit the customer to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customers' transformers, the above energy charge will be decreased by 0.6%.

Superseding Revised Sheet No. 53
Effective September 1, 1992

REVISED SHEET NO. 53
Effective

SCHEDULE G -(continued)

Primary Supply Voltage Service - continued:

The Primary Supply Voltage Service will be closed to new customers after _____, 2005.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 54
Effective January 1, 1997

REVISED SHEET NO. 54
Effective

SCHEDULE J

General Service Demand

Availability:

Applicable to general light and/or power loads which exceed 5000 kilowatthours per month three times within a twelve-month period, or 25 kilowatts but less than 300 kilowatts per month, and supplied through a single meter.

Rate:

CUSTOMER CHARGE:

Single-Phase Service - per month	$50.00/month
Three-Phase Service - per month	$70.00/month

DEMAND CHARGE - (To be added to Customer Charge)

All kW of billing demand - per kW per month $8.50/kW

ENERGY CHARGE: (To be added to Customer and Demand Charges)

First	200 kWhr/month/kW of billing demand - per kWhr	13.6400¢/kWhr
Next	200 kWhr/month/kW of billing demand - per kWhr	12.4919¢/kWhr
All over	400 kWhr/month/kW of billing demand - per kWhr	11.4629¢/kWhr

Minimum Charge:

The minimum monthly charge shall be the sum of the Customer and the Demand Charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand, but not less than $212.50 per month. The kilowatts of demand for the minimum charge calculation each month shall be the highest of the maximum demand for the month, the greatest maximum demand of the preceding eleven months or 25 kW.

Determination of Demand:

The maximum demand for each month shall be the maximum average load in kW during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the highest of the maximum demand for such month, or the mean of maximum demand for the

Superseding Revised Sheet No. 54A
Effective January 1, 1996

REVISED SHEET NO. 54A
Effective

SCHEDULE J - (continued)

Determination of Demand - Continued

current month and the greatest maximum demand for the preceding eleven (11) months, whichever is the higher, but not less than 25 kW.

This Schedule is closed to new customers with kW demand equal to or greater than 300 kW after _____, 2005. Existing customers with maximum measured kW demand equal to, or greater than 300 kW per month may continue to receive service under this Schedule, until the customer transfers to other applicable rate schedule.

Power Factor:

The above demand and energy charges are based upon an average monthly power factor of 85%. For customers with maximum measured demands in excess of 200 kilowatts per month for one time within a twelve-month period, the following power factor adjustment will apply for all succeeding billing periods.

For each 1% the average power factor is above or below 85%, the energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%. The power factor will be computed to the nearest whole percent.

In no case, however, shall the power factor be taken as more than 100% for the purpose of computing the adjustment.

The average monthly power factor will be determined from the readings of a kWh meter and a Kvarh meter. The Kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Superseding Revised Sheet No. 54B
Effective September 1, 1992

REVISED SHEET NO. 54B
Effective

SCHEDULE "J" (continued)

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	3.0%
Distribution voltage supplied without further transformation	2.1%

Metering will normally be at the delivery voltage. When customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 2.4% and 0.6%, respectively.

NETWORK SERVICE ADJUSTMENT:

Because of the inherent operating conditions in the downtown area supplied from the Company's underground network system, the Company will deliver and meter the service to customers in this area at 120/208Y or 277/480Y volts. The demand and energy charges will be increased by 0.9%.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges, Supply Voltage Delivery Adjustment, Power Factor Adjustment, and Network Service Adjustment.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy Charges, Supply Voltage Delivery Adjustment, Power Factor Adjustment, Network Service Adjustment, and energy cost adjustment.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113, D&O No. _____.

REVISED SHEET NO. 54C
Effective

SCHEDULE J - (continued)

Term of Contract:

Not less than five years beginning from the service start date. If service is terminated before the end of the initial contract term, the customer shall be charged a termination fee equal to the total connection costs incurred by the Company to serve the customer less customer advance and/or contribution paid by the customer.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 55
Effective January 1, 1997

REVISED SHEET NO. 55
Effective

SCHEDULE "H"

Commercial Cooking, Heating
Air Conditioning and Refrigeration Service

Availability:

Applicable to commercial cooking, heating (including heat pump waterheaters), air conditioning and refrigeration service. This schedule applies only where the voltage supplied by the Company is less than 600 volts.

Rate:

CUSTOMER CHARGE:

Single phase service - per month	$25.00
Three phase service - per month	$60.00

DEMAND CHARGE: (To be added to Customer Charge)

$9.00 per kw per month of required kw load, but in no case less than $9.00 per month.

ENERGY CHARGE: (To be added to Customer and Demand Charges)

All kwhr per month - per kwhr 13.8583 ¢/kWhr

Minimum Charge:

The minimum monthly charge shall be the sum of Customer and Demand Charges.

Determination of Required kw load:

The required kw load for billing purposes shall be:

A. The sum of:

1) The total connected motor load;
2) 50% of the connected heating load, exclusive of cooking and all-electric resistance and heat pump waterheating; and
3) the connected all-electric waterheating load in excess of one-sixth kilowatt per gallon of storage capacity; or

Superseding Revised Sheet No. 56
Effective September 1, 1992

REVISED SHEET NO. 56
Effective

SCHEDULE "H" (continued)

B. When the load is 25 KW or more the demand may be determined by measured demand. The maximum demand for each month shall be the maximum average load during any fifteen-minute period as indicated by a demand meter. The demand for each month shall be the maximum demand for such month, the highest demand in the preceding eleven months, or 25 KW, whichever is highest. Measured demand service under this schedule will be referred to as Schedule "K" service. The Schedule K service will be closed to new customers after August 31, 1992.

The required kw load will be determined to the nearest one-tenth kw.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy Charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Term of Contract:

Not less than one year.

Superseding Revised Sheet No. 57
Effective June 1, 2001

REVISED SHEET NO. 57
Effective

SCHEDULE PS

LARGE POWER SECONDARY VOLTAGE SERVICE

AVAILABILITY:

Applicable to large light and/or power loads equal or greater than 300 kilowatts, supplied and metered at a single voltage and delivery point. Service under this Schedule shall be delivered at a secondary voltage specified by the Company.

RATES:

CUSTOMER CHARGE - $ per customer per month:	$350.00/month
DEMAND CHARGE - $ per kW of billing demand:	
First 500 kW of billing demand - per kW	$16.35/kW
Next 1000 kW of billing demand - per kW	$15.85/kW
Over 1500 kW of billing demand - per kW	$14.85/kW
ENERGY CHARGE - ¢ per kWh:	
First 200 kWh/month/kW of billing demand - per kWhr	11.9578¢/kWhr
Next 200 kWh/month/kW of billing demand - per kWhr	11.1595¢/kWhr
Over 400 kWh/month/kW of billing demand - per kWhr	10.8503¢/kWhr

NETWORK SERVICE ADJUSTMENT:

Because of the inherent operating conditions in the downtown area supplied from the Company's underground network system, the Company will deliver and meter the service to customers in this area at 120/208Y or 277/480Y volts. The demand and energy charges will be increased by 0.9%.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No.04-0113; D&O No. _____.

Superseding Revised Sheet No. 58
Effective June 1, 2001

REVISED SHEET NO. 58
Effective

SCHEDULE PS - (continued)

MINIMUM CHARGE:

The minimum monthly charge shall be the sum of the Customer and Demand charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall be the highest of the maximum demand for the month, the greatest maximum demand for the preceding eleven months, or 300 kW.

DETERMINATION OF DEMAND:

The maximum demand for each month shall be the maximum average load in kW during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the highest of the maximum demand for such month, or the mean of maximum demand for the current month and the greatest maximum demand for the preceding eleven (11) months, whichever is the higher, but not less than 300 kW.

Power Factor:

The above demand and energy charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed above, shall be decreased or increased, respectively, by 0.10%. The power factor will be computed to the nearest whole percent.

Superseding Revised Sheet No. 58A
Effective June 1, 2001

REVISED SHEET NO. 58A
Effective

Schedule PS - (continued)

Power Factor - continued

In no case, however, shall the power factor be taken as more than 100% for the purpose of computing the adjustment.

The average monthly power factor will be determined from the readings of a kWhr and Kvarh meter. The Kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges, Network Service adjustment, and Power Factor adjustment.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, Network Service adjustment, Power Factor adjustment, and energy cost adjustment.

TERM OF CONTRACT:

Not less than five years beginning from the service start date. If service is terminated before the end of the contract term, the customer shall be charged a termination fee equal to the total connection costs incurred by the Company to serve the customer less customer advance and/or contribution paid by the customer.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No.04-0113; D&O No. _____.

Superseding SHEET NO. 58B
Effective June 1, 2001

REVISED SHEET NO. 58B
Effective

SCHEDULE PP

LARGE POWER PRIMARY VOLTAGE SERVICE

AVAILABILITY:

Applicable to large light and/or power loads equal or greater than 300 kilowatts, supplied and metered at a single voltage and delivery point. Service under this Schedule shall be delivered at a primary voltage specified by the Company.

RATES:

CUSTOMER CHARGE - $ per customer per month:	$400.00/month
DEMAND CHARGE - $ per kW of billing demand:	
First 500 kW of billing demand - per kW	$16.15/kW
Next 1000 kW of billing demand - per kW	$15.65/kW
Over 1500 kW of billing demand - per kW	$14.65/kW
ENERGY CHARGE - ¢ per kWh:	
First 200 kWh/month/kW of billing demand - per kWhr	11.9604¢/kWhr
Next 200 kWh/month/kW of billing demand - per kWhr	11.1772¢/kWhr
Over 400 kWh/month/kW of billing demand - per kWhr	10.8737¢/kWhr

SECONDARY METERING ADJUSTMENT FOR SERVICE AT PRIMARY VOLTAGE:

Metering will normally be at the delivery point. For services delivered at primary voltage and metered on the secondary side of the customer's transformers which are adjacent to the delivery point, and where the metering point is approved by the Company, a secondary metering adjustment of 0.2168 ¢/kWhr shall be added to the above energy charge.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No.04-0113; D&O No. _____.

Superseding SHEET NO. 58C
Effective June 1, 2001

REVISED SHEET NO. 58C
Effective

SCHEDULE PP - (continued)

MINIMUM CHARGE:

The minimum monthly charge shall be the sum of the Customer and Demand charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall be the highest of the maximum demand for the month, the greatest maximum demand for the preceding eleven months, or 300 kW.

DETERMINATION OF DEMAND:

The maximum demand for each month shall be the maximum average load in kW during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the highest of the maximum demand for such month, or the mean of maximum demand for the current month and the greatest maximum demand for the preceding eleven (11) months, whichever is the higher, but not less 300 kW.

Power Factor:

The above demand and energy charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed above, shall be decreased or increased, respectively, by 0.10%. The power factor will be computed to the nearest whole percent. In no case, however, shall the power factor be taken as more than 100% for the purpose of computing the adjustment.

The average monthly power factor will be determined from the readings of a kWhr and Kvarh meter. The Kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Superseding SHEET NO. 58D
Effective June 1, 2001

REVISED SHEET NO. 58D
Effective

Schedule PP - (continued)

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges, Secondary Metering adjustment, and Power Factor adjustment.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, Secondary Metering Adjustment, Power Factor, and energy cost adjustment.

TERM OF CONTRACT:

Not less than five years beginning from the service start date. If service is terminated before the end of the contract term, the customer shall be charged a termination fee equal to the total connection costs incurred by the Company to serve the customer less customer advance and/or contribution paid by the customer.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

Superseding SHEET NO. 58E
Effective June 1, 2001

REVISED SHEET NO. 58E
Effective

SCHEDULE PT

LARGE POWER TRANSMISSION VOLTAGE SERVICE

AVAILABILITY:

Applicable to large light and/or power loads equal or greater than 300 kilowatts, supplied and metered at a single voltage and delivery point. Service under this Schedule shall be delivered at transmission voltage specified by the Company.

RATES:

CUSTOMER CHARGE - $ per customer per month:	$400.00/month
DEMAND CHARGE - $ per kW of billing demand:	
First 500 kW of billing demand - per kW	$16.00/kW
Next 1000 kW of billing demand - per kW	$15.50/kW
Over 1500 kW of billing demand - per kW	$14.50/kW
ENERGY CHARGE - ¢ per kWhr:	
First 200 kWh/month/kW of billing demand - per kWhr	11.7511 ¢/kWhr
Next 200 kWh/month/kW of billing demand - per kWhr	10.9792 ¢/kWhr
Over 400 kWh/month/kW of billing demand - per kWhr	10.6800 ¢/kWhr

SECONDARY METERING ADJUSTMENT FOR SERVICE AT TRANSMISSION VOLTAGE:

Metering will normally be at the delivery point. For services delivered at transmission voltage and metered on the secondary side of the customer's transformers which are adjacent to the delivery point, and where the metering point is approved by the Company, the above demand and energy charges shall be increased by 0.6%.

Superseding SHEET NO. 58F
Effective June 1, 2001

REVISED SHEET NO. 58F
Effective

SCHEDULE PT - (continued)

MINIMUM CHARGE:

The minimum monthly charge shall be the sum of the Customer and Demand charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall be the highest of the maximum demand for the month, the greatest maximum demand for the preceding eleven months, or 300 kW.

DETERMINATION OF DEMAND:

The maximum demand for each month shall be the maximum average load in kW during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the highest of the maximum demand for such month, or the mean of maximum demand for the current month and the greatest maximum demand for the preceding eleven (11) months, whichever is the higher, but not less than 300 kW.

Power Factor:

The above demand and energy charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed above, shall be decreased or increased, respectively, by 0.10%. The power factor will be computed to the nearest whole percent. In no case, however, shall the power factor be taken as more than 100% for the purpose of computing the adjustment.

The average monthly power factor will be determined from the readings of a kWhr meter and Kvarh meter. The Kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Superseding SHEET NO. 58G
Effective June 1, 2001

REVISED SHEET NO. 58G
Effective

Schedule PT - (continued)

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges, Secondary Metering adjustment, and Power Factor adjustment.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, Secondary Metering adjustment, Power Factor adjustment, and energy cost adjustment.

TERM OF CONTRACT:

Not less than five years beginning from the service start date. If service is terminated before the end of the contract term, the customer shall be charged a termination fee equal to the total connection costs incurred by the Company to serve the customer less the customer advance and/or contribution paid by the customer.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 59
Effective January 1, 1997

REVISED SHEET NO. 59
Effective

SCHEDULE F

Public Street Lighting, Highway Lighting and
Park and Playground Floodlighting

Availability:

Applicable only to public street and highway lighting, and public outdoor park and playground floodlighting service where the customer owns, maintains and operates the lighting fixtures and interconnecting circuits and conversion equipment. This rate is applicable to gaseous discharge lighting (Mercury Vapor) provided the regulator is corrected to power factor equivalent to the addition of one (1) KVAR of capacitors for each kW of name plate rating of the regulator. Under this schedule energy shall be supplied and metered at a nominal voltage of 2400 volts or more, as specified by the Company, except as set forth below under Special Terms and Conditions.

Rate:

CUSTOMER CHARGE:
$20.00 per month for each point of delivery.

ENERGY CHARGE - ¢ per kWhr:

First 150 kWhr/month/kW of billing demand - per kWhr	18.8659	¢/kWhr
All over 150 kWhr/month/kW of billing demand - per kWhr	14.8920	¢/kWhr

Minimum Charge:

$35.00 per month for each point of delivery.

Determination of Demand:

The maximum demand for each month shall be the maximum average load in kW during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the maximum demand for such month but not less than 50% of the greatest maximum demand for the preceding eleven months.

Optional Secondary Metering for Street and Highway Lighting:

The street and highway lighting customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the energy charge will be increased by 1.5%.

Superseding Revised Sheet No. 60
Effective September 1, 1992

REVISED SHEET NO. 60
Effective

SCHEDULE F - (continued)

Special Terms and Conditions:

Multiple street lighting lamps may be individually served unmetered at secondary voltage along public streets and highways when, (1) in an overhead area, secondary voltage is available on the lamp pole or (2), in an underground area, secondary voltage is available along the public street. The total connected lamp load per connection point shall not exceed 2 KW. A one-year contract is required for service under this provision and each such contract will remain in effect from year to year thereafter unless, after the first year, terminated by 30 days notice in writing. Each contract will constitute a point of delivery. The monthly billing demand will be the connected lamp load expressed in kilowatts times 1.02 to the nearest one-tenth kilowatt, and the monthly billing kilowatt-hours will be 340 times the billing demand. The customer will provide a switching device for each lamp to limit the annual burning time to not more than 4100 hours.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Sheet No. 61
Effective January 1, 1995

REVISED SHEET NO. 61
Effective

SCHEDULE U

TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads equal to or greater than 300 kilowatts per month and supplied and metered at a single voltage and delivery point. This Schedule cannot be used in conjunction with load management Riders M, T, and I.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods shall be as follows:

On-Peak Period: 7:00 a.m. - 9:00 p.m., daily
Priority Peak Period: 5:00 p.m. - 9:00 p.m., Monday through Friday
Mid-Peak Period: All On-Peak hours outside of Priority Peak hours
Off-Peak Period: 9:00 p.m. - 7:00 a.m., daily

RATE:

CUSTOMER CHARGE - per month $350.00/month

DEMAND CHARGE - (To be added to Customer Charge)

Priority Peak	- per kW of billing demand	$18.00/kW
Mid-Peak	- per kW of billing demand	$16.00/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE - (To be added to Customer and Demand Charges)

All On-Peak kWhr per month	- per kWhr	13.4400 ¢/kWhr
All Off-Peak kWhr per month	- per kWhr	10.0000 ¢/kWhr

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113, D&O No. _____.

Superseding Sheet No. 61A
Effective January 1, 1995

REVISED SHEET NO. 61A
Effective

SCHEDULE U - (continued)

Minimum Charge:

The monthly minimum charge shall be the sum of the Customer and the Demand Charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of billing demand for the minimum charge calculation for each month shall be the highest of the maximum on-peak demands for such month but not less than 300 kW.

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-day rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The on-peak kilowatts of billing demand for each month shall be the maximum on-peak demand for such month but not less than 300 kilowatts.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Special Terms and Conditions:

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation -3.0%
Distribution voltage supplied without further transformation -2.1%

Superseding Sheet No. 61B
Effective January 1, 1996

REVISED SHEET NO. 61B
Effective

SCHEDULE U -(continued)

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 2.4% and 0.6%, respectively.

Because of the inherent operating conditions in the downtown area supplied from the Company's underground network system the Company will deliver and meter service to customers in this area at 120/208Y or 277/480Y volts (See Rule 2). The demand and energy charges will be increased 0.9%.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges, Service Voltage adjustment, Network Service adjustment, and Power Factor adjustment.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, Service Voltage adjustment, Network Service adjustment, Power Factor adjustment, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

TERM OF CONTRACT:

Not less than five years beginning from the service start date. If service is terminated before the end of the contract term, the customer shall be charged the total connection costs incurred by the Company to serve the customer less any customer advance and/or contribution paid by the customer.

Superseding Revised Sheet No. 62
Effective August 21, 1972

REVISED SHEET NO. 62
Effective June 1, 1996

SCHEDULE E

Electric Service for Employees

Availability:

Applicable to all regular full-time Company employees, Company retirees, members of the Company Board of Directors, and retirees of Hawaii Electric Light Company, Inc. and Maui Electric Company, Ltd. who retired on or after January 1, 1996 and who are served by Hawaiian Electric Company, Inc. This schedule is applicable to the above customers' residential electric service in a single family dwelling unit metered and billed separately by the Company, subject to the Special Terms and Conditions specified below. This schedule does not apply where a residence and business are combined.

Rate:

The rates applicable to service under this schedule shall be two-thirds (2/3) of the current effective Schedule R rates - Residential Service, for usage up to 825 kwh per month. Energy usage above 825 kwh shall be charged the full Schedule R energy rates.

Special Terms and Conditions:

1. "Regular full-time Company employee" is defined as an employee who has successfully completed any required probationary requirements, is hired for an indefinite period, and who works no less than 40 hours per week.

2. This schedule is applicable only to primary residences.

3. Availability of this schedule terminates six months after death of eligible employee, retiree, or member of the Board of Directors.

Rules and Regulations:

Service supplied under this schedule shall be subject to the Rules and Regulations of the Company.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 7766
Decision and Order No. 14412

Superseding Revised Sheet No. 63
Effective January 1, 1996

REVISED SHEET NO. 63
Effective

ENERGY COST ADJUSTMENT CLAUSE

Applicable To

Schedule R	- Residential Service
Schedule E	- Electric Service for Employees
Schedule G	- General Service - Non-Demand
Schedule J	- General Service - Demand
Schedule H	- Commercial Cooking, Heating, Air Conditioning and Refrigeration Service
Schedule PS	- Large Power Secondary Voltage Service
Schedule PP	- Large Power Primary Voltage Service
Schedule PT	- Large Power Transmission Voltage Service
Schedule F	- Public Street Lighting, Highway Lighting and Park and Playground Floodlighting
Schedule U	- Time-of-Use Service
Schedule TOU-R	- Residential Time-of-Use Service
Schedule TOU-C	- Commercial Time-of-Use Service

All terms and provisions of Schedules R, E, G, J, H, PS, PP, PT, F, U, TOU-R, and TOU-C are applicable, except that the Energy Cost Adjustment described below will be added to the customer bills.

All base rate schedule discounts, surcharges, and all other adjustments will not apply to the energy cost adjustment.

Energy Cost Adjustment Clause:

This Energy Cost Adjustment Clause shall include the following:

FUEL AND PURCHASED ENERGY - The above rates are based on the cost of fuel for Company generation (exclusive of company-owned distributed generation(DG)) of 869.64 cents per million Btu for fuel delivered in its service tanks, 14.076 cents per kilowatthour of company-owned DG generation for fuel delivered to the fuel tank at the site used for the company-owned DG, and the cost of purchased energy of 5.568 cents per kilowatthour. Company-generated energy from non-fuel sources shall be considered as zero fuel cost in the determination of the composite fuel cost. When the Company-generated net energy cost is more or less than 869.64 cents per million Btu, and/or the company-owned DG energy cost is more or less than 14.076 cents per kilowatthour, and/or the purchased energy cost is more or less than 5.568 cents per kilowatthour, a corresponding

Energy Cost Adjustment Clause - (continued)

adjustment(Energy Cost Adjustment Factor) to the energy charges shall be made. This adjustment shall be comprised of a Company Generation Component, a DG Generation Component and a Purchased Energy Component.

The Company Generation Component shall be the difference between the current generation cost and the base generation cost, adjusted for additional revenue taxes. The current generation cost shall be determined by the current fuel cost in cents per million Btu, multiplied by a generation conversion factor of 0.011140 million Btu per kilowatthour, weighted by the proportion of current Company generation (exclusive of company-owned DG) to total system net energy in kilowatthours. The base generation cost is the base fuel cost of 869.64 cents per million Btu multiplied by a generation conversion factor of 0.011140 million Btu per kilowatthour, weighted by the proportion of the 2005 test year generation to total system net energy in kilowatthours.

The DG Energy Component shall be the difference between the current cost of DG energy in cents per kilowatthour weighted by the proportion of current company-owned DG energy to total system net energy, and the base DG energy cost of 14.076 cents per kilowatthour weighted by the proportion of the 2005 test year DG energy to total system net energy, adjusted to the sales delivery level and for revenue taxes.

The Purchased Energy Component shall be the difference between the current purchased energy cost weighted by the proportion of current purchased energy to total system net energy, and the base purchased energy cost of 5.568 cents per kilowatthour weighted by the proportion of the 2005 test year purchased energy to total system net energy, adjusted to the sales delivery level and for additional revenue taxes.

The Energy Cost Adjustment Factor shall be the sum of the Generation Component, the DG Energy Component and the Purchased Energy Component.

The revenue tax requirement shall be calculated using current rates of the Franchise Tax, Public Service Company Tax, and Public Utility Commission fee.

The Energy Cost Adjustment shall be effective on the date of cost change. When a cost change occurs during a customer's billing period, the Energy Cost Adjustment will be prorated for the number of days each cost was in effect.

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Energy Cost Adjustment Clause -(continued)

This Energy Cost Adjustment Clause is consistent with the terms of the Company's operations, purchased energy contracts, and DG contracts, and may be revised to reflect any revisions or changes in the Company's operations, purchased energy contracts, and DG contracts, subject to approval by the Commission.

Reconciliation Adjustment:

In order to reconcile any differences that may occur between recorded and forecasted Energy Cost Adjustment Clause revenues, the year-to-date recorded revenue from the Energy Cost Adjustment Clause will be compared with the year-to-date revenue expected from the Energy Cost Adjustment Clause on a quarterly basis. If there is a variance between the recorded Energy Cost Adjustment Clause revenue and the expected Energy Cost Adjustment Clause revenue, an adjustment, lagged by two months, shall be made to the Energy Cost Adjustment Clause to reconcile the revenue variance over the sales estimated for the subsequent quarter.

Superseding Sheet No. 64
Effective January 1, 1986

REVISED SHEET NO. 64
Effective

RIDER I

Interruptible Contract Service

Availability:

This Rider is applicable to service supplied and metered at a single voltage and delivery point where 100 kW or greater is subject to disconnection by the utility under the terms and conditions as set forth in the contract agreement.

Rates:

Reduction in demand charge as set forth in a contract between the customer and the utility and approved by the Public Utilities Commission.

Term of Contract:

Not less than five years.

Superseding Revised Sheet No. 65
Effective February 1, 1998

REVISED SHEET NO. 65
Effective

RIDER M

Off-Peak and Curtailable Service

AVAILABILITY:

This Rider is available to customers served under rate Schedule J, PS, PP, or PT, whose maximum measured demands prior to any load modifications effected under this rider, exceed 100 and 300 kilowatts, respectively. This Rider cannot be used in conjunction with Rider T, Rider I, Schedule U, and Schedule TOU-C.

RATES:

A. Basic Rates

The rate(s) for service under this Rider shall be as specified under the regular Schedule J, PS, PP, or PT whichever is applicable, except that the Minimum Charge and the determination of billing demand used in the calculation of demand and energy charges shall be as defined below, subject to the requirements under the Determination of Demand provision of the applicable rate schedule.

The customer shall select Option A - Off-Peak Service or Option B - Curtailable Service:

OPTION A - OFF-PEAK SERVICE:

1) Any demand occurring during the off-peak period shall not be considered in determining the billing kW demand for each month, but shall be used in determining the excess off-peak charge. Only the maximum kW demand occurring during the on-peak period shall be used in the determination of the billing kW demand for the calculation of the demand charge, energy charge and minimum charge as specified in the regular Schedule J, PS, PP, or PT.

2) An excess Off-Peak Charge of $2.00 per kilowatt shall be added to the regular rate schedule charges for each kilowatt that the maximum off-peak demand exceeds the maximum demand during of the on-peak period.

RIDER M - (continued)

OPTION A - continued:

3) For calculation of the excess off-peak charge for each month, the maximum off-peak demand and maximum demand during the on-peak period shall be the highest measured demands during the respective periods for such month.

4) The time-of-use rating period shall be defined as follows:

On-Peak Period: 7 a.m. - 9 p.m. Fourteen hours, Daily

Off-Peak Period: 9 p.m. - 7 a.m. Ten hours, Daily

5) The monthly minimum charge shall be the sum of the customer charge, demand charge, Excess Off-Peak Charge, and Time-of-Day Metering Charge specified below.

OPTION B - CURTAILABLE SERVICE:

1) A customer who chooses curtailable service shall curtail his/her kW demand during the Company's curtailment hours, and shall indicate the load that he/she is willing to curtail. This curtailable load must be load that is normally operated during the Company's curtailment hours and must be at least 50 horsepower for motor loads served under Schedule J, and 150 horsepower for motor loads served under Schedule PS, PP, and PT, or 50 and 150 kilowatts for other than motor loads, respectively.

2) The Company may install a meter, in accordance with Rule 14, to measure the customer's curtailable load prior to the start of curtailable service under this Rider.

3) For billing purposes, the curtailed kW demand shall be determined monthly as the difference between the maximum kW demands outside of the curtailment hours and the maximum kW

Superseding Revised Sheet No. 65B
Effective February 1, 1998

REVISED SHEET NO. 65B
Effective

RIDER M - (continued)

OPTION B - continued:

demand during the curtailment hours measured for each month, but not to exceed the curtailable kW load specified in the customer's Rider M contract.

4) The customer shall choose one of the curtailment periods specified below. The billing demand under this curtailable service option shall be the normal billing demand under Schedule J, PS, PP, or PT reduced by:

Option 1) 75% of the curtailed kilowatt demand if the curtailment period is fixed throughout the year from 5 p.m. to 9 p.m., Monday through Friday; or

Option 2) 40% of the curtailed kilowatt demand if the curtailment period is two (2) consecutive hours as specified by the Company.

5) The monthly minimum charge shall be the sum of the customer charge, demand charge, and the Time-of-Day Metering Charge specified below.

Where the Company specifies the curtailment period, the Company shall give the customer at least 30 days notice prior to changing the curtailment period.

B. TIME-OF-DAY METERING CHARGE:

The Company shall install a time-of-use meter to measure the customer's maximum kW load during the time-of-day rating periods and curtailment periods.

An additional time-of-day metering charge of $10.00 per month shall be assessed to cover the additional cost of installing, operating, and maintaining a time-of-use meter.

Superseding Revised Sheet No. 65C
Effective February 1, 1998

REVISED SHEET NO. 65C
Effective

RIDER M - (continued)

C. TERMS OF CONTRACT:

1. The initial term of contract shall be at least 5 years. Thereafter, the contract shall continue from year-to-year until terminated by either party by a 30-day written notice.

2. A customer applying for service under this Rider shall sign a standard Rider M contract form with the Company.

3. The customer shall be allowed to take service under this Rider for a six-month trial period without penalty for termination within this period.

4. If the contract is terminated after the first six-months trial period, but before the first five-year period which begins from the start date of the customer's service under this Rider, the customer shall be assessed a termination charge equal to the last six months discount received under this Rider.

5. The customer may request a change of Rider options (Option A - Off-Peak Service or Option B - Curtailable Service) or curtailment hours (Options 1 or 2 under Curtailable Service) by providing a 30-day written notice to the Company. The change will become effective after the next regular meter reading following the receipt of such written notice by the Company, provided however, the Company may not be required to make such change until 12 months of service has been rendered after the last change, unless a new or revised Rider has been authorized, or unless a customer's operating conditions have altered so as to warrant such change.

6. If under the curtailable service option the customer fails to curtail his maximum demand during the curtailment period three times within a twelve-month period, the Company may terminate the Rider M contract by a 30-day written notice to the customer. If service under this Rider

Superseding Sheet No. 65D
Effective February 1, 1998

Revised SHEET NO. 65D
Effective

RIDER M - (continued)

C. TERMS OF CONTRACT - continued:

is terminated due to the customer's failure to curtail his demand as provided in the contract, the customer shall be assessed a termination charge equal to the last six months discount received under this Rider.

7. Service supplied under this Rider shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 67 REVISED SHEET NO. 67
Effective January 1, 1995 Effective

RIDER T
TIME-OF-DAY RIDER

AVAILABILITY:

This rider is available to customers on rate Schedule J, PS, PP, or PT but cannot be used in conjunction with the load management Rider M, Rider I, Schedule U, and Schedule TOU-C.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods under this Rider shall be as follows:

On-Peak Period: 7:00 a.m. - 9:00 p.m., Daily
Off-Peak Period: 9:00 p.m. - 7:00 a.m., Daily

RATE:

The rate(s) for service under this Rider including the Customer Charge, Energy Charge, and Demand Charge shall be as specified in the regular rate Schedule J, PS, PP, or PT except that the following charges shall be added:

TIME-OF-DAY METERING CHARGE - per month $10.00

TIME-OF-DAY ENERGY CHARGE ADJUSTMENTS:

On-Peak Energy Surcharge - all on-peak kwh +2.00 cents/kwh
Off-Peak Energy Credit - all off-peak kwh -3.00 cents/kwh

MINIMUM CHARGE:

The Minimum Charge shall be as specified under the regular rate schedule except that it shall include the Time-of-Day Metering Charge. In addition, the monthly average energy charge computed from the regular energy charge and the above Time-of-Day energy charge adjustments including the energy cost adjustment, cannot be lower than the off-peak avoided energy cost at the metering point.

DETERMINATION OF DEMAND:

The Determination of Demand shall be as specified in the regular rate schedule, except that only the on-peak Kw demand shall be used in the determination of the kilowatts of billing demand for the Demand Charge, the regular Energy Charge and the Minimum Charge calculations.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113, D&O No. _____.

Superseding Revised Sheet No. 67A
Effective January 1, 1995

REVISED SHEET NO. 67A
Effective

Rider T (Continued)

VOLTAGE SERVICE AND POWER FACTOR ADJUSTMENTS:

The voltage service and power factor adjustments shall be as specified in the regular rate schedule.

MEASUREMENT OF TIME-OF-DAY ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's energy consumption and maximum kW demand during the time-of-day rating periods.

TERMS OF AGREEMENT:

A customer applying for service under this Rider shall sign a standard Rider T contract form with the Company. Service under this Rider shall not be less than five years. The customer may terminate service under this Rider during the first six months without penalty. If the customer terminates service after the first six months but before the end of the first five-year period which begins from the start date of the customer's service under this Rider, the customer shall be charged a termination fee equal to the amount of the last six months of discount received under this Rider.

A customer may perform emergency maintenance on his equipment or load served under this rider during the on-peak period and the customer's maximum demand during that time will not be considered in the determination of the billing kW demand under the following conditions:

a. The conditions under which the customer may perform emergency maintenance on his equipment or load during on-peak period will be defined in the customer's contract.

b. The customer may perform such emergency maintenance during on-peak period only when approved by HECO, and will operate only for the duration approved by HECO. Such HECO approval shall be by phone, or by e-mail, or in writing to the customer.

c. The customer must notify HECO as far in advance as possible, but not less than 1 hour before performing such emergency maintenance on his equipment or load during the on-peak period. Such notice shall be by phone, by e-mail, or in writing. HECO may approve the customer's request on capacity availability

Rider T - (continued)

basis. Service to the customer under this condition may be interrupted at any time when HECO's system conditions dictate the necessity to interrupt service, or when in HECO's sole judgment the system may be impaired or the startup of another unit would be uneconomic.

d. The customer's request to operate its load during the on-peak period under this condition cannot exceed four (4) times within a 12-month period.

Superseding Revised Sheet No. 68
Effective June 1, 2005

REVISED SHEET NO. 68
Effective

INTEGRATED RESOURCE PLANNING
COST RECOVERY PROVISION

Supplement To

Schedule R	- Residential Service
Schedule E	- Electric Service For Employees
Schedule G	- General Service Non-Demand
Schedule J	- General Service Demand
Schedule H	- Commercial Cooking, Heating, Air Conditioning and Refrigeration Service
Schedule PS	- Large Power Secondary Voltage Service
Schedule PP	- Large Power Primary Voltage Service
Schedule PT	- Large Power Transmission Voltage Service
Schedule F	- Public Street Lighting, Highway Lighting and Park and Playground Floodlighting
Schedule U	- Time of Use Service
Schedule TOU-R	- Residential Time-of-Use Service
Schedule TOU-C	- Commercial Time-of-Use Service

All terms and provisions of Schedules R, E, G, J, H, PS, PP, PT, F, U, TOU-R, and TOU-C are applicable except that the total base rate charges for each billing period shall be increased by the following Integrated Resource Planning (IRP) Cost Recovery Adjustment, Residential Demand Side Management (DSM) Adjustment, and Commercial and Industrial Demand Side Management (DSM) Adjustment:

A: INTEGRATED RESOURCE PLANNING COST RECOVERY ADJUSTMENT:

All Rate Schedules .....0.000 percent

The total base rate charges for all rate schedules shall be increased by the above Integrated Resource Planning Cost Recovery Adjustment, which is based on the recovery of the ____ IRP Planning Costs and the reconciliation of _____ IRP Planning Costs, including interest and taxes, of $_____, as approved by the Public Utilities Commission.

The total base rate charges for the current billing period shall include all base rate schedule charges, discounts, surcharges, or base rate adjustments, excluding the Energy Cost Adjustment, Residential DSM Adjustment, and Commercial and Industrial DSM Adjustment and temporary Rate Adjustment.

B: Residential Demand-Side Management (DSM) Adjustment:

Schedules R and TOU-R - per kWhr . . . . . _____¢/kWhr

The total residential monthly bill shall include the above Residential DSM adjustment applied to all kWh per month. The above Residential DSM adjustment is based on recovering $_____ for the 200_ residential program costs and lost revenue margins, the reconciliation of the 200_ program cost recovery including lost revenue margins and revenue taxes, and the 200_ shareholder incentives, for which recovery has been approved by the Commission.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113, D&O No. _____.

Superseding Revised Sheet No. 68A
Effective June 1, 2005

REVISED SHEET NO. 68A
Effective

Integrated Resource Planning Cost Recovery Provision - (continued)

C: Commercial and Industrial Demand-Side Management (DSM) Adjustment:

Schedules G, J, H, PS, PP, PT, U, TOU-C - per kWh _____¢/kWhr

The total monthly bill for Schedules G, J, H, PS, PP, PT, U, and TOU-C customers shall include the above Commercial and Industrial DSM adjustment applied to all kWh per month. The above adjustment is based on recovering $_____ for the 200_ program costs and lost revenue margins, the reconciliation of the 200_ C&I program costs including the lost revenue margins and revenue taxes, and the 200_ shareholders incentives, for which recovery has been approved by the Public Utilities Commission.

RECONCILIATION ADJUSTMENT: (To be added to Integrated Resource Planning Cost Recovery Adjustment, Residential DSM Adjustment, and Commercial and Industrial DSM Adjustment):

In order to reconcile any differences that may occur between the above costs to be recovered and the revenues received from the above adjustments, recorded revenues will be compared with the above costs. The Integrated Resource Planning Cost Recovery Adjustment, Residential DSM Adjustment, and the Commercial and Industrial DSM Adjustment will be reconciled annually. If there is a variance between the recorded revenues from the adjustments and the costs to be recovered, a reconciliation adjustment, lagged by two months, will be made to the above adjustments.

Superseding Revised Sheet No. 81
Effective January 1, 1996

REVISED SHEET NO. 81
Effective

SCHEDULE Q

Purchases From Qualifying Facilities - 100 KW or Less

Availability:

This schedule is available to customers with cogeneration and/or small power production facilities which qualify under the Commission's Rules, Chapter 74 of Title 6, Subchapter 2 with a design capacity of 100 kilowatts or less. Such qualifying facilities (QF's) shall be designed to operate properly in parallel with the Company's system without adversely affecting the operations of its customers and without presenting safety hazards to the Company's or other customer's personnel. The customer shall comply with the Company's requirements for customer generation interconnected with the utility system.

Energy delivered to the customer by the Company will be metered separately from the energy delivered by the customer to the Company.

Rate for Energy Delivered to the Company by Customer

The Company will pay for energy as follows:

All kwh per month - per kwhr	10.63 ¢/kWhr

Energy Delivered to the Customer by the Company:

Energy delivered to the customer shall be billed under the Company's applicable rate schedule.

Service Charge:

A service charge of $20.00 per month shall be added to the customer's total electric bill for the energy delivered to the customer for the billing and administration of the purchase power.

If a customer is only selling power to the Company under this Schedule, and is not receiving electric power service from the Company under any of the Company's applicable rate schedule, the customer shall be billed the customer charge under Schedule J to cover the metering, meter reading, billing and administration of the purchase power. In this situation, the above Service Charge will not apply.

Superseding Revised Sheet No. 81A
Effective January 1, 1996

REVISED SHEET NO. 81A
Effective

SCHEDULE Q - (continued)

System Compatibility:

The customer must deliver electric power at 60 hertz and the same phase and voltage as the customer receives service from the Company.

Interconnection Facilities:

The customer shall furnish, install, operate and maintain facilities such as relays, switches, synchronizing equipment, monitoring equipment and control and protective devices designated by the Company as suitable for parallel operation with the Company system. Such facilities shall be accessible at all times to authorized Company personnel. All designs should be approved by the Company prior to installation.

If additional Company facilities are required or the existing facilities must be modified to accept the QF's deliveries, the QF shall make a contribution for the cost of such additional facilities.

Contract:

The Company shall require a contract specifying technical and operating aspects of parallel generation.

Energy Cost Adjustment Clause:

The above rate for energy delivered to the Company by the Customer is based on a composite cost of fuel for Company generation and Company Distributed Generation (DG) of 870.43 cents per million Btu for fuel delivered in its service tanks. Effective the first day of January, April, July, and October an Adjustment shall be made to reflect the composite cost of Company-generated and Company DG-generated fuel cost on file with the Commission and shall be effective for the following three months.

The Adjustment shall be the sum of the time-weighted on-peak adjustment (14 hours of 24 hours) and off-peak adjustment (10 hours of 24 hours). On-peak and off-peak adjustments shall be determined by the amount of the composite cost of Company-generated and Company DG-generated fuel cost increase or decrease (in terms of cents per million Btu) from the base of 870.43 cents per million Btu multiplied by an on-peak heat rate of 13,382 Btu per net kilowatthour and

SCHEDULE Q - (continued)

and an off-peak heat rate of 9,929 Btu per net kilowatthour.

This Energy Cost Adjustment Clause is consistent with the terms of the Company's operations and may be revised to reflect any revisions or changes in operations, subject to approval by the Commission.

Superseding Sheet No. 82
Effective October 23, 1996

REVISED SHEET NO. 82
Effective January 1, 1999

GREEN PRICING PROGRAM PROVISION

AVAILABILITY:

Available to all residents/non-residents of the Island of Oahu who wish to make voluntary contributions for the development of renewable energy resources on Oahu.

GREEN PRICING PROGRAM:

The objective of the Green Pricing Program is to encourage the development of Hawaii's renewable energy resources. The participant's voluntary contributions under the Green Pricing Program Provision are used to develop renewable energy facilities.

The Company's Sun Power for Schools Pilot Program is a pilot project under which photovoltaic systems are installed on selected public schools on the Island of Oahu. The participating school will own the photovoltaic facility and use the energy produced by the system at no cost. Contributions received from the participants in this Green Pricing Program Provision are used to help fund this pilot program.

Other renewable energy projects may be developed in the future as part of the Company's Green Pricing Program, depending on the availability of contributions received from this Green Pricing Program Provision.

VOLUNTARY PARTICIPATION:

1. Participation in the Green Pricing Program through the Green Pricing Program Provision, is voluntary and may be terminated by the participant at any time.

2. Any resident/non-resident of the Island of Oahu may contribute to the Green Pricing Program through the Green Pricing Program Provision by completing a standard program sign-up form which indicates the participant's mailing address, electric service account number (if participant is currently a HECO customer), and the contribution payment option desired. The Green Pricing Program Provision contribution payment options are listed below.

Superseding Sheet No. 82A
Effective October 23, 1996

REVISED SHEET NO. 82A
Effective January 1, 1999

GREEN PRICING PROGRAM PROVISION (Continued)

3. A participant may terminate his/her voluntary contribution to the Green Pricing Program at any time by submitting a written or telephonic request to the Company to terminate participation in the Green Pricing Program Provision.

CONTRIBUTION PAYMENT OPTIONS:

A participant will specify the amount of his/her voluntary contribution (in whole dollars) and shall elect one of the following payment options:

Option 1: Monthly Contribution - the participant will be billed monthly based on the participant's specified dollar contribution amount.

Option 2: One Time Contribution - the participant will be billed one time for one lump sum contribution.

TERMS AND CONDITIONS:

1. Payments received by the Company shall be applied first to the participant's outstanding electric service bill balance, if any, and the remainder shall be applied to the participant's contribution to the Green Pricing Program under the Green Pricing Program Provision.

2. Electric Service will not be terminated if the participant fails to make contribution payments under the Green Pricing Program Provision.

3. The Company may terminate a participant's participation in the Green Pricing Program Provision, if the participant fails to make contribution payments for two (2) consecutive months.

4. The Company's late payment charge shall not apply to the participant's voluntary contributions under the Green Pricing Program Provision.

SHEET NO. 83
Effective

SCHEDULE TOU-C

COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads less than 300 kilowatts per month and supplied and metered at a single voltage and delivery point. This Schedule cannot be used in conjunction with load management Riders M, T, and I.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods shall be as follows:

Priority Peak:	5:00 p.m. - 9:00 p.m.,	Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m.,	Monday - Friday
	7:00 a.m. - 9:00 p.m.,	Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m.,	Daily

RATE:

NON-DEMAND SERVICE:

Applicable to general light and/or power loads less than or equal to 5000 kWhr per month, and less than 25 kW, and supplied and metered at single voltage and delivery point.

CUSTOMER CHARGE:

Single-Phase Service - per month	$35.00/month
Three-Phase Service - per month	$60.00/month

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period - per kWhr	21.2616 ¢/kWhr
Mid-Peak Period - per kWhr	18.2616 ¢/kWhr
Off-Peak Period - per kWhr	11.2616 ¢/kWhr

MINIMUM CHARGE:

Single-Phase Service - per month	$40.00/month
Three-Phase Service - per month	$60.00/month

SCHEDULE TOU-C - continued

DEMAND SERVICE:

Applicable to general light and/or power loads greater than 5000 kWhr per month, or equal to or greater than 25 kW but less than 300 kW, and supplied and metered at single voltage and delivery point.

CUSTOMER CHARGE:

Single-Phase Service - per month	$50.00/month
Three-Phase Service - per month	$70.00/month

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period - per kWhr	18.0944 ¢/kWhr
Mid-Peak Period - per kWhr	15.0944 ¢/kWhr
Off-Peak Period - per kWhr	10.0000 ¢/kWhr

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak - per kW of billing demand	$15.00/kW
Mid-Peak - per kW of billing demand	$8.50/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 25 kW.

SHEET NO. 85
Effective

SCHEDULE TOU-C - (continued)

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-day rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 25 kW.

Power Factor: (Applicable to Demand Service)

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery: (Applicable To Demand Service)

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation -3.0%
Distribution voltage supplied without further transformation -2.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 2.4% and 0.6%, respectively.

SHEET NO. 85A
Effective

SCHEDULE TOU-C -(continued)

Supply Voltage Delivery - continued:

Because of the inherent operating conditions in the downtown area supplied from the Company's underground network system the Company will deliver and meter service to customers in this area at 120/208Y or 277/480Y volts (See Rule 2). The demand and energy charges will be increased 0.9%.

Energy Cost Adjustment Clause: (For Non-Demand and Demand Service)

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges, Service Voltage adjustment, Network Service adjustment, and Power Factor adjustment.

Integrated Resource Planning Surcharge: (For Non-Demand and Demand Service)

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, Service Voltage adjustment, Network Service adjustment, Power Factor adjustment, and energy cost adjustment.

Rules and Regulations: (For Non-Demand and Demand Service)

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

TERM OF CONTRACT: (For Non-Demand and Demand Service)

Not less than five years beginning from the service start date. If service is terminated before the end of the contract term, the customer shall be charged the total connection costs incurred by the Company to serve the customer less any customer advance and/or contribution paid by the customer.

Superseding Sheet No. 86
Effective May 12, 2003

REVISED SHEET NO. 86
Effective

SCHEDULE TOU-R

RESIDENTIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to residential power service metered and billed separately by the Company. This Schedule does not apply where a residence and business are combined. Service under this Schedule will be delivered at secondary voltage specified by the Company.

This Schedule is limited to 1,000 residential customers on a first come first serve basis until the new Customer Information System is implemented.

RATES:

CUSTOMER CHARGE - $ per customer per month:	
Single-Phase Service - per month	$11.50/month
Three-Phase Service - per month	$20.50/month
TIME-OF-USE ENERGY CHARGE - ¢ per kWh:	
Priority Peak Period - per kWhr	22.3318 ¢/kWhr
Mid-Peak Period - per kWhr	19.3318 ¢/kWhr
Off-Peak Period - per kWhr	13.8318 ¢/kWhr
MINIMUM CHARGE:	
Single-Phase Service - per month	$21.50/month
Three-Phase Service - per month	$25.50/month

Superseding Sheet No. 87
Effective May 12, 2003

REVISED SHEET NO. 87
Effective

SCHEDULE TOU-R - (continued)

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods under this Schedule shall be defined as follows:

Priority Peak:	5:00 p.m.-9:00 p.m., Monday-Friday
Mid-Peak:	7:00 a.m.-5:00 p.m., Monday-Friday
	5:00 p.m.-9:00 p.m., Saturday-Sunday, Holidays
Off-Peak:	7:00 a.m.-5:00 p.m., Saturday-Sunday, Holidays
	9:00 p.m.-7:00 a.m., Daily

Holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWh energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1. The Company may meter the customer's energy usage pattern for one to three months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.
2. The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

3. The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

Superseding Sheet No. 88
Effective May 12, 2003

REVISED SHEET NO. 88
Effective

Schedule TOU-R - (continued)

TERMS AND CONDITIONS - continued:

4. A customer may terminate service under this rate Schedule and return to the regular Schedule R at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

ENERGY COST ADJUSTMENT CLAUSE:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

INTEGRATED RESOURCE PLANNING COST RECOVERY PROVISION:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 2
Effective June 17, 2005

REVISED SHEET NO. 2
Effective

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HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113, D&O No. _____.

Superseding REVISED SHEET NO. 12
Effective: October 28, 1966

REVISED SHEET NO. 12
Effective

RULE NO. 4

Service Contracts

A. SERVICE CONTRACTS REQUIRED

Service contracts will be required as a condition precedent to service when:

1. Required by a rate schedule; or

2. A line extension advance is required under Rule No. 13; or

3. Temporary service is installed under Rule No. 12.

B. LARGE LOADS

A service contract may be required of a customer who has a large load requiring the Company to make a substantial investment in facilities to serve him. Such contract may include termination charges, a guaranteed minimum charge or a minimum demand higher than specified in the rate schedule.

C. COMMISSION APPROVAL

Form contracts for service other than regular utility service provided under the provisions of the tariffs contained in these rules, are contained in these rules and are authorized by the Public Utilities Commission. Special contracts for service other than that provided under the tariffs or attached form contracts must be authorized by the Public Utilities Commission prior to the effective date of said contract.

Each contract for service will contain a statement that it shall at all times be subject to changes or modifications by the Public Utilities Commission as said Commission may from time to time direct in the exercise of its jurisdiction.

SUPERSEDING REVISED SHEET NO. 15
Effective: October 28, 1966

REVISED SHEET NO. 15
Effective:

RULE NO. 7

Discontinuance and Restoration of Service

A. REASONS FOR DENYING SERVICE

The Company may refuse or discontinue service for any of the reasons listed below:

1. Without notice in the event of a condition determined by the Company to be hazardous. The Company shall have the right to refuse service to any applicant and to refuse or discontinue service to any customer whose wire, appliances, apparatus, or other equipment, or use thereof shall be determined by the Company to be unsafe or in violation of applicable laws, ordinances, rules or regulations of any public authority, or if any condition exists upon the applicant's or customer's premises shall be determined by the Company to endanger the Company's service facilities;

   The Company does not assume any duty of inspecting or repairing any applicant's or customer's wire, appliances, apparatus, or other equipment or any part thereof and assumes no liability therefor;

2. Without notice in the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or the Company's service to others;

3. Without notice in the event of tampering with the equipment furnished and owned by the Company;

4. Without notice in the event of unauthorized use or use in violation of applicable laws, ordinances, rules, or regulations of any public authority;

5. For violation of and/or non-compliance with the Company's tariff or rules on file with and approved by the Commission. The Company may discontinue service to a customer if after written notice of such non-compliance the customer fails to comply within 5 days after date of presentation of such notice or within such other period of time after date of presentation of such notice as may be specified in such notice;

Superseding Revised Sheet No. 16
Effective January 1, 1995

REVISED SHEET NO. 16
Effective

RULE NO. 7 (Continued)

Discontinuance and Restoration of Service

6. For failure of the customer to fulfill his contractual obligations for service and/or facilities subject to regulation by the Commission;

7. For failure of the customer to permit the Company reasonable access to its equipment;

8. For non-payment of bill provided that the Company has made a reasonable attempt to effect collection and has given the customer written notice that he has at least 5 days, excluding Sundays and holidays, in which to make settlement on his account or have his service denied;

9. If, for an applicant's convenience, the Company should provide service before credit is established or should continue service to a customer when credit has not been re-established in accordance with Rule No. 5 and he fails to establish or re-establish his credit within 5 days after date of presentation of written notice to do so or within such other period of time after date of presentation of such notice as may be specified in such notice, the Company may discontinue service;

10. For failure of the customer to furnish such service equipment permits, certificates, and/or rights-of-way, as shall have been specified by the Company as a condition to obtaining service, or in the event such equipment or permission are withdrawn or terminated; or

II. Fraud against the Company:

Unless otherwise stated, the customer shall be allowed a reasonable time in which to comply with the rule before service is discontinued. No service shall be discontinued on the day preceding or day or days on which the Company's business office is closed unless provisions are made for payment or reconnection on days when the Company's business offices are closed, except as provided in Rules 7A1 and 7A2.

Superseding SHEET NO. 16A
Effective January 1, 1995

REVISED SHEET NO. 16A
Effective

RULE No. 7 (Continued)

B. CUSTOMER'S REQUEST FOR SERVICE DISCONTINUANCE

When a customer desires to terminate his responsibility for service, he shall give the Company not less than 2 days notice and state the date on which he wishes the termination to become effective. A customer may be held responsible for all service furnished at the premises until 2 days after receipt of such notice by the Company or until the date of termination specified in the notice, whichever date is later.

C. RETURNED PAYMENT CHARGE

Payment by check or by any electronic payment form such as payment by credit card, debit card, or any form of automatic bill payment for any service covered herein which is returned by the financial institution on which it is issued will result in a fee to the customer of $16.00 per returned check or returned payment.

D. FIELD COLLECTION CHARGE

The Company shall require payment of $20.00 for a field call to the customer's service location necessitated by the customer's nonpayment of bills. This charge will be added to the customer's bill.

E. SERVICE ESTABLISHMENT CHARGE

The Company shall require payment of $20.00 for each establishment, supersedure, or re-establishment of electric service to any customer. This service establishment charge is in addition to the charges calculated in accordance with the applicable rate schedule and will be required each time an account is opened, including a turn on, a reconnection of electric service, or a change of customer which requires a meter reading.

When a customer requests same day service or that electric service be turned on or reconnected outside of regular business hours, an additional charge of $25.00 will be assessed.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113, D&O No. _____.

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2005, DOCKET NO: 040113
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE R: RESIDENTIAL SERVICE

SINGLE PHASE

KWH	Present Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase %
100	$23.64	$27.33	$3.69	15.61%
200	$40.30	$44.66	$4.36	10.82%
300	$56.97	$62.00	$5.03	8.83%
400	$73.63	$79.33	$5.70	7.74%
500	$90.30	$96.66	$6.36	7.04%
600	$106.95	$113.99	$7.04	6.58%
700	$123.63	$131.32	$7.69	6.22%
800	$140.28	$148.65	$8.37	5.97%
900	$156.96	$165.99	$9.03	5.75%
1,000	$173.61	$183.32	$9.71	5.59%
1,100	$190.27	$200.65	$10.38	5.46%
1,200	$206.94	$217.98	$11.04	5.33%
1,300	$223.60	$235.31	$11.71	5.24%
1,400	$240.28	$252.65	$12.37	5.15%
1,500	$256.93	$269.98	$13.05	5.08%

* Present Rates Effective January 1, 1997
Test -year 2005 FOA:
@present rates = 5.414 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2005 AES Refund:
@present rates = -.400%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2005, DOCKET NO: 040113
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE R: RESIDENTIAL SERVICE

THREE PHASE

KWH	Present Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase %
100	$31.60	$37.33	$5.73	18.13%
200	$48.27	$54.66	$6.39	13.24%
300	$64.93	$72.00	$7.07	10.89%
400	$81.60	$89.33	$7.73	9.47%
500	$98.26	$106.66	$8.40	8.55%
600	$114.92	$123.99	$9.07	7.89%
700	$131.59	$141.32	$9.73	7.39%
800	$148.25	$158.65	$10.40	7.02%
900	$164.92	$175.99	$11.07	6.71%
1,000	$181.58	$193.32	$11.74	6.47%
1,100	$198.24	$210.65	$12.41	6.26%
1,200	$214.91	$227.98	$13.07	6.08%
1,300	$231.57	$245.31	$13.74	5.93%
1,400	$248.25	$262.65	$14.40	5.80%
1,500	$264.90	$279.98	$15.08	5.69%

* Present Rates Effective January 1, 1997
Test -year 2005 FOA:
@present rates = 5.414 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2005 AES Refund:
@present rates = -.400%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2005, DOCKET NO: 040113
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE G: GENERAL SERVICE, NON-DEMAND

SINGLE PHASE

KWH	Present Rate $/Mo.	Proposed Rate $/Mo.	Increase $/Mo.	Increase %
100	$36.45	$51.26	$14.81	40.63%
200	$52.97	$67.52	$14.55	27.47%
300	$69.50	$83.78	$14.28	20.55%
400	$86.03	$100.05	$14.02	16.30%
500	$102.56	$116.31	$13.75	13.41%
600	$119.07	$132.57	$13.50	11.34%
700	$135.61	$148.83	$13.22	9.75%
800	$152.13	$165.09	$12.96	8.52%
900	$168.66	$181.35	$12.69	7.52%
1,000	$185.18	$197.62	$12.44	6.72%
2,000	$350.45	$360.23	$9.78	2.79%
3,000	$515.71	$522.85	$7.14	1.38%
4,000	$680.97	$685.46	$4.49	0.66%
5,000	$846.24	$848.08	$1.84	0.22%

* Present Rates Effective January 1, 1997
Test -year 2005 FOA:
@present rates = 5.414 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2005 AES Refund:
@present rates = -.400%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2005, DOCKET NO: 040113
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE G: GENERAL SERVICE, NON-DEMAND

THREE PHASE

KWH	Present Rate $/Mo.	Proposed Rate $/Mo.	Increase $/Mo.	Increase %
100	$61.35	$76.26	$14.91	24.30%
200	$77.87	$92.52	$14.65	18.81%
300	$94.40	$108.78	$14.38	15.23%
400	$110.93	$125.05	$14.12	12.73%
500	$127.46	$141.31	$13.85	10.87%
600	$143.97	$157.57	$13.60	9.45%
700	$160.51	$173.83	$13.32	8.30%
800	$177.03	$190.09	$13.06	7.38%
900	$193.56	$206.35	$12.79	6.61%
1,000	$210.08	$222.62	$12.54	5.97%
2,000	$375.35	$385.23	$9.88	2.63%
3,000	$540.61	$547.85	$7.24	1.34%
4,000	$705.87	$710.46	$4.59	0.65%
5,000	$871.14	$873.08	$1.94	0.22%

* Present Rates Effective January 1, 1997
* Test -year 2005 FOA:
  @present rates = 5.414 ¢/kWh
  @ proposed rates = 0.000 ¢/kWh
* Test - year 2005 AES Refund:
  @present rates = -.400%
  @proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2005, DOCKET NO: 040113
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE J: GENERAL SERVICE DEMAND

SINGLE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
25	2,500	100	$529.77	$603.50	$73.73	13.92%
25	5,000	200	$881.50	$944.50	$63.00	7.15%
25	10,000	400	$1,527.79	$1,569.10	$41.31	2.70%
25	12,500	500	$1,825.31	$1,855.67	$30.36	1.66%
25	15,000	600	$2,122.84	$2,142.24	$19.40	0.91%
50	5,000	100	$1,024.67	$1,157.00	$132.33	12.91%
50	10,000	200	$1,728.13	$1,839.00	$110.87	6.42%
50	20,000	400	$3,020.71	$3,088.19	$67.48	2.23%
50	25,000	500	$3,615.75	$3,661.34	$45.59	1.26%
50	30,000	600	$4,210.80	$4,234.48	$23.68	0.56%
100	10,000	100	$2,014.48	$2,264.00	$249.52	12.39%
100	20,000	200	$3,421.41	$3,628.00	$206.59	6.04%
100	40,000	400	$6,006.55	$6,126.38	$119.83	1.99%
100	50,000	500	$7,196.65	$7,272.67	$76.02	1.06%
100	60,000	600	$8,386.74	$8,418.96	$32.22	0.38%
300	30,000	100	$5,973.73	$6,692.00	$718.27	12.02%
300	60,000	200	$10,194.50	$10,784.00	$589.50	5.78%
300	120,000	400	$17,949.94	$18,279.14	$329.20	1.83%
300	150,000	500	$21,520.23	$21,718.01	$197.78	0.92%
300	180,000	600	$25,090.51	$25,156.88	$66.37	0.26%

* Present Rates Effective January 1, 1997
Test -year 2005 FOA:
@present rates = 5.414 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2005 AES Refund:
@present rates = -.400%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2005, DOCKET NO: 040113
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE J: GENERAL SERVICE DEMAND

THREE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
25	2,500	100	$554.67	$623.50	$68.83	12.41%
25	5,000	200	$906.40	$964.50	$58.10	6.41%
25	10,000	400	$1,552.69	$1,589.10	$36.41	2.34%
25	12,500	500	$1,850.21	$1,875.67	$25.46	1.38%
25	15,000	600	$2,147.74	$2,162.24	$14.50	0.68%
50	5,000	100	$1,049.57	$1,177.00	$127.43	12.14%
50	10,000	200	$1,753.03	$1,859.00	$105.97	6.04%
50	20,000	400	$3,045.61	$3,108.19	$62.58	2.05%
50	25,000	500	$3,640.65	$3,681.34	$40.68	1.12%
50	30,000	600	$4,235.70	$4,254.48	$18.78	0.44%
100	10,000	100	$2,039.38	$2,284.00	$244.62	11.99%
100	20,000	200	$3,446.31	$3,648.00	$201.69	5.85%
100	40,000	400	$6,031.45	$6,146.38	$114.93	1.91%
100	50,000	500	$7,221.55	$7,292.67	$71.12	0.98%
100	60,000	600	$8,411.64	$8,438.96	$27.32	0.32%
300	30,000	100	$5,998.63	$6,712.00	$713.37	11.89%
300	60,000	200	$10,219.40	$10,804.00	$584.60	5.72%
300	120,000	400	$17,974.84	$18,299.14	$324.30	1.80%
300	150,000	500	$21,545.13	$21,738.01	$192.88	0.90%
300	180,000	600	$25,115.41	$25,176.88	$61.47	0.24%

* Present Rates Effective January 1, 1997
Test -year 2005 FOA:
@present rates = 5.414 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2005 AES Refund:
@present rates = -.400%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2005, DOCKET NO: 040113
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE H: COMMERCIAL COOKING, HEATING, A/C, & REFRIGERATION SERVICES

SINGLE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
10	1,000	100	$240.81	$253.58	$12.77	5.30%
10	2,000	200	$372.06	$392.17	$20.11	5.41%
10	3,000	300	$503.32	$530.75	$27.43	5.45%
10	4,000	400	$634.57	$669.33	$34.76	5.48%
25	2,500	100	$572.16	$596.46	$24.30	4.25%
25	5,000	200	$900.28	$942.92	$42.64	4.74%
25	7,500	300	$1,228.42	$1,289.37	$60.95	4.96%
25	10,000	400	$1,556.54	$1,635.83	$79.29	5.09%
50	5,000	100	$1,124.38	$1,167.92	$43.54	3.87%
50	10,000	200	$1,780.64	$1,860.83	$80.19	4.50%
50	15,000	300	$2,436.90	$2,553.75	$116.85	4.80%
50	20,000	400	$3,093.17	$3,246.66	$153.49	4.96%
100	10,000	100	$2,228.84	$2,310.83	$81.99	3.68%
100	20,000	200	$3,541.37	$3,696.66	$155.29	4.39%
100	30,000	300	$4,853.89	$5,082.49	$228.60	4.71%
100	40,000	400	$6,166.41	$6,468.32	$301.91	4.90%

* Present Rates Effective January 1, 1997
Test -year 2005 FOA:
@present rates = 5.414 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2005 AES Refund:
@present rates = -.400%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2005, DOCKET NO: 040113
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE H: COMMERCIAL COOKING, HEATING, A/C, & REFRIGERATION SERVICES

THREE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
10	1,000	100	$265.71	$288.58	$22.87	8.61%
10	2,000	200	$396.96	$427.17	$30.21	7.61%
10	3,000	300	$528.22	$565.75	$37.53	7.10%
10	4,000	400	$659.47	$704.33	$44.86	6.80%
25	2,500	100	$597.06	$631.46	$34.40	5.76%
25	5,000	200	$925.18	$977.92	$52.74	5.70%
25	7,500	300	$1,253.32	$1,324.37	$71.05	5.67%
25	10,000	400	$1,581.44	$1,670.83	$89.39	5.65%
50	5,000	100	$1,149.28	$1,202.92	$53.64	4.67%
50	10,000	200	$1,805.54	$1,895.83	$90.29	5.00%
50	15,000	300	$2,461.80	$2,588.75	$126.95	5.16%
50	20,000	400	$3,118.07	$3,281.66	$163.59	5.25%
100	10,000	100	$2,253.74	$2,345.83	$92.09	4.09%
100	20,000	200	$3,566.27	$3,731.66	$165.39	4.64%
100	30,000	300	$4,878.79	$5,117.49	$238.70	4.89%
100	40,000	400	$6,191.31	$6,503.32	$312.01	5.04%

** Present Rates Effective January 1, 1997*
Test -year 2005 FOA:
@present rates = 5.414 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2005 AES Refund:
@present rates = -.400%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2005, DOCKET NO: 040113
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE PS: LARGE POWER SECONDARY VOLTAGE SERVICE

KW	MWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
300	60	200	$10,863.04	$12,429.68	$1,566.64	14.42%
300	120	400	$17,942.29	$19,125.38	$1,183.09	6.59%
300	150	500	$21,389.47	$22,380.47	$991.00	4.63%
300	180	600	$24,836.65	$25,635.56	$798.91	3.22%
300	210	700	$28,283.83	$28,890.65	$606.82	2.15%
500	100	200	$17,892.59	$20,482.80	$2,590.21	14.48%
500	200	400	$29,691.34	$31,642.30	$1,950.96	6.57%
500	250	500	$35,436.64	$37,067.45	$1,630.81	4.60%
500	300	600	$41,181.94	$42,492.60	$1,310.66	3.18%
500	350	700	$46,927.24	$47,917.75	$990.51	2.11%
1,500	300	200	$52,542.32	$60,248.40	$7,706.08	14.67%
1,500	600	400	$87,938.59	$93,726.90	$5,788.31	6.58%
1,500	750	500	$105,174.48	$110,002.35	$4,827.87	4.59%
1,500	900	600	$122,410.38	$126,277.80	$3,867.42	3.16%
1,500	1,050	700	$139,646.27	$142,553.25	$2,906.98	2.08%
5,000	1,000	200	$170,330.37	$195,928.00	$25,597.63	15.03%
5,000	2,000	400	$288,317.96	$307,523.00	$19,205.04	6.66%
5,000	2,500	500	$345,770.94	$361,774.50	$16,003.56	4.63%
5,000	3,000	600	$403,223.92	$416,026.00	$12,802.08	3.17%
5,000	3,500	700	$460,676.90	$470,277.50	$9,600.60	2.08%
10,000	2,000	200	$338,599.02	$389,756.00	$51,156.98	15.11%
10,000	4,000	400	$574,574.19	$612,946.00	$38,371.81	6.68%
10,000	5,000	500	$689,480.15	$721,449.00	$31,968.85	4.64%
10,000	6,000	600	$804,386.11	$829,952.00	$25,565.89	3.18%
10,000	7,000	700	$919,292.07	$938,455.00	$19,162.93	2.08%

* Present Rates Effective January 1, 1997
Test -year 2005 FOA:
@present rates = 5.414 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2005 AES Refund:
@present rates = -.400%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2005, DOCKET NO: 040113
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE PP: LARGE POWER PRIMARY VOLTAGE SERVICE

KW	MWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
300	60	200	$10,724.28	$12,421.24	$1,696.96	15.82%
300	120	400	$17,730.62	$19,127.56	$1,396.94	7.88%
300	150	500	$21,143.11	$22,389.67	$1,246.56	5.90%
300	180	600	$24,555.60	$25,651.78	$1,096.18	4.46%
300	210	700	$27,968.09	$28,913.89	$945.80	3.38%
500	100	200	$17,661.31	$20,435.40	$2,774.09	15.71%
500	200	400	$29,338.56	$31,612.60	$2,274.04	7.75%
500	250	500	$35,026.04	$37,049.45	$2,023.41	5.78%
500	300	600	$40,713.52	$42,486.30	$1,772.78	4.35%
500	350	700	$46,401.00	$47,923.15	$1,522.15	3.28%
1,500	300	200	$51,858.46	$60,006.20	$8,147.74	15.71%
1,500	600	400	$86,890.20	$93,537.80	$6,647.60	7.65%
1,500	750	500	$103,952.64	$109,848.35	$5,895.71	5.67%
1,500	900	600	$121,015.08	$126,158.90	$5,143.82	4.25%
1,500	1,050	700	$138,077.52	$142,469.45	$4,391.93	3.18%
5,000	1,000	200	$168,132.20	$195,004.00	$26,871.80	15.98%
5,000	2,000	400	$284,904.66	$306,776.00	$21,871.34	7.68%
5,000	2,500	500	$341,779.47	$361,144.50	$19,365.03	5.67%
5,000	3,000	600	$398,654.27	$415,513.00	$16,858.73	4.23%
5,000	3,500	700	$455,529.07	$469,881.50	$14,352.43	3.15%
10,000	2,000	200	$334,237.54	$387,858.00	$53,620.46	16.04%
10,000	4,000	400	$567,782.47	$611,402.00	$43,619.53	7.68%
10,000	5,000	500	$681,532.07	$720,139.00	$38,606.93	5.66%
10,000	6,000	600	$795,281.68	$828,876.00	$33,594.32	4.22%
10,000	7,000	700	$909,031.28	$937,613.00	$28,581.72	3.14%

* Present Rates Effective January 1, 1997
Test -year 2005 FOA:
@present rates = 5.414 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2005 AES Refund:
@present rates = -.400%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2005, DOCKET NO: 040113
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE PT: LARGE POWER TRANSMISSION VOLTAGE SERVICE

KW	MWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
300	60	200	$10,622.27	$12,250.66	$1,628.39	15.33%
300	120	400	$17,575.13	$18,838.18	$1,263.05	7.19%
300	150	500	$20,962.16	$22,042.18	$1,080.02	5.15%
300	180	600	$24,349.19	$25,246.18	$896.99	3.68%
300	210	700	$27,736.22	$28,450.18	$713.96	2.57%
500	100	200	$17,491.30	$20,151.10	$2,659.80	15.21%
500	200	400	$29,079.40	$31,130.30	$2,050.90	7.05%
500	250	500	$34,724.45	$36,470.30	$1,745.85	5.03%
500	300	600	$40,369.50	$41,810.30	$1,440.80	3.57%
500	350	700	$46,014.55	$47,150.30	$1,135.75	2.47%
1,500	300	200	$51,358.37	$59,153.30	$7,794.93	15.18%
1,500	600	400	$86,122.68	$92,090.90	$5,968.22	6.93%
1,500	750	500	$103,057.84	$108,110.90	$5,053.06	4.90%
1,500	900	600	$119,992.99	$124,130.90	$4,137.91	3.45%
1,500	1,050	700	$136,928.14	$140,150.90	$3,222.76	2.35%
5,000	1,000	200	$166,511.71	$192,161.00	$25,649.29	15.40%
5,000	2,000	400	$282,392.75	$301,953.00	$19,560.25	6.93%
5,000	2,500	500	$338,843.26	$355,353.00	$16,509.74	4.87%
5,000	3,000	600	$395,293.76	$408,753.00	$13,459.24	3.40%
5,000	3,500	700	$451,744.27	$462,153.00	$10,408.73	2.30%
10,000	2,000	200	$331,016.48	$382,172.00	$51,155.52	15.45%
10,000	4,000	400	$562,778.56	$601,756.00	$38,977.44	6.93%
10,000	5,000	500	$675,679.58	$708,556.00	$32,876.42	4.87%
10,000	6,000	600	$788,580.59	$815,356.00	$26,775.41	3.40%
10,000	7,000	700	$901,481.60	$922,156.00	$20,674.40	2.29%

* Present Rates Effective January 1, 1997
Test -year 2005 FOA:
@present rates = 5.414 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2005 AES Refund:
@present rates = -.400%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2005, DOCKET NO: 040113
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE F: PUBLIC STREET LIGHTING, HIGHWAY LIGHTING, AND PARK AND PLAYGROUND LIGHTING

KW	KWH	KWH/KW	Present Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase (%)
1	150	150	$34.86	$48.30	$13.44	38.55%
1	340	340	$53.91	$76.59	$22.68	42.07%
5	750	150	$135.51	$161.49	$25.98	19.17%
5	1,700	340	$269.56	$302.97	$33.41	12.40%
10	1,500	150	$271.02	$302.99	$31.97	11.80%
10	3,400	340	$539.11	$585.94	$46.83	8.69%
25	3,750	150	$677.55	$727.47	$49.92	7.37%
25	8,500	340	$1,347.78	$1,434.84	$87.06	6.46%
50	7,500	150	$1,355.11	$1,434.94	$79.84	5.89%
50	17,000	340	$2,695.55	$2,849.68	$154.13	5.72%
100	15,000	150	$2,710.21	$2,849.89	$139.67	5.15%
100	34,000	340	$5,391.11	$5,679.37	$288.26	5.35%

* Present Rates Effective January 1, 1997
Test -year 2005 FOA:
@present rates = 5.414 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2005 AES Refund:
@present rates = -.400%
@proposed rates = 0.000%

HECO RT-23
DOCKET NO. 04-0113

REBUTTAL TESTIMONY OF
WILLIAM A. BONNET

VICE PRESIDENT
GOVERNMENT AND COMMUNITY AFFAIRS
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Results of Operations, including Revenue Requirements, and Implementation of the Proposed Rate Increase

1 INTRODUCTION

2 Q. Please state your name and business address.

3 A. My name is William A. Bonnet and I am the Vice President of Government and
4 Community Affairs for Hawaiian Electric Company, Inc. ("HECO").

5 Q. Have you previously submitted testimony in this proceeding?

6 A. Yes. I submitted written direct testimony, exhibits and workpapers as HECO T-
7 23.

8 Q. What will you address in this testimony?

9 A. In this testimony, I will address our Results of Operations and Revenue
10 Requirements for the 2005 test year, and discuss our proposed implementation of
11 the requested increase.

12

13 RESULTS OF OPERATIONS AND REVENUE REQUIREMENTS

14 Q. What is HECO's rebuttal position with respect to revenue requirements for the
15 2005 test year at this point in this proceeding?

16 A. HECO's rebuttal testimonies and exhibits support normalized 2005 test year
17 revenue requirements of $1,284,637,000, as shown in HECO-R-2301. (These
18 amounts are based on May 1, 2005 fuel oil and purchased energy prices and a
19 8.83% return on average rate base, including a 11.0 % return on common equity.)
20 HECO is requesting that it be granted a revenue increase of $63,035,000 (based
21 on May 1, 2005 fuel oil and purchased energy prices), or 5.2% over revenues of
22 $1,221,602,000 at present rates for a normalized 2005 test year. Based on current
23 effective rates (i.e. rates that are currently in effect for our customers) explanation
24 is basically a restatement of the term....suggest we either reword or deleteof
25 $1,233,760,000 (based on May 1, 2005 fuel oil and purchased energy prices), the

amount of the increase in revenues is $50,877,000, or 4.1%. See HECO-R-2302.

Q. How much of a rate increase did HECO request in its Application?

A. The total rate increase HECO requested in its Application (filed on November 12, 2004) was $98,614,000 (based on May 1, 2004 fuel oil and purchased energy prices), or 9.9% over revenues at present rates for a normalized 2005 test year. The amount of the increase in revenues requested was $74,194,000 (based on May 1, 2004 fuel oil and purchased energy prices), or 7.3% over revenues at current effective rates (i.e. rates that are currently in effect for our customers).

Q. What are present rates and charges?

A. As shown on HECO-R-2301, HECO's revenues at present rates (and at proposed rates) are calculated in accordance with the base rates that were established as a result of Decision and Order No. 14412 (December 11, 1995) in Docket No. 7766, which utilized a 1995 test year, and Decision and Order No. 20292 issued July 1, 2003 and Order No. 20310 issued July 9, 2003 in Docket No. 03-0126, which implemented a rate reduction made possible as a result of the amendment of HECO's power purchase agreement with AES Hawaii, Inc. (Revenues at present rates include revenues that would be collected under the Energy Cost Adjustment Clause ("ECAC"), based on May 1, 2005 fuel oil and purchased energy prices.)

Q. What is the difference between HECO's present rates and current effective rates?

A. Revenues at present rates (and at proposed rates) are calculated without including revenues recovered through the Integrated Resource Planning Cost Recovery Provision ("IRP Clause"). Current effective rates are the rates currently in effect, which include revenues recovered through the IRP Clause.

Q. What amount of current effective rates in the Results of Operations, proposed in

rebuttal, relates to revenues recovered through the IRP Clause?

A. HECO's estimated revenues at current effective rates for the 2005 test year include revenues of $12,158,000 from the IRP Clause, including $11,479,000 for recovery of lost margins for demand-side management ("DSM") programs currently in effect, and $678,000 for recovery of a normalized level of incremental IRP planning costs included in the rebuttal 2005 test year estimates. (See HECO-R-2303.) Revenues collected from customers already reflect these costs, thus this portion of the rate increase request, which shifts revenues from the IRP Clause to base rates, does not increase customer bills.

Q. How do the revenues from the IRP Clause included in current effective rates in rebuttal testimony compare to the IRP Clause revenues used in determining the current effective rates in direct testimony?

A. The IRP Clause revenues in current effective rates in direct testimony amounted to $24,423,000, including $23,744,000 for recovery of DSM program costs, lost margins and shareholder incentives for DSM programs currently in effect, and $678,000 for recovery of a normalized level of incremental IRP planning costs included in the test year expenses. (See HECO-2303). The amount related to incremental IRP planning costs has not changed from direct testimony.

Q. Why have the IRP Clause revenues related to the DSM program costs, lost margins and shareholder incentives for DSM programs currently in effect been revised?

A. As a result of the PUC-approved stipulations in 2001, as modified in 2002, HECO requested approval of its new and existing energy efficiency DSM programs and associated utility incentive mechanism in its rate case application, and direct testimony filing, and included the related costs in its proposed rate increase. On

March 16, 2005, the PUC issued Order No. 21698, separating HECO's requests for approval of its existing and proposed DSM programs from the rate case proceeding into a new docket. As a part of the bifurcation order, HECO is allowed to continue its existing DSM programs and cost recovery mechanisms (under which programs costs, shareholder incentives, and lost margins between rate cases, are recovered through the DSM portion of the IRP surcharge.) The program costs related to the existing DSM programs (as well as the costs for new enhanced energy efficiency DSM programs) to the extent recovered through the DSM portion of the IRP surcharge has been removed from the rate increase request. The DSM portion of the IRP Clause revenues has been reduced to reflect only the lost margin portion of the existing DSM programs currently being recovered through the IRP surcharge. Mr. Alan Hee's rebuttal testimony HECO RT-10 discusses the calculation of the IRP Clause revenues.

Q. What would HECO's 2005 test year return on average rate base be for ratemaking purposes without rate relief?

A. Without rate relief, HECO's normalized Results of Operations (based on May 1, 2005 fuel and purchased energy prices) indicate a rate of return on average rate base of 5.63 % based on revenues at present rates, and 6.24% based on revenues at current effective rates (which include IRP Clause revenues) for the 2005 test year, as shown in HECO-R-2301, and HECO-R-2302, respectively.

Q. What evidence has HECO presented to the Commission to support its test year revenue requirements?

A. HECO's normalized test year revenue requirements have been justified by a completely documented rate case evidentiary record. The reasons for HECO's need for rate relief have been explained in HECO's Application filed on

November 12, 2004, with detailed discussion included in HECO's direct and rebuttal testimonies, and associated exhibits and workpapers. The evidentiary record has subsequently been further developed by HECO's responses to the Consumer Advocate's ("CA") and the Department of Defense's ("DOD") information requests.

Q. Does this documentation represent all of the evidentiary record prior to the evidentiary hearing?

A. No. The CA and the DOD have contributed in developing the prefiled record in this proceeding. The CA and DOD have submitted written testimonies, exhibits and workpapers that included information based on documentation provided in writing by HECO as discussed above, as well as informal meetings and telephone conversations at the staff level between HECO and the CA, and HECO and the DOD. The CA and the DOD also provided responses to HECO's information requests.

Q. Do you believe the record as described above is sufficient for the Commission to make an informed decision?

A. Yes. Moreover, the record described above only details the prefiled written evidence up to this point in the proceeding. The Commission's decision will also have the benefit of the Company's responses to rebuttal information requests, and the evidence presented in the evidentiary hearing which is scheduled to begin on September 13, 2005.

RATE INCREASE IMPLEMENTATION

Q. How does HECO propose to implement its proposed rate increase?

A. HECO proposes to implement the proposed rate increase in two steps:

1) Interim Step, and

2) Final Increase.

Q. What is HECO proposing for the Interim Step?

A. HECO proposes an Interim Step increase in an amount equal to the increase in rates to which the Commission believes HECO is "probably entitled" based on the evidentiary record before it, in accordance with H.R.S. Section 269-16(d). HECO requests that it be allowed to implement its proposed Interim Increase as soon as practicable after the evidentiary hearing is concluded. HECO is requesting an interim increase as soon as possible, since HECO requires rate relief as near to the beginning of the 2005 test period as practicable to provide the Company an opportunity to earn the rate of return on rate base authorized by the Commission in this proceeding.

Q. How should the Commission determine what the Company is "probably entitled" to <u>based on the evidentiary record before it</u>?

A. The amount of the interim increase to which HECO has shown "probable entitlement" should <u>not</u> be limited to the amount of the rate increase that is "uncontested" by the CA and the DOD. Instead, the Commission should also review the contested issues and add to the uncontested amounts, those amounts for which probable entitlement has been demonstrated. The starting point for the Commission in reviewing contested issues should be its own decisions in prior cases - - if the CA or DOD is proposing to disallow an expense that has been previously approved by the Commission, then the CA or DOD position should <u>not</u> be accepted for purposes of the interim rate order. Conversely, if HECO is proposing to include an expense that has been previously rejected by the Commission, then HECO's position should not be accepted for purposes of the

interim rate order. In addition, the Commission should not accept a CA or DOD estimate for purposes of the interim where HECO has demonstrated that the CA or DOD made a computational or input error in arriving at its estimate, or where later available information demonstrates the unreasonableness of the CA or DOD estimate, or where the CA or DOD estimate is clearly too low. The same holds true for HECO's estimates.

Q. When does HECO propose to make the Final Step Increase effective?

A. The Final Step Increase would become effective when the Commission issues its final decision and order to provide the balance of the total requested increase authorized but not included in the Interim Step.

Q. What rate mechanism does HECO propose to implement the Interim Step?

A. HECO proposes to implement the final increase with the proposed rates and charges that are reflected in HECO-R-2224, or with such other rates and charges as approved by the Commission. HECO proposes to implement the Interim Step as surcharges to the various classes based on a percentage of the customer's bill (exclusive of Energy Cost Adjustment charges and other surcharges). HECO proposes that the allocation to each rate class be consistent with the likely final rate increase allocation.

SUMMARY

Q. Mr. Bonnet, could you please summarize your testimony?

A. Yes. HECO requests Commission approval of a general rate increase and revised rate and rule changes to be granted in the steps outlined above.

In order for HECO to maintain its financial integrity and its ability to attract capital for its capital expenditures, it is essential that the Commission grant an

appropriate interim increase as soon as practicable after the evidentiary hearing is held.

I believe the evidence presented by HECO has demonstrated the reasonableness of this request and has satisfied HECO's burden of proof.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaiian Electric Company, Inc.
Rebuttal
Results of Operations
2005
($ Thousands)

	Present Rates	Additional Amount	Revenue Requirements to Produce 8.83% Return on Average Rate Base
Electric Sales Revenue	1,218,267	62,308	1,280,575
Other Operating Revenue	2,967	727	3,694
Gain on Sale of Land	368		368
TOTAL OPERATING REVENUES	1,221,602	63,035	1,284,637
Fuel	449,447		449,447
Purchased Power	345,433		345,433
Production	56,497		56,497
Transmission	8,081		8,081
Distribution	20,113		20,113
Customer Accounts	11,436		11,436
Allowance for Uncoll. Accounts	1,152	59	1,211
Customer Service	5,284		5,284
Administration & General	55,277		55,277
Labor Adjustment	(246)		(246)
Operation and Maintenance	952,474	59	952,533
Depreciation & Amortization	70,731		70,731
Taxes Other Than Income	113,917	5,581	119,498
Interest on Customer Deposits	378		378
Income Taxes	21,207	22,332	43,539
TOTAL OPERATING EXPENSES	1,158,707	27,972	1,186,679
OPERATING INCOME	62,895	35,063	97,958
AVERAGE RATE BASE	1,117,830	(8,458)	1,109,372
RATE OF RETURN ON AVERAGE RATE BASE	5.63%		8.83%

Hawaiian Electric Company, Inc.
With IRP Cost Recovery Provision
Results of Operations
2005
($ Thousands)

	Current Effective Rates	Additional Amount	Revenue Requirements to Produce 8.83% Return on Average Rate Base
Electric Sales Revenue	1,230,425	50,162	1,280,587
Other Operating Revenue	2,967	715	3,682
Gain on Sale of Land	368		368
TOTAL OPERATING REVENUES	1,233,760	50,877	1,284,637
Fuel	449,447		449,447
Purchased Power	345,433		345,433
Production	56,497		56,497
Transmission	8,081		8,081
Distribution	20,113		20,113
Customer Accounts	11,436		11,436
Allowance for Uncoll. Accounts	1,164	47	1,211
Customer Service	5,284		5,284
Administration & General	55,277		55,277
Labor Adjustment	(246)		(246)
Operation and Maintenance	952,486	47	952,533
Depreciation & Amortization	70,731		70,731
Taxes Other Than Income	114,997	4,501	119,498
Interest on Customer Deposits	378		378
Income Taxes	25,513	18,026	43,539
TOTAL OPERATING EXPENSES	1,164,105	22,574	1,186,679
OPERATING INCOME	69,655	28,303	97,958
AVERAGE RATE BASE	1,116,198	(6,827)	1,109,371
RATE OF RETURN ON AVERAGE RATE BASE	6.24%		8.83%

Hawaiian Electric Company, Inc.
Docket No. 04-0113
Test Year 2005
Reconciliation of
Electric Sales Revenue at Present Rates to Current Effective Rates
($ Thousands)

Electric Sales Revenue at Present Rates[1]				**$ 1,218,267**
Estimated 2005 Residential Lost Margins in IRP Clause Revenues[2]	$ 2,495			
Estimated 2005 C&I Lost Margins in IRP Clause Revenues[2]	8,984			
Total Lost Margins in IRP Clause Revenues		$ 11,479		
Normalized Incremental IRP Planning Costs in test year[3]	618			
Revenue tax factor (1.0975)	1.0975			
Normalized Incremental IRP Costs in IRP Clause Revenues		678		
Total IRP Clause Revenues				**12,158**
Electric Sales Revenue at Current Effective Rates[4]				**$ 1,230,425**

Source
[1] HECO-R-2301
[2] HECO-R-2303, page 2
[3] HECO-1027
[4] HECO-R-2302

Total may not add exactly due to rounding.

Hawaiian Electric Company, Inc.
Docket No. 04-0113, Test Year 2005
Lost Margin Component of 2005 DSM Adjustments [1]

2005 Residential DSM Adjustment	
Residential DSM Overcollection 2004	-$1,649,380
Interest Accrual for Jan 2004 - May 2005	70,254
2004 Residential Program Shareholders Incentives	1,311
Estimated 2005 Residential Program Costs	4,682,517
Estimated 2005 Residential Lost Margin	2,495,398
Revenue Taxes on 2005 Program Costs, 2004 Shareholders Incentives & 2004-2005 Interest	463,523
Total Residential DSM Program Costs to be Recovered	$6,063,623
2005 C&I DSM Adjustment	
C&I DSM Undercollection 2004	$1,221,395
Interest Accrual for Jan 2004 - May 2005	557,798
2004 C&I Program Shareholders Incentives	1,912,242
Estimated 2005 C&I Program Costs	4,294,901
Estimated 2005 C&I Lost Margin	8,983,563
Revenue Taxes on 2005 Program Costs, 2004 Shareholders Incentives & 2004-2005 Interest	659,582
Total C&I DSM Program Costs to be Recovered	$17,629,481
Total DSM Program Costs to be Recovered, Residental & C&I	$23,693,104

Lost Margin Component of 2005 DSM Adjustments	
Estimated 2005 Residential Lost Margin	$2,495,398
Estimated 2005 C&I Lost Margin	$8,983,563
Total Estimated 2005 Lost Margin to be Recovered in DSM Adj.	$11,478,961

[1] Based on HECO DSM Cost Recovery as reported in HECO's Demand-Side Management Programs Accomplishment and Surcharge Report dated May 31, 2005 ("A&S Report") and provided to the Commission, the Consumer Advocate and the Department of Defense on May 31, 2005. See HECO-RWP-2303 for excerpts of the A&S Report supporting the Loss Margin component of the 2005 DSM Adjustments.

Hawaiian Electric Company, Inc.
Docket No. 04-0113, Test Year 2005
2005 Lost Margin

	(A) Rebuttal	(B) Direct
From 1996-2003 Installations	$10,025,668	$9,440,334
From 2004 Installations	$990,868	$1,115,799
From 2005 Installations	$462,425	$404,159
Total	$11,478,961	$10,960,292

Source:

Column A: Based on HECO DSM Cost Recovery as reported in HECO's Demand-Side Management Programs Accomplishment and Surcharge Report dated May 31, 2005 ("A&S Report") and provided to the Commission, the Consumer Advocate and the Department of Defense on May 31, 2005. See HECO-RWP-2303 for excerpts of the A&S Report supporting the Loss Margin component of the 2005 DSM Adjustments.

Column B: See HECO-WP-2302, Page 1.