HECO T-9
DOCKET NO. 2008-0083

TESTIMONY OF
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HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Customer Accounts Expense includes
Customer Information System (CIS)
Customer Deposits
Interest on Customer Deposits
Revenue Lag Days
Non-Sales Electric Utility Charges

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Darren S. Yamamoto and my business address is 900 Richards Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Manager of the Customer Service Department for Hawaiian Electric Company, Inc. ("HECO"). My experience and educational background are listed in HECO-900.

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

A. My testimony will cover HECO's 2009 test year estimate of:

1) Customer Accounts Expense, which includes the following four accounts:
   a) Account No. 901 – Supervision;
   b) Account No. 902 – Meter Reading;
   c) Account No. 903 – Customer Records and Collections including the post go-live expenses for the new Customer Information System ("CIS"); and
   d) Account No. 904 – Uncollectibles.

My testimony will also describe:

2) Customer Deposits and Interest on Customer Deposits;
3) Revenue Lag Days;
4) Non-Sales Electric Utility Charges (excluding Payment Protection Program).

Q. What is HECO's test year estimate of Customer Accounts Expense?

A. As shown on HECO-901, page 1, the 2009 test year estimates of Customer Accounts Expense are provided as follows:

1) $17,237,000 at present rates;

2) $17,293,000 at current effective rates;

3) $17,363,000 with CIP CT-1 step at present and current effective rates;

4) $17,345,000 without CIP CT-1 at present and current effective rates; and

5) $17,354,000 for base case at present and current effective rates.

These five estimates are explained further in my testimony.

Q. Why did you need these different estimates of Customer Accounts Expense?

A. As noted in Mr. William Bonnet's testimony, HECO T-23, different Results of Operations were developed for the test year based on different assumptions, which then resulted in different estimates of uncollectibles expense which I discuss below. The assumptions underlying the different Results of Operations are discussed by Mr. Bonnet.

Q. What are HECO's estimates of Customer Deposits and Interest on Customer Deposits for the 2009 test year?

A. The 2009 test year estimate for Customer Deposits is $7,695,000 as shown on HECO-902. Based on this estimate of customer deposits, the test year estimate of interest on customer deposits is $471,000, as shown on HECO-903.

Q. What level of revenue lag days is proposed for test year 2009?

A. HECO estimates the test year revenue lag days to be 37 days as calculated in HECO-WP-904. In the calculation of working cash, Mr. Darren Doi (HECO T-18) uses the revenue lag days estimate.

Q. What are HECO's estimates of Non-Sales Electric Utility Charges, excluding the Payment Protection Program?

A. The 2009 test year estimates for Non-Sales Electric Utility Charges, excluding the Payment Protection Program are:

1) $2,935,000 at present rates,

2) $3,003,000 at current effective rates;

3) $3,123,000 with CIP CT-1 step at present and current effective rates;

4) $3,101,000 without CIP CT-1 at present and current effective rates; and

5) $3,112,000 for base case at present and current effective rates, as reflected in HECO-906.

These estimates are further explained in my testimony.

Q. Who is responsible for the test year estimates of Payment Protection Program?

A. Discussion of these charges is included in Mr. Peter Young's direct testimony, HECO T-3.

<u>CUSTOMER ACCOUNTS EXPENSE EXCLUDING UNCOLLECTIBLES EXPENSE</u>

Q. What is the test year estimate of Customer Accounts Expense, excluding uncollectibles expense?

A. HECO's test year Customer Accounts total expense estimate, excluding uncollectibles expense, is $15,954,000 as shown on HECO-901, page 1.

Q. What expenses are included as Customer Accounts Expense, excluding uncollectibles expense?

A. These expenses are primarily related to providing, managing and maintaining services and information for customer account services and customer account management. These activities include:

1) receiving and responding to customer calls and requests;

2) processing customer requests to start, change or terminate service;

3) meter reading;

4) field services and field investigations;

5) monthly billing (calculation and physical rendering);

6) collecting and processing of payments;

7) managing delinquent accounts; and

8) maintaining customer records.

The costs for these activities are recorded in accounts 901, 902, and 903, which are described in HECO-WP-901, page 1.

Q. How did HECO develop its test year estimate for these expenses?

A. The test year expenses are based on HECO's Operations and Maintenance ("O&M") expense budget for 2009.

Q. How was the O & M expense budget for Customer Accounts Expense prepared?

A. Briefly, HECO prepared its O & M expense budget as follows. First, staffing requirements were determined based on forecasted operational and workload requirements. Second, labor expenses for bargaining unit and salaried (merit) employees were estimated based on the wage and salary assumptions as discussed by Ms. Lorie Nagata in HECO T-17. Third, non-labor expenses were based on historical costs that are updated for anticipated 2009 price increases. The development of labor and non-labor costs for each account is detailed further in my testimony.

Q. What adjustments were made to the 2009 test year budget to determine the test year estimates?

A. The following adjustments were made to account 903 and are reflected on HECO-901:

1) A decrease of $48,000 for non-labor expense to reflect the revised amortization of the CIS Project cost based on HECO's CIS Notification Filing ("Notification Filing"), submitted to the Commission on July 1, 2008,

as required by Decision and Order No. 21798, issued in Docket No. 04-0268.

2) An increase of $13,000 of non-labor expenses to reflect the revised CIS vendor and consultant costs related to procedure development, conversion and post implementation resolution.

I discuss these adjustments in the CIS section of my testimony below.

Q. How do the 2009 test year Customer Accounts Expenses, excluding uncollectibles expense, compare to expenses in previous years?

A. The 2009 test year expenses of $15,954,000 are higher by $4,676,000 than the recorded 2007 customer accounts expense of $11,278,000. The reasons for this increase are explained by account below.

Employee Count

Q. How many employees in the Customer Service department are included in the 2009 test year labor expense?

A. There are 148 employees reflected in the test year as indicated on HECO-904, excluding the employees in the Senior Vice President Operations office. Ms. Faye Chiogioji discusses the estimated employee count for the Senior Vice President Operations office in HECO T-15.

Q. How does the test year labor force compare to previous years?

A. The actual average, highest, and end-of–year (“EOY”) employee counts are as follows:

Year	Average	High	EOY
2003	115	116	110
2004	119	128	126
2005	129	132	130

2006	126	129	126
2007	132	136	136
March 31, 2008	NA	NA	142
2008*	147	147	147
2009*	148	148	148

*Forecasted

The test year EOY staffing level of 148 is an increase of twelve positions over the 2007 actual EOY staffing level.

Q. What was the actual headcount of the Customer Service Department (excluding the Senior VP Operations office) on March 31, 2008?

A. On March 31, 2008, the actual headcount was 142. This is six employees less than the 2009 Test Year staffing level of 148.

Q. Please describe the six vacant positions.

A. The six vacant positions are for: 1) a credit supervisor; 2) a billing and account analyst; 3) a revenue protection investigator; and 4) three HECO temps. All of the labor costs for the vacant positions are reflected in the Customer Account expenses, except for the revenue protection investigator position. The labor expenses associated with the revenue protection investigator is budgeted under account 587, which is included under Mr. Robert Young‘s testimony, HECO T-8.

Q. What is the status of filling these vacancies?

A. The credit supervisor position was filled on June 9, 2008. The billing and account analyst position is scheduled to be posted and filled in July 2008. For two of the HECO temp positions we are in the stage of the employment process of reviewing, then interviewing applicants who have completed testing requirements. These positions are planned to be filled by August 2008. The remaining HECO temp position is currently being filled by an Agency Temp. The duties of the revenue protection investigator position are currently being performed on an interim basis by an employee from another area until the position is filled. However, the notice for the position will be posted in the latter half of the third quarter to ensure the position is filled by the beginning of 2009.

Q. Please summarize the need for the increased level of staffing in the test year?

A. The filling of these vacant positions for replacement of regular staff will allow the Company to continue to maintain its daily operations. In addition, the three HECO Temp positions are required during the implementation period of CIS and during the transitional period (post go-live) to perform duties of regular employees who have been assigned to the CIS project. These temp positions are used to perform various functions such as meter reading, payment processing, and customer accounting and billing.

Account 901 - Supervision

Q. What is the 2009 test year expense estimate for account 901 – supervision?

A. HECO's test year account 901 – supervision expense estimate is $1,658,000, as shown in HECO-901, page 1. This includes $177,000 for labor and $1,481,000 for non-labor expenses. (See HECO-901, page 2.)

Q. What labor expenses are included in account 901 – Supervision?

A. This account includes the projected labor costs for the Customer Service Department manager and secretary.

Q. What non-labor expenses are included in account 901 – Supervision?

A. This account includes non-labor costs for operational initiatives (i.e., technical improvements, customer initiatives, and operations projects) and in-house Information Technology support services.

Q. How does the 2009 test year expense estimate for account 901 – Supervision compare with the recorded 2007 expense of $1,331,000?

A. The 2009 test year is $327,000 higher than the recorded 2007 expense.

Q. What is the reason for the increase in the 2009 test year labor expense estimate over the 2007 recorded expense?

A. The 2009 labor costs recorded in account 901 are higher by $24,000, primarily due to the vacancy of the department secretary for the first quarter of 2007. The 2009 Test Year reflects a full year's worth of salary for the department secretary position.

Q. What is the reason for the increase in the 2009 test year non-labor expense estimate over the 2007 recorded expense?

A. The increase in the non-labor expense of $303,000 is partially due to higher labor and non-labor charges into the Information Technology System ("ITS") clearing account 2007 which resulted in an additional ITS expense of $142,000. Ms. Patsy Nanbu provides more detail of these costs in HECO T-11. The balance of the increase in non-labor is for system upgrades and process improvements for overall customer service process improvements which include customer assistance center, meter reading, field service and credit activities.

<u>Account 902 – Meter Reading</u>

Q. What is the 2009 test year expense estimate for account 902 – Meter Reading?

A. HECO's test year 2009 expense estimate for account 902 – Meter Reading is $3,545,000, as shown in HECO-901, page 1. This includes labor expense estimate of $3,016,000 and non-labor expense estimate of $529,000, as shown in HECO-901, page 2.

Q. What expenses are included in account 902 – Meter Reading labor expense estimate for test year 2009?

A. Meter Reading labor expense includes the labor cost for:

1) Thirty-two meter readers and eleven HECO temporary meter readers. The number of required Meter Reading positions has remained stable since 1992 (as previously stated in the 2005 test year rate case, Docket No. 04-0113, HECO T-9, page 13, and in my testimony, HECO T-8, in the 2007 test year rate case, Docket No. 2006-0386, page 8). The temporary Meter Readers are required to supplement the permanent meter readers in the implementation of CIS and the transition from the current ACCESS system;
2) one clerk;
3) one supervisor;
4) one translation system coordinator;
5) a 20% allocation of the labor expense for the director and analyst of Customer Field Services; and
6) labor expense related to the "rereading" of meters for billing purposes.

Q. How does the test year 2009 labor expense estimate for account 902 compare with the recorded 2007 labor expense of $2,133,000?

A. The test year estimate is $883,000 higher than the 2007 recorded labor expense.

Q. What are the reasons for the increased labor expense in the 2009 test year?

A. The primary reasons for the increase in estimated labor cost for the 2009 test year are:

1) Contractual bargaining unit and salaried employee wage increases as discussed in Ms. Lorie Nagata's testimony in HECO T-17;

2) The addition of the labor costs for the eleven HECO temporary meter readers as discussed above; and

3) lower 2007 labor costs due to new hires experiencing "time-in-grade wage increases", i.e., where meter readers' wages ramp up to the top wage tier during the first two years in their position.

Q. What expenses are included in account 902's $529,000 non-labor expense estimate for the 2009 test year?

A. The 2009 test year non-labor expenses include the costs of vehicle operation and maintenance, maintenance for the meter reading devices used to record meter readings in the field, the support equipment used to transfer those readings from the meter reading devices to the mainframe computer, company identification uniforms, and miscellaneous supplies such as meter seals required by the meter readers.

Q. How does the 2009 test year non-labor expense estimate compare with the amount recorded in 2007?

A. The test year is $144,000 higher than 2007 recorded expense of $385,000.

Q. What is the reason for this increase?

A. The increase in 2009 test year expenses reflects normal levels of operating expenses and the expected increase in operations and workload due to the continued increase in customer accounts, customer meters and customer service requests and related work and vehicle upgrades.

<u>Account 903 – Customer Records and Collection Expense</u>

Q. What is the 2009 test year expense estimate for account 903 – Customer Records and Collection Expense?

A. HECO's test year account 903 – Customer Records and Collection Expense estimate is $10,751,000 as shown on HECO-901, page 1. This includes $4,909,000 of labor and $5,842,000 of non-labor expenses, as shown on HECO-901, page 2.

Q. Were any budget adjustments made to the 2009 test year estimate for ratemaking purposes?

A. Yes. There were two separate non-labor budget adjustments. The reduction of $48,000 for the CIS Project amortization cost was offset by an increase of $13,000 for CIS outside service costs, resulting in a net reduction of $35,000.

Q. Please explain the non-labor adjustments.

A. The adjustments for the amortization and outside services costs were required to reflect the most current estimate of CIS Project costs as provided to the Commission in the CIS Notification Filing, dated July 1, 2008, in Docket No. 04-0268.

Q. What customer service functions are charged to account 903?

A. Included in this account are the labor and non-labor expenses for:

1) handling customer calls and requests;
2) processing customer requests to start, change or terminate service;
3) maintenance of customer accounts within the current customer information system, ACCESS, and maintenance, support and expanded functionalities of the new CIS which are described later in my testimony;
4) bill calculation;

5) printing and mailing of bills;
6) processing of customer payments; and
7) managing delinquent accounts and credit related activities.

Q. What functional areas in Customer Service budget and charge to account 903?

A. Labor expenses are budgeted in account 903 by the Administration Division, the Credit Division which includes Payment Processing, the Field Service & Collections Division (excluding the Meter Reading Section), and the Customer Account Services Division, which includes the Customer Accounting & Billing section and the Customer Assistance Center.

Q. How does the 2009 test year expense estimate for account 903 compare with the 2007 recorded expense of $7,429,000?

A. The test year expense estimate is $3,322,000 higher than what was recorded in 2007.

Q. What was the reason for this increase?

A. The increase is primarily due to the CIS project and the concurrent implementation of the Company's plans to outsource its bill printing, Interactive Voice Response ("IVR"), and Interactive Web Response ("IWR") functions. HECO-908 shows the impact of these initiatives on the expenses budgeted in account 903.

Q. What is the reason for the increase of $470,000 in the 2009 test year labor estimate from the 2007 recorded expense?

A. The primary reason is that the labor cost associated with the Customer Service department staff assigned to the development of the CIS database were deferred in 2007 which I discuss below. In 2009, most of the labor costs for these staff members are reflected in their "normal" expense account as they return to their routine job duties. Also, included in the labor costs for CIS are training costs of $265,113 and post go-live deployment costs for $99,123 as noted in HECO-908. More detail on the labor costs is provided in the Notification Filing.

In addition, the labor costs for three HECO temps that were not in the department in 2007 are reflected in this account. The three temps are required to supplement the regular account services clerks and the customer billing reps to assist in the implementation of and transition to the new CIS.

Q. What costs are included in account 903's $5,842,000 non-labor expense estimate for the test year 2009?

A. The 2009 test year non-labor expense includes costs for vehicle operation and maintenance, field service tools and equipment, seals, postage, maintenance of the different systems, e.g., Unisys, ACD/IVR , mV-90 and eBill, billing forms and envelopes, uniforms, miscellaneous supplies such as office supplies and printing and revised allocation of software maintenance and other data support services. In addition, costs for the maintenance, support and expanded functionalities of the new CIS are included.

Q. How does the test year non-labor expense estimate for account 903 compare with the 2007 recorded expense?

A. The test year non-labor expense is $2,852,000 higher than recorded 2007 non-labor expense.

Q. Please provide the reasons for the increase in the non-labor estimate over the 2007 recorded expense?

A. The primary reasons for the increase relate to the amortization of the CIS deferred expenses, implementation expenses for the new CIS system, and additional costs associated with the new technology additions of the Bill Print System, IVR and IWR which are noted above.

The break-down of these costs are:

1) CIS related costs budgeted to the CIS Project P0000571 in the amount of $520,238 is made up of various outside consultant fees (see HECO-908). This is discussed in further detail under CIS.

2) Amortization of deferred CIS costs of $977,000 (see HECO-WP-908). The deferred CIS costs are discussed in the Notification Filing and are reflected in HECO-1117 in Ms. Patsy Nanbu's testimony, HECO T-11.

3) Post CIS Implementation related costs of $1,250,000 (see HECO-908) are made up of:

- CIS vendor costs for maintenance of system - $438,000
- CIS report design and development - $173,000
- CIS consultant services for support and new functionalities - $198,000
- Outsourcing of bill printing functions - $322,000
- Outsourcing of IVR $88,000
- Outsourcing of IWR $31,000

The CIS Project

Q. Please describe the CIS.

A. CIS is a new customer information system that consists of the purchase and installation of hardware and software, including support system software, which will replace HECO's existing ACCESS customer information system. In Decision and Order No. 21798 ("CIS Order"), dated May 3, 2005, issued by the

Public Utilities Commission in Docket No. 04-0268, HECO's purchase and implementation of CIS was approved.

Q. Please identify what the CIS project is.

A. The CIS Project involves the purchase and installation of a new, commercially available software, CIS, including purchase, configuration and testing of the software for the new system, purchase and installation of related hardware, conversion and "cleansing" of data (i.e., making sure the data that is converted is in the standard format), development and testing of interfaces between the new system and other HECO systems, including the Outage Management System ("OMS"), the Bill Print System, the IVR system, and the IWR system and associated training for employees.

Q. What does the CIS software do?

A. Besides providing the Company with the features and functionality necessary to manage its customers, accounts, premises, products and services, the new CIS software applications focus on improving the interactions between the utility and its customers. They are designed to deliver timely information over different channels of communication (i.e., call center, walk-in, interactive voice response and internet).

Other features offered by CIS include: multiple service billing for metered and non-metered accounts; bill settlement; flexible rates and non-conventional (complex) price offerings; meter management; contract management; service order processing; credit and collections; payment plans; deposits; correspondence; transaction history; and internet access. However, the core modules of CIS are the management and billing modules that simplify complex charge handling, billing and service request transactions while allowing real-time interactions with customers. CIS also serves as the hub for all other modules that are integrated into an enterprise-wide solution.

Q. Please describe the CIS project's expected benefits.

A. The new CIS system will: (1) allow the Company to more quickly and accurately store, maintain, and manage customer-specific information necessary to provide basic customer service functions, such as producing bills, collecting payments, establishing service, and fulfilling customer requests; and (2) have substantially greater capabilities and features than the current CIS, thus enabling the Company to enhance its operations, including customer service.

These new capabilities and features will enable the Company to: (1) update and modernize its customer service abilities by providing more extensive and complete information in a readily accessible format; (2) automate processes that are currently performed manually; (3) record, store, manage, and access customer data more effectively; and (4) more easily integrate with the other new systems, e.g., Outage Management System, ELLIPSE, Human Resources Suite System), (5) expand internet customer self-service options (e-business), (6) provide billing capabilities for interval management, complex billing structures and contract billing, and pricing programs (e.g., tiered rates, green pricing, time-of-use rates), and (7) net energy metering billing.

CIS will be based on current industry standard platforms, including the operating system, programming languages, relational databases, end-user interfaces, and hardware, replacing the outdated existing that was designed in the 1980's and implemented in 1991.

Q. What is the current status of the CIS project at HECO?

A. The Company signed an agreement with PEACE Software in March 2006 to license the use of the PEACE CIS and provide the services to replace the Company's existing customer information system with the new PEACE CIS. Currently, the CIS Project is in the Construction and Testing Phase of the project. Upon successful completion of the testing in March 2009, training of HECO personnel to properly use the system in daily operations would then commence. Training is targeted to be complete and the new CIS system in service in May 2009.

As discussed in the Notification Filing, the CIS project did not meet the schedule initially established. PEACE was informed that not maintaining the schedule was a breach of its obligations under the implementation contract and therefore, PEACE's invoices would not be paid until an appropriate contract amendment reflecting the delayed schedule was negotiated. PEACE was informed that HECO was not terminating the contract and that HECO desired to see the project completed successfully with PEACE.

In addition, as noted in the Notification Filing, additional management processes have been implemented to increase oversight of the CIS project in an attempt to further mitigate risks to the project. Please refer to the Notification Filing for further detail.

Q. How are the project costs being treated?

A. In the CIS Order, the Commission approved the Company's request (as modified by the stipulation with Consumer Advocate) to defer certain software development costs for the CIS project, accumulate AFUDC on the deferred costs during the deferral period, amortize the deferred costs over a twelve year period and to include the deferred costs in rate base. Costs for the CIS project are accounted for in accordance with the Company's Computer Software Development policy, which is described by Ms. Patsy Nanbu in HECO T-11.

Q. What expenses for CIS are reflected in the Company's 2009 test year estimate?

A. HECO-907 details the CIS expenses of approximately $1,854,000 in the 2009 test year. As noted in HECO-907, the implementation of CIS will affect multiple departments' test year estimates besides Customer Service due to the training that is required as with the implementation of any new software. Also there are "Post Go-Live Deployment" expenses reflected in this amount.

Q. Please describe these "Post Go-Live Deployment" expenses.

A. Post Go-Live Deployment is under Phase 6 of the project. The primary objectives of this phase are to monitor the performance of the new system and resolve any discrepancies that occur. Post deployment is scheduled to begin in the beginning of June 2009 and complete at the end of July 2009.

Q. Are the expenses for the implementation and Post Go-Live Deployment of CIS the same as what are reflected in the Notification Filing?

A. Yes, it is. The detail for CIS expenses (excluding the amortization of the deferred expenses) in HECO-907 is provided in Attachment 5 of the Notification Filing.

Q. What kinds of expenses were deferred and are now being amortized in Account No. 903?

A. In the CIS Order, the Commission approved the Company's request (as modified by the stipulation with Consumer Advocate) to defer certain software development costs for the CIS project, accumulate AFUDC on the deferred costs during the deferral period, amortize the deferred costs over a twelve year period and to include the deferred costs in rate base.

Q. How much is the amortization expense in the test year?

A. The amortization amount that is reflected in non-labor expenses of the test year is $977,000 as reflected in HECO-WP-908 and HECO-1117. This is a net result of the original amount of $1,025,000 less the adjusted decrease amount of $48,000. The amortization was reduced based on the most current estimate of the deferred expenses as provided in the Notification Filing.

Q. How was the amortization expense calculated?

A. The deferred balance at the end of May 2009 is divided by 144 months to straight-line the monthly amortization expense over 12 years. As additional deferred costs are projected to be paid in the months June through September 2009, those specific monthly amounts are also calculated on a straight-line amortization basis. However, for those deferred costs incurred from June 2009 through September 2009, each projected month's deferred expense is reduced from the complete 144 months (of amortization) by the respective number of months that will have passed beyond the amortization start date of June 2009, to calculate the straight-line amortization amount to be applied to the remaining months with the 12 year stipulation. See HECO-WP-908 for the calculation of the amortization amount.

Q. HECO-907 shows approximately $31,000 of capital costs incurred in the test year. What is this for?

A. These costs are for hardware costs to support the system data storage and performance requirements for the CIS Project.

Q. Are the capital costs reflected in the 2009 test year plant additions estimate?

A. Yes, they are. Please see Ms. Lorie Nagata's testimony, HECO T-17, for a listing of the test year plant additions.

<u>Outsourcing of the Bill Printing Function</u>

Q. What are the tasks involved in the printing of bills?

A. Currently, the Company utilizes internal resources and facilities to print documents (e.g., customer bills, customer notification), insert the documents into the envelopes and mail (via the United States Postal System) the documents to its customers. In February 2007, the Company conducted an assessment to compare the benefit of utilizing internal resources and facilities versus using vendors to provide the bill printing and distribution functions.[1]

Q. Has the Company decided to outsource its bill printing function?

A. Yes. The outsource vendors provide high reliability and additional services that the Company's internal staff and facilities cannot provide. Cost estimates from outsource vendors compared to the internal costs reflected that the outsourcing opportunity may provide some economic benefits.

Q. When does the Company plan to begin outsourcing the bill printing function?

A. Based on the timing of the CIS, the Company has decided to begin outsourcing these bill printing functions with the implementation of the CIS project, i.e., in June 2009.

Q. How much will it cost in the test year to outsource the bill printing function?

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[1] The Decision Synopsis for CIS Print Services was provided to the Commission under Protective Order No. 21444 of Docket No. 04-0268, as Attachment 3 in the Company's Notification Filing.

A. As noted in HECO-908, the test year expense is estimated at approximately $320,000 to outsource the bill printing function and is budgeted in account 903. These costs represent the service charges for the printing and mailing of the Companies' customer bills, excluding postage fee, on a per bill basis.[2]

<u>Outsourcing of the IVR Functions</u>

Q. Please identify what the outsourcing IVR system is.

A. The outsourcing IVR system allows the Company's customers to use their telephones to perform the following basic functions: report an outage (transfers to Outage Management System IVR), access customer account information using either a customer number or telephone number, request a duplicate copy of last bill to be mailed to address on record, access information about bill payment methods, office hours, payment locations, and energy solutions and special programs, and transfer to an appropriate HECO customer service queue. In addition, when a call is transferred, the outsourcing IVR system will provide to the utility's customer service agent a call chronology screen pop window with relevant call chronology and an appropriate CIS screen.

Currently, the Company licenses the use of the Avaya IVR system and maintains the system. In 2006, it was announced that First Data ("FD") had acquired PEACE Software and FD presented an alternative IVR system to the Company. In light of this and the potential synergies and efficiencies for the Company, the Company conducted an assessment to compare the benefit of continuing to utilize the existing Avaya IVR system with the required upgrades, modifications and integration effort to connect the IVR to the new CIS versus to

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[2] The Decision Synopsis for CIS Print Services was provided to the Commission under Protective Order No. 21444 of Docket No. 04-0268, as Attachment 3 in the Company's Notification Filing.

utilize FD's outsource IVR system. The assessment favored utilizing FD's outsource IVR system.[3] The Company decided to implement utilizing FD's outsource IVR system.

Q. Please describe the expected benefits of utilizing FD's outsource IVR solution?

A. Some of the benefits of utilizing FD's IVR solution include that it is an affordable alternative to upgrading the Company's existing IVR system; more functionality can be provided in the future with less future custom PEACE software modifications to add features; and the fact that HELCO may also be able to utilize this system since it currently does not have an IVR system.

Q. What is the cost impact of implementing the FD IVR solution in the test year?

A. As noted in HECO-908, in the test year, the Company estimates that it will incur approximately $88,000 for the implementation of the FD IVR solution in account 903. These costs represent service charges for the processing of customer phone calls through the vendor IVR solution.

Outsourcing of the IWR Functions

Q. Please identify what service the new IWR system provides.

A. The new IWR system will provide online services between the Company and its customers. Customers will be able to register for online services, update customer information, view their customer information (i.e. bills, payment, etc.), view Company information such as payment locations, office hours, request

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[3] The Decision Synopsis was provided to the Commission under Protective Order No. 21444 of Docket

transactions with the Company (e.g., turn on electric service, etc.), and provide comments regarding their account to the Company.

Currently, the Company has an inhouse web services system with limited functionality and features. In 2006, it was announced that First Data (FD) had acquired PEACE Software and FD presented an alternative outsource vendor IWR solution to the Company. Like the IVR solution, the Company conducted an assessment to compare the benefits of continuing to support the existing inhouse web services with the alternative of utilizing FD's IWR system. The assessment favored utilizing FD's outsource IWR system.[4] The Company decided to implement utilizing FD's outsource IWR system.

Q. Please describe the expected benefits of utilizing FD's outsource IWR solution?

A. The following are examples of the benefits of utilizing FD's IWR

Solution: more functionality with less future custom PEACE software modifications to add features, the IWR system is productized and will have an R&D life-cycle, and FD's IWR solution will fully integrate with the bill print and mailing outsourcing which is provided by FD.

Q. What is the 2009 test year cost for the implementation of the new IWR solution?

A. As noted in HECO-908, the expenses associated with the implenentation of the new IWR solution is approximately $31,000 which is reflected in account 903.

No. 04-0268, Attachment 4 of the July 1, 2008 Notification Filing.

[4] The Decision Synopsis was provided to the Commission under Protective Order No. 21444 of Docket No. 04-0268, Attachment 4 of the July 1, 2008 Notification

These costs represent the estimated service charges based on FD's flat monthly rate.

ACCOUNT 904 – UNCOLLECTIBLE ACCOUNTS

Q. What is the test year 2009 expense estimate for Account No. 904 – Uncollectible Accounts Expense?

A. I am presenting five test year estimates of uncollectibles expense as shown in HECO-901 and HECO-905. These are:

1) $1,283,000, at present rates;
2) $1,339,000, at current effective rates;
3) $1,409,000 with CIP CT-1 step at present and current effective rates;
4) $1,391,000 without CIP CT-1 at present and current effective rates;
5) $1,400,000 for the base case at present and current effective rates.

Q. What is the reason for these different test year estimates?

A. As noted above, these test year estimates were calculated to reflect the varying level of uncollectibles expense associated with the test year electric sales revenues. The development of these revenue estimates is discussed by Mr. Peter Young in HECO T-3. Adjustments reflected in HECO-901, page 1, were made to the O & M expense budget to reflect these different estimates of uncollectibles expense.

Q. Were the different estimates of electric sales revenues the only driver of all of the adjustments to the O & M budget?

A. Yes. The uncollectibles factor of 0.0719% is the same factor used in all three calculations.

Q. Why does the Company calculate both the Uncollectible Accounts Expense between present rates and current effective rates (present rates with the interim surcharge)?

A. The uncollectible accounts expense based on present rates and current effective rates as input into the Results of Operations presented by Mr. William Bonnet in HECO T-23. Further discussion regarding these presentations may be found in Mr. Bonnet's testimony.

Q. Please explain the general method used to determine the uncollectibles expense?

A. HECO uses the "Percentage of Electric Sales Revenue" method, as accepted by the Commission in previous dockets, including HECO's previous rate cases (Decision and Order No. 24171 in Docket No. 04-0113, dated May 1, 2008, for the 2005 test year and Docket No. 7766 where the Commission issued Decision and Order No. 14412, dated December 11, 1995, for the 1995 test year). However, in the 2007 Test Year Rate Case, the settlement agreement filed on September 6, 2007, the parties agreed to the absolute amount of $970,000 as a fixed uncollectibles expense.

Q. What is the "Percentage of Electric Sales Revenue" method?

A. This method calculates uncollectibles for a given period by multiplying electric sales revenues for that period by a net write-off percentage. The net write-off percentage (or factor) is determined by dividing the total net write-offs for the latest twelve months for which write-off percentage data is available by the total electric sales revenue lagged by four months.

Q. What is the estimated net write-off percentage used to calculate test year 2009 uncollectibles?

A. The estimated net write-off percentage for 2009 test year is 0.0719%. (See HECO-WP-905, page 2).

Q. Why was a five year time series used to calculate the 2009 uncollectibles?

A. Historically, write-offs fluctuate from year to year due to a number of external factors including bankruptcy filings, the economy, and increases in fuel prices. An example of a decelerating write-off period was in years 2004 and 2005 when the write-offs dipped to .03% from a relative stable period of near .10% from years 1999 through 2003. However, in the past several months the Company has experienced higher write-off levels, similar to those experienced in 2004 (HECO-WP-905). To reflect the long run uncollectibles experience of the Company, the data from the most recent five year period from January 2003 through December 2007 was used to estimate HECO's uncollectible rate.

CUSTOMER DEPOSITS

Q. What is HECO's average test year estimate of customer deposits?

A. HECO's average test year estimate of customer deposits is $7,695,000, as shown in HECO-902.

Q. Why are customer deposits collected?

A. Customer deposits are collected from customers as security for their electric service. These customers are either new customers who have not established their creditworthiness with HECO, or are past or existing customers who have failed to maintain creditworthiness with us.

Q. When does HECO require a deposit?

A. A deposit is required in cases when the applicant for service cannot establish credit by any of the other means allowed under HECO Tariff Rule No. 5, Establishment and Re-establishment of Credit. The deposit is held until the customer has established a record of twelve months of continuous prompt payments, has closed the account, or service has been terminated for nonpayment of the full deposit and/or electric bills.

Q. Are there any changes proposed regarding customer deposits?

A. No.

Q. How was the test year estimate of customer deposits derived?

A. The test year's EOY estimate of customer deposits was developed in two steps. First, the 2008 EOY estimate of customer deposits was derived by multiplying the 2007 actual EOY customer deposit balance by a growth factor of 8.521% and adding the resulting product to the 2007 EOY balance. The 2009 EOY estimate of customer deposits was derived by multiplying the 2008 EOY balance estimate with the same growth factor of 8.521% and adding the resulting product to the 2008 estimated EOY estimated balance. Second, the average test year estimate of customer deposits was derived from calculating a simple average of the estimated EOY 2008 and 2009 customer deposit balances of $7,380,000 and $8,009,000, respectively.

Q. How was the factor of 8.521% derived?

A. The factor represents the average annual growth rate in year-end deposit balances for the period from 2003 through 2007, as shown in HECO-WP-902. This methodology has been used and accepted in the last two rate case.

INTEREST ON CUSTOMER DEPOSITS

Q. What is HECO's test year estimate of Interest on Customer Deposits?

A. HECO's test year estimate of Interest on Customer Deposits is $471,000 as shown in HECO-903.

Q. How was this estimate of Interest on Customer Deposits derived?

A. First the 2008 amount was estimated by multiplying the 2007 actual interest on customer deposits with the growth factor of 1+8.521%. Then the 2009 amount was estimated by multiplying the 2008 estimate of $434,000 with the growth factor of 1+8.521%, resulting in the test year estimate of $471,000 (HECO-WP-903). The 8.521% growth factor is the same annual growth rate calculated for customer deposits balances for 2009 as discussed above and is shown in HECO-WP-902.

REVENUE LAG DAYS

Q. What level of revenue lag days is proposed for test year 2009?

A. The estimated revenue lag days for the test year are 37 days.

Q. What are revenue lag days?

A. Revenue lag days measure the amount of time between the date that electricity is used by the customer and the date that HECO is paid for such use.

Q. How did HECO calculate its test year estimate of revenue lag days?

A. The test year estimate of revenue lag days was calculated by adding a fixed number of days (representing the mid-point of the monthly bill) to a variable number that represents the average amount of time it takes to bill a customer and receive payment for the bill.

Q. What are these numbers of days for test year 2009?

A. The fixed days for the test year is 15.5; the variable days are 21.3.

Q. Is the proposed revenue lag days estimate for the test year 2009 reasonable?

A. Yes. Over the past five years from 2003 to 2007 the actual average revenue lag days were 36.8 days as shown on HECO-WP-904, page 3.

NON-SALES ELECTRIC UTILITY CHARGES

Q. What non-sales electric utility charges do you cover in your testimony?

A. I am covering the Service Establishment Charge, Late Payment Charge, Field Collection Charge, and the Returned Payment Charge as reflected in HECO-907. Mr. Peter Young in HECO T-3 covers the other non-sales electric utility charges from the Payment Protection Program.

Q. How are the revenues from non-sales electric utility charges determined?

A. The estimated revenues at present rates from the Service Establishment Charge, Field Collection Charge, and Returned Payment Charge are based on the forecasted transaction levels for each type of charge for the 2009 test year, as noted in HECO-WP-906, page 2, then multiplied by the rate charged by the Company as specified in the Rule No. 7, Sections C, D, and E of HECO's tariff, sheets 16 and 16A, and as reflected in HECO-WP-906, page 1.

Q. How were the transactions for these charges forecasted for the test year?

A. The estimated number of transactions is equal to the average annual number of transactions for the past five years.

Q. Are there changes proposed to non-sales electric utility charges at proposed rates?

A. Yes. The Company is proposing the same charge of $22.00 for the Returned Payment Charge that was proposed in the 2007 HECO rate case, Docket No. 2006-0386, and approved in the Interim Decision and Order No. 23749 on October 2, 2007. The present rate which was approved in Docket No. 04-0113 in Decision and Order No. 24171 on May 1, 2008 is $16.00.

Q. Why is the Company proposing the higher charge?

A. Because the banks have increased their charges to the Company for processing returned payments, the returned payment charges to cost causers should also be increased.

Q. How was the proposed Returned Payment Charge of $22.00 per returned payment determined?

A. Mr. Peter Young discusses the development of the proposed rate for the Returned Payment Charge in HECO T-22.

Q. Does the Company propose any changes to the Field Collection charge or the Service Establishment charges?

A. No, it does not.

Q. Please explain how the Field Collection Charge is currently applied.

A. HECO's current Field collection Charge is applied only when a field call results in actual collection of payment from the customer.

Q. Is HECO proposing any changes in regard to the application of the Field Collection Charge?

A. No. The Company will not pursue any changes to the application of the field collection charges at this time.

Q. How are the Late Payment Charge revenues calculated?

A. The Late Payment Charge revenues are calculated by multiplying the estimated test year late payment percentage factor and the estimated electric sales revenues.

Q. How was the Late Payment Charge percentage factor determined?

A. The Late Payment Charge percentage factor of 0.089% of electric sales revenues is calculated as the historical proportion of annual revenues from late payment charges to the total billed revenues during the period from year 2002 through 2007 as shown on HECO-WP-907.

Q. How was the Late Payment Charge estimated for OCARS (Other Customer Account Receivables – non Light & Power)?

A. The amount used was based on a review of historical payments from 2002 through 2007.

Q. Who provided the estimates of electric sales revenues for the different presentations?

A. Mr. Peter Young provided these estimates and discusses their development in HECO T-22.

SUMMARY

Q. Please summarize your testimony.

A. The 2009 test year estimate for Customer Accounts Expense is $17,237,000 at present rates, $17,293,000 at current effective rates, $17,363,000 with CIP CT-1 step at present and current effective rates, $17,345,000 without CIP CT-1 at present and current effective rates, and $17,354,000 for base case at present and current effective rates. This level of expense reflects the level of staffing (labor expense) and corresponding non-labor expenses that are required to provide service to customers each day. The test year level of spending also reflects HECO's continued effective management of delinquent accounts and bad debt, supports the implementation of new technologies and system enhancements, and provides the level of miscellaneous expenses needed to provide good service to our customers.

The 2009 test year estimate for Customer Deposits is a simple average of year-end 2008 and 2009 estimated customer deposit balances of $7,380,000 and $8,009,000, respectively. The Interest on Customer Deposits for 2009 test year is $471,000. The revenue collection lag days for the test year are 37 days. Revenues from non-sales electric utility charges at present rates, present rates with the interim surcharge, and proposed rates for the 2009 test year are $2,935,000, $3,036,000, and $3,123,000 respectively.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY, INC.

DARREN S. YAMAMOTO

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company, Inc. 900 Richards Street, Honolulu, HI 96813
POSITION:	Manager, Customer Service Department Hawaiian Electric Company, Inc. (December 2004 to present)
YEARS OF SERVICE:	24 Years
EDUCATION:	University of Hawaii (1983), Bachelor of Business Administration, Finance
PREVIOUS POSITIONS:	Director, Customer Field Services, Customer Service Department Hawaiian Electric Company, Inc. (September 2002 to December 2004)
	Supervisor, Construction & Maintenance Department Hawaiian Electric Company, Inc. (November 1999 to September 2002)
	Working Foreman, Construction & Maintenance Department Hawaiian Electric Company, Inc. (October 1995 to November 1999)
	Transmission & Distribution Line Inspector, Construction & Maintenance Department Hawaiian Electric Company, Inc. (May 1994 to September 1995)
	Linemen, Construction & Maintenance Department Hawaiian Electric Company, Inc. (August 1984 to May 1994)

HAWAIIAN ELECTRIC COMPANY, INC.
CUSTOMER ACCOUNTS EXPENSE
2003 - 2009

($ THOUSANDS)

		RECORDED					BUDGET		ADJUST	TEST YEAR BUDGET
	CUSTOMER ACCOUNTS	2003	2004	2005	2006	2007	2008	2009		2009
901.00	Supervision	620	856	973	1,156	1,331	1,279	1,658	0	1,658
902.00	Meter Reading Expenses	2,085	2,413	2,192	2,472	2,518	3,123	3,545	0	3,545
903.00	Cust Records & Collection	6,335	7,049	7,644	7,106	7,429	10,168	10,786	(35)	10,751
905.00	Misc. Customer Accounts	0	1	1	0	0	0	0	0	0
	Subtotal less Uncollectible Acct.	9,040	10,319	10,810	10,734	11,278	14,570	15,989	(35)	15,954
904.00	Uncollectible Accounts	1,015	413	339	1,582	976	970	1,093	190	1,283
	Total Customer Account Expense **Present Rates**	10,055	10,732	11,149	12,316	12,254	15,540	17,082	155	17,237
904.00	Uncollectible Accounts	1,015	413	339	1,582	976	970	1,093	246	1,339
	Total Customer Account Expense **Current Effective Rates**	10,055	10,732	11,149	12,316	12,254	15,540	17,082	211	17,293
904.00	Uncollectible Accounts	1,015	413	339	1,582	976	970	1,093	316	1,409
	Total Customer Account Exp.**CIP1 CT-1 (Full Cost) @ Present & Current Effective Rates**	10,055	10,732	11,149	12,316	12,254	15,540	17,082	281	17,363
904.00	Uncollectible Accounts	1,015	413	339	1,582	976	970	1,093	298	1,391
	Total Customer Account Exp. **Interim Increase (w/o CIP1 CT-1) @ Present & Current Effective Rates**	10,055	10,732	11,149	12,316	12,254	15,540	17,082	263	17,345
904.00	Uncollectible Accounts	1,015	413	339	1,582	976	970	1,093	307	1,400
	Total Customer Account Expense **Base Case at Present & Current Effective Rates**	10,055	10,732	11,149	12,316	12,254	15,540	17,082	272	17,354

Source: HECO-WP-101 (B), Reports S1 & S2 for Recorded 2003-2007, 2008 Budget latest update & 2009 TY.

Uncollectible expense based on Revenues 6-24-08 from Lori Okazaki

S:_Company\RegulatoryAffairs\HECO 2009 TY Rate Case\09 Direct Testimonies\09HECO T-9 Yamamoto\T-9 Exhibits & Workpapers\[HECO-901 Cust.Acc.'03-'09_P.1 & 2_rev2008_7-03-

HAWAIIAN ELECTRIC COMPANY, INC.
CUSTOMER ACCOUNTS EXPENSE
2003 - 2009

($ THOUSANDS)

LINE	CUSTOMER ACCOUNTS		----RECORDED---- 2003	2004	2005	2006	2007	----BUDGET---- 2008	2009	ADJUST	TEST YEAR 2009
	Acct 901 - Supervision										
1		Labor	60	43	80	146	153	169	177		177
2		Non-labor	560	813	893	1,010	1,178	1,110	1,481		1,481
3		TOTAL	620	856	973	1,156	1,331	1,279	1,658		1,658
	Acct 902 - Meter Reading										
4		Labor	1,847	1,963	1,852	2,090	2,133	2,635	3,016		3,016
5		Non-labor	238	450	340	382	385	488	529		529
6		TOTAL	2,085	2,413	2,192	2,472	2,518	3,123	3,545		3,545
	Acct 903 - Cust Rec. & Collec.										
7		Labor	3,724	4,012	4,400	4,105	4,439	5,358	4,909		4,909
8		Non-labor	2,611	3,037	3,244	3,001	2,990	4,810	5,877	(35)	5,842
9		TOTAL	6,335	7,049	7,644	7,106	7,429	10,168	10,786	(35)	10,751
	Acct 905 - Misc Cust Accts.										
10		Labor	0	1	1	0	0	0	0		0
11		Non-labor									
12		TOTAL	0	1	1	0	0	0	0		0
	Sub total	901,902,903,905									
13		Labor	5,631	6,019	6,333	6,341	6,725	8,162	8,102	0	8,102
14		Non-Labor	3,409	4,300	4,477	4,393	4,553	6,408	7,887	(35)	7,852
15		TOTAL	9,040	10,319	10,810	10,734	11,278	14,570	15,989	(35)	15,954
	Acct 904 - Uncollectible Accts.										
16		Non-labor	1,015	413	339	1,582	976	970	1,093	190	1,283
17		TOTAL	1,015	413	339	1,582	976	970	1,093	190	1,283
	Total Cust. Accts **Present Rates**										
18		Labor	5,631	6,019	6,333	6,341	6,725	8,162	8,102	0	8,102
19		Non-labor	4,424	4,713	4,816	5,975	5,529	7,378	8,980	155	9,135
20		TOTAL	10,055	10,732	11,149	12,316	12,254	15,540	17,082	155	17,237
	Account 904 - Uncollectible Accts.										
21		Non-labor	1,015	413	339	1,582	976	970	1,093	246	1,339
22		TOTAL	1,015	413	339	1,582	976	970	1,093	246	1,339
	Total Cust. Accts **Current Effective Rates**										
23		Labor	5,631	6,019	6,333	6,341	6,725	8,162	8,102	0	8,102
24		Non-labor	4,424	4,713	4,816	5,975	5,529	7,378	8,980	211	9,191
25		TOTAL	10,055	10,732	11,149	12,316	12,254	15,540	17,082	211	17,293
	Account 904 - Uncollectible Accts.										
26		Non-labor	1,015	413	339	1,582	976	970	1,093	316	1,409
27		TOTAL	1,015	413	339	1,582	976	970	1,093	316	1,409
	Total Cust. Accts **CIP1 CT-1 (Full Cost) at Present & Curent Effective Rates**										
28		Labor	5,631	6,019	6,333	6,341	6,725	8,162	8,102	0	8,102
29		Non-labor	4,424	4,713	4,816	5,975	5,529	7,378	8,980	281	9,261
30		TOTAL	10,055	10,732	11,149	12,316	12,254	15,540	17,082	281	17,363
	Account 904 - Uncollectible Accts.										
31		Non-labor	1,015	413	339	1,582	976	970	1,093	298	1,391
32		TOTAL	1,015	413	339	1,582	976	970	1,093	298	1,391
	Total Cust. Accts **Interim Increase (w/o CIP1 CT-1) at Present & Current Effective Rates)**										
33		Labor	5,631	6,019	6,333	6,341	6,725	8,162	8,102	0	8,102
34		Non-labor	4,424	4,713	4,816	5,975	5,529	7,378	8,980	263	9,243
35		TOTAL	10,055	10,732	11,149	12,316	12,254	15,540	17,082	263	17,345
	Account 904 - Uncollectible Accts.										
36		Non-labor	1,015	413	339	1,582	976	970	1,093	307	1,400
37		TOTAL	1,015	413	339	1,582	976	970	1,093	307	1,400
	Total Cust. Accts **Base Case at Present & Current Effective Rates**										
38		Labor	5,631	6,019	6,333	6,341	6,725	8,162	8,102	0	8,102
39		Non-labor	4,424	4,713	4,816	5,975	5,529	7,378	8,980	272	9,252
40		TOTAL	10,055	10,732	11,149	12,316	12,254	15,540	17,082	272	17,354

Source: HECO-WP-101 (B), Reports S1 and S2 for Recorded 2003-2007, 2008 Budget latest update & 2009 TY.

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HAWAIIAN ELECTRIC COMPANY, INC.

CUSTOMER DEPOSITS

(ACCOUNT 235.01)

($ THOUSANDS)

Line		
1	Recorded Balance 12/31/03	5,072
2	Recorded Net Increase in 2004	-6
3	Recorded Balance 12/31/04	5,066
4	Recorded Net Increase in 2005	321
5	Recorded Balance 12/31/05	5,387
6	Recorded Net Decrease in 2006	982
7	Recorded Balance 12/31/06	6,369
8	Recorded Net Increase in 2007	432
9	Recorded Balance 12/31/07	6,801
10	**Estimated** Net Increase in 2008	579
11	**Estimated Balance 12/31/08**	7,380
12	**Estimate Increase 12/31/09**	629
13	**Estimated Balance 12/31/09**	8,009
	Estimated Balance 12/31/08	7,380
	Estimated Balance 12/31/09	8,009
		15,389 /2
		7,695

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HAWAIIAN ELECTRIC COMPANY, INC.

INTEREST ON CUSTOMER DEPOSITS

(ACCOUNT 431.05)

($ THOUSANDS)

Line		
1	Recorded Balance 12/31/03	280
2	Recorded Net Increase in 2004	27
3	Recorded Balance 12/31/04	307
4	Recorded Net Increase in 2005	2
5	Recorded Balance 12/31/05	309
6	Recorded Net Increase in 2006	39
7	Recorded Balance 12/31/06	351
8	Recorded Net Increase in 2007	49
7	Recorded Balance 12/31/07	400
8	Recorded Net Increase in 2008	34
9	**Estimated Balance 12/31/08**	434
10	**Estimated Increase in 2009**	37
11	**Estimated Balance 12/31/09**	**471**

Source: HECO-WP- DEP INT 2-29-08

S:_Company\RegulatoryAffairs\HECO 2009 TY Rate Case\09 Direct Testimonies\09HECO T-9 Yamamoto\T-9 Exhibits & Workpapers\[HECO-902 & 903 HECO-WP 902 & 903_05-09-08.xls]DEP BAL

HAWAIIAN ELECTRIC COMPANY, INC.
Summary Recorded and End of Year Number of Employees

	2004	2005	2006	2007	2007	2008 YTD	2009
	Recorded	Recorded	Recorded	Test Year	Recorded	Recorded	Test Year
	EOY	EOY	EOY	EOY	EOY	3/3/1/08	EOY
Sr. VP Operations	2	3	3	3	2	2	2
Customer Service	126	130	126	133	136	142	148
TOTAL	128	133	129	136	138	144	150

Source: Faye Chiogioji

HAWAIIAN ELECTRIC COMPANY, INC.
UNCOLLECTIBLE ACCOUNTS EXPENSE
2009
ACCOUNT 904
($ THOUSANDS)

Line		Estimated Test Year Revenue 2009
1	Electric Sales Revenue used for 2009 BUDGET	$1,520,000
2	Times Uncollectible Factor used for 2009 BUDGET	0.0719%
3	Equals Uncollectible Accounts Expense	$1,093
4	Electric Sales Revenue at **Present Rates**	$1,785,019
5	Times Uncollectible Factor	0.0719%
6	Equals Uncollectible Accounts Expense	$1,283
7	Electric Sales Revenue at **Current Effective Rates**	$1,862,228
8	Times Uncollectible Factor	0.0719%
9	Equals Uncollectible Accounts Expense	$1,339
10	Electric Sales Revenue **CIP1 CT-1 (Full Cost) at Present & Current Effective Rates**	$1,959,290
11	Times Uncollectible Factor	0.0719%
12	Equals Uncollectible Accounts Expense	$1,409
13	Electric Sales Revenue **Interim Increase (w/o CIP1 CT-1) at Present & Current Effective Rates**	$1,935,449
14	Times Uncollectible Factor	0.0719%
15	Equals Uncollectible Accounts Expense	$1,392
17	Electric Sales Revenue **Base Case at Present & Current Effective Rates**	$1,947,493
18	Times Uncollectible Factor	0.0719%
19	Equals Uncollectible Accounts Expense	$1,400

S:_Company\RegulatoryAffairs\HECO 2009 TY Rate Case\09 Direct Testimonies\09HECO T-9 Yamamoto\T-9 Exhibits & Workpapers\[HECO-905 Uncoll Exp%_2009_rev.07-03-08_1100hrs.xls]H-905_Uncol Exp@VariRevScenario

HAWAIIAN ELECTRIC COMPANY, INC.
2009 TEST YEAR
$000

NON-SALES ELECTRIC UTILITY CHARGES

	At Present Rates	**At Current Effective Rates**	CIP1 CT-1 (Full Cost) at Present & Current Effective Rates	Interim Increase (w/o CIP1 CT-1) at Present & Current Effective Rates	Base Case at Present & Current Effective Rates
Non-Sales Electric Utility Charges					
Service Establishment Charges	$1,145	$1,145	$1,145	$1,145	$1,145
Field Collection Charges	$106	$106	$106	$106	$106
Returned Payment Charges	$90	$90	$123	$123	$123
Late Payment Charges - OCARS	$5	$5	$5	$5	$5
Late Payment Charges *	$1,589	$1,657	$1,744	$1,722	$1,733
Total Other Operating Revenues	$2,935	$3,003	$3,123	$3,101	$3,112

*revenues * 0.089% factor

Note: Svc. Est Chrge, Fld Collec Chrg & Returned Pay. - Present Rates based on Dkt 04-0113 PUC D&O 24171

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Customer Information Service ("CIS")

2009 Test Year

Line No.	NARUC Account	PROJECT	Account Description	Line Item Description	2009 TY YEAR
			POWER PRODUCTION OPERATION		
1	506	P0000571	Miscellaneous Steam Power Expenses	Training	$8,790
			DISTRIBUTION EXPENSE OPERATION		
2	581	P0000571	Load Dispatching	Training	$103,096
3	587	P0000571	Customer Installations Expenses	Training	$360,305
4	588	P0000571	Miscellaneous Distribution Expenses	Training	$62,358
5			**sub total Dist. Exp. Oper.**		**$525,759**
			CUSTOMER ACCOUNTS EXPENSE		
6	903	P0000571	Customer Records & Collection Expense	Training & Post Go-Live Deployment	$1,148,716
7	903	NPCZZZZZ	Customer Records & Collection Expense	Amortization of Deferred Expenses	$976,941
8			**subtotal Cust. Acc. Expenses**		**$2,125,657**
			CUSTOMER SERVICE EXP. OPERATION		
9	910	P0000571	Customer Assistance Expenses	Training	**$68,710**
			ADMINISTRATIVE & GENERAL EXP.		
10	920	P0000571	Administrative & General Expenses	Training	$41,006
11	921	P0000571	Office Supplies & Expenses	Training	$60,823
12	925	P0000571	Injuries & Damages	Training	$459
13			**sub total A&G Expenses**		**$102,288**
14		P0000571	Total NARUC PROJECT EXPENSE		$1,854,263
15		NPCZZZZZ	**Total NARUC Amortization Expense**		$976,941
16			**Total NARUC Project & Amortize. Exp.**		**$2,831,204**
17		P000571	Capital	Upgrade in computer/server storage capacity	$30,948
18			**Total TY 2009: CIS Exp., Capital & Amortization Exp.**		**$2,862,152**

Note: Test Year $ include oncosts $ for expense elements: 404 Energy Delivery, 405 Power Supply, 406 Corp Admin., 421 Non-productive wages, 422 employee benefits, 423 payroll taxes.

CIS
NARUC ACCOUNT 903
PROJECT & POST GO-LIVE NON PROJECT

Line No.	NARUC Account	Account Description	Line Item Description	DIRECT * Non Labor Amount	DIRECT * Non Labor Amount	DIRECT * Total NARUC
1		**PROJECT P0000571 EXPENSES**				
2	903	Customer Records & Collection Expense	Training	$265,113	$0	$265,113
3	903	Customer Records & Collection Expense	Post Go-Live Deployment	$99,123	$520,238	$619,361
5		**sub total P0000571 Expenses**		**$364,236**	**$520,238**	**$884,474**
6		**NON-PROJECT EXPENSES NPCZZZZZ**	POST GO-LIVE PROJECT			
7	903	Customer Records & Collection Expense	Amortization		$976,941	$976,941
8	903	Customer Records & Collection Expense	Maintenance of CIS system		$438,000	$438,000
9	903	Customer Records & Collection Expense	Report Design & Development		$172,534	$172,534
8	903	Customer Records & Collection Expense	Consultant Services for new functionalities		$198,042	$198,042
10	903	Customer Records & Collection Expense	Outsourcing of bill printing functions		$321,657	$321,657
11	903	Customer Records & Collection Expense	Outsourcing of IVR		$88,314	$88,314
12	903	Customer Records & Collection Expense	Outsourcing of IWR		$31,126	$31,126
13		sub total NPCZZZZZ Non Proj. Expense	Post Go-Live Project	**$0**	**$2,226,614**	**$2,226,614**
14	**903**	**Total Labor & Non Labor**	**Project & Non Proj CIS**	**$364,236**	**$2,746,852**	**$3,111,088**

Note: Costs are Direct Labor (incl. non prod. wages) & Direct Non Labor (excl. on-costs)

HECO T-10
DOCKET NO. 2008-0083

TESTIMONY OF
ALAN K.C. HEE

MANAGER
ENERGY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Customer Service Expense,
Demand-Side Management Expense,
Integrated Resource Planning Expense,
Energy Cost Adjustment Clause

Table of Contents

INTRODUCTION

Q. Please state your name and business address.

A. My name is Alan K.C. Hee and my business address is 220 South King Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Manager of Hawaiian Electric Company, Inc.'s Energy Services Department ("ESD").

Q. What is your educational background and professional experience?

A. My experience and educational background are listed in HECO-1000.

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

A. My testimony will cover HECO's 2009 test year estimate of Customer Service Expense (including Demand-Side Management ("DSM") expenses), Integrated Resource Planning ("IRP") Expense, and the Energy Cost Adjustment Clause ("ECAC"), including a discussion of the risk sharing properties of the Clause per the requirements of Act 162 (2006).

CUSTOMER SERVICE EXPENSE

Q. What is HECO's 2009 test year estimate for Customer Service Expense?

A. HECO's normalized 2009 test year Customer Service Expense is $7,007,000, as shown in HECO-1001.

Q. What expenses are included as Customer Service Expense?

A. Customer Service Expense includes the following block of accounts:

Account 909 - Supervision – Customer Service Expense
Account 910 - Customer Assistance Expense
Account 911 - Informational Advertising Expense
Account 912 - Miscellaneous Customer Service Expense

Q. Please describe the kinds of costs that are included in these accounts.

A. The following is the NARUC definition of the customer service expense accounts[1]:

1. Account 909: General direction and supervision of customer service activities, the object of which is to promote safe, efficient and economical use of the utility's service.
2. Account 910: Providing instructions or assistance to present customers, the objective of which is to promote safe, efficient and economical use of the utility's service.
3. Account 911: Advertising activities which primarily convey concrete information as to what the utility urges or suggests customers should do in using electric service to: protect health and safety, promote environmental protection, utilize electric equipment safely and economically, and conserve electric energy. Included also in this account are advertising activities relating to actions by the electric utility which bear directly on its provision of service to the customer.
4. Account 912: Customer service activities which are not includable in other customer service expense accounts.

I will describe in detail the estimated costs that are reflected in these accounts below.

Q. Are costs associated with the Company's DSM efforts included in the Customer Service block of accounts?

A. Certain DSM program and DSM-related base labor and base non-labor costs are included in Accounts 909 and 910. However, incremental DSM program costs recovered through the DSM Surcharge component ("DSM Surcharge") of the IRP

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[1] NARUC, *Uniform System of Accounts for Classes A and B Electric Utilities*.

Cost Recovery Provision ("IRP Clause") have been removed from the test year expense through a rate case adjustment and are not included in the Company's test year revenue requirement. This and other rate case adjustments are discussed later in my testimony.

Q. When has HECO assumed that the transition of energy efficiency DSM programs to the Public Benefits Fund ("PBF") Administrator is complete?

A. HECO has assumed that the transition is complete by the end of 2008, such that the energy efficiency DSM programs are entirely transferred by January 1, 2009.

Q. Following the rate case and other adjustments, what is the split between base DSM and non-DSM expenses in the Customer Service Expense block of accounts?

A. The split between base DSM and non-DSM expenses is shown in HECO-1002, along with the adjusted G/L code.[2] Over 96% of DSM expenses in the Customer Service Expense account blocks are included in Customer Assistance Expense.

Q. How does HECO's test year 2009 Customer Service Expense compare with preceding years' recorded information?

A. HECO's recorded Customer Service Expenses for the period from 2003 through 2007, the budget forecast for 2008, and the test year estimate for 2009 are reflected in HECO-1003. Customer Service Expense is projected to increase in 2008 and 2009, primarily because of an increase in base non-labor expenses for the load management programs, which remain with the utility. The expense impact of the DSM activities remaining with HECO can be demonstrated by removing base DSM expenses from the Customer Service expenses. As shown in HECO-1004, the costs excluding DSM base expenses are relatively stable, with the exception of Account 911 – Informational Advertising, which will be

[2] The G/L code adjustment is discussed later in this testimony.

addressed later in this testimony.

Q. How will the rest of your testimony be organized?

A. I will first address the rate case and normalization adjustments made to the Company's 2009 O&M budget that results in the test year estimate for Customer Service Expense. Since DSM is a large expense item within the Customer Service block of accounts, my testimony continues with the expenses associated with DSM. This is followed by a discussion of test year expenses by NARUC account arranged by Department/Division area. Thereafter, I enumerate the head count for the Customer Solutions Process Area, and discuss Integrated Resource Planning Expenses. My testimony then concludes with a section on the Energy Cost Adjustment ("ECA") Clause and the ECA factors at present and proposed rates.

G/L CODE ADJUSTMENT, RATE CASE ADJUSTMENTS, AND NORMALIZATIONS

G/L Code Adjustment

Q. Was there a G/L code adjustment made to Customer Service expense for test year purposes?

A. Yes, there was.

Q. What is a G/L code adjustment?

A. The G/L code adjustment removes expense elements ("EE") corresponding to Corporate Administration (406), Employee Benefits (422), and Payroll Taxes (423) from Customer Service non-labor expense. These expenses are classified as non-labor expenses even though they are related to employees. This adjustment is necessary because the Company's Customer Service O&M Expense Budget by activity, program, and responsibility area includes these expense elements. However, for rate case purposes these expenses are collected under other NARUC accounts. The G/L code adjustment removes those expenses from the Customer Service Expense estimate (as shown in HECO-1002) and collects them under different NARUC accounts, thus, avoiding a double counting of these expense elements. Further discussion of the GL codes is found in Ms. Patsy Nanbu's testimony (HECO T-11).

Rate Case Adjustments

Q. Were there any rate case adjustments or normalizations made to the Company's O&M budget for 2009 for rate case purposes?

A. Yes, there were, as shown in HECO-1005. (Note that the O&M Expense Budget in column A of HECO-1005 has already been reduced by EE 406, 422, and 423.)

Q. What adjustments to the O&M budget were made for rate case purposes?

A. There are four O&M budget adjustments:

1) Removal of restricted stock awards;
2) Removal of incremental DSM expenses;
3) Addition of an incremental Customer Efficiency Programs ("CEP") Analyst position into base ESD DSM labor; and
4) Removal of a vacant Senior Technical Engineer position in the Customer Technology Applications Division that is being transferred to the Pricing Division as a Senior Rate Analyst.

Details of the rate case adjustments are shown in HECO-1006.

Q. Please describe the adjustment for restricted stock awards.

A. The adjustment removes $5,000 of restricted stock awards from Account 909 expenses. HECO will not be seeking the recovery for these awards in the rate case. Ms. Nanbu discusses this adjustment in her testimony, HECO T-11.

Q. Please describe the removal of incremental DSM expenses.

A. Estimated 2009 DSM expenses were examined to determine which costs are allowed to be recovered in base rates and which costs are incremental and would be recovered through the DSM Surcharge. Because incremental DSM expenses are recovered through the DSM Surcharge, they are removed from the rate case and will not be recovered through base rates. The total amount of the adjustment to remove incremental DSM expense is ($20,678,000), as shown on line 13 of HECO-1006.

Q. What are incremental DSM expenses?

A. Simply stated, incremental DSM expenses are expenses not recovered in base rates. The identification of which DSM expenses are recovered in base rates is based on the settlement agreement stipulated to by the parties in HECO's 2007 test year rate case (Docket No. 2006-0386) dated September 5, 2007, and adopted by the Commission in Interim Order No. 23749, dated October 22, 2007.

In general, for energy efficiency DSM programs, labor costs for HECO employees are considered base, and all other expenses are incremental and recovered through the DSM surcharge. However, some HECO employees were classified as incremental in the September 5, 2007 agreement. For load management DSM programs, direct labor costs for employees, tracking, evaluation, advertising, administrative, and miscellaneous costs are considered base. All other load management DSM program expenses are incremental. Additional detail supporting the Company's basis for base versus incremental cost recovery was provided in HECO's response to CA-IR-263, in HECO's 2007 test year rate case docket.

Q. Why were incremental DSM program costs included in the 2009 O&M Expense Budget if HECO is assuming that the transition to the PBF Administrator is complete before December 31, 2008?

A. This was due to timing. The 2009 O&M Expense Budget was prepared on a "business as usual" basis in early 2008 when HECO was uncertain as to the timing of the transition. At a May 12, 2008 Public Benefits Fund Docket[3] status conference held at the Commission's offices, the Commission indicated that the transition was scheduled to occur in 2009. As stated earlier, HECO assumes a complete transition of the energy efficiency DSM programs to the PBF Administrator by December 31, 2008, with load management DSM programs remaining with the utility. The load management DSM program test year expenses include both base and incremental DSM expenses.

Q. Why were incremental costs removed from test year expense?

A. Incremental DSM program costs were removed from test year expenses because incremental costs are recovered through the DSM Surcharge. To avoid double recovery of those costs through base rates, DSM incremental costs were removed from test year expenses. The identification of the incremental DSM costs removed is shown in HECO-1007.

Q. What is the impact on the G/L code due to the removal of incremental DSM program expenses from the test year?

A. The original G/L code adjustment used to reduce the O&M Expense Budget shown in Column A in Exhibit HECO-1005, included incremental DSM program expenses. Total incremental DSM program expenses, including EE 406, 422, and 423, equal to $20,871,000, as shown in HECO-1007, line 36. The portion of EE 406, 422, 423 expenses in incremental DSM program expenses is $193,000, as shown in HECO-1008, lines 4-6 and line 20.

To correctly remove incremental DSM expenses from the O&M Expense Budget for test year purposes, $20,871,000 less $193,000 (or $20,678,000) must be subtracted from the O&M Expense Budget, as shown in HECO-1007, line 37.

[3] Docket No. 2007-0323.

If $20,871,000 had been removed, the EE 406, 422, and 423 expenses associated with incremental DSM program expenses would have been subtracted twice and double counted.

The removal of incremental DSM program costs means that amounts collected under other NARUC accounts must be reduced. The G/L code adjustments to these other NARUC accounts are as follows:

NARUC 922 Admin	(EE 406)	($ 43,000)
NARUC 926 Employee Benefits	(EE 422)	($118,000)
NARUC 408 Payroll Taxes	(EE 423)	($ 32,000)
Total		($193,000)

The resulting G/L code adjustment for Account 910, Customer Assistance Expense is $1,599,000 less $193,000, or $1,406,000, as shown in HECO-1002, line 2.

Q. Why is HECO moving the incremental CEP Analyst position into base expense?

A. HECO is moving the position into base expense because it is needed to perform budget analysis, regulatory reporting, and contract administration tasks for the DSM programs that remain with the utility after the energy efficiency DSM programs are transferred to the PBF Administrator. I discuss this move in further detail in the “Demand Side Management Program” section of my testimony below.

Q. What is the expense impact of moving this position into base rates?

A. The labor and non-labor expenses associated with this position are included in the incremental DSM expenses removed above. Therefore, HECO is proposing to move those expenses back into base expense. This increases base labor expense by $72,000, and increases on-costs (EE 406, 422, and 423) by $31,000, for a total of $103,000 increase to the Company’s test year as shown on lines 4 and 10 in

HECO-1006.

Q. Why is HECO removing costs associated with a Senior Technical Engineer ("STE") position from the test year Customer Services expense?

A. HECO is removing a STE from Customer Service expense because it is transferring this currently vacant position to the Pricing Division as a Senior Rate Analyst. The Senior Rate Analyst position provides policy direction, coordination, and implementation of rate initiatives, studies, and existing rules and tariffs that support strategic focus areas of the Company. HECO has decided that the focus on rate initiatives and customer rate options to assist customers with managing their electric bills has added importance in the current environment of rising fuel prices.

The STE being removed was originally assigned to the CIDLC Program to assist with customer site visits, assessments, and evaluations. Due to lower than expected participation in the direct load control and voluntary load control elements of the CIDLC Program and difficulties with proposals received to implement the Small Business Direct Load Control ("SBDLC") element, the STE position is being removed from the CIDLC Program. This is discussed further in the DSM Expense portion of my testimony to follow.

Q. Why have rate initiatives and customer rate options taken on added importance to the Company?

A. The State is currently entering a period in which the confluence of energy policy objectives is focused on electricity. These objectives include:

1. Managing the cost of electricity in an environment of rising oil prices;
2. Acquiring and accommodating increased renewable energy as a hedge against rising oil prices, enhance energy security and lessen dependency on crude oil; and

3. Managing HECO's reserve capacity shortfall to maintain service reliability. Rate initiatives and options such as aggressive time-of-use rates, inclined block rates, and dynamic pricing provide customers opportunities to help achieve all three objectives.

Rate options that price electricity based on cost differences to provide electrical service during different periods are likely to price electricity higher during peak demand periods than for other daily periods. Implementing these rate options provide customers with an opportunity to reduce their electricity bills if they are able to shift usage from the higher cost peak demand periods to lower cost off-peak periods. This has taken on much greater importance due to oil prices that are significantly higher now than a year ago. By reducing load during peak demand periods, these rate options also help the Company maintain its service reliability during reserve capacity shortfall situation.

The policy objective of increasing renewable energy resources reduces our State's dependency on oil, enhances energy security, and hedges against the impact of changes in oil prices to the extent that the price of renewable energy is delinked from oil prices. In the short term, acquisition and accommodation of additional renewable resources will likely raise electricity prices. Thus, rate options that permit customers to manage their bill will also assist in lessening the impact of higher prices that are likely to result from pursuing greater amounts of renewable energy.

Green pricing is a voluntary option that permits participants to purchase renewable energy priced at a premium above the Company's avoided energy cost. Without green pricing the expense of this higher priced renewable energy would have been recovered through the ECAC (following Commission approval) from all customers. With green pricing participants in the voluntary tariff accept the higher costs themselves and help temper the increase in electricity price to non-participants. HECO intends to file a green pricing tariff by the end of 2008.

Customer rate options serve a variety of purposes and help the State and utility achieve many of the important energy policy objectives that are crucial to the State's energy future.

Q. What is the impact of removing the STE on test year Customer Service expense?

A. The impact is to reduce the test year expense by $72,000 of labor expense, as shown in line 5 of HECO-1006. To reflect the salary of the new Senior Rate Analyst position in its proper account, a corresponding increase in Administration and General labor expenses (NARUC 920) is included in Ms. Nanbu's testimony (HECO T-11). In addition, $31,000 of non-labor on-costs (EE 406, 422, and 423 expenses) are also removed from Customer Service expense, as shown in line 11 of HECO-1006, for a total reduction of $103,000.

<u>Rate Case Normalizations</u>

Q. What adjustments were made to normalize the O&M Expense Budget for test year purposes?

A. Two normalization adjustments were made to Customer Service expense. The first normalizes Pacific Coast Electrical Association ("PCEA") conference expenses, and the second normalizes IRP non-labor expenses. The total normalization adjustment is a reduction of $127,000, as shown in HECO-1009.

Q. What is the amount and basis for the PCEA conference adjustment?

A. The O&M Expense Budget was reduced by $60,000 because the PCEA conference, the costs of which are included in the 2009 O&M Expense Budget, is held once every two years, as shown in HECO-1010.

Q Is the budgeted amount for the PCEA conference costs higher than previous years?

A. It only appears so. In 2007, the Company recorded the expenses for the PCEA conference after deducting registration fees collected from conference attendees. However, an accounting change in late 2007 now requires PCEA conference registration fees be recorded to revenue. For 2009, $64,000 in revenue was included in the 2009 O&M Expense Budget. This revenue was also normalized for test year purposes and only $32,000 in test year revenue is being included in Miscellaneous Other Operating Revenue. Please see Mr. Peter Young's testimony (HECO T-3) for the PCEA revenues.

Q. What is the amount and basis for the IRP adjustment?

A. The IRP adjustment reduces the 2009 O&M Expense Budget by $67,000. This adjustment is the Customer Service allocation of the IRP normalization adjustment discussed later in my testimony when I address IRP expenses.

DEMAND-SIDE MANAGEMENT PROGRAMS

Q. What are Demand-Side Management ("DSM") programs?

A. DSM programs are designed to influence how utility customers use energy to produce desired changes in demand. They include load management and energy efficiency programs.

Q. Please describe HECO's DSM programs.

A. HECO currently administers and implements 11 DSM programs:

1) Commercial and Industrial Energy Efficiency ("CIEE")
2) Commercial and Industrial New Construction ("CINC")
3) Commercial and Industrial Customized Rebate ("CICR")
4) Residential Efficient Water Heating ("REWH")
5) Residential New Construction ("RNC")
6) Energy Solutions for the Home ("ESH")

7) Residential Low Income ("RLI")

8) SolarSaver Pilot ("SSP")

9) Residential Customer Energy Awareness ("RCEA")

10) Commercial and Industrial Direct Load Control ("CIDLC")

11) Residential Direct Load Control ("RDLC")

Q. Please briefly describe the eleven DSM programs.

A. A brief description is included in HECO-1011, along with cites to HECO's Opening Brief filed on October 25, 2006 in the Energy Efficiency Docket and to other dockets that contain more DSM program details.

Q. Please provide a brief history of HECO's energy efficiency DSM programs.

A. HECO began its energy efficiency DSM programs in late 1996 with customer incentives for a standard set of commercial and industrial energy efficiency measures contained in three programs: (1) the Commercial and Industrial Energy Efficiency Program; (2) the Commercial and Industrial Customized Rebate Program; and (3) the Commercial and Industrial New Construction Program. In late 1996 HECO also began its energy efficiency DSM programs for the residential market segment with customer incentives for solar water heating systems in both the retrofit (Residential Efficient Water Heating Program) and new construction (Residential New Construction Program) sectors.

For the nine years between 1996 and 2004, HECO's energy efficiency programs achieved an annual average of 38 GWh of energy savings each year[4], as shown in HECO-1043, such that by the end of 2004 cumulative savings each year from all measures installed between 1996 and 2004 was 343 GWh[5]. During the same period, HECO DSM programs achieved an annual average of 6.4 MW of

[4] At the gross generation (system) level, including free riders.
[5] Assuming that all of the measures installed remain in service.

demand reductions each year[6] such that by the end of 2004 the total annual demand reduction from all measures installed was nearly 58 MW[7].

In 2005, HECO introduced two new load management programs: (1) the Commercial and Industrial Direct Load Control Program; and (2) the Residential Direct Load Control Program. The addition of these two programs (for a total of seven DSM programs) increased incremental demand reductions in 2005 and 2006 to 13 and 18 MW, respectively, more than twice the 9-year average annual peak demand reduction of 6.4 MW achieved by HECO's energy efficiency programs since 1996. In 2006, HECO's programs achieved incremental demand savings equal to 1.4% of HECO's 2006 annual demand peak of 1315 MW (at the system level)[8].

Q. Have additional programs been added since 2006?

A. Yes. In 2007, HECO introduced four new DSM programs: (1) the Energy Solutions for the Home Program; (2) the Residential Low Income Program; (3) the Solar Saver Pilot Program; and (4) the Residential Customer Energy Awareness Pilot Program. In 2007, these four programs, plus the seven existing programs, achieved additional energy and demand savings of 121 GWh and 39.8 MW. The incremental demand reduction was equivalent to 3.2% of HECO's 2007 annual demand peak of 1261 MW (at the system level)[9].

Assuming (for illustration) that all measures installed since 1996 were still in service, at the end of 2007 these measures represent a cumulative annual savings of 568 GWh and an annual demand reduction of 129 MW, which is equivalent to a generating unit at the Kahe Power Plant.

Q. Please discuss HECO's Rider SSP SolarSaver ("SolarSaver") Pilot Program.

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[6] At the gross generation (system) level, including free riders.
[7] Assuming that all of the measures installed remain in service.
[8] 1265 MW at the net-to-system level.
[9] 1216 MW at the net-to-system level.

A. The SolarSaver Pilot Program is a pilot program designed to overcome the barrier of up-front costs in the residential solar water heating market. Residential customers participating in the program incur no upfront cost and pay for the cost of the installed solar water heating system over time through savings in the customer's electricity bill. The SolarSaver Pilot Program has a three-year pilot program period. As of mid-June 2008, there have been 50 solar water heating systems installed under this pilot program.

As background, Section 13 of Act 240, Session Laws of Hawaii (2006) ("Act 240") authorized and directed the Commission to implement a pilot project to be called the "solar water heating pay as you save program", to determine the time frame of the pilot program, to gather and evaluate information to evaluate the pilot program, and to ensure that "all reasonable costs incurred by electric utilities to start up and implement the pay as you save model system are recovered as part of the utility's revenue requirement, including necessary billing system adjustments and any costs for pay as you save model system efficiency measures that are not recovered via participating residential consumers' pay as you save model system bill payments or otherwise."

Q. Did the Commission open a docket in response to Act 240?

A. Yes. By Order No. 22974, filed October 24, 2006, in Docket No. 2006-0425, the Commission opened an investigation to examine the issues and requirements raised by, and contained in, Hawaii's program, as mandated by Act 240. HECO filed its proposed SolarSaver Pilot Program on December 29, 2006. By Decision and Order No. 23531, issued June 29, 2007, the Commission approved, with modifications, HECO's (as well as HELCO's and MECO's) SolarSaver Pilot Program. HECO filed its SolarSaver Pilot Program tariff with the Commission on July 9, 2007.

Q. How does HECO recover the costs of these DSM programs?

A. HECO currently recovers some of the costs of these programs through a DSM Surcharge and some of the costs through its base rates. "Incremental" DSM program costs are those costs that are recovered through the DSM Surcharge and "base" DSM costs are those costs recovered through the Company's base rates.

Q. What DSM costs are incremental?

A. Please see earlier section "G/L CODE ADJUSTMENTS, RATE CASE ADJUSTMENTS, AND NORMALIZATIONS" for a discussion of what DSM costs are incremental and what DSM costs are base.

<u>Transition to the PBF Administrator</u>

Q. What is the status of transitioning HECO's energy efficiency DSM programs to the PBF Administrator?

A. The transition of the energy efficiency DSM programs to the PBF Administrator was the result of the Commission's Decision and Order ("D&O") No. 23258, dated February 13, 2007, in the Energy Efficiency Docket, Docket No. 05-0069. D&O No. 23258 also indicated that the Commission would open a subsequent docket to select the PBF Administrator and refine the details of the new market structure.[10]

Q. Has the new docket been opened?

A. Yes. On September 26, 2007, the Commission issued Order No. 23681, which initiated a proceeding (Docket No. 2007-0323) to select a PBF Administrator and implement a new market structure. On February 19, 2008, the Commission issued a draft Request for Proposal ("RFP"), soliciting proposals for the PBF Administrator and requested comments. Comments were submitted as requested by the Commission. On May 12, 2008, the Commission held a status conference

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[10] D&O 23258, page 140.

to discuss: 1) the establishment of an initial public benefits fund surcharge, and 2) a transition process that includes the continuation of current energy efficiency DSM programs by the HECO Companies (HECO, HELCO, and MECO) for up to six months after the contract start date of the third-party PBF Administrator, which is scheduled to be January 1, 2009. An order relating to the items discussed at the May 12, 2008 status conference is anticipated to be issued by the Commission shortly.

Q. What is the impact of the transition on HECO's DSM programs?

A. Based on D&O No. 23258, HECO's energy efficiency programs will be transferred to the PBF Administrator. Those programs are:

1) Commercial and Industrial Energy Efficiency ("CIEE")
2) Commercial and Industrial New Construction ("CINC")
3) Commercial and Industrial Customized Rebate ("CICR")
4) Residential Efficient Water Heating ("REWH")
5) Residential New Construction ("RNC")
6) Energy Solutions for the Home ("ESH")
7) Residential Low Income ("RLI")
8) Residential Customer Energy Awareness ("RCEA")

Based on discussion with the Commission at the May 12, 2008 status conference, HECO understands that the SolarSaver Pilot Program will remain with the utilities at least until the pilot program ends on June 30, 2010.

Q. For test year purposes, when has HECO assumed that the transition of energy efficiency programs to the PBF Administrator is complete?

A. HECO has assumed that the transition is complete by the end of 2008 and the energy efficiency programs are entirely transferred by January 1, 2009.

Q. If HECO will continue to administer the energy efficiency DSM programs for up to six months after the contract start date for the PBF Administrator, why is the assumption that the energy efficiency programs are entirely transferred by January 1, 2009 reasonable?

A. The assumption is reasonable because the timing of when the transition is complete has minimal impact on test year expense. Further, where there is minimal impact, there are cost recovery mechanisms available to appropriately account for those impacts as discussed below.

Q. What DSM programs will HECO be administering during the 2009 test year?

A. HECO will be administering the following DSM programs during the test year:

1) SolarSaver Pilot ("SSP");
2) Commercial and Industrial Direct Load Control ("CIDLC"); and
3) Residential Direct Load Control ("RDLC").

Q. What other DSM programs will HECO be administering in the test year?

A. The Company has also assumed that it will implement and administer the Dynamic Pricing Pilot Program. HECO filed an application requesting the Commission's approval of this program on April 24, 2008 (Docket No. 2008-0074).

Q. What is the Dynamic Pricing Pilot ("DPP") Program?

A. The DPP Program is a demand response program that provides through peak time customer incentives rebates ("PTR"). A PTR program provides monetary incentives to customers for every kilowatthour saved during the applicable peak time period. The objective of this pilot is to test the effect of a demand response program on a sample of residential customers for system reliability purposes. DPP is considered a demand-side load management program because price incentives are paid to encourage customer curtailment of load during critical peak periods when there is insufficient generation to meet a projected peak demand period (in a manner similar to the Company's RDLC and CIDLC Programs).

Q. What is the schedule for implementing the DPP Program?

A. HECO plans to implement the DPP Program upon Commission approval. The schedule anticipates that pilot program participants would be recruited beginning in September 2008, the pilot study would begin January 2009 and end in December 2009, and an evaluation of the pilot would be completed in February 2010.

Q. How does the forthcoming transition of the energy efficiency DSM programs to a new PBF Administrator affect HECO's test year expense estimates?

A. The transition has three effects on test year expense:

1) HECO proposes to switch one of the CEP Analyst positions that is currently incremental to a base position, resulting in an increase of $72,000 in base labor expense and $31,000 in on-cost (EE 406, 422, and 423) expense;

2) The allocation of office space rental to the energy efficiency DSM programs of $108,000 has been reclassified as a base Facilities expense from an incremental DSM expense; and

3) Certain base labor expense that had been allocated to specific DSM programs has been allocated to base DSM administration expense. This latter effect has no impact on total test year expense because it is a transfer among base labor expense activities.

Q. Why has HECO moved one of the incremental CEP Analyst positions to a base position?

A. As indicated earlier, HECO is adding the position into base expense because it is needed to continue to support and perform budget analysis, regulatory reporting, and contract administration tasks for the DSM programs that remain with the utility after the energy efficiency programs are transferred to the PBF Administrator. This position is a regular HECO position and is currently filled. Previously, it was "classified" as a base position and became an incremental position as the result of the settlement negotiations between the parties to the HECO 2007 Test Year Rate Case. Because these functions will be required to be performed by the Company after the transition of the energy efficiency DSM programs, the return of this position as a base position and the inclusion of associated costs in base rates are appropriate.

Q. Why has HECO reclassified office space rental allocated to the energy efficiency DSM programs from incremental to base expense?

A. The costs were reclassified because after the energy efficiency DSM programs are completely transitioned to the PBF Administrator, HECO will use the vacated office space for other utility activities. These activities include the possible expansion for HECO's load management programs, with the possible use by a third party contractor to implement the Small Business Direct Load Control program element of the CIDLC Program. Also, floor space rental is a base expense for the load management programs. However, this use of additional space for the program is not included in the CIDLC Program budget.

Another possible use contemplated for the vacated floor space is for use by an expanded Pricing Division, which currently shares floor space with the Customer Efficiency Programs ("CEP") Division. (The CEP Division is responsible for the development, planning, design, and implementation of DSM programs.) Because of the increased focus by the Companies on demand response and rate options, rate design will become a priority for HECO. HECO has proposed that the Pricing Division employee count be increased for a senior rate analyst position in preparation for this renewed emphasis.

Because HECO intends to use the floor space vacated by HECO's energy efficiency DSM staff for utility activities, the floor space rental expense is included as a base Facilities expense rather than an incremental DSM expense.

Q. Why has HECO reallocated base labor expense for specific DSM programs to base DSM administration expense?

A. When the 2009 O&M Expense Budget was prepared in early 2008, it was uncertain as to when the transition to the PBF Administrator was to take place. Therefore, the 2009 O&M Expense Budget was prepared as if HECO were administering the energy efficiency DSM programs. Approximately $126,000 of base labor and related non-labor expense was budgeted in the 2009 O&M Expense Budget for the administration of specific energy efficiency DSM programs. This represents fractions of base full-time regular HECO positions that worked on those programs. However, when the energy efficiency DSM programs are transferred to the PBF Administrator, those resources will be used in a continued effort by HECO to develop, plan, and design new demand response programs that would reduce demand and maintain service reliability. The Dynamic Pricing Pilot Program is one example of the effort that would take place to develop new demand response programs. This represents a transfer from one base labor activity to another base labor activity and a zero net impact on base labor expense.

Q. What effect will a delay in transition date beyond January 1, 2009 have on base and incremental DSM expenses actually incurred for the CEP Analyst, office space, and DSM program administration, as compared to test year estimates?

A. As the transition completion date moves further into 2009, base CEP Analyst and base office space rental expenses will decrease in comparison to test year estimates, but the level of base DSM program administration expenses is not affected.

For example, as the transition is delayed into 2009, more of the CEP Analyst's labor will be charged to incremental rather than base as labor hours will need to be spent administering the energy efficiency DSM programs that remain temporarily under utility administration. A delay in the transition will also reduce base office space rental expense as office space rental charges will continue to accrue as incremental expenses. However, a delay will not affect the total amount of test year base labor expense associated with the DSM program administration (exclusive of the CEP Analyst) because HECO is proposing to switch these labor costs between two existing base expense budget items, and not between base and incremental.

Q. If actual incurred base expenses are affected by the timing of the transition, shouldn't the test year estimate of DSM expenses also be affected?

A. No. An adjustment to test year estimates of DSM expenses is not needed to reflect a difference between the assumed January 1, 2009 transition date and the actual date. The DSM Surcharge recovery mechanism can be used to reconcile the recovery of actual expenses incurred. Thus ratepayers are not at risk for overpayment due to a delay in the transition completion date.

The mode of DSM cost recovery depends on: 1) when the transition is completed, and 2) when an interim decision is issued. When the transition is completed, HECO's recovery of incremental DSM costs associated with the energy efficiency DSM programs transferred to the PBF Administrator will end (subject to a reconciliation of actual versus recovered costs in the following annual DSM Accomplishments and Surcharge ("A&S") report). Recovery of DSM labor costs for regular HECO incremental positions identified in the HECO 2007 test year Interim Rate Increase (D&O No. 23749, dated October 22, 2007) will also end. Recovery of base DSM costs will continue in base rates per the

HECO 2007 test year rate case Interim Rate Increase. If the interim rate relief in the instant proceeding has not yet been approved, then HECO is at risk for being unable to recover the labor costs for the CEP Analyst and the non-labor costs of office space rental for the period between the transition completion and the date of interim rate relief.

On the other hand, if interim rate relief is granted before the transition is complete, HECO will begin to recover CEP Analyst and office space rental expenses through the approved interim rate increase. HECO would reduce the level of expenses recovered through the DSM surcharge to the extent that those expenses are recovered in base rates.

Therefore, ratepayers will not be harmed if the transition to the PBF Administrator is delayed beyond January 1, 2009.

Q. Does HECO intend to participate in the implementation of energy efficiency DSM programs as a subcontractor to potential DSM Administrators?

A. HECO is exploring a role as subcontractor with potential bidders for the PBF Administrator role. HECO has requested clarification of its possible participation as a subcontractor in its comments filed on March 27, 2008 on the draft PBF Administrator RFP. If HECO participates as a subcontractor, the costs associated with its role as a subcontractor will be recovered through direct billing to the PBF Administrator.

Test Year Customer Service DSM Expense

Q. What is HECO's estimate of test year Customer Service DSM expense?

A. Test year Customer Service DSM expenses are $2,340,000, as shown in HECO-1012. These expenses are included in the test year estimates for Accounts 909 – Supervision, and 910 – Customer Assistance.

Q. Are there DSM expenses included in HECO's test year that are outside of the Customer Service block of accounts?

A. Yes, the test year estimate of total DSM expenses is $2,374,000, of which $2,340,000 is in Customer Service expense and $34,000 is reflected in accounts 903, 920, and 921, also as shown in HECO-1012.

Q. Does the removal of incremental DSM program costs from the revenue requirement have an impact on the level of rate relief that HECO is requesting?

A. No, there is no impact because HECO is currently allowed to recover all prudent and reasonable incremental DSM program costs through the DSM Surcharge. As long as HECO is permitted to continue to recover incremental DSM program costs through the DSM Surcharge, the incremental program costs plus associated revenue taxes are completely offset by revenue recovered through that surcharge.

Q. Are any lost margins associated with the DSM programs included in the Company's test year estimates?

A. No. Cumulative energy savings (on an annualized basis) from DSM measures installed prior to the test year, plus an estimate of ramped energy savings from DSM measures installed during the test year either by the Company (while it continues to administer the energy efficiency DSM programs) or by the PBF Administrator (once the energy efficiency DSM programs are fully transitioned) are included in the Company's estimate of test year sales and peak. HECO has not included a separate recovery of lost margins for the balance of the ramped 2009 test year measure impacts in any of its test year estimates.

Q. Are DSM Utility Incentives for pursuing DSM programs on a going forward basis included in any of the Company's test year estimates?

A. No. HECO has not included any Utility Incentives for implementing DSM programs in its test year estimates. If DSM Utility Incentives are earned during the test year they should not be included as test year revenue. To include DSM Utility Incentives in test year revenue would eliminate the incentive nature of the DSM Utility Incentives since rate relief would be reduced by the amount of the incentive. Further, DSM Utility Incentives are not currently earned on demand reductions resulting from the two existing load management programs.

Q. How is the test year DSM expense estimate organized?

A. The discussion of DSM expenses will be organized into two sections:

1) Base DSM <u>program</u> expenses directly related to the administration and implementation of <u>specific</u> DSM programs, including direct labor, tracking, evaluation, advertising, training, and miscellaneous, and

2) Other base DSM-<u>related</u> expenses such as administration expenses for the overall supervision of the DSM programs that are not attributable to specific programs, and (ITS) expenses that are incurred in support of all DSM programs.

Q. What are the associated estimates of test year expenses for DSM program and DSM-related expenses?

A. The test year expense estimates for DSM program and DSM-related expenses are $1,609,000 and $765,000, respectively, as shown in HECO-1013.

Q. How are the adjustments for adding the CEP Analyst, removing the STE, and re-allocating the base labor expenses from the energy efficiency DSM programs to DSM administration accounted for in the test year estimates?

A. As shown in HECO-1014, these adjustments are included in the test year estimates.

<u>DSM Program Expense</u>

Q. What is HECO’s test year estimate of DSM program expense?

A. HECO’s test year estimate of DSM program expense is $1,609,000, as shown in

HECO-1015. Of that amount, $1,590,000 is in Customer Service Expense, Account 910 – Customer Assistance Expense, and $19,000 is incurred outside of Customer Service expense in Accounts 903, 920, and 921. These expenses are included in test year expenses supported by Mr. Yamamoto (HECO T-9) and Ms. Nanbu (HECO- T-11).

Q. What DSM program costs are currently being recovered through base rates?

A. HECO currently recovers base labor costs associated with that portion of the seven base positions associated with DSM program costs, as shown in HECO-1016. However, as indicated above, HECO proposes to shift a currently incremental CEP Analyst position to base rates and transfer a Senior Technical Engineer position to the Pricing Division. Also recovered through base rates are non-labor costs for tracking, evaluation, advertising, training, and miscellaneous costs associated with HECO's two load management programs, the CIDLC Program and the RDLC Program.

Q. How does the test year base DSM program Customer Assistance Account 910 expense estimate compare to actual 2007 expenditures?

A. As shown in HECO-1017, the Account 910 test year base program expense is $526,000 higher than 2007 actual expense resulting from a $130,000 decrease in base labor and a $656,000 increase in base non-labor expense.

Q. What is the reason for the lower base labor expense?

A. The decrease in base DSM program labor expense is primarily due to the energy efficiency DSM programs transferring to the PBF Administrator. About $248,000 in 2007 base labor expense will no longer be incurred to administer the transferred programs. This decrease is partially offset by an increase in base labor expense for administration and support of the CIDLC, RDLC, other DSM programs that remain with the utility and the planned implementation of the DPP Program.

Q. What are the reasons for test year DSM program non-labor expense being higher than 2007 actual expenses?

A. The increase is primarily due to higher base non-labor expenses for the two load management programs, CIDLC and RDLC, partially offset by the elimination of non-labor overhead costs associated with reductions in labor costs related to the energy efficiency DSM programs that are transferred to the PBF Administrator.

Q. What are the reasons for the increase in the CIDLC Program expenses?

A. The primary reasons for the increase in base CIDLC program expenses are the increased efforts needed to achieve the demand reduction goals for the program and implementation of the SBDLC program element of the CIDLC program that was not present in 2007 (the SBDLC program element was approved by the Commission on August 15, 2007).[11] A comparison of the CIDLC Program base labor and non-labor test year expense estimates against actual 2007 program costs is shown in HECO-1018.

Q. Why is the test year estimate of CIDLC base labor expense greater than the 2007 actual expense?

A. The Commission approved the CIDLC program in October 2004. After nearly four years, the opportunities to enroll large individual demand reductions from large customers are less. The remaining demand reduction potential now resides with smaller customers who have smaller loads available for interruption. To attain the same MW level of demand reduction equivalent to a large customer, many small customers must be enrolled. The time and resources to enroll small customers are greater than enrolling large customers.

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[11] The CIDLC Program consist of three program elements: 1) Direct load control ("DLC") which involves the installation of underfrequency relays on customers' premises and mandatory load curtailment during critical peak periods, 2) Voluntary load control ("VLC") in which participants choose to participate in voluntary load reductions during a critical peak period, and 3) Small business direct load control ("SBDLC"), in which underfrequency relays are installed on small business customer premises and load curtailment is mandatory.

Recent modifications approved by the Commission to reduce the minimum load size eligible to participate in the DLC program element and to create the VLC program element have also increased the pool of potential qualifying customers. Efforts to evaluate and enroll the increased pool of potential program participants to achieve program demand reduction goals will also increase base labor expense.

A third reason why test year base labor expense is greater than in 2007 is that additional labor is needed to oversee the third-party SBDLC effort.

Q. What is the status of the SBDLC program element?

A. In the first week of April 2008, HECO sent the RFP to nine potential vendors. On April 30 and May 1, 2008, HECO received two responses. One respondent did not fulfill the RFP requirements and was rejected. The second respondent with similar program experience on the mainland, exceeded the approved SBDLC budget by a significant amount. It became apparent from both proposals that efforts to enroll small business customers into a load management program are more costly than HECO had initially expected. The cause of the higher cost being proposed by the second respondent is the uncertainty regarding the rate of customer acceptance and enrollment into the program, which can differ among service territories and significantly affect marketing and sales cost.

HECO has used the second vendor proposal as the basis for the Company's estimates for SBDLC base non-labor expenses that are included in the test year CIDLC Program expenses. The Company is now in negotiations with the second vendor to scale down the program and proceed in the latter part of 2008 with a pilot effort funded out of base program expenses. The pilot will help validate the levels of fixed (administrative, tracking, evaluation, marketing, advertising, and miscellaneous) and variable (per customer sales and enrollment, hardware, and installation) costs that were included in the second vendor proposal.

Q. What are the reasons for higher test year CIDLC Program non-labor expenses than 2007?

A. Test year non-labor expenses are higher than in 2007 primarily because of the addition of the SBDLC program element, which was not present in 2007. The addition of SBDLC expenses to the estimated expenses for the DLC and VLC program elements leads to higher costs in all program budget line items, as shown in HECO-1019.

Q. What are the reasons for the increase in RDLC Program expenses?

A. The increase is due to additional focus on central air-conditioning load control and on increased evaluation and advertising expenses for water heating load control. This results in increases above 2007 actual expenditures in both labor and non-labor expenses, as shown in HECO-1020.

Q. What is the reason for the increase in base labor program expense?

A. The increase in base labor expense is due to additional labor resources needed to administer the growing central air-conditioning portion of the program as well as evaluating other measures that may be added to the program such as split air-conditioning systems. Administration of the water heating portion at historical expense levels continues to be necessary even though some drop off in the number of water heating load control switches is expected.

Q. What is the reason for the increase in non-labor program expense?

A. The increase in non-labor expense is caused primarily by an increase in the amount of advertising necessary to maintain the number of new enrollments in the program and for evaluation efforts, as the number of water heating program participants moves closer to saturation. As of the end of May 2008, more than 29,200 residential customers with electric resistance water heating are enrolled in the RDLC program. The number of new water heater enrollments reached 10,072 in 2007, but is expected to decrease thereafter as HECO expects most of the military project water heater installations to be completed by 2008. The expected number of new enrollment of water heaters in the test year is 4,000.

Residential customers on Oahu have received multiple mailings regarding RDLC program participation and many customers have received in excess of five mailings through the Company's direct mail campaign. As the number of participants increase, it will be harder to enroll additional participants in the program because most of the remaining customers are likely to be those who have refused previous calls to participate. Thus, more effort will need to be expended to motivate the remaining customers to participate. Telemarketing and other strategies will be tested and more cost-effective tools will be identified to augment or replace the direct mail campaign.

Additional advertising is also necessary as effort to target central air-conditioning begins to pick up. Most of the advertising thus far has focused on residential electric water heating. A shift towards central air-conditioning cycling will need new advertising strategies.

Q. What are the estimated test year sales and demand savings from the DSM programs?

A. The annualized test year savings for DSM program measures installed in 2009 are 39.7 gigawatthours (GWh) of energy at the customer level and 16.0 MW of demand at the net-to-system level, as shown in HECO-1021. The exhibit also shows the cumulative savings estimated over the 2008 through 2012 period. This includes savings from programs to be transitioned to the PBF Administrator.

Q. The test year sales estimate discussed by Dr. Willoughby in HECO T-2 indicates a future DSM sales impact of 89.7 GWh. Why is there a difference?

A. The difference is due to different base years from which DSM impact is measured and the assumed timing of DSM measure installations. The test year DSM energy impact of 39.7 GWh shown in HECO-1021 represents the annualized impact of measures installed in 2009. This is the incremental reduction in sales from the prior year, with 2008 being the base year. Furthermore, the 2009 energy impact is annualized, i.e. the DSM measures are all assumed to be installed on January 1, 2009.

On the other hand, the test year DSM sales impact in HECO T-2 reflects a base year of 2007 (for sales forecast purposes, "future DSM" is defined as DSM installed in 2008 and thereafter). The 89.7 GWh is the accumulation of DSM reductions since the end of 2007, i.e., for 2008 and 2009. In addition, measures installed in 2008 and 2009 are assumed to be installed throughout the year, rather than all at the beginning of the year. The derivation of the two measures of DSM impact is shown in HECO-1022.

DSM-Related Expenses

Q. What are DSM-related expenses?

A. DSM-related expenses include DSM Administration and Information and Technology Services ("ITS") expenses. DSM Administration costs include labor and non-labor costs incurred by the VP, Customer Solutions and the Energy Services Department Administration Division (Account 909) and by other staff (Account 910) that are related to the overall supervision and direction of the Company's energy efficiency and load management efforts. ITS expenses are non-labor charges for ITS support of the Company's energy efficiency and load management efforts.

Q. What is the test year estimate for DSM-related expense?

A. The test year estimate is $765,000, consisting of $81,000 in Account 909,

$669,000 in Account 910, and $15,000 in Accounts 920 and 921, as shown in HECO-1023. Thus, DSM-related expenses in the Customer Services block of accounts are $750,000.

Q. How do the test year estimates for DSM-related expenses compare with actual 2007 expenses?

A. The test year estimate is $195,000 above 2007 actuals, as shown in HECO-1024. The primary reason for the increase is due to abnormally low expenses in 2007 for Account 909 – Administration. In 2007, an inadvertent miscoding led to $54,000 of labor expenses incurred by the Manager, Energy Services Department, to be charged to Account 910 – Administration. A second reason for the increase in DSM-related labor expenses is the re-allocation to Account 910 – Administration of $126,000 in base labor that used to be charged to energy efficiency DSM program expense, Account 910. Most of the increase in non-labor expenses is due to on-costs (EE 406, 422, and 423) that are related to the increase in labor expense and to an increase in ITS expenses.

Q. What is the reason for an increase in ITS expenses?

A. The increase is due to increased labor and non-labor charges that are captured in the ITS clearing account and allocated to various Company accounts. The 2009 test year ITS expenses were allocated to DSM expenses based on actual prorations used in 2007. Please see Ms. Nanbu's testimony (HECO T-11) for a discussion of ITS expenses.

CUSTOMER SERVICE EXPENSE

Account 909 – Supervision

Q. What is the 2009 test year estimate for Account 909 – Supervision?

A. HECO's 2009 test year estimate for Account 909 – Supervision expense is

$427,000, as shown in HECO-1001. The test year estimate consists almost entirely of labor, representing the salaries and overheads of the Customer Solutions Vice President and Secretary (the VP, Customer Solutions Division) and the Manager, Energy Services Department. The VP, Customer Solutions position was created on June 28, 2004, after a re-organization in the HECO Energy Solutions process area.

Q. What is the mission of the Customer Solutions process area?

A. The mission of the Customer Solutions process area is to provide customers with a wide range of choices related to energy options and optimum energy usage. The process area consists of the following:

1) VP, Customer Solutions Division,
2) Energy Services Department (including Administration, Customer Efficiency Programs, and Pricing Divisions),
3) Customer Technology Applications Division,
4) Marketing Services Division, and
5) Forecasts and Research Division.

Q. How was the test year labor estimate for Account 909 – Supervision developed?

A. The test year labor estimate is based on the 2009 O&M Expense Budget of $393,000 as shown in HECO-1003. This estimate was based primarily on the hours spent by the VP, Customer Solution and Secretary and the Manager, Energy Services Department on general supervision and the direction of the Customer Solutions process area.

Q. How was the test year non-labor estimate for Account 909 developed?

A. The non-labor amount of $34,000, as shown in HECO-1003, was estimated by taking continuing 2008 non-labor costs for the VP, Customer Solutions Division and adjusting for higher anticipated costs for various goods and services.

Q. How much of the test year Account 909 expense estimate is associated with DSM?

A. There is about $81,000 of base DSM labor expenses included in the Account 909 test year estimate, as shown in HECO-1002.

Q. How does HECO's 2009 test year Account 909 – Supervision labor expense estimate compare with the recorded expense for the past five years, 2003-2007?

A. The test year labor expense is higher than in 2007, as shown in HECO-1003, due to the following factors:

1) more hours are expected to be allocated to General Supervision by the VP, Customer Solutions and the Manager, Energy Services Department in 2009 in comparison to 2007, and
2) 2007 actual labor expenses are lower by approximately $54,000 due to the inadvertent miscoding of the Energy Services Manager's labor related to DSM program supervision to Account 910 rather than Account 909.

Account 910 – Customer Assistance Expense

Q. What is the 2009 test year estimate for Account 910 – Customer Assistance Expense?

A. HECO's 2009 test year estimate of Account 910 – Customer Assistance Expense is $5,411,000, as shown in HECO-1001. This amount includes a 2009 test year labor expense estimate of $2,973,000 and a non-labor expense estimate of $2,438,000, as shown in HECO-1003.

Q. How much of the test year Account 910 – Customer Assistance Expense is associated with DSM?

A. The amount of Customer Assistance Expense that is associated with DSM is $2,259,000 (before G/L adjustment), as shown in HECO-1025. Customer

Assistance Expenses include nearly all of the DSM expenses for the test year.

Q. How does the estimated 2009 test year expense for Account 910 compare with the recorded 2007 expense for this account?

A. The test year 2009 expense estimate for Account 910 is $5,411,000 as compared to $4,368,000 recorded expenses in 2007, an increase of $1,043,000, as shown in line 11 of HECO-1025. All of the increase is in non-labor expense.

Q. What are the various divisions included in Account 910?

A. The divisions captured in this account are as follows, as shown in HECO-1026:

1) Administration Division – Energy Services Department;
2) Customer Efficiency Programs Division (responsible for DSM programs) – Energy Services Department. Note that all DSM expenses for Account 910, including those DSM expenses that are incurred outside the CEP Division, are consolidated here for descriptive purposes;
3) Customer Technology Applications Division;
4) Marketing Services Division;
5) Forecasts and Research Division;
6) Corporate Communications Division;
7) Education and Consumer Affairs Division;
8) Others – Customer Service Expense

Administration Division, Energy Services Department

Q. What is the mission of the Energy Services Department ("ESD")?

A. ESD is responsible for developing fair and competitive rates, ensuring that customers are provided with accurate information about rates, and planning, designing, and implementing DSM programs.

Q. What are the activities of the Energy Services Department?

A. The divisions of ESD that roll up into Customer Service Expenses include

Administration, Customer Efficiency Programs, and Pricing Divisions. I will discuss the activities of the ESD later in my testimony when I cover each of the organizational areas that contribute to Customer Service Expense.

Q. What are the mission and major activities of the Administration Division?

A. The Administration Division of ESD is responsible for the supervision of the Divisions that report to it. A portion of the expenses for the Administration Division is charged to Account 909, as stated earlier.

Q. What is the 2009 test year labor expense estimate, and how does it compare to 2007 recorded expense?

A. The 2009 test year labor expense estimate is $31,000 in comparison to the 2007 recorded expense of $70,000, or a decrease of $39,000, as shown in HECO-1026, line 4.

Q. Why has the Administration Division's labor expenses decreased?

A. The lower expense estimate in the 2009 test year is due primarily to reduced rate case filing work (a decrease of $17,600), reduced contract evaluation work (a decrease of $8,600), and lower Customer Services marketing program planning costs (a decrease of $7,800).

Q. What is the test year non-labor expense estimate and 2007 recorded expense for Administration?

A. The 2009 test year expense estimate for non-labor is $17,000 as compared to $93,000 in 2007 reflecting a decrease of $76,000, as shown in HECO-1026, line 5. The decrease is largely due to 2007 expenditures being high in comparison to the 2009 budget as a result of $67,000 in HECO IRP non-labor costs being charged to the ESD, Administrative Division. These expenses were unusual in that these expenses are normally charged to the Forecasts and Research Division, which administers IRP-related service agreements on behalf of the ESD, Administration

Division. Thus, the Division's 2007 non-labor expenses were high given this $67,000 one-time charge.

<u>Customer Efficiency Programs Division</u>

Q. What is the mission of the Customer Efficiency Programs ("CEP") Division?

A. The mission of the CEP Division is to design cost effective Demand-Side Management (load management and demand response) programs to be included in HECO's IRP plan and to manage and implement those programs once they are approved by the Commission.

Q. What are the CEP Division's major activities?

A. The major activities of the CEP Division include:

1. <u>Program Planning.</u> The Division develops DSM program concepts, establishes budgets, develops estimates of kW and kWh impacts and performs preliminary cost benefit tests for proposed DSM programs to be included in HECO's IRP plan.
2. <u>Preparing Regulatory Applications and Testimony:</u> The Division prepares the DSM sections and exhibits of HECO's IRP reports. This also includes preparing and presenting written testimony, responding to information requests, and presenting oral testimony as needed to support the DSM programs in the IRP dockets.
3. <u>Preparing DSM Program Applications:</u> The Division prepares DSM program applications for those programs included in the IRP plan. This includes preparing and presenting written testimony, responding to information requests, and presenting oral testimony as needed to support the programs.
4. <u>Implementing the DSM Programs:</u> Following approval of the DSM program applications by the Commission, the Division implements the programs.

These duties include visiting customers to promote the programs, conducting customer training and workshops, processing customer applications and directing other implementation duties.

5. Managing the DSM Programs: CEP Division manages the DSM programs including processing all customer applications, tracking program costs, and maintaining the Demand-Side Management Information System which accounts for all customer incentives and program impacts. The Division also prepares and files the Annual Program Modification and Evaluation ("M&E") Report and the Annual Program Accomplishments and Surcharge ("A&S") Report.

Q. What is the 2009 test year expense estimate for the CEP Division, and how does it compare to 2007 recorded expense?

A. The 2009 test year expense estimate for the CEP Division is $2,259,000 as compared to 2007 recorded expense of $1,631,000 as shown in HECO-1026, line 3, and HECO-1012, line 8. Both figures include all Account 910 DSM expenses incurred outside the CEP Division.

Q. Why is the 2009 test year expense estimate for DSM $628,000 higher than the recorded 2007 cost?

A. As described earlier in this testimony, the increase is primarily due to increases in non-labor costs associated with the CIDLC and RDLC Programs (see HECO-1017).

Customer Technology Applications Division

Q. What is the mission of the Customer Technology Applications ("CTA") Division?

A. CTA Division's overall mission is to provide multi-faceted technical support to our residential, commercial, and industrial customers. The Division identifies, promotes, and introduces innovative and beneficial applications of electro-technologies, and provides engineering expertise in the measurement and analysis of power quality.

Q. What are the CTA Division's major activities?

A. The CTA Division focuses on the following program areas:

- Commercial customer power quality education, technical support, and onsite measurements/analyses,
- Residential customer power quality education, technical support, and onsite measurements/analyses,
- Net Energy Metering ("NEM") Program administration, technical support, application processing, customer and contractor interface,
- Marketing publications - *Powerlines* Newsletter,
- Electro-technologies education, technical support, and promotion.

Examples of electro-technology applications in which the Division has been an active participant are as follows:

- Ice Thermal Energy Storage ("TES") or Cool Storage Systems
- Ultraviolet Germicidal Irradiation ("UVGI") for Tuberculosis Mitigation and Mold Control
- Medical Waste Disposal Technologies including Plasma Vitrification
- Post-Harvest Cooling Systems
- Integrated Dual-Path Air-Conditioning Systems for Supermarkets
- Voltage Ride-Through Systems using Advanced Flywheel Technologies and the Roesel Written Pole Motor Generator
- Demand-Controlled Ventilation ("DCV") Techniques
- Ozone Laundry and Water Disinfection Systems
- Ultraviolet Disinfection of Water and Wastewater Systems
- Membrane Separation Processes for Food Processing

- Adjustable Speed Drives
- Advanced Heat Pump Systems Research and Field Testing
- Web-Based Monitoring and Control Systems
- Magnetic Levitation Compressor Technology
- Energy Efficient Electronic Ballast for High Intensity Discharge ("HID") Lighting
- High Efficiency DC Fluorescent Ballast Technology for Renewable Energy Source Applications

The Division also provides technical support for HECO's Commercial and Industrial Direct Load Control (CIDLC) Program, particularly in the areas of engineering support and site evaluations.

Q. What is the test year labor expense estimate for the CTA Division, and how does it compare to the 2007 actual expense?

A. The 2009 test year labor expense estimate of $403,000 is $46,000 lower than the 2007 recorded expense of $449,000, as shown in HECO-1026, line 7.

Q. What are the reasons for the decrease?

A. Costs for the Net Energy Metering ("NEM") Program are captured under NARUC 586 (Meter Expenses – Distribution Operation). CTA Division's focus on this program has increased and this shifting of work has contributed to a decrease to CTA labor in NARUC 910. The decrease reflects the planned shift of labor resources from work that is accounted for in Account 910 to work accounted in Account 586, a distribution operation account. Labor for the NEM Program experienced a $54,000 increase in its 2009 budgeted costs over its 2007 actual costs. The NEM program is required to meet the requirements of Hawaii Law (Act 104) and the Rule 18 tariff. More time and effort is envisioned in 2009 vs. 2007 for this program due to anticipated increases in: 1) PV installations; and

2) NEM requests. NEM installations grew from 10 in 2006 to 73 in 2007. In 2008 and beyond, system installations are expected to grow in excess of 20% per year.

An increase in filled positions partially offsets the above-noted decrease. In 2007, a Senior Technical Engineer position was vacant for approximately four months while a clerk position was vacant for approximately two months, resulting in lower 2007 labor. A second Senior Technical Engineer position was vacant in 2007. However, in the test year that position has been transferred to the Pricing Division. All CTA Division positions are currently filled.

Q. How does the CTA Division 2009 test year non-labor expense estimate for Account 910 compare with the 2007 recorded expense in this account?

A. The test year non-labor expense estimate of $328,000 is $73,000 higher than the recorded 2007 non-labor expense of $255,000, as shown in HECO-1026, line 8.

Q. Why does the 2009 test year expense estimate increase?

A. The CTA Division non-labor budget includes overhead expenses, employee benefits, and education, promotion, and development work associated with HECO power quality, electro-technologies, cool storage, heat pump technical support, publications, and other normal support activities. For 2007, non-labor recorded expenses reflected a reduction in education, promotion, and development associated with the Division's core program area and other normal support activities compared to years prior to 2007. A $102,000 increase in the 2009 non-labor estimate reflects a return to the funding support for the Division's core program area and other normal support activities. This higher non-labor expense estimate for 2009 is partly offset by approximately $29,000 lower on-costs due to fewer 2009 budgeted labor hours/dollars (the bases for on-costs computation) in comparison to 2007 actuals.

Marketing Services Division

Q. What is the mission of the Marketing Services Division?

A. The Marketing Services Division is responsible for providing account management services for the Company's largest customers.

Q. What are the Marketing Services Division's major activities?

A. The Marketing Services Division provides a single point of contact for HECO's major customers. There are about 400 major commercial customers, primarily Schedules PP, PS, and PT, representing a total of over 6,200 accounts and about 51% of HECO's billed kWh sales in 2007. The account managers in the Marketing Services Division provide frequent proactive contact and develop multilevel relationships with each customer organization.

Major customer services also include communication during power outages, rate analyses, meter and billing consolidation analyses, power factor payback calculations, and coordination of service connections and related services. The Division provides energy solutions assessments and recommendations for major customers; sponsors and conducts conferences, seminars, workshops, trade shows; conducts power quality assessments and recommendations; and assists major customers with electro-technologies applications.

While the account managers assist customers with information about the Company's DSM programs that is only a small portion of their entire customer-related responsibilities. Therefore, the account managers are not considered DSM positions.

Q. What is the 2009 test year labor expense estimate, and how does it compare to the 2007 recorded expense for the Marketing Services Division?

A. The 2009 test year labor expense estimate for the Marketing Service Division is $869,000 as compared to 2007 recorded expense of $822,000, an increase of

$47,000, as shown in HECO-1026, line 10.

Q. Why has the Marketing Services Division's labor expense increased?

A. In 2007, a Marketing Services Account Manager position was vacant for four months thereby resulting in lower 2007 labor. For 2009, all positions are assumed filled for the year. In addition, the increase in labor costs can also be attributed to higher 2009 budgeted non-productive wages on-costs and standard hourly rates used in comparison to the actual 2007 non-productive wages on-costs and hourly rates, thereby resulting in increased labor costs.

Q. What is the total non-labor cost of the Marketing Services Division?

A. The total non-labor cost for the Marketing Services Division for 2009 test year is $498,000, a decrease of about $32,000 from 2007 actual expenditures of $530,000, as shown in HECO-1026, line 11.

Q. What are the reasons for the decrease?

A. The primary reasons for the decrease are due to: 1) a $53,000 normalization adjustment reduction to the 2009 O&M Budget (see HECO-1010 lines 6 and 9 for Marketing Services Division-SN); and 2) approximately $5,000 lower on-costs (primarily employee benefits) in 2009 versus 2007. These decreases were partially offset by a $26,000 increase in other non-labor items reflecting, in part, a return to the normal level of funding support for the Division's various support activities.

Forecasts and Research Division

Q. What is the mission of the Forecasts and Research Division?

A. The Forecasts and Research Division provides support for a number of activities that help the Company provide products, services, and features designed to meet the wants, needs, and expectations of its customers.

Q. What are the Forecasts and Research Division's major activities?

A. The Division has seven main areas of focus.

1. Sales and peak forecasting: The Division develops short and long-term projections of sales and peak demand for HECO, and assists HELCO and MECO with their respective forecast processes. This includes collecting historical data, developing projections for the local economies, analyzing market segments, and integrating all of this information into a forecast of electricity sales and demand.
2. Customer and market research: The Division conducts ongoing assessments of customer satisfaction and expectations, market conditions and trends, energy usage and technology adoption patterns, and related activities intended to help the Company understand and meet customer expectations. The Division conducts similar work for HECO's subsidiary companies, HELCO and MECO, as well.
3. DSM planning and evaluation: The Division develops market potential studies for new and enhanced DSM programs for IRP purposes. In addition, the Division is responsible for the impact evaluations of implemented DSM programs. Through these efforts, new options are made available to our customers for energy efficiency, and existing programs are refined. These efforts also contribute to fulfilling reporting requirements. The Division conducts similar work for HECO's subsidiary companies, HELCO and MECO as well.
4. Load research: The Division coordinates and conducts load research projects that help the Company understand energy usage by different classes of customers. An example of these studies is the 2003 HECO Class Load Study, which provides support for forecasting, pricing, and IRP efforts. The

Division conducts similar work for HECO's subsidiary companies, HELCO and MECO as well.

5. Advertising and promotional activities: The Division manages the Company's mass market advertising efforts for DSM and educational and awareness purposes. These efforts help the Company inform the public about issues related to energy use and efficiency, and about programs and options offered by the Company.

6. Budget and accounting support: The Division provides budget and accounting support for the Energy Services Department to ensure proper accounting, tax treatment, and recording of transactions in accordance with Generally Accepted Accounting Principles ("GAAP").

7. Ad hoc studies and consultative support: In addition to these activities, the Division provides ad hoc studies and consultative support as needed. The Division conducts similar work for HECO's subsidiary companies, HELCO and MECO as well.

Q. What is the 2009 test year labor expense estimate, and how does it compare to the 2007 recorded expense?

A. 2009 test year labor expense estimate for the Forecasts and Research Division of $351,000 is comparable to the 2007 recorded expense of $348,000, representing an increase of $3,000, as shown in HECO-1026, line 13.

Q. How does the Forecasts and Research Division 2009 test year non-labor expense estimate for Account 910 compare with the 2007 recorded expense in this account?

A. The Forecasts and Research Division 2009 non-labor test year expense estimate is $418,000, an increase of $141,000 above 2007 recorded expenses of $277,000, as shown in HECO-1026, line 14.

Q. Why is the test year non-labor cost higher than the 2007 actual non-labor expenses?

A. The primary reasons for the increase in non-labor costs include higher 2009 budgeted costs for IRP non-labor ($92,000) and Marketing Research expenditures ($58,000). This is partially offset by lower budgeted expenditures ($9,000) in other areas. During 2007, Forecasts and Research Division undertook some cost reduction measures which resulted in reduced O&M non-labor spending for the above two areas.

IRP: Forecasts and Research Division's 2007 IRP actual expenditures were low given that a one-time $67,000 HECO IRP charge was recorded to the ESD Administration Division rather than to the Forecasts and Research Division. In addition to this item, 2007 expenditures for other IRP items were generally lower than budget given cost reduction measures in effect such as the Commercial End Use Survey, which was scheduled in 2007, but was deferred to 2008.

Market Research: Market survey efforts in 2007 were reduced and two surveys (major customer, small commercial customer research) were deferred to 2008. The 2009 budgeted amount restores market research support to a more normal level than is evidenced by the 2007 expenditure level.

Corporate Communication Division

Q. What is the mission of the Corporate Communications Division?

A. The Division's mission is to support the Company's strategic plan with clear and credible external public communications, media and community relations, issues management, and employee communications.

Q. What are the Corporate Communications Division's major activities included in account 910?

A. The Division's major activities include:

- Writing and designing *Consumer Lines*, the Company's monthly informational bill insert to customers, preparing website version of the insert,
- Managing content on the www.heco.com website,
- Providing video production and other audiovisual assistance for customer communication needs,
- Participating in partnership efforts with major customers such as the Department of Defense and the University of Hawaii,
- Providing promotional and other support for customer events such as the HECO-sponsored Pacific Coast Electrical Association conference, the Efficient Electro-technology Expo and Seminar, and *Live Energy Lite* energy efficiency program,
- Responding to customer information requests or complaints,
- Communicating with customers and media about outages and other system problems, and
- Planning for and preparing general public communications about issues such as planned company infrastructure projects, rate increases, renewable energy, underground lines, and other topics.

Q. What is the 2009 test year expense estimate for Account 910 for Corporate Communications?

A. Corporate Communications' 2009 test year labor expense estimate for Account 910 – Customer Service Expense is $201,000. The estimated labor expense is for planning and executing customer communications.

Q. How does the 2009 test year expense estimate compare to the 2007 recorded expense?

A. The 2009 test year estimate of $201,000 is $8,000 higher than the 2007 recorded expense amount of $193,000, as shown in HECO-1026, line 16. The primary reason for the increase is the backfilling of staff vacancies due to a retirement and an employee transfer. The division was fully staffed by year end 2007. The 2009 labor charges reflect full staffing for the entire year.

Q. What is the 2009 test year non-labor expense estimate for Corporate Communications for Account 910?

A. Corporate Communications' 2009 test year non-labor expense estimate is $217,000 as shown in HECO-1026, line 17. The estimated non-labor expense for Corporate Communications includes costs for producing and printing customer communications including the *Consumer Lines* monthly newsletter, and miscellaneous supporting audiovisual charges for Corporate Communication Division activities.

Q. How does the 2009 test year non-labor estimate for Account 910 compare to the 2007 recorded amounts?

A. The $2009 test year estimate of $217,000 is only $1,000 higher than the 2007 recorded amount of $216,000.

Education & Consumer Affairs Division

Q. What is the mission of the Education and Consumer Affairs ("E&CA") Division?

A. E&CA educates residential customers and provides information about electrical safety, efficiency, conservation, renewable energy, and alternative energy technologies. E&CA is also responsible for developing, implementing and directing programs and efforts to build and sustain good relations with the community, and facilitating two-way communication with the public.

Q. What are the E&CA Division's major activities?

A. The E&CA Division accomplishes its mission through the following programs:

- HECO in Your Community: Educational exhibits, interactive tools, and information on safe, efficient, and wise use of energy, conservation, renewable energy, and DSM programs are provided at community-sponsored events.

- Home Energy Challenge: In 2007, Hawaiian Electric partnered with the State Department of Education to launch its new Home Energy Challenge program. It works with students to make energy conservation an everyday habit at home.
- Lending Library: Educational materials, brochures, videos and information on the safe, efficient, and wise use of energy, conservation, renewable energy, and the environment are available via the internet or by direct contact with E&CA. Educational materials and speakers are available to schools, customers, and community organizations.
- Electric Magnetic Fields ("EMF"): Educational information and surveys of residential properties are provided to customers.
- Educational Materials: Information on the safe, efficient, economical use of electricity and energy related technology is provided to customers through publications and materials such as the Energy Tips and Choices and Handbook for Emergency Preparedness brochures.
- Sun Power for Schools: HECO supports the Department of Education's implementation of the PowerQuest program, an educational program about electricity, photovoltaics, and alternative energy, which teaches students about energy and the environment.
- Customer Education Campaign: Community outreach and information to provide information, awareness, and knowledgeable choices on electrical safety, power quality, outage prevention, and energy conservation. The campaign focuses on energy conservation, with the theme "Live Energy

Lite", to teach customers ways to conserve in general and especially during peak hours. A Business Employee Conservation Kit and outreach was developed and is being disseminated to encourage energy conservation at the workplace and at home by employees and their families. The campaign includes a Mylar Balloon Outage Prevention Campaign to educate customers about actions they can take to prevent outages caused by Mylar balloons and subsequent safety hazards, customer losses and financial damages.

- <u>The Electric Kitchen</u>: The Electric Kitchen is a venue to promote safe, efficient use of electrical appliances and energy conservation through the use of new electric technologies and proven energy saving tips for the home. This information is provided to customers in a popular weekly newspaper column that features recipes from our recipe files and from various civic and community service groups.
- <u>Integrated Resource Planning ("IRP")</u>: Assistance with the planning, developing, implementing, and reporting of HECO's IRP Plan, with emphasis on the expanded community outreach and public input.

Q. What is the 2009 test year labor expense estimate, and how does it compare to 2007 recorded expense?

A. The E&CA Division's 2009 test year labor is $453,000 as compared to $340,000 recorded expense in 2007, an increase of $113,000, as shown in HECO-1026, line 19.

Q. Why is the 2009 test year labor estimate cost higher than 2007 actual labor cost?

A. The increase in labor costs is primarily due to staff vacancies in 2007. The 2009 labor estimates reflect the effect of full staffing levels for direct labor costs and associated overheads.

Q. How does the E&CA Division 2009 test year non-labor expense estimate for

Account 910 compare with the 2007 recorded expense in this account?

A. E&CA Division 2009 test year expense estimate is $482,000, an increase of $72,000 above 2007 recorded expenses of $410,000, as shown in HECO-1026, line 20.

Q. Please explain the difference between the 2009 test year expense estimate and 2007 recorded expense.

A. The increase is due to increased labor on-costs associated with increased staffing. The 2007 expenditures were lower due to staff vacancies and subsequent temporary reductions in program expenses and operations. Positions have been filled and 2009 projections are at full capacity. Also, 2009 reflects increased outreach to encourage customer energy conservation in response to customer demand and to help mitigate reduced reserve margins and higher peak usage. The 2009 expense estimates also reflect increased printing costs of and demand for highly requested educational publications and an increase in associated overhead charges.

<u>Others – Customer Service Expense</u>

Q. What is included in the expense labeled “Others” in HECO-1026 lines 22 to 24?

A. The major departments that have included cost in “Others” are Legal, Energy Projects, Customer Installations, Engineering and System Operations. These departments provide support to the activities coded to Account 910.

Q. What is the 2009 test year labor expense estimate and 2007 recorded expense for “Others – Customer Service Expense”?

A. 2009 test year expense estimate is $48,000 versus $87,000 recorded in 2007, a decrease of $39,000, as shown in HECO-1026, line 22.

Q. What is the 2009 test year non-labor expense estimate, and how does it compare to the 2007 recorded non-labor expense?

A. The 2009 test year non-labor expense estimate of $242,000 is $17,000 higher than 2007 recorded non-labor expense of $225,000, as shown in HECO-1026, line 23.

Q. What non-labor expenses are included in the "Others – Customer Service Expense"?

A. The test year non-labor expense estimate of $242,000 consists primarily of ITS charges in support of activities coded to Account 910 ($222,000 – See Ms. Nanbu's testimony, HECO T-11), plus related on-costs ($20,000) for associated labor included in the "Others – Customer Services Expense" category.

<u>Account 911 – Informational Advertising Expense</u>

Q. What is the 2009 test year expense estimate for Account 911 – Informational Advertising?

A. HECO's 2009 test year expense is $1,148,000, as shown in HECO-1003. The estimated expenses in this account for Corporate Communications include labor costs of $32,000 and non-labor costs of $1,116,000. These costs are for the development and placement of print and radio advertising and related print materials to inform customers about energy efficiency and safety (including education about outages caused by mylar balloons), rights to submit damage claims, and customer programs and services such as HECO's *Sun Power for Schools* and Arbor Day "Right Tree, Right Place".

The estimated expenses also include television, radio and print advertising and collateral materials to more aggressively inform customers about energy efficiency and conservation measures, including publicizing the Company's *Live Energy Lite* events and programs, and to help build a conservation "ethic" with customers.

Also included are labor costs ($5,000) for communications work to support

HECO's IRP-4. Other labor costs from the Forecasts and Research Division ($5,000) comprise the rest of the labor included in Account 911.

Q. How does the 2009 test year estimate for Account 911 compare to the 2007 recorded amounts?

A. The $1,148,000 test year estimate is $498,000 higher than the 2007 amount recorded to account 911 of $650,000. However, this not does reflect an additional $9,000 of informational advertising which was inadvertently charged to Account 910 in 2007. Thus, the adjusted total for informational advertising in 2007 is $659,000. In addition, in 2007, the Company also spent an additional $1,752,000 of DSM funds for the Residential Consumer Energy Awareness (RCEA) pilot program on complementary advertising and marketing to encourage the use of specific DSM energy efficiency measures such as solar water heating, EnergyStar appliances, and compact fluorescent lights. RCEA Program expenses are incremental costs recovered through the DSM Surcharge.

Q. What is the primary reason for the increase in non-RCEA advertising in 2009 versus 2007?

A. In its Final D&O for HECO's 2005 rate case (Docket No. 04-0113, Order No. 24171) dated May 1, 2008, HECO's request for additional informational advertising funding was not granted on the basis that the request was "moot" because HECO's RCEA customer advertising program had since been approved. However, per the Commission's February 13, 2007 D&O (Docket No. 05-0069, Order No. 23258) the RCEA and other DSM programs are slated to be transitioned to the PBF Administrator in 2009.

Given that HECO will no longer have RCEA program funding beginning in 2009, the issue of funding for needed energy efficiency and conservation advertising is no longer moot for this rate case.

The Company still has a responsibility to continue to aggressively increase customer awareness of energy efficiency and conservation measures and the importance of making such actions an everyday habit. Consistent with our position in the 2005 and 2007 HECO rate cases, this funding is instrumental in driving reductions in demand, which are especially critical as the Company continues to operate under tight generating reserve margins and as the Company must still achieve the required goals under the Renewable Portfolio Standards law, as well as those promulgated by the State of Hawaii Global Warming Solutions Act of 2007 and the Hawaii Clean Energy Initiative. The Company also has a responsibility to provide such information to assist customers in managing their energy costs, an expectation that is even greater during this time of rising fossil fuel prices.

Such education also directly supports the State's Energy Policy. Specifically, Section 226-18(c) of the Hawaii Revised Statutes states the following:

> (c) To further achieve the energy objectives, it shall be the policy of this State to:
>
> (4) Promote cost-effective conservation of power and fuel supplies through measures including:
>
> (A) Development of cost-effective demand-side management programs;
>
> (B) Education; and
>
> (C) Adoption of energy-efficient practices and technologies.

The planned advertising helps carry out the State's objectives by increasing awareness of the importance of energy conservation from the standpoint of consumer savings and environmental benefits. The messages reinforce the importance of conservation by promoting specific action steps customers can take to achieve conservation. Further, it should be noted that energy conservation is recognized as the most effective way to reduce greenhouse gas emissions and thus help achieve the requirements of the State's new greenhouse gas law.

Q. Please describe how HECO would spend the requested funding to aggressively inform customers about energy efficiency and conservation measures.

A. To educate Oahu customers on the importance of conserving electricity requires a comprehensive effort. The Energy Education and Conservation Campaign is designed to reach people with multiple messages in a variety of different media. The ultimate goal is to educate Oahu consumers of electricity about energy issues and options, and ultimately help households on Oahu adopt energy efficient products and strategies. To change people's habits of energy usage requires a well-planned, sustained effort and it is important to continue the momentum built up as a result of the Company's existing successful RCEA and informational advertising efforts.

In 2009, HECO plans to deliver conservation messages across a variety of media, using a broad-based television, radio, newspaper, and magazine schedule. The reach and frequency of these messages will be adjusted throughout the year.

To convey these education and conservation messages, HECO will develop and produce 30-second television spots, 60-second radio spots, newspaper and magazine advertisements and internet website content. Themes will range from personal to global perspectives. On the personal level, energy conservation will help households save money on their electricity bills. On the global level, energy conservation will help reduce the level of greenhouse gasses, which will make Hawaii and the world a healthier place for future generations.

The 2009 expenditures for the projected media and production budget total $1,000,000:

	Media Budget
Television	$ 442,000
Radio	167,000
Print	147,000
Media Total	$ 756,000

	Production Budget
TV Production (two :30 sec. spots w/ :10 donut[12])	$175,000
Radio Production (four :60 spots)	14,000
Music (:30 and :60 versions)	25,000
Print Ads (two shells w/ ability to rotate energy tips)	20,000
Web updates	10,000
Production Total	$244,000

This advertising will be supplemented with heavy public and community relations outreach efforts.

Q. How much does the Company plan to spend on informational advertising in 2008?

A. Consistent with the amount approved by the Commission in its interim order (Order No. 23749, Docket 2006-0836) for the Company's 2007 rate case, the Company plans to spend $174,000 in informational advertising charged to O&M accounts. In addition, it plans to spend an additional $1,720,000 for complementary RCEA advertising. This advertising is being supplemented with heavy public relations and community outreach efforts, resulting in media features and other media coverage and community fairs, including HECO's major *Live Energy Lite* fair at Pearlridge Center, which helped to publicize conservation tips and the importance of energy conservation.

Q. In summary, how do the 2009 test year estimates for informational advertising compare with amounts spent by the Company on similar advertising in 2007 and

[12] A donut is a 10 second time slot in which new energy efficiency information can be rotated to keep the overall 30 second radio spot fresh. For example, the slot might be used to plug an upcoming Live Energy Lite event or to promote a special limited time offer.

planned for 2008?

A. The Company is requesting recovery of $1,148,000 in informational advertising costs. Of this amount, $1,116,000 is for non-labor, an amount the Company believes is a conservative amount to achieve the important energy conservation and efficiency goals elaborated on in this testimony, especially relative to the total $2,411,000 that was spent in 2007 and $1,894,000 planned to be spent in 2008 for customer informational and RCEA advertising.

Account 912 – Miscellaneous Customer Service Expense

Q. What is the 2009 test year estimate for Account 912 – Miscellaneous Customer Service Expense?

A. HECO's 2009 test year expense estimate for Account 912 – Miscellaneous Customer Service Expense is $21,000, as shown on HECO-1003.

Q. What expenses are included in Account 912 - Miscellaneous Customer Service Expense?

A. The 2009 test year estimate represents an estimate of outside services consultants to conduct technological advances and process improvements such as training in project management skills and attendance at workshops for credit and customer assistance center representatives.

CUSTOMER SOLUTIONS HEAD COUNT

Q. What is the test year year-end employee count for the Customer Solutions process area?

A. The test year employee count is 48, which is 3 more than the count as of March 31, 2008, as shown in HECO-1027.

Q. Is the entire labor expense for all of the 48 positions encompassed within the

Customer Services block of accounts?

A. No. HECO-1027 shows that the primary NARUC accounts for the different organizational areas within the Customer Solutions process area, including Account 920, which is not in the Customer Services block of accounts. There are also some labor expenses in the Customer Services block of accounts that originate from other areas of the company. However, by and large, the labor expenses included in Customer Service expense originate within the Customer Solutions process area.

Q. Does this test year employee count exclude incremental DSM labor?

A. Yes. The test year employee count does not include five regular HECO employees that are incremental, or the nine contract DSM positions that are incremental.

Q. Please briefly describe the increase in employee count shown in HECO-1027.

A. The increase of three positions originates from the following areas:

1) One position in the Customer Efficiency Programs (CEP) Division
2) One position in the Pricing Division
3) One position in the Marketing Services Division

CEP Division. As noted above, the CEP Analyst position will be moved from incremental to base DSM expenses to consolidate the division budget, perform budget analysis, validate invoices for payment, write portions of the annual DSM program A&S and M&E reports, and administer contracts. Since HECO will retain the RDLC and CIDLC load management programs, and additional demand response programs will likely be proposed (e.g., the Dynamic Pricing Pilot Program filed with the Commission on April 24, 2008), this position will continue to be necessary to implement and support utility-administered DSM programs.

<u>Pricing Division.</u> As noted above, a Senior Pricing Analyst will be added to provide supplemental policy direction and rate initiative coordination, and, when required, support rate case efforts as either a rate case witness or as the person responsible for providing draft testimony, exhibits, workpapers, and IR responses. Rate initiatives that support customer choice rate options, demand response, and increasing the amount of renewable energy resources on the system are forthcoming in the immediate future. These initiatives include: green pricing, budget billing, enhanced time-of-use, and dynamic pricing.

<u>Marketing Services Division.</u> This vacancy is due to an internal employee transfer of an Account Manager on December 2007 to fill a position in the CEP Division. This position is planned to be filled on January 1, 2009, the assumed date of the transition of energy efficiency DSM programs to the PBF Administrator, as regular HECO employees now classified as incremental become available to fill existing vacancies.

INTEGRATED RESOURCE PLANNING

Q. What is the test year expense estimate for IRP costs that HECO is proposing to be included in base rates?

A. HECO is proposing a total of $1,153,400 be included in base rates as shown in HECO-1028. This amount is comprised of labor and non-labor components. The labor component consists of $736,900 in labor and associated on-costs for employees who support HECO's IRP process, as shown in HECO-1029. These employees are currently in base rates. The second component consists of $416,500, as shown in HECO-1030, which represents the 2009 IRP normalized test year estimate of HECO's IRP planning non-labor costs.

Q. Please describe the costs associated with Integrated Resource Planning ("IRP")?

A. The costs for IRP are those costs for planning activities associated with the IRP process. Included in these costs are the costs of data gathering, development of models, research and development of options in meeting the demand for energy, and obtaining public input into the IRP process. The costs for IRP include: (1) consultant services; (2) legal services; (3) information services; (4) labor and associated on-costs; (5) materials and supplies, travel, training, and other miscellaneous costs.

Q. How does HECO currently recover the costs associated with IRP?

A. In HECO's Test Year 2005 rate case, Docket No.04-0113, HECO proposed to change the method for recovering IRP associated costs such that IRP costs are recovered entirely through base rates. The Commission, in granting HECO an interim rate increase in Interim Decision & Order No. 22050, allowed HECO to recover its entire IRP costs through base rates. Accordingly, as of September 28, 2005, the effective date of the interim rate increase, HECO discontinued recovering its IRP expenses incurred through the IRP Clause.

Further, the Commission continued to allow HECO to recover its IRP related costs through base rates per its rulings in Interim Decision & Order No. 23749 (HECO 2007 test year rate case), issued October 22, 2007, and in Final Decision & Order No. 24171 (HECO 2005 test year rate case), issued May 1, 2008. However, pending before the Commission for decision making is a final decision and order for the recovery of HECO IRP incremental costs between and including the years 1997 through 2005. Any reconciling balances between what has already been recovered and the amount ultimately approved by the Commission will be returned/recovered through the IRP Clause, with interest.

Q. Is HECO proposing any further change to the method of recovering IRP costs?

A. No. The Company is proposing to continue recovering its IRP costs entirely through base rates.

Q. Did HECO make a normalizing adjustment to its O&M Expense Budget for rate case purposes?

A. Yes. HECO decreased its O&M Expense Budget for non-labor by $173,400, as shown in HECO-1030. The normalization calculation is shown in HECO-1031. The amount was determined by taking the average of:

1) Actual IRP-related planning non-labor costs incurred in 2007;
2) The actual IRP-related planning non-labor costs incurred from January to April 2008 plus the forecasted IRP-related non-labor cost from May to December 2008; and
3) The forecasted amount of IRP-related planning non-labor costs for 2009.

The derived average then served as a basis for the normalization adjustment.

Q. Why is this methodology for derivation of the normalization amount considered reasonable?

A. The Company's methodology for derivation of the normalization amount is reasonable because it is consistent with the methods used in Docket No. 04-0113 (HECO 2005 test year rate case) and in Docket No. 2006-0386 (HECO 2007 test year rate case) in that the IRP non-labor costs to be included in base rates were derived using an average of three years.

Q. How does the test year IRP expense estimate compare with 2007 actual expenses?

A. The test year IRP expense estimate is only $86,300 lower than 2007, as shown in HECO-1032.

Q. Why is the test year expense estimate lower than 2007 actual expenses?

A. The test year expense estimate is lower by $86,300 primarily due to lower 2009 budgeted labor and on-costs versus 2007 actuals ($220,200 decrease). This was primarily due to higher level of activity in 2007 to prepare the IRP-4 plan filing due in 2008. The favorable labor variance was partially offset by higher 2009 normalized non-labor expenses in comparison to 2007 actuals ($133,900 increase).

Generally, 2007 non-labor expenditures were lower than 2009 due in part to 2007 cost reduction measures which resulted in reduced expenditures. The 2009 test year non-labor estimate, however, is a normalized estimate of IRP non-labor expenses and thus reflects a more average level of IRP-related non-labor expenses.

Refer to the respective NARUC areas for more specific labor and non-labor IRP variances.

ENERGY COST ADJUSTMENT CLAUSE

Q. What is the test year Energy Cost Adjustment ("ECA") factor at current and proposed rates?

A. The test year ECA factor is 7.221 ¢/kWh at current rates, and 0.000 ¢/kWh at proposed rates as shown in HECO-1033.

Q. What is the Energy Cost Adjustment Clause ("ECAC")?

A. The ECAC is an automatic adjustment provision in the utility's rate schedules that allows the utility, without a rate proceeding, to automatically increase or decrease charges to reflect changes in the Company's energy costs of fuel and purchased energy above or below the levels included in the base charges. The Company's current base fuel energy charges and central station fixed efficiency factor embedded in the base charges, shown in HECO-1034, were established in HECO's 2005 Test Year rate case, Docket No. 04-0113.

Q. What is the purpose of ECAC?

A. The purpose of ECAC is: 1) to address price changes in the Company's cost of fuel and purchased energy; and 2) to accommodate changes to the actual mix of generation, utility-DG (distributed generation) and purchased energy resources, without the need for a rate case.

Q. How does ECAC work?

A. A rate case proceeding determines the base electricity rates which are predicated on test year levels of fuel prices, payment rates for purchased energy, and resource mix. The ECAC mechanism, expressed in cents per kilowatt-hour, allows the Company to recover costs due to subsequent changes in: 1) fuel and purchased energy costs; 2) the resource mix between utility-owned generation, utility-DG and purchased energy; 3) the resource mix among the central station utility plants and utility-DG; and 4) the resource mix among purchased energy producers. A rate case proceeding also established a fixed efficiency factor(s), or sales heat rate(s), for the utility central station generation units to encourage efficient operation of the system units. An ECA Factor, which sets the rate adjustment that reflects these changes for the coming month, is filed with the Commission monthly.

Q. How much revenue has been collected/returned through HECO's ECAC on a historical basis?

A. Since 1984 annual revenues have varied between a return to customers of $184,000,000 in 1988, to a collection from customers of $528,000,000 in 2007, as shown in HECO-1035. In years with declining fuel prices, returns were prevalent such as the period between 1984 and 1992. In recent years, rapidly increasing fuel prices have resulted in collections from customers.

Q. What costs are currently passed through the ECAC?

A. The Company's fuel oil, trucking, and fuel related costs associated with its central station units, diesel fuel and trucking costs associated with its utility-DG units, and its purchased energy costs pass through the ECAC. The low sulfur fuel oil (LSFO) and diesel fuel oil costs in the central station units and diesel fuel oil costs in the utility-DG units are discussed by Mr. Sakuda (HECO T-4) and Mr. Cox (HECO T-5). Fuel related costs that currently pass through the ECAC include fuel inspection costs (referred to as Petrospect expenses) and trucking costs for the central station Honolulu units and utility-DG units. Payments for purchased energy, but not capacity costs, are passed through the ECAC.

Q. With respect to Kalaeloa and AES Hawaii, what is included in the ECAC?

A. For both current and proposed rates, only the fuel and fuel additive components of Kalaeloa's energy charge and the fuel component of AES Hawaii's energy charge are included in the ECAC.

Q. How does the Distributed Generation ("DG") component allow ratepayers to benefit from the improved efficiency resulting from the installation of utility-owned DGs?

A. HECO expects that additional utility-owned or operated DG units will be installed in the near future (e.g., distributed standby generation at the Honolulu Airport). Furthermore, the efficiency of utility-owned DG units is better than the efficiency of the utility's central station units (see HECO-404). Therefore, as additional DG units are added to the HECO system over time, the system efficiency may improve. Including the existing utility-owned DG units in the ECAC fixed efficiency factor would not allow ratepayers to benefit from improvement in the efficiency factor expected when additional utility-owned or operated DG units come on-line because the ECAC fixed efficiency factor is not adjusted until the next rate proceeding.

On the other hand, a separate DG component recovers DG fuel and transportation costs at actual expense levels and would not be subject to a fixed efficiency factor. Thus, to the extent that the added DG unit efficiencies are better than the fixed efficiency factor, the separate DG component will pass the impact of improved efficiency through the ECAC to ratepayers.

Q. Why does the Company need the ECAC?

A. The Company needs the ECAC because fuel costs are a large portion of its expenses and because fuel price levels are largely beyond the Company's control.

In the test year, fuel and purchased energy expenses make up about 74% of total O&M expenses. This makes the Company's financial condition very sensitive to changes in fuel prices. The ECAC benefits the Company and its shareholders by:

- Limiting the swings in cash flow and earnings,
- Reducing the cost of capital,
- Improving the Company's ability to earn a fair return on investor capital, and;
- Providing a more timely recovery of fuel and purchased energy costs.

Q. How does the ECAC benefit customers?

A. The ECAC benefits customers by:

- Reducing the Company's financial risk and lowering the cost of capital. The resulting savings are passed on to our customers through lower base rates in rate proceedings such as this one.
- Passing through to customers, savings incurred when fuel prices fall below the prices embedded in base rates, to the same extent that they will incur additional costs when fuel prices are above the embedded fuel prices.

Q. What other benefits does the ECAC have?

A. Since the ECAC is an automatic clause it allows the Commission time to concentrate on other key, substantive strategic issues.

Q. How is the ECA factor computed at present rates?

A. The calculation of the ECA factor at present rates has three base composite cost components: (1) the central station generation component, (2) the utility-DG energy component, and (3) the purchased energy component. The ECA factor is equal to the difference between: (1) test year central station generation, utility-DG, and purchased energy weighted composite costs and (2) central station generation, utility-DG, and purchased energy weighted composite costs established in the last rate case. The fixed efficiency factor for the central station generation is also established in the last rate case. Computation of the ECA factor at present rates is similar to the monthly factor computation filed with the Commission, as shown in HECO-1036.

Q. Are the fuel additive costs passed through the ECAC?

A. At present rates, the fuel additives costs are not being passed through the ECAC. However, the Company is proposing to pass through the fuel additive costs for Kahe 6 unit in ECAC at proposed rates. Since additives may also be injected into other HECO generating units, HECO is proposing that the cost of additives, when used in other generating units, would also be passed through the ECAC.

The recovery of the fuel additive in the ECAC was approved in HECO's test year 2007 rate case, Docket No. 2006-0386. On October 22, 2007, the Company received from the Commission, Interim D&O No. 23749 for HECO's 2007 test year rate case. The 2007 test year estimate of fuel additive costs is included in the determination of the Company's 2007 test year interim increase. Since the 2007 test year interim rates are included in the estimate of revenue at current effective rates, the recovery of fuel additives is included in that estimate.

Q. Are the fuel costs from the CIP CT-1 passed through the ECAC at present rates?

A. Yes, the diesel fuel and biodiesel fuel that are burned by the unit are passed through the ECAC at present rates to the extent that they are not recovered in base rates. On December 1, 2009, the Campbell Industrial Park ("CIP") CT-1 unit is projected to switch from diesel fuel to 100% biodiesel purchased from Imperium Services, LLC ("Imperium"). Approval of the Imperium biodiesel contract and HECO's request to include contract costs in HECO's ECAC are pending at the Commission (Docket No. 2007-0346, "Imperium Docket"). Because the biodiesel fuel costs are in both test year current effective rates and proposed rates, these costs will not be reflected in an interim rate award. However, the test year biodiesel costs will be incorporated into base rates when the Commission approves the final rates in this proceeding, similar to other test year fuel costs. In the event that there are changes resulting from a decision in the Imperium Docket by the Commission or from change in the final contract provisions, the ECA factors at present and proposed rates for the test year will be revised accordingly.

Until such time as the Commission approves the Imperium contract and the inclusion of contract costs in the ECAC, HECO will not pass through the biodiesel fuel costs through the monthly ECAC filings.

The Company added new fuel price and btu mix line items in the central station generation component section of the ECAC calculations for CIP CT-1, as shown in HECO-1037, page 1. While CIP CT-1 is burning regular diesel fuel, the fuel price will be the price of diesel. If by the time CIP CT-1 begins burning biodiesel fuel and approval to include biodiesel contract and fuel costs has not been received from the Commission, the fuel price for biodiesel will be zero in the monthly ECAC filings. Whether CIP CT-1 is burning diesel or biodiesel, the weighted fuel cost will be included in the monthly determination of the central station composite cost of generation.

Q. Why is there a difference between the composite cost of generation at present rate and proposed rates, as shown on HECO-1038?

A. The Company is proposing to pass the fuel additives costs through the ECAC only at the proposed rates and not at present rates.

Q. How is the ECA factor computed at proposed rates?

A. The proposed calculation of the ECA factor consists of the same three base composite cost components as in present rates -- central station generation, DG energy, and purchased energy. However, the Company is proposing four separate efficiency factors and a weighted efficiency factor in its central station generation component, as shown in HECO-1039.

Q. Why are the ECA factors different at current and proposed rates?

A. There are two reasons for the difference. First, the base central station fuel cost, base DG energy cost, and base purchased energy cost at proposed rates have been reset to reflect the test year composite costs for central station fuel, DG energy, and purchased energy. The ECA factor at present rates include the base composite costs for fuel and purchased energy approved by the Commission in HECO's 2005 test year rate case, Docket No. 04-0113.

Second, the fuel efficiency factors (sales heat rates) used to calculate the base central station generation component cost at proposed rates has been revised to reflect the test year fuel weighted efficiency. In the ECA factor at present rates the central station fuel efficiency factor is that approved by the Commission in HECO's 2005 test year rate case.

Q. Why is the Company proposing a weighted efficiency factor in its central station generation component?

A. The Company is proposing to include a weighted efficiency factor in its ECAC calculations in the same manner as was introduced in Docket No. 05-0315, Hawaii Electric Light Company, Inc. (HELCO) 2006 test year rate case; Docket No. 2006-0387; Maui Electric Company, Ltd. (MECO) 2007 test year rate case; and in Docket No. 2006-0386, HECO 2007 test year rate case. These dockets are pending before the Commission. As discussed in these dockets, the proposed weighted efficiency factor addresses the diversity of fuel burned in the central station generating units.

Q. How is the weighted efficiency factor determined?

A. The fixed efficiency factors for LSFO, diesel, and biodiesel burning central station generating units, shown in HECO-1039, are determined from the production simulation discussed in Mr. Sakuda's testimony (HECO T-4). The efficiency factor for each of the three generating unit types is weighted by the MWh contribution of each type to the total central station MWh generation.

At HELCO, another efficiency factor was derived for Company-owned renewable generating units (wind and hydro at HELCO). While HECO does not currently own any renewable generating units, a fourth "Other" efficiency factor has been derived and included in HECO's proposed ECA clause for consistency.

Q. Why is HECO proposing to add biodiesel fuel as a fuel type?

A. The biodiesel fuel is added as a fuel type in determining the weighted efficiency factor because the CIP CT-1 unit is anticipated to burn biodiesel in 2009.

Q. How are the avoided energy cost rates and Schedule Q rates for Qualifying Facilities less than 100 kW determined?

A. The avoided energy cost rates and Schedule Q rates are determined using the QF In/QF Out methodology approved by the Commission in Docket No. 7310. The Company will replace the previous proxy method calculations with the QF In/QF

Out method approved in Docket No.7310. Please refer to Mr. Ching's testimony (HECO T-6) for more details on the QF In/QF Out methodology.

Act 162

Q. On June 2, 2006, the Governor of Hawaii signed into law Act 162, which amends Section 269-16 of the Hawaii Revised Statutes. How does Act 162 affect the ECAC?

A. The Company addressed Act 162 in HECO's 2007 test year rate case as well as in HELCO's 2006 and MECO's 2007 test year rate cases. Act 162, in part, states "any automatic fuel rate adjustment clause requested by a public utility in an application filed with the commission shall be designed, as determined in the commission's discretion, to:

(1) Fairly share the risk of fuel cost changes between the public utility and its customers;
(2) Provide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy;
(3) Allow the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as through fuel hedging contracts;
(4) Preserve, to the extent reasonably possible, the public utility's financial integrity; and
(5) Minimize, to the extent reasonably possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs."

Q. On June 19, 2006, the Commission issued Order No. 22537, in which the Commission directed the parties to HECO's 2005 test year rate case (including the

Consumer Advocate and the Department of Defense) to file a procedural schedule on this matter. How did the Company comply with the Commission's order?

A. On August 7, 2006, the Company, Consumer Advocate, and the Department of Defense filed a stipulation, which stated in part:

"4. It would be more efficient to explicitly address the Act 162 factors in the context of HECO's ECAC in HECO's next general rate case, given (a) the need to develop information on matters such as hedging, (b) the opportunity to address the factors in the context of HELCO's ECAC in HELCO's pending general rate case (Docket No. 05-0315) . . ."

The Company complied with the Commission's Order in HECO's 2007 test year rate case as follows.

1) The Company selected a highly qualified consultant, National Economic Research Associates, Inc. ("NERA"), to provide assistance in evaluating the extent to which HECO, HELCO and MECO ("the Companies") currently comply with the requirements of Act 162. On December 29, 2006, the Companies filed the consultant's final report, *Report on Power Cost Adjustments and Hedging Fuel Risks*, (see HECO-1040) with the Commission.

2) The Company addressed the issues consistent with the stipulation on August 7, 2006 in HECO's 2007 test year rate case.

   a) Jeff D. Makholm, a Senior Vice President at National Economic Research Associates, Inc. ("NERA"), provided testimony explaining the role of fuel adjustment clauses ("FACs") in utility ratemaking in the United States, and addressing the compliance of HECO's current power cost recovery mechanism, the ECAC, with Act 162. Mr. Makholm concluded that (1) FACs are a standard and longstanding part of U.S.

utility ratemaking, (2) HECO's ECAC is a well-designed FAC and benefits HECO and its ratepayers, and (3) HECO's ECAC complies with the statutory requirements of Act 162.

b) In addition, Eugene T. Meehan, who also is a Senior Vice President at NERA, provided a summary of the type of fuel price hedging that potentially could be performed by HECO in the marketplace and an assessment of the potential impacts of fuel price hedging on HECO, its customers and the regulatory ratemaking process. His conclusions with respect to fuel price hedging included:

1. Hedging of oil by HECO would not be expected to reduce fuel and purchased power costs and in fact would be expected to increase the overall level of such costs in the long run because of the costs of implementing the hedging program[13],
2. The liquidity of standard financial hedging products with a term of over a year is limited, and while HECO could partially hedge against oil price risk for periods of just over a year into the future, there would be considerable costs to doing so,
3. It would not be reasonable for HECO to take the position of a principal and speculate in the oil market with shareholders assuming the risk of oil derivative gains and losses, and
4. Even if rate smoothing is a desired goal, there may be more effective means of meeting the goal, and there is no compelling reason for HECO to use fuel price hedging as the means to achieving the objective of increased rate stability.

[13] At least 12 states (Alabama, Florida, Georgia, Louisiana, Iowa, Missouri, Mississippi, Minnesota, North Dakota, South Dakota, Nevada, Colorado, and Michigan) allow the pass through of hedging costs and/or sharing of hedging benefits between the utility and its customers, usually through their respective Power Cost Adjustments.

Q. Act 162 authorizes the Commission to evaluate the ECAC from the perspective of fuel price risk-sharing between the Company and its ratepayers. What is HECO's position on the appropriate level of fuel price risk sharing in the ECAC?

A. As discussed in HECO's 2007 test year rate case, the Company's position is that the current level of ECAC fuel price risk-sharing is appropriate and that no change is necessary to the current ECAC risk-sharing approach.

The ECAC does not necessarily pass 100% of any change in fuel expenses to ratepayers. As indicated above, HECO's ability to recover its fuel expenses is subject to an efficiency factor, which measures how efficiently HECO converts fuel energy into electrical energy. If HECO cannot meet the efficiency factor embedded in the ECAC, it recovers only a portion of its fuel expenses. Thus, HECO is already at risk for the non-recovery of fuel expense and this risk profile is inherent in the currently employed ECAC mechanism.

The risk associated with meeting the efficiency factor is one that HECO can address through the overhaul and maintenance of its generating units and unit commitment schedule among others. Thus, it is reasonable for the Commission to hold the Company responsible for not meeting the efficiency standard and for its fuel expenses to be subject to the risk of non-recovery as a result.

However, fuel prices are subject to market forces and geopolitical events that HECO cannot control. A risk-sharing mechanism which penalizes the Company because prices increase above an expected base price, even one which provides a symmetric positive incentive when prices are below the base, holds the Company financially responsible for events beyond its control. Such a risk-sharing mechanism places the Company in an untenable financial position, for which it is not compensated.

Therefore, HECO maintains that the current level of ECAC risk-sharing is appropriate, and that no change is necessary to the current ECAC risk-sharing approach.

Q. In the HECO 2007 test year rate case - Stipulated Settlement Letter ("SSL") dated September 5, 2007 to the Commission, signed by the Company, Consumer Advocate and Department of Defense, was there agreement on the issue of whether there should be a change in the current risk sharing arrangement associated with changes in the price of oil as reflected in the existing ECAC?

A. The Stipulated Settlement Letter indicated that, "The Parties are continuing discussions with respect to the final design of the ECAC to be approved in the final decision and order and will either submit a further stipulation regarding this matter, or address the matter in their respective proposed findings of fact and conclusions of law. The Parties agree, however, that their resolution of this issue will not affect their agreement regarding revenue requirements, and that it is appropriate for the Commission to issue its interim rate order based on the stipulated revenue requirements." (SSL, Exhibit 1, page 4)

However, in the Stipulated Settlement Letter the Parties also stated, "In CA-T-1, the Consumer Advocate agreed that the ECAC should continue to be employed and did not object to the continuation of the ECAC to provide HECO with recovery of changes in energy costs." (SSL, Exhibit 1, page 3)

Further: "For purposes of the interim rate increase, the Parties agree that the ECAC should continue in its present form… Furthermore, as a result of the settlement discussions, the Parties agree on the methodology for calculating the Energy Cost Adjustment Factor ('ECAF'), including the inclusion of fuel additives, fuel trucking, the addition of the 'DG Component', and the use of three fixed efficiency factors to replace the single Central Station efficiency factor at present rates, as proposed in HECO T-9..." (SSL, Exhibit 1, page 3)

Q. Did the Parties to MECO's 2007 test year rate case (Docket No. 2006-0386) reach agreement on the ECAC?

A. Yes. In the MECO 2007 test year rate case, on December 7, 2007, the parties filed a stipulation that stated, among other things, "the Parties agree that no further changes are required to MECO's ECAC in order to comply with the requirements of Act 162."

Q. Did the Parties to HELCO's 2006 test year rate case (Docket No. 05-0315) reach agreement on the ECAC?

A. Yes. In the HELCO 2006 Test Year Rate Case, the April 5, 2007 Stipulated Settlement Letter between HELCO and the Consumer Advocate stated the following on page 1 of Exhibit 1: "The Parties agree that the ECAC should continue and that it satisfies Act 162 (Session Laws of Hawaii, 2006), and agree to the methodology used to calculate the ECAF, including the addition of the 'DG Component' and propane start-up costs in said calculation, as proposed in HELCO RT-22."

Q. What is the Company's position regarding the ECAC structure for HECO, HELCO, and MECO?

A. The Company's position is that the ECAC structure for HECO, HELCO, and MECO should be identical. Uniformity across the utilities' ECACs reduces the administrative costs for all Parties. Treating the fuel and purchased energy cost recovery of one utility differently from another would require further and unnecessary utility and Commission resources devoted to the treatment of fuel and purchased power costs.

Q. On June 17, 2008, HELCO received from the Commission three information requests ("PUC-IRs") to complete the Commission's evaluation of HELCO's 2006 test year rate increase application (Docket No. 05-0315). What was the key issue in those information requests?

A. One of the issues in Docket No. 05-0315 is whether HELCO's ECAC complies with the requirements of Hawaii Revised Statutes § 269-16(g). In PUC-IR-01, the Commission requested information on the impact on customers rates if the "pass through" of the change in the cost of power (i.e., fuel and purchase power costs) to HELCO's customers was: (a) 80%; (b) 90% and (c) 95%.

Q. What is HECO's position on partial pass-through versus full pass-through of fuel and purchased energy costs?

A. HECO maintains that partial pass-through of fuel and purchased energy costs is not a viable option for Hawaii. Partial pass-through mechanisms and their impact on utility financial health were discussed in a study conducted by NERA in a *Report on Power Cost Adjustments and Hedging Fuel Risks* that was forwarded to the Commission in Docket No. 2006-0386 (HECO's 2007 Test Year Rate Case) on December 29, 2006. In that study, NERA concluded:

1) Some states, e.g., Arizona, Colorado, Idaho, and Washington, have adopted partial pass-through mechanisms. These are sometimes referred to as "risk sharing" mechanisms. However, this characterization is incorrect because the utility is a price taker and has no control over the price of fuel in the global market place. (Page 26)

2) These partial pass-through states actually represent a broad movement towards less risk imposed on the utilities. For example, Idaho Power had been subject to a zero pass-through and moved toward a 90% pass-through. (Page 27)

3) Oil generally plays an insignificant role in these utilities' generation mix. These utilities typically get most of their power from hydro, nuclear, and coal. (Page 28)

4) "...Fuel prices constitute a large and volatile cost for price taking utilities. A well established, frequently updated FAC is essential to maintain a utility's credit and operational viability. Partial pass through mechanisms that defer power cost recovery in an attempt to shield ratepayers from power cost changes present an inefficient solution to the rate stability issues and the rising cost of electricity input costs. Forcing a utility to temporarily absorb a portion of power cost changes (assuming that the utility can defer the recovery of costs not passed through a FAC to a future rate case) does not prevent consumers from ultimately having to pay the full amount for their power usage, and may harm the utility's financial position." (Page 29)

The NERA report concluded that, "Sharing of the risk of oil price fluctuations between customers and shareholders is not good regulatory policy when the utility has no control over world oil markets. Such sharing would not exempt consumers from ultimately having to pay the full amount for their power usage, (assuming that the utility can defer the recovery of costs not passed through a FAC to a future rate case) and thereby harm the utility's financial position." (Page 30)

Q. Has HECO conducted a national survey of FACs subsequent to NERA's December 29, 2006 report?

A. Yes. In March 2008 HECO requested NERA to conduct a survey of all 50 states and the District of Columbia to determine to what extent FAC mechanisms were used in the United States.

Q. What was the result of the survey?

A. The survey found that 33 traditionally regulated states incorporate FAC mechanisms into their regulation of electric utilities. Of those 33 states, 22 states allow 100% pass through of fuel and power costs (including Hawaii, which is subject to an energy efficiency factor), as shown in HECO-1041. Thus, Hawaii is not the only state which allows full pass-through of fuel and purchased energy costs.

Q. Why do 18 states (including the District of Columbia) not have FAC mechanisms?

A. Adjustment clauses in 15 of those 18 states are not applicable because the utilities there are typically restructured, distribution-only, utilities that do not have their own generation. Thus, those utilities do not need a FAC. These distribution-only utilities pass on the full cost of generation to customers in the cost of the electricity that the customers purchase from producers. Two additional states, Nebraska and Alaska, are public power states where there are no investor-owned utilities. Finally, Utah is an investor-owned utility, that has not restructured, that does not have a FAC. It recovers its fuel costs through temporary rate increases.

Q. Of the 33 states that have FACs, 22 states have 100% pass-through of fuel and power costs. Please briefly describe the FACs in the remaining 11 states.

A. The FACs in the remaining 11 states utilize some form of dead-bands, sharing, or caps on fuel cost pass-through. The primary source of fuel in these states is either coal or hydro[14]. Coal is generally secured under long-term contracts and exhibit less volatility than oil or natural gas. Hydroelectric power has low marginal costs. Thus, in those states using primarily coal or hydro, the change in costs of generation are low relative to states that use oil or natural gas. Therefore, 100% pass-through does not have the financial significance in those states that it does in Hawaii.

Q. What would be the impact on HECO if the pass-through in the change in the cost of power is limited to 80%, 90%, or 95%?

A. Limiting the change in the cost of power to 80%, 90%, or 95% would decrease

[14] The exception is Arizona, which has a mix of coal, nuclear, and natural gas.

HECO's test year 2009 ECA revenues at current effective rates by approximately $110,600,000, $55,300,000, or $27,600,000, respectively, as shown in HECO-1042. Had the limitation been in effect it would have resulted in severe financial hardship for the utility.

In addition to financial impacts, a partial pass-through would not send an accurate and correct price signal to customers. Sending an accurate and correct price signal to reflect 100% of the true cost of fuel would allow customers to make appropriate decisions regarding their energy efficiency and conservation behavior, which could lead to lower energy use.

Q. Does this conclude your testimony?

A. Yes, it does.

ALAN K.C. HEE

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company, Inc. 220 South King Street Honolulu, Hawaii 96813
POSITION:	Manager, Energy Services Department
YEARS OF SERVICE:	22 Years
EDUCATION:	MBA, University of Hawaii, 1982 BS, Civil Engineering Cornell University, NY, 1974
OTHER QUALIFICATIONS:	Registered Professional Engineer, Hawaii Civil Engineering Branch
OTHER EXPERIENCE:	Director, Forecasts Division Energy Services Department, 1995-2004
	Director, Forecasting Division Rate and Regulatory Affairs Dept., 1991-1995
	Planning Analyst, Forecasting Division Rate and Regulatory Affairs Dept., 1986-1991
	Operations Engineer GASCO, Inc., Hilo 1982-1986
	Peace Corps Volunteer Fiji Islands, 1974-1976

Hawaiian Electric Company, Inc.

CUSTOMER SERVICE EXPENSE
2009 Test Year
($1000s)

Line			Test Year 2009
1	909	Supervision	427
2	910	Customer Assistance	5,411
3	911	Informational Advertising	1,148
4	912	Miscellaneous Customer Service	21
5		TOTAL	7,007

Source
HECO-1002

T-10 Exhibits.xls

Hawaiian Electric Company, Inc.

CUSTOMER SERVICE EXPENSE
DSM vs. Non-DSM Expenses
2009 Test Year

($1000s)

Line			A DSM *	B NON DSM *	C GL CODE		D TEST YEAR ESTIMATE
1	909	Supervision	81	456	**(110)**		427
2	910	Customer Assistance	2,259	4,558	**(1,406)**	(1)	5,411
3	911	Informational Advertising		1,162	**(14)**		1,148
4	912	Miscellaneous Customer Service		21	**0**		21
5		TOTAL	2,340	6,197	**(1,530)**		7,007

SOURCE
Column A: HECO-1012
Column B: For Accounts 911 and 912: HECO WP-101(D)
For Account 910: HECO-1026, line 27
Column C: HECO-WP-101(D)
Column D: Columns (A+B+C)

* Includes:
EE 406 corporate administration
EE 422 employee benefits
EE 423 payroll taxes

NOTE:
(1) GL Code of ($1,406,000) is net of initial GL Code amount of ($1,599,000) and ($193,000) of primarily DSM incremental on-costs (EE's 406, 422, 423).
Rate Case adjustments related to the transfer of the ($193,000) Expense Elements have been made directly to the end NARUC account.

Hawaiian Electric Company, Inc.

CUSTOMER SERVICE EXPENSES*
(**Excludes** EE #406, 422, & 423)
2003-2009
($1000s)

Line			A	B	C	D	E	F	G
			Recorded 2003	Recorded 2004	Recorded 2005	Recorded 2006	Recorded 2007	Budget 2008	Test Year 2009
	909	Supervision							
1		Labor	0	115	229	217	239	373	393
2		Non-labor	0	9	17	17	23	31	34
3		Total	0	124	246	234	262	404	427
	910	Customer Assistance							
4		Labor	2,685	2,456	2,824	2,859	3,011	2,763	2,973
5		Non-labor	794	1,175	1,437	1,395	1,357	2,199	2,438
6		Total	3,479	3,631	4,261	4,254	4,368	4,962	5,411
	911	Informational Advertising							
7		Labor	15	15	25	11	17	29	32
8		Non-labor	55	477	554	187	633	172	1,116
9		Total	70	492	579	198	650	201	1,148
	912	Miscellaneous Customer Services							
10		Labor	1	8	1	0	0	0	0
11		Non-labor	0	1	3	3	1	21	21
12		Total	1	9	4	3	1	21	21
		TOTAL CUSTOMER SERVICE EXPENSES							
13		Labor	2,701	2,594	3,079	3,087	3,267	3,165	3,398
14		Non-labor	849	1,662	2,011	1,602	2,014	2,423	3,609
15		Total	3,550	4,256	5,090	4,689	5,281	5,588	7,007

* DSM Incremental costs (Act. 714) have been excluded for all years.
Reflects impact of GL Code Transfer

Hawaiian Electric Company, Inc.

NON DSM* CUSTOMER SERVICE EXPENSES
(**Includes** EE# 406, 422, & 423)
2003-2009
($1000s)

Line			A	B	C	D	E	F	G
			Recorded 2003	Recorded 2004	Recorded 2005	Recorded 2006	Recorded 2007	Budget 2008	Test Year 2009
	909	Supervision							
1		Labor	0	103	229	216	235	256	330
2		Non-labor	0	28	76	84	104	109	126
3		Total	0	131	305	300	339	365	456
	910	Customer Assistance							
4		Labor	2,438	2,213	2,168	2,083	2,309	2,251	2,356
5		Non-labor	1,618	1,469	1,795	1,828	2,006	2,275	2,202
6		Total	4,056	3,682	3,963	3,911	4,315	4,526	4,558
	911	Informational Advertising							
7		Labor	15	15	25	11	17	29	32
8		Non-labor	60	481	563	193	642	185	1,130
9		Total	75	496	588	204	659	214	1,162
	912	Miscellaneous Customer Services							
10		Labor	1	8	1	0	0	0	0
11		Non-labor	0	4	4	3	1	21	21
12		Total	1	12	5	3	1	21	21
		TOTAL CUSTOMER SERVICE EXPENSES							
13		Labor	2,454	2,339	2,423	2,310	2,561	2,536	2,718
14		Non-labor	1,678	1,982	2,438	2,108	2,753	2,590	3,479
15		Total	4,132	4,321	4,861	4,418	5,314	5,126	6,197

* Not reduced by the GL Code Credit for all years
Amount excludes all DSM expenses

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Hawaiian Electric Company, Inc.

CUSTOMER SERVICE EXPENSE
TEST YEAR 2009 ($1000s)

Line		A O&M EXPENSE BUDGET	B RATE CASE ADJ	C NORMALIZATION	D TEST YEAR ESTIMATE
	909 SUPERVISION				
1	LABOR	393			393
2	NON-LABOR	39	(5)		34
3	TOTAL ACCT. 909	432	(5)	0	427
	910 CUSTOMER ASSISTANCE				
4	LABOR	3,407	(434)		2,973
5	NON-LABOR	22,809	(20,244)	(127)	2,438
6	TOTAL ACCT. 910	26,216	(20,678)	(127)	5,411
	911 INFORMATIONAL ADVERTISING				
7	LABOR	32			32
8	NON-LABOR	1,116			1,116
9	TOTAL ACCT. 911	1,148	0	0	1,148
	912 MISC. CUSTOMER SERVICE				
10	LABOR	0			0
11	NON-LABOR	21			21
12	TOTAL ACCT. 912	21	0	0	21
13	TOTAL CUSTOMER SERVICE	27,817	(20,683)	(127)	7,007
	RECAP:				
14	LABOR	3,832	(434)	0	3,398
15	NON-LABOR	23,985	(20,249)	(127)	3,609
16	TOTAL	27,817	(20,683)	(127)	7,007

SOURCE
Column A: HECO-WP-101(B), excludes EE 406, 422, 423.
Column B: HECO-1006
Column C: HECO-1009
Column D: Columns (A+B+C)

Hawaiian Electric Company, Inc.

CUSTOMER SERVICE EXPENSE
Summary of 2009 Rate Case Adjustments
($1000s)

Line		A	Total B
	ACCT. 909		
	Non-Labor:		
1	Remove Restricted Stock Amount		(5)
2	**Total Adjustment - Account 909**		(5)
	ACCT. 910		
	Labor		
3	Remove Incremental DSM Program Expenses		(434)
4	Add Back CEP Analyst Position Reclassifed from Incremental to Base		72
5	Transfer Vacant Senior Technical Engineer to Senior Rate Analyst		(72)
6	Total Labor Adjustments		(434)
	Non-Labor:		
7	Incremental DSM Program Expenses -Non Labor	20,437	
8	Incremental DSM Program -GL Code Adjustment	(193)	
9	Remove Incremental DSM Program Expenses	20,244	(20,244)
10	GL Code Impact - CEP Analyst Position	31	
11	GL Code Impact - Transfer Senior Tech Engineer	(31)	
12		0	
13	**Total Adjustments - Account 910**		(20,678)

	Adjustment Summary	Line #(s)	Amount
14	Restricted stock awards	1	(5)
15	Remove Incremental DSM	3, 7-9	(20,678)
16	Add CEP position into base	4, 10	103
17	Transfer Senior Tech Engr.	5, 11	(103)
18	Total Adjustments		(20,683)

Reference - Lines 3, 7-9, 15: HECO-1007

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Hawaiian Electric Company, Inc.

DSM PROGRAM EXPENSES ($000)

2009 FORECAST ADJUSTMENT
Remove Incremental DSM Program Expenses

Line		LABOR	NON-LABOR	TOTAL
	DSM Program Costs*			
1	CIEE	105	3,333	3,438
2	CINC	111	1,590	1,701
3	CICR	118	1,637	1,755
4	REWH	12	2,825	2,837
5	RNC	0	1,774	1,774
6	ESH	58	1,496	1,554
7	RLI	30	935	965
8	CIDLC	264	3,821	4,085
9	RDLC	54	3,684	3,738
10	SSP	27	558	585
11	DDP	15	77	92
12	Total Program Costs	794	21,730	22,524
	DSM Base Program Costs*			
13	CIEE	0	0	0
14	CINC	0	0	0
15	CICR	0	0	0
16	REWH	0	0	0
17	RNC	0	0	0
18	ESH	0	0	0
19	RLI	0	0	0
20	CIDLC	264	700	964
21	RDLC	54	574	628
22	SSP	27	12	39
23	DDP	15	7	22
24	Total Base Program Costs	360	1,293	1,653
	DSM Incremental Program Costs*			
25	CIEE	105	3,333	3,438
26	CINC	111	1,590	1,701
27	CICR	118	1,637	1,755
28	REWH	12	2,825	2,837
29	RNC	0	1,774	1,774
30	ESH	58	1,496	1,554
31	RLI	30	935	965
32	CIDLC	0	3,121	3,121
33	RDLC	0	3,110	3,110
34	SSP	0	546	546
35	DDP	0	70	70
36	Total Incremental Costs	434	20,437	20,871
37	Less G/L code adjustment		-193	-193
38	Rate Case Adjustment	434	20,244	20,678

* Includes EE 406, 422, 423

Reference - Lines 36-38: HECO-1008 (lines 19, 20, 21)

Hawaiian Electric Company, Inc.

Incremental Account 910 DSM Program Expense
By Expense Element

Line	Incremental Labor	Expense Element	Dollars ($)	
1		150	378,959	
2		421	54,605	
3	Incr. Labor Total		433,564	
	Incremental Non-Labor			
4	Corporate Admin	406	43,356	EE elements 406, 422, 423
5	Employee Benefits	422	118,274	= 193,046
6	Payroll Taxes	423	31,416	
7		201	316,959	
8		205	19,669	
9		301	9,282	
10		401	33,376	
11		462	3,623	
12		501	18,953,074	
13		503	811,956	
14		520	19,468	
15		521	47,343	
16		522	3,936	
17		640	25,680	
18	Total Incr. Non-Labor		20,437,412	
19	Total Incremental DSM Program Exp (Including EE elements 406, 422, 423)		20,870,976	
20	G/L Code Adjustment		-193,046	
21	**Rate Case Adjustment**		**20,677,930**	

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Hawaiian Electric Company, Inc.

SUMMARY OF 2009 TEST YEAR NORMALIZATION ADJUSTMENTS
Customer Service Expense

($1000s)

Line		Total
	ACCT. 910	
	Non-Labor:	
1	Normalize PCEA Expenses	**(60)**
2	Normalize IRP Non-labor Expenses	**(67)**
3	**Total Non-labor Adjustments**	**(127)**

References:
HECO-1010 for PCEA Conference Normalization Adjustment
HECO-1030, line 2, for IRP Non-labor Normalization Adjustment

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Hawaiian Electric Company, Inc.

PCEA CONFERENCE NORMALIZATION
Customer Service Expense

($1000s)

Line		A 2009 O&M Expense Budget	B Normalization	Note
	ACCT. 909			
	Non-Labor:			
1	PCEA Travel Expense (1W)	1	--	
2	**Total Normalization - Account 909**	1	--	
	ACCT. 910			
	Non-Labor:			
3	PCEA Travel Expense (SA)	1	--	
4	PCEA Travel Expense (SD)	3	(2)	(1)
5	PCEA Travel Expense (SM)	4	(2)	(1)
6	PCEA Travel Expense (SN)	11	(6)	(1)
7	PCEA Travel Expense (SP)	3	(2)	(1)
8	PCEA Travel Expense (SR)	3	(1)	(1)
9	PCEA Sponsorship (SN)	94	(47)	(1)
10	**Total Normalization - Account 910**	119	(60)	

Note
(1) Normalization for 50% of Pacific Coast Electrical Association (PCEA) - Hawaii biennial conference expenses forecast in 2009.

Existing DSM Program Descriptions

Program	Program Description	Docket No. 05-0069 Opening Brief Reference
CIEE Commercial & Industrial Energy Efficiency	Provides prescriptive incentives to commercial and industrial customers for purchasing and installing energy efficient motors, air conditioning systems, and lighting systems.	Pp. 67-81
CINC Commercial & Industrial New Construction	Seeks to maximize opportunities for saving energy in new commercial and industrial buildings and in major renovations of commercial/industrial facilities.	Pp. 81-89
CICR Commercial and Industrial Customized Rebate	Addresses the large number of DSM measures that are available to the commercial and industrial sector, which, due to the limited potential size of the market for these measures or to the site-specific savings resulting from their installation, do not lend themselves to a prescriptive incentive program design.	Pp. 89-98
REWH Residential Efficient Water Heating	Encourages customers to reduce their electricity consumption for water heating by promoting the sale, installation, and use of energy-efficient water heaters in the existing residential market. The program specifically offers financial incentives for the installation of solar, heat pump, and high efficiency electric water heaters.	Pp. 98-107
RNC Residential New Construction	Encourages homebuilders, including HECO customers who are building their own homes, to reduce electricity consumption in newly constructed homes. The program promotes the installation and use of solar water heaters, heat pumps, high efficiency electric water heaters, and high efficiency electric water heaters coupled with load control devices in newly constructed homes.	Pp. 107-117

Program	Program Description	Docket No. 05-0069 Opening Brief Reference
RLI Residential Low Income	Enables qualified low-income customers, as defined by the State of Hawaii guidelines for low income residents, to receive CFLs and high-efficiency water heating measures at no cost to them.	Pp. 117-120
ESH Energy Solutions for the Home	Provides a comprehensive range of energy efficiency options that address several major appliance end-uses. The program is intended to work in parallel with the US-EPA's Energy Star program to maximize the benefits of this national initiative.	Pp. 120-127
SSP SolarSaver Pilot	A 3-year pilot program designed to overcome the barrier of up-front costs in the residential solar water heating market. Residential customers participating in the Pilot Program will incur no upfront cost and will pay for the cost of the installed solar water heating system over time through the savings in the participant's electricity bill.	Not Applicable, Docket No. 2006-0425
RCEA Residential Customer Energy Awareness	Increases customers' awareness of 1) the benefits of higher energy efficient appliances, and 2) their impact on the need for future electrical generation, and educates customers on the many low cost, or no cost, DSM measures and products available to them through a mass media campaign.	Not Applicable, Docket No. 03-0142

Program	Program Description	Docket No. 05-0069 Opening Brief Reference
CIDLC Commercial and Industrial Direct Load Control	Increases HECO's system reliability and potentially reduces its spinning reserve requirements by curtailing contracted commercial and industrial customer loads during generation shortfall conditions. In return, customers receive incentives based on their level of participation. Three program elements exist, each targeting specific customer segments to maximize enrolled loads. The Direct Load Control (DLC) element targets medium to large C&I customers (> 50 kW) whereby a dispatchable and/or underfrequency load control relay is installed on customer equipment to automate load curtailment. The Voluntary Load Control (VLC) element provides the customer with the voluntary option of curtailing load manually. The VLC element may also act as an introduction to load control programs with the goal of migrating customers to the DLC program element. The Small Business Direct Load Control (SBDLC) element is aimed at smaller commercial customers (25 kW – 100 kW) and is very similar to DLC element in that an underfrequency load control relay is installed on a variety of end-uses to automate load curtailment.	Pp. 132-134. Also, D&O No. 23605 (August 15, 2007) Docket No. 03-0415, Amendments to the CIDLC Program
RDLC Residential Direct Load Control	Obtain load reductions through the installation of load control devices on residential customer water heaters and central air-conditioners. These reductions will help HECO to reduce its system requirements during peak load periods and thus potentially avoid service disruptions due to insufficient capacity. In return the customer will receive a $3 monthly credit for load control of a water heater, and a $5 monthly credit for load control of a central air-conditioner.	Pp. 132-134. Also, D&O No. 23574 (August 1, 2007) Docket No. 03-0166, RDLC Program.

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Hawaiian Electric Company, Inc.

TEST YEAR DSM EXPENSES
Customer Service vs. Non-Customer Service Expenses
($1,000s)

Line		Labor	Non-Labor	TOTAL
1	**Account 909**			
2	Supervision	63	18	81
3	**Account 910**			
4	DSM Program Costs	317	1,273	1,590
5	DSM-Related Costs			
6	Administration	300	150	450
7	ITS	0	219	219
8	Total Acct 910 DSM Expenses	617	1,642	2,259
9	**Customer Service DSM Expense**	**680**	**1,660**	**2,340**
10	**Other Than Customer Service**			
11	DSM Expenses			
12	Account 903 - Cust Rec/Coll Exp	4	2	6
13	Account 920 - Regulatory	17	0	17
14	Account 921 - Regulatory	2	9	11
15	**Total Other Than Customer Service**	**23**	**11**	**34**
16	**Total DSM Expenses**	**703**	**1,671**	**2,374**

Reference: HECO-1013

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Hawaiian Electric Company, Inc.

TEST YEAR DSM EXPENSE
DSM Program vs. DSM-Related Costs
($1,000s)

Line		Labor	Non-Labor	TOTAL
1	**DSM Program Costs**			
2	Account 910 - Customer Assistance	317	1,273	1,590
3	Account 903 - Cust Rec/Coll Exp	4	2	6
4	Account 920 - Regulatory	7	0	7
5	Account 921 - Regulatory	1	5	6
6	**Total DSM Program Costs**	**329**	**1,280**	**1,609**
7	**DSM-Related Costs**			
8	Account 909 - Admin	63	18	81
9	Account 910 - Adminstration	300	150	450
10	Account 910 - ITS	0	219	219
11	Accounts 920/921 - Admin	11	4	15
11	**Total DSM-Related Costs**	**374**	**391**	**765**
12	**Total DSM Expenses**	**703**	**1,671**	**2,374**

Reference: HECO-1015, HECO-1023

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Hawaiian Electric Company, Inc.

TEST YEAR DSM EXPENSES
Adjustments to Base DSM Expenses

($1,000s)

Line		O&M Expense Budget	TY Adjustment CEP Analyst	TY Adjustment STE	Reallocate Base Energy Efficiency Labor	Revised TY
1	DSM Program Costs					
2	CIEE	37			-37	0
3	CINC	6			-6	0
4	CICR	15			-15	0
5	REWH	38			-38	0
6	RNC	27			-27	0
7	ESH	3			-3	0
8	RLI	0				0
9	CIDLC	964	29	-104		889
10	RDLC	629	29			658
11	SSP	40				40
12	DDP	22				22
13	Total Program Costs	1,781	58	-104	-126	1,609
14	DSM-Related Expenses					
15	Administration	374	45	1	126	546
16	ITS	219				219
17	Total DSM-Related Expenses	593	45	1	126	765
18	**Total DSM Expenses**					
	All NARUC Accounts	**2,374**	**103**	**-103**	**0**	**2,374**

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Hawaiian Electric Company, Inc.

TEST YEAR DSM PROGRAM COSTS

($1,000s)

Line		Labor	Non-Labor	TOTAL
1	**Acct. 910 DSM Program Costs**			
2	CIEE	0	0	0
3	CINC	0	0	0
4	CICR	0	0	0
5	REWH	0	0	0
6	RNC	0	0	0
7	ESH	0	0	0
8	RLI	0	0	0
9	CIDLC	212	677	889
10	RDLC	75	583	658
11	SSP	18	8	26
12	DDP	12	5	17
13	Total Acct. 910 DSM Program Costs	317	1,273	1,590
	Other Than 910 - DSM Program Costs			
14	Account 903 - Cust Rec/Coll Exp	4	2	6
15	Account 920 - Regulatory	7	0	7
16	Account 921 - Regulatory	1	5	6
17	Total Other than 910 - Subtotal	12	7	19
18	**Total DSM Program Expenses**	**329**	**1,280**	**1,609**

Hawaiian Electric Company, Inc.

Position Matrix -- DSM Program Positions

Base Rates	Incremental
ESD CEP Division (5)	ESD CEP Division (6)
Director	CEP Analyst
PM, RDLC	C&I Engineer
PM, CIDLC	PM, Residential
LM Engineer	PM, Commercial
Clerk	CEP Analyst
<======================	CEP Analyst (a)
Customer Technology Applications (2)	
Sr Technical Svc Engr	
~~Sr Technical Svc Engr~~ (b)	

Notes:
a. CEP Analyst position to be transferred into base.
b. Senior Technical Engineer to be transferred out of the CTA Dvision into the Pricing Division as a Senior Rate Analyst.

Excludes contract employees.

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Hawaiian Electric Company, Inc.

Test Year DSM Program Costs in Account 910
Comparison with Actual 2007
($1,000s)

Line		2007	2009 TY	TY - 2007 Difference
	Account 910 DSM Program Labor Costs			
1	CIEE	75	0	-75
2	CINC	49	0	-49
3	CICR	42	0	-42
4	REWH	21	0	-21
5	RNC	14	0	-14
6	ESH	27	0	-27
7	RLI	17	0	-17
8	CIDLC	162	212	50
9	RDLC	25	75	50
10	RCEA	3	0	-3
11	SSP	12	18	6
12	DDP	0	12	12
13	Total Program Costs	447	317	-130
	Account 910 DSM Base Program Non-Labor Costs			
14	CIEE	46	0	-46
15	CINC	25	0	-25
16	CICR	22	0	-22
17	REWH	10	0	-10
18	RNC	7	0	-7
19	ESH	13	0	-13
20	RLI	8	0	-8
21	CIDLC	152	677	525
22	RDLC	327	583	256
23	RCEA	1	0	-1
24	SSP	6	8	2
25	DDP	0	5	5
26	Total Program Costs	617	1,273	656
27	Account 910 Total DSM Program Costs	1,064	1,590	526

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Hawaiian Electric Company, Inc.

COMMERCIAL & INDUSTRIAL DIRECT LOAD CONTROL PROGRAM
BASE PROGRAM EXPENSES
2007 ACTUALS VS 2009 TEST YEAR BUDGET
($1,000s)

Line		2007 Base Actuals	2009 Test Year Base	Variance
1	LABOR	162	212	50
2	NON-LABOR (See below)	152	677	525
3	**TOTAL**	**314**	**889**	**575**
	NON-LABOR DETAILS			
4	NON-LABOR OVERHEADS	76	94	18
5	TRACKING & EVALUATION	1	118	117
6	ADVERTISING	61	160	99
7	TRAINING & MISC.	14	305	291
8	TOTAL NON-LABOR	152	677	525

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Hawaiian Electric Company, Inc.

Test Year CIDLC Base Program Budget
By Program Element

Line		HECO DLC, VLC, SBDLC Costs	3rd Party SBDLC Costs	2009 CIDLC Budget
	Direct Labor			
1	Administration	306,000	0	306,000
2	Tracking & Evaluation	37,264	80,736	118,000
3	Total Base Labor	343,264	80,736	424,000
4	Advertising/Marketing	95,416	64,584	160,000
5	Materials & Miscellaneous	46,664	258,336	305,000
6	Advertising/Admin Subtotal	142,080	322,920	465,000
7	**TOTAL PROGRAM COSTS**	**$485,344**	**$403,656**	**$889,000**

NOTES:
Total Base Labor, Advertising/Marketing, and Materials & Miscellaneous expenses are recovered through base rates and not the IRP Cost Recovery Adjustment.

Assumes Full Year Implementation of DLC, VLC, & SBDLC program implementation costs

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Hawaiian Electric Company, Inc.

RESIDENTIAL DIRECT LOAD CONTROL PROGRAM
BASE PROGRAM EXPENSES
2007 ACTUALS VS 2009 TEST YEAR BUDGET
($1,000s)

Line		2007 Base Actuals	2009 Test Year Base	Variance
1	LABOR	25	75	50
2	NON-LABOR (See below)	327	583	256
3	**TOTAL**	**352**	**658**	**306**
4	NON-LABOR DETAILS			
5	NON-LABOR OVERHEADS	13	33	20
6	TRACKING & EVALUATION	1	111	110
7	ADVERTISING	300	424	124
8	TRAINING & MISC.	13	15	2
9	TOTAL NON-LABOR	327	583	256

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Hawaiian Electric Company, Inc.

Cumulative DSM Program Impacts (Net of Free-riders)
For DSM Measures Implemented in 2006 and Thereafter

Line		2008	TY 2009	2010	2011	2012
1	Energy (GWh - Grs Gen Level)	76.7	121.4	164.3	194.6	228.7
2	Energy (GWh - Cust Level) [1]	68.1	107.9	146.0	172.8	203.1
3	Demand (MW - Grs Gen Level)	27.5	44.6	59.7	67.8	76.4
4	Demand (MW - Net-to-Sys Level) [2]	25.7	41.6	55.8	63.3	71.3

Incremental DSM Program Impacts

Line		2008	TY 2009	2010	2011	2012
5	Energy (GWh - Cust Level) [1]	68.1	**39.7**	38.1	26.9	30.3
6	Demand (MW - Net-to-Sys Level) [2]	25.7	**16.0**	14.1	7.5	8.0

Notes:
[1] Customer Level, Including Free-riders, Annualized. 11.17% losses from the Grs Gen Level.
[2] Net-to-System Level, Net of Free-riders. 4.864% losses to the Customer Level.

Reference: HECO-1021, page 2

Hawaiian Electric Company, Inc.

DSM Program Impacts, Gross Generation Level, Reduced by Free-riders

Line	Incremental MWh	2007*	2008**	TY 2009#	2010	2011	2012
1	REWH	4,318	3,792	2,746	2,746	2,746	2,746
2	RNC	1,993	3,107	2,374	2,374	2,188	2,188
3	CIEE	14,700	15,266	15,266	15,266	15,245	13,440
4	CINC	9,602	5,823	5,822	5,822	5,793	5,228
5	CICR	14,629	9,583	9,583	9,583	9,583	9,583
6	ESH	46,445	36,208	6,071	4,193	**(7,064)**	**(809)**
7	RLI	0	2,633	2,633	2,633	1,751	1,751
8	SSP	29	250	250	250	0	0
9	Total	91,716	76,662	44,746	42,868	30,242	34,127
10	Cumulative MWh		76,662	121,408	164,276	194,518	228,645

Line	Incremental kW	2007*	2008**	TY 2009#	2010	2011	2012
11	REWH	982	874	632	632	632	632
12	RNC	699	989	993	993	957	957
13	CIEE	2,146	2,284	2,284	2,284	2,279	1,964
14	CINC	1,621	874	874	874	868	778
15	CICR	1,963	1,245	1,245	1,245	1,245	1,245
16	ESH	8,706	7,534	1,832	1,483	**(619)**	548
17	RLI	0	591	591	591	426	426
18	CIDLC	11,737	8,331	7,768	6,951	2,280	2,026
19	RDLC	7,159	4,708	834	0	0	0
20	SSP	6	59	59	59	0	0
21	Total	35,019	27,489	17,111	15,110	8,066	8,576
22	Cumulative kW		27,489	44,599	59,710	67,775	76,351

* Actual 2007 impacts
** 2008 from HECO's Annual DSM M&E Report, dated Nov. 30, 2007, Attachment A
\# 2009 and thereafter from EE Docket,
Docket DSM Backup Sheets (07-14-06) ESD 082106.xls

Gross generation losses to sales = 11.17%
Net to system losses to sales = 4.864%

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Hawaiian Electric Company, Inc.

DSM Energy Impact
Test Year Sales vs. Program Year

		Test Year Sales Estimate (mWh)			Annualized Program Year (mWh)
Line		2007	2008	2009	2009
1	Jan	0	491	6,073	3,376
2	Feb	0	845	5,719	3,049
3	Mar	0	1,427	6,619	3,376
4	Apr	0	1,841	6,674	3,267
5	May	0	2,394	7,183	3,376
6	Jun	0	2,777	7,220	3,267
7	Jul	0	3,361	7,747	3,376
8	Aug	0	3,852	8,034	3,376
9	Sep	0	4,188	8,043	3,267
10	Oct	0	4,819	8,598	3,376
11	Nov	0	5,124	8,589	3,267
12	Dec	0	5,786	9,162	3,376
13	Total	0	36,904	89,658	39,748

T-10 Exhibits.xls

Hawaiian Electric Company, Inc.

Test Year DSM-Related Expenses
($1,000s)

Line		Labor	Non-Labor	TOTAL
	DSM-Related Expenses			
1	Account 909 - Admin	63	18	81
	Account 910			
2	Administration	300	150	450
3	ITS	0	219	219
4	Acct 910 Other DSM Expense	300	369	669
5	Accounts 920/921 - Admin	11	4	15
6	**Total DSM-Related Expenses**	**374**	**391**	**765**

T-10 Exhibits.xls

Hawaiian Electric Company, Inc.

Test Year DSM-Related Expenses

Comparison with Actual 2007
($1,000s)

Line		2007	2009 Test Year	Difference
	Labor			
1	Account 909 - Admin	4	63	59
2	Account 910 - Admin	255	300	45
3	Accounts 920/921 - Admin	0	11	11
4	Total Labor	259	374	115
	Non-Labor			
5	Account 909 - Admin	1	18	17
	Account 910			
6	Administration	124	150	26
7	ITS	186	219	33
8	Accounts 920/921 - Admin	0	4	4
9	Total Non-Labor	311	391	80
10	**Labor/Non-Labor Total**	**570**	**765**	**195**

T-10 Exhibits.xls

Hawaiian Electric Company, Inc.

TEST YEAR ACCOUNT 910 - CUSTOMER ASSISTANCE EXPENSE
Comparison to Actual 2007
($1000s)

Line		Recorded 2007	**Test Year 2009**		Change
	Demand-Side Management Expense *				
1	Labor	702	**617**		(85)
2	Nonlabor	929	**1642**		713
3	Total	1631	**2259**		628
	Non-DSM				
4	Labor	2309	**2356**		47
5	Nonlabor	2006	**2202**		196
6	Total	4315	**4558**		243
7	**GL Code (Nonlabor)**	(1578)	**(1406)**	**	172
8	**Total Customer Assistance Expense**	4368	**5411**		1043
	Total Customer Assistance Expense (Recap)				
9	Labor	3011	**2973**		(38)
10	Nonlabor	1357	**2438**		1081
11	Total	4368	**5411**		1043

* Base DSM expenses only. Incremental DSM program costs (Activity 714) have been excluded.
** GL Code of ($1,406,000) is net of initial GL Code amount of ($1,599,000) and ($193,000) of primarily DSM incremental on-costs (EE's 406, 422, 423).
Rate Case adjustments related to the transfer of the ($193,000) Expense Elements have been made directly to the end NARUC account.

Reference: HECO-1026

Hawaiian Electric Company, Inc.

TEST YEAR ACCOUNT 910 - CUSTOMER ASSISTANCE EXPENSE
Comparison to Actual 2007
($1000s)

Line	Acct. 910		Recorded 2007	Test Year 2009	Change
	Customer Efficiency Programs Division (DSM Expense)				
	(includes all DSM Acct. 910 support from outside the Customer Efficiency Programs Div.*)				
1		Labor	702	617	(85)
2		Nonlabor	929	1,642	713
3	**Total DSM**		**1,631**	**2,259**	**628**
	Non-DSM Expense				
4	Energy Services-Administration	Labor	70	31	(39)
5		Nonlabor	93	17	(76)
6			163	48	(115)
7	Cust Tech. Appl.	Labor	449	403	(46)
8		Nonlabor	255	328	73
9			704	731	27
10	Mktg. Svcs.	Labor	822	869	47
11		Nonlabor	530	498	(32)
12			1,352	1,367	15
13	Fcst & Research	Labor	348	351	3
14		Nonlabor	277	418	141
15			625	769	144
16	Corporate Communications	Labor	193	201	8
17		Nonlabor	216	217	1
18			409	418	9
19	Education & Consumer Affairs	Labor	340	453	113
20		Nonlabor	410	482	72
21			750	935	185
22	Others	Labor	87	48	(39)
23		Nonlabor	225	242	17
24			312	290	(22)
	Total				
25		Labor	2,309	2,356	47
26		Nonlabor	2,006	2,202	196
27	**Total Non-DSM**		**4,315**	**4,558**	**243**
28	GL Code		(1,578)	(1,406) **	172
29	**TOTAL 910**		**4,368**	**5,411**	**1,043**
		RECAP			
30		Labor	3,011	2,973	(38)
31		Nonlabor	1,357	2,438	1,081
32		Total	**4,368**	**5,411**	**1,043**

* DSM incremental program costs (Act. 714) have been excluded from the DSM amount summaries.
Only Act. 713 transactions (base DSM program costs and other base DSM costs) are summarized.

** GL Code of ($1,406,000) is net of initial GL Code amount of ($1,599,000) and ($193,000) of primarily DSM incremental on-costs (EE's 406, 422, 423).
Rate Case adjustments related to the transfer of the ($193,000) Expense Elements have been made directly to the end NARUC account.

Customer Solutions Employee Count
Major NARUC Labor Charges (to Customer Service Expenses)

(Excludes Incremental DSM Program Employees)

	Primary NARUC Codings	2007 Recorded Yr-End	2007 Rate Case	MARCH 31, 2008 Recorded	2008 Budget	2009 Rate Case
Cust. Technology Applications Division	910	9	10	9	9	9
Forecasts & Research Division	910,920	10	10	10	10	10
Marketing Services Division	910	11	12	11	12	12
VP - Customer Solutions' Office	909	2	2	2	2	2
Energy Services	909, 910, 920	12	13	13	13	15
--- Admin.	909, 910	3	3	3	3	3
--- Pricing	920	5	5	5	5	6
--- Cust. Eff. Prgm.	910	4	5	5	5	6
TOTAL CUSSOL		44	47	45	46	48

T-10 Exhibits.xls

Hawaiian Electric Company, Inc.

TOTAL BASE INTEGRATED RESOURCE PLANNING COSTS [(1)]
2009 TEST YEAR
($1000s)

Line	NARUC Acct.	Description	Cost Type	O&M EXPENSE BUDGET 2009	NORM. ADJ.	TEST YEAR 2009
1	506	Miscellaneous Stm Power Expense	Non-Labor	11.4	(3.3)	8.1
2						
3	909	Supervision	Labor	1.0		1.0
4			Non-Labor: On-Costs[(2)]	0.3		0.3
5				1.3		1.3
6	910	Customer Assistance	Labor	235.9		235.9
7			Non-Labor: On-Costs[(2)]	100.8		100.8
8			Non-Labor	228.5	(67.2)	161.3
9				565.2	(67.2)	498.0
10	911	Informational Advertising	Labor	6.0		6.0
11			Non-Labor: On-Costs[(2)]	2.7		2.7
12				8.7		8.7
13	920	A&G - Labr	Labor	241.2		241.2
14	921	A&G - Nlabr	Non-Labor: On-Costs[(3)]	31.8		31.8
15			Non-Labor: On-Costs[(2)]	117.2		117.2
16			Non-Labor	350.0	(102.9)	247.1
17				499.0	(102.9)	396.1
18		TOTAL		1,326.8	(173.4)	**1,153.4**

NOTES:
(1) Represents gross amounts charged to the respective NARUC accounts.
Excludes impact of GL Code transfers.

(2) Non-Labor On-Costs represents the total of the following EE#s loaded directly onto labor.
EE# 404 (Energy Delivery)
EE# 406 (Corporate Administration)
EE# 422 (Employee Benefits)
EE# 423 (Payroll Taxes)
Such amounts are ultimately reversed with the GL code transfer and recorded directly to the end NARUC account.

(3) Non-Labor On-Costs represents the total of EE# 421 (Non Productive Wages) loaded directly onto labor.

Reference: HECO-1029, 1030, 1031

T-10 Exhibits.xls Hawaiian Electric Company, Inc.

BASE INTEGRATED RESOURCE PLANNING COSTS-LABOR/OVERHEADS [1]
2009 TEST YEAR
($1000s)

Line				TEST YEAR 2009
1	909	Supervision	Labor[2]	1.0
2			Non-Labor: On-Costs[3]	0.3
3				1.3
4	910	Customer Assistance	Labor[2]	235.9
5			Non-Labor: On-Costs[3]	100.8
6				336.7
7	911	Informational Advertising	Labor[2]	6.0
8			Non-Labor: On-Costs[3]	2.7
9				8.7
10	920	A&G - Labr	Labor[2]	241.2
11	921	A&G - Nlabr	Non-Labor: On-Costs[4]	31.8
12			Non-Labor: On-Costs[3]	117.2
13				149.0
14		TOTAL		**736.9**

NOTES:
(1) Represents gross amounts charged to the respective NARUC accounts.
Excludes impact of GL Code transfers.

(2) Labor Costs represent EE#150 (Labor) and EE#421 (Non Productive Wages) charges.

(3) Non-Labor On-Costs represents the total of the following EE#s loaded directly onto labor.
EE# 404 (Energy Delivery)
EE# 406 (Corporate Administration)
EE# 422 (Employee Benefits)
EE# 423 (Payroll Taxes)
Such amounts are ultimately reversed with the GL code transfer and recorded directly to the end NARUC account.

(4) Non-Labor On-Costs represents EE#421 charges loaded directly onto labor.

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Hawaiian Electric Company, Inc.

BASE INTEGRATED RESOURCE PLANNING COSTS-NONLABOR COSTS ONLY*
2009 TEST YEAR
($1000s)

Line				O&M EXPENSE BUDGET 2009	NORMALIZATION ADJUSTMENT	TEST YEAR 2009
1	506	Miscellaneous Stm Power Expense	Non-Labor	11.4	(3.3)	8.1
2	910	Customer Assistance	Non-Labor	228.5	(67.2)	161.3
3	921	A&G - Nlabr	Non-Labor	350.0	(102.9)	247.1
4		TOTAL		589.9	(173.4)	416.5

* Activtiy 711 Non-labor costs. Excludes non-labor on-costs (EE#s 404, 406, 421{Acct. 921}, 422 and 423) of 252.8.

Reference: HECO-1031

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Hawaiian Electric Company, Inc.

INTEGRATED RESOURCE NON LABOR PLANNING COSTS

IRP NON-LABOR COST NORMALIZATION ADJUSTMENT
($1000s)

Line			
1	2007 HECO IRP NON LABOR		282.6
	2008 HECO IRP NON LABOR		
2	JAN - APRIL	26.2	
3	UPDATE MAY - DECEMBER	350.9	
4			377.1
5	2009 HECO IRP NON LABOR		589.9
6	THREE YEAR TOTAL		1249.6
7	TEST YEAR NORMALIZED NON-LABOR COSTS (line 8 ÷ 3)		416.5
8	2009 HECO IRP NON LABOR		589.9
9	NORMALIZATION ADJUSTMENT TO OPERATING FORECAST		(173.4)

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Hawaiian Electric Company, Inc.

TOTAL BASE INTEGRATED RESOURCE PLANNING COSTS [1]
2007 ACTUALS vs. 2009 TEST YEAR
($1000s)

Line				ACTUALS 2007	TEST YEAR 2009	TY -2007 Dfference
1	506	Miscellaneous Stm Power Expense	Non-Labor	0.0	8.1	8.1
2	909	Supervision	Labor	5.6	1.0	(4.6)
3			Non-Labor: On-Costs[2]	1.8	0.3	(1.5)
4				7.4	1.3	(6.1)
5	910	Customer Assistance	Labor	251.2	235.9	(15.3)
6			Non-Labor: On-Costs[2]	112.9	100.8	(12.1)
7			Non-Labor	136.5	161.3	24.8
8				500.6	498.0	(2.6)
9	911	Informational Advertising	Labor	4.7	6.0	1.3
10			Non-Labor: On-Costs[2]	2.6	2.7	0.1
11			Non-Labor	15.5	0.0	(15.5)
12				22.8	8.7	(14.1)
13	920	A&G - Labr	Labor	354.6	241.2	(113.4)
14	921	A&G - Nlabr	Non-Labor: On-Costs[3]	43.9	31.8	(12.1)
15			Non-Labor: On-Costs[2]	179.8	117.2	(62.6)
16			Non-Labor	130.6	247.1	116.5
17				354.3	396.1	41.8
18		TOTAL		1,239.7	1,153.4	(86.3)

NOTES:
(1) Represents gross amounts charged to the respective NARUC accounts.
Excludes impact of GL Code transfers.

(2) Non-Labor On-Costs represents the total of the following EE#s loaded directly unto labor.
EE# 404 (Energy Delivery)
EE# 405 (Power Supply)
EE# 406 (Corporate Administration)
EE# 422 (Employee Benefits)
EE# 423 (Payroll Taxes)
Such amounts are ultimately reversed with the GL code transfer and recorded directly to the end NARUC account.

(3) Non-Labor On-Costs represents the total of EE# 421 (Non-Productive Wages) loaded directly onto labor.

Reference: HECO-1028

Hawaiian Electric Company, Inc.

2009 TEST YEAR ENERGY COST ADJUSTMENT FACTORS
DIRECT TESTIMONY

PRESENT RATES	PROPOSED RATES
7.221 ¢/KWH	0.000 ¢/KWH

Source: HECO-1036, HECO-1037

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Hawaiian Electric Company, Inc.

BASE FUEL ENERGY CHARGE AND
FIXED EFFICIENCY FACTOR (OR SALES HEAT RATE)

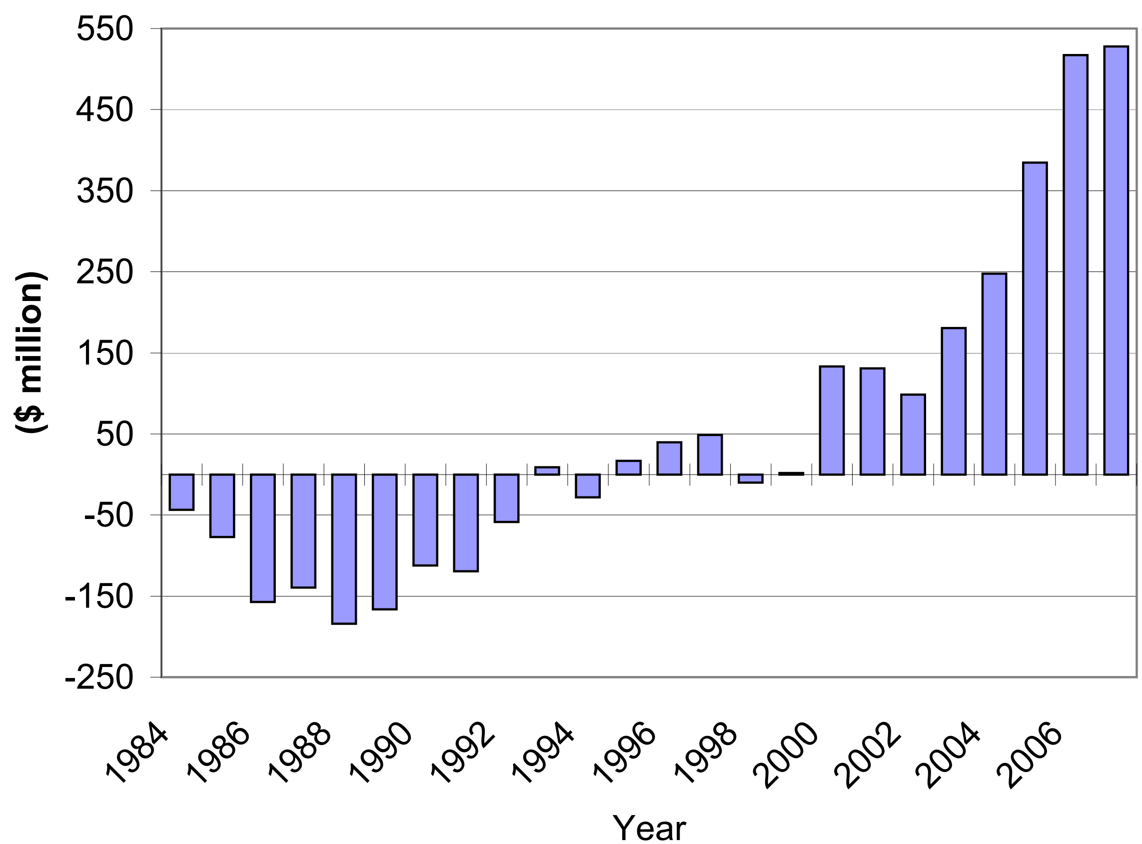
Line			
	Rate Proceeding	Docket No. 04-0113, effective June 20, 2008	
1	Base Fuel Energy	8.8903	¢/kWh
	Fuel Price		
2	LSFO	$ 53.73	/bbl
3	Diesel	$ 79.44	/bbl
	Base Composite Cost		
4	Generation	869.64	¢/mil btu
5	Purchased Energy	5.568	¢/kWh
6	DG Energy	14.076	¢/kWh
	Fixed Efficiency Factor or		
7	Sales Heat Rate	11,140	btu/kWh of sales

Year	ECA Revenue ($ million) **
1984	-43.408
1985	-77.146
1986	-157.098
1987	-139.662
1988	-184.172
1989	-166.246
1990	-112.381
1991	-119.346
1992	-58.726
1993	8.951
1994	-28.189
1995	16.882
1996	39.733
1997	48.656
1998	-10.042
1999	1.646
2000	133.240
2001	130.984
2002	98.611
2003	180.738
2004	247.831
2005	384.550
2006	517.395
2007	527.737

** Includes Revenue Taxes

Note:
Positive values are collections.
Negative values are returns.

Hawaiian Electric Company, Inc.
ECA Revenue



T-10 Exhibits.xls

Hawaiian Electric Company, Inc.
ENERGY COST ADJUSTMENT FILING
Present Rates

Line		
1	**Effective Date**	**2009 Test Year - Direct**
2	**Supercedes Factor**	

GENERATION COMPONENT

Line		
	FUEL PRICES, ¢/MBTU	
3	Honolulu	1,652.16
4	Kahe	1,602.06
5	Waiau-Steam	1,602.06
6	Waiau-Waste	**0.00**
7	Waiau-Diesel	2,366.04
8	CIP-Diesel	2,402.08
9	CIP-Biodiesel	4,643.68
	BTU MIX, %	
10	Honolulu	4.03
11	Kahe	69.33
12	Waiau-Steam	25.12
13	Waiau-Waste	0.00
14	Waiau-Diesel	0.57
15	CIP-Diesel	0.88
16	CIP-Biodiesel	0.07
		100.00
17	COMPOSITE COST OF GENERATION, ¢/MBTU	1,617.60
18	% Input to system kWh Mix	58.39
19	Efficiency Factor, Mbtu/kWh	**0.011140**
20	WEIGHTED COMPOSITE GEN COST, ¢/KWH (Line 17 x 18 x 19)	10.52192
21	BASE GENERATION COST, ¢/Mbtu	**869.64**
22	Base % Input to System kWh Mix	**58.41**
23	Efficiency Factor, Mbtu/kWh	**0.011140**
24	WEIGHTED BASE GEN COST, ¢/KWH (Line 21 x 22 x 23)	5.65864
25	Cost Less Base (Line 20 - 24)	4.86328
26	Revenue Tax Req Multiplier	**1.0975**
27	GENERATION FACTOR, ¢/KWH (Line 25 x 26)	5.33745

DG ENERGY COMPONENT

Line		
28	COMPOSITE COST OF DG ENERGY, ¢/kWh	24.993
29	% Input to System kWh Mix	0.07
30	WTD COMP DG ENRGY COST, ¢/KWH (Line 28 x 29)	0.01750
31	BASE DG ENERGY COMP COST	**14.076**
32	Base % Input to System kWh Mix	**0.09**
33	WTD BASE DG ENERGY COST, ¢/KWH (Line 31 x 32)	0.01267
34	Cost Less Base (Line 30 - 33)	0.00483
35	Loss Factor	**1.051**
36	Revenue Tax Req Multiplier	1.0975
37	DG FACTOR, ¢/KWH (Line 34 x 35 x 36)	0.00557
38	TOTAL GENERATION FACTOR ¢/KWH (Line 27 + 37)	5.34302

PURCHASED ENERGY COMPONENT

Line				
	PURCHASED ENERGY PRICE - ¢/KWH			
39	THC	- On Peak		20.440
40		- Off Peak		14.990
41	HRRV	- On Peak		17.132
42		- Off Peak		12.642
43	HRRV	- On Peak	(excess)	0.000
44		- Off Peak	(excess)	12.642
45	Chevron	- On Peak		20.440
46		- Off Peak		14.990
47	Hoku Solar			19.000
48	Kalaeloa			14.992
49	AES-HI			2.869
	PURCHASED ENERGY KWH MIX, %			
50	THC	- On Peak		0.07
51		- Off Peak		0.05
52	HRRV	- On Peak		5.76
53		- Off Peak		2.60
54	HRRV	- On Peak	(excess)	0.00
55		- Off Peak	(excess)	1.52
56	Chevron	- On Peak		0.01
57		- Off Peak		0.01
58	Hoku Solar			0.01
59	Kalaeloa			44.25
60	AES-HI			45.72
61	COMPOSITE COST OF PURCHASED ENERGY, ¢/KWH			9.481
62	% Input to System kWh Mix			41.54
63	WTD CMP PURCH ENRGY COST, ¢/KWH (Line x 61)			3.93841
64	BASE PURCH ENERGY COMP COST			**5.568**
65	Base % Input to System kWh Mix			**41.50**
66	WTD BASE PRCH ENERGY COST, ¢/KWH (Line 64 x 65)			2.31072
67	Cost Less Base (Line 63 - 66)			1.62769
68	Loss Factor			**1.051**
69	Revenue Tax Req Multiplier			**1.0975**
70	PURCHASED ENERGY FACTOR, ¢/KWH (Line 67 x 68 x 69)			1.87750

Line	**SYSTEM COMPOSITE**	
71	Total Generation and Purchased Energy Factor, ¢/kWh (Line 38 + 70)	7.22052
72	Adjustment, ¢/kWh	**0.000**
73	ECA Reconciliation Adjustment, ¢/kWh	**0.000**
74	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH (Line 71 + 72 + 73)	7.221

Reference: HECO-WP-1036

HAWAIIAN ELECTRIC COMPANY, INC.
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Rates

ENERGY COST ADJUSTMENT (ECA) FILING - 2009 Test Year - Direct (page 1 of 2)

Line					
1	Effective Date	2009 Test Year - Direct			
2	Supercedes Factors of				

GENERATION COMPONENT

CENTRAL STATION

Line					
	FUEL PRICES, ¢/mmbtu				
3	Honolulu				1,652.16
4	Kahe				1,602.36
5	Waiau-Steam				1,602.06
6	Waiau-Diesel				2,366.04
7	CIP-Diesel				2,402.08
8	CIP-Biodiesel				4,643.68
9	Other				0.00
	BTU MIX, %				
10	Honolulu				4.03
11	Kahe				69.33
12	Waiau-Steam				25.12
13	Waiau-Diesel				0.57
14	CIP-Diesel				0.88
15	CIP-Biodiesel				0.07
16	Other				0.00
					100.00
17	COMPOSITE COST OF GENERATION, CNTRL STN + OTHER ¢/mmbtu				1,617.81
18	% Input to System kWh Mix				58.39
	EFFICIENCY FACTOR, mmbtu/kWh				
	(A)	(B)	(C)	(D)	
			Percent of		
		Eff Factor	Centrl Stn +	Weighted	
	Fuel Type	mmbtu/kwh	Other	Eff Factor	
19	LSFO	0.011092	99.30	0.011014	
20	Diesel	0.024358	0.66	0.000162	
21	Biodiesel	0.022909	0.04	0.000009	
22	Other	0.011185	0.00	0.000000	
	(Lines 19 through 22): Col(B) x Col(C) = Col(D)				
23	Weighted Efficiency Factor, mmbtu/kWh [lines 19(D) + 20(D) + 21(D) + 22(D)]				0.011185
24	WGTD. COMPOSITE CNTRL STN + OTHER GEN COST, ¢/kWh (lines (17x18x23))				10.56579
25	BASE CNTRL STN + OTHER GEN. COST, ¢/mmbtu				1,617.81
26	Base % Input to Sys kWh Mix				58.39
27	Efficiency Factor, mmbtu/kwh				0.011185
28	WEIGHTED BASE CNTRL STN + OTHER GEN COST ¢/kWh (lines (25x26x27))				10.56579
29	COST LESS BASE (line(24-28))				0.00000
30	Revenue Tax Req Multiplier				1.0975
31	CNTRL STN + OTHER GENERATION FACTOR, ¢/kWh (line (29x30))				0.00000

DG ENERGY COMPONENT

Line		
32	COMPOSITE COST OF DG ENERGY, ¢/kWh	24.993
33	% Input to System kWh Mix	0.07
34	WTD COMP DG ENRGY COST, ¢/kWh (Lines 32 x 33)	0.01750
35	BASE DG ENERGY COMP COST	24.993
36	Base % Input to System kWh Mix	0.07
37	WTD BASE DG ENERGY COST, ¢/kWh (Line 35 x 36)	0.01750
38	Cost Less Base (Line 34 - 37)	0.00000
39	Loss Factor	1.052
40	Revenue Tax Req Multiplier	1.0975
41	DG FACTOR, ¢/kWh (Line 38 x 39 x 40)	0.00000

SUMMARY OF TOTAL GENERATION FACTOR, ¢/kWh

Line		
42	Cntrl Stn+Other (line 31)	0.00000
43	DG (line 41)	0.00000
44	TOTAL GENERATION FACTOR, ¢/kWh (lines 42 + 43)	0.00000

HAWAIIAN ELECTRIC COMPANY, INC.
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Rates

ENERGY COST ADJUSTMENT (ECA) FILING - 2009 Test Year - Direct (page 2 of 2)

Line	PURCHASED ENERGY COMPONENT			
	PURCHASED ENERGY PRICE, ¢/kWh			
45	THC	- On Peak		20.440
46		- Off Peak		14.990
47	HRRV	- On Peak		17.132
48		- Off Peak		12.642
49	HRRV	- On Peak	(excess)	0.000
50		- Off Peak	(excess)	12.642
51	Chevron	- On Peak		20.440
52		- Off Peak		14.990
53	Hoku Solar			19.000
54	Kalaeloa			14.992
55	AES-HI			2.869
	PURCHASED ENERGY KWH MIX, %			
56	THC	- On Peak		0.07
57		- Off Peak		0.05
58	HRRV	- On Peak		5.76
59		- Off Peak		2.60
60	HRRV	- On Peak	(excess)	0.00
61		- Off Peak	(excess)	1.52
62	Chevron	- On Peak		0.01
63		- Off Peak		0.01
64	Hoku Solar			0.01
65	Kalaeloa			44.25
66	AES-HI			45.72
				100.00
67	COMPOSITE COST OF PURCHASED ENERGY, ¢/kWh			9.481
68	% Input to System kWh Mix			41.54
69	WEIGHTED COMP. PURCH. ENERGY COST, ¢/kWh (lines (67x68))			3.93841
70	BASE PURCHASED ENERGY COMPOSITE COST, ¢/kWh			9.481
71	Base % Input to Sys kWh Mix			41.54
72	WEIGHTED BASE PURCH ENERGY COST, ¢/kWh (lines (70 x 71))			3.93841
73	COST LESS BASE(lines (69 - 72))			0.00000
74	Loss Factor			1.052
75	Revenue Tax Req Multiplier			1.0975
76	PURCHSD ENERGY FCTR, ¢/kWh (lines (73 x 74 x 75))			0.00000

Line	SYSTEM COMPOSITE	
77	GEN AND PURCHASED ENERGY FACTOR, ¢/kWh (lines (44 + 76))	0.00000
78	Adjustment, ¢/kWh	0.000
79	ECA Reconciliation Adjustment	0.000
80	ECA FACTOR, ¢/kWh (lines (77 + 78 + 79))	0.000

Reference: HECO-WP-1036, HECO-WP-1037

T-10 Exhibits.xls

HAWAIIAN ELECTRIC COMPANY, INC.
Comparison of
Composite Cost of Generation - Central Station
At Present Rates and Proposed Rates

2009 Test Year - Direct Testimony

Line		(A) At Present Rates	(B) At Proposed Rates	(C) Difference (B) - (A)
	FUEL PRICES, ¢/mmbtu			
1	Kahe	1,602.06	1,602.36	0.30
2	Waiau-Steam	1,602.06	1,602.06	0.00
3	Honolulu	1,652.16	1,652.16	0.00
4	Waiau-Diesel	2,366.04	2,366.04	0.00
5	CIP-Diesel	2,402.08	2,402.08	0.00
6	CIP-Biodiesel	4,643.68	4,643.68	0.00
7	Other	0.00	0.00	0.00
	BTU MIX, %			
8	Kahe	69.33	69.33	0.00
9	Waiau-Steam	25.12	25.12	0.00
10	Honolulu	4.03	4.03	0.00
11	Waiau-Diesel	0.57	0.57	0.00
12	CIP-Diesel	0.88	0.88	0.00
13	CIP-Biodiesel	0.07	0.07	0.00
14	Other	0.00	0.00	0.00
		100.00	100.00	0.00
15	COMPOSITE COST OF GENERATION ¢/mmbtu	1,617.60	1,617.81	0.21

Source:
Col (A): HECO-WP-1036, p. 3
Col (B): HECO-WP-1037, p. 2

Hawaiian Electric Company, Inc.
WEIGHTED COMPOSITE GENERATION COST CALCULATIONS CENTRAL STATION AND OTHER

2009 Test Year - Direct Testimony

At Proposed Rates

		LSFO	Diesel	Biodiesel	Other	Total	units
1	Fixed Efficiency Factor	0.011092	0.024358	0.022909	0.011185		mbtu/kwh
2	Gen Mwh %	99.30	0.66	0.04	0.00	100.00	%
3	Weighted Efficiency Factor (line 1 x line 2)	0.011014	0.000162	0.000009	0.000000	0.011185	mbtu/kwh

Reference:
1 HECO-WP-1037, page 2.
2 HECO-WP-1036, page 3.

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-000

William A. Bonnet
Vice President
Government & Community Affairs

December 29, 2006

FILED
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PUBLIC UTILITIES COMMISSION

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

Dear Commissioners:

Subject: Docket No. 2006-0386 - HECO 2007 Test Year Rate Case
Act 162 Consultant Report

Enclosed for filing are the original and eight copies of the Report on Power Cost Adjustments and Hedging Fuel Risks prepared by NERA Economic Consulting.

Sincerely,

William A. Bonnet

cc: Division of Consumer Advocacy

December 29, 2006

Report on Power Cost Adjustments and Hedging Fuel Risks

Hawaiian Electric Company, Inc.

NERA
Economic Consulting

Marsh & McLennan Companies

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I. INTRODUCTION

NERA Economic Consulting ("NERA") was retained by Hawaiian Electric Company, Inc. and its affiliates, Hawaii Electric Light Company ("HELCO") and Maui Electric Company ("MECO") (collectively, "HECO" or "the Utilities"), to evaluate whether its fuel adjustment clause ("FAC") – the Energy Cost Adjustment Clause ("ECAC") as it currently exists – is in compliance with Act 162, which was signed into law in June 2006. [1] In addition, HECO sought NERA's assistance with respect to fuel price hedging and other approaches to stabilizing end-user electricity rates to present to the Hawaii Public Utilities Commission ("HPUC" or "the Commission"). This report presents a summation of NERA's findings on these matters.

FAC mechanisms (and other similar cost adjustment and tracking mechanisms) give utilities a reasonable opportunity to recover their legitimate costs of procuring electricity on behalf of customers. By providing timely cost recovery for power costs, the amount of time between rate cases can increase. The breadth of adjustment clauses is not limited to fuel and purchased power expenses. Rather, the ECAC or a similar adjustment mechanism can be implemented efficiently for recovery of other costs that meet the three classic reasons for an automatic rate adjustment , which include:

1. The cost of the purchased resource is outside the control of the utility that purchases it.
2. The item accounts for a significant or large component of the utility's total operating costs.
3. Costs related to the resource are volatile and unpredictable.

Adjustment and cost tracking mechanisms may also be implemented to allow for the parallel treatment of similar costs categories. For example, demand-side management ("DSM") costs provide a substitute for pursuing supply-side resources. If supply-side resources are recovered under a FAC, DSM costs could be treated symmetrically, which would put supply- and demand-side energy costs on an equal footing.

The ECAC that HECO and its affiliates currently have in place is comparable to the FACs that are used by other traditionally regulated jurisdictions in the United States. Nearly all traditionally regulated and most restructured states in the US have some similar mechanism for power cost recovery. Like the ECAC, most (approximately 22) of the 30 restructured states with fuel clauses have some form of "true-up" mechanism to reconcile actual and forecasted costs. Also, thirteen of those states have rate adjustments on a quarterly or more frequent basis.

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[1] A Bill for an Act Relating to Energy, S.B. No. 3185, S.D. 2, H.D. 2, C.D. 1, Act No. 162 signed into law by the Governor of Hawaii on June 2, 2006 (hereinafter, "Act 162" or "the Act") amended Section 269-16 of the Hawaii Revised Statutes to include a subsection (g) that specifies requirements for the design of "any automatic fuel rate adjustment clause," of which the ECAC is one.

Both fuel costs and purchased energy costs are recovered through the ECAC. A weighted average of the various fuel and purchased energy costs is computed monthly based on an estimated fuel mix. This is then converted to a rate for customers based on the estimated MWh sales for the month. An efficiency factor (MBtu/kWh) is used to calculate the conversion between the MBtu of fuel purchased and the amount of kWhs generated. The ECAC is updated monthly and an Energy Cost Adjustment ("ECA") factor is determined on a prospective basis. A reconciliation is done on a quarterly basis, which compares revenues recovered through the ECAC and revenues allowed using actual fuel mix, kWh sales and prices. The overcollection or undercollection is adjusted in the ECA factor for the following three months. The monthly ECAC filings with the Hawaii Public Utility Commission ("Commission" or "HPUC") ensures timely recovery of fuel and purchased energy costs for HECO.

Act 162 is concerned specifically with the incentive structure facing utilities. Just as it is important for utilities to have incentives to control—to the extent they can—fuel and purchased power costs, so too should ratepayers have a cost-based price signal. Ratepayers will not choose to consume an efficient level of electricity it they are shielded from the true costs of producing electricity and a timely FAC therefore has an important role to play. When consumers are aware of, and can respond to, the cost effects of their energy consumption decisions, they can reduce their demand when the price outweighs the benefit of consuming the product. The efficient allocation of resources concerns the price signals faced by customers. Failure to allow rates to reflect fuel and purchased power costs in a timely manner would distort this efficiency, since customers would be receiving an inappropriate price signal regarding the value in the market of the services they choose to consume.

II. COMPLIANCE WITH ACT 162

Act 162 incorporates five requirements for the design of any public utility automatic rate adjustment.

A. Fair Risk Sharing of Fuel Cost Changes

Act 162 requires that any automatic rate adjustment be designed to "[f]airly share the risk of fuel cost changes between the public utility and its customers." The risk of fuel cost changes is determined by:

1. Changes in the price of fuel as a single productive input; and,

2. Changes in the cost to deliver and produce electricity from HECO's fuel inputs. This reflects any changes in the technical ability of the utility to turn fuel purchased into electricity, which may require HECO to purchase a greater quantity of fuel, and thus increase the overall level of fuel costs, in order to produce the same amount of electricity.

Efficient risk sharing occurs when the party that has the means to control a cost has an incentive to do so. This distinction is critical because the price of fuel is, realistically, beyond the control of the utility. HECO acts as a price taker in the world-wide market for fuel (oil) and the design of the ECAC and the recovery of fuel and purchased energy costs should recognize this fact.

Accordingly, the ECAC acts to pass exogenous changes in input costs onto consumers. In fuel markets (as in other markets where HECO is a price taker—as in vehicles), it is straightforward to demonstrate prudent purchasing. There is a well defined market price and a well defined need to buy from this market (i.e., ratepayers' demand for electricity). In a price-taking market, "risk sharing" of fuel price changes would lead to no efficiency gains resulting from management incentives to minimize costs. Accordingly, changes in the price of fuel should be fully passed onto ratepayers. This would provide them with a price signal, which is an incentive to use resources efficiently. This supports the utility's ability to maintain its financial viability, and would increase regulatory lag—the time between rate cases—for costs that are within the utility's control, which would enhance the utility's incentive to control its base rate costs.

The ECAC, with its "heat rate" efficiency factor, provides a partial pass through of fuel and purchased power. It shares the risk/benefit of increased plant operating efficiency by tying HECO's ability to recover its fuel costs (and thus its financial performance) to its power plant performance over which it has managerial control, while also allowing HECO to pass through the exogenous changes in the price of an input over which it has no control, the price of fuel and purchased power.

HECO has considerable control over the operation of its plants—limited by engineering realities—and therefore it is reasonable, as the Commission already does, to provide HECO with an incentive to improve its operating efficiency to manage or lower its fuel costs. As discussed in the next section, putting fuel oil expense recovery at risk in an attempt to give the Company an incentive to look for non fuel oil resources would be an inefficient, indirect and counterproductive way of subsidizing renewables. Directly subsidizing renewables or enforcing renewable portfolio standards will increase the usage of renewable generation resources, but without having the perverse effect of harming the utility's financial position or distorting the cost recovery mechanism to favor one fuel cost over another.

The general role that management plays in an investor-owned, regulated enterprise should be recognized. Efficient and prudent management strives to minimize the amount of inputs while maximizing the production of the final product (*i.e.*, to maximize total factor productivity). Viewed from this perspective, management should have an incentive to manage efficiently the selection of inputs (of which fuel and purchased power are two of many)—and HECO does have this incentive.

This heat rate efficiency factor properly shares the risk of fuel usage decisions and recognizes that the added risk of cost recovery associated with plant operation is balanced with rewards from productivity increases.

State commissions in Florida, Louisiana, and North Carolina are examples of jurisdictions that have established specific incentives for power plant performance. A "Generating Performance Incentive Factor" is included in fuel and purchased power recovery clauses in Florida that rewards the utility (up to a 25 basis point spread) when its generation assets achieve certain performance benchmarks in availability and heat rate. In North Carolina, the allowed level of fuel cost recovery is linked to achieved nuclear capacity factors. These are reasonable approaches that provide the utility incentives to improve plant performance, something over which it has considerable control.

Because the ECAC contains an efficiency factor that transfers plant operation risk to HECO, but also passes uncontrollable changes in fuel prices to ratepayers, NERA concludes that the ECAC complies with the fair risk sharing requirement of Act 162.

B. Utility Incentives for Fuel Costs and Renewable Energy

Act 162 requires that automatic rate adjustment mechanisms "[p]rovide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy." This condition is closely tied to the previous one. Accordingly, the targeted efficiency factor promotes productive fuel use decisions and gives HECO an incentive to reasonably manage or lower its fuel costs.

If HECO achieves more efficient plant performance than the level of the efficiency factor (which, for example, is currently set at 0.11170 Mbtu/kWh), then HECO is rewarded. If it fails to meet this target for some reason, then it is not allowed to recover the additional expenditures required to produce the kWhs with the fuel it purchased.

The ECAC should cover all purchased energy costs, including renewable sources, on an equal footing within the cost recovery mechanism. Renewable energy resources can be part of a utility's power procurement to the extent that they are cost-efficient, reliable and represent a diverse source of generation relative to the traditional non-renewable resources. Like many utilities, HECO creates and follows an Integrated Resource Plan ("IRP"), which determines the extent of renewables used in HECO's fuel mix. The IRP process balances cost-minimization with resource diversity and other concerns. Like purchasing fuel oil from the oil markets, purchasing energy from renewables is not without risks. To ensure the efficient use of renewable resources, the ECAC would cover all purchased energy costs, including renewable sources, on an equal footing. Currently, the ECAC is adjusted each month for changes in the energy mix of the sources of fuel and purchased power. Under an equal footing structure, there is no disincentive from a cost recovery standpoint to purchase renewable energy. The encouragement of renewable energy above and beyond a treatment paralleling non-renewables (*i.e.*, direct subsidization) is a matter of public policy and should not be confused with energy cost recovery. The ECAC should provide no disincentive for HECO to purchase energy from renewable resources.[2]

The ECAC has positive financial implications and can improve a utility's credit ratings, thereby moderating the cost of capital borne by ratepayers. In addition, the utility serves as a counter-party for renewable energy companies, so its credit standing frequently serves as an important determinant of the financial viability of renewable energy projects. Weakening the utility's credit rating through partial power cost recovery could harm renewable resources that rely on utility counter-party credit to support their investments. Through the ECAC, HECO can retain its high level of credit worthiness and as party to renewable IPPS, which essential for IPP financing. By improving utility finances, the ECAC, in turn, accommodates renewable energy investors.

NERA concludes that a fuel adjustment clause with an efficiency target incentive that recovers renewable energy costs on an equal footing, such as the ECAC, complies with the incentive requirement of Act 162.

C. Management of Price Volatility

Thirdly, Act 162 requires automatic rate adjustments "to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as fuel hedging contracts."

There are no free lunches in risk management. Hedging imposes real costs to the party that wishes to reduce its exposure to price movements. Although in years that prices rise, ratepayers may benefit from a price hedge, this will not be the case when prices do not rise or fall. In the long run, hedging programs can be expected to increase the overall level of costs associated with fuel and purchased power expenses. Accordingly, if there is a mandate for the utility to reduce

[2] Including the capital costs associated with capacity purchases, such as renewable capacity purchases, in the ECAC (or a tracker mechanism that could operate in parallel with the ECAC) would be one way to ensure immediate cost recovery and thereby reduce any economic disincentive.

ratepayers' exposure to the potential rise in fuel costs, these hedging costs should be passed onto ratepayers.

Act 162 recognizes that there are options "commercially available" to customers that can mitigate price risk for customers. In principle, a utility can mitigate the risk of fuel cost changes through two forms of hedges:

1. *Physical hedges*, such as long-term supply and purchased power contracts and maintaining fuel inventories. The costs of existing contracts are included in the current ECAC computations.

2. *Financial hedges*. Generally, financial hedges either require payment to intermediaries in cash to bear risks or otherwise pay through giving up the prospect for lower future fuel prices. If utility ratepayers are willing to pay for the additional service of hedging their price risk, HECO must be provided a means to recover the costs it incurs. In order to do this and to give HECO a proper incentive to mitigate price changes on behalf of its customers, the ECAC would include recovery of financial hedging costs. Currently, the ECAC allows the recovery of the unhedged fuel costs, but is unclear whether financial hedging costs would be recovered in the ECAC.

In order to meet the electricity demands of its customers, HECO operates oil-fired power plants. HECO purchases the oil for these plants. HECO's position in oil is therefore a short physical position. HECO hedges its short physical position by entering into an offsetting long position in delivered oil. This long position is achieved through the companies' existing fuel supply contracts. These fuel supply contracts tie the price paid by HECO for oil to a base component. The base component is the month-to-date average of a third-party assessment calculated on the 20th of the month before delivery. For example, HECO's industrial fuel oil deliveries for January 2007 will be based on the average of the Platts Los Angeles Bunker C assessments from November 21st to December 20th 2006. The actual contract price includes taxes and a standard premium (based on quantity). Depending on the contract, the price may include a locational premium and adjustments for heat content, premia to Pertamina,[3] quality differentials and freight. In addition, the contracts provide for quantities and delivery of fuel that are more than sufficient to cover HECOs needs. Hence, HECO and HECO's customers are hedged with respect to availability and delivery of the physical commodities. HECO's fuel costs are variable as the price it pays will vary with the daily assessments for the terms of HECO's fuel contracts.

With respect to price, despite the fact that the price varies with assessment values, HECO is hedged from the perspective of the utility. HECO's physical fuel supply contracts are struck at floating assessments. Similarly, its electricity rates float in accordance with the prices of oil that HECO pays. As discussed earlier, this is a logical regulatory framework, since HECO has no

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[3] The premia represent market premiums (or discounts) achieved in the spot market relative to a price assessment called the Pertamina Price Formula for LSWR.

control over world oil prices. The matching of variable fuel operating expenses with variable electricity revenues helps to assure the financial integrity of the utility, while providing an economically-correct price signal to customers.

The fuel hedging contracts referred to by the Act, if reasonably available, would only be entered into by HECO to meet the objective of mitigating oil price fluctuations for customers. Customers are exposed to fluctuations in world oil prices, while hedged against availability and physical delivery risks and costs. If HECO were to hedge, it would be to reduce this exposure. Of course, there would be a cost to reducing the exposure that may not be justified by the benefit. It should be noted that there are other alternatives (described in **Section IV**) available that may provide the similar benefits sought through hedging programs (*e.g.,* rate stability and reduced exposure to input cost increases), but would not require pursuing these potentially costly hedging options.

Therefore, NERA concludes that under HECO's current procurement strategies, the ECAC complies with the price stabilization requirement of Act 162. However, if there were demand from customers and/or a mandate from the Commission acting on behalf of ratepayers for a hedging program seeking to stabilize fuel costs, then recovery of the hedging and risk premium costs associated with physical and financial hedges would be included in the ECAC.[4]

D. Preservation of Utility Financial Integrity

The fourth requirement imposed by Act 162 on automatic rate adjustments is to "[p]reserve, to the extent reasonably possible, the public utility's financial integrity."

For modern utilities that operate in a world of volatile fuel prices an FAC is critical to:

- Reduce the volatility of utility earnings. Companies exhibiting large earnings volatility are typically those with most difficulty in tracking input costs.
- Provide the utility with a reasonable opportunity to recover its prudently-incurred costs in rates.
- Lower the risks to capital invested in a utility and thus lower the utility's cost of capital (and ultimately, rates) as well as help maintain the utility's credit rating. Volatile wholesale power and oil and gas commodity markets have led the rating agencies to more closely

[4] At least 12 states (Alabama, Florida, Georgia, Louisiana, Iowa, Missouri, Mississippi, Minnesota, North Dakota, South Dakota, Nevada, Colorado and Michigan) allow the pass through of hedging costs and/or the sharing of hedging benefits between the utility and its customers, usually through their respective Power Cost Adjustments.

scrutinize cost-recovery mechanisms. Credit rating agencies, for example, recognize the need for robust and frequently updated FAC mechanisms.[5]

- Maintain HECO's liquidity. Because oil and other fuel expenses are a large portion of HECO's operational costs, the ECAC is needed to enable HECO to raise capital in time to meet expenses and investment requirements.

Utility regulators have long recognized the crucial role that cost-recovery mechanisms play in allowing the utility an opportunity to recover its costs. FACs permit a utility to recover its costs and assure the capital markets that the company can meet its obligations to shareholders and bondholders. Colorado provides an example of its Commission balancing the concerns of utility and its customers. The Colorado PUC explained its long-term use of FAC mechanisms by stating that it established its FAC in order to permit rapid recovery of increased costs over which the utility has no control. The PUC recognized that, in the circumstances which existed at the time, unless increased fuel costs were passed through to customers expeditiously, the utility would undergo a serious erosion of earnings jeopardizing the its ability to provide service.[6]

When approving the Arizona Public Service Company's ("APS") proposed Power Supply Adjustor, the Arizona Corporation Commission stated "we agree that the use of an adjustor when fuel costs are volatile prevents a utility's financial condition from deteriorating" and that "an adjustor that works correctly, over time, reduces the volatility of a utility's earnings and the risk reduction can be reflected in the cost of equity in a rate case and result in lower rates."[7]

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[5] Each of the three major credit rating agencies recognize the importance of FAC mechanisms. *Fitch* states: "[i]n today's environment, the safest bonds in the utility industry may be those of vertically integrated utilities operating under commission-approved mechanisms to recoup prudently incurred power costs. Such companies typically operate in supportive regulatory environments which continue to feel the need for healthy reserve margins of generation."

S&P also notes that "[a]utomatic pass-through mechanisms that hold companies harmless from uncontrollable costs, such as fuel or foreign exchange effects, are viewed favorably."

Moody's concludes that: "Regulated vertically integrated utilities operating without regulatory recovery of potentially high electricity costs from spot-market purchases are equally vulnerable, particularly during periods of peak energy demand and/or supply shortages."

See: *Fitch*, "Procuring Power in California: A Potential Stranded Cost," September 7, 2000, p. 4.
Standard & Poor's, "Rating Methodology For Global Power Utilities," Standard & Poor's Infrastructure Finance, September 1998, p. 66.
Moody's, "Credit Implications of Power Supply Risk," July 2000, p. 3.

[6] Before the Public Utilities Commission of the State of Colorado, "In the Investigation of Electric Cost Adjustment Clauses For Regulated Electric Utilities," Docket No. 93I-702E, Decision No. C95-248, February 6, 1995.

[7] Before the Arizona Public Corporation Commission, In the Matter of the Application of Arizona Public Service for Approval of Adjustment Mechanisms, Docket No. E-01345A-02-0403, Decision No. 66567, November 13, 2003, p. 5.

As a frequently updated, fully reconciled pass through mechanism for a large and volatile expense, the ECAC plays a critical role. Continuation of the ECAC would allow HECO to more readily raise capital in the future. This will improve its ability to meet future infrastructure needs and preserve the level of service demanded by its ratepayers and the Commission. HECO recognizes this fact when it states in its most recent 10-K that:

> Risks, uncertainties and other important factors that could cause actual results to differ materially from those in forward−looking statements and from historical results include, but are not limited to…fuel oil price changes, performance by suppliers of their fuel oil delivery obligations and the continued availability to the electric utilities of their energy cost adjustment clauses.

Because the ECAC provides a transparent, well-structured and consistently-applied cost recovery mechanism that contains an efficiency incentive that HECO's management can readily affect, NERA concludes that the ECAC complies with the financial integrity requirement of Act 162.

E. Minimize Regulatory Costs

The fifth and final requirement established by Act 162 is to "[m]inimize, to the extent possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs."

In general, FACs are designed to reduce regulatory costs by separating the volatility of fuel costs from the base rates. Calculations supporting the ECAC are submitted to the Hawaii PUC for review on a monthly basis. A number of states have similar monthly fuel clauses. Braulio Baez, the Chairman of the Florida Public Service Commission states in a Consumer Bulletin concerning fuel price adjustments:

> The action of removing fuel costs from base rates had the effect of reducing fluctuations in base rates. Both the utilities and their customers now had a better incentive to respond to fuel price changes. Because non-fuel expenditures are more stable than fuel expenditures, utilities were not only less likely to seek base rate adjustments, but any rising costs also provided the utility with a greater incentive to use other, less expensive fuels to generate electricity.[8]

The reduction of frequent base rate cases does not reduce the Commission's oversight of HECO's fuel and purchased power expenditures. Electricity FACs can allow for recovery of narrowly-defined categories of fossil fuel costs, nuclear fuel costs, purchased power, fuel transportation costs, and hedging costs among others.

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[8] Braulio L Baez, "Customer Bulletin," Florida Public Service Commission, April 2004.

To further minimize regulatory costs, regulators can see that any other cost category that meets the three criteria for an automatic rate adjustment discussed in the background section receive parallel treatment to those costs already included in the ECAC. Cost categories to consider including in the ECAC (or tracking in a separate adjustment clause):

- All fuel and purchased power costs,
- Purchased capacity,
- Hedging costs,
- Environmental compliance costs, and
- Any other costs specific to the jurisdiction.

The breadth of adjustment clauses are not limited to fuel and purchased power expenses. Rather, the ECAC or a similar adjustment mechanism can be implemented efficiently for broader categories of costs, which would help to assure that supply- and demand-side energy resources are treated symmetrically in the ratemaking process.

Uniformity across the Hawaiian utilities' ECACs reduces the administrative costs associated with using a FAC to recover fuel and purchased power costs. Treating the fuel and purchased energy cost recovery of one HECO subsidiary separately from another would require further and unnecessary utility and Commission resources devoted to the treatment of fuel and purchased power costs.

Therefore, because the ECAC allows HECO to readily recover in rates a significant and volatile cost over which its has little control, NERA concludes that the ECAC reduces HECO's need to file base rate cases and thus complies with the minimization of regulatory cost requirement of Act 162.

III. ASSESSMENT OF FUEL HEDGING OPTIONS

This section of the report addresses fuel hedging options available in the marketplace. It gives a general overview of the objectives of hedging, a description of available hedging strategies, a discussion of the oil derivatives market and potential implementation constraints facing HECO and its affiliates as they consider entering into a hedging program.

A. Objectives of Fuel Hedging

EEI defines hedging as "the attempt to eliminate at least a portion of the risk associated with owning an asset or having an obligation by acquiring an asset or obligation with offsetting risks."[9] Hedging can, in principle, allow a firm to offset and reduce risk. Act 162 raises the question of whether HECO should hedge by reference to "fuel hedging contracts" as a commercially available means to mitigate the risk of fuel price changes.[10] Hedging with respect to energy commodities can take two forms: (1) physical hedges, such as physical supply contracts and fuel inventories; and (2) financial hedges, such as fixed-price financially-settled futures contracts and financial options contracts. As described in **Section II.C**, HECO already engages in physical hedging.

In regulatory parlance and in many industries, the term hedging most often refers to short-term (less than two years in duration) activities. This is because forward markets offer liquid price hedging contracts covering delivery periods that often extend only for one or two years forward. For the oil derivatives markets,[11] price hedging contracts are only reasonably available for periods of up to twelve months. This means that hedging contracts, if pursued by HECO, could only mitigate the impacts of oil price changes on costs and rates for a defined period such as one quarter or potentially one year. Fuel hedging contracts cannot be expected to cover durations longer than this.

Long-term hedging – i.e., hedging for multi-year periods – is a possibility for HECO, but cannot reasonably be achieved through commercially available fuel hedging contracts. Long-term hedging for HECO could be done through diversification away from oil-based generation. This diversification would require investment in non-oil based generation capacity, either by rate-based generation or through long-term contracts with non-utility generators. In addition, another long-term hedge could conceivably be the purchase of oil reserves. However, utilities that have purchased fuel reserves have almost universally regretted the decision and eventually disposed of the reserves. It is not recommended that HECO seriously consider this option.

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[9] EEI Glossary of Electric Industry Terms, April 2005.

[10] Act 162, (g) (iii).

[11] Derivatives are a term used to describe financial instruments whose value is derived from the price of an underlying commodity. Hence, an oil price swap or call option is a derivative as its value is based on the price of oil, the underlying commodity.

Hedging is most often done to lock in a range of outcomes. But, hedging creates costs and risks. Hedging will not necessarily produce the lowest-cost outcome in any particular case—and will, overall, raise costs because of the costs of implementing the hedging program. For a buyer of fuel like HECO, hedging may be perceived as a bad decision in hindsight if the buyer locks in a price and then market prices decline. Similarly, hedging may be perceived as a good decision if market prices increase after the buyer places its hedges. The utility, the regulator, and interveners must understand the costs and risks of hedging before a utility decides or is directed by its regulators to embark on a hedging program.

There are certain situations where firms face business or financial risks that make hedging particularly important. For example, if prices for the firm's product will remain relatively fixed as a significant input cost varies, then hedging that input cost may be necessary to protect cash flows and maintain financial stability. This will be the case when the firm is more reliant on a specific commodity than the industry in general and changes in that commodity's price have a disproportionately strong impact on market prices. This could also be the case when industry competitive pressures are so severe that product prices cannot rapidly adjust to meet changes in input costs.

Hedging also makes sense for firms whose financial structures are highly leveraged or for firms whose liquidity is dependent upon commodity prices or price spreads. Examples of such situations in the electricity industry include:

- an unregulated generator using coal or renewable fuel may only be viable if oil and gas prices are high and may only build if hedged by a long term contract at a fixed price.
- an unregulated generator using gas or oil may only be viable if spark spreads are high and may want to hedge spark spreads through forward power sales.[12]
- retailers in deregulated electric markets who sign fixed price contracts with customers will need to hedge supply costs to avoid losses that could exceed their liquidity limits.

The need to hedge in these cases arises because the entity has assumed obligations – debt, a contractual obligation to a third party, or an expectation by investors of stable earnings – that can only be achieved if prices of input commodities or spreads between input commodities are within a certain range. Hedging allows those firms to assure that input prices are within a certain range.

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[12] The spark spread represents the theoretical margin for a power plant. If a spark spread is a positive number, then the price of the power is higher than that of the fuel and the spread is profitable. If the spread is a negative number, the power is priced at less than the cost of fuel and is not profitable. The spread can be determined using the natural gas, coal, or heating oil futures contracts. Mathematically, Spark Spread (in $/MWh) = [Electricity Total Value - Fuel Total Value] / [Amount of Electricity Delivered]. See: New York Mercantile Exchange, Conversion Calculator: Spark Spreads, http://www.nymex.com/calc_spark.aspx (Accessed December 22, 2006).

The motivation for regulated utilities to hedge is different from the motivation of firms in competitive industries. Regulated utilities that manage their businesses prudently are entitled to stable cash flows as a result of the regulatory compact. Regulated utilities with highly variable fuel costs generally have fuel adjustment clauses in place that provide for timely and adequate recovery of costs.

Hedging by regulated utilities is oriented toward managing customer rates; its objective is to insulate customers from the price fluctuations in an underlying commodity. For example, some gas and power distribution utilities hedge the commodities they sell in order to provide a fixed- or near-fixed price to customers. Integrated utilities with generation may hedge fuel costs in order to reduce the impact of fuel price changes on rates.

Hedging programs are generally designed and implemented by utilities in collaboration with the commissions that regulate them. The utilities agree upon an objective with the regulator and then they clearly establish a program for achieving that objective. The need for a regulated entity to hedge is created by a specific and customer-focused objective. Therefore, it must involve considerable regulatory oversight and guidance.

B. Overview of Strategies Used By Buyers of Commodities

Buyers of commodities can use a number of different hedging strategies to manage short-term price risk. There are three products that are commonly used by buyers of commodities:

- Forward contracts.
- Call option contracts.
- Collars.

These are addressed in turn below.

1. Forward or Futures Contracts

A forward contract is an agreement between two parties to buy or sell an asset or commodity at a pre-agreed future point in time. A standardized forward contract that is traded on an exchange is called a futures contract. Forward contracts are in most cases struck at fixed prices. A fixed-price forward contract locks in the price of the underlying commodity for both the buyer and seller.

Basis risks are the price risks that a buyer would be exposed to if the buyer cannot find a forward contract for the specific commodity it needs at the delivery location it needs. If the marketplace does not offer forward contracts that exactly match the commodity and the location where the buyer takes delivery, the buyer may purchase derivatives for a different commodity whose price is highly correlated with the product the buyer wishes to hedge. In addition, the buyer could purchase the same commodity it needs but at a delivery location other than the one where it takes delivery. In these cases, the buyer faces the risk associated with changes in the difference in prices between the two commodities or the two locations. The changes in these price differences are termed basis risk. Forward contracts are not readily available for the oil products and delivery locations that HECO needs, which means that if HECO decides to hedge, it will be exposed to basis risk.

A fixed-for-floating swap is also akin to a forward contract. A fixed-for-floating swap is a contract between two parties under which one party agrees to swap a fixed price for a published index price on a notional quantity. A fixed-for-floating swap is economically equivalent to a fixed-price forward contract. The difference is that the fixed-for-floating swap is a purely financial instrument, while a forward contract generally anticipates physical delivery.

2. Call Option Contracts

A call option gives its owner the right, but not the obligation, to buy an asset or commodity on a specified date (the expiration date), for a specified price (the strike price). Call options cap the price that will be paid by a buyer for a commodity.

3. Collars

A collar is a portfolio of options that is used to assure that the price of a commodity is within a given range. A buyer of a commodity who wishes to put a cap and floor on the price paid would sell a put option and buy a call option. This strategy assures that the price of the commodity will be within a given range – i.e., no lower than the strike price of the put (the floor) and no higher than the strike price of the call (the cap).

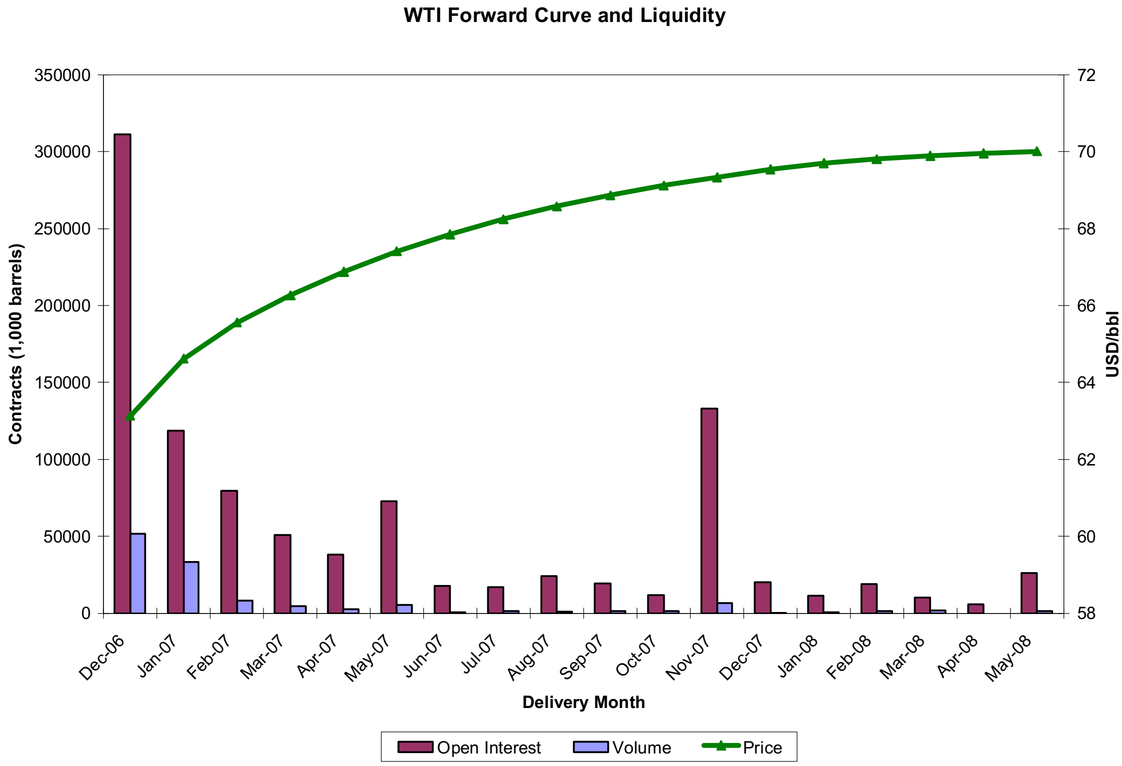
C. Characteristics of Oil Derivatives Markets

While the strategies outlined above work well in theory, they do not account for some of the practical considerations that must be considered with respect to implementing a hedging strategy. There are a number of practical implementation constraints that complicate hedging for HECO and its affiliates. These constraints are described below.

1. Duration of Derivatives

The first important constraint relates to the duration of the hedge. The forward and futures contracts that are traded in the marketplace do not reasonably extend beyond a term of 12 months. While there may be some quotes, the markets are quite illiquid beyond 18 months. Further, the most liquid (i.e., readily-available to trade) fuel hedging contracts are contracts that cover time periods of up to six months into the future. This is illustrated in **Figure 1** below.

Figure 1. Forward Curve and Liquidity in Oil Markets

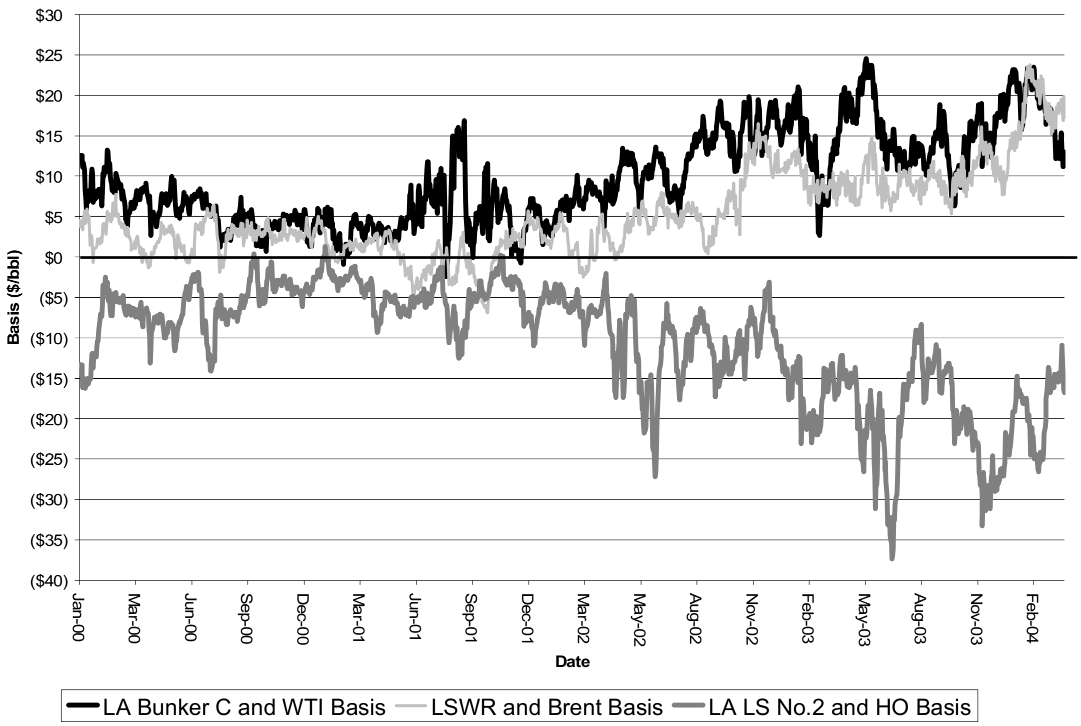


Notes: -The other fuel oils used by HECO (Heating Oil and Brent Crude Oil) display similar characteristics;
-Data as of November 30, 2006.

2. Delivery Points & Basis Risk

The second constraint faced by HECO and its affiliates is that hedging contracts for the precise oil products and delivery points that they would need are not visible in the marketplace. HECO would therefore be exposed to considerable basis risks if it used the oil derivatives that are readily-available in the marketplace. It is possible that a customized swap agreement could be obtained that hedges the price of the specific oil products in the specific locations that HECO and its affiliates need. However, such a swap is less transparent and it can be expected to be more expensive because the seller of such a swap would need to be remunerated for absorbing the basis risks and illiquidity of offering such a hedge. **Figure 2** illustrates the historical size of basis risks between the oil products that HECO and its affiliates use relative to spot prices of oil products for which HECO could obtain liquid hedges.

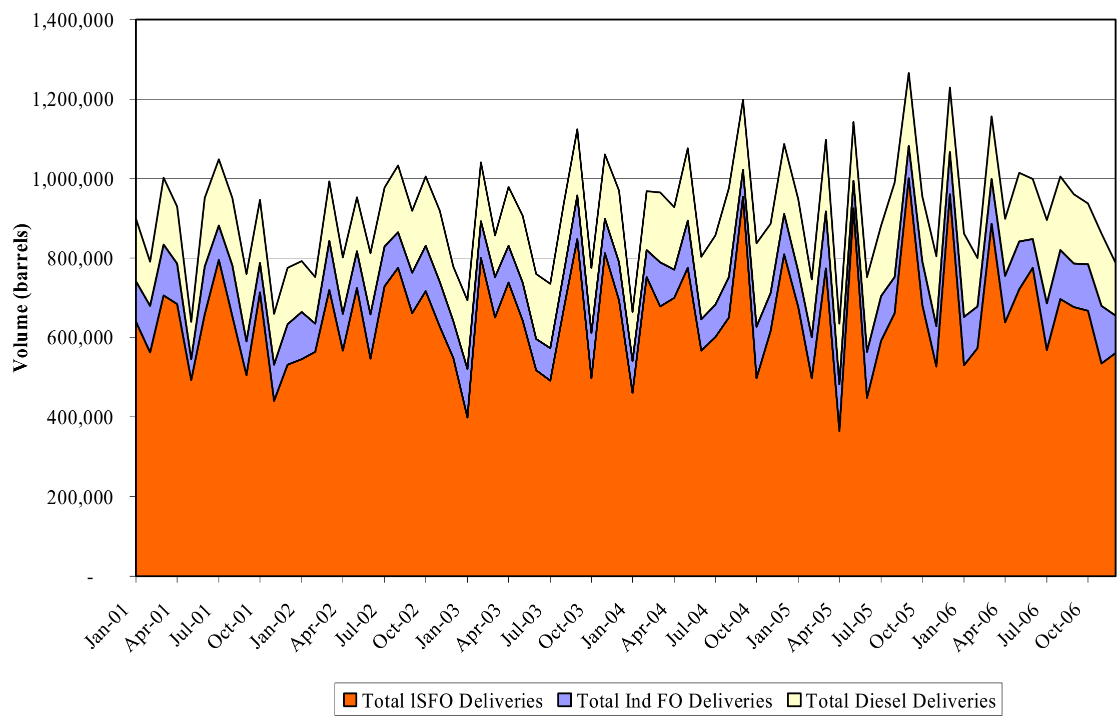
Figure 2. Daily Basis Risk for Heating Oil, WTI and Brent Fuels



3. Quantity Risk

The third constraint faced by HECO and its affiliates is the quantity they would hedge. The quantities that the utilities need of each type of fuel fluctuate month to month and year to year in accordance with changing demand, availability and relative economics of a generation plant, among other factors (as shown in **Figure 3**). The Utilities' existing fuel contracts provide for flexibility on the quantities taken, subject to a minimum and maximum take. The quantity flexibility embedded in the existing fuel contracts would be difficult to match in the financial derivatives markets, which offer fixed quantity products. If the utilities were to hedge the minimum expected quantity, their customers would face market risk exposure for incremental quantities, while hedging the maximum expected quantity would result in market risk exposure for decremental quantities. This quantity risk is important and makes accurate hedging difficult.

Figure 3. Quantity Risk: HECO's Monthly Deliveries of Fuel Oil Products



D. Implementation Issues

1. Credit Risks

If HECO and its affiliates decide to engage in hedging, they may face credit risk. Credit risk is the risk of a financial loss associated with the failure of a party to perform on its obligations under a hedging contract. Credit risk is an important factor when considering fuel hedging contracts. Market practice is to mark forward contracts to market and to collateralize the credit exposure embedded in forward contracts. This means that the value of the contract is calculated every day and any exposure must be covered as margin. If the utilities engage in hedging, counterparties may require that HECO and its affiliates provide collateral. The provision of collateral would add to the cost of hedging. Further, the utilities would, in most instances, be exposed to the risk of counterparty default and non-performance.

2. Liquidity Risks

The execution of fuel hedging contracts would expose HECO and its affiliates to liquidity risks. Liquidity is the ability to execute transactions in the marketplace. Markets that are highly liquid have active trading and many buyers and sellers. Market liquidity for oil derivatives ebbs and flows. When the markets are less liquid, a buyer or seller may face difficulties entering into or exiting positions. This is important because HECO or an affiliate may be forced to replace a position as a result of counterparty default. It is also important because it affects the price paid. In less liquid markets, it is more difficult for a buyer to get a good price. The risk that the markets HECO needs access to in order to execute or unwind and replace its hedge positions would not be liquid is a real one.

3. *Ex Post* Price Risk and Regulatory Scrutiny

It is not possible to predict the outcome of a particular hedging strategy before the fact. The ex post outcome will depend, to a large extent, on the price path of the underlying commodity during the hedging period. For example, assume that HECO fully hedges its fuel need with futures contracts at $40/bbl. No matter what happens to the price of oil from this point on, HECO will pay $40/bbl for oil. However, even though the initial hedge may have been perfectly rational *ex ante*, subsequent decreases in the price of oil will increase costs relative to a no-hedging strategy and increases in the price of oil will decrease costs relative to a no-hedging strategy. All hedging instruments contain similar risks relative to their respective strike prices. As the price of fuel oil changes, a prudent and reasonably managed hedging program implemented by HECO may become costly relative to another hedging strategy (including the strategy of not hedging at all).[13]

Like all potential costs and benefits to the utilities and their ratepayers, the risk of regulatory disallowance should be fully understood and examined prior to embarking on a hedging program. **Table 1** summarizes all of the costs and risks facing a utility implementing a hedging program.

[13] For an in depth treatment of this issue, see: Jeff D. Makholm, Eugene T. Meehan, and Julia E. Sullivan, "Ex Ante or Ex Post? Risk, Hedging and Prudence in the Restructured Power Business," *The Electricity Journal*, April 2006, Vol. 19, Issue 3, pp. 11-29.

Table 1. Costs and Risks of Hedging Programs

Administrative costs	▪ Corporate governance of hedging activities ▪ Risk assessment and control ▪ Cost of collateral postings ▪ Compliance with hedge accounting rules ▪ Up-front regulatory costs (cost of establishing hedging objective and hedging program including execution timeframe, contract types, contract duration) ▪ Ongoing regulatory costs of hedging proceedings
Market risks	▪ Market risks on incremental/decremental quantities ▪ Basis spread widens or contracts, thus reducing the effectiveness of the hedge
Credit risks	▪ Counterparty default risk
Liquidity risks	▪ Ability to unwind or replace positions
Duration of hedge	▪ Increase in market, credit and liquidity risks for long-dated hedges
Regulatory Risk	▪ Risk of hedging cost disallowances of a prudent *ex ante* hedging strategy that became costly.

E. Summary of Available Hedging Alternatives and Recommendations

It may be possible for HECO to hedge price risk for periods of up to 12 months into the future and, in the process, potentially provide customers with reduced (but not eliminated) exposure to sudden fuel cost changes. The process of executing hedges, setting rates based on the hedge costs, and informing customers of those rates would take time and the development of some level of expertise and sophistication on the part of HECO. Price hedging should not be expected to address rate periods more than one year at a time, nor should it be expected to insulate customers from long-term changes in the supply and demand for the resources used to produce electricity. Further, HECO could not reasonably hedge to eliminate all exposure to fuel cost fluctuations due to the multiple risks described above.

Were HECO to hedge, it would encounter periods during which it experienced gains on its hedges and other periods during which it experienced losses. The gains in large part would be offset by increased fuel purchase costs and the losses offset in large part by reduced fuel purchase costs. The ECAC framework would need to be revised so that the difference between the hedging gains and the increased fuel costs and the difference between the hedging losses and the reduced fuel costs were reflected in rates through the ECAC. This would cause HECO's fuel costs to fluctuate, but theoretically they would fluctuate to a lesser extent than they otherwise would. Hedging by HECO would not be expected to reduce fuel and purchased power costs and, in the long run, would be expected to increase the overall level of costs.

There are alternative mechanisms for achieving customer rate stability that could be more effective than hedging. Given the costs and risks of hedging described above, HECO and its affiliates could consider these options as an alternative to embarking on a fuel price hedging program. These alternatives will be discussed in the next section.

IV. ALTERNATIVES TO HEDGING

There is no compelling reason for HECO to use fuel price hedging as the means to achieve the goals of short-term customer rate stability and efficient fuel and power procurement practices. Two rate smoothing mechanisms will be discussed as potential alternatives to hedging programs. In addition, we will discuss the inclusion of power cost sharing conditions in traditional FAC mechanisms.

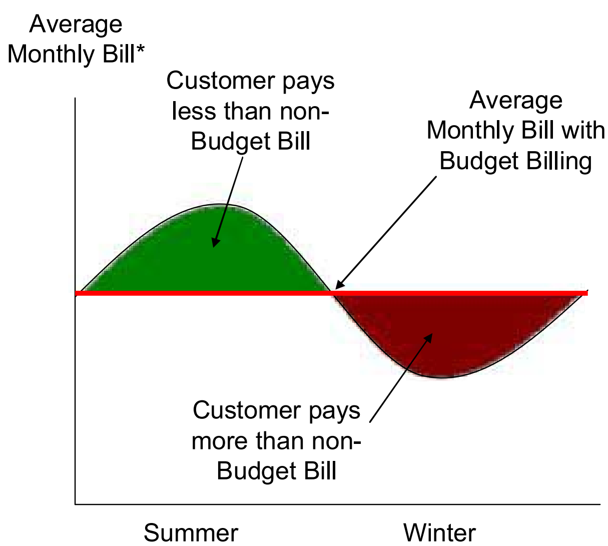
A. Rate Smoothing Mechanisms

This section presents an overview of two alternative rate smoothing ratemaking methods that could be used to provide customers with more stable rates in the short term, and in one case, temporarily limit customers' exposure to unexpected rises in fuel costs.

1. Budget Billing Rates

Budget billing is an "optional" payment program that allows the customer to pay the same amount each month for electricity or natural gas usage throughout the entire year. The voluntary nature of these programs limits any negative consumer feedback and targets the program to the consumers that want it. A monthly bill based upon previous usage patterns is estimated for the upcoming year as shown in **Figure 4**. At the end of the year, there is a true-up between the amount paid by the ratepayer and the amount the ratepayer would have paid, given his actual usage, under a non-budget billing rate plan.

Figure 4. Budget Billing Example



* for a summer peaking utility

Budget billing is typically offered to residential and small commercial customers as part of a plan to manage volatile changes in monthly energy costs, usually to seasonal changes in consumption. It should be noted that budget billing does nothing to mitigate rising electricity costs. Participants still pay the full amount for electricity, only the timing of payments over the course of the year is adjusted. Most states currently have a form of budget billing program available to residential customers.[14]

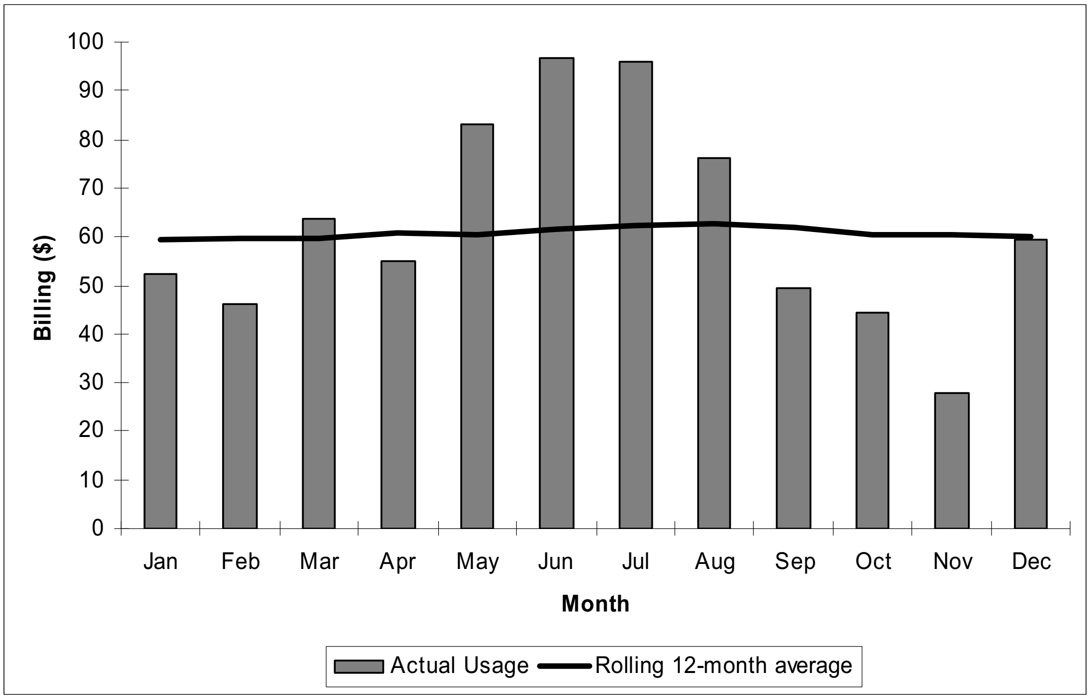
Budget billing has variations. For instance, NSTAR calculates its budget billing in the following fashion:

- Provides an equal payment from month to month based on usage for the previous year.
- At the end of the 12-month period, the Company reconciles any over or under usage from the estimate with the customer and sets the per-month payment for the next year.
- Reconciliation occurs in August/September time period each year.

An alternative to NSTAR's equal payment over a 12 month period is FPL's rolling average calculation for its budget billing. FPL calculates the bill for the current month by averaging the bills for the previous twelve months. As shown in **Figure 5**, this method results in slightly more volatility than NSTAR's equal payment plan, but allows the Company to recover their costs in a more timely fashion. The customer may also experience less true-up at the end of the period.

[14] In our survey, evidence of some form of budget billing was found in 47 U.S. states and the District of Columbia. Only Hawaii, Alaska and Rhode Island did not have a budget billing program.

Figure 5. Rolling 12-Month Average Budget Billing Example



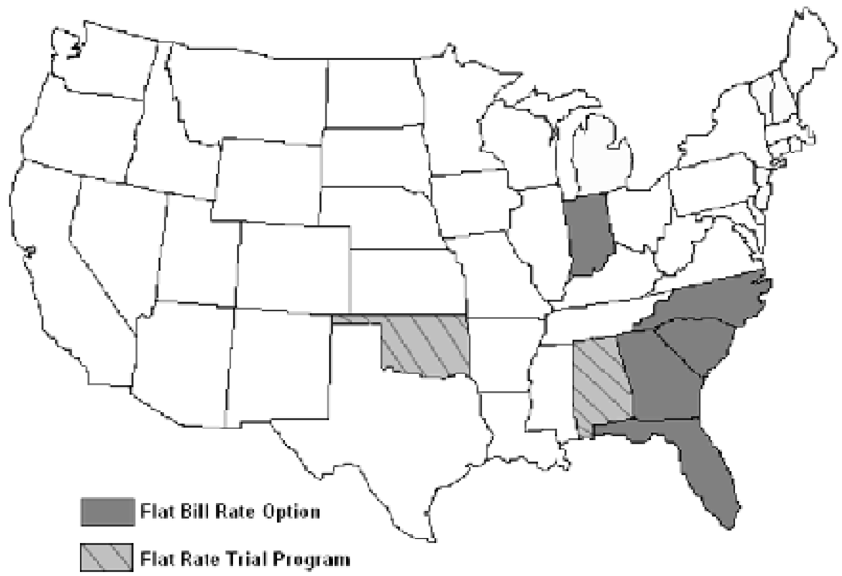
Source: Based on FPL's illustration found at: http://www.fpl.com/pay/contents/budget_billing.shtml (Accessed December 19, 2006).

The need for a budget billing plan in Hawaii may not be as large as most continental U.S. states due to the relative mild seasonality in demand. Nevertheless, budget billing may serve to aid low-income customers achieve rate stability, while perhaps helping the Company to decrease its uncollectible expenses.

2. Fixed Rate / Flat Bill Options

Some states have allowed utilities to have a rate option called "fixed rate" or "flat bill" in which a customer pays the same bill each month with no periodic reconciliation or true-up. The rates charged under these programs include risk premiums to reflect the risk the utility assumes by offering these programs. Fixed rate billing programs are generally available for larger commercial and industrial users who value (and are willing to pay for) insulation from unexpected price increases. **Figure 6** shows the states that have implemented flat bill rate options and trial programs.

Figure 6. Flat Bill Programs



Source: Michael O'Sheasy, "The Fixed Bill: Newborn Becomes Toddler!" January 4, 2005, http://topics.energycentral.com/centers/billing/view/detail.cfm?aid=900 (Accessed December 19, 2006).

Fixed rate billing is a voluntary rate option, which can help to identify customers that value rate stability. Voluntary rate plans can raise a whole host of issues, since customers will tend to switch to the plan that they find most advantageous. These issues include adverse selection, moral hazard and rate rebalancing issues.[15] In the case of fixed rate options, adverse selection and moral hazard problems may mean that only those customers who will alter their behavior to take advantage of the fixed rate nature of the program (*i.e.,* increase consumption without the risk of electricity price spikes) will be the customers that enroll. This was seen in Gulf Power's trial program where "Gulf noted that bills were adjusted by a 3.9 percent consumption adder only. The results of the pilot program showed an actual increase in kWh usage of 8 percent."[16]

[15] Adverse selection and moral hazard are economic problems that result from incomplete or asymmetric information. When buyers and sellers have asymmetric information, trades actually completed may be biased to favor the party with better information. Adverse selection typically refers to information asymmetry that exists prior to the transaction and leads to a selection bias in the group participating in the activity. Moral hazard refers to information asymmetry that occurs after the transaction occurs. For example, insurance coverage may affect the behavior of the insured to undertake activities and risks that may change the likelihood of incurring losses.

[16] Florida Public Service Commission, Memorandum, Re: Docket No. 040442-EI – Petition for authority to implement proposed FlatBill rate schedule by Gulf Power Company, September 23, 2004, p. 6. http://www.psc.state.fl.us/agendas/041005cc/04100516.html (Accessed December 27, 2006).

The revenue neutrality of the rate design (or rate rebalancing) is achieved through proper construction of the fixed rate premium. However, designing a balanced optional tariff depends on many parameters, such as the actual size of the program, the size of any premiums and the behavior of the program's participants, many of which are not known and can only be estimated prior to the program.

A risk premium is necessary because fixed rate billing present costs and risks to the utility, leading it to incur additional costs. If fuel and purchased power prices are higher than expected, fixed rate billing will under-collect. The opposite is also true. Therefore, fixed rate billing effectively forces the utility to take a position in the underlying commodity market; therefore, the utility may make the business decision to hedge this exposure to the commodity markets. The costs of this hedging as well as any additional costs, such as any administrative costs and costs associated with any expected increase in demand by these customers, would necessarily be included in the fixed rate premium.

Fixed rate programs would offer a utility the ability to limit the risks typically associated with hedging fuel costs by limiting the program to those customers willing to pay for a price-hedged product. When evaluating Gulf Power's proposed fixed rate program, the Florida Public Service Commission ("FL PSC") discussed the magnitude of a risk adder:

> Gulf has indicated that two of the factors used to calculate a customer's FlatBill rate will be a risk adder and a consumption adder. The adders account for various types of risk that Gulf has identified in offering a customer the level bill…The proposed permanent program utilizes both a consumption adder and a risk adder. The risk adder recognizes that actual usage and response may differ from what Gulf expected. The risk adder reflects three sources of risk: modeling risk, weather risk, and price risk. Gulf estimated a 5% risk premium based on their Value-at-Risk methodology. This methodology requires as inputs an aggregate risk measure, which is based on the variability of the three sources of risk, and a cost of capital input…[The Commission recommended that] the consumption adder applied to the customer's forecasted annual usage [shall] not exceed eight percent (8%) and the risk adder, used to account for financial, weather, and other risks [shall] not exceed five percent (5%).[17]

Further, the FL PSC discussed how Gulf Power's fixed rate program can impact the utility's revenue requirement and profitability:

> Under the FlatBill program proposal, Gulf intends to determine the amount of revenues for earnings surveillance and other regulatory purposes by using the actual energy usage of the FlatBill customer and multiplying that actual energy usage by the otherwise applicable tariff rate including the appropriate cost

[17] *Id.*, pp. 6-9.

> recovery factors. The difference between the actual FlatBill revenues and the calculated "otherwise applicable" revenues would be *excluded for all regulatory purposes*. In other words, any FlatBill revenues in excess of the otherwise applicable revenues would flow to Gulf's shareholders. Conversely, the shareholders would absorb any loss if the FlatBill revenues were less than the otherwise applicable revenues.[18]

Ultimately, fixed rate billing provides benefits to larger customers similar to budget billing (rate stability) with the added benefit of insulation from input cost increases. Rates will, on average be higher for the customers who select this option.

B. "Risk Sharing" Mechanisms

Act 162 recognizes the impact an automatic rate adjustment can have on utilities and requires that a FAC provide a utility with an incentive to minimize – to the extent it can – fuel costs. As discussed earlier, the ECAC achieves this goal through the efficiency parameter, which is a targeted measurement of utility plant performance. Some states, however, have adopted partial pass-through mechanisms. Note that these are some times referred to as "risk sharing" mechanisms, but that characterization is incorrect given that a utility is a price taker, and would not be able to control the price of fuel and purchased power acquired from the market. **Table 2** provides a brief overview of these mechanisms.

[18] *Id*., p. 9. (emphasis added)

Table 2. State Experience with Partial Pass Through Mechanisms

State (Utility)	Mechanism
Arizona (Arizona Public Service)	90 percent of any costs or savings relative to the base level would be allocated to customers and 10 percent is allocated to the company.
Colorado (Public Service Co. of Colorado)	Graduated sharing mechanism relative to a base level: The first $15 million is allocated 50/50. The next $15 million is allocated 75/25 between ratepayers and the utility, respectively. Any changes above $30 million are to be recovered from or flowed back to ratepayers. The maximum profit or loss that PSCO will absorb is $11.25 million in any one year.
Idaho (Idaho Power)	The power cost adjustment is 90 percent of the difference between the projected power cost and the base power cost plus the true-ups.
Washington (Puget Sound Energy)	Graduated sharing mechanism: PSE will absorb the first $20 million relative to the baseline, 50% of the next $20 million, 10% of the next $80 million, and 5% of any amount that exceeds $120 million. The Washington Commission also implemented a "power-cost-only rate case," so PSE can update its baseline rate to reflect changing power costs.
Washington (Avista)	Originally, the first $9 million is absorbed by the company (an $18 million deadband) and 90 percent of the energy cost differences exceeding the initial $9 million to be deferred for a later rebate or surcharge to customers. The parameters were modified in July 2006 to a $4 million deadband, a 50/50 sharing of energy cost differences between $4 million and $10 million and a 90/10 sharing of power costs in excess of $10 million.

These jurisdictions blur the distinction between risk sharing for productive purposes and risk sharing in the price-taking purchase of inputs. In other words, some jurisdictions impose risk sharing on the price of fuel and purchased power.

These cases are idiosyncratic and have generally represented a broad movement toward less risk imposed on the utilities involved in fuel and power purchases. In Arizona, FACs were suspended in 1989, but APS established a new one in a settlement to its 2003 rate case. Thus, APS went from no pass through to 90 percent pass through of fuel and purchased power costs. In Colorado, Public Service Company of Colorado ("PSCO") has other adjustment clauses for DSM costs, air quality improvement costs and purchased capacity that may compensate the utility for the increased fuel and purchased power risks. In its current rate case, PSCO extended its use of its fuel adjustment clause, but was also granted two associated incentive mechanisms: (1) if PSCO achieves coal production greater than a benchmark target, the associated savings would be shared 80/20 with customers; and (2) PSCO would share 80 percent of savings (above a deadband) related to the purchase of economic short term energy. In Idaho, Idaho Power absorbed all fuel cost changes prior to 1993, 40 percent from 1993 to 1995, and only 10 percent thereafter. Still, major deferrals occurred during Western Power Crisis (for later collection after contentious base rate proceedings). The story in Washington follows similar lines. Neither utility had a FAC and power costs were recoverable through base rate cases. Recent variations in hydroelectric generation supply (due to a seven year drought) increased the size of deferrals and threatened the utilities' finances. Avista filed a petition on January 30, 2006, proposing to eliminate the $18 million deadband of their Energy Recovery Mechanism ("ERM"). In a settlement, Avista's deadband was narrowed to $8 million ($4 million above and below the base level) with a 50/50 sharing of power costs between $4 million and $10 million and a 90/10 sharing of power costs starting at $10 million above or below the base level. The settlement also called on Avista to examine the cost of capital impact of the ERM, as well as the company's hedging strategy for fuel and wholesale power purchases. This represents another movement towards full pass through of power costs.

The fuel mix and thus exposure (and risk) to oil market price risk of the above utilities are also dramatically different than HECO, which relies heavily upon oil for its generation needs. **Table 3** shows that oil plays an insignificant role in these utilities' generation mix and its fuel and purchased power costs. Their large hydro, nuclear and coal resources mitigate much of their exposure to the volatile oil and natural gas markets.

Table 3. Fuel Mix for Utilities / States with Partial Pass Through Mechanisms

Fuel Type / Source	HECO[1]	APS[2]	PSCO[3]	Idaho[4]	Washington[5]
Hydro	0.5%	0.0%	0.0%	46.0%	66.0%
Coal	14.3%	39.3%	45.0%	47.0%	17.7%
Nuclear	0.0%	22.6%	10.0%	0.0%	5.3%
Gas	0.0%	9.1%	38.0%	6.0%	9.5%
Oil	79.3%	9.1%	0.0%	0.0%	0.1%
Renewables / other	5.9%	19.7%	7.0%	1.0%	1.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Sources:

1 HECO website, About Our Fuel Mix, http://www.heco.com/portal/site/heco/menuitem.508576f78baa14340b4c0610c510b1ca/?vgnextoid=047a5e658e0fc010VgnVCM1000008119fea9RCRD&vgnextchannel=deeaf2b154da9010VgnVCM10000053011bacRCRD&vgnextfmt=default&vgnextrefresh=1&level=0&ct=article (Accessed on December 12, 2006).

2 Arizona Public Service, Generation Fuel Mix and Emission Characteristics, http://www.aps.com/_files/services/BusRates/disclosure.pdf (Accessed on December 18, 2006). Note that APS does not distinguish between gas and oil. They report that gas/oil comprises 18.2% of generation, for illustrative purposes this was split 50/50.

3 Xcel Energy Fuel Supply Sources, http://library.corporate-ir.net/library/89/894/89458/items/223379/12_6XcelUtilityWeekSECwAppendix12062006.pdf (Accessed on December 18, 2006)

4 Generation Options for Idaho's Energy Plan, presentation to the Subcommittee on Generation Resources, August 10, 2006, http://www.legislature.idaho.gov/sessioninfo/2006/Interim/energy_e3_0810.ppt#561,31,2005 Idaho Electricity Fuel Mix (Accessed on December 12, 2006).

5 State of Washington, Department of Community, Trade and Economic Development, Fuel Mix Disclosure, http://www.cted.wa.gov/site/539/default.aspx (Accessed on December 12, 2006).

A fuel efficiency factor is an incentive targeted at a utility's production decisions and isolates the utility's production performance directly. Partial pass through mechanisms are relatively rare, and have been adopted for utilities with no existing FAC in place. They should not be considered a viable option for fair risk sharing of fuel and purchased energy costs in Hawaii.

Fuel prices constitute a large and volatile cost for price taking utilities. A well established, frequently updated FAC is essential to maintain a utility's credit and operational viability. Partial pass through mechanisms that defer power cost recovery in an attempt to shield ratepayers from power cost changes present an inefficient solution to the rate stability issues and the rising cost of electricity input costs. Forcing a utility to temporarily absorb a portion of power cost changes (assuming that the utility can defer the recovery of costs not passed through a FAC to a future rate case) does not prevent consumers from ultimately having to pay the full amount for their power usage, and may harm the utility's financial position.

V. CONCLUSIONS

NERA's conclusions can be summarized as follows.

1. The ECAC framework that is currently in place for HECO and its affiliates is compliant with Act 162, but the eligible costs would need to be broadened if HECO were to engage in hedging using financial hedge products.

2. Short-term price hedging by HECO and its affiliates is possible in the oil derivatives market, but such activities would not eliminate fuel price fluctuations because ratepayers would continue to be exposed to basis risks, hedge quantity risks and other risks. In addition, hedging in the oil derivatives market would introduce new costs and risks for ratepayers. Fuel price hedging in oil derivatives markets is not, therefore, a compelling way to achieve the objective of customer rate stability.

3. Rate smoothing, in the form of budget billing or flat bills, is an alternative mechanism for achieving customer rate stability that could achieve the objective at a lower expected cost. NERA recommends that HECO and its affiliates consider rate smoothing in more detail.

Sharing of the risk of oil price fluctuations between customers and shareholders is not good regulatory policy when the utility has no control over world oil markets. Such sharing would not exempt consumers from ultimately having to pay the full amount for their power usage, (assuming that the utility can defer the recovery of costs not passed through a FAC to a future rate case) and thereby harm the utility's financial position.

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CERTIFICATE OF SERVICE

I hereby certify that on December 29, 2006, I served copies of the foregoing Report on Power Cost Adjustments and Hedging Fuel Risks together with this Certificate of Service, by hand delivery or carrier to the following at the following addresses:

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Lyndon Haack

Lyndon Haack

States with 100% Fuel and Power Cost Recovery

1. ALABAMA
2. ARKANSAS
3. CALIFORNIA
4. COLORADO
5. FLORIDA
6. GEORGIA
7. **HAWAII**
8. INDIANA
9. IOWA
10. KENTUCKY
11. LOUISIANA
12. MINNESOTA
13. MISSISSIPPI
14. NEVADA
15. NORTH CAROLINA
16. NORTH DAKOTA
17. OKLAHOMA
18. SOUTH CAROLINA
19. TENNESSEE
20. VERMONT
21. VIRGINIA
22. WEST VIRGINIA

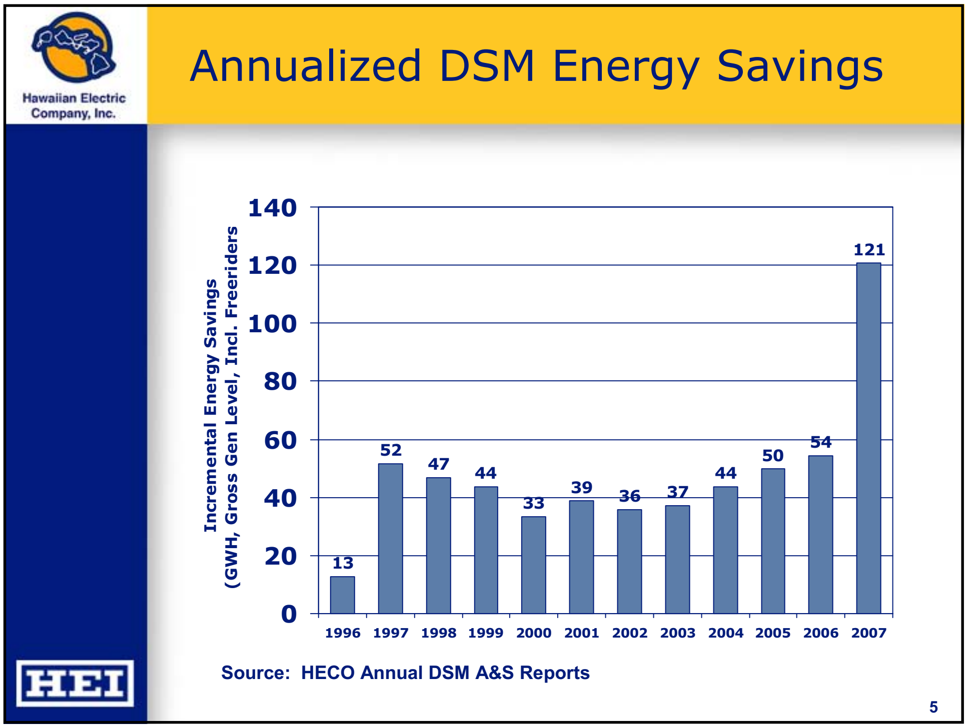
Reference:
March 2008 NERA Survey

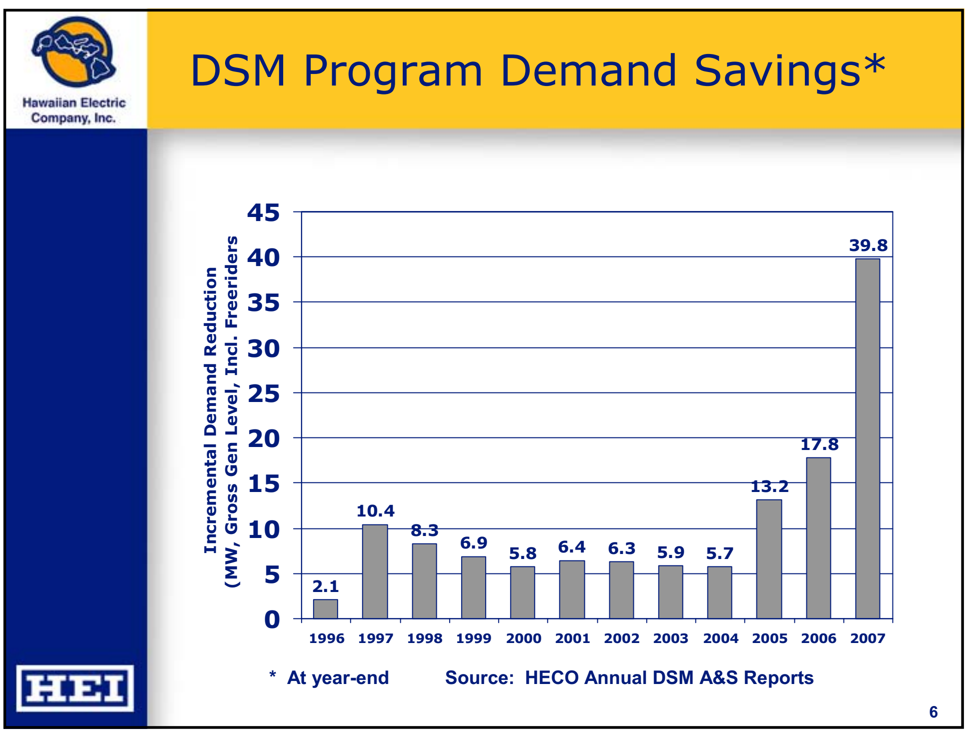
Hawaiian Electric Company, Inc.

ECA Revenue Impact of 80%, 90% and 95% Pass-through
in the Change in the Cost of Power
$ (in thousand)

		Pass Through in Change in Cost of Power at		
		80%	90%	95%
1	ECA Revenue	$ 552,969.8	$ 552,969.8	$ 552,969.8
2	% Passed through ECAC	80%	90%	95%
3	ECA Revenue with % pass-through ECAC	442,375.8	497,672.8	525,321.3
4	ECA Revenue Impact of not passing through 100% of the change in cost of power in ECAC	$ (110,594.0)	$ (55,297.0)	$ (27,648.5)

Reference
1 HECO-302
3 Line 1 x Line 2
4 Line 3 - Line 1


Hawaiian Electric Company, Inc.
Annualized DSM Energy Savings
Incremental Energy Savings (GWH, Gross Gen Level, Incl. Freeriders)
140
120
100
80
60
40
20
0
13
52
47
44
33
39
36
37
44
50
54
121
1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007
Source: HECO Annual DSM A&S Reports
HEI
5


Hawaiian Electric Company, Inc.
DSM Program Demand Savings*
Incremental Demand Reduction (MW, Gross Gen Level, Incl. Freeriders)
45
40
35
30
25
20
15
10
5
0
2.1
10.4
8.3
6.9
5.8
6.4
6.3
5.9
5.7
13.2
17.8
39.8
1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007
* At year-end
Source: HECO Annual DSM A&S Reports
HEI
6

TESTIMONY OF
PATSY H. NANBU

CONTROLLER
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Administrative & General Expense; Standard Labor Rates, Information Technology Services, Accounting for Computer Software Development Costs; Abandoned Capital Project Costs, Unamortized Gain on Sale of Land; Iolani Court Plaza Lease Premium; Accounting for Reverse Osmosis Water Pipeline Costs; Accounting for Pensions and Postretirement Benefits Other than Pensions; General Accounting Department Staffing

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Patsy H. Nanbu and my business address is 900 Richards Street, Honolulu, Hawaii.

Q. By whom are you employed and in what position?

A. I am Hawaiian Electric Company, Inc.'s ("HECO" or "Company") Controller. My educational background and experience are shown in HECO-1100.

Q. What are your areas of responsibility in this rate case?

A. I am responsible for presenting the Company's overall normalized test year 2009 estimates for Administrative and General ("A&G") Expenses, which include Account Nos. 920-932. I am the Company's primary witness for Administrative Expenses (Account Nos. 920, 921 and 922), Outside Services (Account Nos. 923010 and 923020) and Employee Benefits Transferred (Account No. 926020).

Besides addressing A&G expenses, I am responsible for addressing information technology and services costs, the accounting and ratemaking treatment for computer software development costs, abandoned capital projects, the accounting and ratemaking treatment for the reverse osmosis water pipeline costs, and the unamortized gain on sale amounts and Iolani Court Plaza lease premium included in rate base. In addition, I will discuss the accounting for pensions and postretirement benefits other than pensions. Finally, I will discuss the General Accounting department's staffing.

Q. Will certain A&G expenses be addressed by other Company witnesses?

A. Yes. Several witnesses will address detailed test year A&G expense estimates as follows:

1) Mr. Russell Harris (HECO T-12) will address Insurance Expense (Account

Nos. 924 and 925),

2) Ms. Julie Price (HECO T-13) will address Employee Benefit Expenses (Account Nos. 926000 and 926010), and

3) Mr. Bruce Tamashiro (HECO T-14) will address Miscellaneous A&G Expenses (Account Nos. 928, 9301, 9302, 931 and 932).

ADMINISTRATIVE AND GENERAL EXPENSES

Q. What is the Company's normalized estimate of total A&G expenses for test year 2009?

A. The Company's normalized estimate of total A&G expenses for test year 2009 is $76,583,000 in support of the Interim Increase and $76,849,000 in support of the Campbell Industrial Park Generating Station and Transmission Project ("CIP1 Generating Unit") Step Increase. For reference purposes, an unadjusted estimate of total A&G expenses for test year 2009 is $76,708,000 (referred to as "base case").

Q. Please describe the Interim Increase and the CIP1 Generating Unit Step Increase.

A. HECO is requesting a revenue increase that will be implemented in steps to more closely match cost recovery with cost incurrence. The first step is an Interim Increase (based on the Company's revenue requirements exclusive of any 2009 CIP1 Generating Unit costs[1]). The second step is a Step Increase based on the return on investment of the full cost of the 2009 CIP1 Generating Unit and recovery of associated on-going production operations and maintenance expenses, employee benefits, and payroll taxes. This second step is to be effective on the in-

[1] The Interim Increase includes certain 2008 plant additions associated with the CIP Generating Unit project.

service date of the CIP1 Generating Unit. The Interim Increase (without CIP1 Generating Unit) and CIP1 Generating Unit Step Increase being proposed are discussed by Mr. Robert Alm in HECO T-1 and further discussed by Mr. William Bonnet in HECO T-23.

Q. How will you present your testimony?

A. Within my testimony, I will detail the A&G expense amounts in relation to the base case. If any differences exist between the A&G expenses of the Interim Increase, CIP Generating Unit Full Cost scenario, or base case, I will discuss such differences in my testimony.

Q. What does the normalized estimate of total A&G expenses for test year 2009 represent?

A. The estimate of total A&G expenses represents the combined test year estimates for Account Nos. 920 through 932. HECO's test year estimates for the base case, summarized by primary account for the various expense categories included within the broad A&G expense category, are as follows:

Primary Account		Test Year 2009 Estimate Base Case ($ Thousands)
920	A&G Expense - Labor	$19,417
921	A&G Expense – Non Labor	$15,202
922	Administrative Expenses Transferred	($ 3,197)
923	Outside Services	$ 2,666
924	Property Insurance	$ 3,062
925	Injuries & Damages	$ 7,192
926	Employee Benefits	$23,407
928	Regulatory Commission Expense	$ 440
930	Miscellaneous	$ 3,893
931	Rents	$ 3,062
932	Maintenance of General Plant	$ 1,565
	Total A&G Expenses	$76,708

Q. Is the total test year 2009 normalized base case A&G expense estimate presented by detailed accounts and sub-accounts?

A. Yes. HECO-1101, pages 2 through 5 presents the detailed accounts and sub-accounts by labor and non-labor amounts, and shows any related budget adjustments and test year normalizations. HECO-1102, page 1, presents the detailed account and sub-account amounts for 2003 through 2007 (recorded), 2008 and 2009 (budget) and the test year 2009 base case estimate. Pages 2 and 3 of HECO-1102 identify, by account number and code block, the significant differences (variance greater than ± $200,000 and 10%) between the 2009 budget amounts and the recorded 2007 amounts. Brief explanations of the differences are provided on pages 2 and 3 of HECO-1102, as a cross reference to the more detailed explanations provided later in this testimony under the related account numbers.

Q. Please explain the difference between the test year A&G expense amount for the base case, the Interim Increase (without the CIP1 Generating Unit) and the CIP1 Generating Unit Step Increase?

A. The difference between the three amounts relates to the employee benefits expenses for the difference in the labor/staffing under the three scenarios as described by Mr. Robert Alm in HECO T-1 and Mr. Dan Giovanni in HECO T-7. The A&G expenses (including the employee benefits) under the base case reflect the employee benefits for the labor costs that would be charged to expense in the test year. Under the Interim Increase (without CIP1 Generating Unit) scenario, the A&G expense exclude the employee benefits for the labor costs related to the CIP1 Generating Unit. For the CIP1 Generating Unit Full Cost scenario, the A&G expenses reflect the full year impact of the employee benefits for the labor costs related to the CIP1 Generating Unit. HECO-1101 presents the amounts for each of the scenarios, and HECO-WP-1101 provides the calculation of the change in employee benefits expense for each of the scenarios. The rest of this testimony focuses on the expenses under the base case.

Q. How were the test year estimates developed?

A. As described by Ms. Nagata in HECO T-17, the 2009 test year estimates are the result of a detailed budget process, as well as three types of adjustments that were made to determine the test year estimates: 1) budget adjustments, 2) issue simplification adjustments, and 3) normalization adjustments.

General Nature of A&G Expenses

Q. What is the general nature of A&G expenses?

A. A&G expenses represent a diverse group of expenses under the National Association of Regulatory Utility Commissioners Uniform System of Accounts ("NARUC USOA"), which the Commission has directed HECO to follow.

Q. Why are A&G expenses so diverse?

A. Under the NARUC USOA, A&G expenses often represent operating expenses not provided for in other functional areas. For example, the NARUC USOA description for Account 923 - Outside Services includes the statement, "This account shall include the fees and expenses of professional consultants and others for general services which are not applicable to a particular operating function or to other accounts." Another reason for the diversity in A&G expenses is that these expenses represent the total Company costs for certain specific items, e.g., Property Insurance (Account No. 924).

Q. How will A&G expenses be organized and presented in this rate case?

A. Because A&G expenses cover such a diverse group of expenses, the A&G expense estimates will be presented and analyzed by individual account numbers. However, to make the presentation more meaningful, the sequential account numbers in HECO-1101 and HECO-1102 have been arranged into groups where there is some relationship between the accounts in a particular group. There are five groups of accounts as follows:

1) Administrative (Accounts 920 - 922),
2) Outside Services (Accounts 923010 and 923020),
3) Insurance (Accounts 924 and 925),
4) Employee Benefits (Accounts 926000 - 926020), and
5) Miscellaneous (Accounts 928 - 932).

ADMINISTRATIVE

Q. What are the accounts and test year estimates for the Administrative group of accounts?

A. As shown in HECO-1101, page 1, the Administrative group of accounts, and the associated amounts totaling $31,422,000 for test year 2009 are as follows:

Acct. No.	Description	Test Year 2009 Estimate ($ Thousands)
920	A&G Expense - Labor	$19,417
921	A&G Expense – Non Labor	$15,202
922	Administrative Expenses Transferred	($ 3,197)

Q. What is the nature of Administrative expenses?

A. The Administrative group of expenses represents the expenses incurred in connection with the general administration of the Company's operations that are not chargeable against other specific functional accounts. Administrative expenses include the labor and related non-labor costs of Company officers, as well as employees in diverse functional areas such as accounting and finance, corporate compliance, internal audit, purchasing, human resources, information services (e.g., mailing, printing, records management, and word processing), legal, government relations, regulatory affairs, environmental, information technology, safety and security, risk management, energy services, energy projects, forecasts and research, corporate communications, facilities planning, energy projects and integrated resource planning. The specific departments that charge the Administrative accounts and the amounts charged for years 2003 through 2007 and budgeted for 2008 and 2009 are shown by department in HECO-WP-101(C) pages 59-62.

Q. Where are gross Administrative expenses charged?

A. Administrative labor costs are charged to Account No. 920 – A&G Expense - Labor, while related non-labor costs are charged to Account No. 921 – A&G Expense – Non Labor. Included in Account No. 921 are the Information Technology and Services ("ITS") charges for the areas that are administrative in nature.

Q. Do all of the gross costs remain classified as Administrative expenses?

A. No. Some of the Administrative activities support the Company's plant construction effort. An appropriate portion of gross Administrative costs charged to Account Nos. 920 and 921 is, therefore, transferred to construction projects. This transfer is accomplished by means of an on-cost (overhead) charge to construction projects, with a concurrent credit to Account No. 922 - Administrative Expenses Transferred, which I will cover later in my testimony.

Q. Are any Administrative costs incurred by HECO charged to other parties?

A. Yes. The Company provides administrative, as well as other types of services, to its operating electric utility subsidiaries, Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Limited ("MECO"); to its non-regulated subsidiaries, Renewable Hawaii, Inc. ("RHI") and Uluwehiokama Biofuels Corporation ("UBC"); to other affiliated companies, including its parent company, Hawaiian Electric Industries, Inc. ("HEI"); and to various outside parties. To the extent practical, labor and non-labor costs incurred by HECO in providing such administrative and other services are billed directly to the party receiving the services. The labor amounts billed are based primarily on the actual time spent by individuals on various billable activities, although some other reasonable basis for allocation is used when keeping time is not practical or appropriate. Because these amounts are directly charged to outside parties (e.g., time-sheets are coded with a charge number referencing a "receivable from customer" account), the amounts are not charged to HECO operations. However, a portion of the charges billed directly to HEI is charged back to HECO, as explained later in this testimony under Account No. 921 – A&G Expense – Non Labor.

Besides directly billable costs, the Company incurs a certain amount of indirectly assignable administrative costs with respect to the various services provided, such as the labor costs of clerical support personnel. These costs are first charged to HECO A&G Expenses. Appropriate amounts of the indirectly assignable administrative costs are then billed, primarily in the form of on-cost charges, to HELCO, MECO, RHI, UBC, HEI, other affiliated companies and outside parties, with concurrent credits to Account No. 922 - Administrative Expenses Transferred.

Q. Please describe in more detail the types of costs included in Administrative Expenses.

A. For each organization budgeting charges to administrative expenses, a brief description of the organization's major administrative activities is provided in HECO-1103. The amounts estimated by each organization for 2009 to Administrative Expense Account Nos. 920 and 921 are summarized, by responsibility area code, in HECO-WP-101(C), beginning on page 59.

920 - Administrative and General Expense -Labor

Q. What is the test year 2009 normalized estimate for Account No. 920 - A&G Expense-Labor?

A. As shown in HECO-1101, page 2, the test year 2009 estimate for Account No. 920 is $19,417,000, after a net downward adjustment of $2,981,000.

Q. What are the specific adjustments?

A. There are four specific adjustments included in the $2,981,000:

1) a budget adjustment reduction of $2,994,000 for performance incentive plans compensation ("PIP"),
2) a budget adjustment reduction of $52,000 to reclassify costs related to maintenance of general plant to Account No. 932,
3) a budget adjustment increase of $64,000 to reclassify costs for a Senior Rate Analyst position to Administrative expenses, and
4) a budget adjustment increase of $1,000 for abandoned capital project costs.

Q. What is the PIP adjustment?

A. The Company offers several incentive plans consisting of an Executive Incentive Compensation Plan ("EICP"), Long-Term Incentive Compensation Plan ("LTIP"), a restricted stock plan, Team Merit Incentive Awards, Individual Merit Incentive Awards, and service awards program. PIP refers to awards made under these plans/programs. The Company has removed from its test year 2009 estimate $2,994,000 for the PIP payments/awards that it estimates will be earned by employees in 2009. Although PIP costs are appropriate costs of doing business, the Company adjusted its operation and maintenance ("O&M") expense budget for PIP costs to reduce the number of issues in this case. The Company reserves its right to seek recovery of these costs in future rate cases.

Q. Please describe the budget reclassification adjustment of $52,000.

A. Labor costs related to structural maintenance and repair work for the King Street office building and the Ward Avenue facilities were budgeted to activities that translated to Account No. 921, instead of activities that translated to Account No. 932. A corresponding increase to Account No. 932 is discussed by Mr. Tamashiro in HECO T-14.

Q. Please explain the budget increase of $64,000 for a Senior Rate Analyst.

A. Mr. Alan Hee in HECO T-10 describes the need for an additional Senior Rate Analyst, and the adjustment in the staffing of the Energy Services area. The work related to the Senior Rate Analyst is an administrative function, and costs would be reflected in Account No. 920. The test year estimate for Account No. 920 is adjusted to reflect an additional Senior Rate Analyst.

Q. What is the $1,000 adjustment for abandoned capital project costs?

A. The costs of abandoned capital projects (where a "no go" decision is made during the time project costs are classified as Construction Work in Progress) are generally written off to appropriate O&M expense accounts, including Account No. 920. The recorded 2003 through 2007 amounts for Account No. 920 include abandoned capital project costs. However, the 2008 and 2009 budget estimates for O&M expenses do not include amounts for abandoned capital project costs as forecasters do not generally contemplate that projects will be abandoned. The $1,000 adjustment is necessary, therefore, to include in revenue requirements a reasonable amount for the write-off of abandoned capital project costs in Account No. 920.

Q. How was the $1,000 adjustment computed?

A. The calculation of the $1,000 adjustment and more details regarding abandoned capital project costs, are provided later in this testimony.

Q. How does the test year 2009 estimate for Account No. 920 – A&G Expense – Labor compare to prior year amounts?

A. A comparison is shown below, based on the amounts shown in HECO-1102, reduced by the amount of PIP included in Account No. 920 each year.

	($ Thousands)		
	Per HECO-1102*	Less PIP	Adj. Total
2003 Recorded	14,593	1,311	13,282
2004 Recorded	15,185	1,616	13,569
2005 Recorded	15,759	1,634	14,125
2006 Recorded	13,506	(935)	14,441
2007 Recorded	15,767	397	15,370
2008 Budget	18,978	2,212	16,766
2009 Test Year	22,411**	2,994**	19,417**

* A breakdown of the HECO-1102 amounts, before adjustments, by responsibility area code is provided on HECO-WP-101(C), pages 59 and 60.

** HECO-1102 shows the adjusted total of $19,417,000. The $22,411,000 before PIP adjustment is shown here for consistency of presentation. It reflects the amount on HECO-WP-101(C) and other budget adjustments.

Q. Are PIP amounts recorded and budgeted in accounts other than Account 920?

A. Yes. The recorded and budgeted PIP amounts by account number are shown in HECO-1104.

Q. Why is the test year 2009 estimate for Account No. 920 higher than the amount for 2007?

A. The test year 2009 estimate of $19,417,000 is $4,047,000 higher than the recorded 2007 amount, adjusted for PIP amounts. The major reasons for the increase are approximately as follows:

1) general wage increases $1,012,000,
2) increase in positions that perform administrative activities $1,759,000, and
3) impact of positions primarily for administrative activities not filled throughout 2007 is approximately $722,000.

Item 1. General Wage Increases

Q. What is the impact of general wage increases?

A. General wage rates for test year 2009 are expected to be 7.50% (for bargaining unit employees) and 8.55% (for merit employees) higher than the respective 2007 wage rates (see HECO-1105). This accounts for an increase of approximately $1,012,000 in labor costs (excluding PIP) between 2007 and 2009, other things being equal. The assumptions used in determining the bargaining unit and merit salary increases included in the 2009 budget are discussed by Ms. Lorie Nagata in HECO T-17. In HECO T-13, Ms. Julie Price discusses in more detail how the bargaining unit and merit salary increases are determined.

Item 2. Increase in Positions Performing Administrative Activities

Q. How many positions are to be added by the Company in 2008 and 2009 where most, if not all, of the labor costs are charged to Account No. 920?

A. HECO-1106, page 1, shows the 20 positions to be added to the Company's administrative staffing in 2008 and 2009. The labor costs for these positions would not have been reflected in the actual 2007 expenses, but are included in the 2009 test year estimate.

Q. What is the impact of the increased number of employees?

A. As detailed in HECO-1106, page 1, the increase of 20 employees accounts for approximately $1,759,000 of the increase in Account No. 920 labor costs between 2007 and test year 2009.

Q. What is the justification for the 20 new positions?

A. The addition of a new Corporate Accountant is discussed later in my testimony. The justification for each of the other new positions is provided by the other witnesses as described by Ms. Faye Chiogioji in HECO T-15.

<u>Item 3. Impact of positions not filled throughout 2007</u>

Q. Please explain the amount attributed to the impact of positions not filled throughout 2007.

A. During the year, administrative positions that are necessary to meet the Company's workload may not be filled for a period of time as a result of transfers, promotions, retirement, and terminations. During that time, actual labor charges for such positions would not be reflected in Account 920 (although there may be offsetting increases in the overtime charges for other positions or increase in non-labor charges for external temporary hires). For the test year, these positions are required and assumed to be filled during the year.

Q. The above three items account for less than the increase in costs between 2007 and the test year 2009 estimates. Are there other factors that contribute to the change in labor charges to Account No. 920?

A. As mentioned earlier, charges to Account 920 include labor in connection with the general administration of the Company's operations that are not chargeable against other specific functional accounts. Time spent on specific projects that are administrative in nature are budgeted to Account No. 920. To the extent that there are more administrative type projects in 2009, such as the Ellipse 6 upgrade, and to the extent departments that normally do not charge their time to Account No. 920 are involved in the project, labor charges to Account No. 920 would be higher in 2009.

In addition, if administrative type positions worked on more billable work or projects that are not administrative in nature in 2007, the costs were recorded to those specific project/functional areas, reducing the charges to Account No. 920 in 2007. For example, in 2007, HECO's payroll area needed to assist HELCO due to the retirement of HELCO's payroll accountant. During the several months in 2007 that HECO's payroll area provided assistance to HELCO, HECO's billable charges to HELCO were higher and the labor costs recorded in Account No. 920 was lower than normal. HECO does not expect to provide HELCO with as much payroll assistance in 2009, thus, HECO's labor charges to Account 920 in 2009 will be higher when compared to actual 2007 expenses.

Q. Why is the 2009 test year estimate of $19,417,000 for A&G labor costs reasonable?

A. The test year estimate is reasonable because the increase is due principally to wage and salary increases, including wage increases set forth in the Company's negotiated labor agreement and estimated for non-bargaining unit employees. The increase is also due to additional positions needed to perform the Company's administrative functions.

<u>921 – Administrative and General Expenses – Non Labor</u>

Q. What is the test year 2009 normalized estimate for Account No. 921 – A&G Expenses – Non Labor?

A. As shown in HECO-1101, page 2, the test year 2009 normalized estimate for Account No. 921 is $15,202,000 after a net downward adjustment totaling $1,578,000.

Q. What are the specific adjustments?

A. There are five specific adjustments included in the $1,578,000:

1) an increase of $10,000 for abandoned capital project costs,
2) a decrease of $34,000 to reflect the revision to the amortization amount for computer software development project costs for the HR Suite project expected to be completed in 2009,

3) a decrease of $103,000 to reflect a normalized level of integrated resource planning costs in the test year,

4) a budget adjustment reduction of $1,108,000 to reclassify costs related to maintenance of general plant to Account No. 932, and.

5) a decrease of $343,000 to remove performance incentive plan compensation amounts from the test year 2009 estimates (including incentive compensation amounts in the HEI charges to HECO).

Q. What is the $10,000 adjustment for abandoned capital project costs?

A. As discussed earlier in this testimony, the costs of abandoned capital projects (where a “no go” decision is made during the time project costs are classified as Construction Work in Progress) are generally written off to appropriate O&M expense accounts, including Account No. 921. The recorded 2003 through 2007 amounts for Account No. 921 include abandoned capital project costs. However, the 2008 and 2009 budget estimates for O&M expenses do not include amounts for abandoned capital project costs as forecasters do not generally contemplate that projects will be abandoned. The $10,000 adjustment is necessary, therefore, to include in revenue requirements a reasonable amount for the write-off of abandoned capital project costs in Account No. 921.

Q. How was the $10,000 adjustment computed?

A. The calculation of the $10,000 adjustment, as well as more details regarding abandoned capital project costs, is provided later in this testimony.

Q. What is the $34,000 adjustment for the HR Suite software development project?

A. As described by Ms. Julie Price in HECO T-13, the HR Suite project is expected to be implemented in April 2009, and amortization of the deferred software development costs would begin in May 2009. A revision to the cost estimate was made after the budget was completed. The $34,000 adjustment reflects a reduction in the amortization expense to $201,000, as the deferred costs to be amortized was reduced. The accounting for computer software development projects is discussed later in my testimony.

Q. What is the normalization adjustment of $103,000 related to Integrated Resource Planning ("IRP") expenses?

A. Mr. Alan Hee in HECO T-10 discusses the normal level of IRP expenses, and the adjustment to the 2009 budget to reflect a three-year average for IRP non-labor costs.

Q. What is the budget reclassification adjustment of $1,108,000?

A. The 2009 budget reflected maintenance expense for structural maintenance and repair work for the King Street office building and the Ward Avenue facilities that were included in Account No. 921, which should have been reflected in Account No. 932. As a result, a budget reclassification adjustment was made to decrease the expenses for Account No. 921 by $1,108,000. A corresponding budget adjustment to increase the test year estimate for Account No. 932 is discussed by Mr. Bruce Tamashiro, in HECO T-14.

Q. What is the $343,000 downward adjustment for PIP amounts?

A. As discussed earlier in this testimony, the Company has excluded from its test year 2009 estimates all budgeted PIP amounts, including the $343,000 budgeted to Account No. 921. Recorded and budgeted PIP amounts from 2003 through 2009 are shown on HECO-1104.

Q. How does the test year 2009 estimate for Account No. 921 compare with prior year amounts?

A. In order to compare the test year 2009 estimate for Account No. 921 with prior year amounts, the available PIP amounts (the HEI PIP amounts included in intercompany charges for 2003 through 2004 are not available) should be excluded from the prior year amounts as they are not included in the test year estimates. In addition, the recorded amount in 2003 included the amortization of APPRISE project costs of $485,000. Because amortization of APPRISE project costs ended in 2003 and such costs are not included in the test year estimate, the costs should be removed in comparing the 2009 test year estimate with prior years. Further, in 2007, certain maintenance expense for the air conditioning repair work for the King Street office building and the Ward Avenue parking structure roof level repairs amounting to $417,000 should have been charged to Account No. 932 instead of Account No. 921. After excluding the available PIP amounts, the amortization costs for project APPRISE and the maintenance expense from the 2003 through test year 2009 data shown on HECO-1102, the test year 2009 normalized estimate for Account No. 921 of $15,202,000 compares with prior year amounts as follows:

($ Thousands)

	Per HECO-1102*	Less Other Adjust/PIP	Adj. Total
2003 Recorded	9,831	485/359	8,987
2004 Recorded	12,539	0/380	12,159
2005 Recorded	14,276	0/1,124	13,152
2006 Recorded	11,529	0/555	10,974
2007 Recorded	13,656	417/456	12,783
2008 Budget	12,605	0/169	12,436
2009 Adj. TY Estimate	15,545	0/343	15,202**

* A breakdown of the HECO-1102 amounts, before adjustments, by responsibility area code is provided on HECO-WP-101(C), pages 61 and 62.

** HECO-1102 shows the adjusted total of $15,202,000. The $15,545,000 before PIP adjustment is shown here for consistency of presentation. It reflects the amount on HECO-WP-101(C) and other budget adjustments/normalizations.

Q. What is the difference between 2007 and the 2009 test year estimate for the costs in Account No. 921?

A. The test year 2009 estimate for Account No. 921 is $2,419,000 higher than the adjusted actual expenses in 2007. The primary reasons for the increase are due to the following:

1)	Consultant fees for internal audits	$750,000
2)	Information Technology and Services ("ITS") charges	$655,000
3)	Ellipse 6 software	$362,000
4)	eMESA software	$122,000
5)	Amortization of HR Suite	$201,000
6)	Treasury Management System upgrade	$114,000
7)	Higher HEI Charges to HECO	$447,000

The increase due to the above items are offset in part by lower expenses for other items incurred in 2007 that will not be incurred in 2009.

Item 1. Consultant fees for internal audits

Q. What is Internal Audit's function in the company?

A. The Corporate Audit and Compliance Department, formerly Internal Audit, is responsible for (1) conducting independent analyses, appraisals and reviews of the adequacy and effectiveness of the system of internal controls, risk management practices, and corporate governance process of HECO and its subsidiaries for management and the Audit Committee of the Board of Directors; (2) reviewing organizational activities and processes, and providing recommendations for improving existing business practices; (3) testing the design and operating effectiveness of the Company's internal controls over financial reporting to assist management in achieving compliance with the requirements of the Sarbanes-Oxley Act of 2002 (SOX); (4) reviewing new or existing information technology systems, applications and devices to ensure the reliability of the Company's operating systems, accuracy of data outputs and protection of equipment and information; (5) performing special studies and examinations requested by management; and (6) coordinating documentation for annual audit activities.

Q. What are the consultant fees for internal audit?

A. Internal Audit consultant fees are to co-source conducting independent analyses and review of risk management practices, review of corporate governance process of HECO and its subsidiaries, reviewing organizational activities and processes and providing recommendations for improving existing business practices, and performing special studies and examinations requested by management. Prior to 2004, HECO's internal audit staff conducted the activities described above. Since that time, the Internal Audit staff has been spending a significant amount of its resources on evaluating the design and testing the operating effectiveness of the Company's internal controls over financial reporting in order to comply with the requirements of SOX. In addition, there have been more information technology systems, applications and devices installed or are being installed that require Internal Audit's resources to ensure accuracy of data outputs and security and protection of equipment and information. As a result of dedicating Internal Audit resources to the SOX and information technology efforts, minimal amount of resources have been spent conducting independent analyses, risk reviews, and monitoring and testing operational, financial and compliance risk of the Company. The consultant services fees for co-sourcing will provide the resources required for the Internal Audit area to conduct independent analyses, review organizational activities and processes, provide recommendations for improving existing business practices and evaluate the risk management process of the Company. Standard and Poor's has announced that it will begin Enterprise Risk Management reviews in its ratings of non-financial companies starting in 2009, and it is important that HECO enhance its process to manage enterprise risk.

HECO has identified KMH LLP to provide the required services, and will begin its co-sourcing efforts in the second half of 2008. The test year estimate of $750,000 represents a full year's impact of the co-sourcing efforts. With the additional work performed by KMH LLP, HECO will have a better risk assessment process and practice, and will be able to monitor and test the operational, financial and compliance risk of the company.

Q. Item 2. ITS charges. Please explain ITS charges.

A. The ITS department operates and maintains the IT system used at HECO. ITS costs are generally charged to the ITS Clearing Account and allocated or "costed" to the various capital, O&M and clearing accounts through the ITS costing process. I will discuss later in my testimony the ITS costs (costs charged to the ITS Clearing Account) for the test year and the allocation or "costing" process. The amounts for ITS included in Account 921, represent the ITS costs related to the administrative function. In 2009, the ITS charges "costed" to Account No. 921 are higher than in 2007 because the ITS costs are estimated to be higher as explained later in my testimony.

Q. Item 3. Ellipse 6 software. Please explain this software expense.

A. The Company's core business system, Ellipse (formerly referred to as Mincom Information Management System, or MIMS, which was purchased from Mincom, Inc., an Australian based company) was implemented effective January 1, 1999. HECO is required to implement periodic software upgrades based on the vendor software life cycle. The last MIMS upgrade HECO implemented was in 2002-2003, with a go-live in October 2003. Mincom's Supported Software Platform document indicates that the end of the release lifecycle for the version of Ellipse currently being run by HECO (Ellipse 5.2.3.7) is in the first quarter of 2010, thus HECO plans to complete its implementation of the upgrade to Ellipse 6 by the end of 2009. The costs included in Account No. 921 relate to the software for the upgrade.

Q. Item 4. eMESA software. Please explain this software expense.

A. The eMESA software is a 3rd party web based application developed by Dimension Technology Solutions ("DTS"), an authorized Mincom partner, that extends certain Ellipse functions on to a user friendly web interface. This includes the maintenance work scheduling function, the document management function, equipment register search function and requisition creation/approval functions.

Q. Item 5. Amortization of HR Suite. What is this amortization expense?

A. As mentioned earlier in my testimony regarding adjustments to the budget for Account No. 921, Ms. Julie Price discusses the HR Suite project in HECO T-13. The $201,000 is the amortization of the deferred software development costs. The accounting for computer software development projects is discussed later in my testimony.

Q. Item 6. Treasury Management System upgrade. Please explain the Treasury Management System upgrade.

A. HECO has been using its current treasury management system, ICMS, for nearly 20 years. The system has been in service since 1989 and is reaching its limitations. A newer system would provide more efficient data management, better controls and the ability to interface with various financial institutions' web applications. Such enhancements will allow HECO to mechanize fund transfers and recording of these transactions in the general ledger. Also, the ICMS vendor may discontinue future software support of the older version HECO is using as they dedicate resources to newer versions of their software.

<u>Item 7. HEI Charges to HECO</u>

Q. Of the total test year 2009 estimate for Account No. 921, what is the estimate for billings from HECO's parent company, HEI?

A. The test year 2009 estimate for billings from HEI to HECO reflected in Account No. 921 is $2,156,000. A summary of the total HEI billing amount by type of activity is provided in HECO-1107.

Q. Does the test year 2009 estimated billings from HEI include any performance incentive plan compensation (PIP)?

A. No. PIP amounts are excluded from the test year estimate of billings from HEI to HECO.

Q. How does the test year 2009 HEI billing amount compare with amounts billed in previous years (excluding PIP)?

A. The 2009 HEI billings estimate of $2,156,000 is comparable to recorded amounts of $1,677,000, $1,718,000 and $1,709,000 for 2005, 2006, and 2007, respectively.

Q. What services are provided by HEI to HECO?

A. HEI provides HECO with a variety of services, including financial accounting and reporting, administrative, investor relations and stock transfer activities. Detailed descriptions of the types of services performed by HEI on HECO's behalf are identified in the service agreement between HEI and HECO, which is provided in

HECO-1108. The service agreement also provides the basis used by HEI to allocate (when direct charging is not possible or practical) billing amounts to its various subsidiaries.

Q. Has HEI's billing to HECO been reviewed for appropriateness?

A. Yes. In 1992, HECO requested Arthur Andersen & Co. to evaluate HEI's intercompany billing system. HEI's current billing methodology essentially incorporates all of the significant recommendations made by Arthur Andersen & Co. in its report on the study, which was addressed in detail in Docket No. 7700.

Q. Why do billing amounts from HEI to HECO include certain costs initially incurred by HECO and billed to HEI?

A. HECO provides HEI with staff support in a number of functional areas. In most cases, the staff support provided by HECO represents services for HEI corporate functions that are commonly required by most businesses, such as payroll, office services (e.g., printing, mailing, record storage) and personnel administration. To the extent that HEI activities benefit all HEI-affiliated companies, it is proper that the cost of staff support for commonly required corporate functions, whether provided by HECO or a non-HEI-affiliated company, be allocated among all HEI subsidiaries, including HECO.

Q. Has the Company provided a detailed list of the services performed by HECO for HEI?

A. Yes. The list is provided in HECO-1109.

Q. On what basis does HECO charge HEI for services rendered?

A. HECO charges HEI on a full-cost basis to the extent practical.

Q. How does HECO bill HEI for services rendered?

A. HECO's billing amounts are directly charged to the extent possible and practical.

However, some amounts are allocated, such as the costs of HECO's pension accounting services.

Q. For test year 2009, what is HECO's estimated billing to HEI for services rendered?

A. HECO's estimated billings to HEI, excluding PIP amounts, total $1,839,000. A breakdown of the total billing amount by HECO organization is shown in HECO-1109.

Q. What portion of HECO's total billings to HEI is charged back to HECO?

A. Of the estimated $1,839,000 in billings from HECO to HEI for 2009, only $46,000 is included in HEI's billing to HECO (see HECO-1107, page 6). The "charge-back" to HECO from HEI is quite conservative. Only a limited amount of HECO billings to HEI is being allocated by HEI to its subsidiaries. In general, only those costs of HECO services that have a direct benefit to HEI subsidiary companies (i.e., services which involve activities that would otherwise have to be performed by the subsidiaries themselves if they were on a "stand alone" basis) are being allocated by HEI. The costs of other types of HECO services, although indirectly benefiting HEI's subsidiary companies, are not being billed by HEI.

Q. How was the test year estimate for HEI charges to HECO determined?

A. The 2009 estimate starts with the 2007 actual charges, and adjusts the amounts based on the 2008 allocation factors and known changes for the 2009 year and escalated for inflation for 2008 and 2009. The actual 2007 amounts were adjusted to exclude costs related to incentive compensation. The specific adjustments made are described in the notes provided on HECO-1107, pages 5.

Q. How does the estimate of HEI charges to HECO in Account No. 921 for the 2009 test year compare to the charges in 2007?

A. The 2009 test year estimate is $447,000 higher than the actual charges in 2007, adjusted for PIP expenses, due to four major items. First, HEI expects increased charges to HECO in 2009 to reflect the full year's effect of the HEI Internal Auditor, who started in July 2007 and who also holds the position of HECO Internal Auditor. In 2009, the HEI Internal Auditor anticipates spending approximately 50% of his time on HECO matters. Second, a new HEI Vice President – General Counsel was hired in August 2007, who is responsible for HEI's continuous compliance with all laws, regulations and administrative orders. He is responsible for working closely with HECO's general counsel to coordinate legal work across HECO and the other HEI subsidiaries. HEI's charges to HECO are expected to be higher as the HEI VP General Counsel estimates spending 25% of his time working on the HECO matters related to 1) corporate governance issues, 2) Securities and Exchange Commission work as it relates to HECO, 3) assisting HECO's legal department and 4) administering the hotline for whistleblower complaints for the Company. Third, HEI charges to HECO for 2009 also reflect a 2.5% adjustment for estimated cost increases. Fourth, HECO's test year estimate is based on the HEI allocation factors for 2008, which are based on recorded 2007 information. HECO's equity percentage as a percentage of total subsidiary equity was higher at the end of December 2007 compared to the end of December 2006. Allocation factors used for 2008 (and the test year 2009) and 2007 are provided as HECO-WP-1107.

<u>922 - Administrative Expenses Transferred</u>

Q. What is the Company's test year 2009 estimate for Account No. 922 - Administrative Expenses Transferred?

A. As shown in HECO-1101, page 2, the test year 2009 estimate for Account No. 922 - Administrative Expenses Transferred is ($3,197,000), after a net adjustment of $290,000. The calculation of the ($3,197,000), including a list of the budget and normalization adjustments, is shown on HECO-1111.

Q. What does the test year 2009 estimate represent?

A. The estimated amount transferred represents that portion of the total costs charged to Account Nos. 920 – A&G Expense - Labor and 921 – A&G Expense – Non Labor that relate to plant construction or services provided by HECO to affiliated companies and outside third parties.

Q. What types of services are billed to affiliated companies and to outside third parties?

A. HECO bills affiliated companies for various services performed, such as those related to executive management, accounting, finance, risk management, benefits administration and communications. HECO bills outside third parties for services such as repairing poles and other Company property damaged by outsiders, and for providing temporary electrical service to contractors and carnival operators.

Q. How does the Company account for Administrative Expenses related to non-capital, non-billable work, i.e., Administrative Expenses in support of O&M expense related work?

A. Under the NARUC USOA, the O&M expense related portion of Administrative Expenses must be classified as A&G expense. As discussed in prior rate cases, including in HECO T-10 in Docket No. 2006-0386 and in HECO T-13 in Docket No. 04-0113, the Company's core business software system called Ellipse (formerly referred to as Mincom Information Management System, or MIMS, which was purchased from Mincom, Inc., an Australian based company) generally applies on-costs to the designated clearing base regardless of the NARUC account number being charged. As a result, Ellipse applies Administrative Expenses on-costs to the various O&M expense accounts (e.g., production, transmission and distribution O&M expense accounts). In order to comply with the NARUC USOA, the Administrative Expenses on-costs (identified by expense element 406) applied by Ellipse to the various O&M expense accounts are "reversed" and added back to Administrative and General expenses.

Q. Does this reversing entry concept/procedure apply to other on-costs besides Administrative Expenses?

A. Yes. The concept/procedure is applied to three other on-costs as follows:

1) The O&M expense related portion of Employee Benefits on-costs (identified by expense element 422) applied to various O&M expense accounts is reversed and added back to Administrative and General Expenses.

2) Under the NARUC USOA, the O&M expense portion of the on-cost for Payroll Taxes (e.g., FICA, FUTA and SUTA)(identified by expense element 423) must be classified as Taxes Other Than Income Taxes. Therefore, the Payroll Taxes on-costs applied by Ellipse to O&M accounts are reversed and added back to Taxes Other Than Income Taxes.

3) The Customer Installations on-cost (identified by expense element 407) should be applied only to capital projects and work billable to other parties. Therefore, Customer Installations on-costs applied by Ellipse to O&M accounts are reversed and added back to the Customer Installations clearing account.

Q. How are the reversed amounts identified in the Company's application?

A. The reversed amounts can generally be identified in the detailed Pillar test year 2009 O&M expense budget reports provided as work papers in this docket, i.e., the HECO-WP-101 series of work papers. On these work papers, the line items labeled "(G/L codes)" include the reversal amounts. With respect to estimated amounts, (i.e., amounts for 2008 and test year 2009) the (G/L codes) amounts will equal the reversed amounts. With respect to recorded amounts, the (G/L codes) amounts will not necessarily equal the reversed amounts since (G/L codes) include other types of accounting entries required to complete the financial closing process.

Q. Please illustrate how the reversed amounts are identified in the HECO-WP-101 series of work papers.

A. For ease of reference, HECO-1110 represents a duplication of pages selected from the HECO-WP-101 series of work papers to illustrate how to identify the reversed amounts. Page 1344 of HECO-WP-101 (I) (HECO-1110, page 1) shows that a total of $9,359, i.e., the Total (G/L codes) amount, was reversed out of Account No. 596 and added back to Administrative and General Expenses and Taxes Other than Income Taxes. The specific amounts that were reversed are also provided on this work paper, i.e., the on-cost amounts for Corporate Administration Expense, Employee Benefits and Payroll Taxes (see expense elements 406, 422 and 423, respectively). The total on-costs for Account No. 596 net to zero, as can be expected as the on-cost amounts initially charged to the account were reversed.

Q. Do the total on-cost amounts always net to zero for each of the accounts?

A. No. While the (G/L codes) amount for test year 2009 will always equal the total on-cost amount reversed for an account, the total on-cost amount for the account will not necessarily net to zero for the following two reasons:

1) Not all of the on-costs applied to an account are subject to being reversed. For example, the on-cost amounts for Energy Delivery are not reversed,

except for a small portion as explained in item 2) below.

2) A portion of some on-cost amounts that are mostly not reversed represents other on-costs that are reversed. For example, a portion of the Energy Delivery on-cost amounts represent Corporate Administration Expense, Employee Benefits and Payroll Taxes on-cost amounts, which are reversed. While such reversed amounts are included in the (G/L codes) amount, the amounts are not specifically identified on the work papers as Corporate Administration Expense, Employee Benefits and Payroll Taxes, but rather, are included as part of the Energy Delivery on-cost amount.

Q. Please illustrate the situation where the total on-costs for an account do not net to zero.

A. Pages 1495 and 1496 of HECO-WP-101 (I) (HECO-1110, pages 2 and 3) show that the net on-cost total for Account No. 9301 is not zero but is $7,175. The (G/L codes) amount of ($7,868) represents the total on-cost amount reversed. The on-cost amounts reversed include a portion (i.e., $1,650) of the Energy Delivery on-cost amount of $8,825 (see expense element 404).

Q. Please summarize your testimony with respect to the "reversal" of certain on-costs and how the reversal relates to "(GL codes)" amounts.

A. The Company's core business software system called Ellipse generally applies on-costs to the designated clearing base regardless of the NARUC account number being charged. However, for Corporate Administration Expenses, Employee Benefits and Payroll Taxes, the NARUC USOA requires that the O&M expense related portion of the on-cost be charged to a particular account or accounts. Therefore, the Ellipse applied on-costs are "reversed" and added back to the NARUC designated account numbers. With respect to the 2008 and 2009 budget expenses, the reversed amounts equal the (GL codes) amounts (e.g., see HECO-WP-101 series of work papers). With respect to recorded year amounts, the (G/L codes) amount will not necessarily equal the reversed amounts, since (G/L codes) include other types of accounting entries required to complete the financial closing process.

Q. How is the estimated Account No. 922 – Administrative Expenses Transferred amount determined?

A. The calculation of the test year 2009 estimate of $3,197,000 is shown on HECO-1111.

Q. How does the test year 2009 estimate for Account No. 922 compare with prior year amounts?

A. As shown in HECO-1102, page 1, the test year 2009 estimate for Account No. 922 of ($3,197,000) compares with prior year amounts as follows:

	($ Thousands)
2003 Recorded	(1,965)
2004 Recorded	(1,833)
2005 Recorded	(1,815)
2006 Recorded	(2,067)
2007 Recorded	(3,045)
2008 Budget	(3,360)
2009 Adj. TY Estimate	(3,197)

Q. What are the more significant factors affecting the amount of Administrative Expenses Transferred from year to year?

A. The year-to-year differences are driven by the individual factors that are used to calculate the transfer amount. The most significant factors are the amount of costs charged to Account Number 921, and the relative proportion of HECO capital and billable work to non-capital and non-billable work. In addition, starting in 2007, the transfer amount reflected a change in the accounting for the Contract Administrators in the Purchasing Division. In 2006, three Contract Administrators, who were previously included in the Power Supply and Construction and Maintenance areas (and whose costs were charged to the Power Supply O&M expense and Construction and Maintenance clearing accounts), were consolidated under the Purchasing Division. Upon consolidation, the Contract Administrators began charging their time to Account 920, similar to the other Purchasing Division employees (Buyers, and Purchasing Administrators), and were included in the labor cost pool to determine the Administrative Expenses to be transferred. Similarly, the non-labor costs for the Contract Administrators were included in Account 921 and included in determining the Administrative Expenses transferred rate.

OUTSIDE SERVICES

Q. What are the accounts and test year amounts for the Outside Services group of accounts?

A. As shown in HECO-1101, page 2, the Outside Services group of accounts, and the associated normalized amounts totaling $2,666,000 for test year 2009 are as follows:

Acct. No.	Description	Test Year 2009 Estimates ($ Thousands)
923010	Outside Services - Legal	$ 131
923020	Outside Services – Other	$2,535

Q. What is the general nature of Outside Services expenses?

A. Outside Services expenses include amounts paid by the Company for the services of attorneys (Account No. 923010 - Outside Services - Legal) and for the services of other outside services such as auditors and consultants (Account No. 923020 - Outside Services - Other). Billings from HEI for services rendered to HECO are included in Account No. 921 – A&G Expenses – Non Labor, and have been discussed earlier in my testimony. Some of the outside services are needed by HECO on an ongoing basis, such as the audit by the Company's independent auditor, KPMG LLP. Other outside services are incurred on an "as needed" basis. For example, the cost of consultants to assist the Company in matters such as fuel oil contract negotiations and salary administration are charged to Outside Services.

923010 - Outside Services - Legal

Q. What is the Company's test year 2009 estimate for Account No. 923010 - Outside Services - Legal?

A. The test year 2009 estimate for Account No. 923010 - Outside Services - Legal is $131,000 as shown in HECO-1101, page 2.

Q. How was the test year amount determined?

A. The test year 2009 estimate was developed as part of the Company’s budgeting process. In general, forecasters most knowledgeable about the requirements for outside legal services estimate these costs and include them in preparing their 2009 O&M expense budget.

Q. How does the test year 2009 amount compare with amounts for previous years?

A. The test year 2009 estimate of $131,000 is $85,000 more than the 2007 recorded amount. Refer to HECO-1102, page 1.

Q. What are the reasons for the increase?

A. The increase is due largely to the following items:

Grievances and arbitration expenses	$60,000
Managing securities	$27,000
Other	($ 2,000)

Q. Please explain the $60,000 increase related to grievances and arbitration expenses.

A. The test year 2009 amount of $75,000 for grievances and arbitration expenses reflects the number of cases pending arbitrations for 2009. Currently there are 18 cases pending arbitration. In 2006, HECO incurred $76,000 for legal fees related to two arbitration hearing cases and seven other grievances in the process of arbitration. The 2007 recorded amount of $15,000 is low because cases pending arbitration did not go forward due to the union contract negotiations.

Q. Please explain the $27,000 increase related to managing securities.

A. The test year 2009 amount for legal services related to managing securities is $31,000, which reflects an increase of $27,000 over 2007 expenses of $4,000. Legal services for the Treasury area are expected to be higher due to increased financing requirements, such that more legal services will be required to review documents. Also, costs incurred each year vary with the number and complexity of issues that arise during the year. For example, increased legal fees are anticipated due to a law enacted by the Hawaii Legislature in 2007 (Act 61), which impacts eligibility requirements for capital projects which could potentially be funded with the proceeds of special purpose revenue bonds in the future.

<u>923020 - Outside Services – Other</u>

Q. What is the Company's test year 2009 estimate for Account No. 923020 - Outside Services - Other?

A. As shown in HECO-1101, page 2, the test year 2009 estimate for Account No.

923020 - Outside Services – Other is $2,535,000.

Q. What is included in the test year estimates for Account No. 923020?

A. Each year, a large portion of the costs included in Account No. 923020 is for KPMG LLP audit fees and cash management related fees such as bank fees, line of credit fees and rating agency fees. The other costs included in this account are generally for consultant fees to various firms. Although the nature of the consulting work varies from year to year, the Company requires a certain overall level of consulting work each year. For the test year, Account No. 923020 includes consulting fees for:

1)	Integrated audit fees to KPMG	$769,000
2)	Cash management and financing related fees	$295,000
3)	Consultants for Ellipse Upgrade implementation	$1,145,000
4)	Consultants for eMESA software implementation	$127,000
3)	Other	$199,000

Q. How does the test year estimate for Account 923020 compare with the actual costs incurred during 2007?

A. The Company's 2009 test year estimate for Account No. 923020 of $2,535,000 is $1,185,000 higher than the actual 2007 expenses. Refer to HECO-1102, page 1.

Q. What are the reasons for the increase?

A. The primary reason for the increase in the outside services is due to the consultant costs for the Ellipse 6 upgrade implementation and the eMESA software implementation. As discussed earlier, the nature of consultant work varies from year to year.

Q. Please describe the Ellipse 6 upgrade implementation consultant costs.

A. As discussed earlier in my testimony, HECO is required to implement periodic software upgrades for its Ellipse system based on the vendor software life cycle. The costs included in Account 923020 relate to the consultants from Mincom that will be needed to implement the software upgrade. The consultants' work will include performing an upgrade planning or scoping study, technical consulting to install and configure the new version of Ellipse, functional consulting on software changes contained within the new version of Ellipse, technical consulting assistance on various data conversions used during testing, software consulting to migrate custom code, software consulting assistance to troubleshoot program problems, mock go-live conversion assistance and go-live assistance.

Q. How was the estimate for the consultant fees determined?

A. Since the Ellipse 6 upgrade scoping study is anticipated to begin in the fourth quarter of 2008, the Mincom consulting estimate was prepared using project timelines for the prior upgrade and UNIX Migration projects as a guideline on where consulting resources would be required. The following major stages of the project will require Mincom consulting:

1) Upgrade scoping study
2) Initial data conversion
3) Initial software installation
4) Ellipse 6 familarization training
5) Mincom Ellipse Reporting training
6) Technical Admin Training
7) First user conversion
8) Test system conversion
9) Mock go-live conversion
10) Go-live conversion

11) Migration of custom code

Q. Please explain the consultant costs related to the eMESA software.

A. As discussed earlier in my testimony, the eMESA software is a 3rd party web based application that extends certain Ellipse functions on a user friendly web interface. Consulting fees will be required for hardware and software sizing specifications, software installation, detailed configuration and setup, software customization, user training, and go-live support.

Q. Since the above costs for the Ellipse 6 upgrade implementation and the eMESA software implementation are specific for the test year, should these expenses be normalized out of the test year for rate making purposes?

A. No. While there are specific costs for the Ellipse 6 upgrade and eMESA software in the 2009 test year, in other years, there are other software implementation related costs that are inevitably required. For example, during 2007, HECO incurred $324,000 for software and consulting costs for the Ellipse UNIX migration project and expect to incur $417,000 in 2008. HECO also expects to spend $53,000 in consulting costs for the Ellipse 6 upgrade in 2008, and expects costs of $379,000 for the project in 2010. Thus, software implementation costs are not exclusive to the 2009 test year and should be included in determining HECO's revenue requirements.

INSURANCE

Q. What are the accounts and test year 2009 amounts for the Insurance group of accounts?

A. As shown in HECO-1101, page 3, the Insurance group of accounts, and the associated test year 2009 amounts totaling $10,254,000, are as follows:

Acct. No.	Description	Test Year 2009 Estimate ($ Thousands)
924	Property Insurance	$3,062
925	Injuries and Damages	$7,192

Q. Why are these accounts grouped together, and what are the differences among the accounts?

A. Incurring these expenses is necessary to prevent or control the financial impact of accidental losses on the Company's performance. Account No. 924, "Property Insurance", includes the cost of insurance for utility property owned by the Company and claims reserves for damage to this property.

Account No. 925, "Injuries & Damages", includes the cost of insurance to protect the utility against injuries to, and damage claims of, employees as well as claims reserves for payments not covered by insurance. Account No. 925 also includes the cost of insurance or claims reserves to protect the Company against injuries to, and damage claims of, members of the general public. Further, Account No. 925 includes the costs incurred for safety and accident prevention programs and activities.

Q. Are the costs for the Insurance group of accounts addressed by another Company witness?

A. Yes. The Company's witness for insurance costs is Mr. Russell Harris (HECO T-11).

EMPLOYEE BENEFITS

Q. What are the accounts and test year 2009 base case amounts for the Employee Benefits group of accounts?

A. As shown in HECO-1101, page 4, the Employee Benefits group of accounts, and the associated test year 2009 normalized amounts totaling $23,407,000, are as follows:

Acct. Nos.	Description	Test Year 2009 Base Case Estimates ($ Thousands)
926000	Employee Pensions and Benefits	$21,197
926010	Employee Benefits – Flex Credits	$11,173
926020	Employee Benefits Transfer	($ 8,963)

Employee benefits expense for the Interim Increase (without CIP1 Generating Unit) is $23,282,000 and employee benefits expense for the CIP1 Generating Unit Full Cost scenario is $23,548,000. As discussed earlier in my testimony, these employee benefits expense numbers are associated with the labor costs for the different scenarios discussed by Mr. Robert Alm in HECO T-1 and Mr. Dan Giovanni in HECO T-7.

Q. What is the general nature of Employee Benefits expense?

A. These expenses represent the amount of employee benefit costs charged to O&M expenses. The amount of employee benefits charged to O&M expenses represents a net amount resulting from (1) the total cost of employee benefits (Account Nos. 926000 and 926010 and the electric discount for retirees) less (2) the amount transferred to plant construction or billed to affiliated companies and outside third parties for services rendered (Account No. 926020).

Q. Are employee benefit expenses addressed in detail by another Company witness?

A. Yes. Ms. Julie Price (HECO T-13) addresses the gross costs of employee benefits expenses (Account Nos. 926000 and 926010 and the electric discount for retirees). The employee benefits transferred amount is addressed later in this testimony.

Q. Do employee benefit expenses include post-employment benefit costs?

A. Yes.

Q. What are post-employment benefits?

A. Post-employment benefits are benefits to former or inactive employees (including beneficiaries and covered dependents) after employment but before retirement. Inactive employees are those who are not currently rendering service to the employer and who have not been terminated. Examples of post-employment benefits include salary continuation, severance benefits, job training, counseling, and the continuation of health care benefits and life insurance coverage.

Q. What are the most significant post-employment benefits costs incurred by HECO?

A. The most significant post-employment benefit costs incurred by the Company are disability and medical coverage payments to employees on long-term disability ("LTD"). The liability for this LTD benefit, as of March 31, 2008, was $411,000.

Q. What does Statement of Financial Accounting Standards ("SFAS") No. 112 - Employers' Accounting for Post-employment Benefits say about accounting for post-employment benefit costs?

A. SFAS No. 112 requires the Company to recognize an expense and a liability (accrual method) for the full amount of post-employment benefits to be paid to qualifying employees <u>if</u>: 1) the liability is attributable to the employees' services already rendered, 2) the employees' rights to those benefits accumulate or vest, 3) payment of the benefits is probable, and 4) the amount of the benefits can be reasonably estimated.

Q. Does the Company's test year 2009 estimate for Employee Benefits Expense include post-employment benefit expenses on an accrual basis?

A. No. Post-employment benefit expenses are included in the Company's test year 2009 estimate based on when the benefits are paid (pay-as-you-go method) versus when the liability for the benefit is incurred. The Commission has approved post-employment benefit expenses based on the pay-as-you-go method of accounting for such benefits in its decision and orders in prior rate cases.

Q. Is the Company requesting that the costs under SFAS No. 112 (accrual method) be included in its test year 2009 Employee Benefits Expense?

A. No. The Company's test year 2009 estimates reflect post-employment benefits costs on a pay-as-you-go basis.

Q. If SFAS No. 112 costs (accrual method) are not included in revenue requirements in this rate case, what will be the impact on the Company's financial statements?

A. The Company's liability for post-employment benefits under SFAS No. 112 is being recorded, even if the costs are not included in the current rate case. The costs to establish the liability are accrued and classified as a regulatory asset until the benefits are paid, after which time the amounts paid are reclassified from regulatory asset to expense.

Q. Has this changed from the 2007 test year rate case?

A. No. The Company has consistently accounted for post-employment benefit costs as described above since the effective date of SFAS No. 112 in 1993.

Q. Is the Company's accounting treatment for post-employment benefits in compliance with accounting principles generally accepted in the United States of America?

A. Yes. The Company's accounting treatment is in accordance with SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, if it is probable that future rates will provide recovery of the liability for post-employment benefits, i.e., if the Commission's decision and order in this case affirms the continued use of the pay-as-you-go method of accounting for post-employment benefit costs.

Account No. 926020 – Employee Benefits Transferred

Q. What is the Company's test year 2009 estimate for Account Number 926020 – Employee Benefits Transferred?

A. As shown on HECO-1101, page 4, the test year 2009 estimate for Account 926020 – Employee Benefits Transferred is ($8,963,000).

Q. What does the transfer amount represent?

A. The transfer amount represents the portion of total employee benefits expenses, most of which are initially recorded in Accounts 926000 and 926010, which is transferred as an on-cost to the costs of plant construction or billed as an on-cost to affiliated companies and outside third parties for services rendered.

Q. How does the Company account for Employee Benefits Costs related to non-capital, non-billable work, i.e., Employee Benefits Costs with respect to O&M expense related work?

A. Similar to Account No. 922-Administrative Expenses Transferred, under the NARUC USOA, the O&M expense related portion of Employee Benefits Costs must be classified as A&G expense. As a result, the O&M expense related portion of Employee Benefits on-costs applied to various O&M expense accounts by Ellipse (the Company's core business software system) is "reversed" and added back to Administrative and General Expenses.

Q. How was the test year 2009 transfer estimate determined?

A. The calculation of the test year 2009 estimate of ($8,963,000) is shown in HECO-

1112.

Q. How does the test year 2009 transfer estimate compare with previous year amounts?

A. The test year 2009 transfer estimate is ($8,963,000) and the recorded 2007 was ($9,893,000), resulting in a difference of $930,000. Refer to HECO-1102, page 1. As a percentage of the employee benefits charged to Account 926, the test year 2009 transfer estimate is 27.7% of the total charges, compared to 27.5% of the charges for the actual 2007.

Q. What are the more significant factors affecting the amount of Employee Benefits Transferred from year to year?

A. The year-to-year differences are driven by the individual factors used to calculate the transfer amount. The most significant factors are the amount of costs charged to Account Number 926, and the relative proportion of HECO capital and billable work to non-capital and non-billable work. In addition, there have been large swings in recorded benefit costs (primarily pension and postretirement benefit other than pensions) over the past several years due to significant volatility in the stock market, which impacts the trust fund's return on assets.

MISCELLANEOUS

Q. What are the accounts and test year 2009 estimates for the Miscellaneous group of accounts?

A. As shown in HECO-1101, page 5, the Miscellaneous group of accounts, and the associated amounts totaling $8,960,000 for test year 2009, are as follows:

Acct. No.	Description	Test Year 2009 Estimates ($ Thousands)
928	Regulatory Commission Expense	$ 440
9301	Inst or Goodwill Adv Expense	$ 36
9302	Misc General Expenses	$3,857
93100	Rents Expense	$3,062
93200	A&G Maintenance	$1,565

Q. What is the nature of the costs charged to the miscellaneous group of accounts?

A. The miscellaneous group of accounts includes a variety of unrelated costs which are necessary for Company operations, but which are not provided for in other functional accounts.

Q. Are Miscellaneous A&G Expenses addressed in detail by another Company witness?

A. Yes. Miscellaneous A&G Expenses are addressed in detail by Mr. Bruce Tamashiro in HECO T-13.

STANDARD LABOR RATES

Q. What is the general concept behind standard labor rates?

A. The general concept is to distribute labor costs (amounts paid to employees) using the same rate per hour regardless of the type of “pay” hour involved (e.g., straight time, time and one-half, or double time pay).

Q. Why is HECO using standard labor rates?

A. One key reason is that the Company’s core business software system called Ellipse (formerly referred to as the Mincom Information Management System, or MIMS, which was purchased from Mincom, Inc., an Australian based company) requires the use of standard labor rates in distributing labor costs.

Q. How are the Companies accounting for the difference between the amounts paid employees for hours worked and the amount of labor costs distributed using standard labor rates?

A. The difference between labor amounts paid and the amounts distributed is "trued up" in that the difference is used to adjust the amounts distributed so that, in total, the amounts distributed equal the amounts paid for each employee.

Q. How were the Standard Labor Rates calculated?

A. The basic calculation is to divide actual amounts paid by total labor hours, e.g., straight time, time and one-half and double time hours. Separate standard labor rates are calculated based on employees grouped with similar roles or positions. These employee groupings are called labor classes. The calculated hourly rate is then adjusted to reflect any general pay increases expected during the year in which the Standard Labor Rates will be in effect. The Standard Labor Rates are re-evaluated at least once a year, and adjusted as appropriate.

Q. What is the basis for the standard labor rates used for the test year?

A. Recorded 2007 labor information was used to develop the standard labor rates for the 2009 test year labor estimates. The 2007 labor hours information was then adjusted for the merit overtime hours that were not compensated to determine the base standard labor rate for 2009. For the bargaining unit labor classes, 2007 hours were adjusted to reflect the overtime levels anticipated in 2009.

Q. Is this consistent with what was done for the 2007 test year standard labor rate calculation?

A. Yes. The process to adjust the base information (2007 actual labor hours for the overtime levels anticipated in the test year) to determine the standard labor rates is consistent with the method used in the 2007 test year rate case (Docket No. 2006-0386). In the direct testimony filing in the 2005 test year rate case (Docket No. 04-0113), HECO did not adjust the base information for the bargaining unit labor classes to reflect the overtime levels anticipated in the test year. In the discovery process, HECO proposed an adjustment to reflect the overtime levels for the bargaining unit labor classes. The adjustment was accepted by the Consumer Advocate and Department of Defense in that proceeding.

Q. How is the true-up calculated?

A. The true-up is based on the proportionate share of labor dollars charged to each activity, work order, etc. to the total amount of labor dollars charged during the applicable period. For each employee, the true-up is calculated and applied at the time of each paycheck run and the processing of each month-end payroll accrual. The payroll accrual records labor costs from the end of the last pay-period in the month to the end of the month.

Q. Can you illustrate the “true-up” process?

A. Yes. The “true-up” process is illustrated in HECO-1113. The left side of the exhibit illustrates how an employee’s pay is calculated, and how the pay would be distributed if the employee’s actual pay rate was used. The right side of the exhibit illustrates how the standard labor rate is calculated and how the employee's labor costs are initially distributed and then trued-up to the employee’s total actual pay. For simplicity, the illustration is based on an assumed actual straight time pay rate of $10.00 per hour, and an assumed equivalent calculated standard labor rate of $10.00 per hour.

Q. Were the details of standard labor rates and the true-up process discussed in a prior rate case?

A. Yes. The details of standard labor rates and the true-up process were discussed in HECO T-13 in Docket No. 04-0113 and in HELCO T-10 in Docket No. 99-0207, HELCO's 2000 Test-Year Rate Case.

Q. What is the impact of using standard labor rates instead of actual employee pay rates in calculating the test year 2009 labor estimates?

A. The impact has not been quantified, and the calculation would be very difficult to perform. However, a sense of the possible difference can be obtained from reviewing the size of the net true-up adjustment in prior years. The annual net true-up adjustments for 2003 through 2007, by block of NARUC account numbers, are provided in HECO-1114.

INFORMATION TECHNOLOGY SERVICES ("ITS") COSTS

Q. Please describe ITS costs?

A. ITS costs are those costs incurred by the Information Technology & Services department. This department operates and maintains the Information Technology ("IT") systems used at HECO. The department consists of four divisions: IT Infrastructure and Operations, Development Services, IT Customer Care, and Information Assurance. The IT Customer Care division also has a section called Office Services that handles the Mailing Services, Records Management, and Printing Services functions for the Company. The major department costs include labor, outside services expenses, IT consulting, materials and other (primarily software costs and equipment rentals).

Q. Where are ITS costs reflected in this filing and how are they developed?

A. ITS costs are reflected in each NARUC expense area, based on the functions benefiting from the ITS services. These costs are either directly charged or "costed" (allocated) via the ITS costing process. See HECO-WP-1115, pages 1 through 5 for the distribution of "costed" ITS expenses to the various NARUC accounts.

Q. Please describe the ITS costing process.

A. As mentioned, a portion of the ITS department costs are directly charged to functional areas. Direct charged costs primarily relate to the IT Customer Care division's Office Services section (Mailing Services, Records Management and Printing Services). All ITS department operating costs, other than direct charges, are charged to the ITS Clearing Account and subsequently "costed" to the functional areas of the Company, and reflected as costs under the responsibility area ("RA") code PEZ and expense element 451. The ITS costing process for 2009 test year expenses is documented in detail in workpapers provided as HECO-WP-1115, pages 6 through 185a. The process is summarized in a narrative provided in pages marked "A" (pages 6 through 9) with additional details reflected in the other workpapers (pages 10 through 185a of HECO-WP-1115 marked as A-1 through M-3).

Q. How much of the ITS costs are estimated to be either directly charged or cleared through the Clearing Account in test year 2009?

A. Direct charges for ITS Department's Office Services area for 2009 are estimated at $891,549 and budgeted directly to the functional areas. These costs are shown on HECO-WP-1115, page 155 (workpaper K). The ITS department also maintains HECO's Facilities Attachment Program to manage requests by wireline and wireless telecommunication carriers to utilize poles, ducts and other utility owned property for the attachment of telecom cables, fiber and wireless antennas. The estimated cost to manage the program is $201,100, which is offset by

Facilities Attachment Program revenues of $209,000 included in Other Operating Revenues (which is addressed by Mr. Peter Young in HECO T-3) for a net program benefit before taxes of $7,877, as shown on HECO-WP-1115, page 163 (workpaper M-1). These charges are budgeted directly to the functional areas. For 2009, HECO projects $17,366,000 to be charged to the ITS clearing account and "costed "via the ITS costing process. These costs are shown on HECO-WP-1115, page 10 (workpaper A-1).

Q. When did the Company start using the ITS clearing account and costing process?

A. The current ITS costing system has been used by the Company since 2001, the year the ITS department was reorganized into its current structure.

Q. Have there been any changes made to the 2009 Costing process since 2001?

A. Yes. In 2006, ITS implemented a new procedure for costing software maintenance and license costs. A new allocation was established to ensure that all software maintenance and license costs are charged to expense, per American Institute of Certified Public Accountants' ("AICPA") Statement of Position 98-1 – Accounting for the Costs of Computer Software Developed or Obtained for Internal Use. Prior years' allocations included charges to clearing accounts (i.e. Energy Delivery clearing, Power Supply clearing, Customer Installations clearing), which did not result in the full allocation of these costs to expense.

Q. How was the costing process modified to ensure that all ITS costs are charged to expense?

A. The Company established a new allocation by using one predominant expense code for each NARUC expense category benefiting from the software costs.

Q. Did the Company use this new allocation in preparing the budget used for the test year?

A. Yes, it did.

Q. Is the clearing account process for the 2009 test year similar to the process described in the prior HECO general rate case Docket No. 2006-0386?

A. Yes, the clearing account process used in Docket No. 2006-0386 remains the same and HECO-WP-1115 documenting this process is very similar to HECO-WP-1051, submitted in Docket No. 2006-0386. For 2009, additional documentation of non-labor charges into the ITS clearing account is included as HECO-WP-1115, pages 41-154 (workpaper J – J111).

Q. What types of costs are included in the ITS Charges to Clearing?

A. HECO-1115, pages 1-2, provide a summary of the costs that budgeted to the clearing account for the 2009 test year.

Q. Of the charges to the clearing account, how much of the costs are "costed" to O&M expenses in 2009?

A. Approximately 71.4% of the costs are "costed" to O&M expenses.

Q. How do the budgeted charges to ITS clearing in 2009 compare to the charges to the clearing account in 2007?

A. Labor and non-labor charges to the clearing account have increased compared to 2007. Three additional ITS positions have been added to the clearing account primarily for Development Services support of new enterprise systems' software applications [Outage Management System ("OMS"), and Mobile Workforce Management ("MWM") System] and third party software products for new enterprise UNIX/Oracle platforms. In addition, non-labor charges into the clearing account have also increased primarily for Development Services support of new enterprise systems' software applications (CIS/HR Suite) and maintenance charges for various UNIX platform hardware and software added in 2009. The increases for the labor and non-labor charges to the ITS Clearing account are shown in HECO-1115, page 3.

Q. Please describe the need for additional Development Services labor.

A. The cost of three additional employees is estimated at approximately $330,000, for direct labor charges of $198,000 plus labor on-costs. These positions are required to support new enterprise systems' software applications and to support third party software products for new enterprise UNIX/Oracle platforms, including configuration/change management, reporting and interface systems. Specifically, these positions will support the OMS, Mobile Workforce Management MWM system, Field Laptops' software, Mobius (IDARS) archive/reporting software, CA Harvest software (change control for OMS, CIS, Ellipse, etc.), Apache and Tomcat Servers, WebLogic Applications Server, Business Objects software, and IBM Websphere software. Exhibit HECO-1115, pages 4 through 6, provide the descriptions, installation dates, and support requirements for these applications and third party software products. Most of these systems have been installed over the past 2 years and must be fully supported after the Enterprise projects on the UNIX platform (OMS, CIS, HR Suite, and Ellipse) are all operational. While OMS has been in service since 2007, ITS currently does not have proper staffing to support the application. There was no addition to the Development Services staff after implementation of the OMS and existing staff has temporarily absorbed the additional support requirements on an interim basis. The current addition for OMS is also required to provide back up support capabilities. In addition to the OMS, the CIS and HR Suite will also reside on the UNIX/Oracle platform. As discussed by Mr. Darren Yamamoto in HECO T-9, and Ms. Julie Price in HECO T-13, both the CIS and HR Suite are expected to be in service in 2009. The

Ellipse migration to UNIX is expected to be completed in August 2008. Each of these IT enterprise projects will benefit from the new enterprise systems' software applications and third party software products for new enterprise UNIX/Oracle platforms described above.

Q. Please describe the primary components of the increase in non-labor charges to the clearing account charge?

A. As shown in HECO-1115, page 3, the increase is attributable to outsourced Development Services support for the CIS and HR Suite systems after implementation in 2009 and the maintenance expenses for the UNIX platform hardware and software. The UNIX platform is the computer network consisting of hardware, operating system/third party software to run the CIS, HR Suite, Ellipse and OMS applications. This is analogous to a Dell PC/Vista operating system, which is the platform to run EXCEL, Word, and other PC applications. The significant items contributing to the increase include: $728,000 for outsourced Development Services support of the CIS, $202,000 for outsourced Development Services support of the HR Suite, and $310,000 for maintenance charges for various hardware and software to support the UNIX platform. A list of the changes in the non-labor charges to the Clearing Account is provided as HECO-WP-1115, pages 157-161 (workpaper L – L4).

Q. Please describe the $728,000 for outsourced Development Services support of the CIS.

A. The $728,000 for outsourced development services to support the CIS represents the costs of 5 full time developers for the post go-live period of June through December. The new CIS is a much more sophisticated computer system than the current legacy ACCESS system and will require additional support from external service providers with the required competencies. HECO ITS has initially elected to use an outsourced development services staff augmentation approach for the new CIS in lieu of adding internal labor positions for the anticipated full post go-live support requirement. Sometime in 2009, ITS will revisit the longer-term decision on whether to use outsourced staff augmentation vs. additional internal staff support positions. The 5 additional outsourced FTEs are based on external consultant, Bruce Goldblatt, recommendations and the experience of another mainland utility, Direct Energy, utilizing the same CIS.

Q. Please describe the $202,400 for outsourced Development Services support of the HR Suite.

A. The $202,400 represents the costs of one developer and application Data Base Analyst services for the post go-live period of May through December for the HR Suite system. Similar to the situation with the new CIS, the HR Suite is a much more sophisticated computer system than the current HR application and will require the additional support from external outside service providers with the required competencies. HECO ITS has elected to initially use an outsourced HR Suite Development Services staff augmentation approach in lieu of adding internal labor positions for this new requirement. Sometime in 2009, ITS will revisit the longer-term decision on whether to use outsourced support vs. internal staff support. This level of outsourced support is based on the recommendation of the HR Suite system integrator, Solbourne.

Q. Please describe the $310,000 increase in hardware and software maintenance charges for the UNIX platform.

A. The CIS, HR Suite, Ellipse, and OMS will run on a UNIX computer network platform. After the implementation of these systems, hardware and software maintenance will be required to support this platform on a recurring basis. Some of these maintenance expenses have been incurred as implementation costs with the initial purchase of the hardware/software. Included in the estimated 2009 charges to the ITS clearing account are additional annual charges for maintenance which will be payable in 2009. Specifically, this increased maintenance includes the following items: $85,000 – UNIX Utility, $90,000 – CA Fees, $80,000 – SAN Equipment Maintenance, and $55,000 – UNIX Hardware/OS support.

COMPUTER SOFTWARE DEVELOPMENT COSTS

Q. What directive has the Commission issued regarding the ratemaking treatment for computer software development costs?

A. In Decision and Order No. 18365 in Docket No. 99-0207 (Hawaii Electric Light Co., Inc.'s test year 2000 rate case), the Commission ruled that its pre-approval is required before any computer software development project costs can be deferred and amortized for ratemaking purposes.

Q. How is the Company currently recording the costs of computer software development projects?

A. In accordance with the Commission's ruling in Docket No. 99-0207, the Company is expensing as incurred, for ratemaking purposes, all computer software development project costs, unless prior Commission approval is obtained to defer and amortize certain project costs.

Q. If Commission approval is obtained to defer and amortize certain project costs, how is the Company currently recording computer software development costs?

A. The Company's current accounting policy on computer software development costs is provided in HECO-1116. The Company's policy, updated as of April 1, 2006, is consistent with the accounting treatment specified in the stipulated agreements approved by the Commission in the OMS, CIS, and HR Suite proceedings. As a result of those dockets, the previous policy was updated to incorporate more of the details of implementing the policy.

The Company's policy is also consistent with the AICPA's Statement of Position 98-1 (SOP 98-1) – Accounting for the Costs of Computer Software Developed or Obtained for Internal Use, issued in March 1998, and Emerging Issues Task Force ("EITF") Issue 97-13 – Accounting for Costs Incurred in Connection with a Consulting Contract or an Internal Project that Combines Business Process Reengineering and Information Technology Transformation, discussed by the EITF on November 20, 1997.

Q. What specific details were incorporated into the policy as a result of the stipulated agreements?

A. In the stipulated agreements, HECO agreed to work with the Consumer Advocate to identify costs related to process reengineering, and agreed that such costs would be expensed as incurred. In addition, HECO and the Consumer Advocate agreed that certain overhead costs related to energy delivery, customer installations and corporate administration, which would be included in the deferred costs as the current Ellipse system includes such costs as part of the normal overhead calculation process, should be expensed in accordance with SOP 98-1.

Q. Please summarize how the costs are treated under the policy.

A. In summary, software development projects can be segregated into three stages as follows:

1. Preliminary Project Stage (Stage I) - includes conceptual formulation of software alternatives, evaluation of the alternatives, determination of the existence of needed technology, and final selection of alternatives, and if necessary, selection of a consultant to assist in the

> development/installation. These costs are expensed as incurred.
>
> 2. Application Development Stage (Stage II) - includes the design of a chosen path, including software configuration and software interface, coding, software installation, and testing of the software and parallel processing. Certain internal and external costs incurred during this stage should be capitalized (i.e., charged to a deferred account.) However, external and internal training costs, as well as certain conversion costs, are charged to expense.
>
> 3. Post-Implementation/Operation Stage (Stage III) - includes training and application maintenance. Internal and external costs incurred during this stage should be charged to expense as incurred.
>
> 4. Allowance for funds used during construction ("AFUDC") would be applied to the deferred project costs during Stage II. The deferred costs would be amortized over a straight-line basis over the useful life of the software (or such other amortization period as the Commission determines to be reasonable) beginning the month following when the software is ready for intended use. Generally, the software is ready for intended use after substantial testing is completed.
>
> 5. Similar to the un-depreciated costs of capitalized plant and equipment, the unamortized costs of computer software development projects should be included in the calculation of rate base. Rate base treatment is appropriate because investors have provided the funds up front to develop the computer software system and should be allowed to earn a fair return on their unamortized investments.
>
> 6. Under the current Company policy, the costs of projects estimated at less than $500,000 are expensed as incurred based on immateriality, even though some of the costs could theoretically be capitalized. For purposes of HECO's Test Year 2009 estimates, the costs of projects estimated at less than $500,000 were assumed to be expensed. This is consistent with the treatment for costs in Docket No. 04-0113, HECO's pending rate case. The parties in the proceeding did not object to such treatment for software development costs below $500,000.

Q. Has the Commission approved the deferral and amortization of computer software development costs for certain projects?

A. Yes. The Commission has approved in Decision and Order No. 21899 in Docket No. 04-0131, issued June 30, 2005, the Company's request (as modified by the stipulation with the Consumer Advocate) to defer certain software development costs for the OMS project, accumulate AFUDC on the deferred costs during the deferral period, amortize the deferred costs over a twelve year period, and include the unamortized deferred costs in rate base. In addition, the Commission has approved in Decision and Order No. 21798 in Docket No. 04-0268, issued May 3, 2005, the request of HECO, HELCO and MECO (as modified by the stipulation with the Consumer Advocate) to defer certain computer software development costs for the CIS project, accumulate AFUDC on the deferred costs during the deferral period, amortize the deferred costs over a twelve year period, and include the unamortized deferred costs in rate base. Further, the Commission has also approved in Decision and Order No. 23413 in Docket No. 2006-0003 issued May 3, 2007, HECO, HELCO and MECO's request to defer certain software development costs for the HR Suite project, accumulate AFUDC on the deferred costs during the deferral period, amortize the deferred costs over a twelve year period, and include the unamortized deferred costs in rate base.

Q. How are the costs related to the OMS project reflected in the test year estimates?

A. As described by Mr. Robert Young in HECO T-8, the project was completed in July 2007, and portions completed in 2008. Costs incurred during the development stage of the project were charged to a deferred account, and such costs accrued AFUDC until the project was ready for use. HECO began amortization of the deferred costs in August 2007, and amortization will continue for twelve years through 2019. Additional development costs incurred for the remaining portions of the project and for delayed payments for development services incurred prior to the in service date were added to the deferred costs during 2008 (however, no AFUDC was accrued on such amounts.) The additional deferred costs are amortized over the remaining twelve-year period, starting the month after the costs are incurred. The unamortized deferred cost for the OMS project at the end of 2008 is estimated at $4,568,000. The amortization expense for the 2009 is estimated at $432,000, and included in Distribution Operation expense as discussed by Mr. Robert Young in HECO T-8. The unamortized deferred cost for the OMS project at the end of the 2009 test year is estimated at $4,137,000, as shown on HECO-1117. The beginning of the year and end of the year unamortized deferred costs are included in rate base as discussed by Mr. Darren Doi in HECO T-18.

Q. How are the costs related to the CIS project reflected in the test year estimates?

A. As described by Mr. Darren Yamamoto in HECO T-9, the 2009 test year estimates were developed under the assumptions that (1) the software would be ready for use in May 2009, (2) HECO's portion of the deferred CIS project costs (including AFUDC) would amount to $23,760,000, and (3) amortization of the deferred costs over a twelve year period would begin in June 2009. The amortization expense from June through December 2009 was estimated to be $977,000, and included as a Customer Accounts expense for the test year, as discussed by Mr. Darren Yamamoto in HECO T-9. The unamortized cost as of the end of the test year was estimated at $22,783,000, as shown on HECO-1117, and included in the year end rate base, as discussed by Ms. Darren Doi in HECO T-18.

Q. How are the costs related to the HR Suite project reflected in the test year estimates?

A. As described by Ms. Price in HECO T-13, the HR Suite project is expected to be completed in April 2009. HECO's portion of the deferred HR Suite project costs (including AFUDC) are estimated at $3,618,000, which will be amortized over a twelve year period beginning May 2009. Amortization expense for 2009 amounts to $201,000, and included in the test year Administrative and General expense as discussed earlier in my testimony. The estimated unamortized balance at December 31, 2009 for the HR Suite project amounts to $3,417,000, as shown on HECO-1117 and is included in the year-end rate base as discussed by Mr. Darren Doi in HECO T-18.

ABANDONED CAPITAL PROJECT COSTS

Q. What is an abandoned capital project?

A. An abandoned capital project is one in which a “no go” decision is made during the time the project costs are classified as Construction Work in Progress, i.e., a “no go” decision is made sometime during the detailed engineering through construction completion stages of the project’s life cycle. A project is also considered to be abandoned if the project is significantly delayed at management’s discretion, i.e., delayed generally for more than two years.

Q. How are abandoned project costs treated?

A. Under normal circumstances, the costs of abandoned capital projects are charged to appropriate operation and maintenance expense account(s), unless the costs result in items that have future value. If any of the costs represent items that have future value, e.g., assets that are usable on another capital project, the related costs are transferred to the other project or to other accounts (e.g., inventory in the case of stock material) as appropriate. If a capital project is abandoned and unusual circumstances exist, e.g., the accumulated costs are significant, the Company may seek Commission approval for special accounting and ratemaking treatment as appropriate under the circumstances.

Q. Is there a more detailed description of how the Company accounts for capital project costs?

A. Yes. The Company's policy is provided at HECO-1118.

Q. Why is an adjustment for abandoned project costs necessary?

A. The Company expects that projects will be abandoned from time to time, and that the related costs incurred will be written off to expense. However, the Company's 2009 O&M expense budget does not include estimates for specific abandoned project costs since forecasters do not generally contemplate that projects will be abandoned. Therefore, an adjustment to the Company's 2009 O&M expense budget is necessary to include in revenue requirements a reasonable amount for abandoned project costs since such costs are expected to be incurred.

Q. How were the adjustment amounts for abandoned project costs determined?

A. The adjustment amounts represent the five-year average of actual abandoned project cost write-offs from 2003 through 2007. As shown on HECO-1119, the test year estimate for abandoned project costs is $172,000.

Q. How are the adjustment amounts presented in the Company's test year 2009 estimates?

A. The adjustment amounts were provided to the respective witnesses (Mr. Dan Giovanni, HECO T-7 for Production O&M expenses; Mr. Robert Young, HECO T-8 for Transmission and Distribution O&M expenses; myself for A&G expenses) for inclusion in their test year estimates, based on the historical account numbers that were charged with the write-offs. In other words, the Company assumed that future abandoned project costs would be written off to the various NARUC expense accounts in the same proportions that were recorded from 2003 to 2007.

Q. Has abandoned capital project costs been included in revenue requirements in the past proceedings?

A. Yes. In HECO's test year 2005 rate case, Docket No. 04-0113, HECO proposed to include $294,000 in its test year estimates for abandoned projects, based on an average historical level of abandoned project write-offs. In Decision and Order No. 24171 issued May 1, 2008 in Docket No. 04-0113, the Commission included HECO's estimate for abandoned projects in determining HECO's revenue requirements. Similarly, in HECO's test year 2007 rate case, Docket No. 2006-0386, based on a stipulation among the parties in the proceeding, an estimate of $130,000 for abandoned projects was included in determining HECO's revenue requirements in Interim Decision and Order No. 23749 issued October 22, 2007.

Q. Please describe the accounting for preliminary engineering costs related to capital projects?

A. As described in the Accounting for Capital Project Costs included as HECO-1118, preliminary engineering costs are charges for work associated with potential projects prior to formal approval by management. Some of the potential projects are eventually constructed, while others do not materialize. Preliminary engineering costs (costs incurred under step 2 of the process described in HECO-1118) are identified with the related potential project, and are temporarily held in a clearing account. If the project is approved for construction, the preliminary engineering costs are transferred to construction work in progress. However, if the related potential project does not materialize, the costs are allocated as an on-cost (either a power supply on-cost or energy delivery on-cost, depending on the nature of the project).

Q. Do the test year on-cost rates include costs for preliminary engineering for potential projects that will not materialize?

A. In the Company's budgeting process, it does not include estimates for preliminary engineering that it expects will not materialize in its on-cost rates, since forecasters do not generally contemplate that projects will not materialize.

UNAMORTIZED GAIN ON THE SALE OF LAND AND IOLANI COURT PLAZA LEASE PREMIUM

Q. What is the test year 2009 amount for gains on the sale of land and the Iolani Court Plaza lease premium?

A. As discussed by Mr. Peter Young in HECO T-2, included in test year 2009 Other Operating Revenue is $615,000 for the amortization of gains on the sale of land and $3,000 for the amortization of the Iolani Court Plaza lease premium, for a total of $618,000. In addition, as discussed by Mr. Darren Doi in HECO T-18, subtractions in the calculation of rate base include the unamortized gains on the sale at the beginning of the test year of $1,364,000 ($1,359,000 for unamortized utility gain on sale and $5,000 for the unamortized Iolani Court Plaza lease premium) and $746,000 at the end of the year ($744,000 for unamortized utility gain on sale and $2,000 for the unamortized Iolani Court Plaza lease premium).

Q. What is the support for the test year amounts?

A. The support is provided on HECO-1120, which shows information by the individual property sold, and the docket number and decision and order number approving the sale and accounting and ratemaking treatment for the sale. For one property, the Haiku Corridor Site, the sale is pending approval from the Commission in Docket No. 2007-0424.

Q. What is the Commission approved accounting and ratemaking treatment for the gains on sale of land?

A. The accounting and ratemaking treatment approved by the Commission is generally as follows:

1) The net gain is prorated between utility and non-utility based on the period during which the property was classified as utility property and the period during which the property was classified as non-utility property.

2) With respect to the utility portion of the net gain, the gain is amortized to income over a five-year period beginning with the month following the sale.

3) The amount of unamortized gain is deducted in the calculation of rate base.

Q. How were the test year estimates for the Haiku Corridor Site determined?

A. To determine the test year estimates, HECO followed the revised accounting treatment proposed in Docket No. 2007-0424. HECO assumed the entire net gain from the sale of the Haiku Corridor Site would be apportioned to utility gain on sales. HECO also assumed the sale would occur in December 2008, the amortization of the gain apportioned to the utility property would begin in January 2009, and the unamortized balance at the beginning of the test year and end of the year would be reflected as a reduction in rate base.

Q. What is the status of Docket No. 2007-0424?

A. HECO filed its application for commission approval of the sale of the Haiku Corridor Site on December 27, 2007, and in a January 29, 2008 letter filed in the proceeding, indicated its modification to its proposed accounting treatment to record the entire net gain on sale of the property to utility income. On February 22, 2008, the Consumer Advocate issued its Statement of Position indicating it did not object to the approval of the Company's request to sell the property and to the Company's revised proposed accounting treatment.

Q. What is the Commission approved accounting and ratemaking treatment for the Iolani Court Plaza lease premium?

A. The unamortized lease premium attributable to the leased fee interests that are sold are amortized to income over the same five year period as is the related net gain. The unamortized lease premium attributable to the leased fee interests that are not sold and thus retained continue to be amortized over the original thirty year period (1980 through 2010) until such time as the units are sold. The unamortized lease premium amount is subtracted in the calculation of rate base.

ACCOUNTING FOR REVERSE OSMOSIS WATER PIPEPLINE COSTS

Q. What is the reverse osmosis water pipeline project?

A. The reverse osmosis ("RO") water pipeline project is a new water pipeline being constructed to allow HECO to use reclaimed water from the Honouliuli Water Recycling facility at the Kahe power plant. Using reclaimed waters will reduce HECO's potable water usage at the Kahe power plant. This is a project that is part of a community benefits package relating to HECO's Campbell Industrial Park ("CIP") generation station project approved by the Commission in Decision and Order No. 23514 ("D&O 23514") issued June 27, 2007 in Docket No. 05-0146. Under this project, HECO will design and construct the RO water pipeline project. Upon completion, HECO plans to dedicate the RO water pipeline to the Board of Water Supply ("BWS") from the connection at the west end of Roosevelt Avenue in Kapolei up to the BWS meter located within the Kahe power plant.

Q. How is HECO accounting for the cost of the RO water pipeline project?

A. HECO is accounting for the cost of the RO water pipeline project as approved by the Commission in D&O 23514. HECO will accumulate the costs related to design and construction of the project in Construction Work in Progress ("CWIP"). During the time project related costs are classified as CWIP, an allowance for funds used during construction ("AFUDC") will be applied on the project costs. At the time the RO water pipeline is declared used or useful, the costs would be transferred to Plant in Service, similar to other capital expenditure projects.

Upon completion of the RO pipeline project, which is expected to be in August 2009, HECO will include the costs in Plant in Service. Upon dedication of the portion of the RO water pipeline up to the water meter to BWS, which is expected to be in September 2009, HECO will reduce the plant in service balance for that portion of the RO pipeline and reflect a corresponding amount in a deferred debit account (a regulatory asset). HECO will begin amortizing the regulatory asset over fifty years, beginning in October 2009, the month following the dedication of that portion of the pipeline. HECO will begin depreciating the portion of the RO pipeline retained by HECO starting in 2010. As approved in D&O 23514, the unamortized RO pipeline regulatory asset would be included in rate base in determining HECO's revenue requirements. The unamortized RO pipeline regulatory asset, represents the portion of the pipeline not owned by HECO, but continues to benefit ratepayers, and the cost should be recovered from ratepayers.

Q. How are the costs for the RO pipeline project reflected in the rate case?

A. The estimated cost of $1,173,000 for the portion of the RO pipeline project that will continue to be owned by HECO is included in plant additions as shown by Ms. Lorie Nagata in HECO T-17, and included in the plant in service balance as of the end of the test year. The cost for the portion of the pipeline expected to be dedicated to the BWS is $6,398,000, and included in RO regulatory asset as shown in HECO-1121. The amortization expense of $32,000 (= $6,398,000 / 50 years * 3/12) for the test year is included in Production Operations expense as discussed by Mr. Dan Giovanni in HECO T-7. The unamortized balance is included in rate base as discussed by Mr. Darren Doi in HECO T-18.

ACCOUNTING FOR PENSION AND OPEB PLANS

Pension and OPEB Background

Q. Please briefly explain the Company's qualified pension and postretirement benefit plans.

A. As described by Ms. Julie Price in HECO T-13, the Company provides pension benefits to its employees by participating in the Retirement Plan for Employees of Hawaiian Electric Industries, Inc. and Participating Subsidiaries, a qualified defined benefit pension plan. HECO provides postretirement benefits other than pensions through participation in the Postretirement Welfare Benefits Plan for Employees of Hawaiian Electric Company, Inc. and Participating Employers.

Q. Please briefly describe the accounting and reporting requirements for pensions and postretirement benefits other than pensions ("OPEB").

A. The Companies' accounting and reporting requirements with respect to its pension and OPEB plans are recorded in accordance with generally accepted accounting principles ("GAAP"), specifically under Statement of Financial Accounting Standards ("SFAS") No. 87, "Employers' Accounting for Pensions", SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions", and under SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132 (R)". Later in my testimony, I discuss the pension and OPEB tracking mechanisms. The tracking mechanism impact the pension and OPEB financial statement reporting, however the discussion in this section explains the accounting treatment prior to adoption of the tracking mechanisms.

Pension

Q. Under the guidance provided by SFAS No. 87 and SFAS No. 158, how are pensions reflected on the Company's financial statements?

A. Pensions are reflected on the financial statements as follows:

- Income Statement

  The costs of the benefits provided by the Company's pension plan are recognized as net periodic pension costs ("NPPC") over the period the benefits are earned (i.e., as employees provide the related employment services). The NPPC is the annual amount that the Company must recognize on its financial statement as the cost of providing pension benefits to its employees for the year, and includes amounts ultimately charged primarily to both expense and to capital. In addition, a portion of the NPPC is charged to outside third parties for services rendered, i.e., to billable work. As explained by Ms. Julie Price in HECO T-13, the five major components of the NPPC are: service cost, interest cost, actual return on plan assets, amortization of prior service cost, and amortization of gains and losses. There are a number of factors that affect the NPPC, such as the provisions of the plan, the demographic characteristics of the employees, the performance of the pension fund as it is invested over time, and the actuarial assumptions used in the calculations.

- Balance Sheet

  SFAS No. 158 requires balance sheet recognition of the funded status of defined benefit pension plans measured as the difference between the fair value of the pension assets and the projected benefit obligation ("PBO"). The PBO is an estimate of the pension promise as of a specified date, and is measured using various assumptions including an assumption for future compensation levels. More specifically, HECO is required to (1) recognize the overfunded or underfunded status of its defined benefit pension plan (based on the difference between the fair value of the plan assets and the PBO) in its balance sheet, and (2) recognize as a component of equity, called accumulated other comprehensive income ("AOCI"), net of tax, the actuarial gains and losses, the prior service costs and credits that arise during the period but are not recognized as components of NPPC, and any remaining transition obligation from the initial application of SFAS No. 87.

- Financial Statement Footnote

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

<u>Postretirement Benefits Other Than Pensions ("OPEB")</u>

Q. Under the guidance provided by SFAS No. 106 and SFAS No. 158, how are OPEBs reflected on the Company's financial statements?

A. OPEBs are reflected on the financial statements as follows:

- Income Statement

  The costs of the benefits provided by the Company's OPEBs are recognized as net periodic benefit costs ("NPBC") over the period the benefits are earned (i.e., as employees provide the related employment services). The NPBC is the annual amount that the Company must recognize on its financial statement as the cost of providing OPEBs to its employees for the year, and includes amounts ultimately charged primarily to both expense and to capital. A portion of the NPBC also is charged to outside third parties for services rendered, i.e., to billable work. As explained by Ms. Julie Price in HECO T-13, similar to pensions, the five major components of the NPBC are: service cost, interest cost, actual return on plan assets, amortization of prior service cost, and amortization of gains and losses. The factors that impact NPPC, such as the provisions of the plan, the demographic characteristics of the employees, the performance of the plan assets as they are invested over time, and the actuarial assumptions used in the calculations, impact the NPBC as well. In addition, the income statement reflects the amortization costs of the unrecognized transition obligation regulatory asset related to the timing of the initial adoption of SFAS No. 106 (SFAS No. 106 amortization), as approved by the Commission in Interim Decision and Order No. 12886 dated April 6, 1993, Decision and Order No. 13659 dated November 29, 1994, and the letter from the Commission dated December 28, 1994 in Docket Nos. 7233 and 7243 (Consolidated).

- Balance Sheet

SFAS No. 158 requires balance sheet recognition of the funded status of the OPEB plan measured as the difference between the fair value of the OPEB Plan's assets and the accumulated postretirement benefit obligation ("APBO") for the OPEB Plan. HECO is required to (1) recognize the overfunded or underfunded status of its OPEB plan based on the difference between the fair value of the plan assets and the APBO in its balance sheet, and (2) recognize as a component of AOCI, net of tax, the actuarial gains and losses, the prior service costs and credits that arise during the period but are not recognized as components of NPBC and any remaining transition obligation from the initial application of SFAS No. 106.

- Financial Statement Footnote

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

Ratemaking Treatment

Q. How have pension and OPEB costs been treated for ratemaking purposes?

A. In Docket No. 2006-0386 in HECO's 2007 test year rate case, HECO, the Consumer Advocate and the Department of Defense (the parties in the proceeding) agreed on pension and OPEB tracking mechanisms. The Commission, in its Interim Decision and Order No. 23749, issued October 22, 2007, approved on an interim basis, the adoption of a pension tracking mechanism and an OPEB tracking mechanism. The pension tracking mechanism is provided in HECO-1122 and the OPEB tracking mechanism is provided in HECO-1123. The pension tracking mechanism ensures that over time, the pension costs recovered through rates are based on the SFAS No. 87 NPPC as reported for financial reporting purposes, and ensures that all amounts contributed to the pension trust funds (after the pension asset, which is the cumulative pension contributions in excess of cumulative pension costs recognized, is reduced to zero) are in an amount equal to actual NPPC and are recoverable through rates. The OPEB tracking mechanism ensures that over time, the OPEB costs recovered through rates are based on the SFAS No. 106 NPBC as reported for financial reporting purposes, and ensures that all amounts contributed to the OPEB trust funds are in an amount equal to the actual NPBC and are recoverable through rates.

Q. What are the benefits of the pension tracking mechanism?

A. The benefits of the pension tracking mechanism are (1) it specifies agreement on the ratemaking treatment of pension costs and pension fund contributions, thus reducing disputable items in rate cases, (2) it demonstrates rate support for the Company's pension plan and (3) it results in leveling pension costs reported on the financial statements.

Q. Please explain in general the mechanics of the pension tracking mechanism.

A. Under the pension tracking mechanism, the test year NPPC is identified and incorporated into rates in each rate case ("NPPC in rates"). Once new rates are effective and until rates are changed in a subsequent rate case, the amount of NPPC in rates and the actual NPPC is separately tracked. The difference between the NPPC in rates and the actuarially calculated NPPC for the year is charged/credited to a regulatory asset/liability. This unamortized regulatory asset/liability is included in rate base. When new rates are established in a rate case, the regulatory asset/liability is amortized over a five year period. The total test year pension cost is the test year NPPC ("NPPC in rates") plus or minus the amortization of the regulatory asset/liability. For HECO, from the start of implementation of the pension tracking mechanism until the pension asset (the cumulative pension contributions in excess of cumulative pension costs recognized) is reduced to zero, the Company would be required to fund the pension trust at the minimum required level under the law. Thereafter, the mechanism requires HECO to make fund contributions at the actuarially calculated NPPC as determined under generally accepted accounting principles, subject to certain exceptions. The pension tracking mechanism also allows HECO to reverse the pension AOCI charge to equity and create a regulatory asset for financial statement purposes. The mechanism allows the utility to recover through rates the amount of contributions to the pension trust in excess of the SFAS No. 87 NPPC that were made for specific reasons. The mechanism also addresses the situation when the SFAS No. 87 NPPC becomes negative. The objective of the pension tracking mechanism is that, over time, the Company will recover through rates SFAS No. 87 based NPPC, including the amortization of the unrecognized amounts.

Q. What are the benefits of the OPEB tracking mechanism?

A. The OPEB tracking mechanism specifies the ratemaking treatment which allows financial statement treatment of benefit costs to be smoothed based on the amount of NPBC established in a rate case, and addresses potential situations in the future where contributions to OPEB trusts are not equal to the NPBC recognized.

Q. Please explain in general the mechanics of the OPEB tracking mechanism.

A. Similar to the pension tracking mechanism, an amount for OPEB costs is identified[2] and incorporated into rates in each rate case ("OPEB costs in rates"). Once new rates are effective and until rates are changed in a subsequent rate case, the amount of OPEB costs in rates is separately tracked. The difference between the OPEB costs in rates and the actuarially calculated NPBC (excluding executive life costs) plus the SFAS No. 106 amortization for the year is charged/credited to a regulatory asset/liability. This unamortized regulatory asset/liability is included in rate base. When new rates are established in a rate case, the regulatory asset/liability is amortized over a five year period. The total test year OPEB cost

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[2] OPEB costs is the test year NPBC excluding executive life costs plus SFAS No... 106 amortization.

is the test year NPBC (excluding executive life costs) plus the SFAS No. 106 amortization plus or minus the amortization of the regulatory asset/liability. The mechanism requires HECO to make fund contributions at the actuarially calculated NPBC as determined under generally accepted accounting principles subject to certain exceptions. The OPEB tracking mechanism also allows HECO to reverse the OPEB AOCI charge to equity and create a regulatory asset for financial statement purposes. The mechanism allows the utility to recover through rates the amount of contributions to the pension trust in excess of the SFAS No. 106 NPBC that were made for specific reasons. The mechanism also addresses the situation when the SFAS No. 106 NPBC becomes negative. The objective of the OPEB tracking mechanism is that, over time, the Company will recover through rates SFAS No. 106 based NPBC, including the amortization of the unrecognized amounts.

Q. How is the pension tracking mechanism reflected in the test year estimates?

A. As required in the pension tracking mechanism, HECO has reflected in its results of operations, a pension expense based on the estimated SFAS No. 87 based NPPC for 2009 less the amortization of the regulatory liability, and the unamortized regulatory liability in rate base. HECO did not make contributions to the pension fund in 2007, and does not expect to make contributions in 2008 or 2009, as HECO still has a pension asset (cumulative pension contributions in excess of cumulative pension costs recognized), thus no other regulatory asset/liability is included in rate base.

The pension tracking mechanism was approved on an interim basis in October 2007 in the 2007 test year rate case, in the same interim decision approving an interim rate increase. The NPPC included in determining HECO's revenue requirements was $17,711,000 as reflected in Exhibit 2 page 1 of the June 2007 Update for HECO T-12 filed on June 15, 2007 in Docket No. 2006-0386. Because the actual NPPC in 2007 was the same as the test year estimate, there was no regulatory asset/liability related to the difference between the NPPC in rates and the actual NPPC as of the end of 2007. In 2008, the actual NPPC is $14,660,000 compared to the $17,711,000 included in HECO's current rates. As shown on HECO-1124, the difference of $3,051,000 is the estimated regulatory liability as of the end of 2008. One-fifth of the estimated regulatory liability balance as of the end of 2008 of $610,000 is the estimated amortization for the 2009 test year, and is subtracted from the balance as of the end of 2008 to arrive at the unamortized balance as of the end of 2009. The average balance for the year (the sum of the ending balances as of the end 2008 and 2009 divided by two) is included as a reduction to rate base as discussed by Mr. Darren Doi in HECO T-18. As discussed by Ms. Julie Price in HECO T-13, the employee benefits expense includes a pension expense of $14,013,000, which reflects the estimated NPPC for 2009 as calculated by Watson Wyatt Worldwide of $14,623,000 less the amortization (based on one fifth of the balance of the regulatory liability at the beginning of the year) of $610,000.

Q. How is the OPEB tracking mechanism reflected in the test year estimates?

A. As required in the OPEB tracking mechanism, HECO has reflected in its results of operations, an OPEB expense based on the estimated SFAS No. 106 based NPBC for 2009 less the amortization of the regulatory liability, and the unamortized regulatory liability in rate base. Because HECO's contributions to the OPEB trust funds equaled the SFAS No. 106 based OPEB amount[3], no other regulatory asset/liability is included in rate base.

The OPEB tracking mechanism was approved on an interim basis in October 2007 in the HECO 2007 test year rate case, in the same interim decision approving an interim rate increase. The NPBC included in determining HECO's revenue requirements was $6,350,000 as reflected on page 1 of the June 2007 Update for HECO T-12 filed on June 15, 2007 in Docket No. 2006-0386. Because the actual NPBC in 2007 was the same as the test year estimate, there was no regulatory asset/liability related to the difference between the NPBC in rates and the actual NPBC as of the end of 2007. In 2008, the actual NPBC is $5,573,000 compared to the $6,350,000 included in HECO's current rates. As shown on HECO-1125, the difference of $777,000 is the estimated regulatory liability as of the end of 2008. One-fifth of the estimated regulatory liability balance as of the end of 2008 of $155,000 is the estimated amortization for the 2009 test year, and is subtracted from the balance as of the end of 2008 to arrive at the unamortized balance as of the end of 2009. The average balance for the year (the sum of ending balances as of the end 2008 and 2009 divided by two) is included as a reduction to rate base as discussed by Mr. Darren Doi in HECO T-18. As discussed by Ms. Julie Price in HECO T-13, the employee benefits expense includes OPEB expense which reflects the estimated NPBC for 2009 as calculated by Watson Wyatt Worldwide of $5,224,000 less the executive life portion that has been disallowed by the Commission of $873,000, less the

[3] The SFAS No. 106 based OPEB amount excludes the executive life portion that has been disallowed by the Commission and includes the amortization of the regulatory asset for the deferred OPEB costs between January 1, 1993 to December 31, 1994 as approved in Decision and Order No. 13659 (November 29, 1994) and letter dated December 28, 1994 in Docket No.7243 and 7233 (consolidated).

amortization (based on one fifth of the balance of the regulatory liability at the beginning of the year) of $155,000, and the amortization of the SFAS No. 106 regulatory asset. Ms. Price also excludes the electric discount portion of OPEB for the year in the employee benefits expense, as it is already reflected in the reduced revenues for the test year. To the extent the contributions are not currently deductible for tax purposes, negative deferred taxes are established as these contributions are temporary differences for which we are entitled to deduct for tax purposes in the future.

Pension Asset

Q. Under the tracking mechanism, until the pension asset is reduced to zero, the Company would be required to fund the minimum required level under the law. What is the pension asset?

A. The pension asset is the cumulative amounts of contributions to the pension trust in excess of cumulative pension costs (NPPC accrual), as shown on HECO-1124, page 2. It represents the net of the cumulative investor supplied fund contributions in excess of the cumulative previously recognized pension cost. Fund contributions are the cash payments the Company has made to the pension fund over the years. Recognized pension cost is the accumulated NPPC that the Company has recognized on its financial statements.

Q. What is the estimated balance of the pension asset in the test year?

A. HECO projects that the pension asset as of the end of 2009 will be $21,266,000.

Q. Has HECO included the pension asset in rate base or the amortization of the pension asset in its expenses for the test year?

A. No. In the settlement agreement among the parties in Docket No. 2006-0386, and under the pension mechanism approved by the Commission on an interim basis, HECO's revenue requirement does not include the amortization of the pension asset in expense or the pension asset in rate base. Not including the amortization had the effect of deferring the issue of whether the pension asset should be amortized for ratemaking purposes to this rate case proceeding. In the settlement agreement, the parties agreed that if the existing pension asset amount is not reduced to zero by the next rate case, the parties would address the funding requirements for the pension tracking mechanism in the next rate case (which would be this rate case.) Since that time, the Commission issued Decision and Order No. 24171 in Docket No. 04-0113, which excluded the pension asset from the revenue requirements in that proceeding. In order to simplify the issues in this proceeding, HECO has not included the pension asset in rate base, or included any amortization of the prepaid pension asset in determining its revenue requirements. Since the existing pension asset has not been reduced to zero, HECO proposes to continue the same funding requirements wherein HECO is required to fund the pension trust at the minimum required level under the law, until the pension asset is reduced to zero.

<u>Pension and OPEB Summary</u>

Q. How should pension and OPEB costs be included in the test year for ratemaking purposes?

A. Pension and OPEB costs should be reflected for ratemaking purposes based on the pension and OPEB tracking mechanisms agreed to by HECO, the Consumer Advocate and the Department of Defense in Docket No. 2006-0386 (and provided in HECO-1122 and HECO-1123) and approved on an interim basis by the Commission in Interim Decision and Order No. 23749 issued October 22, 2007. The test year estimates reflect the pension and OPEB tracking mechanisms approved on an interim basis to continue through the test year.

STAFFING-GENERAL ACCOUNTING DEPARTMENT

Q. How many employees are in the General Accounting Department?

A. There were 26 employees in the General Accounting Department at the end of 2007, and there were 26 employees as of March 31, 2008. The staffing count projected for the 2009 test year for the General Accounting department is 27 employees as shown on HECO-1503. HECO is planning to add an additional Corporate Accountant in the Corporate Accounting Division of the General Accounting Department by the beginning of 2009.

Q. What is the current staffing for the Corporate Accounting Division?

A. Currently, the Corporate Accounting Division consists of four Corporate Accountants and one Lead Corporate Accountant. The Corporate Accountants report to the Director of Corporate and Property Accounting, who reports to the Controller.

Q. What is the primary function of the Corporate Accounting Division?

The primary function of the Corporate Accounting Division is to record and maintain the financial records of the Company, including preparing and providing internal and external financial statements and reports. Since HECO is a registrant of the Securities and Exchange Commission ("SEC") and regulated by the Public Utilities Commission of the State of Hawaii, HECO must provide a significant amount of timely and accurate monthly, quarterly and annual financial information to management, investors, regulators and the general public. Ultimately, the Corporate Accounting Division bears much of the responsibility to process and prepare the financial information in accordance with generally accepted accounting principles ("GAAP").

Q. Why is an additional corporate accountant required?

A. In this post-Enron era, the number of accounting pronouncements and interpretations that are being issued have increased significantly. As a result there has been an increase in the amount of analysis required to prepare the financial information in accordance with GAAP, and HECO's auditors are requiring more documentation to support the Company's analyses and conclusions.

In addition, with the release in late 2006 of the SEC's Staff Accounting Bulletin No. 108 (SAB 108) regarding quantifying and analyzing financial statement misstatements, there has been an increased emphasis in ensuring that loss contingencies, type 1 subsequent event adjustments and out-of-period adjustments, regardless of immateriality, are recorded in the proper accounting period. In the past, adjustments identified after the closing of the financial records that were considered immaterial, may have been recorded in the following month (as a subsequent month's business) rather than re-opening the Company's financial records to record the adjustment in the proper period. As a result, at quarter ends, there generally are multiple financial closings. To re-open, and close the Company's financial account records require a significant amount of resources. Further, as part of ensuring that all loss contingencies are liabilities and are recorded in the proper period, there has been an increased emphasis, on HECO's auditor's part, on their search for unrecorded liabilities procedures. Thus, the Company has significantly expanded its activities to ensure all costs are properly accrued.

Q. When is the additional Corporate Accountant expected to be hired?

A. HECO plans to go through the formal approval process for the position and recruit for the position in the second half of this year, such that the position is filled by the beginning of the test year.

SUMMARY

Q. Please summarize your testimony.

A. The test year 2009 base case normalized amounts which the Company has demonstrated to be fair and reasonable in this docket include the following:

Description	Test Yr. Estimates
Administrative and General Expenses (Base Case)	$76,708,000
Administrative and General Expenses (Interim Increase)	$76,583,000
Administrative and General Expenses (CIP1 Full Cost)	$76,849,000
Computer Software Develop Costs	
Unamortized System Development costs 12/31/08	$ 4,568,000
Unamortized System Development costs 12/31/09	$30,336,000
Abandoned Capital Project Costs	$ 172,000
Gain on Sales of Land –	
Amount of gain amortized in 2009	$ 615,000
Unamortized gain – 12/31/08	$ 1,359,000
Unamortized gain – 12/31/09	$ 744,000
Iolani Court Plaza Lease Premium	
Amortization of premium in 2009	$ 3,000
Unamortized lease premium – 12/31/08	$ 5,000
Unamortized lease premium – 12/31/09	$ 2,000
RO Water Pipeline Regulatory Asset	
Amortization of regulatory asset in 2009	$ 32,000
RO water pipeline regulatory asset – 12/31/08	$ 0
RO water pipeline regulatory asset – 12/31/09	$ 6,366,000
Pension Liability	
Balance at 12/31/08	$ 3,051,000
Balance at 12/31/09	$ 2,441,000
OPEB Liability	
Balance at 12/31/08	$ 777,000
Balance at 12/31/09	$ 622,000

The test year 2009 base case normalized Administrative and General Expense estimates (see HECO-1101) are presented by Mr. Russell Harris (HECO T-12), Ms. Julie Price (HECO T-13), Mr. Bruce Tamashiro (HECO T-14) and I. The Unamortized System Development costs related to the OMS project, CIS project and the HR Suite project represent costs for systems that are in use or expected to be ready for use in 2009, and the unamortized amounts are shown on HECO-1117. The $172,000 with respect to abandoned capital project costs represents the historical five year average of abandoned project cost write-offs (from 2003 through 2007), which would not otherwise be included in the Company's test year estimates as forecasters do not generally contemplate that projects will be abandoned. See HECO-1119 for the distribution of the $172,000 to various operation and maintenance expense accounts. The test year 2009 amortization amounts and year end 2008 and 2009 unamortized amounts with respect to gains on the sale of land and the Iolani Court Plaza lease premium, which are detailed on HECO-1120, reflect the accounting and ratemaking treatments previously approved by the Commission.

With respect to the pension and OPEB plans, the Commission should approve the pension and OPEB tracking mechanisms approved on an interim basis by Interim D&O No. 23749 issued October 22, 2007 in Docket No. 2006-0386. The pension and OPEB liabilities reflected in the test year rate base should be included in rate base as they are consistent with the pension and OPEB tracking mechanisms

Q. What other accounting and ratemaking treatment is the Company requesting of the Commission in this docket?

A. The Company is asking the Commission to specifically reaffirm, in its Decision and Order in this docket, the continued use of the pay-as-you-go method of accounting for post-employment benefit costs. Please see the earlier discussion with respect to SFAS No. 112 under EMPLOYEE BENEFITS.

Q. Ms. Nanbu, does this conclude your testimony?

A. Yes, it does.

PATSY H. NANBU

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 900 Richards Street, Honolulu, HI 96813
Position:	Controller of Hawaiian Electric Company, Inc.
Previous Positions:	Director, Regulatory Affairs Director, Internal Audit Senior Regulatory Analyst Budget Administrator Budget Analyst
Years of Service:	22 years
Education:	Bachelor of Business Administration in Accounting with Distinction, University of Hawaii, 1981 Master of Accountancy, University of Hawaii, 1983
Professional Registration:	Certified Public Accountant (not in public practice) State of Hawaii, 1984
Other Experience:	Senior Auditor, Arthur Young & Company
Previous Testimony:	Docket No. 2006-0386 – HECO 2007 Test Year Rate Case Administrative &General Expense; Budgeting Process; Accounting for Computer Software Development Costs; Abandoned Capital Project Costs; Unamortized Gain on Sale of Land; Iolani Court Plaza Lease Premium; Accounting for Pensions and Postretirement Benefits Other than Pensions; General Accounting Department Staffing Docket No. 05-0315 – HELCO 2006 Test Year Rate Case – Accounting Policy – Allowance for Funds Used During Construction Docket No. 05-0146 – Campbell Industrial Park Generation Station Project Community Benefits Package - Accounting and Ratemaking Treatment for Reverse Osmosis Water Pipeline Project and Environmental Monitoring Programs

HAWAIIAN ELECTRIC COMPANY, INC.
ADMINISTRATIVE AND GENERAL EXPENSES
($ Thousands)

		A&G at Base Case	less CIP1 Ave Cost	A&G w/ Interim Increase	add CIP1 Full Cost	A&G w/ CIP1 Gen Unit at Full Cost
	ADMINISTRATIVE					
920	A&G Expense - Labor	19,417		19,417		19,417
921	A&G Expense - Non labor	15,202		15,202		15,202
922	A&G Expenses Transferred	(3,197)		(3,197)		(3,197)
	Total Administrative	31,422	0	31,422	0	31,422
	OUTSIDE SERVICES					
923010	Outside Services - Legal	131		131		131
923020	Outside Services - Other	2,535		2,535		2,535
	Total Outside Services	2,666	0	2,666	0	2,666
	INSURANCE					
924	Property Insurance	3,062		3,062		3,062
925	Injuries & Damages - Employees	7,192		7,192		7,192
	Total Insurance	10,254	0	10,254	0	10,254
	EMPLOYEE BENEFITS					
926000	Employee Pensions and Benefits	21,197	(125)	21,072	266	21,338
926010	Employee Benefits - Flex Credits	11,173		11,173		11,173
926020	Employee Benefits Transfer	(8,963)		(8,963)		(8,963)
	Total Employee Benefits	23,407	(125)	23,282	266	23,548
	MISCELLANEOUS					
928	Regulatory Commission Expenses	440		440		440
9301	Inst. or Goodwill Advertising Expense	36		36		36
9302	Miscellaneous General Expenses	3,857		3,857		3,857
931	Rents Expense - A&G	3,062		3,062		3,062
932	Admin and General Maintenance	1,565		1,565		1,565
	Total Miscellaneous	8,960	0	8,960	0	8,960
TOTAL ADMINISTRATIVE & GENERAL EXPENSES		76,708	(125)	76,583	266	76,849

Totals may not add due to rounding

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2009 BASE CASE
($ THOUSANDS)

	BUDGET	BUD ADJ	NORM	BASE CASE DIRECT
ADMINISTRATIVE & GENERAL O&M EXPENSE				
ADMINISTRATIVE				
920 ADMIN & GENL EXP - LABR				
LABOR	19,410	7		19,417
NON-LABOR	2,988	(2,988)		0
TOTAL 920	22,398	(2,981)	0	19,417
921 ADMIN & GENL EXP - NLABR				
NON-LABOR	16,780	(1,578)		15,202
TOTAL 921	16,780	(1,578)	0	15,202
922 ADMIN EXPENSES TRANSFERRED				
NON-LABOR	(3,487)	290		(3,197)
TOTAL 922	(3,487)	290	0	(3,197)
TOTAL ADMINISTRATIVE	35,691	(4,269)	0	31,422
OUTSIDE SERVICES				
923010 OUTSIDE SERVICES - LEGAL				
NON-LABOR	131			131
TOTAL 923010	131	0	0	131
923020 OUTSIDE SERVICES - OTHER				
NON-LABOR	2,535			2,535
TOTAL 923020	2,535	0	0	2,535
923030 OUTSIDE SERVICES - ASSOC CO				
NON-LABOR	0			0
TOTAL 923030	0	0	0	0
TOTAL OS SVCS	2,666	0	0	2,666
TOTAL 920-923 EXPENSE	38,357	(4,269)	0	34,088

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2009 BASE CASE
($ THOUSANDS)

	BUDGET	BUD ADJ	NORM	BASE CASE DIRECT
INSURANCE EXPENSE				
INSURANCE				
924 PROPERTY INSURANCE				
LABOR	216			216
NON-LABOR	2,926	(80)		2,846
TOTAL 924	3,142	(80)	0	3,062
925 INJURIES & DAMAGES				
LABOR	1,450			1,450
NON-LABOR	6,025	(283)		5,742
TOTAL 925	7,475	(283)	0	7,192
TOTAL INSURANCE	10,617	(363)	0	10,254

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2009 BASE CASE
($ THOUSANDS)

	BUDGET	BUD ADJ	NORM	BASE CASE DIRECT
EMPLOYEE BENEFITS EXPENSE				
EMPLOYEE BENEFITS				
926000 EMPL PENSIONS AND BENEFITS				
LABOR	841	0		841
NON-LABOR	23,210	(2,854)		20,356
TOTAL 926000	24,051	(2,854)	0	21,197
926010 EMPL BENEFITS - FLEX CREDITS				
LABOR	211	0		211
NON-LABOR	10,999	(37)		10,962
TOTAL 926010	11,210	(37)	0	11,173
926020 EMPL BENEFITS TRANSFER				
NON-LABOR	(9,655)	692		(8,963)
TOTAL 926020	(9,655)	692	0	(8,963)
TOTAL EMP BEN	25,606	(2,199)	0	23,407

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2009 BASE CASE
($ THOUSANDS)

	BUDGET	BUD ADJ	NORM	BASE CASE DIRECT
OTHER ADMINISTRATIVE & GENERAL EXPENSE				
OTHER ADMIN & GENL				
928 REGULATORY COMMISSION EXPENSES				
NON-LABOR	760		(320)	440
TOTAL 928	760	0	(320)	440
9301 INSTITUTN/GOODWILL ADVERT EXP				
LABOR	14			14
NON-LABOR	22			22
TOTAL 9301	36	0	0	36
9302 MISCELLANEOUS GENERAL EXPENSES				
LABOR	316	(101)		215
NON-LABOR	3,888	(246)		3,642
TOTAL 9302	4,204	(347)	0	3,857
931 RENTS EXPENSE				
NON-LABOR	3,026	36		3,062
TOTAL 931	3,026	36	0	3,062
932 ADMIN AND GENL MAINTENANCE				
LABOR	195	52		247
NON-LABOR	398	1,108	(188)	1,318
TOTAL 932	593	1,160	(188)	1,565
TOTAL OTHER A&G	8,619	849	(508)	8,960
TOTAL A&G	83,199	(5,982)	(508)	76,708
ADMIN & GENL - TOTAL				
LABOR	22,653	(42)	0	22,611
NON-LABOR	60,546	(5,940)	(508)	54,098
TOTAL	83,199	(5,982)	(508)	76,708

HAWAIIAN ELECTRIC COMPANY, INC.
ADMINISTRATIVE AND GENERAL EXPENSES
($ Thousands)

		RECORDED					BUDGET		Normalization/ Rate Case	Test Year 2009 Base
		2003	2004	2005	2006	2007	2008	2009	Adjustment	Case
	ADMINISTRATIVE									
920	A&G Expense - Labor	14,593	15,185	15,759	13,506	15,767	18,978	22,398	(2,981)	19,417
921	A&G Expense - Non labor	9,831	12,539	14,276	11,529	13,656	12,605	16,780	(1,578)	15,202
922	A&G Expenses Transferred	(1,965)	(1,833)	(1,815)	(2,067)	(3,045)	(3,360)	(3,487)	290	(3,197)
	Total Administrative	22,459	25,891	28,220	22,968	26,378	28,223	35,691	(4,269)	31,422
	OUTSIDE SERVICES									
923010	Outside Services - Legal	38	15	34	146	46	152	131		131
923020	Outside Services - Other	731	872	1,729	1,086	1,350	1,681	2,535		2,535
	Total Outside Services	769	887	1,763	1,232	1,396	1,833	2,666	0	2,666
	INSURANCE									
924	Property Insurance	2,356	3,088	2,541	2,308	2,549	2,661	3,142	(80)	3,062
925	Injuries & Damages - Employees	4,919	6,761	3,870	6,488	7,458	6,400	7,475	(283)	7,192
	Total Insurance	7,275	9,849	6,411	8,796	10,007	9,061	10,617	(363)	10,254
	EMPLOYEE BENEFITS									
926000	Employee Pensions and Benefits	15,199	7,398	14,532	23,437	26,729	26,595	24,051	(2,854)	21,197
926010	Employee Benefits - Flex Credits	7,044	8,245	9,081	8,919	9,310	10,514	11,210	(37)	11,173
926020	Employee Benefits Transfer	(6,543)	(4,446)	(6,783)	(8,992)	(9,893)	(11,011)	(9,655)	692	(8,963)
	Total Employee Benefits	15,700	11,197	16,830	23,364	26,146	26,098	25,606	(2,199)	23,407
	MISCELLANEOUS									
928	Regulatory Commission Expenses	0	0	61	258	512	320	760	(320)	440
9301	Inst. or Goodwill Advertising Expense	93	76	73	65	36	34	36		36
9302	Miscellaneous General Expenses	3,842	2,803	2,841	732	3,523	4,068	4,204	(347)	3,857
931	Rents Expense - A&G	1,524	1,544	2,202	2,691	3,011	2,916	3,026	36	3,062
932	Admin and General Maintenance	496	505	524	444	454	793	593	972	1,565
	Total Miscellaneous	5,955	4,928	5,701	4,190	7,536	8,131	8,619	341	8,960
TOTAL ADMIN & GENERAL EXPENSES		52,158	52,752	58,926	60,552	71,461	73,346	83,198	(6,490)	76,708

Totals may not add due to rounding

Account	Codeblock	2007 Recd	2009 O&M Expense Budget	Inc/(Dec)	%Inc/(Dec)	Explanation
920	P8M723PHENENPZZZZZZ150	275,558	0	(275,558)	-100%	These costs are related to Performance Incentive Compensation Plans ("PIP"). The variance is a result of budgeting the 2009 amounts to a different codeblock (with a 900 rather than 150 expense element used in 2007). The PIP amount was removed from the 2009 O&M expense budget as a rate case adjustment to determine the 2009 TY estimate.
920	P8M723PHENENPZZZZZZ900	0	2,363,556	2,363,556	-	
920	P8V700PHENENPASVP8Z150	0	260,996	260,996	-	These costs represent the labor costs of the Senior VP, Operations' office to develop and administer business plans. The variance is a result of budgeting the 2009 amounts to a different codeblock (with a P8Z rather than the 7ZZ default project number used in 2007)
920	P8V700PHENENPAVP7ZZ150	257,539	0	(257,539)	-100%	
920	PED891PHENEP0001147150	0	210,691	210,691	-	These amounts are related to the Ellipse 6 Upgrade.
920	PFC723PHENENPFZZZZZ900	0	252,000	252,000	-	These costs relate to the Merit Key Contributor and Merit Team awards which were included in the budget adjustment to remove PIP compensation to determine the 2009 TY estimate. No awards were made in 2007.
920	PFI785PHENEP0000128150	0	302,542	302,542	-	The increase is due to additional positions that are part of the Corporate Mentorship Program as discussed by Ms. Chiogioji in HECO T-15.
920	PNP738PHENENPNPZZZZ150	161,769	590,365	428,596	265%	The increase is due to additional positions as discussed by Ms. Chiogioji in HECO T-15.
921	PEZ750PHENENPNEZZZZ451	0	213,672	213,672	-	The 2009 O&M expense budget amounts were charged to codeblocks which are different from those used to record the 2007 actuals. The net increase is due to higher labor and non-labor charges into the ITS clearing account as explained in HECO T-11.
	PEZ750PHENENPHZZZZZ451	151,384	177,780	26,396		
	PEZ750PHENENPQCZZZZ451	247,468	88,584	(158,884)		
	PEZ750PHENENPQEZZZZ451	48,455	56,904	8,449		
		447,307	536,940	89,633	20%	
921	PEZ818PHENENPAVP2ZZ451	210,674	6,636	(204,038)	-97%	The 2009 O&M expense budget amounts were charged to codeblocks which are different from those used to record the 2007 actuals. The net increase is due to higher labor and non-labor charges into the ITS clearing account as explained in HECO T-11.
	PEZ818PHENENPAVP4ZZ451	496,419	747,716	251,297	51%	
	PEZ818PHENENPAZZZZZ451	61,859	72,648	10,789		
		768,952	827,000	58,048	8%	
921	PFB766PHENENPFZZZZZ901	0	234,672	234,672	-	The increase is due to the amortization of deferred HR Suites project costs which are forecasted to begin in 2009. See discussion of HR Suites in HECO T-13.
921	PHB931WRDNENPHZZZZZ501	42,728	321,766	279,038	653%	The increase is due to higher contracted custodian costs (53K) and sewage fees (12K). The variances are also due to budgeting the 2009 O&M expense amounts to codeblocks different from those used to record the 2007 actuals.
	PHB931WRDNENPHZZZZZ205	10,883	0	(10,883)		
	PHB934WRDNENPHZZZZZ501	135,873	0	(135,873)		
	PHB931PDMNENPHZZZZZ501 (Account 598)	59,676		(59,676)		
		249,160	321,766	72,606	29%	

Account	Codeblock	2007 Recd	2009 O&M Expense Budget	Inc/(Dec)	%Inc/(Dec)	Explanation
921	PHS930WRDNENP0001402501	327,448	0	(327,448)	-100%	The decrease is due to the incorrect posting of the Ward parking structure roof level repairs to an activity that translated to Account 921 rather than Account 932 as discussed in HECO T-14.
921	PHF930WRDNEP0001571201	0	200,000	200,000	-	The increase is due to the incorrect budgeting of the Ward parking structure roof level repairs to an activity that translated to Account 921 rather than Account 932. This budget adjustment is discussed in HECO T-14.
921	PHF930WRDNEP0001571501	0	330,002	330,002	-	The decrease is due to the incorrect budgeting of the Ward parking structure roof level repairs to an activity that translated to Account 921 rather than Account 932. This budget adjustment is discussed in HECO T-14.
921	PKM891PHENEP0001147462	0	361,892	361,892	-	These amounts are related to the Ellipse 6 Upgrade software costs.
921	PNA760PHENENPNAZZZZ501	735	750,000	749,265	101941%	The increase is due to outsourcing internal audit functions to assist the department in meeting the needs of the Company.
923020	PKM891PHENEP0001147501	0	1,144,765	1,144,765	-	These amounts are related to the Ellipse 6 Upgrade consultant fees.

BRIEF DESCRIPTION OF ADMINISTRATIVE ACTIVITIES BY ORGANIZATION

PA0 - GENERAL ACCOUNTING DEPARTMENT

The General Accounting Department is comprised of three divisions, i.e. the Administrative Division, Cost Accounting Division, and Corporate & Property Accounting Division. The major functional responsibilities for each division are as follows:

The Administrative Division is responsible for the overall supervision, direction and support of the other divisions in the department. The division is also responsible for providing support, direction, and training on the use of the Project Control module in the Enterprise Resource Planning ("ERP") system; improving work processes and reporting where possible; and testing and implementing software fixes and upgrades to the ERP system. In addition, the Division is responsible for managing and enhancing the Company's process and activities for the design and operating effectiveness of internal controls over financial reporting pursuant to the provisions of the Sarbanes-Oxley Act of 2002 (SOX), and manages the Company's requirements under SOX.

The Cost Accounting Division is comprised of two sections, i.e. the Payroll section and the Disbursements section.

The Payroll section is responsible for maintaining and enhancing the Company's payroll and payroll tax reporting systems. This section is responsible for processing payroll data (e.g. timesheets, withholding exemptions, and deductions), and for monitoring and enforcing Company compliance with payroll tax laws and regulations.

The Disbursements section is responsible for maintaining and enhancing the Company's accounts payable and purchasing card systems. This section is responsible for the timely and proper processing of disbursement documents (e.g., invoices, employee expense reports, check request vouchers); and for monitoring and enforcing Company compliance with disbursement procedures.

The Corporate & Property Accounting Division is comprised of two sections, i.e. the Corporate Accounting section and the Property Accounting section.

The Corporate Accounting section is responsible for meeting the Company's internal and external financial accounting and reporting requirements. This section closes the books each month, and prepares monthly, quarterly and annual financial statements for internal and external distribution for HECO as well as is non-regulated subsidiaries, Renewable Hawaii, Inc. and Uluwehiokama Biofuels Corporation. This section keeps abreast of generally accepted accounting policies and procedures necessary to insure that the Company's accounting practices comply with the requirements of such bodies as the Financial Accounting Standards Board, the Public Utilities Commission and NARUC's Chart of Accounts. The Corporate Accounting Division is also responsible for maintaining other financial and statistical data for the Company. This section is also responsible for reconciling all of the Company's bank accounts.

The Property Accounting section is responsible for maintaining the Company's property, plant and equipment, and related records, which involve such activities as the unitization of plant installation costs, the recording of plant removal costs, and the calculation of depreciation expense. This division conducts the detailed depreciation study for HECO. The Property Accounting Division also processes billing information for all billings to affiliated companies, based on information provided by other HECO organizations.

PK0 - MANAGEMENT ACCOUNTING & FINANCIAL SERVICES

The Management Accounting & Financial Services organization is comprised of five divisions, i.e. the Administrative Division, the Budgets Division, Treasury Division, Financial Analysis Division, and ERP Administration Division. The major functional responsibilities for each division are as follows:

The Administrative Division is responsible for the overall supervision and direction of the other divisions in the department, including providing support to the other divisions.

The Budgets Division is responsible for directing and coordinating the preparation of the detailed annual budget of Company earnings and capital budgeting process at HECO. The test year estimates, before normalizations and adjustments, used in this proceeding were developed under the direction of the Budgets Division. This Division also directs and coordinates the preparation of updates to the annual earnings estimate, and prepares the Company's long-range financial forecasts, including the estimates of external financing requirements.

The Treasury Division administers all of the outstanding long-term securities for the three electric utilities, including coordinating the work necessary for the sale of long-term securities. This Division is also responsible for the Company's cash management function, including borrowing and investing funds on a daily basis. This Division also maintains operational contacts with the Company's banks and brokers.

The Financial Analysis Division is responsible for conducting various financial and economic analyses. Examples include the analyses of purchase power contracts, avoided cost analyses, and lease versus buy analyses. This division is also responsible for assisting other departments in analyzing the revenue requirement impact of various decisions.

The ERP Administration Division is responsible for maintaining the application security and authorization within our ERP system. Additionally, this division assists users with resolving functional problems which includes the submitting and tracking of software problems reported to the software vendor.

PE0 - INFORMATION TECHNOLOGY & SERVICES DEPARTMENT

The Information Technology & Services Department charges a portion of its costs directly to administrative expenses.

The IT Customer Care Division of the Information Technology & Services Department directly charges Mailing Services, Records Management, corporate printing and word processing, and printer copier maintenance functions to administrative expenses.

The Mailing Services section is responsible for the pickup and delivery of all inter-office mail, and for providing messenger service as required by the Company. This section is also responsible for mailings external to the company, including such bulk mailing projects as light and power bills, dividend checks, and annual reports.

The Records Management Services section is responsible for the Company's overall records management function, including maintaining and upgrading the company's records filing system. This section also coordinates the microfilming of various corporate documents and records.

The Printing Services section is responsible for mass Company printing projects.

The Word Processing section is responsible for providing word processing services as requested by various departments. The section prepares documents such as manuals, contracts, agreements, mailing labels and mass mailing material.

Printer/copier maintenance expenses related to Administrative and General, Customer Accounts, and Customer Services functions are charged directly to administrative expenses.

PFB - COMPENSATION & BENEFITS

The Compensation & Benefits Department is comprised of two divisions, which incur costs chargeable to Administrative expenses, i.e. the Benefits Division and the Compensation Division.

The Benefits Division is responsible for the administration, management and delivery of the Company's employee benefits program to employees and retirees. The division's functions include the maintenance of data and administration systems, legal compliance, communication to employees and the calculation of benefit payments. The Benefits Division is responsible for maintaining and enhancing the Company's Flex Benefits system. This division is responsible for preparing all benefit information and for processing all benefit payments.

The Compensation Division is responsible for managing and administering the compensation programs for the Company's non-bargaining employees. Their activities include conducting and/or coordinating compensation analyses of the Company's compensation levels to insure that they are competitive with the industry and local job market, and evaluating and rating all non-bargaining unit positions. The Compensation Division also monitors all salary actions related to changes in non-bargaining employee status (e.g. hires, promotions, terminations, etc.).

PF1 - WORKFORCE STAFFING & DEVELOPMENT

The Workforce Staffing & Development Department is comprised of three divisions, which incur costs chargeable to Administrative expenses, i.e. the Administrative Division, the Client Services & Consulting Division and the Organizational Development Division.

The Administrative Division is responsible for the overall supervision and direction of the work of the other divisions. Also part of this division is the Human Resources Information Systems (HRIS) function, which provides information systems oversight and coordination specific to employee data maintenance, reporting, security and integrity.

The Client Services & Consulting Division provides organizational and workforce planning consulting and is responsible for acquiring and deploying talent to fill all job vacancies that exist within the Company. This division coordinates all activities with respect to recruitment and hiring, employing traditional recruitment methods to acquire talent such as advertising and participating in job fairs and through management of strategic recruitment programs such as the summer internship program and partnerships with community colleges. The Division has responsibility over the Company’s pre-employment aptitude testing programs that assess applicants’ suitability to utility positions and the New Hire First Day and Corporate Orientation Programs. The Division manages activities related to employee development, career and performance coaching, complaint investigations, and discipline of merit (non-union) employees. The Division also has responsibility for diversity initiatives and programs and the corporate Equal Employment Opportunity and Affirmative Action Program compliance and reporting.

The Organizational Development Division provides organization-wide systems, processes and programs that serve to build a competitive corporate culture, cultivate effective leadership, and increase team effectiveness. This includes the designing, directing and managing of the following: workforce training & development (e.g., executive, leadership, team, and individual development), succession planning, change management, performance development (e.g., performance appraisals), talent management, knowledge management, and corporate culture.

PH9 - SAFETY, SECURITY & FACILITIES DEPARTMENT

The Safety, Security & Facilities Department is made of seven divisions (Safety, Administration, Facilities Operation, Facilities Planning, Security, Corporate Health & Wellness, and Workers Compensation), of which four divisions (Administration, Facilities Operations, Facilities Planning and Security) charges their costs directly to administrative expenses. The major functional responsibilities for the four divisions are as follows:

The Administrative Division is responsible for the overall supervision, direction and support of the other divisions in the department.

The Facilities Operations Division is responsible for the building service expenses with respect to the Company's King Street office building and the extensive Ward Avenue Operation's complex, such as in-house custodial and grounds-keeping labor costs, structural, electrical and mechanical repairs, painting, office rearrangements, and classroom and meeting set ups. External costs include supplemental custodial and grounds-keeping cost, refuse collection, fire alarm and water leak monitoring, window cleaning, and carpet and drapes cleaning.

The Facilities Planning Division is responsible for planning building infrastructure improvements/evaluation, space planning, relocations, renovations, system furniture purchase, and monitoring indoor air quality issues for the King Street building and the Ward Avenue Operations complex.

The Security Division charges to administrative expenses relate to developing and implementing policies to control access to all sites, ID card access reading and monitoring and CCTV coverage monitored at Ward Avenue's Security Command Center. External costs include contract security personnel.

PJ0 - ENVIRONMENTAL DEPARTMENT

The Environmental Department is comprised of four divisions, i.e. Air Quality/Noise ("Air"), Water & Hazardous Materials, Environmental Chemistry Laboratory, and the Administrative. In general, the department's activities involve the permitting of proposed operations, renewal of permits for existing operations, and the review of ongoing operations for compliance with existing permit conditions. In addition, the department monitors federal and state environmental legislation and regulations, and prepares the utility for cost effective compliance and potential impacts to the Company. Each of the divisions in the department provides services for HECO, MECO and HELCO. The department interacts with environmental regulators on issues raised by HECO, its subsidiaries, or by the regulators relative to existing or planned future operations. The department also interacts with industry, customers, community associations and other public constituents on environmental matters related to HECO and its subsidiaries.

More specifically, the Air Division is responsible for air permit applications, renewals, and compliance monitoring. The Water & Hazardous Materials Division is responsible for water quality permitting, compliance, and monitoring. The division is also involved in various hazardous materials management activities (e.g. activities related to PCBs, hazardous waste, Emergency Planning, and Superfund), including permitting and compliance. Both the Air and

Water and Hazardous Material divisions monitor federal and state legislation, conduct compliance training, and keep Company supervisors informed of the Company's obligations in order to minimize the potential financial exposure for noncompliance.

The Environmental Chemistry Laboratory Division of the Environmental Department conducts analytical chemistry work for the Company and its subsidiaries, primarily in support of environmental permit or other regulatory and operational requirements. This includes testing of water, soil, oils and fuels to support energy production and delivery operations.

The Administrative Division provides administrative support as well as environmental audit services. The purpose of the environmental audit program is to achieve regulatory and permit compliance through the audit function for all three companies.

PKID - RISK MANAGEMENT DIVISION

The Risk Management Division is responsible for all aspects of property and liability insurance administration for the Company, including the review, negotiation, and acquisition of insurance coverage. This division is responsible for the analyses and control of risk exposures. The division is also responsible for the investigation and settlement of certain claims and lawsuits.

PNX / PNA – CORPORATE AUDIT AND COMPLIANCE DEPARTMENT

The Corporate Audit & Compliance Department (CACD) is responsible for (1) conducting independent analyses, appraisals and reviews of the adequacy and effectiveness of the system of internal controls, risk management practices, and corporate governance process of HECO and its subsidiaries for management and the Audit Committee of the Board of Directors; (2) reviewing organizational activities and processes and providing recommendations for improving existing business practices; (3) testing the design and operating effectiveness of the Company’s internal controls over financial reporting to assist management in achieving compliance with the requirements of the Sarbanes Oxley Act (SOX); (4) reviewing new or existing information technology systems, applications and devices to ensure the reliability of the Company’s operating systems, accuracy of data outputs and protection of equipment and information; (5) performing special studies and examinations requested by management; (6) coordinating documentation for annual audit activities.

PNC - LEGAL DEPARTMENT

The Legal Department provides legal advice and guidance to company management and employees on all areas of the company’s operations and strategic initiatives. Among other areas, the Legal Department handles legal matters involving environmental laws and compliance; regulatory matters; contract drafting, review and negotiation; litigation and claims monitoring; fuels, materials and services procurement; EEO compliance and claims (e.g., civil rights, workers' compensation, etc.); due diligence investigations for Securities and Exchange Commission filings and financing applications, including special purpose revenue bonds; purchase power agreements; land and easement acquisitions; compliance investigations;

statutory research and interpretation; counseling on engineering and construction issues; information technology rights; customer service matters; guidance on legislative matters; counseling on employment and labor contract issues; collections. The Legal Department also conducts training sessions on a variety of topics pertinent to the company's business.

The Land and Rights-of-Way Division of the Legal Department is involved in all Company land acquisition, disposition and land management functions. This typically includes obtaining required easements, substation sites, office space, generating sites and general management of the Company's real property assets.

PNID - GOVERNMENT RELATIONS DEPARTMENT

The Government Relations Department is responsible for coordinating all of the Company's legislative activities. The department monitors both the State Legislative and City Council sessions, and coordinates the Company's support of or opposition to the various bills and resolutions having an impact on the Company. The Government Relations Department coordinates the Company's government contact program involving the State Legislature and the Honolulu, Hawaii, and Maui County Councils.

PNP - REGULATORY AFFAIRS DIVISION

The Regulatory Affairs Division coordinates regulatory matters before the Public Utilities Commission. These regulatory matters include rate cases, routine filings (e.g., monitoring and regulatory compliance reports) required by the Commission or its rules, tariff filings, capital projects with estimated expenditures over $2,500,000, applications and public hearings for overhead transmission or sub-transmission lines, power purchase agreements, IRP and DSM programs, fuel contracts, customer complaints, and commission investigations.

PNR - TECHNOLOGY

The Technology Division was formed in September 2002 to monitor, evaluate, pursue, recommend and implement new energy-related technologies and alternatives (focusing on renewable energy research, development and demonstration); manage EPRI membership, technology transfer and integration with Company strategies; and support Integrated Resource Planning related to renewable energy supply-side development.

PNG – ENERGY PROJECTS DEPARTMENT

The Energy Projects Department was created in 2003 to develop utility distributed generation (DG) projects for HECO and its subsidiaries. The Department is a part of the Energy Solutions process area and its mission has expanded to include other forms of distributed energy technologies such as energy storage.

Energy Projects was responsible for the implementation of HECO's Substation DG Projects, installing 30MV of generation at various utility sites. In addition to its utility-owned DG projects, the Department is currently overseeing HECO's Archer Photovoltaic (PV) project and is developing a dispatchable standby generation (DSG) option that will allow the Company to dispatch customer-owned emergency generators to provide additional capacity during times of peak demand. Energy Projects is also a lead department in HECO's assessment of distributed energy storage technologies that may help integrate intermittent renewables and provide other ancillary services to the grid.

The Department is responsible for all aspects of project development. Energy Projects develops the business case and project scope, prepares the schedule and budget, coordinates regulatory and permit applications, and if approved, provides project management for implementation and construction.

PP0 - INDUSTRIAL RELATIONS DEPARTMENT

The Industrial Relations Department is comprised of two divisions, i.e. the Administrative Division and the Labor Relations & Wage Administration Division.

The department's major responsibilities include labor relations and wage administration (which includes day-to-day dealings with labor unions regarding compliance with the collective bargaining agreements for HECO, MECO and HELCO), personnel administration, and recognition program administration.

The following programs specifically represent major components of Labor Relations responsibilities.

- Negotiating the Collective Bargaining Agreement for HECO, MECO and HELCO.
- Administration of the Substance Abuse Program, the Federal Department of Transportation Drug and Alcohol Program.
- Administration of the Apprenticeship Program
- Administration of the Preventive Vehicle Accident and Loss of License policy.
- Performance Appraisal and wage administration system for union employees.

PQC – CORPORATE COMMUNICATIONS

Corporate Communications is responsible for coordinating external company public and media communications, as well as internal employee communications. Corporate Communications coordinates the development of the communications strategy for company issues, and helps carry out that strategy through activities such as preparing communications materials and responding to the media about issues such as proposed company infrastructure projects, rate increases, alternative energy projects, energy conservation initiatives, and other topics; communicating with customers and the media about power outages and other electric system issues; production of the company's monthly *Currents* employee newsletter; and reviewing and contributing to the development of content for the employee Intranet portal. The department also provides video and other audiovisual assistance to support employee training and safety needs; manages the corporate engineering library; provides other internal communications support functions; and helps develop investor communications regarding utility operations.

PS0 – ENERGY SERVICES DEPARTMENT

The Energy Services Department is comprised of three divisions. They are the Administrative Division, Customer Efficiency Programs Division, and Pricing Division. The major functional responsibilities for each of the divisions are as follows:

The Administrative Division is responsible for the overall supervision and direction of the work of the other divisions.

The Customer Efficiency Programs Division plans and implements the Company's demand-side management energy efficiency and load management programs. The program manager for the commercial and industrial energy efficiency programs oversees the following Division activities: meeting with large commercial customers one-on-one to explain the programs, conducting customer meetings to explain any changes in existing programs, conducting workshops on energy efficiency practices and technologies, and directing the work of outside engineering firms that support the Division in performing detailed analyses of customers' facilities. The program manager for the residential programs directs and manages a contractor who implements most of the activities of the Company's residential water heating programs. The program managers for the Company's two load control programs are responsible for all aspects of implementing those programs, including marketing, meeting with customers' facility managers and engineers, managing outside consults, and developing load control protocols. The Division develops and supports tracking and accounting systems used to monitor and report program expenses and kW and kWh impacts achieved by the programs. The Division also prepares regulatory reports and filings including program applications; the Annual Modification and Evaluation Report, which provides the findings of any Impact Evaluations and presents any recommended modifications to the programs to be made in the following year; and the Annual Accomplishments and Surcharge Report, which details the programs' performance in the past year and provides the basis for adjustments in the IRP surcharge. The Division also tracks monthly program costs for HELCO and MECO and supports those companies in IRP Planning, regulatory reporting requirements, and in implementation issues as they arise.

The Pricing Division's primary responsibilities include: the development and accurate implementation of the Company's tariffs (both rates and rules) for HECO, HELCO, and MECO; (2) providing expert testimonies on revenues, cost-of-service, and rate design for rate case purposes for HECO, HELCO, and MECO; (3) development of cost of service studies and rate research studies for new tariff proposals for HECO, HELCO, and MECO for PUC filings; (4) development and implementation of cost recovery mechanisms and any temporary rate adjustments approved and/or ordered by the PUC; (5) development of tariff-related customer contracts, including preparation of the applications for PUC approval of such contracts; (6) providing rate analyses and/or tariff interpretations to other employees upon request, in response to customers' tariff inquiries, and (7) administering and calculating the utilities' monthly Energy Cost Adjustment Clause and quarterly Avoided Cost Payment Rate filings.

PSM – FORECASTS AND RESEARCH

The Forecasts and Research Division develops the Company's short and long-term sales and demand forecasts and assists HELCO and MECO with their sales and demand forecast process. These projections are used for financial planning and resource planning purposes. The Division also provides electric revenue forecasts for the utility companies. The Division also provides follow-up support for the Company's forecasts including variance reporting. The Division also coordinates and conducts load research projects for HECO, MECO and HELCO.

The Division also provides support for a number of activities that help the Company provide products, services, and features designed to meet the wants, needs, and expectations of its customers, for which the labor is recorded in account 910. The Division conducts ongoing assessments of customer satisfaction and expectations, market conditions and trends, energy usage and technology adoption patterns, and related activities intended to help the Company understand and meet customer expectations. The Division coordinates the modeling of the impacts of new and enhanced demand-side management ("DSM") programs for IRP purposes and is responsible for conducting evaluations of implemented DSM programs. The Division coordinates the Company's mass market advertising efforts for DSM and educational and awareness purposes. The Division also provides budget and accounting support to ensure proper accounting and tax treatment, and to ensure that transactions are recorded in accordance with generally accepted accounting principles. The Division conducts similar work to that described above for HECO's subsidiary companies, HELCO and MECO.

V9 - SUPPORT SERVICES DEPARTMENT

The Support Services Department is comprised of five divisions. Two of the five divisions incur costs chargeable to administrative expenses, i.e. the Administrative Division, and the Purchasing Division. The Purchasing Division handles procurement of all HECO expenditures for goods and provides purchasing assistance to HELCO and MECO. The Purchasing Division also administers contracts for the majority of HECO's expenditures for services.

PYP - INTEGRATED RESOURCE PLANNING

The test year amounts represent the costs of activities directly related to coordinating and managing of the Integrated Resource Planning (IRP) process within HECO and with the public advisory group, which include meeting with the advisory group and public, development of the IRP plan, preparation of the IRP report, and regulatory activities. Also included in the test year amounts are long range resource planning activities that are related to HECO's IRP Plan, such as working with government agencies on their energy plans or on HECO's business strategies.

PXO – SYSTEM PLANNING

The System Planning department consists of the Generation Planning Division, Transmission Planning Division and the Generation Bidding Division. Most of the costs for the department are charged to functional accounts, and only a small portion of the expenses of the department are administrative in nature. For the test year administrative costs relate to supporting the integrated resource planning process, and support for the rate case.

PY9 – ENGINEERING

Only a small portion of the Engineering Department's costs is charged to administrative expenses. The test year amount represents the Structural Division's assistance to the Facilities Planning Division's work related to infrastructure improvements.

PY9 – POWER SUPPLY ENGINEERING

Only a small portion of the Power Supply Engineering Department's costs is charged to administrative expenses. The test year amount represents the costs of activities with respect to testing/training on the upgrade to Ellipse 6.

P1V-P9V - EXECUTIVE RELATED COSTS

Labor and non-labor costs associated with the Company's executives are included in administrative expenses. Executive-related costs generally represent the costs incurred in the overall supervision and direction of Company activities.

Hawaiian Electric Company, Inc.
Performance Incentive Compensation
($ Thousands)

	Account	2003	2004	2005	2006	2007	Budget 2008	Budget 2009
PRODUCTION OPERATIONS - OTHER AWARDS	506	140	50	173	(254)	-	357	386
PRODUCTION MAINTENANCE - OTHER AWARDS	514	-	1	-	-	-	-	-
TRANSMISSION OPERATION - RESTRICTED STOCK	560	-	-	-	-	2	3	8
TRANSMISSION OPERATION - OTHER AWARDS	566	41	12	39	(41)	-	54	59
DISTRIBUTION OPERATION - OTHER AWARDS	588	110	(13)	126	(115)	-	132	143
DISTRIBUTION MAINTENANCE - OTHER AWARDS	598	2	1	-	2	-	-	-
CUSTOMER SERVICE - RESTRICTED STOCK	909	-	-	-	-	1	2	5
LTIP/EICP	920	986	1,188	1,192	(625)	276	1,779	2,364
ADMIN & GENL - OTHER AWARDS	920	325	428	442	(310)	4	239	258
ADMIN & GENL - RESTRICTED STOCK	920	-	-	-	-	117	194	372
TOTAL FOR ACCOUNT 920		1,311	1,616	1,634	(935)	397	2,212	2,994
ADMIN & GENL - OTHER AWARDS	921	42	42	44	44	42	40	55
ADMIN & GENL - RESTRICTED STOCK	921	-	-	-	-	2	6	16
HEI CHARGES TO HECO (included in interco charges)	921	-	-	260	217	231	-	223
HEI CHARGES TO HECO	921	317	338	820	294	181	123	49
TOTAL FOR ACCOUNT 921		359	380	1,124	555	456	169	343
HEI CHARGES TO HECO	926	-	-	-	-	-	-	74
MISC GENERAL - RESTRICTED STOCK	9302	-	-	-	-	1	1	3
HEI CHARGES TO HECO	9302	-	-	-	-	-	-	104
TOTAL FOR ACCOUNT 9302		-	-	-	-	1	1	107
HEI CHARGES TO HECO	931	-	-	-	-	-	-	(22)
Total Performance Incentive Compensation		1,963	2,047	3,096	(788)	857	2,930	4,097

*HEI Charges to HECO in interco charges for recorded years 2003-2004 is not available.

HAWAIIAN ELECTRIC COMPANY, INC.
EFFECT OF GENERAL PAY INCREASE

RELATIVE WAGE RATES

	2007		2008		2009	
	BU	Merit	BU	Merit	BU	Merit
JAN	1.0000	1.0000	1.0350	1.0401	1.0750	1.0816
FEB	1.0000	1.0000	1.0350	1.0401	1.0750	1.0816
MAR	1.0000	1.0000	1.1050	1.0401	1.0750	1.0816
APR	1.0000	1.0000	1.0350	1.0401	1.0750	1.0816
MAY	1.0000	1.0350	1.0350	1.0764	1.0750	1.1249
JUN	1.0000	1.0350	1.0350	1.0764	1.0750	1.1249
JUL	1.0000	1.0350	1.0350	1.0764	1.0750	1.1249
AUG	1.0000	1.0350	1.0350	1.0764	1.0750	1.1249
SEP	1.0000	1.0375	1.0350	1.0795	1.0750	1.1281
OCT	1.0000	1.0375	1.0350	1.0795	1.0750	1.1281
NOV	1.0000	1.0375	1.0350	1.0795	1.0750	1.1281
DEC	1.0000	1.0375	1.0350	1.0816	1.0750	1.1303
TOTAL	12.000	12.290	12.490	12.786	12.900	13.341
	(A)	(B)	(C)	(D)	(E)	(F)

			BU	Merit	
Percentage increase 2009 over 2007 (G)	BU (E-A)/A	Merit (F-B)/B	7.50%	8.55%	
FY2007 Account 92000 Labor ($000)			1,106	10,868	
Increase in labor from 2007 due to general pay increase ($000			83 +	929 =	1,012

Assumptions:

BU Increases	11/1/2007	3.5% of 10/31/07 rates retroactive payment in 3/08
	1/1/2009	4.0% of 10/31/07 rates
Merit Increases	5/1/2007	3.5% of 4/30/2007 rates
	9/1/2007	0.25% of 4/30/2007 rates
	11/1/2007	0.25% of 4/30/2007 rates retroactive payment in 1/08
	5/1/2008	3.5% of 4/30/08 rates
	9/1/2008	0.30% of 4/30/2008 rates
	12/1/2008	0.20 % of 4/30/08 rates
	5/1/2009	4.0% of 4/30/09 rates
	9/1/2009	0.30% of 4/30/2009 rates
	12/1/2009	0.20% of 4/30/09 rates

HAWAIIAN ELECTRIC COMPANY, INC.
A/C 920-A&G SALARIES
Additional Positions Performing Administrative Activities

	Position	Budget Assumption Hire Date	Hours	2009
6V	Director, Corporate Excellence Compliance	04/2008	1,904	84,328
7V	Manager, Renewable Integration	01/2008	1,753	101,621
9W	Senior Executive VP & Chief Operating Officer	02/2008	1,896	228,240
9W	Executive Secretary	02/2008	1,840	46,644
AC	Corporate Accountant	12/2008	1,944	67,457
FD	Talent Assessment and Development Specialist	01/2009	1,904	66,069
FD	Testing Specialist (Part-time)	01/2009	952	24,133
FI	Organizational Development Analyst	01/2009	1,887	65,479
FI	Corporate Internship Program (2)	01/2009	3,968	175,743
FI	Corporate Mentorship Program (2 & 1 Part-time)	01/2009	4,960	298,146
HS	Security Officer	01/2009	1,904	48,266
NP	Director, Regulatory Affairs (2)	12/2008	3,660	162,101
NP	Regulatory Analyst II (2)	12/2008	3,176	110,207
NP	Legal Assistant	02/2008	1,916	48,571
SP	Senior Rate Analyst	01/2009	1,615	56,041
	Subtotal		35,279	1,583,046
	Add: Nonproductive Wages On-cost			176,395
	Total Effect of "New" Positions			1,759,441

HAWAIIAN ELECTRIC COMPANY, INC.
A/C 920-A&G SALARIES
Impact of positions not filled for entire 2007

		2007	2009				
		Actual	Merit		BU		TOTAL
	Position	Charges	Hours	Dollars	Hours	Dollars	
6V	Analyst	21,456	1,824	63,293			
AC	Financial Systems Analyst	32,431	1,548	53,716			
AD	Various Clerks	148,345			6,900	185,265	
EC	Records Clerk (formerly machine operator)[1]	0			1,888	50,693	
EM	Mail Clerk (formerly machine operator)[1]	0			1,896	50,908	
EM	Mailing Service Coordinator	19,275	1,896	48,064			
HB	Custodian	0			1,851	59,843	
HS	Security Officer	0	1,702	43,146			
KB	Secretary	29,856	1,752	44,413			
KF	Financial Analyst	33,268	1,894	65,722			
NA	Auditor	11,538	1,329	46,116			
NA	Auditor (Interns)	26,122	2,464	36,344			
NI	Director	46,813	1,688	74,762			
NP	Sr. Regulatory Analyst	42,453	1,588	55,104			
NX	Manager, Corporate Audit & Compliance	44,729	1,624	97,619			
NX	Secretary	0	660	16,731			
PI	Consultant	29,846	1,968	68,290			
QC	Director	24,092	856	37,912			
SP	Rate Analyst [3]	0	1,493	51,807			
	Subtotal	510,224 (a)	24,286	803,037	12,535	346,708	
	Add: 2009 Nonproductive Wages On-cost			121,430		62,675	
				924,467		409,383	
	2009 General Wage Increase Factor[3]			1.0855		1.0750	
				851,651		380,822	1,232,472
	2007 Actual Charges						(510,224)
	Total Effect of Vacancies						722,248

1 Former positions' labor charges were recorded to Account 903, not to Account 920.

2 Incumbent was on temporary leave in 2007; no labor charges in Account 920 in 2007.

3 HECO-1105

INFLATION ADJUSTMENT 1.025 1.025

Activity code	HECO EXCLUDING INCENTIVE COMPENSATION ACTIVITY CODE DESCRIPTIONS	Direct Charges-2007 Direct Labor Hours	Direct Charges-2007 Direct Labor Dollars	Direct Charges-2007 Direct Nonlabor Dollars	Shared Charges-2007 Shared Labor Hours	Shared Charges-2007 2008 Allocation Factor	Shared Charges-2007 Shared Labor Dollars	Shared Charges-2007 Shared Nonlabor Dollars	2007 Actual w/ 2008 Alloc Factor	2008 Adjustments	2008 Estimate (1)	2009 Adjustments	2009 Estimate (2)
ACC	**Accounting**												
ACC 001	Research accounting issues				1.00	41.0%	33.35		33.35		34.18		35.03
ACC 004	Maintain general ledger	15.00	960.60						960.60		984.62		1,009.24
ACC 009	Monitor accounting and reporting standards				34.00	41.0%	2,026.58	571.42	2,598.00		2,662.95		2,729.52
ACC 018	Intercompany billing administration	2.00	112.75		495.50	40.0%	11,048.71		11,161.46		11,440.50		11,726.51
	System rounding adjustment						(0.02)		(0.02)		(0.02)		(0.02)
		17.00	1,073.35	0.00	530.50		13,108.62	571.42	14,753.39	0.00	15,122.23	0.00	15,500.28
ADM	**Administrative**												
ADM 004	Maintenance of corporate records			389.02					389.02		398.75		408.72
ADM 006	Assist on HECO rate case	572.50	48,163.29						48,163.29	26,584.45 (3)	76,616.43		78,531.84
ADM 007	Corporate risk review				6.25	40.0%	678.23	63.60	741.83		760.38		779.39
ADM 008	Administration of company policies				11.50	41.9%	1,625.26		1,625.26		1,665.89		1,707.54
ADM 011	Telephone charges			4.81					4.81	(4.81) (5)	0.00		0.00
ADM 012	Rent - ASB Tower			25,766.43					25,766.43	(25,766.43) (5)	0.00		0.00
ADM 014	Rent - Central Pacific			12,096.00					12,096.00	(12,096.00) (5)	0.00		0.00
ADM 015	Assist on HELCO rate case	254.00	23,761.66	11.39					23,773.05	(23,773.05) (6)	0.00		0.00
ADM 016	Assist on MECO rate case	847.50	68,258.54						68,258.54	(68,258.54) (6)	0.00		0.00
	System rounding adjustment		(0.03)						(0.03)		(0.03)		(0.03)
		1,674.00	140,183.46	38,267.65	17.75		2,303.49	63.60	180,818.20	(103,314.38)	79,441.42	0.00	81,427.46
ANN	**Annual meeting**												
ANN 001	Annual shareholder meeting planning & coordination				68.50	40.7%	5,203.83	44,160.41	49,364.24		50,598.35		51,863.31
ANN 002	Annual meeting facilities					40.7%		317.26	317.26		325.19		333.32
	System rounding adjustment							(0.03)	(0.03)		(0.03)		(0.03)
		0.00	0.00	0.00	68.50		5,203.83	44,477.64	49,681.47	0.00	50,923.51	0.00	52,196.60
AUD	**Audits**												
AUD 004	Audit Committee meeting preparation	10.00	2,776.45						2,776.45		2,845.86		2,917.01
AUD 005	Audit Committee meeting attendance	17.00	9,934.35	856.13					10,790.48		11,060.24		11,336.75
AUD 006	Coordinate activities with external auditors					41.0%		179.74	179.74		184.23		188.84
	System rounding adjustment		(0.02)					(0.01)	(0.03)		(0.03)		(0.03)
		27.00	12,710.78	856.13	0.00		0.00	179.73	13,746.64	0.00	14,090.30	0.00	14,442.57
CON	**Consulting - general**												
CON 002	Meetings	93.50	90,690.34	57.14					90,747.48		93,016.17		95,341.57
CON 015	HECO Internal Audit	312.00	28,713.36						28,713.36	77,489.26 (7)	108,857.69		111,579.13
CON 016	VP General Counsel								0.00		0.00	142,095.00 (8)	145,647.38
	System rounding adjustment		(0.01)						(0.01)		(0.01)		(0.01)
		405.50	119,403.69	57.14	0.00		0.00	0.00	119,460.83	77,489.26	201,873.85	142,095.00	352,568.07
FIN	**Financing**												
FIN 002	Debt financing due diligence	18.00	2,248.92						2,248.92	(2,248.92) (5)	0.00		0.00
FIN 009	Rating agency matters	9.00	643.58						643.58		659.67		676.16
	System rounding adjustment		(0.01)						(0.01)	0.01	0.00		0.00
		27.00	2,892.49	0.00	0.00		0.00	0.00	2,892.49	(2,248.91)	659.67	0.00	676.16

HECO

EXCLUDING INCENTIVE COMPENSATION

Activity code	ACTIVITY CODE DESCRIPTIONS	Direct Charges-2007: Direct Labor Hours	Direct Charges-2007: Direct Labor Dollars	Direct Charges-2007: Direct Nonlabor Dollars	Shared Charges-2007: Shared Labor Hours	Shared Charges-2007: 2008 Allocation Factor	Shared Charges-2007: Shared Labor Dollars	Shared Charges-2007: Shared Nonlabor Dollars	2007 Actual w/ 2008 Alloc Factor	2008 Adjustments	2008 Estimate (1)	2009 Adjustments	2009 Estimate (2)
HUM	**Human Resources**												
HUM 001	Benefits consulting services					41.9%		460.68	460.68		472.20		484.01
HUM 002	Compensation consulting services	15.50	1,218.92		227.50	53.3%	9,535.70	16,191.94	26,946.56	372.95 (9)	28,002.50		28,702.56
HUM 003	Personnel issues					41.9%		272.01	272.01		278.81		285.78
HUM 008	Code of Conduct development and administrative assistance	7.00	1,702.59		193.50	41.9%	8,619.56		10,322.15		10,580.20		10,844.71
HUM 010	Compensation committee meetings	28.65	7,338.63		762.25	53.3%	55,494.80	4,583.49	67,416.92	186.48 (9)	69,293.49		71,025.83
HUM 011	Long-term incentive plan (LTIP)	5.60	1,087.86		94.25	30.0%	2,650.74	3,712.94	7,451.54	(7,451.54) (10)	0.00		0.00
HUM 012	Executive incentive compensation plan (EICP)	5.25	1,972.65		86.00	51.6%	5,819.58	3,163.84	10,956.07	(10,956.07) (10)	0.00		0.00
HUM 013	Stock options with dividend equivalents	23.85	1,366.56		446.50	41.6%	15,588.25	25,267.71	42,222.52	(42,222.52) (10)	0.00		0.00
HUM 015	Executives deferred compensation	0.75	43.73		4.50	66.7%	202.30		246.03	(246.03) (10)	0.00		0.00
HUM 017	Executive incentive compensation consulting services				3.50	51.6%	169.37	352.56	521.93	(521.93) (10)	0.00		0.00
HUM 018	Other incentive compensation consulting services			4,933.45					4,933.45	(4,933.45) (10)	0.00		0.00
HUM 019	Executive Incentive Compensation - Sarbanes Oxley Related Charges				32.50	51.6%	1,310.63	2,183.67	3,494.30	(3,494.30) (10)	0.00		0.00
HUM 023	Restricted stock grants	8.00	662.96		181.90	41.0%	6,471.74	13,019.59	20,154.29	(20,154.29) (10)	0.00		0.00
HUM 024	Directors compensation				33.00	23.8%	679.98	1,353.10	2,033.08		2,083.91		2,136.01
	System rounding adjustment		(0.01)				(0.05)	(0.09)	(0.15)		(0.15)		(0.15)
		94.60	15,393.89	4,933.45	2,065.40		106,542.60	70,561.44	197,431.38	(89,420.70)	110,710.96	0.00	113,478.75
INV	**Investor Relations**												
INV 001	Analyst/media communications				113.50	40.7%	5,503.70		5,503.70		5,641.29		5,782.32
INV 003	Fact sheet				5.00	40.7%	132.42	1,260.16	1,392.58		1,427.39		1,463.07
INV 004	Financial mailing list				6.50	40.7%	158.20	5,259.00	5,417.20		5,552.63		5,691.45
INV 005	Financial news releases	3.00	2,909.85		249.75	40.7%	15,304.26	3,343.46	21,557.57		22,096.51		22,648.92
INV 006	Group analyst meetings			1,439.13	610.50	40.7%	51,690.14	76,454.51	129,583.78		132,823.37		136,143.95
INV 007	HEI stock - share forecast				26.00	40.7%	688.57		688.57		705.78		723.42
INV 008	Investor base/stockholder monitoring				16.00	40.7%	613.72		613.72		629.06		644.79
INV 009	Investor relations planning				16.00	40.7%	456.22		456.22		467.63		479.32
INV 012	One-on-one meetings/visits with analysts				47.00	40.7%	6,457.34	183.22	6,640.56		6,806.57		6,976.73
INV 013	Other investor relations activities				320.00	40.7%	12,106.40	47,363.54	59,469.94		60,956.69		62,480.61
INV 014	Retail program				19.00	40.7%	933.94	562.69	1,496.63		1,534.05		1,572.40
INV 015	Retail/broker/shareholder communications				73.00	40.7%	3,530.44		3,530.44		3,618.70		3,709.17
INV 018	Statistical supplement				26.50	40.7%	763.00		763.00		782.08		801.63
INV 019	Surveys				21.50	49.4%	875.38		875.38		897.26		919.69
INV 020	Teleconferencing	7.50	906.83		106.25	40.7%	5,089.87	1,018.07	7,014.77		7,190.14		7,369.89
INV 022	Investor Relations-Sarbanes Oxley Related Chgs				4.00	40.7%	103.74	295.99	399.73		409.72		419.96
	System rounding adjustment						(0.04)	(0.07)	(0.11)		(0.11)		(0.11)
		10.50	3,816.68	1,439.13	1,660.50		104,407.30	135,740.57	245,403.68	0.00	251,538.76	0.00	257,827.21
RPT	**Reports**												
RPT 001	10K preparation	105.75	8,488.88	6,249.57	1,032.50	41.0%	44,897.00	50,090.59	109,726.04		112,469.19		115,280.92
RPT 004	10K - Sarbanes Oxley Related Charges				65.00	41.0%	2,333.05		2,333.05		2,391.38		2,451.16
RPT 011	10Q preparation	4.50	420.66		1,008.75	41.0%	38,359.24	36,204.46	74,984.36		76,858.97		78,780.44
RPT 021	8K preparation	2.00	158.66	5,988.61	79.50	41.0%	2,597.13	7,584.25	16,328.65		16,736.87		17,155.29
RPT 041	Proxy preparation				774.70	40.7%	37,330.56	83,385.65	120,716.21		123,734.12		126,827.47
RPT 045	Proxy printing and mailing					38.3%		166,291.10	166,291.10		170,448.38		174,709.59
RPT 051	Annual report preparation				452.00	41.0%	20,572.17	124,492.25	145,064.42		148,691.03		152,408.31
RPT 055	Annual report printing and mailing					38.6%		78,576.49	78,576.49		80,540.90		82,554.42
RPT 098	Financial Reporting-Sarbanes Oxley Related Charges				6.50	41.0%	275.58	1,370.22	1,645.80		1,686.95		1,729.12
	System rounding adjustment		(0.02)				(0.07)	0.04	(0.05)		(0.05)		(0.05)
		112.25	9,068.18	12,238.18	3,418.95		146,364.66	547,995.05	715,666.07	0.00	733,557.74	0.00	751,896.67

HECO

EXCLUDING INCENTIVE COMPENSATION

		Direct Charges-2007			Shared Charges-2007								
Activity code	ACTIVITY CODE DESCRIPTIONS	Direct Labor Hours	Direct Labor Dollars	Direct Nonlabor Dollars	Shared Labor Hours	2008 Allocation Factor	Shared Labor Dollars	Shared Nonlabor Dollars	2007 Actual w/ 2008 Alloc Factor	2008 Adjustments	2008 Estimate (1)	2009 Adjustments	2009 Estimate (2)
STO	**Stock Transfer activities**												
STO 001	Preferred stock dividend payments	35.05	2,366.86						2,366.86		2,426.03		2,486.68
STO 003	Form 1099 (for preferred stockholders)	10.50	730.97						730.97		749.24		767.97
STO 004	Preferred stockholder database maintenance	3.00	168.09						168.09		172.29		176.60
STO 006	Preferred stock transfer administrative activities	32.60	1,965.15	263.65					2,228.80		2,284.52		2,341.63
STO 011	Common stock dividend payments				113.80	38.3%	2,671.23	3,636.47	6,307.70		6,465.39		6,627.02
STO 012	HEI dividend reinvestment program administration				2,011.25	38.3%	46,382.07	95,021.46	141,403.53	(36,997.46) (13)	107,016.22	18,498.73 (14)	128,652.82
STO 013	Form 1099 Dividends				45.00	38.3%	1,047.97	1,361.66	2,409.63		2,469.87		2,531.62
STO 014	Common stockholder database maintenance	1.00	61.34		603.65	38.3%	13,321.67	1,180.40	14,563.41		14,927.50		15,300.69
STO 015	Other common stock communications				1,650.95	38.3%	39,943.84		39,943.84		40,942.44		41,966.00
STO 016	Common stock transfer administrative activities				2,429.55	38.3%	66,106.91	9,843.40	75,950.31		77,849.07		79,795.30
STO 018	Stock transfer system				111.50	38.3%	2,471.42	51,288.75	53,760.17		55,104.17		56,481.77
STO 019	Stock transfer division expenses					38.3%		45,298.46	45,298.46		46,430.92		47,591.69
STO 020	Stock transfer division miscellaneous income					38.3%		(42,705.79)	(42,705.79)		(43,773.43)		(44,867.77)
STO 021	Stock Transfer division -Sarbanes Oxley Related Chgs				49.50	38.3%	1,740.64	2,947.43	4,688.07		4,805.27		4,925.40
	System rounding adjustment		(0.09)				(0.06)	(0.07)	(0.22)		(0.23)		(0.24)
		82.15	5,292.32	263.65	7,015.20		173,685.69	167,872.17	347,113.83	(36,997.46)	317,869.27	18,498.73	344,777.18
STR	**Strategic Planning**												
STR 002	Financial planning, research, analysis	2.50	228.63						228.63	(228.63) (5)	0.00		0.00
STR 005	Performance standards, measurement, analysis	1.00	91.45						91.45	(91.45) (5)	0.00		0.00
	System rounding adjustment								0.00		0.00		0.00
		3.50	320.08	0.00	0.00		0.00	0.00	320.08	(320.08)	0.00	0.00	0.00
TAX	**Tax**												
TAX 101	Federal income tax return preparation	243.75	15,616.05	36,861.18	156.75	29.6%	3,014.99	5,114.13	60,606.35	(20,000.00) (15)	41,621.51		42,662.05
TAX 102	Hawaii state income tax return preparation including franchise	31.50	2,991.01		6.00	29.6%	96.54		3,087.55		3,164.74		3,243.86
TAX 104	Other information returns preparation	3.50	205.25						205.25		210.38		215.64
TAX 105	Federal income tax return review	49.50	4,996.35		32.00	29.6%	1,014.60		6,010.95		6,161.22		6,315.25
TAX 106	Hawaii state income tax return review including franchise	1.00	95.12		21.00	29.6%	389.37		484.49		496.60		509.02
TAX 108	Other information return review	48.00	3,019.80						3,019.80		3,095.30		3,172.68
TAX 110	Tax research	97.25	6,184.05	112.84	3.50	29.6%	55.23		6,352.12		6,510.92		6,673.69
TAX 111	Tax accrual preparation and review	182.25	14,110.27		52.75	29.6%	1,891.74		16,002.01		16,402.06		16,812.11
TAX 112	Quarterly tax account reconciliations	86.50	6,076.48						6,076.48		6,228.39		6,384.10
TAX 113	Federal tax audits and inquiry responses	337.75	23,334.39	25.42	109.50	29.6%	2,682.39		26,042.20		26,693.26		27,360.59
TAX 114	State tax audits and inquiry responses	0.25	23.78						23.78		24.37		24.98
TAX 116	Federal income estimated tax payment	3.50	332.39		17.70	29.6%	372.07		704.46		722.07		740.12
TAX 117	Other nonpayroll federal tax payments	1.00	64.04						64.04		65.64		67.28
TAX 118	Hawaii state income estimated tax payment	1.10	102.83		28.50	29.6%	530.35		633.18		649.01		665.24
TAX 120	Other Hawaii state and county tax payments	34.25	2,116.57						2,116.57		2,169.48		2,223.72
TAX 121	Payroll tax payments and information reporting	63.50	3,658.85						3,658.85		3,750.32		3,844.08
TAX 122	Executive payroll matters	16.00	1,016.65						1,016.65		1,042.07		1,068.12
TAX 123	Sarbanes Oxley compliance	55.00	3,918.80		16.00	29.6%	365.75	1,204.72	5,489.27		5,626.50		5,767.16
TAX 124	Technical reading				139.75	29.6%	3,800.38		3,800.38		3,895.39		3,992.77
TAX 125	Fixed assets	88.00	5,612.12						5,612.12		5,752.42		5,896.23
TAX 126	Tax administrative matters	12.25	685.59						685.59		702.73		720.30
TAX 128	Tax and financial planning	191.75	18,739.74		69.00	29.6%	2,513.58		21,253.32		21,784.65		22,329.27
TAX 129	Tax Clearances	12.75	682.31						682.31		699.37		716.85
TAX 130	Other tax matters	74.00	9,307.26		6.50	29.6%	146.58		9,453.84		9,690.19		9,932.44
	System rounding adjustment		(0.13)				(0.05)		(0.18)		(0.18)		(0.18)
		1,634.35	122,889.57	36,999.44	658.95		16,873.52	6,318.85	183,081.38	(20,000.00)	167,158.41	0.00	171,337.37
	Total of all activity codes	4,087.85	433,044.49	95,054.77	15,435.75		568,489.71	973,780.47	2,070,369.44	(174,812.27)	1,942,946.12	160,593.73	2,156,128.32

HECO

EXCLUDING INCENTIVE COMPENSATION

Activity code	ACTIVITY CODE DESCRIPTIONS	Direct Charges-2007 Direct Labor Hours	Direct Charges-2007 Direct Labor Dollars	Direct Charges-2007 Direct Nonlabor Dollars	Shared Charges-2007 Shared Labor Hours	Shared Charges-2007 2008 Allocation Factor	Shared Charges-2007 Shared Labor Dollars	Shared Charges-2007 Shared Nonlabor Dollars	2007 Actual w/ 2008 Alloc Factor	2008 Adjustments	2008 Estimate (1)	2009 Adjustments	2009 Estimate (2)
BOD	**Board of Directors**												
BOD 001	Board of Directors meetings	351.50	24,316.10	931.36					25,247.46		25,878.65		26,525.62
BOD 002	Attendance (presentations)	32.25	24,363.10	753.30					25,116.40		25,744.31		26,387.92
BOD 003	Minutes	18.00	4,386.37						4,386.37		4,496.03		4,608.43
BOD 004	Review of minutes	4.00	970.65						970.65		994.92		1,019.79
BOD 005	Misc. board matters	1.50	360.70	5,185.83					5,546.53		5,685.19		5,827.32
	System rounding adjustment		(0.03)						(0.03)		(0.03)		(0.03)
		407.25	54,396.89	6,870.49	0.00		0.00	0.00	61,267.38	0.00	62,799.07	0.00	64,369.05
PEN	**Pension plan**												
PEN 005	HEIRS				628.45	47.1%	20,566.00	13,212.75	33,778.75	(33,778.75) (11)	0.00		0.00
PEN 007	HEI Retirement Plan				13.50	71.3%	788.03		788.03		807.73		827.92
PEN 009	Master pension trust				1,034.50	65.1%	77,538.49	7,973.72	85,512.21	1,574.25 (12)	89,263.62		91,495.21
PEN 010	Pension-Sarbanes Oxley Related Charges				18.25	65.1%	1,037.42	1,136.46	2,173.88		2,228.23		2,283.94
PEN 022	Supplemental Exec. Retirement plan	1.00	243.98		17.50	33.3%	1,421.79	881.95	2,547.72	(2,547.72) (11)	0.00		0.00
PEN 025	HECO OPEB NBU VEBA				76.50	69.2%	4,091.11		4,091.11		4,193.39		4,298.22
PEN 026	OPEB funded plans/trusts			836.74	964.75	68.2%	61,168.42	2,736.32	64,741.48	1,649.21 (12)	68,050.46		69,751.72
PEN 027	Excess plans				2.50	61.1%	372.68	809.12	1,181.80	(1,181.80) (11)	0.00		0.00
PEN 028	HECO OPEB Plan	7.00	451.15		70.75	68.2%	3,510.42		3,961.57		4,060.61		4,162.13
PEN 030	HEI postretirement benefits trust (electric discount)				3.00	48.5%	118.13		118.13		121.08		124.11
	System rounding adjustment						(0.01)	(0.05)	(0.06)		(0.06)		(0.06)
		8.00	695.13	836.74	2,829.70		170,612.48	26,750.27	198,894.62	(34,284.81)	168,725.06	0.00	172,943.19
ADM	**Administrative**												
ADM 010	Training rooms			71,461.94					71,461.94	906.35 (4)	74,177.50		76,031.94
INT	**Internet**												
INT 002	Firewall services					32.0%		12,508.41	12,508.41	2,156.96 (16)	15,032.00	1,194.35 (16)	16,632.01
INT 003	Internet services					33.0%		5,088.59	5,088.59	(1,342.41) (16)	3,839.83	324.88 (16)	4,268.83
INT 004	Shared internet connection					58.6%		30,316.11	30,316.11	2,271.18 (16)	33,401.97	4,902.39 (16)	39,261.97
INT 005	File Transfer Protocol (FTP) server					90.0%		10,708.21	10,708.21	(3,368.60) (16)	7,523.10	79.92 (16)	7,793.10
INT 006	Disaster recovery (ISDN line)			36.21					36.21		37.12		38.05
	System rounding adjustment							0.07	0.07		0.07		0.07
		0.00	0.00	36.21	0.00		0.00	58,621.39	58,657.60	(282.87)	59,834.09	6,501.54	67,994.03

HECO

EXCLUDING INCENTIVE COMPENSATION

Activity code	ACTIVITY CODE DESCRIPTIONS	Direct Charges-2007 Direct Labor Hours	Direct Charges-2007 Direct Labor Dollars	Direct Charges-2007 Direct Nonlabor Dollars	Shared Charges-2007 Shared Labor Hours	Shared Charges-2007 2008 Allocation Factor	Shared Charges-2007 Shared Labor Dollars	Shared Charges-2007 Shared Nonlabor Dollars	2007 Actual w/ 2008 Alloc Factor	2008 Adjustments	2008 Estimate (1)	2009 Adjustments	2009 Estimate (2)

Notes:

(1) The 2008 estimate was based upon the 2007 actuals using the 2008 allocation factors adjusted by 2.5% for estimated cost increases.

(2) The 2009 estimate was based upon the 2008 estimate adjusted by 2.5% for estimated cost increases.

(3) The 2007 actual was adjusted to include more time to be spent to provide assistance in the HECO rate case primarily by the HEI Tax Department (HECO does not have its own tax department).

(4) The 2007 actual was adjusted to include slightly higher rent & related charges associated with the usage of the ASB Tower training rooms by HECO.

(5) The 2007 actual was adjusted to exclude rent for ASB Tower and Central Pacific, telephone charges, debt financing charges and strategic planning charges which are not expected to be incurred in the future.

(6) The 2007 actual was adjusted to exclude costs related to rate case assistance which are not expected to occur in 2008 and 2009.

(7) The 2007 actual was adjusted to include the full year impact of the HEI Internal Auditor who also holds the position of HECO Internal Auditor. The HEI Internal Auditor expects to spend approximately 50% of his time on HECO matters and the other 50% on HEI and other subsidiary matters.

(8) The 2009 estimate was increased for the HEI VP General Counsel who expects to spend approximately 25% of his time working on the following HECO matters: 1) Corporate Governance issues for the HECO board 2) SEC work as it relates to HECO the SEC Registrant (Forms 10-K and 10-Q) 3) assisting the HECO legal department in providing a greater role in the company and 4) administering the ethics point hotline for whistleblower complaints against the company.

(9) The 2007 actual was adjusted to include more time assisting with HECO compensation matters by the HEI Compensation & Accounting Administrator hired in 08/07.

(10) The 2007 actual was adjusted to exclude costs related to incentive compensation. This adjustment was made to simplify the issues related to this rate case only.

(11) The 2007 actual was adjusted to exclude costs related to the administration of the HEI Retirement Savings Plan, Supplemental Executive Retirement Plan and Excess Plans. These adjustments were made to simplify the issues related to this rate case only.

(12) The 2007 actual was adjusted to include time for the Manager, Treasury in her new role as a member of the Investment Committee which serves the Pension Investment Committee effective in 2008.

(13) The 2007 actual was adjusted to exclude DRIP prospectus and registration costs for 2008 as these costs are expected to be incurred every 2 - 3 years.

(14) The 2008 estimate was adjusted to include a normalization adjustment for DRIP prospectus and registration costs for 2009. These cost are expected to be incurred every 2 - 3 years.

(15) The 2007 actual was adjusted to exclude certain outside tax consulting costs which are not expected to be incurred in the future.

(16) The 2007 actual was adjusted to projected 2008 internet expense. The 2009 increase is primarily due to the increased total bandwidth to handle the growth in the usage of the internet.

HECO Charges to HEI

2009 Test Year

Group	ICB Code	Workorder #	Description	2007 Total (3)	2008 Estimate (1)	2009 Estimate (2)
ANNUAL MEETING ACTIVITIES						
	ANN 001	AD000684	GM Svc Fees for HEI - Annual mtg	11,346.76	11,630.43	11,921.19
	ANN 001	CR000047	Annual meeting - communications	2,900.81	2,973.33	3,047.66
	ANN 002	AD001377	HECO work for HEI - Ann Mtg Setup	779.51	799.00	818.98
			Total annual meeting charges	15,027.08	15,402.76	15,787.83
			2008 HECO allocation factor	40.7%	40.7%	40.7%
			Total annual meeting charges billed to HECO	6,116.02	6,268.92	6,425.65
HUMAN RESOURCES						
	HUM010	HR001476	HEI - Executive Comp	6,446.87	6,608.04	6,773.24
			Total human resources charges	6,446.87	6,608.04	6,773.24
			2008 HECO allocation factor	53.3%	53.3%	53.3%
			Total human resources charges billed to HECO	3,436.18	3,522.09	3,610.14
INVESTOR RELATIONS ACTIVITIES						
	INV004	IT000293	HEI - IR Printing Services	93.67	96.01	98.41
	INV006	AD000201	GM Service Fees for HEI-Inv Rel	14,183.68	14,538.27	14,901.73
	INV006	AD000202	GM Service Fees for HEI-Inv Rel Meals	2,894.40	2,966.76	3,040.93
	INV013	AD000196	GM Service Fees for HEI-Inv Rel	3,700.27	3,792.78	3,887.60
			Total investor relations charges	20,872.02	21,393.82	21,928.67
			2008 HECO allocation factor	40.7%	40.7%	40.7%
			Total investor relations charges billed to HECO	8,494.91	8,707.28	8,924.97
PENSION PLAN ACTIVITIES						
	PEN005	FI000031	Pension Accounting	94.13	96.48	98.89
			Total Pension accounting charges	94.13	96.48	98.89
			2008 HECO allocation factor	47.1%	47.1%	47.1%
			Total Pension accounting charges billed to HECO	44.34	45.44	46.58
	PEN009	AD000578	GM Svc Fees for HEI - Pension	3,023.44	3,099.03	3,176.51
			Total Master Pension Trust charges	3,023.44	3,099.03	3,176.51
			2008 HECO allocation factor	65.1%	65.1%	65.1%
			Total Master Pension Trust charges billed to HECO	1,968.26	2,017.47	2,067.91
	PEN026	AD000578	GM Svc Fees for HEI - Pension	3,023.43	3,099.02	3,176.50
			Total OPEB funded plans/trusts charges	3,023.43	3,099.02	3,176.50
			2008 HECO allocation factor	68.2%	68.2%	68.2%
			Total OPEB funded plans/trusts charges billed to HECO	2,061.98	2,113.53	2,166.37
REPORTING ACTIVITIES						
	RPT001	FI000016	Monthly accounting services - HEI	154.08	157.93	161.88
	RPT001	FI000046	Quarterly reporting	470.83	482.60	494.67
			Total 10K charges	624.91	640.53	656.55
			2008 HECO allocation factor	41.0%	41.0%	41.0%
			Total 10K charges billed to HECO	256.21	262.62	269.19
	RPT041	AD000164	Proxy Statement	26,364.01	27,023.11	27,698.69
	RPT041	HR000516	Proxy Review Services	14,170.62	14,524.89	14,888.01
			Total proxy charges	40,534.63	41,548.00	42,586.70
			2008 HECO allocation factor	40.7%	40.7%	40.7%
			Total proxy charges billed to HECO	16,497.59	16,910.04	17,332.79
	RPT 051	CR000048	Annual report	7,856.28	8,052.69	8,254.01
			Total annual report charges billed	7,856.28	8,052.69	8,254.01
			2008 HECO allocation factor	41.0%	41.0%	41.0%
			Total annual report charges billed to HECO	3,221.07	3,301.60	3,384.14
STOCK TRANSFER ACTIVITIES						
	STO011	CS000164	HEI Dividend Check Mailout	5,623.96	5,764.56	5,908.67
	STO012	IT000298	HEI - DRIP Stmts - Shareholder Svcs	505.68	518.32	531.28
	STO013	CS000164	HEI 1099-B mailout	651.69	667.98	684.68
	STO013	CS000164	HEI 1099-DIV mailout	805.35	825.48	846.12
	STO016	IT000295	HEI - Shareholder service	236.47	242.38	248.44
	STO019	IT000255	HEI Stock Transfer Job-Printing	3,352.08	3,435.88	3,521.78
			Total stock transfer charges	5,551.27	5,690.04	5,832.30
			2008 HECO allocation factor	38.3%	38.3%	38.3%
			Total stock transfer charges billed to HECO	2,126.14	2,179.29	2,233.77
			Total shared charges to HECO	44,222.70	45,328.28	46,461.51

(1) The 2008 estimate was based upon the 2007 actual adjusted by 2.5% for estimated cost increases.
(2) The 2009 estimate was based upon the 2008 estimate adjusted by 2.5% for estimated cost increases.
(3) The 2008 allocation factors were applied to the 2007 shared charges since these were the most current allocation factors available at the time that the 2009 estimate was calculated.

Hawaiian Electric Company, Inc.
HEI Charges to HECO
2009 Test Year

HECO Acct. No	HEI Activities	HECO Activity	2009 Budget	2009 Test Year Estimate	Adjustment
921	ACC Accounting	815 Dev. Adm Acctg Pol	33,750	15,500	(18,250)
921	ADM Admistrative	700 Dev & Admin	199,420	81,427	(117,993)
921	ANN Annual Meeting	756 Maint Rel-Invest	19,510	52,197	32,687
921	AUD Audits	760 Audits-Internal	7,530	14,443	6,913
921	CON Consulting-General	760 Audits-Internal	102,000	111,579	9,579
921	CON Consulting-General	700 Dev & Admin	144,916	95,342	(49,574)
921	CON Consulting-General	961 Conduct Legal Due Diligence	88,008	145,647	57,639
921	FIN Financing	826 Manage Financing	560	676	116
921	HUM Human Resources	775 Empl Com PolPrac Proc	202,620	113,479	(89,141)
	INV Investor Relations	756 Maint Rel-Invest	297,600	257,827	(39,773)
	RPT Reports	836 Fin Rpts/StatInfo-Ext	759,130	751,897	(7,233)
921	STO Stock Transfer activities	756 Maint Rel-Invest	337,250	344,777	7,527
	TAX Tax	819 Admin Tax Return &Rpts	186,940	171,337	(15,603)
921					
			2,379,234	2,156,128	(223,106)
921		723 Manage Incentive & Rec Prg	48,873	-	(48,873)
	Total Account 921		2,428,107	2,156,128	(271,979)
926	PEN Pension Plan	779 Adm Retirement Pgm	246,600	172,943	(73,657)
9302	BOD Board of Directors	755 Maint Rel-BOD	168,600	64,369	(104,231)
931	ADM Admin - Training Rooms	926 Manage Property	54,504	76,032	21,528
	Total HEI Charges excl. Internet		2,897,811	2,469,472	(428,339)

ADMINISTRATIVE SERVICES AGREEMENT
BETWEEN
HAWAIIAN ELECTRIC INDUSTRIES, INC.
AND
HAWAIIAN ELECTRIC COMPANY, INC.

THIS AGREEMENT ("Agreement") is made this 4th day of February, 1993, but is effective as of January 1, 1993, by and between HAWAIIAN ELECTRIC INDUSTRIES, INC. (hereinafter referred to as "HEI"), a Hawaii corporation and HAWAIIAN ELECTRIC COMPANY, INC., (hereinafter referred to as "HECO"), a Hawaii corporation.

WHEREAS, the Managements of both HEI and HECO have determined in the exercise of their sound business judgment that in order to achieve their common goals, HECO will purchase certain administrative support services from HEI ("Services"), and

WHEREAS, HECO desires to reimburse HEI for the cost of providing these administrative support services,

NOW, THEREFORE, in consideration of the mutual covenants contained herein, the parties agree as follows:

ARTICLE I. SCOPE OF SERVICE

1.1 HEI will render to HECO those administrative support services listed in Exhibit A. Additional activity codes may be added to those listed in Exhibit A in order to provide greater detail of the services being performed.

1.2 HECO reserves the right to terminate certain administrative support services provided by HEI. Cancellation of certain services must be in writing and submitted to HEI at least 60 days prior to the effective cancellation date.

1.3 Services rendered, if any, by the HEI Internal Audit Department and the HEI Data Center are covered under separate agreements.

1.4 Notwithstanding anything to the contrary, the parties understand and agree that the President of HECO and its Board of Directors have not, by virtue of this Agreement or any corporate practice, delegated their responsibility or discretion to accept or reject any Services covered by this Agreement.

1.5 All services and decisions related hereto shall be rendered in a manner acceptable to the President of HECO.

ARTICLE II. TERM/CANCELLATION

2.1 The initial annual term of this Agreement shall commence on January 1, 1993 and shall automatically renew each year until canceled. Cancellation of this Agreement must be in writing and submitted at least 60 days prior to the effective cancellation date.

ARTICLE III. COMPENSATION AND MANNER AND TIME OF PAYMENT

3.1 HECO will pay HEI for the Services listed in Exhibit A. In addition, HECO will pay HEI for any charges from third parties paid by HEI on behalf of HECO for the Services listed in Exhibit A.

3.2 a. Beginning February 20, 1993, and on or before the twentieth day of each month thereafter, HEI shall bill HECO for the services performed in the prior month (the billing period). Invoices will be rendered for each activity group listed in Exhibit A where HEI renders services to HECO (e.g. Administrative services, Accounting services, Stockholder Relations services, etc.). Costs will be accumulated by chargeable activities within the activity groups.

b. Included in the cost of chargeable activities will be the cost of shared activities. Shared activities are activities which would be necessary for HECO to perform if HECO were a stand-alone publicly traded company. See Exhibit B for the allocation methods for shared activities. The allocation percentages will be calculated annually, and will be based primarily on prior year data. Allocation percentages are effective January 1 of each year. Existing allocation percentages will be used until data to calculate the new allocation percentages are available. Retroactive adjustments will be made as necessary to adjust billings made in any given year before the new allocation percentages for that year are available.

c. In order to charge for labor and certain departmental costs, HEI employees will complete reports twice a month to document the time spent on chargeable activities. Invoices will show the labor hours charged to activities and the related employee loaded labor rate.

d. Loaded labor rates will be developed for each HEI employee who will perform services for HECO. Labor costs will be based upon actual labor rates. Labor rates will be changed twice a year. Once, effective May 1 for base salary rate changes and again, effective January 1 for changes in loadings. A listing of loaded labor rates by employee will be provided annually for the existing employees at that time.

e. Loadings will be added onto labor costs to ensure fair recovery of normal departmental costs. These costs include those with respect to rent, office supplies, dues and subscriptions, meetings and seminars, employee benefits, pension costs, depreciation, computer costs, utilities, insurance, incentive compensation, telephone, etc. Loading rates will be developed annually based upon the prior year actual costs and submitted to HECO. Existing loading rates will be used until the new loading rates are developed. Loading rates are effective January 1 of each year. Retroactive adjustments will be made as necessary to adjust billings made prior to the updating of HEI computer programs for the new loading rates.

f. Other nonlabor costs which relate to chargeable activities, but which have not been reflected in the loaded labor rate will also be billed to HECO. Invoices or other supporting documentation for these other nonlabor costs will be provided with the billings to HECO.

3.3 a. HECO shall pay each invoice upon receipt. HECO shall have the right to request further documentation of the fees and charges. In the event there is a dispute with respect to an invoice, HECO shall pay all portions of the invoice which are not in dispute and may withhold the disputed charge.

b. Disputed charges will be resolved internally between HECO and HEI to the extent possible. The HECO and HEI representatives listed in Section 4.1 will initially attempt to resolve the disputed charges. After resolution of the disputed charges, HEI will submit a revised bill to HECO based upon the agreed upon amount. Payment will be due upon receipt of the revised bill. Refunds, if any, will be applied to HECO's next bill.

c. If the disputed charges cannot be resolved between the HECO and HEI representatives, disputes will be taken to the President of HECO and the HEI Diversified Group Vice President. If resolution cannot be reached between the HECO President and the HEI Diversified Group Vice President, then the disputes will be taken up to the HEI Chief Executive Officer. If resolution of disputed charges is still not accomplished, HEI will seek the help of an outside arbitrator for final resolution.

3.4 Billing corrections may be made from time to time to correct any errors. HEI will submit revised bills to HECO. Payments will be due upon receipt of the revised bill. Refunds will be applied to HECO's next bill.

ARTICLE IV. REPRESENTATIVES

4.1 The individuals identified below are the Representatives of HECO and HEI. An employee of HEI performing services hereunder shall be entitled to rely on the advice and direction of the HECO Representative, who shall have the authority to make any decisions and give any direction on behalf of HECO that does not materially change the Services hereunder. Similarly, an employee of HECO shall be entitled to rely on the advice and direction of the HEI Representative concerning matters hereunder, who shall have the authority to make any decisions on behalf of HEI that do not materially change the Services, hereunder.

HECO Representative:
Controller
HAWAIIAN ELECTRIC COMPANY, INC.
900 Richards Street
Honolulu, Hawaii 96813
(808) 543-7552

HEI Representative:
Controller
Hawaiian Electric Industries, Inc.
900 Richards Street
Honolulu, Hawaii 96813
(808) 543-7350

ARTICLE V. ADMINISTRATION

5.1 The HEI Controller's office will be responsible for administering the intercompany billing function. The HEI Controller's office will maintain an intercompany billing database to capture time and expenses billed to subsidiaries. HECO will reimburse HEI for a portion of the costs relating to the administration of the intercompany billing system.

ARTICLE VI. CONFIDENTIALITY OF INFORMATION

6.1 All information pertaining to the labor rates of HEI employees should not be disclosed externally without prior written release by an HEI officer.

ARTICLE VII. HEI'S ACCOUNTING RECORDS; AUDIT

7.1 HEI shall maintain and retain books and accounts of its charges. These records are to be kept at HEI's principal office. HECO shall at all reasonable times have access to these books and accounts to the extent required to verify all costs and charges incurred by HEI. Such verification would be at the expense of HECO. The HEI Controller's office is located on the fourth floor at 900 Richards Street, Honolulu, Hawaii 96813, Telephone (808) 543-7350.

7.2 HEI agrees to fully cooperate with HECO or its designee (as evidenced in writing signed by a HECO representative) in connection with HECO's audit functions and with regard to audits or examinations by the Public Utilities Commission of the State of Hawaii ("PUC") and any other regulator having jurisdiction over HECO. If the PUC or other regulator requests or directs program or procedural changes concerning Services under the Agreement, HEI will work with HECO to make such changes as agreed to be appropriate.

ARTICLE VIII. PRIOR NEGOTIATIONS; AMENDMENTS

8.1 This Agreement supersedes all prior negotiations, representations, or agreements with respect to the matters set forth herein, either written or oral. This Agreement may be amended only by written instrument signed by both parties.

ARTICLE IX. MISCELLANEOUS

9.1 All questions concerning the validity, operation and interpretation of this Agreement and the performance of the obligations imposed upon the parties hereunder or thereunder shall be governed by the laws of the State of Hawaii.

9.2 If any non-material term or provision of this Agreement shall be found to be illegal or unenforceable then, notwithstanding, this Agreement shall remain in full force and effect so long as the purposes hereof or the expectations of the parties shall not be frustrated thereby, and such term or provision shall be deemed stricken.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on the date first above written.

HAWAIIAN ELECTRIC COMPANY, INC.

By Howard W. Williams
Its President

By Paul Oyer
Its Vice-President

("HECO")

HAWAIIAN ELECTRIC INDUSTRIES, INC.

By Robert F. Mougeot
Its Financial Vice President and Chief Financial Officer

By Curtis Y. Harada
Its Controller

("HEI")

HEI CHARGEABLE ACTIVITY CODES
(Effective 1/1/93)

Exhibit A

ACTIVITY CODE	ACTIVITY CODE DESCRIPTIONS
	Administrative
ADM 001	Activity no longer valid
ADM 002	Activity no longer valid
ADM 003	Activity no longer valid
ADM 004	Maintenance of corporate records
ADM 005	Activity no longer valid
ADM 006	Assist on rate cases
ADM 007	Insurance procurement/administration
ADM 008	Administration of company policies
ADM 009	Assist administrator of HECO's President's office
	Accounting
ACC 001	Research accounting issues
ACC 002	SFAS 106 (Postretirement Benefits)
ACC 003	SFAS 107 (Fair Value of Financial Instruments)
ACC 004	Maintain general ledger
ACC 005	Bank reconciliations (common dividend account)
ACC 006	Cash receipts
ACC 007	Activity no longer valid
ACC 008	Analyze financial results
ACC 009	Monitor accounting and reporting standards
ACC 010	Consolidation of financial results
ACC 011	Preparation of audit workpapers
ACC 012	Resolve audit/tax issues
ACC 013	Maintain detailed property, plant & equipment records
ACC 014	Maintain depreciation schedules
ACC 015	Depreciation study
ACC 016	Payroll
ACC 017	Intercompany billing study
ACC 018	Intercompany billing administration
ACC 019	Interisland communication system
ACC 020	EDGAR (SEC electronic data filing)
	Acquisitions/Divestitures
ACQ 001	Due diligence (set up separate project code number)
ACQ 002	Special project code number
	Annual meeting
ANN 001	Annual shareholder meeting planning & coordination
ANN 002	Annual meeting facilities
	Audits
AUD 001	Review audit plans
AUD 002	Assist with audits
AUD 003	Review audit reports
AUD 004	Audit Committee meeting preparation
AUD 005	Audit Committee meeting attendance
AUD 006	Coordinate activities with external auditors
AUD 007	EDP audits
AUD 008	Operational audits
AUD 009	Activity no longer valid
AUD 010	Audit expenses
	Board of Directors Meetings
BOD 001	Preparation
BOD 002	Attendance (presentations)
BOD 003	Minutes
BOD 004	Review of minutes
BOD 005	Misc. board matters

Exhibit A

HEI CHARGEABLE ACTIVITY CODES
(Effective 1/1/93)

ACTIVITY CODE	ACTIVITY CODE DESCRIPTIONS
	Budgets
BUD 001	Preparation
BUD 002	Attendance (presentations)
BUD 003	Review
	Capital Appropriations
CAP 001	Capital appropriations analysis
CAP 002	Capital appropriations review
	Cash Management (Short-term)
CAS 001	Monthly cash review and report
CAS 002	Bank lines & relationships
CAS 003	Other relationships (dealer, trustee, etc.)
CAS 004	Cash resolutions, policies, & procedures
CAS 005	Rating agency reports
CAS 006	Cash disbursements & check signing
	Community relations
COM 001	Media relations and communications
COM 002	Administration of HEI Charitable Foundation
	Consulting - general
CON 001	Review of monthly results
CON 002	Meetings
CON 003	Preparation
CON 004	Other
	Financing (Long-term)
FIN 001	Debt financing planning & coordination
FIN 002	Debt financing due diligence
FIN 003	Presentations
FIN 004	Debt compliance
FIN 005	Rating agencies - communications
FIN 006	Rating agencies - planning
FIN 007	Rating agencies - presentations
FIN 008	Rating agencies - meetings
FIN 009	Rating agency matters
FIN 050	Equity financing planning & coordination
FIN 051	Equity financing due diligence
FIN 052	Presentations
FIN 099	Dividend policy
FIN 100	Stock split
	Human Resources
HUM 001	Benefits administration
HUM 002	Compensation administration
HUM 003	Personnel issues
HUM 004	Benefit plan report preparation
HUM 005	Employee benefit consulting
HUM 006	Activity no longer valid
HUM 007	Activity no longer valid
HUM 008	Code of Conduct administration & development
HUM 009	Code of Conduct review
HUM 010	Compensation committee meetings

HEI CHARGEABLE ACTIVITY CODES
(Effective 1/1/93)

Exhibit A

ACTIVITY CODE	ACTIVITY CODE DESCRIPTIONS
	Investor Relations
INV 001	Analyst/media communications
INV 002	Broker meetings
INV 003	Fact sheet
INV 004	Financial mailing list
INV 005	Financial news releases
INV 006	Group analyst meetings
INV 007	HEI stock - share forecast
INV 008	Investor base/stockholder monitoring
INV 009	Investor relations planning
INV 010	Investment Society of Hawaii
INV 011	National Association of Investors Corporation (NAIC)
INV 012	One-on-one meetings/visits with analysts
INV 013	Other investor relations activities
INV 014	Retail program
INV 015	Retail/broker/shareholder communications
INV 016	Smith Barney utility diversified seminar
INV 017	Smith Barney West Coast seminar
INV 018	Statistical supplement
INV 019	Surveys
INV 020	Teleconferencing
	Legal
LEG 001	Review of reports
LEG 002	Legal overview
LEG 003	KCPL litigation
LEG 004	Other legal work
	Legislation
LEI 001	Review of legislative proposals
LEI 002	Monitor executive/legislative proposals
LEI 003	Lobbying
LEI 004	Preparation of testimony and other reports on proposed legislation
LEI 005	Preparation for meetings on govt. issues
LEI 006	Meetings on govt. issues
LEI 007	Preparation of govt. reports
	Pension plan
PEN 001	Activity no longer valid
PEN 002	Activity no longer valid
PEN 003	Activity no longer valid
PEN 004	Activity no longer valid
PEN 005	HEIRS
PEN 006	Activity no longer valid
PEN 007	HEI Retirement Plan
PEN 008	HTB Salaried Plan
PEN 009	Defined Benefit Commingled Trust
PEN 010	HEI Diversified Defined Contribution Plan
PEN 018	American Savings Bank Retirement Plan
PEN 019	Young Brothers, Limited Pension Plan
PEN 020	Directors Retirement Plan
PEN 021	Individual arrangements
PEN 022	Supplemental Executive Retirement Plan
PEN 023	Excess Benefit Plan
PEN 024	Other Postretirement Benefits

Exhibit A

HEI CHARGEABLE ACTIVITY CODES
(Effective 1/1/93)

ACTIVITY CODE	ACTIVITY CODE DESCRIPTIONS
	Reports
	Government filings
RPT 001	10K
RPT 011	10Q
RPT 021	8K
RPT 031	Amendments to articles of incorporation
RPT 032	U-3A-2 filing
RPT 039	Other government reports
	Proxy
RPT 041	Proxy
	Annual Report
RPT 051	Annual report
	Quarterly Reports
RPT 061	Quarterly report
	Other reports
RPT 099	Other
	Stock Transfer activities
STO 001	Preferred stock dividend payments
STO 002	Preferred stock redemption payments
STO 003	Form 1099 (for preferred stockholders)
STO 004	Preferred stockholder database maintenance
STO 005	Other preferred stock communications
STO 006	Preferred stock transfer administrative activities
STO 011	Common stock dividend payments
STO 012	HEI Dividend Reinvestment program administration
STO 013	Form 1099 Dividends
STO 014	Common stockholder database maintenance
STO 015	Other common stock communications
STO 016	Common stock transfer administrative activities
STO 017	Promotions
STO 018	Stock transfer system
STO 019	Stock transfer division expenses
	Strategic Planning
STR 001	Strategic planning, research, analysis
STR 002	Financial planning, research, analysis
STR 003	Capital allocation policies and standards
STR 004	Project analysis or management
STR 005	Performance standards, measurement, analysis
STR 006	Investment/business research and analysis
STR 007	Securities market (stock market) analysis
STR 008	Peer, industry, market, or environmental analysis
STR 009	Economic research and analysis
STR 010	Special projects

HEI CHARGEABLE ACTIVITY CODES
(Effective 1/1/93)

Exhibit A

ACTIVITY CODE	ACTIVITY CODE DESCRIPTIONS
	Tax
TAX 001	Tax return preparation
TAX 002	Tax return review
TAX 003	Tax and financial planning
TAX 004	Tax issues on leveraged leases
TAX 005	SFAS 109 planning and implementation
TAX 006	Tax research
TAX 007	Tax accrual review
TAX 008	Tax compliance software implementation
TAX 009	Assistance on the IRS examination
TAX 010	Information returns
TAX 011	IRS/Dept. of Taxation correspondence
TAX 012	Estimated tax computation
TAX 013	General excise tax returns
TAX 014	Payroll tax withholding

Exhibit B

ALLOCATION METHODS FOR HEI CHARGEABLE ACTIVITIES

Note: Where there are negative data values (i.e. if a subsidiary has a pretax loss) the absolute value will be used since a negative value would be illogical.

METHOD	ACTIVITY CODE	ACTIVITY CODE DESCRIPTIONS
		Administrative
n/a	ADM 001	Activity no longer valid
n/a	ADM 002	Activity no longer valid
n/a	ADM 003	Activity no longer valid
Direct charged	ADM 004	Maintenance of corporate records
n/a	ADM 005	Activity no longer valid
Direct charged	ADM 006	Assist on rate cases
General allocator	ADM 007	Insurance procurement/administration
Employees	ADM 008	Administration of company policies
Direct charged	ADM 009	Assist administrator of HECO's President's office
		Accounting
Publicly held equity (common & preferred)	ACC 001	Research accounting issues
OPEB pension expense	ACC 002	SFAS 106 (Postretirement Benefits)
Publicly held equity (common & preferred)	ACC 003	SFAS 107 (Fair Value of Financial Instruments)
Direct charged	ACC 004	Maintain general ledger
Common equity	ACC 005	Bank reconciliations (common dividend account)
Direct charged	ACC 006	Cash receipts
n/a	ACC 007	Activity no longer valid
Publicly held equity (common & preferred)	ACC 008	Analyze financial results
Publicly held equity (common & preferred)	ACC 009	Monitor accounting and reporting standards
Publicly held equity (common & preferred)	ACC 010	Consolidation of financial results
Publicly held equity (common & preferred)	ACC 011	Preparation of audit workpapers
Publicly held equity (common & preferred)	ACC 012	Resolve audit/tax issues
Direct charged	ACC 013	Maintain detailed property, plant & equipment records
Direct charged	ACC 014	Maintain depreciation schedules
Direct charged	ACC 015	Depreciation study
Gross payroll	ACC 016	Payroll
General allocator	ACC 017	Intercompany billing study
General allocator	ACC 018	Intercompany billing administration
Direct charged	ACC 019	Interisland communication system
Publicly held equity (common & preferred)	ACC 020	EDGAR (SEC electronic data filing)
		Acquisitions/Divestitures
Direct charged	ACQ 001	Due diligence (set up separate project code number)
Direct charged	ACQ 002	Special project code number
		Annual meeting
Common equity	ANN 001	Annual shareholder meeting planning & coordination
Common equity	ANN 002	Annual meeting facilities
		Audits
Publicly held equity (common & preferred)	AUD 001	Review audit plans
Publicly held equity (common & preferred)	AUD 002	Assist with audits
Publicly held equity (common & preferred)	AUD 003	Review audit reports
Publicly held equity (common & preferred)	AUD 004	Audit Committee meeting preparation
Publicly held equity (common & preferred)	AUD 005	Audit Committee meeting attendance
Publicly held equity (common & preferred)	AUD 006	Coordinate activities with external auditors
Direct charged	AUD 007	EDP audits
Direct charged	AUD 008	Operational audits
n/a	AUD 009	Activity no longer valid
Publicly held equity (common & preferred)	AUD 010	Audit expenses
		Board of Directors (BOD) Meetings
BOD agenda	BOD 001	Preparation
BOD agenda	BOD 002	Attendance (presentations)
BOD agenda	BOD 003	Minutes
BOD agenda	BOD 004	Review of minutes
BOD agenda	BOD 005	Misc. board matters

Exhibit B

ALLOCATION METHODS FOR HEI CHARGEABLE ACTIVITIES

Note: Where there are negative data values (i.e. if a subsidiary has a pretax loss) the absolute value will be used since a negative value would be illogical.

METHOD	ACTIVITY CODE	ACTIVITY CODE DESCRIPTIONS
		Budgets
Direct charged	BUD 001	Preparation
Direct charged	BUD 002	Attendance (presentations)
Direct charged	BUD 003	Review
		Capital Appropriations
Direct charged	CAP 001	Capital appropriations analysis
Direct charged	CAP 002	Capital appropriations review
		Cash Management (Short-term)
Projected short-term borrowings	CAS 001	Monthly cash review and report
Projected short-term borrowings	CAS 002	Bank lines & relationships
Projected short-term borrowings	CAS 003	Other relationships (dealer, trustee, etc.)
Projected short-term borrowings	CAS 004	Cash resolutions, policies, & procedures
Projected short-term borrowings	CAS 005	Rating agency reports
Direct charged	CAS 006	Cash disbursements & check signing
		Community relations
Direct charged	COM 001	Media relations and communications
Direct charged	COM 002	Administration of HEI Charitable Foundation
		Consulting - general
Direct charged	CON 001	Review of monthly results
Direct charged	CON 002	Meetings
Direct charged	CON 003	Preparation
Direct charged	CON 004	Other
		Financing (Long-term)
Direct charged	FIN 001	Debt financing planning & coordination
Direct charged	FIN 002	Debt financing due diligence
Direct charged	FIN 003	Presentations
Direct charged	FIN 004	Debt compliance
Direct charged	FIN 005	Rating agencies - communications
Direct charged	FIN 006	Rating agencies - planning
Direct charged	FIN 007	Rating agencies - presentations
Direct charged	FIN 008	Rating agencies - meetings
Direct charged	FIN 009	Rating agency matters
Equity to be financed	FIN 050	Equity financing planning & coordination
Equity to be financed	FIN 051	Equity financing due diligence
Equity to be financed	FIN 052	Presentations
General allocator	FIN 099	Dividend policy
Common equity	FIN 100	Stock split
		Human Resources
Employees	HUM 001	Benefits administration
Executives	HUM 002	Compensation administration
Employees	HUM 003	Personnel issues
Employees	HUM 004	Benefit plan report preparation
Employees	HUM 005	Employee benefit consulting
n/a	HUM 006	Activity no longer valid
n/a	HUM 007	Activity no longer valid
Employees	HUM 008	Code of Conduct administration & development
Employees	HUM 009	Code of Conduct review
Executives	HUM 010	Compensation committee meetings

Exhibit B

ALLOCATION METHODS FOR HEI CHARGEABLE ACTIVITIES

Note: Where there are negative data values (i.e. if a subsidiary has a pretax loss) the absolute value will be used since a negative value would be illogical.

METHOD	ACTIVITY CODE	ACTIVITY CODE DESCRIPTIONS
		Investor Relations
Common equity	INV 001	Analyst/media communications
Common equity	INV 002	Broker meetings
Common equity	INV 003	Fact sheet
Common equity	INV 004	Financial mailing list
Common equity	INV 005	Financial news releases
Common equity	INV 006	Group analyst meetings
Common equity	INV 007	HEI stock - share forecast
Common equity	INV 008	Investor base/stockholder monitoring
Common equity	INV 009	Investor relations planning
Common equity	INV 010	Investment Society of Hawaii
Common equity	INV 011	National Association of Investors Corporation (NAIC)
Common equity	INV 012	One-on-one meetings/visits with analysts
Common equity	INV 013	Other investor relations activities
Common equity	INV 014	Retail program
Common equity	INV 015	Retail/broker/shareholder communications
Common equity	INV 016	Smith Barney utility diversified seminar
Common equity	INV 017	Smith Barney West Coast seminar
Common equity	INV 018	Statistical supplement
Debt + Equity	INV 019	Surveys
Common equity	INV 020	Teleconferencing
		Legal
Direct charged	LEG 001	Review of reports
Direct charged	LEG 002	Legal overview
Direct charged	LEG 003	KCPL litigation
Direct charged	LEG 004	Other legal work
		Legislation
General allocator	LEI 001	Review of legislative proposals
General allocator	LEI 002	Monitor executive/legislative proposals
General allocator	LEI 003	Lobbying
General allocator	LEI 004	Preparation of testimony and other reports on proposed legislation
General allocator	LEI 005	Preparation for meetings on govt. issues
General allocator	LEI 006	Meetings on govt. issues
General allocator	LEI 007	Preparation of govt. reports
		Pension plan
n/a	PEN 001	Activity no longer valid
n/a	PEN 002	Activity no longer valid
n/a	PEN 003	Activity no longer valid
n/a	PEN 004	Activity no longer valid
HEIRS participants	PEN 005	HEIRS
n/a	PEN 006	Activity no longer valid
Plan assets	PEN 007	HEI Retirement Plan
Plan assets	PEN 008	HTB Salaried Plan
Plan assets	PEN 009	Defined Benefit Commingled Trust
Plan participants	PEN 010	HEI Diversified Defined Contribution Plan
Direct charged	PEN 018	American Savings Bank Retirement Plan
Direct charged	PEN 019	Young Brothers, Limited Pension Plan
Plan participants	PEN 020	Directors Retirement Plan
Direct charged	PEN 021	Individual arrangements
Direct charged	PEN 022	Supplemental Executive Retirement Plan
Direct charged	PEN 023	Excess Benefit Plan
OPEB pension expense	PEN 024	Other Postretirement Benefits

Exhibit B

ALLOCATION METHODS FOR HEI CHARGEABLE ACTIVITIES

Note: Where there are negative data values (i.e. if a subsidiary has a pretax loss) the absolute value will be used since a negative value would be illogical.

METHOD	ACTIVITY CODE	ACTIVITY CODE DESCRIPTIONS
		Reports
		Government filings
Publicly held equity (common & preferred)	RPT 001	10K
Publicly held equity (common & preferred)	RPT 011	10Q
Publicly held equity (common & preferred)	RPT 021	8K
Publicly held equity (common & preferred)	RPT 031	Amendments to articles of incorporation
Publicly held equity (common & preferred)	RPT 032	U-3A-2 filing
Publicly held equity (common & preferred)	RPT 039	Other government reports
		Proxy
Common equity	RPT 041	Proxy
		Annual Report
Publicly held equity (common & preferred)	RPT 051	Annual report preparation
		Quarterly Reports
Publicly held equity (common & preferred)	RPT 061	Quarterly report preparation
		Other reports
Publicly held equity (common & preferred)	RPT 099	Other
		Stock Transfer activities
Preferred equity	STO 001	Preferred stock dividend payments
Preferred equity	STO 002	Preferred stock redemption payments
Preferred equity	STO 003	Form 1099 (for preferred stockholders)
Preferred equity	STO 004	Preferred stockholder database maintenance
Preferred equity	STO 005	Other preferred stock communications
Preferred equity	STO 006	Preferred stock transfer administrative activities
Common equity	STO 011	Common stock dividend payments
Common equity	STO 012	HEI Dividend Reinvestment program administration
Common equity	STO 013	Form 1099 Dividends
Common equity	STO 014	Common stockholder database maintenance
Common equity	STO 015	Other common stock communications
Common equity	STO 016	Common stock transfer administrative activities
Common equity	STO 017	Promotions
Common equity	STO 018	Stock transfer system
Common equity	STO 019	Stock transfer division expenses
		Strategic Planning
Direct charged	STR 001	Strategic planning, research, analysis
Direct charged	STR 002	Financial planning, research, analysis
Direct charged	STR 003	Capital allocation policies and standards
Direct charged	STR 004	Project analysis or management
Direct charged	STR 005	Performance standards, measurement, analysis
Direct charged	STR 006	Investment/business research and analysis
Common equity	STR 007	Securities market (stock market) analysis
Direct charged	STR 008	Peer, industry, market, or environmental analysis
Direct charged	STR 009	Economic research and analysis
Direct charged	STR 010	Special projects

Exhibit B

ALLOCATION METHODS FOR HEI CHARGEABLE ACTIVITIES

Note: Where there are negative data values (i.e. if a subsidiary has a pretax loss) the absolute value will be used since a negative value would be illogical.

METHOD	ACTIVITY CODE	ACTIVITY CODE DESCRIPTIONS
		Tax
Pretax income	TAX 001	Tax return preparation
Pretax income	TAX 002	Tax return review
Pretax income	TAX 003	Tax and financial planning
Pretax income	TAX 004	Tax issues on leveraged leases
Pretax income	TAX 005	SFAS 109 planning and implementation
Pretax income	TAX 006	Tax research
Pretax income	TAX 007	Tax accrual review
Pretax income	TAX 008	Tax compliance software implementation
Pretax income	TAX 009	Assistance on the IRS examination
Pretax income	TAX 010	Information returns
Pretax income	TAX 011	IRS/Dept. of Taxation correspondence
Pretax income	TAX 012	Estimated tax computation
Pretax income	TAX 013	General excise tax returns
Pretax income	TAX 014	Payroll tax withholding

ADDENDUM DATED AS OF 4/22/94 TO THE
ADMINISTRATIVE SERVICES AGREEMENT
DATED AS OF 2/4/93 BETWEEN
HAWAIIAN ELECTRIC INDUSTRIES, INC. (HEI)
AND
HAWAIIAN ELECTRIC COMPANY, INC.

The terms and conditions of the above referenced Administrative Services Agreement (Agreement) shall be amended as follows and shall be retroactive to January 1, 1993:

ARTICLE I. SCOPE OF SERVICE

1.3 Services rendered, if any, by the HEI Data Center are covered under separate agreements.

IN WITNESS WHEREOF, the parties hereto have executed this Addendum:

HAWAIIAN ELECTRIC COMPANY, INC.

By Howard D. Williams

Its President

By Paul Oyer

Its Vice-President

("HECO")

HAWAIIAN ELECTRIC INDUSTRIES, INC.

By Robert F. Mougeot

Its Financial Vice President
and Chief Financial Officer

By Curtis Y. Harada

Its Controller

("HEI")

ADDENDUM No. 2 TO THE
ADMINISTRATIVE SERVICES AGREEMENT
BETWEEN
HAWAIIAN ELECTRIC INDUSTRIES, INC. (HEI)
AND
HAWAIIAN ELECTRIC COMPANY, INC. (HECO)

WHEREAS, HEI and HECO entered into an Administrative Services Agreement dated as of February 4, 1993; and

WHEREAS, the position of HEI Diversified Group Vice President was not and will not be filled after the retirement of Edward J. Blackburn; and

WHEREAS, HEI and HECO desire to amend Paragraph 3.3 c. to reflect this change.

NOW, THEREFORE, HEI and HECO agree as follows:

1) Paragraph 3.3 c. is amended to read in its entirety as follows:

> 3.3 c. If the disputed charges cannot be resolved between the HECO and HEI representatives, disputes will be taken up to the HEI Chief Executive Officer. If resolution of disputed charges is still not accomplished, HEI will seek the help of an outside arbitrator or consultant for final resolution.

2) The amendment above shall be effective as of July 1, 1994.

3) All other terms and conditions of the Agreement, as amended, shall remain unchanged.

IN WITNESS WHEREOF, the parties hereto have executed this Addendum No. 2:

HAWAIIAN ELECTRIC COMPANY, INC.

By Howard D. Wilson
Its President

By Paul Oyer
Its Vice-President

("HECO")

HAWAIIAN ELECTRIC INDUSTRIES, INC.

By Robert F. Mougeot
Its Financial Vice President
and Chief Financial Officer

By Curtis Y. Harada
Its Controller

("HEI")

ADDENDUM No. 3 DATED AS OF JANUARY 1, 1999
TO THE ADMINISTRATIVE SERVICES AGREEMENT
DATED AS OF FEBRUARY 4, 1993
BETWEEN
HAWAIIAN ELECTRIC INDUSTRIES, INC. (HEI)
AND
HAWAIIAN ELECTRIC COMPANY, INC. (HECO)

The terms and conditions of the above referenced Administrative Services Agreement shall be amended as follows and shall be retroactive to January 1, 1999:

ARTICLE III. COMPENSATION AND MANNER AND TIME OF PAYMENT

3.2 a. On or before the last day of each month, HEI shall bill HECO for the services performed in the prior month (the billing period). Invoices will be rendered for each activity group listed in Exhibit A where HEI renders services to HECO (e.g., Administrative services, Accounting services, etc.). Costs will be accumulated by chargeable activities within the activity groups.

b. Included in the cost of chargeable activities will be the cost of shared activities. Shared activities are activities which would be necessary for HECO to perform if HECO were a stand-alone publicly traded company. See Exhibit A for the allocation methods for shared activities. The allocation percentages will be calculated annually, and will be based primarily on prior year data. Allocation percentages are effective January 1 of each year.

Existing allocation percentages will be used until data to calculate the new allocation percentages are available. Retroactive adjustments will be made as necessary to adjust billings made in any given year before the new allocation percentages for that year are available.

c. In order to charge for labor and certain departmental costs, HEI employees will complete reports twice a month to document the time spent on chargeable activities. Invoices will show the labor hours charged to activities and the related employee loaded labor rate.

d. Loaded labor rates will be developed for each HEI employee who will perform services for HECO. The detailed loaded labor rate calculations will be available for review at the HEI Controller's office. Labor costs will be based upon actual labor rates.

e. Loadings will be added onto labor costs to ensure fair recovery of normal departmental costs. These costs include those with respect to rent, office supplies, dues and subscriptions, meetings and seminars, employee benefits, pension costs, depreciation, computer costs, utilities, insurance, incentive compensation, telephone, etc. Billings will be based upon estimated loading rates until the actual loading rates can be calculated. An annual true-up will be made to reflect actual loading rates.

f. Other nonlabor costs which relate to chargeable activities, but which have not been reflected in the loaded labor rate will also be billed to HECO. Invoices or other supporting documentation for these other nonlabor costs will be provided with the billings to HECO.

IN WITNESS WHEREOF, the parties hereto have executed this Addendum No. 3:

HAWAIIAN ELECTRIC COMPANY, INC.

By T Michael May
Its President

By Paul Oyer
Its Vice-President

("HECO")

HAWAIIAN ELECTRIC INDUSTRIES, INC.

By Robert F. Mougeot
Its Financial Vice President
and Chief Financial Officer

By Curtis Y. Harada
Its Controller

("HEI")

UPDATED EXHIBIT A TO THE

ADMINISTRATIVE SERVICES AGREEMENT BETWEEN

HAWAIIAN ELECTRIC INDUSTRIES, INC. (HEI) AND

HAWAIIAN ELECTRIC COMPANY, INC. (HECO)

The parties hereto have acknowledged receipt of the updated (12/29/03) Exhibit A to the Administrative Services Agreement Between HEI and HECO.

HAWAIIAN ELECTRIC COMPANY, INC.

By______________________
Its Financial Vice President

By______________________
Its Controller

("HECO")

HAWAIIAN ELECTRIC INDUSTRIES, INC.

By______________________
Its Financial Vice President, Treasurer & Chief Financial Officer

By Curtis Y. Harada
Its Controller

("HEI")

Exhibit A

ACTIVITY CODES & ALLOCATION METHODS FOR HEI ACTIVITIES
Updated 12/29/03

Note: Where there are negative data values (i.e. if a subsidiary has a pretax loss) the absolute value will be used since a negative data value would be illogical.
n/a. not applicable

ACTIVITY CODE	ACTIVITY CODE DESCRIPTIONS	ALLOCATION METHOD
ADM	**Administrative**	
ADM 001	Activity no longer valid	n/a
ADM 002	Activity no longer valid	n/a
ADM 003	Activity no longer valid	n/a
ADM 004	Maintenance of corporate records	Direct charged
ADM 005	Activity no longer valid	n/a
ADM 006	Assist on rate cases	Direct charged
ADM 007	Corporate risk review	General allocator
ADM 008	Administration of company policies	Employees
ADM 009	Assist administrator of HECO's President's office	Direct charged
ADM 010	Training rooms	Direct charged
ADM 011	Telephone charges	Direct charged
ADM 012	Rent- Pacific Tower	Direct charged
ADM 013	Supplies	Direct charged
ADM 014	Rent- Central Pacific	Direct charged
ADM 100	HEI/HECO review	Direct charged
ADM 101	Federal insurance lawsuit	Direct charged
ADM 102	Four Star insurance agency lawsuit	Direct charged
ADM 103	Acquisition advisory service	n/a
ADM 104	Year 2000	n/a
ADM 105	Honolulu Harbor investigation	n/a
ADM 106	Collateralized debt obligations	n/a
ADM 107	PaineWebber lawsuit	n/a
ADM 108	Part-time help	n/a
ADM 109	AES lawsuit	n/a
ADM 110	Disaster recovery lines	Direct charged
ADM 111	Sarbanes-Oxley Section 404	n/a
ADM 112	Sarbanes-Oxley Section 302	n/a
ACC	**Accounting**	
ACC 001	Research accounting issues	Publicly held equity (common & preferred)
ACC 002	Activity no longer valid	n/a
ACC 003	SFAS 107 (Fair Value of Financial Instruments)	Publicly held equity (common & preferred)
ACC 004	Maintain general ledger	Direct charged
ACC 005	Bank reconciliations	Common equity (if for the common dividend account)
ACC 006	Cash receipts	Direct charged
ACC 007	Activity no longer valid	n/a
ACC 008	Analyze financial results	Publicly held equity (common & preferred)
ACC 009	Monitor accounting and reporting standards	Publicly held equity (common & preferred)
ACC 010	Consolidation of financial results	Publicly held equity (common & preferred)
ACC 011	Preparation of audit workpapers	Publicly held equity (common & preferred)
ACC 012	Resolve audit/tax issues	Publicly held equity (common & preferred)
ACC 013	Maintain detailed property, plant & equipment records	Direct charged
ACC 014	Maintain depreciation schedules	Direct charged
ACC 015	Depreciation study	Direct charged
ACC 016	Payroll	Gross payroll
ACC 017	Intercompany billing study	General allocator
ACC 018	Intercompany billing administration	General allocator
ACC 019	Interisland communication system	Direct charged
ACC 020	EDGAR (SEC electronic data filing)	Publicly held equity (common & preferred)
ACQ	**Acquisitions/Divestitures**	
ACQ 001	Due diligence (set up separate project code number)	Direct charged
ANN	**Annual meeting**	
ANN 001	Annual shareholder meeting planning & coordination	Common equity
ANN 002	Annual meeting facilities	Common equity
AUD	**Audits**	
AUD 001	Review audit plans	Direct charged
AUD 002	Assist with audits	Direct charged
AUD 003	Review audit reports	Direct charged
AUD 004	Audit Committee meeting preparation	Publicly held equity (common & preferred) for HECO, HELCO, MECO only
AUD 005	Audit Committee meeting attendance	Publicly held equity (common & preferred) for HECO, HELCO, MECO only
AUD 006	Coordinate activities with external auditors	Direct charged
AUD 007	EDP audits	Direct charged
AUD 008	Operational audits	Direct charged
AUD 009	Activity no longer valid	n/a
AUD 010	Audit expenses	Direct charged

Exhibit A

ACTIVITY CODES & ALLOCATION METHODS FOR HEI ACTIVITIES

Updated 12/29/03

Note: Where there are negative data values (i.e. if a subsidiary has a pretax loss) the absolute value will be used since a negative data value would be illogical.
n/a: not applicable

ACTIVITY CODE	ACTIVITY CODE DESCRIPTIONS	ALLOCATION METHOD
BOD	**Board of Directors (BOD) Meetings**	
BOD 001	Preparation	Direct charged
BOD 002	Attendance (presentations)	Direct charged
BOD 003	Minutes	Direct charged
BOD 004	Review of minutes	Direct charged
BOD 005	Misc. board matters	Direct charged
BUD	**Budgets**	
BUD 001	Preparation	Direct charged
BUD 002	Attendance (presentations)	Direct charged
BUD 003	Review	Direct charged
CAP	**Capital Appropriations**	
CAP 001	Capital appropriations analysis	Direct charged
CAP 002	Capital appropriations review	Direct charged
CAP 003	Capital appropriations - other	Direct charged
CAS	**Cash Management (Short-term)**	
CAS 001	Monthly cash review and report	Projected short-term borrowings
CAS 002	Bank lines & relationships	Projected short-term borrowings
CAS 003	Other relationships (dealer, trustee, etc.)	Projected short-term borrowings
CAS 004	Cash resolutions, policies, & procedures	Projected short-term borrowings
CAS 005	Rating agency reports	Projected short-term borrowings
CAS 006	Cash disbursements & check signing	Direct charged
COM	**Community relations**	
COM 001	Media relations and communications	Direct charged
COM 002	Administration of HEI Charitable Foundation	Direct charged
CON	**Consulting - general**	
CON 001	Review of monthly results	Direct charged
CON 002	Meetings	Direct charged
CON 003	Preparation	Direct charged
CON 004	Other	Direct charged
CON 010	HELCO network project	Direct charged
CON 011	Corporate structure	Direct charged
CON 012	General financial consulting	Direct charged
CON 100	General consulting for enery services	Direct charged
CON 101	Hyatt Regency Maui	Direct charged
CON 102	Hyatt Regency Waikiki	Direct charged
CON 103	Ala Moana Hotel	Direct charged
CON 104	Pacific Beach Hotel	Direct charged
CON 105	Bishop Museum	Direct charged
CON 106	Schofield Barracks	Direct charged
CON 107	Pacific Grand Condo	Direct charged
CON 108	Royal Gardens	Direct charged
FIN	**Financing (Long-term)**	
FIN 001	Debt financing planning & coordination	Direct charged
FIN 002	Debt financing due diligence	Direct charged
FIN 003	Presentations	Direct charged
FIN 004	Debt compliance	Direct charged
FIN 005	Activity no longer valid	n/a
FIN 006	Activity no longer valid	n/a
FIN 007	Activity no longer valid	n/a
FIN 008	Activity no longer valid	n/a
FIN 009	Rating agency matters	Direct charged
FIN 050	Equity financing planning & coordination	Equity to be financed
FIN 051	Equity financing due diligence	Equity to be financed
FIN 052	Presentations	Equity to be financed
FIN 099	Dividend policy	General allocator
FIN 100	Stock split	Common equity
FIN 101	Capital structure	Direct charged
HUM	**Human Resources**	
HUM 001	Benefits consulting services	Employees
HUM 002	Compensation consulting services	Executives
HUM 003	Personnel issues	Employees

Exhibit A

ACTIVITY CODES & ALLOCATION METHODS FOR HEI ACTIVITIES
Updated 12/29/03

Note: Where there are negative data values (i.e. if a subsidiary has a pretax loss) the absolute value will be used since a negative data value would be illogical.
n/a: not applicable

ACTIVITY CODE	ACTIVITY CODE DESCRIPTIONS	ALLOCATION METHOD
HUM 004	Benefit plan report preparation	Employees
HUM 005	Employee benefit consulting (excl. ASB)	Employees (excluding ASB)
HUM 006	Activity no longer valid	n/a
HUM 007	Activity no longer valid	n/a
HUM 008	Code of Conduct development & administrative assistance	Employees
HUM 009	Code of Conduct review	Employees
HUM 010	Compensation committee meetings	Executives
HUM 011	Long-term incentive plan (LTIP)	Executives
HUM 012	Executive incentive compensation plan (EICP)	Executives
HUM 013	Stock options with dividend equivalents	Executives
HUM 014	Stock options	Executives
HUM 015	Executives deferred compensation	Executives
HUM 016	Directors deferred compensation	Directors
HUM 017	Executive incentive compensation consulting services	Executives
HUM 018	Other incentive compensation consulting services	Direct charged
INT	**Internet**	
INT 001	Internet billing	Direct charged
ITA	**Internal Audit**	
ITA 001	Audit planning	Direct charged
ITA 002	Operational auditing	Direct charged
ITA 003	Financial auditing	Direct charged
ITA 004	Savings application (ASB)	Direct charged
ITA 005	ACF2 (ASB)	Direct charged
ITA 006	Computer operations (ASB)	Direct charged
ITA 007	Branch automation (ASB)	Direct charged
ITA 008	Quarterly follow-up (ASB)	Direct charged
ITA 009	CAAT support (ASB)	Direct charged
ITA 010	Wire transfer review	Direct charged
ITA 011	Dividend checks review	Direct charged
ITA 012	CAAT support - ACCESS (HECO)	Direct charged
ITA 013	CAAT support - job cost (HECO)	Direct charged
ITA 014	Activity no longer valid	n/a
ITA 015	Activity no longer valid	n/a
ITA 016	HEIRS audit	Direct charged
ITA 017	Pension audit	Direct charged
ITA 018	DRIP audit	Direct charged
ITA 019	Stock transfer audit	Direct charged
ITA 020	EDP access controls	Direct charged
ITA 021	LAN security audit	Direct charged
ITA 022	Activity no longer valid	n/a
ITA 023	Internet billings to subs	Direct charged
ITA 025	Internet billing to HECO	Direct charged
ITA 026	Sarbanes-Oxley	Direct charged
ITA 101	LAN/WAN Master Design (HECO)	Direct charged
ITA 102	APPRISE security review (HECO)	Direct charged
ITA 401	ACF2 follow-up audit (ASB)	Direct charged
ITA 402	OTS audit (ASB)	n/a
ITA 410	General consulting (ASB)	Direct charged
ITA 411	Pension plan (ASB)	Direct charged
ITA 412	Bank of America Runoff (ASB)	Direct charged
ITA 413	ASB Home Banking (ASB)	Direct charged
ITA 501	Activity no longer valid	n/a
ITA 502	Activity no longer valid	n/a
ITA 503	Activity no longer valid	n/a
ITA 608	Honolulu Harbor Investigation	Direct charged
ITA 801	Financial reporting (Controller)	Direct charged
ITA 802	Activity no longer valid	n/a
ITA 803	Activity no longer valid	n/a
ITA 804	Mac LAN management (Z6)	Direct charged
ITA 805	Wyatt actuary assistance (HEI retirement plan)	Direct charged
ITA 806	Network security (Z6)	Direct charged
ITA 807	Internet security (Z6)	Direct charged
ITA 808	Internet projects (Z6)	Direct charged
ITA 809	HEI IT-Change Management Audit (Z6)	Direct charged
ITA 900	Consulting	Direct charged

Exhibit A

ACTIVITY CODES & ALLOCATION METHODS FOR HEI ACTIVITIES

Updated 12/29/03

Note: Where there are negative data values (i.e. if a subsidiary has a pretax loss) the absolute value will be used since a negative data value would be illogical.
n/a: not applicable

ACTIVITY CODE	ACTIVITY CODE DESCRIPTIONS	ALLOCATION METHOD
ITA 930	Activity no longer valid	n/a
ITA 931	Activity no longer valid	n/a
ITA 950	Office administration: timesheets, expense reports, staff meetings, budgets	n/a
ITA 951	Professional organizations	n/a
ITA 952	Training, seminars	n/a
ITA 953	Community services	n/a
ITA 954	Software management: upgrades, installation, trouble-shooting	n/a
ITA 955	Electronic vaulting project	n/a
ITA 956	General audit research & development	n/a
ITA 957	Network projects: WAN, HEI InterLAN design, planning & implementing	n/a
ITA 958	Internet WEB page maintenance & design for HEI financial data	n/a
ITA 959	Revisions of financial data to WEB	n/a
ITA 960	AP data base	n/a
ITA 961	HEI data vaulting	n/a
ITA 962	Network meetings	n/a
ITA 963	State libraries	n/a
ITA 964	Year 2000	n/a
ITA 965	Pension system	n/a
ITA 966	Business Continuity Planning	n/a
ITA 967	Quarterly disclosure controls	n/a
ITA 968	Quarterly financial reporting	n/a
ITA 969	Quarterly stock transactions	n/a
ITA 970	Annual proxy	n/a
ITA 971	Annual report	n/a
ITA 972	Other 8-Ks	n/a
ITA 973	Regulation FD	n/a
ITA 974	Governance Charters & Guidelines	n/a
ITA 975	Code of Conduct	n/a
ITA 976	HEI Post Retirement Benefits	n/a
ITA 977	Procedures support	n/a
ITA 999	Special assignments	Direct charged
INV	**Investor Relations**	
INV 001	Analyst/media communications	Common equity
INV 002	Broker meetings	Common equity
INV 003	Fact sheet	Common equity
INV 004	Financial mailing list	Common equity
INV 005	Financial news releases	Common equity
INV 006	Group analyst meetings	Common equity
INV 007	HEI stock - share forecast	Common equity
INV 008	Investor base/stockholder monitoring	Common equity
INV 009	Investor relations planning	Common equity
INV 010	Investment Society of Hawaii	Common equity
INV 011	National Association of Investors Corporation (NAIC)	Common equity
INV 012	One-on-one meetings/visits with analysts	Common equity
INV 013	Other investor relations activities	Common equity
INV 014	Retail program	Common equity
INV 015	Retail/broker/shareholder communications	Common equity
INV 016	Activity no longer valid	n/a
INV 017	Activity no longer valid	n/a
INV 018	Statistical supplement	Common equity
INV 019	Surveys	Debt + Equity
INV 020	Teleconferencing	Common equity
INV 021	NatWest utility seminar	Common equity

Exhibit A

ACTIVITY CODES & ALLOCATION METHODS FOR HEI ACTIVITIES
Updated 12/29/03

Note: Where there are negative data values (i.e. if a subsidiary has a pretax loss) the absolute value will be used since a negative data value would be illogical.
n/a: not applicable

ACTIVITY CODE	ACTIVITY CODE DESCRIPTIONS	ALLOCATION METHOD
LEG	**Legal**	
LEG 001	Review of reports	Direct charged
LEG 002	Legal overview	Direct charged
LEG 003	Activity no longer valid	n/a
LEG 004	Other legal work	Direct charged
LEI	**Legislation**	
LEI 001	Review of legislative proposals	General allocator
LEI 002	Monitor executive/legislative proposals	General allocator
LEI 003	Lobbying	General allocator
LEI 004	Preparation of testimony and other reports on proposed legislation	General allocator
LEI 005	Preparation for meetings on govt. issues	General allocator
LEI 006	Meetings on govt. issues	General allocator
LEI 007	Preparation of govt. reports	General allocator
PEN	**Pension plan**	
PEN 001	Activity no longer valid	n/a
PEN 002	Activity no longer valid	n/a
PEN 003	Activity no longer valid	n/a
PEN 004	Activity no longer valid	n/a
PEN 005	HEIRS	HEIRS participants
PEN 006	Activity no longer valid	n/a
PEN 007	HEI Retirement Plan	Plan assets
PEN 008	HTB Salaried Plan	Plan assets
PEN 009	Master pension trust	Plan assets
PEN 010	Activity no longer valid	n/a
PEN 018	American Savings Bank Retirement Plan	Direct charged
PEN 019	Young Brothers, Limited Pension Plan	Direct charged
PEN 020	Directors Retirement Plan	Plan participants
PEN 021	Activity no longer valid	n/a
PEN 022	Supplemental Executive Retirement Plan	Plan participants
PEN 023	not used	n/a
PEN 024	Nonpension postretirement benefits plans/trusts	Plan assets
PEN 025	not used	n/a
PEN 026	OPEB funded plans/trusts	Plan assets
PEN 027	Excess Plans	Plan participants
PEN 028	HECO OPEB Plan	Plan assets
PEN 029	YB OPEB Plan	Direct charged
PEN 030	HEI postretirement benefits trust (electric discount)	Plan costs
PEN 031	Postretirement Executive Life Trust	Plan costs
RPT	**Reports**	
	Government filings	
RPT 001	10K	Publicly held equity (common & preferred)
RPT 005	10K printing and mailing	Publicly held equity (common & preferred) including discontinued operations
RPT 011	10Q	Publicly held equity (common & preferred)
RPT 015	10Q printing and mailing	Publicly held equity (common & preferred) including discontinued operations
RPT 021	8K	Publicly held equity (common & preferred)
RPT 025	8K printing and mailing	Publicly held equity (common & preferred) including discontinued operations
RPT 031	Amendments to articles of incorporation	Publicly held equity (common & preferred)
RPT 032	U-3A-2 filing	Publicly held equity (common & preferred)
RPT 039	Other government reports	Publicly held equity (common & preferred)
	Proxy	
RPT 041	Proxy	Common equity
RPT 045	Proxy printing and mailing	Common equity including discontinued operations
	Annual Report	
RPT 051	Annual report	Publicly held equity (common & preferred)
RPT 055	Annual report printing and mailing	Publicly held equity (common & preferred) including discontinued operations
	Quarterly Reports	
RPT 061	Quarterly report	Publicly held equity (common & preferred)
RPT 065	Quarterly report printing and mailing	Publicly held equity (common & preferred) including discontinued operations
	Other reports	
RPT 099	Other	Publicly held equity (common & preferred)

Exhibit A

ACTIVITY CODES & ALLOCATION METHODS FOR HEI ACTIVITIES
Updated 12/29/03

Note: Where there are negative data values (i.e. if a subsidiary has a pretax loss) the absolute value will be used since a negative data value would be illogical.
n/a: not applicable

ACTIVITY CODE	ACTIVITY CODE DESCRIPTIONS	ALLOCATION METHOD
STO	**Stock Transfer activities**	
STO 001	Preferred stock dividend payments	Preferred equity
STO 002	Preferred stock redemption payments	Preferred equity
STO 003	Form 1099 (for preferred stockholders)	Preferred equity
STO 004	Preferred stockholder database maintenance	Preferred equity
STO 005	Other preferred stock communications	Preferred equity
STO 006	Preferred stock transfer administrative activities	Preferred equity
STO 011	Common stock dividend payments	Common equity including discontinued operations
STO 012	HEI Dividend Reinvestment program administration	Common equity including discontinued operations
STO 013	Form 1099 Dividends	Common equity including discontinued operations
STO 014	Common stockholder database maintenance	Common equity including discontinued operations
STO 015	Other common stock communications	Common equity including discontinued operations
STO 016	Common stock transfer administrative activities	Common equity including discontinued operations
STO 017	Promotions	Common equity including discontinued operations
STO 018	Stock transfer system	Common equity including discontinued operations
STO 019	Stock transfer division expenses	Common equity including discontinued operations
STO 020	Stock transfer division miscellaneous income	Common equity including discontinued operations
STR	**Strategic Planning**	
STR 001	Strategic planning, research, analysis	Direct charged
STR 002	Financial planning, research, analysis	Direct charged
STR 003	Capital allocation policies and standards	Direct charged
STR 004	Project analysis or management	Direct charged
STR 005	Performance standards, measurement, analysis	Direct charged
STR 006	Investment/business research and analysis	Direct charged
STR 007	Securities market (stock market) analysis	Common equity
STR 008	Peer, industry, market, or environmental analysis	Direct charged
STR 009	Economic research and analysis	Direct charged
STR 010	Special projects	Direct charged
TAX	**Tax**	
TAX 001	Tax return preparation	Pretax income
TAX 002	Tax return review	Pretax income
TAX 003	Tax and financial planning	Pretax income
TAX 004	Tax issues on leveraged leases	Pretax income
TAX 005	SFAS 109 planning and implementation	Pretax income
TAX 006	Tax research	Pretax income
TAX 007	Tax accrual review	Pretax income
TAX 008	Tax compliance software implementation	Pretax income
TAX 009	Assistance on the IRS examination	Pretax income
TAX 010	Information returns	Pretax income
TAX 011	IRS/Dept. of Taxation correspondence	Pretax income
TAX 012	Estimated tax computation	Pretax income
TAX 013	General excise tax returns	Pretax income
TAX 014	Payroll tax withholding	Pretax income
TAX 015	OTS Information Requests	Direct charged
TAX 016	Payroll Taxes	Direct charged
TAX 017	Other tax matters	Direct charged
TAX 018	Executive payroll issues	Direct charged

186400 - HECO Billings to HEI
Test Year 2009

acct	ra	ra desc	act	act desc	Exp Type	TY09
186400	P1V	VP-Corp Relations	756	Maint Rel-Invest	LABOR	6,144
186400	P1V	VP-Corp Relations	756	Maint Rel-Invest	NONLABOR	1,214
						7,358
186400	P4V	Sr VP-Finance & Admin	755	Maint Rel-BOD	LABOR	26,970
186400	P4V	Sr VP-Finance & Admin	755	Maint Rel-BOD	NONLABOR	7,674
						34,644
186400	P4V	Sr VP-Finance & Admin	756	Maint Rel-Invest	LABOR	33,749
186400	P4V	Sr VP-Finance & Admin	756	Maint Rel-Invest	NONLABOR	9,602
						43,351
186400	P6V	VP-Corp Excellence	778	Adm Flexible Ben Pgm	LABOR	975
186400	P6V	VP-Corp Excellence	778	Adm Flexible Ben Pgm	NONLABOR	340
						1,315
186400	P9P	President	700	Dev & Adm Business Plans	LABOR	15,499
186400	P9P	President	700	Dev & Adm Business Plans	NONLABOR	22,386
						37,885
186400	P9P	President	779	Adm Retirement Pgm	LABOR	1,578
186400	P9P	President	779	Adm Retirement Pgm	NONLABOR	361
						1,939
186400	P9S	Sr VP-Energy Solutions	827	Perf Econ/Fin Anlys	LABOR	325
186400	P9S	Sr VP-Energy Solutions	827	Perf Econ/Fin Anlys	NONLABOR	113
						438
186400	PAC	Corp Accounting	836	Fin Rpts/StatInfo-Ext	LABOR	953
186400	PAC	Corp Accounting	836	Fin Rpts/StatInfo-Ext	NONLABOR	424
						1,377
186400	PAD	Cost Accounting	777	Process Payroll	LABOR	5,547
186400	PAD	Cost Accounting	777	Process Payroll	NONLABOR	3,594
						9,142
186400	PCP	Pmt Proc & Supp Ctr	600	Resp to Cus Inq/Svc Req	LABOR	11,084
186400	PCP	Pmt Proc & Supp Ctr	600	Resp to Cus Inq/Svc Req	NONLABOR	5,925
						17,009
186400	PED	Development Svcs	778	Adm Flexible Ben Pgm	LABOR	1,707
186400	PED	Development Svcs	778	Adm Flexible Ben Pgm	NONLABOR	760
						2,467
186400	PEI	Infrastruct & Oper	895	Op & Maint Mainframe	NONLABOR	3,180
						3,180
186400	PEI	Infrastruct & Oper	900	Op Desktop OffcTelecom	NONLABOR	24,000
						24,000

186400 - HECO Billings to HEI
Test Year 2009

acct	ra	ra desc	act	act desc	Exp Type	TY09
186400	PEZ	ISD Chargeback	775	Empl Comp PolPracProc	NONLABOR	2,400
						2,400
186400	PEZ	ISD Chargeback	776	Ben Plan PolPracProc	NONLABOR	96
						96
186400	PEZ	ISD Chargeback	778	Adm Flexible Ben Pgm	NONLABOR	1,200
						1,200
186400	PEZ	ISD Chargeback	779	Adm Retirement Pgm	NONLABOR	444
						444
186400	PEZ	ISD Chargeback	825	Manage Cash	NONLABOR	7,047
						7,047
186400	PFA	Admin-WFS & Dev	766	Maint Employee Recds	LABOR	238
186400	PFA	Admin-WFS & Dev	766	Maint Employee Recds	NONLABOR	106
						344
186400	PFA	Admin-WFS & Dev	778	Adm Flexible Ben Pgm	LABOR	792
186400	PFA	Admin-WFS & Dev	778	Adm Flexible Ben Pgm	NONLABOR	353
						1,145
186400	PFB	Employee Benefits	701	Dev & Mg Forecasts	LABOR	159
186400	PFB	Employee Benefits	701	Dev & Mg Forecasts	NONLABOR	71
						230
186400	PFB	Employee Benefits	755	Maint Rel-BOD	LABOR	7,488
186400	PFB	Employee Benefits	755	Maint Rel-BOD	NONLABOR	2,275
						9,763
186400	PFB	Employee Benefits	761	Audits-External	LABOR	714
186400	PFB	Employee Benefits	761	Audits-External	NONLABOR	318
						1,032
186400	PFB	Employee Benefits	776	Ben Plan PolPracProc	LABOR	5,473
186400	PFB	Employee Benefits	776	Ben Plan PolPracProc	NONLABOR	2,453
						7,927
186400	PFB	Employee Benefits	778	Adm Flexible Ben Pgm	LABOR	6,571
186400	PFB	Employee Benefits	778	Adm Flexible Ben Pgm	NONLABOR	42,623
						49,194
186400	PFB	Employee Benefits	779	Adm Retirement Pgm	LABOR	14,054
186400	PFB	Employee Benefits	779	Adm Retirement Pgm	NONLABOR	15,455
						29,509
186400	PFB	Employee Benefits	780	AdmBen Oth than Flex Ret	LABOR	812

186400 - HECO Billings to HEI
Test Year 2009

acct	ra	ra desc	act	act desc	Exp Type	TY09
186400	PFB	Employee Benefits	780	AdmBen Oth than Flex Ret	NONLABOR	110,550
						111,362
186400	PFC	Compensation	755	Maint Rel-BOD	LABOR	5,619
186400	PFC	Compensation	755	Maint Rel-BOD	NONLABOR	2,106
						7,725
186400	PFC	Compensation	775	Empl Comp PolPracProc	LABOR	9,865
186400	PFC	Compensation	775	Empl Comp PolPracProc	NONLABOR	3,767
						13,632
186400	PFC	Compensation	778	Adm Flexible Ben Pgm	LABOR	493
186400	PFC	Compensation	778	Adm Flexible Ben Pgm	NONLABOR	185
						678
186400	PFD	Client Svcs & Consult	767	Recruit PolPracProc	LABOR	4,293
186400	PFD	Client Svcs & Consult	767	Recruit PolPracProc	NONLABOR	1,910
						6,203
186400	PFD	Client Svcs & Consult	778	Adm Flexible Ben Pgm	LABOR	358
186400	PFD	Client Svcs & Consult	778	Adm Flexible Ben Pgm	NONLABOR	159
						517
186400	PFI	Org Development	778	Adm Flexible Ben Pgm	LABOR	388
186400	PFI	Org Development	778	Adm Flexible Ben Pgm	NONLABOR	176
						564
186400	PFS	Corporate Safety	778	Adm Flexible Ben Pgm	LABOR	148
186400	PFS	Corporate Safety	778	Adm Flexible Ben Pgm	NONLABOR	55
						203
186400	PHB	Facilities Operation	934	Prov&Mg Svcs-Custodial	LABOR	7,951
186400	PHB	Facilities Operation	934	Prov&Mg Svcs-Custodial	NONLABOR	3,723
						11,675
186400	PKI	Risk Management	749	Maint Rel-Ind Assoc	NONLABOR	19
						19
186400	PKI	Risk Management	789	Attend Training	NONLABOR	16
						16
186400	PKI	Risk Management	950	Prov Risk Mgt Svcs-Liab	LABOR	25,239
186400	PKI	Risk Management	950	Prov Risk Mgt Svcs-Liab	NONLABOR	960,935
						986,174
186400	PKI	Risk Management	951	Prov Risk Mgt Svcs-Prop	LABOR	1,118
186400	PKI	Risk Management	951	Prov Risk Mgt Svcs-Prop	NONLABOR	11,203
						12,320

186400 - HECO Billings to HEI
Test Year 2009

acct	ra	ra desc	act	act desc	Exp Type	TY09
186400	PKI	Risk Management	953	Prov Risk Mgt Svcs-WC	LABOR	22
186400	PKI	Risk Management	953	Prov Risk Mgt Svcs-WC	NONLABOR	1,108
						1,129
186400	PKT	Treasury	749	Maint Rel-Ind Assoc	NONLABOR	1,552
						1,552
186400	PKT	Treasury	825	Manage Cash	LABOR	29,616
186400	PKT	Treasury	825	Manage Cash	NONLABOR	169,915
						199,531
186400	PKT	Treasury	826	Manage Financing	NONLABOR	98,315
						98,315
186400	PNA	Internal Audit	836	Fin Rpts/StatInfo-Ext	LABOR	1,843
186400	PNA	Internal Audit	836	Fin Rpts/StatInfo-Ext	NONLABOR	786
						2,628
186400	PNC	Legal	756	Maint Rel-Invest	LABOR	650
186400	PNC	Legal	756	Maint Rel-Invest	NONLABOR	227
						877
186400	PNC	Legal	961	Cond Legal Due Diligence	LABOR	759
186400	PNC	Legal	961	Cond Legal Due Diligence	NONLABOR	423
						1,181
186400	PNX	Admin-Audit & Complnc	760	Audits-Internal	LABOR	38,969
186400	PNX	Admin-Audit & Complnc	760	Audits-Internal	NONLABOR	21,702
						60,671
186400	PPW	Workers Compensation	778	Adm Flexible Ben Pgm	LABOR	148
186400	PPW	Workers Compensation	778	Adm Flexible Ben Pgm	NONLABOR	55
						203
186400	PQC	Corp Communications	753	Maint Rel-Community	LABOR	397
186400	PQC	Corp Communications	753	Maint Rel-Community	NONLABOR	177
						574
186400	PQC	Corp Communications	756	Maint Rel-Invest	LABOR	3,553
186400	PQC	Corp Communications	756	Maint Rel-Invest	NONLABOR	1,373
						4,926
186400	PVP	Purchasing	753	Maint Rel-Community	NONLABOR	7,324
						7,324
186400	PVP	Purchasing	807	Co-wide Empl Commun	NONLABOR	14,596
						14,596
					Grand Total	**1,839,029**

BLOCK OF ACCOUNT / ACCOUNT / DEPARTMENT / RA / EXPENSE ELEMENT / ACTIVITY / LOCATION	2009 Budget
596 MAINT OF STREET LIGHTING & SIGNAL	
(G/L codes)	
	-9,359
Total (G/L codes)	**-9,359**
Total (G/L codes)	**-9,359**
PW9 Cust Installations	
PWX Engineering & Meter	
406 Corp Admin Expense	
493 Maint St Lighting Fac	
OAH Oahu	2,104
422 Employee Benefits	
493 Maint St Lighting Fac	
OAH Oahu	5,740
423 Payroll Taxes	
493 Maint St Lighting Fac	
OAH Oahu	1,515
Total PWX	**9,359**
Total PW9	**9,359**
Total 596	**0**
597 MAINT OF METERS - DIST	
(G/L codes)	
	-13,201
Total (G/L codes)	**-13,201**
Total (G/L codes)	**-13,201**
PW9 Cust Installations	
PWX Engineering & Meter	
406 Corp Admin Expense	
495 Rep Rev Meters & Rel Eq	
OAH Oahu	2,930

BLOCK OF ACCOUNT / ACCOUNT / DEPARTMENT / RA / EXPENSE ELEMENT / ACTIVITY / LOCATION	2009 Budget
PPI Labor Rel & Wage Adm	
406 Corp Admin Expense	
778 Adm Flexible Ben Pgm	
PHE HECO	1,413
422 Employee Benefits	
778 Adm Flexible Ben Pgm	
PHE HECO	3,855
423 Payroll Taxes	
778 Adm Flexible Ben Pgm	
PHE HECO	1,003
Total PPI	**6,272**
Total PP0	**12,204**
Total 926010	**-6,124**
926020 EMPLOYEE BENEFITS TRANSFER	
(G/L codes)	
	25,353,845
422 Employee Benefits	
	-35,009,264
Total (G/L codes)	**-9,655,419**
Total (G/L codes)	**-9,655,419**
Total 926020	**-9,655,419**
9301 INSTITUTN/GOODWILL ADVERT EXP	
(G/L codes)	
	-7,868
Total (G/L codes)	**-7,868**
Total (G/L codes)	**-7,868**

BLOCK OF ACCOUNT / ACCOUNT / DEPARTMENT / RA / EXPENSE ELEMENT / ACTIVITY / LOCATION	2009 Budget
PQCD Corp Communications	
PQC Corp Communications	
406 Corp Admin Expense	
754 Adm Inst or Goodwill Ad	
PHE HECO	476
422 Employee Benefits	
754 Adm Inst or Goodwill Ad	
PHE HECO	1,300
423 Payroll Taxes	
754 Adm Inst or Goodwill Ad	
PHE HECO	277
Total PQC	**2,053**
Total PQCD	**2,053**
PV9 Support Services	
PVL Electric & Welding Svcs	
404 Energy Delivery	
754 Adm Inst or Goodwill Ad	
PHE HECO	8,825
406 Corp Admin Expense	
754 Adm Inst or Goodwill Ad	
PHE HECO	921
422 Employee Benefits	
754 Adm Inst or Goodwill Ad	
PHE HECO	2,513
423 Payroll Taxes	
754 Adm Inst or Goodwill Ad	
PHE HECO	731
Total PVL	**12,990**
Total PV9	**12,990**
Total 9301	**7,175**

9302 MISCELLANEOUS GENERAL EXPENSES

(G/L codes)	
	-176,556
Total (G/L codes)	**-176,556**
Total (G/L codes)	**-176,556**

HAWAIIAN ELECTRIC COMPANY, INC.
ADMINISTRATIVE EXPENSES TRANSFERRED
ACCOUNT 922

				2009 (000)
Cost Pool:				
Labor			$ 1,881	
Transfer Rate per updated KPMG study		X	40%	
				$ 752
NPW				121
Payroll Taxes				62
Emp Ben				261
Nonlabor-Acct. 921			$ 17,933	
Transfer Rate per updated KPMG study		X	6%	
				$ 1,076
Capital Budgets Labor				175
NPW				25
Payroll Taxes				15
Emp Ben				54
	A			$ 2,542
Cost Base:				
Capital Labor Hours			434	
Clearings to Capital		+	209	
	B			643
Corporate Admin rate per hour	C = A ÷ B			$ 3.95
Total Productive hours	D	X		3,232
Administrative Expenses Transferred - based on total productive hours	E = C X D			$ 12,766
Reversal of Corporate Admin on-cost charged to O&M	F	+		(9,474)
Subtotal - Naruc 922	G = E + F			3,292

HAWAIIAN ELECTRIC COMPANY, INC.
ADMINISTRATIVE EXPENSES TRANSFERRED
ACCOUNT 922

Naruc 922 per Rate Case Report D1	H			3,487
Naruc 922 (subtotal from page 1)	G	3,292		
Naruc 922 per Rate Case Report D1	H	3,487		
Correction to Naruc 922				(195)
Administrative Expenses Transfer Adjustments and Normalizations:				
Budget adjustment HEI charges		(272)		
Performance Incentive Compensation		(16)		
Abandoned capital project adjustment		10		
Maintenance expense reclassification		(1,108)		
Service awards adjustment		(55)		
IRP normalization adjustment		(103)		
HR Suites Amortization reduction		(34)		
			(1,578)	
Transfer Rate per updated KPMG study	X		6%	
				(95)
Administrative Expenses Transferred				$ 3,197

HAWAIIAN ELECTRIC COMPANY, INC.
EMPLOYEE BENEFITS TRANSFER
ACCOUNT 926020

		2009 (000)		Adjustments: Other*	Pension	DSM	SSF	Total		Adjusted 2009 (000)	
Cost Pool:											
Labor to 926		$ 920		2				2		$ 922	
NPW		130						0		130	
Payroll Taxes		76						0		76	
Eng Del		0						0		0	
Corp Admin		103						0		103	
Stores		6						0		6	
Emp Ben		282						0		282	
Nonlabor		33,487		722	-2,891			-2,169		31,318	
	A	$ 35,004		$ 724	$ (2,891)	$ -	$ -	$ (2,167)	A1	$ 32,837	
Cost Base:											
Total Company Productive Hours		3,232				-9	-2	-11		3,221	
	B	3,232		0	0	-9	-2	-11	B1	3,221	
Employee Benefits rate per hour	C = A ÷ B	$ 10.83							C1 = A1 ÷ B1	$ 10.19	
Total Company Productive Hours	D X	3,233							D1	3,221	
Employee Benefits transfer - based on total productive hours	E = C X D		$ 35,009						E1 = C1 X D1		$ 32,826
Reversal of Employee Benefits on-cost charged to O&M	F +		-25,354						F1		-23,863
Employee Benefits transfer	G = E + F		$ 9,655						G1 = E1 + F1		$ 8,963
926020 Employee Benefits Transfer per Report D1									H1		9,655
Adjustment to 926020 Employee Benefits Transfer									J1 = H1 - G1		$ 692

* Difference between oncost calculation and budget.

Standard Labor Rates + True-up

(Illustration Only)

Actual ST Pay = $10.00/hr

	hrs		Amt
	8	@ st	$ 80
	2	@ ot	30
	1	@ dt	20
Total	11		$ 130

Standard Rate Calculation

Calculation is made for each labor class.

(A)	Total labor $'s	$223,000	
(B)	Total hours of work	23,000	
(C)	Std labor rate - unadjusted	$9.70/hr	(A)/(B)
	Std labor rate - adj for GPI	$10.00/hr	

Cost Distribution

Under Previous "Actual" Method

	hrs	type	Descr	Amt
s-tot	4	@ st	Proj 1	$ 40
	4	@ st	Proj 2	40
	1	@ ot	Proj 2	15
s-tot	5		Proj 2	55
	1	@ ot	Billable	15
	1	@ dt	Billable	20
s-tot	2		Billable	$ 35
total	11			$ 130 *

Under Standard Labor Rates

	hrs	Descr	Amt	True-up**	Adj Tot
	4	Proj 1	$ 40	$ 7	$ 47
	5	Proj 2	50	9	59
	2	Billable	20	4	24
Total	11		110 *	20	130

* Actual costs under-distributed by $20 ($130-110)

** True-up is in proportion to the amount of dollars charged e.g. the $7 true-up for Proj 1 = (40/110) x 20

True-Up (Expense Element 155)
2003 - 2007 Recorded

acctgrp	acct group desc	acct	acct desc	2003	2004	2005	2006	2007
G10	Operating Revenues	454100	RENTAL OF ELEC PROP-EXPENSES	1,248	550	41	-	-
G10	Operating Revenues	456100	OTHER ELEC REV - EXPENSES	156	(11)	(86)	(21)	(52)
G10 Total				1,403	539	(45)	(21)	(52)
G20	Fuel & Purch Pwr	501010	FUEL-HONOLULU	6,863	32,599	1,160	(594)	1,329
G20	Fuel & Purch Pwr	501020	FUEL-WAIAU	9,201	8,228	6,941	3,728	1,238
G20	Fuel & Purch Pwr	501030	FUEL-KAHE	(2,334)	2,432	2,615	2,456	(724)
G20	Fuel & Purch Pwr	501090	FUEL-CAMPBELL	(70)	4	(13)	221	(995)
G20	Fuel & Purch Pwr	547	FUEL - DIESEL	2,486	2,360	1,527	3,614	2,585
G20 Total				16,146	45,623	12,230	9,425	3,433
G30	O&M	500010	OPER SUPV & ENG-HONOLULU	-	-	-	-	54
G30	O&M	500020	OPER SUPV & ENG-WAIAU	2,228	6,531	12,170	4,073	(10,856)
G30	O&M	500030	OPER SUPV & ENG-KAHE	(953)	6,689	16,591	8,002	(280)
G30	O&M	502010	STEAM EXP-HONOLULU	52,414	79,542	17,308	5,176	(8,083)
G30	O&M	502020	STEAM EXP-WAIAU	104,684	117,702	74,133	101,215	26,315
G30	O&M	502030	STEAM EXP-KAHE	2,728	41,685	18,517	56,324	(26,362)
G30	O&M	505010	ELECTRIC EXPENSES-HONOLULU	45,205	76,073	17,379	6,703	(4,032)
G30	O&M	505020	ELECTRIC EXPENSES-WAIAU	104,646	111,233	78,279	101,116	37,708
G30	O&M	505030	ELECTRIC EXPENSES-KAHE	7,064	46,837	36,237	49,475	(12,930)
G30	O&M	506010	MISC STEAM POWER EXP-HONOLULU	2,431	3,410	1,447	(4,114)	(12,057)
G30	O&M	506020	MISC STEAM POWER EXP-WAIAU	(14,295)	(8,165)	(45,052)	(33,470)	(43,240)
G30	O&M	506030	MISC STEAM POWER EXP-KAHE	(12,370)	7,222	(30,752)	(12,786)	(21,960)
G30	O&M	510010	MAINT SUPV & ENG-HONOLULU	(197)	-	(65)	(13)	(23)
G30	O&M	510020	MAINT SUPV & ENG-WAIAU	262	(704)	(351)	(431)	(7)
G30	O&M	510030	MAINT SUPV & ENG-KAHE	19,064	13,502	646	(53)	(2)
G30	O&M	511010	MAINT OF STRUCTURES-HONOLULU	6,405	7,873	222	(1,427)	842
G30	O&M	511020	MAINT OF STRUCTURES-WAIAU	12,240	13,817	7,533	10,752	(5,795)
G30	O&M	511030	MAINT OF STRUCTURES-KAHE	(3,590)	7,624	6,780	13,526	26,843
G30	O&M	512010	MAINT BOILER & FO PLANT-HONOLULU	66,108	4,898	(4,513)	(1,350)	(12,475)
G30	O&M	512020	MAINT BOILER & FO PLANT-WAIAU	101,619	200,224	72,997	69,326	80
G30	O&M	512030	MAINT BOILER & FO PLANT-KAHE	92,048	144,671	159,394	97,798	93,486
G30	O&M	513010	MAINT ELECTRIC PLANT-HONOLULU	77,291	4,107	974	(2,572)	(16,155)
G30	O&M	513020	MAINT ELECTRIC PLANT-WAIAU	48,387	69,277	24,826	(866)	(62,288)
G30	O&M	513030	MAINT ELECTRIC PLANT-KAHE	22,872	68,322	37,117	40,335	36,733
G30	O&M	514010	MAINT MISC STEAM PLANT-HONOLULU	4,315	3,918	(1,561)	(1,553)	(7,796)
G30	O&M	514020	MAINT MISC STEAM PLANT-WAIAU	(5,085)	(12,416)	(4,771)	4,043	(15,534)
G30	O&M	514030	MAINT MISC STEAM PLANT-KAHE	36,540	6,681	11,492	15,990	8,818
G30	O&M	546	OPER SUPV & ENG- OTH PRD	-	-	12,350	4,182	23,208
G30	O&M	548	GENERATION EXP- OTH PROD	4	(11)	(1,902)	(9,206)	(5,437)
G30	O&M	549	MISC EXPENSES- OTH PROD	-	3,419	(689)	(14,636)	(9,565)
G30	O&M	551	MAINT SUPV & ENG- OTH PRD	-	850	3,008	5,228	672
G30	O&M	552	MAINT STRUCTURES- OTH PRD	18	592	3,208	189	(57)
G30	O&M	553	MAINT ELEC PLANT- OTH PROD	2,593	10,858	24,434	20,605	(1,405)
G30	O&M	554	MAINT MISC PLANT- OTH PROD	-	24	(5)	-	-
G30	O&M	557	OTHER POWER SUPPLY EXPENSES	39,369	28,815	30,588	29,401	31,229
G30	O&M	560	OPER SUPV & ENG - TRANS OPER	(7,241)	(10,097)	9,148	(4,580)	(12,573)
G30	O&M	561	LOAD DISPATCHING - TRANS OPER	(3,240)	44,749	55,939	(4,272)	6,881
G30	O&M	562	STATION EXPENSES - TRANS OPER	8,807	29,128	(183)	3,302	(455)
G30	O&M	563	OVERHEAD LINE EXP- TRANS OPER	6,137	15,382	36	(7,829)	(5,060)
G30	O&M	564	UNDERGRND LINE EXP - TRANS OPER	24	73	36	(165)	(98)
G30	O&M	566	MISC TRANS OPER EXPENSES	22,924	608	1,361	(2,992)	(1,106)
G30	O&M	569	MAINT OF SUBSTN STRUCTURES - TRANS	1,501	1,734	2,074	858	392
G30	O&M	570	MAINT OF STATION EQUIP - TRANS	6,963	16,948	20,438	68,690	51,483
G30	O&M	571	MAINT OF OVERHEAD LINES-TRANS	8,939	18,431	(9,389)	(2,589)	(5,544)
G30	O&M	572	MAINT OF UNDERGRND LINES-TRANS	25,459	5,803	3,399	2,078	1,096
G30	O&M	573	MAINT OF MISC TRANSM PLANT	1,684	895	626	1,978	(320)
G30	O&M	580	OPER SUPV & ENG - DIST OPER	(1,333)	(7,876)	13,085	2,954	(13,348)
G30	O&M	581	LOAD DISPATCHING - DIST OPER	(5,830)	24,897	38,613	18,879	(21,422)
G30	O&M	582	STATION EXPENSES - DIST OPER	4,486	16,047	4,635	23,701	(5,808)
G30	O&M	583	OVERHEAD LINE EXP - DIST OPER	10,046	51,966	13,076	11,559	12,604
G30	O&M	584	UNDERGRND LINE EXP - DIST OPER	20,992	(1,269)	17,022	9,872	(7,767)
G30	O&M	586	METER EXPENSES - DIST OPER	37,332	48,267	4,506	23,828	48,672
G30	O&M	587	CUSTOMER INSTALLATION EXPENSES	(16,978)	(8,888)	(7,289)	5,458	7,081
G30	O&M	588	MISC DISTRIBUTION OPER EXPENSES	42,519	105,867	7,887	21,676	39,900
G30	O&M	591	MAINT OF STRUCT - DIST	57	78	(5,095)	(213)	(1,856)
G30	O&M	592	MAINT OF SUBSTN EQUIP - DIST	5,775	11,653	17,726	54,310	5,191
G30	O&M	593	MAINT OF OVERHEAD LINES-DIST	79,123	162,544	102,873	60,293	132,555
G30	O&M	594	MAINT OF UNDERGRND LINES-DIST	110,533	174,463	176,752	48,184	32,987
G30	O&M	595	MAINT OF LINE TRANSFORMER-DIST	30,997	67,940	19,631	9,482	6,295
G30	O&M	596	MAINT OF STREET LIGHTING & SIGNAL	1,129	3,175	4,261	(6)	1,871
G30	O&M	597	MAINT OF METERS - DIST	122	118	(58)	(590)	(767)

acctgrp	acct group desc	acct	acct desc	2003	2004	2005	2006	2007
G30	O&M	598	MAINT OF MISC DIST PLT	7,197	24,419	(18,963)	(479)	(11,036)
G30	O&M	901	SUPERVISION- CUSTOMER ACCOUNTS	(7,782)	(6,384)	(20,148)	(42,896)	(28,947)
G30	O&M	902	METER READING EXPENSES	(74,838)	(157,666)	(184,426)	(18,362)	2,202
G30	O&M	903	CUSTOMER RECORDS & COLLECT EXP	160,875	214,630	101,788	283,093	252,143
G30	O&M	905	MISC CUSTOMER ACCOUNTS	-	73	(243)	-	-
G30	O&M	909	SUPERVISION- CUST SERVICE EXP	-	(21,910)	(42,720)	(50,030)	(39,680)
G30	O&M	910	CUSTOMER ASSISTANCE EXPENSES	104,434	145,213	128,414	93,014	86,238
G30	O&M	911	INFORMATIONAL ADVERTISING EXP	2,106	1,020	694	(79)	(602)
G30	O&M	912	MISC CUSTOMER SERVICE EXPENSES	11	(1,114)	(157)	(1)	(9)
G30	O&M	920	ADMIN & GENL EXP - LABR	(226,113)	(540,651)	(983,999)	(960,808)	(658,775)
G30	O&M	924	PROPERTY INSURANCE	(3,156)	(5,624)	(6,094)	(9,402)	(4,634)
G30	O&M	925	INJURIES & DAMAGES	(55,650)	(21,814)	8,044	(1,420)	4,295
G30	O&M	926000	EMPLOYEE PENSIONS AND BENEFITS	(23,959)	(13,770)	(37,158)	(39,418)	(39,713)
G30	O&M	926010	EMPL BENEFITS - FLEX CREDITS	(2,802)	(4,776)	(7,482)	(5,481)	(8,140)
G30	O&M	9301	INSTITUTN/GOODWILL ADVERT EXP	958	912	194	196	113
G30	O&M	9302	MISCELLANEOUS GENERAL EXPENSES	(30,732)	2,888	(24,594)	(23,554)	(13,374)
G30	O&M	932	ADMIN AND GENL MAINTENANCE	4,938	2,883	136	(318)	(3,491)
G30 Total				1,060,457	1,456,064	(17,636)	128,910	(182,876)
G40	Oth Income Statement	416	COSTS & EXP OF CONTRACT SERVICES	499	-	-	-	-
G40	Oth Income Statement	417200	EXPENSES FROM NONUTILITY OPERATIONS	4,829	4,403	7,604	683	(718)
G40	Oth Income Statement	426	MISC INC DEDUCTIONS	1,022	8,661	13,804	7,956	(1,513)
G40	Oth Income Statement	426020	MISC INC DEDUCTIONS- MAHAKEA	49	2,005	832	132	146
G40 Total				6,398	15,069	22,239	8,771	(2,085)
G50	Capital	107	CONSTRUCTION WORK IN PROGRESS	746,878	864,025	(118,303)	(12,400)	(180,987)
G50	Capital	108300	ACC DEPR-RWIP	120,200	156,565	11,604	28,074	25,482
G50 Total				867,079	1,020,590	(106,698)	15,675	(155,505)
G60	Billable	186200	CHARGES BILL TO ASSOC COS-HELCO	(3,781)	13,891	(34,675)	(49,157)	(50,317)
G60	Billable	186300	CHARGES BILL TO ASSOC COS-MECO	7,352	26,719	(4,677)	(52,190)	(28,421)
G60	Billable	186390	CHARGES BILL TO ASSOC COS-HEICF	-	-	(10)	16	6
G60	Billable	186400	CHARGES BILL TO ASSOC COS-HEI	12,405	947	(6,481)	(5,729)	(11,902)
G60	Billable	186410	CHARGES BILL TO ASSOC COS-HEIII	(0)	(230)	(103)	(104)	(104)
G60	Billable	186420	CHARGES BILL TO ASSOC COS-MPC	20	-	-	-	-
G60	Billable	186430	CHARGES BILL TO ASSOC COS- TOOTS (HTB)	74	(100)	(36)	(48)	(212)
G60	Billable	186450	CHARGES BILL TO ASSOC COS-ASB	(953)	(730)	(946)	204	358
G60	Billable	186460	CHARGES BILL TO ASSOC COS-PECS	(313)	(289)	(283)	(364)	(356)
G60	Billable	186470	CHARGES BILL TO ASSOC COS-HEIPC	3,296	5,219	(285)	4	(44)
G60	Billable	186480	CHARGES BILL TO ASSOC COS-HEIDI	(19)	(219)	(100)	(47)	(57)
G60	Billable	186481	CHGS BILL HEIDC INC	32	-	-	-	-
G60	Billable	186482	CHARGES BILL TO PROVISTECH	(79)	-	-	-	-
G60	Billable	186483	CHARGES BILL TO HEI LEASING INC.	9	-	-	-	-
G60	Billable	186484	CHARGES BILL TO HEI PROPERTIES INC.	(344)	(34)	(32)	(39)	(52)
G60	Billable	186486	Charges Billable-Renewable Hawaii, Inc.	(336)	(299)	6,662	267	3,202
G60	Billable	186487	Charges Billable-Uluwehi Biofuels	-	-	-	-	(1,623)
G60 Total				17,363	44,876	(40,964)	(107,186)	(89,523)
G70	Deferred Debit	185	TEMPORARY FACILITIES	2,691	7,961	(13,507)	(7,488)	(13,141)
G70	Deferred Debit	186000	OTHER DEFERRED DEBITS - MISC	2,120	1,282	377	1,890	13,984
G70	Deferred Debit	186050	CIS Project Deferred Costs	-	-	-	(9,174)	(8,425)
G70	Deferred Debit	186060	HR Suite Proj Phase 1	-	-	-	-	(3,899)
G70	Deferred Debit	186070	OMS Project Deferred Costs	-	-	(977)	(18,621)	(10,591)
G70	Deferred Debit	186910	REG ASSET-IRP COSTS	18	(2,782)	(4,008)	(0)	0
G70	Deferred Debit	186990	PAYROLL HOME COST DEFAULT	(2,634,606)	(3,332,522)	231,027	72,176	482,995
G70 Total				(2,629,777)	(3,326,062)	212,913	38,783	460,923
G80	Charges to Clearing	163	STORES EXPENSE	188,192	241,379	138,972	153,314	204,589
G80	Charges to Clearing	184050	CLR-POWER SUPPLY	36,348	(58,606)	(271,500)	(218,035)	(313,927)
G80	Charges to Clearing	184060	CLR-ENERGY DELIVERY	304,162	297,517	(118,060)	(194,835)	(225,428)
G80	Charges to Clearing	184080	CLEARINGS-CUSTOMER INSTALLATIONS	(798)	(11,643)	(41,797)	(35,278)	31,754
G80	Charges to Clearing	184110	CLEARINGS-VEHICLES	50,905	113,712	122,204	156,512	81,260
G80	Charges to Clearing	184120	CLEARINGS-ITS DEPT.	81,662	161,202	87,646	48,481	186,129
G80 Total				660,470	743,561	(82,534)	(89,840)	(35,623)
G90	Oth Balance Sheet	253000	OTHER DEFERRED CREDITS - MISC	74	106	17	498	(768)
G90	Oth Balance Sheet	253150	DEFERRED GAINS ON SALE OF LAND	(281)	3	290	98	(829)
G90 Total				(207)	109	307	596	(1,597)
			GRAND TOTAL	(669)	369	(189)	5,112	(2,904)

Hawaiian Electric Company, Inc.
ITS costs
Charges to Clearing
2009 Test Year

Increase in Charges to Clearing from 2007 primarily due to the following:

Labor	
Increase of 3 additional devloper analysts	330,000
(based on $198,297 base labor + 66.8% on-cost)	
HECO - WP-1115, page 17	
Non-labor	
Outsourced development services to support new CIS	728,000
Outsourced development services to support new HR suite	202,400
Hardware and software maintenance charges to support UNIX Platform	
- CA Unix utilities	85,000
- CA fees for Unix	90,000
- Unix hardwars/OS support	55,000
- SAN Equipment maintenance	80,000
Other, net	166,600
Increase in Charges to Clearing	1,737,000
Test Year 2009 Charges to ITS Clearing	17,366,000
2007 Actual Charges to ITS Clearing	15,629,000
Increase in Charges to Clearing	1,737,000

Hawaiian Electric Company, Inc.
ITS costs
2009 Test Year

Charges to ITS Clearing Account

Item	Description of item	HECO-WP-1115	Reference	Amounts	Subtotals
Base Labor					
84 ITS staff	Labor dollars by position	page 17	B-2	4,883,582	4,883,582
	141,426 productive hours by position	pages 20-22	B-5 to B-7		
Labor On-Cost	Labor On-cost related to Base Labor	page 15	B	3,262,233	3,262,233
Material					
Infrastructure LAN	LAN related components, storage tapes, cables	pages 48-50	J-7 to J-9	124,293	
Copiers/Printers/Fax	Paper and Printer Supplies (Toner, Fuser, Rollers, staples, maintenance kits)	pages 91-110	J-48 to J-67	142,522	
Data Center	Battery modules, Toner, Paper for Data Center Equipment	pages 43-44	J-2 to J-3	30,918	
Dept Misc	Cell phone/pager equipment/services on Procard, office supplies	pages 73-77	J-32 to J-36	28,072	
Desktop Business	PC related components (Memory, disk drives, Surge protectors, laptop batteries, key boards, mice)	pages 56-59	J-15 to J-18	23,548	
Telecom/Com/Development	Telecom equipment components	pages 72, 88	J-31, J-46	21,495	
Total Materials		page 18	B-3		370,848
Other					
Information Systems Consultants (461)					
Development Services	Outsourced Development Services consulting for CIS, HRMS, Benefits System, DARS (reporting system), SQL Server, Oracle Database, Ebusiness Development support	pages 82-87	J-41 to J-45	1,955,800	
Mainframe	Outsourced Mainframe technical support	page 153	J-110	112,000	
Network Administration	Outsourced Network Security support	page 154	J-111	81,482	
Departmental miscellaneous	Other IT initiatives including SOX and organizational issues			97,900	
Total Information Systems Consulting (461)		page 18	B-3	2,247,182	
Software licenses (462)					
Infrastructure LAN	LAN software, including Microsoft Enterprise Agreement	pages 146, 149	J-103, J-105	134,095	
Desktop Business	Microsoft Enterprise Agreement software	page 148	J-106	69,243	
Data Center	CA Harvest Change Management software	page 144	J-101	60,187	
Other	Communication system and Development Services software	page 151, 142, 143	J-108, J-99, J-100	52,279	
Total Software Licenses (462)		page 18	B-3	315,804	
Rents and Equipment Maintenance (570/600)					
Copiers/Printers/FAX	Lease and maintenance cost of XEROX Copiers/Printers	pages 112-119	J-69 to J-76	444,941	
Infrastructure LAN	Data Circuit monthly lease charges	pages 52-53	J-11 to J-12	240,011	
Telecom trunk/circuit charges	PBX trunks, backup Interisland circuits, long distance	pages 66, 69, 71, 120	J-25 to J-28, J-30, J-77	196,705	
Data Center	Enterprise storage server and printer lease	pages 45-46	J-4 to J-5	65,498	
Total Rents and Equipment Maintenance (570/600)		page 19	B-4	947,155	
Travel (520/522)					
Mainland		pages 89-90, 19	J47-J47b, B-4	19,289	
Interisland		page 19	B-4	12,519	
Total Travel (520/522)				31,808	
Total Other		page 15	B		3,541,949
Outside Services					
Data Center SW Maintenance	Data Center Mainframe Software. Products include: IBM, MacKinney,Allen Systems Group, CA Harvest, Group 1, Computer Associates, Oracle.	pages 144-145	J-101 to J-102	709,010	
Infrastructure LAN Maint	Local Area Network and Storage Area Network Hardware maintenance. Products include: HP Smartnet, Aventail, Cisco, Scriptlogic.	pages 51-52, 53-54	J-10 to J-11, J-12 to J-13	655,470	
Infrastructure LAN SW Maint	Local Area Network and Unix Software maintenance. Products include: Microsoft, McAffee, NTP, Verisign, Hummingbird, Retina, NSI Doubletake, Websense, Evault, Centrify, HP	pages 146-147, 149	J-103 to J-105	443,108	
Desktop Bus SW Maintenance	Desktop software maintenance. Products include: Microsoft, McAffee, Aeroprise	page 148	J-106	412,380	
Data Center OS Svc	Data Center Mainframe Hardware. Products include: IBM, InfoPrint Solutions, Rosetta, Symmetra	pages 44-46	J-3 to J-5	385,773	
Desktop Business OS Svc	Desktop outsourced support and maintenance. Vendors include: Haztech Environmental, BDI, Century Computers, Toshiba America.	page 61	J-20	342,466	
Desktop Technical SW Maint	Desktop software maintenance. Products include: Microsoft, Axiom, Bentley, Advantica, Intergraph, Intelligent Search.	page 150	J-107	241,744	

Hawaiian Electric Company, Inc.
ITS costs
2009 Test Year

Charges to ITS Clearing Account

Item	Description of item	HECO-WP-1115	Reference	Amounts	Subtotals
Development - SW Maint	Development Services software maintenance: IBM Websense, Weblogic, Quest Toad, Sybase, Camellia Software, Business Objects, Seagull Software	pages 142-143	J-99 to J-100	217,837	
Computer Security Analysis	Computer Security software. Products include: AT&T Intrusion Detection, Security Event and Information Management, Accuvant Vulnerability, Managed Penetration tool	page 152	J-109	216,100	
Telecom Equip Maint	Avaya telephone system equipment maintenance.	page 88	J-46	191,387	
Desktop Technical OS Svc	Desktop outsourced support and maintenance. Vendors include: Maintec, Bentley, IC Logic, Xerox, OCE North America, Ricoh	pages 63-65	J-22 to J-24	99,200	
HEI Internet Charges OS Svc	Internet charges and email protection services	page 42	J-1	84,300	
Interisland Circuit Charges	High Speed data circuit charges	page 120	J-77	70,051	
Department Miscellaneous	Gartner Research, Time Warner Roadrunner, Parking, WDI Movers, Water, Background information service	pages 78-80	J-37 to J-40	66,914	
Copiers/Printers/FAX	Printer and Copier maintenance. Vendors include: Maintec, Hawaii Business Equipment.	pages 110-112	J-67 to J-69	61,738	
Other	Travel, Training, Development, Long Distance, UTC membership	pages 55, 70-72, 89	J-14, J-29 to J-31, J-47	65,175	
Total Outside Services		page 15	B		4,262,653
Transportation	ITS Department pool car use	page 78	J-37	8,450	8,450
EFMS Program	Electric Facilities Management Systems Program entails implementing systems that improve work processes; improve information management, including data access & sharing, system interfaces, and asset management; and make our personnel more efficient & effective Consist of several subprojects shown on Workpaper C-1	pages 10, 25	A-1, C-1	650,000	650,000
EBus Program	EBusiness Program consists of our on-line services, including web page services and e-mail contact with customers, web and database application development and support to provide employees with the information and data jobs. Consist primarily of annual maintenance and support of the EBusiness platform. Cost components are shown on Workpaper C-2	pages 10, 26	A-1, C-2	364,000	364,000
Other Projects					
Collaborative Communications Program	Collaborative Communications program consist of teleconferencing and videoconferencing systems. These costs represent the non-capital cost components of maintaining these systems.	page 10	A-1	21,901	21,901
Total Charges to ITS Clearing Account		page 10	A-1		17,365,616

Hawaiian Electric Company, Inc.
ITS Costs
2009 Test Year

Software applications to be supported by three additional developers (HECO employees):

1. **Outage Management System (OMS)**
   Mobile Workforce Management System (MWM)
   Field Services Laptops

   Installation date: 2007
   Estimated full-time employee requirement 1.25

   System Description: System discussed by Mr. Robert Young in HECO T-8.

2. **Mobius (IDARS) archive reporting software**

   Installation date: 2007
   Estimated full time employee requirement 1.50

   System Description:
   Mobius is the name of the software product used to implement HECO's Integrated Document Archive and Retrieval System (IDARS). IDARS is used to manage reports. It is used to automatically distribute reports that need to be sent to users rather than run on demand, assign the appropriate security settings so they' are only viewable to those with access, archive reports for later reference, etc. The new CIS and Ellipse to UNIX projects both plan to use the Mobius product as part of their overall reporting solution. Mobius is the replacement product for SAR on the mainframe, which both ACCESS and Ellipse use today. We also plan to use IDARS to meet other needs, including reports for the OMS.

3. CA Harvest Software

Installation date: 2007
Estimated full time employee requirement (included as part of 1.5 full-time equivalent for Mobius)

System Description:
Harvest is the name of a configuration control product similar to Microsoft's Source Safe software. It is, or will be, used by the developers to manage and control changes to the OMS, CIS, Ellipse, and possibly other systems. It prevents multiple developers from working on the same code at the same time. It creates a record of what code is used in the production environment at any given time and provides a mechanism to rollback to previous versions of the software should problems arise.

4. Apache, Tomcat and Weblogic

Installation date: 2004-2006
Estimated full time employee requirement 0.25

System Description:
These products are used in conjunction with running systems recently purchased/installed and are collectively referred to as application server software. The new CIS requires Weblogic software to run. Our Vignette platform (Internet and Collaboration tool) and Bentley training software requires Tomcat. Apache is needed for our Websphere platform as well as for components of Ellipse. At the risk of oversimplifying, these products do not provide added functionality but are required to run other systems and HECO staff is required to be knowledgeable in the products. In that regard, it is similar to database software in that the database doesn't provide functionality by itself, but all the systems need a database product to store data.

5. Business Objects Software

Installation date: 2006
Estimated full time employee requirement (included as part of 1.5 full-time equivalent for Mobius)

System Description:
This software is the foundation of the company's standard reporting platform. It is used, or will be used, for creating reports for the Energy Management System, OMS, CIS and Ellipse systems. Reporting software is used to pull data, typically from a database, in a predefined manner to make it available to those that need it. By way of example, the Ellipse database records all of HECO's financial transactions. An engineer may want to run a report that depicts only those financial transactions that pertain to his/her project.

6. IBM Websphere Software

Installation date: 2004
Estimated full time employee requirement (included as part of 1.5 full-time equivalent for Mobius)

System Description:
Websphere software is middleware consisting of various components. Websphere Business Integration is used to send, receive and transform messages between disparate systems. Websphere Data Integration provides many standard message transformations out of the box. Of specific interest were the EDI (Electronic Data Interchange) transformations that are commonly used to share information with banks and benefits carriers. Websphere Application Server provides application level access into Ellipse.

ACCOUNTING FOR THE COSTS OF COMPUTER SOFTWARE DEVELOPED OR OBTAINED FOR INTERNAL USE

(Updated as of April 1, 2006)

Introduction

The following guidelines are provided to assist in the accounting for computer hardware and software costs (acquired, internally developed, or modified solely to meet the entity's needs). This is not meant to be all-inclusive, however we will continue to add or revise the information below, as needed, to provide additional clarification. Questions with respect to these guidelines should be addressed to the Controller or Director of Corporate and Property Accounting.

As a general rule, the costs of computer software, including applicable labor to install the software, and ongoing maintenance are generally charged to the appropriate functional operation and maintenance (O&M) expense account(s), i.e. expensed as incurred, based on the benefiting organization unless:

1. Deferrable software costs have been identified in accordance with applicable accounting standards AND approval has been obtained from the PUC allowing the Company to defer those costs,
2. The computer software is an operating system-type (e.g., Windows XP) software needed to render the new computer hardware "used or useful",
3. Specific overhead costs allowed to be applied to deferrable software costs,
4. AFUDC on deferrable software costs.

Costs for software development projects less than $500K would generally be expensed as incurred. (The $500K threshold refers to the amount of costs that would be deferred during the application development stage described below. It does not refer to the total costs that would be incurred during all three project stages described below.) Please notify the Controller or Director of Corporate and Property Accounting of projects that are less than $500K that will be expensed.

Accounting for Computer Software Guidelines

The costs of software upgrades and enhancements that do not provide additional functionality to the existing software (i.e., modifications to the existing software that would enable the software to perform tasks that it was previously incapable of performing) should be charged to the appropriate functional O&M expense account(s), i.e. expensed as incurred, based on the benefiting organization.

Software that is acquired, internally developed, or modified solely to meet the entity's needs should adhere to the guidance set forth below. In general, software development can be segregated into three stages as follows (also summarized in Exhibit 1):

- Preliminary Project Stage. This stage includes conceptual formulation of software alternatives, evaluation of the alternatives, determination of the existence of needed technology, and final selection of alternatives. Internal and external costs incurred during this stage should be charged as incurred to the appropriate functional O&M expense account(s), based on the benefiting organization, i.e. expensed as incurred.

- Application Development Stage. This stage includes the design of a chosen path, including software configuration and software interface, coding, software installation, and testing, including parallel processing. Certain internal and external costs incurred during this stage should be deferred, including costs to develop or obtain software that allows for access of old data by new systems. Certain applicable overhead and AFUDC costs on the deferrable software costs is also deferred.

  The process of data conversion from old to new systems may include purging or cleansing of existing data, reconciliation or balancing of the old data and the old/new system, creation of new/additional data, and conversion of old data to the new system. Data conversion often occurs during the Application Development Stage; however, data conversion costs, other

ACCOUNTING FOR THE COSTS OF COMPUTER SOFTWARE DEVELOPED OR OBTAINED FOR INTERNAL USE

(Updated as of April 1, 2006)

than the costs to develop or obtain software that allows for access of old data by new systems, should be charged as incurred to the appropriate functional O&M expense account(s), based on the benefiting organization, i.e. expensed as incurred.

- Post-Implementation/Operation Stage. This stage includes training and application maintenance. Internal and external costs incurred during this stage should be charged as incurred to the appropriate functional O&M expense account(s), based on the benefiting organization, i.e. expensed as incurred.

Further, costs of activities typically associated with business process reengineering should be charged as incurred to the appropriate functional O&M expense account(s), based on the benefiting organization, i.e. expensed as incurred. Note that these activities can occur during any stage above. Examples include the following:

- Preparation of a request for proposal

- Current state assessment – The process of documenting the entity's current business process, except as it relates to current software structure. Often referred to as *mapping, developing an "as-is" baseline, flow charting,* and *determining current business process structure.*

- Process reengineering – The effort to reengineer the entity's business process to increase efficiency and effectiveness. This activity is sometimes referred to as *analysis, determining "best-in-class," profit/performance improvement development,* and *developing "should-be" processes.*

- Restructuring the work force – The effort to determine what employee is necessary.

Accounting for Computer Hardware Guidelines:
Any computer hardware costs incurred relative to the development or acquisition of software should be capitalized following existing Company policies and procedures. Computer operating system software which is acquired in connection with new hardware should be capitalized together with the hardware under the basis that the operating system is needed to deem the hardware "used or useful".

ACCOUNTING FOR THE COSTS OF COMPUTER SOFTWARE DEVELOPED OR OBTAINED FOR INTERNAL USE

(Updated as of April 1, 2006)

Exhibit 1

The following table sets forth the accounting for typical components of a software development project based on whether the item should be expensed, deferred, or capitalized. Please note that some of the activities listed below may occur in multiple stages.

	Internal or Third Party		
Steps	**Expensed**	**Deferred**	**Capitalized**
Business process reengineering and information technology transformation (these activities primarily occur, but not limited to, prior to preliminary project stage):			
Preparation of request for proposal (RFP)	X		
Current state assessment (*i.e., mapping, developing an "as-is" baseline, flow charting, determining current business process structure.*)	X		
Process reengineering (*i.e., analysis, determining "best-in-class," profit/ performance improvement development, developing "should-be" processes.)*	X		
Restructuring work force	X		
Preliminary software project stage activities:			
Conceptual formulation of alternatives	X		
Evaluation of alternatives	X		
Determination of existence of needed technology	X		
Final selection of alternatives	X		
Examples of the preliminary project stage include: • Strategic decisions to allocate resources between alternative projects at a given point in time (e.g., should programmers develop a new payroll system or direct their efforts toward correcting existing problems in an operating payroll system?) • Determine the performance requirements (i.e., what the software needs to do) and systems requirements for the project • Invite vendors to perform demonstrations of how their software will fulfill an entity's needs • Explore alternative means of achieving specified performance requirements (e.g., should an entity	X		

ACCOUNTING FOR THE COSTS OF COMPUTER SOFTWARE DEVELOPED OR OBTAINED FOR INTERNAL USE

(Updated as of April 1, 2006)

	Internal or Third Party		
Steps	**Expensed**	**Deferred**	**Capitalized**
make or buy the software? Should the software run on a mainframe or a client server system?) • Determine that the technology needed to achieve performance requirements exists • Select a vendor if an entity chooses to obtain software • Select a consultant to assist in the development or installation of the software			
Application development stage activities:			
Design of chosen path, including software configuration and software interface		X	
Coding		X	
Installation to hardware		X	
Testing, including parallel processing phase		X	
Data conversion costs: a. Costs to develop or obtain software that allows for access of old data by new system		X	
b. Process of converting data from old to new systems (e.g., purging or cleansing of existing data), reconciliation or balancing of the old data and the new data in the new system, creation of new/additional data, and conversion of the old data to the new system.	X		
Training	X		
Post-implementation/ operation stage activities:			
Training	X		
Application maintenance	X		
Ongoing support	X		
Acquisition of fixed assets:			
Purchase of hardware, office furniture, or work stations, including operating system			X
Reconfiguration of work area - architect fees and hard construction costs			X

Hawaiian Electric Company, Inc.

Unamortized System Development Costs

($ Thousands)

	Outage Management System (OMS)	Customer Information System (CIS)	HR Suite	TOTAL
BALANCE - 12/31/07	4,300		0	4,300
Deferred Project cost	676		0	676
Amortization	(408)		0	(408)
ESTIMATED BALANCE - 12/31/08	4,568	0	0	4,568
Deferred Project cost	0	23,760	3,618	27,378
Amortization	(432)	(977)	(201)	(1,610)
ESTIMATED BALANCE - 12/31/09	4,137	22,783	3,417	30,336
AVERAGE 2009 BALANCE	17,452			

NOTE: Totals may not add exactly due to rounding.

ACCOUNTING FOR CAPITAL PROJECT COSTS

(As of October 1, 2000) *

The purpose of this document is to describe the general policies and procedures with respect to accounting for capital project costs. This document does not address how to account for the costs of non-capital projects. A chart summarizing the discussion below is attached. There may be facts and circumstances unique to a given project (e.g. a new generating unit addition project) that are not specifically or adequately addressed by the following discussion. When in doubt as to the proper accounting treatment for capital project costs, please consult with the Controller or a Property Accountant in the Property Accounting Division of the General Accounting Department.

Usual Capital Project Life Cycle

The steps usually encountered in a project's life cycle, which provide useful reference points in describing the accounting for capital project costs, are as follows:

1. General planning work to determine overall system requirements. Work includes analyses, feasibility studies and investigations to determine if there is sufficient justification to propose potential projects.
2. Preliminary engineering work associated with potential projects prior to formal project approval by management. Some of the potential projects are eventually constructed, while others do not materialize.
3. Project is initiated, and formally approved by management.
4. Detailed design and permitting work on projects formally approved by management.
5. Purchase of equipment and materials.
6. Construction of plant facilities.
7. Facilities are declared to be used or useful.
8. Closing (capitalization) of project costs.

Potential capital projects are identified and evaluated during step 2. Preliminary engineering work on potential projects is usually intermittent during step 2 because decisions have not yet been made regarding which projects will move forward.

During step 3, projects selected to move forward are initiated by the Project Manager or other appropriate individual, and formally approved by management. As a general rule, management's approval should not be obtained until work on the project needs to begin in order to meet the project's required "in service" date. Management's approval normally means that work on the project should start now and should continue until completion. Once a project is started, steps 4 through 8 should be completed on a planned progressive basis, i.e. without delay, except for the delays that are inherent in the asset acquisition process such as the ordering, purchasing and delivering of long lead time material, and delays due to permitting and external approval processes.

*Clarified on May 1, 2006

Accounting for Capital Project Costs - Usual Project Life Cycle

Under the usual project life cycle summarized above, general planning costs incurred in step 1 are charged initially to appropriate clearing accounts and are then allocated as an on-cost (overhead) charge to projects during steps 4-6 of the projects' life cycles (note that a portion of the costs are actually charged to expense or other accounts as a result of the clearing process). Preliminary engineering costs incurred in step 2 are also charged initially to appropriate clearing accounts. However, preliminary engineering costs are identified with the related potential project, and are temporarily held in the clearing account. The preliminary engineering costs incurred in step 2 are eventually allocated as an on-cost (i.e. treated the same as costs incurred in step 1) if no project is formulated. However, if the related potential project is approved for construction, the preliminary engineering costs are transferred to construction work in progress (CWIP) as explained in the next paragraph.

After a potential project is formally approved by management (step 3), a fifth segment project is activated in the MIMS General Ledger and concurrently set up in the MIMS Project Control Module. Project Managers or other appropriate individuals can then set up the project hierarchy in the MIMS Project Control Module, after which all related project costs incurred during steps 4-7 are classified as CWIP. In addition, any related preliminary engineering costs incurred in step 2 are transferred from the clearing account to the now approved project and CWIP.

During the time project related costs are classified as CWIP (steps 4-7), an Allowance For Funds Used During Construction (AFUDC) is applied on the project costs. AFUDC represents the cost to finance the project during the construction period. When the facilities being constructed are declared to be used or useful, the application of AFUDC is stopped, and the project costs are closed (capitalized), i.e. transferred from CWIP to Plant in Service (step 8).

Facilities become used when they are placed into service. Facilities become useful generally when: 1) construction is for the most part complete, 2) the facilities have been tested (if testing is possible and appropriate), and 3) the facilities are ready for use (i.e. they are able to perform their intended function, and can be energized, pending completion of a related facility(ies), without a significant amount of additional costs incurred). As a general rule, it is expected that facilities will become used within a reasonable period of time after they become useful.

To facilitate the proper and timely closing of capital project costs, we will generally close costs at the controlled fifth segment project level. Therefore, controlled fifth segment projects should be scoped/structured with the following in mind: 1) the facilities included in the project scope should represent full units of property as defined in the company's property unit catalog, 2) the planned completion dates for all of the facilities should be approximately the same and 3) the facilities should be used or useful (see guidelines in the previous paragraph) at the time the facilities are completed. With respect to item 2) in the previous sentence, if the planned completion dates for the facilities included in a fifth segment project (each of which represent full property units) become significantly different, the cost of any facilities which are completed and ready for service (used or useful) should be closed, i.e. capitalized.

Accounting for Capital Project Costs - Delayed or Abandoned Projects

Delayed Projects - The accounting for delayed project costs depends on the cause and length of the delay. As a general rule, if the delay is imposed upon the company by external factors (i.e. the delay is unavoidable and beyond the company's control), project costs are treated as described under the Usual Project Life Cycle scenario above, provided that the costs are recoverable from ratepayers. If cost recoverability is uncertain, the appropriate accounting treatment (which is beyond the scope of this discussion) depends on the facts and circumstances of the situation. In these situations, the Controller should be consulted regarding the appropriate accounting treatment.

If a project is delayed at management's discretion rather than by external factors, the treatment of costs will generally depend on the length of the delay. As a general rule, costs related to projects delayed for two years or less will be treated as described under the Usual Project Life Cycle scenario above, except that AFUDC will not be applied during the period(s) of project delay. If the delay is for more than two years, the costs will be treated as though the project were abandoned as described below.

Regardless of the reason for the delay (e.g. external factors or internal management decisions), project costs need to be analyzed when delays of more than one or two months are anticipated. If any of the facilities included in the project scope are used or useful at the time of such project delays, it will generally be necessary to close (capitalize) the costs related to the facilities that are used or useful.

Please note: the determination that a delay has occurred does not necessarily require a complete stoppage of work. A delay generally means that work on the project is no longer proceeding on a planned progressive basis, i.e. is no longer proceeding without delay, except for the delays that are inherent in the asset acquisition process. In other words, if construction is not proceeding as fast as would normally be expected for the type of construction involved, a delay in the project may have occurred.

Abandoned Projects - An abandoned project is one in which a "no go" decision is made during the time the project costs are classified as CWIP, i.e. a "no go" decision is made sometime during steps 4 through 6 of the project's life cycle. Under normal circumstances, the costs of abandoned capital projects are charged to appropriate operation and maintenance expense account(s), unless the costs result in items that have future value. If any of the costs represent items that have future value, e.g. assets that are usable on another capital project, the related costs are transferred to the other project or accounts (e.g. inventory in the case of stock material) as appropriate. If a capital project is abandoned and unusual circumstances exist, e.g. the accumulated costs are significant, the Company will seek PUC approval for special accounting and ratemaking treatment as appropriate under the circumstances.

Required Communications

The policies and procedures described above with respect to accounting for capital project costs are administered by the Property Accounting Division of the General Accounting Department, based on input required from Project Managers or other appropriate individuals. Project Managers or other appropriate individuals must provide, on a timely basis, the Property Accountants with all the information necessary to properly account for capital project costs. For example, the Property Accountants must be advised when preliminary engineering costs incurred in step 2 need to be transferred from a clearing account to the approved capital project. The Property Accountants must also be advised as soon as projects are completed and/or facilities become used or useful, and as soon as projects are delayed, re-started, or abandoned.

Steps - Construction of Capital Projects

				CWIP/ AFUDC					
	Gen plng (clrng)	Prelim eng (e.g., pewon)	Proj. ini; appvd by mgt	Detailed eng	Permits/ apprvls	Purch equip/ mtl	Construct plant	Used or useful	Close proj costs
Step	1	2	3	4	4	5	6	7	8

Usual Treatment of Costs Under Various Scenarios
(please consult with Controller or Property Accountants)

Scenario	Cost Treatment	AFUDC Treatment
1. Delays due to external factors and cost recovery is probable	Hold in CWIP	Continue
2. Delays </= 2 yrs @ mgt's discretion	Hold in CWIP	Stop until work resumes
3. Work **PERMANENTLY** stopped (project is abandoned)	Transfer to replacement project, inventory, etc. if costs represent items with value	Continue or stop depending on status of new project
	If no replacement project, etc.: Write-off costs to various appropriate O&M expense accounts	Stop and write-off AFUDC
	If costs are significant, seek PUC determination of cost treatment	PUC decides treatment
4. Delays > 2 yrs @ mgt's discretion	Same as 3. above	Same as 3. above

* Clarified on May 1, 2006

HAWAIIAN ELECTRIC COMPANY, INC.
ABANDONED CAPITAL PROJECTS
TEST YEAR 2009 ($ THOUSANDS)

Sum of SumOfDEC_ACTUAL_YTD								2003 - 2007	2003-2007 Average write-off		Amount by Account Block/
NARUC	PROJ_WO_NO	WO_DESC	2003	2004	2005	2006	2007	Grand Total	per year	Account	Account No.
500	HP001833	ABAN-P4683000-K7 EMS & Comm Equip		17				17			
500 Total				17				17	3	500	
502	HP001833	ABAN-P4683000-K7 EMS & Comm Equip		24				24			
	PR068577	ABAN-PR053122 GPS Clocks HPP Cntrol Rm					2	2			
502 Total				24			2	26	5	502	**8** Prod Op
546	AD001618	Expense Project - Pacific Allied			99			99			
546 Total					99			99	20	546	**20** Prod. Maint
566	EE005651	Frq/Vlt for Kalae to DATAQ:P0000157	4					4			
	LA000180	ABAN-AES-CEIP #2 Trans Ln	4					4			
566 Total			8					8	2	566	**2** Trans Op
570	EE011498	KAHE 5-8 CBL TRENCH COVER:P1470000				20		20			
570 Total						20		20	4	570	
571	EE013573	P171 KAHEKILI HY POLE RELOC:P1690000					16	16			
571 Total							16	16	3	571	**7** Trans Maint
580	EE007815	BP NAS PRIVATIZATION:Y00004	143					143			
	EE009592	DIAMOND HEAD RD OH/UG IMPVT:P0000597		1				1			
580 Total			143	1				144	29	580	
588	EE007815	BP NAS PRIVATIZATION:Y00004	335					335			
	EE009592	DIAMOND HEAD RD OH/UG IMPVT:P0000597		15				15			
588 Total			335	15				350	70	588	**99** Dist Op
591	EE011292	Mobile Substation Storage:P0001029				8		8			
591 Total						8		8	2	591	
592	EE013003	Various minor distribution substation additions					17	17			
592 Total							17	17	3	592	
593	EE007803	WAIMANALO DRAINAGE IMPVMT:P1690000	1					1			
	EE012176	KAHUKU CACTF 12KV RELO & SVC:P0001122				18		18			
593 Total			1			18		19	4	593	
594	EE012438	KAKAAKO ID-11:P0001034					162	162			
	EE012741	KAKAAKO ID-11:P0001034					(80)	(80)			
594 Total							82	82	16	594	**25** Dist Maint
920	FA127056	P0000722 - Tsf Oil Spill Containment		1				1			
	FA127087	P0001022 - Employee Smart Cards				2		2			
920 Total				1		2		3	1	920	**1** Acct. 920
921	FA127056	P0000722 - Tsf Oil Spill Containment		1				1			
	FA127063	P0000586 - King Street Attic			31			31			
	FA127087	P0001022 - Employee Smart Cards				17		17			
921 Total				1	31	17		49	10	921	**10** Acct. 921
Grand Total			**487**	**59**	**130**	**65**	**117**	**858**	**172**		**172**
			486,717	59,011	129,881	64,673	117,157				

HECO-1119
DOCKET NO. 2008-0083
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Hawaiian Electric Company, Inc.
Test Year 2009
Unamortized Gain on Sales of Land

Description	Docket No.	Decision and Order No.	Balance 12/31/2007	Additions	Amortize	Balance 12/31/2008	Additions	Amortize	Balance 12/31/2009
Gain on Sales:									
Haiku *	2007-0424		0	318,504		318,504		63,701	254,803
Barbers Point Sub *	2007-0188	24077	0	34,905	3,490	31,415		6,981	24,434
Waianae Remnant Site (7)	2007-0189	24098	0	15,343	2,046	13,297		3,069	10,228
Aiea Park Place (6)	2006-0323	23154	111,522		23,478	88,044		23,478	64,566
Palolo (5)	05-0280	22664	33,057		8,815	24,242		8,815	15,427
Queen Emma (1)	02-0098	19839	583,278		279,974	303,304		279,974	23,330
Iolani Court Plaza (2)	98-0170	16833	490,124	127,439	183,768	433,795		168,265	265,530
Waianae (3)	98-0314	16935	81,566	77,245	35,119	123,692		37,694	85,998
Kuliouou (4)	98-0314	16935	63,219		39,928	23,291		23,291	0
Utility Gain on Sales			1,362,766	573,436	576,618	1,359,584	0	615,268	744,316
Iolani Court Plaza Lease Premium (8)	2640	3921	7,871	0	3,172	4,699	0	2,950	1,749
Total Gain on Sales			1,370,637	573,436	579,790	1,364,283	0	618,218	746,065
Non-utility Gain on Sales **									
Waianae Remnant Site (Non-Utility)	2007-0189	24098	0	35,015	35,015	0	0	0	0
Waianae (Non-utility)	98-0314	16935	0	39,819	39,819	0	0	0	0
Total Non-utility Gain on Sales			0	74,834	74,834	0	0	0	0

(1) Amortized to 41408000
(2) Amortized to 41403000
(3) Amortized to 41412000
(4) Amortized to 41409000
(5) Amortized to 41411000
(6) Amortized to 41414000
(7) Amortized to 41413000
(8) Amortized to 45407100

* Assumptions and estimates provided by Land and Rights-of-Way.
** Non-utility gain recognized entirely in month of sale to NARUC acct 422.

Hawaiian Electric Company, Inc.

Reverse Osmosis Water Pipeline Regulatory Asset

($ Thousands)

BALANCE - 12/31/07	0
Transfer	0
Amortization	0
ESTIMATED BALANCE - 12/31/08	0
Transfer to Regulatory Asset - 2008	6,398
Amortization	(32)
ESTIMATED BALANCE - 12/31/09	6,366
AVERAGE 2009 BALANCE	3,183

NOTE: Totals may not add exactly due to rounding.

PENSION TRACKING MECHANISM

Purpose: The proposed pension tracking mechanism is designed to achieve the following objectives:

A. Ensure that the pension costs recovered through rates are based on the FAS87 NPPC, as reported for financial reporting purposes;

B. Ensure that all amounts contributed to the pension trust funds (subject to the exceptions in Item 3 below) are in an amount equal to actual NPPC (after the pension asset is reduced to zero as provided in Item 2 below) and are recoverable through rates; and

C. Clarify the future treatment of any charges that would otherwise be recorded to equity (e.g., increases/decreases to other comprehensive income) as required by FAS87, FAS158 or any other FASB statement or procedure relative to the recognition of pension costs and/or liabilities.

Procedure:

1. The amount of FAS87 NPPC included in rates shall be equal to the amount recognized for financial reporting purposes.

2. Until the pension asset is reduced to zero, the Company would be required to fund the minimum required level under the law. Thereafter, except when limited by the ERISA minimum contributions requirements or the maximum contribution imposed by the IRC, or the contribution exceeds the NPPC for a reason provided in Item 3, the annual contribution to the pension trust fund will be equal to the amount of FAS87 NPPC.

3. The utility will be allowed to recover through rates the amount of any contributions to the pension trust in excess of the FAS87 NPPC that were made for the following reasons[1]:

    - the minimum required contribution is greater than the FAS 87 NPPC,

    - the increased contribution was made to avoid a significant increase in Pension Benefit Guaranty Corporation (PBGC) variable premiums,

    - the increased contribution was made to avoid a charge to other comprehensive income, or

[1] The Company or the Consumer Advocate (jointly, the "Parties") may initiate discussions with the Parties and the Hawaii Public Utilities Commission to modify these provisions between rate cases (with Commission approval) if there are future changes in accounting standards, federal tax law or federal tax regulations that materially impact the costs otherwise recoverable through this tracking mechanism.

- the increased contribution was made to avoid: (i) higher minimum contribution requirements under the Pension Protection Act,[2] or (ii) other adverse funding requirements under federal pension regulations (provided funding does not exceed 100% of the PBO as a result). The recoverability of any discretionary contributions (as described under this bullet item) shall be subject to review in the Company's next rate case.

Any such "excess" contributions shall be recorded in a separate regulatory asset account, which will be included in rate base.

4. A regulatory asset (or liability) will be established on the Company's books to track the difference between the level of actual FAS87 NPPC during the rate effective period and the level of FAS87 NPPC included in rates during that same period.

    - The amortization of any unamortized cumulative net ratepayer benefit at the end of the test year in the next HECO rate case shall be determined in that rate case proceeding.

    - If the actual FAS87-determined NPPC recorded during a given rate-effective period is greater than the FAS87 NPPC included in rates during the immediately preceding rate case, the Company will establish a separate regulatory asset account to accumulate such difference, but only to the extent that such amount is <u>not</u> used to reduce a regulatory liability recorded pursuant to Item 5.

    - If the actual FAS87-determined NPPC recorded during the rate-effective period, adjusted for any amount of such expense used to reduce a regulatory liability maintained pursuant to Item 5, is less than the expense built into rates, the Company will establish a separate regulatory liability account to accumulate such difference.

    - If the actual FAS87 NPPC becomes negative, the regulatory liability will be increased by the difference between the level of FAS87 NPPC included in rates for that period and "zero" (i.e., $0).

    - Since this is considered to be a <u>cash</u> item under the tracking mechanism, the regulatory asset or liability will be included in rate base and amortized over a five (5) year period at the time of the next following rate case.

[2] Transitional relief applies under the Pension Protection Act if the plan's target liability funded level meets the prescribed phase-in percentages for 2008 through 2011. The Parties recognize that such transitional relief or related requirements may be subject to change or revision in future years.

5. If the FAS87 NPPC becomes negative, the Company will set up a regulatory liability to offset the prepaid pension asset created by the negative amount. This regulatory liability will increase by the amount of any negative NPPC, or decrease by the amount of positive NPPC, in each subsequent year. Positive NPPC in each subsequent year will be used to reduce the regulatory liability before being used to establish a regulatory asset pursuant to Item 4.

    - If NPPC is negative at the time of the next rate case, the amount included in rates will be "zero" (i.e., $0).

    - If NPPC is positive at the time of the next rate case, the positive expense will not be included in rates and the Company will not be required to make contributions to the trust until any regulatory liability created under this Item 5 has been reduced to "zero" (i.e., $0).

    - Since this regulatory liability is considered to be a non-cash item under the tracking mechanism, it is not subjected to amortization and should not be recognized in determining rate base in future years.

6. The objective of this tracking mechanism is that, over time, the Company will recover through rates FAS87-based NPPC, including the amortization of unrecognized amounts as set forth above.

    - The Company will establish a separate regulatory asset/liability account to offset any charge, or credit, that would otherwise be recorded against equity (e.g., decreases to other comprehensive income) caused by applying the provisions of FAS87, FAS158 or any other FASB statement or procedure that requires accounting adjustments due to the funded status or other attributes of the Company's pension plan.

    - This regulatory asset/liability will not be amortized into rates or included in rate base, because any such charges are expected to be recovered in rates through the valuation of FAS87 NPPC in future accounting periods, which will be subject to the true-up process described herein. In other words, this regulatory asset/liability will automatically be reversed through the mechanics of FAS87 and, pursuant to other provisions of this proposal, all FAS87-determined NPPC will over time ultimately be recovered from ratepayers.

    - The regulatory asset/liability will increase or decrease each year by the same amount that the equity charge increases or decreases.

7. Recognizing that rate cases do not typically occur on a five-year cycle, the Company will continue to record any amortizations allowed herein throughout the effective term that the approved rates remain in effect, regardless of whether the term is longer or shorter than five years.

    - The Company will be required to establish a separate regulatory asset or liability to accumulate any excess negative amortization or positive amortization (separate from the pension asset existing at the adoption of the tracking mechanism), which shall be included in rate base and amortized over a five year period in the next following rate case.

8. Any prepaid pension asset or accrued liability recorded pursuant to the terms and conditions of FAS87 (as opposed to regulatory assets arising from the provisions of this proposed tracking mechanism) will not be included in Rate Base in any future rate case, except for the cumulative net ratepayer benefits previously identified is allowed by the Commission. The regulatory assets/liabilities discussed herein specifically identify all rate base includable amounts for pension differences.

Comments & Clarifications
Proposed Pension Tracking Mechanism

1. The proposed tracking mechanism refers to “NPPC” in explaining how the mechanism operates, which is intended to represent actuarially determined total FAS87 net periodic costs.

2. “NPPC” intentionally encompasses total actuarially determined amounts without regard to any expense allocation or capitalization accounting the Company may recognize on its books and records.

3. Unless limited by IRC maximum contributions or ERISA minimum contributions, the proposed tracking mechanism requires the Company to make annual fund contributions in an amount equal to the total FAS87 net periodic costs determined for each calendar year.

4. The proposed tracking mechanism requires the Company to establish a regulatory asset or liability for the difference between the total FAS87 net periodic costs determined for a given year and the amount of such costs included in then-existing utility rates.

5. The provisions of FAS87 may require a Company to record a prepaid pension asset in the normal course of business, without regard to any regulatory agreements or orders adopting a tracking mechanism:

a. The proposed tracking mechanism would exclude from rate base for ratemaking purposes any future prepaid pension asset resulting from an actuarial study that resulted in "negative" net periodic costs.

b. The proposed tracking mechanism would exclude, or not recognize, any "negative" net periodic costs for ratemaking purposes, instead setting the amount equal to "zero" (i.e., $0).

6. If the utility is allocated a portion of the FAS87 net periodic costs from an affiliated entity in the normal course of business and the tracking mechanism is approved by the Commission, when the Company is required to fund the NPPC, the Company would be required to commit to funding 100% of the FAS87 net periodic costs for both HECO and the affiliate **or** to maintain segregated pension trust fund accounting for each entity in order to avoid any funding conflicts or issues that might arise in the future.

7. Any commitment by HECO to fund 100% of its FAS87 net periodic costs (when required under item 2 or as limited under item 3) will not be contingent on implementing a substantially similar tracking mechanism for each HECO affiliate.

PROPOSED OPEB TRACKING MECHANISM

Purpose: The proposed OPEB tracking mechanism is designed to achieve the following objectives:

A. Ensure that the OPEB costs recovered through rates are based on the FAS106 NPBC, as reported for financial reporting purposes;

B. Ensure that all amounts contributed to the OPEB trust funds (subject to the exception in Item 3 below) are in an amount equal to actual NPBC and are recoverable through rates; and

C. Clarify the future treatment of any charges that would otherwise be recorded to equity (e.g., increases/decreases to other comprehensive income) as required by FAS106, FAS 158 or any other FASB statement or procedure relative to the recognition of OPEB costs and/or liabilities.

Procedure:

1. The amount of FAS106 NPBC included in rates shall be equal to the amount recognized for financial reporting purposes.

2. Except when limited by material, adverse consequences imposed by federal regulations, the annual contribution to the OPEB trust funds will be equal to the amount of FAS106 NPBC. The utility will use tax advantaged funding vehicles, whenever possible, as specified in D&O 13659, dated November 29, 1994, in Docket Nos. 7243 and 7233 (Consolidated).

3. The utility will be allowed to recover through rates the amount of any contributions to the OPEB trusts in excess of the FAS106 NPBC that were made for the following reason[1]:

    - the increased contribution was made to avoid a charge to other comprehensive income.

   Any such "excess" contributions shall be recorded in a separate regulatory asset account, which will be included in rate base.

4. A regulatory asset (or liability) will be established on the Company's books to track the difference between the level of actual FAS106 NPBC during the rate effective period and the level of FAS106 NPBC included in rates during that same period.

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[1] The Company or the Consumer Advocate (jointly, the "Parties") may initiate discussions with the Parties and the Hawaii Public Utilities Commission to modify these provisions between rate cases (with Commission approval) if there are future changes in accounting standards, federal tax law or federal tax regulations that materially impact the costs otherwise recoverable through this tracking mechanism.

- If the actual FAS106-determined NPBC recorded during a given rate-effective period is greater than the FAS106 NPBC included in rates during the immediately preceding rate case, the Company will establish a separate regulatory asset account to accumulate such difference, but only to the extent that such amount is not used to reduce a regulatory liability recorded pursuant to Item 5.

- If the actual FAS106-determined NPBC recorded during the rate-effective period, adjusted for any amount of such expense used to reduce a regulatory liability maintained pursuant to Item 5, is less than the expense built into rates, the Company will establish a separate regulatory liability account to accumulate such difference.

- If the actual FAS106 NPBC becomes negative, the regulatory liability will be increased by the difference between the level of FAS106 NPBC included in rates for that period and "zero" (i.e., $0).

- Since this is considered to be a cash item under the tracking mechanism, the regulatory asset or liability will be included in rate base and amortized over a five (5) year period at the time of the next following rate case.

5. If the FAS106 NPBC becomes negative, the Company will set up a regulatory liability to offset the OPEB asset created by the negative amount. This regulatory liability will increase by the amount of any negative NPBC, or decrease by the amount of positive NPBC, in each subsequent year. Positive NPBC in each subsequent year will be used to reduce the regulatory liability before being used to establish a regulatory asset pursuant to Item 4.

    - If NPBC is negative at the time of the next rate case, the amount included in rates will be "zero" (i.e., $0).

    - If NPBC is positive at the time of the next rate case, the positive expense will not be included in rates and the Company will not be required to make contributions to the trust until any regulatory liability created under this Item 5 has been reduced to "zero" (i.e., $0).

    - Since this regulatory liability is considered to be a non-cash item under the tracking mechanism, it is not subjected to amortization and should not be recognized in determining rate base in future years.

6. The objective of this tracking mechanism is that, over time, the Company will recover through rates FAS106-based NPBC, including the amortization of unrecognized amounts as set forth above.

- The Company will establish a separate regulatory asset/liability account to offset any charge, or credit, that would otherwise be recorded against equity (e.g., increases/decreases to other comprehensive income) caused by applying the provisions of FAS106, FAS158 or any other FASB statement or procedure that requires accounting adjustments due to the funded status or other attributes of the Company's OPEB plans.

- This regulatory asset/liability will not be amortized into rates or included in rate base, because any such charges are expected to be recovered in rates through the valuation of FAS106 NPBC in future accounting periods, which will be subject to the true-up process described herein. In other words, this regulatory asset/liability will automatically be reversed through the mechanics of FAS106 and, pursuant to other provisions of this proposal, all FAS106-determined NPBC will over time ultimately be recovered from ratepayers.

- The regulatory asset/liability will increase or decrease each year by the same amount that the equity charge increases or decreases.

7. Recognizing that rate cases do not typically occur on a five-year cycle, the Company will continue to record any amortizations allowed herein throughout the effective term that the approved rates remain in effect, regardless whether the term is longer or shorter than five years.

   - If the rate effective period is less than five years, the Company will be allowed to recover any unamortized and unrecovered amounts in the next following rate case over a five year period and any unamortized balance shall be included in rate base.

   - If the rate effective period is greater than five years, the Company will be required to establish a separate regulatory asset or liability to accumulate any excess amortization, which shall be included in rate base and amortized over a five year period in the next following rate case.

8. Any OPEB asset or accrued liability recorded pursuant to the terms and conditions of FAS106 (as opposed to regulatory assets arising from the provisions of this proposed tracking mechanism) will <u>not</u> be included in Rate Base in any future rate case. The regulatory assets/liabilities discussed herein specifically identify all rate base includable amounts for OPEB differences.

Comments & Clarifications
Regarding the Proposed OPEB Tracking Mechanism

1. The proposed tracking mechanism refers to "NPBC" in explaining how the mechanism operates, which is intended to represent actuarially determined total FAS106 net periodic costs.

2. "NPBC" intentionally encompasses total actuarially determined amounts without regard to any expense allocation or capitalization accounting the Company may recognize on its books and records.

3. Unless limited by adverse consequences under federal regulations, the proposed tracking mechanism requires the Company to make annual fund contributions in an amount equal to the total FAS106 net periodic costs determined for each calendar year.

4. The proposed tracking mechanism requires the Company to establish a regulatory asset or liability for the difference between the total FAS106 net periodic costs determined for a given year and the amount of such costs included in then-existing utility rates.

5. The provisions of FAS106 may require a company to record an OPEB asset in the normal course of business, without regard to any regulatory agreements or orders adopting a tracking mechanism:

    a. The proposed tracking mechanism would exclude from rate base for ratemaking purposes any future OPEB asset resulting from an actuarial study that resulted in "negative" net periodic costs.

    b. The proposed tracking mechanism would exclude, or not recognize, any "negative" net periodic costs for ratemaking purposes, instead setting the amount equal to "zero" (i.e., $0).

6. If the utility is allocated a portion of the FAS106 net periodic costs from an affiliated entity in the normal course of business and the tracking mechanism is approved by the Commission, the Company would be required to commit to funding 100% of the FAS106 net periodic costs for both HECO and the affiliate **or** to maintain segregated OPEB trust fund accounting for each entity in order to avoid any funding conflicts or issues that might arise In the future.

7. Any commitment by HECO to fund 100% of its FAS106 net periodic costs (as limited under item 3) will not be contingent on implementing a substantially similar tracking mechanism for each HECO affiliate.

Hawaiian Electric Company, Inc.
Regulatory Liability - NPPC vs NPPC in Rates
($ Thousands)

Balance, 12/31/07	$	-	[A]
2008			
NPPC in rates ($17,711) vs. NPPC for 2008 ($14,660)	$	3,051	[B]
Balance, 12/31/08 est		3,051	[C] = [A] + [B]
2009 test year			
Amortization (1/5 of 12/31/08 balance)		(610)	[D]=[C] /5
NPPC in rates ($14,623) vs NPPC for 2009 ($14,623)		0	[E]
Balance, 12/31/09 estimate	$	2,441	[F]=[C]+[D]+[E]
Average		2,746	[G] = ([C]+[F]/2

Sources:
[B] NPPC in rates per Docket No. 2006-0386; NPPC estimates per Watson Wyatt
[E] NPPC estimate per Watson Wyatt

[A] Tracking mechanism implemented in Oct. 2007 with interim D&O in Docket No. 2006-0386.
NPPC in rates equaled SFAS 87 NPPC.

Hawaiian Electric Company, Inc.
Pension Asset
1987-2009
($ Thousands)

Year		Contributions to Trust	NPPC Accrual	Ending Pension Asset Balance
		A	B	C= Prior C+A-B
1986				$ 480
1987		$ 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		6,972	8,381	1,241
1997		5,876	7,117	-
1998		2,206	1,871	335
1999		0	(1,074)	1,409
2000		0	(19,322)	20,731
2001		0	(20,465)	41,196
2002		0	(15,656)	56,852
2003		13,394	5,894	64,352
2004		15,186	(1,547)	81,085
2005		6,000	4,588	82,497
2006		0	14,237	68,260
2007		0	17,711	50,549
2008	*	0	14,660	35,889
2009	*	0	14,623	21,266
Total		$ 138,348	$ 117,562	

Recorded balances for 1987-2005.

* NPPC accrual amounts for 2008 and 2009 are estimates.

Hawaiian Electric Company, Inc.

OPEB

Regulatory Liability - NPBC vs NPBC in rates

($ Thousands)

Balance, 12/31/07		$ -	[A]
2008			
NPBC in rates ($6,350) vs NPBC for 2008 ($5,573)		(777)	[B]
Balance, 12/31/08 estimate		(777)	[C] = [A] + [B]
2009 test year			
Amortization (1/5 of 12/31/08 balance)		155	[C]/5
NPBC in rates		0	
Balance, 12/31/09 estimate		(622)	
Average		(700)	
OPEB in rates:			
NPBC (2007)	6,291		
Amortization of 106 Regulatory Asset	1,302		
Electric Discount	(408)		
Executive Life	(835)		
OPEB in rates	6,350		Per Docket No. 2006-0386
2008 OPEB			
NPBC	5,549		Per Watson Wyatt
Amortization of 106 Regulatory Asset	1,302		Per page 2
Electric Discount	(408)		same as OPEB in rates
Executive Life	(870)		Per Watson Wyatt
2008 OPEB	5,573		
2009 OPEB			
NPBC	5,224		Per Watson Wyatt
Amortization of 106 Regulatory Asset	1,302		per page 2
Executive Life	(873)		per Watson Wyatt
2009 OPEB in rates	5,653		

Notes:
[A] Tracking mechanism implemented in October 2007 with interim D&O in Docket No. 2006-0386.
[A] & [B] Estimates per Watson Wyatt

Hawaiian Electric Company, Inc.
SFAS 106 OPEB Regulatory Asset
1994-2009
($ Thousands)

Year	Amortization & Adjustment	Ending FAS 106 Reg Asset Balance
	A	B Prior Year B - A
1994		$ 24,882
1995	$ 2,751	22,131
1996	1,302	20,829
1997	1,302	19,528
1998	1,302	18,226
1999	1,302	16,924
2000	1,302	15,622
2001	1,302	14,320
2002	1,302	13,018
2003	1,302	11,717
2004	1,302	10,415
2005	1,302	9,113
2006	1,302	7,811
2007	1,302	6,509
2008	1,302	5,207
2009	1,302	3,905
Total	$ 20,977	

Source: Recorded balances for 1994-2007.

Hawaiian Electric Company, Inc.

1994-2009
($ Thousands)

Year	NPBC Actuarial Accrual*	less: Payments & Electric Discount to Retirees[2]	less: Contributions to Trusts	add: Trust Reimbursement[2]	less: Executive Life Adj	Timing & Reconciling Differences	Ending OPEB Liability Balance	
	A	B	C	D	E	F	G=Prior G+ A-B-C+D-E+F	
1994							$ 21,286	
1995	$ 15,725	$ 3,227	$ 14,270	$ -	$ 609		18,904	
1996	14,936	3,858	15,580	7,059	657	26	20,829	
1997	14,393	3,257	15,024	3,009	671	248	19,528	
1998	9,285	3,280	10,046	2,995	540	284	18,226	
1999	3,574	3,398	4,357	3,936	519	(538)	16,924	
2000	1,761	4,106	2,605	4,103	458	3	15,622	
2001	2,107	1,633	2,857	1,635	551	(2)	14,320	
2002	4,263	3	4,927		637	3	13,018	
2003	6,906	1	7,364		844	1	11,717	
2004	6,233	4	6,680		855	4	10,415	
2005	7,034		7,435		900	0	9,113	
2006	6,620		7,060		862	0	7,811	1
2007	6,291		6,758		835	0	6,509	1
2008	5,549		5,981		870	0	5,207	1
2009	5,224		5,653		873	0	3,905	1

* Amount is actuarial NPBC accrual amount. NPBC in rates is provided on page 1 of 3.

Recorded balances for 1994-2005.
[1] 2006 through 2009 "OPEB liability balances" are for illustrative purposes.
[2] From 1995-2001, HECO made payments to retirees and was reimbursed by the trust. Beginning in 2002, trust reimbursements for electric discount to retirees are shown net in col. C.

TESTIMONY OF
RUSSELL R. HARRIS

DIRECTOR
RISK MANAGEMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Insurance as included in Administrative and General Expenses

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Russell R. Harris, and my business address is 220 South King Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Director of Risk Management for Hawaiian Electric Company, Inc. ("HECO"). My educational background and experience are shown in HECO-1200.

Q. What are your areas of responsibility with respect to this case?

A. I am the Company's primary witness for presenting the Company's normalized test year 2009 estimates for insurance expense. These costs are included in the test year 2009 administrative and general ("A&G") expenses addressed by Ms. Patsy Nanbu in HECO T-11.

INSURANCE

Q. What are the accounts and test year 2009 amounts for the insurance group of accounts?

A. As shown in HECO-1201, page 1, the insurance group of A&G accounts and the associated test year 2009 amounts totaling $10,254,000 are as follows:

Acct. No.	Description	Test Year 2009 Estimate
924	Property Insurance	$ 3,062,000
925	Injuries and Damages	7,192,000
	Total (Net of budget and G/L code adjustments)	$10,254,000

Q. What are the G/L code adjustments?

A. The G/L code adjustments, as shown on HECO-1201, page 1, are on-costs that have been reversed from the accounts' non-labor totals in this testimony and included in the testimony of Ms. Patsy Nanbu (HECO T- 11) in her discussion of A&G expenses.

Q. Were adjustments made to HECO's 2009 insurance operations and maintenance O&M expense budget to develop its 2009 test year expense estimate?

A. Yes. A budget adjustment totaling ($363,000) as shown in HECO-1201, pages 1, 2, 3 and 6 was made to reduce the 2009 insurance O&M expense budget. This downward adjustment was based on updated estimates for six specific budgeted items. The explanations for the budget adjustments are provided in my testimony under the related account numbers.

Q. How does the test year estimate compare with recorded 2007 costs?

A. The total $10,254,000 projected for test year 2009 are comparable (2% higher) to the recorded $10,006,000 costs in 2007. Market increases in insurance premiums, trended absorbed loss projection increases for workers compensation, and higher property and liability exposures contributed to the 2009 increase over 2007. For more details on specific expenses' year over year changes from recorded 2007 actual amounts, please refer to HECO-WP-1201, page 1.

Q. How does the 2009 estimate compare with the Company's experience over the last several years?

A. As reflected in HECO-1201, page 1, actual expenses have been variable over the past several years. Actual expenses from 2003 – 2005 ranged from a low of $6,411,000 in 2005 to $10,006,000 in 2007. With claim deductibles or retentions typically ranging from $750,000 to $1 million, a single serious incident can cause a significant swing in recorded costs. HECO-1201, page 3 shows the variability of the actual loss costs which are reflected in the total costs shown on HECO-1201, page 1. Recorded 2005 costs were relatively low partly due to a $1 million claim reserve reversal resulting from a co-defendant contractor's contribution to a settlement that satisfied HECO's retention for its own insurer. Likewise in 2006, HECO reversed a $496,000 reserve when the statute of limitations expired on a claim against HECO and the claim could no longer be pursued. HECO's 2009 expenses are projected to be higher than previous years primarily due to higher projected insurance premiums and absorbed losses which will be discussed later in this testimony. As pointed out above, HECO's 2009 test year expense levels are comparable to recorded 2007 levels.

Q. Why are accounts 924, 925.01 and 925.02 grouped together in your testimony, and what are the differences among these accounts?

A. These accounts are grouped together because they represent expenses incurred in order to prevent or control the financial impact of accidental losses on the Company. Account 924, "property insurance", includes the cost of insurance for utility property owned by the Company and claims payments or reserves for damage to this property not covered by insurance.

Account 925, "injuries & damages" has two components:

1) Employees (account 925.01) includes the cost of insurance to protect the Company against injuries to employees as well as claims payments or reserves for costs not covered by insurance. This component also includes the cost of safety and accident prevention.

2) Public (account 925.02) includes the cost of insurance and claims payments or reserves to protect the Company against injuries to, and damage claims brought by members of the public.

Q. What is the general nature of expenses included in these accounts?

A. As indicated below, the expenses represent labor and non-labor costs. Non-labor costs, which represent the lion's share of the expenses, include insurance premiums, absorbed losses, a safety program designed to control losses, other costs and a G/L credit.

Combined Accounts 924 and 925:	Test Year 2009 Estimate
Labor	$ 1,665,000
Non-Labor (Net of budget and G/L code adjustments)	8,589,000
Total for Accounts 924 and 925	$10,254,000

Total Non-Labor Expenses for Accounts 924 and 925:	
Premiums (net of budget adjustments) (HECO-1201, Page 2)	$ 4,142,000
Absorbed Losses (net of budget adjustments) (HECO-1201, Page 3)	3,319,000
Safety Program (HECO-1201, Page 6)	1,338,000
Other Costs (HECO-1201, Page 4)	587,000
G/L Code Adjustments	(797,000)
Total Non-Labor Expenses for Accounts 924 and 925	$8,589,000

Q. What are the premium-related expenses that are included in accounts 924, 925.01 and 925.02?

A. Premium-related expenses are estimated at $4,142,000 (approximately 40% of the total costs for the insurance group of accounts). These expenses include insurance premiums, premium taxes and insurance broker fees. The totals of premium-related expenses by account, for 2003 through 2009, are shown in HECO-1201, page 2.

Q. What are the non-labor "absorbed losses" that are included in accounts 924, 925.01, and 925.02?

A. Non-labor "absorbed losses" are costs borne by the Company (i.e., costs not reimbursed by insurance). These non-labor costs are estimated at approximately $3,319,000 for test year 2009 (approximately 32% of the total costs for the insurance group of accounts). Absorbed losses result from many types of events, including work-related injuries to Company employees, injuries and damages to the public, and property losses subject to insurance deductibles or are self-insured. (Deductibles are HECO's portion of insured losses and self-insured amounts are HECO's portion of losses payable before any excess level of insurance applies.) The totals of these non-labor costs, by account, for the six-year period 2003 through 2009, are shown in HECO-1201, page 3.

Q. What are the non-labor safety program expenses included in account 925.01?

A. These costs include tasks associated with employee safety, fire safety and public safety. Expenses related to safety materials such as protective equipment and outside services such as laboratory analysis are also included. Non-labor safety program costs total approximately $1,338,000 for test year 2009 as shown in HECO-1201, page 6 (which is approximately 13% of the total costs for the insurance group of accounts).

Q. What are the "other costs" included in accounts 924 and 925?

A. These include costs for Information Technology services (see Ms. Patsy Nanbu's testimony, HECO T-11, for an explanation of Information Technology cost allocations), outside services, and office supplies and transportation. These expenses total $587,000 for the test year 2009 as shown in HECO-1201, page 4 (which is approximately 6% of the total costs for the insurance group of accounts).

Q. What are the G/L code adjustments included in accounts 924 and 925?

A. The G/L code adjustments of ($797,000), are the on-costs amounts which have been removed from account 924 and 925 non-labor totals presented in this testimony (see HECO-1201, page 1) and are discussed in the testimony of Ms. Patsy Nanbu (HECO T-11). The G/L code adjustment amounts represent approximately (8%) of the amounts in the insurance group of accounts.

Q. What are the labor expenses included in accounts 924 and 925?

A. These are costs to administer the safety and insurance programs, and for internal coordination of claims processing. The labor costs total approximately $1,665,000, as shown in HECO-1201, page 5 and account for approximately 16% of the total costs for the insurance group of accounts.

Q. What employees are involved in the preparation of test year 2009 budgeted labor and non-labor direct expense amounts for NARUC accounts 924 and 925?

A. Refer to HECO-WP-1202, pages 1 and 2, for a listing of the employees.

Q. Are the calculations, spreadsheet files, "pencil" workpapers, surveys and other analyses performed available to completely support and document the test year expense amounts by department, responsibility area (RA), activity and NARUC account?

A. Yes. Refer to HECO-WP-1202, pages 3 to 152, for copies of the worksheets associated with the cost projections.

Company Policy with Respect to Insurance Coverage

Q. What is the Company's policy with respect to purchasing insurance coverage?

A. The Company's policy is to minimize the combined cost of insurance and absorbed losses. The Company purchases insurance as protection against catastrophic losses when it is economically feasible to do so. HECO does not insure against smaller, on-going, and relatively predictable losses that are an inevitable part of doing business in the electric utility industry. These less significant losses are paid directly by the Company in the form of an insurance policy deductible or a formal self-insured program. It is HECO's policy to do everything as economically as possible to contain the on-going types of losses and to control conditions which might cause catastrophic losses.

<u>HECO Covered in HEI Policies</u>

Q. Is HECO covered in insurance policies purchased by Hawaiian Electric Industries, Inc. ("HEI")?

A. Yes. HECO's coverage is part of a consolidated HEI program.

Q. How does HECO get charged for its share of the HEI premium-related expenses?

A. For the most part, the insurance companies provide a breakdown of the total premiums by company. HECO's share of the expenses is based on the portion of total premium that the insurer attributes to the risks at HECO. When insurance companies do not provide a breakdown of the total premium, the Company's insurance broker provides a breakdown based on the underwriting statistics submitted to the insurers. (A measurable statistic such as payroll, which reflects the Company's exposure to loss, is used as the basis for the broker's allocation.)

<u>Determining Insurance Requirements</u>

Q. How does the Company determine insurance requirements for a given category of insurance?

A. First, the Company identifies how it could experience catastrophic losses. The types of losses which could occur are researched and an assessment is made with respect to the probability of each type of loss. In particular, HECO's loss history (i.e., losses which have already occurred) is examined to assess the probable level of future losses for the given category of insurance. HECO's insurance broker assists in reviewing losses and providing its evaluation as part of HECO's review process.

In some cases, after evaluating the financial impact of its exposure to loss, the Company decides that the potential is small enough that insurance is not warranted. However, even when losses are not financed with insurance, the exposure area is still subjected to loss control (e.g., safety precautions) to reduce or prevent any losses.

Once probable levels of losses are estimated, the Company's broker, on HECO's behalf, requests bids for various levels of insurance coverage. Alternatives are compared with respect to the total costs of projected losses within various deductible levels, plus associated premiums. The Company then selects the insurance proposal that gives the best overall protection in light of the cost of probable losses and premium. HECO's broker and its industry experts give the Company very valuable advice in this process and HECO relies heavily on their expertise.

Q. How was the test year 2009 estimate for insurance premiums determined?

A. The Company expects that it will need all the same types of coverage in 2009 as it has needed in 2008. The cost of this insurance typically changes annually. Projected insurance premium expenses (shown in HECO-1201, page 2) for the 2009 O&M expense budget costs were estimated in May 2008, based on known costs of annual policies purchased in 2007 and early 2008. Where applicable, current costs were adjusted for any of three factors: 1) future insurance market pricing, 2) insurance coverage changes, and 3) risk exposure changes (i.e., changes in the number of things insured or in levels of risk).

Account 924 – Property Insurance

Q. What is the Company's estimate of expenses to be charged to account 924, property insurance, for the 2009 test year?

A. The Company's test year 2009 estimate for account 924 totals $3,062,000, as shown in HECO-1201, page 1. The expenses are broken into labor and non-labor costs. Non-labor costs include premiums, absorbed losses, other costs and a G/L adjustment to remove on-costs:

Property:		Test Year 2009 Estimate
Labor		$ 216,000
Non-Labor (net of budget adjustment and G/L code adjustment)		2,846,000
Total for Account 924		$3,062,000

Breakdown of Non-labor Expense:		
Premiums: Property*	$1,787,000	
Boiler & Machinery*	$ 598,000	
Crime	$ 61,000	
Freight	$ 17,000	$2,463,000
* Net of budget adjustments		
Absorbed Losses		269,000
Other Costs		224,000
G/L Code Adjustment		(110,000)
Total Account 924 Non-Labor		$2,846,000

(See HECO-1201, pages 1 through 4 for a breakdown of non-labor expenses.)

Q. How do the estimates for test year 2009 compare with amounts from previous years?

A. The changes in annual premium expense are caused by several factors, including the market price for insurance, loss history, inflation, and increases in the amount of property insured. HECO experienced significant premium increases during the tumultuous property insurance market after the September 11, 2001 (“9/11”) terroists attack losses in New York City. The market subsequently stabilized in 2003. As reflected in HECO-1201, page 2**,** premiums decreased by 6% in 2004 and 2% in 2005. After HECO’s September 1, 2005 renewal, Hurricane Katrina and other losses adversely affected the insurance market (especially for locations with hurricane exposures such as those found in HECO’s service territory) and the market hardened considerably. Fortunately, with HECO’s renewal in September, 2006, the higher premiums only impacted the final four months, and annual costs reflect only a 5% increase in 2006. However, the full impact resulted in a 9% increase in 2007.

With respect to absorbed property/ boiler and machinery losses, the total costs have fluctuated significantly from year to year, ranging from a low of $106,000 in 2006 to a high of $908,000 in 2004 (see HECO-1201, page 3). These swings in costs are typical of property damage claims, which usually involve low-frequency, high-dollar losses.

Q. What types of insurance are included in account 924?

A. There are four main types of insurance in account 924:

1) Property coverage for perils such as fire, wind, earthquake and flood;
2) Boiler and machinery for mechanical breakdown and electrical arcing;

3) Freight insurance; and

4) Crime insurance.

Property/boiler and machinery coverages are on a combined policy and cover scheduled locations such as each power plant and substation. Freight insurance is for property in transit (such as a turbine shipped for repair) and is under a separate policy. Crime insurance insures HECO against losses due to theft or fraud.

<u>Property Insurance</u>

Q. Why does the Company purchase property insurance?

A. The Company buys property insurance to repair or replace physical assets in the event that they are damaged by insurable events. HECO has various types of utility property that might be damaged or destroyed. Real property such as power plants, and personal property such as computer equipment, computer software and mobile equipment are subject to damage from various perils.

HECO's property insurance coverage is quite broad and covers losses resulting from fire, vandalism, riot, sprinkler leakage, lightning, wind, hail, explosion, smoke, liquid damage, vehicle impact, aircraft impact, sonic boom, collapse, flood and earthquake.

Q. How is property insurance premium priced?

A. The Company provides total replacement values by scheduled location to the underwriters who assess the risk exposure and determine the property insurance costs.

Q. How was the estimated property insurance premium for test year 2009 calculated?

A. The test year 2009 estimate is based on maintaining the same types of coverage in place at the time the 2009 O&M expense budget was prepared in May 2008 with further adjustment to the 2009 O&M expense budget after the September 2008 renewal information became available. Projected expenses for premiums (shown in HECO-1201, page 2) were originally based on the known cost of the annual policy purchased in 2007 but have been adjusted for 2008 purchases. Policy period purchases were adjusted to a 2009 calendar year basis. The test year 2009 estimate of $1,787,000 after adjustment, is based on projected insurance market conditions and similar replacement costs of property owned.

Q. What specific adjustments were made in deriving the 2009 test year estimate of $1,787,000?

A. A budget adjustment of ($60,000) was made to reflect the updated cost of property insurance premiums. (See HECO-1201, page 2.)

Q. What is the deductible for property insurance?

A. The deductible is $1 million per occurrence for catastrophic perils such as earthquake and flood. The hurricane wind deductible is two percent of location value with a minimum of $1 million per location. For other perils such as fire, the deductible is $750,000 at generating plant locations, and $100,000 at non-generating locations.

Q. What types of property are not insured under this policy?

A. Examples of uninsured property are transmission and distribution ("T&D") lines and business interruption exposures. Because of HECO's hurricane wind exposures, insurance underwriters generally do not offer T&D property coverage, and if coverage is made available, reasonable pricing is not offered. Similarly, because HECO is not connected to a larger grid, as Mainland utilities are, business interruption coverage is not available to HECO based on the lack of replacement power from other utilities to mitigate the interruption.

<u>Boiler and Machinery Insurance</u>

Q. Why does HECO buy boiler and machinery insurance?

A. Boiler and machinery insurance pays for replacement or repairs related to steam explosions or machinery breakdowns. HECO's boiler and machinery policy covers losses to boilers, pressure vessels (fired and unfired), electrical equipment (such as generators, transformers, motors and switch gear) and mechanical power equipment (such as turbines, pumps, compressors and fans). The boiler and machinery coverage is insured with the same insurer as the property coverage to avoid potential gaps in coverage where it is difficult to determine whether a claim should be covered under the property coverage or under the boiler and machinery coverage.

Q. How is the boiler and machinery insurance premium priced?

A. The underwriters base their charges on their appraisal of the risk of loss for each type of equipment and the possible consequences of an insured accident.

Q. How was the estimated boiler and machinery insurance premium for test year 2009 calculated?

A. The 2009 test year estimate is based on maintaining the same coverage in place at the most recent renewal in September 2007 and extended in 2008. The 2009 cost is expected to be $598,000 after adjustment. This cost is projected to be 8% more than 2007 (see HECO-1201, page 2).

Q. What specific adjustments were made in deriving the 2009 test year estimate of $598,000?

A. A budget adjustment of ($20,000) was made to reflect the updated cost of boiler and machinery insurance premiums. (See HECO-1201, page 2.)

Q. What is the deductible for boiler and machinery insurance?

A. The deductible is $750,000 per occurrence.

Freight Insurance

Q. Why does the Company buy "freight" insurance?

A. Freight insurance is purchased to cover the cost of loss or damage to property being transported from one location to another. Because of the various modes of transportation and the limited liability assumed by carriers, it is often less expensive and safer for HECO to buy its own freight insurance. This way, the freight insurance coverage is in place and will reimburse HECO for the costs of loss or damage to HECO's property.

Q. How are the premiums for freight insurance determined?

A. The freight insurance premium is calculated by multiplying the declared value of the shipment times the applicable premium rate.

There are two types of freight insurance: "ocean freight" and "inland freight". If freight is transported by land only (such as between a plant and a repair facility), the inland freight rate applies. The ocean freight rate applies to freight shipped via ocean even if partially shipped by land or air.

Q. How were the estimated freight premiums for test year 2009 calculated?

A. The projected cost for test year 2009 is $17,000, as shown in HECO-1201, page 2, based on the Company's insurance broker's projection for market pricing. This is a conservative estimate when compared to the 2004 costs of $46,000, 2005 costs of $22,000 and 2006 costs of $24,000.

Crime Insurance

Q. Why does the Company buy "crime" insurance?

A. Crime insurance is purchased to cover acts of theft or fraud.

Q. How were the estimated crime premiums for test year 2009 calculated?

A. The projected cost for the test year 2009 is $61,000, as shown in HECO-1201, page 2. This was based on the Company's insurance broker's projected market pricing. Like freight insurance, the crime insurance costs are very reasonable when compared to the 2003, 2004, and 2005 costs of $67,000, $74,000, and $75,000, respectively.

Absorbed Property and Boiler/Machinery Losses

Q. How was the cost for absorbed property and boiler and machinery losses estimated for test year 2009?

A. The Company's deductible of $750,000 per loss was used as a maximum cost per loss under our insurance program. The frequency of this type of loss is relatively low, making such losses very difficult to predict. On the other hand, the value of the loss can be quite substantial.

Besides absorbed losses related to the Company's insured property insurance program, HECO regularly experiences damage by third parties to its uninsured transmission and distribution property (e.g., poles damaged/destroyed in automobile accidents). A portion of these losses are unrecoverable and must be absorbed.

As discussed previously and shown in HECO-1201, page 3, total absorbed losses in account 924 for property/boiler and machinery amounted to a high of $908,000 in 2004 and a low of $106,000 in 2006. In developing the 2009 test year estimate, the Company calculated a 98-month annual loss average of $257,000 (see HECO-1202, page 1) for the period spanning January 2000 through February 2008. This amount was inflated by 2.1% to project 2008 losses of $262,000 and another 2.5% for test year 2009 totaling $269,000 – a very conservative estimate when compared to the 2003-2007 non-inflated loss average of $354,000 (see HECO-1201, page 3).

HECO's 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 $16 million and Waiau Power Plant has a deductible of $14 million. If the two plants were struck by a hurricane, HECO would have to cover the first $25 million in damage costs before insurance would contribute.

<u>Other Non-labor Expenses</u>

Q. What are the "other costs" included in account 924?

A. These include information technology services, office supplies, and transportation. On-costs are included which will be addressed by Ms. Patsy Nanbu (HECO T-11) in her discussion of A&G expenses. These "other costs" expenses total $224,000, as reflected in HECO-1201, page 4.

Q. What are the G/L code adjustments?

A. The ($110,000) G/L code adjustments, as shown on HECO-1201, page 1, are reversed amounts of on-costs which have been removed from the account 924 non-labor totals presented in this testimony and included in the testimony of Ms. Patsy Nanbu (HECO T-11) in her discussion of A&G expenses.

<u>Labor Expense</u>

Q. What are the Labor expenses included in account 924?

A. Labor expenses include direct labor to administer the insurance program and for internal coordination of claims processing. In addition, they include on-costs. In total, the labor expense for account 924 is $216,000 (see HECO-1201, page 5). Recorded costs for 2007 labor were exceptionally low due to two positions being temporarily vacated in the Risk Management division for a combined period of four months until replacements were made. An Insurance Administrator position was open for one month and a Claims Adjuster position responsible for property claims was vacant for almost three months before they were filled during the year.

Account 925.01 – Injuries and Damages – Employees

Q. What is the Company's test year 2009 estimate of labor and non-labor expenses including the non-labor costs of premium, absorbed claims, the safety program and other expenses charged to account 925.01, Injuries and Damages – Employees?

A. The test year 2009 estimates for account 925.01, which total to $4,202,000 (see HECO-1201, page 1), are as follows:

Account 925.01	Test Year 2009 Estimate
Labor	$1,073,000
Non-Labor	3,129,000
Total Account 925.01 (before G/L credit)	$4,202,000

Q. How do estimates for the 2009 test year compare with previous years' amounts?

A. These costs have fluctuated considerably from year to year. Costs increased 14% in 2004, decreased 17% in 2005, increased 25% in 2006 and increased another 9% in 2007. The estimate for test year 2009 for all charges to account 925.01 is $4,202,000 after adjustment, or 5% more than the $4,010,000 recorded for 2007 (see HECO-1201, page 1). The increase is due to higher excess workers' compensation insurance and absorbed workers' compensation losses, and increased Safety Program costs, as explained further in my testimony.

Q. What are the Labor expenses included in account 925.01?

A. These costs are for direct labor for the Safety Program, insurance program and internal coordination of claims processing, and also include non-productive labor and on-costs. The safety program accounts for $930,000 and workers' compensation for $143,000 of the total $1,073,000 in labor costs. (See HECO-1201, page 5.)

Q. What are the amounts of the non-labor components of account 925.01?

A. The amounts for the various non-labor components are as follows:

<u>925.01 Non-labor</u>	<u>Test Year 2009 Estimate</u>	
Premium:		
Excess Workers' Compensation Premium (net of budget adjustment)	$ 192,000	
State Workers' Compensation Special Fund	15,000	
United States Longshore & Harborworkers (USL&H)	<u>1,000</u>	$ 208,000
Absorbed Losses		1,459,000
Other Workers Compensation Non-labor Expense		124,000
Safety Program (net of budget adjustment)		1,338,000
Total Account No. 925.01 Non-labor (before G/L credit)		<u>$3,129,000</u>

(See HECO-1201, pages 2 through 4 and 6.)

Q. What are the premium expenses for account 925.01?

A. The insurance premium expenses for this account are the:

1) Excess Workers' Compensation insurance premium,
2) State Worker's Compensation special fund assessments, and
3) An USL&H bond.

Q. How are the test year 2009 premiums estimated?

A. Test year 2009 premiums are based on no changes in the current programs maintained by the Company and are estimated by HECO's insurance broker at $208,000 after adjustment (see HECO-1201, page 2). Refer to the section below for an explanation of the specific adjustment made to account 925.01 for excess workers compensation insurance premiums.

Excess Workers' Compensation

Q. What is meant by "excess" workers' compensation insurance?

A. In order to limit HECO's financial exposure to catastrophic losses, the Company purchases "excess" insurance above the first $750,000 of workers' compensation claim costs per occurrence. In this case, the insurance industry term "excess" simply means "above"; it does not mean "more than necessary".

Q. How is the premium for excess workers' compensation insurance derived?

A. The Company's insurance carrier charges a fixed premium for this coverage, based on such factors as payroll, job classifications and accident prevention measures.

Q. How was the estimated excess workers' compensation premium for test year 2009 calculated?

A. The estimated premium for test year 2009 for excess workers' compensation was based on the known cost of similar coverage in 2007, which was approximately $181,000. Based on HECO's insurance broker's projections and the Company's recent 2008 renewals, the Company estimates a premium rate increase of 6% for test year 2009 compared to 2007 recorded expenses. Included in the O&M expense budget are net premiums, broker's fees, commissions, and other expenses. The resulting test year 2009 estimate for excess workers' compensation premium of $192,000 after adjustment, is shown in HECO-1201, page 2.

Q. What specific adjustment was made in deriving the 2009 test year estimate of $192,000?

A. A budget adjustment of ($25,000) was made to account 925.01 to reflect the updated cost of excess workers' compensation premiums.

<u>State Workers' Compensation Special Fund</u>

Q. What are the State workers' compensation special fund assessments?

A. HECO has the State of Hawaii's approval to be self-insured up to $750,000 for workers' compensation. This means that claims under $750,000 are not insured. (The cost of these claims is charged to account 925.01, as discussed in the preceding section.) HECO purchases workers' compensation insurance for loss occurrences over $750,000 to provide protection against catastrophic losses (such as a bus load of workers injured in one accident).

Under the State's workers' compensation program, a special compensation fund is established and maintained to pay for certain benefits not provided through the employer's workers' compensation benefits. This fund is maintained by an annual levy, the "special fund assessment," against insurers and self-insured employers.

Q. How is the State workers' compensation special fund assessment derived?

A. The State has a formula based on the "average annual compensation" paid out for injuries and damages to employees over the two consecutive calendar years immediately preceding the year for which the charge is assessed. The formula relates to total compensation paid by all employers during this period, as well as the compensation paid by all insurance carriers on behalf of employers. For each calendar year, the Director of Commerce and Consumer Affairs determines the amount of the charge to be paid by HECO and notifies the Company in the following year.

Q. How was the estimated State workers' compensation special fund premium for test year 2009 calculated?

A. The estimated workers' compensation special fund assessment for test year 2009 is $15,000. (See HECO-1201, page 2.) The 2009 O&M expense budget projected this amount based on the downward trend of historical assessments as shown in HECO-1205.

USL&H Bond

Q. What is the USL&H bond?

A. HECO has the Federal Government's approval to be self-insured up to $750,000 for USL&H exposures. USL&H is a Federal act (sometimes referred to as the Longshore Harbor Worker's Compensation Act—LHWCA) designed to provide compensation to an employee if an injury or death occurs upon navigable waters of the US—including any adjoining pier, wharf, dry dock, terminal, building way, marine railway or other adjoining area customarily used by an employer in loading, unloading, repairing, dismantling or building a vessel. HECO has incidental exposure for claims arising from situations where employees are working around docking facilities.

Q. How was the estimated USL&H bond premium for test year 2009 calculated?

A. The estimated USL&H bond premium for test year 2009 is $1,000 (see HECO-1201, page 2). The 2009 O&M expense budget includes this amount based on broker projections for this product.

Absorbed Losses

Q. What are the "absorbed losses" for account 925.01?

A. Under authority of the State of Hawaii Department of Labor and Industrial Relations, the Company operates a "self-insured" workers' compensation program, whereby HECO directly pays costs related to injured workers for any losses up to $750,000 per occurrence (for injuries), or $750,000 per person (for disease). HECO does this because it is more economical to self-insure against such losses and avoid paying for insurance company profit and overhead.

Under the self-insured program, the Company is responsible for paying monetary awards for degrees of disability, as well as wage benefits. In addition, medical costs are a substantial portion of workers' compensation claims, and the Company sometimes incurs legal expenses related to settling its claims. Absorbed workers' compensation amounts for 2003-2009 are shown in HECO-1201, page 3.

Q. How does the Company record workers' compensation losses?

A. The Company accrues the costs of workers' compensation awards and related expenses (e.g., medical costs and legal fees) at the time an accident/incident is reported. The best estimate of the ultimate value of the loss is recorded in (matched to) the period in which the accident/incident is reported, rather than the year of settlement or payment. Claims settlements often occur years after the accident occurred, and the payment of related costs often continues in subsequent years as well.

Q. What specific actions are required to accomplish the cost accrual?

A. The Company has established a reserve liability for workers' compensation claims, representing the estimated awards and related costs to be paid (absorbed) by the Company for all known accidents. The reserve liability balance is evaluated and adjusted for significant changes at the end of each month and updated for all claims at the end of each quarter. Any required increase in the reserve balance adds to the workers' compensation recorded expenses, and any required decrease in the reserve balance reduces workers' compensation recorded expenses except to the degree they are offset by actual payments made. As actual payments are made, reserve amounts are reduced in like amounts and previously recorded expenses remain unchanged.

Q. How does the test year 2009 estimate for workers' compensation claims compare with prior year recorded amounts?

A. A comparison of the non-labor costs for workers' compensation claims from 2003 through test year 2009 is shown in HECO-1201, page 3. The 2009 test year estimate of $1,459,000 compares to a low of $276,000 in 2003 and a high of $1,166,000 in 2007. Costs of workers' compensation claims have fluctuated widely from year to year.

Q. Is estimating the costs of workers' compensation claims relatively straightforward?

A. No. Predicting workers' compensation claims is somewhat difficult because in any given year, a single severe claim can substantially distort the annual expense. In other years, it may take many small claims to produce the same effect as one severe claim.

Q. How was the workers' compensation cost estimate for test year 2009 derived?

A. As previously detailed in HECO T-10, Docket No. 7766, pages 24-27 (test year 1995), HECO T-14, Docket No. 04-0113, pages 22-24, and most recently in HECO T-11, Docket No. 2006-0386, pages 21-23, several methods have been evaluated to determine a way to smooth out, or normalize, the test year estimate. It has been determined that the best method is to use the actual amounts paid toward all open claims during each calendar year to project forward as to future claims payments. HECO used the same methodology in deriving the workers' compensation cost estimate of $1,459,000 for test year 2009 (see HECO-1203). The steps are:

1) Calculate the average number of claims for 1980 through 2007, based on the annualized number of claims as of December 2007.

2) Calculate the average cost per claim for each year from 1980 through December 2007.

3) Adjust the average cost per claim for each year from 1980 through December 2007 to 2007 constant dollars based on the Consumer Price Index for All Urban Consumers.

4) Calculate a 28-year average cost per claim in 2007 constant dollars.

5) Calculate a 2008 estimate, assuming the average 245 claims per year and a 2.5% general inflation factor, and using the 28-year average cost per claim in 2007 constant dollars (derived in step 4 above).

6) Apply a 2.5% inflation factor to the 2008 estimate (the amount calculated in step 5 above to derive the 2009 estimate.

Q. Why were the historical costs adjusted to 2007 constant dollars?

A. The average cost per claim for each year from 1980 through December 2007 was adjusted to 2007 constant dollars because 2007 was used as the base to which the 2.5% inflation factor was applied. In essence, the data available was restated to 2007 levels before applying the inflation factor.

Q. Why was a 2.5% general inflation factor used?

A. Workers' compensation claims consist of wage benefits, monetary awards for degrees of disability and medical and legal costs. While wage and salary increases are independent of injuries, the medical and legal costs depend upon the nature of the injury and projected price increases for medical and legal services. Due to the uncertainty with respect to the severity of future claims, which may also affect the amount of the monetary award, the Company concluded that a reasonable cost estimate would result from using the general inflation factor of 2.5%.

Q. Why was the 1980 through December 2007 history used to develop the test year estimate?

A. The test year estimate is based on historical information that was available at the time the estimate was prepared. An attempt was made to go as far back as practicable. The roughly 28 years of historical information should provide a sufficient history of the severity of claims and cost escalations.

Q. What are the workers' compensation other non-labor expenses included in account 925.01?

A. These include information technology services, office supplies and outside services. Also included are on-costs addressed by Ms. Patsy Nanbu in HECO T-11. These combined other non-labor expenses total $124,000. (See HECO-1201, page 4.)

Safety Program

Q. What specific adjustments were made in deriving the 2009 test year estimate of $2,268,000?

A. A budget adjustment of ($163,000) was made to normalize the costs of the safety banquet and awards provided when HECO meets or exceeds its annual goal for lost time hours. This is based on actual costs reflecting the expense in 2 out of 5 years during 2003 – 2007 or 40% of the annual cost projection. See HECO-1201, page 6.

Q. What are the Safety Program expenses for account 925.01?

A. Safety Program costs (which include prevention of injuries and damages to both employees and the public) have fluctuated from a high of $2,208,000 in 2006 to a low of $1,889,000 in 2004. The 2009 test year estimate for Safety Program costs is $2,268,000 after budget adjustment (including labor at $930,000 and non-labor at $1,338,000, see HECO-1201, page 6) compared to 2007's $2,174,000. Cost increases are due to increased labor expense and contracting for outside services. These increases are offset by decreases in safety materials and transportation/travel costs.

Q. What costs are included in employee safety?

A. As an electric utility, HECO is governed and bound by the Hawaii Occupational Safety & Health Division ("HiOSH") to provide electrical safety training (to maintain and ensure that its crews are "qualified" electrical workers). Other HiOSH-related training include: hazard communications; personal protection equipment training (safety hat, glasses/face shield, gloves, respirators, hearing protectors, proper fire–flame resistive burn protection clothing, electrical protective equipment); emergency rescue training (cardio-pulmonary resuscitation (CPR), pole top, aerial bucket, underground, structure, first aid, and automated external defibrillator ("AED") use); and vehicle fleet safety training (e.g., training for commercial drivers license, crane, forklift, and State of Hawaii Department of Transportation ("DOT") required driver improvement training). Other employee safety costs include: HiOSH and DOT required medical exams for our employees; outside services such as laboratory analysis for lead, asbestos and air conditioner related mold exposures; and personal protection equipment purchases.

Q. What costs are included in fire safety?

A. Fire safety include costs of programs to ensure that HECO conforms with fire and building code standards relative to fire protection and fire safety training, including emergency evacuation for all facilities owned and operated by HECO. Additionally, costs are included to repair and maintain fire protection, detection and emergency notification systems (including 52 automatic fire sprinkler systems, four Halon systems, two Cardox systems for the Waiau Gas Turbines and 10 Carbon Dioxide (CO_2) high pressure systems within the power plants).

Q. What costs are included in public safety?

A. HECO's Safety Division provides electrical safety education and related inspections for outside "emergency responders" (e.g., the Honolulu Fire Department (HFD), the Honolulu Police Department and other State and County Agencies) and customers such as contracting firms, schools and Federal agencies.

Q. How does HECO's safety record and program compare with comparable companies and utilities in Hawaii?

A. HECO's safety record and safety/health programs have long been recognized as some of the best in the State. HECO has received numerous awards for safety excellence at the biennial Governor's Pac-Rim Health & Safety Conference in 1996, 1998, 2002 and 2006. This conference is co-sponsored by HiOSH and the American Society of Safety Engineers. Given the nature of HECO's work and the hazards associated with working in close proximity to energized, high voltage electricity, helicopter operations, high pressure and high temperature steam, and chemicals, HECO's employees have sustained EXCELLENCE in working safely and minimizing worker's compensation costs to the Company. This is achieved through continuous and effective training, constant reinforcement, combined with incentive programs set with high attainment standards.

Q. How do HECO's safety programs translate to lost time per employee?

A. In 2003, HECO enjoyed its best safety achievement record in the Company's history with only 96 Lost Time Hours per 100 employees. In 2006, HECO achieved its second best safety record with only 124 Lost Time Hours per 100 employees. The comparable annual rate for the State of Hawaii was 630 Lost Time Hours per 100 employees, and for the Transportation and Utility Group, 978 Lost Time Hours per 100 employees. The Company's record is remarkable in view of the dangerous exposures that are experienced daily by HECO's more than 575 Trades and Crafts employees. In addition to more than 200 workers handling energized electrical equipment, HECO conducts field work involving activities such as climbing steel towers/poles up to 100 feet high and cliff side trails/work sites in the Koolau Mountains. HECO's costs for absorbed losses and premiums are favorably impacted by this excellent record.

Q. Please describe the safety incentive programs.

A. Like all successful safety programs, incentive awards play a key role in rewarding and acknowledging in a meaningful manner, our employees for appropriate and proper safety behavior and complying with all State and Federal safety/health regulations. These awards are provided when the Company's safety performance meets and/or exceeds annual safety targets approved by its Board of Directors. These goals are extremely difficult to achieve and exceed the safety performance of other utilities in the State.

Incentive awards include the Safety Celebration Banquet ($162,000), the Process Area Awards ($96,000), and Special Recognition Awards ($14,000).

These programs are assessed annually with funding accrued monthly to ensure that funds for these awards are available if targets are met. When it is determined in a calendar year that annual safety targets will not be achieved, the accruals are reversed out and not expensed. They are awarded only if annual safety targets are achieved. HECO previously achieved its annual safety goal in 2003 and 2006.

Q. How are the costs for the Safety Program calculated?

A. The Safety Program costs are primarily costs incurred by the Company's Safety Division. These costs are estimated based on historical costs and adjusted as necessary to meet changing requirements such as new regulations and to satisfy business and social needs to ensure that deaths and serious disabling injuries are not suffered by HECO employees and customers.

Q. What do the safety program costs include?

A. The primary cost elements are labor, materials, information services, transportation and outside contract services. Non-labor on-costs are also included and later reduced by G/L code adjustments discussed by Ms. Patsy Nanbu in HECO T-11. These costs for 2003-2007 recorded, and for 2008 O&M expense budget and test year 2009 are detailed in HECO-1201, page 6. Activities of the Safety Division include all elements of a program which promotes a safe work environment and safe work practices as mandated by HiOSH, the Hawaii Public Utilities Commission, the Honolulu Fire Department, the Hawaii Department of Transportation and Hawaii Department of Health. This helps to control both the frequency and size of workers' compensation and general liability claims, as well as aiding electrical system reliability. Examples of Safety Division activities include conducting safety surveys, providing safety equipment, and servicing of safety equipment including more than 125 AEDs for HECO's employees with electrical exposure. In addition to HECO's Safety Division, the operating departments of the Company also incur safety-related costs, primarily for purchase of safety materials, such as protective shoes, fire resistive clothing (Nomex coveralls), electrical insulated high and low voltage rubber protective gloves, sleeves, hot sticks and line protective covers. Safety-related costs incurred by the operating departments also include the HiOSH required di-electric (insulated) testing of the rubber protective equipment, hot sticks, etc., including the more than 75 aerial bucket and boom trucks that enable HECO employees to safely work on energized electrical transmission lines without interruption to service.

Account 925.02 – Injuries and Damages – Public

Q. What components are included in the Company's test year 2009 for account 925.02, Injuries and Damages – Public?

A. The Company's estimate of account 925.02 expenses, which totals to $3,677,000 (see HECO-1201, page 1), includes $376,000 of labor and $3,301,000 of non-labor expenses. Non-labor includes premiums, absorbed losses and other expenses:

Liability Non-labor		Test Year 2009 Estimate
Premiums: General Liability (net of budget adjustment)	$1,121,000	
Directors'& Officers' Liability	$ 172,000	
Fiduciary	$ 144,000	
Errors & Omissions Liability	$ 34,000	$1,471,000
Absorbed losses (after budget adjustment)		1,591,000
Other non-labor		239,000
Subtotal Account 925.02 Non-labor (net of budget adjustment and before G/L credits)		$3,301,000

(See HECO-1201, pages 2 to 4.)

Q. What causes the annual changes in these costs?

A. Changes in the cost of general liability insurance have a significant impact on the costs for account 925.02 (see HECO-1201, pages 1 and 2). Changes in the annual cost of general liability insurance are caused primarily by insurance market conditions and prices. Absorbed losses can also have a significant impact, as HECO retains the first $1 million of insured general liability losses. Changes in the limits and the deductibles and retentions selected by the Company can also cause cost variations.

Q. Why does the Company buy liability insurance?

A. The Company buys liability insurance because of the difficulty in predicting the size and frequency of the related types of losses. Exposure to liability loss is among the most difficult of risks to assess. The amounts of losses can depend on the circumstances of an event, the nature and severity of the injury or damage, the degree of negligence, applicable laws, decisions of judges or juries, and even general societal trends.

Liability losses can arise from many things, such as the ownership and use of property, conduct and activities of employees, conduct and actions of subcontractors, lease of aircraft services, contractual assumption of liability and the ownership of vehicles.

Liability claims are not commonly self-insured due to the difficulty in predicting such claims. A review of the past several years of loss history guides both HECO and insurance company underwriters in identifying smaller, more frequent losses. This “predictable” level is an appropriate amount for a deductible and the Company adapts the deductible to the particular type of exposure/insurance. However, insurance is necessary to transfer the risk of unpredictable, catastrophic losses.

Q. How are liability premiums determined?

A. Underwriters base general liability rates for electric utilities on various factors such as kWh sales by type, revenue, employee count, geographical location and claims history. Executive risk is rated by underwriters based on corporate governance, losses, business activities, financial and management performances.

Q. How were the estimated liability premiums for test year 2009 calculated?

A. The estimates for test year 2009 were developed as follows:

1) General Liability – The 2009 premium is based on the actual cost for the June 1, 2007-2008 policy period, when two layers of coverage were purchased to achieve adequate limits. These were adjusted for future periods based on broker-provided projections. The 2009 test year estimate reflects a combination of two policy periods: June 1, 2008-2009 and June 1, 2009-2010. When preparing the test year 2009 O&M expense budget, premiums were projected to be $1,251,000 but with 2008 renewal information, this has been adjusted to $1,121,000. A budget adjustment of ($130,000) was made to account 925.02 to reflect the updated cost of general liability premiums. See HECO-1201, page 2.

2) Executive Risk – This cost consists of premiums for exposures including directors and officers ("D&O") liability and fiduciary liability. The D&O premium is the largest of these items at $172,000 while the fiduciary is $144,000 for test year 2009 (as shown in HECO-1201, page 2). The 2009 test year estimate is based on the actual expense incurred for each exposure area at the February 1, 2008 policy purchase, escalated for future purchases

in February 2009. The 2008 actual purchase cost was adjusted by broker-provided projections for two policy periods, February 1, 2008-2009 and February 1, 2009-2010, to derive the 2009 test year estimate.

3) Professional Liability Insurance – The test year 2009 estimate for engineers' professional liability insurance is $34,000 (as shown in HECO-1201, page 2). This is based on projections from HECO's broker under current market conditions. The previously recorded years from 2005 to 2007 have recorded costs ranging from $27,000-$30,000. Prior to 2005, the coverage was included in HECO's general liability insurance.

<u>Absorbed Liability Losses</u>

Q. Are there different types of liability losses?

A. Yes. There are various liability loss exposures such as general liability, auto liability, errors and omissions liability and employment practices liability.

Q. Does the Company apply an inflation factor to trended claims costs?

A. Yes. Inflation impacts liability claims' cost components such as defense, medical care, equipment repair, spoiled food replacement and others. Since these components are included in the Company's absorbed losses, there is a need to account for effects of inflationary forces when estimating claims trending.

Q. How is the cost for absorbed liability losses calculated?

A. The Company's self-insured retention or deductible, as applicable, for each risk exposure was used as a maximum cost exposure per occurrence. The recorded losses from January 2000 through February 2008 were first indexed to 2007 dollars. A 98-month average was then calculated and annualized to a 2007 annual estimated cost (see HECO-1204).

The 2008 estimate was developed by applying a conservative 2.1% inflation factor to the 2007 annual estimated cost. The 2009 estimate is based on the 2008 O&M expense budget, with a conservative 2.5% factor added. Ms. Lorie Nagata addresses general inflation factors in HECO T-17. The resulting 2009 absorbed losses estimate is $1,410,000, as shown in HECO-1204. A budget adjustment of $35,000 was added to the 2009 O&M expense budget in account 925.02 to reflect the higher costs related to Honolulu Harbor remediation than included in the trended number. The combined total would be $1,445,000.

Q. Are any other liability losses projected in addition to the liability losses projected in HECO-1204?

A. Yes. Employment practices liability loss costs were separately projected for test year 2009 at $146,000, as shown in HECO-WP-1202 page 137, item 52. This $146,000 projection coupled with the HECO-1204 trended liability loss projection of $1,445,000 (after budget adjustment) totals $1,591,000 as shown in HECO-1201, page 3. This is well below the 2007 recorded amount of $2,161,000, and similar to the 2006 actual amount of $1,400,000. The exceptionally low amount in year 2005 actual ($550,000) was due to a significant claim reserve reversal resulting from HECO's insurer not requiring HECO's retention to be paid when HECO's co-defendant contractor's insurance paid first on a settlement.

Other Non-Labor

Q. What is the projected cost for "other non-labor" items related to account 925.02?

A. "Other non-labor" costs are projected at $239,000 as shown in HECO-1201, page 4. These include Information Technology Department service charges for usage and equipment (e.g., batch processing, disk storage, terminal lease rent, LAN connection fee, etc.) and in-house systems development work. Costs also include a claims management information system annual fee, office supplies and transportation costs. Also included are on-costs that are addressed by Ms. Patsy Nanbu in HECO T-11.

Labor

Q. What is the projected cost for labor related to account 925.02?

A. Labor is projected at $376,000 for test year 2009 which is a 2% increase from 2007 recorded. Labor costs have ranged from a low of $320,000 in 2004 to a high of $437,000 in 2005 (see HECO-1201, page 5).

Total Account 925

Q. In summary, what is the total Labor and Non-Labor cost for account 925 – Injuries & Damages?

A. The total costs for account 925, which include labor and non-labor costs for both account 925.01 – Injuries & Damages – Employees, and account 925.02 – Injuries & Damages – Public, with the combined non-labor costs adjusted by a G/L credit (discussed in Ms. Patsy Nanbu's HECO T-11 testimony) are as follows:

Account 925.01	Test Year 2009 Estimate
Labor	$1,073,000
Non-Labor (net of budget adjustment)	3,129,000
Account 925.02	
Labor	$ 376,000
Non-Labor (net of budget adjustment)	3,301,000
G/L code adjustment (Acct. 925.01, 925.02)	(687,000)
Grand Total Account 925	$7,192,000

CONCLUSION

Q. Please summarize your testimony regarding the test year 2009 premium-related expenses, safety program costs, and absorbed losses estimates for account Nos. 924, 925.01, and 925.02.

A. Insurance is a necessary cost of doing business. The costs related to securing reasonable levels of coverage should be included in the electric rates charged to the Company's customers. The Company believes that coverages planned for test year 2009 give HECO and its customers a reasonable level of protection against catastrophic losses.

The most cost-effective approach with respect to covering losses is for the Company to:

1) make reasonable efforts to provide a safe work environment and implement other loss control measures to protect Company property and prevent liability to others,
2) absorb losses which are somewhat predictable, and
3) purchase insurance for less predictable catastrophic losses.

Therefore, the following premium-related expenses, safety program costs, and absorbed losses should be included in the calculation of HECO's test year 2009 revenue requirements upon which electric rates will be set:

1) $3,062,000 for account 924, Property Insurance
2) $7,192,000 for account 925, Injuries and Damages

Q. Does this conclude your testimony?

A. Yes.

Hawaiian Electric Company

RUSSELL R. HARRIS

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 220 South King Street Honolulu, Hawaii 96813
Position:	Director, Risk Management
Education:	Masters in Business Administration, 1984 University of Hawaii Bachelor in Business Administration (Travel Industry Management), 1972 University of Hawaii
Other Qualifications:	Chartered Property & Casualty Underwriter (CPCU) designation, 1993 American Institute for Chartered Property Casualty Underwriters Associate in Marine Insurance Management (AMIM), 1990 American Institute for Chartered Property Casualty Underwriters Associate in Risk Management (ARM), 1987 Insurance Institute of America
Previous Positions:	Risk Management Coordinator, 1984-1987 Pacific Resources, Inc. Manager, Safety & Security, 1981-1984 Aloha Airlines, Inc.
Previous Testimony:	Docket Nos.7766, 04-0113, 2006-0386 - HECO: A&G Expense – Insurance Docket No. 95-0051 (Consolidated) - Self-Insured Property Damage Reserve

HAWAIIAN ELECTRIC COMPANY, INC.
Combined Insurance Premium, Absorbed Losses, Non Labor Expenses and Labor and Related Expenses ($000s)

Type of Expense	2003 Recorded	* Change * Percent	2004 Recorded	* Change * Percent	2005 Recorded	* Change * Percent	2006 Recorded	* Change * Percent	2007 Recorded	* Change * Percent	2008 Budget	* Change * Percent	2009 Budget	2009 Adjustment	2009 Test Yr Est
ACCOUNT 924.00, PROPERTY															
Labor	178.0	4%	184.5	5%	194.5	4%	201.5	-19%	164	26%	207.2	4%	215.6	0.0	215.6
Non-Labor	2,258.9	31%	2,967.0	-18%	2,429.0	-9%	2,214.3	12%	2,485.2	3%	2,569.9	15%	3,036.2	(80.0)	2,956.2
Less: G/L Code	(81.3)	-22%	(63.6)	30%	(82.7)	30%	(107.9)	-7%	(100.6)	15%	(116.0)	-5%	(109.7)	0.0	(109.7)
Total Non-Labor	2,177.6	33%	2,903.4	-19%	2,346.3	-10%	2,106.4	13%	2,384.6	3%	2,453.9	16%	2,926.5	(80.0)	2,846.5
Combined 924	2,355.5	31%	3,087.9	-18%	2,540.8	-9%	2,307.9	10%	2,548.6	4%	2,661.1	15%	3,142.1	(80.0)	3,062.1
ACCOUNT 925.01, INJURIES & DAMAGES - EMPLOYEES															
Labor - Workers' Compensation	372.4	-11%	332.3	-20%	267.0	-2%	262.5	39%	365.2	-68%	117.6	21%	142.6	0.0	142.6
Labor - Safety Program	834.0	-6%	785.9	-2%	769.1	7%	820.0	2%	837.1	-8%	769.9	21%	930.6	0.0	930.6
Subtotal	1,206.4	-7%	1,118.2	-7%	1,036.1	4%	1,082.5	11%	1,202.3	-26%	887.5	21%	1,073.2	0.0	1,073.2
Non-Labor - Workers' Compensation	598.3	118%	1,305.2	-46%	710.5	69%	1,203.3	22%	1,470.4	12%	1,647.5	9%	1,816.0	(25.0)	1,791.0
Non-Labor - Safety Program	1,288.3	-14%	1,103.0	7%	1,185.0	17%	1,387.7	-4%	1,337.5	-12%	1,174.0	14%	1,500.8	(163.2)	1,337.6
Subtotal	1,886.6	28%	2,408.2	-21%	1,895.6	37%	2,591.0	8%	2,807.9	0%	2,821.5	11%	3,316.8	(188.2)	3,128.6
Combined 925.01	3,093.0	14%	3,526.4	-17%	2,931.7	25%	3,673.5	9%	4,010.2	-8%	3,709.0	13%	4,390.0	(188.2)	4,201.8
ACCOUNT 925.02, INJURIES & DAMAGES - PUBLIC															
Labor - Liability	328.0	-2%	320.0	10%	351.2	24%	436.7	-15%	369.8	0%	369.9	2%	376.3	0.0	376.3
Non-Labor - Liability	2,122.6	58%	3,344.3	-67%	1,094.8	43%	3,031.1	26%	3,807.6	-20%	3,055.4	8%	3,395.6	(95.0)	3,300.6
Combined 925.02	2,450.6	50%	3,664.3	-61%	1,446.0	140%	3,467.8	20%	4,177.4	-18%	3,425.3	7%	3,771.9	(95.0)	3,676.9
COMBINED ACCOUNT 925, INJURIES & DAMAGES															
Total Labor 925	1,534.4	-6%	1,438.2	-4%	1,387.3	10%	1,519.3	3%	1,572.1	-20%	1,257.4	15%	1,449.5	0.0	1,449.5
Total Non-Labor 925	4,009.3	43%	5,752.5	-48%	2,990.4	88%	5,622.1	18%	6,615.5	-11%	5,877.0	9%	6,712.4	(283.2)	6,429.2
Less: G/L Codes	(624.7)	-31%	(429.2)	18%	(507.3)	29%	(652.7)	12%	(729.9)	-6%	(682.8)	1%	(687.0)	0.0	(687.0)
Total Non-Labor 925	3,384.6	57%	5,323.3	-53%	2,483.1	100%	4,969.4	18%	5,885.6	-12%	5,194.2	11%	6,025.4	(283.2)	5,742.2
Combined 925	4,919.0	37%	6,761.5	-43%	3,870.4	68%	6,488.7	15%	7,457.7	-13%	6,451.6	11%	7,474.9	(283.2)	7,191.7
GRAND TOTAL	7,274.5	35%	9,849.4	-35%	6,411.2	37%	8,796.6	14%	10,006.3	-9.1%	9,112.7	13%	10,617.1	(363.2)	10,253.9

HAWAIIAN ELECTRIC COMPANY, INC.
Non-Labor Insurance Premiums and Related Expenses ($000's)

Type of Expense	2003 Recorded	* Change * Percent	2004 Recorded	* Change * Percent	2005 Recorded	* Change * Percent	2006 Recorded	* Change * Percent	2007 Recorded	* Change * Percent	2008 Budget	* Change * Percent	2009 Budget	2009 Adjustment	2009 Test Yr Est
ACCOUNT 924.00, PROPERTY															
Property	1,444.3	-7%	1,349.9	-1%	1,341.7	2%	1,373.2	11%	1,518.4	-2%	1,487.8	24%	1,846.7	(60.0) (d)	1,786.7
Boiler/Machinery	553.1	-8%	509.5	-1%	505.7	-1%	501.0	10%	553.4	-2%	542.6	14%	617.9	(20.0) (e)	597.9
Crime (a)	*66.5*	*0.1*	*74.0*	*0.0*	*75.3*	*(0.2)*	62.1	-10%	55.7	12%	62.1	-1%	61.7		61.7
Other (b)	*3.4*	*(0.9)*	*0.3*	*0.0*	*0.3*	*6.0*	*2.1*	*0.1*	4.8	-100%	0.0		0.0		-
Freight	19.3	138%	46.0	-53%	21.5	13%	24.2	-58%	10.1	-23%	7.8	117%	16.8		16.8
Subtotal	2,016.7	-6%	1,905.4	-2%	1,868.9	5%	1,960.5	9%	2,142.4	-2%	2,100.3	21%	2,543.1	(80.0)	2,463.1
ACCOUNT 925.01, INJURIES & DAMAGES - EMPLOYEES															
Excess Workers' Compensation (W/C)	156.1	5%	164.2	0%	163.4	2%	166.4	9%	181.4	9%	197.9	9%	216.7	(25.0) (f)	191.7
State W/C Special Fund	46.4	1%	46.7	27%	59.1	-49%	29.9	-42%	17.4	97%	34.2	-57%	14.6		14.6
USL&H Bond	1.3	8%	1.4	0%	1.4	0%	1.4	-29%	1.0	40%	1.4	0%	1.4		1.4
Subtotal	203.8	4%	212.3	5%	223.9	-12%	197.7	1%	199.8	17%	233.5	0%	232.7	(25.0)	207.7
ACCOUNT 925.02, INJURIES & DAMAGES - PUBLIC															
General Liability	764.0	20%	916.5	13%	1,037.8	4%	1,075.0	1%	1,082.9	5%	1,140.1	10%	1,251.1	(130.0) (g)	1,121.1
D&O	3.8	4284%	166.6	2%	169.5	7%	181.4	-7%	169.1	9%	184.2	-7%	172.0		172.0
Fiduciary	39.2	216%	123.8	-3%	120.4	44%	173.3	-17%	143.4	2%	146.4	-1%	144.4		144.4
Crime (c)	66.5	11%	74.0	2%	75.3	-18%	*62.1*	*-10%*	*55.7*	*12%*	*62.1*	*-1%*	*61.7*		*61.7*
Professional Errors & Omissions					27.4	9%	29.8	-2%	29.2	5%	30.5	10%	33.6		33.6
Other	3.4	-91%	0.3	0%	0.3	600%	2.1	10%	2.3	-100%	0.0		0.0		-
Subtotal	876.9	46%	1,281.2	12%	1,430.7	2%	1,461.6	-2%	1,426.9	5%	1,501.1	7%	1,601.1	(130.0)	1,471.1
GRAND TOTAL	3,097.4	10%	3,398.9	4%	3,523.5	3%	3,619.8	4%	3,769.1	2%	3,834.9	14%	4,376.9	(235.0)	4,141.9

Notes:
(a) (c) Prior to 2006, premiums for Crime were captured under Account 925.02
(b) Prior to 2007, premiums for Other were captured Under Account 925.02
(d) ($60k) reduction to property insurance premium
(e) ($20K) reduction to boiler & machinery insurance premium
(f) ($25k) reduction to excess workers compensation premium
(g) ($130k) reduction to general liability insurance premium

HAWAIIAN ELECTRIC COMPANY, INC.
Non-Labor Absorbed Losses and Expenses (000's)

Type of Expense	2003 Recorded	* Change * Percent	2004 Recorded	* Change * Percent	2005 Recorded	* Change * Percent	2006 Recorded	* Change * Percent	2007 Recorded	* Change * Percent	2008 Budget	* Change * Percent	2009 Budget	2009 Adjustment	2009 Test Yr Est
ACCOUNT 924.00, PROPERTY															
Property Losses	126.5	618%	908.0	-45%	496.6	-79%	105.6	27%	133.6	86%	248.6	8%	268.7		268.7
Subtotal	126.5	618%	908.0	-45%	496.6	-79%	105.6	27%	133.6	86%	248.6	8%	268.7		268.7
ACCOUNT 925.01, INJURIES & DAMAGES - EMPLOYEES															
Workers' Comp Losses	275.5	256%	979.7	-57%	422.7	119%	925.3	26%	1,166.2	13%	1,314.9	11%	1,458.8		1,458.8
Subtotal	275.5	256%	979.7	-57%	422.7	119%	925.3	26%	1,166.2	13%	1,314.9	11%	1,458.8		1,458.8
ACCOUNT 925.02, INJURIES & DAMAGES - PUBLIC															
Liability Losses	869.7	108%	1,812.4	-130%	(549.6)	-355%	1,400.1	54%	2,160.7	-40%	1,301.6	20%	1,556.0	35.0 (b)	1,591.0
Subtotal	869.7	108%	1,812.4	-130%	(549.6) (a)	-355%	1,400.1	54%	2,160.7	-40%	1,301.6	20%	1,556.0	35.0	1,591.0
GRAND TOTAL	1,271.7	191%	3,700.1	-90%	369.7	558%	2,431.0	42%	3,460.5	-17%	2,865.1	15%	3,283.5	35.0	3,318.5

Notes:
(a) 2005 Recorded Public Liability is exceptionally low partly due to a significant reversal of an established reserve. A reversal of $1 million was made because our insurer considered our $1 million retention covered by the payments of our co-defendant contractor whose insurance was primary. 2006 Recorded Public Liablity was also reduced by $496,000 when we reversed a reserve for a claim which had not been pursued against Hawaiian Electric before the two year statute of limitations ended.

(b) $35k increase to liability loss projection

HAWAIIAN ELECTRIC COMPANY, INC.
Other Non-Labor Expenses (000's)

Type of Expense	2003 Recorded	* Change * Percent	2004 Recorded	* Change * Percent	2005 Recorded	* Change * Percent	2006 Recorded	* Change * Percent	2007 Recorded	* Change * Percent	2008 Budget	* Change * Percent	2009 Test Yr Est
ACCOUNT 924.00, PROPERTY													
Property Other Non-Labor Expenses	115.7	33%	153.7	-59%	63.4	134%	148.2	41%	209.2	6%	221.1	2%	224.4
Subtotal	115.7	33%	153.7	-59%	63.4	134%	148.2	41%	209.2	6%	221.1	2%	224.4
ACCOUNT 925.01, INJURIES & DAMAGES - EMPLOYEES													
Workers' Comp Other Non-Labor Expenses	119.0	-5%	113.2	-44%	63.9	26%	80.3	30%	104.4	-5%	99.1	26%	124.5
Subtotal	119.0	-5%	113.2	-44%	63.9	26%	80.3	30%	104.4	-5%	99.1	26%	124.5
ACCOUNT 925.02, INJURIES & DAMAGES - PUBLIC													
Liability Other Non-Labor Expenses	376.0	-33%	250.7	-15%	213.8	-21%	169.4	30%	220.0	15%	252.7	-6%	238.5
Subtotal	376.0	-33%	250.7	-15%	213.8	-21%	169.4	30%	220.0	15%	252.7	-6%	238.5
GRAND TOTAL	610.7	-15%	517.6	-34%	341.1	17%	397.9	34%	533.6	7%	572.8	3%	587.4

Note: "Other Non-Labor Expenses" do not include Premiums, Absorbed Losses or Safety Program related non-labor expenses.
Included are on-costs discussed in Ms. Patsy Nanbu's testimony, HECO T-11. These are adjusted by the G/L code cost reversals after all costs are combined as shown on HECO-1101, page 1.
On-cost amounts included above are $102.7 for Property, $169.3 for Liability and $59.6 for Workers' Compensation.
See calculations for Other Non-Labor Expenses in HECO-WP-1203

HAWAIIAN ELECTRIC COMPANY, INC.
Labor and Related Expenses ($000's)

Type of Expense	2003 Recorded	* Change * Percent	2004 Recorded	* Change * Percent	2005 Recorded	* Change * Percent	2006 Recorded	* Change * Percent	2007 Recorded	* Change * Percent	2008 Budget	* Change * Percent	2009 Test Yr Est
ACCOUNT 924.00, PROPERTY													
Direct Labor	150.8	5%	158.6	8%	170.8	2%	174.2	-19%	141.2	26%	178.5	4%	186.1
On-Cost	27.2	-4%	26.0	-9%	23.7	15%	27.3	-16%	22.8	26%	28.7	3%	29.5
Subtotal	178.0	4%	184.6	5%	194.5	4%	201.5	-19%	164.0	26%	207.2	4%	215.6
ACCOUNT 925.01, INJURIES & DAMAGES - EMPLOYEES													
Workers' Comp Direct Labor	141.2	-6%	133.3	-15%	112.9	-12%	99.1	-1%	98.0	6%	104.2	21%	126.0
Workers' Comp Non-Prod Labor	207.0	-14%	177.7	-21%	139.5	7%	149.3	69%	252.6	-100%	0.0		0.0
Workers' Comp On-Cost	24.2	-12%	21.3	-31%	14.6	-3%	14.1	3%	14.5	-8%	13.4	24%	16.6
Subtotal	372.4	-11%	332.3	-20%	267.0	-2%	262.5	39%	365.1	-68%	117.6	21%	142.6
Safety Program Direct Labor	716.3	-4%	685.3	0%	684.1	5%	717.8	2%	730.7	-8%	668.9	22%	813.0
Safety Program On-Cost	117.7	-15%	100.6	-16%	85.0	20%	102.2	4%	106.4	-5%	101.0	16%	117.6
Subtotal	834.0	-6%	785.9	-2%	769.1	7%	820.0	2%	837.1	-8%	769.9	21%	930.6
Combined Direct Labor	857.5	-5%	818.6	-3%	797.0	2%	816.9	1%	828.7	-7%	773.1	21%	939.0
Combined Non-Prod Labor	207.0	-14%	177.7	-21%	139.5	7%	149.3	69%	252.6	-100%	0.0		0.0
Combined On-Cost	141.9	-14%	121.9	-18%	99.6	17%	116.3	4%	120.9	-5%	114.4	17%	134.1
Total Account 925.01	1,206.4	-7%	1,118.2	-7%	1,036.1	4%	1,082.5	11%	1,202.2	-26%	887.5	21%	1,073.2
ACCOUNT 925.02, INJURIES & DAMAGES - PUBLIC													
Direct Labor	281.1	-1%	278.0	12%	311.2	26%	391.8	-18%	321.7	0%	321.9	2%	328.3
On-Cost	46.9	-10%	42.0	-5%	39.9	13%	44.9	7%	48.1	0%	48.0	0%	48.0
Total Account 925.02	328.0	-2%	320.0	10%	351.1	24%	436.7	-15%	369.8	0%	369.9	2%	376.3
Account 925.01 & 925.02 Direct Labor	1,138.6	-4%	1,096.6	1%	1,108.2	9%	1,208.7	-5%	1,150.4	-5%	1,095.0	16%	1,267.4
Account 925.01 & 925.02 Non-Prod Labor	207.0	-14%	177.7	-21%	139.5	7%	149.3	69%	252.6	-100%	0.0		0.0
Account 925.01 & 925.02 On-Cost	189	-13%	164	-15%	140	16%	161	5%	169	-4%	162	12%	182
Total 925.01 &925.02	1,534.4	-6%	1,438.2	-4%	1,387.2	10%	1,519.2	3%	1,572.0	-20%	1,257.4	15%	1,449.5
GRAND TOTAL	1,712.4	-5%	1,622.8	-3%	1,581.7	9%	1,720.7	1%	1,736.0	-16%	1,464.6	14%	1,665.1

HAWAIIAN ELECTRIC COMPANY, INC.
Safety Program Expenses ($000's)
Included in Account 925.01

Description of Safety Program Expenses	2003 Recorded	* Change * Percent	2004 Recorded	* Change * Percent	2005 Recorded	* Change * Percent	2006 Recorded	* Change * Percent	2007 Recorded	* Change * Percent	2008 Budget	* Change * Percent	2009 Budget	2009 Adjustment	2009 Test Yr Est
Labor (asbestos work, accident investigation, trai	834.0	-6%	785.9	-2%	769.1	7%	820.0	2%	837.1	-8%	769.9	21%	930.6		930.6
Non-Labor:															
Safety Materials Purchased by Safety Division (SS (equipment, promotional, educational)	206.8	-1%	204.8	-5%	194.4	-4%	186.4	31%	244.8	-23%	189.0	-41%	111.8		111.8
Safety Materials Purchased Outside Safety Divisic	132.5	38%	182.5	-2%	178.7	22%	218.6	-32%	149.5	-28%	108.0	-5%	102.9		102.9
Information Services	74.4	31%	97.3	-2%	95.5	-6%	89.6	12%	100.7	-7%	93.6	26%	118.2		118.2
Transportation/Travel	137.2	18%	162.2	7%	173.3	19%	206.6	-12%	182.6	33%	243.1	-49%	124.2		124.2
Outside Services (a)	323.8	-42%	188.4	29%	242.4	20%	289.9	-26%	214.4	-33%	143.2	214%	604.0	(154.8) (c)	449.2
Other Costs (b)	413.5	-35%	267.8	12%	300.7	32%	396.5	12%	445.5	-11%	397.1	9%	439.7	(8.4) (c)	431.3
Subtotal Non-Labor	1,288.2	-14%	1,103.0	7%	1,185.0	17%	1,387.6	-4%	1,337.5	-12%	1,174.0	14%	1,500.8	(163.2)	1,337.6
GRAND TOTAL SAFETY PROGRAM	2,122.2	-11%	1,888.9	3%	1,954.1	13%	2,207.6	-1%	2,174.6	-11%	1,943.9	17%	2,431.4	(163.2)	2,268.2

(a) "Outside Services" includes fire protection system, outside laboratory analysis, physical (motor vehicles), membership dues, communications, staff training, heavy truck licensure, and records/reports.

(b) "Other Costs" include primarily on-costs which will be reduced by G/L Code reversals after all NARUC 925 components are combined (see HECO-1101, page 1). For Test Year 2009, these costs total $425.7 of $439.7 shown above for Safety. G/L Code Adjustments are addressed by Ms. Patsy Nanbu in HECO T-11.

(c) $163.2k reduction to normalize the safety banquet and awards at 40% of projected cost based on historical frequency (2 out of 5 years).

($thousands)	2009 Bud	Normalizatı	Adjustment
Safety Celebration (See HECO-WP-1202, page 124)	162	-60%	(97.2)
Process Area Team Safety Awards (See HECO-WP-1202, pages 126-127)	96	-60%	(57.6)
Merit Supervisor Safety Awards (See HECO WP-1202, page 128)	14	-60%	(8.4)
Total	272		(163.2)

HAWAIIAN ELECTRIC COMPANY, INC.

PROPERTY/BOILER MACHINERY INSURANCE - ABSORBED LOSSES

BUDGET FORECAST FOR 2009/2010

951 ACTIVITY		2000	2001	2002	2003	2004	2005	2006	2007	2/08
Property Losses	(a)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Boiler/Mach Losses	(a)	$0	$0	$0	$0	$750,000	$399,964	($143,760)	$0	$0
OH/UG Uncollectibles	(a)	$63,340	$73,019	$114,946	$148,425	$153,516	$38,616	$159,320	$73,794	($2,519)
OH/UG Collect Exp		$6,264	$2,482	$3,696	$1,041	$4,167	$346	$5,715	$6,327	$41
Bad Debt		($39,704)	$22,836	($13,069)	($22,937)	$34,416	($38,301)	$18,627	$51,450	$0
		$29,899	$98,337	$105,572	$126,528	$942,099	$400,625	$39,902	$131,571	($2,478)

HANDY/WHITMAN INDEX:

	2000	2001	2002	2003	2004	2005	2006	2007	2/08	
ALL STEAM PLNT	387	398	412	417	451	480	519	519	519	(1/07)
DVLPMNT FACTR	1.34	1.30	1.26	1.24	1.15	1.08	1.00	1.00	1.00	
OH/UG DISTR PLNT	400	420	434	439	466	480	503	503	503	(1/07)
DVLPMNT FACTR	1.26	1.20	1.16	1.15	1.08	1.05	1.00	1.00	1.00	
UG COND & DSTR	342	342	347	353	395	432	511	511	511	(1/07)
DVLPMNT FACTR	1.49	1.49	1.47	1.45	1.29	1.18	1.00	1.00	1.00	
CPI	176.30	178.40	180.30	184.50	190.60	197.80	209.40	219.50	219.50	(12/07)
DVLPMNT FACTR	1.25	1.23	1.22	1.19	1.15	1.11	1.05	1.00	1.00	

92409 SUB ACTIVITY		2000 (2007 $'s)	2001 (2007 $'s)	2002 (2007 $'s)	2003 (2007 $'s)	2004 (2007 $'s)	2005 (2007 $'s)	2006 (2007 $'s)	2007 (2007 $'s)	2008 (2/08)	98 MONTH TOTAL	MONTHLY AVERAGE	YEARLY TOTAL	2008 Forecast	2009 Forecast	2010 Forecast
Property Losses	(a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Boiler/Mach Losses	(a)	$0	$0	$0	$0	$862,500	$431,961	($143,760)	$0	$0	$1,150,701	$11,742	$140,904	$143,863	$147,460	$151,147
OH/UG Uncollectibles	(a)	$79,808	$87,623	$133,337	$170,688	$165,797	$40,547	$159,320	$73,794	($2,519)	$908,395	$9,269	$111,228	$113,564	$116,403	$119,313
OH/UG Collect Exp		$7,830	$3,053	$4,509	$1,239	$4,792	$384	$6,001	$6,327	$41	$34,176	$349	$4,188	$4,276	$4,383	$4,493
Bad Debt		($49,630)	$28,088	($15,945)	($27,295)	$39,578	($42,514)	$19,558	$51,450	$0	$3,290	$34	$408	$417	$427	$438
													$256,728	$262,120	$268,673	$275,391

		2008	2009	2010
2008 Budget = Yearly total +2.1%.	TOTAL PROPERTY:	$ 118,257	$ 121,213	$ 124,244
2009 Budget = 2008 Budget +2.5%.				
2010 Budget = 2009 Budget +2.5%.	TOTAL BOILER/MACHINERY:	$ 143,863	$ 147,460	$ 151,147
		$ 262,120	$ 268,673	$ 275,391

H/W all steam plnt (1) - Property and Boiler & Machinery Losses.
H/W Dist. Plant (44) - OH conductors & devices.
H/W Dist. Plant (47) - UG conductors & devices.
Honolulu CPI All Urban Consumers

NOTE:

(a) The 2007 recorded amounts for Property Losses, Boiler/Mach Losses and OH/UG Uncollectibles were captured at the workorder level and therefore do not tie to the 2007 recorded amount for the specific codeblock PKI951PHENENPKZZZZZ501 The workorder amounts were lower than the codeblock amount. If codeblock amounts were used, the 2009 trended forecast amount would be $6.9K higher.
Likewise, certain General Liability loss-related expenditures for 2007 in HECO-1204 were similarly captured at the workorder level, however the difference would lower the 2009 General Liability trended loss forecast by $4.8K. The net impact of the $6.9K increase for property losses and the 4.8K decrease for general liability losses is a $2.1K increase.

Property Code Blocks

92409 SUB ACTIVITY	RA	ACT.	LOC.	IND.	PROJECT	EXPENSE ELEMENT	YEARLY TOTAL	(a) 2008 FORECAST	(b) 2009 FORECAST	(c) 2010 FORECAST	YR 2009 TOTAL BY EXPENSE TYPE	MONTHLY YR 2009	YR 2010 TOTAL BY EXPENSE TYPE	MONTHLY YR 2010	YR 2008 TOTAL BY EXPENSE TYPE	MONTHLY YR 2008
Property Losses	PKI	951	PHE	NE	NPKZZZZZ	501	$0	$0	$0	$0						
Boiler Mach. Losses	PKI	951	PHE	NE	NPKZZZZZ	501	$140,904	$143,863	$147,460	$151,147						
OH/UG Uncollect.	PKI	951	PHE	NE	NPKZZZZZ	501	$111,228	$113,564	$116,403	$119,313	$263,863	$ 21,989.00	$270,460	$ 22,538.00	$257,427	$ 21,452.00
OH/UG Collect Exp.	PKI	951	PHE	NE	NPKZZZZZ	502	$4,188	$4,276	$4,383	$4,493	$4,383	$ 365.00	$4,493	$ 374.00	$4,188	$ 349.00
BAD DEBT	PKI	951	PHE	NE	NPKZZZZZ	905	$408	$417	$427	$438	$427	$ 36.00	$438	$ 37.00	$408	$ 34.00
							$256,728	$262,120	$268,673	$275,391		$ 22,390.00		$ 22,949.00	$262,023	$ 21,835.00
					TOTAL PROPERTY:			$118,257	$121,213	$124,244						
					TOTAL BOILER/MACHINERY:			$143,863	$147,460	$151,147						
								$262,120	$268,673	$275,391						

CONSOLIDATION OF CODE BLOCKS:

							MONTHLY YR 2009	TOTAL YR 2009	MONTHLY YR 2010	TOTAL YR 2010
ALL	PKI	951	PHE	NE	NPKZZZZZ	501	$ 21,989.00	$ 263,868.00	$ 22,538.00	$ 270,456.00
ALL	PKI	951	PHE	NE	NPKZZZZZ	502	$ 365.00	$ 4,380.00	$ 374.00	$ 4,488.00
ALL	PKI	951	PHE	NE	NPKZZZZZ	905	$ 36.00	$ 432.00	$ 37.00	$ 444.00
							$ 22,390.00	$ 268,680.00	$ 22,949.00	$ 275,388.00

Notes:
(a) 2008 Budget = Yearly total +2.1%.
(b) 2009 Budget = 2008 Budget +2.5%.
(c) 2010 Budget = 2009 Budget +2.5%.

Hawaiian Electric Company, Inc.
Account 925
Workers' Compensation Claims Estimate

Year	Total Cost [1]	Total # Claims [1]	Avg $ per Claim	CPI Factor [2]	Avg $ /Claim (2007$'s)
1980	439,177	300	1,464	207.3/82.4	3,582
1981	470,000	291	1,615	207.3/90.9	3,582
1982	486,293	284	1,712	207.3/96.5	3,577
1983	479,120	265	1,808	207.3/99.6	3,660
1984	778,975	223	3,493	207.3/103.9	6,778
1985	633,346	235	2,695	207.3/107.6	5,050
1986	642,200	202	3,179	207.3/109.6	5,848
1987	634,420	217	2,924	207.3/113.6	5,188
1988	433,077	228	1,899	207.3/118.3	3,237
1989	790,583	261	3,029	207.3/124.0	4,925
1990	1,088,905	238	4,575	207.3/130.7	7,057
1991	897,187	261	3,437	207.3/136.2	5,088
1992	821,953	273	3,011	207.3/140.3	4,326
1993	888,673	270	3,291	207.3/144.5	4,592
1994	1,367,042	265	5,159	207.3/148.3	7,013
1995	1,243,215	236	5,268	207.3/152.5	6,964
1996	1,000,976	219	4,571	207.3/156.9	5,873
1997	804,469	172	4,677	207.3/160.5	5,875
1998	639,717	190	3,367	207.3/163.0	4,164
1999	1,394,275	297	4,695	207.3/166.6	5,681
2000	1,700,930	223	7,627	207.3/172.2	8,930
2001	1,413,314	236	5,989	207.3/177.1	6,817
2002	1,438,039	216	6,658	207.3/179.9	7,461
2003	1,148,514	185	6,208	207.3/184.0	6,802
2004	1,149,435	166	6,924	207.3/188.9	7,390
2005	810,769	157	5,164	207.3/207.3	5,331
2006	820,670	135	6,079	207.3/200.2	6,122
2007	1,173,725	152	7,722	207.3/212.5 [3]	7,776
1980-2007 (28 year avg)		245 [4]			5,667

[1] Note: Above data for 1980-Dec. 2007 obtained from WC Dir.'s worksheet dated 02/08.

[2] Note: Above CPI Factor from US Department of Labor - Bureau of Labor Statistics for report call fax-on-demand (415) 975-4567 document # 9210.

	Avg$/Claim - 2007 $		5,667
Per JT ==>	08 Inflation Factor		1.025
	2008 Avg $/Claim		5,809
	Avg # of Claims	X	245
	2008 Estimate		1,423,205
	Inflation Factor for '09 Fcst [5]		1.025
	2009 Estimate		1,458,785
	Inflation Factor for '10 Fcst [5]		1.025
	2010 Estimate		1,495,255

[3] Assumes 2.5% inflation factor in 2008, (per latest CPI (per Blue Chip Indicators).

[4] Based on December 2007 annualized total # of claims

[5] Assumes inflation factor of 2.5%, per Blue Chip Economic Indicators 2008 Consumer Price Index

HAWAIIAN ELECTRIC COMPANY, INC.
LIABILITY INSURANCE - ABSORBED LOSSES
BUDGET FORECAST FOR 2009/2010

Work Order	2000	2001	2002	2003	2004	2005	2006	2007	2/08
Gen Liab Prop Dmg (PD) (a)	$305,937	$352,991	$348,878	$390,219	$537,575	$470,110	$599,002	$560,311	$34,029
Gen Liab Bod Inj (BI) (a)	$29,180	$816,445	$97,700	$401,049	$115,093	$48,428	$22,688	$53,484	$13,023
Gen Liab PD Adj Exp (a)	$4,091	$10,784	$936	$148	$18,525	$1,715	$22,960	$40,570	$1,419
Gen Liab BI Adj Exp (a)	$14,936	$22,054	$11,123	$10,047	$3,429	($14,060)	$1,648	$22	$0
Gen Liab Legal PD	$27,731	$129,004	$263	$20,878	$15,666	$18,522	$27,647	$24,528	$0
Gen Liab Legal BI	$106,265	$273,469	$258,467	$307,157	$175,964	$15,005	$35,324	$18,270	$0
Prof Liab Claims	$0	$0	$0	$0	$0	$33,278	$0	$0	$0
Auto Liab Prop Dmg (PD)	$20,113	$15,493	$31,757	$14,326	$22,256	$33,278	$35,019	$26,462	($7,506)
Auto Liab Bod Inj (BI)	$215,921	$0	$18,721	$524	$238	$20,000	$0	$446,000	($205,071)
Auto Liab PD Adj Exp	$534	$1,911	$1,071	$163	$476	$1,926	$1,519	$503	$0
Auto Liab BI Adj Exp	$120	$0	$152	$0	$0	$0	$0	$0	$0
Auto Liab Legal PD	$0	$0	$0	$0	$0	$0	$0	$0	$0
Auto Liab Legal BI	$20,124	$0	$0	$0	$0	$7,590	$2,214	$14,232	($14,043)
Auto Liab Reserves	($72,600)	$0	$0	$0	$35,000	$121,000	$50,000	($107,000)	($24,000)
Gen Liab Reserves	$29,000	$182,800	$536,200	($145,000)	$904,000	($964,000)	$895,300	$1,334,300	$0
Gen Liab Legal Reserves	$24,700	$95,461	$93,700	($113,200)	$60,500	($136,700)	$42,500	$7,100	($8,100)
Auto Liab Legal Reserves	($5,000)	$0	$5,000	$0	$0	$17,400	($2,200)	($15,200)	$0
CPI	176.30	178.40	180.30	184.50	190.60	197.80	209.40	219.50	219.50 12/07
DVLPMNT FCTR	1.25	1.23	1.22	1.19	1.15	1.11	1.05	1.00	1.00

Work Order	2000 (2007 $'s)	2001 (2007 $'s)	2002 (2007 $'s)	2003 (2007 $'s)	2004 (2007 $'s)	2005 (2007 $'s)	2006 (2007 $'s)	2007 (2007 $'s)	2008 (2/08)	98 MONTH TOTAL	MONTHLY AVERAGE	YEARLY TOTAL	2008 Forecast	2009 Forecast	2010 Forecast
Gen Liab Prop Dmg (PD) (a)	$382,421	$434,179	$425,631	$464,361	$618,211	$521,822	$628,952	$560,311	$34,029	$4,069,917	$41,530	$498,360	$508,826	$521,547	$534,586
Gen Liab Bod Inj (BI) (a)	$36,475	$1,004,227	$119,194	$477,248	$132,357	$53,755	$23,822	$53,484	$13,023	$1,913,585	$19,526	$234,312	$239,233	$245,214	$251,344
Gen Liab PD Adj Exp (a)	$5,114	$13,264	$1,142	$176	$21,304	$1,904	$24,108	$40,570	$1,419	$109,001	$1,112	$13,344	$13,624	$13,965	$14,314
Gen Liab BI Adj Exp (a)	$18,670	$27,126	$13,570	$11,956	$3,943	($15,607)	$1,730	$22	$0	$61,410	$627	$7,524	$7,682	$7,874	$8,071
Gen Liab Legal PD	$34,664	$158,675	$321	$24,845	$18,016	$20,559	$29,029	$24,528	$0	$310,637	$3,170	$38,040	$38,839	$39,810	$40,805
Gen Liab Legal BI	$132,831	$336,367	$315,330	$365,517	$202,359	$16,656	$37,090	$18,270	$0	$1,424,420	$14,535	$174,420	$178,083	$182,535	$187,098
Prof Liab Claims	$0	$0	$0	$0	$0	$36,939	$0	$0	$0	$36,939	$377	$4,524	$4,619	$4,734	$4,852
Auto Liab Prop Dmg (PD)	$25,141	$19,056	$38,744	$17,048	$25,594	$36,939	$36,770	$26,462	($7,506)	$218,248	$2,227	$26,724	$27,285	$27,967	$28,666
Auto Liab Bod Inj (BI)	$269,901	$0	$22,840	$624	$274	$22,200	$0	$446,000	($205,071)	$556,768	$5,681	$68,172	$69,604	$71,344	$73,128
Auto Liab PD Adj Exp	$668	$2,351	$1,307	$194	$547	$2,138	$1,595	$503	$0	$9,303	$95	$1,140	$1,164	$1,193	$1,223
Auto Liab BI Adj Exp	$150	$0	$185	$0	$0	$0	$0	$0	$0	$335	$3	$36	$37	$38	$39
Auto Liab Legal PD	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Auto Liab Legal BI	$25,155	$0	$0	$0	$0	$8,425	$2,325	$14,232	($14,043)	$36,094	$368	$4,416	$4,509	$4,622	$4,738
Auto Liab Reserves	($90,750)	$0	$0	$0	$40,250	$134,310	$52,500	($107,000)	($24,000)	$5,310	$54	$648	$662	$679	$696
Gen Liab Reserves	$36,250	$224,844	$654,164	($172,550)	$1,039,600	($1,070,040)	$940,065	$1,334,300	$0	$2,986,633	$30,476	$365,712	$373,392	$382,727	$392,295
Gen Liab Legal Reserves	$30,875	$117,417	$114,314	($134,708)	$69,575	($151,737)	$44,625	$7,100	($8,100)	$89,361	$912	$10,944	$11,174	$11,453	$11,739
Auto Liab Legal Reserves	($6,250)	$0	$6,100	$0	$0	$19,314	($2,310)	($15,200)	$0	$1,654	$17	$204	$208	$213	$218
												TOTAL:	$1,478,941	$1,515,915	$1,553,812
												Less Clearing Charges:	$103,261	$105,843	$108,490
												NET:	$1,375,680	$1,410,072	$1,445,322

2008 forecast = Yearly total +2.1%
2009 forecast = 2008 forecast +2.5%
2010 forecast = 2009 forecast +2.5%

NOTE:

(a) The 2007 recorded amounts for Gen Liab PD, Gen Liab BI, Gen Liab PD Adj Exp and Gen Liab BI Adj Exp were captured at the workorder level and therefore do not tie to the 2007 recorded amount for the specific codeblock PKI950PHENENPKZZZZZ509. The workorder amounts were higher than the codeblock amount. If codeblock amounts were used, the trended 2009 forecast amount would be lower by $4.8K.
Likewise, certain Property loss-related expenditures for 2007 in HECO-1202 were similarly captured at the workorder level, however the difference would increase the 2009 Property trended loss forecast by $6.9K. The net impact of the 4.8K reduction for general liability losses and the 6.9K increase for property losses is a $2.1K increase.

Work Comp Special Fund Forecast
$thousands

Note: The following forecast is based on prior years accrual estimate recorded in December and actual payment made in arrears the following September (cashflow)

	Recorded ----					----|	Forecast ----		----|
HECO	2002	2003	2004	2005	2006	2007	2008	2009	2010
Net of accrual estimate, actual payment and any reversal or adjustment	175.8	46.4	46.7	59.1	29.9	17.4	14.6	14.6	14.6
% change		-74%	1%	27%	-49%	-42%	-16%	0%	0%

Note:
The 2008 forecast is based upon the 2004 thru 2007 average percentage change multiplied by the 2007 expense.
A flat forecast is assumed for 2009 and 2010 instead of a downward trend because of increases in 2004 and 2005.