HECO T-3
DOCKET NO. 2008-0083

TESTIMONY OF
PETER C. YOUNG

DIRECTOR, PRICING DIVISION
ENERGY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

SUBJECT: Total Operating Revenue

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Peter C. Young and my business address is 220 South King Street, Suite 1201, Honolulu, Hawaii.

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

A. I am director of the Pricing Division of the Energy Services Department at the Hawaiian Electric Company, Inc. ("HECO" or the "Company"). My experience and background are listed in HECO-300.

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

A. My testimony in HECO T-3 will cover total operating revenue, including estimates of electric sales revenue at present rates, at current effective rates, and at proposed rates for the test year 2009. I will estimate miscellaneous other operating revenue in the test year 2009, and combine it with an estimate of non-sales electric utility charges to estimate total other operating revenue for test year 2009.

ESTIMATES OF TOTAL OPERATING REVENUE

Q. What are the estimates of total operating revenue at present rates, at current effective rates, and at proposed rates for the 2009 test year?

A. The estimates of total operating revenue at present rates and at current effective rates for the test year 2009 are $1,790,052,900 and $1,867,389,600, respectively. See HECO-301, pages 1 and 4. The estimate of total operating revenue at proposed rates assuming a CT-1 Step is $1,964,401,000 which represents an increase of $97,011,400 or 5.20% over the estimated revenue at current effective rates. See HECO-301, page 1. The estimate of total operating revenue at proposed rates assuming no CT-1 unit is $1,940,454,000. This is a $73,064,400 increase over the estimated revenue at current effective rates, or approximately 3.91%. See HECO-301, page 2. Finally, the estimate of total operating revenue at proposed rates assuming the base case is $1,952,579,000. That is an $85,189,400 increase over the estimated revenue at current effective rates, or approximately 4.56%. A summary of the total operating revenue estimates for the 2009 test year at present rates, at current effective rates, and at proposed rates, is shown in HECO-301, page 3.

Q. What is the difference between the revenue estimate at present rates and the revenue estimate at current effective rates?

A. The revenue estimate at present rates is based on rates effective June 20, 2008, which were approved in Docket No. 04-0113, plus revenues from the test year estimate of the energy cost adjustment factor ("ECAF"). The revenue estimate at current effective rates is the sum of the revenue estimates at present rates plus the estimated revenue from the revised test year 2007 Interim rate increase in Docket No. 2006-0386, which was approved June 20, 2008.

ESTIMATES OF TEST-YEAR ELECTRIC REVENUES

Q. What are the estimated electric revenues at present rates, at current effective rates, and at proposed rates for the 2009 test year?

A. The estimated electric revenues at present rates and at current effective rates for the 2009 test year are $1,785,018,900 and $1,862,287,600, respectively, as shown in HECO-302. Note that HECO presents two versions of electric revenues at present rates and current effective rates, one that allocates the electric revenues across the existing eight rate schedules and one that allocates the electric revenues across the proposed six rate schedules, as shown in HECO-302. I will discuss the proposed six rate schedules in my rate design testimony in HECO T-22.

The estimated electric revenue at proposed rates assuming the CT-1 step is in place is $1,959,179,000, which represents an increase of $96,891,400 or about 5.20% over the estimated electric revenue at current effective rates, as shown in HECO-303, page 1. The estimated electric revenue at proposed rates assuming no CT-1 is in place is $1,935,254,000, which represents an increase of $72,966,400 or about 3.92% over the estimated electric revenue at current effective rates. See HECO-303, page 2. The estimated electric revenue at proposed rates assuming the base case is in place is $1,947,368,000, which represents an increase of $85,080,400 or about 4.57% over the estimated electric revenue at current effective rates. See HECO-303, page 3. A summary of the electric revenue estimates for the 2009 test year at present rates, at current effective rates, and at proposed rates, by rate class is shown in HECO-303.

DERIVATION OF ELECTRIC SALES REVENUES

Q. What revenues are included in the estimates of electric sales revenue for each rate class?

A. The estimates of the electric sales revenues for each rate class include the revenues from the base electric charges as well as the revenues from the Energy Cost Adjustment Clause (“ECAC”). Electric sales revenues at current effective rates also include revenues from the test year 2007 interim rate increase in Docket No. 2006-0386. The base electric charges are comprised of the customer, demand, energy and minimum charges, the power factor adjustment, service voltage adjustment, and other adjustments as provided in each rate and rate rider schedule.

Q. How are the revenues from the base charges for each rate class determined?

A. The determination of the electric sales revenues for each class is based on the same method used in previous dockets by the Company and the Consumer Advocate. It is based on the following data:

1) 2009 test year sales forecasts for each rate class;
2) 2009 test year forecasts of number of customers for each rate class;
3) recorded billing loads by subgroups and rate blocks within each rate class; and
4) 2009 test year forecasts of rate rider adjustments.

The revenues from base electric charges are derived by simulating the billing procedure for each rate class using the following steps:

1) The 2009 test year forecasts of sales and number of customers are allocated into subgroups and rate blocks within each rate class, based on recorded billing data. The allocation of the 2009 test year sales by rate blocks, as in Schedule J's energy rate blocks and in Schedule PS's demand rate and energy rate blocks, is based on the Ogive method, using recorded billing data for the 12-month period from January 2007 to December 2007.
2) The sales and number of customers allocated to each subgroup and rate block are multiplied by the corresponding unit charges, and then summed to derive the base electric sales revenues for each rate class.
3) For customers who are on rate riders (such as Rider M, Rider T, and Rider I), electric sales revenues are calculated for each customer at their regular class rates and at their rate rider rates. The differences

are included as adjustments to the base electric revenues of their respective rate classes.

Q. Are there any changes to the method of determining the base revenues for test year 2009?

A. Yes. The estimate of Schedule J revenues at present rates includes adjustments to the estimates of billed demand charges ("kWb") to reflect the approved change in determination of demand approved in HECO's test year 2005 rate case, Docket No. 04-0113.

Q. How did you calculate this adjustment to Schedule J's billing demand?

A. Schedule J customer actual monthly billing data for the year 2005 were re-calculated to derive the adjusted kWb based on the proposed determination of Schedule J kWb. The percentage increase in kWb between the adjusted kWb based on the proposed determination of Schedule kWb and the actual monthly kWb for 2005 was calculated. The test year forecast Schedule J billing kWb at present rates was calculated by applying this percentage increase in kWb to what would otherwise be the test year Schedule J billing kWb at present rates. These calculations are illustrated in HECO-WP-302.

Q. Are there any additional changes to the method of determining the base revenues for test year 2009?

A. Yes, HECO proposed in HECO's test year 2007 rate case, Docket No. 2006-0386, to modify the flat rate energy charge of Schedule R, residential service to a tiered, inclining block rate design to lessen the rate impact on low usage customers and to encourage energy conservation. HECO again proposes this Schedule R rate design as shown in my testimony in HECO T-22. In addition, HECO proposes for test year 2009 to eliminate the energy charge tiers in Schedule J, Schedule P, and

Schedule F, and to eliminate the demand charge tiers in Schedule P, as discussed in the rate design testimony in HECO T-22.

Q. What customers are reflected in the rate rider adjustments?

A. The rate rider adjustments include estimates of rider adjustments from existing rider customers only. Existing rider customers have rate rider adjustments, including Rider M, Rider T, Rider I, and Schedule U, on Schedules J, PS and PP.

Q. How is the estimate of revenues from the Energy Cost Adjustment Clause determined?

A. The estimate of revenue from the ECAC is derived by multiplying the 2009 test year sales by the ECAF. The ECAF at present rates and at current effective rates is 7.221 cents per kWh and 0.000 cents per kWh at proposed rates, as discussed by Mr. Hee in HECO T-10. The derivation of the ECAF at present and at proposed rates is summarized in HECO-1037.

Q. Are there any adjustments to electric revenues included in the test year estimates for cost recovery of Demand-Side management ("DSM") programs or Integrated Resource Planning ("IRP") programs?

A. No. There are no adjustments to electric revenues included in the test year estimates at present rates, at current effective rates, or at proposed rates for cost recovery of DSM programs or IRP programs.

OTHER OPERATING REVENUES

Q. What is the test year 2009 estimate for other operating revenues?

A. Test year 2009 other operating revenues are $5,102,000 at current effective rates and $5,222,000 at proposed rates, as shown in HECO-2301. Other operating revenues vary from scenario to scenario, because late payment charges are a function of electric sales revenue as reflected in HECO-2301 through HECO-

2306. Revenue from non-sales electric utility charges are $3,003,000 at current effective rates, as shown in HECO-304, and in greater detail in HECO-906.

Q. What is the test year 2009 estimate for the Miscellaneous Other Operating Revenues?

A. As shown in HECO-304, the Miscellaneous Other Operating Revenues estimate for test year 2009 is $2,099,000. Miscellaneous Other Operating Revenues arise from amortization of deferred gains, property licenses and leases, parking and carpool revenue, telecom rent, payment protection insurance and other sources.

Q. What is the Company's test year 2009 estimate for amortization of deferred gains?

A. The test year 2007 estimate of amortization of deferred gains is $615,000 as shown in HECO-304.

Q. What is included in amortization of deferred gains?

A. Amortization of deferred gains represents the amortization of deferred gains from the Commission-approved sales of Company-owned property. In general, gains and losses from the sale of Company property are deferred and amortized over five years.

Q. How were the test year 2009 estimates derived?

A. The test year 2009 estimates for amortization of deferred gains were made based on the known Commission-approved sales of Company-owned property plus the anticipated approval of the sale of the Haiku property (Docket No. 2007-0424) in 2008.

Q. What is the Company's test year 2009 estimate for revenues from the Company's property licenses and leases?

A. The test year 2009 estimate for revenues from the Company's property licenses and leases is $353,000 as shown in HECO-304.

Q. What is included in property licenses and leases revenues?

A. Included are: 1) rent from Hawaiian Electric Industries, Inc. for use of office space in the HECO building, 2) miscellaneous rent from various licenses and leases of the Company's land, and 3) revenues from the Hawaii Natural Energy Institute of the University of Hawaii for use of warehouse space at HECO's Ward Avenue facility.

Q. What is the Company's test year 2009 estimate for parking and carpool revenues?

A. The test year 2009 estimate for parking revenues is $311,000 as shown in HECO-304.

Q. What is included in parking revenues?

A. Parking revenues primarily represents revenues from employees for parking privileges at the Ward Avenue facility and Honolulu Power Plant.

Q. What is the Company's test year 2009 estimate for telecom rent revenues?

A. The test year 2009 estimate for telecom rent revenues is $207,000 as shown in HECO-304.

Q. What is included in telecom rent revenues?

A. Telecom rent revenues are primarily rent revenues from telecommunication companies that attach communication equipment to the Company's electric poles and towers or place fiber optic cables in underground ducts, under the Company's Facilities Attachment Program. Under this program, companies are charged a monthly attachment fee pursuant to negotiated contracts with the Company that are approved by the Commission.

Q. What is the Company's test year 2009 estimate for Payment Protection Insurance revenues?

A. The test year 2009 estimate for the Payment Protection Insurance program revenues is $118,000 as shown in HECO-304.

Q. What is the Payment Protection Insurance Program?

A. The Company has an agreement with CSI (Central States Indemnity Co.), an insurance company based in Omaha, Nebraska, which allows CSI to solicit the Company's customers for enrollment in CSI's Insurance Program and to assist CSI with processing and administrative services in connection with CSI's Insurance Program. The insurance coverage offered includes disability insurance, involuntary unemployment insurance and family leave insurance, all intended to pay amounts owed to HECO by insured customers for services rendered.

Q. What do the CSI Insurance Program revenues represent?

A. Under the agreement, the Company is paid a processing and administrative services fee equal to 20% of the billed monthly premiums owed to CSI. Also, the Company and CSI equally share the CSI Program Insurance annual net revenues (total annual premiums net of the Company's 20% service fee, CSI's retention, claim payouts, general costs such as taxes, marketing and other fees and assessments, as defined in the agreement).

Q. What is the Company's test year 2009 estimate for other miscellaneous other operating revenues?

A. The test year 2009 estimate for other miscellaneous other operating revenues is $495,000 as shown in HECO-304.

Q. What is included in the test year 2009 other miscellaneous other operating revenues?

A. The test year 2009 estimate is comprised of: 1) $400,000 from the reimbursement of HECO services provided in support of transmission and distribution planning studies for potential independent power producers, as discussed by Mr. Robert Young in HECO T-8, 2) $60,000 from the reimbursement of minor or incidental engineering services provided to customers under the Company's Minor T&D Customer programs, 3) $32,000 for PCEA conference fees, as discussed by Mr. Hee in HECO T-10, and 4) $3,000 for amortization of the Iolani Court Plaza lease premiums, as discussed by Ms. Nanbu in HECO T-11.

SUMMARY

Q. Please summarize your testimony.

A. HECO's estimates of total operating revenues at present rates, current effective rates, and proposed rates for the CT-1 step for the 2009 test year are $1,790,052,900, $1,867,389,600, and $1,964,401,000, respectively, which represents a proposed increase of $174,348,100 or 9.74% over revenues at present rates; and $97,011,400 or 5.20% over revenues at current effective rates. The revenues at present rates are based on the current electric rates, which became effective June 20, 2008, in Docket No. 04-0113. The revenues at current effective rates are based on current electric rates, plus revenues from the revised interim rate increase approved June 20, 2008 in Docket No. 2006-0386.

The determination of the 2009 test year total operating revenues is based on the same methodology used and approved by the Commission and used by the Consumer Advocate in previous dockets.

Q. Does this conclude your testimony?

A. Yes, this concludes my direct testimony.

PETER C. YOUNG

BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company P.O. Box 2750 Honolulu, Hawaii 96840
CURRENT POSITION:	Director, Pricing Division, Energy Services Department
YEARS OF SERVICE:	20 Years
OTHER EXPERIENCE:	Financial Analyst, Pacific Resources, Inc. Corporate Analyst, Pentagram, Inc.
EDUCATION:	MBA (Finance), University of Washington BA (Economics, Political Science), Claremont McKenna College, Claremont, CA
OTHER TESTIMONY:	Docket No. 2006-0387 - Electric Sales Revenue; Cost of Service and Rate Design (MECO) Docket No. 2006-0386 - Electric Sales Revenue; Cost of Service and Rate Design (HECO) Docket No. 05-0315 - Electric Sales Revenue; Cost of Service and Rate Design (HELCO) Docket No. 05-0146 – Residential Rate Reduction Program; Revenue Requirements and Customer Impact (HECO) Docket No. 05-0145 – Revenue Requirements and Customer Impact (HECO) Docket No. 04-0113 - Electric Sales Revenue; Cost of Service and Rate Design (HECO) Docket No. 99-0207 - Electric Sales Revenue; Cost of Service and Rate Design (HELCO) Docket No. 97-0346 - Electric Sales Revenue; Cost of Service and Rate Design (MECO) Docket No. 7766 - Rate Base (HECO) Docket No. 7764 - Rate Base (HELCO) Docket No. 7700 - Rate Base (HECO)

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
TEST YEAR 2009

TOTAL OPERATING REVENUES
SUMMARY

Rate Class	At Current Effective Rates ($000s)	At Proposed With CT-1 Step ($000s)	PROPOSED INCREASE Amount ($000s)	PROPOSED INCREASE Percent (%)
Electric Sales Revenue	$1,862,287.6	$1,959,179.0	$96,891.4	5.20%
Other Operating Revenue				
Non-Sales Electric Utility Charges	$3,003.0	$3,123.0	$120.0	4.00%
Miscellaneous Other Operating Revenue	$2,099.0	$2,099.0	$0.0	0.00%
Subtotal Other Operating Revenue	$5,102.0	$5,222.0	$120.0	2.35%
Total Operating Revenue	**$1,867,389.6**	**$1,964,401.0**	**$97,011.4**	**5.20%**

Source: HECO-303, HECO-906, HECO-304

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
TEST YEAR 2009

TOTAL OPERATING REVENUES
SUMMARY

Rate Class	At Current Effective Rates ($000s)	At Proposed w/o CT-1 ($000s)	PROPOSED INCREASE Amount ($000s)	PROPOSED INCREASE Percent (%)
Electric Sales Revenue	$1,862,287.6	$1,935,254.0	$72,966.4	3.92%
Other Operating Revenue				
Non-Sales Electric Utility Charges	$3,003.0	$3,101.0	$98.0	3.26%
Miscellaneous Other Operating Revenue	$2,099.0	$2,099.0	$0.0	0.00%
Subtotal Other Operating Revenue	$5,102.0	$5,200.0	$98.0	1.92%
Total Operating Revenue	**$1,867,389.6**	**$1,940,454.0**	**$73,064.4**	**3.91%**

Source: HECO-303, HECO-906, HECO-304

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
TEST YEAR 2009

TOTAL OPERATING REVENUES
SUMMARY

Rate Class	At Current Effective Rates ($000s)	At Proposed Base Case ($000s)	PROPOSED INCREASE Amount ($000s)	PROPOSED INCREASE Percent (%)
Electric Sales Revenue	$1,862,287.6	$1,947,368.0	$85,080.4	4.57%
Other Operating Revenue				
Non-Sales Electric Utility Charges	$3,003.0	$3,112.0	$109.0	3.63%
Miscellaneous Other Operating Revenue	$2,099.0	$2,099.0	$0.0	0.00%
Subtotal Other Operating Revenue	$5,102.0	$5,211.0	$109.0	2.14%
Total Operating Revenue	**$1,867,389.6**	**$1,952,579.0**	**$85,189.4**	**4.56%**

Source: HECO-303, HECO-906, HECO-304

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
TEST YEAR 2009

TOTAL OPERATING REVENUES
SUMMARY

Rate Class	At Present Rates ($000s)	At Proposed With CT-1 Step ($000s)	PROPOSED INCREASE Amount ($000s)	PROPOSED INCREASE Percent (%)
Electric Sales Revenue	$1,785,018.9	$1,959,179.0	$174,160.1	9.76%
Other Operating Revenue				
Non-Sales Electric Utility Charges	$2,935.0	$3,123.0	$188.0	6.41%
Miscellaneous Other Operating Revenue	$2,099.0	$2,099.0	$0.0	0.00%
Subtotal Other Operating Revenue	$5,034.0	$5,222.0	$188.0	3.73%
Total Operating Revenue	**$1,790,052.9**	**$1,964,401.0**	**$174,348.1**	**9.74%**

Source: HECO-303, HECO-906, HECO-304

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
TEST YEAR 2009

TOTAL OPERATING REVENUES
SUMMARY

Rate Class	At Present Rates ($000s)	At Proposed w/o CT-1 ($000s)	PROPOSED INCREASE Amount ($000s)	PROPOSED INCREASE Percent (%)
Electric Sales Revenue	$1,785,018.9	$1,935,254.0	$150,235.1	8.42%
Other Operating Revenue				
Non-Sales Electric Utility Charges	$2,935.0	$3,101.0	$166.0	5.66%
Miscellaneous Other Operating Revenue	$2,099.0	$2,099.0	$0.0	0.00%
Subtotal Other Operating Revenue	$5,034.0	$5,200.0	$166.0	3.30%
Total Operating Revenue	**$1,790,052.9**	**$1,940,454.0**	**$150,401.1**	**8.40%**

Source: HECO-303, HECO-906, HECO-304

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
TEST YEAR 2009

TOTAL OPERATING REVENUES
SUMMARY

Rate Class	At Present Rates ($000s)	At Proposed Base Case ($000s)	PROPOSED INCREASE Amount ($000s)	Percent (%)
Electric Sales Revenue	$1,785,018.9	$1,947,368.0	$162,349.1	9.10%
Other Operating Revenue				
Non-Sales Electric Utility Charges	$2,935.0	$3,112.0	$177.0	6.03%
Miscellaneous Other Operating Revenue	$2,099.0	$2,099.0	$0.0	0.00%
Subtotal Other Operating Revenue	$5,034.0	$5,211.0	$177.0	3.52%
Total Operating Revenue	**$1,790,052.9**	**$1,952,579.0**	**$162,526.1**	**9.08%**

Source: HECO-303, HECO-906, HECO-304

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
TEST YEAR 2009

SUMMARY OF ELECTRIC REVENUES AT PRESENT AND CURRENT EFFECTIVE RATES

Rate Class	TY 2009 Sales (mWh)	Base Revenues ($000s)	Fuel Oil Adj. Revenues ($000s)	Revenue at Present Rates ($000s)	2007 Interim Rate Increase ($000s)	Revenue at Cur. Eff. Rates ($000s)
	A	B	C	D = B + C	E	F = D+E
Schedule R	2,088.4	$382,767.5	$150,803.4	$533,570.9	$27,253.0	$560,823.9
Schedule G	383.1	$75,440.4	$27,663.7	$103,104.1	$5,318.5	$108,422.6
Schedule J	2,086.1	$333,898.8	$150,637.3	$484,536.1	$19,900.4	$504,436.5
Schedule H	33.7	$5,361.5	$2,433.5	$7,795.0	$388.2	$8,183.2
Schedule PS	872.4	$128,887.6	$62,992.5	$191,880.1	$9,620.3	$201,500.4
Schedule PP	1,977.9	$275,734.2	$142,826.8	$418,561.0	$12,780.4	$431,341.4
Schedule PT	178.7	$23,604.7	$12,904.7	$36,509.4	$1,548.5	$38,057.9
Schedule F	37.5	$6,354.4	$2,707.9	$9,062.3	$459.4	$9,521.7
Total	7,657.8	$1,232,049.1	$552,969.8	$1,785,018.9	$77,268.7	$1,862,287.6

Source: HECO-WP-302

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
TEST YEAR 2009

SUMMARY OF ELECTRIC REVENUES AT PRESENT AND CURRENT EFFECTIVE RATES

Rate Class	TY 2009 Sales (mWh)	Base Revenues ($000s)	Fuel Oil Adj. Revenues ($000s)	Revenue at Present Rates ($000s)	2007 Interim Rate Increase ($000s)	Revenue at Cur. Eff. Rates ($000s)
	A	B	C	D = B + C	E	F = D+E
Schedule R	2,088.4	$382,767.5	$150,803.4	$533,570.9	$27,253.0	$560,823.9
Schedule G	394.3	$77,341.0	$28,475.6	$105,816.6	$5,456.1	$111,272.7
Schedule J	2,108.6	$337,359.7	$152,258.9	$489,618.6	$20,151.0	$509,769.6
Schedule P	1,819.6	$262,565.2	$131,394.1	$393,959.3	$19,786.9	$413,746.2
Schedule DS	1,209.4	$165,661.3	$87,329.9	$252,991.2	$4,162.3	$257,153.5
Schedule F	37.5	$6,354.4	$2,707.9	$9,062.3	$459.4	$9,521.7
Total	7,657.8	$1,232,049.1	$552,969.8	$1,785,018.9	$77,268.7	$1,862,287.6

Source: HECO-WP-302, HECO-WP-303

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
TEST YEAR 2009

SUMMARY OF ELECTRIC REVENUES AT CURRENT EFFECTIVE AND PROPOSED RATES

Rate Class	At Current Effective Rates ($000s)	At Proposed With CT-1 Step ($000s)	PROPOSED INCREASE Amount ($000s)	PROPOSED INCREASE Percent (%)
Schedule R	$560,823.9	$590,002.7	$29,178.8	5.20%
Schedule G [1]	$111,272.7	$117,062.0	$5,789.3	5.20%
Schedule J [1]	$509,769.6	$536,291.9	$26,522.3	5.20%
Schedule P [2]	$413,746.2	$435,272.6	$21,526.4	5.20%
Schedule DS [3]	$257,153.5	$270,532.7	$13,379.2	5.20%
Schedule F	$9,521.7	$10,017.1	$495.4	5.20%
Total Sales Revenue	$1,862,287.6	$1,959,179.0	$96,891.4	5.20%

[1] Includes the allocation of Schedule H.
[2] Current Schedule PP, PS, PT customers excluding those assigned to Schedule DS.
[3] Current Schedule PP, PS, PT Directly Served from Substation.

Source: HECO-WP-302, HECO-WP-303

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
TEST YEAR 2009

SUMMARY OF ELECTRIC REVENUES AT CURRENT EFFECTIVE AND PROPOSED RATES

Rate Class	At Current Effective Rates ($000s)	At Proposed w/o CT-1 Step ($000s)	PROPOSED INCREASE Amount ($000s)	PROPOSED INCREASE Percent (%)
Schedule R	$560,823.9	$582,797.6	$21,973.7	3.92%
Schedule G [1]	$111,272.7	$115,632.5	$4,359.8	3.92%
Schedule J [1]	$509,769.6	$529,742.9	$19,973.3	3.92%
Schedule P [2]	$413,746.2	$429,957.2	$16,211.0	3.92%
Schedule DS [3]	$257,153.5	$267,229.0	$10,075.5	3.92%
Schedule F	$9,521.7	$9,894.8	$373.1	3.92%
Total Sales Revenue	$1,862,287.6	$1,935,254.0	$72,966.4	3.92%

[1] Includes the allocation of Schedule H.
[2] Current Schedule PP, PS, PT customers excluding those assigned to Schedule DS.
[3] Current Schedule PP, PS, PT Directly Served from Substation.

Source: HECO-WP-302, HECO-WP-303

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
TEST YEAR 2009

SUMMARY OF ELECTRIC REVENUES AT CURRENT EFFECTIVE AND PROPOSED RATES

Rate Class	At Current Effective Rates ($000s)	At Proposed Base Case ($000s)	PROPOSED INCREASE Amount ($000s)	PROPOSED INCREASE Percent (%)
Schedule R	$560,823.9	$586,445.7	$25,621.8	4.57%
Schedule G [1]	$111,272.7	$116,356.3	$5,083.6	4.57%
Schedule J [1]	$509,769.6	$533,058.9	$23,289.3	4.57%
Schedule P [2]	$413,746.2	$432,648.6	$18,902.4	4.57%
Schedule DS [3]	$257,153.5	$268,901.8	$11,748.3	4.57%
Schedule F	$9,521.7	$9,956.7	$435.0	4.57%
Total Sales Revenue	$1,862,287.6	$1,947,368.0	$85,080.4	4.57%

[1] Includes the allocation of Schedule H.
[2] Current Schedule PP, PS, PT customers excluding those assigned to Schedule DS.
[3] Current Schedule PP, PS, PT Directly Served from Substation.

Source: HECO-WP-302, HECO-WP-303

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
TEST YEAR 2009

SUMMARY OF ELECTRIC REVENUES AT PRESENT AND PROPOSED RATES

Rate Class	At Present Rates ($000s)	At Proposed With CT-1 Step ($000s)	PROPOSED INCREASE Amount ($000s)	PROPOSED INCREASE Percent (%)
Schedule R	$533,570.9	$590,002.7	$56,431.8	10.58%
Schedule G [1]	$105,816.6	$117,062.0	$11,245.4	10.63%
Schedule J [1]	$489,618.6	$536,291.9	$46,673.3	9.53%
Schedule P [2]	$393,959.3	$435,272.6	$41,313.3	10.49%
Schedule DS [3]	$252,991.2	$270,532.7	$17,541.5	6.93%
Schedule F	$9,062.3	$10,017.1	$954.8	10.54%
Total Sales Revenue	$1,785,018.9	$1,959,179.0	$174,160.1	9.76%

[1] Includes the allocation of Schedule H.
[2] Current Schedule PP, PS, PT customers excluding those assigned to Schedule DS.
[3] Current Schedule PP, PS, PT Directly Served from Substation.

Source: HECO-WP-302, HECO-WP-303

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
TEST YEAR 2009

SUMMARY OF ELECTRIC REVENUES AT PRESENT AND PROPOSED RATES

Rate Class	At Present Rates ($000s)	At Proposed w/o CT-1 ($000s)	PROPOSED INCREASE Amount ($000s)	PROPOSED INCREASE Percent (%)
Schedule R	$533,570.9	$582,797.6	$49,226.7	9.23%
Schedule G [1]	$105,816.6	$115,632.5	$9,815.9	9.28%
Schedule J [1]	$489,618.6	$529,742.9	$40,124.3	8.20%
Schedule P [2]	$393,959.3	$429,957.2	$35,997.9	9.14%
Schedule DS [3]	$252,991.2	$267,229.0	$14,237.8	5.63%
Schedule F	$9,062.3	$9,894.8	$832.5	9.19%
Total Sales Revenue	$1,785,018.9	$1,935,254.0	$150,235.1	8.42%

[1] Includes the allocation of Schedule H.
[2] Current Schedule PP, PS, PT customers excluding those assigned to Schedule DS.
[3] Current Schedule PP, PS, PT Directly Served from Substation.

Source: HECO-WP-302, HECO-WP-303

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
TEST YEAR 2009

SUMMARY OF ELECTRIC REVENUES AT PRESENT AND PROPOSED RATES

Rate Class	At Present Rates ($000s)	At Proposed Base Case ($000s)	PROPOSED INCREASE Amount ($000s)	PROPOSED INCREASE Percent (%)
Schedule R	$533,570.9	$586,445.7	$52,874.8	9.91%
Schedule G [1]	$105,816.6	$116,356.3	$10,539.7	9.96%
Schedule J [1]	$489,618.6	$533,058.9	$43,440.3	8.87%
Schedule P [2]	$393,959.3	$432,648.6	$38,689.3	9.82%
Schedule DS [3]	$252,991.2	$268,901.8	$15,910.6	6.29%
Schedule F	$9,062.3	$9,956.7	$894.4	9.87%
Total Sales Revenue	$1,785,018.9	$1,947,368.0	$162,349.1	9.10%

[1] Includes the allocation of Schedule H.
[2] Current Schedule PP, PS, PT customers excluding those assigned to Schedule DS.
[3] Current Schedule PP, PS, PT Directly Served from Substation.

Source: HECO-WP-302, HECO-WP-303

Hawaiian Electric Company, Inc.
DOCKET NO. 2008-0083
TEST YEAR 2009

OTHER OPERATING REVENUE
($000s)

	At Present Rates	At Current Eff. Rates	At Proposed With CT-1 Step
Non-Sales Electric Utility Charges[1]	$ 2,935	$ 3,003	$ 3,123
Miscellaneous Other Operating Revenue..			
Amortization of Deferred Gains	615	615	615
Property Licenses and Leases	353	353	353
Parking and Carpool Revenue	311	311	311
Telecom Rent	207	207	207
Payment Protection Insurance	118	118	118
Other[2]	495	495	495
Subtotal, Miscellaneous Other Operating Revenue	$ 2,099	$ 2,099	$ 2,099
Total, Other Operating Revenue	$ 5,034	$ 5,102	$ 5,222

[1]See HECO-906.
[2]Includes amortization of Iolani Court lease premiums of approximately $3,000, T&D Planning Studies of $400,000, Engineering Services of approximately $60,000, and PCEA conference fees of $32,000.

HECO T-4
DOCKET NO. 2008-0083

TESTIMONY OF
ROSS H. SAKUDA, P.E.

DIRECTOR
GENERATION PLANNING DIVISION
POWER SUPPLY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Fuel Oil Expense and
Generation Efficiency

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Ross Sakuda and my business address is 820 Ward Avenue, Honolulu, Hawaii.

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

A. I am employed by Hawaiian Electric Company, Inc. ("HECO" or "Company") as the Director of the Generation Planning Division in the System Planning Department. My educational background and work experience are given in HECO-400.

Q. What will your testimony cover?

A. My testimony will cover the following topics:

1) test year fuel oil expense, including the test year biodiesel expense for testing and operating the new combustion turbine, Campbell Industrial Park Unit CT-1 ("CIP CT-1"), and
2) generation efficiency factor (heat rate).

OVERVIEW

Q. What are the normalized 2009 test year estimates for the items in your area of responsibility?

A. The normalized test year estimates in my area of responsibility[1] are:

Test Year 2009

		Units
1) Fuel Expense	816,654,000	$
a) Fuel Oil Expense	809,058,000	$

[1] Fuel-Related Expense is summarized here to derive HECO's total fuel expense. Please refer to the testimony of Mr. Ronald Cox in HECO T-5 for the description and supporting information regarding Fuel-Related Expense.

	b) Fuel-Related Expense	7,596,000	$
2)	Purchased Energy Forecast	3,345.6	GWh
3)	Efficiency Factor (Sales Heat Rate)	0.011185	MBtu/kWh (sales)

The units of measure used above include gigawatt-hours ("GWh") and millions of British thermal units per kilowatt-hour ("MBtu/kWh").

<u>HECO's GENERATING SYSTEM</u>

Q. Please briefly describe the existing generating units on HECO's system.

A. There are 16 HECO-owned and operated generating units on the system. These include Waiau Units 3 to 6, which are cycling steam units, Waiau Units 7 and 8, which are baseloaded steam units, Waiau Units 9 and 10, which are diesel oil-fired peaking combustion turbines, Honolulu Units 8 and 9, which are cycling steam units, and Kahe Units 1 to 6, which are baseloaded steam units. All of HECO's steam units use Low Sulfur Fuel Oil ("LSFO"). Please refer to the testimony of Mr. Dan Giovanni in HECO T-7 for additional information regarding these generating units.

HECO also operates 18 distributed generation ("DG") units, totalling approximately 29.5 MW.

There are also three generating power plants that are owned and operated by Independent Power Producers ("IPPs") on the system. These include the 46 MW waste-to-energy Honolulu Program of Waste Energy Recovery ("H-Power") unit, the 180 MW coal-fired AES Hawaii ("AES") unit, and the 208 MW LSFO-fired Kalaeloa Partners, L.P. ("Kalaeloa") combined cycle unit.

Q. Will HECO be adding any generating units to its system?

A. Yes. HECO will be adding a 110 MW (nominal) simple cycle combustion turbine in Campbell Industrial Park at its Barbers Point Tank Farm site (referred to as

"CIP CT-1"). On May 23, 2007, the Commission issued Decision and Order ("D&O") No. 23457 in Docket No. 05-0145 approving HECO's request to expend funds for the purchase and installation of this generating unit and related transmission additions. In addition, HECO will be purchasing as-available energy from Hoku Solar, Inc.'s ("Hoku Solar") nominal 218 kWdc photovoltaic ("PV") facility to be located atop HECO's Archer substation building ("Archer PV").

Q. When will CIP CT-1 go into service?

A. The target in-service date for CIP CT-1 is July 31, 2009. Please refer to the testimony of Ms. Lorie Nagata in HECO T-17.

Q. What type of fuel will CIP CT-1 use?

A. Diesel oil will be used in the CIP CT-1 unit for initial startup, commissioning and acceptance testing. After CIP CT-1 meets the acceptance criteria, biodiesel will temporarily be used to obtain emissions data. This biodiesel emissions data will then be used in HECO's request to modify the CIP CT-1 air permit to allow use of biodiesel. In the meantime, CIP CT-1 will continue to use diesel oil until the air permit modification is received, after which biodiesel will be used.

Q. When will purchases from the Hoku Solar Archer PV facility commence?

A. HECO anticipates that purchases from the Hoku Solar Archer PV facility will commence in late 2008. Therefore, the production simulation assumes that the energy is available for purchase from January 1st of 2009. Mr. Daniel Ching describes the power purchase agreement ("PPA") for this small renewable system in HECO T-6.

FUEL EXPENSE

Q. For the purposes of this proceeding, what are the components of fuel expense?

A. For the purposes of this proceeding, the components of fuel expense are fuel oil expense and fuel-related expense.

Q. What is HECO's normalized test year estimate of fuel expense?

A. HECO's normalized test year estimate of fuel expense is $816,654,000, as shown in HECO-401. This fuel expense includes $809,058,000 of fuel oil expense and $7,596,000 of fuel-related expense. The fuel oil expense represents the cost of fuel, including LSFO, diesel oil and biodiesel, required by HECO to produce the energy required in addition to purchased power to meet the projected needs of its customers. Please see the testimony of Mr. Ronald Cox in HECO T-5 for an explanation of fuel-related expense.

FUEL OIL EXPENSE

Q. What are the primary determinants of fuel oil expense?

A. There are two primary determinants of the test year fuel oil expense: fuel price and projected fuel consumption (i.e., the quantity of fuel needed to produce the required energy).

Fuel Prices

Q. What are the test year fuel prices?

A. HECO's test year prices for LSFO, diesel oil and biodiesel are shown in HECO-502.

Q. How were these prices determined?

A. Please refer to the testimony of Mr. Ronald Cox, in HECO T-5, for an explanation of how these prices were determined.

Q. How are these fuel prices used in this proceeding?

A. Fuel prices are used in the calculation of:

1) fuel oil expense,
2) purchased energy expense, which is covered by Mr. Daniel Ching in HECO T-6,
3) avoided energy costs applicable to certain non-utility generators, and
4) fuel inventory, which is covered by Mr. Ronald Cox in HECO T-5.

Fuel oil expense is fuel consumption times fuel prices. (See HECO-501.) Purchased energy expenses, discussed by Mr. Daniel Ching in HECO T-6, are also calculated using fuel prices. The purchased energy expenses are listed for each IPP in HECO-607. Fuel inventory is the number of barrels in inventory times fuel prices. (See HECO-505.) This method of calculating fuel oil expense, purchased energy expense and fuel inventory is consistent with that used in other Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Limited ("MECO") rate cases.

Fuel Consumption

Q. What is the estimated test year fuel consumption?

A. An estimated 7,943,375 barrels of LSFO will be burned in HECO's steam generators to produce 4,669,500 MWh of energy. This constitutes the vast majority (over 99%) of the MWh produced by the HECO units. Much smaller quantities of diesel and biodiesel will be consumed by HECO combustion turbines and DG. HECO's combustion turbines will burn an estimated 124,139 barrels of diesel oil to produce 31,000 MWh of energy. As described earlier, HECO's CIP CT-1 will primarily consume diesel until the air permit modification is received, after which time it will consume an estimated 7,020 barrels of biodiesel to produce 1,800 MWh of energy. HECO DGs will burn an estimated 9,571 barrels of diesel oil to produce 5,400 MWh of energy. (See HECO-501 for barrels of fuel consumption, and HECO-403 for energy generated by each type of fuel.)

Q. How is HECO's fuel consumption determined?

A. The fuel consumption in the test year is determined through the use of a computer production simulation model. The model, P-MONTH, is a production simulation program supplied by the P Plus Corporation ("PPC"). This model simulates the chronological, hour-by-hour operation of HECO's generation system by dispatching (mathematically allocating) the forecasted hourly kilowatt load among the generating units in operation. Unit commitment and dispatch levels are based on unit type, fuel cost, transmission loss (or "penalty") factors and any transmission system requirements. The load is dispatched by the model such that the overall fuel expense of the system is minimized (i.e., "economic dispatch"). The model calculates the fuel consumed using the unit commitment and dispatch described above, based on the load carried by a unit and the unit's efficiency characteristics. The total fuel consumed is the summation of each unit's hourly fuel consumption. The simulation's results are then adjusted using a calibration factor for each power plant and for the combustion turbines which I will explain later in my testimony.

Q. Is this the same production simulation model that HECO used in its 2005 and 2007 test year rate cases?

A. Yes. The P-MONTH production simulation model was used in the HECO 2005 and 2007 test year rate cases (Docket Nos. 04-0113 and 2006-0386, respectively). The same model was also used in the MECO test year 1999 and 2007 rate cases (Docket Nos. 97-0346 and 2006-0387, respectively), and the HELCO 1999, 2000 and 2006 test year rate cases (Docket Nos. 97-0420, 99-0207 and 05-0315, respectively). P-MONTH is supplied by an outside vendor that has dedicated staff to maintain and update the program. As a result, the program algorithms used in this model are consistent with current industry standards.

Q. What generating facilities are subject to HECO's dispatch control?

A. HECO has dispatch control over its own central-station generating units at Kahe, Waiau, and Honolulu Power Plants, as well as the DG units. HECO also has dispatch control over the generating facilities at Campbell Industrial Park operated by Kalaeloa, AES, and H-Power, from which HECO purchases firm capacity and energy pursuant to power purchase agreements ("PPAs") approved by the Commission. HECO will also have dispatch control over its CIP CT-1.

Q. How are dispatchable generating units dispatched by the production simulation model to determine the estimated energy to be produced by HECO's generating units and purchased from Kalaeloa, AES and H-Power?

A. The HECO, Kalaeloa and AES units are dispatched on the basis of economic dispatch, subject to any applicable generation or system constraints. The H-Power waste-to-energy facility is modeled as a dispatchable thermal unit with zero fuel cost. This means of modeling the unit simulates the provisions of the H-Power PPA, where HECO accepts the energy made available by H-Power, subject to the contract maximum and minimum power outputs and to facility or system constraints.

Q. Did the Company's production simulation assume any unusual system constraints?

A. No. For this rate case, the production simulation assumed that there were no unusual system constraints present.

Q. Have there been any significant changes to HECO's generating system since HECO's 2007 test year rate case (Docket No. 2006-0386) that would have a significant impact on the determination of fuel consumption for the test year 2009?

A. There will be a change in HECO's generating system in the 2009 test year with the addition of CIP CT-1. However, generation efficiency has not changed significantly from HECO's 2007 test year rate case: HECO's estimated 2007 test year net heat rate was 10,666 Btu/kWh as given in the response to CA-IR-214, page 16, in Docket No. 2006-0386, versus 10,635 Btu/kWh shown in HECO-403 in this docket.

Q. What are the key inputs to the P-MONTH production simulation model?

A. The key inputs to the production simulation model, when applied to the HECO system, are as follows:

1) energy and hourly load to be served by the HECO system,
2) energy and hourly load to be served by firm and non-firm purchased power producers,
3) load carrying capability of each HECO and firm purchased power producer generating unit,
4) efficiency characteristics of each HECO generating unit,
5) pricing formulas for the fuel and variable operations and maintenance ("O&M") components of the Kalaeloa and AES energy charges,
6) planned maintenance schedules for the generating units,
7) estimated forced outages rates for HECO, Kalaeloa and AES units, and
8) prices for fuels used by the HECO generating units.

<u>Energy and Hourly Load to be Served by the System</u>

Q. How is the energy to be served by the system determined?

A. The total net system input, or total net energy required by the system, is determined based on the forecasted estimates for sales, Company use, and system losses for the test year. For the base case test year 2009, total net system input (sales plus Company use energy plus losses) is estimated to be 8,053.6 GWh. (See HECO-402, line 5.)

Q. What was the source of the 2009 test year sales?

A. Test year sales of 7,657.8 GWh were obtained from Mr. George Willoughby in HECO T-2. See HECO-201.

Q. How is the Company use for the test year determined?

A. Company use (or Company No Charge Energy) is determined from a five-year (2003-2007) average of recorded Company use. The Company use for the test year is 16.1 GWh as shown in HECO-402, line 2.

Q. How are the system losses for the test year determined?

A. System losses are determined from a five-year average of system losses as shown on HECO-WP-403, page 2. The five-year average of losses as a percentage of net-to-system energy is 4.71%. This percentage was multiplied by the test year net-to-system energy. The system losses for the test year are 379.7 GWh as shown in HECO-402, line 4.

Q. How is the system's hourly load determined?

A. The hourly load on the HECO system is based on the actual 2007 hourly load adjusted for the annual sales and peak forecast, as shown in HECO-WP-201, and for the Company use and system losses.

Q. How is the system's hourly load adjusted for Company use and system losses?

A. Company use and system losses are added to the sales to derive the total net system energy of 8,053.6 GWh as shown in HECO-402, line 5. This total net-to-system energy is used to estimate hourly loads based on historical load patterns.

Energy and Hourly Load to be Served by Firm and Non-Firm Purchased Power Producers

Q. What is the source of the test year 2009 purchased power estimate for HECO?

A. Four methods were used to determine the purchased power estimate:

1) modeling the firm, dispatchable units (Kalaeloa and AES) in the production simulation,
2) estimating the total energy purchased from the firm, scheduled dispatch H-Power unit based on historical information,
3) estimating the total energy purchased from non-firm units, Chevron US Inc. (“Chevron”) and Tesoro Hawaii Corporation (“Tesoro”) from historical purchases, and
4) estimating the total energy purchased from the non-firm PV system based on a projection provided by Hoku Solar of energy to be delivered to HECO.

The purchased energy estimates for H-Power, Chevron and Tesoro were supplied by the Power Purchase Division. Mr. Daniel Ching will discuss these estimates in HECO T-6.

Q. How is the hourly load served by purchased power producers determined?

A. The hourly loads for Kalaeloa, AES, and H-Power are determined through dispatch of the units in the production simulation. Hourly operating costs are developed for Kalaeloa and AES based on their contract pricing formulas.

The estimated energy dispatched from Kalaeloa and AES by the production simulation model has been used in HECO T-6 to develop purchased power expense estimates for these two IPPs.

The hourly loads for non-firm purchased power producers (Chevron and Tesoro) are modeled at a constant level throughout the 24-hour day period, seven days per week.

The energy output from the Hoku Solar Archer PV system was modeled as a fixed energy transaction based on the estimated energy output profile.

Load Carrying Capability of HECO Units

Q. What is the load carrying capability of each HECO generating unit?

A. The load carrying capability of each unit is the ability to generate electricity to supply the load from a unit's minimum rating to its normal top load rating ("NTL"). In actual operations, HECO uses an Energy Management System ("EMS") to control the dispatch of the units. In EMS, each generating unit is limited to a range of output through which the machine can be operated predictably without reconfiguring the plant from normal operation. In general, EMS limits match NTL ratings.

A list of HECO and non-utility, firm power IPP generating unit load carrying capabilities is provided in HECO-WP-406, page 1.

Efficiency Characteristics of HECO Generating Units

Q. What are a generating unit's "efficiency characteristics"?

A. The "efficiency characteristics" of a generating unit are the relationship between fuel input to the unit and the electrical output of the unit. This relationship can be expressed as a second-degree polynomial equation in the form of:

$$\text{Fuel input} = A + (B^*\text{Load}) + (C^*\text{Load}^2)$$

where Load is the operating level in MW.

The values for A, B, and C are the "heat rate constants" for the generating unit and are sometimes referred to as the "ABC coefficients."

Q. How were the HECO unit efficiency characteristics determined?

A. The unit efficiency characteristics for the HECO generating units were developed from test data. The fuel consumption rates at various output levels have been measured, and the "heat rate constants" of the units were determined by fitting a curve of fuel consumption versus output level through the test data points. The "heat rate constants" determined are used as inputs in the production simulation model. The heat rate constants are shown in HECO-WP-406, page 2, and are consistent with those used in HECO's 2007 test year rate case (Docket No. 2006-0386). The heat rate constants for CIP CT-1 are based on engineering estimates provided by Siemens, the engine manufacturer.

<u>Pricing Formulas for the Kalaeloa and AES Energy Charges</u>

Q. How are the pricing formulas for Kalaeloa and AES modeled in the production simulation?

A. The contractual payment provisions for each producer were used to develop cost curves for the production simulation model. Each of the Kalaeloa and AES pricing formulas, in essence, expresses the cost per kWh of energy and variable O&M as a function of the unit's output. This relationship is approximated by a second-degree polynomial equation of the form:

Fuel and variable O&M cost = A + B*Load + C*Load^2

where Load is the operating level in MW.

A curve-fitting technique is used to determine the coefficients A, B and C. These coefficients are then used to represent the cost curve of the Kalaeloa and AES units in the production simulation.

Planned Maintenance Schedules

Q. What is the source of the 2009 test year planned maintenance schedule?

A. HECO's Power Supply O&M Department developed the test year normalized planned maintenance schedule. Please refer to the testimony of Mr. Dan Giovanni in HECO T-7.

Q. What is the source of the calibration year planned maintenance schedule?[2]

A. The planned maintenance schedule for the calibration year uses the actual maintenance and overhaul days for 2007.

Equivalent Forced Outage Rate ("EFOR")

Q. What is the source of the 2009 test year EFOR for HECO's generating units and IPPs?

A. The EFOR for the 2009 test year for HECO's generating units were the forward-looking EFOR values used in HECO's 2008 Adequacy of Supply ("AOS") report, filed with the Commission on January 30, 2008. An extensive discussion of the derivation of the forward-looking EFOR values is provided in Appendix 5 of the 2008 AOS report. The forced outage rate for the IPPs are generally based on recent experience and expectations for the future. (See HECO-WP-406, page 3.)

Q. What forced outage rate was estimated for CIP CT-1?

A. HECO estimated a forced outage rate of 4.0% for CIP CT-1?

Q. What is the source of this estimate?

A. HECO obtained this estimate from Black & Veatch, an engineering consultant with expertise in designing and building large power plants. HECO will obtain actual reliability statistics after the unit is placed in service.

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[2] As explained later in this testimony, the calibration year is the recorded year used to determine the Company's calibration factors. For this rate case, the calibration year is 2007.

Q. What is the source of the calibration year forced outage rates for the HECO system?

A. Forced outage rates for the calibration year are based on the recorded forced outage rates by unit in 2007.

Fuel Prices

Q. What fuel prices were used in the production simulation for the 2009 test year?

A. The fuel prices used in the production simulation model were as follows:

- $99.3149 per bbl for Kahe LSFO,
- $99.3149 per bbl for Waiau LSFO,
- $102.4214 per bbl for Honolulu LSFO,
- $138.6074 per bbl for Waiau combustion turbine diesel oil,
- $140.7018 per bbl for DG diesel oil,
- $138.6074 per bbl for CIP CT-1 diesel, and
- $232.0913 per bbl for CIP CT-1 biodiesel.

The fuel prices for the calibration year are based on the actual prices paid for fuel by HECO in 2007.

Q. What is the source of the 2009 test year fuel prices?

A. Please refer to the testimony of Mr. Ronald Cox in HECO T-5 and HECO-502. The fuel prices for Kahe, Waiau and Honolulu Power Plants were based on April 2008 pricing according to the fuel supply contracts with Chevron and Tesoro.

Results of the Production Simulation

Q. What are the results of the test year production simulation?

A. The results of the test year production simulation (net MWh) can be seen in HECO-405, page 1 (net MWh generation).

Q. Are the results of the HECO production simulation checked against actual historical operations?

A. Yes. For this rate proceeding, the results of the HECO production simulation are calibrated against data for actual operations for the January through December 2007 period. This is the most recent available historical data for a full calendar year at the time the production simulation was developed for the test year. Historical data including load data, planned maintenance schedules, forced outages, fuel prices, and unit efficiency characteristics are input into the production simulation model. The model is run in a manner to simulate how the system was actually run in the historical year. The model results are compared to the historical recorded data on a monthly and annual basis.

The differences between the heat rates from the calibration production simulation described above and from actual operations are due to "real-world" conditions which cannot be completely duplicated by a production simulation.

Q. How are these differences incorporated into the determination of the test year's fuel consumption?

A. The differences are accounted for in the test year fuel consumption by applying calibration factors to the production simulation's output for Kahe, Waiau (LSFO portion), Honolulu Power Plants, the diesel-fired combustion turbines at Waiau, and the CIP CT-1 unit.

Calibration Factor

Q. What is a calibration factor?

A. A calibration factor is a constant number that can be greater than, equal to, or less than 1.00. The test year heat rate (in Btu/kWh) determined by the production simulation is multiplied by this factor.

Q. What is the purpose of the calibration factor?

A. The purpose of the calibration factor is to adjust the fuel consumption determined by the production simulation for actual operating conditions that cannot be completely duplicated by the computer model.

Q. How is a calibration factor determined?

A. The calibration factor is determined by simulating the output of the utility production system for a recorded year, called a "calibration year," and finding the ratio between the computer model outputs and recorded amounts.

Q. Please identify the actual operating conditions that cannot be completely duplicated by the computer model.

A. The actual operating conditions that cannot be completely duplicated by the computer model include, but are not limited to, the following:

a) temporary unit deratings,
b) changes in unit commitment,
c) unpredictable nature of intermittent, as-available resources,
d) actual system conditions,
f) actual system load, and
g) steam turbine and combustion turbine performance.

Each of these factors are discussed in detail in my rebuttal testimony in Docket No. 99-0207, HELCO test year 2000 rate case, HELCO RT-4, page 17, line 15, to page 30, line 8. As the HECO and HELCO systems are not identical, the magnitude of the calibration factor may differ. However, the contributing factors which result in the need for a calibration factor are similar – there are common, practical limitations to duplicating actual conditions for any system.

Q. In which previous dockets has the Commission approved use of a calibration factor?

A. The Commission accepted results of production simulations that used calibration factors in the following HECO, HELCO and MECO rate cases:

1) Docket No. 7700, HECO Test Year 1994
2) Docket No. 7766, HECO Test Year 1995
3) Docket No. 94-0140, HELCO Test Year 1996
4) Docket No. 94-0345, MECO Test Year 1996
5) Docket No. 96-0040, MECO Test Year 1997
6) Docket No. 97-0346, MECO Test Year 1999
7) Docket No. 99-0207, HELCO Test Year 2000
8) Docket No. 04-0113, HECO Test Year 2005
9) Docket No. 05-0315, HELCO Test Year 2006
10) Docket No. 2006-0386, HECO Test Year 2007
11) Docket No. 2006-0387, MECO Test Year 2007

In Docket No. 99-0207, the Consumer Advocate opposed the use of a calibration factor in that docket. However, D&O No. 18365 (pages 18-19), issued on February 8, 2001, stated:

> The commission concludes that in lieu of elimination, it will allow for the continued use of the calibration factor. HELCO must, however, on a going forward basis, file with the commission and Consumer Advocate, annual reports identifying the actual system value for each year, the computer model results, and the adjustment resulting from the calibration factor. This should supply the Commission and Consumer Advocate with appropriate data and information to more effectively address this issue in future rate cases.

HELCO has complied with the Commission's order and has filed calibration factor reports covering calibration factors for the years 2000 through 2007.

Q. Is HECO also required to file annual calibration factor reports to the Commission?

A. Yes. In HECO's test year 2005 rate case, in Docket No. 04-0113, HECO filed a Stipulated Settlement Letter ("Settlement Letter") on September 16, 2005, that documented certain agreements between HECO, the Division of Consumer Advocacy ("Consumer Advocate") and the Department of Defense ("DOD") regarding matters in HECO's 2005 test year rate case proceeding.[3] Paragraph 4.a. of the Settlement Letter stated, "For the purposes of Settlement, the Consumer Advocate and the DOD agree with HECO's proposal to incorporate use of the 2004 calibration factor in determining test year fuel expense, as HECO in turn agrees to the same calibration factor reporting requirements that were required of HELCO in Docket No. 99-0207." Interim D&O No. 22050 in Docket No. 04-0113 stated on page 7, "Where the Parties agree, we accepted such agreement for purposes of this Interim Decision and Order." In its final Decision and Order in that proceeding, the Commission found reasonable HECO's estimate of fuel expense that was based in part on the calibration factor to which the parties agreed in the Stipulated Settlement Letter. See D&O No. 24171, dated May 1, 2008, pages 32-33.

Q. What calibration factors is HECO using in the instant proceeding to determine 2009 test year fuel consumption?

A. HECO is using the following calibration factors, broken down by power plant and fuel type and based on the Monte Carlo technique, which I will discuss later in my testimony:

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[3] The Settlement Letter stated in relevant part on page 1, "The agreements are for the purpose of simplifying and expediting this proceeding, and represent a negotiated compromise of the matters agreed upon, and do not constitute an admission by any party with respect to any of the matters agreed upon herein."

Power Plant	Calibration Factor (2007)
Kahe Power Plant (LSFO)	1.013
Waiau Power Plant Steam Units (LSFO)	1.003
Waiau Power Plant Combustion Turbines (Diesel Oil)	1.203
Honolulu Power Plant (LSFO)	0.989
Total HECO System	1.015

Q. Are these the same calibration factors HECO reported to the Commission in its filing dated March 14, 2008?

A. Yes, they are.

Q. How do these calibration factors compare with those derived for the previous three years?

A. The calibration factors HECO reported to the Commission in its three prior calibration factor filings were as follows:

	Calibration Factors		
	2006	2005	2004
Kahe (LSFO)	1.014	1.017	1.0134
Waiau Steam (LSFO)	1.012	1.008	1.0278
Waiau CTs (Diesel Oil)	1.082	1.275	1.2288
Honolulu (LSFO)	0.994	0.943	0.9747
HECO System	1.018	1.024	1.0275

Q. What modeling technique did HECO apply for the purpose of determining the 2007 calibration factors, which are being used in the instant proceeding?

A. For the purpose of determining the calibration factors, HECO applied a Monte Carlo technique. In essence, in the Monte Carlo technique, forced outages for generating units are treated as random, discrete outages, in one week increments.

For example, for a 20 MW generating unit with a 5% forced outage rate, the computer model will randomly take the unit out of service (during periods when it is available) up to a total forced outage time of 5%. In other words, the unit can operate at 20 MW for 95% of the time it is not on a planned outage, and will not be able to operate (i.e., will have a zero output) for 5% of the time it is not on a planned outage. The user of the computer program can specify the number of iterations that the program should perform this outage simulation. In each iteration, the computer program will take the generating unit out during a different period. The program will essentially take the average of the results of multiple iterations. A greater number of user-specified iterations will increase the time needed to run each simulation. The Monte Carlo technique (compared to a probabilistic technique) is better able to match actual operating hours and energy production from the peaking units and combustion turbines.

Q. Is this the same modeling technique that was used in HECO's 2007 test year rate case?

A. Yes, it is.

Q. Was a calibration factor applied to the production simulation results pertinent to the CIP CT-1 unit?

A. Yes.

Q. What calibration factor was applied to adjust the results of the fuel consumption for CIP CT-1?

A. A calibration factor of 1.100 was applied to adjust the results of the fuel consumption for CIP CT-1.

Q. How did HECO arrive at this factor?

A. HECO arrived at this estimate by reviewing the calibration factors derived for the existing Waiau combustion turbines (Waiau 9 and 10), which can be a proxy since there are no recorded data for CIP CT-1. HECO observed that the calibration factor for the Waiau CTs has ranged from 1.082 to 1.275 over the last three years. For the purposes of this proceeding, HECO used an estimated calibration factor at an intentionally round number of 1.100 for CIP CT-1. HECO anticipates revising this number once actual operating experience has been gathered.

Derivation of Fuel Expense

Q. How was fuel consumption for CIP CT-1 determined?

A. For the purposes of the production simulation, it was assumed that CIP CT-1 began operating on August 1, 2009, based on the estimated in-service date. The unit will be started up and tested on diesel oil. HECO estimates that the unit will begin operation with biodiesel beginning on December 1, 2009. In addition, HECO plans to commit CIP CT-1 ahead of Waiau Units 9 and 10 and the DGs (i.e., when additional generation must be brought on line to serve system demand or provide spinning reserve, CIP CT-1 will be started up before either Waiau 9 and 10 or the DGs are started up). The determination of CIP CT-1's diesel oil and biodiesel consumption was based on this assumption.

Q. Once fuel consumption is determined, and fuel price assumptions are made, how is fuel oil expense derived?

A. Once fuel consumption is determined, fuel oil expense is derived by applying the applicable fuel price per barrel. The derivation of the fuel oil expense is shown in HECO-501.

Q. What is HECO's estimate of fuel oil expense in the test year?

A. HECO's estimate of fuel oil expense in the test year is $809,058,000 (HECO-401).

FUEL-RELATED EXPENSE

Q. What are fuel-related expenses?

A. Fuel-related expenses are non-fuel expenses that are related to the handling, transportation and inspection of the fuel and to the operation and maintenance of the facilities used to store and deliver the fuel. Mr. Ronald Cox explains each of these items in HECO T-5.

Q. Are the results of the production simulation used to determine any of the fuel-related expenses?

A. Yes, the fuel volumes determined from the production simulation and adjusted with the calibration factor, are used to determine fuel-related expenses. Please refer to the testimony of Mr. Ronald Cox in HECO T-5.

HECO GENERATION EFFICIENCY

Q. What is the test year net generation heat rate for HECO?

A. The Total test year net heat rate for HECO is 10, 635 Btu/kWh, and the Central Station unit heat rate is also 10,635 Btu/kWh. These figures are shown in HECO-403, lines 14, and 15, respectively.

Q. What is a "net heat rate"?

A. The net heat rate is a measure of generation efficiency. It is the heat content of the fuel consumed (in Btus) per net kWh generated. That is, for HECO in the test year, an estimated 10,635 Btus of fuel heat are required for the HECO Central Station units, on average, to produce one kWh of energy, net to the system (i.e., after auxiliary consumption has been subtracted but before system losses have been subtracted).

Q. How does the test year net heat rate compare to historical performance?

A. As shown in HECO-404, lines 6 and 7, the estimated base case test year net system heat rate is -0.1 percent, or 14 Btu/kWh, lower than actual 2007.

Q. How does the test year net heat rate affect ratemaking in this proceeding?

A. The net heat rate directly affects the "sales heat rate." The sales heat rate is calculated in a similar manner as the net heat rate, except the sales heat rate is the heat content of the fuel consumed per kWh of sales. The sales heat rate in the form of a Generation Efficiency Factor is used in the Energy Cost Adjustment Clause to translate the base generation cost in cents per MBtu to the weighted base generation cost in cents per kWh of sales.

For HECO, the sales heat rate is computed by dividing the test year fuel consumption (in MBtus) by the proportion of sales provided by HECO generation (in kilowatt-hours). The resulting base case Generation Efficiency Factor is 0.011185 MBtu/kWh. (See HECO-403, line 21.) The Energy Cost Adjustment Clause is discussed by Mr. Alan Hee in HECO T-10.

SUMMARY

Q. Please summarize your testimony.

A. The testimony presented supports the reasonableness of the following values for the 2009 test year:

Test Year 2009

			Units
1)	Fuel Expense	816,654,000	$
	a) Fuel Oil Expense	809,058,000	$
	b) Fuel-Related Expense	7,596,000	$
2)	Purchased Energy Forecast	3,345.6	GWh

3) Efficiency Factor (Sales Heat Rate) 0.011185 MBtu/kWh (sales)

The above items were determined by detailed analyses and methodologies, are consistent with historical values considering known and expected conditions, and are consistent with all items in this case as they relate to each other.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaiian Electric Company, Inc.

Ross H. Sakuda, P.E.

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 820 Ward Avenue P. O. Box 2750 Honolulu, HI 96840
Current Position:	Director, Generation Planning System Planning Department
Previous Positions:	Project Manager Senior Planning Engineer Senior Mechanical Engineer Mechanical Engineer Mechanical Designer
Years of Service:	28
Education:	Bachelor of Science in Mechanical Engineering University of Hawaii, 1978
Other Qualifications:	Registered Professional Engineer Hawaii Mechanical Branch – 1983
Other Experience:	Mechanical Designer, Nakashima Associates
Other Curriculum:	Corporate Training Course Zenger-Miller Supervision Course Utility Finance and Accounting Course
Previous Testimonies:	Maui Electric Company, Limited Request for Approval of Rate Increase Docket No. 2006-0387 Hawaiian Electric Company, Inc. Request for Approval of Rate Increase Docket No. 2006-0386

Previous Testimonies: (continued)

Hawaiian Electric Company, Inc.
Campbell Industrial Park Generation Station
and Transmission Additions Project
Docket No. 05-0145

HECO/HELCO/MECO
PUC Proceeding to Investigate Competitive Bidding
for New Generation in Hawaii
Docket No. 03-0372

Hawaiian Electric Company, Inc.
Request for Approval of Rate Increase
Docket No. 04-0113

HECO/HELCO/MECO
PUC Proceeding to Investigate Distributed Generation
Docket No. 03-0371

Hawaii Electric Light Company, Inc.
Apollo Energy Corporation Petition
Docket No. 00-0135

Hawaii Electric Light Company, Inc.
Request for Approval of Rate Increase
Docket No. 99-0207

Hawaiian Electric Company, Inc.
Waiau Water Agreements
Docket No. 7277

Hawaiian Electric Company, Inc.

TEST YEAR FUEL EXPENSES

Line	Item	Reference	TY 2009 Fuel Expense ($000)
1.	Total Fuel Oil Expense	HECO-401, p. 2, Line 5	$809,058
2.	Total Fuel Related Expense	HECO-503, p. 1, Line 5	$7,596
3.	TOTAL FUEL EXPENSE		$816,654

Hawaiian Electric Company, Inc.

TEST YEAR FUEL EXPENSES
TOTAL FUEL OIL EXPENSES

Line	Fuel Type	Reference	TY 2009 Fuel Oil Expense ($000)
1.	Low Sulfur Fuel Oil	HECO-501, p. 1, Line 4	$788,896
2.	Diesel Fuel Oil	HECO-501, p. 1, Line 7	$17,207
3.	Biodiesel Fuel Oil	HECO-501, p. 1, Line 8	$1,629
4.	Sub. DG Diesel Fuel Oil	HECO-501, p. 1, Line 10	$1,327
5.	TOTAL FUEL OIL EXPENSE		$809,058

Note: Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

2009 TEST YEAR GENERATION

Line		(A) Energy (GWh)	(B) Percent of Net System Input
1.	Sales	7,657.8	
2.	Company Use[1]	16.1	
3.	Sales + NC	7,673.9	
4.	Losses[2]	379.7	
5.	Net System Input	8,053.6	100.00%
6.	- Purchase Power[3]	3,345.6	41.54%
7.	Net HECO	4,708.0	58.46%
7a.	Central Station	4,702.6	58.39%
7b.	Substation DG[4]	5.4	0.07%

[1] No Charge based on 2003-2007 5 year average, 16.1 GWh. (HECO-WP-403, p. 1)
[2] Losses of 4.71% based on 5-year average (2003-2007), (HECO-WP-403, p. 2)
[3] HECO-405, page 6
[4] HECO-405, page 7

Hawaiian Electric Company, Inc.

TEST YEAR FUEL EFFICIENCY

Line			
	ENERGY		
1.	**Company Generated Energy**	4,707.8	Net GWh
2.	**Central Station Generated Energy**	4,702.4	Net GWh
3.	**Steam Generated Energy**	4,669.5	Net GWh
4.	**CT Generated Energy (w/ Diesel)**	31.0	Net GWh
5.	**CT Generated Energy (w/ Biodiesel)**	1.8	Net GWh
6.	**Sub. DG Generated Energy**	5.4	Net GWh
7.	**Test Year Sales**	7,657.8	Net GWh
	FUEL CONSUMPTION		
8.	**Total Fuel Consumed**	50,067,551	MBtu
9.	**Central Station Fuel Consumed**	50,011,467	MBtu
10.	**Steam Fuel Consumed**	49,248,926	MBtu
11.	**CT Fuel Consumed (Diesel)**	727,455	MBtu
12.	**CT Fuel Consumed (Biodiesel)**	35,087	MBtu
13.	**Sub. DG Fuel Consumed**	56,084	MBtu
	HEAT RATE		
14.	**Total Heat Rate**	10,635	Btu/kWh
15.	**Central Station Heat Rate**	10,635	Btu/kWh
16.	**Steam Heat Rate**	10,547	Btu/kWh
17.	**CT Heat Rate (w/ Diesel)**	23,457	Btu/kWh
18.	**CT Heat Rate (w/ Biodiesel)**	19,236	Btu/kWh
19.	**Sub. DG Heat Rate**	10,409	Btu/kWh
20.	**HECO Central Station Generation of Net System Input**	58.39%	Percent
21.	**Sales Heat Rate - Central Station**	0.011185	MBtu/kWh Sales[1]

Reference

[1] 50,011,467 MBtu / (7,657.8 GWh x 58.39% x 1,000,000 kWh/GWh) = 0.011185 MBtu/kWh Sales.

Source: HECO-405, page 1 and 7.

Hawaiian Electric Company, Inc.

HISTORICAL FUEL EFFICIENCY
(Btu/Net kWh)

Line		(A) 2003	(B) 2004	(C) 2005	(D) 2006	(E) 2007	(F) Test Year 2009
1.	**Central Station Steam**	10,413	10,540	10,620	10,540	10,583	10,547 [1]
2.	**Percent Increase**		1.2%	0.8%	-0.7%	0.4%	-0.3%
3.	**Central Station Diesel**	21,081	21,327	20,985	22,716	36,556	23,457 [2]
4.	**Percent Increase**		1.2%	-1.6%	8.3%	60.9%	-35.8%
5.	**Central Station Biodiesel**						19,236 [3]
6.	**Central Station Average**	10,452	10,621	10,690	10,582	10,649	10,635 [4]
7.	**Percent Increase**		1.6%	0.7%	-1.0%	0.6%	-0.1%
8.	**Substation DG**			10,081	10,243	10,525	10,409 [5]
9.	**Percent Increase**				1.6%	2.7%	-1.1%

[1] HECO-403, Line 16.
[2] HECO-403, Line 17.
[3] HECO-403, Line 18.
[4] HECO-403, Line 15.
[5] HECO-403, Line 19.

Hawaiian Electric Company, Inc.

2009 Production Simulation - (Rate Case - 2009 Test Year - Direct Testimony)

Sales and Peak Forecast dated March 2008

2009 Normalized Planned Maintenance Schedule

Fuel Prices April 2008 Contract Prices

	Calibrated (Source: HECO-WP-409)						
	1.013	1.003	0.989	1.203	1.1	1.1	
	Mbtu Consumption						
Month	**Kahe**	**Waiau**	**Honolulu**	**WPP Diesel**	**CIP Diesel**	**Biodiesel**	**Total**
Jan	2,529,819	1,060,856	122,066	23,517	-	-	3,736,258
Feb	2,464,834	873,147	185,886	28,064	-	-	3,551,931
Mar	2,804,363	851,345	145,318	14,106	-	-	3,815,132
Apr	3,059,814	1,125,996	208,254	49,234	-	-	4,443,298
May	2,975,095	1,201,154	227,833	33,859	-	-	4,437,941
Jun	2,834,334	1,027,331	183,341	24,265	-	-	4,069,271
Jul	2,916,083	1,132,401	143,043	55,022	-	-	4,246,548
Aug	3,018,463	1,159,147	238,625	20,338	137,938	-	4,574,511
Sep	3,023,833	1,119,137	219,292	10,927	104,735	-	4,477,922
Oct	3,288,371	948,747	192,281	11,138	90,244	-	4,530,782
Nov	2,814,337	1,074,991	95,809	11,300	107,120	-	4,103,557
Dec	2,942,562	988,403	52,617	5,647	-	35,087	4,024,315
Total	34,671,908	12,562,654	2,014,364	287,418	440,036	35,087	50,011,467
Sub. DG							56,084
HECO w/ DG							50,067,551

	Net MWh Generation							
	Kahe	**Waiau**	**Honolulu**	**WPP Diesel**	**CIP Diesel**	**Biodiesel**	**Total**	**Net Heat Rate**
Jan	245,570	91,786	9,442	568	-	-	347,366	10,756
Feb	241,497	77,448	14,610	737	-	-	334,292	10,625
Mar	274,041	76,515	11,298	380	-	-	362,234	10,532
Apr	300,587	99,859	16,672	1,392	-	-	418,510	10,617
May	293,381	106,191	18,198	975	-	-	418,745	10,598
Jun	278,049	91,544	14,513	594	-	-	384,700	10,578
Jul	287,360	99,787	11,512	1,522	-	-	400,181	10,612
Aug	298,482	102,926	19,169	591	7,286	-	428,454	10,677
Sep	297,265	99,302	17,423	299	5,504	-	419,793	10,667
Oct	323,149	81,794	15,211	343	4,766	-	425,263	10,654
Nov	275,851	93,040	7,398	327	5,591	-	382,207	10,736
Dec	287,315	87,352	3,995	137	-	1,824	380,623	10,573
Total	3,402,547	1,107,544	159,441	7,865	23,147	1,824	4,702,368	10,635
% of Total	72.4%	23.6%	3.4%	0.2%	0.5%	0.0%	100.0%	
Unit Heat Rate	10,190	11,343	12,634	36,544	19,011	19,236		
Sub. DG							5,388	10,409
HECO w/ DG							4,707,756	10,635

Note: Totals may not add exactly due to rounding.

AES Hawaii, Inc

2009 Production Simulation - (Rate Case - 2009 Test Year - Direct Testimony)

Sales and Peak Forecast dated March 2008
2009 Normalized Planned Maintenance Schedule
Fuel Prices April 2008 Contract Prices

	2 Boiler Operation			1 Boiler Operation		
Month	**MWh**	**Hrs**	**Avg MW**	**MWh**	**Hrs**	**Avg MW**
Jan	132,192	734	180.00	0	0	0.00
Feb	89,240	496	179.84	14,893	165	90.00
Mar	114,740	637	180.14	8,510	95	90.00
Apr	128,261	713	179.99	0	0	0.00
May	131,717	732	179.99	0	0	0.00
Jun	127,310	707	179.99	0	0	0.00
Jul	131,976	733	180.00	0	0	0.00
Aug	132,365	735	179.99	0	0	0.00
Sep	126,965	705	179.99	0	0	0.00
Oct	131,847	733	180.00	0	0	0.00
Nov	128,002	711	180.01	0	0	0.00
Dec	131,458	730	180.01	0	0	0.00
Total	1,506,072	8,367	180.00	23,404	260	90.00

Note: Totals may not add exactly due to rounding.

Kalaeloa Partners

2009 Production Simulation - (Rate Case - 2009 Test Year - Direct Testimony)

Sales and Peak Forecast dated March 2008
2009 Normalized Planned Maintenance Schedule
Fuel Prices April 2008 Contract Prices

	2 CT Operation			1 CT Operation		
Month	**MWh**	**Hrs**	**Avg MW**	**MWh**	**Hrs**	**Avg MW**
Jan	122,487	624	196.45	9,840	109	90.00
Feb	113,112	567	199.36	8,510	95	90.00
Mar	121,654	629	193.28	9,308	103	90.00
Apr	15,755	82	192.71	40,513	450	90.00
May	81,218	402	202.10	27,659	307	90.00
Jun	123,339	615	200.67	8,510	95	90.00
Jul	127,638	635	200.90	8,776	98	90.00
Aug	125,800	618	203.69	10,372	115	90.00
Sep	123,557	615	201.02	8,510	95	90.00
Oct	115,896	573	202.17	12,500	139	90.00
Nov	122,402	606	202.06	9,308	103	90.00
Dec	125,086	638	195.97	8,510	95	90.00
Total	1,317,942	6,603	199.58	162,318	1,804	90.00

Note: Totals may not add exactly due to rounding.

HPOWER

2009 Production Simulation - (Rate Case - 2009 Test Year - Direct Testimony)

Sales and Peak Forecast dated March 2008
2009 Normalized Planned Maintenance Schedule
Fuel Prices April 2008 Contract Prices

Month	On-Peak MWh	Off-Peak MWh	Total MWh	NonFirm (Chevron/Tesoro) MWh
Jan	17,658	12,613	30,271	405
Feb	15,804	11,288	27,092	366
Mar	17,710	12,650	30,360	405
Apr	17,079	12,199	29,278	392
May	6,633	4,738	11,371	405
Jun	16,602	11,859	28,461	392
Jul	17,613	12,581	30,194	405
Aug	17,716	12,655	30,371	405
Sep	16,956	12,112	29,068	392
Oct	17,768	12,691	30,459	405
Nov	16,535	11,810	28,345	392
Dec	14,863	10,617	25,480	405
Total	192,938	137,813	330,750	4,768

Note: Totals may not add exactly due to rounding.

Archer PV

2009 Production Simulation - (Rate Case - 2009 Test Year - Direct Testimony)

Sales and Peak Forecast dated March 2008
2009 Normalized Planned Maintenance Schedule
Fuel Prices April 2008 Contract Prices

Month	System Level MWh
Jan	20
Feb	21
Mar	26
Apr	27
May	30
Jun	30
Jul	31
Aug	30
Sep	27
Oct	24
Nov	20
Dec	19
Total	305

IPP Summary

2009 Production Simulation - (Rate Case - 2009 Test Year - Direct Testimony)

Sales and Peak Forecast dated March 2008
2009 Normalized Planned Maintenance Schedule
Fuel Prices April 2008 Contract Prices

	MWh
AES	1,529,476
KPLP	1,480,260
HPOWER	330,750
NonFirm	4,768
Archer PV	305
Total IPP	3,345,559

Substation DG Generation

2009 Production Simulation - (Rate Case - 2009 Test Year - Direct Testimony)

Sales and Peak Forecast dated March 2008
2009 Normalized Planned Maintenance Schedule
Fuel Prices April 2008 Contract Prices

Month	System Level MWh	MBtu
Jan	418	4,351
Feb	455	4,736
Mar	282	2,935
Apr	922	9,597
May	743	7,734
Jun	440	4,580
Jul	903	9,399
Aug	384	3,997
Sep	222	2,311
Oct	213	2,217
Nov	276	2,873
Dec	130	1,353
Total	5,388	56,084
Net Heat Rate (Btu/kWh)	10,409	

Note: Totals may not add exactly due to rounding.

HECO T-5
DOCKET NO. 2008-0083

TESTIMONY OF
RONALD R COX

MANAGER
POWER SUPPLY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Mission and Organization
Fuel Price
Fuel-Related Expense
Fuel Inventory

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name and business address.

A. My name is Ronald Cox and my business address is 475 Kamehameha Highway, Pearl City, Hawaii.

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

A. I am employed by Hawaiian Electric Company, Inc. ("HECO" or "Company") as the Manager, Power Supply Services Department ("PSSD"). My educational background and work experience are given in HECO-500.

Q. What will your testimony cover?

A. My testimony will cover the following:

1) mission and organization of PSSD,
2) fuel prices,
3) fuel-related expense, and
4) fuel inventory.

MISSION AND ORGANIZATION OF PSSD

Q. What is the mission of the PSSD?

A. The mission of the PSSD is fourfold: (1) Negotiate and administer power purchase agreements; (2) Negotiate and administer fuel purchase and distribution agreements; (3) Plan and coordinate fuel deliveries, including pipeline, tanker, and truck shipments; and (4) Assure regulatory compliance related to fuels infrastructure.

Q. Describe the major elements of the PSSD business.

A The PSSD is organized into three divisions and the major elements of work for each are as follows:

Power Purchase Division. This division is responsible for power purchase agreements and policies with Independent Power Producers (IPP's), cogenerators, and Qualifying Facilities for HECO and its two subsidiaries, MECO and HELCO. The Division administers only the HECO power purchase agreements. MECO and HELCO employees administer their respective power purchase agreements.

Fuels Resources Division. This division is responsible for developing and negotiating fuel supply and fuel distribution facilities' contracts in support of the operation of current and proposed utility generating assets; administering fuel supply, fuel storage and fuel transportation contracts; and planning and coordinating fuel supplier deliveries, pipeline and tanker truck shipments, and HECO plant and tank farm fuel inventories. In addition, it plans and coordinates ocean barge deliveries of fuel to support utility operations on Maui, Molokai and the Big Island.

Fuels Infrastructure Division. This division facilitates fuel asset management, assures regulatory compliance related to fuels infrastructure, and supports the initiative to integrate renewable fuels into the HECO fuel system. Additionally, this division provides fuels infrastructure technical support to MECO and HELCO.

Q. What are the priorities of the PSSD?

A. The PSSD supports the corporate goals of ensuring reliable fuel procurement and delivery for current operations while seeking to negotiate new renewable energy contracts with IPP and renewable (biofuels) fuel suppliers to increase the HECO consolidated companies portfolio of renewable energy. More specifically, the department priorities in 2009 are to:

1) Procure biofuels for operational and emission testing for HECO, MECO and HELCO.
2) Procure biodiesel for operational use at HECO's Campbell Industrial Park unit 1 generating unit ("CIP1") and other generating units on the MECO and HELCO systems.
3) Facilitate fuel asset management and ensure compliance with the policies, requirements, and regulations regarding the various fuel delivery and storage infrastructure on the HECO system. Provide fuels infrastructure technical support to MECO and HELCO.
4) Manage the fuel infrastructure transition to accommodate the addition of biofuels and the transition strategy from fossil to biofuels.
5) Conclude power purchase agreements necessary to meet renewable energy portfolio goals and objectives for HECO, MECO and HELCO. Administer and renegotiate, when necessary, existing renewable energy and fossil fuel power purchase agreements.

Q. Is the PSSD taking any steps to mitigate the environmental impact of the increasing use of biofuels?

A. Yes. HECO is aware of the environmental issues arising out of the use of biofuel feedstock, such as palm oil. In conjunction with its commitment in Docket No. 05-0145 to use 100% biofuels in its new generating unit to be installed at Campbell Industrial Park, as reflected in its Joint Stipulation with the Consumer Advocate, HECO undertook a project to develop an environmental policy for sourcing biofuel feedstock. Community meetings were held on Oahu, Big Island and Maui in late June and early July, 2007 to discuss the study's preliminary findings, and receive community feedback on the environmental policy. Additionally, the policy was reviewed by an academic panel that included Alex Farrell, U.C. Berkeley, Michael Hamnett, University of Hawaii, and Pamela Matson and Peter Vitousek, Stanford University. HECO and the Natural Resources Defense Council (NRDC) released the final policy on August 21, 2007, which is intended to ensure that HECO, MECO and HELCO purchase only biodiesel fuel produced from locally grown sustainable feedstocks and palm oil that complies with international standards established by the Roundtable on Sustainable Palm Oil. The final policy placed a priority on research, development, and deployment efforts to jumpstart sustainable local production of agricultural feedstocks for biodiesel fuel. The eight components of the policy are: (1) local feedstock support mechanisms, (2) sourcing requirements for palm oil, (3), baseline criteria for all biodiesel feedstocks, (4) chain of custody tracking for feedstocks and oils, (5) global warming pollution accounting and reporting, (6) establishment of a Biofuels Public Trust Fund, (7) public review and notification, and (8) public progress reporting and contingencies. The "Environmental Policy for the Hawaiian Electric Company's Procurement of Biodiesel from Palm Oil and Locally-Grown Feedstocks, Prepared by HECO and NRDC" can be viewed at www.nrdc.org/energy or http://www.hawaiisenergyfuture.corn/.

Q. Will HECO incur costs to implement this policy?

A. Yes. HECO will hire an independent auditor to certify sustainable practices and trace the biofuel supply throughout the entire supply chain to ensure compliance.

The associated costs will be included in Fuel Handling Expense as explained later in my testimony.

Q. Has HECO taken any steps to implement this policy?

A. Yes. As explained later in my testimony, HECO has entered into a contract with Imperium Services, LLC, for the supply of biofuel for HECO’s CIP1 combustion turbine that will go into service on August 1, 2009. The approval of this contract is the subject of Docket No. 2007-0346, currently pending before the Commission. (As explained later in my testimony, the pricing provisions of this contract are confidential.) The contract contains a provision that provides for a local feedstock incentive. This incentive reflects the State of Hawaii Legislature's intent to "decrease Hawaii's need to import large amounts of oil, and increase import substitution, economic efficiency, and productivity, by increasing the use and development of Hawaii's renewable energy resources through a partnership between the State and private sector." ACT 95 section 1. In addition, the incentive is intended to advance the State's goal of encouraging development of local agriculture by providing a market for locally grown and produced biofuels.

OVERVIEW

Q. What are the normalized 2009 test year estimates for the items in your area of responsibility?

A. The normalized test year estimates in my area of responsibility are:

Test Year 2009

1)	Fuel Price		See HECO-502
2)	Fuel Related Expense	$7,595,000	See HECO-503
3)	Fuel Inventory	$82,683,000	See HECO-505

Q. What are the test year fuel prices?

A. HECO's test year contract prices for Low Sulfur Fuel Oil ("LSFO"), Diesel fuel and Biodiesel are as follows:

- Honolulu LSFO $99.3149/bbl
- Kahe LSFO $99.3149/bbl
- Waiau LSFO $99.3149/bbl
- Waiau Diesel $138.6074/bbl
- CIP-Diesel $138.6074/bbl
- CIP-Biodiesel $232.0913/bbl
- Substation DG-Diesel $138.6074/bbl

See HECO-502 .

Q. How were these prices determined?

A. For test year 2009, the prices for LSFO and diesel fuel to be purchased by HECO are based on the actual April 2008 contract prices from HECO's fuel suppliers, which were the latest available contract prices at the time this testimony was being prepared. Chevron Products Company ("Chevron") and Tesoro Hawaii Corporation ("Tesoro") fuel supply contract pricing provisions have not changed since HECO's 2007 test year rate case, Docket No. 2006-0386. HECO-WP-502, pages 1 and 2 supporting the development of HECO-502 have been provided. The test year biodiesel price is based on an estimate of the April 2008 price had deliveries commenced under the provisions of the Imperium Biodiesel Supply Contract, which I describe further below.

Q. What are the contract prices of LSFO, diesel fuel and biodiesel based on?

A. The LSFO price is based on an index derived from the average daily market price of the Pacific Basin's most commonly traded grade of low sulfur fuel oil, Singapore/Indonesian region low sulfur waxy residue ("LSWR") fuel oil, plus freight and other components including taxes. The LSWR price index reflects a number of market price assessments reported in multiple third-party market price reporting service publications. The LSWR index averages the daily price reporting service publication market price assessments for each day between the 21st day of the second preceding month and the 20th day of the preceding month for the volume of LSFO designated for receipt during that month.

Since HECO plans to receive LSFO from both Chevron and Tesoro in the test year, the Company has weighted the LSFO price based on the recent historical volumes supplied by each. The resulting price is shown in HECO-502.

For diesel fuel, the price is based on an index derived from an average of the daily West Coast Pipeline, Los Angeles California Low Sulfur No. 2 Diesel as reported by a market price reporting service for the reporting period noted above for LSFO (i.e. the 21st day of the second preceding month and the 20th day of the preceding month for the volume designated for receipt during that month) plus other components, including taxes. HECO's diesel purchases in the test year will be supplied by Chevron.

The biodiesel price is based on the Imperium Biodiesel Supply Contract, which is indexed to reflect the daily average commodity exchange futures price of the primary feedstock used for biodiesel production, such as palm oil or soybean oil, plus freight and other components, including taxes. Some minor component price values are estimates, pending actual commencement of deliveries.

Q. Does the biodiesel price reflect the pricing terms of the Imperium Biodiesel Supply Contract?

A. Yes, the test year biodiesel price is a reasonable price representation pursuant to the pending Imperium Biodiesel Supply Contract. The approval of this contract is the subject of Docket No. 2007-0346, currently pending before the Commission. In Docket No. 2007-0346, Protective Order No. 24145, filed April 10, 2008, designated the Imperium Biodiesel Supply Contract pricing provisions as confidential business information, and accorded this information the status of Level Two Confidential Information. The disclosure of Level Two Confidential Information under Protective Order No. 24145 is limited to the Commission and the Consumer Advocate. The test year biodiesel price is a reasonable representative amount for ratemaking purposes, and because the specific pricing formula provisions, calculations and timeframe for the calculations are not disclosed, this amount can be part of the public record in this rate case proceeding. However, in compliance with Protective Order No. 24145, the specific pricing formula provisions, calculations and timeframe for the calculations continue to be confidential business information, the public disclosure of which would likely result in substantial competitive harm to HECO in negotiating terms and conditions for future biodiesel contracts. As such, HECO is willing to provide this detailed pricing information only to the Commission and the Consumer Advocate pursuant to a suitable protective order in the subject rate case proceeding that comports with Protective Order No. 24145 in Docket No. 2007-0346.

Q. When do the existing Chevron and Tesoro fuel supply contracts expire?

A. The two LSFO supply contracts and the diesel fuel supply contract with Chevron expire on December 31, 2014.

Q. When does the existing contract for biodiesel supply with Imperium Services LLC expire?

A. The Imperium Biodiesel supply contract expires on December 31, 2011.

Q. How are these fuel prices used in this proceeding?

A. Fuel prices are used in the calculation of:

1) fuel expense,
2) purchased energy expense, and
3) fuel inventory, which is covered later in my testimony.

Fuel expense is the product of fuel consumption volumes and fuel prices. See pages 1 and 2 of HECO-501. Purchased energy expenses, discussed by Mr. Daniel Ching in HECO T-6, are also calculated using fuel prices. The purchased energy expenses are listed for each independent power producer in HECO-607. Fuel inventory value is the number of barrels of fuel in inventory times fuel prices. See HECO-505.

FUEL-RELATED EXPENSE

Q. What is the total fuel-related expense for the 2009 test year?

A. Estimated 2009 test year fuel-related expenses are $7,595,000, as shown on HECO-503.

Q. What types of costs are included in the test year forecast of fuel-related expenses?

A. Fuel-related expenses include the following:

1) Fuel Handling Expenses: Pipeline Facilities expense,
2) Fuel Handling Expense: Pipeline Maintenance expense,
3) Fuel Handling Expense: Tank Farm Management Fee,
4) Fuel Handling Expense: HECO Fuel Handling expenses,
5) Thruput (LSFO and Diesel Fuel trucking) expense,
6) Petroleum inspection (Petrospect) expense on fuel purchases, and
7) Kahe 6 Fuel Additive expense.

Q. What was the basis for the estimates for fuel-related expenses?

A. The fuel-related expenses are based primarily on internal and third-party costs to operate and maintain HECO's fuel facilities, procure, receive, store and otherwise handle the fuel consumed by HECO's generating units. It also includes (1) diesel transport by truck from Chevron's Honolulu distribution terminal to the various sites of HECO's Substation DG units, (2) LSFO transport from HECO's central storage depot at Barbers Point Tank Farm ("BPTF") via pipelines to HECO's Waiau and Kahe generating stations, (3) LSFO transport by truck from BPTF to Iwilei Tank Farm ("ITF") for subsequent transfer by pipeline to the Honolulu generating station, and (4) the cost of fuel additive for Kahe unit 6 which is necessary for environmental compliance.

Q. Describe the operations of HECO's BPTF.

A. HECO's BPTF receives all LSFO deliveries from suppliers Chevron and Tesoro. Prior to the installation of pumps, piping, valves and related facilities that formed a portion of the installation of the Waiau Fuel Pipeline project, Docket No. 01-0444, LSFO shipments to HECO's Kahe and Waiau generating stations and HECO's ITF could and often did originate from storage tanks in the Chevron refinery.

Q. Describe additional components of HECO's fuel facilities used for the distribution of LSFO from HECO's BPTF.

A. HECO's fuel facilities also includes HECO Kahe pipeline which is utilized to deliver LSFO from BPTF to HECO's Kahe generating station and the HECO Waiau pipeline (which went into service December 2004) which is utilized to deliver LSFO from BPTF to HECO's Waiau generating station. HECO delivers LSFO from BPTF to HECO's ITF via trucks loaded from a truck loading system installed at BPTF as part of the Waiau Fuel Pipeline Project (the service commenced January 2005). From the ITF, fuel is delivered to the Honolulu Power Plant through an existing HECO 6-inch fuel pipeline.

Also, as part of the Waiau Fuel Pipeline Project, a diesel storage tank and diesel truck unloading facility was installed in BPTF for emergency displacement of the Kahe and/or Waiau pipelines to prevent heated LSFO from cooling and solidifying inside the pipelines.

Q. Please describe how HECO's fuel facilities will be operated and maintained in the test year.

A. Operation and maintenance of HECO's fuel facilities will be as follows:

<u>Barbers Point Tank Farm</u>

Chevron was contracted under the terms of the "Operations and Maintenance Agreement," dated December 14, 2004, to provide:

1) LSFO delivery coordination services into HECO's BPTF,
2) Operations and maintenance of BPTF, Waiau and Kahe pipelines, including the leak detection system for those pipelines,
3) Gauging and sampling BPTF tanks outside of custody transfer (fuel purchase) transactions (fuel purchase gauging and sampling is performed by a third-party petroleum inspection service),
4) Fuel inventory and transfer accounting and reporting services,
5) Preparation and maintenance of all documents, records and procedures required by the U.S. Department of Transportation,
6) Pipeline right-of-way inspections and maintenance required by federal regulations,
7) Laboratory services, and

8) Safety and emergency response training of contractors, subcontractors and HECO personnel working at the BPTF facility.

Chevron was also contracted under the terms of the "Barbers Point Tank Farm Services Agreement," dated December 14, 2004, to provide low pressure steam to BPTF tank heaters for steam tracing and to provide fire protection water and services. These two contracts are the successor agreements to the "Facilities and Operations Contract" between Chevron and HECO under which HECO used certain Chevron refinery support infrastructure, facilities and the Chevron Black Oil pipeline, and Chevron also provided operations and maintenance services of HECO's BPTF and Kahe pipeline.

There have been no changes to the Operations and Maintenance Agreement or the Barbers Point Tank Farm Services Agreement since HECO's 2007 test year rate case, Docket No. 2006-0386. Contract administration, including oversight of Chevron's operating and maintenance services, is performed by HECO's Fuels Infrastructure Division.

<u>HECO's Kahe Fuel Pipeline</u>

There are no changes planned for the operation of the 5.144 mile un-insulated Kahe pipeline. Kahe will continue to primarily utilize high pour point/high viscosity LSFO (to the extent product quality segregation can be maintained at BPTF) and the pipeline will operate in the continuous flow mode.

<u>HECO's Waiau Fuel Pipeline</u>

There are no changes planned for the operation of the 12.804 miles insulated Waiau pipeline. Waiau will continue to primarily utilize low pour point/low viscosity LSFO (to the extent product quality segregation can be practically maintained at BPTF) and the pipeline will operate in the continuous flow mode.

Delivery to HECO's Iwilei Tank Farm

Truck loading facilities at BPTF allow for the loading of approximately 130 barrels of low pour point/low viscosity LSFO (to the extent product quality segregation can be maintained at BPTF) into trailer mounted cradled container tanks. These tanks are filled by a truck driver with site and loading system access through an automated security system which generates product loading documents and is monitored by Chevron refinery personnel. The driver and equipment for delivery of LSFO from BPTF to ITF are provided by Bering Sea Eccotech, Inc. ("BSE") under the terms of a trucking freight contract dated November 24, 2004. Discharge of the LSFO into a storage tank at ITF is controlled by the BSE truck driver through an automated system. The day-to-day operations and oversight of the delivery of fuel from ITF to the Honolulu generating station via the HECO pipeline dedicated for this use will continue to fall under Honolulu Plant Operations.

Facilities Base Expense

Q. What is HECO's cost estimate of the Facilities Base Expense in the test year?

A. HECO's cost estimate of the Facilities Base Expense for the HECO Kahe Pipeline and the HECO Waiau Pipeline in the test year is $3,029,000. See HECO-504.

Q. Please explain the basis for the portion of HECO's cost estimate of the Facilities Base Expense that pertains to the HECO Kahe Pipeline in the test year.

A. As shown in HECO-504, the portion of the Facilities Base Expense for the HECO Kahe Pipeline is $868,000. This cost is based on two components. First an allocated portion of the average historical cost of the pipelines "Base Fee" actually incurred for years 2005, 2006 and 2007, under the terms and conditions of the HECO-Chevron "Operations and Maintenance Agreement," adjusted to 2009 dollars totaling $631,000 as shown on HECO-WP-504. The historical costs serve as a reasonable basis for estimates of test year costs.

The Base Fee which is subject to allocation between the Kahe and Waiau pipelines consists of a fixed portion, $48,986 per month (total monthly charge before proration), and a portion subject to escalation.

The portion of the Base Fee subject to escalation when the agreement commenced had a value of $114,302 per month (total monthly charge without escalation before proration). Thereafter, this amount is escalated quarterly based on the increase in quarterly average hourly earnings for the petroleum and coal products industry compared to a base period value, as published by the U.S. Bureau of Labor Statistics.

The actual average 2005-2007 charges (converted to same-year dollars by the Gross Domestic Product Implicit Price Deflator (GDPIPD)) are further adjusted to 2009 dollars by applying the U.S. Department of Energy (DOE)/Energy Information Administration forecast for the GDPIPD published in the May 2008 edition of the "Short Term Energy Outlook."

The portion of the Base Fee allocated respectively to the Kahe and Waiau pipelines is determined by reference to the length of the Kahe Pipeline, 5.144 miles, compared to the combined length of the Kahe and Waiau pipelines operated and maintained by Chevron (5.144 miles + 12.804 miles = 17.948 miles).

The second component of the Facilities Base Expense for the Kahe Pipeline is $237,000, which is a prorata share of the $1,694,000 HECO 2009 budgeted non-facilities Fuel Handling Expenses. The derivation of the prorata share of the non-facilities fuel handling expense is shown on HECO-WP-511.

The Base Fee nominal amount, escalation methodology, use of three year period to normalize incurred historical costs, and the non-facilities fuel handling expense proration methodology used to determine 2009 test year expenses have not changed since HECO's 2007 test year rate case, Docket No. 2006-0386**.**

Q. Please explain the basis for the portion of HECO's cost estimate of the Facilities Base Expense that pertains to the HECO Waiau Pipeline in the test year.

A. The portion of the Facilities Base Expense for the HECO Waiau Pipeline is $2,161,000. See HECO-504. This cost is based on two components. First an allocated portion of the average historical cost of the pipelines "Base Fee" actually incurred for years 2005, 2006 and 2007 under the terms and conditions of the HECO-Chevron Operations and Maintenance Agreement, adjusted to 2009 dollars totaling $1,570,000 as shown on HECO-WP-505. The historical costs serve as a reasonable basis for estimates of test year costs.

The Base Fee consists of a fixed portion, $48,986 per month (total monthly charge before proration), and a portion subject to escalation.

The portion subject to escalation is treated in the same way as the escalated portion of the Base Fee for the HECO Kahe Pipeline that I described above.

The total pipeline fee proration for the Waiau Pipeline is also derived using the same method that I described regarding the Kahe Pipeline, namely dividing the length of the Waiau Pipeline by the combined length of both pipelines.

The second component of the Facilities Base Fee Expense for the Waiau Pipeline is $591,000, which is the prorata share of the HECO non-facilities Fuel Handling Expenses as described regarding the Kahe Pipeline. The derivation of the prorata share of the non-facilities fuel handling expense is shown on HECO-WP-511.

The Base Fee nominal amount, escalation methodology, use of three year period to normalize incurred historical costs, and the non-facilities fuel handling expense proration methodology used to determine 2009 test year expenses have not changed since HECO's 2007 test year rate case, Docket No. 2006-0386.

Pipeline Maintenance Expense

Q. What is HECO's cost estimate of the Pipeline Maintenance Expense in the test year?

A. HECO's cost estimate of the Pipeline Maintenance Expense for the HECO Kahe Pipeline and the HECO Waiau Pipeline in the test year is $713,000. See HECO-504.

Q. Please explain the basis for the portion of this cost estimate which pertains to the HECO Kahe Pipeline in the test year.

A. The portion of the Kahe Pipeline Maintenance Expense is $602,000. See HECO-504. This cost is based on two components. The first component is the average historical Kahe Pipeline non-base/variable maintenance costs incurred for years 2005, 2006 and 2007 under the terms and conditions of the HECO-Chevron "Operations and Maintenance Agreement," converted to same-year dollars via the GDPIPD, totaling to $437,000 as shown on HECO-WP-506. The historical costs serve as a reasonable basis for estimates of test year costs.

The actual average 2005-2007 charges (converted to same-year dollars via the GDPIPD) are further adjusted to 2009 test year dollars by applying the U.S. DOE/EIA forecast for the GDPIPD published in the May 2008 edition of the "Short Term Energy Outlook."

The second component of the Kahe Pipeline Maintenance Expense is $164,000, which is a prorata share of the HECO non-facilities Fuel Handling

Expenses applied to Pipeline Maintenance Expense for the HECO Kahe Pipeline as shown on HECO-WP-511.

The use of a three-year period to normalize incurred historical cost, methodologies employed to convert historical expense to test year expense and HECO Fuel Handling Expenses proration methodology have not changed since HECO's 2007 test year rate case, Docket No. 2006-0386.

Q. Please explain the basis for the portion of this cost estimate which pertains to the HECO Waiau Pipeline in the test year.

A. The portion of the Waiau Pipeline Maintenance Expense is $111,000. See HECO-504. This cost is based on two components. The first component consists of the average historical Waiau Pipeline non-base/variable maintenance costs incurred for years 2005, 2006 and 2007 under the terms and conditions of the HECO-Chevron "Operations and Maintenance Agreement," converted to same-year dollars via the GDPIPD, totaling to $81,000 as shown on HECO-WP-507. The historical costs serve as a reasonable basis for estimates of test year costs.

The actual average 2005-2007 charges (converted to same-year dollars via the GDPIPD) are further adjusted to 2009 test year dollars by applying the U.S. DOE/EIA forecast for the GDPIPD published in the May 2008 edition of the "Short Term Energy Outlook."

The second component of the Waiau Pipeline Maintenance Expense is $30,000, which is a prorata share of the HECO non-facilities Fuel Handling Expenses applied to Pipeline Maintenance Expense for the HECO Waiau Pipeline as shown on HECO-WP-511.

The use of a three-year period to normalize incurred historical cost, methodologies employed to convert historical expense to test year expense and

HECO Fuel Handling Expenses proration methodology have not changed since HECO's 2007 test year rate case, Docket No. 2006-0386.

<u>Tank Farm Management Fee</u>

Q. What is HECO's cost estimate of the Tank Farm Management Fee in the test year?

A. HECO's cost estimate of the Tank Farm Management Fee in the test year is $2,455,000. See HECO-504.

Q. Please explain the basis for this cost estimate.

A. The estimated cost of $2,455,000 for the operations, maintenance and provision of services for HECO's BPTF is comprised of several individual components including the Tank Farm Base Fee, Low Pressure Steam Expense, Tank Farm non-base/variable Maintenance Expense, these totaling $1,784,000, and a $671,000 prorata share of HECO non-facilities Fuel Handling Expense.

Q. Please explain the basis for the portion of HECO's BPTF operations, maintenance and services costs that pertain to the test year Tank Farm Base Fee.

A. The portion of the Tank Farm Management Fee that pertains to the Tank Farm Base Fee is $332,000 as shown on HECO-WP-508. This component is based upon the average historical cost of the BPTF "Base Fee" actually incurred for the years 2005, 2006 and 2007, under the terms and conditions of the HECO-Chevron Barbers Point Tank Farm Services Agreement, dated December 14, 2004, adjusted to 2009 dollars. The historical costs serve as a reasonable basis for estimates of test year costs.

The Base Fee consists of a fixed $23,156 per month and a portion subject to escalation.

The portion subject to escalation was valued at $1,219 per month at the commencement of the agreement. Thereafter, this amount is escalated quarterly based on the increase in quarterly average hourly earnings for the petroleum and coal products industry published by the U.S. Bureau of Labor Statistics compared to a base period value.

The actual average 2005-2007 charges (converted to same-year dollars via the GDPIPD) are further adjusted to 2009 dollars by applying the U.S. DOE/EIA GDPIPD forecast published in the May 2008 edition of the "Short Term Energy Outlook."

The base period amount, escalation methodology, use of a three-year period to normalize incurred historical cost, methodologies employed to convert historical expense to test year expense have not changed since HECO's 2007 test year rate case, Docket No. 2006-0386.

Q. Please explain the basis for the portion of HECO's BPTF operations, maintenance and services costs that pertain to the test year low pressure steam expense.

A. The portion of the Tank Farm Management Fee that pertains to the cost of low pressure steam provided to the storage tanks and piping heat tracing systems is $622,000 as shown on HECO-WP-509. This component is based upon the average historical purchase cost of low pressure steam actually incurred for the years 2005, 2006 and 2007, under the terms and conditions of the HECO-Chevron Barbers Point Tank Farm Services Agreement, dated December 14, 2004. The historical costs serve as a reasonable basis for estimates of test year costs.

The actual average 2005-2007 expenses (converted to same-year dollars by the GDPIPD) are further adjusted to 2009 test year dollars by applying the U.S.

DOE/EIA forecast for the GDPIPD published in the May 2008 edition of the "Short Term Energy Outlook."

The use of a three-year period to normalize incurred historical costs and methodologies employed to convert historical expense to test year expense have not changed since HECO's 2007 test year rate case, Docket No. 2006-0386.

Q. Please explain the basis for the portion of HECO's BPTF operations, maintenance and services that pertain to the test year Tank Farm non-base/variable Maintenance Expense.

A. The portion of the Tank Farm Management Fee that pertains to non-base/variable maintenance expense is comprised of several components, the total of which is $830,000. The first component is the average historical cost of non-base/variable maintenance (on-going routine maintenance and repair of support infrastructure such as piping, pumps, heaters and instrumentation) HECO's BPTF incurred for each of the years 2005, 2006 and 2007 under the terms and conditions of the HECO-Chevron Operations and Maintenance Agreement, is converted to same-year dollars via the GDPIPD, totaling to $686,000 as shown on page 1 of HECO-WP-510. These historical costs serve as a reasonable basis for estimates of test year costs for activities of this type.

The actual average 2005-2007 charges (converted to same-year dollars by the GDPIPD) are further adjusted to 2009 test year dollars by applying the U.S. DOE/EIA forecast for the GDPIPD published in the May 2008 edition of the Short Term Energy Outlook.

Unlike the case for pipelines, where in-line inspection and major maintenance occurs every 2 to 3 years (thus the 3-year normalization period used to average historical pipeline and related costs), the timing of major maintenance at BPTF requires normalization over longer periods. Typical major maintenance activity at BPTF consists of such activities as tank cleaning, bottom thickness inspection and measurement, bottom plate repair, bottom/lower side wall epoxy coating and other related maintenance and repairs to the three fuel storage tanks in the facility. This inspection/maintenance/repair cycle was estimated at 12 years in Docket No. 2006-0386, but currently is forecast at 13 years.

Q. Why did the normalization period change?

A. The three BPTF LSFO storage tanks last went through the major clean, inspect, maintenance, and repair cycle in 1995, 1996 and 1997, respectively. They are scheduled to repeat this maintenance cycle in 2007-2008, 2009, and 2010, respectively. Each tank requires approximately 12 months to complete cleaning, inspection, maintenance and repair.

However, tank 131 inspection in 2007 revealed significant tank bottom corrosion. The recommended repair was installation of an “El Segundo” style double bottom, with secondary containment and leak detection features. This bottom replacement was approved on May 15, 2008 in Commission Decision and Order No. 24228 in Docket No. 2007-0409. The project work will continue through the remainder of 2008, with an estimated return to service date in early 2009. Tanks 133 and 132 cleaning, inspection, maintenance and repairs are currently planned to follow in 2009 and 2010, respectively.

The non-capital tank maintenance and repair cost component included in the Tank Farm Services expense for maintenance and repair work being performed Tank 131 is based on an engineering operations and maintenance budget estimate of $866,348, which includes such activities as tank insulation removal, tank shell top and side shell preparation and repair, inspection services, fire and safety watch, administrative, engineering, and operations and maintenance support costs. The installation of a double-bottom of this design and the extensive amount of other corrosion mitigation maintenance and repair work being performed on Tank 131 is expected to extend the inspection/maintenance/repair cycle to 20 years. Therefore, the total non-capital Tank 131 tank maintenance and repair cost included in the Tank Farm Services expense for maintenance and repair work being performed is normalized over a period a 20 year period converted to 2009 dollars is $45,068 as shown on page 2 of HECO-WP-510.

The component for tank maintenance and repair cost included in the Tank Farm Services expense for the maintenance and repair of Tank 132 and Tank 133 is the actual annual amounts of such major maintenances actually incurred in the years 1996 and 1997 normalized over a 13 year inspection cycle, and adjusted to 2009 dollars using the GNPIPD in the manner described earlier in this testimony is $99,069 as shown on page 2 of HECO-WP-510.

Except for the revised periodicities noted above for normalization of historical costs, methodologies employed to convert historical expense to test year expense have not changed since HECO’s 2007 test year rate case, Docket No. 2006-0386.

Q. Please explain the basis for the portion of HECO’s BPTF operations, maintenance and services that pertain to the test year Fuel Handling Expense.

A. The portion of the Tank Farm Services that pertains to a prorata share of the $1,694,000 HECO 2009 budgeted Fuel Handling Expenses is $671,000 as shown on HECO-WP-511.

HECO Fuel Handling Expense

Q. What is HECO's cost estimate of the test year internal Fuel Handling Expense prorated to Facilities Base Fee, Pipeline Maintenance and Tankfarm Management Fee as previously discussed in my testimony?

A. HECO's cost estimate of the internal fuel handling expense in the test year is $1,693,614.

Q. Please explain the basis for this cost estimate.

A. The estimated cost of $1.694 million for internal fuel handling operations within HECO are comprised of four components including HECO Information Technology & Services Department labor and non-labor expenses, the labor and non-labor expenses each of HECO Fuels Resources and HECO Fuels Infrastructure divisions personnel, allocated PSSD supervisory overhead, and HECO Operations & Maintenance personnel labor and non-labor expenses.

Q. Please explain the basis for the portion of HECO's cost estimate for internal Fuel Handling Expenses that pertains to HECO Information Technology & Services Department labor and non-labor expenses.

A. The portion of the internal Fuel Handling Expenses that pertains to HECO Information Technology & Services Department labor and non-labor expenses is $42,600 as shown on HECO-WP-511. This includes charges by the HECO Information Technology & Services Department for software licenses, hardware and other non-labor charges incurred for the maintenance of the Fuel Management and Reporting System (FMRS). The FMRS converts and reports tank reading data including liquid height gauges, product temperature, and product density into temperature corrected tank and plant inventory volumetric data, pipeline shipment received volumes, and plant consumption volumes. It combines data inputs on purchased and shipped LSFO and diesel heat content with data inputs on unit watt-hour meter readings to compute and report plant gross, auxiliary and net generation in KWh, system BTU consumption, and related heat rate values.

Q. Please explain the basis for the portion of HECO's test year internal Fuel Handling Expenses costs that pertains to the labor of the Fuels Resources Division, Fuels Infrastructure Division personnel and supervisory overhead.

A. The portion of the internal Fuel Handling Expenses that pertains to HECO Fuels Resources Division, Fuels Infrastructure Division and PSSD supervisory overhead is $954,000, $258,000 and $9,700, respectively, as shown on HECO-WP-511. This includes the labor and related overheads of the Fuels Resources and Fuels Infrastructure personnel that manage HECO fuel procurement, fuel supply planning, fuel distribution operations, fuel supply contracts, fuel facilities services contract administration, fuel facilities condition assessment for regulatory compliance, maintenance planning, oversight of fuel facilities maintenance and repair. Labor and overheads for work performed for the Maui, Molokai and Lanai divisions of MECO and for HELCO are excluded.

It includes the activities of the Manager of Power Supply Services (allocated portion), Director of Fuels Resources, Director of Fuels Infrastructure, two Fuel Contract Administrators, two Staff Engineers, and other administrative personnel.

Q. Please explain the basis for the portion of HECO's test year internal Fuel Handling Expenses costs that are non labor expenses.

A. Major elements of the non-labor costs included in HECO Fuel Handling Expenses include petroleum inspection expense incurred for the gauging of intra-facility pipeline shipments and power plant storage tanks on a periodic basis. Prior to 2005 the cost of petroleum inspection fees on intra-facility shipments was recovered via the Energy Cost Adjustment mechanism because the fees were incurred to determine the shipment volumes for throughput charges which were levied by Chevron under the terms of the then applicable HECO-Chevron Facilities and Operations Contract.

Also included in the non-labor expense of the Fuels Resources Division are costs necessary to support the operations of BPTF and ITF multi-shift fuel shipment activity. The one-shift security service provided by Chevron for BPTF and ITF under the provisions of the HECO-Chevron Operations and Maintenance Agreement, proved inadequate to accommodate trucking operations on a three-shift, weekend and holiday basis. In addition, there was a need for increased security at ITF because of the installation of substation DG units on site and the need for higher levels of security service for the Utility's critical infrastructure. This increased security service requirement included consistent security clearance management for contractor personnel and emergency response procedure integration with security for HECO's generating plants, substations, pipeline rights-of-way and other facilities.

Q. What other types of services are included in the non-labor expenses that are part of HECO Fuel Handling Expense?

A. HECO Security provides safety and emergency response training and oversight to HECO personnel and contractors entering the BPTF site. The unexpected high level of trucking activity (about 2,300 truck shipments in calendar year 2006 and 2,800 individual truck shipments in calendar year 2007) resulted in a large number of truck loading and truck discharging operations, increasing the risk of oil spills or machinery breakdown. Fuel Handling non-labor expense includes the cost of a maintenance contractor retained by the Fuels Resources Division who provides oversight of proper load and discharge operations by trucking personnel and assesses the equipment conditions and responds to equipment and machinery breakdown outside of normal work hours.

Also included in the Fuels Resources Division Fuel Handling Expenses is the estimated cost for Biodiesel HECO-NRDC Sustainability Certification/Audit Expense. HECO is committed to using 100% biodiesel in CIP1. In August 2007, HECO adopted the Environmental Policy for the Hawaiian Electric Company's Procurement of Biodiesel from Palm Oil and Locally-Grown Feedstock (Environmental Policy). This document, jointly authored by the Natural Resources Defense Council (NRDC) and HECO, defines how HECO will procure sustainably-produced palm oil and provides that locally-sourced feedstock shall be procured as a biofuel feedstock. HECO will hire an independent auditor to certify sustainable practices and trace the biofuel supply throughout the entire supply chain to ensure compliance. Performance under the biodiesel procurement contract has not yet begun.

Q. Please explain the basis for the portion of HECO's cost estimate for internal Fuel Handling Expenses that pertains to the labor and non-labor of the personnel of the HECO Power Supply Operations and Maintenance Department in the test year.

A. The portion of HECO Fuel Handling Expenses that pertains to the labor and related overheads of the Power Supply Operations and Maintenance Department personnel reflect the activities of the Utility Operators and Shift Supervisors who perform tasks related to the receipt of pipeline shipments at the Kahe, Waiau and Honolulu generating stations, such as coordinating shipment receiving tank piping and valve line ups with Chevron control operators, measuring and recording liquid heights in HECO Plant and ITF tanks (not related to fuel purchase transactions or otherwise taken by Petrospect personnel), measuring and recording product temperatures in storage tanks, mixing post-receipt tank contents and taking samples of tank contents for delivery to the HECO Chemistry lab. This labor and overhead expense was based upon the actual labor hours of HECO personnel charged to such activities in recent years. Historic activity is considered a reasonable basis for estimates of test year costs. The total HECO Fuel Handling Expense is applied on a prorata basis to each area of fuel facilities HECO Fuel Handling Expense (Base Facilities, Kahe Pipeline, Waiau Pipeline, and Tank Farm) as shown on HECO-WP-511. This is consistent with previous HECO rate case expense methodology.

<u>Fuel Trucking Expense</u>

Q. What is HECO's cost estimate of the Fuel Trucking Expense in the test year?

A. HECO's cost estimate of the Fuel Trucking Expense in the test year is $1,191,000. See page 2 of HECO-503.

Q. Please explain the basis for this cost estimate.

A. The estimated cost of $1.191 million includes costs for the following services: trucking LSFO from BPTF to ITF; trucking diesel purchased from Chevron from its truck loading facility at the Honolulu Distribution Terminal to various Substation Distributed Generation (DG) sites; trucking diesel purchased from Chevron from its truck loading facility at the Honolulu Distribution Terminal to BPTF for diesel stored there and used for emergency displacement of the HECO Kahe or HECO Waiau Pipelines, or to be consumed by the new CIP1 generating unit during its warranty and performance testing phase of operations and prior to the approval of air permit modifications to allow biodiesel use.

Q. Please explain the basis for the portion of the test year cost estimate for HECO Trucking Expense that pertains to the transportation of LSFO from BPTF to ITF.

A. The portion of the HECO Trucking Expense for the transport of LSFO from BPTF to ITF is $1.009 million in the test year as shown on page 2 of HECO-503. LSFO is transported by truck to ITF under the terms of a trucking freight contract between HECO and Bering Sea Eccotech, Inc. (BSE) dated November 24, 2004. The contract provides for two types of trucking freight rates. The first rate is not subject to escalation. The second rate is an overtime rate based on aggregate annual volume for hours outside of 0600 hours to 1800 hours business weekdays. It is fixed at $3.15 per barrel. The other type of freight rate, applicable to “normal” operating hours and days, changes (moves to a lower rate) on the basis of annual aggregate volume thresholds of 105,000 barrels and 200,000 barrels trucked annually and are subject to a stipulated annual rate of escalation of 1.5%. Annual rates are subject to tariff approval by the Hawaii Public Utilities Commission (see Local Specialized Freight Tariff 14, Section 4, Part D, Item 6405). In lieu of attempting to forecast shipments trucked during “normal” and other than “normal” hours, the test year estimated cost is based on the historic cost per barrel of LSFO shipped during calendar year 2007 plus 2.5%. This per unit cost is multiplied by the test year consumption for HECO’s Honolulu Plant to derive the test year LSFO trucking cost.

Q. Please explain the basis for the portion of the test year cost estimate for HECO Trucking Expense that pertains to the transportation of diesel from Chevron’s Honolulu loading facility to HECO’s Substation DG unit sites.

A. The portion of the HECO Trucking Expense for the transport of diesel from Chevron’s Honolulu Distribution Terminal to the various sites of HECO’s

Substation DG units is $20,000 as shown on page 2 of HECO-503. Fuel consumed by the DG units at the various sites is purchased under the terms of an existing contract between Chevron and HECO which provides for the purchase of diesel at the truck loading facility of Chevron's Honolulu Distribution Terminal (HDT) in Iwilei. The diesel is transported from Chevron's facility to the various DG sites including ITF, HECO's Ewa Nui substation, HECO's Helemano substation, HECO's "Pole Yard" (adjacent to the IPP, Kalaeloa Partners Limited Partnership generating facility located within the Campbell Industrial Park) and HECO's Campbell Industrial Park Substation under the terms of a contract between HECO and D&K Petroleum, Inc. (dba D&K Trucking) a local Oahu petroleum wholesaler. Such shipments are supplemented from time to time by deliveries made by petroleum transporter Yamashiro Trucking (if D&K equipment is not available or does not have sufficient capacity) under an open purchase order control mechanism.

Both D&K Trucking and Yamashiro Trucking rates are subject to tariff approval by the Hawaii Public Utilities Commission (see Local Specialized Freight Tariff 14, Section 4, Part D, Item 6695). Because the Substation DG units are dispatched as a single unit for fuel consumption forecasting purposes, the test year estimated cost is based on the historic cost per barrel of diesel shipped to all HECO DG sites during the period April 2007 – March 2008 plus 2.5%. This per unit cost is multiplied by the test year consumption for HECO's Substation DG units to derive the test year Substation DG diesel trucking cost.

Q. Please explain the basis for the portion of the test year cost estimate for HECO Trucking Expense that pertains to the transportation of diesel from Chevron's Honolulu loading facility to HECO's BPTF.

A. The portion of the HECO Trucking Expense for the transport of diesel from Chevron's Honolulu Distribution Terminal to storage tanks at the BPTF, where it is forecast to be consumed in the CIP1 during the test year, is $162,000 as shown on page 2 of HECO-503. Fuel for the new CIP1 located at BPTF is assumed to be purchased under the terms of the existing contract between Chevron and HECO which provides for the purchase of diesel at Chevron's Honolulu Distribution Terminal ("HDT") truck loading facility in Iwilei.

As is the case for diesel purchased for consumption by HECO's Substation DG units, it is assumed that the majority of diesel for CIP1 is expected to be transported from Chevron's facility by Yamashiro Trucking in loads of approximately 8,000 gallons each. The diesel freight cost was estimated on the basis of averaging actual invoices received from Yamashiro Trucking for the transportation of approximately the same volume of diesel (loads of 8,000 gallons) from Chevron's Honolulu facility to a HECO Substation DG site, HECO's "Pole Yard," which is located a few blocks from the current entrance to BPTF on Hanua Street. This per unit cost is multiplied by the test year consumption for HECO's CIP1 to derive the test year CIP1 diesel trucking cost.

<u>Petroleum Inspection (Petrospect) Expense</u>

Q. What is HECO's cost estimate of the Petroleum Inspection (Petrospect) Expense that is being passed through the ECAC in the test year?

A. HECO's cost estimate of the Petroleum Inspection (Petrospect) Expense in the test year is $102,000. See page 3 of HECO-503.

Q. Please explain the basis for this cost estimate.

A. The use of an independent third-party petroleum inspection service to measure the change in storage tank heights and product temperature for the determination of the volume of LSFO and diesel purchased in bulk by HECO from Chevron and Tesoro is a long-term requirement of the terms of HECO's fuel supply contacts with each of the parties, as approved by the Hawaii Public Utilities Commission. In each case, the selection of the particular petroleum inspection service vendor is a joint decision between HECO and Tesoro or Chevron, respectively, and the charge of the petroleum inspector is accordingly shared on an equal basis between the companies.

The estimated expense for petroleum inspection services performed by Petrospect, Inc. under the terms of a contract between Petrospect and HECO dated July 8, 2005, is based upon the actual petroleum inspection charges incurred in relation to actual fuel purchases from Chevron and Tesoro made during calendar year 2007. A "costing" rate was computed on the basis of the petroleum inspections fees actually incurred and the volume of fuel purchased from each supplier and these costing rates were then applied to the fuel consumption volumes forecast for the test year, adjusted to 2009 dollars as shown on HECO-WP-503.

The costing rate applied to the forecasted Honolulu, Waiau, and Kahe power plant LSFO volumes was derived from individual LSFO costing rates for purchases from Chevron and Tesoro. It is then weighted based on the relative LSFO purchase volumes from Chevron and Tesoro for calendar year 2007, employing the same methodology used to derive LSFO price as shown on HECO-WP-503.

A separate costing rate for Chevron diesel fuel purchases for delivery to HECO storage at the Waiau plant was similarly developed from actual costs incurred for diesel fuel purchases delivered by pipeline to the Waiau plant during

2007, adjusted to 2009 dollars and applied to the forecast diesel consumption of the Waiau plant. Since purchases of diesel fuel for the Substation DG units and purchases of diesel and biodiesel for the new CIP1 unit are delivered by tanker truck, Petrospect expenses will not apply. Historic activity is considered a reasonable basis for test year cost estimates. The methodology to derive costing rates for LSFO and Diesel Fuel purchases and their application to forecast HECO plant consumption is consistent with that employed in HECO's 2007 test year rate case, Docket No. 2006-0386.

Kahe 6 Fuel Additive Expense

Q. What is HECO's cost estimate of the Kahe 6 Fuel Additive Expense that is being passed through the ECAC in the test year?

A. HECO's cost estimate of the Kahe 6 Fuel Additive Expense in the test year is $105,000. See page 1 of HECO-503.

Q. Please explain the basis for this cost estimate.

A. The estimated test year expense of calcium nitrate additive necessary to control air emissions within the regulatory and permitting requirements pertaining to the operation of generating unit Kahe 6 is based upon its test year generation expressed in gallons of LSFO equivalent (655,791 MWh, which equates to 6,834,002 MBtu, which in turn equates to 46,294,852 gallons). See HECO-WP-512. Based upon technical research and field testing, confirmed by actual experience, the fuel additive dosage is estimated at 1 gallon of additive per 4,000 gallons of LSFO consumed – which equates in the test year to 11,574 gallons of additive usage. The estimated cost of the additive delivered to plant, ocean shipping to Hawaii and truck transport to the Kahe Plant's stores/warehouse was based upon the most recent actual purchase. Including application of related taxes, the cost is approximately $9.039 per gallon.

The methodology to derive fuel usage, additive dosage rates, additive volume and the application of historical expense is consistent with the methodology used in HECO's 2007 test year rate case, Docket No. 2006-0386.

FUEL INVENTORY

Q. What is the test year estimate of fuel inventory?

A. The estimated base case fuel inventory is $82,683,000. This inventory value is based on the average of the beginning test year fuel inventories, 761,694 bbls of LSFO, with a value of $75,754,000, and 31,624 bbls of diesel fuel, with a value of at $4,399,000, and the ending year fuel inventories, comprising the same volume and value of LSFO and 29,266 bbls of biodiesel with a value of $6,792,000, and 19,144 bbls of Diesel Fuel with a value of $2,668,000. See HECO-505.

<u>LSFO Inventory</u>

Q. How was the amount and value of LSFO inventory determined?

A. The LSFO inventory amount and value were determined from a 35-day inventory. HECO proposed a 35-day LSFO inventory amount in a previous rate case (test year 2005, Docket No. 04-0113) based on a conclusion in its December 2003 Fuel Inventory Study.

Q. Did the Commission accept this 35-day inventory amount for inclusion in its rate base?

A. Yes. The Settlement Letter executed by HECO, the Consumer Advocate and the Department of Defense ("DOD") in Docket No. 04-0113 stated the following in paragraph 16.c. (Fuel Inventory):

There are no differences with respect to the methodology used to calculate LSFO and diesel fuel inventory. For purposes of settlement, the Consumer Advocate and the DOD have accepted HECO's estimated test year fuel amounts and fuel prices. For purposes of settlement, the Consumer Advocate and the DOD also accept HECO's estimated fuel inventory amounts, including HECO's revised diesel fuel inventory based on updated 5-year data.

Interim Decision and Order No. 22050 effectively accepted the inventory amount as it stated on page 7, "Where the Parties agree, we accepted such agreement for purposes of this Interim Decision and Order." In Decision and Order No. 24171, issued on May 1, 2008, in Docket No. 04-0113, the Commission accepted HECO's 35-day LSFO inventory amount in rate base.

Q. How was the 35-day value used to determine the total LSFO inventory volume and value?

A. The 35-day value was multiplied by the average daily fuel consumption rate to arrive at the total inventory volume in barrels. See HECO-506, line 3. This total inventory volume was multiplied by the price of the fuel to arrive at the total inventory value in dollars. See HECO-506, line 5.

Q. How is the average daily fuel consumption rate determined?

A. The average daily LSFO consumption for HECO is derived from the estimated test year fuel consumption and divided by 365 days. See HECO-506 line 2.

Q. What is the impact on daily fuel consumption of purchased energy from Kalaeloa and AES?

A. As discussed earlier, under the topic of fuel expense, HECO units produce the energy required above purchased power to meet the needs of the Company's customers. Therefore, the increase in purchased energy from Kalaeloa and AES during the 2009 test year decreases the amount of energy that HECO's generating units need to produce. This also reduces the amount of fuel burned and results in lower daily fuel consumption.

Q. What has been the historical level of LSFO inventory?

A. Over the past five years, LSFO inventory has been approximately 39 days, as shown in HECO-508.

<u>Diesel Fuel Inventory</u>

Q. How was the amount and value of diesel fuel inventory determined?

A. The amount of diesel fuel inventory included in the test year annual Fuel Inventory is the average of the volume estimated for the start of test year 2009, prior to the start of the CIP1 unit, and the volume estimated for the end of test year 2009, reflecting the estimated impact of the operation of CIP1 fueled with biodiesel.

Q. How was the amount and value of diesel fuel inventory at the start of test year 2009 determined?

A. The amount of diesel fuel inventory estimated for the start of test year 2009, prior to the start of operations of the CIP1 unit, is 31,624 bbls as shown on page 1 of HECO-507. It is comprised of several components. The first component is 24,961 bbls and is the average month-end Waiau Plant diesel inventory which supports the fuel consumption of units Waiau 9 ("W9") and Waiau 10 ("W10"), combustion turbines, for years 2003, 2004, 2005, 2006 and 2007. The second component is 4,950 bbls and is the average month-end diesel inventory at BPTF since the beginning of the fill of Tank 400 in February 2005 through April 2008. This diesel storage capability was added to BPTF as a portion of the installation of the Waiau Fuel Pipeline project, Docket No. 01-0444 and its purpose is to provide a displacement media for the LSFO in the Kahe and Waiau pipelines when emergency conditions place at risk continuous liquid flow, SCADA operation or pipeline leak detection, for example. The third component is 1,713 bbls and is the average month-end diesel inventory of the sites and units comprising the HECO Substation DG unit system from May 2007, when the system was built out to its current state, through April 2008. See page 1 of HECO-507. The total inventory value was derived by multiplying the start of test year diesel volume by the price of the diesel fuel to arrive at the start of test year diesel inventory value of $4,399,000. See HECO-505, line 2.

Q. Why was a five-year average inventory used for diesel fuel?

A. This was based on the methodology used in HECO’s previous rate cases (test year 2005 in Docket No. 04-0113, and test year 2007 in Docket No. 2006-0386) and in Decision and Order No. 24171, issued on May 1, 2008 in Docket No. 04-0113, the Commission accepted HECO’s fuel inventory amounts in rate base.

Q. How was the amount and value of diesel fuel inventory at the end of test year 2009 determined?

A. The amount of diesel fuel inventory estimated for the end of test year 2009, after the start of operations of the CIP1 unit, is 19,144 bbls as shown on page 2 of HECO-507. It is comprised of several components. The first component is 12,481 bbls and is the average month Waiau Plant diesel inventory which supports the fuel consumption of units W9 and W10, combustion turbines, for years 2003, 2004, 2005, 2006 and 2007, reduced by one half, which is displaced by the use of biodiesel for CIP1 operations. It is estimated that the air permit modification necessary to allow continuous operation of CIP1 on biodiesel will be complete by

December 2009. Therefore, the appropriate amount of biodiesel will be procured and stored in inventory by December 1, 2009 to support CIP1 operations on biodiesel, while diesel inventory is materially reduced. Since the assumed operating modes of CIP1 when operating on biodiesel will occur primarily during load peak scenarios, W9 and W10 generation and their related fuel consumption, will decline. This is assumed to reduce the required diesel inventory stored at Waiau to approximately one half the historical average level.

An inventory reduction of one half was assessed as reasonable given the uncertainties associated with the different operating constraints of CIP1 versus the W9 and W10 combustion turbines. For example, although peak generating capacity will double when CIP1 enters service, a higher CIP1 minimum operating load of approximately 39MW is expected to consume more biodiesel (MBTUs) than W9 and W10 have historically. A one-half reduction in diesel inventory is estimated to be an operationally prudent level based on expected operations. Over time, this may be adjusted higher or lower as operational experience increases with the new CIP1.

The diesel inventory volumes for the second component of the end test year diesel inventory is 4,950 bbls for BPTF and the third component of the end test year diesel inventory is 1,713 bbls for HECO Substation DG unit system are derived in like manner to the corresponding values for the start of the test year as shown on page 2 of HECO-507. The total inventory value was derived for the end of the test year by multiplying the end of test year diesel inventory volume by the price of the diesel fuel to arrive at an end of test year inventory value of $2,668,000. See HECO-505, line 5.

Q. Does the diesel fuel inventory include an amount of inventory for the DG units at HECO sites that are discussed in the testimony of Mr. Giovanni in HECO T-7?

A. Yes.

Biodiesel Inventory

Q. How was the amount and value of biodiesel fuel inventory determined?

A. Since there is no operating history with the new peaking CIP1 to use as a basis for determining an average inventory, the heat content of the Waiau diesel inventory, converted into barrels of biodiesel was established as a reference inventory for the commencement of operations. The resulting inventory volume of Biodiesel is 29,266 bbls. See HECO 507, page 2, lines 7 and 8. The Biodiesel inventory value was derived for the end of the test year by multiplying the Biodiesel inventory volume by the price of Biodiesel to arrive at the end of test year Biodiesel inventory value of $6,792,000. See HECO-505, line 6.

Q. Why was this method chosen?

A. Recognizing that the new CIP1 will operate under different operational constraints, the W9 and W10 peaking combustion turbines historical fuel inventory represented the best available approximation of future CIP1 fuel requirements, on a MBTU basis. Therefore, the historical diesel average fuel inventory, converted to MBTUs, was used as proxy for determination of biodiesel inventory necessary at the commencement of CIP1 operations. See page 2 of HECO-507, lines 7 and 8 for the derivation of the inventory volume. Over time, this may be adjusted higher or lower as operational experience increases with the new CIP1.

Q. How does the total fuel inventory for all types of fuel compare to historical levels?

A. The average test year total fuel inventory is 801,710 bbls as shown on HECO-505, line 7A. The level of fuel inventory is lower than either the average of the month-end LSFO and diesel fuel inventories for the years 2003, 2004, 2005, 2006 and 2007 of 886,269 bbls or the actual month-end total fuel inventory level of any of the individual years during this period. See HECO-509.

SUMMARY

Q. Please summarize your testimony.

A. The testimony presented supports the reasonableness of the following values for the 2009 test year:

1)	Fuel Price		See HECO-502
2)	Fuel Related Expense	$7,595,000	See HECO-503
5)	Fuel Inventory	$82,683,000	See HECO-505

The above items were determined by detailed analyses and methodologies, are consistent with historical values considering known and estimated conditions, and are consistent with all items in this case as they relate to each other.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY, INC.

RONALD R. COX

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 475 Kamehameha Highway Pearl City, Hawaii 96782
Position:	Manager Power Supply Services Department
Education:	Bachelor of Science in Chemical Engineering Northwestern University, 1979
	Master of Science in National Security Studies National War College, 2001
Experience:	HAWAIIAN ELECTRIC COMPANY, INC. January 2007 to Present Manager, Power Supply Services Dept.
	November 2005 to January 2007 Manager, Operations Strategic Planning
	U. S. NAVY 1979 to 2005 Various Assignments

Hawaiian Electric Company, Inc.

DERIVATION OF FUEL EXPENSE
(Contract Fuel Prices)

Line	LSFO	(A) Fuel Consumption (Barrels)	(B)[1] Contract Prices ($/bbl)	(C) = (A) x (B) (C) Fuel Expense ($000)
1.	**Honolulu**	324,897	99.3149	$ 32,267
2.	**Kahe**	5,592,243	99.3149	$ 555,393
3.	**Waiau-Steam**	2,026,235	99.3149	$ 201,235
4.	**Subtotal**	7,943,375		$ 788,896
5.	**Waiau-Diesel**	49,048	138.6074	$ 6,798
6.	**CIP-Diesel**	75,092	138.6074	$ 10,408
7.	**Subtotal**	124,139		$ 17,207
8.	**Biodiesel**	7,020	232.0913	$ 1,629
9.	**Central Station Total**	8,074,534		$ 807,731
10	**Substation DG**	9,571	138.6074	$ 1,327
11	**Grand Total**	8,084,105		$ 809,058
		Composite Fuel Price		**100.0801 $/bbl**

[1] See HECO-502 and HECO-WP-502.

Hawaiian Electric Company, Inc.

DERIVATION OF FUEL EXPENSE
(Including Trucking and Petrospect Costs)

Line	LSFO	(A) Fuel Consumption (Barrels)	(B)[1] Fuel Costs ($/bbl)	(C) = (A) x (B) (C) Fuel Expense ($000)
1.	Honolulu	324,897	102.4340	$ 33,281
2.	Kahe	5,592,243	99.3275	$ 555,463
3.	Waiau-Steam	2,026,235	99.3275	$ 201,261
4.	Subtotal	7,943,375		$ 790,005
5.	Waiau-Diesel	49,048	138.6497	$ 6,800
6.	CIP-Diesel	75,092	140.7616	$ 10,570
7.	Subtotal	124,139		$ 17,370
8.	Biodiesel	7,020	232.0913	$ 1,629
9.	Central Station Total	8,074,534		$ 809,004
10.	Substation DG	9,571	140.7018	$ 1,347
11.	Grand Total	8,084,105		$ 810,351
		Composite Fuel Price		**100.2400 $/bbl**

[1] See HECO-502.

HECO-502 is confidential and will be provided

after a Protective Order is issued in this proceeding.

Hawaiian Electric Company, Inc.

TEST YEAR FUEL RELATED EXPENSES

Line		Dollars ($000)	Reference
1.	Fuel Handling Expenses	$ 6,197	HECO-504; HECO-WP-511
2.	Fuel Trucking Expenses	$ 1,191	HECO-503, page 2
3.	Petrospect Expenses	$ 102	HECO-503, page 3; HECO-WP-503
4.	Kahe 6 Fuel Additive Expense	$ 105	HECO-WP-512
5.	Total	$ 7,595	

Hawaiian Electric Company, Inc.

DERIVATION OF FUEL EXPENSE
(Trucking Costs)

Line	LSFO	(A) Fuel Consumption (Barrels)	(B)[1] Trucking Cost ($/bbl)	(C) = (A) x (B) (C) Fuel Expense ($000)
1.	Honolulu	324,897	3.1065	$ 1,009
2.	Kahe	5,592,243	-	$ -
3.	Waiau-Steam	2,026,235	-	$ -
4.	Subtotal	7,943,375		$ 1,009
5.	Waiau-Diesel	49,048	-	$ -
6.	CIP-Diesel	75,092	2.1542	$ 162
7.	Biodiesel	7,020	-	$ -
8.	Subtotal	131,159		$ 162
9.	Central Station Total	8,074,534		$ 1,171
10.	Substation DG	9,571	2.0944	$ 20
11.	Grand Total	8,084,105		$ 1,191

[1] See HECO-502

Hawaiian Electric Company, Inc.

DERIVATION OF FUEL EXPENSE
(Petrospect Costs)

Line	LSFO	(A) Fuel Consumption (Barrels)	(B)[1] Petrospect Cost ($/bbl)	(C) = (A) x (B) (C) Fuel Expense ($000)
1.	Honolulu	324,897	0.0126	$ 4
2.	Kahe	5,592,243	0.0126	$ 70
3.	Waiau-Steam	2,026,235	0.0126	$ 25
4.	Subtotal	7,943,375		$ 100
5.	Waiau-Diesel	49,048	0.0423	$ 2
6.	CIP-Diesel	75,092	-	$ -
7.	Biodiesel	7,020	-	$ -
8.	Subtotal	131,159		$ 2
9.	Central Station Total	8,074,534		$ 102
10.	Substation DG	9,571	-	$ -
11.	Grand Total	8,084,105		$ 102

[1] See HECO-502, Line 8 and HECO-WP-503.

Hawaiian Electric Company, Inc.

TEST YEAR FUEL HANDLING EXPENSES
($000)

Line	Description	(A) Kahe	(B) Waiau	(C) Honolulu	(D) Other	(E) = (A)+(B)+(C)+(D) (E) Total
1.	Facilities Base Fee	$ 868	$ 2,161	-	$ -	$ 3,029
2.	Pipeline Maintenance	$ 602	$ 111	-	$ -	$ 713
3.	Tankfarm Management Fee	$ -	$ -	-	$ 2,455	$ 2,455
4.	Total	$ 1,470	$ 2,272	-	$ 2,455	$ 6,197

Sources:

Line 1: HECO-WP-504, HECO-WP-505, and HECO-WP-511
Line 2: HECO-WP-506, HECO-WP-507 and HECO-WP-511.
Line 3: HECO-WP-508 to HECO-WP-511.

Hawaiian Electric Company, Inc.

TEST YEAR FUEL OIL INVENTORY

Line		(A) Average Barrels[1]	(B) Price per Barrel		(C) = (A) x (B) (C) Fuel Oil Inventory ($000)
	Start of Year Without CIP1:				
1.	**Residual Fuel Oil**	761,694	99.4545	$	75,754
2.	**Diesel Oil**	31,624	139.0914	$	4,399
3.	**TOTAL INVENTORY**	**793,318**		**$**	**80,152**
	End of Year With CIP1:				
4.	**Residual Fuel Oil**	761,694	99.4545	$	75,754
5.	**Diesel Oil**	19,144	139.3794	$	2,668
6.	**Biodiesel**	29,266	232.0913	$	6,792
7.	**TOTAL INVENTORY**	**810,103**		**$**	**85,214**
7A.	**AVERAGE ANNUAL TOTAL INVENTORY**	**801,710**		**$**	**82,683**

Line			
	AVERAGE RESIDUAL FUEL OIL PRICE		
8.	**Residual Fuel Oil Expense (HECO-501, p. 2, Line 4, Column C)**	$	790,005
9.	**Barrels of Residual Fuel Oil (HECO-501, p. 2, Line 4, Column A)**		7,943,375
10.	**Average Price per Barrel (Line 8 ÷ Line 9)**	$	99.4545
	AVERAGE DIESEL OIL PRICE		
11.	**No BP-CT Waiau CT Diesel Inventory Volume (HECO-507, p.1, Line 6)**		24,961
12.	**With BP-CT Waiau CT Diesel Inventory Volume (HECO-507, p.2, Line 2)**		12,481
13.	**BP Diesel Oil Inventories Total Volume (HECO-507, p.1, Line 7)**		4,950
14.	**Substation DG Diesel Oil Inventory Volume (HECO-507, p.1, Line 9)**		1,713
15.	**Waiau CT Diesel Oil Price (HECO-501, Page 2, Line 5, Column B)**	$	138.6497
16.	**BP Diesel Oil Price (HECO-501, Page 2, Line 6, Column B)**	$	140.7616
17.	**Substation DG Diesel Oil Price (HECO-501, Page 2, Line 10, Column B)**	$	140.7018
18.	**No BP-CT Waiau CT Diesel Oil Inventory Value (Line 11 * Line 15)**	$	3,460,835
19.	**With BP-CT Waiau CT Diesel Oil Inventory Value (Line 12 * Line 15)**	$	1,730,417
20.	**BP Diesel Oil Inventory Value (Line 13 * Line 16)**	$	696,770
21.	**Substation DG Diesel Oil Inventory Value (Line 14 * Line 17)**	$	241,022
22.	**No BP-CT Total Diesel Inventory Value (Line 18 + Line 20 + Line 21)**	$	4,398,627
23.	**With BP-CT Total Diesel Inventory Value (Line 19 + Line 20 + Line 21)**	$	2,668,209
24.	**No BP-CT Diesel Inventory Average Value (Line 22/Line 2, Column A)**	$	139.0914
25.	**With BP-CT Diesel Inventory Average Value (Line 23/Line 5, Column A)**	$	139.3794
	AVERAGE BIODIESEL PRICE		
26.	**Biodiesel Expense (HECO-501, p. 2, Line 8, Column C)**	$	1,629
27.	**Barrels of Biodiesel (HECO-501, p. 2, Line 8, Column A)**		7,020
28.	**Average Price per Barrel (Line 26/Line 27)**	$	232.0913

[1] Residential Fuel Oil - HECO-506; Diesel Oil & Biodiesel: HECO-507

Hawaiian Electric Company, Inc.

DERIVATION OF RESIDUAL FUEL OIL INVENTORY

Line				
1.	**Forecast Residual Fuel Oil Consumption**[1]		7,943,375	Barrels
2.	**Burn Rate (Line 1 / 365 days)**		21,763	Barrels/Day
3.	**35 Day Inventory (Line 2 X 35 days)**		761,694	Barrels
4.	**Fuel Price**[2]	$	99.4545	$/Barrel
5.	**Residual Fuel Oil Inventory (Line 3 x Line 4)**	$	75,754	$000

[1] See HECO-501, line 4, column A.
[2] See HECO-505, line 10.

Hawaiian Electric Company, Inc.

DERIVATION OF DIESEL OIL & BIODIESEL INVENTORIES
PORTION OF YEAR WITHOUT CIP1 GENERATION

Line		Monthly Data Period	Average Month Ending Inventory (Barrel)	Average Period Inventory (Barrel)
	Diesel			
1.	**Waiau CT**	**2003**	23,827	
2.		**2004**	22,414	
3.		**2005**	25,174	
4.		**2006**	23,405	
5.		**2007**	29,985	
6.		**Average**		24,961
7. [1]	**BPTF**	**2/2005-4/2008**		4,950
8.	**Central Station Inventory**			29,911
9. [2]	**DG Inventory**			1,713
10.	**Total Diesel Oil Inventory**			31,624

[1] Average month end inventory for emergency pipeline displacement since tank fill start in 2/2005.
[2] Average month end inventory since full build out (5/2007 - 4/2008).

Hawaiian Electric Company, Inc.

DERIVATION OF DIESEL OIL & BIODIESEL INVENTORIES
PORTION OF YEAR WITH CIP1 GENERATION

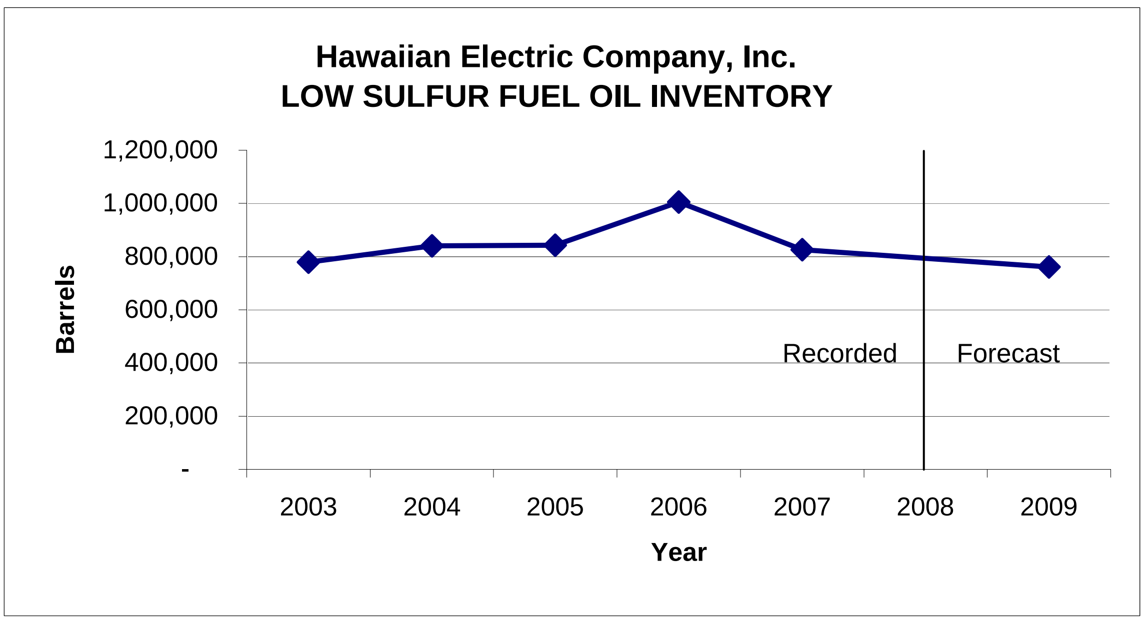
Line		Monthly Data Period	Inventory (Barrel)	Average Ending Inventory (Barrel)
	Diesel			
1.	**Waiau CT**	**from above 1/2003-12/2007**	24,961	
2.	**Waiau CT**	**Assume 50% less output with CIP1 available**		12,481
3. [1]	**BPTF**	**2/2005-4/2008**		4,950
4.	**Central Station Inventory**			17,431
5. [2]	**DG Inventory**			1,713
6.	**Total Diesel Oil Inventory**			19,144
	Biodiesel			
7.	**CIP1**	**BTU content of Waiau diesel inventory**	24,961 X 5.86 MBTU/Bbl	= 146,271 MBTU
8.		**Barrels Biodiesel with heat content @ 4.998 MBTU per Barrel**		29,266

[1] Average month end inventory for emergency pipeline displacement since tank fill start in 2/2005.
[2] Average month end inventory since full build out (5/2007 - 4/2008).

Hawaiian Electric Company, Inc.

AVERAGE MONTHLY LSFO INVENTORY COMPARED WITH TEST YEAR LSFO INVENTORY

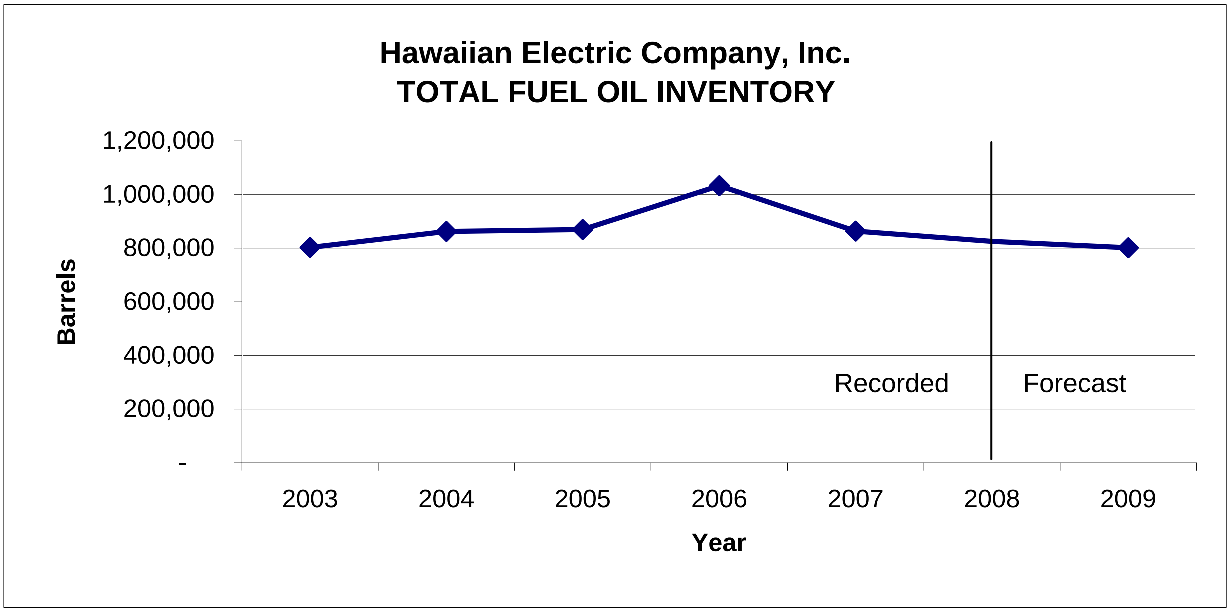
Line	Year	(A) Barrels Consumed Per Day	(B) Average Ending Inventory (Barrel)	(C) = (B) / (A) (C) Average Days Supply
1.	**2003**	20,974	778,717	37
2.	**2004**	22,229	840,343	38
3.	**2005**	21,574	842,358	39
4.	**2006**	22,128	1,005,056	45
5.	**2007**	22,188	826,331	37
6.	**2003 - 2007 Average**	21,818	858,561	39



Hawaiian Electric Company, Inc.

AVERAGE MONTHLY TOTAL FUELS INVENTORY COMPARED WITH TEST YEAR TOTAL FUELS INVENTORY

Line	Year	(A) LSFO Barrels	(B) Diesel Barrels	(C) Biodiesel Barrels	(D) = (A) + (B) + (C) (D) Total Barrels
1.	**2003**	778,717	23,827	0	802,544
2.	**2004**	840,343	22,414	0	862,757
3.	**2005**	842,358	26,632	0	868,990
4.	**2006**	1,005,056	28,281	0	1,033,337
5.	**2007**	826,331	37,389	0	863,720
6.	**2003 - 2007 Average**	858,561	27,709		886,269



TESTIMONY OF
DANIEL S. W. CHING

DIRECTOR
POWER PURCHASE DIVISION
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Purchased Power Expense

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INTRODUCTION

Q. Please State your name and business address.

A. My name is Daniel S. W. Ching and my business address is 475 Kamehameha Highway, Pearl City, Hawaii.

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

A. I am the Director of the Power Purchase Division within the Power Supply Services Department at Hawaiian Electric Company, Inc. ("HECO"). My experience and educational background are listed in HECO-600.

Q. What is your responsibility as a witness in this proceeding?

A. My testimony will support the 2009 test year estimate for purchased power expense. It will cover both purchased energy and capacity expenses.

PURCHASED POWER EXPENSES

Q. What are the 2009 test year estimated purchased power expenses?

A. The normalized 2009 test year purchased power expense estimate is $ 477,055,480. This includes:

$369,123,533	purchased energy expenses
$107,931,947	firm capacity expenses
$477,055,480	total purchased power expenses

(See HECO-601.)

Q. How are purchased energy expenses determined?

A. Purchased energy expenses are based on the projected amount of energy to be purchased by, or made available to, HECO in the test year and the contract pricing terms for the various purchased power producers. These energy terms vary for different purchased power producers.

Q. How are firm capacity expenses determined?

A. Firm capacity expenses are based on the individual contract terms for delivery of firm capacity by the purchased power producers. These capacity terms are different for the various contracts.

Q. What purchased power contracts ("contracts" or "PPAs") does HECO have?

A. HECO purchases energy and capacity from three firm capacity and three as-available energy power producers, as shown on HECO-602. These are:

<u>Firm</u>

1) AES Hawaii, Inc. ("AES Hawaii"), formerly known as AES Barbers Point, Inc.,
2) Honolulu Program of Waste Energy Recovery ("H-POWER"), and
3) Kalaeloa Partners, L.P. ("Kalaeloa");

<u>As-available</u>

1) Chevron USA Inc. ("Chevron"),
2) Tesoro Hawaii Corporation ("Tesoro"), formerly known as Hawaiian Independent Refinery, Inc., and
3) Hoku Solar, Inc. ("Hoku Solar") HECO Archer Substation PV Plant.

HECO has purchased as-available energy in the past from Chevron and Tesoro, but not from the Hoku Solar HECO Archer Substation PV Plant ("Archer Sub PV plant").

Q. Please describe the Archer Sub PV plant.

A. On November 16, 2007, HECO and Hoku Solar executed the Solar Energy Purchase Agreement For As-Available Energy ("Agreement"). The Agreement provides for HECO to purchase as-available energy from the Hoku Solar-owned photovoltaic system with a generating capacity up to 300 kilowatts dc to be located on HECO's Archer Substation. HECO provided a detailed description of the project and the Agreement in its Application for approval of the Agreement in Docket No. 2007-0425, filed on December 27, 2007.

Q. What is the current status of the project?

A. The Commission, by Decision and Order No. 24225, dated May 13, 2008, approved the Application. Hoku Solar recently set the size of its project to have a generating capacity of 218 kilowatts dc. According to the most recent schedule, the project could be completed by August 2008, with system start up occurring in September 2008.

PURCHASED ENERGY

Energy (kilowatt-hours) Purchased

Q. What is HECO's normalized estimate of the amount of energy to be purchased in the test year?

A. For the normalized 2009 test year, HECO estimates approximately 3,345 gigawatthours (GWh) in purchased energy. This represents approximately 41.54% of the total net energy produced of 8,053.6 GWh required in test year 2009 as shown in HECO-402. A breakdown of this estimate by purchased power producers is shown in HECO-603.

Q. How was the normalized estimate determined?

A. The test year estimate of energy purchases was derived from the HECO 2009 Production Simulation - (Rate Case - 2009 Test Year - Direct Testimony) dated May 21, 2008. Please refer to the testimony of Mr. Ross Sakuda, HECO T-4, for an explanation of the production simulation.

Q. How were energy purchases for operating year 2009 forecasted?

A. Four methods were used to develop the 2009 forecast of purchased energy. These are:

1) economic dispatch,
2) power dispatch schedules,
3) historical data review for as-available sources, and
4) contract requirements.

Q. What method of forecasting purchased energy was applied to each of the providers of purchased energy (also known as Independent Power Producers ("IPPs"))?

A. Energy purchases from AES Hawaii and Kalaeloa are forecasted based on the expected economic dispatch of their facilities for the test year. Both of these facilities are fully dispatchable by HECO (between upper and lower levels in accordance with their contracts) and hence they are dispatched in the most economic fashion for our system, taking into account any applicable system constraints. H-POWER energy deliveries are forecasted using power dispatch schedules, historical trends, and contract requirements. The as-available producers' purchased energy amounts are forecasted based on historical trends and contract requirements.

Q. How was <u>economic dispatch</u> used to forecast the amount of energy provided by large firm power producers?

A. Kalaeloa and AES Hawaii were simulated as generating units in the production simulation model in a manner similar to HECO's own generating units. (See Mr. Sakuda's testimony in HECO T-4.) However, instead of using heat rate curves as the basis for determining production costs for Kalaeloa and AES Hawaii, the contractual payment provisions for energy and variable O&M for each producer were translated into second order equations.

The second order equations for both AES and Kalaeloa are of the form:

$F = A + BL + CL^2$

Where F = Unit fuel consumption rate in MBtu/Hr

L = Load on the Unit in MW

For AES,

A = 258.7479

B = 14.9713

C = 0.0051019

The coefficients A, B and C do not change from month to month for AES. Changes in pricing are handled by adjusting the AES fuel price.

For Kalaeloa, A, B and C are developed through a curve-fitting process, whereby LSFO fuel price relationships (for 6.0 MBtu/Bbl fuel), fuel additive price relationships, and Gross National Product Implicit Price Deflator ("GNPIPD") price relationships play a factor in the determination of the coefficients. B may change from month to month. Simulating Kalaeloa and AES Hawaii as generating units permits their energy costs to be compared to the costs of energy from HECO's own units for the purpose of dispatching the required energy in the most economical fashion. This simulation provides the optimum or lowest cost operation of the generation on our system consistent with the "real world" constraints of HECO's electrical system.

Q. How were power dispatch schedules, historical trends and contract requirements used to forecast the amount of energy provided by H-POWER?

A. For H-POWER a typical daily dispatch schedule is developed based on the firm capacity obligation of this producer and the contract energy targets. The H-POWER plant normally operates around 46 MW during the fourteen-hour per day on-peak period during the entire year. During the off-peak hours for the months of December through May, the contract provides that HECO shall accept from H-POWER up to 40 MW during week days and 25 MW on Saturdays, Sundays and holidays. However, in past years, H-POWER requested HECO to waive this off-peak provision, in order to help optimize waste disposal at H-POWER. HECO's position is that it cannot agree in advance to waive the contract requirement due to technical limitations associated with the minimum loading on HECO's units during system minimum loads at night during the December through May period. Unforeseeable technical constraints on the Oahu grid, including the transmission system and constraints at night due to low loading on HECO's generating units, may require HECO to curtail H-POWER as well as other generating units. However, HECO is willing to accept up to 46 MW during the off-peak hours between December 1 and May 31 as system conditions allow. In fact, H-POWER off peak energy deliveries have matched on peak deliveries in average MWh per hour for the time period January 2007 through April 2008. (36.15 average MWh per hour off peak and 36.10 average MWh per hour on peak.) During other months of the year, i.e., June 1 through November 30, the H-POWER plant is normally operating up to 46 MW during the off-peak period.

The forecast assumes that the plant is normally completely shut down for about two weeks and half the plant is shut down for about three weeks every year for routine maintenance, based on a review of historical information and on H-POWER's projected maintenance.

Q. How is <u>historical data review for as-available sources</u> used in HECO's test year cost of purchased energy?

A. The estimates of purchased energy from Chevron and Tesoro were based on the average of the respective purchases over the most recent five-year period (2003-2007). They are summarized in HECO-604.

Q. How are contract requirements used to forecast the amount of energy provided by the Archer Substation PV plant?

A. Under the Agreement between HECO and Hoku Solar, HECO will purchase all energy generated and delivered from the plant. Based on the size and operating characteristics of the plant, HECO estimates that it will purchase 305,272 kilowatthours in 2009. The estimate of monthly energy purchases is shown in HECO-605.

Q. How does the test year estimate of energy purchases compare with the historical level of energy purchases?

A. For the firm capacity producers, the test year energy purchases are estimated to be close to the actual 2007 energy purchases. The comparison of test year energy purchases versus historical energy purchases is presented in HECO-606.

Q. Please summarize why HECO's estimate of purchased energy is reasonable.

A. The test year purchased energy estimate is reasonable because of the detailed methodology used to derive the operating forecast and because it is consistent with historical production, taking into consideration known changes to our system. Furthermore, this methodology is consistent with the way in which we operate our system.

<u>Purchased Energy Expenses</u>

Q. What are the estimated purchased energy expenses for the 2009 test year?

A. The estimated purchased energy expenses for the 2009 test year are $369,123,533. (See HECO-601 for summary and HECO-607 for breakdown by IPPs.)

Q. How did HECO determine the test year estimate of purchased energy expenses?

A. For the Chevron, Tesoro, and Hoku Solar as-available energy contracts and the H-POWER contract, purchased energy expenses were determined by multiplying the estimated energy deliveries (kilowatt-hours) by the applicable contract prices.

For the AES Hawaii contract, purchased energy expenses were determined by: (1) multiplying the estimated AES Hawaii energy deliveries (kilowatt-hours) by the applicable fuel and fuel-related ("variable O&M") components of the contract energy charge, and (2) multiplying the estimated kilowatt-hours made available by AES Hawaii for dispatch by the applicable non-fuel ("fixed O&M") component of the contract energy charge.

For the Kalaeloa contract, purchased energy expenses were determined by multiplying the estimated Kalaeloa energy deliveries (kilowatt-hours) by the applicable fuel, fuel-related ("additive"), and non-fuel ("O&M") components of the contract energy charge.

Q. How were the test year purchased energy prices determined?

A. The purchased power contracts have three general types of pricing provisions. These are:

1) pricing that uses the avoided energy cost rates and the Schedule Q rates that are filed quarterly with the Commission,
2) pricing that is derived from "formulas" specified in the individual PPAs, and
3) pricing that is fixed in the PPA.

As shown in the last column of HECO-602, only Kalaeloa and AES Hawaii are paid by contract-specific formulas. Chevron, Tesoro, and H-POWER are paid based on avoided energy cost rates. The H-POWER PPA further specifies certain adjustments to the avoided energy cost rates, as described below. Energy from the Hoku Solar Archer Sub PV plant is paid based on a fixed price in that PPA.

Q. How were the test year purchased energy rates determined for producers who are paid in accordance with the avoided energy cost rates and Schedule Q rates filed quarterly with the Commission?

A. Purchased energy prices were derived for these producers based on their respective contract pricing terms and the avoided energy cost rates determined in accordance with the Commission's Decision and Order No. 24086 ("D&O No. 24086") in Docket No. 7310, filed March 11, 2008.

Q. What are avoided energy costs?

A. Avoided energy costs are those energy-related generation costs that the utility would avoid if a given amount of energy were generated by an entity, such as an IPP, other than the utility. Avoided energy costs comprise avoided fuel costs and avoided variable operations and maintenance ("O&M") costs.

Q. How are avoided energy costs calculated for the purposes of this proceeding?

A. For the purposes of this proceeding, the avoided energy costs were calculated using the QF-in/QF-out[1] method described in the Updated Stipulation to Resolve Proceeding in Docket No. 7310 ("Updated Stipulation") and approved by the Commission in D&O No. 24086, dated March 11, 2008. In this methodology, total production costs, including fuel and variable O&M costs, are determined for a base (or QF-out) case and an alternate case (or QF-in) case using production simulations and applying the calibration factors. The QF is representative of the energy purchased by the utility from as-available producers whose payment rates

[1] QF stands for Qualifying Facility.

are a function of the utility's avoided energy cost. The difference in fuel and variable O&M costs between the base and alternate cases is the utility's avoided energy cost. This avoided energy cost is divided by the amount of energy purchased from the QF to arrive at a unit avoided energy cost in cents per kWh.

HECO purchases energy from Chevron and Tesoro on an as-available basis. The test year production simulation included the purchase of 4,768.0 MWh from these two as-available producers. This was based on a five-year (2003-2007) average of purchases.

The QF in the calculation was represented by a generator producing 1 MW of power for 8,760 hours in the year. This is in accordance with Exhibit B, page 1, paragraph 1, of the Updated Stipulation. That paragraph states in relevant part, "If less than 8,760 mwh of as-available energy is anticipated for that year, the avoided fuel cost will be determined on the basis of 8,760 mwh (1 mw) of as-available energy." The total energy purchased from Chevron and Tesoro is less than 8,760 MWh.

The production simulation for the base case of the avoided cost calculation excluded the Chevron and Tesoro energy purchases and the 8,760 MWh of QF energy. The production simulation for the alternate case included only the 8,760 MWh of QF energy.

Q. Why do avoided energy costs need to be calculated in this proceeding?

A. Avoided energy costs are needed to calculate purchased energy costs for those IPPs whose payment rates are a function of the utility's avoided energy cost. The Updated Stipulation requires that the new methodology be implemented four months after the issuance of the D&O in Docket No. 7310. The QF-in/QF-out method will be used to calculate avoided energy costs effective August 1, 2008.

Q. What avoided energy cost rates were calculated using the QF-in/QF-out method?

A. The avoided energy cost rates calculated using the QF-in/QF-out method were 20.44 cents per kWh (on-peak) and 14.99 cents per kWh (off-peak). (See HECO-609 and HECO-WP-607.)

In H-POWER's case, there are floor level rates (or minimum purchased on-peak and off-peak energy rates) in its contract based on the avoided energy costs in effect at the time the Commission approved that contract. Floor level rates were originally established by Title 6, Chapter 74, Hawaii Administrative Rules, Standards for Small Power Production and Cogeneration in the State of Hawaii and in force during the negotiation of the H-POWER contract. (However, the minimum purchase rate was later eliminated by the Legislature in 2004 (see HRS 269-27.2).) If the H-POWER contract floor level rates are higher than the calculated test year energy prices, then the floor level rates are used to determine the purchased energy expense.

Also, in H-POWER's contract, if the avoided energy cost rates reach certain thresholds in the contract, the on-peak and off-peak energy payment rates are the filed on-peak or off-peak avoided energy costs as applicable, less a discount equal to a percentage of the differential between such rates and the respective floor level rates in the contract. If the calculated test year energy prices based on the filed avoided energy costs reach certain thresholds, then the discounted avoided energy cost rates are used to determine the purchased energy expense for H-POWER.

<u>H-POWER Energy Payment Rate</u>

Q. Under what PPA does HECO purchase energy from H-POWER?

A. The H-POWER energy price is based on the Purchase Power Contract dated March 10, 1986, as amended by the Firm Capacity Amendment (dated April 8, 1991). The Purchase Power Contract was approved by the Commission in Decision and Order No. 8698 (March 31, 1986) in Docket No. 5514. The Firm Capacity Amendment (Docket No. 6983) was approved by the Commission in Decision and Order No. 11700 (dated June 30, 1992).

Q. How is the energy to be produced by H-POWER priced?

A. Under the amended agreement, the purchased energy prices are based on the higher of avoided energy cost rates filed with the Commission quarterly or floor level rates, and with adjustments specified in the PPA. For energy delivered up to 644 MWh/day on-peak and 250 MWh/day off-peak, H-POWER has floor level rates of 7.21 cents/kWh and 5.60 cents/kWh, respectively. For energy delivered in excess of the above stated amounts, the floor level rates are 6.7 cents/kWh on-peak and 5.19 cents/kWh off-peak.

If the filed avoided energy cost rates reach certain thresholds, certain adjustments to the purchased energy prices apply. The adjustments are specified in Appendix D of the Firm Capacity Amendment. For example, if the on-peak avoided energy cost is 11.16 cents/kWh, a 25% discount is applied to the differential between the on-peak avoided energy cost and the respective floor level rates. The rate for the on-peak energy in this example would be discounted from 11.16 cents/kWh to 10.172 cents/kWh. If the off-peak avoided energy cost is 8.50 cents/kWh, a 25% discount is applied to the differential between the off-peak avoided energy costs and the respective floor level rates. The rate for off-peak energy in this example would be discounted from 8.50 cents/kWh to 7.775 cents/kWh.

<u>Kalaeloa Energy Payment Rate</u>

Q. Under what terms and conditions does HECO purchase energy from Kalaeloa?

A. HECO purchases energy from Kalaeloa under a PPA dated October 14, 1988, as amended by Amendment No. 1 (dated June 15, 1989), Restated Amendment No. 2 (dated February 9, 1990), Amendment No. 3 (dated December 10, 1991), and Amendment No. 4 (dated October 1, 1999). The amended PPA was approved by the Commission in Decision and Order Nos. 10369 (October 16, 1989), 10824 (October 31, 1990), 11494 (February 24, 1992) (ratifying Amendment No. 3) in Docket No. 6378, and 17647 (March 30, 2000) in Docket No. 00-0001 (ratifying Amendment No. 4). In addition, HECO and Kalaeloa signed Amendment No. 5 (dated October 12, 2004), and Amendment No. 6 (dated October 12, 2004). Amendment No. 5 and Amendment No. 6 have provisions which govern the purchase of energy when Kalaeloa is dispatched at 180,000 kW or greater. Amendment Nos. 5 and 6 were approved by the Commission in Decision and Order No. 21820 in Docket No. 04-0320 (May 13, 2005).

Q. How is energy produced by Kalaeloa priced?

A. Kalaeloa's energy payment rate is divided into three components:

1) fuel,
2) fuel additive, and
3) non-fuel (O&M).

HECO's energy payments to Kalaeloa also must take into account the minimum purchase obligations (and corresponding shortfall charges) in the Kalaeloa PPA.

Q. What is the test year Kalaeloa energy expense?

A. The estimated Kalaeloa test year energy expense is $244,004,996:

1) fuel, $219,439,016;
2) fuel additive, $2,492,245; and
3) non-fuel (O&M), $22,073,735.

Q. How is Kalaeloa's fuel component determined for the test year?

A. The fuel component is based on formulas in the PPA, which depends on the fifteen-minute load of the facility (in megawatts), the fifteen-minute kWh purchased from the facility, and the number of combustion turbines being dispatched. The fuel component is adjusted monthly based on changes in Kalaeloa's actual low sulfur fuel oil ("LSFO") cost from a base fuel cost of $19.50 per barrel with a gross heating value of 6,000,000 BTU per barrel. At full output of 180 MW and above, with three generators operating, the base contract price is 2.77 cents/kWh (before application of the LSFO adjustment).

Q. What is the fuel price assumed for Kalaeloa?

A. The test year fuel price for low sulfur residual oil for the Kalaeloa facility is $102.567 per barrel.

Q. How was this price determined?

A. The Kalaeloa fuel price is based on the fuel oil contract between Hawaiian Independent Refinery, Inc. ("HIRI") and Kalaeloa. (See Exhibit C of the Application for approval of the Kalaeloa Power Purchase Contract, Docket No. 6378.) The test year fuel component price is shown in HECO-WP-601.

Q. How does it compare to oil prices for other HECO units?

A. The Kalaeloa price (per million Btu) is slightly higher than HECO's price due primarily to the treatment necessary to remove contaminants so that the fuel can be burned by Kalaeloa's combustion turbines.

Q. How is Kalaeloa's fuel additive component determined for the test year?

A. The fuel additive component as used for the test year is calculated in accordance with Amendment No. 5 and is more fully described in Docket No. 04-0320, Application dated November 5, 2004, pages 17 to 21. Refer to the calculation in HECO-WP-601.

Q. How is Kalaeloa's <u>non-fuel component</u> determined for the test year?

A. As a result of Amendment No. 5, the non-fuel, or O&M, component is comprised of three rates: 1) a base rate of 0.96 cents/kWh for all kilowatt-hours purchased up to the minimum energy purchase obligation, 2) a Variable O&M Component rate of 0.48 cents/kWh for all kilowatt-hours purchased past the minimum energy purchase obligation when Kalaeloa is dispatched at less than 180,000 kW, and 3) a Variable O&M Component rate of 0.144 cents/kWh for all kilowatt-hours purchased past the minimum energy purchase obligation when Kalaeloa is dispatched at 180,000 kW or greater. Each of these rates is escalated annually by changes in the GNPIPD.

Q. What GNPIPD did HECO use for test year 2009?

A. The GNPIPD used for test year 2009 for the purposes of forecasting Kalaeloa O&M escalation is 122.894, which is the forecasted fourth quarter 2008 GNPIPD.

Q. How was the fourth quarter 2008 GNPIPD forecasted?

A. The Energy Information Administration Annual Energy Outlook 2008 (Table A19, Macroeconomic Indicators (http://www.eia.doe.gov/oiaf/aeo/pdf/appa.pdf)) forecast of the gross domestic product (GDP) chain-type price index was used to estimate quarterly escalation values. These quarterly escalation values were used with the actual fourth quarter 2007 GNPIPD value to produce the forecasted GNPIPD shown in HECO-WP-602.

Q. What is HECO's minimum energy purchase obligation under the Kalaeloa PPA?

A. HECO is required to purchase a minimum of 1,235 GWh per contract year, as adjusted based on the ratio of the actual Equivalent Availability Factor ("EAF") (not to exceed 92%) to a base EAF of 85%.

Q. What level of Kalaeloa energy purchases is estimated for the 2009 test year?

A. In the test year, HECO estimates that it will purchase 1,480 GWh from Kalaeloa. (See HECO-603.)

Q. What is the forecasted EAF for Kalaeloa for the test year?

A. The estimated EAF for Kalaeloa for the test year is 92.00%.

Q. How was the estimated EAF determined?

A. The 92.00% EAF for the Kalaeloa plant was estimated as the 12-month test year EAF based on a review of the recent historical EAF record, the present plant performance and practices, and the projected performance of the plant over the next few years. The 2009 test year value is the same as used in the 2007 test year (Docket No. 2006-0386, HECO-WP-501). The 92% value was not quantitatively calculated but represents a general approximation after considering the above noted factors, which are discussed in further detail below.

The historical record for Kalaeloa statistics for EAF begins at the Kalaeloa plant in-service date of May 23, 1991. Generally, the more recent years are considered more accurate as a predictor of future performance in that the more recent years would incorporate changes in scheduled outage patterns and the occurrence of unplanned events that might be more prevalent as the plant ages. HECO-WP-601 shows the EAF and EFOR statistics for the entire plant operation. The initial three years had various issues which required various remedies to improve performance. The Contract Year 9 EAF of 92.18% includes the major steam turbine inspection and maintenance where the entire plant was off-line. This was the first time the major steam turbine work had been performed since the in-service date. Such planned activities normally result in a lower EAF given the larger amount of scheduled outage time compared to the more normal year-to-year outages. The next such steam turbine outage will not occur until the year 2010 based on current projections from Kalaeloa. The scheduled outage plans for 2009 and years 2011 to the expiration of the PPA in 2016 are currently projected to be repeated with only minor variation as needed to support a specific maintenance activity. The forced outage events are the other component of the EAF. With Kalaeloa these have generally been in the range of 1% with the exception of Contract Years 13 and 15.

Currently Kalaeloa has been experiencing increased outage time related to water or steam leaks from the heat recovery steam generators ("HRSG"). We note that Kalaeloa has taken steps in 2007 and 2008 to replace the most leak prone tube bundle sections of the HRSGs. Some additional tube bundle replacements are planned during the 2009 scheduled outage. Kalaeloa expects this effort to help them maintain good EAF performance in the coming years. Kalaeloa has also taken step to increase in-house capability to repair HRSG leaks so that the time required to complete repairs and return to service can be minimized.

In past years, Kalaeloa very often completed the scheduled outage ahead of schedule. Kalaeloa has incentives through the PPA to complete the scheduled outages on time. The non-fuel component payments only occur when the plant is running. Also a higher EAF (up to a cap of 92%) increases the required minimum purchase amount (see discussion filed February 14, 1994 pursuant to Docket No. 6998 on "shortfall charges"). Also, Kalaeloa can in certain circumstances incur penalties if the plant remains unavailable more than 48 hours after the scheduled completion of the outage (see PPA Section 3.2D.7). In addition, there are liquidated damages if certain performance criteria pertaining to EAF and EFOR are not met (see PPA Section 3.2E).

The improvement in EAF gained from completing the scheduled outage ahead of schedule is counterbalanced by the increased outage time related to events such as HRSG leaks. If the leak is not too severe, a forced outage is averted and the event does not contribute to an EFOR event but is statistically handled similar to a scheduled outage as far as impact on EAF. HRSG leaks can more than use up all of the saving in outage time that is gained by completing the normal scheduled outage ahead of time.

In summary, we project that 92% is a reasonable estimate for EAF for use in the 2009 test year.

AES Hawaii Energy Payment Rate

Q. Under what PPA does HECO purchase power from AES Hawaii?

A. HECO purchases power from AES Hawaii based on the PPA dated March 25, 1988, as amended by Amendment No. 1 (dated August 28, 1989), as modified by a letter agreement regarding “Conditional Notice of Acceptance” (dated January 15, 1990), and as amended by Amendment No. 2 (dated May 8, 2003). The PPA and Amendment No. 1 were approved by the Commission in Decision and Order Nos. 10296 (July 28, 1989) and 10448 (December 29, 1989) (“D&O 10448”) in Docket No. 6177. As a result of D&O 10448, the PPA, as amended by Amendment No. 1, was modified by the letter agreement. Amendment No. 2 was approved by the Commission in Decision and Order Nos. 20292 (July 1, 2003) and 20310 (July 9, 2003) in Docket No. 03-0126.

Q. How is the energy to be produced by AES Hawaii priced?

A. AES Hawaii's energy pricing is divided into three components:

1) fuel,
2) variable O&M, and
3) fixed O&M.

Q. What is the test year AES Hawaii energy expense?

A. The estimated AES Hawaii test year energy expense is $73,717,877:

1) fuel, $43,879,802,
2) variable O&M, $1,297,088, and
3) fixed O&M, $28,540,987.

(See HECO-WP-603, page 1.)

Q. How is AES Hawaii's <u>fuel component</u> determined for the test year?

A. The fuel component is based on the formula in the PPA, which depends on the hourly load of the facility (in megawatts) and the hourly kWh purchased from the facility. The fuel component is adjusted semi-annually based on changes in GNPIPD from the first quarter 1987 GNPIPD. At full output the base contract price is 1.69 cents/kWh delivered (in July 1987 dollars). The calculation of the test year fuel component is shown in HECO-WP-603.

Q. What GNPIPD estimate did HECO use for test year 2009?

A. For the first six months of 2009, HECO used an estimated GNPIPD index of 122.300. This is the forecasted third quarter 2008 GNPIPD. For the last six months of test year of 2009, a GNPIPD index of 123.491 was used. This is the forecasted first quarter 2009 GNPIPD.

Q. Why were the estimated third quarter 2008 and first quarter 2009 GNPIPDs used for this adjustment?

A. The energy charge in the AES Hawaii PPA is adjusted semiannually as of January 1 and July 1 of each year based on the third quarter GNPIPD of the previous year and first quarter GNPIPD of that year, respectively.

Q. How were the GNPIPDs forecasted?

A. They were forecasted using the methodology described earlier in the discussion of GNPIPD for Kalaeloa.

Q. What value did HECO use for the first quarter 1987 GNPIPD?

A. HECO used a first quarter 1987 GNPIPD value of 72.465.

Q. How was the first quarter 1987 GNPIPD value determined?

A. The first quarter 1987 GNPIPD value of 72.465 is the value published by the Bureau of Economic Analysis on March 27, 2008.

Q. How is AES Hawaii's <u>variable O&M component</u> determined for the test year?

A. The variable O&M component consists of a base charge of 0.05 cent/kWh delivered (in July 1987 dollars) that is escalated based on changes in the GNPIPD. The calculation of the test year variable O&M component is shown in HECO-WP-603. The variable O&M component is adjusted for changes in the GNPIPD in the same method as described for the fuel component.

Q. How is AES Hawaii's <u>fixed O&M component</u> determined for the test year?

A. The fixed O&M component is a charge of 1.1 cents/kWh (in July 1987 dollars) escalated by changes in the GNPIPD. This charge is applied to the total kilowatt-hours available for dispatch. The calculation of the test year fixed O&M component is shown in HECO-WP-603. The fixed O&M component is adjusted for changes in GNPIPD as described in the preceding discussion for the fuel component.

PURCHASED FIRM CAPACITY

Q. What are the firm capacity IPP expenses?

A. Firm capacity payments will be made to Kalaeloa, AES Hawaii and H-POWER. The firm capacity expenses are estimated to be $107,931,947 for 2009. (See HECO-601 for summary and HECO-608 for breakdown by IPPs.)

Kalaeloa Firm Capacity

Q. How are capacity payments to Kalaeloa determined?

A. The capacity charge for the 180 MW of firm capacity provided by Kalaeloa under the PPA and Amendment Nos. 1 through 4 is $164.35 per kW per year (as adjusted from $167.51 per kW per year pursuant to Amendment No. 3). The capacity charge for the new capacity of 28 MW provided under Amendment Nos. 5 and 6 is $112 per kW per year.

AES Hawaii Firm Capacity

Q. How are capacity payments to AES Hawaii determined?

A. AES Hawaii capacity payments are based on the capacity charge of 4.4095 cents per available kilowatt-hour and a firm capacity commitment of 180,000 kW.

H-POWER Firm Capacity

Q. How are capacity payments to H-POWER determined?

A. H-POWER capacity payments are based on 4.89 cents per available kilowatt-hour during weekday on-peak periods. H-POWER's on-peak weekday firm capacity commitment is 46,000 kW. (See HECO-WP-604.)

AES Hawaii and H-POWER Plant Availability

Q. Is the AES Hawaii capacity payment a function of the EAF of that facility?

A. Yes. The capacity expense for AES Hawaii is calculated by multiplying the capacity charge of 4.4095 cents per available kilowatt-hour times the EAF times the number of hours in a year times its committed capacity of 180,000 kW.

Q. Historically, what has been the EAF of the AES Hawaii facility?

A. During the period September 1, 1992 through April 30, 2008, AES Hawaii had an average EAF of 97.05%.

Q. What is the estimated EAF for the AES Hawaii facility for test year 2009?

A. The estimated EAF for the AES Hawaii facility for test year 2009 is 97.02%.

Q. Is the capacity expense for H-POWER a function of that facility's availability?

A. Yes. The H-POWER capacity payments are calculated using a rate of 4.89 cents per available kilowatt-hour. HECO-WP-605 shows that for the 15th contract year (July 1, 2006 through June 30, 2007), the On-peak Availability, as defined in the PPA, is 86.31%.

Q. Historically, what has been H-POWER's On-peak Availability?

A. During the first Contract Year of the Firm Capacity Amendment, H-POWER's On-peak Availability (also known as the Availability Factor ("AF") in the contract) was 92.96%. The AF fell to a low of 72.99% in the 10^{th} contract year, due to a catastrophic generator failure. During the 11^{th} contract year, the AF was 91.61%, during the 12^{th} year it was 86.41%, during the 13^{th} year 87.26%, during the 14^{th} year it was 85.51%, and during the 15^{th} year it was 86.31%. Omitting the AF of the 10^{th} contract year, H-POWER's average AF over the last 5 years (Contract Years 11, 12, 13, 14, 15) is 87.42%, while its average availability factor from the first Contract Year through the 15th contract year is 87.24%. (See HECO-WP-605.)

HECO estimates an average of 87% AF for the 2009 test year and beyond. This estimate is based upon past performance but may prove to be conservative based upon continuous improvements H-POWER has made to its facility to enhance the facility's ability to stay on line generating power. Those improvements include, but are not limited to:

1) Improved combustion knowledge and monitoring of waste, particularly in regards to the variable composition and characteristics of the waste (refuse derived fuel).
2) Replacement and improvement of electrical equipment such as protective relays to allow H-POWER to stay on line generating power during frequency excursions.
3) Changes to power and control circuitry for motor drives, which allows H-POWER to ride through voltage excursions on the Oahu grid.
4) Installation of new computer electrical memory boards for maintaining Induction Draft fans, and furnace supervisory combustion control logic.
5) Revised maintenance schedules for primary and secondary superheater tubes replacements, which allow the boilers to improve availability and improve predictability.
6) Replacement of 80% of the internal components of the electrostatic precipitators and controls upgrades to the system.
7) On-line cleaning using blasting techniques while the boilers are running (2006).

<u>AES Hawaii Availability Bonus</u>

Q. Are there any other payments that would be due to AES Hawaii during the test year 2009?

A. Yes. Per Section 5.2 of the AES Hawaii PPA, AES Hawaii will be paid an Availability Bonus if the EAF for the facility exceeds 91% on average for the current and prior contract years.

Q. What is the purpose of the Availability Bonus?

A. The Availability Bonus is in the PPA to provide an incentive for the AES Hawaii plant to achieve high levels of availability. This, in turn, helps in providing reliable service to HECO customers.

Q. What level of EAF is being used for calculation of the Availability Bonus?

A. For the calculation of the Availability Bonus, the assumed EAF is 96.24%, which is an estimate of the two year running average EAF for Contract Years 16 and 17 in accordance with the terms of the PPA. Refer to HECO-WP-603.

Q. How does this EAF compare with the historical performance of AES Hawaii?

A. Thus far, the AES Hawaii plant has been rather reliable. From September 1, 1992 through April 30, 2008, the average EAF was 97.05%. This period represents the first through fifteenth Contract Years and the first seven months of the sixteenth Contract Year.

Q. How is the Availability Bonus calculated?

A. For each 1/10th of a percentage point that the EAF is over 91% on average for two consecutive contract years, HECO pays AES Hawaii $15,000 in 1987 dollars. This is escalated using the formula provided in Section 8.lC. of the PPA.

Q. What is the expected Availability Bonus for the test year?

A. This bonus is expected to be $1,041,933. The calculation for this is shown on HECO-WP-603.

RENEWABLE ENERGY

Q. How much of the energy purchased by HECO is derived from renewable energy resources?

A. In 2007, the amount of energy purchased by HECO that was derived from renewable energy resources included 24 GWh from AES Hawaii, which reflects the amount of energy derived from burning shredded tires, specification used oil, and used activated carbon, and 302 GWh from H-POWER.

Q. What is HECO doing to increase the amount of energy generated from renewable energy resources?

A. In the purchased power area, the Company's efforts are governed by the Framework for Competitive Bidding (the "Framework") established by the Commission on December 8, 2006, in Decision and Order No. 23121. HECO is actively engaged in negotiations with the developers of three potential renewal energy projects that are exempt from the Framework process ("grandfathered proposals") because they were submitted to HECO prior to the adoption of the Framework in Docket No. 03-0372. In parallel with the Company's on-going negotiations, the Generation Bidding Division issued HECO's Request for Proposals for Renewable Energy Projects ("RE RFP") on the Island of Oahu. The Company is also working with the City and County of Honolulu ("City and County") on its planned expansion of the H-POWER facility. In addition, the Company is working on its future plans to acquire additional renewable energy resources in the IRP-4 process that is currently underway, and in conjunction with the Hawaii Clean Energy Initiative discussed by Mr. Robert Alm in HECO T-1.

Grandfathered Renewable Energy Project Proposals

Q. What is the status of the grandfathered renewable energy project proposals?

A. HECO is engaged in negotiations with developers of the grandfathered proposed renewable energy projects. These proposals involve offers to sell energy by non-fossil fuel producers and qualify towards meeting HECO's Renewable Portfolio Standards ("RPS") requirements. (Some details of the proposals submitted prior to October 2007 have been provided to the Commission and the Consumer Advocate under protective order in status reports in the competitive bidding proceeding, Docket No. 03-0372.) The additional projects for which proposals have been received include a wind farm project, an ocean thermal energy conversion project, and a small waste-fired facility. The grandfathered proposals could result in power purchase agreements for approximately 60 – 135 MW of renewable energy. The grandfathered proposals consist of approximately 30 MW of wind energy located on the north shore of Oahu, 6 MW of energy from synthetic gas derived from waste products, and 25 MW of energy from ocean thermal energy conversion which could potentially increase to 100 MW.

The Commission issued an order on April 30, 2008 (Order No. 24170 in Docket No. 03-0372) setting a deadline of September 2, 2008 for HECO to reach material agreement on all three remaining grandfathered Oahu projects as evidenced in writing by fully executed terms sheets filed with the Commission by the September 2, 2008 deadline. Any resulting PPA would be subject to Commission approval.

<u>Request for Proposals for Renewable Energy Projects</u>

Q. In addition to negotiating with developers of the grandfathered proposals, is HECO taking any other steps to obtain energy from renewable sources?

A. In parallel with the Company's on-going negotiations, HECO is seeking proposals for additional renewable energy for the island of Oahu pursuant to its RE RFP. This procurement process has been initiated in accordance with the Framework.

On September 24, 2007, HECO submitted a request for approval to proceed with a competitive bidding process to acquire up to approximately 100 MW of non-firm renewable energy for the Island of Oahu, as identified in HECO's IRP-3 2007 Evaluation Report filed on May 31, 2007 in Docket No. 03-0253. HECO also issued a Solicitation of Interest on September 28, 2007 to preliminarily determine the interest of suppliers in responding to the planned RE RFP, and to obtain background information from potential suppliers. By Order No. 23699, issued October 9, 2007, the Commission noted that its approval to proceed was not required at that juncture, and opened Docket No. 2007-0331 to receive filings, review approval requests, and serve as a forum to resolve disputes, if necessary, related to the proposed competitive bidding process.

On February 11, 2008, HECO issued (and filed with the Commission) its Draft Request for Proposals for Renewable Energy Projects, Island of Oahu, February 2008 ("Draft RE RFP"). A technical conference for interested parties was held on March 14, 2008. A proposed Final RE RFP was submitted to the Commission on May 19, 2008, and revised on June 12 and 17, 2008. On June 18, 2008, the Commission approved the proposed RE RFP, and on June 19, 2008 HECO issued the RE RFP and posted it on its website. Any resulting PPA would be subject to Commission approval.

HECO seeks to acquire these renewable energy resources which could commence commercial operation in the 2010-2014 timeframe, with a preference for resources that achieve commercial operation before 2013.

H-POWER

Q. What is the current status of the City and County's planned expansion of the H-POWER facility?

A. In January 2008, the City and County of Honolulu announced plans to cancel the bidding process for a new waste-to-energy facility and instead expand the existing H-POWER waste-to-energy facility by adding a third boiler. The City and County plans to negotiate with Covanta, the current operator of H-POWER, to build a third boiler at the H-POWER facility by 2011.

CONCLUSION

Q. Please summarize your testimony.

A. For the normalized 2009 test year, HECO estimates purchasing approximately 3,345 GWh from three firm capacity and three as-available IPPs. The 2009 test year purchased energy costs, which are summarized in HECO-607, are $369,123,533. The 2009 test year purchased capacity costs, which are summarized in HECO-608, are $107,931,947. The 2009 test year total purchased power expenses, which are summarized in HECO-601, and for which HECO is seeking rate recovery, are $477,055,480.

In 2007, HECO purchased approximately 326 GWh of renewable energy from existing purchased power producers. HECO expects to purchase a similar amount of renewable energy from purchased power producers in the 2009 test year. HECO expects to increase its supply of energy from renewable resources in the future. Such energy may be derived from PPAs with the three grandfathered proposals, with the successful bidders to HECO's RE RFP, and with H-POWER from an expansion of its existing facility.

Q. Does this conclude your testimony?

A. Yes.

Hawaiian Electric Company, Inc.

DANIEL S. W. CHING

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 475 Kamehameha Highway P. O. Box 2750 Honolulu, Hawaii 96840
Position:	Director, Power Purchase Division
Years of Service:	35 years
Education:	Master of Business Administration University of Hawaii, 1980 Master of Science in Electrical Engineering University of Michigan, 1972 Bachelor of Science in Electrical Engineering University of Hawaii, 1971
Other Qualifications:	Registered Professional Engineer - Hawaii Electrical Branch
Experience:	1994 - Present Director, Power Purchase Division 1990 - 1994 Purchased Power Contracts Administrator Generation Planning Department Hawaiian Electric Company, Inc. 1987 - 1990 Senior Customer Engineer Distribution Engineering Department Hawaiian Electric Company, Inc. 1983 - 1987 Customer Engineer Distribution Engineering Department Hawaiian Electric Company, Inc.

Experience: (continued)	1976 - 1983 Electrical Engineer System Planning Department Hawaiian Electric Company, Inc.
	1972 - 1976 Designer Engineering Department Hawaiian Electric Company, Inc.

Hawaiian Electric Company, Inc.

TOTAL PURCHASED POWER EXPENSES
Recorded 2007 and 2009 Test Year Estimate

	Reference	2007 Recorded	2009 Test Year Estimate
Energy Payments	HECO-607	$261,963,245	$369,123,533
Firm Capacity Payments	HECO-608	$106,847,767	$107,931,947
Total Purchased Power Expenses		$368,811,012	$477,055,480

Note:
Totals may not add due to rounding.

Hawaiian Electric Company, Inc.

PURCHASED POWER CONTRACTS WITH INDEPENDENT POWER PRODUCERS

Contract	Contract Capacity MW	Type	Payment Terms
AES Hawaii	180	Firm	Non-escalating capacity payment paid on a kilowatt-hour available basis; O&M and fuel components escalated on a GNPIPD basis; O&M paid on both kilowatt-hour available and kilowatt-hour delivered bases; fuel component paid on basis of a formula similar to unit heat rate.
Chevron	0	As-available	Quarterly avoided energy cost.
Hoku Solar	0	As-available	Fixed, non-escalating rate per contract.
H-POWER	46	Firm	Non-escalating capacity payment based on on-peak kilowatt-hour available; energy based on quarterly avoided energy cost with floor and ceiling rates.
Kalaeloa Partners, L.P.	208	Firm	Non-escalating capacity payment paid on a kilowatt-year basis; fuel component escalated on fuel price basis; additive component escalated on a GNPIPD basis; O&M escalated on a GNPIPD basis; fuel component paid on basis of a formula similar to unit heat rate; O&M and additive paid on kilowatt-hour delivered basis; O&M subject to minimum annual purchase.
Tesoro	0	As-available	Quarterly avoided energy cost.

Hawaiian Electric Company, Inc.

TEST YEAR PURCHASED ENERGY FORECAST

	2009 Test Year (GWh)
As-available	
1. Chevron USA (Note 2)	1
2. Tesoro (Note 2)	4
3. Hoku Solar (Note 3)	0
Subtotal	5
Firm Power	
1. H-POWER	331
2. Kalaeloa	1,480
3. AES Hawaii	1,529
Subtotal	3,340
TOTAL TEST YEAR PURCHASED ENERGY (GWh)	3,345

Notes:
1. Totals may not add due to rounding.
2. Refer to HECO-604.
3. Refer to HECO-605.

Hawaiian Electric Company, Inc.

PURCHASED ENERGY FROM CHEVRON AND TESORO FROM 2003 TO 2007
Annual kWh

	2003	2004	2005	2006	2007	Total	5-Yr Avg
Chevron	2,105,228	90,146	104,958	1,149,623	110,403	3,560,358	712,072
Tesoro	5,449,573	3,677,119	3,967,680	3,420,836	3,765,568	20,280,776	4,056,155

Hawaiian Electric Company, Inc.

PURCHASED ENERGY FROM HOKU SOLAR ARCHER SUBSTATION PV PLANT
Monthly kWh During 2009 Test Year

	KWH
January	19,838
February	21,170
March	26,352
April	26,797
May	30,202
June	29,905
July	30,794
August	29,757
September	27,389
October	23,984
November	19,986
December	19,098
TOTAL	305,272

Hawaiian Electric Company, Inc.

HISTORICAL PURCHASED POWER PRODUCTION
Annual GWh

	2003	2004	2005	2006	2007	2009 Test Year
As-available	8	4	4	5	4	5
Firm Energy	3,232	3,205	3,379	3,245	3,235	3,340
Total	3,240	3,208	3,383	3,250	3,238	3,345

Note:
Totals may not add due to rounding.

Hawaiian Electric Company, Inc.

2009 TEST YEAR ENERGY EXPENSE
($000)

	2007 Actual	2009 Test Year
Kalaeloa- Fuel	137,723	219,439
Additive	2,283	2,492
Non-Fuel	20,079	22,074
Shortfall	0	0
Total	160,084	244,005
AES Hawaii- Fuel	41,302	43,880
O&M	28,165	29,838
Total	69,466	73,718
H-POWER- Energy	31,930	50,476
Other		
Chevron	2	129
Tesoro	482	737
Hoku Solar	0	58
Total	483	924
Total Energy	261,963	369,124

Note:

1. Totals may not add due to rounding.
2. Amounts for energy reflect only the cost of energy received, without adjustments for reactive or the meter charge in their contracts.

Hawaiian Electric Company, Inc.

2009 TEST YEAR FIRM CAPACITY EXPENSE

	Capacity Payment ($000)	
Firm Capacity Producer	2007 Actual	2009 Test Year
Kalaeloa	32,719	32,719
AES Hawaii	66,772	67,454
H-POWER	6,200	6,717
AES Hawaii bonus	1,157	1,042
TOTAL	106,848	107,932

Notes:

1 Totals may not add due to rounding.

2 For 2007, the H-POWER capacity payment amount is reduced by sanction amount.

Hawaiian Electric Company, Inc.

AVOIDED ENERGY COST RATES
ADJUSTED FOR APRIL 2008 FUEL PRICES

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost	19.948	14.707	¢/kwh
(2)	Avoided O&M Cost	0.170	0.011	¢/kwh
(3)	Avoided Working Cash	0.186	0.136	¢/kwh
(4)	Avoided Fuel Inventory	0.136	0.136	¢/kwh
(5)	Total Avoided Energy Cost Rates	20.440	14.990	¢/kwh
	Total Weighted Avoided energy Cost Rate*	18.169		¢/kwh

* Weighted 14/24 On-peak, 10/24 Off-peak

Hawaiian Electric Company, Inc.

DERIVATION OF SCHEDULE Q PAYMENT RATES

Schedule "Q" Rate - Under 100 KW

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost	19.948	14.707	¢/kwh
(2)	Avoided O&M Cost	0.170	0.011	¢/kwh
(3)	Power Factor Adjustment	-0.120	-0.280	¢/kwh
(4)	Pre Time-Weighted "Q" Payment Rate (line 1 + 2 + 3)	19.998	14.438	¢/kwh
(5)	Hour Weighting	14/24	10/24	Hours/Hours
(6)	Time-weighted Peak Time-Related Schedule "Q" Energy Payment Rate (line 4 x 5)	11.67	6.02	¢/kwh
(7)	Time-weighted "Q" ON PEAK Payment Rate	11.67	¢/kwh	
(8)	Time-weighted "Q" OFF PEAK Payment Rate	6.02	¢/kwh	
(9)	Schedule "Q" Energy Payment Rate (line 7 + 8)	17.69	¢/kwh	
(10)	Base 2005 Schedule "Q" Energy Payment	10.63	¢/kwh	
(11)	Difference between 2009 Test Year Direct and Base Sch "Q" Rates (line 9 - 10)	7.06	¢/kwh	

Note

Calculations based on:

Docket No. 7310 - Instituting a Proceeding to Investigate the Proxy Method and the Proxy Method Formula Used to Calculate Avoided Energy Costs and Schedule Q Rates of the Electric Utilities in the State of Hawaii

Updated Stipulation and Decision Order No. 24086 dated 3/11/08.

HECO T-7
DOCKET NO. 2008-0083

TESTIMONY OF
DAN V. GIOVANNI

MANAGER
POWER SUPPLY O&M
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Production Operations & Maintenance Expenses; Production Materials Inventory

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name and business address.

A. My name is Dan V. Giovanni. My business address is 475 Kamehameha Highway, Pearl City, Hawaii.

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

A. I am the Manager of the Power Supply Operations and Maintenance ("PSO&M") Department at Hawaiian Electric Company ("HECO"). HECO-700 provides my educational background and work experience.

Q. What is your responsibility as a witness in this proceeding?

A. In this proceeding it is my responsibility to present the appropriate Other Production Operations & Maintenance Expense ("O&M") (other than fuel and purchased power), and Production Stores Inventory for test year 2009.

Q. What is the scope of your testimony?

A. My testimony comprises the following major components:

1) Summary of Other Production O&M Expenses
2) Description, Operation, and Reliability of the HECO Generating System
3) Power Supply Organization
4) Other Production O&M Expense
5) Production Materials Inventory
6) Summary

Q. What are some of the key points to keep in mind in reviewing this testimony?

A. There are several major points to keep in mind in reviewing my testimony, including:

- The generating units that are operated and maintained by Production fulfill a critical role on the HECO grid, and despite their respective ages the duty cycles for these units are extreme relative to similar units on other electric systems.

- HECO's generating units are reliable.
- HECO's new generating unit, Campbell Industrial Park Combustion Turbine Unit 1 ("CIP CT-1"), will be a peaking unit firing biofuels. The cost to operate and maintain CIP CT-1 will begin in 2009, the first year of commercial operation, and directly contribute to increases in the Other Production O&M Expense. As discussed in the 2008 Adequacy of Supply (2008 AOS) which was filed with the Commission on January 30, 2008, CIP CT-1 will add needed generation reserve for the system. It will not, however, provide relief for the arduous duty of the older generating units.
- HECO generating assets will play key roles as renewable energy sources are added to the grid.
- Maintenance of HECO's generating units is planned and executed to sustain the annual Equivalent Forced Outage Rate ("EFOR") for the generating system below 5%.
- Maintenance is planned in advance but as the year unfolds resources are shifted to address highest priority issues, and overall the level of the maintenance effort is consistent year over year.
- The costs for labor, materials, and services have escalated significantly in recent years and this has directly contributed to increases in the Other Production O&M Expense.
- Production continues to effectively manage its costs to levels that are reasonable.

SUMMARY OF OTHER PRODUCTION O&M EXPENSE

Q. Please provide a summary of HECO's estimate of its 2009 test year Other Production O&M Expense.

A. HECO's 2009 test year estimate for Other Production O&M Expense (after adjustment and normalization) other than fuel and purchased power ("Other Production O&M Expense") is $80,391,000 as shown in HECO-701. Of this total, $32,400,000 is for Other Production Operations Expense and $47,991,000 is for Other Production Maintenance Expense as shown in HECO-701.

Q. What makes up the 2009 test year estimate for Other Production Operations Expense?

A. As shown on HECO-701, the 2009 test year estimate for Other Production Operations Expense is $32,400,000. Of this total, $15,402,000 is for labor expense and $16,998,000 is for non-labor expense.

Q. What makes up Other Production Maintenance Expense?

A. As shown on HECO-701, the 2009 test year estimate for Other Production Maintenance Expense is $47,991,000. Of this total, $17,610,000 is for labor expense and $30,381,000 is for non-labor expense.

Q. Does HECO's 2009 test year estimate for Other Production O&M Expense include expenses for the new CIP CT-1 unit?

A. Yes. The 2009 test year estimate includes $1,489,000 of Other Production O&M expenses for CIP CT-1. (This amount is shown in HECO-702, the sum of columns (B) and (C).) As described in Mr. Robbie Alm's testimony, HECO T-1, HECO is proposing a CIP CT-1 Step when the CIP CT-1 unit goes into service on July 31, 2009 and is used or useful for electric utility purposes. The CIP CT-1 Step includes the full cost of operation of CIP CT-1. Explanation of the CIP CT-1

Step will follow later in my testimony.

Q. How will you present your testimony?

A. Within my testimony, I will detail the Other Production O&M Expense amounts in relation to the base case. If any differences exist between the Other Production O&M expenses of the base case, Interim Increase or CIP CT-1 Step, I will discuss such differences in my testimony.

Q. What is the 2009 test year estimate for Production Material Inventory?

A. As shown on HECO-703, the year-end "average value" of Production Material Inventory for the 2009 test year is $8,809,000.

DESCRIPTION, OPERATION AND RELIABILITY OF THE HECO GENERATING SYSTEM

Description of Generating Units on the HECO System

Q. Please describe the electric power generating system and the generating units that supply power to HECO's customers on Oahu.

A. HECO-704 summarizes the primary sources of electric power supplied to Oahu. For the test year, HECO's generating system comprises 14 HECO-owned steam-electric units, three HECO-owned combustion turbines, and 18 leased Distributed Generator ("DG") units. Of the 14 steam-electric units, eight are "baseload" and usually operate continuously, and six are "cycling" and may be started and stopped each day. HECO also purchases power from three baseload units that are owned and operated by Independent Power Producers ("IPP"), and purchases energy from a small number of as-available energy producers. As of 2009, the average age of the steam-electric units is 45.7 years. The newest HECO generating unit is CIP CT-1, a combustion turbine, which is scheduled to start commercial operation in mid-2009. The second-to-the-newest HECO generating unit is Kahe 6 which started commercial operation in 1981. The three combustion turbines and DG engines are intended to operate as "peaking" units and are operated only when needed, usually to meet short-duration and emergency system requirements. HECO-704 shows the respective generating unit capacities, type of unit, intended operating mode, installation date, and age for all the units.

All of the base load and cycling generating units in the HECO generating system are staffed with operating personnel for 24-hours/day-7-days/week (24 X 7) operation, and CIP CT-1 will be staffed with operating personnel for 16-hours/day-7-days/week (16 X 7) operation. The other two peaking units, Waiau 9 and 10, are not staffed with operating personnel, however, operating personnel attending to the steam-electric units at Waiau Power Plant may be called upon to locally operate these two units as necessary. The DG units are not staffed with operating personnel and may be remotely started and stopped anytime by personnel at HECO's Dispatch Center.

Q. Please describe the age of the generating units and related infrastructure in the HECO system.

A. As shown in HECO-704, the average age of HECO's six cycling steam units and eight baseload steam units as of 2009 are 54.3 years and 39.3 years, respectively. HECO's two peaking combustion turbines, Waiau 9 and 10, are 36 years of age. The IPP facilities, H-Power, Kalaeloa and AES are 19, 18, and 17 years of age, respectively. Regarding infrastructure, some of the Waiau Power Plant infrastructure still in use today dates back to 1938. The Honolulu Power Plant infrastructure dates back to 1930.

Q. How are these aging generating assets benefiting the ratepayer?

A. Relative to mainland counterparts and as discussed below, HECO generating units continue to operate with a high degree of reliability despite their age and duty. Comprehensive maintenance, replacement/upgrade of equipment, and process improvements on these aging units benefit the ratepayer by avoiding the need to replace existing generating capacity.

Operation of Generating Units on the HECO System

Q. Please explain how baseload, cycling, and peaking units are dispatched to meet daily customer demand.

A. At any particular time, generating units that are not on outage for scheduled or unscheduled maintenance are designated as "available." Available HECO and IPP generating units are typically dispatched to: (1) meet system load requirements; (2) satisfy spinning reserve ("SR") and quick load pickup ("QLPU") criteria; and/or (3) provide voltage support throughout the system. Baseload generating units are operated 24 X 7 (i.e., 24 hours per day, seven days per week), cycling generating units are typically started and stopped on a daily basis but may operate as needed, and peaking generating units are quick starting units that typically operate for a few hours at a time.

As described by Mr. Ross Sakuda in HECO T-4, the commitment order and dispatch of the baseload and cycling units are typically based on their respective availabilities at any particular time and the relative economics.

Peaking units are primarily used to help meet SR and QLPU criteria at the highest peak demand period of the day, and for emergency generation when other units are available. In the future, the peaking units may also be utilized to provide stability to the grid when there will be increasing amounts of variable generation (e.g., wind turbine generators) connected to the grid.

Q. What are the definitions of SR and QLPU in the context of the HECO Generating System?

A. SR and QLPU in the context of the HECO Generating System were described in detail in my direct testimony in the HECO 2007 test year rate case (Docket No. 2006-0386, HECO T-6, pages 4 to 7). In general, SR is the sum of the capabilities of all generating units operating on the grid less the system load demand at any point in time, and QLPU is the combined increase in generation (within three seconds) of all generating units that are on line at the time of an unexpected generator forced outage.

Q. What is Capacity Factor?

A. Capacity Factor for a generating unit is a measure of its power generation in a given year. Capacity Factor is expressed in percent, and is defined as the actual kilowatt-hours produced in a year times 100, divided by the rated kilowatt capacity of the generating times 8,760 hours (for a non-leap year). A capacity factor of 100% is equivalent to the generating unit being operated at its rated capacity for every hour of the year. Capacity Factors for steam-electric units tend to range from several percent to more than 50 percent depending on their duty. Units having similar Capacity Factors may be dispatched differently during the course of the year. For example, a generating unit operated at its rated capacity for half of the hours in a year and being off line for the other half would have a Capacity Factor equal to 50%, and a second generating unit with the same rated capacity and operated at different loads every hour of the year could produce the same total kilowatt-hours as the first unit, and would thus, also have a Capacity Factor equal to 50%.

Q. Is the Capacity Factor of the HECO generating units indicative of their duty?

A. Yes, for baseload generating units. Generating units having Capacity Factors of 50% or greater are generally producing the bulk of the power for an electric grid, and are typically baseload units.

Q. What have been the historical Capacity Factors for the HECO generating units?

A. The annual Capacity Factors for 1986 through 2007 are tabulated in HECO-705 for HECO's baseload, cycling, and peaking units. In addition, HECO-706 is a chart that shows the average Capacity Factors for each type of generating units, the total HECO generating system without the peaking units (i.e., the 14 steam-electric baseload and cycling units), and the total HECO generating system. The Capacity Factors for the eight baseload units for the 22-year period ranged from 38.0% to 86.9%, and averaged 62.5%. For the most recent 5-year period, from 2003 to 2007, the Capacity Factors ranged from 42.0% to 69.9%, and averaged 58.6%.

Q. What can be concluded about the duty of HECO's baseload generating units from these historical Capacity Factors?

A. For units of the design and age of the HECO generating units, Capacity Factors of 50% or higher would considered to be indicative of extreme duty. Generating units that have experienced Capacity Factors of 50% or greater for many years would have experienced considerable wear and tear over their life, and would require comprehensive maintenance to sustain reliable performance.

In 2006, HECO commissioned EPRI Solutions, Inc. ("ESI") to perform a review of HECO's Power Supply operations, maintenance and outage management programs. The review report, entitled *"Review of HECO's Power Supply Operations, Maintenance, and Outage Management Programs"* was filed with the Commission on October 20, 2006. A comparison of the Capacity Factors between HECO's generating units and an industry peer group of similar units was included in that review. Figure 8 of the report, *"Net Capacity Factor (NCF) of HECO's Steam Fleet,"* shows the general trend of HECO's generating system Net Capacity Factor for 1986-2005. (This page of the ESI report is included as HECO-707.) The trend for the "HECO Steam Fleet" is similar to that in HECO-705 for "HECO Total System without Combustion Turbines." ESI concluded: "First, the figure clearly indicates that HECO's steam units run at consistently higher capacity factors than the industry peer group. ESI also presented a comparison of the 5-year Capacity Factor (i.e., for the period 2001 to 2005) in Table 3 of the report, *"5-year Average Net Capacity Factor of Steam Units."* (This page of the ESI Report is included as HECO-708.) This table illustrated that the 5-year Capacity Factors for HECO's baseload generating units ranged from 51.5% to 68.5%, and averaged 58.9%. ESI concluded: "Many of the HECO units are running at nearly double the industry peer group average. This reflects the severe capacity strain placed on the entire fleet. Because HECO's supply and demand margin is so tight, every unit is required to contribute that much more to the power supply. This results in more stress and strain on the equipment and fewer opportunities for equipment maintenance and repair." ESI also concluded: "The second aspect of this figure is that it shows a trend upwards in Capacity Factor." (See HECO-707.)

Another consideration noted by ESI is: "HECO's baseload units are impacted by daily minimum loads on their respective auxiliary equipment. This is attributed to the addition of IPP baseload capacity in the early 1990's that required HECO baseload units to share the minimum load with IPP baseload units. Due to the relative differences in efficiency between the HECO units and the IPP units, HECO baseload units are operated down to their respective minimum loads to meet system requirements while IPP baseload units operate close to their maximum output. In order to operate safely at minimum loads, HECO baseload units must cycle (on/off operation) critical auxiliaries on a daily basis. This mode of operation increases wear and tear on critical auxiliaries (e.g., pumps, motors, valves, breakers, etc.) and increases the potential for breakdown and subsequent operation with a derating."

The HECO situation has not changed since 2005. As shown in HECO-705, the Capacity Factors for the baseloaded steam units (W7, W8, and K1 through K6) ranged from 51.2% to 69% in 2006 and from 49.7% to 68.8% in 2007.

Q. Will the addition of CIP CT-1, the new peaking unit, relieve the duty of the HECO baseload generating units?

A. The addition of CIP CT-1 will not materially affect the commitment, dispatch, or duty of the HECO baseload generating units. CIP CT-1 will provide increased reserve capacity, which will be utilized to help meet SR and QLPU criteria, and will help prevent generation shortfall incidents (i.e., rolling blackouts) during certain system emergencies. CIP CT-1 will also provide more flexibility in scheduling maintenance outages of the other generating units, including the baseload units, and this will result in fewer MWh than would otherwise be lost due to extended operation of derated baseload units that require an outage for corrective maintenance. Moreover, CIP CT-1 will provide for increased stability of the grid as more intermittent renewable energy sources are added in the future.

Q. What is the expected duty for the HECO baseload generating units in the future?

A. As discussed in the 2008 AOS, the HECO baseload generating units are expected to continue to provide the bulk of energy produced on the HECO grid for the foreseeable future. Moreover, each of the eight baseload units are expected to continue to have Capacity Factors greater than 50% and duty similar to that experienced in recent years.

Q. What may be concluded about the duty of HECO's baseload generating units?

A. Because HECO's baseload generating units will continue to experience high Capacity Factors in the future, it is important to perform the necessary maintenance to sustain the relatively high reliability of these units.

Q. What would be indicative of the historical duty for HECO's cycling units?

A. Capacity Factor would not be a good measure of the duty of cycling units because they rarely operate at high loads for extended periods. A more representative indicator would be annual service hours, that is, the number of hours per year that the unit is committed and synchronized to the grid.

Q. Based on service hours, how would one characterize the duty of HECO's cycling units?

A. HECO-709 provides a historical perspective of the duty of HECO's cycling units, which include Waiau 3 through 6, and Honolulu 8 and 9. Over the past twenty-two years, the annual service hours of HECO's cycling units have ranged from 11,702 hours/year to more than 37,000 hours per/year. In the late 1980's, a period that corresponded to relatively low generating reserve margins on the HECO system, annual service hours were at their highest levels. Conversely, during the 1990's, a period that corresponded to relatively high generating reserve margins on the HECO system, annual service hours were at their lowest levels. Since 2004, the annual service hours of the cycling units have trended higher, indicative of increasing duty and lower generating reserve margins.

Q. What would be indicative of the historical duty for HECO's peaking units?

A. Over the past twenty years the situation for the peaking units, Waiau 9 and 10, has paralleled that for the cycling units. As discussed in my direct testimony in the HECO 2007 test year rate case (Docket No. 2006-0386, HECO T-6, page 16), HECO's peaking units were designed to start and stop daily, and to operate for a few hours per day. This would be equivalent to approximately 500 annual service hours. As shown in HECO-710, over the past twenty years the annual service hours of HECO's two peaking units have ranged from less than 500 hours/year to a few thousand hours per/year. In the late 1980's, a period that corresponded to relatively low generating reserve margins on the HECO system, annual service hours were at their highest levels, and in 1988 they exceeded 3,000 hours/year. Conversely, during the 1990's, a period that corresponded to relatively high generating reserve margins on the HECO system, annual service hours were at their lowest levels. Since 2004, the annual service hours of the peaking units have trended higher, indicative of higher duty and lower generating reserve margins. As stated in my direct testimony in the HECO 2007 test year rate case (Docket No. 2006-0386, HECO T-6, page 16), "this operation (i.e., of a few thousand service hours per year) is more like cycling duty, and the longer operating hours are increasing the 'wear and tear' on these units."

Also, as stated in my direct testimony in the HECO 2007 test year rate case (Docket No. 2006-0386, HECO T-6, page 15), "The cycling and peaking units and their associated auxiliary equipment must turn on and off, on a daily basis, and this results in cyclic thermal stresses and accelerated wear on cycled auxiliary equipment, which could exacerbate damage to critical parts, and could result in a generating unit forced outage or derating."

Q. What is the expected duty for the HECO's cycling and peaking generating units in the future?

A. As generating reserve margins increase on the HECO generating system, as they will with the addition of CIP CT-1, the duty for HECO's cycling and peaking units are expected to trend lower. This assumes that the reliability of the generating system will be sustained at today's levels, and that major long-term forced outages are infrequent.

Q. What may be concluded about the duty of HECO's cycling and peaking generating units?

A. Because HECO's cycling and peaking generating units will continue to experience high duty in the future it is important to perform the necessary maintenance to sustain the relatively high reliability of these units.

<u>Conventional Generation on the HECO System</u>

Q. How does generation affect system frequency?

A. Operation of the electric grid requires a constant matching of the amount of generation (i.e., MWs being generated) with the total amount of demand for electricity by customers (i.e., MWs of customer load). When generation matches the demand for electricity, the system frequency will be 60 cycles per second (Hertz or Hz). If generation exceeds the demand, system frequency will increase. If generation is lower than demand, then system frequency will decrease. Customer equipment depends on 60 Hz (i.e., the standard for system frequency in the United States) for proper operation. In addition, generating units are designed to operate at 60 Hz. Deviation from 60 Hz of greater than 0.5 Hz can cause cumulative damage to customer equipment and generating units.

Matching the generation with demand basically involves changing the level of generation to match, or follow, the total customer load. The ability for generation to match the demand depends upon the operating characteristics of the individual generating units that are on-line.

Q. What type of generating units can help maintain system frequency at 60 Hz?

A. Only generating units that are dispatchable and/or generating units with local governor control (i.e., automatic response to change in rotational speed) can help towards following the total customer load and therefore maintain system frequency at 60 Hz. When on-line, the unit should be fully dispatchable from minimum to full load by the utility and should be capable of load-following, providing frequency control, and voltage support.

Q. What does "full dispatchability" mean?

A. "Full dispatchability" means that the utility would be able to control the output of the unit from moment to moment from its minimum load rating to its normal top load capability to serve the load (load-following, economic dispatch) or to help maintain system frequency or voltage. In order to maintain a stable grid with stable frequency, the aggregate output of all generating units (including that of as-available units) must be equal to total system demand. System demand changes from moment to moment as customers turn lighting, appliances and equipment on or off. The generating units must react to these changes in demand by increasing or decreasing their output either through automatic dispatch via Automatic Generator Controls or through dispatch by the system operator. Steam units that have high rotational inertia also help keep the system stable in the event of system disturbances (such as generating unit or transmission circuit trips) and also provide frequency regulation capability.

Q. What is "conventional generation?"

A. "Conventional generation" are units that are fully dispatchable from minimum to full load by the utility, and are not only capable of load-following, but also provide frequency control and voltage support. Voltage on the system must also be controlled to within certain ranges. For example, General Order No. 7 provides the following voltage tolerances:

- Retail service, except power service: ±5% of nominal voltage (¶7.2a)
- Retail power service: ±7½% of nominal voltage (¶7.2a)
- Industrial service: ±5% of nominal voltage (¶7.2b)
- Transmission voltage: ±10% of nominal voltage (¶7.2c)

Q. What could be the consequences of not controlling frequency and voltage?

A. Frequency and voltage excursions could result in interruptions in service or damage to customer equipment or utility equipment. Therefore, frequency and voltage must be carefully controlled.

Q. What is the role of conventional generation if intermittent renewable energy sources are added to the grid?

A. Having conventional generation operating on the grid is critical when integrating intermittent renewable energy resources (also referred to as "variable generation"), such as wind farms into the grid. As discussed in greater detail below in my testimony, to be able to quickly offset the changes in wind farm output, it is necessary to have regulating reserve on-line such that total generation can be ramped either up or down to cover the potential variation in wind farm output. When the outputs of the as-available units increase, the outputs of the firm units must be decreased through automatic dispatch so that supply and demand can remain balanced. Similarly, when the outputs of as-available units decrease, the outputs of the firm units must be increased. The larger the total amount of wind farms that are on-line, the larger the potential variation in wind farm output and the larger the required amount of regulating reserves. If system demand is increasing or decreasing as as-available unit output is increasing or decreasing, dispatch decisions must then take the two simultaneous actions into account in dispatching the firm generating units. Therefore, having fully dispatchable units is critical in maintaining a stable grid.

Q. What will be the major challenges to the HECO as more renewable energy sources are added to the grid?

A. The challenges for us as a utility will be to (1) optimize the performance of the generation that provides the critical ancillary services of load following, frequency control, voltage support, as well as back up when intermittent resources are not available, and (2) convert even conventional generation to "green" generation as sustainable biofuels become available.

<u>Distributed Generators</u>

Q. Why did HECO install DG units?

A. As discussed in the 2008 AOS, "HECO has taken a number of steps to mitigate the effects of reserve capacity shortfalls, such as installing temporary, limited run-hour DG at substations and other HECO sites. HECO has approximately 29.5 MW of temporary, leased HECO-sited DG in operation.

Q. Does HECO intend to install additional DG capacity?

A. HECO's ability to install DG at additional company sites is limited, primarily due to technical, zoning, and space considerations. HECO would need to consider smaller sites capable of accommodating fewer DG units, which would result in higher dollar per kilowatt installed costs. HECO is not actively pursuing development of additional utility-sited temporary DG resources at this time, but would consider doing so depending on the needs of the system.

Q. How is the duty of HECO's DG units measured?

A. As shown HECO-711, the DG Monthly Report for December 2007, the service hours (i.e., "engine hours") are recorded for the previous twelve months for each engine. This report, which is prepared at the end of each calendar month, provides a snapshot of the service hours for each DG for each of the previous twelve months. In general, the DG units have been utilized for two primary purposes: (1) to provide economic power generation for short periods; and (2) to provide peaking power during periods when SR and QLPU criteria can not be met with the other generating units available on the HECO system. The dispatch of the DG units also takes into consideration the total number of engines hours that are allowed during any contiguous twelve month period by the conditions of the air emissions permit, which is also specified on the DG Monthly Report.

Q. Based on the DG Monthly Report for December 2007, how would one characterize the duty of HECO's DG units?

A. All of the DG units have been utilized to different extents, and all have more than 50% of the engine hours allowed by their respective air permits kept in reserve for potential use during a system emergency.

Q. What is the expected duty for HECO's DG units in the future?

A. Until such time that generating reserves increase and HECO's DG units have been disconnected from the grid, the duty of HECO's DG units is expected to be similar to that experienced in 2007.

Q. What is dispatchable standby generation ("DSG")?

A. DSG refers to the active operation of customer-owned standby generators by the electric utility to meet utility system needs. As such, the generating units serve dual purposes as emergency generators for a customer facility and as limited duty distributed generating units for the utility. The utility would contribute funding to the DSG customer for paralleling, interconnection, communication, and other equipment. This equipment would allow HECO to remotely start and stop the standby generators to supplement HECO's grid capacity as needed for a portion of the hours in a year (e.g., up to 1,500 run hours per year). Regardless of whether HECO is dispatching the generator or not, the standby generator facility would serve the customer with emergency power if grid power was lost. HECO would reimburse customer fuel costs or provide the DSG fuel, pay for routine maintenance and permitting, and provide a monthly incentive payment to the DSG customer. The electricity generated by the DSG facility would be considered as utility power since HECO is providing the fuel and maintenance of the unit.

Q. What are the benefits of DSG to the customer and to HECO?

A. The potential benefits of DSG to the DSG customer include (1) reduced or avoided capital, operations, and maintenance costs, (2) improved generating unit reliability due to regular startups and testing under load, and (3) utility consulting and collaboration. The primary benefits to HECO of such an arrangement are the provision of cost-effective utility system reserve capacity and the ability to support the operation of a critical customer.

Q. Is HECO pursuing, or has HECO pursued any DSG projects?

A. Yes. HECO has pursued DSG projects at Kaiser Hospital ("Kaiser"), Queen's Hospital ("Queen's"), and the Honolulu Airport. HECO also evaluated a possible DSG opportunity at the City and County of Honolulu's Wahiawa Wastewater Treatment Plant but did not provide a DSG proposal for this facility. Of these, the Honolulu Airport DSG project is the only project that is still actively being developed.

Q. Is HECO forecasting any DSG expenses in the 2009 test year?

A. No. HECO is not including any DSG expenses in the 2009 test year. Although HECO is still pursuing the Honolulu Airport DSG project and has submitted a proposed DSG Agreement to the State Department of Transportation, the DSG Agreement has not been executed yet and the project is not slated for service until 2010. HECO expects to execute a DSG Agreement in 2008, after which HECO would file the DSG Agreement for approval by the Commission.

Q. Please explain what happened with the Kaiser and Queen's DSG projects.

A. As described in my testimony in the HECO 2007 test year rate case (Docket No. 2006-0386, HECO T-6, pages 68 to 71) HECO was pursuing a 1.64 MW DSG project at Kaiser. HECO anticipated execution of the Kaiser DSG agreement in December, 2006 and installation and operation of the DSG unit at Kaiser beginning in August, 2007. In March 2007, HECO withdrew its DSG proposal from Kaiser due to projected increases in DSG project costs caused by Kaiser's construction schedule. In HECO's June 2007 Update to the HECO 2007 test year rate case (Docket No. 2006-0386) HECO removed Kaiser DSG expenses due to cancellation of the project.

In March, 2007, HECO initiated a DSG evaluation with Queen's, eventually leading to a HECO proposal in late August 2007 for a 6.6 MW DSG operating arrangement. After several months of negotiation, Queen's decided to not go forward with the HECO DSG proposal due to Queen's concerns that the DSG arrangement might negatively affect the tax-exempt financing of their project, and that additional DSG design requirements imposed by HECO might delay installation of the emergency generators. Accordingly, HECO withdrew its

Queen's DSG proposal on January 8, 2008.

Q. Please describe how expenses for HECO's DSG projects are tracked while they are being developed.

A. Expenses for DSG projects in the conceptual stage are expensed. After the customer has committed to developing the project as documented by the execution of a Letter of Intent, Memorandum of Understanding or similar agreement the project charges are accumulated in a preliminary engineering work order number (PEWON). Preliminary engineering for the project continues while PUC approval is being sought. After Commission approval is granted the charges in the PEWON are transferred to capital work in progress. The project is then authorized for expenditures for engineering, materials and construction.

Q. What happens to the charges if the potential project is not developed?

A. If the decision to cancel the project is made before Commission approval is received, the accumulated expenses in the PEWON account are transferred to Power Supply's clearing account. The total clearing charges are allocated through the application of the Power Supply on-costs.

Q. How are project costs treated if a project is abandoned after Commission approval?

A. Project-related expenses that are recognized as construction work in progress are expensed if the project is not completed, unless the costs result in items that have future value. If any of the costs represent items that have future value that are usable on another capital project, the related costs are transferred to other projects or accounts as appropriate.

Q. Did HECO incur preliminary engineering expenses for the Kaiser, Queen's, and Wahiawa DSG projects, and if so, what were the amounts and when were these expenses transferred to Power Supply's clearing account?

A. HECO incurred $13,157 in preliminary engineering expenses for the Kaiser DSG project (Work Order No. AD001815), which were transferred to Power Supply's clearing account on April 20, 2007. HECO incurred $52,091 in preliminary engineering expenses for the Queen's DSG project (Work Order No. AD002003), and transferred this to Power Supply's clearing account on December 28, 2007. HECO incurred $492 in preliminary engineering expenses for the Wahiawa Wastewater Treatment Plant DSG evaluation (Work Order No. AD002002), and transferred to Power Supply's clearing account on May 15, 2008.

Q. Does HECO forecast expenses for the pursuit of DSG?

A. No. In the 2009 test year HECO does not have any expenses for the pursuit of DSG.

Biofuels for Conventional Generation

Q. What is the status of HECO's multi-year, multi-phase research and development program to examine biofuels for conventional generation?

A. As stated in my testimony in the HECO 2007 test year rate case (Docket No. 2006-0386, HECO T-6, page 69), "HECO has an active multi-year, multi-phase research and development program to examine biofuels for conventional generation consisting of the following: Phase 1 – Biofuels resource assessment; Phase 2 – Combustion testing; Phase 3 – Generating unit assessment and infrastructure and operational assessment; and Phase 4 – Utility-scale demonstration." Phases 1, 2, and 3 have been completed. Regarding Phase 4, HECO is planning to perform a comprehensive test of biofuel operation at one of its 90 MW, steam-electric generating units at Kahe Power Plant in 2009 (aka, "Kahe 3 Biofuel Cofiring Project"). The test will address operational, environmental, and safety aspects of biofuel operation for different biofuel blends with LSFO, potentially up to 100% biofuel operation. The testing period will last about 30 days and will consume approximately 1,000,000 gallons of biofuel. It is expected that the test would be performed using a "crude" biofuel such as crude palm oil, and not biodiesel. The test is tentatively scheduled to occur in late 2009. Project activities leading up to the test will include: laboratory analysis of prospective biofuel-LSFO fuel blends, specification of the biofuel, procurement and arrangement for on-island storage of the biofuel, arrangements for transport to and storage of the biofuel at the HECO power plant, modifications to power plant fuel handling and combustion equipment, design and construction of an automated fuel blending system, Commission approval for procurement of the biofuel, and design and organization of the testing program. The results from the test program will serve, in part, as a technical basis for future conversions to biofuel operation of HECO's fourteen steam-electric units on Oahu.

Q. Does the 2009 Other Production O&M Expense include any costs in support of the Kahe 3 Biofuel Cofiring Project?

A. No. Expenses for planning and implementing of the Kahe 3 Biofuel Cofiring Project are not included in the 2009 Other Production O&M Expenses. The expenses for the Kahe 3 Biofuel Cofiring Project are comprised of three parts: (1) Incremental cost for biofuel relative to the cost of Low Sulfur Fuel Oil; (2) Capital cost for equipment to be installed at Kahe 3; and (3) O&M expenses for performing the tests, analysis, and reporting. The incremental fuel costs will be addressed in a separate application to the Commission to recover the costs through the Energy Cost Adjustment Clause (ECAC). The estimated costs for the capital assets are discussed in Ms. Lorie Nagata's testimony at HECO-WP-1701.

The O&M expenses are included in the new technology expense discussed in Mr. Bruce Tamashiro's testimony, HECO T-14.

Q. Will HECO be operating any or all of its combustion turbines on biofuels in the future?

A. Yes. HECO plans for the new generating unit at Campbell Industrial Park, CIP CT-1, to be operated on biodiesel. In accordance with the air permit, CIP CT-1 will be commissioned firing petroleum diesel (i.e., No. 2 oil) in mid-2009. A test will subsequently be performed to characterize the performance and air emissions firing biodiesel. The test results will be used as a basis to modify the air permit to allow for continuous operation firing 100% biodiesel. Once the modified air permit is issued, CIP CT-1 will be operated firing biodiesel.

Similarly, HECO is considering converting the operation of Waiau 9 and 10 from firing petroleum diesel to biodiesel, but this would not occur in 2009.

<u>HECO Generating System Facilitates the Addition of Renewable Energy</u>

Q. Please describe the challenges presented by accommodating more as-available renewable energy on the grid.

A. The operation and maintenance of HECO's current generating units will be impacted in several ways as more as-available renewable energy sources (aka, "variable generation") become connected to the HECO grid, including:

- HECO's baseload, cycling, and peaking generating units will have to operate in a more dynamic mode (i.e., changing loads more often and at higher load ramp rates) to counter balance the more volatile and unpredictable power from the as-available energy sources such as wind.

- As more energy is produced from as-available renewable energy sources, Capacity Factors of HECO's baseload, cycling, and peaking units will decrease. However, since these units need to been on line as a counter balance for potential load reductions from the as-available renewable energy sources, the decreases in Capacity Factors will mean that the HECO units will operate more hours at lower loads.
- Operation of HECO's baseload units more hours at lower loads will result in increased heat rates (i.e., poorer thermal efficiency).
- As-available renewable energy sources typically do not provide ancillary services (e.g., voltage support, frequency control, etc.) for the grid. HECO may have to compromise economic dispatch of its firm power generating units, and commit and dispatch generating units based on other factors in order to manage the grid. This would also negatively affect heat rate.

Q. Why are HECO generating units needed to support intermittent as-available renewable generation such as wind or photovoltaic ("PV") generation on the HECO system?

A. Power systems require that the generation resources on the system collectively provide several characteristics that the system fundamentally needs for reliable operation. These characteristics include adequate firm generating capacity, controlled dispatch of generation, frequency regulation, and sufficient rotational inertia to maintain system stability. Baseload, cycling, and peaking generating units are commonly referred to as "firm" power, and their power output can be dispatched as needed. As-available resources like wind and PV are not firm, can not be dispatched, and are unable to provide prescribed amounts of power upon command or at scheduled times.

The important characteristics of HECO's generating fleet that facilitate and support the integration of intermittent renewable energy resources, and without which the safe and reliable operation of the system is not possible, are further discussed below.

Capacity

HECO's obligation to serve means it needs to have enough generating capacity on the system to reliably serve the expected system loads. To do this HECO needs generation that it can count on when needed. By definition, the output of intermittent generation can change rather unexpectedly and cannot be fully counted on to serve system loads. As such, there needs to be sufficient HECO firm capacity generation available and online to be able to make up the difference should the power output of intermittent as-available generation fall off or be entirely unavailable at any time.

Dispatchability

HECO's dispatchable generating units are needed to maintain a balance between the system generation and the system load. For example, as the load grows during the day, dispatchable generators that can be reliably set to specified output levels are needed to maintain this balance. As-available intermittent generation resources like wind and PV are not dispatchable and their maximum power output is a function of the natural conditions of the environment from moment to moment. The power output of HECO's generating units must be dispatched to counter balance changes (either up or down) in the output of as-available generation.

Frequency Regulation

The system also needs to carry an adequate amount of regulating reserve, which is the amount of operating reserve measured in megawatts (both up and down) that is controlled by HECO's automated Energy Management System. The purpose of regulating reserve is to maintain a "cushion" for responding to changes in load demand or power output from generation sources connected to the grid. In this way, total system demand and supply are kept in balance and system frequency is maintained at 60 Hertz. Firm generating units have the needed capability to increase or decrease their power output quickly and in a controlled manner in response to changes in system frequency driven by fluctuations in the output of intermittent renewable energy resources.

Rotational inertia

System stability is the ability of an electrical system to continue to operate and remain stable during a period of disturbances, such as a sudden loss of load resulting from a power interruption, or the initiation of system protection measures resulting from a system fault condition. What gives systems stability are features that include the appropriate dynamic characteristics of generating units (such as a unit's rotational inertia), the overall strength of the transmission system, and the location of generation resources relative to load. The overall rotational inertia of generation connected to the system needs to be large enough to enable the system to effectively ride through system disturbances. The rotational inertia of HECO's firm generating units keep the rate of change of the system frequency low enough during disturbances to allow the system to recover before frequency reaches unacceptable levels that cause either load or other generation to disconnect from the system. In severe events, disconnection of generation or load can result in a domino effect that can culminate in a complete system collapse and an island-wide blackout. Intermittent renewable generation resources generally provide little or no rotational inertia to the system and when on-line, can displace generators that have this critical characteristic. Stability issues are extremely important on island electrical systems that are not interconnected with other utility grids and, thus, cannot receive assistance from another grid in the event of a destabilizing disturbance.

Ultimately, the addition of new firm generating units on the grid that have flexible characteristics like quick starting and fast ramping capabilities, like HECO's CIP CT-1, will further support the integration of intermittent as-available renewable generation on the HECO system.

Reliability of the HECO Generating System

Q. What metrics are used to measure the reliability of HECO's generating system and its individual generating units?

A. HECO uses two metrics to track generating unit reliability: Equivalent Availability Factor ("EAF"), and Equivalent Forced Outage Rate ("EFOR"). Both are standard measures of generating reliability and are regularly compiled and reported to the North American Electric Reliability Corporation ("NERC"). A detailed discussion on EAF and EFOR was presented my direct testimony in the HECO 2007 test year rate case (Docket No. 2006-0386, HECO T-6, pages 7 to 10). As described in the 2008 AOS (Section 3.2 and Appendix 5), EFOR is also a critical factor that is used in capacity planning criteria to determine the adequacy of supply and whether or not there is enough generating capacity on the system.

Q. What does EAF measure?

A. EAF measures the percentage of time that a generating unit, combination of generating units, or the generating system as a whole is available to operate at full capacity. A higher EAF rating indicates better reliability.

Q. What does EFOR measure?

A. EFOR measures the percentage of time that a generating unit, a combination of generating units, or the generating system as a whole is unavailable to operate at full capacity due to unplanned (i.e., "forced") outages and deratings. A lower EFOR rating indicates better reliability.

Q. Has HECO established a reliability goal in order to meet system requirements?

A. Yes, on an annual basis the reliability goal is for EFOR to be below the Forward-Looking EFOR values presented in the AOS report submitted to the Commission. For 2008, the Forward-Looking EFOR value is 6.1% and the HECO reliability goal is for EFOR to be less than 6.1%. The longer-term reliability goal is for EFOR to be sustained below 5%.

Q. How does HECO's EFOR performance in recent years compare to the corresponding Forward-Looking EFOR values expressed in the 2006, 2007, and 2008 AOS?

A. A comparison of actual EFOR to corresponding Forward-Looking EFOR values is presented in the table below. The actual values have compared reasonably well to the Forward-Looking values, and the annual goal has been met in recent years.

	EFOR (Actual)	**EFOR (AOS Forward-Looking)**
2006	**5.30%**	**6.8%**
2007	**5.13%**	**5.4%**
05/31/08	**4.06%**	**6.1%**

Q. Were the 2006, 2007, and 2008 AOS Forward-Looking EFOR values reasonable?

A. Yes. As stated in the 2006 AOS: "This higher EFOR projection (compared to the

2005 AOS projection) reflects an expectation of continued constraints on maintenance flexibility, continued aging of the generating units, and deratings resulting from the cycling operation of certain units and their auxiliary equipment, and more frequent and longer duration overhauls and maintenance outages."

It should also be noted, however, that during the subject period HECO did not experience a forced outage of multiple-month duration of any of its generating units. During 2004 and overlapping into 2005, HECO, experienced a 23-week forced outage at Waiau 9. In 2005 and overlapping into 2006, HECO experienced a 17-week forced outage at Waiau 8. These types of outages can not be forecast and are not incorporated in the Forward-Looking EFOR. For reference purposes, a single two-month forced outage of a 90 MW steam-electric baseload generating unit would increase the annual EFOR for the system by approximately 1%.

Unplanned deratings and/or unit trips also can not be forecast, but are due, in part, to the arduous duty that HECO's aging units experience, and the amount of reserve margin available to perform repairs while minimizing risk to the system. When problems are detected, corrective action is taken as soon as possible once the root cause is identified. In the case of unplanned deratings, corrective action may be delayed depending on expected system demand, available reserve margin, outage priorities on other units, and parts/materials availability.

Q. How does HECO's Generating System EAF and EFOR compare with NERC statistics for other generating systems?

A. As discussed in my direct testimony in the HECO 2007 test year rate case (Docket No. 2006-0386, HECO T-6, pages 8 to 9), HECO has been comparing its performance to that for an industry peer group for many years. Summaries and discussions of these comparisons have been provided in prior rate testimony. An analysis of these statistics was also performed by ESI in 2006, and included in their report (*"Review of HECO's Power Supply Operations, Maintenance, and Outage Management Programs"* filed with the Commission on October 20, 2006). ESI's conclusion, stated on page 32 of their report, is "ESI observed that, over the past two (2) decades the HECO steam fleet has performed exceptionally well compared to industry averages in both of these categories."

As summarized below, since 2006, HECO's EFOR and EAF have continued to be substantially better than the historical values for "Industry EFOR" and "Industry EAF."

Year	HECO EFOR	Industry EFOR	HECO EAF	Industry EAF
2004	6.18%	41.81%	85.84%	72.40%
2005	9.25%	18.72%	84.54%	82.07%
2006	5.30%	20.09%	86.52%	80. 84%
2007	5.13%	n/a	85.48%	n/a
Thru 05/31/08	4.06%	n/a	86.00%	n/a

HECO's historical EFOR and EAF statistics are presented graphically HECO-712 and HECO-713, respectively. Also included in these graphical figures are corresponding statistics for an industry peer group. The statistics for the industry peer group are presented for calculations using two methods, referred to as: "Industry – New Method" and "Industry – Old Method."

Q. Please explain why the statistics for the industry peer group were calculated by two methods?

A. The methodology used to determine the industry EFOR and EAF values changed in 2005. The methodology used prior to 2005 is referred to as the "Industry – Old Method," and the methodology used since 2005 is referred to as the "Industry – New Method." Both methods are described in HECO-WP-704. The Industry – Old Method combined and normalized data for generating units on a megawatt basis, and the Industry – New Method combines and normalizes data for generating units based on the number of units in each size category. In general, the net effect is that the statistical result for EFOR or EAF in any particular year may vary by up to a few percent depending on the method used. The only exception was 2004, where the differences were several percent. The 2004 data can not be explained and is considered to be an anomaly.

Q. Does the choice of methodology for calculating the industry peer group reliability statistics impact the conclusion about the comparative performance of the HECO generating system?

A. No. Although the EAF and EFOR for the industry group changed, the conclusion has not. HECO's EAF and EFOR have consistently been better than corresponding values for industry peer groups since 1990, and this continues to be the case.

Q. How does EFOR contribute to the reserve margin shortfall situation that HECO has been facing?

A. As explained in the 2008 AOS, HECO's capacity planning criteria are applied to determine the adequacy of supply and whether there is enough generating capacity on the system. HECO's capacity planning criteria consist of two rules and one reliability guideline. The reserve capacity shortfalls calculated in the annual AOS reports are determined by the application of the reliability guideline, which involves a Loss of Load Probability ("LOLP") calculation. The outputs of the LOLP calculation are driven by the input assumptions. The key input assumptions include the load to be served, the amount of firm capacity on the system, and the availabilities of the generating units. The EFOR of each generating unit are key determinants of the availability of the unit. As EFORs increase, the amount of reserve margin necessary to satisfy the reliability guideline also increases. In the LOLP analysis summarized in the 2008 AOS for the reference scenario, the Forward-looking EFORs (summarized in Table 1 and discussed in Appendix 5 of the 2008 AOS) were utilized to calculate the Reserve Capacity Shortfall (expressed in megawatts) and presented in Table 4 of the 2008 AOS, and reproduced below. If the EFOR increased then the Reserve Capacity Shortfall calculated by the LOLP method would be greater.

Year	Reserve Capacity Shortfall (MW)
2008	-80
2009	-40
2010	-20
2011	-30
2012	-50
2013	-50
2014	-70

Q. What steps is HECO taking to address the Reserve Capacity Shortfall situation?

A. As discussed in the 2007 IRP-3 Evaluation Report and the 2008 AOS, and will be further addressed in HECO's IRP-4 Report, from Production's perspective, the Action Plan and Mitigation Measures include (but are not limited to):

- Sustaining an operational staff to allow for 24 hours a day, 7 days a week operation of all steam generating units, and 16 hours a day, 7 day a week operation of CIP CT-1.
- Rescheduling maintenance of generating units when feasible,
- Pursuing initiatives that improve EFOR for HECO generating units,
- Evaluating long-term DG and DSG resource opportunities,
- Assessing potential DG sites on Oahu military bases.

Each of these measures is included in the Other Production O&M Expense and is being discussed in my testimony.

Q. Is Reserve Capacity Shortfall more of a concern for an island utility like HECO as compared to a mainland utility?

A. Yes. On the mainland, utilities are interconnected to neighboring utility systems and can rely on this large, interconnected power grid for reserve capacity and system stability. HECO's grid is isolated from other electric system and relies only on the generation resources on Oahu.

Q. Will the addition of CIP CT-1 alleviate the Reserve Capacity Shortfall?

A. As discussed in the 2008 AOS, CIP CT-1 will reduce but not eliminate the Reserve Capacity Shortfall when it is added to the grid in 2009.

Q. How do the current demands upon the HECO Generating System affect O&M requirements?

A. In general, the current demands upon the HECO Generating System impact O&M requirements in two ways: (1) all of HECO's units have to be available for 24 X 7 operation except during periods of planned and unplanned maintenance; and (2) adequate amounts of preventative and corrective maintenance must be performed on a continuing basis to sustain the reliability of HECO's generating units at acceptable levels.

Q. What is the targeted level of reliability for HECO's generating units?

A. In general, based on the type, age, and duty of its generating units, HECO's target is for the annual EFOR to be less than 5% for the HECO Generating System. In any particular year, HECO's target also would be for the annual EFOR to be less than the corresponding Forward-Looking EFOR in the AOS reports submitted to the Commission. For 2006, 2007, and 2008, the Forward-Looking EFOR's were 6.8%, 5.4%, and 6.1%, respectively.

Q. How is HECO sustaining an acceptable level of reliability?

A. HECO achieves an acceptable level of reliability through a comprehensive maintenance program that consists of planned and unplanned work. The maintenance work comprises preventative (PM), corrective (CM), and predictive (PdM) maintenance as discussed in my direct testimony in the HECO 2007 test year rate case (Docket No. 2006-0386, HECO T-6, pages 20-21). The majority of the maintenance work is performed during outages (i.e., when the generating unit is out of service). As discussed in detail in my direct testimony in the HECO 2007 test year rate case (Docket No. 2006-0386, HECO T-6, pages 16-19), there are three categories of maintenance outages: (1) Planned Outages ("PO's") or overhauls; (2) Maintenance Outages ("MO's"); and (3) Forced Outages ("FO's"). PO's and MO's are scheduled in advance and are included in the Planned Maintenance Schedules ("PMS's") discussed later in this testimony.

<u>Types of Maintenance</u>

Q. Describe the different types of maintenance work that are generally performed.

A. As discussed in my direct testimony in the HECO 2007 test year rate case (Docket No. 2006-0386, HECO T-6, pages 19-21), HECO generally performs the following types of maintenance:

- <u>Preventative Maintenance ("PM").</u> PM is generally performed on a scheduled basis to prevent equipment failure while in service and to sustain equipment performance in accordance with design specifications. PM would include items such as replacement of fluid and gas filters, changing lubricating fluids, replacement of wear components in moving equipment, periodic greasing of traveling screen chains and soot blower drives, and boiler tube cleaning (internal and external).
- <u>Corrective Maintenance ("CM").</u> CM is generally performed to repair or replace equipment that has failed in service or whose performance has deteriorated by a significant degree. Types of CM may include: rebuilding or replacement of large pumps, motors, regulators, valves; repair or replacement and turbine-generator bearings and rebalancing of the rotor; and repair or replacement of failed boiler tube sections.
- <u>Predictive Maintenance ("PdM").</u> PdM is implemented based on the assessed condition of equipment and is scheduled to prevent equipment failure while it's in service. Equipment condition is assessed utilizing techniques that monitor and analyze specific operating parameters. PdM measurement techniques include vibration analysis of rotating equipment, chemical analysis of lubrication and hydraulic fluids, ultrasonic analysis, on-line infrared thermography, and pump pressure-flow performance tests. State-of-the-art instruments and software are used to monitor and track the condition of critical equipment. PdM work may consist of PM or CM type

work. For example, a generating unit that has multiple pump-motor sets (e.g., boiler feed pumps, circulating water pumps, condensate pumps) will have a PdM assessment of each. Then, based on the PdM results CM maintenance would be performed on the pump-motor set(s) that are in the poorest condition and prone to failure.

Q. Do all types of maintenance work require an outage?

A. No. In many cases the equipment requiring maintenance may be safely isolated and operational maintenance may be implemented without an outage. In other cases a derating of the unit or an outage will be required while the maintenance work will be performed. For example, if a boiler feed pump needs to be repaired it is typical that the work may be performed while the unit is derated. A HECO unit typically has two boiler feed pumps and the unit may be operated at approximately half its capability on one boiler feed pump, while the other boiler feed pump is isolated for repair. In this case the unit would be derated to approximately half capability until the second boiler feed pump was repaired and returned to service.

Q. What is enhanced condition monitoring?

A. Enhanced equipment condition monitoring ("ECM") is technology that monitors power plant instrumentation and controls values to determine if the equipment is operating within normal bounds. These techniques are used to assess the condition of equipment and the need for maintenance. Benefits are realized through early detection of incipient equipment failures such that the required maintenance can be completed on a scheduled rather than an emergency basis.

Q. What work has HECO done concerning enhanced equipment condition monitoring?

A. HECO initiated an evaluation of enhanced ECM systems in early 2005. HECO conducted a pilot project to evaluate the SmartSignal ECM system on one of the HECO generating units. This project was initiated in early 2006 and completed in February 2007. While the technical results of the evaluation were promising, HECO decided to not pursue further implementation of the SmartSignal ECM product due to commercial issues. HECO continued its evaluation of other commercially available enhanced ECM products and services in parallel with the SmartSignal pilot project. That work lead to another pilot project with Black & Veatch ("B&V"), a power plant engineering consulting firm. The B&V pilot project started in September 2007 and was completed in May 2008.

Q. What is the status of the B&V ECM program?

A. Based on the results of the B&V pilot ECM project, HECO has identified candidate actions for expansion of the enhanced ECM program. While these candidate actions and the associated costs and benefits are still under evaluation, the pilot projects have demonstrated the benefits of enhanced ECM and enhanced performance monitoring systems at HECO.

<u>Planning, Budgeting, and Execution of Overhauls</u>

Q. In general, can you describe the process to plan and execute an overhaul?

A. Yes. The "life cycle" of an overhaul consists of several steps:

- 20-year (ahead) Long Range Planning Schedule
- 5-year (ahead) Planned Maintenance Schedules (PMS)
- 2-year (ahead) Overhaul Plan and Budget
- 1-year (ahead) Overhaul Plan and Budget
- 1-month (ahead) Overhaul "Turnover" Plan and Updated Budget
- Outage (one to three months)

- Return to Service and Performance Testing

Q. What is included in the 20-year (ahead) Major Maintenance Plan?

A. The 20-year (ahead) Long Range Planning Schedule (LRPS) is an Excel workbook that is divided into worksheets, one worksheet for each of HECO's generating units (not including the DG's). Each worksheet is divided into 20 columns, one column for each of the next 20 years. For the year corresponding to an outage overhaul the major work items to be included in the respective overhaul are listed. For example, these major work items may include "Boiler Standard Package," "Generator Major Inspection," "Air Preheater Rotor Replacement," "Boiler Refractory Replacement," "Major Steam Turbine Inspection," etc. The 20-year (ahead) LRPS also includes a long range planning schedule similar to that provided as Attachment 1 to the Company's response to CA-IR-64 in the HECO 2007 test year rate case (Docket No. 2006-0386). The 20-year (ahead) LRPS is updated annually and the latest revision is provided as HECO-714. [Note, this revision actually contains data looking forward more than 20 years, but for purposes of maintenance planning it is referred to as the "20 year (ahead) LRPS."]

Q. How does HECO mitigate the potential for major costs associated with catastrophic equipment failures?

A. As described in HECO's response to CA-IR-231, part c. in Docket No. 2006-0386, major maintenance of boilers, turbines, generators, and combustion turbines is planned to occur nominally every three, six, nine, and eight years, respectively. The nominal planning interval for any specific work can vary based on unit specific condition evaluation, operation, machine type, etc. Experience gained from problems found at each inspection or during operation is also utilized in making future maintenance decisions, including re-evaluation of the nominal planning intervals. HECO also reviews and evaluates the number of run hours and number of starts in making maintenance decisions on the combustion turbine maintenance intervals.

Q. What is included in the 5-year (ahead) PMS?

A. As described in HECO-608 in the HECO 2007 test year rate case (Docket No. 2006-0386), and HECO's response to CA-IR-64 (Docket No. 2006-0386), PMS's are prepared five years in advance and include specific time slots for PO's and MO's for individual generating units. The PMS are updated periodically (up to several times per year) as needed to reflect changing circumstances.

Q. What is included in the 2-year (ahead) Overhaul Plan and Budget?

A. The work scope for an overhaul is based on information from many sources, including but not limited to: (1) Standard packages for preventive maintenance; (2) Open work orders; (3) PdM assessments; (4) Capital projects; (5) Discoveries in previous overhauls, and (6) Recommendations of System Owners. A team of two resource planners develop a preliminary plan, schedule, and cost estimate for the overhaul based on the work scope. The preliminary overhaul plan is reviewed by Power Supply supervisory personnel for content. The resource planners revise the plan (including refining of the cost estimates) and the updated plan is submitted to Power Supply senior management for review, approval, and inclusion in the 2-year (ahead) budget.

Q. What is included in the 1-year (ahead) Overhaul Plan and Budget?

A. The process is similar to that described for the 2-year (ahead) except that it includes greater detail in the specification of work and the cost estimates.

Q. What is included in the 1-month (ahead) Overhaul "Turnover" Plan and Updated Budget?

A. Approximately four months before the beginning of the scheduled outage for an overhaul the resource planners refine and update the Overhaul Plan and Budget. Approximately one month before the beginning of the scheduled outage, the Overhaul Plan and Budget is presented to the Department Manager, Maintenance Superintendent, and Sr. Supervisor, Overhauls for review and approval. This version of the plan includes work scopes for each of the maintenance crews and estimates of outside services that will be required to execute the Overhaul Plan. If approved, this version of the plan and budget is labeled: "Overhaul Turnover Plan and Updated Budget." Responsibility for work to be performed (i.e., scope, schedule, and budget) is transferred to the Sr. Supervisor, Overhauls for execution.

Planning and Execution of Station Maintenance

Q. What type of work makes up Station Maintenance?

A. Station Maintenance typically includes: (a) Preventive and corrective maintenance that is performed on the generating units when they are in operation; (b) Maintenance of facilities and infrastructure in the power plant other than the generating units; (c) MO's of relatively short duration that are planned days to weeks in advance; (d) Engineering and environmental projects implemented at the power plants that are not part of an overhaul plan; and (e) Corrective maintenance that is performed on the generating units during forced outages.

Q. In general, how is Station Maintenance work identified?

A. Station Maintenance work requirements are identified from a variety of sources, including: (1) Equipment failure or deteriorated performance; (2) PdM condition assessments of equipment; (3) Root cause analysis of chronic operational problems; (4) Scheduled preventive maintenance based on the Maintenance Basis

Optimization ("MBO"); and (5) Capital and O&M engineering and environmental projects. A work order is prepared for each element of maintenance work.

Q. How is the Station Work prioritized?

A. Once identified, the work is prioritized through a collaborative process involving Operations, Maintenance, and Planning & Engineering personnel. Each work order is given a relative priority by the person initiating the work order. The work orders with the highest priority are given preferential attention. The highest priority work is scheduled utilizing planning and scheduling software. Station Maintenance work is typically scheduled four weeks in advance based, in part, on the relative priority and the availability of resources to perform the work. Meetings are held daily at each of the power plants to review the priorities of work scheduled for that day and that week. As mutually agreed, the schedule would be adjusted to perform the highest priority work as soon as possible. At any time there may be a need to perform "emergent" work (e.g., forced outage of a generating unit due to boiler tube failure) and this work would take the highest priority and would be performed immediately. The resource planners would then update the four-week schedule accordingly.

Q. How are equipment failures and deteriorated performance identified?

A. Equipment failures and deteriorated performance may be identified by personnel operating and/or testing the generating units. The personnel would write a maintenance work order describing the problem and request maintenance work to address the problem. The work orders are accumulated in a data base. The work orders are typically divided into two groups: (1) those which do not require a unit outage to address (e.g., calibration of instrumentation); and (2) those which require a unit outage to address (e.g., boiler tube leak). The collection of outstanding work orders in the data base is referred to as the work order backlog.

Q. Please describe the backlog of maintenance work.

A. In the HECO 2007 test year rate case (Docket No. 2006-0386, HECO's response to CA-IR-77), HECO reported the backlog of maintenance work as 2,937 work orders as of 05/28/06, and 2,913 as of 12/31/06. In the HECO 2007 test year rate case (Docket No. 2006-0386, HECO's response to CA-IR-333, the backlog was 3,385 as of 07/08/07. As shown in HECO-715, as of 12/31/07 the work order backlog was 3,810, and as of 05/31/08 the backlog was 3,687. Of the total of 3,687 work orders, 2,049 are for Waiau Power Plant, 1,221 are for Kahe Power Plant, and 417 are for Honolulu Power Plant. Each week about 100 new work orders are added and about the same amount are cleared because the required maintenance was performed. During overhauls the work orders that apply to the generating unit being overhauled are typically cleared. In 2009, the expectation is that the backlog will be reduced significantly when the Maintenance Division work force is at its full complement.

Planned Maintenance Schedule (PMS)

Q. Please describe the process used to develop the PMS.

A. The process to develop a PMS is described in HECO-WP-705. In summary, the process begins with the 20-year (ahead) Long Range Planning Schedule. The long-range maintenance schedules for the IPPs also serve as initial inputs. From the LRPS and IPP maintenance schedules, the units to be placed into the PMS as PO's are identified, along with the durations of their respective outages. The units are assigned a scheduled start date in such a way as to ensure that the generation Reserve Margin is not exceeded. MO's are also identified and placed into the schedule. The PO's, the MO's are scheduled in such as way as to avoid exceeding the generation Reserve Margin at any time during the year.

Q. Is the PMS updated periodically as the year unfolds?

A. Yes. As was described in my direct testimony in the HECO 2007 test year rate case (Docket No. 2006-0386, HECO T-6, beginning at page 18) the scheduling of planned overhauls and maintenance outages is dynamic. As unplanned problems and forced outages occur, changes to the PMS may be required. This dynamic nature of scheduling outages was discussed in HECO's 2005 test year and 2007 test year rate cases. HECO-716 shows two PMS for 2007, one developed coincident with One-Year (ahead) Overhaul Plan and Budget, and one at the end of 2007. The latter PMS represents the actual outages that occurred in 2007. As can be seen, there were many changes as the year unfolded.

Q. Given the changes during any given year in the scheduling of planned outages and maintenance outages, what schedule is used for the 2009 test year production simulation?

A. HECO developed a 2009 Normalized Planned Maintenance Schedule for use in the Production Simulation. As discussed above, and in my direct testimony and responses to information requests in the HECO 2007 test year rate case (Docket No. 2006-0386), the PMS for a given year is a living "plan" that undergoes many changes as the subject year approaches and as events unfold during the course of the subject year. Despite the dynamic nature of the maintenance activity and the corresponding changes in the PMS, HECO's overall level of maintenance is relatively consistent on a yearly basis. A normalized PMS was thought to be a better representation of this overall level of maintenance and a preferred basis for rate case analysis, as compared to the actual PMS for any particular year. The rate case analysis would be better served by focusing on the normalized PMS (that was based on historical experience and maintenance plans covering a multiple-year period), and not to focus on a PMS for the test year that was subject to multiple changes. With this approach the focus would be on the overall level of effort and not on the changes.

Q. How was the 2009 Normalized PMS developed?

A. The process to develop the 2009 Normalized PMS is described in HECO-WP-706. In summary, actual outage scheduling information from 1999 to 2007 was consolidated on a spreadsheet with future schedules for the years 2008 to 2013. The planned and actual schedules for the years 1999 to 2007 were reviewed and a "Duration Correction Factor" was calculated and applied to the 2009 to 2013 outage durations for planned outages. This corrected for factors including emergent work that led to extensions of past overhauls, and that will likely occur in the future. The different HECO units were placed in the spreadsheet to allow consolidation of overhaul information by unit class. The classes included Reheat 140MW, Reheat 90MW, Cycling, and CT. The average overhaul duration for each unit class was multiplied by the average number of overhauls per year, for each unit class, to obtain the "Average Overhaul-Days" per year per unit class. The average number of overhauls per year per unit class was rounded either up or down to obtain a non-decimal amount of overhauls per year per unit class to represent the normalized number of overhauls to schedule per unit class per year. The normalized number of overhauls was divided into the "Average Overhaul-Days" to obtain the "Normalized Overhaul Duration" for each unit class to use in the Normalized PMS. The Normalized Planned Maintenance Schedule is presented in HECO-717.

Q. How does the Normalized PMS compare to the 2009 PMS used for the One Year (ahead) Overhaul Plan and Budget?

A. The number of overhauls of cycling units was the most significant difference between the Normalized PMS and the 2009 PMS used for the One Year (ahead) Overhaul Plan and Budget. The Normalized PMS contains overhauls for two cycling units whereas the 2009 PMS used for the One Year (ahead) Overhaul Plan and Budget, shown in HECO-718, has only one.

Q. How was the Normalized PMS used?

A. The Normalized PMS was used for the Production Simulation in the HECO 2009 test year rate case. It was also used to estimate 2009 maintenance expenses for overhauls on a normalized basis.

POWER SUPPLY ORGANIZATION

Q. How is the Power Supply Process Area Organized?

A. As shown in HECO-719, the Power Supply Process Area is headed by the Vice President, Power Supply, and consists of the Office of the Vice President, Power Supply and five departments: (1) Power Supply Operations & Maintenance (PSO&M); (2) Power Supply Engineering (PSED); (3) Power Supply Services (PSSD); (4) System Planning; and (5) Environmental. In general, costs for work performed by the Power Supply Process Area are charged to the Other Production O&M accounts.

Q. What is the staffing level for the Power Supply Process Area?

A. As shown in HECO-1503, the staffing level for the Power Supply Process Area was 436 at the end of 2007, and is forecast to increase from an actual staffing level of 437 as of March 31, 2008, to 464 at 2008 year end, and to 492 in test year 2009. Hence, the change in staffing level from March 31, 2008, to the end of 2009 is expected to be 55.

Q. How will the increase of 55 employees between March 31, 2008 and the end of 2009 be distributed among the departments in the Power Supply Process Area?

A. The distribution of the increase is summarized below:

	03/31/08 Recorded	2009TY Year End	Difference
Office of Vice President, Power Supply	3	3	0
Power Supply O&M Dept.	332	375	43
Power Supply Engineering Dept.	47	52	5
Power Supply Services Dept.	12	15	3
System Planning Dept.	19	22	3
Environmental Dept.	24	25	1
TOTAL	437	492	55

HECO-720 provides descriptions for each position in the Power Supply Process Area for each of the vacant positions that will be filled by 2008 year-end and in 2009.

Office of the Vice President, Power Supply

Q. What is the organization of the Office of the Vice President, Power Supply?

A. There are three positions in the office, and they include: (1) Vice President, Power Supply; (2) Manager, Renewable Integration; and (3) Executive Secretary. The Manager, Renewable Integration was added in 2008.

Q. Please explain the need for the Manager, Renewable Integration.

A. In the foreseeable future, significant renewable resources will be added to the HECO system. The benefits of adding diverse renewable resources are often offset by many technical, operational and logistical challenges that must be understood and properly addressed in order to integrate substantial amounts of as-available renewable resources into the HECO system, while maintaining system reliability. The Manager, Renewable Integration position was created to work with other areas of responsibility within HECO (e.g., Transmission Planning Division of the Systems Planning Department, and the System Operation Department) and direct the development of performance standards and interconnection requirements for renewable projects on Oahu. A position description for the Manager, Renewable Integration is provided as HECO-721.

Q. What positions report directly to the Vice President, Power Supply?

A. In addition to the Executive Secretary and the Manager, Renewable Integration, the managers of the five other departments in the Power Supply Process Area report directly to the Vice President, Power Supply. The organizations for each of these departments are discussed below.

Power Supply Operations & Maintenance (PSO&M) Department

Q. What is the mission of the PSO&M Department?

A. The mission of the PSO&M Department is comprised of the following:

- Operation and maintenance of HECO's generating units at Kahe, Waiau, Honolulu, and Campbell Industrial Park (CIP) Power Plants. As described earlier in this testimony, the generating fleet includes the 14 steam-electric units, three combustion turbines, and 18 internal combustion engines. In addition, PSO&M operates and maintains two black-start internal combustion engines at Kahe Power Plant, one black-start combustion turbine at Waiau Power Plant, and two black-start internal combustion engines at CIP.
- Training of O&M employees.

- Coordination with HECO's System Operation Department for generating unit commitment and dispatch.
- Coordination with Independent Power Producers (IPP) on Oahu for scheduling of maintenance outages.
- Fiscal administration of non-fuel O&M expenses for the Power Supply Process Area.
- Preparation and support of Production testimony and responses to IR's for rate cases and other regulatory proceedings.

Q. How is the PSO&M Department organized?

A. HECO-722 shows the PSO&M Department organization as of March 31, 2008. The PSO&M Department is organized into four divisions as follows: (1) Operating; (2) Maintenance; (3) Planning & Engineering; and (4) O&M Services.

Q. How is the increase of 43 positions distributed within the PSO&M Department?

A. The distribution of the increase of 43 positions in the PSO&M Department is summarized below:

	03/31/08 Recorded	2009 Test Year	Difference
Operating Division	151	158	7
Maintenance Division	148	174	26
Planning & Engineering Div	23	26	3
O&M Services Division	8	15	7
Administration	2	2	0
TOTAL	332	375	43

As described in my testimony below, the PSO&M Department was reorganized in June 2008, to create the O&M Services Division. The eight positions shown above for the O&M Services Division, as of 3/31/08, were previously assigned to other divisions within the PSO&M Department.

Q. How many of the 43 positions are associated with new CIP CT-1 facility?

A. There will be 15 new positions at CIP CT-1, seven of the positions will be in the Operating Division and eight will be in the Maintenance Division. There are 28 other positions that make up the difference.

Q. What are the general factors creating the need for the increase in staffing level of the other 28 positions (other than CIP CT-1) for the PSO&M Department from the end of March 31, 2008, to the end of 2009?

A. The major reasons why the staffing level in PSO&M is being increased by 28 positions in addition to the 15 new positions at CIP CT-1 between March 31, 2007 and 2009 are summarized in the table below. Of the total, 19 positions are "replacements" for established [vacant] positions and nine are new positions.

Reason for Increased Staffing in PSO&M (other than CIP CT-1 staffing)	Number of Positions	Replacement Or New
Established trades-and-craft vacancy to perform necessary maintenance	15 1	Replace New
Maintenance planning and supervisory personnel for more improved management of overhauls	4	New
In-house technical training staff	1 2	Replace New
Technical staff for power plant diagnostics and engineering studies	1 2	Replace New
Improved financial administration	2	Replace
TOTAL	19 9 28	Replace New

Q. Does the 2009 test year estimate for Other Production O&M expense assume that all positions are filled January 1, 2009?

A. Yes. However, significant portions of the direct labor costs for personnel assigned to CIP CT-1 for the period January 1 to July 31, 2009, are not charged to the Other Production O&M expense. These respective direct labor costs are charged to the CIP CT-1 capital project (P4900000).

Q. Why wasn't an adjustment made to the 2009 test year estimate for Other Production O&M Expense to reflect the fact that positions would be vacant at the beginning of 2009?

A. In June 2008, it was evident that selected positions included in the 2009 test year estimate for the PSO&M Department would be vacant for some portion of 2009. The analysis that was presented in the HECO 2007 test year rate case (Docket No. 2006-0386, HECO's response to CA-IR-67), and is considered to be applicable to the present situation, concluded that HECO's cost to perform the requisite work with vacant position among the PSO&M staff is more than if all the vacancies were filled. This was due to the higher costs for supplemental labor and overtime in order to perform the requisite work. An adjustment was not made to the 2009 test year estimate for Other Production O&M Expense to reflect the fact that position would be vacant because HECO's costs will actually be higher.

Operating Division of the PSO&M Department

Q. How is the Operating Division organized and staffed?

A. The organization of the PSO&M Operating Division, as of March 31, 2008, is illustrated in HECO-723. Kahe, Waiau, and Honolulu Power Plants each require a supervisory structure that includes the Station Superintendent, Sr. Supervisor Operations, Power Plant Clerk, and Shift Supervisors. In addition, there must be a full complement of qualified operators, as summarized in the table below, and discussed in detail in my direct testimony in the HECO 2007 test year rate case (Docket No. 2006-0386, HECO T-6, pages 42-47). Also shown in the table below are the seven new operating positions for the CIP Power Plant. The CIP operating personnel report to the Kahe Power Plant Sr. Supervisor and Superintendent. This level of staffing provides for 24 X 7 operation of the steam-electric generating units and 16 X 7 operation of CIP CT-1.

2009TY PSO&M Operating Division – Staff Positions by Power Plant

Position	Kahe	Waiau	Honolulu	CIP	Total
Station Superintendent	1	1	--	--	2
Sr. Supervisor	1	1	1	--	3
Shift Supervisor	7	7	5	1	20
Control Operator	15	15	5	--	35
Jr. Control Operator	15	15	5	--	35
Utility Operator	5	10	5	--	20
Equipment Operator	15	15	5	--	35
Operator Trainee	0	0	0	--	0
CT Operator	--	--	--	6	6
Power Plant Clerk	1	1	--	--	2
Total	60	65	26	7	158

Q. How many additional positions are included for the PSO&M Operating Division in the 2009 test year estimate versus the target level in 2007?

A. There are 158 positions in the Operating Division in 2009, a net increase of two positions from the targeted staffing level of 156 for 2008. There are seven new positions in the Operating Division at CIP in 2009, and this is offset by a staffing reduction of five Operator Trainee positions that were included in 2008.

Q. Why was the Operating Division staffing reduced by the five Operator Trainee positions?

A. When the six positions for CIP CT-1 Operators are posted and filled, most of the CIP CT-1 positions are anticipated to be filled by transferring Operators from Kahe, Waiau, or Honolulu power plants. These transfers will create vacancies which will then have to be filled at those power plants. Consideration was given to the difficulties HECO has been facing with finding qualified applicants and the filling of recent Operator Trainee vacancies. As a result, the 2009 staffing count for Operator Trainees was reduced by five to reflect the Operating Division staffing level that HECO will most likely be able to attain in 2009. HECO fully intends to restore the Operator Trainee staffing count following 2009 as more available qualified applicants become available. With the high turnover of Operating Division personnel being currently experienced, HECO's ability to meet Operator training needs is becoming a more and more critical issue. The Operator Trainee positions play an important role in HECO successfully meeting these training needs and, as such, need to be restored as soon as practical and possible.

Q. Is it possible to operate all the steam-electric units on a 24 X 7 basis, and CIP CT-1 on a 16 x 7 basis without having a full complement of 158 operating personnel?

A. Yes. It is possible to operate all the steam electric units on a 24 X 7 basis and CIP CT-1 on a 16 x 7 basis without having a full complement of 158 operating staff. However, this is only possible by existing personnel working excessive overtime, deferring training, deferring vacation, or combinations of these factors. The vacant positions can not be filled by outside contractors because of the unit-specific training and qualification that is required for operators. PSO&M

averaged 145 operators in 2005 and 2006, and 147 operators in 2007. As shown on HECO-724, in 2005, 2006, and 2007, the Operating Division worked 46,921 hours, 46,826 hours, and 42,714 hours of overtime, respectively. In the 2009 test year estimate, the Operating Division is expected to have 158 personnel and to work only 38,551 hours of overtime. The estimated reduction in overtime is based on the assumption that the Operating Division work force is fully staffed.

Moreover, as discussed in the Company's responses to CA-IR-67 and CA-IR-346 in the HECO 2007 test year rate case (Docket No. 2006-0386), if a given power plant does not have the full complement of qualified operators in accordance with the staffing levels in the table above, all the requisite shifts would still be staffed by scheduling qualified operators to work additional overtime at an incrementally higher expense to HECO.

Q. What is the consequence of five fewer operator positions among Kahe, Waiau, and Honolulu Power Plants?

A. As shown in HECO-724, a consequence of not having the five Operator Trainee positions the qualified operators would have to work incrementally more overtime to cover all the required shifts and allow support for training.

Q. How does this staffing level compare to previous years?

A. HECO-725 reflects the Operating Division trades and crafts staffing level from 1980 to now (not including supervisory and administrative positions).

Q. Please provide examples of initiatives, processes, and programs that help manage costs in the Operating Division of the PSO&M Department.

A. Examples of initiatives in the Operating Division of the PSO&M Department to manage costs include:

1) Participation in the new "Operator Technician" curriculum at Leeward

Community College. HECO is working to develop better candidates for its operator positions.

2) Changes in the master schedule for Waiau Power Plant operators to reduce training and overtime costs.

3) Department-wide implementation of unit-specific cycle chemistry programs to prevent boiler tube failures.

Maintenance Division of the PSO&M Department

Q. How is the PSO&M Maintenance Division organized?

A. The organization of the PSO&M Maintenance Division, as of March 31, 2008, is illustrated in HECO-726. HECO performs the bulk of required maintenance utilizing qualified trades-and-craft personnel, organized into Travel and Station Maintenance crews. The Travel Maintenance crews perform major overhaul work and relocate among the power plants as needed. The Station Maintenance crews are dedicated to daily preventative and corrective maintenance at each of the power plants. HECO's permanent maintenance staff is complemented by contractor personnel (i.e., "Supplemental Labor") depending on the scope and timing of work. The distribution of trades-and-crafts and supervisory personnel in the Maintenance Division is illustrated in the table below.

2009TY PSO&M Maintenance Division – Staff Positions by Crew

Position	Admin	Kahe	Waiau	Hon	Travel	CIP	Total
Superintendent	1						1
Clerk	1				1	1	3
Sr. Super, Overhaul					1		1
Maint Outage Coord					1		1
Supervisor		2	2	1	4	1	10
Mach Work Foreman		1	1	1	2		5
Machinists		3	3	1	9		16
Elec Work Foreman		1	1	1	2	1	6
Electricians		4	4	1	10	1	20

Pipefitter Mechanics		5	5	1	7		18
Welders		4	4	1	9		18
Control Techs		8	8	3	9	2	30
Insulator Work Foreman					1		1
Insulators		1	1	1	14		17
Boiler Work Foreman		1	1	1	2		5
Helpers		2	1		3		6
Mobile Crane Operator		1	1		1		3
CT & Diesel Mech						2	2
Condenser Crew Lead					1		1
Condenser Cleaner					8		8
Cert Equip Mechanic					2		2
Total	2	33	32	12	87	8	174

Q. What is the breakdown of supervisory and trades-and-crafts personnel in the Maintenance Division in the 2009 test year estimate?

A. As shown in HECO-725 and HECO-726, there are a total of 174 staff positions, consisting of 16 supervisory and clerical, and 158 trades-and-crafts positions. The trades-and-crafts positions are distributed among the Travel and Station Maintenance Crews.

Q. What is the difference in the Maintenance Division staffing level between March 31, 2008 and the 2009 test year estimate?

A. Referring to HECO-720, there were 148 employees in the Maintenance Division as of March 31, 2008, and there are 174 positions in the Maintenance Division for the 2009 test year estimate, a difference of 26. These 26 positions in fall into two categories: 15 replacements (i.e., filling of vacant established positions) and 11 new positions.

Q. What are the prospects for filling the 15 vacant positions that are designated as "replacement?"

A. It has continued to be difficult to recruit qualified trades-and-craft personnel to fill the vacant maintenance positions. As summarized in HECO-727, HECO has made limited progress in filling long-established, vacant maintenance positions. In order to perform the requisite maintenance in consideration of this dilemma, HECO continues to utilize increased amounts of Supplemental Labor and to for the 2009 test year.

Q. What are the 11 new positions in the Maintenance Division in 2009?

A. The 11 new positions in the Maintenance Division in 2009, include eight positions for CIP CT-1, insulator at Honolulu Power Plant, Overhaul Coordinator, and Clerk (Travel) as discussed below:

- CIP Power Plant Maintenance Station Maintenance Crew

Position	Number of Positions
Maintenance Supervisor	1
Electrical Working Foreman	1
Senior Electrician	1
Control Technician	2
CT & Diesel Mechanic	2
Clerk/Storekeeper	1
TOTAL Maintenance for CIP CT-1	8

- Insulator, Honolulu Power Plant. For the health and safety of personnel working at the Honolulu Power Plant Staff, this new position will be dedicated to the repair and replacement of the deteriorating thermal insulation throughout the plant.
- Overhaul Coordinator, Travel Maintenance. As discussed in my direct testimony in the HECO 2007 test year rate case (Docket No. 2006-0386, HECO T-6, page 48), the Senior Supervisor Maintenance, Overhauls position was created in 2006. This position has resulted in more effective execution of

overhauls in several ways, including: (1) the work among the different crafts is better organized and more directly supervised; (2) costs are monitored and controlled more effectively, (3) coordination with respective work requirements on capital projects (to be implemented during overhauls) is improving, (4) communications among maintenance, engineering, planning, operating personnel is improving, (5) the overhaul plans are being executed to an improved degree, and (6) overhaul schedules are being met. Due to the continuous, back-to-back scheduling for overhauls of the HECO generating units, the opportunity existed to leverage the positive impacts of focused overhaul supervision. Moreover, the overhaul performance could be improved further by maintenance supervisory personnel spending more time working with the overhaul planners in the development of the unit-specific overhaul plans, and working with operating personnel and engineers reviewing the effects of the overhaul work once the unit is back on line. Accordingly, the maintenance staff has been increased to add the position of Overhaul Coordinator. The Overhaul Coordinator reports directly to the Senior Supervisor Maintenance, Overhauls. The Overhaul Coordinator and the Senior Supervisor Maintenance, Overhauls alternate having lead responsibility representing the Maintenance Division on successive overhauls.

In 2006, the ESI report "Review of HECO's Power Supply Operations, Maintenance, and Outage Management Programs" included a candidate action to: "Select and Empower Outage Managers, a single point of focus and accountability for the performance and conduct of an outage." The Senior Supervisor Maintenance, Overhauls and Overhaul Coordinator positions fill this need.

- Clerk, Travel Maintenance. The Clerk, Travel Maintenance position was created to support the administrative work of the Senior Supervisor Maintenance, Overhauls and Overhaul Coordinator. The Clerk, Travel Maintenance performs multiple functions, including: (1) Monitoring and reviewing contractor timesheets and other cost records for accuracy; (2) Tracking of critical parts and equipment; (3) Collecting and inventorying test, material, and equipment technical data; (4) Developing an applications parts and materials guide for standard overhaul maintenance packages.

Q. How is Travel Maintenance organized?

A. Travel Maintenance, as of March 31, 2008, is organized as shown in HECO-726.

Q. How does Maintenance Division trades-and-crafts staffing level compare to previous years?

A. HECO-725 shows the Maintenance Division trades-and-crafts staffing level from 1980 through 2009. The 2009 staffing requirement for maintenance trades-and-crafts personnel is 158 personnel including the new positions described.

Q. What have been the consequences of the vacancies for the established trades-and-craft positions in the Maintenance Division?

A. As a result of having approximately 20 vacancies (some months more and some months less during 2006 to 2008) in the Maintenance Division since 2005, HECO has experienced the following consequences:

- The utilization of contractors has increased, that is Supplemental Labor, to be greater than that budgeted to perform maintenance work that would otherwise be performed by Maintenance Division trades-and-crafts personnel.
- The level of overtime worked by Maintenance Division trades-and-crafts personnel has increased.

- The backlog of lower priority work has increased.

Q. Can you demonstrate the higher outside use of Supplemental Labor for 2006 to 2008?

A. Yes. HECO-728 shows the actual expenses for Labor and Supplemental Labor for 2001 through 2007, and the budgeted expense for Labor and Supplemental Labor in 2007 through 2009. Comparing the recorded versus budgeted data for Labor expense in 2007, the recorded Labor expense follows the trend of the prior years and is significantly below the budgeted amount due to reduced staffing. Conversely, the 2007 recorded Supplemental Labor expense is significantly higher than the budgeted amount, and follows the trend of the previous years. The decrease in the Labor expense is offset by the increase in the Supplemental Labor expense.

Q. What are the comparable levels of overtime for the Maintenance Division personnel for 2006 to 2009?

A. As shown on HECO-729, in 2006 and 2007, the Maintenance Division worked 66,436 hours and 76,088 hours of overtime, respectively. In the 2008 budget and 2009 test year estimate, the Maintenance Division is expected to have 164 and 174 personnel and to work 58,366 and 62,036 hours of overtime, respectively. The budgeted reduction in overtime is attributable to the anticipated increased size of the Maintenance Division work force.

Q. Please provide examples of initiatives and processes to mitigate costs in the Maintenance Division of the PSO&M Department.

A. There are many initiatives and processes in the Maintenance Division of the PSO&M Department that help manage costs, including:

Power Supply Reliability Optimization ("PSRO"). The PSRO program is utilized to define, prioritize, plan, and implement work to be performed by station and traveling maintenance crews. The PSRO program is based on program, processes, and technologies developed by EPRI for optimal use of maintenance resources and equipment performance. An effective PSRO program leads to less of the "more costly" corrective maintenance work, and more of the "less costly" preventative and predictive maintenance work. A Maintenance Basis Optimization (MBO) has been created specifically for the HECO generating units, which specifies the required preventative maintenance for all the major equipment systems and most of the equipment components. System Owners have been assigned from among the PSO&M and PSED staff to track the performance of key equipment systems, provide input to the MBO, and specify required maintenance on select equipment. Resource Planners utilize PSRO protocols, in part, to plan and schedule station maintenance and overhauls. As discussed earlier in my testimony and in accordance with the recommendations of the report entitled *"Review of HECO's Power Supply Operations, Maintenance, and Outage Management Programs"* filed with the Commission on October 20, 2006, two new positions (PSRO Program Manager and MBO Coordinator) were added to the PSO&M staff to increase the effectiveness of the PSRO program.

Predictive Maintenance (PdM) Program. Equipment condition is assessed utilizing techniques that monitor and analyze specific operating parameters. If the equipment condition is acceptable it may be unnecessary to perform any maintenance work. PdM assessments are also used to assess the relative condition of redundant equipment so that maintenance resources can be devoted to the equipment that is in the poorest condition. Similarly, during overhauls the internal conditions (e.g., deposition of mineral deposits) of the boiler tubes are assessed at the outset of an overhaul. If conditions are found to be acceptable it may be possible to cancel the scheduled chemical cleaning of boiler. In 2008, scheduled chemical cleanings of Waiau 5 and Honolulu 8 were cancelled midway through the overhaul outage because conditions were found to be acceptable. The corresponding savings from these cancellations exceeded $500,000.

Planning & Engineering Division of the PSO&M Department

Q. How is the Planning & Engineering Division organized?

A. The organization of the PSO&M Planning & Engineering Division, as of March 31, 2008, is illustrated in HECO-730. The division is subdivided into two groups: (1) Planning, and (2) Engineering and PdM (Predictive Maintenance). The Planning group has six resource planners dedicated to overhauls and major project work, and four dedicated to station maintenance. The Engineering & PdM group is further divided into two sub-groups: O&M engineers that are stationed in the power plants and PdM specialists. The O&M engineers perform diversified technical assignments in support of daily engineering needs in the power plants, including troubleshooting, performance testing, project coordination, and engineering analysis. The PdM specialists perform PdM testing and analysis at all of HECO's power plants.

Q. What positions are included in the Planning and Engineering Division?

A. The Planning & Engineering Division consists of 26 positions as summarized in HECO-720.

Q. What is the difference in the Planning & Engineering Division staffing level between March 31, 2008 and the 2009 test year estimate?

A. There are 26 positions in the Planning & Engineering Division, an increase of three positions from the actual staffing level as of March 31, 2008. One of the positions is a replacement for a vacancy created by an internal transfer, and the other two positions are new.

Q. What are the two new positions in the Planning & Engineering Division?

A. The two new positions in the Planning & Engineering Division of the PSO&M Department are:

- PdM Specialist. The staff of PdM specialists was increased from three to four in 2009. The fourth PdM Specialist allows the development of in-house expertise for air-in-leakage acoustic testing, provides backup for the other three PdM specialists, and provides more flexibility for HECO to support the PdM needs of its subsidiaries, HELCO and MECO.
- O&M Engineer. The staff of O&M engineers was increased from six to seven in 2009. The seventh O&M engineer supports the engineering projects in the power plants and is the new "System Owner" for Combustion Systems in HECO's PSRO Program.

O&M Services Division of the PSO&M Department

Q. How is the O&M Services Division organized?

A. The O&M Services Division is organized as shown in HECO-731. Effective June 23, 2008, the PSO&M Department was reorganized to consolidate groups and personnel who had previously reported directly to the Department Manager (other than the secretary and superintendents of the Operating, Maintenance, and Planning & Engineering Divisions). HECO-732 is a copy of the announcement of the reorganization. The Senior Technical Analyst position was eliminated and a Superintendent, O&M Services position was created. The Training, Financial Administration, and Environmental Compliance groups were reassigned to the

O&M Services Division. The PSRO Program group was created and it was also assigned to the O&M Services Division. The heads of each of these groups reports directly to the Superintendent, O&M Services.

Q. What is the difference in the O&M Services Division staffing level between March 31, 2008 and the 2009 test year estimate?

A. There are 15 positions in the O&M Services Division, an increase of seven positions from the actual staffing level as of March 31, 2008. The eight positions that were filled on March 31, 2008, were assigned to other divisions in the PSO&M department at that time.

Q. What are the seven additional positions in the O&M Services Division?

A. The new and/or additional positions in the O&M Services Division of the PSO&M Department are listed below:

- <u>Superintendent, O&M Services.</u> This new position is responsible for leading and coordinating the diversified activities performed by the O&M Services Division. The new staff position was justified, in part, by the elimination of the former Senior Technical Analyst position. Thus, there is no net increase in the staff level as a result of this new position.
- <u>Technical Trainer, Training (2 positions).</u> One of these two additional positions is an established position that has been vacant. HECO retained a consultant in 2007 and 2008 to perform work that otherwise would have been done by the Technical Trainer. The second technical trainer position is new in 2009. The two Technical Trainers support the training requirements of the Operating and Maintenance Divisions, respectively.
- <u>Administrative Clerk, Training.</u> This is a new position in 2009, and is needed to support the administrative needs of the Training group,

including: (1) organization of historical records; (2) management of training materials; and (3) construction of new administrative tools (e.g., software such as "Plantview" HRSuites").

- Lead Financial Administrator, Financial Administration. This position was described in the June 2007 Update to HECO 2007 test year rate case (Docket No. 2006-0386). The position was filled in May 2008.
- Budget Analyst, Financial Administration. This was position was described in the June 2007 Update to to HECO 2007 test year rate case (Docket No. 2006-0386). The position was filled in May 2008. The financial administration, overhaul supervisory personnel, and work management specialist have collaborated to produce new management tools for tracking and control maintenance costs during overhauls. The information being produced enables senior staff of the PSO&M Department to make more informed decisions to prioritize the overhaul work, control the costs, and adjust outage schedules.
- PSRO Program Manager and MBO Coordinator, PSRO Program. The two positions are new in 2009. EPRI recommended that these two positions be created when the Power Supply PSRO Program was launched several years ago. However, instead of filling them permanently HECO assigned others in the PSO&M Department to fill these roles on a temporary basis. In 2006, the ESI report report entitled *"Review of HECO's Power Supply Operations, Maintenance, and Outage Management Programs"* filed with the Commission on October 20, 2006, included candidate actions to: (1) Assign a full-time PSRO Project Manager to ensure more effective ongoing implementation (of the PSRO

Program), and (2) Perform an assessment to better understand the barriers that are standing in the way of implementation of the maintenance basis optimization ("MBO"), and define and expedite corrective action. Filling the PSRO Program Manager position addresses the former candidate action. In 2007 and 2008, senior staff members of the PSO&M Department initiated an effort in response to the latter candidate action. In mid-2008, the MBO team comprised of three maintenance trades-and-craft personnel were temporarily assigned to update and upgrade the MBO basis. It was concluded that the MBO could not be sustained unless a full-time employee, an MBO Coordinator, was assigned to the task.

Administration (PSO&M Department)

Q. How is the Administration group for the PSO&M Department organized?

A. There are two positions in the PSO&M Administration group, the Department Manager and Secretary. The Superintendents of the four divisions described above report directly to the Department Manager.

Power Supply Engineering Department

Q. What is the mission of the Power Supply Engineering Department?

A. The mission of the Power Supply Engineering Department is to provide, in concert with overall corporate goals and objectives, quality power supply engineering services and technical support services for the HECO, HELCO and MECO generating facilities that are timely, cost-effective, credible and consistent with system, safety, regulatory and environmental requirements.

Q. Describe the major elements of the Power Supply Engineering Department business.

A. The major elements of the Power Supply Engineering Department business are the capital improvement program for the existing HECO generation assets, generation unit addition projects (e.g., HECO's CIP CT-1 in the Campbell Industrial Park and HELCO's Keahole ST-7 on the Big Island), and the technical services support (i.e., field engineering, condition assessments, performance monitoring and trouble shooting) for the PSO&M Department.

Q. What are the priorities of the Power Supply Engineering Department?

A. The priorities of the Power Supply Engineering Department are to: (1) Manage the Power Supply Process Area capital projects; (2) Provide power plant engineering support to operate and maintain HECO, HELCO and MECO generating facilities, and (3) Provide power plant technical expertise support to HECO, HELCO and MECO generating facilities.

Q. How is the Power Supply Engineering Department organized to accomplish its work?

A. The Power Supply Engineering Department is organized into four major divisions: (1) Power Plant Engineering, (2) Project Management, (3) Technical Services and (4) Administrative Support. There are 52 employees included in the Power Supply Engineering Department for 2009, five more than that as of March 31, 2008. The Power Plant Engineering Division has a Mechanical Engineering Section with 15 engineers (two more than as of March 31, 2008), an Electrical Engineering Section with 14 engineers (two more than as of March 31, 2008), and a Drafting Section with two drafting technicians. The Power Plant Engineering Division provides design engineering, project engineering and project management support for the capital improvement program for the existing HECO generation assets and engineering services for major generation addition projects for HECO, MECO and HELCO. The Power Plant Engineering Division also supports the O&M programs of the PSO&M Department. The Project Management Division consists of four full-time project managers who head major capital projects for HECO, MECO and HELCO. The Technical Services Division has 11 engineers (one more than as of March 31, 2008) and provides field engineering, condition assessment, performance monitoring and trouble shooting services primarily for the HECO PSO&M Department. The Administrative Support group consists of the Department Manager, a financial administrator, a secretary, and three clerical support staff that provide management, administrative and clerical support for the department. The Power Supply Engineering Department organization is summarized in the table below:

	03/31/08 Recorded	2009 Test Year	Difference
Administration	3	3	0
Support Staff	3	3	0
Technical Services	10	11	1
Electrical Engineering Section	12	14	2
Drafting Section	2	2	0
Project Management	4	4	0
Mechanical Engineering Section	13	15	2
TOTAL	47	52	5

Q. Why are five additional engineers required to perform the work of the Power Supply Engineering Department in 2009 as compared to the overall staffing level for the department as of March 31, 2008?

A. There are five new positions in 2009 compared to the March 31, 2008 staffing level for the Power Supply Engineering Department. Two new positions are Engineer II positions in the Electrical Engineering Section in the Power Plant Engineering Division. There are also two new Engineer II positions in the Mechanical Engineering Section in the Power Plant Engineering Division. There is one new Senior Staff Engineer position in the Technical Services Division.

The four new Engineer II positions in the Power Plant Engineering Division are needed to support HECO's capital improvement program, the engineering activities in support of HECO's existing generating units, and engineering programs for the production departments at HELCO and MECO. The increased staffing requirements are based on forecasted increases in capital and O&M workload for HECO, MECO and HELCO, and the cost savings, better response times and scheduling flexibility provided by in-house engineering versus the use of consultants.

The additional senior staff engineer position in the Technical Services Division is required to support the increased work load for field engineering, condition assessment, performance monitoring and trouble shooting services for the aging HECO generation fleet and to support succession planning for critical senior technical positions.

Q. How has the Power Supply Engineering Department accomplished its work in view of the vacant positions that have existed within the department?

A. The Power Supply Engineering Department has managed its workload and the impacts of vacancies on its workload through the use of consultants, staff overtime, and re-prioritization of assignments to meet the higher priority requirements of its customers.

Q. How does the Power Supply Engineering Department help engineer cost saving projects.

A. This is generally done through the "REA" process.

Q. What is the "REA" process?

A. An "REA" is an acronym for Request for Engineering Attention, (aka: "Request for Engineering Assistance"), and is a formal request. REA's are normally initiated by personnel in the PSO&M Department and directed to the Power Plant Engineering Division of the Power Supply Engineering Department. The purpose of an REA is to address O&M problems whose resolution will likely be expensive and/or time-consuming, and if not resolved, could have significant effects on system efficiency, cost, and/or safety. REA's are not used to address routine maintenance or operating problems.

Q. How does the REA process help HECO manage costs?

A. The REA process is used to identify and evaluate alternative solutions to a problem.

Q. What types of solutions are developed from the REA process?

A. The alternatives identified in response to a REA typically include "do nothing", repair, replace in kind, and replace with upgraded equipment. Cost and time estimates are developed to evaluate the alternatives and to identify the recommended alternative. In addition to costs for equipment, material and labor, environmental requirements, operating needs and community factors are also considered. An economic analysis is performed to compare capital expenditures verses on-going, annual O&M expenses. In general, approximately 90% of the recommended alternatives identified through the REA process are capital projects; while the remaining 10% are deemed to be maintenance activities.

Q. Please provide examples of projects that underwent economic analyses and how these analyses contributed to HECO managing its Other Production O&M Expense.

A. Examples of engineering projects and initiatives that have contributed to HECO managing its Other Production O&M Expense, include: (1) Kahe 1 Condenser; (2) Waiau 8 Feedwater Heater No. 85; (3) Chlorine Dioxide (ClO_2) Treatment for Condenser Biofouling; (4) Barbers Point Fuel Tank No. 131; (5) Fuel Shut-off Valve; and (6) Enhanced Condition Monitoring. See HECO-733 for more details on these projects.

Power Supply Services Department

Q. What is the mission of the Power Supply Services Department (PSSD)?

A. The mission of the Power Supply Services department is fourfold: (1) Negotiate and administer power purchase agreements; (2) Negotiate and administer fuel purchase and distribution agreements; (3) Plan and coordinate fuel deliveries, including pipeline, tanker, and truck shipments; and (4) Assure regulatory compliance related to fuels infrastructure.

Q. Describe the major elements of the Power Supply Services Department business.

A. The PSSD is organized into three divisions and the major elements of work for each are as follows:

Power Purchase Division. This division is responsible for power purchase agreements and policies with Independent Power Producers (IPP's), cogenerators, and Qualifying Facilities for HECO and its two subsidiaries, MECO and HELCO. The Division administers only the HECO power purchase agreements. MECO and HELCO employees administer their respective power purchase agreements.

<u>Fuels Resources Division.</u> This division is responsible for developing and negotiating fuel supply and fuel distribution facilities' contracts in support of the operation of current and proposed utility generating assets; administering fuel supply, fuel storage and fuel transportation contracts; and planning and coordinating fuel supplier deliveries, pipeline and tanker truck shipments, HECO plant and tank farm fuel inventories. In addition, it plans and coordinates ocean barge deliveries of fuel to support utility operations on Maui, Molokai and the Big Island.

<u>Fuels Infrastructure Division.</u> This division facilitates fuel asset management, assures regulatory compliance related to fuels infrastructure, and supports the initiative to integrate renewable fuels into the HECO fuel system. Additionally, this division provides fuels infrastructure technical support to MECO and HELCO.

Q. What are the priorities of the Power Supply Services Department?

A. PSSD supports the corporate goals of ensuring reliable fuel procurement and delivery for current operations while seeking to negotiate new renewable energy contracts with IPP and renewable (biofuels) fuel suppliers to increase the HECO consolidated companies portfolio of renewable energy. More specifically, the department priorities in 2009 are to:

1. Procure biofuels for operational and emission testing for HECO, MECO and HELCO.
2. Procure biodiesel for operational use at HECO's CIP CT-1 and other generating units on the MECO and HELCO systems.
3. Facilitate fuel asset management and ensure compliance with the policies, requirements, and regulations regarding the various fuel delivery and storage

infrastructure on the HECO system. Provide fuels infrastructure technical support to MECO and HELCO.

4. Manage the fuel infrastructure transition to accommodate the addition of biofuels and the transition strategy from fossil to biofuels.

5. Conclude power purchase agreements necessary to meet renewable energy portfolio goals and objectives for HECO, MECO and HELCO. Administer and renegotiate, when necessary, existing renewable energy and fossil fuel power purchase agreements.

Q. What are the staffing levels for the Power Supply Services Department?

A. As stated above, the Power Supply Services Department is organized into three divisions plus department administration: (1) Power Purchase, (2) Fuels Resources, (3) Fuels Infrastructure, and (4) Administration. There are 15 employees in the Power Supply Services Department, three more than that as of March 31, 2008. The Power Purchase Division has six employees including one Director, three power purchase administrators and two clerical personnel (one more than that as of March 31, 2008 due to the unplanned loss of an administrator. Position was filled on 21 April 2008.). The Fuel Resources Division consists of the Director, two fuel contract administrators, and one fuels clerk (one more than as of March 31, 2008). The vacant position was filled on June 23, 2008. The Fuels Infrastructure Division consists of the Director and two project engineers (one more than as of March 31, 2008). The vacant position was filled on May 12, 2008. The Administrative group consists of the Department Manager and a secretary. The Power Supply Services Department organization is summarized in the table below:

	03/31/08 Recorded	2009 Test Year	Difference
Administration	2	2	0
Power Purchase	5	6	1
Fuels Resources	3	4	1
Fuels Infrastructure	2	3	1
TOTAL	12	15	3

Q. Why are three additional employees required to perform the work of the Power Supply Services Department in 2009 as compared to the overall staffing level for the department as of March 31, 2008?

A. All three positions are required in 2008 to perform the work of Power Supply Services Department. All positions were filled as of June 23, 2008.

Q. How has the Power Supply Services Department accomplished its work in view of the vacant positions that have existed within the department?

A. Power Supply Services Department prioritized the workload in order to complete critically urgent tasks and in some cases contracted for outside services to complete assignments.

System Planning Department

Q. What is the mission of the System Planning Department ("SPD")?

A. The mission of SPD is to provide, in concert with overall corporate goals and objectives, quality generation planning, transmission planning, and generation bidding services for the HECO, HELCO and MECO companies.

Q. Describe the major elements of the SPD business.

A. The major elements of the SPD business include the planning for and acquisition of generation and transmission facilities for the HECO, MECO, and HELCO systems; providing planning support for required regulatory filings such as the Adequacy of Supply (AOS), Biennial PURPA filings, Integrated Resource Planning Reports, among others, and providing critical support for strategic policy initiatives such as the Hawaii Clean Energy Initiative and renewable portfolio standards requirements. In addition, SPD manages the competitive bidding process for new generation resources in accordance with the Framework for Competitive Bidding dated December 8, 2006 ("Framework"), adopted by the Commission in Decision and Order No. 23121 ("D&O 23121"). Competitive bidding initiatives include the ongoing HECO *Request for Proposals for Renewable Projects, Island of Oahu*, MECO *Request for Proposals for Firm Capacity Resources, Island of Maui*, and planned future requests for proposals ("RFP") for all three companies.

Q. What are the priorities of SPD?

A. The priorities of SPD include the following for the HECO, HELCO and MECO systems:

(1) Planning for and maintaining adequate generation and transmission capacity, system stability and reliability;

(2) Planning support for regulatory filings such as the annual Adequacy of Supply, Biennial PURPA filings, Integrated Resource Planning Reports, rate cases, and Applications for approval of Power Purchase Agreements with independent power producers, among others; and

(3) Administering a fair and equitable generation bidding process.

Q. How is SPD organized?

A. As discussed in HECO's response to CA-IR-68 in the HECO 2007 test year rate case (Docket No. 2006-0386), SPD is organized into three major divisions: Generation Planning, Transmission Planning, and Generation Bidding.

Q. What was the level of staffing in SPD as of March 31, 2008?

A. Actual staff count for SPD on March 31, 2008 was 19.

Q. What is the planned level of staffing in SPD for the 2009 test year?

A. The 2009 test year estimate employee count for SPD is 22, the same as it was in the 2007 test year estimate. The System Planning Department organization is summarized in the table below:

	03/31/08 Recorded	2009 Test Year	Difference
Administration	2	2	0
Generation Planning	9	9	0
Transmission Planning	5	8	3
Generation Bidding	3	3	0
TOTAL	19	22	3

Q. Please summarize the reasons for the increase of three positions in SPD in test year 2009 versus the actual staff level as of March 31, 2008.

A. This difference is the result of three vacancies in existing positions that arose within SPD in the course of 2007, all of which were in the Transmission Planning Division. All other positions within SPD were filled as of March 31, 2008. Efforts to fill these vacancies are ongoing and one of the three vacancies was recently filled bringing the actual staffing level of SPD to 20 as of July 1, 2008. HECO anticipates that the remaining two vacancies in SPD will be filled before the end of 2008, resulting in SPD being fully staffed with an employee count of 22.

Q. Please describe the three existing positions in the Transmission Planning Division that account for the net increase in SPD staff.

A. The increase of 3 positions between the actual SPD staff level on December 31, 2007 and the 2009 test year estimate is comprised of the following:

Increase	Position Title
(1)	Transmission Planning Engineer
(2)	Lead Transmission Planning Engineer

Q. What has been the impact of the Lead Transmission Planning Engineer vacancies?

A. The Transmission Planning Division test year estimate identifies three Lead Transmission Planning Engineers, each with the primary responsibility for planning the respective HECO, HELCO, and MECO transmission systems. While positions remain vacant, it is a continuing struggle to meet increased work demands with the reduced resources, particularly since the division lost significant technical expertise and time-earned knowledge when three of the more experienced transmission planning engineers departed (with intimate knowledge of the HECO and HELCO systems in particular). Examples of these growing work demands include a significant increase in the number of requests for interconnection requirements studies by developers of renewable energy projects (there are currently fourteen proposals for renewable energy generation under consideration), development of new performance standards applicable to the numerous renewable energy projects proposed on the HECO Companies' various isolated grids, and the development of RFPs and related bid evaluation criteria and processes. While these vacancies remain, work is prioritized and existing staff work more overtime hours (uncompensated) and outside consulting engineering services are retained to fill the gap for critical projects. Some lower priority work is deferred.

Q. What are the short-term and long-term effects of these vacancies in SPD?

A. The short-term effects of these vacancies will be that work will continue to be contracted and projects will continue to be prioritized with some lower priority work being deferred. With the projected back-filling of all vacancies within SPD before year-end 2008, there are no long-term effects anticipated. However, contract work may continue while new Lead Transmission Planning Engineers are acclimating to their position and any work backlog is addressed.

Environmental Department

Q. What is the mission of the Environmental Department?

A. The mission of the Environmental Department is to provide strategic oversight of environmental compliance programs for HECO, MECO, and HELCO (collectively, the companies). Environmental compliance is defined by the terms of applicable permits, permits, and laws that can be generally captured in the following categories: air, noise, water, and hazardous materials. Examples of major regulations include the Clean Air Act and the Clean Water Act, each of which have state law counterparts.

Q. Describe the major elements of the Environmental Department programs.

A. The Environmental Department serves as the central resource supporting operations, providing services such as obtaining and renewal of permits, training, developing Standard Operating Procedures, performing environmental audits, and providing laboratory services. An important responsibility is the tracking and interpreting of all current and future regulations, such as changes to Clean Air Act or Clean Water Act and proposed regulation regarding Global Warming, and communicating those changes to management and operational sections of the companies. The Environmental Department also serves as the point of contact and interface with environmental regulatory agencies such as the Department of Health and Environmental Protection Agency.

Q. What are the priorities of the Environmental Department?

A. Since environmental compliance is the primary mission of the Environmental Department, its priorities are driven by regulatory requirements and changes to them. As described above, these priorities include operational compliance on a day to day basis, permit applications and renewals, as well as planning for anticipated changes to regulations.

Q. How is the Environmental Department organized?

A. The Environmental Department currently consists of 24 employees organized into four divisions as follows:

Administration. Consists of the Department Manager, a Sr. Scientist responsible for the Environmental Audit program, and a secretary.

Air/Noise Division. Responsible for permitting and compliance related primarily to the Clean Air Act and its state analog, and the State's Community Noise Control requirements.

Water/Hazardous Material Division. Responsible for permitting and compliance primarily related to the Clean Water Act, Safe Drinking Water Act, Toxic Substances Control Act, Resource Conservation and Recovery Act, DOT Hazardous Materials, site evaluation and cleanup (the Hawaii Environmental Response Law and the Comprehensive Environmental Response, Compensation, and Liability Act) and environmental release reporting (including Emergency Planning and Community Right to Know Act, Toxic Release Inventory and related programs).

Environmental Chemistry Lab. Responsible for performing laboratory analysis to support permit compliance and operational needs for both Power Supply and Energy Delivery.

Q. What is being done to help manage compliance with the conditions of applicable environmental permits?

A. HECO is using an Environmental Management Information System ("EMIS") to help manage compliance with the conditions of its environment permits. EMIS is a software system developed to support regulatory compliance. Five modules were selected to make up the system. Each module is designed to help manage a specific compliance area as follows: 1) Task Management; 2) Waste Management; 3) Wastewater Management; 4) Air Quality Management; and 5) Incident Reporting.

Q. What work is being done in 2008 on EMIS?

A. In 2008, the Task Manager is being installed on an external hosting site and implemented (populated and configured). The module officially went live on April 30, 2008.

Q. What are the plans for 2009?

A. Detailed design work for the remaining modules is planned for 2009. During the detailed design phase, the functional and technical requirements for each of the remaining modules will be specified and prioritized. From the detailed design we will determine the required resources, budget and schedule for each module. The results of the detailed design will be used to get internal consensus of the next priority module that should be selected for implementation in 2009. The 2009 test year estimate includes $191,645 for EMIS, and includes the following work: (1) maintenance of the first module; (2) design work for the remaining modules; and (3) purchase and implementation of another module.

Q. What is the 2009 test year staffing level for the Environmental Department?

A. The staffing level for the Environmental Department in the 2009 test year is 25 (one more than that as of March 31, 2008). The Power Supply Services Department organization is summarized in the table below:

	03/31/08 Recorded	2009 Test Year	Difference
Administration	4	4	0
Air Quality / Noise	6	6	0
Chemistry	6	7	1
Water & Hazardous Materials	8	8	0
TOTAL	24	25	1

Q. What is the reason for the increase one additional position in 2009?

A. The one additional position is for an Analytical Chemist position in the Environmental Chemistry Lab. This position is necessary in order to support the HECO's increasing initiatives in biofuels and to support the additional laboratory work associated with HECO's CIP CT-1 slated for operation in mid-2009.

Q. Is this position necessary for all of 2009 or only in time to support the new unit in July 2009?

A. This position is necessary from the start of 2009 in order to support the biofuel initiatives of HECO and its subsidiaries. The use of biofuels is generally new to the utility industry. As such, the development of new methodologies and analysis for testing must be developed well in advance of the July 2009 date and advance training will be required.

Q. What are other environmental challenges that HECO may be facing in the near term?

A. Other environmental challenges that HECO may be facing in the near term include: (1) Global Warming and Green House Gas regulation; (2) Fuel oil nickel hazardous regulations; and (3) Regional haze regulations.

OTHER PRODUCTION O&M EXPENSE

Q. What is included in Other Production O&M Expense?

A. Other Production O&M Expense includes expenses incurred to ensure reliable, efficient, safe and compliant operation and maintenance of HECO's 14 steam, three combustion turbine, and 18 leased DG units at four power plants and associated facilities.

Q. What HECO departments contribute to Other Production O&M Expense?

A. The majority of Other Production O&M Expense is incurred in the Power Supply Operations and Maintenance (PSO&M) Department, the Technical Services Division of the Power Supply Engineering Department, and the Administrative staff in the Power Supply Services Department. Portions of the Environmental Department, System Operation Department, Purchasing and Materials Management Department, Transportation & Facilities Maintenance Department, Engineering Department, Information Technology Services Department, Generation Planning Department, Energy Services Department and other HECO departments also contribute to Other Production O&M Expense.

Q. How was Other Production O&M Expense developed for HECO's 2009 test year?

A. The test year estimate is based on HECO's 2009 operating budget, with nine adjustments and one normalization. The test year estimate is the sum of our estimates for Other Production Operation Expense - Labor and Non-labor accounts as shown in HECO-701, and for Other Production Maintenance Expense - Labor and Non-labor accounts, as shown in HECO-701. A more detailed discussion of how Other Production O&M Expenses is presented below in my testimony. The nine adjustments (tabulated in HECO-734) and the one normalization (tabulated in HECO-735) are summarized in the table below.

Adjustments	Account	Amount
1. Performance incentive compensation	Ops Non-Labor	($386,000)
2. Air quality monitoring station	Ops Labor	$83,000
	Ops Non-Labor	$72,000
3. Fish monitoring program	Ops Labor	$4,000
	Ops Non-Labor	$23,000
4. Emissions fees	Ops Non-Labor	($89,000)
5. Reverse osmosis amortization	Maint Non-Labor	($32,000)
	Ops Non-Labor	$32,000
6. Abandoned projects	Ops Non-Labor	$8,000
	Maint Non-Labor	$20,000
7. Research and development	Ops Non-Labor	($26,000)
8. Environmental – 316(b)	Ops Non-Labor	$356,000
9. Security	Ops Labor	($58,000)
SUBTOTAL – Adjustments		$7,000
Normalizations	Account	Amount
1. Integrated Resource Planning	Ops Non-Labor	($3,000)
SUBTOTAL – Normalizations		($3,000)
TOTAL – Adjustments and Normalizations		$4,000

Q. What is the explanation for the first adjustment of minus $386,000 for performance incentive plans compensation?

A. The first adjustment is to remove $386,000 of performance incentive plans compensation expenses budgeted in Other Production Maintenance non-labor expense. Ms. Patsy Nanbu discusses this adjustment in her testimony, HECO T-11.

Q. What is the explanation for the second adjustment of $155,000 for air quality monitoring stations?

A. The second adjustment is an increase of $155,000 to Other Production Operations labor and non-labor expenses for the air quality monitoring stations program which is part of the community benefits package relating to HECO's 2009 Campbell Industrial Park generating unit (Docket No. 05-0146). This adjustment is a reclassification of the expenses from Miscellaneous Administrative and General ("A&G") Expenses to the Other Production O&M block of accounts. A corresponding decrease to Miscellaneous A&G Expenses is discussed by Mr. Bruce Tamashiro in HECO T-14.

Q. What is the explanation for the third adjustment of $27,000 for fish monitoring?

A. The third adjustment is an increase of $27,000 to Other Production Operations labor and non-labor expenses for the fish monitoring program which is part of community benefits package relating to HECO's 2009 Campbell Industrial Park generating unit as describe above. This adjustment is a result of the reclassification of the expenses from Miscellaneous A&G expenses to the Other Production O&M block of accounts. A corresponding decrease to Miscellaneous A&G Expenses is discussed by Mr. Bruce Tamashiro in HECO T-14.

Q. What is the explanation for the fourth adjustment of minus $89,000 for emission fees?

A. The fourth adjustment is a decrease of $89,000 to Other Production Operations non-labor expenses for emission fees which were recalculated using the 2009 test year production simulation run.

Q. What is the explanation for the fifth adjustment of $32,000 for reverse osmosis amortization?

A. The fifth adjustment is a reclassification of $32,000 for the reverse osmosis amortization from Other Production Maintenance non-labor expense to Other Production Operations non-labor expenses. The net impact to Other Production O&M Expense is zero.

Q. What is the explanation for the sixth adjustment of $28,000 for abandoned projects?

A. The sixth adjustment is an increase of $28,000 to Other Production O&M expenses for abandoned projects. Of this total, $8,000 and $20,000 were applied to Operations Non-Labor and Maintenance Non-Labor, respectively. Please refer to Ms. Patsy Nanbu's testimony, HECO T-10, for additional discussion related to this adjustment.

Q. What is the explanation for the seventh adjustment of minus $26,000 for research and development?

A. The seventh adjustment is a decrease of $26,000 for research and development expenses budgeted in Other Production Operations Non-Labor expense. Please refer to Mr. Bruce Tamashiro's testimony, HECO T-14, for additional discussion related to this adjustment.

Q. What is the explanation for the eighth adjustment of $356,000 for Environmental

316(b) expenses?

A. The eighth adjustment is an increase of $356,000 for Environmental 316(b) expenses in Other Production Operations Non-Labor. This adjustment will be discussed in more detail later in my testimony.

Q. What is the explanation for the ninth adjustment of minus $58,000 for security personnel?

A. The ninth adjustment is a decrease of $58,000 due to the elimination of the expense of one Security Officer charging to Other Production Operations Labor expense.

Q. What was the effect of the nine adjustments on Other Production O&M expenses for HECO's 2009 test year?

A. The combined effect of the nine adjustments is to increase the 2009 test year operating budget for Other Production O&M Expense by $7,000.

Q. What is the $3,000 normalization adjustment made to the 2009 operating budget to arrive at the 2009 test year estimate of Other Production O&M Expense?

A. As shown in HECO-735, HECO proposes a normalization adjustment to decrease Operations Non-Labor expenses by $3,000 for integrated resource planning. Mr. Alan Hee discusses this normalization adjustment in his testimony, HECO T-10.

Q. What was the net effect of the adjustments and normalizations on Other Production O&M Expense for HECO's 2009 test year?

A. The net effect of the adjustments and normalizations is to increase 2009 test year estimate for Other Production O&M Expense by $4,000, to $80,391,000, as shown in HECO-701.

<u>Other Production Operation Expense</u>

Q. What is the 2009 test year estimate for Other Production Operation Expense?

A. The 2009 test year estimate for Other Production Operation Expense is $32,400,000. Of this total, $15,402,000 is for Labor expense and $16,998,000 is for Non-labor Expense as shown in HECO-701.

Q. What was the basis for the 2009 test year estimate for Other Production Operation Expense?

A. The 2009 test year estimate is based on the operating budget for 2009, with the adjustments and normalizations identified above.

Q. How was the 2009 Other Production Operation Expense determined?

A. The Other Production Operation Expense was determined by forecasting the operating labor and non-labor requirements to safely and efficiently provide reliable electric power for distribution throughout Oahu, and to do so while in compliance with all applicable regulations and permit conditions.

<u>Other Production Operation – Labor Expense</u>

Q. What was included in the Other Production Operation - Labor Expense?

A. The Other Production Operation - Labor Expense includes salaries and wages for operator and non-operator costs.

Q. What operator costs are included in the Other Production Operation - Labor Expense?

A. Operator wages make up the majority of the operator costs in the Other Production Operation - Labor forecast. The forecast also includes the expense for supervision, plant operation, administration, chemists, environmental specialists, and training.

Q. What non-operator costs are included in the Production Operations - Labor forecast?

A. Non-operator costs in the Other Production Operation Labor forecast include wages and salaries for labor required to keep the plant and associated facilities operating safely, compliantly, efficiently and reliably on a day-to-day basis; environmental services to meet regulatory requirements; and power purchase contract management.

Q. How was the labor expense for operator costs forecasted?

A. The operator cost was developed by identifying manpower and supervision requirements to support 24 X 7 operations at the Kahe, Waiau and Honolulu Power Plants and 16 X 7 operations at CIP CT-1. The labor forecast derivation also includes estimates of overtime costs and non-productive wages to account for vacation, holidays, sick leave, family leave, attending company meetings, and training. The labor forecast derivation assumes that 151 Operations Division positions are filled for the whole year at Kahe, Waiau, and Honolulu Power Plants, and the 7 Operations Division positions are filled at CIP CT-1 when the unit begins commercial operation on August 1, 2009.

Q. How was the labor expense for non-operator costs forecasted?

A. Labor expense for non-operator costs is forecasted by the respective HECO departments based on the support required. For example, the relay section of the System Operation Department normally tests and maintains protective relays in the generating plants. The labor cost to provide this service falls under the non-operator costs in the Other Production Operation - Labor Expense.

Q. How does the 2009 test year Other Production Operation - Labor Expense of $15,402,000 compare with 2007 recorded?

A. The 2009 Other Production Operation - Labor Expense is $2,008,000 or 15% higher than the recorded 2007 amount as shown on HECO-736.

Q. What makes up the increase of $2,008,000?

A. The labor assigned to CIP CT-1 increases the Other Production Operation – Labor Expense by $316,000 as shown in HECO-702. The Other Production Operation Labor adjustments of $83,000 for Air Quality Monitoring Stations and $4,000 for Fish Monitoring (shown in HECO-734) also add to Other Production Operation – Labor Expense in 2009. These three items total $403,000 and amount is 20 percent of the increase of $2,008,000 in the 2009 Other Production Operation – Labor Expense.

Q. What other factors contribute to the above increases between 2007 recorded and 2009 test year Other Production Operation – Labor Expense?

A. Two other factors that contribute to increases in Other Production Operation – Labor Expense includes:

1) Wage increases for bargaining unit employees and merit employees contributes to the increase in Other Production Operation – Labor Expense. On an annual basis, 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). The assumptions used in determining the bargaining unit and merit salary increases are discussed by Ms. Lorie Nagata in HECO T-17. Ms. Julie Price, HECO T-13, discusses in more detail how the bargaining unit and merit salary increases are determined.

2) Expansion of HECO’s training efforts in the PSO&M Department, and the direct labor costs for additional personnel in the training group, also contributes to the increase in the Other Production Operation – Labor Expense.

Q. Please describe the need for and the efforts involved to expand the training in efforts in the PSO&M Department?

A. HECO's PSO&M workforce is young and training requirements are increasing. There are more employees to be trained and more training required to develop and maintain skill levels. HECO recognized the need for more formalized training across the PSO&M Department. Accordingly, as discussed earlier in my testimony, HECO expanded its dedicated training staff to three positions in 2007, and to five positions in 2009.

Q. Please describe HECO's increased commitment to training?

A. HECO has committed to increasing the level of training for operating and maintenance personnel. The following steps have been taken to move forward with this commitment.

1) A new Training Division was created in June 2006.
2) A Senior Supervisor has been assigned to lead the new Training Division in developing new training programs and to expand existing programs.
3) A consultant was contracted in 2007 and 2008 to work in cooperation with the Sr. Supervisor, Training to review and upgrade the training programs.
4) New training protocols for black start of the electric system were developed and implemented at Kahe and Waiau Power Plants.
5) New training program was developed in 2008 for sustaining the proficiency of qualified operators.
6) The Shift Supervisor Training program was revised in 2008.
7) "Plantview" software was purchased in 2008 for recording the technical content of HECO's training materials and information.
8) A new three-year training and qualification program was launched in 2008

for insulators in the Maintenance Division.

Q. How is this commitment to training reflected?

A. Expenditures for training have increased steadily since 2003. HECO-738 provides a graphical plot of this increase in training expense. Since 2003, total training expenses have increased from $1,493,000 to $5,117,000 in 2009. These costs include clearing costs. Of the $1,493,000, a total of $741,000 is Labor Expense, and of the $5,117,000, a total of $2,797,000 is Labor Expense. The increase in training Labor Expense from 2003 to 2009 is $2,056,000.

Other Production Operation – Non-labor Expense

Q. What was included in Other Production Operation - Non-labor Expense?

A. This cost category includes the outside services for operation and maintenance of DG units at HECO's substations. It also includes consumable items such as chemicals (used for boiler, waste and circulating water treatment), lubricants, gases, instrument chart paper, city water and sewer charges, and office supplies. Expenses for technical training, transportation, waste removal, janitorial services, and weed control services are also included.

Q. Are non-operator non-labor costs forecasted in Other Production Operation - Non-labor Expense?

A. Yes. Other Production Operation – Non-labor Expense includes forecasts of non-operator non-labor costs such as: items for operational maintenance, technical training, environmental services and fees, purchase power contract management, and outside services.

Q. How was Other Production Operation - Non-labor Expense forecast?

A. Other Production Operation - Non-labor Expense is forecast for Kahe, Waiau, and Honolulu Power Plants, CIP CT-1, and the DG facilities on the basis of known and identified recurring costs. Non-operator non-labor expenses required to keep the plant operating efficiently and reliably and in compliance with all applicable environmental and other government regulations on a day-to-day basis is forecasted by the respective HECO departments and divisions directly involved with the work.

Q. How does the 2009 test year Other Production Operation - Non-labor Expense compare with 2007 recorded expenditure?

A. As shown in HECO-736, the 2009 test year Other Production Operation - Non-labor Expense of $16,998,000, after adjustments and normalizations, is $2,585,000, or 18% higher than the 2007 recorded amount of $14,413,000.

Q. What was the increase attributed to?

A. HECO-739 shows the breakdown of the 2007 Actual versus 2009 test year variance of $2,585,000. The increase is attributed to the net impact of variances in the expense categories consisting of material, outside services, transportation, labor on-cost, and the budget and normalization adjustments.

Q. Referring to HECO-739, please provide an explanation for the Other Production Operation – Non-labor variance for materials?

A. As shown in HECO-739, Other Production Operation – Non-labor expense for materials was $2,042,000 in 2007, and $2,625,000 for the 2009 test year estimate, for a variance of $583,000. This is a 29 percent increase over the two-year period. The majority of the increase was attributable to higher material prices due escalating commodity prices. For example, as discussed later in my testimony, copper, steel, and cement prices increased 173%, 85%, and 40%, respectively, from 2003 to 2008.

Q. Referring to HECO-739, please provide an explanation for the Other Production Operation – Non-labor variance for transportation?

A. Other Production Operation – Non-labor expense for transportation was $181,000 in 2007, and $222,000 for the 2009 test year estimate, for a variance of $41,000. This is a 23 percent increase over the two-year period. The increase was due to additional vehicles in the Operating Division in 2009, and a higher cost per hour per vehicle.

Q. Referring to HECO-739, please provide an explanation for the Other Production Operation – Non-labor variance for Non-Labor On-Cost?

A. Other Production Operation – Non-labor expense for Non-Labor On -Cost was $2,851,000 in 2007, and $2,337,000 for the 2009 test year estimate, for a variance of minus $514,000. This is an 18 percent decrease over the two-year period.

Q. Referring to HECO-739, please provide an explanation for the Other Production Operation – Non-labor variance for Outside Services/Other?

A. Other Production Operation – Non-labor expense for Outside Services/Other was $9,339,000 in 2007, and $11,827,000 for the 2009 test year estimate, for a variance of $2,488,000. The major components of this increase are: (1) First-time non-labor expenses at CIP CT-1; (2) Increased outside legal expenses for negotiation of power purchase agreements, (3) Increased expenses for Technology, (4) Increased environmental 316(b) expenses; (5) Increased outside service expense in support of Generation Bidding; and (6) Increased DG expense. Item 1, CIP-CT-1 non-labor expense is $450,000 is the 2009 test year estimate and was zero in 2007. Item 2, outside legal expense for power purchase is $280,000 in the 2009 test year estimate and was $8,000 in 2007, for an increase of $272,000. Item 3, Technology, is discussed in greater detail in Mr. Bruce

Tamashiro's testimony in HECO T-14. It is $780,000 in the 2009 test year estimate and was $355,000 in 2007, for an increase of $425,000. Item 4, environmental 316(b) expense is $848,000 in the 2009 test year estimate and was $721,000 in 2007, for an incease of $127,000. More discussion into the background and details of expenses for Environmental 316(b) is provided in HECO-740. Item 5, outside service expense for Generation Bidding is $720,000 in the 2009 test year estimate and was $93,000 in 2007, for an increase of $627,000. Item 6, distributed generator expense is $2,810,000 in the 2009 test year estimate and was $2,693,000 in 2007, for an increase of $117,000. The increases for these six items total $2,018,000, or 81 percent of the total increase in Other Production Operation – Non-labor expense for Outside Services/Other.

Q. Why are Generation Bidding Non-Labor expenses significantly higher in 2009 as compared to 2007?

A. Generation Bidding Division - 2007 recorded expenses reflected only partial year start-up activities for divisional activities in support of the HECO *Request for Proposals for Renewable Projects, Island of Oahu*. The 2009 test year estimate is for a whole year of competitive bidding activities.

Q. What Other Production Operation - Non-Labor expense is included in the 2009 Test Year for the Generation Bidding Division?

A. The Other Production Operation – Non-Labor expense for the 2009 test year includes the following for the Generation Bidding Division: (1) $450,000 for the Competitive Bidding Consultant and Independent Observer; and (2) $270,000 for outside legal services

Q. What competitive bidding projects are occurring in 2009?

A. The following Generation Bidding projects are occurring in 2009:

1) HECO *Request for Proposals for Renewable Projects, Island of Oahu* – RFP issued in June 2008, with final award group and submittal of power purchase agreements for Commission approval expected in 2009.

2) HECO Firm Capacity RFP – Estimates have been included for support of an RFP effort for firm capacity needs. The resource attributes and timing would be determined in HECO's IRP-4 process. RFP efforts are expected to be initiated in 2008 after submittal of HECO's IRP-4 plan.

3) HECO Renewable Energy RFP - Estimates have been included for support of a potential second RFP effort for renewable energy projects targeted for commercial operation after the current HECO *Request for Proposals for Renewable Projects, Island of Oahu*. The resource attributes and timing would be determined in HECO's IRP-4 process. RFP efforts are expected to be initiated in 2008 after submittal of HECO's IRP-4 plan.

Q. Please describe HECO's DG costs that are included in the 2009 test year estimate.

A. HECO has eighteen 1.64 MW diesel-fired DG units totaling 29.52 MW that are currently in service and included in the 2009 test year. Each DG unit is leased from Hawthorne Pacific Corporation. As shown in HECO-741, the 2009 test year estimate for total DG other Production Operation expenses is $2,879,000. Of this amount, $2,810,000 is in Operations Non-labor. The 2009 estimate includes a reduction in rental expense for nine of the DG units compared to 2007.

Q. Please explain why 2009 rental expense for some of the DG units will be lower than in 2007.

A. The lease agreements for the nine DG units installed in 2005 contain a reduced rental rate amount for the units beginning in the fourth year of operation. At that point, the lease rate decreases from $152,000 per DG unit per year to $113,400 per unit per year. This reduced rental rate is not a part of the lease agreements for the DG units installed in 2006 and 2007.

Q. What are the dates when the lower rental rate begins to apply to the DG units installed in 2005?

A. Ewa Nui DG Units 1-3 receive the lower rental rate beginning October 14, 2008. The three Iwilei Tank Farm DG units receive the lower rental rate beginning November 9, 2008. The three DG units at Helemano Substation receive the lower rental rate beginning December 16, 2008. These dates are when the units begin their fourth year in service.

Summary of Other Production Operation Expense

Q. Is HECO's estimate of $32,400,000 for the test year 2009 Other Production Operation Expense reasonable?

A. Yes. The estimate is reasonable because it was derived from a review of the resources required to operate HECO’s generating units while maintaining compliance with all environmental and other regulations and permit requirements.

Other Production Maintenance Expense

Q. What is the test year 2009 estimate for Other Production Maintenance Expense?

A. As shown on HECO-701, the test year 2009 estimate for Other Production Maintenance Expense is $47,991,000. Of this total, $17,610,000 is for labor expenses while $30,381,000 is for non-labor expenses.

Q. What was the basis for the 2009 test year estimate for Other Production Maintenance Expense?

A. The 2009 test year estimate is based on the operating budget for 2009 with the adjustments described earlier in my testimony.

Q. How was the 2009 Other Production Maintenance Expense determined?

A. The Other Production Maintenance Expense was determined by forecasting the maintenance labor and non-labor requirements to safely and efficiently provide reliable electric power for distribution throughout Oahu, and to do so while in compliance with all applicable regulations and permit conditions.

Q. Was there consideration to normalize 2009 Production Maintenance expenses?

A. Yes. As described earlier, HECO produced a Normalized Planned Maintenance Schedule, and it was utilized as the basis for the Production Simulation used in the preparation of the 2009 test year estimate. As described in HECO-WP-707, maintenance expenses for overhauls were calculated and normalized based, in part, on the Normalized Planned Maintenance Schedule. The normalized overhaul costs were compared to the 2009 budget for overhauls in the 2009 Planned Maintenance Schedule. The normalized cost for overhauls was slightly higher than budget cost for overhauls, and HECO decided not to adjust the test year estimate based on this difference

Q. What was HECO's conclusion following the analysis to develop the Normalized Maintenance Overhaul expenses?

A. HECO concluded that the estimated cost for overhauls that is included in the 2009 test year estimate is reasonable, and that it is representative of the level of maintenance effort being applied to overhauls year after year.

<u>Other Production Maintenance – Labor Expense</u>

Q. How does HECO forecast the labor portion of the Other Production Maintenance Expense?

A. Labor expenses for Other Production Maintenance are the summation of labor forecasts for work to be performed by maintenance personnel in the three Station Maintenance groups, the Travel Maintenance group, and other non-maintenance personnel who support maintenance of the generating units and their associated facilities. Labor forecasts are based on staffing level using standard labor rates including an estimated amount of overtime, less estimated labor for capital projects.

Q. How does the 2009 test year estimate of Other Production Maintenance - Labor Expense of $17,610,000 compare with the 2007 recorded expense?

A. As shown on HECO-742, the Other Production Maintenance - Labor Expense for the 2009 test year is $17,610,000, which is $4,631,000 higher (i.e., 36% higher) than the 2007 recorded expense of $12,979,000.

Q. What is the primary reason for the increase of $4,631,000 for Other Production – Labor Expense compared to the 2007 labor expense?

A. The difference of $4,631,000 is primarily attributable to the number of maintenance personnel in 2007 versus 2009. In 2009, there are 26 additional positions than recorded in 2007. Eight of the 26 additional positions are due to staffing of CIP CT-1 at a cost of $236,000. Two of the 26 additional positions are for the new Overhaul Coordinator and Clerk in Travel Maintenance, as was discussed earlier in my testimony. The labor costs for 19 of these 26 positions (excluding the 7 trades and crafts positions at CIP CT-1) are included in the 2009 Other Production – Labor Expense for the entire year. The labor expense for the CIP CT-1 trades and crafts positions begin after July 31, 2009, the in-service date of CIP CT-1.

Q. What other factors contribute to the increase between the 2007 recorded labor expense and 2009 test year Other Production Maintenance – Labor Expense?

A. Besides the 10 new Maintenance positions discussed above, wage increases for bargaining unit employees and merit employees also contributes to the increase in

Other Production Operation – Labor Expense. 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). The assumptions used in determining the bargaining unit and merit salary increases included in the 2009 budget is discussed by Ms. Lorie Nagata in HECO T-17 under Budget Process. Ms. Julie Price, HECO T-13, discusses in more detail how the bargaining unit and merit salary increases are determined.

Q. Does a direct comparison of 2007 labor expense and 2009 test year labor expense provide a complete comparison?

A. No, it does not. In 2007, the actual labor costs were substantially lower than planned, in part because of a staffing shortfall caused by difficulties in filling vacant positions in the maintenance work force. The consequences of these vacancies in 2007 (and also in 2008) were: (1) HECO utilized additional supplemental labor to perform maintenance work that would otherwise be performed by its staff; (2) HECO maintenance personnel worked additional overtime; and (3) the backlog of lower priority work increased.

Because of the utilization of supplemental labor to augment the work force in 2007, in a direct comparison of 2007 labor expense to 2009 test year labor expense, consideration must be given to the cost of the outside service supplemental labor as well, which is included in non-labor expenses. As shown in HECO-728, labor expenses and supplemental labor expenses in 2007 totaled $17,002,000. This total included $4,023,000 in supplemental labor expense. Of the $4,023,000, $2,176,000 was budgeted supplemental labor expense. The difference, $1,847,000, was unbudgeted supplemental labor used to make up for staffing shortfall. Summing the 2007 labor expense (the amount of $12,979,000) and the supplemental labor expense to make up for staffing shortfall in 2007 (the amount of $1,847,000) results in the amount of $14,826,000. This composite amount is a more representative amount for use in comparison against 2009 test year Maintenance labor expense.

Comparing the composite amount of $14,826,000 with the 2009 test year amount of $17,610,000 results in a difference of $2,784,000.

Q. Did you compile a listing of variances greater than $200,000 and 10% between 2007 recorded costs and the 2009 test year estimate for the Other Production O&M Expense?

A. Yes. HECO-WP-701 summarizes the variances greater than $200,000 and 10% between 2007 recorded costs and the 2009 test year estimate. However, my testimony does not address each of the individual variances identified in this work paper. The primary reason is that Other Production O&M Maintenance – Labor expenses typically are allocated to different activities and RAs depending upon the specific generating units being worked on and which varies from year to year.

<u>Other Production Maintenance – Non-labor Expense</u>

Q. What is included in Other Production Maintenance - Non-labor Expense?

A. The Other Production Maintenance - Non-labor Expense consists primarily of total costs for materials, contract services, and transportation to maintain HECO's 14 steam units, three combustion turbines, and associated infrastructure. In addition, a relatively small portion, approximately 9% of the outside service costs to maintain the 18 DG units is included in the Other Production Maintenance – Non-labor Expense.

Q. How is the Other Production Maintenance - Non-labor Expense forecast for maintenance groups?

A. The Other Production Maintenance - Non-labor Expense in the four Station Maintenance groups are forecast based on identifying specific discretionary and non-discretionary work, and trended costs for routine work. The Non-labor expenses for the Travel Maintenance group are forecasted based on the 2009 Planned Maintenance Schedule (HECO-718) where requirements are identified and forecasted. Other factors are considered in the development of the forecast include trended cost for particular items, level of outside service support to supplement labor; special tests and inspections by industry experts, and the estimated costs of long lead items.

Q. How does the 2009 test year Other Production Maintenance - Non-labor Expense compare with the 2007 recorded amount?

A. As shown on HECO-743, page 1, the 2009 test year forecast of Other Production Maintenance - Non-Labor Expense is $30,381,000, which is $2,360,000 higher than 2007 recorded expense of $28,021,000.

Q. What would this difference be if the cost for the additional supplemental labor used to compensate for vacancies in the maintenance staff 2007 was not recorded as an outside service/other expense?

A. The difference would increase by $1,847,000, as discussed above under Other Production Maintenance – Labor Expense, the amount of the “unbudgeted supplemental labor used to make up for staffing shortfall.” Thus, the difference for similar work under Other Production Maintenance – Non-Labor, would be $4, 207,000 (i.e., sum of $2,360,000 and $1,847,000) as shown on HECO-743 (page 2).

Q. What is the primary reason for the increase of $4,207,000 for Other Production Maintenance – Non-labor Expense?

A. As shown in HECO-744 (page 1), the combined costs for materials and outside services/other has been relatively steady in recent years. The respective cost for materials and outside services, however, has varied by much greater percentages (positive and negative) from one year to the next. In 2007 and 2009 the combined cost for materials and outside services (including supplemental labor) are $24,919,000 and $27,236,000, respectively. This cost increase of $2,317,000 is equal to 9% for the two-year period from 2007 to 2009. HECO-744 (page 2) shows the adjusted Outside Service/Other expense for 2007 of $13,287,000 (i.e., the recorded 2007 expense was reduced by $1,847,000 to account for unbudgeted supplemental labor used to make up for staffing shortfall). Similarly, HECO-744 (page 2) shows the adjusted subtotal of $23,072,000 for the combined materials and outside services/other (excluding supplemental labor). HECO-744 (page 2) shows the breakdown of the adjusted 2007 recorded versus the test year 2009 variance of $4,207,000. Of this total, $4,164,000 is attributable to the cost increase for the <u>combined</u> costs for materials and outside services/other. This cost increase also includes first-time maintenance non-labor costs for CIP CT-1 of $338,000, as shown on HECO-702. The combined costs are for diversified maintenance activities and projects that occur through the course of the year. For any given year, the specific activities and projects are different in scope (including specific generating units being overhauled, specific generating units experiencing forced outages, and infrastructure projects being implemented) and the corresponding division of costs between materials and outside services/other, also vary. Some projects are labor-intensive and the costs are primarily for outside services, while others are materials-intensive and the costs are primarily for materials. Overall, the level of effort year for year is relatively consistent and the increase in combined expenses is principally due to escalation.

Q. Referring to HECO-743, please provide an explanation for the Other Production Maintenance – Non-labor variance for transportation?

A. Other Production Maintenance – Non-labor expense for transportation was $364,000 in 2007, and $413,000 for the 2009 test year estimate, for a variance of $49,000. This is a 13 percent increase over the two-year period. The increase was due to additional vehicles in the Maintenance Division in 2009, and a higher cost per hour per vehicle.

Q. Referring to HECO-743, please provide an explanation for the Other Production Maintenance – Non-labor variance for Non-Labor On-Cost?

A. Other Production Maintenance – Non-labor expense for Non-Labor On -Cost was $2,738,000 in 2007, and $2,744,000 for the 2009 test year estimate, for a nominal variance of $6,000.

Q. Has HECO conducted any studies to evaluate the escalation in the price of commodities?

A. HECO receives monthly updates from suppliers on market prices of commodities that affect materials price escalation. These commodity indices are published via The Institute for Supply Management Prices Paid Index (PPI).

Q. What has been the trend in commodity prices in recent years?

A. The rising cost of oil coupled with global market demand has resulted in tremendous increases in the prices of commodities in recent years. In addition to metals used in the power generation materials purchased by HECO, prices are also affected by the rising cost of transportation based on oil prices. Price indices are shown on HECO-826 through March 2008. E-steel (electrical steel) prices have risen 214.4% from January 2005 to March 2008. Copper prices have risen

162.8% from January 2005 to March 2008. Key commodity price indices shown on HECO-826 indicate a dramatic escalation just over the first quarter of 2008 from December 2007 indices, with end-of-March 2008 indices showing a quarterly increase of up to 36% for hot rolled steel sheet.

As shown in HECO-745, prices for commodities commonly used directly and/or incorporated in materials purchased by HECO have risen at rates substantially greater than the consumer price index for the period of January 2003 to April 2008. For example, over this period the consumer price index (CPI) increased 16.6%, whereas the corresponding increases in copper, steel and cement were 173%, 85%, and 40%, respectively.

Q. How has the increase in commodities prices impacted HECO's material purchases?

A. The rising cost of commodities and transportation continues to increase the price paid for materials purchased by HECO. While price increases are dependent upon many factors such as the quantity of a specific commodity in a product and other non-material costs in the product, suppliers are passing on their higher costs for raw materials through increased prices to HECO. In HECO-746, a sampling of 50 items purchased by PSO&M is shown, including boiler tubes, electronic components, turbine material, and generator material. The average price increase for the items in this sampling was 34.5% for the three year period 2004 to 2007. The average price increase from 2006 to 2007 was 8.1%.

Q. What has been the escalation of outside service (expense element 501) prices in recent years?

A. Labor costs for outside contractors' journeymen, field engineers, consultants, and construction services continue to increase. A sampling of rates charged by key Power Supply O&M contractors is depicted on HECO-747. This sampling indicates an average hourly rate increase of 22% from average prices paid in 2004 compared to average prices paid in 2007. The average price increase from 2006 to 2007 was 9%.

Q. Please provide a summary and comments on variances of greater than $200,000 and 10% in Other Production Maintenance expenses between the actual 2007 and 2009 test year estimate expenses.

A. A summary variances of greater than $200,000 and 10% in Other Production Maintenance expenses between the actual 2007 and 2009 is provided in HECO-WP-701. As can readily be observed by a review of this work paper, it is not meaningful to discuss the variances by project. In general, this is because major maintenance work (overhauls and maintenance outages) were performed on different generating units in 2007 and 2009. Nevertheless, the HECO-WP-701 provides remarks to provide clarification for the observed variances.

<u>Summary of Other Production Maintenance Expense</u>

Q. Is HECO's estimate of $47,991,000 for the test year 2009 Other Production Maintenance Expense reasonable?

A. Yes. The estimate is reasonable because it was derived from a review of the work required to maintain reliability and availability of HECO's generating units and facilities. As explained earlier in my testimony, the maintenance staff, outside services, and materials are needed to perform the work necessary to sustain the performance and reliability of HECO generating units at acceptable levels.

<u>Cost Trends</u>

Q. How have costs for Other Production O&M Expense trended in recent years?

A. In general, costs for all aspects of the work have trended upward at a steady slope in recent years. HECO-748 shows the trend for the total Other Production O&M Expense block of accounts for 2003 through 2009. Recorded costs are included in for 2003 through 2007, budgetary values are provided for 2008, and the 2009 test year estimate is included. Costs have risen at a steady rate over this period. Also shown for reference are the values corresponding to the settlement between HECO and the Consumer Advocate in the 2005 rate case, and the 2007 interim decision.

Q. What was the breakdown in the trends for labor and non-labor costs for Other Production O&M Expense block of accounts?

A. HECO-749 presents the breakdown between labor and non-labor for the Other Production O&M Expense for the 2003 to 2009. Similar to above, recorded costs are presented for 2003 through 2007, and estimates are presented for 2008 and 2009. Non-labor expenses are shown to be leveling off to a minor degree in the latter years, while labor expenses are shown to be increasing at a slightly higher rate in recent years. This is due, in part, to the increased staffing levels that have occurred as the HECO cycling units have returned to 24 X 7 operations and CIP CT-1 has been commissioned. The leveling off of maintenance expenses in 2008 and 2009 may be due to the budgetary assumption that all maintenance positions would be filled throughout 2008 and 2009, and there would be less reliance on supplemental labor and overtime to get the work accomplished (as it was in prior years).

Q. What were the trends for Maintenance labor and non-labor for the 2003 to 2009 period?

A. HECO-750 presents the breakdown between labor and non-labor for the Maintenance block of accounts of the Other Production O&M Expense for the

2003 to 2009. Consistent with the discussion above, the non-labor maintenance expense is leveling off in the latter years while the corresponding labor expense increases at a higher rate.

Q. What were the trends for Operations labor and non-labor for the 2003 to 2009 period?

A. HECO-751 presents the breakdown between labor and non-labor for the Operations block of accounts of the Other Production O&M Expense for the 2003 to 2009. The labor expense increased in recent years as more operators were added for 24 X 7 operation of the cycling units and 16 X 7 operation of CIP CT-1. The non-labor expense increased significantly during the 2005 to 2007 time period due to the costs for leasing and maintaining the 18 distributed generators (DG) that were added to the system.

Q. What were the trends for cost of Maintenance Labor and Supplemental Labor for the 2001 to 2009 period?

A. HECO-728 presents a comparison of Maintenance labor and supplemental labor (i.e., a subset of Outside Services) for 2001 to 2009. The combined expense for Maintenance and supplemental labor has trended upward since 2001. Since 2004 it has trended upward at a higher rate than it did previously. The relative proportion of supplemental labor has remained relatively constant. In the recent years that recorded costs for supplemental labor has exceeded the amount that was budgeted. This was because additional supplemental labor was needed when vacant maintenance positions could not be filled. That situation continues through today and expectation is that recorded costs for supplemental labor will exceed the budgeted value for 2008, and perhaps for 2009.

Q. What was the breakdown in for Maintenance block of accounts for Other Production O&M Expense between overhauls and station maintenance?

A. HECO-752 shows the respective trends and the breakdown between overhaul and station maintenance for 2003 to 2009. These values are presented on a "gross" basis (i.e., including the G/L Code Adjustment) for the Maintenance block of accounts, and thus, the amounts do not compare directly to those presented and discussed above. The costs for overhauls and station maintenance have increased at similar rates for the subject period, and the rate of the increases is lower in the latter years compared to that for the earlier years.

<u>CIP CT-1 Step</u>

Q. What costs related to CIP CT-1 are included in the 2009 test year estimate for Other Production O&M expense assuming a service date of July 31, 2009?

A. The costs related to CIP CT-1 that are included in the 2009 test year estimate for Other Production O&M expense assuming a service date of July 31, 2009 are $1,489,000, the sum of columns (B) and (C) on HECO-702.

Q. What is included in the $1,489,000 CIP CT-1 costs?

A. The $1,489,000 represents partial-year CIP CT-1 expenses based on an in-service date of July 31, 2009. HECO-WP-709 has been provided to show the details that comprise the amount of $1,489,000. Summarized, the amount includes, but is not limited to:

1) Labor expense
    a) Operations personnel
        i) (1) Supervisor
        ii) (6) CIP operating personnel
    b) Maintenance personnel

i) (1) Supervisor

ii) (6) Maintenance craft personnel (various crafts)

iii) (1) Clerk/Warehouseman

c) All personnel are assumed to be hired effective January 1, 2009. Most, if not all, are expected to transfer from other work bases.

d) Labor costs from January through July are primarily, but not totally, charged to capital.

i) The partial labor costs from January through July are for supervisory and administrative labor not chargeable to capital, including labor to manage the facility and personnel.

ii) After July 31, 2009, all labor costs are charged to O&M expense.

2) Non-Labor expense

a) Operations

i) Non-labor expenses from June or July 2009, or sometimes later, for all of the items listed in HECO-WP-709, including, but not limited to:

(1) Employee Personal Protective Equipment (PPE)

(2) Consumables:

(a) Lube oil, diesel

(b) Supplies

(c) Chemicals for wastewater treatment

(d) Chemicals for demineralizer

(3) Permit Fees

(4) Utilities expenses

(a) Sewage

(b) Water

(c) Telephone

(d) Cellular phone

(5) Services expenses

(a) Oil spill response

(b) Exterminator

(c) Janitor

(d) Refuse

(e) Landscaping

(f) Hazardous waste disposal

(6) Stores on-cost expense

(7) Vehicle cost

ii) Costs are anticipated to transition from capital to O&M. For example, as the in-service date draws near, increasing amounts will be spent on consumables items that will be used in preparation for the initiation of plant operation.

b) Maintenance

i) Materials and parts charges begin from June 2009 as materials are purchased to support maintenance of the unit.

ii) Outside Service expenses for:

(1) Elevator maintenance

(2) Air conditioner maintenance

(3) Solvent service

(4) Elevator repair service

(5) Grounds maintenance support

(6) Crane inspection service

iii) Facilities maintenance support expenses

iv) Stores on-cost expense

v) Vehicle cost

3) Budget Adjustments related to CIP CT-1

a) Air quality monitoring station expense

b) Fish monitoring expense

c) Emission fee

The expense items above (except for the budget adjustments) are shown as the shaded amounts in HECO-WP-709 and reflect the partial-year expense to operate and maintain CIP CT-1. These costs total to $1,562,000 and were obtained from the Pillar budgeting system. The on-cost amounts of $133,000 for Operations and $89,000 for Maintenance for corporate administration, employee benefits and payroll taxes (reversed out of Other Production O&M expenses through G/L code adjustments) are subtracted to derive the net amount of $1,340,000. The $1,340,000, combined with the budget adjustments of $149,000 shown in HECO-702, column C, total the Base Case 2009 test year CIP CT-1 expense of $1,489,000.

Q. How was the total CIP CT-1 expense (i.e., equivalent to a full year operation) that is to be included in the 2009 test year estimate for Other Production O&M expense derived?

A. HECO-WP-709 describes the derivation of total CIP CT-1 expense as if it had operated from January 1 to December 31, 2009. The total CIP CT-1 expense for a full year operation is $2,598,000, the sum of columns (E) and (F) on HECO-702.

Q. How was the 2009 test year estimate for Other Production O&M Expense adjusted to account for a full year operation of CIP CT-1?

A. The Other Production O&M Expense was adjusted in a series of steps, as summarized on HECO-702, to account for a full year operation of CIP CT-1. Column (A) of HECO-702, equal to $80,391,000, is the "Base Case" for the 2009 test year estimate for Other Production O&M Expenses which includes the nine adjustments and one normalization discussed earlier in my testimony. The "Base Case" includes O&M expenses related to CIP CT-1 assuming it started commercial operation on August 1, 2009. As stated above, the O&M expense related to CIP CT-1 assuming a service date of July 31, 2009 is $1,489,000, the sum of columns (B) and (C) of HECO-702. The "Base Case" was then adjusted to an "Interim Increase" (column (D) of HECO-702) by reversing (i.e., summing columns (A), (B), and (C) of HECO-702) all expenses related to CIP CT-1, including the expenses included in the nine adjustments. The Interim Increase of $78,902,000, is representative of a case with zero expenses related to CIP CT-1. The final step was to sum the Interim Increase (column (D) of HECO-702) and the total CIP CT-1 expense as if it had operated for the full year (columns (E) and (F) of HECO-702. This sum shown as column (G) of HECO-702, equal to $81,500,000, is the 2009 test year estimate for Other Production O&M Expenses including estimated expenses for CIP CT-1 as if it had operated for a full year ("CIP CT-1 Step").

Q. Please describe the revenue increases that HECO is requesting in steps.

A. HECO is requesting revenue increases 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 CIP CT-1 Generating Unit costs) to be implemented as soon as practicable. The second step is a CIP CT-1 Step, based on the full cost of CIP CT-1. This second step is to be effective when the CIP CT-1 Generating Unit goes into service. The Interim Increase (without CIP CT-1) and the CIP CT-1 Step being proposed are discussed by Mr. Robert Alm in HECO T-1 and further discussed by Mr. William Bonnet in HECO T-23.

Q. What is HECO's normalized Other Production O&M Expense for the Interim Increase?

A. As described above and shown as column (D) on HECO-702, HECO's normalized Other Production O&M Expense for the Interim Increase is $78,902,000.

Q. How did HECO estimate the expense for an entire year of operations and maintenance of CIP CT-1?

A. As shown in HECO-WP-709, most of the budgeted expenses included in the 2009 operating budget, and beginning about June or July 2009, were extrapolated for the entire year. Permit fees and other expenses which are expected to occur only periodically were not extrapolated. The extrapolated and budgeted expenses for January through December were then summed to reflect the full-year operations and maintenance expense for CIP CT-1 of $2,890,000. Removal of $474,000 of on-costs for corporate administration, employee benefits, and payroll taxes resulted in the CIP CT-1 Full Cost of $2,416,000.

Q. How was the CIP CT-1 Step derived?

A. The CIP CT-1 Full Cost of $2,416,000 (reflected in HECO-702, column E) and the CIP CT-1 budget adjustment of $182,000 for air quality monitoring and fish monitoring (HECO-702, column F) are summed to obtain the total 2009 test year CIP CT-1 Step of $81,500,000 (HECO-702, column G).

Q. What is HECO's normalized Other Production O&M Expense estimate for the CIP CT-1 Step?

A. As described above and shown as column (G) on HECO-702, HECO's normalized Other Production O&M Expense estimate for the CIP CT-1 Step is $81,500,000.

PRODUCTION MATERIALS INVENTORY

Q. What is the Production Materials Inventory amount for test year 2009?

A. The Production Materials Inventory is $8,562,000 for the 2008 year-end inventory, and $9,057,000 for the year-end 2009. The average of the Production Stores Inventory for test year 2009 is $8,809,000**.** These amounts are shown on HECO-703.

Q. What is included in the Production Materials Inventory?

A. The Production Materials Inventory includes material stock such as spare parts for pumps, turbines, generators, and boilers.

Q. Why does HECO maintain a Production Materials Inventory?

A. Most parts are purchased from mainland suppliers and take from one week to over a year for delivery. The spare parts are needed to maintain unit availability, reliability and operating efficiency.

Q. How was the Production Materials Inventory amount determined for test year 2009?

A. The process used to develop the Production Materials Inventory amount for test year 2009 is detailed in HECO-WP-702. Summarized below, it was developed using the following steps:

1) The first step was to determine the estimated 2008 Receipts and Issues.
   a) January 1 through May 31, 2008 recorded values of receipts ($2,303,000) and issues ($2,448,000) were the starting point.
   b) Because of fluctuations in Receipts and Issues in 2007 and 2008, Receipts and Issues for 2007 and through May 2008 were reviewed to determine the

value that would best represent the projected level of Receipts and Issues for the remainder of 2008.

c) The amount deemed most representative for projected Receipts in 2008 was $546,000 per month, the average of Receipts for 2007. The amount deemed most representative for projected Issues in 2008 was $491,000 per month, the average of Issues from January to May 2008.

d) These projected monthly Receipts ($546,000) and Issues ($491,000) amounts were multiplied by 7 months to determine the Receipts and Issues for the remainder of 2008. The resulting estimated remaining 2008 Receipts was $3,822,000 and estimated remaining 2008 Issues was $3,430,000.

e) An estimated price increase of 12% was used to escalate the June through December amounts for Receipts and Issues for increases in the price of goods and freight. The 12% factor was derived by averaging the average increase in Receipts and Issues from 2004 through 2007. The estimated price increase for 2008 Receipts from June to December was $459,000 and for 2008 Issues was $412,000.

f) The estimated 2008 Receipts is the sum of $2,303,000 plus $3,822,000 plus $459,000 or $6,583,000. The estimated 2008 Issues is the sum of $2,448,000 plus $3,430,000 plus $412,000 or $6,289,000.

2) The estimated 2008 Receipts was added to the 2008 beginning inventory of $8,268,000 and the estimated 2008 Issues was subtracted to result in the 2008 Year End Inventory of $8,562,000. This amount became the 2009 Beginning of Year Inventory.

3) 2008 Issues and Receipts were escalated by 12.7% and 10.6%, respectively,

the average increase for each from 2004 to 2008, to estimate 2009 Issues and Receipts. The resulting 2009 Issues and Receipts are $7,089,000 and $7,284,000, respectively.

4) An estimated amount of $300,000 of New Items to be added to Production Materials Inventory in 2009 was added to Receipts to bring the total estimated 2009 Receipts to $7,584,000. The New Items would include critical replacement parts such as circulating water pump motors, boiler feed pump motors, or other critical spare parts.

5) Adding the estimated 2009 Receipts to and subtracting the estimated 2009 Issues from the 2009 beginning of year inventory results in the estimated 2009 Year End Production Materials Inventory of $9,057,000.

6) The 2009 Average Inventory is $8,809,000, the average of the 2009 beginning inventory and ending inventory.

Q. How did the value of Production Materials Inventory vary over the past years?

A. The value of the year-end stock balances increased from $5,489,000 to $8,268,000 between year-end 2004 and year-end 2007, as shown on HECO-703.

Q. Why is the test year 2009 Production Materials Inventory reasonable for ratemaking purposes?

A. The Production Materials Inventory is reasonable because it was derived from historical trends and the need to maintain an inventory to support both new and original equipment/designs currently in service.

SUMMARY

Q. Mr. Giovanni, please summarize your testimony.

A. HECO's test year 2009 Other Production O&M Expense is estimated to be $80,391,000 after factoring in budget and normalization adjustments for the base case, \$78,902,000 for the Interim Increase, and \$81,500,000 for the CIP CT-1 Generating Unit Step. The test year forecast is reasonable because it reflects a normal and adequate level of spend to operate and maintain the Company's generating plants at acceptable levels of performance and reliability. As mentioned throughout my testimony, generating units on the Oahu system including IPPs are getting older and continue to experience operating duties that exert wear and tear on the equipment. HECO's baseload units are operating at high capacity factors and its cycling units are operating more hours. The addition of CIP CT-1 will improve the overall reliability of the generating system and help facilitate new renewable energy sources to be connected to the grid in the future. It will not, however, relieve the duty on HECO baseload and cycling units. To operate all the baseload and cycling units 24 X 7 and CIP CT-1 16 X 7, provide the requisite personnel training, perform the necessary planned and unplanned maintenance, and provide the additional peaking capacity (i.e., 18 DG units) results in \$11,584,000 higher Other Production O&M Expense in 2009 as compared to 2007. In addition, HECO's 12-month average Production Materials Inventory is estimated to be \$8,809,000. This level of inventory is necessary to store sufficient spare parts and materials to maintain unit availability, reliability and efficiency.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY, INC.

DAN V. GIOVANNI

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 475 Kamehameha Highway, Pearl City, HI 96782
Position:	Manager, Power Supply Operations & Maintenance Department Hawaiian Electric Company, Inc. (HECO) (March 2006 to present)
Prior Position:	Manager, Production Department Hawaii Electric Light Company, Inc. (HELCO) (2001 to 2006)
Years of Service:	7
Education:	University of California, Berkeley, B.S. Mechanical Engineering, 1970 University of California, Berkeley, M.S. Mechanical Engineering, 1971
Experience:	President Electric Power Technologies, Inc. (EPT) (California, New York, and Hawaii) (1982 to 2001)
	Program Manager, Air Quality Control Electric Power Research Institute (EPRI) (1978 to 1982)
	Research Section Manager Kaiser Aluminum and Chemical Corporation (1975 to 1978)
	Consulting Engineer KVB Incorporated 1971 to 1975
Previous Testimonies:	Docket No. 2006-0386 – HECO Other Production O&M Expense, Production Inventory
	Docket No. 05-0315 – HELCO Production Other O&M Expense, System Reliability Improvements, Purchased Power, Production Inventory
	Board of Land and Natural Resources Land Use Commission, State of Hawaii, Keahole Rezoning, 2005

Hawaiian Electric Company, Inc.
2009 TEST YEAR
OTHER PRODUCTION OPERATIONS & MAINTENANCE EXPENSE - BASE CASE
($ Thousands)

		(A) OPERATING BUDGET	(B) BUDGET ADJ	(C) NORMAL-IZATION	(D) 2009 TY ESTIMATE
	OTHER PRODUCTION OPERATIONS EXPENSE				
1	Labor	$ 15,373	$ 29	$ -	$ 15,402
2	Non-Labor	$ 17,011	$ (10)	$ (3)	$ 16,998
3	TOTAL	$ 32,384	$ 19	$ (3)	$ 32,400
	OTHER PRODUCTION MAINTENANCE EXPENSE				
4	Labor	$ 17,610	$ -	$ -	$ 17,610
5	Non-Labor	$ 30,393	$ (12)	$ -	$ 30,381
6	TOTAL	$ 48,003	$ (12)	$ -	$ 47,991
	OTHER PRODUCTION O&M EXPENSE - TOTAL				
7	Labor	$ 32,983	$ 29	$ -	$ 33,012
8	Non-Labor	$ 47,404	$ (22)	$ (3)	$ 47,379
9	TOTAL	$ 80,387	$ 7	$ (3)	$ 80,391

Source:
HECO-WP-101(A), page 2, for Column A.
HECO-734 for Column B.
HECO-735 for Column C.

Hawaiian Electric Company, Inc.
2009 TEST YEAR
OTHER PRODUCTION O&M EXPENSE - BASE CASE, INTERIM INCREASE, CIP CT-1 STEP INCREASE
($ Thousands)

		(A) BASE CASE 2009 TY ESTIMATE	(B) REVERSE CIP CT-1 EXPENSES IN 2009 OPER BUDGET	(C) REVERSE BUDGET ADJ RELATED TO CIP CT-1	(D=A=B+C) INTERIM 2009 TY ESTIMATE W/O CIP CT-1	(E) ADD CIP CT-1 FULL COST	(F) ADD CIP CT-1 BUDGET ADJ	(G=D+E=F) CIP CT-1 GEN UNIT STEP 2009 TY ESTIMATE
	OTHER PRODUCTION OPERATIONS EXPENSE							
1	Labor	$ 15,402	$ (316)	$ (87)	$ 14,999	$ 647	$ 87	$ 15,733
2	Non-Labor	$ 16,998	$ (450)	$ (62)	$ 16,486	$ 773	$ 95	$ 17,354
3	TOTAL	$ 32,400	$ (766)	$ (149)	$ 31,485	$ 1,420	$ 182	$ 33,087
	OTHER PRODUCTION MAINTENANCE EXPENSE							
4	Labor	$ 17,610	$ (236)	$ -	$ 17,374	$ 536		$ 17,910
5	Non-Labor	$ 30,381	$ (338)	$ -	$ 30,043	$ 460		$ 30,503
6	TOTAL	$ 47,991	$ (574)	$ -	$ 47,417	$ 996	$ -	$ 48,413
	OTHER PRODUCTION O&M EXPENSE - TOTAL							
7	Labor	$ 33,012	$ (552)	$ (87)	$ 32,373	$ 1,183	$ 87	$ 33,643
8	Non-Labor	$ 47,379	$ (788)	$ (62)	$ 46,529	$ 1,233	$ 95	$ 47,857
9	TOTAL	$ 80,391	$ (1,340)	$ (149)	$ 78,902	$ 2,416	$ 182	$ 81,500
			Sum of Columns B and C = ($1,489)			Sum of Columns E and F = $2,598		

Source:
Column A: HECO-701, Column D.
Columns B and E: HECO-WP-709. Amounts are net of on-costs for corp administration, payroll taxes and employee benefits that are removed from Other Production O&M expenses as G/L code adjustments.
Column C: HECO-734 and HECO-WP-709. Reverses CIP CT-1 budget adjustments for air quality monitoring stations (minus $155k), fish monitoring (minus $27k) and emission fees (plus $33k).
Column F: HECO-734 and HECO-WP-709. Adds back CIP CT-1 budget adjustments for air quality monitoring stations (plus $155k) and fish monitoring (plus $27k). Emission fees for CIP CT-1 ($33k) are included in CIP CT-1 Full Cost in Column E.

Hawaiian Electric Company, Inc.
2009 TEST YEAR
PRODUCTION MATERIAL INVENTORY
($ Dollars)

	RECORDED				2008 Budget	2009 TEST YEAR	2007 vs 2009	
	(A)	(B)	(C)	(D)	(E)	(F)	(G=F-D)	(H=F/D)
	2004	2005	2006	2007	2008	2009	$	%
1 Year-End Value	5,488,941	6,165,365	6,849,128	8,267,514	8,561,752	9,056,579	789,065	10%
2 Average Value (YE + Previous YE)/2	5,143,278	5,827,153	6,507,247	7,558,321	8,414,633	8,809,166	1,250,845	17%
3 12-Month Rolling Ave	5,336,052	5,967,972	6,346,579	7,336,132				
4 Total Issues	3,937,500	4,483,024	4,505,534	5,096,281	6,289,193	7,089,112	1,992,831	39%
5 Total Receipts	4,472,700	4,912,812	5,107,906	6,551,850	6,583,431	7,583,940	1,000,509	16%

Source: Col (A) and (B), Rows 1, 3, and 4 from Docket No. 2006-0386, HECO-603.
Col (C) through (G), Rows 1, 3, 4, and 5 from HECO-WP-702.

Hawaiian Electric Company, Inc.
2009 TEST YEAR

Age of Generating Units
(as of 2009)

Unit	Capability (MW*)	Type	Operating Mode	Service Date	Age
HECO Generating Units					
Honolulu 8	56	Steam, Non-Reheat	Cycling	1954	55
Honolulu 9	57	Steam, Non-Reheat	Cycling	1957	52
Waiau 3	49	Steam, Non-Reheat	Cycling	1947	62
Waiau 4	49	Steam, Non-Reheat	Cycling	1950	59
Waiau 5	57	Steam, Non-Reheat	Cycling	1959	50
Waiau 6	56	Steam, Non-Reheat	Cycling	1961	48
Waiau 7	92	Steam, Reheat	Base	1966	43
Waiau 8	94	Steam, Reheat	Base	1968	41
Waiau 9	53	Combustion Turbine	Peaking	1973	36
Waiau 10	50	Combustion Turbine	Peaking	1973	36
Kahe 1	92	Steam, Reheat	Base	1963	46
Kahe 2	89	Steam, Reheat	Base	1964	45
Kahe 3	92	Steam, Reheat	Base	1970	39
Kahe 4	93	Steam, Reheat	Base	1972	37
Kahe 5	142	Steam, Reheat	Base	1974	35
Kahe 6	142	Steam, Reheat	Base	1981	28
CIP CT1	110	Combustion Turbine	Peaking	2009	0
HECO Distributed Generators					
Ewa Nui Sub Sta 1/2/3	5	Diesel Engine	Peaking	2005	4
Helemano Sub Sta 1/2/3	5	Diesel Engine	Peaking	2005	4
Iwilei Tank Farm 1/2/3	5	Diesel Engine	Peaking	2005	4
CEIP Sub Sta 1/2/3	5	Diesel Engine	Peaking	2006	3
Kalaeloa Pole Yard 1/2/3	5	Diesel Engine	Peaking	2006	3
Ewa Nui Sub Sta 4/5/6	5	Diesel Engine	Peaking	2007	2
Major Independent Power Producers					
HPOWER	46	Steam, Non-Reheat	Base	1990	19
Kalaeloa	208	Combined Cycle	Base	1991	18
AES	180	Steam, Reheat	Base	1992	17

Average age of HECO Steam Units	**45.7 Years**
Average age of HECO Reheat Steam Units	**39.3 Years**
Average age of HECO Non-Reheat Steam Units	**54.3 Years**
Average age of Independent Power Producers	**18.0 Years**

* HECO units in Gross megawatts; IPP units in Net megawatts.

Hawaiian Electric Company, Inc.
2009 Test Year
Annual Capacity Factor by Unit

UNIT	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
H8	22.6	30.4	31.3	32.2	34.2	15.5	20.0	16.5	16.4	14.4	11.5	7.6	5.6	8.7	4.5	4.0	8.2	2.4	14.8	16.5	17.0	18.6
H9	20.7	34.8	52.6	55.3	60.9	30.2	15.4	15.1	17.4	25.5	21.2	14.7	5.8	11.3	9.4	11.1	13.6	12.1	22.4	21.8	12.3	15.9
W3	18.1	21.8	26.0	20.7	21.4	13.1	12.7	3.9	0.0	-0.5	-0.3	5.9	2.7	9.4	13.3	5.4	8.3	11.0	11.8	33.9	15.7	29.5
W4	11.0	15.1	18.4	19.5	22.6	13.4	12.0	5.7	4.1	6.4	10.2	11.2	5.1	11.5	11.7	4.7	15.5	15.2	22.5	25.5	13.5	23.4
W5	30.5	33.8	40.4	46.8	43.2	29.0	21.2	17.6	9.6	19.1	16.4	20.5	12.0	15.6	17.8	16.8	15.6	19.4	27.7	30.1	27.2	29.6
W6	30.8	32.7	33.7	32.3	39.2	21.8	18.9	14.7	19.9	23.4	20.9	23.7	14.0	20.5	23.1	19.2	29.3	24.7	34.6	25.8	22.9	26.3
W7	74.5	83.7	75.3	79.3	67.8	73.5	55.6	60.4	60.1	69.9	65.7	53.2	69.9	60.5	47.4	65.8	69.8	54.8	59.5	55.5	63.1	50.1
W8	82.3	67.2	82.5	82.1	71.2	74.2	67.5	51.4	62.8	54.2	58.7	48.7	59.7	56.7	49.9	59.2	57.5	55.9	42.0	43.1	56.0	56.7
W9	0.7	3.5	3.6	4.1	4.5	0.5	0.4	0.3	0.6	0.3	0.3	0.2	0.0	0.2	0.3	0.5	1.5	2.3	3.8	3.7	2.4	1.6
W10	0.6	2.3	5.1	4.2	4.3	1.9	0.5	0.5	0.9	0.2	0.2	0.3	0.1	0.4	0.5	0.5	0.7	1.4	4.3	3.5	1.3	1.1
K1	64.3	73.0	71.9	82.6	73.5	72.5	59.6	61.5	47.3	55.8	38.0	52.8	53.3	48.2	62.4	59.1	52.3	60.4	66.6	59.0	51.2	55.2
K2	77.5	70.2	80.5	69.0	81.9	66.3	70.5	62.1	65.3	38.0	57.5	58.3	51.7	76.2	64.7	49.5	65.5	59.5	66.1	45.2	60.6	51.7
K3	80.5	82.3	80.2	65.9	86.9	62.3	71.2	51.2	58.0	53.2	60.2	56.7	54.5	65.2	65.9	50.2	68.4	58.6	68.2	60.9	62.7	49.7
K4	71.7	82.1	77.0	83.6	70.6	77.1	65.1	58.9	43.2	67.4	67.4	70.7	71.0	54.8	64.0	73.5	65.6	63.7	69.9	69.9	54.1	66.6
K5	67.7	62.3	80.2	76.2	78.8	67.1	67.5	48.6	58.0	47.5	53.2	54.3	61.0	59.5	53.6	60.5	57.4	64.7	46.7	63.7	62.4	60.5
K6	72.7	73.1	59.7	79.2	68.0	70.2	56.0	57.0	47.1	52.6	51.3	45.3	45.0	39.9	55.5	54.9	45.0	58.3	63.0	48.4	69.0	68.8
REHEAT W78 K123456	73.8	74.8	77.4	75.0	70.3	64.0	55.7	55.9	54.9	54.2	56.0	54.3	57.6	56.5	57.5	58.9	59.0	59.8	59.5	55.8	60.7	58.4
NOREHEAT H89 W3456	22.7	28.6	34.3	35.0	37.5	20.8	16.9	12.6	11.6	15.2	13.7	14.1	7.7	12.9	13.3	10.4	15.1	14.1	22.4	25.4	18.3	23.7
CTS	0.7	2.9	4.3	4.1	4.4	1.2	0.4	0.4	0.8	0.3	0.2	0.3	0.1	0.3	0.4	0.5	1.1	1.9	4.1	3.6	1.9	1.4
TOTSYSwoCT	58.6	60.3	63.2	65.1	63.9	56.1	50.4	43.5	42.5	43.1	43.9	42.8	43.3	44.1	44.8	45.0	46.5	46.7	48.9	47.1	48.5	48.5
TOTSYSTEM	53.8	55.6	58.3	60.1	59.0	51.5	46.3	39.9	39.0	39.5	40.3	39.3	39.7	40.4	41.1	41.3	42.7	43.0	45.2	43.5	44.7	44.6
HONOLULU	21.7	32.6	42.0	43.3	47.3	22.8	17.7	15.8	16.9	19.9	16.3	11.1	5.7	10.0	6.9	7.5	10.9	7.2	18.6	19.2	14.7	17.3
WAIAU	38.3	39.1	42.3	43.1	39.9	35.4	29.4	24.9	26.1	27.8	27.8	25.2	27.1	27.4	24.8	27.8	30.7	28.1	29.7	30.9	30.5	31.3
WAIAUwoCT	48.1	48.5	52.2	53.4	49.2	44.5	37.1	31.4	32.8	35.2	35.1	31.8	34.3	34.6	31.3	35.0	38.5	35.0	36.5	38.1	38.2	39.2
KAHE	72.1	72.8	74.0	76.4	76.1	69.1	64.4	55.9	53.0	52.1	54.3	55.3	55.6	56.0	59.9	57.9	57.8	61.0	62.0	57.6	61.0	59.8
STMUNIT99	54.8	57.9	61.0	61.0	60.8	51.9	46.6	40.4	39.1	40.8	41.1	40.5	40.1	42.2	41.6	40.8	44.9	41.8	46.9	44.1	42.8	43.1
STMUNITS199	70.2	67.7	69.9	77.7	73.3	68.6	61.7	52.8	52.5	50.1	52.2	49.8	53.0	49.7	54.6	57.7	51.2	61.5	54.8	56.0	65.7	64.7

1986-2007 Minimum Reheat Unit Capability = K2 at 38.0% in 1995 and K1 at 38.0% in 1996.
Maximum Reheat Unit Capability = K3 at 86.9% in 1990.
Average Reheat Unit Capability = 62.5% from 1986 to 2007.

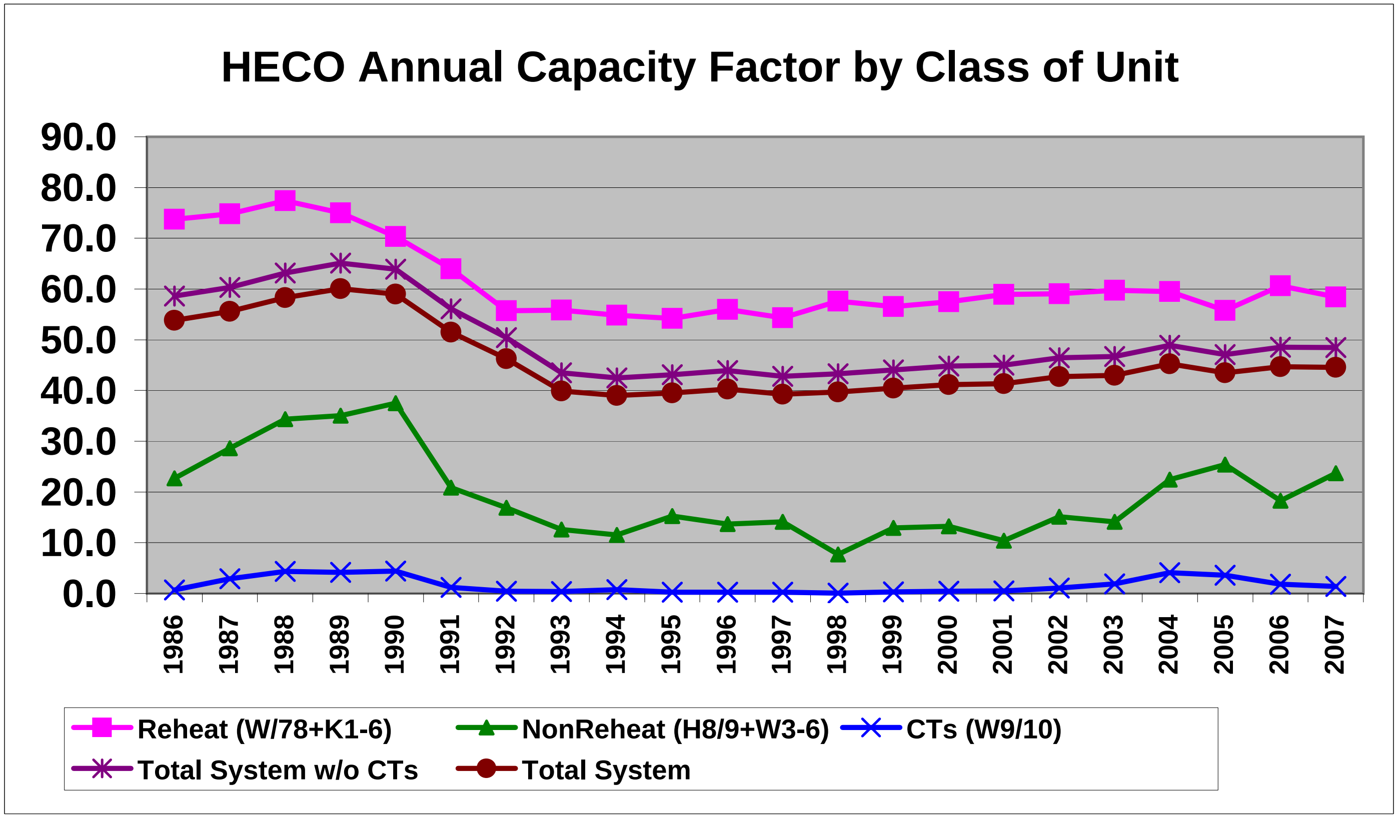
2003-2007 Minimum Reheat Unit Capability = W8 at 42.0% in 2004.
Maximum Reheat Unit Capability = K4 at 69.9% in 2004 and 2005.
Average Reheat Unit Capability = 58.6% from 2003 to 2007.

Source: HECO-WP-703, GENSTAT07 12 31 07.xls

Hawaiian Electric Company, Inc.
2009 Test Year
HECO Annual Capacity Factor by Class of Unit

Annual Capacity Factor by Class of Unit

UNIT	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Reheat (W/78+K1-6)	73.8	74.8	77.4	75.0	70.3	64.0	55.7	55.9	54.9	54.2	56.0	54.3	57.6	56.5	57.5	58.9	59.0	59.8	59.5	55.8	60.7	58.4
NonReheat (H8/9+W3-6)	22.7	28.6	34.3	35.0	37.5	20.8	16.9	12.6	11.6	15.2	13.7	14.1	7.7	12.9	13.3	10.4	15.1	14.1	22.4	25.4	18.3	23.7
CTs (W9/10)	0.7	2.9	4.3	4.1	4.4	1.2	0.4	0.4	0.8	0.3	0.2	0.3	0.1	0.3	0.4	0.5	1.1	1.9	4.1	3.6	1.9	1.4
Total System w/o CTs	58.6	60.3	63.2	65.1	63.9	56.1	50.4	43.5	42.5	43.1	43.9	42.8	43.3	44.1	44.8	45.0	46.5	46.7	48.9	47.1	48.5	48.5
Total System	53.8	55.6	58.3	60.1	59.0	51.5	46.3	39.9	39.0	39.5	40.3	39.3	39.7	40.4	41.1	41.3	42.7	43.0	45.2	43.5	44.7	44.6



Source: HECO-WP-703, GENSTAT07 12 31 07.xls

In the peer group established for HECO's steam fleet, less than half operate as base-loaded units. A base-loaded unit (designed with a reheater to improve its thermal efficiency) is intended to operate continuously and produce maximum power for the grid whenever it is available. Contrastingly, a cycling or peaking unit does not face the high load requirements experienced by a base-loaded unit. Cycling units are used either as peakers (low efficiency simple-cycle combustion turbines) to satisfy seasonal peak power demands, or as a load-following power supply (lower efficiency steam units without reheaters) for supplemental power to meet output (MW) increments as demand fluctuates.

There are a number of advantages and disadvantages associated with base-load operation of a unit. One obvious disadvantage is the limited downtime for equipment maintenance and repair. If a base-loaded unit's load is reduced, it immediately impacts the company due to higher fuel costs and lost power generation. Add the cost of repair and/or maintenance and the problem becomes amplified. In contrast, a peaking or cycling unit has a much greater time frame for equipment maintenance and/or repair, as they regularly experience extended, predetermined downtime throughout the course of the year.

Because of the load requirements on Oahu, each of HECO's steam units is required to operate as a base-loaded or load-following unit - a distinction HECO's units have compared to their industry counterparts. The statistical results may be observed by HECO's unusually high capacity factor (see Figure 8).

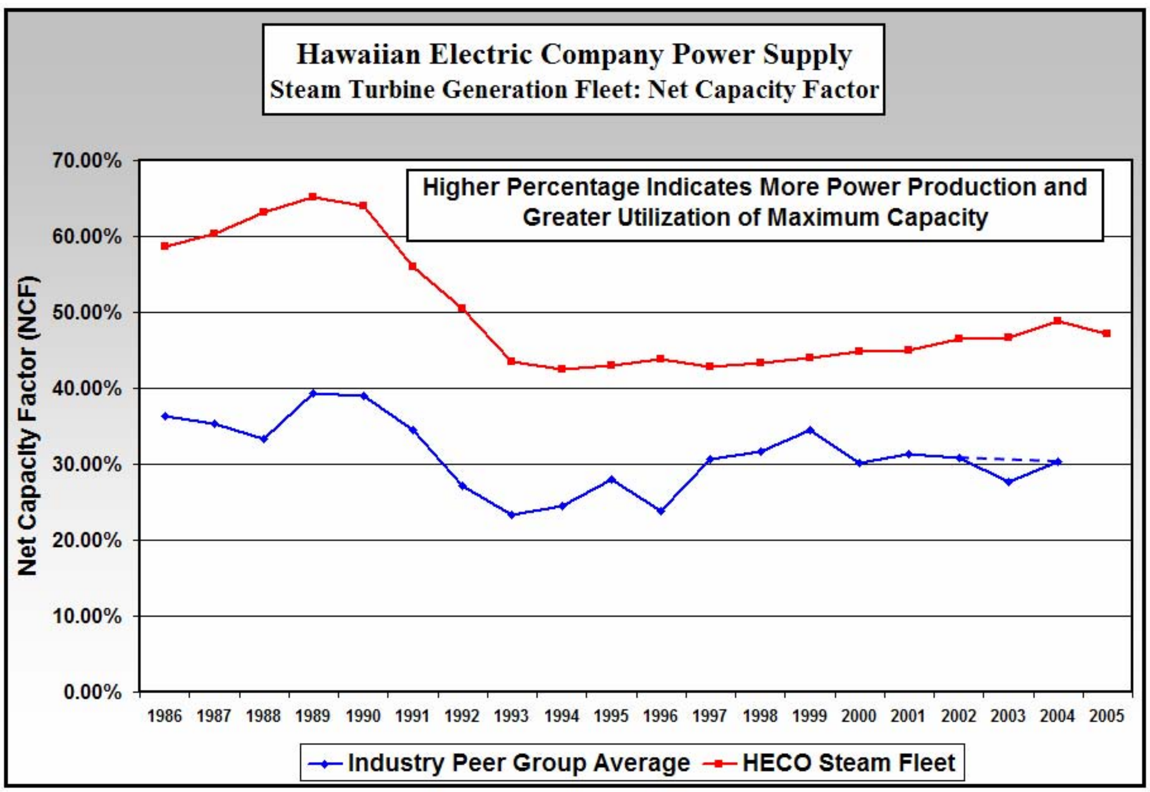


Figure 8: Net Capacity Factor (NCF) of HECO's Steam Fleet

The information provided by Figure 8 is two-fold in nature. First, this figure clearly indicates that HECO's steam units run at consistently higher capacity factors than the industry peer group. Results on a unit-by-unit basis over the past five (5) years reinforce this fact. This can also be seen in Table 3 which shows each unit's Net Capacity Factor compared to the industry peer group average.

Table 3: 5-year Average Net Capacity Factor (NCF) of Steam Units

Unit	5 year NCF
K4	68.50%
K3	61.27%
W7	61.09%
K1	59.50%
K5	58.60%
K2	57.17%
K6	53.91%
W8	51.54%
Industry Average	**30.02%**
W6	26.73%
W5	21.92%
W4	16.69%
H9	16.22%
W3	14.06%
H8	9.19%

Many of HECO's units are running at nearly double the industry peer group average. This reflects the severe capacity strain placed on the entire fleet. Because HECO's supply and demand margin is so tight, every unit is required to contribute that much more to the power supply. This results in more stress and strain on the equipment and fewer opportunities for equipment maintenance and repair. Less than optimally-maintained equipment and increased stress and strain placed on the equipment creates a vicious and continuous cycle.

Despite the high unit NCFs, the HECO generation fleet has exhibited excellent performance over the last twenty (20) years. Since 2001, every unit – with the exception of Waiau 3 – has experienced above-average availability, as can be seen by Table 4.

Table 4: 5-year Average Equivalent Availability Factor (EAF) of Steam Units

Unit	5 year EAF
W7	92.88%
K1	92.70%
W4	92.43%
K4	91.93%
K2	89.65%
K5	88.60%
H9	88.38%
K3	88.28%
W6	87.96%
W8	86.85%
K6	85.94%
W5	85.46%
H8	82.70%
Industry Average	**81.21%**
W3	81.05%

However, as stated previously, the information provided by Figure 8 is two-fold. The second aspect of this figure is that it shows a trend upwards in capacity factor. This reflects an increasing trend in the power demand. As demand increases, more supply will be necessary and less time will be available to repair and maintain equipment until adequate additional capacity is installed on the system. Optimization of operation and maintenance time will be imperative to ensure acceptable fleet performance.

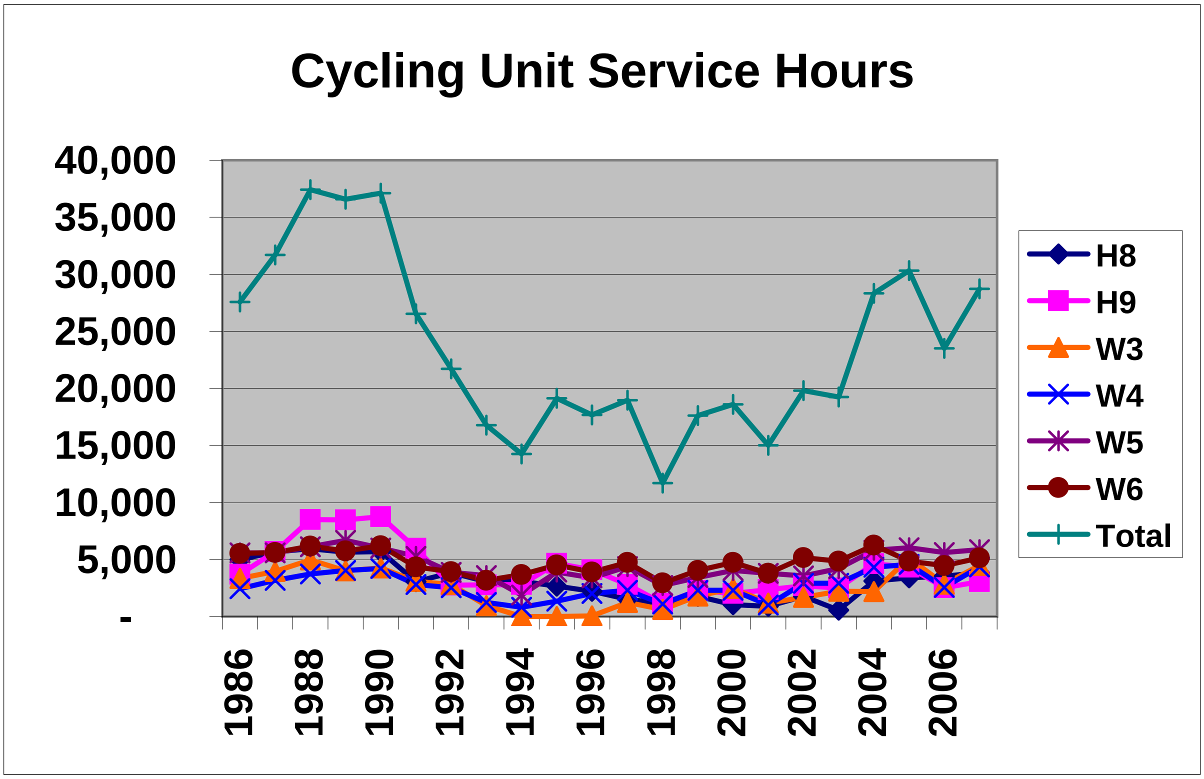
HECO Fleet – Planned and Un-Planned Event Analysis

The next step of this review is to examine the various aspects of power generation that would account for the recent trends in capacity, availability, and reliability.

Forced Outages are classified by NERC as unplanned component failures or other conditions that require the unit to be removed from service immediately (U1), within six hours (U2), or before the end of the next weekend (U3)). Forced Deratings are unplanned component failures or other conditions that require the load on the unit be reduced immediately (D1), within six hours (D2), or before the end of the next weekend (D3)). Maintenance Deratings are removal of a component for scheduled repairs that can be deferred beyond the end of the next weekend, but requires a capacity reduction before the next planned outage (D4).

The immediate concern with Hawaiian Electric Company's power supply involves increasing EFOR. From 2001 to 2005, the generation lost to Forced Outages increased over 405%, rising from just over 156,000 MWh of lost generation in 2001 to over 791,000 MWh in 2005 (see Figure 9). During this time period, an effort was made to curb this trend through the execution

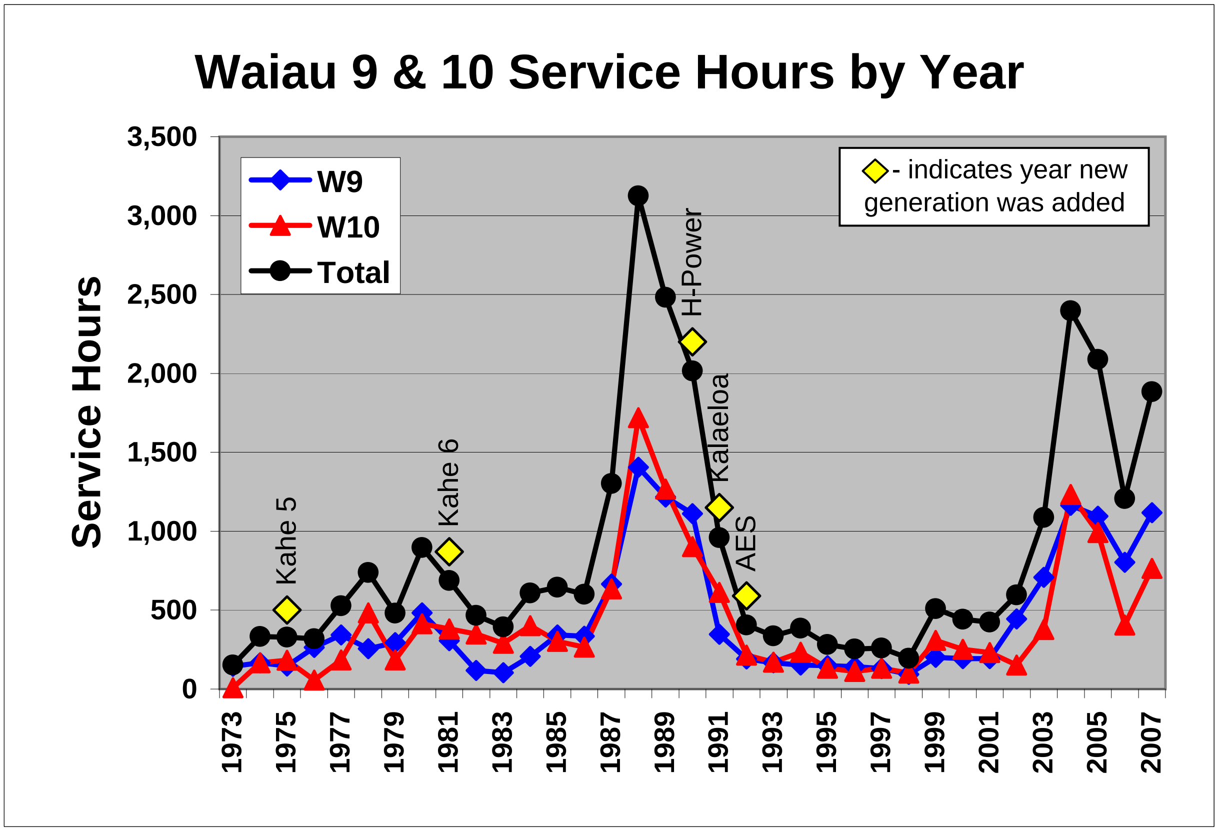
Hawaiian Electric Company, Inc.
2009 Test Year
HECO Cycling Unit Service Hours



	H8	H9	W3	W4	W5	W6	Total
1986	4,982	3,705	3,336	2,439	5,589	5,525	27,562
1987	5,674	5,698	3,967	3,177	5,582	5,623	31,708
1988	5,955	8,505	4,954	3,737	6,102	6,165	37,406
1989	5,651	8,471	4,016	4,037	6,665	5,747	36,576
1990	5,693	8,750	4,262	4,197	6,013	6,207	37,112
1991	3,064	5,961	3,082	2,813	5,274	4,349	26,534
1992	3,841	2,741	2,806	2,525	3,872	3,922	21,699
1993	3,044	2,767	963	1,247	3,601	3,166	16,781
1994	3,093	2,801	-	806	1,887	3,673	14,254
1995	2,671	4,662	10	1,349	3,908	4,525	19,120
1996	2,223	4,104	43	2,018	3,408	3,885	17,677
1997	1,514	2,793	1,223	2,290	4,388	4,752	18,956
1998	1,162	1,161	605	1,106	2,733	2,938	11,702
1999	1,769	2,283	1,786	2,309	3,428	4,047	17,622
2000	1,030	2,027	2,466	2,301	4,049	4,734	18,608
2001	895	2,362	1,170	1,009	3,794	3,773	15,004
2002	1,759	2,693	1,693	2,914	3,556	5,175	19,793
2003	564	2,486	2,205	2,923	4,206	4,855	19,241
2004	3,114	4,634	2,199	4,309	5,817	6,255	28,330
2005	3,383	4,324	5,147	4,582	6,027	4,847	30,315
2006	3,525	2,525	2,831	2,541	5,605	4,460	23,493
2007	3,853	3,068	4,476	4,352	5,849	5,121	28,726

Source: HECO-WP-703, GENSTAT07 12 31 07.xls

Hawaiian Electric Company, Inc.
2009 Test Year
Waiau 9 & 10 Service Hours by Year



Waiau 9 & 10 Service Hours by Year

	W9	W10	Total		W9	W10	Total		W9	W10	Total
1973	144	8	152	1985	342	303	645	1997	129	131	260
1974	167	166	333	1986	335	265	600	1998	93	101	194
1975	146	183	329	1987	666	635	1301	1999	200	309	509
1976	263	56	319	1988	1405	1719	3124	2000	192	251	443
1977	342	185	527	1989	1216	1267	2483	2001	193	231	424
1978	255	483	738	1990	1112	903	2015	2002	444	152	596
1979	295	185	480	1991	347	613	960	2003	708	378	1086
1980	482	414	896	1992	191	215	406	2004	1163	1233	2396
1981	306	382	688	1993	166	170	336	2005	1096	992	2088
1982	118	348	466	1994	153	233	386	2006	802	405	1207
1983	104	289	393	1995	149	132	281	2007	1118	765	1883
1984	206	402	608	1996	141	112	253				

Source: HECO-WP-703, GENSTAT07 12 31 07.xls

Hawaiian Electric Company, Inc.
2009 Test Year
Distributed Generator Monthly Report

DISTRIBUTED GENERATOR MONTHLY REPORT
DECEMBER 2007

	EWA NUI (1,2,3)		IWILEI		HELEMANO		CEIP		POLE YARD		EWA NUI (4,5,6)	
FUEL BURNED	0		4,022		2,921		1,949		1,465		7,377	
KWh PRODUCED	57,672		41,115		34,967		0		18,844		43,838	
ENGINE HOURS (This month)	42		32		26		0		16		34	
	Start date: 10/25/05		Start date: 11/08/05		Start date: 12/15/05		Start date: 11/8/06		Start date: 12/20/06		Start Date: 5/4/07	
	ROLLING 12-MONTH FUEL USAGE & HOURS RUN											
	Eng. Hrs.	Fuel Used	Eng. Hrs.	Fuel Used	Eng. Hrs.	Fuel Used	Eng. Hrs.	Fuel Used	Eng Hrs	Fuel Used	Eng Hrs	Fuel Used
January-07	42	5,898	57	6,820	31	3,741	32	3,583	13	1,616		
February-07	106	12,439	148	17,890	81	9,709	118	13,029	63	7,058		
March-07	84	9,188	132	15,366	61	6,921	67	7,347	48	5,105		0
April-07	50	5,422	88	10,534	23	2,696	50	5,248	46	5,073		0
May-07	79	2,217	105	13,371	54	6,111	109	12,155	81	8,328		1,643
Jun-07	133	14,409	157	19,747	50	6,220	105	11,740	128	13,969		13,588
Jul-07	444	50,496	219	33,070	214	26,975	279	32,205	236	27,294		28,471
Aug-07	190	21,189	133	10,740	90	10,302	176	19,595	118	13,294		
Sep-07	182	20,595	136	16,603	98	11,959	107	12,193	143	15,884		
October-07	177	19,102	179	21,440	109	12,392	168	18,794	179	19,725		
November-07	192	21,771	93	11,051	51	5,626	167	18,681	136	15,080		
December-07	76	7,377	32	4,022	26	2,921	0	1,949	16	1,465		
	Hours based on 120.5 gal/hr.											
Rolling 12-month total allowed:	3,903	470,400	3,903	470,400	3,578	431,200	3,903	470,400	3,903	470,400	Engine run hours & fuel used are combined with Ewa Nui (1,2,3)	
Rolling 12-month actual:	1,755	233,805	1,479	180,654	888	105,573	1,378	156,519	1,207	133,891		
Rolling 12-month remaining:	2,148	236,595	2,424	289,746	2,690	325,627	2,525	313,881	2,696	336,509		
% Remaining:		50.3%		61.6%		75.5%		66.7%		71.5%		

Hawaiian Electric Company, Inc.
2009 Test Year
Distributed Generator Monthly Report

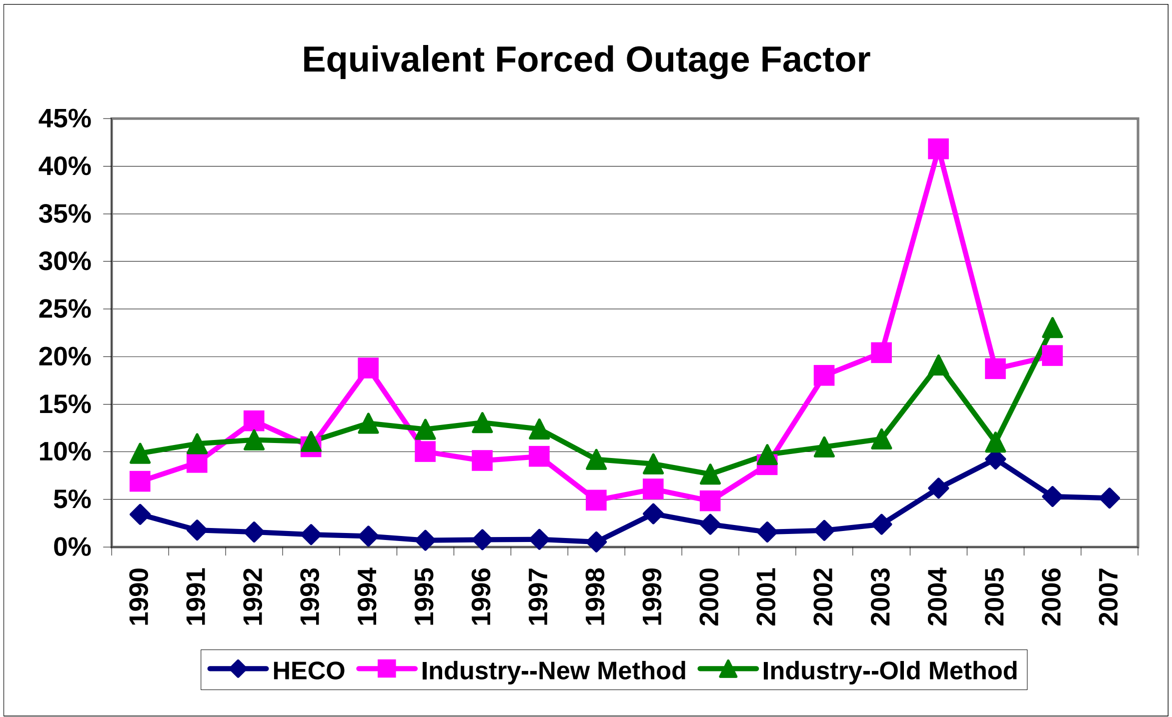
DG FUEL MONTHLY INVENTORY REPORT
DECEMBER 2007

	Ewa Nui (1,2,3)	Iwilei	Helemano	CEIP	Pole Yard	Ewa Nui (4,5,6)
Initial Inventory: - storage tank:	4,217	4,869	2,195	8,675	9,865	8,826
Initial Inventory - day tanks:	3,168	3,168	3,186	3,168	3,168	3,186
Total initial Inventory:	7,385	8,037	5,381	11,843	13,033	12,012
Received:	699	2,897	4,995	0	0	7,400
Expended:	**0**	**4,022**	**2,921**	**1,949**	**1,465**	**7,377**
Calculated end inventory:	8,084	6,912	7,455	9,894	11,568	12,035
Corrections - Fuel temp, gauge fluctuations, when readings taken, etc.:	-8	377	263	-21	27	31
Actual end Inv. in storage tanks:	4,908	4,121	4,532	6,705	8,427	8,880
End inventory - day tanks:	3,168	3,168	3,186	3,168	3,168	3,186
Total end inventory per site:	**8,076**	**7,289**	**7,718**	**9,873**	**11,595**	**12,066**
TOTAL DG END INVENTORY:	**56,617**					

2007 YEAR-TO-DATE EFOR FOR DG UNITS: 49.7%

	THIS MONTH	**YEAR TO DATE (2007)**	
TOTAL FUEL BURNED:	17,734	781,120	Gallons
TOTAL KWH PRODUCED:	196,436	10,316,213	KWh
TOTAL FUEL RECEIVED:	15,991	771,831	Gallons

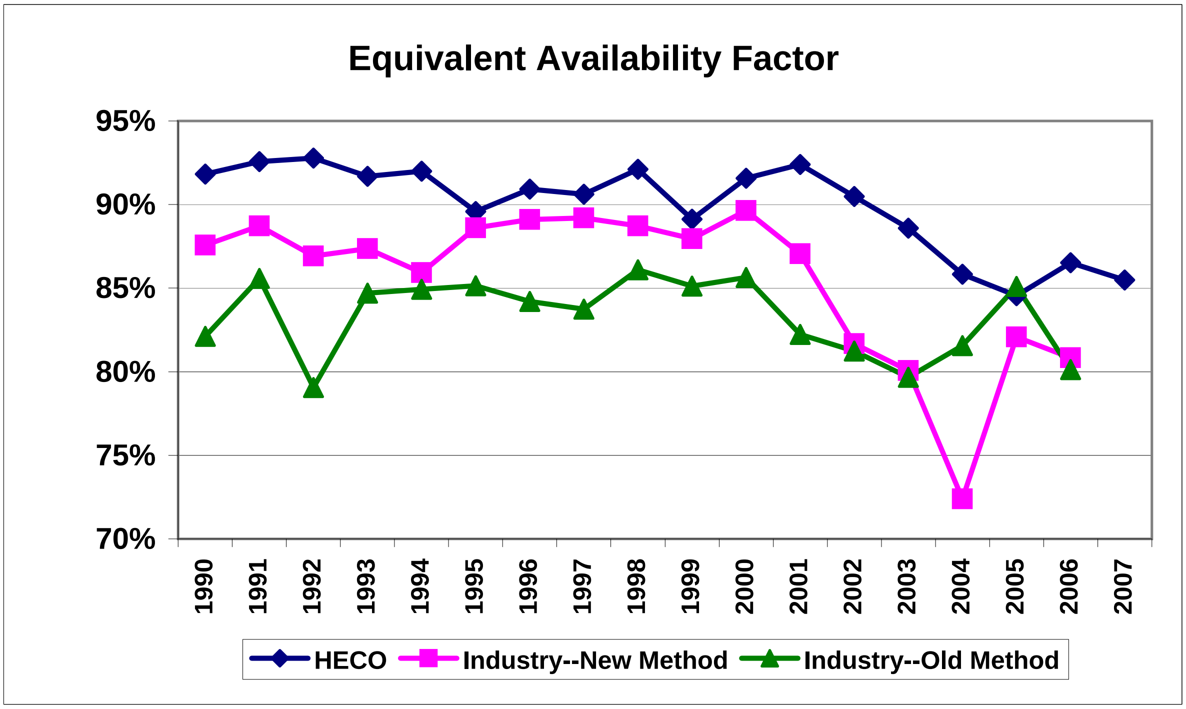
HAWAIIAN ELECTRIC COMPANY, INC.
2009 Test Year
HECO & Industry EFOR 1990-2007



	(A) HECO	(B) Industry--Old Method	(C) Industry--New Method
1990	3.43%	9.86%	6.88%
1991	1.78%	10.84%	8.86%
1992	1.59%	11.25%	13.26%
1993	1.31%	11.08%	10.52%
1994	1.13%	13.02%	18.80%
1995	0.70%	12.38%	10.01%
1996	0.77%	13.07%	9.07%
1997	0.79%	12.39%	9.50%
1998	0.53%	9.21%	4.90%
1999	3.51%	8.75%	6.08%
2000	2.40%	7.65%	4.85%
2001	1.59%	9.71%	8.64%
2002	1.76%	10.51%	18.03%
2003	2.37%	11.35%	20.39%
2004	6.18%	19.11%	41.81%
2005	9.25%	11.03%	18.72%
2006	5.30%	23.05%	20.09%
2007	5.13%		

Source: Column (A): HECO-WP-703.
Column (B) and (C): HECO-WP-704.

HAWAIIAN ELECTRIC COMPANY, INC.
2009 Test Year
HECO & Industry EAF 1990-2007



	(A) HECO	(B) Industry--Old Method	(C) Industry--New Method
1990	91.83%	82.12%	87.58%
1991	92.56%	85.58%	88.72%
1992	92.77%	79.05%	86.92%
1993	91.69%	84.71%	87.35%
1994	92.00%	84.94%	85.93%
1995	89.58%	85.14%	88.60%
1996	90.92%	84.20%	89.10%
1997	90.62%	83.74%	89.20%
1998	92.11%	86.09%	88.72%
1999	89.13%	85.13%	87.96%
2000	91.57%	85.63%	89.63%
2001	92.39%	82.24%	87.05%
2002	90.49%	81.23%	81.68%
2003	88.59%	79.66%	80.07%
2004	85.84%	81.56%	72.40%
2005	84.54%	85.10%	82.07%
2006	86.52%	80.12%	80.84%
2007	85.48%		

Source: Column (A): HECO-WP-703.
Column (B) and (C): HECO-WP-704.

LongRngV042704

HECO Units' - Recommended Interval Inspections (*Mstr. Calendar*) - ENGR/TSD
FOR YEARS: 2004 TO 2035

Printed: 06/27/08

Unit	Item	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
No. Majrs:																																	
HECO Wks:																																	
H8	BlrStd			X		X			X			X			X			X			X			X			X			X			X
H8	BlrCC					X																											
H8	HP	F				X						X						X						X						X			
H8	LP	I				X						X						X						X						X			
H8	GEN	N				X									X									X									X
H9	BlrStd	X		X				X			X			X			X			X			X			X			X			X	
H9	BlrCC				X																												
H9	HP							X						X						X						X						X	
H9	LP							X						X						X						X						X	
H9	GEN	X			X									X									X									X	
W3	BlrStd	X				X			X		X			X			X			X			X			X			X			X	
W3	BlrCC								X					X						X						X						X	
W3	HP	X		X		X			X					X						X						X						X	
W3	LP	X		X					X					X						X						X						X	
W3	GEN	X									X									X									X				
W4	BlrStd			X				X		X			X			X			X			X			X			X			X		
W4	BlrCC							X					X						X			X						X					
W4	HP			X						X						X						X						X					
W4	LP			X						X						X						X						X					
W4	GEN			X									X									X									X		
W5	BlrStd	X				X			X			X			X			X			X			X			X			X			X
W5	BlrCC					X						X						X						X						X			
W5	HP					X						X						X						X						X			
W5	LP					X						X						X						X						X			
W5	GEN								X									X									X						
W6	BlrStd	X	X		X		X				X		X			X			X			X			X			X			X		
W6	BlrCC						X						X						X						X						X		
W6	HP	X					X						X						X						X						X		
W6	LP						X						X						X						X						X		
W6	GEN						X									X									X								
W7	BlrStd				X			X			X			X			X			X			X			X			X			X	
W7	BlrCC				X						X						X						X						X				
W7	HP				X						X						X						X						X				
W7	LP				X						X						X						X						X				
W7	GEN										X									X									X				
W8	BlrStd	X				X			X		X			X			X			X			X			X			X			X	
W8	BlrCC		X						X					X						X									X				
W8	HP	X		X							X						X						X						X				
W8	LP			X							X						X						X						X				
W8	GEN	X									X									X									X				
W9	Major		X								X								X								X						
W9	HotGs						X								X								X								X		
W9	CI				X				X				X				X				X				X				X				X
W9	Gen		X								X								X								X						
W10	Major			X							X								X								X						
W10	HotGs						X								X								X								X		
W10	CI				X				X				X				X				X				X				X				X
W10	Gen			X							X								X								X						
K1	BlrStd		X	X	F			X			X			X			X			X			X			X			X			X	
K1	BlrCC							X									X						X						X				
K1	HP			X	I						X						X						X						X				
K1	LP			X	N						X						X						X						X				
K1	GEN							X									X									X							
K2	BlrStd		X			X			X			X			X			X			X			X			X			X			X
K2	BlrCC		X									X									X						X						X
K2	HP		X						X						X						X						X						X
K2	LP		X						X						X						X						X						X
K2	GEN					X									X									X									X
K3	BlrStd		X		X			X			X			X			X			X			X			X			X			X	
K3	BlrCC				X						X						X						X						X				
K3	HP				X						X						X						X						X				
K3	LP				X						X						X						X						X				
K3	GEN				X									X									X									X	
K4	BlrStd		X				X			X			X			X			X			X			X			X			X		
K4	BlrCC			X						X						X						X			X								
K4	HP						X						X						X						X						X		
K4	LP						X						X						X						X						X		
K4	GEN									X									X									X					
K5	BlrStd	X				X			X		X			X			X			X			X			X			X			X	
K5	BlrCC	X									X									X									X				
K5	HP	X							X					X						X						X							
K5	LP	X							X					X						X						X							
K5	GEN	X									X									X									X				
K6	BlrStd		X				X		X			X			X			X			X			X			X			X			X
K6	BlrCC								X									X									X						
K6	HP						X					X						X						X						X			
K6	LP						X					X						X						X						X			
K6	GEN						X											X									X						

2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035

HAWAIIAN ELECTRIC COMPANY, INC.
2009 Test Year

Backlog Report December 2007

Backlog = Uncompleted work orders, scheduled and unscheduled, work groups
PPKAM, PPKAMMT, PPWAM, PPWAMMT, PPHOM, PPHOMMT
All information in this report is from Ellipse ad hoc, except as noted.

Work Order Gain/(Fall Back) **(101)**

WORK ORDER COUNT SUMMARY by Station				
Count of wo	STATION			
PLAN_PRIORITY	KAHE	WAIAU	HONOLULU	Grand Total
E		17		17
H	142	403	21	566
M	967	1328	173	2468
L	132	275	52	459
	47	91	162	300
Grand Total	1288	2114	408	3810

WORK ORDERS RAISED				
Count of wo	STATION			
PLAN_PRIORITY	KAHE	WAIAU	HONOLULU	Grand Total
E	3	6		9
H	78	61	2	141
M	127	69	3	199
L	6	19		25
	1	4	22	27
Grand Total	215	159	27	401

WORK ORDER COUNT SUMMARY by Craft				
Count of wo	STATION			
CRAFT	KAHE	WAIAU	HONOLULU	Grand Total
Boiler	458	891	112	1461
Electrician	80	143	32	255
Machinist	118	209	44	371
Technician	532	469	105	1106
	100	402	115	617
Grand Total	1288	2114	408	3810

WORK ORDERS COMPLETED				
Count of wo	STATION			
PLAN_PRIORITY	KAHE	WAIAU	HONOLULU	Grand Total
E		3		3
H	55	39	2	96
M	95	69	10	174
L	7	3		10
		2	15	17
Grand Total	157	116	27	300

Oldest Days				
Max of DCURRENTM	STATION			
	KAHE	WAIAU	HONOLULU	Grand Total
Total	**3244**	**3300**	**3262**	3300

MT	12

COMPLETED PMs			
Count of wo	STATION		
PLAN_PRIORITY	KAHE	WAIAU	Grand Total
M	19	1	20
Grand Total	19	1	20

Average Days				
Average of DCURREI	STATION			
	KAHE	WAIAU	HONOLULU	Grand Total
Total	**420**	**553**	**395**	**491**

HAWAIIAN ELECTRIC COMPANY, INC.
2009 Test Year

Backlog Report May 2008

Backlog = Uncompleted work orders, scheduled and unscheduled, work groups
PPKAM, PPKAMMT, PPWAM, PPWAMMT, PPHOM, PPHOMMT
All information in this report is from Ellipse ad hoc, except as noted.

Work Order Gain/(Fall Back) (40)

WORK ORDER COUNT SUMMARY by Station				
Count of wo	STATION			
PLAN_PRIORITY	KAHE	WAIAU	HONOLULU	Grand Total
E	1	24	1	26
H	146	380	25	551
M	903	1295	177	2375
L	143	260	45	448
	28	90	169	287
Grand Total	1221	2049	417	3687

WORK ORDERS RAISED				
Count of wo	STATION			
PLAN_PRIORITY	KAHE	WAIAU	HONOLULU	Grand Total
E	2	7		9
H	87	53		140
M	133	100	4	237
L	14	5		19
	3	17	24	44
Grand Total	239	182	28	449

WORK ORDER COUNT SUMMARY by Craft				
Count of wo	STATION			
CRAFT	KAHE	WAIAU	HONOLULU	Grand Total
Boiler	452	809	69	1330
Electrician	73	163	23	259
Machinist	113	181	46	340
Technician	490	437	87	1014
	93	459	192	744
Grand Total	1221	2049	417	3687

WORK ORDERS COMPLETED				
Count of wo	STATION			
PLAN_PRIORITY	KAHE	WAIAU	HONOLULU	Grand Total
E	1	2		3
H	73	36	1	110
M	163	82	4	249
L	6	7		13
		2	32	34
Grand Total	243	129	37	409

Oldest Days				
Max of DCURREN	STATION			
	KAHE	WAIAU	HONOLULU	Grand Total
Total	**3396**	**3452**	**3414**	3452

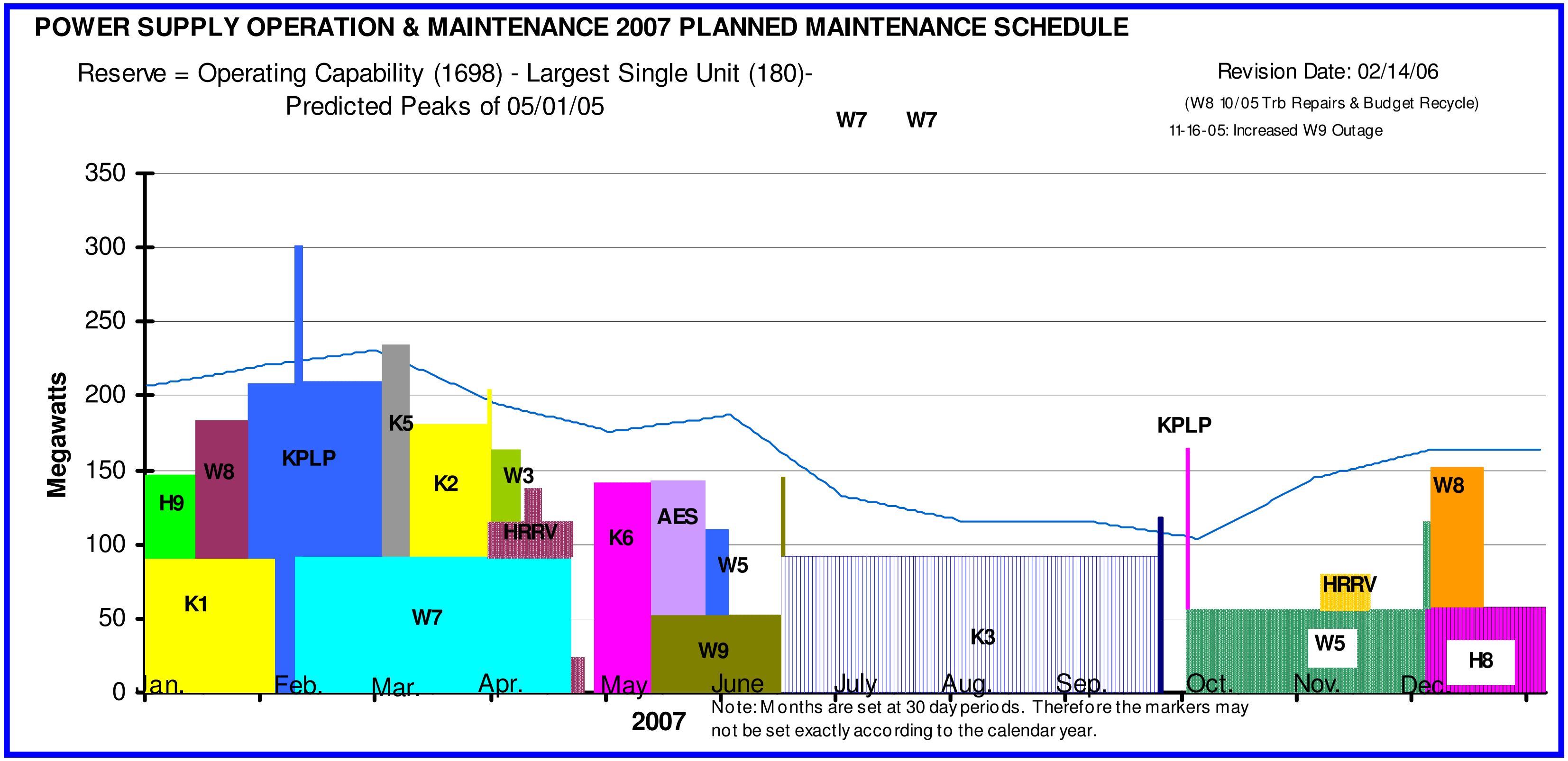
MT	12

COMPLETED PMs			
Count of wo	STATION		
PLAN_PRIORITY	KAHE	WAIAU	Grand Total
M	23	1	24
L		4	4
Grand Total	23	5	28

Average Days				
Average of DCURF	STATION			
	KAHE	WAIAU	HONOLULU	Grand Total
Total	**480**	**532**	**422**	**502**

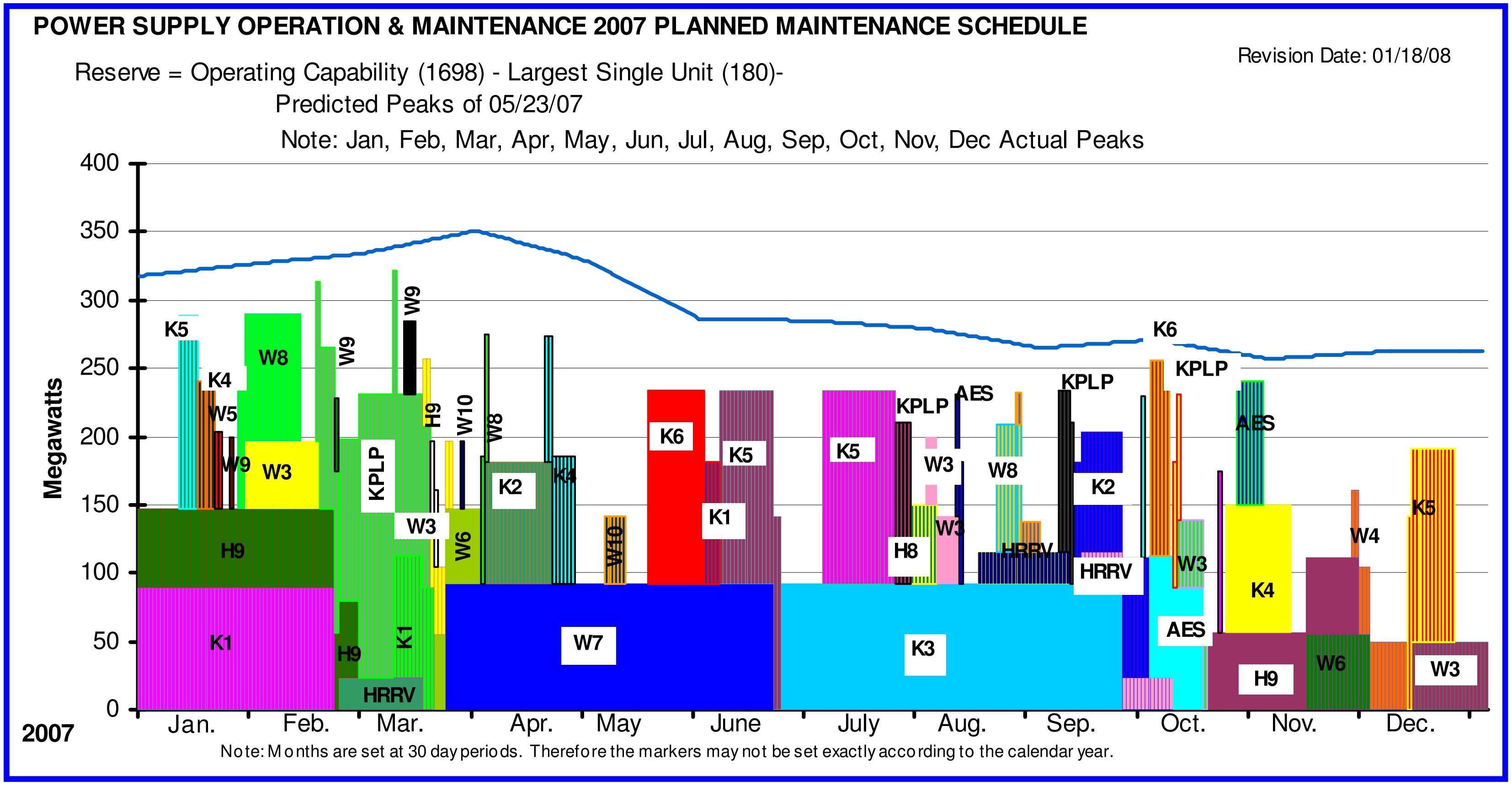
Hawaiian Electric Company, Inc.
2009 Test Year

2007 Planned Maintenance Schedule – dated 02/14/06



Hawaiian Electric Company, Inc.
2009 Test Year

2007 Planned Maintenance Schedule – Actual



Hawaiian Electric Company, Inc.
2009 Test Year
2009 Normalized Planned Maintenance Schedule

An HEI Company

POWER SUPPLY OPERATION & MAINTENANCE
2009 PLANNED MAINTENANCE SCHEDULE (NORMALIZED)

Peaks as of: 5/23/2007
Revision date: 3/20/2008

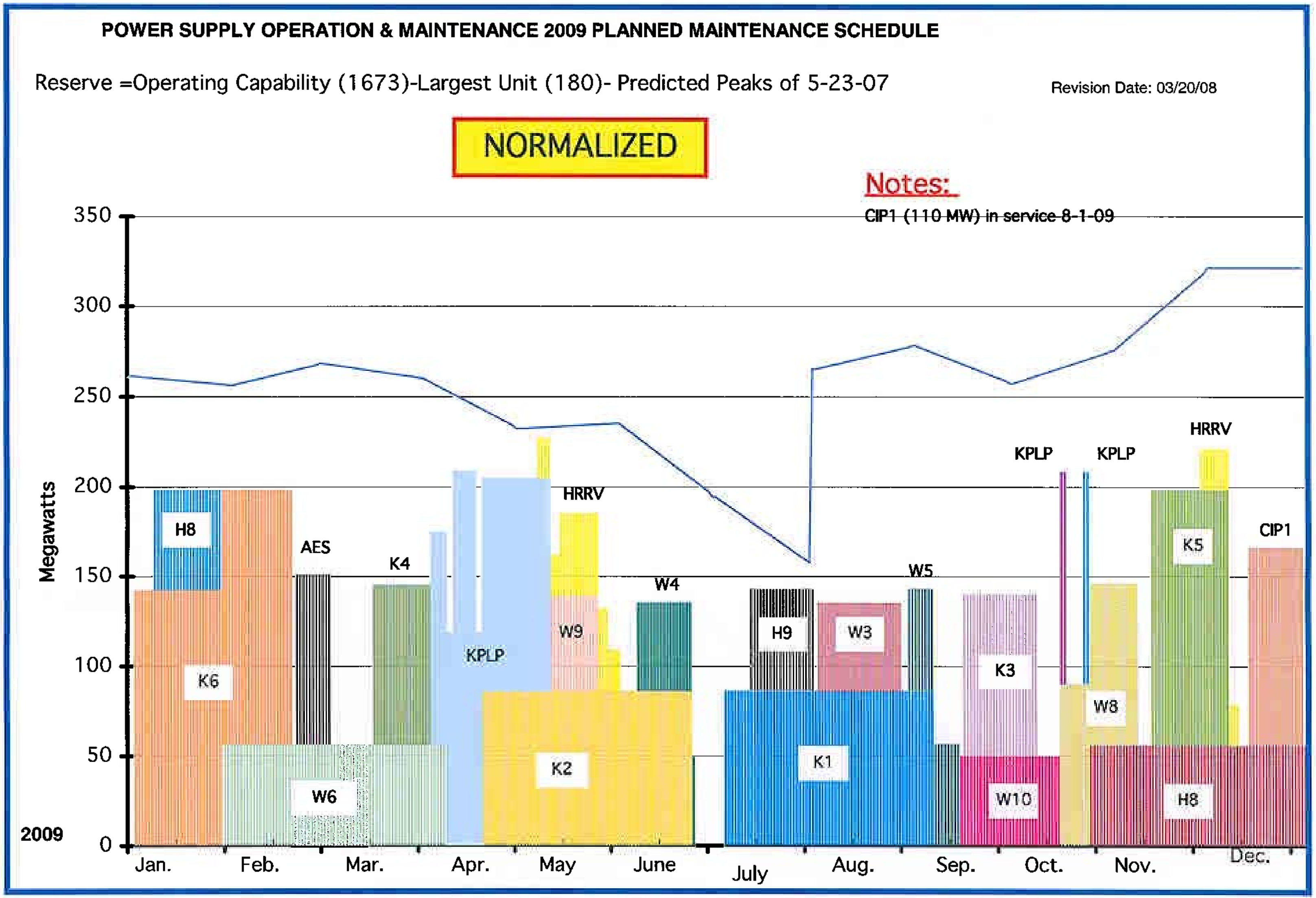
Comments:
Revision 3-20-08

UNIT	DATE				Duration	
	Brk Op	Start	Bkr Cl	Firm	(Wks.Days)	REMARKS
K6	1/3/2009	1/4/2009	2/19/2009	2/20/2009	6.6	PO
H8	1/9/2009	1/10/2009	1/28/2009	1/29/2009	2.6	MO
W6	1/30/2009	1/31/2009	4/8/2009	4/9/2009	9.6	PO
AES-	2/22/2009		3/4/2009		1.4	-90 MW
K4	3/18/2009	3/19/2009	4/3/2009	4/4/2009	2.3	MO
KPLP-	4/5/2009		4/11/2009		1.0	118 MW Loss (CT2 C)
KPLP	4/12/2009		4/18/2009		1.0	208 MW Loss (B, CT1)
KPLP-	4/19/2009		5/11/2009		3.2	118 MW Loss (CT2 C)
K2	4/21/2009	4/22/2009	6/23/2009	6/24/2009	9.1	PO
HRRV-	5/8/2009		5/14/2009		1.0	23 MW Loss
W9	5/12/2009		5/26/2009		2.1	MO
HRRV	5/15/2009		5/29/2009		2.1	46 MW Loss
HRRV-	5/30/2009		6/2/2009		0.4	23 MW Loss
W4	6/8/2009	6/9/2009	6/24/2009	6/25/2009	2.3	MO
K1	7/5/2009	7/6/2009	9/6/2009	9/7/2009	9.1	PO
H9	7/13/2009	7/14/2009	7/31/2009	8/1/2009	2.5	MO
W3	8/3/2009	8/4/2009	8/27/2009	8/28/2009	3.4	MO
W5	8/31/2009	9/1/2009	9/14/2009	9/15/2009	2.1	MO
W10	9/16/2009		10/16/2009		4.3	PO (CI)
K3	9/17/2009	9/18/2009	10/7/2009	10/9/2009	3.0	MO
W8	10/17/2009	10/18/2009	11/8/2009	11/9/2009	3.2	MO
KPLP-	10/17/2009		10/18/2009		0.2	118 MW Loss
KPLP-	10/24/2009		10/25/2009		0.2	118 MW Loss
H8	10/26/2009	10/26/2009	12/31/2009	1/1/2010	9.4	PO
K5	11/14/2009	11/15/2009	12/6/2009	12/7/2009	3.2	MO
HRRV-	11/29/2009		12/5/2009		1.0	23 MW Loss
HRRV-	12/6/2009		12/10/2009		0.5	23 MW Loss
CIP1	12/14/2009		12/30/2009		2.3	MO

Karen Mack for Dan Giovanni
Dan Giovanni
Power Supply O&M Manager

3-24-08
Date

Hawaiian Electric Company, Inc.
2009 Test Year
2009 Normalized Planned Maintenance Schedule

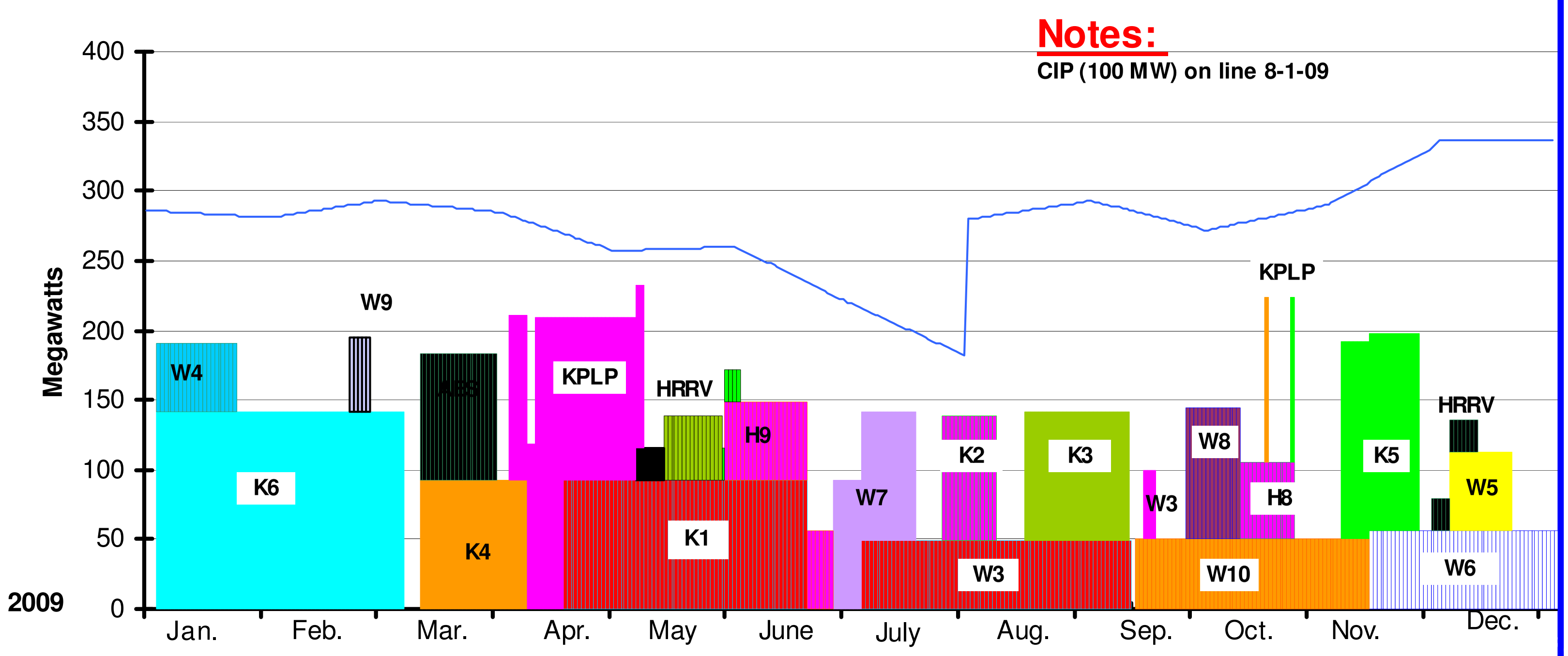


Hawaiian Electric Company, Inc.
2009 Test Year
2009 Planned Maintenance Schedule dated 10/29/07 used to develop 2009 Budget

POWER SUPPLY OPERATION & MAINTENANCE 2009 PLANNED MAINTENANCE SCHEDULE

Reserve =Operating Capability (1698)-Largest Unit (180)- Predicted Peaks of 5-23-07

Revision Date: 10/29/07



Hawaiian Electric Company, Inc.
2009 Test Year
2009 Planned Maintenance Schedule dated 10/29/07 used to develop 2009 Budget

An HEI Company

POWER SUPPLY OPERATION & MAINTENANCE
2009 PLANNED MAINTENANCE SCHEDULE

Peaks as of: 5/23/2007
Revision date: 10/29/2007

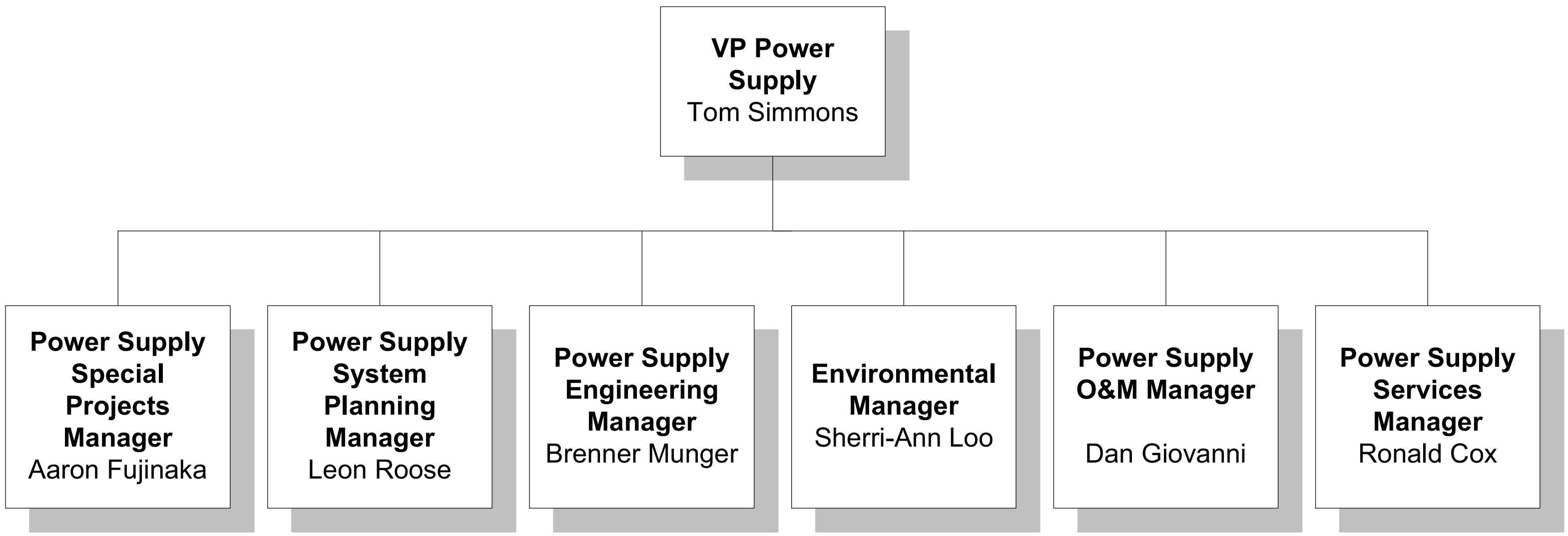
Comments:
Revised 4-18-07
Approved 4-19-07
Revised 6-15-07
Approved 6-15-07
Revised 10-10-07
Revised 10-18-07
Approved 10-29-07

UNIT	DATE				Duration	
	Brk Op	Start	Bkr Cl	Firm	(Wks.Days)	REMARKS
K6	1/4/2009	1/5/2009	3/6/2009	3/8/2009	8.6	PO-(Annun, HP/IP/LP, BCC, Blr PH/Vestb Dmprs, UPS Panel, TGSI,Gen)
W4	1/4/2009	1/5/2009	1/23/2009	1/24/2009	2.6	MO-(APH Wash, Blr Insp permit exp 7/26/09)
W9	2/23/2009		2/27/2009		0.5	PO-Videoprobe
K4	3/13/2009	3/14/2009	4/8/2009	4/9/2009	3.6	MO(Blr permit exp 10/12/09, OCB 170/171/172)
AES-	3/13/2009		4/1/2009		2.6	90 MW Loss
KPLP-	4/5/2009		4/11/2009		1.0	118 mw loss (CT2 C)
KPLP	4/12/2009		4/18/2009		1.0	208 mw loss
KPLP-	4/19/2009		5/9/2009		3.0	118 mw loss (CT2 C)
K1	4/19/2009	4/20/2009	6/19/2009	6/20/2009	8.6	PO-(Cnd Tbe,BCC,FWHs,Main/Aux Xfmr,Gen,Annun,Exc/VR,TG TSI Upgds)
HRRV-	5/8/2009		5/14/2009		1.0	23 MW Loss
HRRV	5/15/2009		5/29/2009		2.1	46 MW Loss
HRRV-	5/30/2009		6/3/2009		0.5	23 mw loss
H9	5/31/2009	6/1/2009	6/26/2009	6/27/2009	3.6	MO-Blr Inspection, permit exp 1/8/10
W7	6/28/2009	6/29/2009	7/17/2009	7/18/2009	2.6	MO(Blr Inspt-permit exp 4/10,CW Tunnel Clng, APH Wash)
W3	7/5/2009	7/6/2009	9/11/2009	9/12/2009	9.6	PO-(Cnd Retbe, SSH, MS Repl, S/B Upgr, Frt WW tbes, OCB4499)
K2	7/26/2009	7/27/2009	8/7/2009	8/8/2009	1.6	MO (APH Wash)
K3	8/16/2009	8/17/2009	9/10/2009	9/11/2009	3.5	MO (APH Wash, Blr Insp est exp 8/2010)
W10	9/14/2009	9/14/2009	11/12/2009	11/12/2009	8.4	PO(CI, Air Inlet Filtration, VR)
W3	9/16/2009	9/16/2009	9/18/2009	9/18/2009	0.3	MO(Rem trb throttlve valve strainers-frm SSH replacmt)
W8	9/27/2009	9/28/2009	10/9/2009	10/10/2009	1.6	MO-(APH Wash, CW Tunnel Cleaning)
H8	10/11/2009	10/12/2009	10/23/2009	10/24/2009	1.6	MO-(APH Wash)
KPLP-	10/17/2009		10/17/2009		0.1	118 mw loss (CT1 A)-Revision to KPLP Request
KPLP-	10/24/2009		10/24/2009		0.1	118 mw loss (CT2 A)-Revision to KPLP Request
K5	11/6/2009	11/7/2009	11/24/2009	11/25/2009	2.5	MO (APH Wash)
W6	11/13/2009	11/14/2009	1/29/2010	1/30/2010	11.1	PO(VR, HP/LP/Gen, APH Rotor, Cond Re-tube, BCC,)
HRRV-	11/29/2009		12/10/2009		1.5	23 MW Loss
W5	12/4/2009	12/5/2009	12/18/2009	12/19/2009	2.1	MO-(APH Wash, CW Tunnel Clng)

Dan Giovanni
Power Supply O&M Manager

Date

Hawaiian Electric Company, Inc.
2009 Test Year
Power Supply Process Area Organization Chart



As of 03/31/08

Hawaiian Electric Company, Inc.
2009 Test Year - Power Supply Process Area
Filling of Vacancies in 2008 and 2009

Position	RA	2007 Actual	03/31/08 Actual	2008 Budget	Proj 2008 YE	Rate Case TY 2009	03/31/08-2009 VARIANCE
ENVIRONMENTAL DEPT							
ADMIN							
Manager	JA	1	1	1	1	1	0
Sr. Environ Scientist	JA	1	1	1	1	1	0
Secretary	JA	1	1	1	1	1	0
Clerk Typist	JA	1	1	1	1	1	0
Admin Subtotal		**4**	**4**	**4**	**4**	**4**	**0**
Air Quality / Noise							
Prin Environ Scientist	JB	1	1	1	1	1	0
Sr. Environ Scientist	JB	4	4	4	4	4	0
Environ Scientist	JB	1	1	1	1	1	0
Air Quality/Noise Subtotal		**6**	**6**	**6**	**6**	**6**	**0**
Chemistry							
Lab Supervisor	JC	1	1	1	1	1	0
Analytical Chemist	JC	5	5	5	5	6	1
Chemistry Subtotal		**6**	**6**	**6**	**6**	**7**	**1**
Water & Hazardous Materials							
Prin Environ Scientist	JW	1	1	1	1	1	0
Sr. Environ Scientist	JW	4	4	4	4	4	0
Environl Scientist	JW	2	2	2	2	2	0
Environl Specialist	JW	1	1	1	1	1	0
Water & Haz Mat Subtotal		**8**	**8**	**8**	**8**	**8**	**0**
TOTAL ENVIRONMENTAL		**24**	**24**	**24**	**24**	**25**	**1**
POWER SUPPLY ENGINEERING							
ADMIN							
Manager	YA	1	1	1	1	1	0
Secretary	YA	1	1	1	1	1	0
Administrator	YA	1	1	1	1	1	0
Admin Subtotal		**3**	**3**	**3**	**3**	**3**	**0**
Support Staff							
Project Clerk	YC	1	1	1	1	1	0
Drawing Control Clerk	YC	1	1	1	1	1	0
Clerk Typist III	YC	0	1	1	1	1	0
Support Staff Subtotal		**2**	**3**	**3**	**3**	**3**	**0**
Technical Services							
Superintendent	YE	1	1	1	1	1	0
Senior Staff Engineer	YE	6	6	6	6	7	1
Staff Engineer	YE	2	3	3	3	3	0
Technical Services Subtotal		**9**	**10**	**10**	**10**	**11**	**1**
Electrical Engineering Section							
Sr. Supervising Engi	YF	1	1	1	1	1	0
Engineer II	YF	2	2	3	3	4	2
Engineer I (DesignerII)	YF	8	8	8	8	8	0
Project Aide	YF	1	1	0	0	1	0
Electrical Eng Sec Subtotal		**12**	**12**	**12**	**12**	**14**	**2**

Hawaiian Electric Company, Inc.
2009 Test Year - Power Supply Process Area
Filling of Vacancies in 2008 and 2009

Position	RA	2007 Actual	03/31/08 Actual	2008 Budget	Proj 2008 YE	Rate Case TY 2009	03/31/08-2009 VARIANCE
Drafting Section							
Drafting Technician II	YG	2	2	2	2	2	0
Drafting Subtotal		**2**	**2**	**2**	**2**	**2**	**0**
Project Management							
Project Manager	YJ	4	4	4	4	4	0
Project Management Subtotal		**4**	**4**	**4**	**4**	**4**	**0**
Mechanical Engineering Section							
Prin Eng, Power Plt Eng	YM	1	1	1	1	1	0
Project Manager	YM	1	1	1	1	1	0
Sr. Supervising Eng	YM	1	1	1	1	1	0
Engineer II	YM	5	4	5	5	6	2
Engineer II (Designer II)	YM	5	5	5	5	5	0
Project Aide	YM	1	1	0	0	1	0
Mechanical Eng Sec Subtotal		**14**	**13**	**13**	**13**	**15**	**2**
TOTAL POWER SUPPLY ENG		**46**	**47**	**47**	**47**	**52**	**5**
POWER SUPPLY SERVICES DEPT							
ADMIN							
Power Supply Srvc Mngr	IA	1	1	1	1	1	0
Power Supply Srvc Secr	IA	1	1	1	1	1	0
Admin Subtotal		**2**	**2**	**2**	**2**	**2**	**0**
POWER PURCHASE							
Power Purchase Dir	IC	1	1	1	1	1	0
Power Purch Contr Adm	IC	3	2	3	3	3	1
Administrative Assistant	IC	2	2	2	2	2	0
Power Purchase Subtotal		**6**	**5**	**6**	**6**	**6**	**1**
FUELS RESOURCES							
Fuel Operations Director	IF	1	1	1	1	1	0
Fuels Contracts Admin	IF	1	1	2	2	2	1
Fuels Records Clerk	IF	1	1	1	1	1	0
Fuels Operations Subtotal		**3**	**3**	**4**	**4**	**4**	**1**
FUELS INFRASTRUCTURE							
Fuels Infrastructure Director	IJ	1	1	1	1	1	0
Fuels Staff Engineer	IJ	1	1	2	2	2	1
Fuels Resources Subtotal		**2**	**2**	**3**	**3**	**3**	**1**
TOTAL POWER SUPPLY SERVICES		**13**	**12**	**15**	**15**	**15**	**3**
SYSTEM PLANNING DEPT							
ADMIN							
Power Supply Srvc Mngr	XA	1	1	1	1	1	0
Power Supply Srvc Secr	XA	1	1	1	1	1	0
Admin Subtotal		**2**	**2**	**2**	**2**	**2**	**0**
GENERATION PLANNING							
Generation Planning Dir	YB	1	1	1	1	1	0
Sr Planning Engineer	YB	3	3	3	3	3	0
Planning Engineer	YB	5	5	5	5	5	0
Generation Planning Subtotal		**9**	**9**	**9**	**9**	**9**	**0**

Hawaiian Electric Company, Inc.
2009 Test Year - Power Supply Process Area
Filling of Vacancies in 2008 and 2009

Position	RA	2007 Actual	03/31/08 Actual	2008 Budget	Proj 2008 YE	Rate Case TY 2009	03/31/08-2009 VARIANCE
TRANSMISSION PLANNING							
Transm Planning Dir	YT	1	1	1	1	1	0
Lead Transm Plan Eng	YT	1	1	3	3	3	2
Transm Planning Eng	YT	3	3	4	4	4	1
Transmission Planning Subtotal		**5**	**5**	**8**	**8**	**8**	**3**
GENERATION BIDDING							
Generation Bidding Dir	XB	1	1	1	1	1	0
Project Manager	XB	2	2	2	2	2	0
Generation Bidding Subtotal		**3**	**3**	**3**	**3**	**3**	**0**
TOTAL SYSTEM PLANNING		**19**	**19**	**22**	**22**	**22**	**3**
POWER SUPPLY O&M							
ADMIN							
Power Supply O&M Mngr	IB	1	1	1	1	1	0
Power Supply O&M Sec	IB	1	1	1	1	1	0
Manager, Special Projects	IB	1	0	0	0	0	0
O&M Services Superintendent	IB	0	0	0	1	0	0
Senior Technical Analyst	IB	1	1	1	0	1	0
Ld Fin Administrator	IB	1	0	1	1	1	1
Administrator	IB	1	1	1	1	1	0
Budget Analyst	IB	1	0	1	1	1	1
PSRO Prog Manager (to IV)	IB	0	0	0	0	0	0
Env Compliance Superv (to IQ)	IB	1	1	1	0	1	0
Station Chemist (to IQ)	IB	2	2	2	0	2	0
Environmental Specialist (to IQ)	IB	1	1	1	0	1	0
Admin Subtotal		**11**	**8**	**10**	**6**	**10**	**2**
ENVIRONMENTAL & COMPLIANCE							
Env Compliance Superv (fr IB)	IQ	0	0	0	1	0	0
Station Chemist (fr IB)	IQ	0	0	0	2	0	0
Environmental Specialist (fr IB)	IQ	0	0	0	1	0	0
Environmental & Compliance Subtotal		**0**	**0**	**0**	**4**	**0**	**0**
TRAINING							
Senior Supv, Trainer	ID	1	1	1	1	1	0
Technical Trainer	ID	1	1	2	2	3	2
Admin/Asst Clerk	ID	0	0	0	0	1	1
Training Subtotal		**2**	**2**	**3**	**3**	**5**	**3**
PSRO PROGRAM							
PSRO Prog Manager (fr IB)	IV	0	0	0	1	1	1
MBO Coordinator (fr IP)	IV	0	0	0	1	1	1
PSRO Program Subtotal		**0**	**0**	**0**	**2**	**2**	**2**

Hawaiian Electric Company, Inc.
2009 Test Year - Power Supply Process Area
Filling of Vacancies in 2008 and 2009

Position	RA	2007 Actual	03/31/08 Actual	2008 Budget	Proj 2008 YE	Rate Case TY 2009	03/31/08-2009 VARIANCE
OPERATIONS							
Station Superintendent (to IK & IW)	IO	2	2	2	0	2	0
Honolulu Senior Superv	IH	1	1	1	1	1	0
Shift Supervisor	IH	5	5	5	5	5	0
Honolulu Operators	IH	19	21	21	21	20	-1
Station Superintendent Kahe (fr IO)	IK	0	0	0	1	0	0
Kahe Senior Shift Suprv	IK	1	1	1	1	1	0
Kahe Power Plant Clerk	IK	1	1	1	1	1	0
Shift Supervisor	IK	7	7	7	7	7	0
Kahe Operators	IK	51	51	52	52	50	-1
Station Superintendent Waiau/Hon (fr IO)	IW	0	0	0	1	0	0
Waiau Sr Shift Super	IW	1	1	1	1	1	0
Waiau Power Plant Clerk	IW	1	1	1	1	1	0
Shift Supervisor	IW	7	7	7	7	7	0
Waiau Operators	IW	52	53	57	58	55	2
CIP Shift Super	IY	0	0	0	0	1	1
CIP Operators	IY	0	0	0	0	6	6
Operations Subtotal		**148**	**151**	**156**	**157**	**158**	**7**
PLANNING							
Planning & Eng Super	IP	1	1	1	1	1	0
Senior Supervisor	IP	2	2	2	2	2	0
Power Plant Clerk	IP	1	1	1	1	1	0
Work Management Spec	IP	1	1	1	1	1	0
Resource Planner	IP	10	9	10	10	10	1
O&M Engineer	IP	4	5	6	7	7	2
PDM Specialist	IP	3	3	3	4	4	1
MBO Coordinator (to IV)	IP	0	0	0	0	0	0
Project Aide	IP	1	1	0	0	0	-1
Planning Subtotal		**23**	**23**	**24**	**26**	**26**	**3**
MAINTENANCE							
Kahe							
Kahe Maint Supervisor	IL	1	1	2	2	2	1
Boiler Working Foreman	IL	1	1	1	1	1	0
Elec Working Foreman	IL	1	1	1	1	1	0
Machinist Work Foreman	IL	1	1	1	1	1	0
Senior Electrician	IL	4	4	4	4	4	0
Machinist	IL	3	3	3	3	3	0
Pipefitter Mechanic	IL	2	2	5	3	5	3
Certified Comb Welder	IL	4	4	4	4	4	0
Insulator	IL	1	1	1	1	1	0
Control Technician	IL	7	7	8	7	8	1
Helper	IL	2	2	2	2	2	0
Mob Crn & Hvy Eq Oper	IL	1	1	1	1	1	0
Kahe Maint Subtotal		**28**	**28**	**33**	**30**	**33**	**5**
Maint Admin							
O&M Maint Superint	IM	1	1	1	1	1	0
Power Plant Clerk	IM	1	1	1	1	1	0
Maint Admin Subtotal		**2**	**2**	**2**	**2**	**2**	**0**

Hawaiian Electric Company, Inc.
2009 Test Year - Power Supply Process Area
Filling of Vacancies in 2008 and 2009

Position	RA	2007 Actual	03/31/08 Actual	2008 Budget	Proj 2008 YE	Rate Case TY 2009	03/31/08-2009 VARIANCE
Honolulu							
Hono Maint Supervisor	IN	1	1	1	1	1	0
Boiler Working Foreman	IN	1	1	1	1	1	0
Elec Working Foreman	IN	1	1	1	1	1	0
Machinist Work Foreman	IN	1	1	1	1	1	0
Senior Electrician	IN	1	1	1	1	1	0
Machinist	IN	1	1	1	1	1	0
Pipefitter Mechanic	IN	1	1	1	1	1	0
Control Technician	IN	3	3	3	3	3	0
Cert Comb Welder	IN	1	1	1	1	1	0
Insulator	IN	0	0	1	1	1	1
Honolulu Maint Subtotal		**11**	**11**	**12**	**12**	**12**	**1**
Travel							
Senior Supv Overhauls	IT	1	1	1	1	1	0
Travel Maint Outage Coor	IT	0	0	0	0	1	1
Travel Clerk	IT	0	0	0	0	1	1
Traveling Maint Superv	IT	4	4	4	4	4	0
Boiler Working Foreman	IT	2	2	2	2	2	0
Elec Working Foreman	IT	2	2	2	2	2	0
Machinist Work Foreman	IT	2	2	2	2	2	0
Insulator Work Foreman	IT	1	1	1	1	1	0
Condenser Crew Leader	IT	1	1	1	1	1	0
Senior Electrician	IT	10	10	10	10	10	0
Machinist	IT	8	7	9	8	9	2
Pipefitter Mechanic	IT	6	6	7	7	7	1
Certified Equip Mechanic	IT	2	2	2	2	2	0
Certified Comb Welder	IT	7	7	9	7	9	2
Control Technician	IT	6	5	9	5	9	4
Helper	IT	3	3	3	3	3	0
Insulator	IT	14	14	11	14	14	0
Mob Crane & Equip Oper	IT	1	1	1	1	1	0
Condenser Cleaner	IT	7	8	8	8	8	0
Travel Crew Subtotal		**77**	**76**	**82**	**78**	**87**	**11**
Waiau							
Waiau Maint Supervisor	IX	2	2	2	2	2	0
Boiler Working Foreman	IX	1	1	1	1	1	0
Elec Working Foreman	IX	1	1	1	1	1	0
Machinist Work Foreman	IX	1	1	1	1	1	0
Senior Electrician	IX	3	3	4	4	4	1
Machinist	IX	3	3	3	3	3	0
Pipefitter Mechanic	IX	5	5	5	4	5	0
Certified Comb Welder	IX	4	4	4	4	4	0
Insulator	IX	1	1	1	1	1	0
Control Technician	IX	7	8	8	7	8	0
Helper	IX	1	1	1	1	1	0
Mob Crn & Hvy Eq Oper	IX	1	1	1	1	1	0
Waiau Maint Subtotal		**30**	**31**	**32**	**30**	**32**	**1**

Hawaiian Electric Company, Inc.
2009 Test Year - Power Supply Process Area
Filling of Vacancies in 2008 and 2009

Position	RA	2007 Actual	03/31/08 Actual	2008 Budget	Proj 2008 YE	Rate Case TY 2009	03/31/08-2009 VARIANCE
CIP							
CIP Maint Supervisor	IZ	0	0	0	0	1	1
Elec Working Foreman	IZ	0	0	0	0	1	1
Sr. Electrician	IZ	0	0	0	0	1	1
Control Technician	IZ	0	0	0	0	2	2
Sr. CT & Diesel Mech	IZ	0	0	0	0	2	2
Clerk/Warehouseman	IZ	0	0	0	0	1	1
CIP Maint Subtotal		**0**	**0**	**0**	**0**	**8**	**8**
Maintenance Subtotal		**148**	**148**	**161**	**152**	**174**	**26**
TOTAL POWER SUPPLY O&M		**332**	**332**	**354**	**350**	**375**	**43**
POWER SUPPLY - VP							
Vice President	7V	1	1	1	1	1	0
VP Secretary	7V	1	1	1	1	1	0
Manager, Renewable Integration	7V	0	1	0	1	1	0
TOTAL POWER SUPPLY - VP		**2**	**3**	**2**	**3**	**3**	**0**
TOTAL PROCESS AREA		**436**	**437**	**464**	**461**	**492**	**55**

Count as of 12/31/06 = 408

HAWAIIAN ELECTRIC COMPANY
MERIT
POSITION DESCRIPTION

Position Title:	**Manager**
Department:	**Renewable Integration**
Reports to:	**Vice President, Power Supply**

Job Code:	J242	***FLSA:***	A
Role:	E	***Date:***	2/8/08

Primary Role/Function

Manages and facilitates,through a matrix organization, the integration of renewable energy projects into the HECO system. Oversees and coordinates activities associated with the development of performance standards, interconnection requirements, and procedures to sustain reliable operation of the electric grid.

Job Responsibilities

This position conceives, plans, directs, and implements specific projects, programs, and activities in support of overall corporate goals and programs with extensive and diversified requirements. Initiates and maintains contacts with key individuals inside/outside of the company in the interest of joint problem solving, coordination, and keeping up with technical, social, political, and regulatory developments. Decisions and actions directly and significantly impact the financial integrity and ability of the company to provide adequate and reliable electric service. Decisions and actions directly impact credibility and/ or liability of the company in the areas of operational safety, environmental compliance, public relations, and regulatory relationships.

*60% Directs the development of performance standards and interconnection requirements for renewable projects. Enables the hiring of consultants and facilitates discussions with developers on the technical aspects of integrating renewable projects into the HECO grid. Collaborates with others on operational assessments of renewable projects on the HECO grid including the development and/or modification of system operating procedures, establishment of communication protocols, renewable start-up, testing, and performance monitoring, incident investigations, and serving as a technical resource to support PPA contract administration.

*20% Directs, prepares, reviews, and/or delivers expert testimonies and other documents, filed with the Public Utilities Commission (PUC) or other external agencies such as the State Legislature, pertaining to the technical aspects of integrating renewable energy projects into the HECO grid.

*** Denotes a "Fundamental Responsibility"**

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

Manager

*20%	Develops and supports training and knowledge transfer activities for various stakeholders and audiences with the objective of facilitating an understanding of renewable integration on the HECO grid. Provides technical, and administrative leadership in the documentation, and development of written standards and procedures. Assists in other cross functional activities as assigned. Acts as Company Representative on a regular basis. Substitutes for Vice President, Power Supply during his/her absence.

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

Manager

Minimum Qualifications

Knowledge Requirements:

- Extensive knowledge of engineering and business principles
- Extensive knowledge and experience in the areas of generation design, system operation and system dynamics.
- Extensive knowledge of utility economic analysis methods, financial and accounting systems, and management reporting systems.
- Extensive knowledge of PUC, environmental, safety, and other federal and state regulations involving the maintenance and operation of power supply systems.
- Practical knowledge of policies and procedures contained in Company/Union agreement, Accident Prevention Manual, General Information Manual, Code of Conduct, and other documents concerning company and department policies and procedures.
- Thorough knowledge of regulatory processes (e.g. PUC Rate Cases, Complaint Proceedings, Capital Expenditure Applications, Environmental Permitting, etc.).
- Working knowledge of personal computers and/or mainframe systems, and related software applications to include word processing, spreadsheets, data bases, resource planning/optimizing specialized simulation models, and the ability to direct development, modification, testing, implementation, documentation, and operation of complex technical engineering/scientific computer programming models.
- Working knowledge of budgeting/forecast process.

Manager M220

Minimum Qualifications (continued)

Skills Requirements

- Excellent department-level managerial skills in analysis, planning, and control, to include, supervision, communication, interpersonal relationships, and budgeting.
- Excellent supervisory/leadership/interpersonal skills including excellent written, oral, listening, and presentation/platform communication skills/conflict resolution skills; the ability to use tact, courtesy, and discretion while working effectively with a variety of individuals, occasionally dealing with sensitive, difficult or confrontational issues; the willingness and ability to train. Strong negotiating, influencing, and persuading techniques.
- Excellent extensive analytical and administrative skills required for such tasks as preparing, monitoring and analyzing forecasts; preparing performance appraisals and conducting interviews; carrying out company/department policies and procedures.
- Sophisticated technical experience and skills required to integrate the many facets of power system planning, design, and operations with nearly all areas of the Company and its subsidiaries.
- Imaginative, flexible, positive thinker. Ability to obtain innovative solutions in a demanding, high stress work environment of previously unsolved or unresolved issues while quickly adapting to rapidly changing priorities.
- Analytical, organizational, and conceptual skills to handle various complex ideas, projects, and programs.
- Must have or be able to qualify for a State of Hawaii driver's license and HECO driver's license in order to travel to/from meetings conducted outside the company.

Experience Requirements

- Minimum 15 years experience in power system planning, design, or operations, with a minimum 3 years in the operations area preferred.

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

Positions Supervised

Title	**Number Supervised**
NA	

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

Manager

Physical Requirements

Only items that are necessary to perform the "fundamental" responsibilities of the position are indicated.

"F" for Frequently: Daily, several times a week, weekly
"O" for Occasionally: Monthly, Couple times a year

O	Standing
O	Walking
F	Sitting
O	Climbing Ascending or descending ladders, stairs, or other objects.
	Balancing on narrow, slippery, or erratically moving surfaces.
	Stooping, kneeling, crouching, crawling, and/or squatting
F	Handling Working with hands, arms or fingers.
	Feeling Perceiving attributes such as size, share, temperature or texture.
F	Ability to follow written/oral instructions

F	Lifting/Carrying below 25 lbs.	
	O	26 to 50 lbs.
		above 50 lbs.
	Vision acuity the ability to see clearly 20 feet or more	
O	Color vision the ability to identify and distinguish different colors.	
	Night vision the ability to perform work at night with the use of portable lighting.	
F	Talking	
F	Hearing	
F	Ability to perform simple, repetitive tasks for an extended period of time	
F	Ability to perform complex and varied tasks for an extended period	

Environmental Conditions

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

	Extreme Cold cold temperatures for an hour or more
	Extreme Heat warm/hot temperatures for an hour or more
	Wetness
O	Use of personal protective equipment (hard hats, respirator, leather gloves, rubber glove, safety shoes, nomex clothing)
F	Work in emergency/potentially "high stress" situations
O	Noise At least 80 decibels

	Working Outdoors may be during prevailing weather/climate conditions
	Hazardous Conditions potentially life-threatening situations
	Work above 5 feet
	Work above 70 feet
	Work on mountain trails/cliff sides

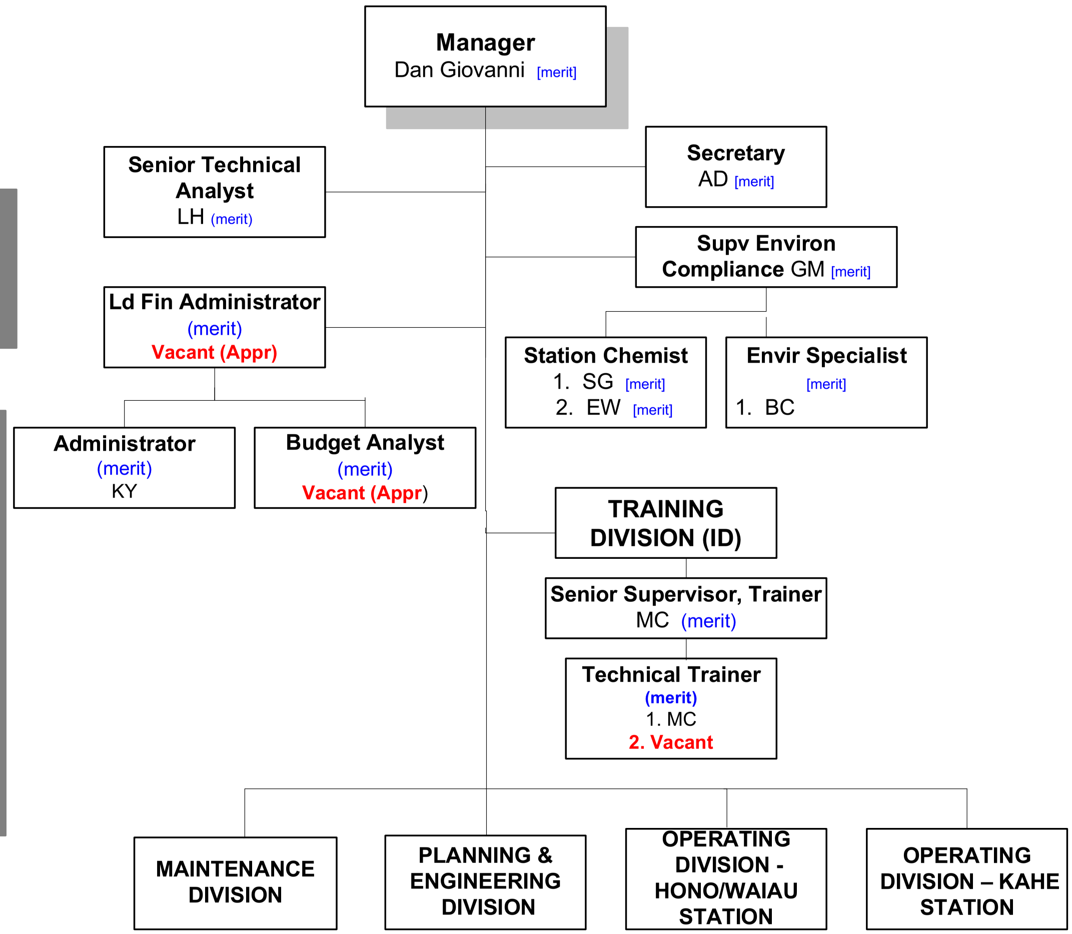
Job responsibilities are subject to possible modification to reasonably accommodate individuals with disabilities.

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

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

POWER SUPPLY OPERATIONS & MAINTENANCE

POWER SUPPLY O&M ADMINISTRATION (IB)
As of 03/31/08



	03/31/08 Actual	2008 Actual & Vac & Vac (Appr)
IB	8	10
ID	2	3

SUMMARY-

	03/31/08 Actual	2008 Actual & Vac & Vac (Appr)
IB	8	10
ID	2	3
IM	2	2
IN	11	12
IX	31	32
IL	28	33
IT	76	82
IP	23	24
IO	2	2
IH	27	27
IW	62	66
IK	60	61
	------	-------
Total	332	354

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03/31/08

Vacant = Not Approved
Vacant (Appr) = Approved

OPERATING DIVISION

OPERATIONS ADMINISTRATION (IO)

As of 03/31/08

NOTE:
Vacant = Not Approved
Vacant (Appr) = Approved

	03/31/08 Actual	2008 Act & Vac & Vac (Appr)
IO	2	2
IH	27	27
IW	62	66
IK	60	61
	----	-------
Total	151	156

Station Superintendent Waiau and Honolulu PP
DA [merit]

Power Plant Clerk
LI (IW) [BU]

Station Superintendent Kahe PP
JV [merit]

Power Plant Clerk
GB (IK) [BU]

HONOLULU STATION (IH)

Senior Supervisor [merit]
CH

Shift Supervisor
1. MY
2. JH
3. LT
4. JD
5. RM

Control Operator
1. BA
2. NN
3. WL
4. RT
5. AY

Jr Control Operator
1. MY
2. RD
3. RC
4. RT
5. GY

Utility Operator
1. JT
2. AL
3. DC
4. SS
5. MK

Equipment Operator
1. LL
2. SS
3. WC
4. MN
5. SK
6. CY

Operator Trainee

WAIAU STATION (IW)

Senior Supervisor [merit]
AT

Shift Supervisor
1. SC
2. DS
3. JDA
4. DQ
5. BE
6. DO
7. JB

Control Operator
1. GC
2. ES
3. EO
4. GK
5. TH
6. SI
7. EV
8. SW
9. EI
10. SO
11. PK
12 PR
13. JG
14. IM
15. AL

Jr Control Operator
1. ND
2. GK
3. EW
4. TL
5. DT
6 JE
7. DA
8. ES
9. IT
10. IM
11. AC
12. CF
13. SY
14. DK
15. CG

Utility Operator
1. SC
2. SM
3. JO
4. DH
5. PG
6. BC
7. AC
8. CA
9. RS
10. RS

Equipment Operator
1. LS
2. JE
3. LH
4. TS
5. GT
6. GT
7. KP
8. AE
9. SS
10. DK
11. Vacant (Appr)
12. Vacant (Appr)
13. Vacant (Appr)
14. Vacant (Appr)

Operator Trainee
1. KY
2. NV
3. CF

KAHE STATION (IK)

Senior Supervisor [merit]
TC

Shift Supervisor
1. TM
2. LJ
3. RC
4. MK
5. AL
6. CH
7. WW

Control Operator
1. WT
2. DT
3. AT
4. JE
5. TP
6. AR
7. AM
8. RW
9. TN
10. KK
11. RK
12. JA
13. MH
14. RK
15. RS

Jr Control Operator
1. SO
2. WW
3. PY
4. DI
5. AD
6. DC
7. MS
8. LY
9. DC
10. RT
11. RG
12. SC
13. MB
14. RE
15. BN

Utility Operator
1. DG
2. DP
3. MK
4. CY
5. DF

Equipment Operator
1. DD
2. CH
3. SL
4. MT
5. MS
6. SW
7. KI
8. RS
9. MM
10. GE
11. KY
12. CT
13. MC
14. KL
15. HH

Operator Trainee
1. GL
2. Vacant (Appr)

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03/31/08

Hawaiian Electric Company, Inc.
2009 Test Year
Production O&M - Operating Division
Overtime/Straight Time Hours

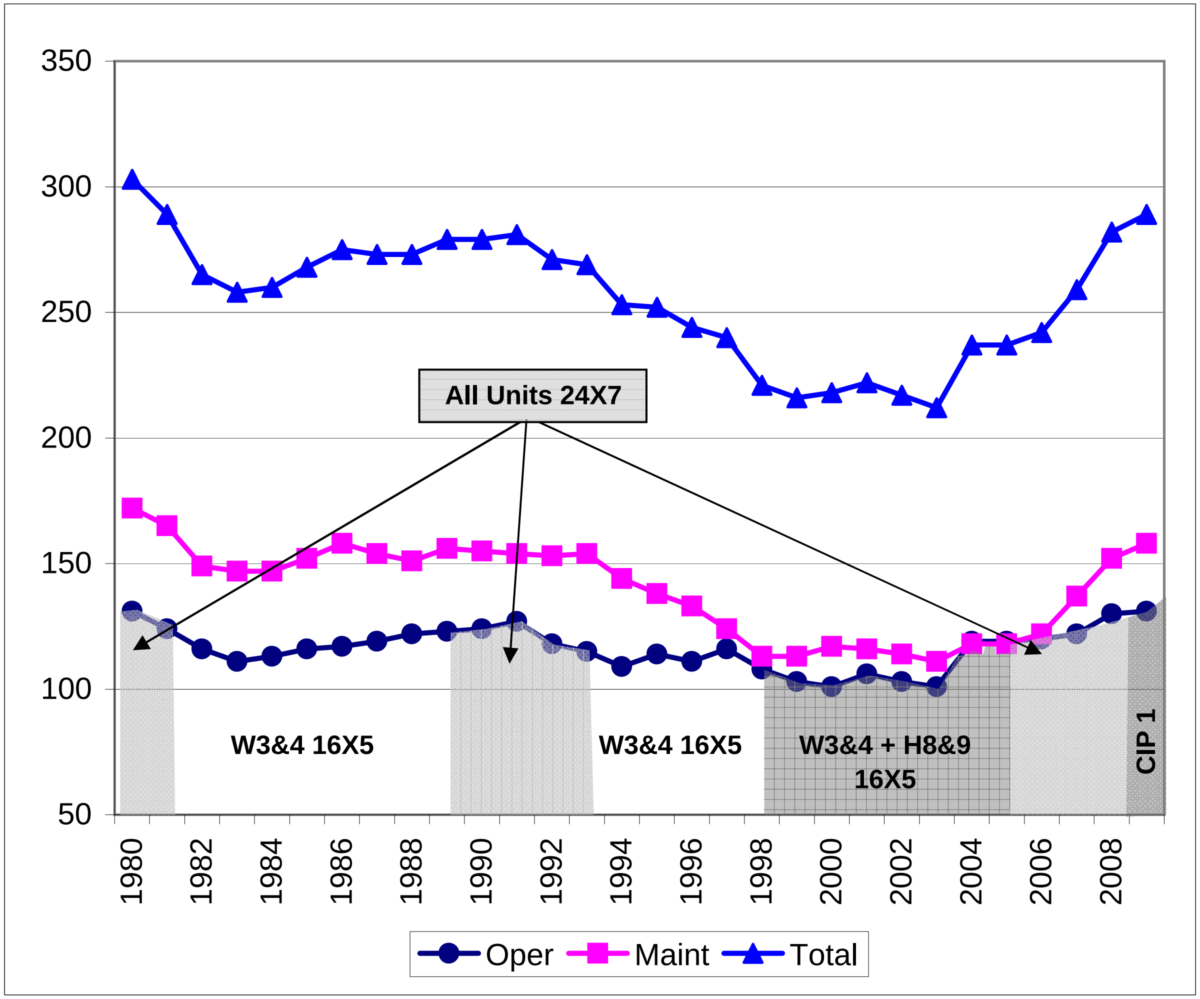
Line			(A) 2005 Act	(B) 2006 Act	(C) 2007 Act	(D) 2008 Budget	(E) 2009 Budget
	Payroll Recap Report Run Date		12/28/05	12/27/06	12/26/07		
	Overtime Hours						
1	PIK	Kahe	17,067	17,989	15,184	11,525	15,560
2	PIH	Honolulu	6,426	6,204	7,560	4,819	6,273
3	PIW	Waiau	23,427	22,633	19,970	10,857	14,765
4	PIO	Admin	1	0	0	366	456
5	PIY	CIP CT1					1,497
6	**Operation OT**		**46,921**	**46,826**	**42,714**	**27,567**	**38,551**
	Straight Time Productive Hours						
7	PIK	Kahe	102,191	98,635	105,476	108,561	106,522
8	PIH	Honolulu	39,775	43,967	43,582	47,727	46,424
9	PIW	Waiau	108,257	106,106	112,669	119,032	115,548
10	PIO	Admin	5,580	3,652	3,477	3,606	3,608
11	PIY	CIP CT1					12,704
12	**Operation ST**		**255,803**	**252,360**	**265,204**	**278,926**	**284,806**
13	**OT/ST**		**18.3%**	**18.6%**	**16.1%**	**9.9%**	**13.5%**
14	**ST + OT**		**302,724**	**299,186**	**307,918**	**306,493**	**323,357**

NOTES:

1) Columns (A) and (B), Lines 1-13: 2005 and 2006 Actuals agree with HECO's response to CA-IR-72, Attachment 2, Docket No. 2006-0386.
2) Line 13, OT/ST = Operation OT / (Operation ST).
3) Hours include capital, clearing, billable and O&M hours.

Hawaiian Electric Company, Inc.
2009 Test Year

O&M DEPARTMENT
TRADES & CRAFTS STAFFING
(does not include Supervisory and Clerical staff)



		T&C Oper	T&C Maint	Total
	1980	131	172	303
	1981	124	165	289
	1982	116	149	265
	1983	111	147	258
	1984	113	147	260
	1985	116	152	268
	1986	117	158	275
	1987	119	154	273
	1988	122	151	273
	1989	123	156	279
	1990	124	155	279
	1991	127	154	281
	1992	118	153	271
	1993	115	154	269
	1994	109	144	253
	1995	114	138	252
	1996	111	133	244
	1997	116	124	240
	1998	108	113	221
	1999	103	113	216
	2000	101	117	218
	2001	106	116	222
	2002	103	114	217
	2003	101	111	212
	2004	119	118	237
	2005	119	118	237
	2006	120	122	242
	2007	122	137	259
Budget	2008	130	152	282
Budget	2009	131	158	289

Source: HECO-617, Docket No. 2006-0386 for 1980-2005 Recorded.
2007-2009 agrees with HECO-720.

MAINTENANCE DIVISION

MAINTENANCE ADMINISTRATION (IM)

As of 03/31/08

Superintendent
LO [merit]

Power Plant Clerk
FK [BU]

NOTE:
Vacant = Not Approved
Vacant (Appr) = Approved

HONOLULU STATION (IN)

Honolulu Maint Supvr
JE [merit]

Boiler Working Foreman
1. GM

Electrical Working Foreman
1. WB

Machinist Working Foreman
1. WN

Sr Electrician
1. GM

Machinist
1. GD

Control Technician
1. EK
2. RK
3. VC

Pipefitter Mechanic
1. CP

Certified Comb Welder
1. SK

Insulator
1. Vac (Appr)

WAIAU STATION (IX)

Waiau Maintenance Supvr
1. RY [merit]
2. BM [merit]

Boiler Working Foreman
1. LL

Electrical Working Foreman
1. GG

Machinist Working Foreman
1. JS

Pipefitter Mechanic
1. BO
2. MI
3. DN
4. RO
5. AM

Certified Combination Welder
1. DM
2. RG
3. RM
4. JM

Sr Electrician
1. GA
2. RR
3. Vacant (Appr)
4. CS

Machinist
1. DT
2. WB
3. FS

Mobile Crn & Hvy Equip Oper
1. ES

Control Technician
1. MG
2. JW
3. RR
4. AC
5. BL
6. UT
7. GB
8. DD

Insulator
1. MH

Maintenance Helper
1. KK

KAHE STATION (IL)

Kahe Maintenance Supvr
1. AY [merit]
2. Vacant (Appr) [merit]

Boiler Working Foreman
1. AS

Electrical Working Foreman
1. MC

Machinist Working Foreman
1. RY

Pipefitter Mechanic
1. MN
2. WK
3. Vacant (Appr)
4. Vacant (Appr)
5. Vacant (Appr)

Certified Combination Welder
1. RT
2. LM
3. WD
4. JC

Sr Electrician
1. WF
2. RM
3. DL
4. DO

Machinist
1. CF
2. SS
3. SL

Mobile Crn & Hvy Equip Oper
1. JA

Control Technician
1. DK
2. BP
3. ES
4. AN
5. RA
6. Vacant (Appr)
7. RT
8. DH

Insulator
1. JK

Maintenance Helper
1. SP
2. RY

TRAVELING MAINT (IT)

Senior Supvr. Overhaul [merit]
1. KH

Traveling Maintenance Supvr
[merit]
1. FB
2. DO
3. JK
4. RM

Boiler Working Foreman
1. KM
2. MV

Electrical Working Foreman
1. OG
2. LF

Machinist Working Foreman
1. CS
2. SQ

Certified Equipment Mechanic
1. LS
2. BH

Pipefitter Mechanic
1. CN
2. CY
3. BM
4. RY
5. KN
6. RL
7. Vacant (Appr)

Certified Combination Welder
1. WS
2. AC
3. TM
4. DB
5. JS
6. RI
7. Vacant (Appr)
8. MC
9. Vacant (Appr)

Sr Electrician
1. CA
2. DC
3. MM
4. RR
5. KD
6. AY
7. JS
8. LS
9. RG
10. RC

Machinist
1. VA
2. BM
3. DP
4. EB
5. CN
6. MM
7. FG
8. Vacant (Appr)
9. Vacant (Appr)

Insulator Working Foreman
1. EA

Condenser Crew Leader
1. CV

Insulator
1. WG
2. DC
3. RA
4. BH
5. TC
6. EK
7. ZS
8.RF
9.GC
10. EE
11. GM
12. JQ
13. KN
14. CC

Condenser Cleaner
1. JR
2. BF
3. JI
4. RC
5.KY
6. DL
7. BK
8. KL

Control Technician
1. JS
2. SC
3. LT
4. MM
5. DP
6. Vacant (Appr)
7. Vacant (Appr)
8. Vacant (Appr)
9. Vacant (Appr)

Mobile Crn & Hvy Equip Oper
1. AA

Maintenance Helper
1. AG
2. MC
3. CA

	03/31/08 Actual	2008 Actuals&Vac & Vac (Appr)
IM	2	2
IN	11	12
IX	31	32
IL	28	33
IT	76	82
	------	------
Total	148	161

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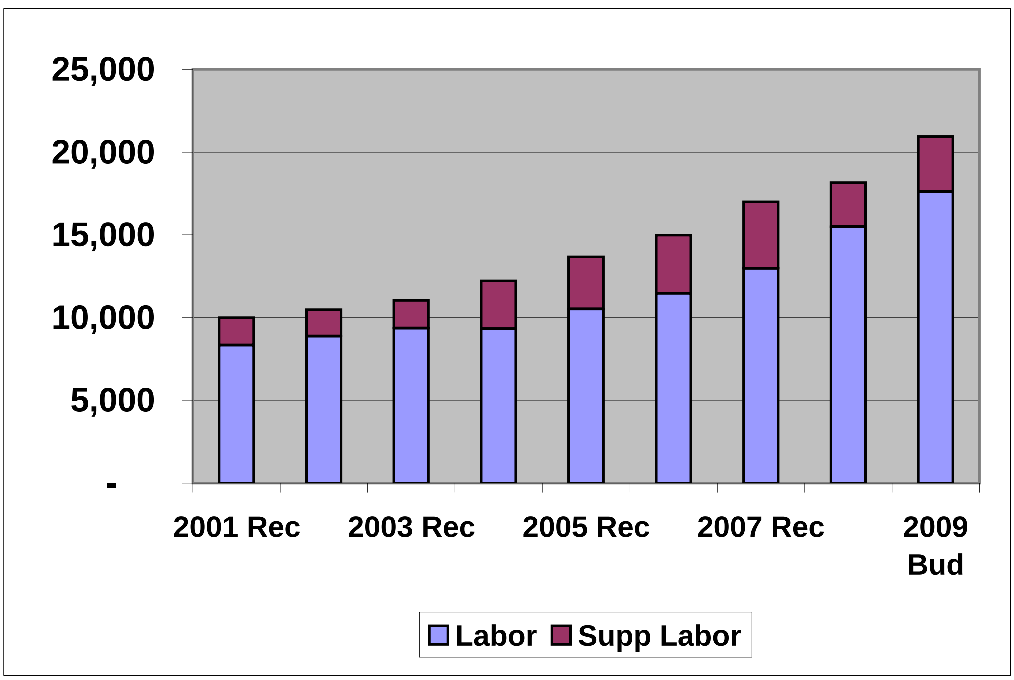
Hawaiian Electric Company, Inc.
2009 TEST YEAR
OTHER PRODUCTION O&M EXPENSE
Maintenance Personnel Replacement Summary

RA	Position	Qty	Status
IL	Kahe Maintenance Supervisor	1	Filled May 12, 2008.
IL	Kahe Pipefitter Mechanic	3	Posted September 2007 with no qualified applicants. Posted April 2008; interviews to be scheduled for September 2008.
IL	Kahe Control Technician	1	Posted October 2007; none of the 6 applicants were qualified.
IX	Waiau Senior Electrician	1	New hire to start June 30, 2008.
IT	Travel Pipefitter Mechanic	1	Posted May 2008; neither of the 2 applicants were qualified.
IT	Travel Machinist	2	Posted March 2006 and September 2007 with no qualified applicants. Posted April 2008; interviews to be scheduled for September 2008.
IT	Travel Certified Combination Welder	2	Posted September 2006, January 2007, and June 2007 with no qualified applicants. Posted April 2008; interviews to be scheduled for September 2008.
IT	Travel Control Mechanic	4	Posted December 2007; 1 in-house job offer made May 28, 2008 and refused. Posted April 2008; interviews to be scheduled for September 2008.
	TOTAL	15	

Hawaiian Electric Company, Inc.
2009 Test Year
Production O&M Expense - Maintenance Division
Labor & Outside Service Supplemental Labor
($ Thousands)

	(A) 2001 Rec	(B) 2002 Rec	(C) 2003 Rec	(D) 2004 Rec	(E) 2005 Rec	(F) 2006 Rec	(G) 2007 Rec	(H) 2008 Bud	(I) 2009 Bud
Labor	8,329	8,867	9,353	9,329	10,519	11,474	12,979	15,491	17,610
Supp Labor	1,675	1,605	1,685	2,894	3,159	3,517	4,023	2,663	3,327
Labor + Supp Labor	10,004	10,472	11,038	12,223	13,678	14,991	17,002	18,154	20,937

	(J) 2007 TY
Labor	15,219
Supplemental Labor	2,176
Labor + Supp Labor	17,395



Source: Col (A) to (F) and Col (J), Docket No. 2006-0386, CA-IR-74, Attachment 10.
Col (G) to (I), HECO-WP-710.

Hawaiian Electric Company, Inc.
2009 Test Year
Production O&M - Maintenance Division
Overtime/Straight Time Hours

Line			(A) 2005 Act	(B) 2006 Act	(C) 2007 Act	(D) 2008 Budget	(E) 2009 Budget
	Payroll Recap						
	Report Run Date		12/28/05	12/27/06	12/26/07		
	Overtime Hours						
1	PIL	Kahe	12,938	13,347	19,036	12,903	13,020
2	PIN	Honolulu	1,346	1,426	2,001	1,775	1,759
3	PIX	Waiau	14,782	15,276	13,372	13,001	13,762
4	PIT	Travel	31,633	36,387	41,679	29,938	30,371
5	PIM	Admin	0	0	0	749	847
6	PIZ	CIP CT1					2,277
7	**Maintenance OT**		**60,699**	**66,436**	**76,088**	**58,366**	**62,036**
	Straight Time Productive Hours						
8	PIL	Kahe	47,666	46,135	47,512	57,830	57,897
9	PIN	Honolulu	14,244	15,064	17,672	20,846	20,957
10	PIX	Waiau	44,495	46,070	50,596	57,096	57,426
11	PIT	Travel	114,026	120,711	125,468	147,496	156,522
12	PIM	Admin	3,490	3,625	3,531	3,664	3,664
13	PIZ	CIP CT1					14,136
14	**Maintenance ST**		**223,921**	**231,605**	**244,779**	**286,932**	**310,602**
15	**OT/ST**		**27.1%**	**28.7%**	**31.1%**	**20.3%**	**20.0%**
16	**ST + OT**		**284,620**	**298,041**	**320,867**	**345,298**	**372,638**

NOTES:

1) Column (A) and (B), Lines 1-15: 2005 and 2006 Actuals agree with HECO's response to CA-IR-74, Attachment 6, Docket No. 2006-0386.
2) Line 15, OT/ST = Maintenance OT / Maintenance ST.
3) Hours include capital, clearing, billable and O&M hours.

PLANNING & ENGINEERING DIVISION

(IP)
As of 03/31/08

Superintendent
Planning & Engineering
KM [merit]

Work Mgmt Spec
SU (merit)

Power Plant Clerk
TU [BU]

Senior Supervisor, Planning
PP [merit]

Resource Planner [merit]
1. RK
2. **Vacant (Appr)**
3. KN
4. CP
5. DS
6. SE
7. JL
8. KP
9. EC
10. SK

Senior Supervisor, Eng & PDM
JI [merit]

O&M Engineer [merit]
1. **Vacant (Appr)**
2. DM
3. DM
4. JN
5. DH
6. JS

PDM Specialist [merit]
1. EM
2. DM
3. SH

Project Aide (Temp) [merit]
1. VH

	03/31/08 Actual	2008 Actual & Vac & Vac (Appr)
IP	22	24
	1 (Temp)	
	23	

Vacant = Not Approved
Vacant (Appr) = Approved

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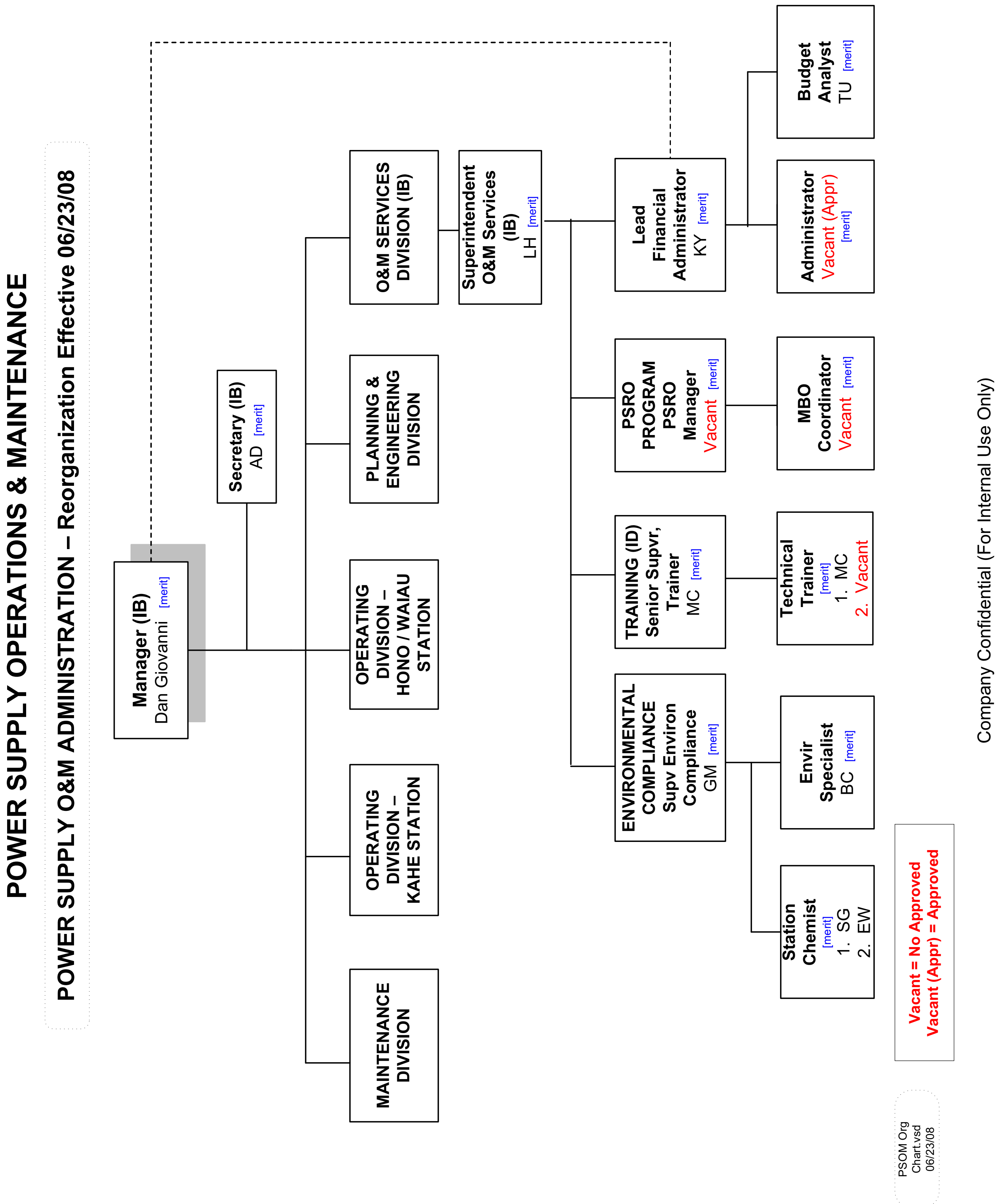
03/31/08

HECO-731
DOCKET NO. 2008-0083



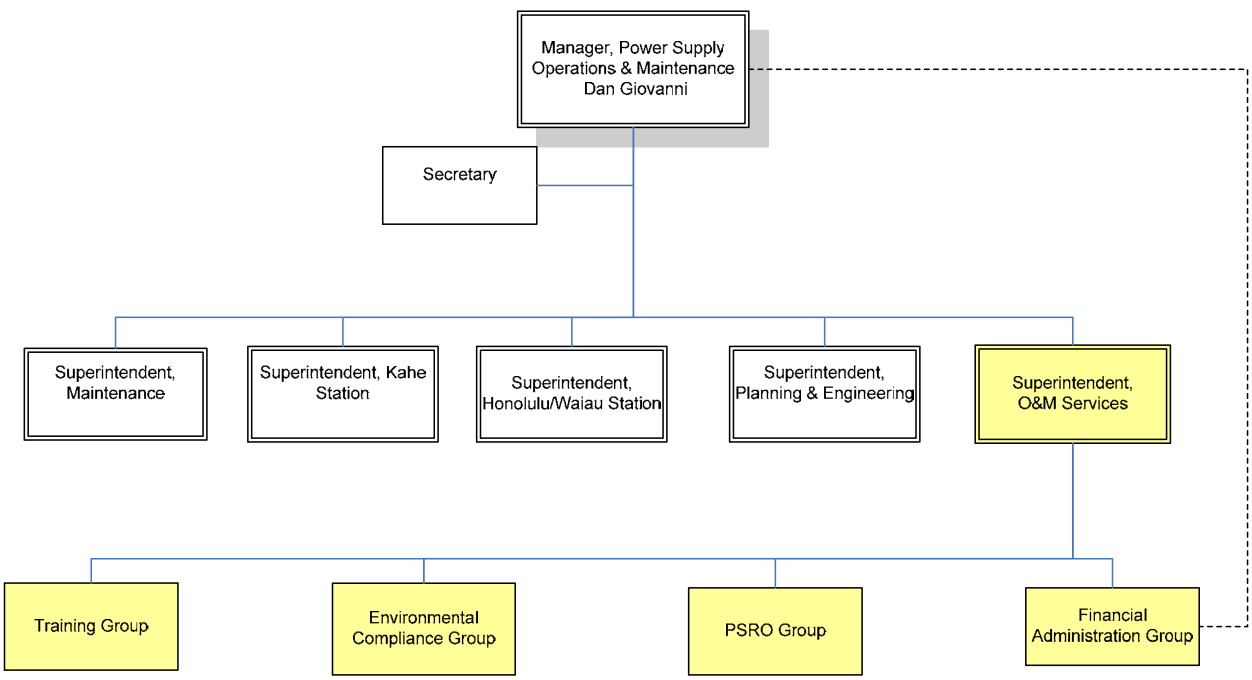
HAWAIIAN ELECTRIC COMPANY, INC.
2009 Test Year

SPLICER: Power Supply Operations and Maintenance Organizational Changes
Sent on behalf of Tom Joaquin, Tom Simmons, and Dan Giovanni:

We are pleased to announce the following changes to the Power Supply Operations and Maintenance (PSO&M) organization, effective June 23, 2008. The PSO&M Department has been reorganized to consolidate groups and personnel who have previously reported directly to the Department Manager. The Training, Financial Administration, and Environmental Compliance Groups have been reassigned to the O&M Services Division. A new Power Supply Reliability Optimization (PSRO) Program Group has been created to enhance the maintenance practices for the generating units. Recruitment to fill the vacant positions in the O&M Services Division are in progress. The heads of each of these groups reports directly to the Superintendent, O&M Services.

We are proud to announce that **Lane Hiramoto** has been named Superintendent, O&M Services. Lane will report to Dan Giovanni, Manager, PSO&M. Lane is currently the Senior Technical Analyst and is instrumental in the preparation of material required by the regulatory agencies. He also provides the department with technical guidance in the operations of the generating units. Lane began his career at HECO as a Betterment Engineer. He held positions within Power Supply O&M to include Superintendent, Operations and Superintendent, Planning.

We ask you to support these organizational changes and the team members within, which will bring about a stronger Company as we manage our day-to-day operations more effectively to meet the challenges of keeping the lights on in today's dynamic environment.



HAWAIIAN ELECTRIC COMPANY, INC.
2009 Test Year

Examples of engineering projects and initiatives reviewed by Power Supply Engineering Department ("PSED") that have contributed to HECO managing its Other Production O&M Expense, include: (1) Kahe 1 Condenser; (2) Waiau 8 Feedwater Heater No. 85; (3) Chlorine Dioxide (ClO_2) Treatment for Condenser Biofouling; (4) Barbers Point Fuel Tank No. 131; and (5) Fuel Trip Valve. Described below are more details on these projects.

Kahe 1 Condenser

The Kahe 1 Condenser project was planned as a complete replacement of more than 8,000 condenser tubes and tube sheets at an estimated cost of approximately $5.6 million. The project was scheduled for the Kahe 1 2009 unit overhaul.

Alternate methods to address the condenser issues were examined. Tube "sleeving" was identified as a viable alternative which could defer the condenser tube and tube sheet replacements for 10 years or more, and would cost significantly less at a total of $400,000.

Waiau 8 Feedwater Heater No. 85

The Waiau 8 feedwater heater (FWH) No. 85 is original equipment that was installed in 1967. A tube sample removed from FWH No. 85 in 2006 indicated deterioration that could lead to sudden failure of the tubes. It was also determined that FWH No. 85 could not be repaired.

The alternatives considered were: (1) "Do nothing" – continue FWH No. 85 operation; (2) operate Waiau 8 with FWH No. 85 permanently out of service; and (3) replace FWH No. 85.

The "Do nothing" alternative was determined to be unacceptable because it jeopardized the reliability of the Waiau 8 generating unit. Should the deteriorating tubes rupture and cause steam turbine water induction damage to the steam turbine, the consequential costs and risks to the operation of the HECO grid could have been substantial.

The second alternative, “Operating with FWH No. 85 permanently out of service,” would have resulted in significant degradation of the generating unit’s thermal efficiency (i.e., “heat rate”). At June 2008 fuel oil prices, the adverse cost impact of FWH No. 85 being out of service would range from \$2,500 to \$3,000 per day.

The “replacement” alternative was estimated to cost approximately \$900,000. The analysis concluded the replacement alternative was more cost-effective than operating with FWH No. 85 permanently out of service. The fuel cost savings would pay for the new FWH in less than two years. The useful life of a replacement FWH is approximately 20 years.

Chlorine Dioxide (ClO_2) Treatment for Condenser Biofouling

This project investigated alternatives to address the marine growth that fouls the condenser tube heat transfer area. Impaired condenser heat transfer results in a loss of condenser vacuum. Depending on the type of unit (cycling or reheat), a 0.1" increase in turbine backpressure due to marine fouling in the steam condenser translates to approximately \$350 to \$750 per day in additional fuel costs based on the current cost of fuel oil. The condenser tubes are manually cleaned periodically, but marine growth rapidly returns between manual cleanings. There was equipment at Waiau and Kahe Power Plants to inject ClO_2 (a biocide) for marine growth control, but by 2006 it had become unreliable and was in need of replacement.

The alternatives investigated included: (1) “Do nothing”; (2) on-line mechanical cleaning system; and (3) replacing the existing biocide system. The “do-nothing” alternative would reduce operating efficiency and incur additional fuel costs. The effectiveness of on-line mechanical cleaning was uncertain and it was very expensive. The on-line mechanical cleaning system equipment was estimated at \$1.5 million versus \$203,000 for replacement ClO_2 system equipment. It was concluded that the best alternative was to install a replacement chlorine dioxide system. A new system was commissioned at Kahe Power Plant in May 2008, and a new system is being installed at Waiau Power Plant with a scheduled service date of July 2008.

HAWAIIAN ELECTRIC COMPANY, INC.
2009 Test Year

Barbers Point Fuel Tank No. 131

Barbers Point Fuel Oil Tank 131 is 210-foot diameter by 56-foot high tank that is above ground, steel, and insulated. This tank was originally constructed in 1980 and provides storage for approximately 14.5-million gallons of low-sulfur fuel oil (LSFO). An internal tank inspection report in 2007 identified significant tank bottom corrosion.

HECO evaluated two tank bottom renovation alternatives for Barbers Point Fuel Oil Tank 131: (1) bottom plate and shell repairs for only those areas with identified corrosion, and (2) new tank bottom based on the El Segundo double bottom design. The evaluation included an analysis of initial capital and ongoing maintenance costs. Qualitative factors such as maintaining fuel supply security and environmental protection were also considered. The estimated cost for the first alternative was approximately $3.0 million. The capital cost for the El-Segundo double bottom alternative was estimated to be approximately $4.1 million. Although the first alternative has a lower initial cost, it carries significant ongoing future maintenance costs. The El Segundo double bottom alternative has a higher initial cost, but future maintenance costs are much lower.

An accumulated present worth revenue requirements ("APWRR") analysis, which included analysis of future inspections and an estimated level of maintenance costs, was performed. The difference in APWRR between the two alternatives at the end of the 30-year analysis is relatively small ($322,000 or 5%) in favor of the in-kind bottom plate repair alternative. However, the El Segundo double bottom design is expected to extend the internal inspection interval to 20 years, would provide new leak detection capabilities, and would incorporate a release prevention barrier that the existing tank does not have. As a result, HECO recommended the complete floor replacement of Barbers Point Tank 131 with an upgraded El Segundo double bottom design. The work is in-progress.

Fuel Oil Trip Valves

A Request for Engineering Attention ("REA"; aka: Request for Engineering Assistance) was submitted to investigate the purchase and replacement of the 60-year-old fuel oil trip valves at Waiau 3 and 4. Due to the age of the valves, it was initially thought that spare parts would not be available. The Power Supply Engineering Department located the original equipment manufacturer and found that the replacement parts were still available. Alternate fuel oil trip valves similar to those used on the other Waiau and Kahe units were investigated as possible replacements and were found to be of different vendors and designs. Although there was a desire to standardize these valves with those on the other Waiau units, replacing the valves at a higher cost was not justified since repair parts for the existing valves were readily available. PSED recommended overhaul of the existing valves with parts from the original equipment manufacturer over installing replacement valves.

Hawaiian Electric Company, Inc.
2009 TEST YEAR

OTHER PRODUCTION O&M EXPENSE BUDGET ADJUSTMENTS
($ Thousands)

Line	Adjustments	(A) Operations Labor	(B) Operations Non-Labor	(B) Maintenance Non-labor	(C) Total
1	Performance Incentive	$ -	$ (386)	$ -	$ (386)
2	Air Quality Monitoring Stations	83	72	0	155
3	Fish Monitoring	4	23	0	27
4	Emission Fees	0	(89)	0	(89)
5	Reverse Osmosis Amortization	0	32	(32)	0
6	Abandoned Projects	0	8	20	28
7	Research and Development	0	(26)	0	(26)
8	Environmental 316(b)	0	356	0	356
9	Security Personnel	(58)	0	0	(58)
10	TOTAL	$ 29	$ (10)	$ (12)	$ 7

Source:
Line 1, Col (B): See HECO T-11.
Line 2, Col (A) and (B): See HECO T-7.
Line 3, Col (A) and (B): See HECO T-7.
Line 4, Col (B): See HECO T-7.
Line 5, Col, (B) and (C): See HECO T-7.
Line 6, Col, (B) and (C): See HECO T-11.
Line 7, Col (B): See HECO T-14.
Line 8, Col (B): See HECO T-7.
Line 9, Col (A): See HECO T-15.
Line 10, Total, agrees with HECO-701, Col (B).

Hawaiian Electric Company, Inc.
2009 TEST YEAR

OTHER PRODUCTION O&M EXPENSE NORMALIZATIONS
($ Thousands)

Line	Normalization	(A) Operations Non-Labor	(B) Maintenance Non-labor	(C) Total
1	IRP	$ (3)	$ -	$ (3)
2	TOTAL	$ (3)	$ -	$ (3)

Source:
Col (A), Line 1: See HECO T-10.

Line 2, Total, agrees with HECO-701, Col (C).

Hawaiian Electric Company, Inc.
2009 Test Year

OTHER PRODUCTION OPERATIONS EXPENSE
($ Thousands)

Line		RECORDED					2008 BUDGET	BASE CASE 2009 TY ESTIMATE	2007 vs 2009	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H=G-E)	(I=H/E)
		2003	2004	2005	2006	2007	2008	2009	$	%
1	Labor	$11,278	$11,742	$12,304	$12,499	$13,394	$14,199	$15,402	$2,008	15%
2	Non-Labor	$8,895	$8,544	$10,154	$12,764	$14,413	$15,904	$16,998	$2,585	18%
3	TOTAL	$20,173	$20,286	$22,458	$25,263	$27,807	$30,103	$32,400	$4,593	17%
	Percentage Change		1%	11%	12%	10%	8%	8%		

Source: Columns A to F: HECO-WP-101(A), S1 Report, page 2.
Column G: Agrees with HECO-701, Column (D).

Note: Figures may not total exactly due to rounding.

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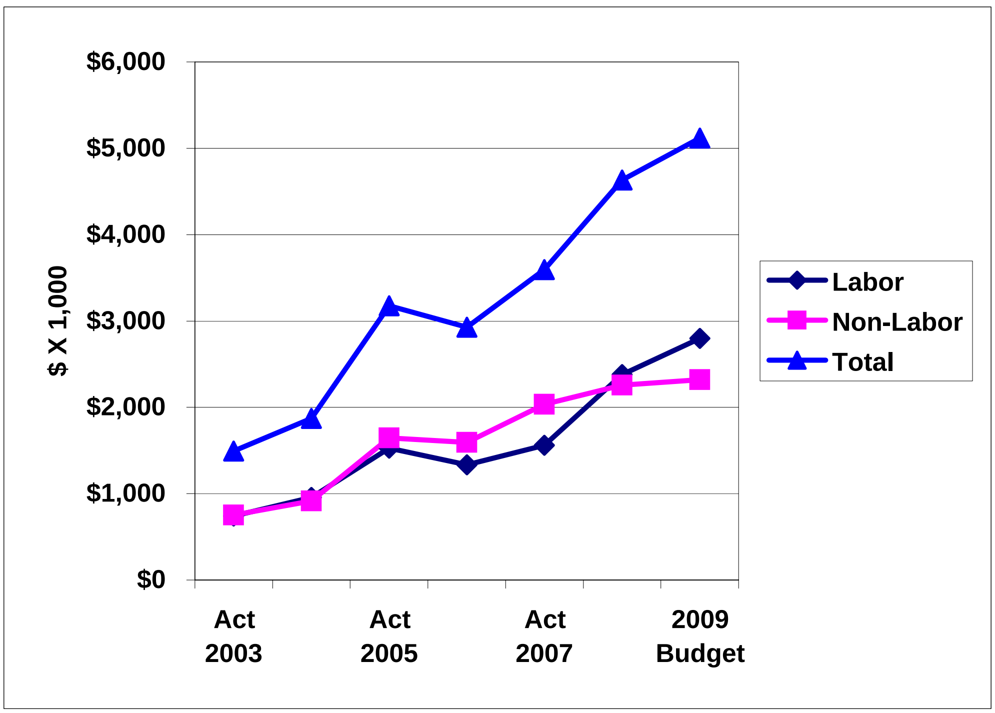
Hawaiian Electric Company, Inc.
2009 Test Year

Training Cost (O&M Direct and Clearing Costs)
($ Thousands) - ABM Activities 785-797

	Act 2003	Act 2004	Act 2005	Act 2006	Act 2007	2008 Budget	2009 Budget
Labor	$741	$955	$1,528	$1,333	$1,560	$2,378	$2,797
Non-Labor	$752	$916	$1,647	$1,593	$2,035	$2,256	$2,320
Total	$1,493	$1,871	$3,175	$2,926	$3,595	$4,634	$5,117



Source: HECO-WP-708

Hawaiian Electric Company, Inc.
2009 TEST YEAR

OTHER PRODUCTION OPERATIONS NON-LABOR EXPENSE
2007 ACTUAL VS. 2009 BASE CASE TEST YEAR ESTIMATE
($ Thousands)

		(A)	(B)	(C)	(D)
			BASE CASE		
		2007	2009 TY		
	EXPENSE	ACTUAL	ESTIMATE	CHANGE	%
1	Material	$ 2,042	$ 2,625	$ 583	29
2	Transportation	$ 181	$ 222	$ 41	23
3	On-Cost	$ 2,851	$ 2,337	$ (514)	(18)
4	Outside Srvcs/Other	$ 9,339	$ 11,827	$ 2,488	27
5	SUBTOTAL	$ 14,413	$ 17,011	$ 2,598	18
6	Adj & Normalizations	$ -	$ (13)	$ (13)	
7	TOTAL	$ 14,413	$ 16,998	$ 2,585	18

Line 3 - Non-labor On-Cost includes Energy Delivery On-Cost and Power Supply On-Cost.

Line 7 TOTAL: Agrees with HECO-736.

Environmental Department – Clean Water Act §316(b) Expense

Background

On February 16, 2004, the U.S. Environmental Protection Agency (EPA) took final action on regulations governing cooling water intake structures at certain existing power producing facilities under section 316(b) of the Clean Water Act (Phase II rule). 69 FR 41576 (July 9, 2004). The Phase II rule applied to HECO's Kahe, Waiau and Honolulu generating facilities. These rules were intended to ensure that the location, design, construction and capacity of cooling water intake structures reflect the best technology available to protect aquatic organisms from being killed or injured by impingement or entrainment.

These regulations were challenged by industry and environmental groups. On judicial review, the U. S. Court of Appeals for the Second Circuit in Riverkeeper, Inc. v. EPA, 475 F.3d 83, (2d Cir., 2007), remanded several provisions of the Phase II rule on various grounds, including EPA's determination of best technology available under section 316(b), the rule's performance standard ranges, the cost-cost and cost-benefit compliance alternatives, the Technology Installation and Operation Plan provision, the restoration provision and the "independent supplier" provision. Under the Riverkeeper decision, EPA has been precluded from applying the Phase II rule unless and until it takes further action to address the decision. As a result, the EPA, on March 20, 2007, announced its intention to suspend the Phase II rule. However, the EPA did not suspend 40 CFR 125.90(b) which retains the requirement that permitting authorities develop Best Professional Judgment (BPJ) controls for existing facility cooling water intake structures that reflect the best technology available (BTA) for minimizing adverse environmental impact.

The EPA did not appeal the Second Circuit's decision and instead will work on revising its rules, now anticipated to be issued in draft at the end of 2008 and issue a final rule by the end of 2009. Due to the uncertainties raised by the Second Circuit's decision, EPA's pending rule changes, and the state regulator's (i.e., Hawaii State Department of Health (HDOH)) forthcoming actions, HECO is unable to predict which compliance options may be necessary or applicable at HECO's facilities. However, since the HDOH incorporated EPA's CWA Section 316(b) compliance requirements into HECO's existing NPDES permits for the Kahe, Waiau and Honolulu Power Plants, HECO is still obligated to comply with existing permit conditions. On November 13, 2007, HECO submitted an NPDES permit modification request to HDOH to revise the existing permits by removing the original CWA Section 316(b) Phase II requirements and replacing them with the proposed BPJ activities as recommended by the Electric Power Research Institute (EPRI). Even though the EPA suspended the Rule, the Phase II requirements for the HECO permits are still in effect since HDOH is the delegated permitting authority. Although HDOH has yet to formally reply to HECO's request for permit modifications, HDOH has indicated verbally that it is complying with EPA's suspension of the Rule and will allow use of BPJs until the EPA issues a new rule.

Although the EPA did not appeal the Second Circuit's decision, three separate appeals, were filed by Entergy Corp., PSEG Fossil LLC and PSEG Nuclear LLC, and Utility Water Act

Group with the U. S. Supreme Court in November 2007. On April 14, 2008, the Supreme Court agreed to review the Second Circuit's decision and consolidated the three appeals. The issue which the Supreme Court has agreed to address is "Whether Section 316(b) of the Clean Water Act, 33 U.S.C. 1326(b), authorizes the Environmental Protection Agency (EPA) to compare costs with benefits in determining the 'best technology available for minimizing adverse environmental impact' at cooling water intake structures." Other portions of the Second Circuit's decision still stand, which means that one of HECO's preferred compliance options, restoration, is no longer viable. HECO has been advised by EPRI that the Supreme Court is expected to hear the case in November 2008, with a decision to be issued during the first half of 2009. Issuance of the Supreme Court's decision will probably fall within the public comment period for EPA's proposed rule.

HECO's Section 316(b) compliance cost projections, including project scope and timelines, continue to be based on input from project consultants, EPRI and Tenera Environmental. EPRI is closely working with EPA to provide comprehensive and persuasive industry background data to convince EPA of the importance and impact of this Section 316(b) issue to the electric power industry, and to assist EPA in making sound rulemaking decisions. Thus, EPRI's and Tenera's guidance to continue data gathering and technology evaluations and to identify other BPJ requirements will allow HECO, as well as the rest of the electric utility industry, to prepare itself for the eventual release of new EPA rules.

<u>The 2009 Test Year 316(b) Compliance Expense Estimate</u>

The 2009 test year estimate for section 316(b) compliance expense is $848,000. The following discussion describes how that estimate was developed.

HECO's section 316(b) compliance expense estimate in Docket No. 2006-0386 was $1,303,000 for 2009. See, HECO T-6 June 2007 Update, Attachment 6, page 1. On February 28, 2008, the 2009 estimate of $1,303,000 was reduced to $492,000 based on three developments. First, a preliminary evaluation was done by HECO that supported a potential decrease in the frequency of IM&E monitoring, and a delay in the implementation of fish protection technology pilot testing. That review of the IM&E data that indicated the frequency of the IM&E monitoring might be able to be reduced without impacting the integrity of the monitoring data set. Based on this initial review, the monitoring forecast was reduced to reflect a relaxation in weekly impingement and biweekly entrainment monitoring to monthly monitoring. This resulted in a reduction of the estimated expense for IM&E monitoring from $583,000 in HECO's T-6 June 2007 Update to $192,000. Please refer to Table I at the end of this exhibit.

The second development was a delay in the implementation of fish protection technology pilot testing from the beginning of 2009 to late 2009. HECO's 2007 test year forecast included $500,000 for pilot testing in 2009, the third year of the Section 316(b) program , making 2009 the most costly in the 3-year forecast with estimated section 316(b) expenses of $1,303,000. See HECO T-6 June 2007 Update, Attachment 6, in Docket No. 2006-0386. Since the time of HECO's T-6 June 2007 Update in Docket No. 2006-0386, the EPA announced plans to issue draft Section 316(b) rules by the end of 2008 and finalize the rules in 2009. This change delayed the need to fully implement pilot testing of potential technologies in 2009. As a result, about 20% of the pilot testing program will be initiated in late 2009, with the remaining 80% (previously forecasted in the HECO T-6 June 2007 Update to be spent in 2009) being carried over into the 2010 forecast. This resulted in a reduction of the estimated expense for Pilot Testing from $500,000 in HECO's T-6 June 2007 Update to $100,000. Please refer to Table I at the end of this exhibit.

Third, the estimated expense for Tenera's report decreased from $70,000 to $50,000 because the reduced frequency of IM&E monitoring would result in less data to process and analyze for the report.

The combined effect of these three developments produced an estimated section 316(b) compliance expense for the 2009 operating budget in the amount of $492,000 as of February 28, 2008.

In April 2008, the estimated section 316(b) compliance expense for 2009 was adjusted to increase the estimate by $356,000 to $848,000 based on two factors. First, a more detailed statistical analysis of the first year data set by Tenera in April, 2008 supported a reduced monitoring frequency, but not to the degree anticipated in February 2008. As a result, the estimate for IM&E monitoring was increased from $192,000 to $441,000. While impingement monitoring can be reduced from weekly to monthly monitoring, entrainment monitoring needs to continue on a biweekly monitoring schedule for at least the months of February through September to substantiate observed seasonal impact trends. IM&E monitoring will continue through 2009 because the EPA's new (or revised) Section 316(b) rule, expected in 2009, will likely require a significant reduction in fish impingement and entrainment through the implementation of a technology (i.e., specialized traveling screens, fish diversion devices, or other intake modifications). In order to select, test and verify the technology upgrade, a statistically sound database of IM&E impacts is critical. If the EPA does require a technology implementation, IM&E monitoring will be required as one of the NPDES operating permit conditions for future years to come.

Second, the expense estimate for Tenera's 2009 report increased from $50,000 to $157,000 because three years of data will be analyzed to produce a consolidated three-year summary report.

The expense estimates for participation in EPRI's section 316(b) studies (fish protection technology evaluation and research life history of fish species) were not changed from HECO's T-6 June 2007 Update in Docket No. 2006-0386. Continued participation in the EPRI studies is an important part of HECO's section 316(b) compliance effort. Not participating in EPRI's Section 316(b) studies could mean that HECO would not have access to critical data, and technology and cost-benefit evaluations that could be utilized to potentially sway Federal and State regulators to impose less stringent IM&E requirements. Not participating also would mean that HECO would not have its data included in EPRI's nationwide database and represented in negotiations with EPA on new rulemaking. Also, if projects are not adequately funded by HECO or other member utilities, the scope of the EPRI project may be reduced or the project may be cancelled all together. A collaborative group approach by EPRI and its member companies is the most efficient means to express concerns and negotiate rulemaking with regulatory agencies.

The two adjustments to HECO's 2009 section 316(b) compliance expense estimate for 2009 discussed above resulted in the 2009 test year estimate for Section 316(b) compliance expense is $848,000. Please refer to Table I at the end of this exhibit.

<u>2009 Test Year Estimate Compared with 2007 Actual Section 316(b) Compliance Expenses</u>

The actual outside service non-labor expense for section 316(b) compliance in 2007 was $721,000. Please refer to Table I at the end of this exhibit. The following factors account for the difference (i.e., $127,000) between the 2007 actual expense and the 2009 test year estimate of $848,000.

Actual expenses incurred during 2007 were primarily for IM&E monitoring, participation in an EPRI Closed Cycle Cooling Study for California (discussed later in this Exhibit) and development of BPJ recommendations for complying with Section 316(b). The only carry-over task between 2007 and 2009 is IM&E monitoring, where the 2009 forecast of $441,000 is less than the 2007 actual cost of $627,000 due to a proposed reduction in monitoring frequency during 2009. Additional funding is needed for new tasks identified for 2009, which were not conducted in 2007. These new tasks include preparation of an annual report (which is actually a report analyzing and summarizing three years of IM&E monitoring) with an estimated cost of $157,000; evaluation of Fish Protection Technologies with an estimated cost of $60,000; initiation of a Pilot Testing program for a selected fish protection technology with an estimated cost of $100,000; research of dominant fish species life histories with an estimated cost of $70,000; and preparation of comments on EPA's proposed new rules with an estimated cost of $20,000. Please refer to Table I at the end of this exhibit.

<u>Impact of the Supreme Court's Forthcoming Decision in the Phase II Rule Litigation</u>

If the Supreme Court overturns the Second Circuit's decision, a cost-benefit analysis could be used to comply with fish protection rules. For HECO, if the data from the EPRI's Section 316(b) studies show that the cost of the fish protection technologies is significantly greater than the benefit of reducing the number of fish impinged and entrained, then HECO may be subject to a less stringent standard. The best case scenario would be that, based on the cost-benefit analyses, HECO's current cooling water system is deemed compliant with the rules and no fish protection technology retrofit is required. The second best compliance option would be installation of a selected technology based on a standard less stringent than closed cycle cooling (CCC). Among other factors, IM&E monitoring data is critical in determining species abundance, biomass, distribution, seasonality, and impacts to commercial, recreational and ecological resources. This data is essential in determining the feasibility and design of selected technologies based on site specific plant operating information and shoreline conditions.

If the Supreme Court upholds the Second Circuit's decision, then it is likely that HECO will have to install fish protection technologies at its power plant facilities. As noted above, HECO is currently participating with EPRI in developing technology assessments for each of the power plants (i.e., assuming CCC is not considered BTA), as well as two EPRI CCC retrofit studies, one an utility-wide impact study (which will be shared with EPA for consideration in its rulemaking) and a California CCC (where specific CCC retrofit cost impact estimates will be produced for HECO facilities). In May 2008, HECO received a draft fish protection technology evaluation report for BPJ compliance at Honolulu power plant, with a range of technology options and costs discussed. These range from no additional cost, if the existing intake system is found to meet BPJ, to $16,000,000 to install narrow-slot wedgewire screens as a potentially acceptable technology alternative to CCC. If CCC becomes BTA, installation of CCC technology at the Waiau and Kahe plants would be extremely costly. Estimated costs to retrofit Waiau and Kahe to CCC standards will be included in reports being prepared for HECO as part of the California CCC study mentioned previously. Draft reports are expected to be issued by August 2008.

In either case, having an extensive and detailed database is critical for the Company to evaluate forthcoming IM&E impact evaluations and resulting technology decisions.

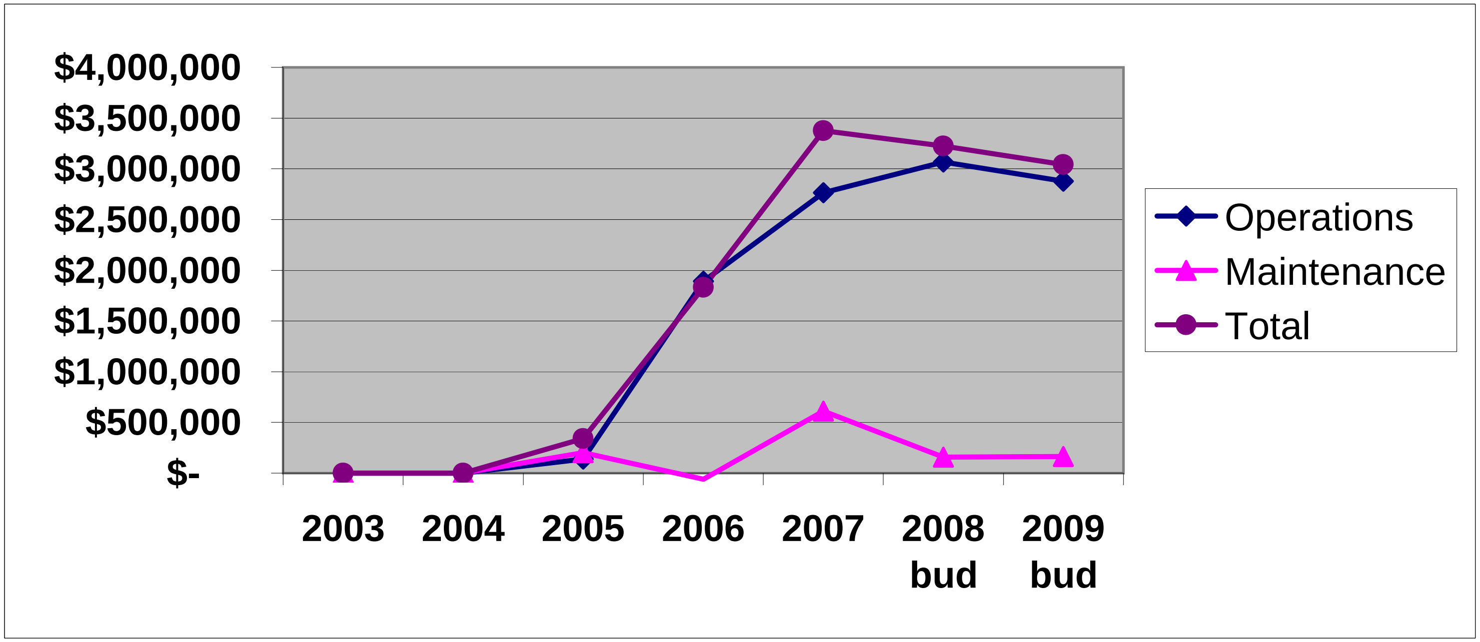
To summarize, the 2009 test year estimate for the section 316(b) compliance expense is $848,000 as shown in the table below.

Table I. Environmental 316(b) Expense Summary

	2007 Actual Expense	Docket No. 2006-0386, HECO T-6, Attachment 6	February 2008 Estimate	April 2008 Adjustment
Closed Cycle Cool Eval - EPRI	$6,000			
Best Prof Judge Eval - EPRI	$88,000			
Continue IM&E Eval	$627,000	$583,000	$192,000	$441,000
Analyze/Eval 2nd Yr data		$70,000	$70,000	$70,000
Research Fish Prot Tech		$60,000	$60,000	$60,000
Pilot Test Select Tech		$500,000	$100,000	$100,000
Research Life History Fish and Invert		$70,000	$50,000	$157,000
Comments to EPA on proposed rule		$20,000	$20,000	$20,000
TOTAL	$721,000	$1,303,000	$492,000	$848,000

Hawaiian Electric Company, Inc.
2009 Test Year
Production Block of Accounts
Distributed Generator O&M Expenses

		(A) 2003	(B) 2004	(C) 2005	(D) 2006	(E) 2007	(F) 2008 bud	(G) 2009 bud
1	Operations	$ -	$ -	$ 138,020	$ 1,890,727	$ 2,764,059	$ 3,066,739	$ 2,879,097
2	Maintenance	$ -	$ -	$ 203,200	$ (59,525)	$ 610,335	$ 158,561	$ 163,597
3	Total	$ -	$ -	$ 341,220	$ 1,831,202	$ 3,374,394	$ 3,225,300	$ 3,042,694



Hawaiian Electric Company, Inc.
2009 Test Year

OTHER PRODUCTION MAINTENANCE EXPENSE
($ Thousands)

Line		RECORDED					2008 BUDGET	BASE CASE 2009 TY EST	2007 vs 2009	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H=G-E)	(I=H/E)
		2003	2004	2005	2006	2007	2008	2009	$	%
1	Labor	$9,353	$9,329	$10,519	$11,474	$12,979	$15,438	$17,610	$4,631	36%
2	Non-Labor	$15,526	$20,841	$24,151	$26,431	$28,021	$28,826	$30,381	$2,360	8%
3	TOTAL	$24,879	$30,170	$34,670	$37,905	$41,000	$44,264	$47,991	$6,991	17%
	Percentage Change		21%	15%	9%	8%	8%	8%		

Source: Columns A to F: HECO-WP-101, S1 Report, page 1.
Column G: Agrees with HECO-701, Column (D)

Note: Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2009 TEST YEAR

OTHER PRODUCTION MAINTENANCE NON-LABOR EXPENSE
2007 ACTUAL VS. 2009 TEST YEAR
($ Thousands)

		(A)	(B)	(C=B-A)	(D)
	EXPENSE	2007 ACTUAL	BASE CASE 2009 TY ESTIMATE	CHANGE	%
1	Material	$ 9,785	$ 8,871	$ (914)	(9)
2	Outside Srvcs/Other	$ 15,134	$ 18,365	$ 3,231	21
3	Transportation	$ 364	$ 413	$ 49	13
4	On-Cost	$ 2,738	$ 2,744	$ 6	0
5	SUBTOTAL	$ 28,021	$ 30,393	$ 2,372	8
6	Adj & Normalization	$ -	$ (12)	$ (12)	
7	TOTAL	$ 28,021	$ 30,381	$ 2,360	8

Line 4 - Non-labor On-Cost includes Energy Delivery On-Cost and Power Supply On-Cost.

Line 7 TOTAL: Agrees with HECO-742.

Hawaiian Electric Company, Inc.
2009 TEST YEAR

OTHER PRODUCTION MAINTENANCE NON-LABOR EXPENSE
2007 ACTUAL VS. 2009 TEST YEAR
($ Thousands)
ADJUSTED FOR OUTSIDE SERVICE /OTHER EXPENSE
USED FOR SUPPLEMENTAL LABOR
NO ADJUSTMENT FOR ON-COST

		(A)	(B)	(C=B-A)	(D)
	EXPENSE	2007 ACTUAL	2009 TY ESTIMATE	CHANGE	%
1	Material	$ 9,785	$ 8,871	$ (914)	(9)
2	Outside Srvcs/Other	$ 13,287	$ 18,365	$ 5,078	38
3	Transportation	$ 364	$ 413	$ 49	13
4	On-Cost	$ 2,738	$ 2,744	$ 6	0
5	SUBTOTAL	$ 26,174	$ 30,393	$ 4,219	16
6	Adj & Normalization	$ -	$ (12)	$ (12)	
7	TOTAL	$ 26,174	$ 30,381	$ 4,207	16

Line 4 - Non-labor On-Cost includes Energy Delivery On-Cost and Power Supply On-Cost.

Hawaiian Electric Company, Inc.
2009 Test Year
Other Production Maintenance Non-Labor Expense ($ Thousands)

Line		(A) 2003 Rec	(B) 2004 Rec	(C) 2005 Rec	(D) 2006 Rec	(E) 2007 Rec	(F) 2008 Bud	(G) 2009 Bud	(H=G-E) Change	(I) %
1	Material	6,849	8,571	9,120	10,110	9,785	10,352	8,871	(914)	(9)
2	Outside Services/Other	7,537	10,744	12,442	13,621	15,134	15,337	18,365	3,231	21
3	Subtotal	14,386	19,315	21,562	23,731	24,919	25,689	27,236	2,317	9
4	Line 3 % Increase		34.3%	11.6%	10.1%	5.0%	3.1%	6.0%		
5	Transportation	215	271	311	342	364	458	413	49	13
6	On-Cost	925	1,255	2,278	2,358	2,738	2,679	2,744	6	0
7	Subtotal Non-Labor	15,526	20,841	24,151	26,431	28,021	28,826	30,393	2,372	8
8	Adj & Normalization					---		(12)	(12)	
9	TOTAL NON-LABOR					28,021		30,381 Base Case	2,360	8

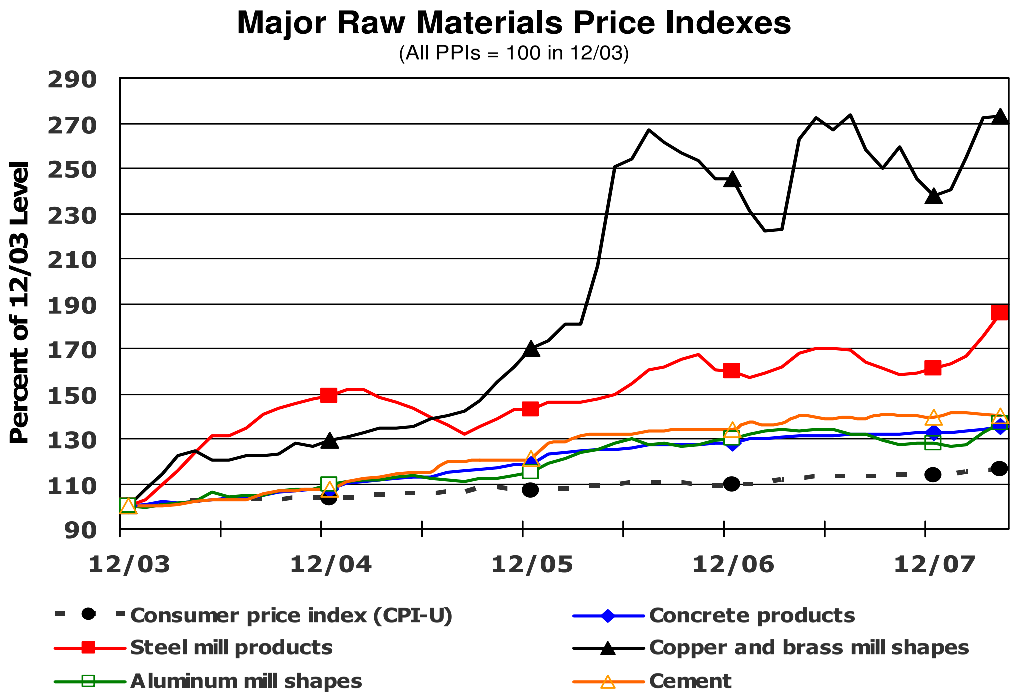
Notes: Line 4 - Line 3 % Increase = [(year/previous year) - 1] X 100.
Line 6 - Non-labor On-Cost includes Energy Delivery On-Cost and Power Supply On-Cost.
Line 9 TOTAL: Agrees with HECO-742

Hawaiian Electric Company, Inc.
2009 Test Year
Other Production Maintenance Non-Labor Expense ($ Thousands)
ADJUSTED FOR OUTSIDE SERVICE/OTHER EXPENSE USED FOR SUPPLEMENTAL LABOR
NO ADJUSTMENT FOR ON-COST

Line		(A) 2003 Rec	(B) 2004 Rec	(C) 2005 Rec	(D) 2006 Rec	(E) 2007 Rec	(F) 2008 Bud	(G) 2009 Bud	(H=G-E) Change	(I) %
1	Material	6,849	8,571	9,120	10,110	9,785	10,352	8,871	(914)	(9)
2	Outside Services/Other	7,537	10,744	12,442	13,621	13,287	15,337	18,365	5,078	38
3	Subtotal	14,386	19,315	21,562	23,731	23,072	25,689	27,236	4,164	18
4	Line 3 % Increase		34.3%	11.6%	10.1%	-2.8%	11.3%	6.0%		
5	Transportation	215	271	311	342	364	458	413	49	13
6	On-Cost	925	1,255	2,278	2,358	2,738	2,679	2,744	6	0
7	Subtotal Non-Labor	15,526	20,841	24,151	26,431	26,174	28,826	30,393	4,219	16
8	Adj & Normalization					---		(12)	(12)	
9	TOTAL NON-LABOR					26,174		30,381 Base Case	4,207	16

Notes: Line 4 - Line 3 % Increase = [(year/previous year) - 1] X 100.
Line 6 - Non-labor On-Cost includes Energy Delivery On-Cost and Power Supply On-Cost.

Hawaiian Electric Company, Inc.
2009 Test Year
Major Raw Materials Price Indexes
100 = December 2003



Source: U.S. Department of Labor – Bureau of Labor Statistics – Consumer Price Index & Series Report
2008 Data is preliminary – All indexes are subject to revision four months after original publication.

Increase from December 2003 to April 2008	
Consumer Price Index (CPI-U)	+ 16.6%
Concrete Products	+ 35.7%
Steel Mill Products	+ 85.3%
Copper and Brass Mill Shapes	+ 173.2%
Aluminum Mill Shapes	+ 36.8%
Cement	+ 39.9%

Hawaiian Electric Company, Inc.
2009 Test year
Major Raw Materials Price Indexes
100 = December 2003

	12/31 2003	1/31 2004	2/29 2004	3/31 2004	4/30 2004	5/31 2004	6/30 2004	7/31 2004	8/31 2004	9/30 2004	10/31 2004	11/30 2004	12/31 2004	1/31 2005	2/28 2005	3/31 2005	4/30 2005	5/31 2005
Consumer Price Index (CPI-U)	100	101	101	102	102	103	103	103	103	103	104	104	103	104	104	105	106	106
Concrete Products	100	101	102	102	102	103	103	104	105	106	107	107	108	111	111	112	113	113
Steel Mill Products	100	103	109	116	124	131	131	135	141	144	146	148	149	151	152	149	147	144
Copper and Brass Mill Shapes	100	108	114	122	125	121	121	123	122	123	128	126	130	131	133	135	135	135
Aluminum Mill Shapes	100	99.7	101	102	103	106	105	105	105	107	107	108	110	111	112	112	113	114
Cement	100	100	100	101	102	103	103	103	106	107	107	108	108	111	113	113	115	115

	6/30 2005	7/31 2005	8/31 2005	9/30 2005	10/31 2005	11/30 2005	12/31 2005	1/31 2006	2/28 2006	3/31 2006	4/30 2006	5/31 2006	6/30 2006	7/31 2006	8/31 2006	9/30 2006	10/31 2006	11/30 2006
Consumer Price Index (CPI-U)	106	106	107	108	108	107	107	108	108	108	109	110	110	110	111	110	110	109
Concrete Products	113	115	116	117	117	119	119	123	124	124	125	126	126	127	127	127	127	128
Steel Mill Products	140	136	132	136	139	143	143	146	146	146	148	150	155	161	162	165	167	161
Copper and Brass Mill Shapes	139	141	143	147	155	162	170	173	181	181	207	251	254	267	261	257	253	245
Aluminum Mill Shapes	112	112	111	112	112	114	115	119	121	124	125	128	130	128	128	127	127	130
Cement	115	120	120	120	120	121	121	128	128	131	132	132	132	133	134	134	134	134

	12/31 2006	1/31 2007	2/28 2007	3/31 2007	4/30 2007	5/31 2007	6/30 2007	7/31 2007	8/31 2007	9/30 2007	10/31 2007	11/30 2007	12/31 2007	1/31 2008	2/29 2008	3/31 2008	4/30 2008
Consumer Price Index (CPI-U)	110	110	110	111	112	113	113	113	113	113	113	114	114	115	115	116	117
Concrete Products	128	130	130	131	131	131	132	132	132	132	132	132	133	132	134	134	136
Steel Mill Products	160	157	159	162	168	170	170	169	164	152	159	159	161	164	166	176	185
Copper and Brass Mill Shapes	245	231	222	223	263	273	267	274	258	250	260	246	238	241	255	272	273
Aluminum Mill Shapes	130	132	133	134	134	134	134	132	132	129	127	128	128	127	128	133	137
Cement	134	138	136	137	140	140	139	139	139	141	140	140	140	141	141	141	140

Power Supply Goods Pricing Survey (2004-2008)

Item	Stock Code	Description	2004 (avg cost)	2005 (avg cost)	% Increase (2004-2005)	2006 (avg cost)	% Increase (2005-2006)	2007 (avg cost)	% Increase (2006-2007)	% INCREASE (2004 to 2007)	Comments
1	161281	GAUGE, PRESSURE, 2-1/2", 0-100#,	$29.37	$30.74	4.66%	$31.50	2.47%	$33.82	7.37%	15.2%	
2	208207	PLATE, SIZE: 1/4" X 4'0" X 8'0".	$419.00	$419.00	0.00%	$598.93	42.94%	$595.42	-0.59%	42.1%	No purchases in 2005, used 2004 costing.
3	220608	CONE, SPRING, #4	$17.00	$19.00	11.76%	$21.44	12.84%	$28.06	30.88%	65.1%	No purchases YTD 2008, used 2007 costing
4	222323	GASKET, COMPRESSED, SHEET, SIZE: 1/16"	$203.22	$203.22	0.00%	$203.22	0.00%	$206.00	1.37%	1.4%	
5	222349	GASKET, COMPRESSED, SHEET, SIZE: 3/32"	$215.64	$215.77	0.06%	$215.64	-0.06%	$228.00	5.73%	5.7%	
6	223909	ROCBOARD, PARTEK, 2 X 24 X 48", 8"	$78.00	$81.44	4.41%	$91.75	12.66%	$99.76	8.73%	27.9%	
7	223966	VI-CRYL, MASTIC COATING, BLACK, 5 GAL,	$65.60	$67.27	2.55%	$68.94	2.48%	$72.35	4.95%	10.3%	
8	223982	ECONOCAST 27 (FORMELY LR CAST 27)	$29.17	$35.85	22.90%	$35.30	-1.53%	$37.00	4.82%	26.8%	
9	224022	INSULATION, KAOWOOL, 2", 4# DENSITY,	$186.11	$222.48	19.54%	$239.78	7.78%	$246.37	2.75%	32.4%	
10	224527	CLOTH, FIBERGLASS, BLACK	$605.81	$654.13	7.98%	$654.59	0.07%	$660.01	0.83%	8.9%	
11	224543	BLANKET, STANDARD INSULATING, 30" METEX,	$332.87	$320.67	-3.67%	$336.02	4.79%	$390.87	16.32%	17.4%	
12	224709	PIPE, CARBON STEEL, 1", SCH. 80	$2.91	$3.64	25.09%	$5.21	43.13%	$5.43	4.22%	86.6%	
13	224881	PIPE, CARBON STEEL, 1", SCH. 160	$5.41	$6.60	22.00%	$16.37	148.03%	$16.37	0.00%	202.6%	
14	226167	ELBOW, SOCKET WELD, 90 DEG., SIZE: 3/4"	$2.38	$2.66	11.76%	$3.29	23.68%	$5.08	54.41%	113.4%	No purchases YTD 2008, used 2007 costing
15	226241	ELBOW, SOCKET WELD, 90 DEG., SIZE: 2"	$10.66	$11.09	4.03%	$13.38	20.65%	$15.12	13.00%	41.8%	
16	226365	TEE, SOCKET WELD, 3000#, SIZE: 2"	$15.73	$15.18	-3.50%	$20.29	33.66%	$20.91	3.06%	32.9%	
17	231522	PIPE, GALV, SCH40, 1-1/2", SEAMLESS, 21	$4.27	$6.82	59.72%	$7.59	11.29%	$7.99	5.27%	87.1%	
18	243683	TUBING, 3/8 O.D. X .049, TYPE 316,	$2.23	$2.26	1.35%	$2.83	25.22%	$3.41	20.49%	52.9%	
19	243725	TUBING, 1/2" O.D. X .065, TYPE 316,	$4.19	$3.79	-9.55%	$4.43	16.89%	$5.09	14.90%	21.5%	
20	245209	ELBOW, MALE, 3/8" TUBE, SS-600-2-4	$11.69	$12.26	4.88%	$13.30	8.48%	$13.45	1.13%	15.1%	
21	246181	CONNECTOR, MALE, 1/2", SS-810-1-6,	$10.17	$10.74	5.60%	$11.63	8.29%	$11.73	0.86%	15.3%	
22	246363	UNION, TUBE, HEX, 1/4", SS-400-6	$7.60	$7.98	5.00%	$8.65	8.40%	$8.75	1.16%	15.1%	
23	246389	UNION, TUBE, HEX, 1/2", SS-810-6	$16.25	$17.54	7.94%	$18.53	5.64%	$18.62	0.49%	14.6%	
24	247742	GAS, COMPRESSED, CARBON DIOXIDE CO2	$27.14	$27.12	-0.07%	$30.55	12.65%	$32.56	6.58%	20.0%	
25	259487	BRUSH, GENERATOR SHAFT	$507.00	$525.00	3.55%	$611.45	16.47%	$690.00	12.85%	36.1%	
26	262262	CONDULET, LB TYPE, SIZE: 1-1/2", IRON	$24.13	$25.60	6.09%	$27.89	8.95%	$30.97	11.04%	28.3%	
27	262263	CONDULET, LB TYPE, SIZE: 2", IRON ALLOY,	$37.46	$40.38	7.79%	$46.47	15.08%	$51.11	9.98%	36.4%	
28	263007	CHANNEL, GALVANIZED, 3-1/4" X 1-5/8"	$4.67	$5.67	21.41%	$5.94	4.76%	$5.94	0.00%	27.2%	
29	264846	OIL, TURBINE, CHEVRON, GST OIL ISO32, 55-GAL DRUM	$6.27	$6.50	3.67%	$7.78	19.69%	$8.64	11.05%	37.8%	
30	265702	SHEET, OIL SORBENT, GRADE 200	$40.00	$40.01	0.02%	$44.55	11.35%	$44.45	-0.22%	11.1%	
31	268301	CLEANER, CHEMICAL, VERSOL 2665	$561.00	$616.00	9.80%	$751.38	21.98%	$737.00	-1.91%	31.4%	
32	268466	BORON NITRITE, POWDER, 100 LB DRUM	$492.99	$524.05	6.30%	$567.71	8.33%	$604.60	6.50%	22.6%	
33	268664	AMMONIA, AQUA-26 DEG. BE, 55 GAL DRUM	$340.52	$340.52	0.00%	$398.82	17.12%	$435.75	9.26%	28.0%	
34	270785	VALVE, REGULATING, W/GRAFOIL PACKING.	$161.40	$169.50	5.02%	$172.66	1.86%	$182.45	5.67%	13.0%	
35	272880	VALVE, GLOBE, 1/2", 800#, 5500W, 910 DEG	$48.00	$48.00	0.00%	$60.61	26.27%	$63.93	5.48%	33.2%	No purchases in 2005, used 2004 costing.
36	272948	VALVE, GLOBE, 3/4", 800#, 5500W,	$53.86	$58.10	7.87%	$61.39	5.66%	$62.60	1.97%	16.2%	
37	273169	VALVE, GLOBE, 1", 1500#, 7130W,	$467.50	$492.00	5.24%	$512.00	4.07%	$532.00	3.91%	13.8%	
38	273409	VALVE, GLOBE, 2", 1500#, 7130W,	$1,210.00	$1,281.00	5.87%	$1,332.00	3.98%	$1,332.00	0.00%	10.1%	
39	273920	VALVE, GATE, BRONZE, 2", 200# WOG	$44.41	$47.95	7.97%	$55.26	15.25%	$57.70	4.42%	29.9%	
40	297200	TUBE, BOILER, CARBON STEEL	$5.50	$7.10	29.09%	$9.30	30.99%	$10.40	11.83%	89.1%	
41	303883	TUBE, LANCE, ASSEMBLY, (K1&2) 25'2" LONG	$2,330.00	$2,672.50	14.70%	$2,741.00	2.56%	$2,853.00	4.09%	22.4%	
42	308908	VALVE, MOTOR CONTROL, COMPLETE, AC-040-P	$373.65	$389.16	4.15%	$408.62	5.00%	$435.18	6.50%	16.5%	
43	332841	GASKET, COVER TO BARREL, REF.#744	$973.50	$973.50	0.00%	$1,084.40	11.39%	$1,239.00	14.26%	27.3%	No purchases in 2004, used 2005 costing.
44	333062	SLEEVE, TAKEOFF, REF.#621	$1,750.50	$2,049.75	17.10%	$2,219.50	8.28%	$2,469.00	11.24%	41.0%	
45	364786	BACK PLATE FOR ATOMIZER	$304.00	$372.00	22.37%	$372.00	0.00%	$389.00	4.57%	28.0%	
46	611137	COOLANT, ULTRA, FOR INGERSOLL RAND	$245.00	$273.52	11.64%	$287.11	4.97%	$290.91	1.32%	18.7%	
47	613893	DRUM, OPEN TOP, METAL, SIZE: 55 GALLON	$71.80	$70.50	-1.81%	$77.93	10.54%	$80.22	2.94%	11.7%	
48	614619	GAS, COMPRESSED, HYDROGEN, 18 CYLINDERS PER RACK	$945.24	$937.51	-0.82%	$990.42	5.64%	$1,036.79	4.68%	9.7%	
49	618678	TESTER, DISSOLVED, 02	$34.66	$40.50	16.85%	$41.29	1.95%	$66.00	59.84%	90.4%	
50	624197	HUB, INSULATED, WEATHER TYPE, 1"	$4.10	$4.66	13.66%	$5.20	11.59%	$5.01	-3.65%	22.2%	
		Average price increase (%)			**8.4%**		**14.5%**		**8.1%**	**34.5%**	

Note: Data obtained from HECO Ellipse system, actual purchase prices averaged over each year.

Confidential Information Deleted
Pursuant To Protective Order, Filed on ____________

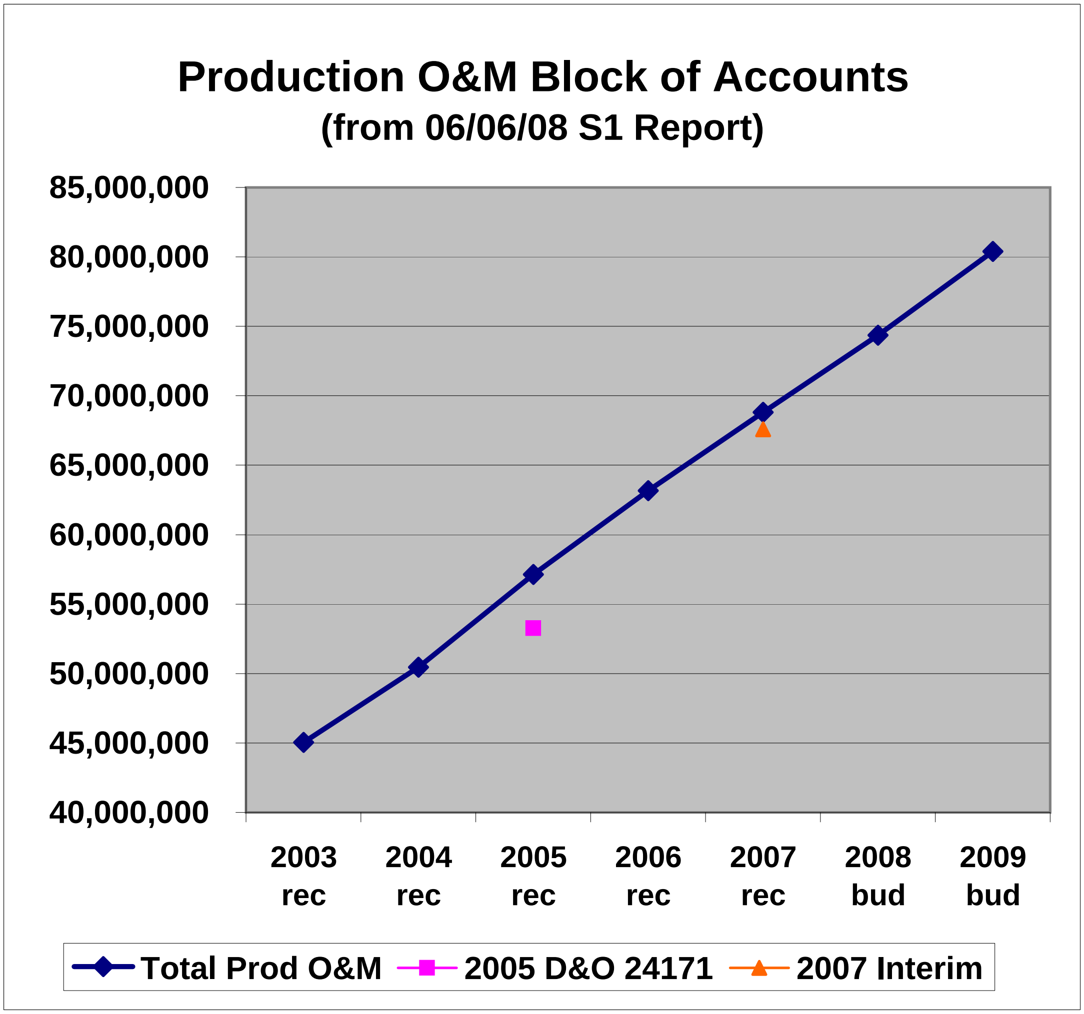
Power Supply Contractor Consultant Services Rates Survey (2004-2007)

Type of Services	Company	Labor Type	2004 Rate	2005 Rate	% Increase (2004-05)	2006 Rate	% Increase (2005-06)	2007 Rate	% Increase (2006-07)	2008 Rate	% Increase (2007-08)	% Increase (2004-2007)	Comments
Generator Maintenance	[redacted]	Engineering Consultant	$ 175.00	$ 190.00	9%	$ 200.00	5%	n/a	n/a	$ 230.00	15%	31%	Compared 2006 to 2008 (no data for 2007)
		Generator Specialist	$ 150.00	$ 160.00	7%	$ 170.00	6%	n/a	n/a	$ 285.00	68%	90%	Compared 2006 to 2008 (no data for 2007)
		Generator Lead Winder	$ 110.00	$ 116.00	5%	$ 125.00	8%	n/a	n/a	$ 136.00	9%	24%	Compared 2006 to 2008 (no data for 2007)
		Generator Winder	$ 90.00	$ 96.00	7%	$ 100.00	4%	n/a	n/a	$ 110.00	10%	22%	Compared 2006 to 2008 (no data for 2007)
		Shop Preparation	$ 50.00	$ 50.00	0%	$ 50.00	0%	n/a	n/a	$ 60.00	20%	20%	Compared 2006 to 2008 (no data for 2007)
Electrician Labor	[redacted]	General Foreman	$ 99.00	$ 103.00	4%	$ 109.00	6%	$ 111.00	2%	$132.00	19%	33%	Data from 2004 to current
		Foreman	$ 92.00	$ 97.00	5%	$ 104.00	7%	$ 106.00	2%	$126.00	19%	37%	Data from 2004 to current
		Cable Splicer	$ 90.00	$ 97.00	8%	$ 103.00	6%	$ 105.00	2%	$124.00	18%	38%	Data from 2004 to current
		Lead-Off Mechanic	$ 86.00	$ 92.00	7%	$ 99.00	8%	$ 101.00	2%	$120.00	19%	40%	Data from 2004 to current
		Journeyman	$ 82.00	$ 89.00	9%	$ 96.00	8%	$ 98.00	2%	$116.00	18%	41%	Data from 2004 to current
General Labor	[redacted]	Marine Superintendent	$ 58.00	$ 58.00	0%	n/a	n/a	$ 59.00	n/a	$67.00	14%	16%	Data from 2004 to current, except for 2006
		Marine Leadman	$ 41.50	$ 41.50	0%	n/a	n/a	$ 42.50	n/a	$42.50	0%	2%	2007 = 2008. No increase from 2007
		Marine Driver/Operator	$ 39.00	$ 39.00	0%	n/a	n/a	$ 40.00	n/a	$40.00	0%	3%	2007 = 2008. No increase from 2007
		Marine Technician	$ 36.00	$ 36.00	0%	n/a	n/a	$ 37.00	n/a	$37.00	0%	3%	2007 = 2008. No increase from 2007
		Marine Laborer	$ 30.00	$ 30.00	0%	n/a	n/a	$ 31.00	n/a	$31.00	0%	3%	2007 = 2008. No increase from 2007
		Envir. Superintendent	$ 49.50	$ 49.50	0%	n/a	n/a	$ 50.50	n/a	$50.50	0%	2%	2007 = 2008. No increase from 2007
		Envir. Safety Officer	$ 44.25	$ 44.25	0%	n/a	n/a	$ 45.25	n/a	$45.25	0%	2%	2007 = 2008. No increase from 2007
		Envir. Leadman	$ 32.00	$ 32.00	0%	n/a	n/a	$ 33.00	n/a	$33.00	0%	3%	2007 = 2008. No increase from 2007
		Envir. Driver/Operator	$ 31.50	$ 31.50	0%	n/a	n/a	$ 32.50	n/a	$32.50	0%	3%	2007 = 2008. No increase from 2007
		Envir. Technician	$ 28.50	$ 28.50	0%	n/a	n/a	$ 29.50	n/a	$29.50	0%	4%	2007 = 2008. No increase from 2007
		Envir. Laborer	$ 26.50	$ 26.50	0%	n/a	n/a	$ 27.50	n/a	$27.50	0%	4%	2007 = 2008. No increase from 2007
Boiler Stack Inspection	[redacted]	Foreman	$ 72.71	n/a	n/a	$ 79.98	n/a	n/a	n/a	n/a	n/a	n/a	n/a
		Top Man	$ 70.36	n/a	n/a	$ 77.39	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Boiler Maint. Labor	[redacted]	Boilermakers	$ 61.39	n/a	n/a	$ 64.34	n/a	n/a	n/a	$72.88	13%	19%	Compared 2006 to 2008 (no data for 2007)
Heat Exch. Consultants	[redacted]	Director of Engineering	$ 190.00	$ 200.00	5%	$ 210.00	5%	$ 210.00	0%	n/a	n/a	n/a	n/a
		Sr. Mechanical Engr	$ 150.00	$ 165.00	10%	$ 175.00	6%	$ 175.00	0%	n/a	n/a	n/a	n/a
		NDE Specialist	$ 135.00	$ 135.00	0%	$ 150.00	11%	$ 150.00	0%	n/a	n/a	n/a	n/a
		Clerical	$ 45.00	$ 45.00	0%	$ 50.00	11%	$ 50.00	0%	$55.00	10%	22%	Data from 2004 to current
Instrument Technicians	[redacted]	Technician Foreman	$ 63.00	$ 71.50	13%	$ 81.50	14%	$ 81.50	0%	$81.50	0%	29%	2007 = 2008. No increase from 2007
		Technician Journeyman	$ 60.00	$ 66.00	10%	$ 76.00	15%	$ 76.00	0%	$76.00	0%	27%	2007 = 2008. No increase from 2007
		Technician Helper	$ 53.00	$ 58.00	9%	$ 61.00	5%	$ 61.00	0%	$61.00	0%	15%	2007 = 2008. No increase from 2007
Elect. Engrg. Field Services	[redacted]	Lead Field Engineer	n/a	$ 180.00	n/a	$ 185.00	3%	$ 191.00	3%	n/a	n/a	n/a	n/a
		Contract Field Engineer	n/a	$ 169.00	n/a	$ 174.00	3%	$ 179.00	3%	n/a	n/a	n/a	n/a
		Specialist Field Engineer	n/a	$ 203.00	n/a	$ 209.00	3%	$ 215.00	3%	n/a	n/a	n/a	n/a
Insulation Labor	[redacted]	Foreman	$ 38.11	$ 47.50	25%	$ 47.50	0%	$ 50.00	5%	$50.00	0%	31%	2007 = 2008. No increase from 2007
		Worker	$ 27.48	$ 35.80	30%	$ 35.80	0%	$ 38.00	6%	$38.00	0%	38%	2007 = 2008. No increase from 2007
	Straight Average % Increase (avail %)				**5%**		**6%**		**2%**		**9%**	**22%**	

Notes:
(1) All rates are straight-time rates, unless otherwise noted.
(2) Companies listed above represent some of the contractors and consultants commonly used by HECO Power Supply.

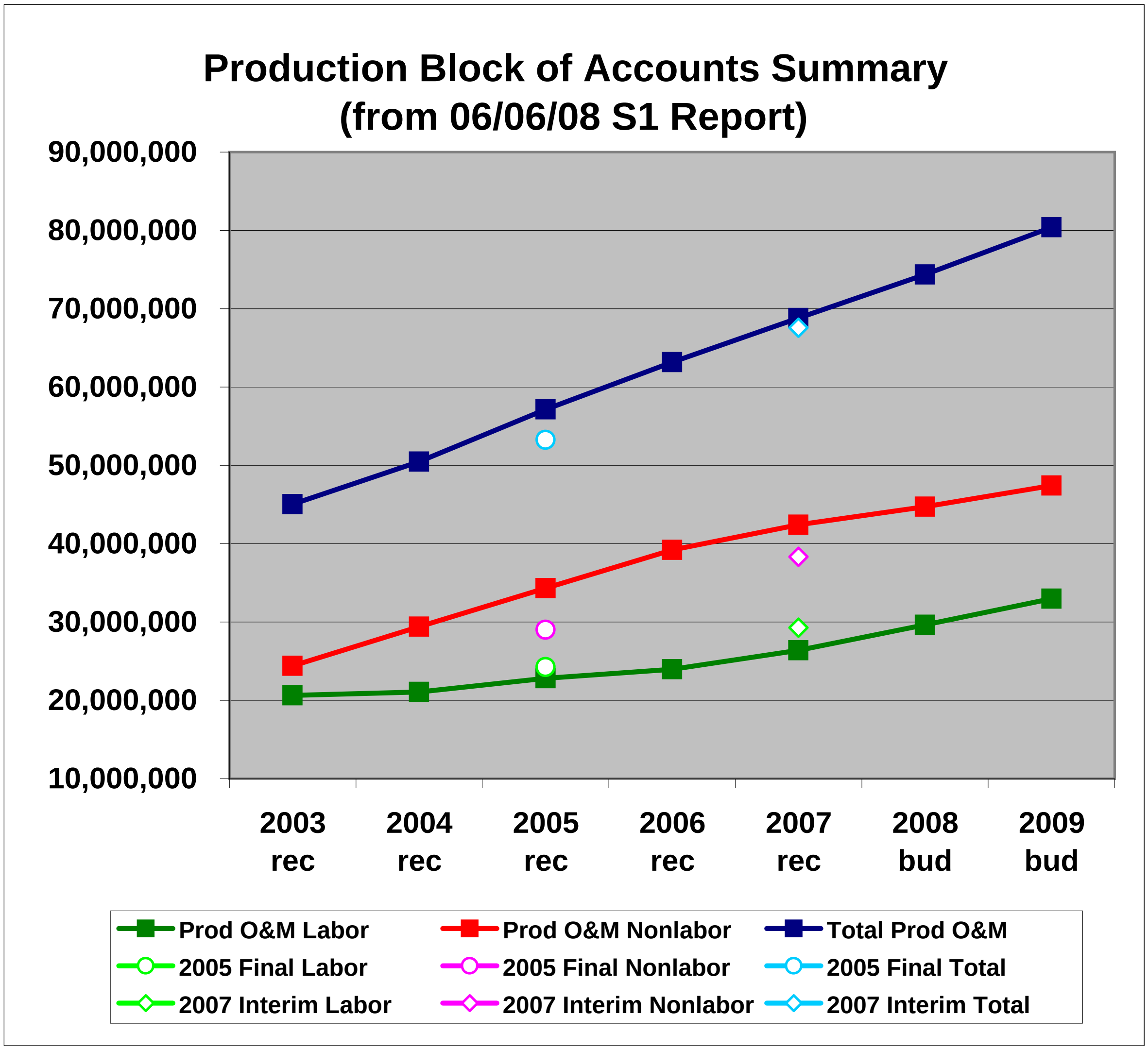
Hawaiian Electric Company, Inc.
2009 Test Year
Production Operations & Maintenance Block of Accounts Summary

	2003 rec	2004 rec	2005 rec	2006 rec	2007 rec	2008 bud	2009 bud
Total Prod O&M	45,052,229	50,456,766	57,128,521	63,168,373	68,807,023	74,367,296	80,387,231
2005 D&O 24171			53,269,000				
2007 Interim					67,597,000		
Delta		5,404,536	6,671,755	6,039,852	5,638,651	5,560,273	6,019,935



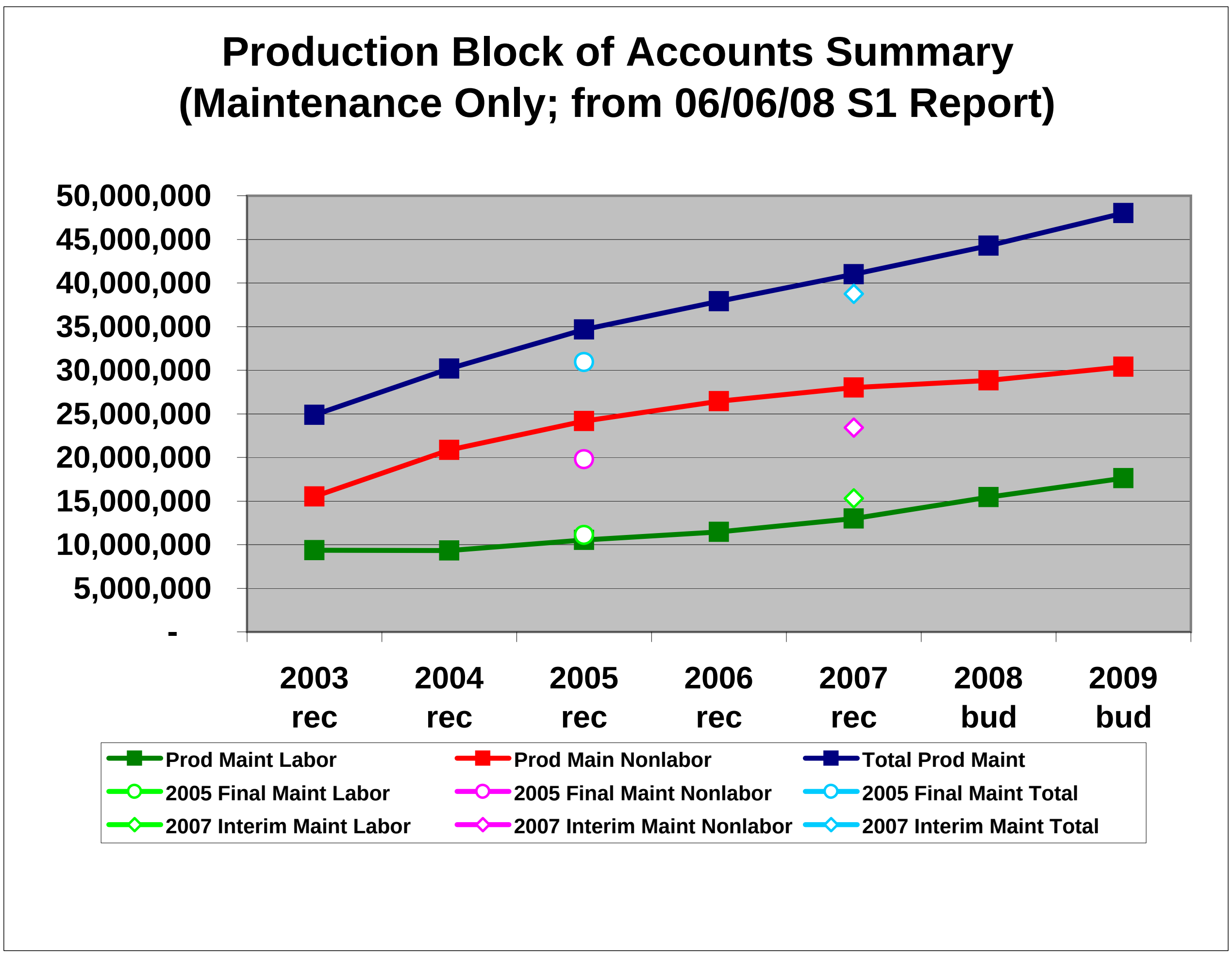
Hawaiian Electric Company, Inc.
2009 Test Year
Production Operations & Maintenance Block of Accounts Summary
Labor & Non-Labor

	2003 rec	2004 rec	2005 rec	2006 rec	2007 rec	2008 bud	2009 bud
Prod O&M Labor	20,631,097	21,071,401	22,822,772	23,973,151	26,373,151	29,637,239	32,983,313
Prod O&M Nonlabor	24,421,132	29,385,364	34,305,749	39,195,222	42,433,872	44,730,057	47,403,918
Total Prod O&M	45,052,229	50,456,766	57,128,521	63,168,373	68,807,023	74,367,296	80,387,231
2005 Final Labor			24,243,000				
2005 Final Nonlabor			29,026,000				
2005 Final Total			53,269,000				
2007 Interim Labor					29,267,000		
2007 Interim Nonlabor					38,330,000		
2007 Interim Total					67,597,000		



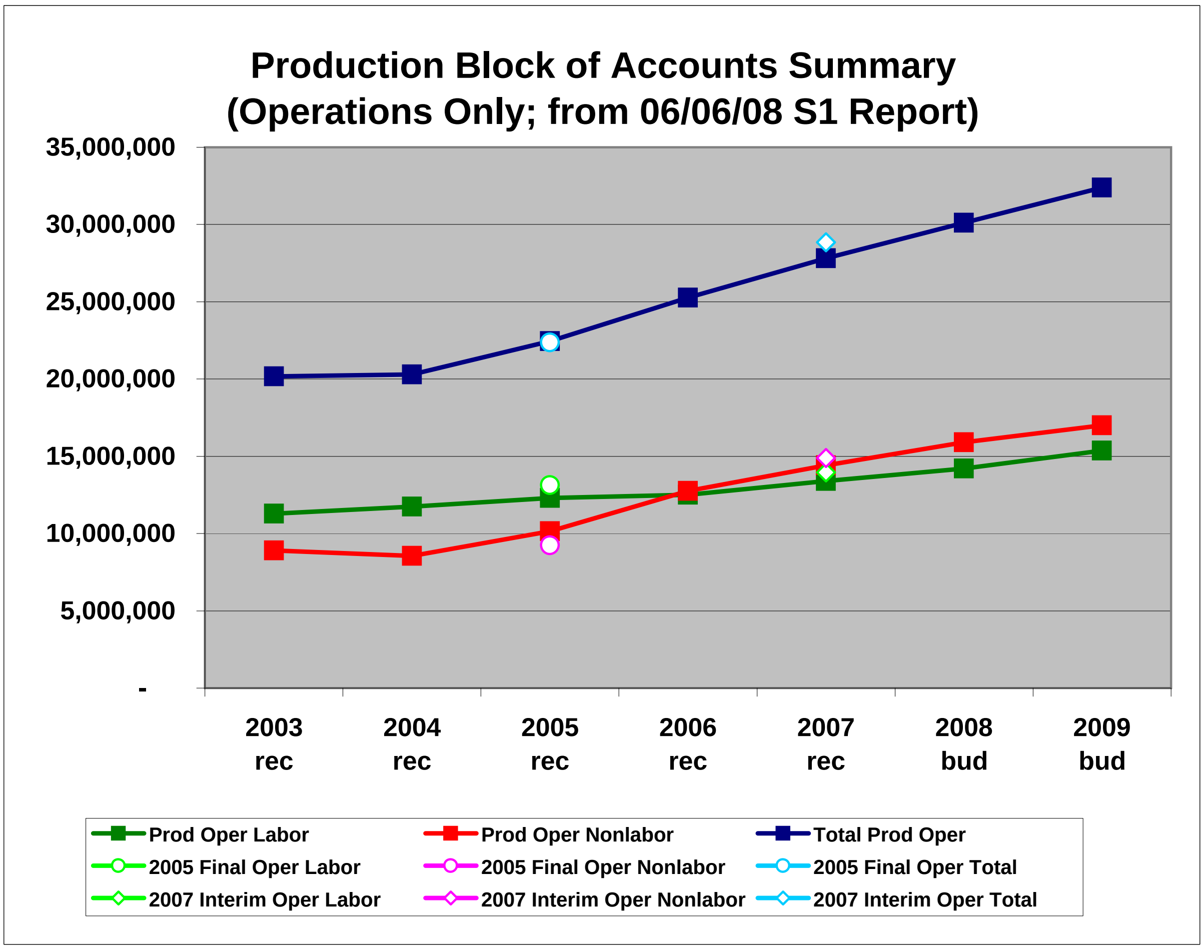
Hawaiian Electric Company, Inc.
2009 Test Year
Production Operations & Maintenance Block of Accounts Summary
Maintenance Only

	2003 rec	2004 rec	2005 rec	2006 rec	2007 rec	2008 bud	2009 bud
Prod Maint Labor	9,353,292	9,329,252	10,519,104	11,473,794	12,979,073	15,438,451	17,610,359
Prod Main Nonlabor	15,525,712	20,841,197	24,151,421	26,430,729	28,020,949	28,825,501	30,392,481
Total Prod Maint	24,879,004	30,170,449	34,670,524	37,904,523	41,000,022	44,263,952	48,002,840
2005 Final Maint Labor			11,115,000				
2005 Final Maint Nonlabor			19,797,000				
2005 Final Maint Total			30,912,000				
2007 Interim Maint Labor					15,308,000		
2007 Interim Maint Nonlabor					23,430,000		
2007 Interim Maint Total					38,738,000		



Hawaiian Electric Company, Inc.
2009 Test Year
Production Operations & Maintenance Block of Accounts Summary
Operations Only

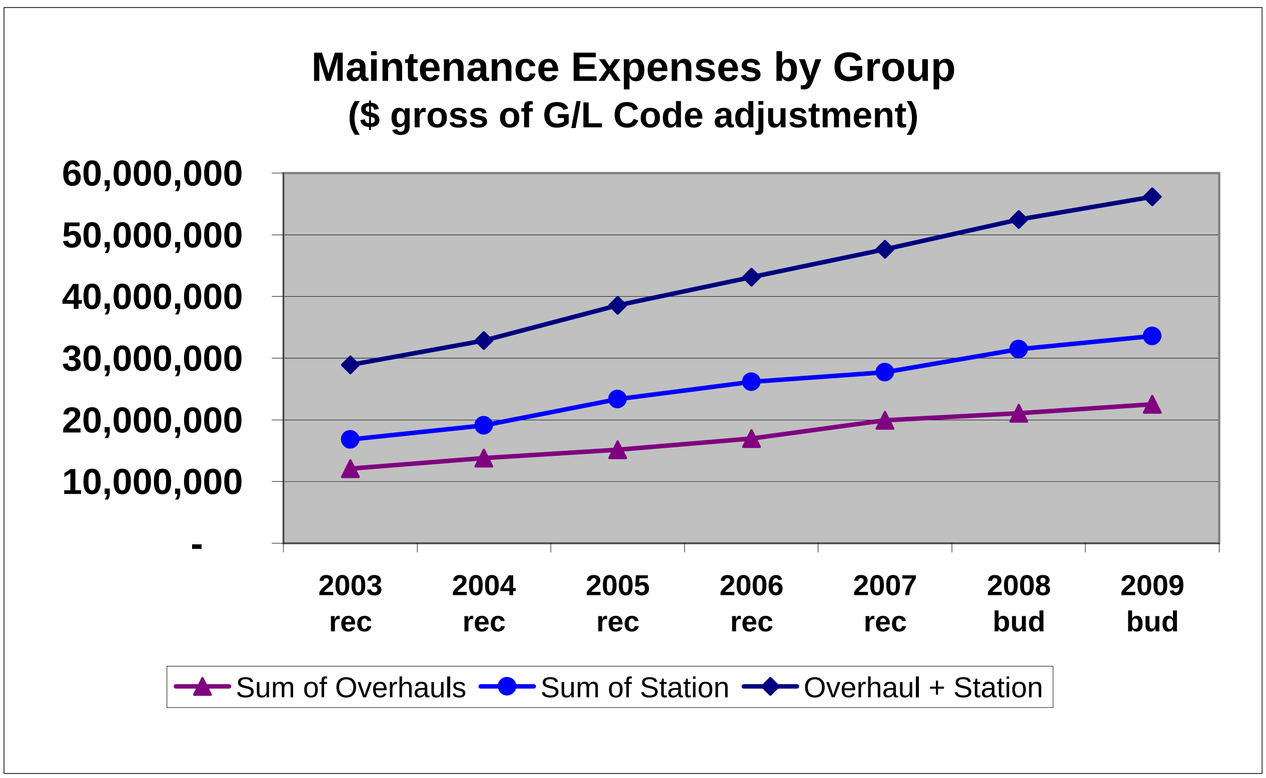
	2003 rec	2004 rec	2005 rec	2006 rec	2007 rec	2008 bud	2009 bud
Prod Oper Labor	11,277,806	11,742,149	12,303,668	12,499,357	13,394,078	14,198,789	15,372,954
Prod Oper Nonlabor	8,895,419	8,544,168	10,154,328	12,764,493	14,412,923	15,904,556	17,011,437
Total Prod Oper	20,173,225	20,286,317	22,457,996	25,263,849	27,807,001	30,103,344	32,384,391
2005 Final Oper Labor			13,128,000				
2005 Final Oper Nonlabor			9,229,000				
2005 Final Oper Total			22,357,000				
2007 Interim Oper Labor					13,959,000		
2007 Interim Oper Nonlabor					14,900,000		
2007 Interim Oper Total					28,859,000		



Hawaiian Electric Company, Inc.
2009 Test Year
Production Operations & Maintenance Block of Accounts Summary
Overhaul vs. Station Maintenance Expense

Category	2003 rec	2004 rec	2005 rec	2006 rec	2007 rec	2008 bud	2009 bud
Cycling Unit Overhauls	8,622,435	3,890,848	2,581,823	5,593,776	2,770,098	11,991,969	2,824,691
Reheat 90 Overhauls	3,104,874	4,691,231	5,489,297	6,689,281	17,201,911	4,712,739	10,432,956
Reheat 140 Overhauls	368,394	4,222,084	3,639,176	18,882	(32,971)	4,359,691	6,820,148
Combustion Turbine	-	981,918	3,458,956	4,695,909	3,067	-	2,467,721
Sum of Overhauls	**12,095,703**	**13,786,081**	**15,169,252**	**16,997,848**	**19,942,105**	**21,064,400**	**22,545,516**
% Increase		**14.0%**	**10.0%**	**12.1%**	**17.3%**	**5.6%**	**7.0%**
Other Project	35,314	51,492	715,719	1,773,780	1,459,412	5,226,193	5,120,588
All Other Maint Exp	16,789,240	19,038,027	22,663,363	24,362,270	26,262,605	26,201,694	28,479,625
Sum of Station	**16,824,554**	**19,089,519**	**23,379,082**	**26,136,050**	**27,722,017**	**31,427,887**	**33,600,213**
% Increase		**13.5%**	**22.5%**	**11.8%**	**6.1%**	**13.4%**	**6.9%**
Overhaul + Station	**28,920,257**	**32,875,600**	**38,548,334**	**43,133,898**	**47,664,122**	**52,492,287**	**56,145,729**
% Increase		**13.7%**	**17.3%**	**11.9%**	**10.5%**	**10.1%**	**7.0%**
G/L Code Adjustment	(4,041,253)	(2,705,151)	(3,877,810)	(5,229,375)	(6,664,100)	(8,228,335)	(8,142,889)
TOTAL	**24,879,004**	**30,170,449**	**34,670,525**	**37,904,523**	**41,000,022**	**44,263,952**	**48,002,840**

Note: "% Increase" = [(year/previous year)-1] X 100



HECO T-8
DOCKET NO. 2008-0083

TESTIMONY OF
ROBERT K. S. Y. YOUNG

MANAGER
SYSTEM OPERATION DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Transmission and Distribution (“T&D”) System
T&D Operation and Maintenance (“O&M”) Expense
T&D Materials Inventory

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert Young and my business address is 820 Ward Avenue, Honolulu, Hawaii.

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

A. I am employed by Hawaiian Electric Company, Inc. ("HECO" or "Company") as the Manager of the System Operation Department in the Energy Delivery Process Area ("EDPA"). HECO-800 provides my educational background and work experience. I have spent over 30 years at HECO in positions involved with the planning and operation of transmission and distribution ("T&D") facilities. These T&D facilities and their proper operation and maintenance are vital to providing reliable service to our customers.

Q. What is your responsibility as a witness in this proceeding?

A. My testimony will cover the following:

1) a brief description of the HECO T&D system;
2) the T&D Operation and Maintenance ("O&M") expense;
3) the reasonableness of the 2009 test year estimate, and
4) T&D materials inventory.

Q. Please summarize the 2009 test year estimate addressed by your testimony.

A. HECO's estimate for T&D O&M expense for the 2009 test year is $44,459,000, as shown in HECO-801. Of this amount, $13,967,000 is for transmission expense and $30,492,000 is for distribution expense, as shown in HECO-802.

Q What is the 2009 test year estimate for the T&D materials inventory?

A. The 2009 test year estimate for T&D materials inventory is an average of $8,211,496 and is further detailed in HECO-803.

DESCRIPTION OF THE HECO T&D SYSTEM

Q. Please describe the HECO T&D system.

A. The HECO T&D system begins at the generating plants where electricity is produced. (Mr. Dan Giovanni describes HECO's generation system in HECO T-7.) Electricity generated at these plants is stepped up in voltage by the generator step-up transformers and sent through transmission lines at a nominal 138,000 volts to transmission substations. At the transmission substations, the power is transformed from 138,000 volts to a nominal 46,000 volts and sent through sub-transmission lines to distribution substations. At the distribution substations, the power is transformed or stepped down to various distribution voltages and sent through the distribution lines to our customers. There are a few transmission substations where the voltage is transformed directly from 138,000 volts to nominal distribution voltages of 11,500 volts or 25,000 volts as further explained on pages 3 and 4 of my testimony. Distribution lines are located either overhead or underground. HECO-804 provides a diagram illustrating HECO's power delivery system.

Q. Please describe HECO'S transmission system in more detail.

A. HECO's transmission system is an interconnected electrical network which links HECO's Kahe, Waiau, and Honolulu generating plants, and the major Independent Power Producers ("IPPs") at Campbell Estate Industrial Park ("CEIP"), to HECO's distribution facilities. The nominal transmission voltage is 138,000 volts, except for the older Honolulu Power Plant, which feeds a 46,000 volt sub-transmission system. There are nineteen transmission substations, one each at Kahe, Waiau and Honolulu generating stations and sixteen other substations located across the island including CEIP, Kalaeloa, AES, Ewa Nui, Wahiawa, Halawa, Koolau, Pukele, Makalapa, Iwilei, School Street, Airport Switching Station, Airport, Archer, Kewalo and Kamoku. These transmission substations house equipment to transform power (transformers), provide switching and protection (switches, breakers, and relays) and collect data (meters and remote terminal units). The remainder of the transmission system consists of 213.6 circuit miles of overhead lines and 8.3 circuit miles of underground lines. HECO-805 provides a diagram of the transmission system.

Q. Please describe in more detail HECO's sub-transmission and distribution system.

A. The nineteen transmission substations provide power to a system of distribution substations through overhead and underground lines that are energized at 46,000 volts. The 46,000 volt lines that carry power to the distribution transformers are referred to as the sub-transmission system. HECO-806 shows the general location of the 46,000-volt sub-transmission lines and distribution substations. HECO's distribution system consists of 125 distribution substations. These distribution substations, and approximately 2,700 circuit miles of overhead and underground lines, connect HECO's electrical system to its customers. At the distribution substations the voltage is transformed from 46,000 volts to lower nominal voltages (12,470 volts, 11,500 volts, and 4,160 volts) and power is sent through overhead and underground lines to HECO's customers or to distribution transformers that lower the voltages further. The distribution transformers further reduce the voltage to 120, 208, or 480 volts and power is fed through service lines to customers. There are 268 distribution substation transformers and approximately 32,720 distribution transformers. In addition, four of the nineteen transmission substations directly serve the distribution system.

Q. Please describe how the four transmission substations directly serve the distribution system.

A. The Iwilei, Kewalo and Kamoku transmission substations transform voltage from 138,000 volts to a distribution voltage of 25,000 volts and send this power through underground lines directly to distribution transformers to the customer's property. Transforming the voltage at the transmission substation eliminates the need for distribution substations and associated land acquisitions and, at this higher distribution voltage, reduces the number of lines required to serve an area. This system works well in areas of high load concentrations where available land is scarce and is currently being developed; such as the Ala Moana, Kakaako and Kapiolani areas in Honolulu. The Iwilei substation also serves the downtown network and transforms the 138,000 volts directly to a distribution voltage of 11,500 volts. At the Airport Substation voltage is also transformed from 138,000 volt to 11,500 volts to serve the loads in the airport area.

Q. What other equipment are used by HECO in the delivery of power to the customer?

A. Other pieces of equipment that are used by HECO to deliver power to the customer include protective relays, circuit breakers, switches, mobile radios, microwave and fiber optic communication systems, remote terminal units ("RTUs"), switch vaults, wood poles, wood and steel structures, and line reclosers[1]. Each piece of equipment has an important function in the overall process of delivering power to the customer and it is important that the equipment is maintained on a periodic basis to ensure proper performance. With each new system addition there will be more equipment to maintain which results in higher maintenance spending. An indication of how much the system has grown is the utility plant in service (see

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[1] This list is not meant to be all inclusive but provides a sampling of the variety of equipment and components of the electrical system that require maintenance.

HECO-817) that has been consistently increasing during the period from 2003 to 2007 and is projected to increase in 2008 and 2009.

<u>Maintaining Reliable Service With An Aging Infrastructure</u>

Q. Please provide an overview of the age of HECO's transmission and distribution infrastructure

A. HECO-813 provides information on the increasing age of HECO's 138,000 volt ("138 kV") overhead transmission circuits. The last major addition to the 138 kV overhead transmission system was in 1995 with the completion of the Waiau to Ewa Nui lines. As shown in HECO-813, the average age of the overhead lines increases each year, with a 2009 estimated average of 38.1 years. In addition, of the 213.6 overhead circuit miles, approximately 78% (167 miles) will be 30 years old or older.

HECO-814 provides information on the age of HECO's 138 kV underground transmission circuits. The system is relatively new with an estimated 2009 average age of 14.7 years.

Q. How else has HECO's T&D plant aged?

A. HECO-815 provides information on the increasing age of HECO's 138 kV transmission transformers. As shown in HECO-815, the 2009 estimated average age of the 138 kV transmission transformers is 32.5 years. In addition, as shown on HECO-815, of the 47 transmission transformers, 66% (31) will be 30 years old or older in 2009. HECO-816 provides information on the increasing age of HECO's distribution substation transformers. As shown, the average age of the distribution substation transformers is forecasted to be 31.7 years in 2009. In addition, of the 271 distribution transformers, 58% (156) are estimated to be 30 years or older in 2009.

Q. Has HECO been able to provide reliable service even though its transmission and distribution assets are aging?

A. Yes. As shown in exhibit HECO-818 to HECO-820, despite the aging of the T&D infrastructure HECO has been able to maintain a fairly level performance in reliability. In one measure, SAIF, shown in exhibit HECO-818 the number of outages experienced by a customer has decreased over time.

Q. How does HECO track overall T&D system reliability?

A. HECO utilizes several indices that are standard within the utility industry to measure overall reliability. The primary indices include the following:

- System Average Interruption Frequency ("SAIF") as shown on HECO-818;
- Customer Average Interruption Duration ("CAID") as shown on HECO-819;
- System Average Interruption Duration ("SAID") as shown on HECO-820; and
- Average Service Availability ("ASA") as shown on HECO-821.

See HECO-822 for an explanation of these indicators.

Q. Given the age of HECO's T&D system, how does HECO's reliability compare to past years' trends?

A. With the exception of HECO's SAIF performance in 2001 and 2003, over the past eight-year period, HECO's reliability has resulted in SAIF measurements ranging from 1.15 to 1.44. HECO's ASA has remained consistently at or above 99.97%.

Q. What were the circumstances that resulted in HECO's higher SAIF measurements reflecting a decrease in reliability for the years 2001 and 2003? (SAIF results of 1.76 and 1.65, respectively.)

A. In 2001 during the winter months, increases in the following outage cause categories - high winds, trees or branches, lightning and unknown failures - were the primary contributors to HECO's SAIF performance falling outside of HECO's normal range.

In 2003, an increase in outages due to equipment deterioration was the primary contributor to HECO's higher SAIF results. The equipment that failed and caused the outage was replaced so that power could be restored to HECO's customers. Included in this category of outages is deterioration of wood poles and this is being addressed through program initiatives for wood poles.

Q. How has HECO been able to maintain reliability within a consistent range of SAIF during six of the past eight years?

A. HECO has been able to achieve high reliability results by making a commitment to reliability. This commitment to reliability can be measured by the expenditures that it has placed into its O&M expense budget. HECO-823 provides a graphical comparison of HECO's O&M expenditures and the number of outages that were experienced (reflected by the SAIF indicator). This graph indicates that the increased O&M expenditures over time are correlated with HECO's ability to reduce the number of outage occurrences. HECO intends to sustain this level of spending in the 2009 test year that is commensurate with the level of inspection and maintenance needed to provide reliable service.

Q. What has been the trend in T&D O&M expenses?

A. To ensure that the equipment functions properly so that power can be delivered reliably to HECO's customers maintenance activities had to be increased to take care of this aging infrastructure. Exhibit HECO-807 shows that generally the trend in the T&D O&M expenses has been gradually increasing to meet the system maintenance demands.

Q. Are there certain underlying factors that contribute to increasing T&D O&M expense?

A. There are four factors that in general contribute to higher overall T&D O&M expense: 1) there is more of the system to maintain as the system grows to serve new businesses and residential customers; 2) the system is aging and with the onset of aging, more work is necessary to ensure that the electrical system equipment and structures are capable of operating as they should; 3) reliability is important and HECO must respond to mitigate outages and when outages do occur HECO must respond quickly to restore power and 4) it costs more today for the equipment, materials and services necessary to maintain the system as evidenced by the impact of the recent increase in price for many goods due the rising costs of copper and petroleum. These factors as they apply to various categories of increased O&M expenses are discussed in more detail later in my testimony.

Q. Have there been times when the Company has had to balance the need to maintain a reliable system against financial constraints?

A. Yes. HECO has had to manage its O&M expenses, when its revenues are not sufficient to cover all of its costs (including the return on investment). There are times when HECO has to deliberately constrain spending, to the extent that it can do so without compromising reliability. However, such constraints in the level of spending can not continue for an indefinite period of time without eventually affecting reliability.

Integration of Power From Renewable Energy

Q. How will sources of renewable energy from independent power producers affect the T&D system?

A. In light of the State's goal to become less dependent on fossil fuels and to use more renewable energy, HECO will see increasing interest from renewable energy producers to interconnect their energy sources to the HECO grid. In fact, this is already happening as noted in the testimony of Mr. Dan Giovanni, HECO T-7. As HECO works toward meeting the State's goal, more new generation will come from alternate energy sources in different locations around the island of Oahu or potentially from off-shore sources including the neighbor islands. These alternate energy developers will be interconnected to the HECO's power grid through its transmission system so that the bulk power from the different sources in various locations around the island can be distributed to customers throughout the island. To integrate power from renewable sources into HECO's grid, it will be important for the T&D system to be reliable and designed with sufficient capacity to meet the bulk power export needs of the renewable energy developers. Transmission system additions or modifications may be necessary based on analyses that are done to determine what is required to interconnect the renewable resources to the HECO grid. These studies are important to evaluate the system capacity and reliability and will be essential to ensuring that the electric system can accept the available power from the renewable sources and transmit it to the customers across the island of Oahu. Later in my testimony, I discuss the interconnection requirements study for the Oahu Renewable Energy Request For Proposals ("RFP").

2009 TEST YEAR ESTIMATES

Q. Please summarize the 2009 test year estimate of T&D O&M expense.

A. HECO's estimate of T&D O&M expense for the 2009 test year is $44,459,000 as shown in HECO-801. Of this amount, $13,967,000 is for transmission expense and $30,492,000 is for distribution expense, as shown in HECO-802.

Q. Did HECO make any adjustments to its 2009 T&D O&M expense budget to develop its 2009 test year estimate?

A. Yes, adjustments to the 2009 T&D O&M expense budget are summarized in HECO-802 and detailed in HECO-WP-810. These adjustments have been incorporated into the 2009 test year estimates represented in the T&D O&M expense exhibits, as referenced in this testimony.

The adjustments that were made to the 2009 O&M budget are as follows:

- Transmission O&M expense was reduced by $58,000. The $58,000 reduction is the net of the removal of $59,000 for performance incentive plan expenses and $8,000 for restricted stock awards and the addition of $9,000 of abandoned project expenses.
- Distribution O&M expense was reduced by a net of $19,000. The $19,000 downward adjustment resulted from the removal of $143,000 of performance incentive plan expenses and an adjustment for the addition of $124,000 in abandoned project expenses.

A discussion of these rate case adjustments is provided by Ms. Patsy Nanbu in HECO T-11.

Budget Process

Q. How were the 2009 Budget T&D O&M expenses derived?

A. The 2009 Budget T&D O&M expenses were developed by multiple entities within the Company who charge to the T&D O&M accounts. However, the majority of charges are incurred and budgeted by the Energy Delivery Process Area. The Energy Delivery Process Area is composed of the following departments:

- Construction and Maintenance ("C&M"): Primarily responsible for the overhead and underground systems, including poles structures, overhead and underground lines.
- System Operation ("SOD"): In general, this department is responsible for the substations and all the equipment in the substations (including breakers, relays, and remote terminal units and other measurement devices), the communication system, and operations (that includes the dispatch center, the dispatchers, the Energy Management and Outage Management Systems and the mapping functions),
- Support Services ("Supp Svc"): This department generally is responsible for the vehicle fleet, purchasing (services and materials), inventory material, electrical and welding work.
- Engineering ("Eng"): This department is responsible for distribution planning, T&D engineering, civil structural engineering, Technical Services and Standards and project management.

Q. Did each department within the Energy Delivery Process Area develop its own budget for 2009?

A. Yes, each department within the Energy Delivery Process Area developed its own budget and, within each department, each responsibility area ("RA")[2] determined

[2] A responsibility area is a division or a section within a division of a department. For example, in SOD there is the Operating Engineering Division that has a Mapping Section and an Operating Engineering Section that supports the energy management system and outage management system.

the O&M work it requires to maintain and operate the system to provide reliable electric service to HECO's customers. (A responsibility area is a division or a section within a division of a department.) The level of work is based on a combination of the original equipment manufacturer's recommended maintenance cycles, inspections, number of units, units of work, historical trends, and is budgeted by staff with working knowledge of the maintenance requirements for HECO's facilities and the operation of the electric system. Starting with the estimate of the work planned for the year, the available labor resources (i.e., the staffing level and the associated productive man-hours) were allocated to perform this work for the year. Each RA also forecasted the non-labor costs for materials needed for the work (in the majority of the situations these estimates were based on historical trends) and the costs for additional outside services such as contractors if HECO did not have the resources with the skills needed to do the work or if the available labor resources were insufficient for all the work planned.

Each labor and non-labor budgeted cost by activity is linked to the National Association of Regulatory Commissioners ("NARUC") account numbers. This initial process resulted in the 2009 O&M budget. Using the 2009 O&M budget as a starting point, adjustments were made to develop the 2009 test year estimate of T&D O&M expenses. I described these adjustments earlier in my testimony.

Q. When referring to the O&M work required for maintaining and operating the system, can you provide a description of some of the work that is done by HECO?

A. HECO-832 contains descriptions of the C&M department's programs. The work in the C&M department is organized into programs where a budget is prepared and tracked for a specific work activity, such as vegetation management, wood pole repair and replacement and underground cable replacement among others. The program budgets are developed by either using historical trends, e.g., programs for corrective work which is emergency repair work that may result from storms, motor vehicle accidents, or equipment failures. As a result the budget estimates for these types of activities are based on trends using historical costs as well as the judgment and knowledge that the person developing the budget has of the system. Program budgets are also developed based on work units, for example, the program for wood pole repair and replacement. This list, however, is not meant to portray all T&D O&M work, as other departments, such as SOD, also perform work to maintain and operate the system but do not organize their work into programs. SOD relies on information from periodic inspections, infrared scans, equipment tests, trends, recommended maintenance cycles and other factors to determine its work for the year and going forward.

Labor Resources and Budgeted Costs

Q. What factors affected how the labor resources were allocated to the planned O&M work in the test year?

A. In addition to O&M work, HECO labor resources also perform capital work. Capital projects were generated throughout the year based on need resulting from studies, customer or government requests, or to address system reliability issues. It is primarily the capital projects developed by the engineers in the Energy Delivery Engineering department that requires resources to perform work on the T&D system. These engineers initiate capital projects based on their studies or analyses of the T&D system, prepare budgets for the projects, and assign the resources from different departments to perform the work. During the budgeting period, the C&M and SOD supervisors reviewed how their resources were allocated to the capital budget and analyzed the impact that the capital projects had on their estimated

O&M labor resource requirements. Supervisors of the resources identified to perform capital work discussed the project scope with the engineers to identify as clearly as possible the amount of man-hours required for the project given the available information of the project scope.

Q. What effect do the capital projects have on the test year O&M expenses?

A. When the O&M and the capital resource requirements were consolidated, the C&M and SOD supervisors were able to review the total demand for the labor resources to perform both the planned capital and O&M work during 2009 and determined whether their resources were over-demanded, that is, the amount of work planned required more resources than would be available to do the work. Because the capital projects and the O&M budgets were developed independently, this result was normal.

Q. Please provide an example of what you mean by "over-demanded"?

A. To understand what it means to be over-demanded, assume that the labor resource was just one person and assume that the individual is forecasted to work an eight hour day every workday for a year. Therefore there are 2088 hours available for that individual. If holidays, vacation, and anticipated sick days, as well as time for mandatory training are removed, we find that the net productive hours may be in the range of 1700 to 1800 hours. If the combined (O&M and capital) man-hour estimate is 2,200 hours for that individual, then the person is over-demanded by 400 to 500 hours. For bargaining unit employees this over-demand may be addressed by having the employees work overtime. For the majority of the merit employees this would be addressed by extra hours worked without compensation. In terms of labor costs (capital or O&M), it is the bargaining unit overtime that is reviewed to determine if it falls within a "reasonable" range. Typically, overtime that is less than 12%-15% is acceptable; however working at this level of overtime for extended periods is not good for the employees because of the impact on their personal lives which then leads to morale issues.

Q. What are the alternatives if there is a large over-demand on the available resources?

A. As explained earlier one alternative is to schedule employees to work overtime. This method to address the over-demand is carefully applied, however, because of the potential need for additional overtime when emergencies occur. Because of the heavy physical labor required to perform the work it is important for the employee's health and safety to manage the impact that added hours of work may have. Another alternative to address the over-demand is to use contractors to perform some of the work. Contractors may be used to address either the capital or O&M work. Regardless of where the contractors are used, they must have the proper qualifications and knowledge to perform the work. Contractors have been used in the past by the Energy Delivery Process Area departments.

Q. Was there a significant over-demand for T&D labor resources in the 2009 operating budget?

A. Yes, there was.

Q. What was the cause of the over-demand?

A. The cause was due to the significant amount of T&D O&M work required to be performed in the test year along with an increase in the resources required for T&D capital projects that are planned for 2009. I discuss these additional T&D O&M work requirements later in my testimony.

Q. How was the over-demand addressed during the budgeting cycle?

A. The over-demand on the labor resources was addressed in the following ways:

1) As noted above, the supervisors discussed the scope of the individual capital projects with the responsible engineers to ensure that the estimated labor requirements were forecasted with as much accuracy as reasonably possible, given the information available about the scope of the planned work at that time;

2) The supervisors reviewed the planned maintenance work to assess whether the hours forecasted for the O&M work could be reduced without impacting the reliability of the system or the equipment to be maintained. However, supervisors were aware that unanticipated circumstances encountered during the year could impact the O&M budget and planned work. These circumstances include corrective work (which the supervisors budget based on historical trends) resulting from problems on the system, equipment failures that need to be addressed right away, changes in work priority because of inspections or equipment testing indicating that maintenance is required, or other maintenance work that materializes unexpectedly for different reasons. Given these uncertainties, the reduction in O&M labor resource hours was done to reflect the work that the supervisor estimated could actually be accomplished during the year;

3) The supervisors looked for opportunities to use outside contractors to perform the work that could not be done by HECO resources. In some cases where outside contractors were used before, estimates were revised to include additional work. If contractors were not used before the supervisor determined what work could be contracted and estimated how much that work would cost, in some cases without the benefit of a detailed scope or bids.

Q. Were there other factors besides the planned O&M and capital work that affected the expenses in the budget?

A. Yes. The amount budgeted for O&M work and capital projects were presented to the Company's officers so that they could see the level of spending that was developed in each department and for the Company in total. If changes were necessary, the supervisors or engineers were tasked to revise their O&M and capital budgets, respectively. This budget process is discussed in more detail by Ms. Lorie Nagata in HECO T-17.

Direct Labor Cost Calculation

Q. How are the direct labor costs calculated?

A. The direct labor costs are calculated using the hours (estimated as man-hours) that are allocated to perform the planned work for the different labor resources. The man-hours are converted to direct labor dollars when multiplied by appropriate standard labor wage rates in the Pillar System. Further discussion on the development of labor costs for the Operating Budget may be found in Ms. Patsy Nanbu's testimony at HECO T-11.

Energy Delivery Process Area Staffing

Q. What labor resources are available to do the planned O&M expense and capital work?

A. The employees in the Energy Delivery Process Area perform the majority of the work charged to T&D O&M expense. The employee count for the Energy Delivery Process Area as of March 31, 2008 was 498 employees compared to the 2009 test year estimate of 510 employees. The difference between the March 2008 employee count and the 2009 test year estimate was due to vacancies in the following departments:

Department	March 31, 2008 EE Count	2009 Test Year EE Count	Vacancies
C&M	213	220	7
System Operation	115	118	3
Engineering	84	85	1
Support Services	84	85	1
VP – Energy Delivery	2	2	0
Total	498	510	12

HECO-825 provides employee counts for years 2006 and 2007.

Filling Vacancies

Q. Does HECO plan to fill these vacant positions?

A. Yes, HECO will be filling the vacancies in the Energy Delivery process area. For the C&M department, the vacancies are senior helper positions. These positions are used to hire entry level employees for the C&M Lineman apprenticeship program. These apprentices eventually, through promotions and job transfers, feed into higher level positions in C&M and other departments – overhead lineman, cable splicers, primary troublemen, inspectors, substation technicians, dispatchers, resource planners, supervisors, and superintendents are just a few of the positions that have been filled with linemen. As of June 18, 2008, job offers were made to five individuals for the senior helper positions. All five have accepted and are scheduled to start July 2008. This will increase C&M's employee count to 218 employees and, therefore, C&M will need to fill only two more positions to meet its 2009 test year estimate employee count of 220. C&M continues to actively seek candidates to fill another three senior helper positions (this is one more than the two existing vacancies because the Field Operations section expects a PTM to retire later this year) with internal and external postings. Through external postings, C&M will develop a “pool” of pre-qualified senior helper candidates from which to draw when needed. Two of the five individuals noted above were from such a “pool”. While in the senior helper position, these individuals will be evaluated during a probationary period and upon demonstrating satisfactory performance as a senior helper, they will be inducted into the C&M lineman apprenticeship program. After three years in the apprenticeship program they graduate and enter the C&M lineman 1st year position. The lineman position continues to be a highly popular position at HECO and the apprenticeship program has been very successful in developing potential candidates into journeyman linemen.

Two of the three vacancies in SOD are to replace a trouble dispatcher and a systems engineer. An additional vacancy for a construction journeyman position is forecasted to be filled in the 2009 test year for the Construction Management (“CM”) section in SOD. The construction journeyman position requires many of the skills and qualifications found in a journeyman carpenter; however, after the person is hired by HECO, the person has to learn additional technical skills besides carpentry for the CM Construction Journeyman position. Because there is a broad base of journeyman carpenters in the industry outside of HECO, it should not be difficult to find good candidates. Additionally, HECO has been using contract laborers to supplement the existing personnel in the CM section. These contract laborers may become potential candidates for the CM construction journeyman position.

The trouble dispatcher and systems engineer positions are more difficult to fill because of the technical requirements necessary for both positions. SOD is currently in the process of recruiting personnel to fill these positions. Advertisements and notice of vacancies have been published to attract applicants for these two positions.

The vacancy in the Support Services Department for an automotive attendant was filled on June 16, 2008. The vacancy in the Engineering Department is temporary due to a job rotation program that was implemented in the Energy Delivery Process Area to broaden the skills and knowledge of merit employees who may in the future be candidates for critical utility skill positions. As this program is confined to the Energy Delivery Process Area, the employee is still included in the March 31, 2008 employee count of 498 employees. At the end of the job rotation, the employee will return to the Engineering Department. Six employees in total were rotated to roles outside of their regular positions for one year to develop a wider perspective of the Company and obtain technical expertise which may be beneficial for their positions in their "home" departments and/or prepare them for greater responsibility. The net change to the Energy Delivery Departments due to the job rotation is one Engineering Department temporary vacancy, and a temporary gain of one employee to the System Operation Department. Aside from this program, other changes to the department employee count may occur from transfers, retirements, or separations from the Company.

<u>Impact of Rising Costs on T&D O&M Expenses</u>

Q. Have rising costs contributed to the increase in T&D O&M?

A. Yes. Rising costs directly affect three basic components of T&D O&M expense:

1) Wage and salary increases for the bargaining unit and merit employees respectively, that are reflected in the standard labor rates used for the operating budget;

2) Inflation factors for non-labor costs that recently have been impacted by the increases in the prices of commodities, for example, copper, and

3) Overheads applied to labor and non-labor expenses.

<u>Wage And Salary Increase</u>

Q. How were wage increases determined for bargaining unit positions for the test year?

A. Wage increases for bargaining unit positions are negotiated between the Company and the IBEW, Local 1260. The Company and the IBEW recently agreed to an extension of the labor agreement until October 31, 2010. Based on the provisions of this extension, wages for bargaining unit positions will increase by 4%, effective January 1, 2009. This is the assumption used in the O&M budget. The change in bargaining unit wages is discussed in detail by Ms. Lorie Nagata in HECO T-17.

Q. How were merit salaries increased for the test year?

A. To estimate salaries for the test year, projected salaries as of April 30, 2009, were increased by 4.0% effective May 1, 2009, plus .30% effective September 1, 2009, and .20% effective December 2009. The changes assumed for merit salaries for the operating budget are discussed in detail by Ms. Lorie Nagata in HECO T-17.

<u>Non-Labor Costs</u>

Q. How are the estimates for non-labor costs developed?

A. Direct non-labor costs reflect estimates for materials, information system services and contracts and services. These costs are budgeted in dollars and represent the non-labor requirements necessary to support the work that needs to be performed. As mentioned earlier in my testimony, to forecast the non-labor expenses, in cases where vendors have provided an estimate for material costs or provided an inflation factor, these inflation estimates were applied to the current year's material cost to determine the non-labor budget for the budget year. If specific information was not available, then either a historical trend was used to estimate the future cost or HECO's non-labor inflation factor of 2.5% was applied to previously budgeted amounts. Please refer to Ms. Lorie Nagata's discussion of this assumption in HECO T-17.

Overheads Applied To Labor And Non-Labor Expenses

Q. Please describe the overhead charges applied to the labor and non-labor expenses.

A. Overhead costs or on-cost charges are applied to direct T&D labor and non-labor expenses. These overhead costs include related indirect expenses such as Energy Delivery Process Area supervision and administrative costs as well as non-productive wages. Therefore, total T&D expense is the sum of direct labor costs, direct non-labor costs and applicable overhead costs.

Q. In addition to the impact of the general wage increases, the appropriate inflation adjustment for non-labor items, and overhead costs, what other factors contributed to the 2009 test year estimate of T&D O&M expense increases?

A. Increased expenses that are specific to Transmission Operation, Transmission Maintenance, Distribution Operation, and Distribution Maintenance O&M expenses are discussed in my testimony below. In addition, HECO-WP-805 provides explanations of 2009 test year expense items that exceed 2007 test year recorded amounts by $200,000 and 10%.

Q. Did you compile a listing of variances greater than $200,000 and 10% between 2007 recorded costs and the 2009 test year estimate for T&D O&M Expense?

A. Yes. HECO-WP-805 summarizes the variances greater than $200,000 and 10% between 2007 recorded costs and the 2009 test year estimate. However, my testimony does not address each of the individual variances identified in this work paper. The primary reason is that, when C&M personnel develop the budget for their O&M expenses, they budget to the responsibility area DS. However as expenses are incurred they are charged to the RA of the work group that actually does the work. Pages 3 and 4 of HECO-WP-805 identify such line items as variances due to procedural reclassification and identify the C&M programs to which the actual expenses were charged.

TRANSMISSION & DISTRIBUTION O&M EXPENSE

Q. What items are included in HECO's T&D O&M expense?

A. T&D O&M expense includes the labor and non-labor expenses incurred in the operation and maintenance of HECO's T&D system. These expenses are recorded in the following accounts as defined by the NARUC Uniform System of Accounts for Classes A and B Electric Utilities.

560-567	-	Transmission Operation Expenses
568-573	-	Transmission Maintenance Expenses
580-589	-	Distribution Operation Expenses
590-598	-	Distribution Maintenance Expenses

HECO-WP-801, HECO-WP-802, HECO-WP-803, and HECO-WP-804 provide descriptions of the expenses that are included in these NARUC accounts.

Transmission O&M Expense

Q. What is HECO's 2009 test year estimate of Transmission O&M expense?

A. HECO's 2009 test year estimate of Transmission O&M expense is $13,967,000 as shown in HECO-808. This amount includes HECO's 2009 test year estimates for Transmission Operation expense of $6,951,000 and Transmission Maintenance expense of $7,016,000.

Transmission Operation Expense

Q. What items are included in Transmission Operation expense?

A. Transmission Operation expense includes labor and non-labor costs as shown in HECO-809 to support activities such as load dispatching and transmission switching operations, transmission substation inspections and operations, communications systems operations and inspections and transmission line, pole, and structure inspections. The corresponding NARUC account numbers for Transmission Operation are detailed further in HECO-WP-801.

Q. How does the 2009 test year estimate of Transmission Operation expense compare to previous years?

A. HECO-810 shows HECO's Transmission Operation expenses from recorded 2003 through 2007, 2008 budget and the 2009 test year estimate. In general, Transmission Operation expenses have been increasing in the 2003-2008 period. The 2007 recorded Transmission Operation expense was $4,520,000, the 2009 test year estimate is $6,951,000 which is $2,431,000 higher than the 2007 recorded Transmission Operation expense as shown in HECO-810.

Q. Please explain what factors contributed to the $2,431,000 increase.

A. The $2,431,000 increase in Transmission Operation expense compared to 2007 recorded is the result of the following factors:

1) Approximately $400,000 in HECO labor and outside services to perform Interconnection Requirement Studies, for HECO's Oahu Renewable Energy RFP.

2) An increase of $1,199,410 as shown in exhibit HECO-830, page 2 of 3, which is attributed to an increase in the number of inspections planned to be conducted on the overhead transmission system due to the aging of the transmission system. In addition, funds originally budgeted for inspections in 2007 were reallocated to the Vegetation Management program in order to manage increasing vegetation costs.

3) An increase of $282,000 for maintenance expenses for HECO's Siemens Energy Management System ("EMS") that was placed in service in 2006 and the video wall board software maintenance.

4) $122,000 in non-labor expense for SOD dispatcher training.

5) $234,000 for outside services for transmission station work.

<u>Interconnection Requirement Studies ("IRS")</u>

Q. Please explain what an IRS is.

A. Earlier this year HECO released the Oahu Renewable Energy RFP. When proposals are received HECO will determine what the system requirements are to interconnect the renewable energy sources to the HECO system. These studies in general are done to determine the system modifications necessary to accept power from the renewable sources and are reimbursable to HECO from the renewable resource developer. The studies include but are not limited to the following:

1) Powerflows or load flow studies to determine if the existing system infrastructure can accept the power from the renewable sources without

exceeding the design limits under normal conditions and under various contingencies;

2) Short circuit studies to determine the system protection requirements and to determine if changes or additions to the relay protection schemes are necessary; and

3) System stability studies to understand the dynamic response of the HECO system with the addition of the renewables. These dynamic simulations show the engineers how the HECO units and the renewables respond to system upsets and whether problems are created because of the different response characteristics of the generation unit mix.

Q. What is the breakdown of the costs to be incurred?

A. The costs in the 2009 test year estimate are for HECO labor of approximately $80,000 and approximately $320,000 for consulting services to perform the studies. As I indicated previously IRS study costs ultimately are to be paid for by the renewable resource developer. The treatment of the revenue to pay for the IRS is covered by Mr. Peter Young in HECO T-3.

<u>Transmission System Inspections</u>

Q. What type of inspections does HECO perform on its transmission system?

A. HECO does a flying/driving quarterly inspection (i.e., four times per year) of the 138,000 volt overhead transmission system to verify the electrical system integrity. The inspections are conducted to look for problems that can be found by visual inspection, such as broken guy wires, spar arms, insulators, or broken/severely leaning poles. HECO also performs detailed overhead climbing inspections on a 12-year cycle. HECO worked with staff from the Electric Power Research Institute ("EPRI") to develop a maintenance basis plan. The maintenance basis plan provides guidelines for inspections and maintenance of T&D equipment and is influenced by best industry practice. Given Hawaii's environment and climate, EPRI's recommendation is to perform a climbing inspection on HECO's transmission system on a 12-year cycle. The 12-year cycle is also similar to the guidelines documented in the EPRI Overhead Transmission Inspection and Assessment Guidelines. In this guideline, a ten-year cycle is suggested. However, this guideline also suggests an equivalent of a three times per year flying/driving inspection of the 138,000 volt overhead transmission system as compared to HECO's quarterly flying/driving inspection. Therefore, HECO believes that a quarterly flying/driving overhead inspection cycle (versus the three times per year inspection cycle) coupled with the 12-year climbing inspection cycle (versus a 10-year climbing inspection cycle), is a more cost effective approach for inspecting HECO's overhead transmission system.

<u>Siemens Energy Management System Maintenance</u>

Q. Transmission Operation expenses also increased because of higher outside services costs for the Siemens EMS maintenance. Why is the Siemens EMS maintenance expense increasing?

A. The Siemens EMS was placed in service in March 2006 and subsequently passed a 1,000 hour test required for HECO's acceptance of the system from the vendor. The 1,000 hour test was completed in December 2006 and the one year Siemens software warranty period began from that date and expired in December 2007. The hardware warranty was provided by the hardware vendor and when the hardware warranty expired HECO paid a third party vendor to maintain the EMS hardware. During the warranty period, HECO paid for 24 hour by 7 day response by Siemens to assist with resolving EMS software problems since the warranty under Siemens provided only an 8 hour by 5 day response. The post warranty agreement purchased by HECO will continue the same service level coverage from Siemens, i.e., 24 hours by 7 days, and similar agreements were put in place for the hardware. The table below summarizes the increases in the Siemens EMS maintenance expense.

Expense	2007 Recorded	2009 test Year Estimate	Variance
Siemens EMS Hardware Maintenance	$24,000	$43,500	$19,500
Siemens EMS Software Maintenance	$22,200	$254,500	$232,300
Linux License[3]	$0	$46,000	$46,000
UPS maintenance, PI license, VPN connection, EMS paging license, Exceed licenses, Live Data license, maintenance[4]	$76,900	$60,800	($16,100)
Total	$123,100.00	$404,800.00	$281,700.00

Q. Why is it necessary to have these maintenance agreements and the higher level of service response for the EMS?

A. The EMS is the central component of the dispatch center and is used to monitor and control generation, the transmission and sub-transmission system and portions

3 During the contract negotiations with Siemens they agreed to have the EMS upgraded in the fourth year of the maintenance agreement so that it would be running the latest version of the software. The Linux operating system software and the hardware would be purchased by HECO and the software maintenance paid to Siemens included the cost to upgrade of the Siemens EMS software.

4 Charges for Exceed and Live Data licenses were charged to Transmission Operation expense erroneously. In the future these expenses will appear in Distribution Operation expense where they are currently budgeted. The 2007 recorded cost of these two licenses was about $10,000, and $10,000 is in the 2009 test year Estimate in Distribution Operation expense.

of the distribution system. The EMS plays an integral role as it automatically dispatches the generating units, i.e., controls the output of the generating units to meet the load demand and does it economically so that given the constraints of the system the lowest cost is achieved. The EMS is also critical to the dispatchers because they use the EMS to control devices in the field to regulate the system voltage, perform switching and monitor the system for abnormal events such as low or high voltages, low or high frequency, or high currents that might exceed the design capability of the equipment or lines. Without the EMS, it would be difficult for the dispatchers to monitor and control HECO's electrical system.

Dispatcher Training

Q. Why is there an increase of $122,000 for dispatcher training expenses?

A. There is a constant need for dispatcher training in the Operating section for the following reasons:

1) To provide training of the technical knowledge and skills required to respond to system upsets to new employee dispatchers;

2) To provide dispatcher refresher training on the new systems that have been added in recent years (i.e., the new Siemens EMS went live in March 2006 and the new Oracle Outage Management System ("OMS") went live in July 2007) and to provide training on new functionalities that are added to these systems;

3) As improvements to the dynamic wallboard display are made it is necessary to provide training to the dispatchers on how to effectively use the wallboard; and

4) To provide training to the dispatchers so they can advance through the line of progression when a vacancy at the higher position occurs. This is the

progression from the entry level Trouble Dispatcher to the next higher bargaining unit position the Load Dispatcher.

Q. Why isn't the Technical Trainer providing all of these training needs?

A. The training program is changing as a result of the addition of the Siemens EMS and the Oracle OMS. In addition to training the dispatchers the specialized skills necessary for the Trouble and Load dispatcher positions, it is now desirable to provide customized training to fully integrate the new systems (Siemens EMS and Oracle OMS) into the HECO dispatcher work processes.

The dispatchers were trained on all the new systems and have been operating and using these systems since they went live. However, the dispatchers have more to learn beyond just an understanding of the functions of the systems. They can improve how they use the system in their jobs by learning how to more fully integrate their work processes with the capabilities of the OMS and EMS. HECO prefers to have professionals with a long history of experience on these types of systems provide training to the dispatchers to improve how they manage outages, keep track of different field resources, communicate the status of the outage, and in the future learn to better manage a large number of outages resulting from big storms. These professionals have knowledge of how to use the systems from a software point of view and they also bring with them the "user" perspective, having had the experience of using these systems in dispatcher positions themselves. This experience and work knowledge is invaluable to HECO's dispatchers that are now learning to work with these systems.

<u>Outside Services For Transmission Station Work</u>

Q. Please explain the variance of $234,000 in SOD for outside contractor costs.

A. As mentioned earlier in my testimony because of the over-demand for the labor resources in SOD one alternative being investigated is to use outside contractors to supplement the workforce. No additional staffing is included in the 2009 test year estimate for SOD except for the one CM construction journeyman and the personnel that are being hired to fill vacant positions. Using contractors to supplement the workforce enables SOD to address the security issues relative to unaccompanied personnel working in a HECO transmission substation. SOD will also have greater control on assigning work and on the quality of the work that is done by the contractor. With HECO's aging assets and with the number of employees currently available this is an alternative that is being used to address the increasing maintenance needs going forward. It will be several years before the aging assets are replaced as HECO needs to balance its spending to meet the needs brought on by new residential and commercial developments, reliability initiatives, and replacing aging assets. Other projects such as the Honolulu rail transit system has the potential of affecting HECO's planned work as the need to move facilities arise when construction begins on the system. The outlook is that HECO resources will continue to be busy balancing all of the work to be done on the system.

<u>Transmission Maintenance Expense</u>

Q. What items are included in Transmission Maintenance expense?

A. Transmission maintenance expense includes labor and non-labor costs as shown in HECO-809 to support activities such as maintenance and repairs related to transmission substation equipment and facilities, communications equipment, transmission lines and cables, and tree trimming. The corresponding NARUC account numbers for Transmission Maintenance are detailed further in HECO-WP-802.

Q. How does the 2009 test year estimate for Transmission Maintenance expense compare to previous years?

A. HECO-810 shows HECO's Transmission Maintenance recorded expenses from 2003 through 2007, 2008 budget, and the 2009 test year estimate. The overall trend shows increasing Transmission Maintenance Expenses since 2003.

The 2007 recorded Transmission Maintenance expense was $5,845,000 and the 2009 test year estimate is $7,016,000 which is a $1,171,000 increase over the 2007 recorded Transmission Maintenance expense.

Q. Please explain what other specific factors beyond the three general factors you provided on pages 21 to 22 of your testimony contributed to the $1,171,000 increase.

A. The $1,171,000 increase in Transmission Maintenance expense compared to 2007 recorded is the result of the following:

1) An increase of $451,000, as shown in exhibit HECO-830, page 2 of 3, for higher vegetation management program expenses to deal with substantial growth in vegetation around HECO's transmission line corridors and sub-transmission lines;
2) An increase of $321,000 primarily due to the Communication Section of SOD performing additional planned mobile radio installation and repair and communication tower maintenance, using outside contractors;
3) An increase of $ 244,000 associated with the use of contractors by the Substation Section of the SOD to perform maintenance in the substations.

Vegetation Management

Q. Please describe HECO's Vegetation Management ("VM") program.

A. HECO's VM program is designed to keep the transmission corridors (138,000 volt lines) clear of vegetation that might otherwise come into contact with the transmission lines as well as to prevent outages from occurring on the sub-transmission (46,000 volt) lines. The transmission and sub transmission overhead lines are the lifeline of Oahu's electrical system. Keeping these transmission corridors clear from vegetation threats is essential to mitigating cascading adverse events on the transmission system that could potentially lead to a major outage or even an island-wide black-out. According to a comprehensive report prepared for the federal government in the aftermath of the largest blackout in North American history, inadequate VM on high-voltage transmission lines was identified as one of the primary causes of the blackout, which left 50 million people without power on August 14, 2003[5].

A. The VM management work in the corridor through which a transmission line is routed is referred to as "Right-of-Way" ("ROW") work. This work is very difficult because of the location of these ROWs. Many of the ROWs are far from the populated areas and traverse valleys and mountainous regions on the island of Oahu, and therefore, are difficult to access. Because of the tropical climate and the absence of severe climatic changes, these areas are also lush with vegetation.

Q. Does the VM Program also include maintaining the areas near the distribution lines?

A. Yes, the VM Program is also designed to keep trees and vegetation clear from all overhead lines on the system including the distribution system which encompasses the nominal 11,500 volt lines and the secondary voltage (120 volt, 208 volt and 480 volt) lines. These lines are used to provide power to HECO's customers and

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[5] "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," U.S.-Canada Power System Outage Task Force, April 5, 2004.

are located in rural and urban areas that are readily accessible by the crews. Trimming around the distribution system in these areas is referred to as "Roadside" work. Expenses for VM work around the distribution lines are categorized as Distribution Maintenance expenses.

Q. How many employee positions are dedicated to the VM Program?

A. HECO's VM section is staffed by a Program Manager, two staff arborists, and one contract arborist. These personnel oversee qualified line clearance tree trimming contractors. VM is necessary to ensure safe, reliable, service oriented, and cost effective delivery of electric service through the overhead line system.

Q. How has the reliability to HECO's customers been affected by tree or vegetation related outages?

A. The chart in HECO-824 shows the reliability trends for various causes of outages. Note that this data represents recorded outages for which customers were affected by a sustained outage (i.e., an outage lasting a minute or longer). The chart shows an increasing trend in the number of interruptions resulting from trees or branches. In 2007, "Trees/Branches In Lines" was the third highest cause of interruptions to HECO's customers. The outage causes that ranked higher were "Cable Faults" (ranked number 1) and "Equipment Deterioration" (ranked number 2).

Q. What does the VM program include?

A. The VM program includes the following activities:

- Tree pruning and removal;
- Vegetation control around poles, substations, and other electric facilities;
- Manual, mechanical or chemical control of vegetation along rights of way;

- Pre- and post inspections of required work;
- Pre- and post inspections of vegetation caused outages;
- Tree planting and transplanting (to relocate them away from the overhead lines);
- Public education; and
- Tree inventories, work management systems and various related computerized functions.

Q. How is HECO's VM Program workload organized?

A. The program consists of three types of work, Roadside and ROWs which I described earlier in my testimony, and Customer/Emergencies. The work is performed by vegetation contractors, and daily operations are overseen by the HECO staff arborists who are each assigned one group of contractors.

The ROW work is done in the off-road areas not accessible with the contractors' bucket trucks. As previously mentioned this is usually in the mountain areas with limited accessibility or in valleys or other regions away from the populated areas, and is primarily where the overhead transmission lines are located (although these contractors may work around the 138,000 volt, 46,000 volt, and some of the 11,500 volt lines in these inaccessible regions). HECO has divided the island into six trimming districts consisting of 115 line segments, with a total length of 370 miles of lines spanning an area of 2,170 acres. These districts are trimmed on a one to five year cycle. Hot spots and known vine areas are checked every six months, and side trimming along both sides of the ROW is done on an "as needed basis." For the distribution overhead lines, the roadside work consists of working in or near the residential and urban areas that are accessible with bucket trucks. There are approximately 1,200 miles of overhead distribution lines divided into eighteen trimming districts, following a twelve to fifteen month cycle of routine maintenance, and a three to six month cycle for hot spot trimming. (Hot spot trimming is when trimming is necessary due to an abundance of growth resulting from the vegetation in that area.) There are currently nine roadside contract crews that manage about 50,000 trees a year. Customer requested trimming and emergency trimming is done as needed and are scheduled using work orders. Two contract crews perform this work.

Q. Were changes made in the management of the VM Program?

A. Yes. Changes were made in late 2007 to deal with the accelerated growth in vegetation due to the recent "wet cycle". HECO reassigned staff arborist responsibilities in order to deal with the increased tree trimming workload in a more efficient and organized manner. Staff arborists were assigned specific areas of responsibilities (ROW, Roadside, Customer/emergency trimming) to streamline oversight of crews and priorities. HECO also added the position of Program Manager ("PM") with responsibility for the oversight of the program as a whole. The PM, with input from various departments and personnel, prioritizes the workload tasks to maximize reliability of the system.

"Wet Cycle" Impact on Vegetation

Q. What is a "wet cycle"?

A. Prior to 2003, the State experienced about twelve years with less active winter seasons and normal or below normal precipitation for most of that time. As shown in HECO-827, annual precipitation in the years 2000, 2001, and 2002 was less than normal at all reported locations on Oahu. Hence, vegetation related outages were lower in those years (Trees/Branches in Lines as a cause of outages was ranked 6, 4, and 8, respectively). However, beginning in October 2003, statewide precipitation began increasing over the previous decade. In 2004, significantly above normal rainfall data was collected from across the State as shown in exhibit HECO-827. In March 2006, rainfall on some Oahu sites exceeded 500% of normal. Precipitation indices as reported by NOAA (National Oceanic & Atmospheric Association) during the winters of 2003-2004, 2004-2005, and 2005-2006, were above the normal precipitation indices across the state.

Q. How did the “wet-cycle” period impact vegetation on Oahu and what was HECO’s response?

A. Hawaii has some of the fastest growing trees in the United States because climate conditions provide an ideal growing environment for particular species. For example, the Albizia species grew from 15-25 feet annually during the dry cycle whereas in 2005 and 2006, as observed by HECO’s arborists, the growth rate has reached as much as 25-35 feet per year. Additionally, HECO arborists have also observed that this growth spurt in vegetation has resulted in more saplings in and around the existing vegetation which have resulted in a greater number of trees that require trimming. HECO arborists continue to observe higher growth rates as compared to growth rates during the dry cycle. As a result of the continued high growth rates and more trees that require trimming HECO has made changes to the management of the program as previously stated and has taken actions as noted below.

Q. Besides the change in the management of the VM Program, what other actions has HECO taken to combat the substantial vegetation growth attributed to the wet cycle?

A. In January, 2008, HECO revised roadside trimming priorities/techniques. In the past, districts were trimmed from one end to the other. We now trim each district based on a modified district /circuit priority. This means that each district is prioritized based on circuit size (customer count), criticality, and design. Trimming takes place in each district, starting with circuits that are the most critical to the system, has the highest customer count, and is located along the backbone (no fuse protection). (A main overhead line that is located along a major road is the "backbone".) This technique ensures that the trees that are trimmed are the ones that have the potential to cause the most number of outages and affects a large number of customers.

Also in early 2008, HECO contracted specialized ground clearing crews, from the mainland, that clear vegetation under the transmission and sub-transmission lines in the ROWs. These crews are scheduled to begin work in July, 2008. HECO is budgeting to have these crews return on an annual basis to keep the ROWs clear of vegetation.

In 2007, HECO solicited proposals from multiple tree trimming contractors qualified to trim near energized lines. As a result, in early 2008, HECO brought in a mainland contractor to handle Customer/Emergency work and has contracted with a local contractor to provide side trimming in the ROW's. The use of multiple contractors encourages competitive pricing and increased productivity.

The Company successfully negotiated the removal of mobilization costs from its contracts with the mainland contractor resulting in an annual savings of $60,000.

In early 2008, HECO took steps to increase productivity by decreasing the travel time of contract crews by basing them at HECO facilities closer to the work area (districts).

Starting in mid 2007, tree trimming inspections were done in conjunction with the T&D overhead line inspectors inspections of the transmission lines using helicopters to eliminate the need for two separate flights.

In early 2008, HECO Staff Arborists were issued pruning tools to make incidental cuts and trim customers' trees that impede on secondary service lines. This reduced the need to redirect a crew off of routine maintenance and priority trimming which had the tendency to reduce the productivity of the crews because of the duplicative set-up and break down times. In addition, customer complaints have decreased because their minor trimming needs were addressed quickly.

All these measures are planned to continue during the 2009 test year and going forward.

Q. Are these VM Program measures enough to address the substantial vegetation growth and ensure reliable service?

A. While the changes HECO has implemented has helped to prioritize the work and ensure that the work is done in a more efficient manner, HECO needs the level of funding requested in the 2009 test year to secure more manpower to manage the substantial vegetation growth. HECO's goals are a twelve to fifteen month cycle for Roadside trimming, a three to six month cycle for hot spot trimming, and keeping the ROWs clear of impeding vegetation growth, all to insure reliable service. With the current contingent of available VM crews and improvements in operational processes, HECO can, at best, achieve a 24 month cycle for trimming.

<u>Outside Contractors – Communication Section</u>

Q. Please explain the reasons for the increased use of contractors by the Communication Section and the Substation Section, which are the second and third factors that led to an increase in the Transmission Operation expense.

A. Earlier in my testimony I described the process that was followed to determine the 2009 test year estimate. In this description I provided a high level overview of the budgeting process and in general how the resources were distributed between capital projects and the O&M workload. Based on the number of employees assigned to the Communication and Substation sections, the review process indicated that an over-demand for these the labor resources existed in the test year. To address this over-demand, overtime by HECO employees and the use of outside contractors will be increased. To determine the amount of work to be contracted, the historical overtime trends were used to determine how much over-demand work could be done by the Communication and Substation sections. The remaining over-demand for work which was not covered by overtime was then designated to be done by outside contractors.

Q. What communications maintenance needs will be addressed by the outside contractors?

A. The areas of work that were designated for contractors were the following:

1) Mobile radio system maintenance (portable and base stations), installation of mobile radios, and the repair of broken mobile radio units. Based on historical trends it is estimated that the contractor will install approximately three to five portable or mobile units a month.

2) Tower inspection and maintenance at the nine antenna sites: At most, only three towers are expected to be done in one year, placing the towers on a three year maintenance cycle. Given the conditions in the field and the exposure to the elements, rust maintenance and repair is an on-going process.

Outside Contractors – Substation Section

Q. What work from the substation area do you plan to have outside contractors address?

A. The work planned to be done by contractors includes the following:

1) Substation rust repair and maintenance that is estimated to be $70,000;

2) SF6 gas leak detection, estimated to be $50,000; and,

3) Specialized maintenance of SF6 transmission and sub-transmission circuit breakers, estimated to be $125,000.

Substation Rust Maintenance

Q. Has HECO previously used contractors to perform any of this work?

A. Yes. HECO has used contractors to address the rust repair and maintenance issues in the distribution substations. There are nineteen transmission substations and 125 distribution substations on HECO's system. Using the current contractor resources, HECO was able to address the rust repair and maintenance needs of about six distribution substations a year, but has not addressed the transmission substations with any regularity. In the past, transmission rust repair and maintenance needs were done on an as needed basis. HECO is including the transmission substations in this rust and repair initiative so that structure and equipment rust issues can be addressed before they worsen to the point where more expensive repairs may be needed later. By having additional contractors, HECO will be able to address the effects of rust at the transmission substations and the distribution substations to prevent potentially more costly repairs in the future. The $70,000 estimated for this service is expected to address the needs of four transmission substations each year, though some transmission substations may require more work than others. Hence all the transmission substations will be addressed using a five year maintenance cycle.

Q. What is SF6?

A. SF6 – Sodium hexafluoride gas is used in the electrical industry as a gaseous dielectric medium for high-voltage circuit breakers, switchgear, and other electrical equipment, often replacing oil filled circuit breakers (OCBs). SF_6 gas under pressure is used as an insulator in gas insulated switchgear (GIS) because it has a much higher dielectric strength than air or dry nitrogen.

Q. Why are contractors being used for the SF6leak detection?

A. As the SF6 equipment ages, SF6 gas leaks may appear. The SF6 gas is important for the proper operation of the equipment as it is the insulating medium in the breaker or switchgear that is used to quench the arc that occurs when the breaker operates to interrupt the flow of electricity. There have been instances when there was insufficient SF6 gas (resulting in inadequate insulating medium) in the breaker and this prevented the breaker from operating. Leaks that occur in readily accessible areas of the SF6 equipment are relatively easy to locate and repair. Leaks in inaccessible locations and extremely small leaks have been difficult to locate. Contractors using special leak detection equipment were hired in the past to find SF6 gas leaks in the equipment. This special equipment detects leaks that are too small to be detected by the equipment that HECO currently employs in its maintenance.

Q. Has HECO used the services of these contractors in the past and what success was achieved?

A. Yes, HECO has used these contractors in the past on a trial basis to validate that the SF6 leak detection system actually found leaks. In 2002 and 2003, a contractor from Asea Brown Boveri ("ABB") was used to find leaks in the Archer Substation SF6 equipment as well as other substations on the system. Using the SF6 leak detection technology, the contractor found some small SF6 gas leaks. These leaks were so small that they were undetectable with the SF6 sniffers that HECO uses or were in locations that were inaccessible so that the sniffers could not be used. The only signs that the gas was leaking was that the SF6 gas pressure would drop and the system needed to be recharged. Using the contractor to find these leaks will lower the amount of SF6 gas that is discharged to the atmosphere and may potentially lower the amount of SF6 gas that is used each year to recharge these systems.

Q. How many facilities and SF6 circuit breakers will need to be inspected by this contractor?

A. There are five substations, Archer, Kamoku, Kewalo, Airport, and Airport Switching Station that have SF6 Gas Insulated Substation ("GIS") equipment. In addition a small section of School Street substation also has GIS equipment. Besides these substations there are fifty-six 138,000 volt SF6 circuit breakers and forty-six 46,000 volt SF6 circuit breakers. Not all the substations and breakers will be surveyed in one year. HECO has prioritized the stations for annual surveys so that leaks can be detected and repaired quickly.

Q. What is the future status of this type of equipment, that is, does HECO expect the number of SF6 equipment installed on the system to increase or decrease?

A. The numbers of this type of equipment are expected to increase in the future. Because of the technology trend, all new breakers and all replacement breakers will be SF6 circuit breakers. There are few or no alternatives to the SF6 breaker at this time. The breaker inspections will be done on a periodic maintenance cycle because not all the breakers can be inspected in one year.

Q. Why is this work required now?

A. Leaks have been found in the past and they have been repaired; however, over time new leaks may appear, particularly as the equipment ages. Using the SF6 leak detection technology, it may be possible to find the leaks when they are much smaller so the problem can be detected earlier and repaired thereby ensuring that the equipment can maintain the required level of SF6 gas necessary for reliable and safe operation. Additionally, HECO has been monitoring the environmental rules and regulations that apply to SF6 gas. Though there are no regulations in place, there is the SF6 Emission Reduction Partnership for Electric Power Systems that is a collaborative effort between the Environmental Protection Agency and the electric power industry to identify and implement cost-effective solutions to reduce sulfur hexafluoride (SF6) emissions. SF6 is a labeled as a greenhouse gas used in the industry for insulation and current interruption in electric transmission and distribution equipment. Currently 81 utilities participate in this voluntary program[6]. Besides the environmental benefits, there is potential economic benefit as finding and detecting leaks sooner might lower the amount spent on SF6 gas to refill the equipment.

DISTRIBUTION O&M EXPENSE

Q. What is HECO's test year estimate of Distribution O&M Expense?

A. HECO's test year estimate of Distribution O&M Expense is $30,493,000 as shown in HECO-811. This amount includes $13,613,000 for Distribution Operation

[6] See the following website for information on this voluntary partnership: http://www.epa.gov/electricpower-sf6/

expense and Distribution Maintenance expense of $16,880,000, as shown on HECO-811.

Distribution Operation Expense

Q. What items are included in Distribution Operation expense?

A. Distribution operation expense items include labor and non-labor costs as shown in HECO-809 to support activities such as trouble dispatching and distribution switching operations, distribution substation inspections and operations, distribution line, pole and structure inspections, connecting, disconnecting and locking meters, and investigating customer complaints. The corresponding NARUC account numbers for Distribution Operation are detailed further in HECO-WP-803.

Q. How does the 2009 test year estimate for Distribution Operation expense compare to previous years?

A. HECO-812 shows HECO's Distribution Operation recorded expenses from 2003 through 2007, 2008 budget and the 2009 test year estimate. These expenses in general have been increasing over the 2003 to 2007 period. The 2007 recorded expense was $10,667,000. The 2009 test year estimate is $13,613,000 which is $2,946,000 higher than the 2007 recorded Distribution Operation expense.

Q. Please explain what factors contributed to the $2,946,000 increase.

A. The $2,946,000 increase in Distribution Operation expense is the result of the following (that are in addition to the three general factors explained in my testimony, pages 21 to 22):

1) An increase of $280,000 due to the full year amortization of deferred expense related to the implementation of the Outage Management System

("OMS"). Because the OMS was placed in service in July 2007, only five months of amortization expense is reflected in the 2007 recorded amount.

2) An increase of $1,040,032, as shown in HECO-830, page 1 of 3, which is attributed to higher preventive inspection expenses for work on underground lines. Outages caused by loss of an underground line continue to be ranked as the top cause of interrupted electrical service to customers and has held this position since 2004. This increase in preventive inspection expense is for very low frequency ("VLF") testing that will be used to perform tests on the underground lines before placing them back in service.

3) Inclusion of an increase of $853,000 for Advanced Meter Infrastructure ("AMI") expenses.

4) An increase of $1,002,766, as shown in exhibit HECO-830, page 1 of 3, is attributed to an increase in PTM switching operations expenses. This increase in cost is due primarily to an increase in staffing of PTMs for additional coverage and succession planning.

5) Training expenses of $526,000 for the new Customer Information System ("CIS") that will be placed in service in May 2009.

<u>OMS Amortization</u>

Q. Please explain the increase in the amortization amount for the OMS project.

A. The OMS Project involved the purchase and installation of a new, commercially available, OMS system, the development and testing of interfaces between the new system and other HECO systems, including the CIS, the Automated Mapping / Facilities Management ("AM/FM") mapping system or as it is currently referred to the Geospatial Information System ("GIS"), the Interactive Voice Response system, and the Energy Management System ("EMS"), and associated training for

HECO employees. The OMS has capabilities that include collecting trouble call information for the purpose of determining, through predictive analysis, the most probable device that is causing the outage and its location, providing status updates of an outage, identifying work crews capable of addressing the outage, scheduling and dispatching work orders to the field, managing field personnel addressing the outage, and providing historical outage data and reports. The field management functionality is available through the Mobile Workforce Management System ("MWM") that allows orders to be sent to field personnel and the dispatchers in the dispatch office are able to receive information from the field via wireless communication systems. PTMs were issued laptops with the OMS/MWM software installed so that information could be exchanged between the PTMs in the field and the dispatchers in the dispatch center. By using laptops in the field and the enabling wireless communication system that provides an alternate way to communicate information to and from the field, this partially freed HECO's mobile radio system from voice communication as the dispatcher and the PTMs exchange information via the MWM system. Additionally, the OMS to MWM integration provides the dispatchers the capability to locate the PTMs in the field though the automatic vehicle locater system. This system allows the dispatcher to locate the PTM closest to the problem which improves the response time to address system needs. The OMS allows the dispatcher to focus on the primary task of restoring power to customers as quickly and safely as possible.

The OMS assists HECO's dispatchers in managing the field personnel to restore electrical power, update the status of an outage, and disseminate such information internally -- particularly to HECO's Customer Service and Energy Services personnel -- so that updated information (e.g., extent of the outage and the estimated time to restore power) is provided when customers call concerning the outage. The OMS is a valuable tool for communicating the impact of an outage to internal groups. Using the OMS they are able to quickly see an update of the status of outage incidents (e.g., estimated time to restore power, when power was restored, or a delay in the restoration) and can then pass on this information to key customers. HECO personnel find this extremely valuable as they receive requests for updates from customers, so that customers (i.e., commercial, military and residential customers) can make their own plans on what they need to do to respond to the outage incident.

The OMS was placed in service in July 2007 and, as directed by the Commission in Decision and Order No. 21899, dated June 30, 2005, the deferred costs from the implementation of the new OMS began to be amortized monthly over a twelve-year period. Because the OMS was placed in service in July 2007, only five months of the amortization costs, $150,200, were recorded in 2007. In the 2009 test year, a full twelve months of expenses are reflected, $280,000 more than what was recorded in 2007.

Q. What is the estimated amortization amount included in the test year?

A. HECO-WP-811 provides the calculation of the test year amortization amount of $432,000 to be included in the test year. As noted, the unamortized system development costs at the end of 2007 amounted to approximately $4,300,000. An additional $676,000 of expenses will also be deferred in 2008, resulting in a projected 2008 end-of-year unamortized balance of $4,568,000, including the impact of the 2008 monthly amortizations that total $408,000. And, at the end of 2009, the balance of the unamortized OMS costs will be $4,136,000, which reflects the 2009 test year amortization of $432,000 (see HECO-1117 presented by Ms. Patsy Nanbu in HECO T-11).

Q. Why is there almost $676,000 of OMS expenses anticipated to be recorded in 2008 after the system was substantially tested and placed in service in July 2007?

A. During the implementation of the OMS, the company that HECO had awarded the contract to, SPL Worldgroup, was purchased by Oracle. Though the acquisition of SPL Worldgroup did not adversely affect the work that was being done to implement the software, administrative functions transitioned to the new owner. and HECO wanted assurances from Oracle that it would honor the terms of the contract that was negotiated between HECO and SPL Worldgroup. Without executing a formal letter of agreement, HECO has been withholding payment until the issue could be resolved. The $676,000 includes the 2007 invoices for software configuration, and software interface, coding, installation, and costs for testing of the software that were not paid in 2007, pending the execution of the document from Oracle, and the remaining project expenses that have been incurred but without incurring any additional AFUDC in 2008. The invoices that were withheld in 2007 totaled $236,000 for deferred software implementation costs and are to be paid in 2008. As of March 31, 2008, as work continues on the implementation of the switching module, $79,000 of deferred expense was incurred (see HECO-835 page 2 of 2 lines 9, 10, and 11). For the remaining months April to December 2008, the amount of software development costs projected to be incurred is $361,000 (see HECO-835, page 1 of 2). The sum of the unpaid invoices $236,000, the $361,000 remaining costs, and the amount spent to date in 2008 of $79,000, totals $676,000. It is expected that the agreement with Oracle will be executed shortly and these expenses will be paid in 2008.

The implementation of this switching and powerflow module software was delayed to allow the dispatchers more time to train on the new OMS software before it went live. After the OMS and MWM software were placed in service in July 2007, more time was given to the dispatchers to work with the OMS/MWM system to better integrate the technology and processes into their work. Additionally, the extra time provided more opportunity for the PTMs to work with their laptops and enabled the HECO and Oracle project teams to address software problems that arose after the system went live. Work on the switching module began in the late August 2007 to early September 2007 time frame. From that time to the present the HECO and Oracle teams have been working to validate the powerflow module, to implement the system model changes necessary for the powerflow and switching module software, investigated the possible conversion of the thousands of switching orders HECO currently uses to perform switching on the system, reviewed and validated the switching development function, and worked on the configuration of the switching module to ensure that all the required information and switching steps were consistently developed. This detailed and tedious work is absolutely necessary because the switching procedures are done to de-energize a portion of the system so that crews can safely work on the system. Problems in the switching module if not detected could result in a serious accident if the switching orders are not generated correctly.

<u>Preventive Inspections</u>

Q. Why are the costs for preventive inspection of the T&D system increasing?

A. Preventive inspection expenses for underground cables are increasing because “Cable Faults” continue to be ranked the highest cause of outages affecting HECO’s customers since 2004. HECO-824 is provided to show the number of interruptions caused by cable faults for the period between 2000 and 2007. To address this reliability issue, HECO is implementing a program in 2008 where HECO crews will perform very low frequency ("VLF") testing on underground cables that have experienced multiple outages. VLF testing is a designed to uncover the weak spots on the cable by applying a test voltage at very low frequency for a specified duration. The weak spots are uncovered when there is a failure on a section of cable. HECO crews then repair or replace the failed cable and the test is conducted again to determine if there are other areas of weakness on the cable. At the point when the cable is able to withstand the test duration without any failures, the cable is determined to be reliable and placed back in service. These tests are time-consuming because the cable has to be de-energized and each phase of the cable individually tested for a given duration and then, if the cable fails the test, the failed section of cable has to be found then repaired or replaced and the test conducted again until the crew determines that the cable has passed the test. Although the tests may take a few hours to conduct, it is the fault finding and repairing of the cable that may be time-consuming which could then mean that overtime is necessary to complete the test.

However, conducting these tests reduces the potential of the cable failing after being returned to service. HECO has experienced situations when a cable failed, the problem was found and repaired and the cable placed back in service and after only a few weeks failed again as a result of another problem. When customers experience multiple outages their activities are disrupted and they become dissatisfied with their reliability. This leads to frustration and complaints to HECO. Using this process to identify the weak spots in the cable will lower the potential for multiple outages from underground cables

<u>New Metering Technology</u>

Q. Please describe the Advanced Metering Infrastructure ("AMI") project.

A. The proposed AMI project includes the installation of advanced solid state meters at residential and commercial/industrial customer sites, a two-way, wireless communications network, a Meter Data Management System ("MDMS"), integration of the MDMS with the CIS and support for the OMS. AMI meters and communications networks will be installed on the islands of Oahu, Maui and Hawaii, while a shared MDMS will be centrally located at HECO. Approximately 400,000 meters will be replaced on Oahu, Maui and the Big Island between 2010 and 2015.

AMI will provide two-way communications between HECO, MECO, and HELCO (collectively, the "Companies"), and the respective utilities' customer meters to allow the Companies to obtain consumption reads, energized states, and voltage status at individual premises much more frequently than the monthly billing cycle as well as "on demand." At selected customer sites, meters will be equipped with a remote reconnect/disconnect feature. These capabilities will allow the Companies to enhance customer services, revenue management, distribution operations and support outage management and improved reliability.

In conjunction with a future Demand Response ("DR") program, AMI enables the Companies' customers to reduce and/or shift energy usage in response to time differentiated energy prices[7]. Furthermore, DR technologies, such as smart programmable/controllable thermostats, smart load cycling controls and in-premise displays, allow customers to execute their choices conveniently.

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[7] Docket 2008-0074, Dynamic Pricing Pilot Program, was filed with the Commission on April 24, 2008. AMI meters have been proposed to gather the necessary interval data to support this program.

The AMI communication and smart metering infrastructure also provides a foundation for the creation of the Smart Grid. A Smart Grid combines intelligent electronic devices (smart relays and distribution automation devices) and advanced applications that utilize timely data on customer loads and voltages through AMI and potential load reductions through DR. AMI and DR together offer important alternatives, in addition to renewable energy, to help address global energy supply and environmental issues.

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

A. HECO has implemented pilot AMI projects using Research and Development ("R&D") funding. Please refer to the testimony of Mr. Bruce Tamashiro, HECO T-14, for a discussion of the pilot AMI R&D projects.

Additionally, AMI meters were installed in 2007 to support HECO's 2008-2009 Class Load Study and to further explore AMI network coverage and performance. Approximately 6,680 AMI meters have been deployed to date[8] and additional AMI meters may be installed in 2008 and 2009 to test next generation products, including those to support HECO's Dynamic Pricing Pilot program. HECO's plans with respect to the timing of a full-scale AMI project roll-out are discussed in further detail by Mr. Alm at HECO T-1.

Q. What AMI project costs are included in the test year?

A. T&D O&M expenses of $853,000 are projected to be incurred for the AMI project in 2009. This projection includes the labor and outside services costs for project management, preliminary engineering, and regulatory support for the AMI application to the Commission which is planned to be filed in the second half

[8] Figures are current as of 2/8/08.

of 2008. The table below reflects the breakdown of estimated costs that are included in the test year.

HECO AMI Project Cost T&D O&M (2009)	
Labor	$261,079
Outside Services	$426,516
Overheads	$165,629
Total	$853,224

PTM Switching Operations

Q. Please explain the increase of $1,002,766, as shown in exhibit HECO-830 for the PTM switching expense, Program P0000740 PTM switching operations.

A. Program P0000740 PTM switching operations in HECO-830 shows a total increase of $1,256,000 over 2007 Recorded expenses. This amount is composed of the following:

- Distribution Maintenance - $194,030
- Distribution Operations - $ 1,002,766
- Transmission Operations - $ 59,764

The increase in PTM switching operations expense is due to a staffing increase in the Field Operations section that is necessary to provide additional system coverage during each shift and for succession planning. The Field Operations section is comprised of PTMs, troublemen (“TM”), and apprentice troublemen. In 2007, the section maintained an average staffing level of 21 PTMs. The 2009 test year estimate is based on a staffing level of 26 PTMs. This staffing level is necessary to provide the following essential services in a timely manner and for the safe and reliable operation of the T&D system:

- Switching to provide electrical clearances so work can be safely performed on a de-energized system;
- First responder for emergencies on the system. Timely response is essential to ensure that the public is not harmed by downed facilities due to automobile accidents, storms, etc.;
- First responder for outages to ensure timely restoration of electrical services; and
- Response to customer complaints or electrical service problems— for example, low voltage, partial power, flickering lights, etc.

To effectively provide these essential services the 26 PTMs and/or TMs are deployed to cover the island of Oahu on a 24 hour by 7 day coverage as follows:

- Six Town PTMs for two to three-man rotation coverage are needed to sustain adequate manpower in the Honolulu, Waikiki and Hawaii Kai areas, due to the highly commercialized and condensed residential demands. This staffing level provides a minimum of two PTMs covering the town area, seven-days per week between the hours of 6 a.m. to 10 p.m.
- Six Leeward PTMs for two to three-man rotation coverage are needed to sustain adequate manpower in the growing Central Oahu, Ewa Plain, Leeward, and North Shore areas. This staffing level provides a minimum of two PTM’s covering seven-days per week between the hours of 6 a.m. to 10 p.m. Currently only a single PTM covers the entire area. With the

growth expected for the "second city" the second PTM is needed to provide the essential services noted above.

- Three Windward PTMs for one to three-man rotation to provide coverage in the Waimanalo, Windward, and North Shore areas. This staffing level provides a minimum of one PTM covering seven days per week between the hours of 6 a.m. to 10 p.m.
- Three Midnight PTMs for one to three-man rotation to provide coverage, island–wide, during the midnight shift. This staffing level provides a minimum of one PTM covering seven days per week between the hours of 10 p.m. and 6 a.m.
- Three Relief PTMs for supplemental coverage during the morning and night shift periods. This staffing level provides island-wide mobility from Monday through Friday and provides for vacation/sickness relief.
- Four TM and/or Apprentices for trouble-shooting coverage, island-wide, from Monday through Friday with shift ranges from 6 a.m. to 10 p.m. This staffing level provides for succession planning due to retirements, transfers, etc., and
- One senior PTM to fill the primary role of "Trainer" for the TM and apprentice TMs.

Q. Will the additional staff assist succession planning?

A. Yes. It takes approximately 6.5 years to fully train a PTM. The entry level for PTMs is the senior helper. The employee spends 6 months as a senior helper. Then with satisfactory performance, the employee is enrolled into the TM apprentice program. This is a three year program after which the employee is promoted to a 1st Year TM position. After one year, the employee is then promoted to a TM for another year. Depending on vacancies at the PTM level, is the employee may then be promoted to a 1st Year PTM. After one year in the 1st year PTM position, the employee is promoted to PTM. Because of the long training period, several TM apprentices are needed at all times for succession planning to fill PTM vacancies caused by retirements, promotions and transfers.

As of June 24, 2008, the Field Operations section was staffed with one senior PTM, 18 PTMs, three TMs and one apprentice, for a total of 23 employees. The C&M department is currently in the process of transferring four lineman apprentices to TM apprentices to reach a staffing level of 27. While this is one more than the 2009 test year employee estimate of 26, the Field Operations section expects a PTM to retire later this year. These are internal transfers within the C&M department so they will not change the overall C&M department employee staffing count. But with the transfer of the lineman apprentices to TM apprentices, there will be a shift from capital to O&M in the test year as TM apprentices charge their time to the same O&M work activities as the PTM or senior PTM who provides on-the-job training.

CIS Training

Q. What organizations in the Company will receive CIS training?

A. CIS is a new customer information system that is currently being implemented at HECO and will replace HECO's existing ACCESS system. The Company anticipates that CIS will be placed into service in May of 2009. There are a number of different departments in Energy Delivery that will use CIS. For example, in C&M customer information is needed when planning an outage of a portion of a circuit or to replace a distribution transformer. To prepare for this scheduled outage, the customers served by that portion of the circuit or by the distribution transformer may be identified in CIS so that notices may be sent to them. The CIS will also used by the dispatchers in SOD to identify the electric circuit that serves the customer when the customer calls to report a problem or an outage. These examples represent a very small subset of the functions that are available in the CIS. The new CIS will have more functionality than the existing ACCESS system and, like any new system, will require that employees be trained on it to maximize its use. In the test year, an estimated $526,000 of CIS training expenses for the following departments is budgeted:

1)	Customer Installations	$360,000
2)	C&M	$ 62,000
3)	SOD	$103,000
4)	Total	$525,000 (totals don't match due to rounding)

For a discussion of the new CIS and the project status, please refer to Mr. Darren Yamamoto's testimony, HECO T-9.

<u>Distribution Maintenance Expense</u>

Q. What items are included in Distribution Maintenance expense?

A. Distribution maintenance expense includes labor and non-labor costs as shown in HECO-809 to support activities such as maintenance and repairs to distribution substation equipment and facilities, distribution lines and cables, tree trimming, and testing and treating wood distribution poles. The corresponding NARUC accounts for Distribution Maintenance are detailed further in HECO-WP-804.

Q. How does the 2009 test year estimate for Distribution Maintenance expense compare to previous years?

A. HECO-812 shows HECO's Distribution Maintenance expenses from recorded 2003 through 2007, 2008 budget and the 2009 test year estimate. The overall trend shows an increase in Distribution Maintenance expenses since 2003. The 2007 recorded expense was $14,908,000 and the 2009 test year estimate is $16,880,000, which is $1,972,000 higher than the 2007 recorded Distribution Maintenance expense.

Q. Please explain what factors contributed to the $1,972,000 increase.

A. The $1,972,000 increase in Distribution Maintenance expense compared to 2007 recorded is primarily the result of the increases in C&M's Distribution Maintenance Programs as shown in HECO-830, page 1 of 3. The major increases are described in the following:

1) An increase of $399,000, as shown in HECO-830, Program P0000126, which is attributed to an increase in the VM Program expenses for contractors to address the substantial growth in vegetation around HECO's distribution lines;
2) An increase of $411,000, as shown in HECO-830, Program P3400000, which is attributed to increased expenses for the wood pole repair and replacement program;
3) An increase of $371,000, as shown in HECO-830, Program P0000127, which in part is attributed to an increase in the test and treat wood pole program for contractors to increase the number of poles inspected and treated for termites and/or rot;
4) An increase of $194,000, as shown in HECO-830, Program P0000740, which is attributed to an increase in staffing of PTM's for additional coverage and succession planning as previously explained in my testimony; and
5) An increase of nearly $1,077,000 as shown in HECO-830, Program P0000122. However, this amount is offset by the reallocation of costs from

Program P0000359 Corrective Maintenance of T&D Systems which shows a decrease of approximately $822,000. This results in a net increase between the two programs, P0000122 and P0000359, of approximately $255,000. This increase is a result of historical trending. As previously mentioned in my testimony, Corrective Programs are based on trends using historical costs. As shown in exhibit HECO-824, cable fault has been the top cause of interruptions to electrical service since 2004.

Vegetation Management - Distribution

Q. How does the VM Program impact distribution maintenance expenses?

A. As described earlier in my testimony, vegetation around the distribution lines will have a direct impact on the reliability of HECO's customers. As shown in HECO-824, outages caused by "Trees/Branches In Lines" was ranked the third highest cause of outages in the year 2007. The VM program expenses and the recent organization of the workload will potentially reduce the number of outages resulting from trees or vegetation.

Wood Pole Repair and Replacement

Q. Why are the expenses for wood pole repair and replacement increasing?

A. Distribution wood pole replacements are based on HECO's wood pole maintenance plan to address all known pole concerns by either replacing poles or restoring poles. HECO has approximately 75,000 wood poles on the system. To date, through inspections and data received from our Test and Treat Program, HECO has identified approximately 3,500 poles that need to be addressed. For these 3,500 poles, the goal is to restore or replace up to 1,000 poles a year, specifically restore 600 poles a year and replace 400 poles a year. In 2007, HECO restored 244 poles and replaced 257 poles. The increase in the test year expense of

$411,000 as shown in exhibit HECO-830 is primarily attributed to the "changeover" costs that are charged to O&M expense for these additional 143 wood pole replacements budgeted in the 2009 test year. "Changeover" costs are expensed and are costs associated with the reinstallation of property units, e.g. costs to move existing conductors from the existing pole to the replacement pole. During subsequent annual inspections and data collected from the Test and Treat program, wood poles will continue to be identified each year for either restoration or replacement.

<u>Test and Treat Wood Poles</u>

Q. Why are the expenses for test and treat program increasing?

A. HECO-830, Program P0000127, test and treat wood poles, shows an increase of $371,000 under Distribution Maintenance expense. However part of this increase is offset by a decrease in the same program under Transmission Maintenance expense. Therefore, the net variance for Program P0000127, as shown in exhibit HECO-830, is $227,000. This net increase is attributed to an increase in the number of poles planned to be test and treated for termites and/or rot in the 2009 test year. Also, as noted previously, data from this test and treat program is used to determine which poles that need to be restored or replaced. In 2007, HECO's test and treat contractor inspected and treated 12,945 wood poles. HECO's goal is to test and treat up to 15,000 poles per year. This net increase of $227,000 in the 2009 test year will increase the number of wood poles to be tested and treated by HECO's test and treat contractor. As a result, HECO will be able to inhibit the deterioration of more wood poles in the test year (and into the future) and reduce the likelihood of wood poles falling and causing outages and/or damage before they are restored or replaced.

T&D MATERIALS INVENTORY

Escalation in Cost of Goods and Services

Q. Has HECO conducted any studies to evaluate the escalation in the price of goods and services?

A. HECO receives monthly updates via our key suppliers on market prices of commodities that affect goods price escalation. These commodity indices are published via The Institute for Supply Management Prices Paid Index ("PPI").

Q. What has been the trend in commodity prices in recent years?

A. The rising cost of oil coupled with global market demand has resulted in tremendous price increases to commodities in recent years. In addition to metals used in the power generation materials purchased by HECO, prices are also affected by the rising cost of transportation based on oil prices. Price indices are shown in HECO-826 for the period from January 2005 to March, 2008. Prices for copper and aluminum have risen 162.8% and 55.5%, respectively, from January, 2005 to March, 2008. Many inventory stock items including cables and conductors are made of copper and aluminum. Crude oil has increased 125% from January 2005 to March, 2008 to $105.42 per barrel, an amount that has already been surpassed as of this writing. Key commodity price indices shown in HECO-826 indicate a dramatic escalation from the December 2007 to the first quarter of 2008 indices, with end-of-March 2008 indices showing a quarterly increase ranging from 14.9% for crude oil to 36% for hot rolled steel sheet.

Q. How has this impacted HECO's material purchases?

A. The rising cost of commodities and transportation continues to increase the price paid for HECO's materials. While price increases are dependent upon many factors such as the quantity of a specific commodity in a product and other non-material costs in the product, suppliers are passing on their higher costs for raw materials through increased prices to HECO.

Q. What is the 2009 T&D materials inventory test year estimate?

A. The average T&D materials inventory is estimated to be $8,211,496 as shown on HECO-803.

Q. What is included in the T&D materials inventory?

A. The T&D materials inventory includes those items required in the day-to-day construction, operation and maintenance of the T&D system. It does not include distribution transformers or substation transformers as these items are pre-capitalized purchased.

Q. How many warehouses does HECO operate to store and distribute the T&D materials inventory?

A. HECO operates three materials warehouses which are located at the following base yards:

1) Ward Avenue;
2) Waiau; and
3) Koolau.

Q. Why is the test year 2009 T&D materials inventory reasonable?

A. Estimates for the 2009 test year T&D materials inventory were derived by taking the May 2008 month-ending values and forecasting for increased values attributed to higher material replacement costs based on historical trends. This informed decision was aided by utilizing monthly recorded figures that portray inventory levels and movement. Values recorded monthly are: year-end inventory, average inventory, annual total issues, and annual total receipts as shown on HECO-803.

Calculations supporting the 2008 and 2009 test year forecast inventory values are shown on HECO-WP-812.

Q. How does the 2009 test year T&D materials inventory compare with levels recorded in preceding years?

A. The average T&D materials inventory for 2009 test year increases $1,529,516 or 23% from the average T&D materials for recorded 2007 as shown on HECO-803. This is higher than the average annual increase of 9.4% per year over the period from 2004 to 2008.

Q. Please explain the factors attributed to the 2009 estimated materials average inventory increase of $1,529,516 over recorded 2007.

A. The Company continues to experience price increases resulting from key commodity increases as discussed above. The historical trends used to forecast the remainder of 2008 to arrive at a 2008 year-end inventory value and to forecast 2009 test year year-end inventory incorporate the continually rising cost of inventory replacement materials in line with commodity price indices.

SUMMARY

Q. Mr. Young, please summarize your testimony.

A. HECO's test year T&D O&M expense is estimated to be $44,459,000 for 2009 test year, as shown in HECO-801, with a breakdown of $13,967,000 for transmission and $30,492,000 for distribution as shown in HECO-802.

HECO's goal is to deliver reliable, cost-effective service to its customers. The costs associated with this goal have been highlighted in this testimony.

HECO is strategically managing expenses to ensure that reliable service can be sustained. HECO's 2009 test year T&D O&M expense estimate of $44,459,000 is 24% higher than actual 2007 T&D O&M expenses, as shown in HECO-807.

This increased level of expenses is critical, given the increasing scope and age of the T&D system. The T&D materials inventory is forecasted to be an average of $8,211,496 as shown in HECO-803. Rising material costs are a primary contributor to the increase in average inventory value.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY, INC.

ROBERT K. S. YOUNG

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company, Inc. 820 Ward Avenue, Honolulu, HI 96814
POSITION:	Manager, System Operation Department. Hawaiian Electric Company, Inc. (April 2005 to present)
YEARS OF SERVICE:	30 Years
EDUCATION:	University of Hawaii
DEGREE:	Bachelor of Science, Electrical Engineering Masters, Business Administration
PREVIOUS POSITIONS:	Manager, New Dispatch Center Project Hawaiian Electric Company, Inc. (December 2002 to March 2005)
	Manager, System Operation Department Hawaiian Electric Company, Inc. (February 1999 to November 2002)
	Senior Engineer, System Operation Department Hawaiian Electric Company, Inc. (October 1991 to January 1999)
	Electrical Engineer, System Operation Department Hawaiian Electric Company, Inc. (November 1988 to September 1991)
	Electrical Engineer, System Planning Hawaiian Electric Company, Inc. (May 1978 to October 1988)
OTHER QUALIFICATIONS:	Licensed Professional Engineer, Electrical State of Hawaii 1983

Hawaiian Electric Company, Inc.
2009 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION & MAINTENANCE EXPENSE
($ Thousands)

	2009 TEST YEAR
TOTAL T&D O&M EXPENSE	44,459

Source: HECO-802
Note: Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2009 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION & MAINTENANCE EXPENSE
($ Thousands)

		(A) OPERATING BUDGET	(B) BUDGET RATEMAKING ADJUSTMENTS	(C) NORMAL-IZATION	(D) 2009 TEST YEAR ESTIMATE
1	Transmission Expense	$ 14,025	$ (58)	$ -	$ 13,967
2	Distribution Expense	$ 30,511	$ (19)	$ -	$ 30,492
3	TOTAL T&D O&M EXPENSE	$ 44,536	$ (77)	$ -	$ 44,459

Source: HECO-833 and HECO-834.
Note: Figures may not total exactly due to rounding.

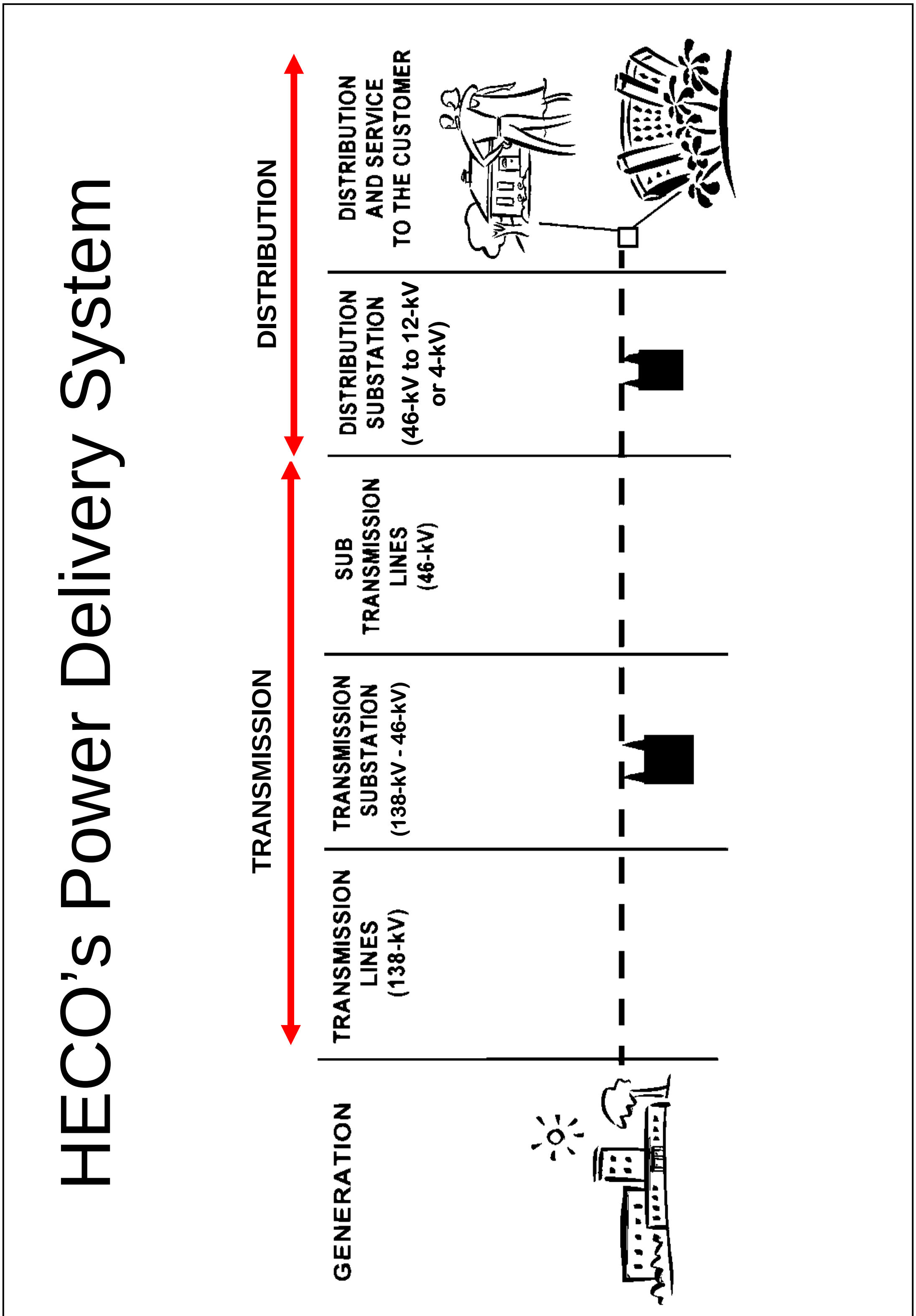
Hawaiian Electric Company, Inc.
2009 TEST YEAR

TRANSMISSION AND DISTRIBUTION MATERIAL INVENTORY

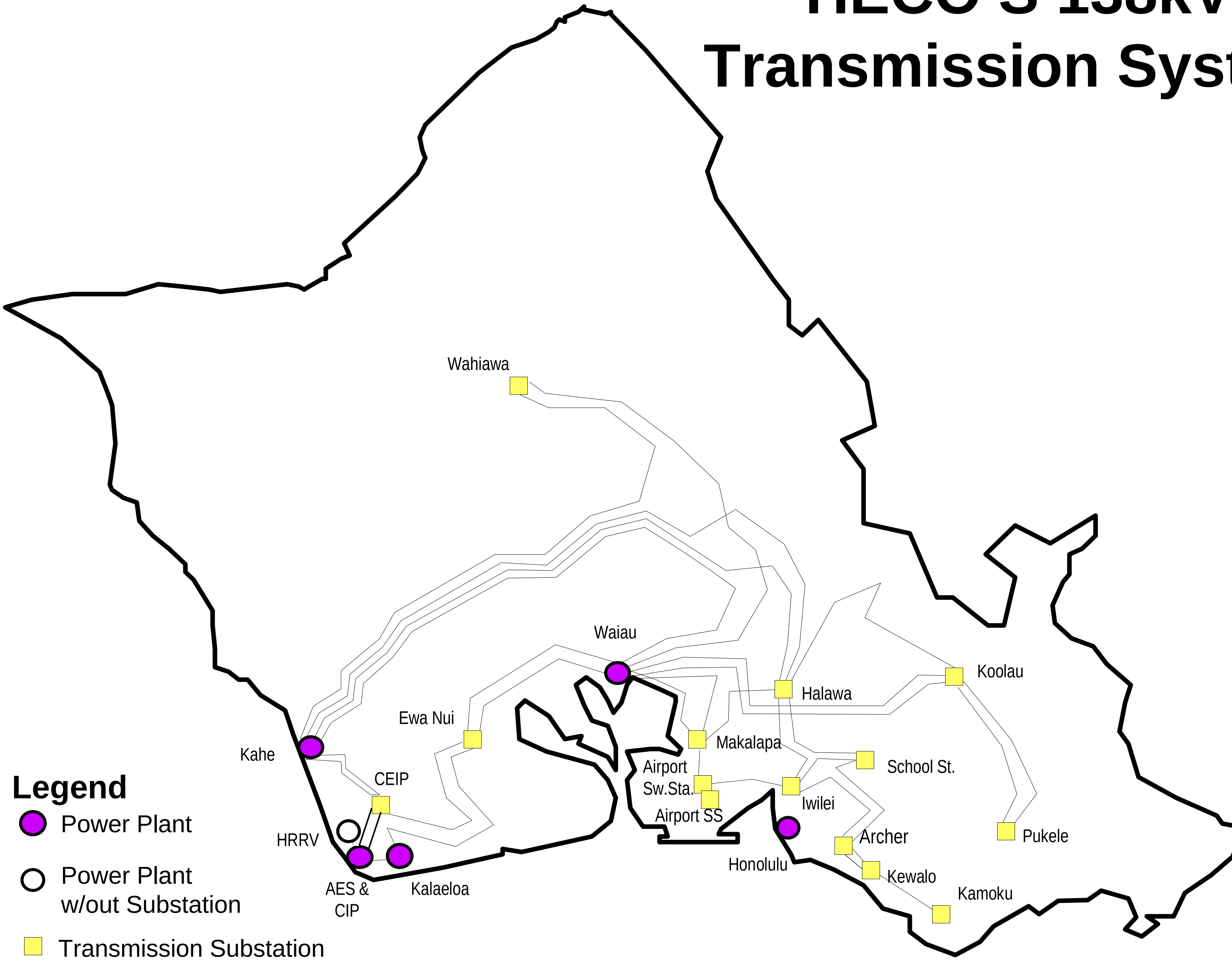
		RECORDED					OPERATING BUDGET	TEST YEAR ESTIMATE	2007 vs 2009	
		(A) 2003	(B) 2004	(C) 2005	(D) 2006	(E) 2007	(F) 2008	(G) 2009	(H=G-E) $	(I =H/E) %
1	Year-End Value	$ 5,728,651	$ 5,554,439	$ 6,645,048	$ 6,360,536	$ 6,851,537	$ 7,842,880	$ 8,580,111	$ 1,728,574	25
2	Average Value	$ 5,134,358	$ 5,237,827	$ 6,069,256	$ 6,580,201	$ 6,681,980	$ 7,347,209	$ 8,211,496	$ 1,529,516	23
3	Total Issues	$ 6,584,028	$ 7,838,220	$ 6,582,250	$ 8,341,937	$ 9,806,146	$ 8,025,836	$ 10,510,714	$ 704,568	7
	Total Receipts	$ 7,817,868	$ 7,086,024	$ 7,857,576	$ 7,885,673	$ 10,167,293	$ 9,017,179	$ 11,247,945	$ 1,080,652	11

Source: HECO-WP-812

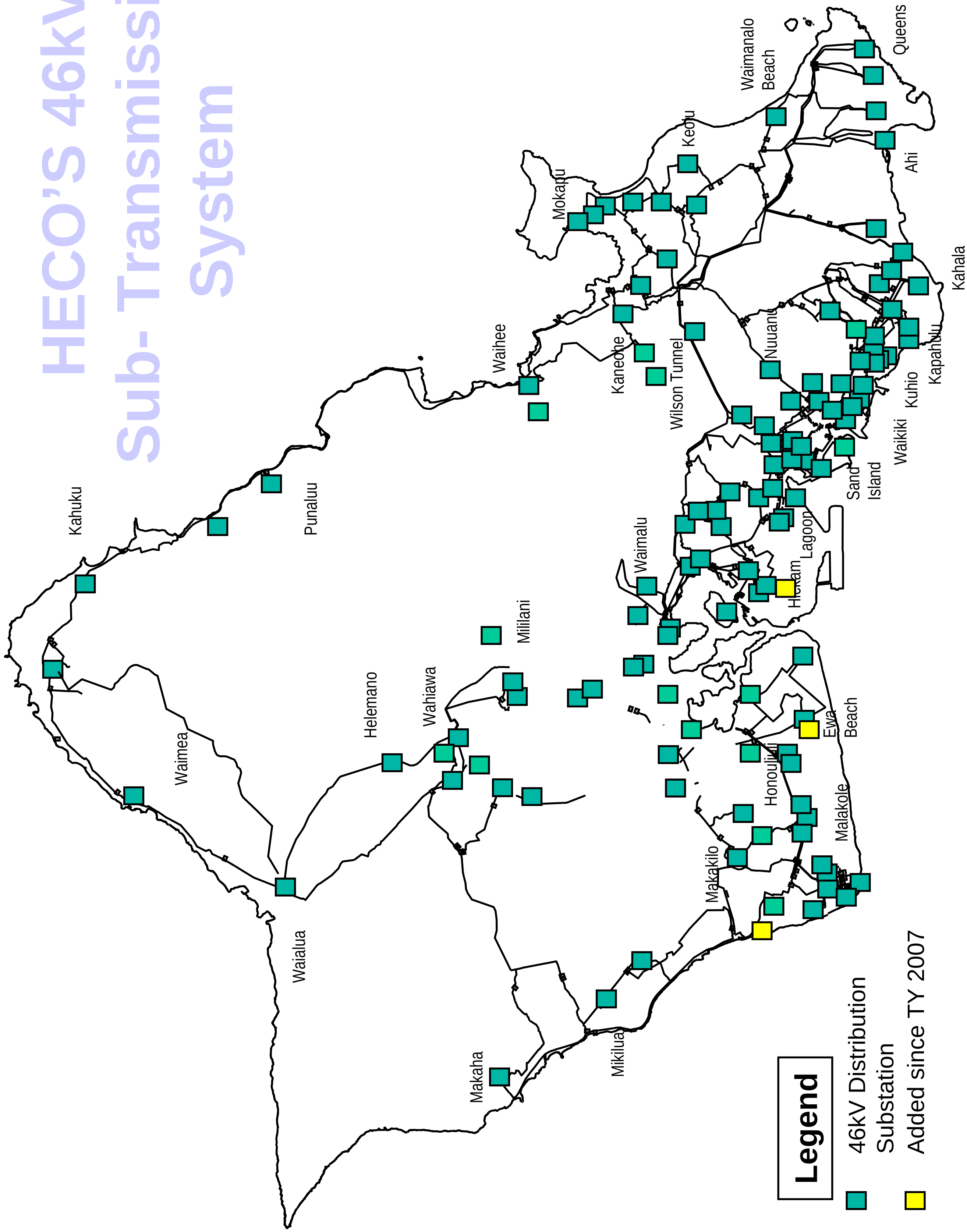
Note:
Figures may not total exactly due to rounding.


HECO's Power Delivery System
TRANSMISSION
DISTRIBUTION
GENERATION
TRANSMISSION LINES (138-kV)
TRANSMISSION SUBSTATION (138-kV - 46-kV)
SUB TRANSMISSION LINES (46-kV)
DISTRIBUTION SUBSTATION (46-kV to 12-kV or 4-kV)
DISTRIBUTION AND SERVICE TO THE CUSTOMER

HECO'S 138kV Transmission System



HECO'S 46kV Sub- Transmission System



Hawaiian Electric Company, Inc.
2009 Test Year

TRANSMISSION & DISTRIBUTION O&M EXPENSE
($ Thousands)

		RECORDED					FORECAST	TEST YEAR ESTIMATE	2007 vs 2009	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H=G-E)	(I=H/E)
		2003	2004	2005	2006	2007	2008	2009	$	%
1	Transmission O&M	$6,989	$8,107	$7,831	$9,490	$10,365	$10,231	$13,967	$3,602	35
2	Distribution O&M	$17,219	$21,002	$23,042	$22,170	$25,575	$24,108	$30,493	$4,918	19
3	Total	$24,208	$29,109	$30,873	$31,660	$35,940	$34,339	$44,460	$8,520	24
4	Increase / (Decrease)		20%	6%	3%	14%	-4%	29%		

Source:
HECO-WP-101(A) pages 3 and 4, run date 6/6/08 Rpt. S1 for columns A-F
HECO-809 lines 7, 14&15 for column G

Note: Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2009 TEST YEAR

TRANSMISSION O&M EXPENSE
($ Thousands)

	Transmission Expense	2009 TEST YEAR ESTIMATE
1	Operations	$ 6,951
2	Maintenance	$ 7,016
3	Total	$ 13,967

Source:
HECO-809 lines 3, 6&7

Hawaiian Electric Company, Inc.
2009 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION AND MAINTENANCE EXPENSE
($ Thousands)

		(A) OPERATING BUDGET	(B) BUDGET RATEMAKING ADJUSTMENTS	(C) NORMAL-IZATION	(D) 2009 TEST YEAR ESTIMATE
	Transmission Operation				
1	Labor	$ 2,902	-	-	$ 2,902
2	Non-Labor	$ 4,114	(65)	-	$ 4,049
3	TOTAL	$ 7,016	(65)	-	$ 6,951
	Transmission Maintenance				
4	Labor	$ 2,083	-	-	$ 2,083
5	Non-Labor	$ 4,926	7	-	$ 4,933
6	TOTAL	$ 7,009	7	-	$ 7,016
7=3+6	TOTAL TRANS O&M	$ 14,025	(58)	-	$ 13,967
	Distribution Operation				
8	Labor	$ 6,712		-	$ 6,712
9	Non-Labor	$ 6,945	(44)	-	$ 6,901
10	TOTAL	$ 13,657	(44)	-	$ 13,613
	Distribution Maintenance				
11	Labor	$ 5,761	-	-	$ 5,761
12	Non-Labor	$ 11,094	25	-	$ 11,119
13	TOTAL	$ 16,855	25	-	$ 16,880
14=10+13	TOTAL DIST O&M	$ 30,512	(19)	-	$ 30,493
15=7+14	GRAND TOTAL O&M	$ 44,537	$ (77)	$ -	$ 44,460

Source:
HECO-WP-101(A) run date 6/6/08 pages 3&4 for column A
HECO-WP-810 for column B
Note: Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2009 TEST YEAR

TRANSMISSION O&M EXPENSE
($ Thousands)

		RECORDED					OPERATING BUDGET	TEST YEAR ESTIMATE	2007 vs 2009	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H=G-E)	(I=H/E)
		2003	2004	2005	2006	2007	2008	2009	$	%
1	Operation	$3,275	$3,532	$3,971	$4,236	$4,520	$5,071	$6,951	$ 2,431	54
2	Maintenance	$3,714	$4,574	$3,861	$5,253	$5,845	$5,161	$7,016	$ 1,171	20
3	Total	$6,989	$8,107	$7,832	$9,489	$10,365	$10,232	$13,967	$ 3,602	35
6	Increase / (Decrease)		16%	-3%	21%	9%	-1%	37%		

Source:
HECO-WP-101(A), page 3 run 6/6/08 Rpt. S1 for columns A-F
HECO-809 lines 3,6&7 for Column G
Note: Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2009 TEST YEAR

DISTRIBUTION O&M EXPENSE
($ Thousands)

	Distribution Expense	2009 TEST YEAR ESTIMATE
1	Operation	$ 13,613
2	Maintenance	$ 16,880
3	Total	$ 30,493

Source: HECO-809 lines 10, 13&14.
Note: Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2009 TEST YEAR
DISTRIBUTION O&M EXPENSE
($ Thousands)

		RECORDED					OPERATING BUDGET	TEST YEAR ESTIMATE	2007 vs 2009	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H=G-E)	(I=H/E)
		2003	2004	2005	2006	2007	2008	2009	$	%
1	Operation	$7,802	$8,404	$9,550	$9,040	$10,667	$10,285	$ 13,613	$2,946	28
2	Maintenance	$9,417	$12,597	$13,492	$13,130	$14,908	$13,823	$ 16,880	$1,972	13
3	Total	$17,219	$21,002	$23,042	$22,170	$25,575	$24,108	$ 30,493	$4,918	19
6	Increase / (Decrease)		22%	10%	-4%	15%	-6%	26%		

Source:
HECO-WP-101(A) page 4 run 6/6/08 Rpt. S1 for columns A-F
HECO-809 lines 10, 13&14 for column G
Note: Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2009 Test Year

AGING OF 138kV OVERHEAD TRANSMISSION LINES

	(A) Year	(B) Line-Age in Service (Mile-Years)	(C) Miles in Service (Miles)	(D) Average Age (Years)
1	2002 (recorded)	6636.4	213.6	31.1
2	2003 (recorded)	6850.0	213.6	32.1
3	2004 (recorded)	7063.6	213.6	33.1
4	2005 (recorded)	7277.2	213.6	34.1
5	2006 (recorded)	7490.8	213.6	35.1
6	2007 (recorded)	7704.4	213.6	36.1
7	2008 (forecast)	7918.0	213.6	37.1
8	2009 (forecast)	8131.6	213.6	38.1

138 kV OH Transmission Line Age (2009 Forecasted)

(A) Years	(B) Miles	(C) % of Total
30+ Years	167.0	78.2%
25+ Years	7.0	3.3%
20+ Years	10.3	4.8%
15+ Years	29.3	13.7%
10+ Years	0.0	0.0%
5+ Years	0.0	0.0%
0+ Years	0.0	0.0%

Source:
HECO-WP-706

Hawaiian Electric Company, Inc.
2009 Test Year

AGING OF 138kV UNDERGROUND TRANSMISSION LINES

	(A) Year	(B) Line-Age in Service (Mile-Years)	(C) Miles in Service (Miles)	(D) Average Age (Years)
1	2002 (recorded)	63.5	8.3	8.7
2	2003 (recorded)	71.8	8.3	8.7
3	2004 (recorded)	80.0	8.3	10.7
4	2005 (recorded)	88.3	8.3	11.7
5	2006 (recorded)	96.6	8.3	11.7
6	2007 (recorded)	104.9	8.3	12.7
7	2008 (forecast)	113.2	8.3	13.7
8	2009 (forecast)	121.5	8.3	14.7

138 kV UG Transmission Line Age (2007 Forecasted)

(A) Years	(B) Miles	(C) % of Total
30+ Years	0.0	0.0%
25+ Years	0.0	0.0%
20+ Years	0.0	0.0%
15+ Years	4.5	54.8%
10+ Years	0.5	6.5%
5+ Years	3.2	38.7%
0+ Years	0.0	0.0%

Source:
HECO-WP-706

Hawaiian Electric Company, Inc.
2009 Test Year

AGING OF 138kV TRANSMISSION TRANSFORMERS

	(A) Year	(B) Number in Service	(C) Total Age (Years)	(D) Avg Age (Years)
1	2002 (recorded)	46	1469	31.9
2	2003 (recorded)	46	1485	32.3
3	2004 (recorded)	46	1474	32.0
4	2005 (recorded)	46	**1520**	**33.0**
5	2006 (**recorded**)	46	1511	32.8
6	2007 (**recorded**)	46	1557	33.8
7	**2008 (forecast)**	**46**	**1481**	**32.2**
8	**2009 (forecast)**	**47**	**1529**	**32.5**

138 kV Transformer Age (**2009** Forecasted)

(A) Years	(B) Number of Transformers	(C) % of Total
30+ Years	31	**66%**
25+ Years	1	**2%**
20+ Years	**2**	**4%**
15+ Years	**3**	**6%**
10+ Years	**2**	**4%**
5+ Years	**3**	**6%**
0+ Years	**5**	**11%**

Source:
HECO-WP-708

Hawaiian Electric Company, Inc.
2009 Test Year

AGING OF DISTRIBUTION SUBSTATION TRANSFORMERS

	(A) Year	(B) Number in Service	(C) Total Age (Years)	(D) Avg Age (Years)
1	2002 (recorded)	254	7312	28.8
2	2003 (recorded)	257	7445	29.0
3	2004 (recorded)	258	7573	29.4
4	2005 (recorded)	265	7783	29.4
5	2006 (recorded)	265	7989	30.1
6	2007 (recorded)	268	8180	30.5
7	2008 (forecast)	271	8324	30.7
8	2009 (forecast)	271	8595	31.7

Distribution Substation Transformer Age (2009 Forecasted)

	(A) Years	(B) Number of Transformers	(C) % of Total
7	30+ Years	156	58%
8	25+ Years	12	4%
9	20+ Years	8	3%
10	15+ Years	32	12%
11	10+ Years	12	4%
12	5+ Years	23	8%
13	0+ Years	28	10%

Source:
HECO-WP-708

Hawaiian Electric Company, Inc.
2009 Test Year

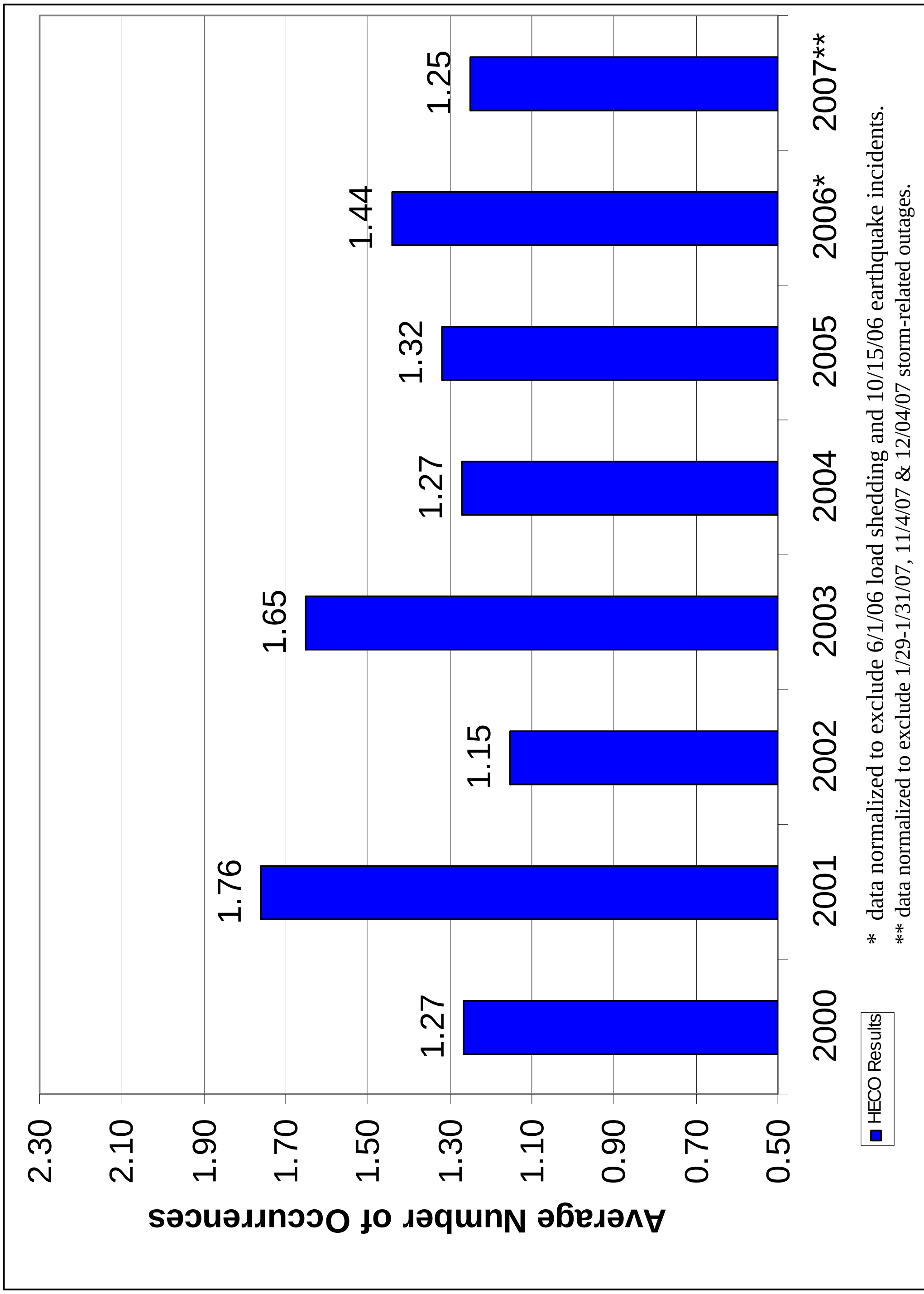
TRANSMISSION AND DISTRIBUTION UTILITY PLANT
YEAR-END TOTALS
($ Thousands)

	(A)	(B) Transmission	(C) Distribution	(D) Total	(E) Annual Increase
1	2009 (estimated)	620,430	1,245,065	1,865,495	67,589
2	2008 (estimated)	603,984	1,193,922	1,797,906	54,927
1	2007 (recorded)	588,298	1,154,681	1,742,979	54,459
2	2006 (recorded)	583,765	1,104,755	1,688,520	71,255
3	2005 (recorded)	557,934	1,059,331	1,617,265	65,352
4	2004 (recorded)	546,710	1,005,203	1,551,913	63,512
5	2003 (recorded)	533,656	954,745	1,488,401	162,598

Note: Transmission and distribution utility plant includes land and land rights.

Note:
Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
System Average Interruption Frequency
SAIF
Lower is Better

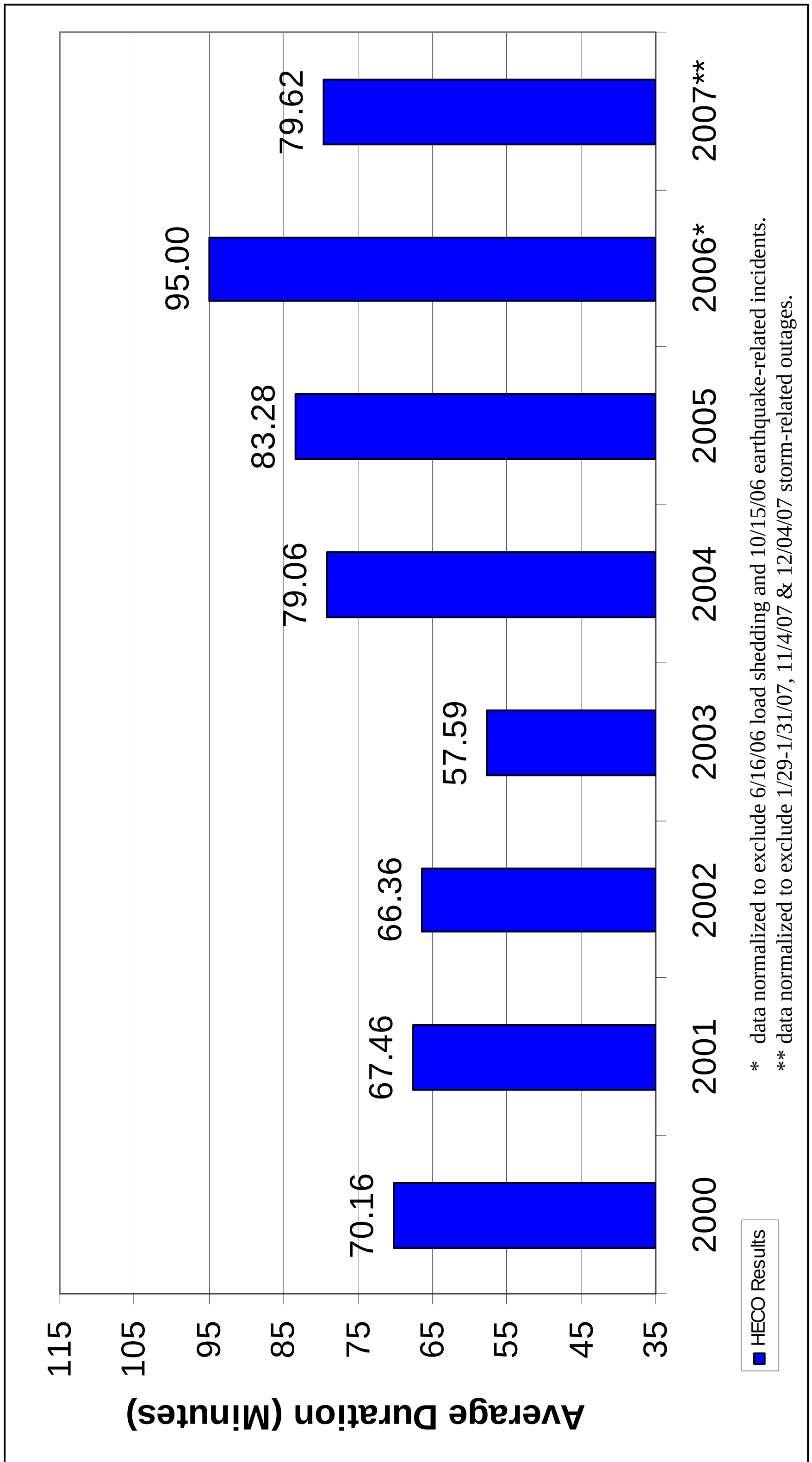


Hawaiian Electric Company, Inc.

Customer Average Interruption Duration

CAID

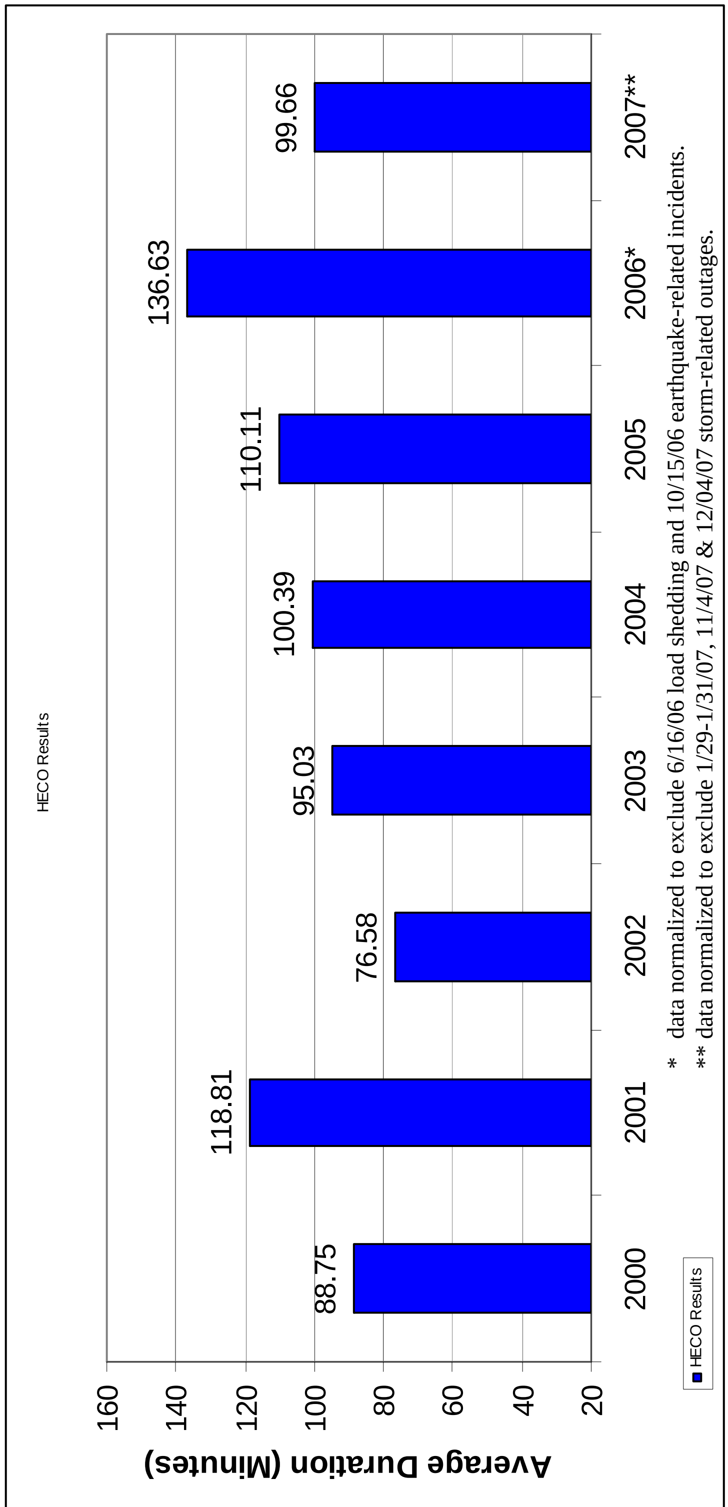
Lower is Better



* data normalized to exclude 6/16/06 load shedding and 10/15/06 earthquake-related incidents.

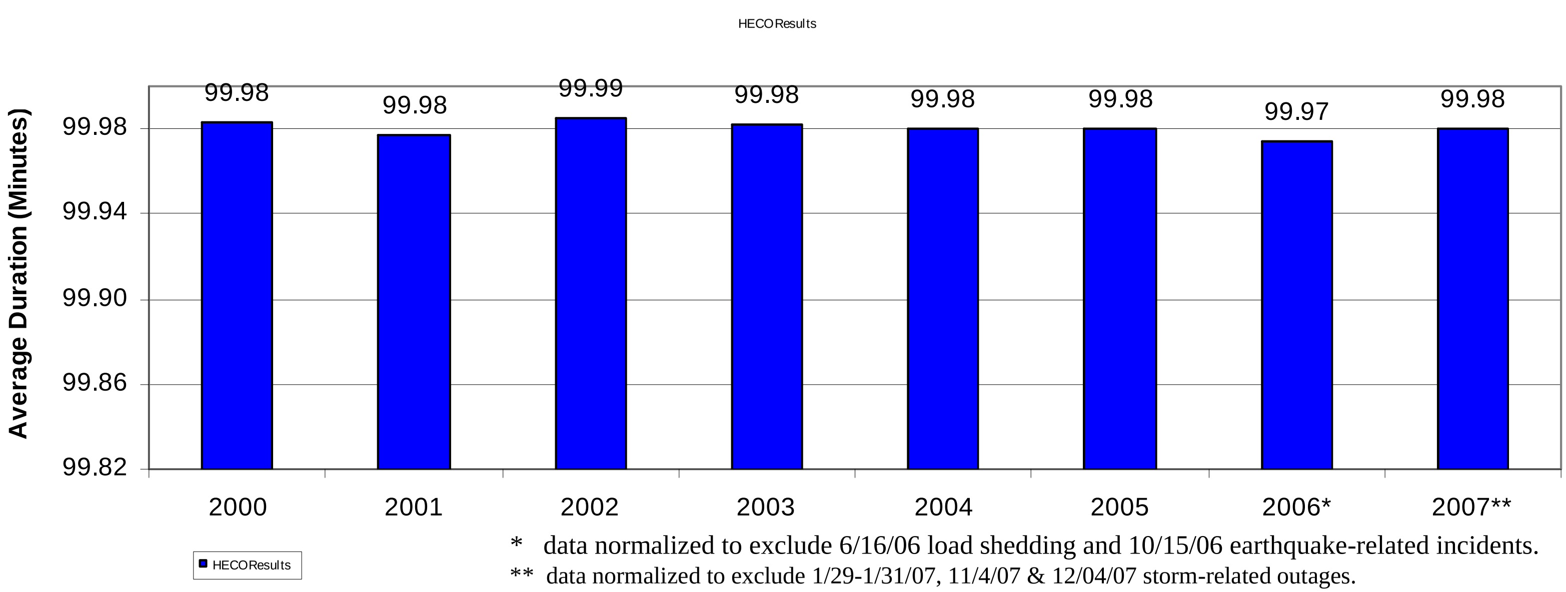
** data normalized to exclude 1/29-1/31/07, 11/4/07 & 12/04/07 storm-related outages.

Hawaiian Electric Company, Inc.
System Average Interruption Duration
SAID
Lower is Better



Hawaiian Electric Company, Inc.
Average Service Availability
ASA

Higher is Better



* data normalized to exclude 6/16/06 load shedding and 10/15/06 earthquake-related incidents.

** data normalized to exclude 1/29-1/31/07, 11/4/07 & 12/04/07 storm-related outages.

Hawaiian Electric Co., Inc.
2009 TEST YEAR

TRANSMISSION & DISTRIBUTION SYSTEM RELIABILITY
INDUSTRY INDICES

System Average Interruption Frequency (SAIF)

The number of customer interruptions per customer served during the year. This index indicates the average number of sustained interruptions experienced by all customers serviced on the system.

$$\text{SAIF} = \frac{\Sigma \text{ Number of Customer Interruptions Experienced During the Year}}{\text{Average Number of Customers Served During the Year}}$$

Customer Average Interruption Duration Index (CAID)

The interruption duration per customer interrupted during the year. This index indicates the average duration of an interruption for those customers affected by a sustained interruption.

$$\text{CAID} = \frac{\Sigma \text{ Duration of Interruptions X Number of Customers Affected}}{\Sigma \text{ Number of Customer Interruptions Experienced for the Year}}$$

System Average Interruption Duration Index (SAID)

The interruption duration per customer served during the year. This index indicates the average interruption time experienced by all customers serviced on the system.

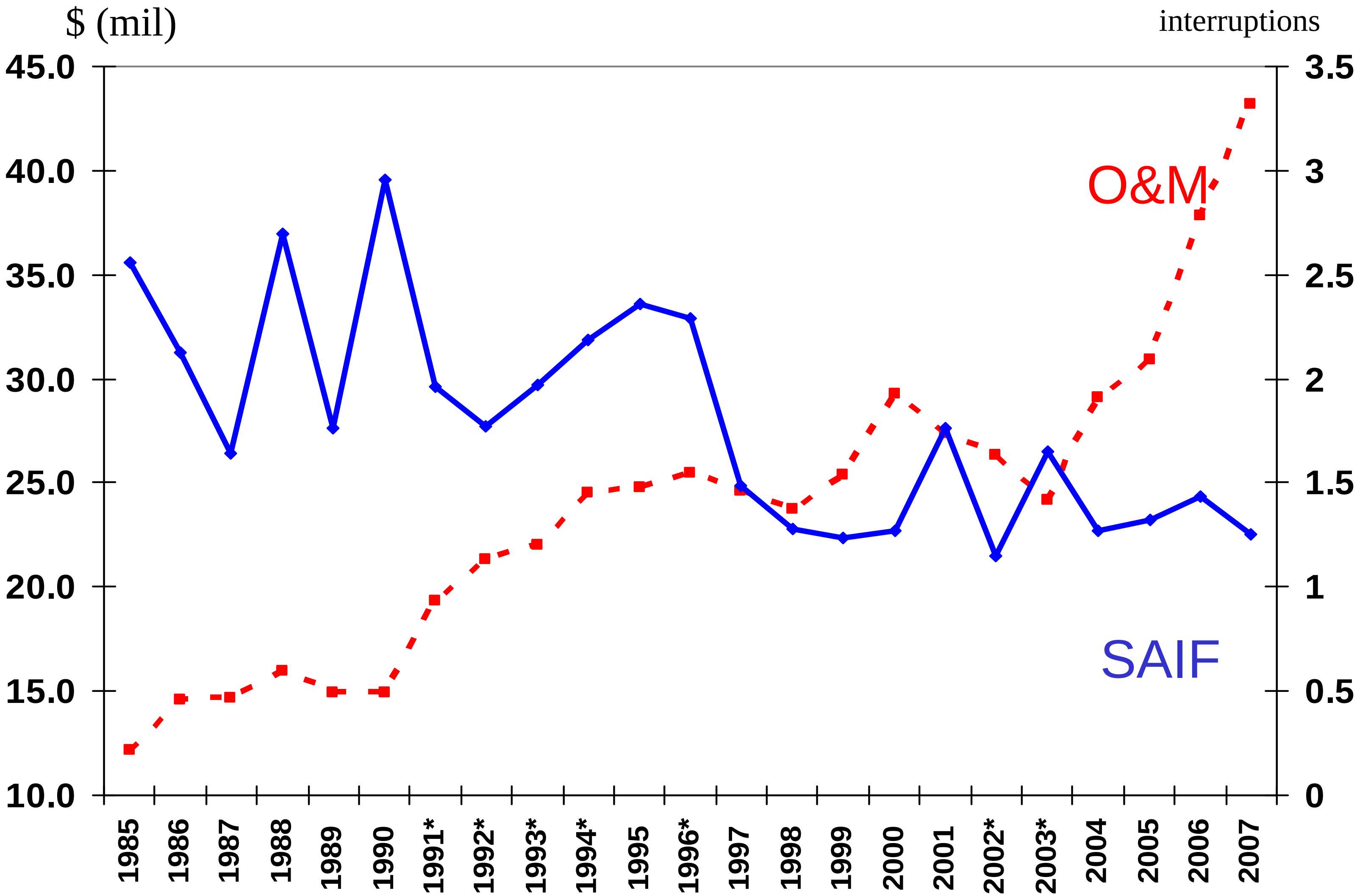
$$\text{SAID} = \frac{\Sigma \text{ Duration of Interruptions X Number of Customers Affected}}{\text{Average Number of Customers Served During the Year}}$$

Average Service Availability (ASA)

Total customer hours actually served as a percentage of total customer hours possible during the year. This indicates the extent to which electrical service was available to all customers. This index has been commonly referred to as the “Index of reliability.” A customer-hour is calculated by multiplying the number of customers by the number of hours in the period being analyzed.

$$\text{ASA} = \frac{\Sigma \text{ Number of Customer Hours Actually Served during the Year}}{\Sigma\text{Number of Customer Hours Possible during the Year}}$$

Hawaiian Electric Company, Inc.
Investing in Reliability
SAIF and O&M Expenses

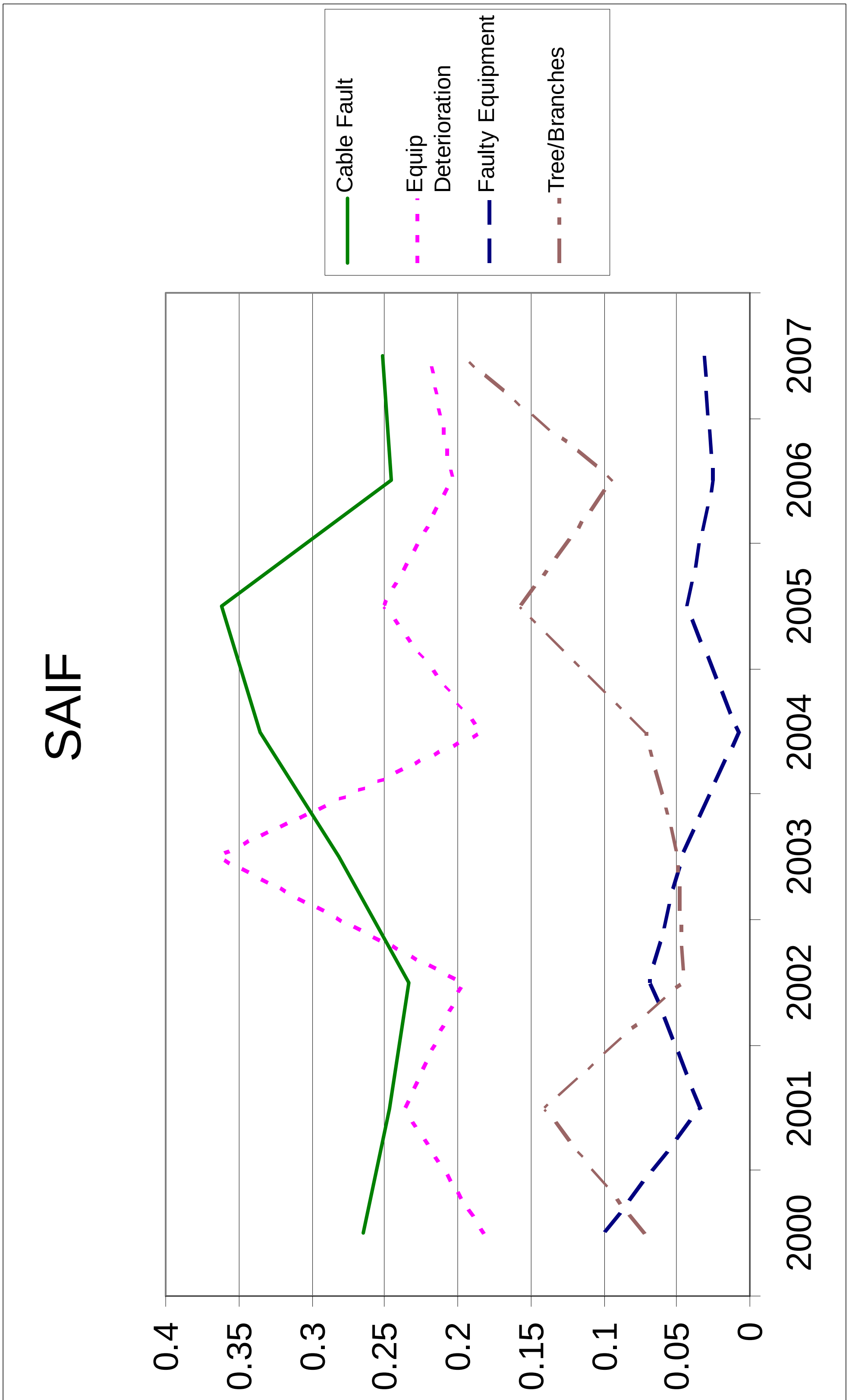


* Data normalized.- see page 2 for list of events

Hawaiian Electric Company, Inc.
SAIF Normalized Data Explanations

Year	Reason for Normalization
1991	April 9 – island wide blackout
1992	September 11 - Hurricane Iniki
1993	August 24 - Koolau pole fire
1994	October 30 - Pukele substation outage
1996	November 15 - AES load shedding
2002	December 19 - AES load shedding
2004	January 14-15, 2004 high wind outage February 26, 2004 – storm March 3, 2004 – Pukele outage
2006	June 1, 2006 – load shedding incident October 15, 2006 – earthquake incident
2007	January 29-31, 2007 – wind storm November 4-5, 2007 – storm December 4-6, 2007 - storm

Hawaiian Electric Company, Inc.
Major Cause of Interruptions



Hawaiian Electric Company, Inc.
2009 Test Year

PERIOD ENDING STAFFING LEVELS

		RECORDED END OF YEAR		2008 YTD RECORDED	2008 EOY PROJECTED	TEST YEAR ESTIMATE
		(A) 2006	(B) 2007	(C) 3/31/2008	(D) 12/31/2008	(E) 2009
1	Construction & Maintenance	220	215	213	220	220
2	System Operation	105	114	115	117	118
3	Support Services	80	84	84	85	85
4	Engineering	84	83	84	85	85
5	VP - Energy Delivery	2	2	2	2	2
6	Total	491	498	498	509	510

Source:
HECO-1503

Source:
Exhibit HECO-1403

Hawaiian Electric Company, Inc.
2009 TEST YEAR

Updated 6/11/08

Price Indices Market Data	Comex Copper (per pound)	Midwest Aluminum (per pound)	WTI Crude Oil (per barrel)	Hot Rolled Steel Sheet (per short ton)	E-Steel Index (per short ton)
Jan-05	1.44995	0.90438	46.85	640	130.4183
Feb-05	1.46645	0.92810	48.05	622	127.3764
Mar-05	1.48680	0.97447	54.63	605	126.6160
Apr-05	1.49340	0.92990	53.22	575	122.8137
May-05	1.47580	0.85513	49.87	535	120.5323
Jun-05	1.62186	0.83887	56.42	495	121.6730
Jul-05	1.63218	0.85200	59.03	460	117.8707
Aug-05	1.71640	0.88529	64.99	435	150.4183
Sep-05	1.75357	0.87123	65.55	500	150.7985
Oct-05	1.90302	0.92019	62.27	535	153.0798
Nov-05	2.01130	0.97954	58.34	535	162.5856
Dec-05	2.17245	1.06958	59.45	550	164.4867
2005 avg.	**1.68193**	**0.91739**	**56.56**	**541**	**137.3891**
Jan-06	2.18258	1.13103	65.54	545	187.6806
Feb-06	2.25079	1.16849	61.93	545	184.0304
Mar-06	2.32409	1.15827	62.97	550	184.3346
Apr-06	2.96853	1.24583	70.16	560	181.3688
May-06	3.75861	1.35788	70.96	575	179.5437
Jun-06	3.39648	1.18455	70.97	605	180.2281
Jul-06	3.62321	1.19951	74.46	630	185.3992
Aug-06	3.53061	1.17549	73.08	630	186.6920
Sep-06	3.46358	1.17985	63.90	620	186.5399
Oct-06	3.39400	1.25990	59.14	600	184.7148
Nov-06	3.16560	1.27120	59.40	565	184.0304
Dec-06	3.01413	1.31153	62.09	535	182.2053
2006 avg	**3.08935**	**1.22029**	**68.22**	**584**	**183.9797**
2006 increase over 2005 average	83.7%	33.0%	20.6%	8.1%	33.9%
Jan-07	2.58305	1.30850	54.67	513	295.057
Feb-07	2.59661	1.31049	59.39	508	298.251
Mar-07	2.92270	1.28759	60.74	530	297.7186
Apr-07	3.50840	1.31256	64.04	557	303.1179
May-07	3.48248	1.29691	63.53	548	307.5285
Jun-07	3.38764	1.24119	67.53	532	306.1597
Jul-07	3.61595	1.26518	74.15	516	301.9772
Aug-07	3.36783	1.17102	72.36	508	302.4335
Sep-07	3.45616	1.11913	79.63	513	302.4335
Oct-07	3.58887	1.14286	85.66	520	303.4981
Nov-07	3.12924	1.17015	94.63	531	303.9544
Dec-07	3.02170	1.11101	91.74	544	304.3346
2007 avg	**3.22172**	**1.22805**	**72.33917**	**526.66667**	**302.20533**
2007 increase:					
over **2005** average	91.5%	33.9%	27.9%	-2.6%	120.0%
over **2006** average	4.3%	0.6%	6.0%	-9.9%	64.3%
Jan-08	3.20171	1.14375	92.93	579	403.4221
Feb-08	3.58955	1.29826	95.35	665	405.4753
Mar-08	**3.81108**	**1.40665**	**105.42**	**740**	**410.038**
Mar-08 increase over Dec-07	26.1%	26.6%	14.9%	36.0%	34.7%
Mar-08 increase over Jan-05	162.8%	55.5%	125.0%	15.6%	214.4%

OAHU PRECIPITATION DATA

Location	Norm	2000 YTD	2000 % Norm	2001 YTD	2001 % Norm	2002 YTD	2002 % Norm	2003 YTD	2003 % Norm	2004 YTD	2004 % Norm	2005 YTD	2005 % Norm	2006 YTD	2006 Norm	2006 % Norm	2007 YTD	2007 Norm	2007 % Norm	2008* YTD	2008* Norm **	2008* % Norm
Hnl Ap	22.00	7.11	32	9.16	42	12.19	66	12.67	69	39.02	212	15.61	71	29.72	18.29	162	11.97	18.29	65	1.44	8.9	16
Waianae	20.00	3.47	17	8.55	43	14.59	73	12.26	61	37.97	190	16.54	83	24.92	20	125	17.48	20	87	5.52	10.9	51
Makua Rdg	43.40									74.20	171	57.36	132	60.64	43.4	140		43.4			23	
Hawaii Kai	28.00	10.95	39	11.33	40	21.70	78	25.48	91	46.74	167	27.48	98	28.55	28	102	26.11	28	93	2.35	15	16
Lualualei	25.00	9.62	38			17.77	71	24.85	99	39.83	159	18.77	75	29.33	25	117	20.84	25	83	5.43	13	42
Palolo Fs	40.00	24.59	61	25.90	65	24.27	61	26.85	67	62.59	156	39.68	99	40.91	40	102	37.11	40	93	8.89	20.4	44
Waimanalo	50.00	19.46	39			23.73	55	32.62	76	65.95	154	43.08	86	50.63	42.8	118	37.98	42.8	89	5.79	21.4	27
Waipio	30.00	16.17	54	17.83	59	21.07	70			45.75	153			29.60	30	99	21.49	30	72	7.38	15.7	47
Luluku	80.00	56.84	71	53.79	67	71.55	89	91.22	114	119.69	150	86.83	109	122.42	80	153	72.82	80	91	19.99	39	51
Schofield E	74.60									111.38	149											
Waianae BH	21.00									30.33	144	14.12	67	19.68	21	94	10.21	21	49	3.37	11.4	30
Mililani	45.00	27.10	60	31.51	70	36.13	80	42.01	93	62.22	138	50.22	112	51.04	45	113	43.97	45	98	13.57	22.7	60
Kunia Sub	28.00	10.90	39	9.81	35	15.05	54	20.98	75	38.07	136	16.75	60	27.08	28	97	15.48	28	55	3.37	14.8	23
Wilson Tunnel	110.00	89.87	82			107.63	98	120.43	109	147.05	134	107.45	98	147.71	110	134	89.61	110	81		51.6	
Aloha Tower	25.00	8.66	35	11.85	47	13.45	54	15.07	60	32.66	131	17.3	69	27.33	25	109	3.44	12.6	27	17.08	25	68
St. Stephens	80.10							77.66	97	104.68	131	76.00	95	108.38	80.1	135	64.82	80.1	81	13.95	39.5	35
Olomana	50.00	29.12	58	30.46	61			35.71	71	65.58	131	39.85	80	56.59	50	113	42.41	50	85	7.83	25.5	31
Waianae Val.	49.10									63.44	129	26.58	54		49.1		34.66	49.1	71	12.33	25.1	49
Bellows	40.20									51.93	129	28.09	70	45.99	40.2	114	29.43	40.2	73		21.7	
Wheeler	50.00	24.87	50	36.33	73	37.17	74	45.54	91	63.10	126	42.85	86	49.90	50	100	42.42	50	85	13.21	24.7	53
Hakipuu M	75.00									94.78	126			87.38	75	117	62.1	75	83	13.86	35.8	39
Kahuku Tng	46.50									58.02	125	31.53	68	72.50	46.5	156	37.39	46.5	80	9.57	24	40
Maunawili	80.00	54.22	68	52.78	66	59.93	75	74.46	93	99.78	125	78.94	99	111.35	80	139	72.68	80	91	15.45	39.4	39
Waiawa	70.00			58.70	84	53.88	77	57.81	83	86.65	124	74.91	107	72.56	70	104	57.19	70	82	18.25	31.6	58
Kahuku	45.00	22.19	49	32.65	73	32.11	71	34.33	76	52.51	117	28.35	63	58.04	45	129	29.98	45	67	5.8	22.3	26
Kamehame	38.00	13.30	35	12.55	33	20.93	55	27.03	71	44.02	116	29.55	78	33.77	38	89	26.76	38	70	2.84	20.5	14
Punaluu P	75.00	40.96	55	40.29	54	54.84	73	50.47	67	85.49	114	61.83	82	89.98	75	120	60.07	75	80	11.73	37.7	31
Manoa Lyon	150.00	141.48	94	130.49	87	119.96	79	116.85	77	171.02	112	151.46	101	140.18	152.2	92	133.97	152.2	88	45.72	63.7	72
Palisades	75.00	42.25	56	51.65	69	48.36	64	54.24	72	81.56	109	63.16	84	72.55	75	97	65.47	75	87	23.42	35.3	66
Poamoho	45.00					24.78	55	29.23	65	48.66	108	30.29	67	25.37	28.8	88						
Ahuimanu	100.00					75.19	75	92.16	92	106.71	107			117.27	100	117	68.77	100	69	16.33	48.8	33
Nuuanu Ws	130.00							101.91	78	138.94	107	124.56	96	117.99	130	91	108.4	130	83	38.28	59.5	64
Moanalua	80.00	41.04	51	50.18	63	39.76	50	46.01	58	79.70	100	57.62	72	51.74	80	65	49.9	80	62	18.33	37.1	49
Waihee P	115.00	50.40	44			80.51	70	98.57	86	105.80	94	80.00	70	124.53	112.5	111	75.99	112.5	68	20.51	50.4	41
Kaneohe M.	39.90							18.07	45	31.27	78	22.69	57	44.39	39.9	111	28.28	39.9	71		20.6	
Kalaeloa	18.30							13.14	72					20.41	18.3	112	12.4	18.3	68	5.48	9.9	55
Schofield B	41.80							37.32	89						41.8			41.8			21.5	
Makua Ran	33.90							20.43	60					29.22	33.9	86	21.05	33.9	62	1.56	19.3	8
Waialua	33.80	12.48	37	13.21	39	21.33	71															
Kii	41.00											22.68	55	50.40	41	123	29.4	41	72	5.3	20.6	26
Niu Valley	40.00	22.90	57			32.17	80	36.84	92					46.82	40	117	30.95	40	77	6.08	19.6	31

* YTD as of May 2008

** YTD normal rainfall for period ending May 2008

Source: National Oceanic & Atmospheric Administration (NOAA) Western Regional limate Center, Rain Gauge Data - www.prh.noaa.gov/hnl

Hawaiian Electric Company, Inc.
2009 TEST YEAR

VEGETATION MANAGEMENT PROGRAM O&M EXPENSE

		2003	2004	2005	2006	2007	2008	2009
NARUC	NARUC DESCRIPTION	Actual	Actual	Actual	Actual	Actual	budget	estimate
571	Maint. OH lines - TRANS	504,541	598,698	480,651	1,075,511	1,196,048	1,158,773	1,647,356
593	Maint. OH lines - DISTR	1,895,205	1,700,985	1,735,644	2,007,224	3,030,136	3,298,750	3,428,859
		2,399,746	2,299,683	2,216,295	3,082,735	4,226,184	4,457,523	5,076,215

Hawaiian Electric Company, Inc.
2009 TEST YEAR

VEGETATION MANAGEMENT PROGRAM O&M EXPENSE

	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 budget	2009 estimate
Outside Contractors	2,142,713	2,000,395	1,880,366	2,951,437	4,076,605	4,232,825	4,843,612
HECO Labor	253,594	298,054	334,307	131,327	149,413	224,697	232,603
HECO Non-Labor	3,439	1,234	1,622	(29)	167	0	0
	2,399,746	2,299,683	2,216,295	3,082,735	4,226,185	4,457,522	5,076,215

Construction & Maintenance Department Programs*

PROGRAM DESCRIPTION	PROJECT NUMBER	LABOR 2007 RECORDED	LABOR 2009 OPERATING BUDGET	LABOR VARIANCE	NON-LABOR 2007 RECORDED	NON-LABOR 2009 OPERATING BUDGET	NON-LABOR VARIANCE	2007 v. 2009 TOTAL VARIANCE Labor & Non-labor
Distribution Maintenance								
– Corrective OH transformer repl program.	P0000120	93,611	93,793	182	107,659	123,279	15,620	15,801
– Corrective UG transformer repl program	P0000121	74,379	73,556	(822)	44,709	89,818	45,109	44,287
– Corrective miscellaneous cable failures.	P0000122	934,246	865,827	(68,419)	1,552,271	2,697,574	1,145,303	1,076,884
– Corrective OH distribution repls.	P0000123	985,176	943,963	(41,212)	1,046,720	1,155,480	108,760	67,548
– Corrective OH subtransmission repls.	P0000124	0	0	0	0	0	0	0
– Vegetation management.	P0000126	99,250	113,552	14,301	2,930,886	3,315,307	384,422	398,723
– Test and treat wood poles.	P0000127	28,176	71,055	42,879	224,067	552,448	328,382	371,261
– Corrective maint of T&D system.	P0000359	383,873	49,990	(333,883)	582,729	94,679	(488,050)	(821,933)
– Preventive maint of T&D system.	P0000360	21,885	21,860	(25)	53,627	90,408	36,782	36,757
– Preventive inspection of T&D system.	P0000361	0	0	0	0	31,897	31,897	31,897
– PTM switching operations.	P0000740	305,385	406,941	101,556	384,152	476,626	92,474	194,030
– Preventive OH tsf repl.	P1789000	14,424	61,336	46,912	19,283	78,485	59,202	106,113
– Preventive UG tsf repl.	P1793000	15,307	26,171	10,864	21,081	36,063	14,982	25,846
– Preventive miscellaneous cable failure repl.	P1810000	15,332	0	(15,332)	22,778	100,632	77,854	62,521
– Preventive OH distribution repls.	P3400000	301,411	464,865	163,453	443,531	690,799	247,268	410,721
– Preventive OH subtransmission repls.	P3401000	0	0	0	0	0	0	0
Distribution Maintenance Total		**3,272,455**	**3,192,907**	**(79,547)**	**7,433,492**	**9,533,496**	**2,100,004**	**2,020,457**
Distribution Operation								
– Corrective OH distribution repls.	P0000123	53,469	0	(53,469)	54,018	0	(54,018)	(107,487)
– Corrective maint of T&D system.	P0000359	0	0	0	0	0	0	0
– Preventive maint of T&D system.	P0000360	22,536	17,341	(5,195)	26,801	20,311	(6,490)	(11,685)
– Preventive inspection of T&D system.	P0000361	363,778	735,451	371,673	456,812	1,125,172	668,360	1,040,032
– Corrective inspection of T&D system.	P0000362	163,892	73,038	(90,854)	197,448	104,835	(92,613)	(183,467)
– PTM switching operations.	P0000740	1,210,571	1,664,563	453,992	1,498,644	2,047,418	548,774	1,002,766
– Preventive OH distribution repls.	P3400000	0	0	0	-185,146	-67,200	117,946	117,946
Distribution Operation Total		**1,814,246**	**2,490,393**	**676,147**	**2,048,578**	**3,230,536**	**1,181,958**	**1,858,105**

* All program totals include oncosts for Non-productive Wages, Energy Delivery, Corporate Administration, Employee Benefits and Payroll Taxes.

Construction & Maintenance Department Programs*

PROGRAM DESCRIPTION	PROJECT NUMBER	LABOR 2007 RECORDED	LABOR 2009 OPERATING BUDGET	LABOR VARIANCE	NON-LABOR 2007 RECORDED	NON-LABOR 2009 OPERATING BUDGET	NON-LABOR VARIANCE	2007 v. 2009 TOTAL VARIANCE Labor & Non-labor
Transmission Maintenance								
– Corrective OH transformer repl program.	P0000120	295	0	(295)	313	0	(313)	(608)
– Corrective miscellaneous cable failures.	P0000122	60,993	12,125	(48,867)	67,031	17,736	(49,295)	(98,163)
– Corrective OH subtransmission repls.	P0000124	133,877	79,634	(54,242)	171,536	97,759	(73,777)	(128,019)
– Corrective OH transmission repls.	P0000125	0	0	0	0	0	0	0
– Vegetation management.	P0000126	50,162	119,052	68,889	1,145,886	1,528,304	382,418	451,308
– Test and treat wood poles.	P0000127	211	726	515	251,524	107,037	(144,487)	(143,972)
– Corrective maint of T&D system.	P0000359	29,649	29,502	(148)	48,030	37,256	(10,774)	(10,922)
– Preventive maint of T&D system.	P0000360	4,542	3,732	(810)	9,229	27,945	18,716	17,906
– Preventive inspection of T&D system.	P0000361	0	0	0	0	64,761	64,761	64,761
– Preventive miscellaneous cable failure repl.	P1810000	0	0	0	10,470	0	(10,470)	(10,470)
– Preventive OH distribution repls.	P3400000	0	0	0	0	0	0	0
– Preventive OH subtransmission repls.	P3401000	145,053	117,962	(27,092)	224,286	184,453	(39,833)	(66,925)
– Preventive OH transmission repls.	P3402000	95,123	104,474	9,351	150,393	225,526	75,134	84,485
Transmission Maintenance Total		**519,907**	**467,207**	**(52,700)**	**2,078,698**	**2,290,778**	**212,080**	**159,380**
Transmission Operation								
– Preventive maint of T&D system.	P0000360	0	0	0	0	0	0	0
– Preventive inspection of T&D system.	P0000361	136,777	666,968	530,191	430,771	1,099,990	669,219	1,199,410
– Corrective inspection of T&D system.	P0000362	60,040	42,653	(17,388)	110,196	70,331	(39,864)	(57,252)
– PTM switching operations.	P0000740	44,798	73,028	28,230	53,999	85,533	31,534	59,764
– Preventive OH subtransmission repls.	P3401000	0	0	0	0	0	0	0
– Preventive OH transmission repls.	P3402000	0	0	0	0	0	0	0
Transmission Operation Total		**241,615**	**782,648**	**541,033**	**594,965**	**1,255,854**	**660,890**	**1,201,922**

* All program totals include oncosts for Non-productive Wages, Energy Delivery, Corporate Administration, Employee Benefits and Payroll Taxes.

Construction & Maintenance Department Programs*

PROGRAM DESCRIPTION	PROJECT NUMBER	LABOR 2007 RECORDED	LABOR 2009 OPERATING BUDGET	LABOR VARIANCE	NON-LABOR 2007 RECORDED	NON-LABOR 2009 OPERATING BUDGET	NON-LABOR VARIANCE	2007 v. 2009 TOTAL VARIANCE Labor & Non-labor
COMBINED TOTAL								
(Trans & Dist / Oper & Maint)								
– Corrective OH transformer repl program.	P0000120	93,907	93,793	(114)	107,972	123,279	15,307	15,193
– Corrective UG transformer repl program	P0000121	74,379	73,556	(822)	44,709	89,818	45,109	44,287
– Corrective miscellaneous cable failures.	P0000122	995,239	877,952	(117,286)	1,619,302	2,715,310	1,096,008	978,722
– Corrective OH distribution repls.	P0000123	1,038,645	943,963	(94,681)	1,100,738	1,155,480	54,742	(39,939)
– Corrective OH subtransmission repls.	P0000124	133,877	79,634	(54,242)	171,536	97,759	(73,777)	(128,019)
– Corrective OH transmission repls.	P0000125	0	0	0	0	0	0	0
– Vegetation management.	P0000126	149,413	232,603	83,191	4,076,771	4,843,612	766,840	850,031
– Test and treat wood poles.	P0000127	28,387	71,781	43,394	475,591	659,485	183,895	227,289
– Corrective maint of T&D system.	P0000359	413,522	79,492	(334,030)	630,760	131,935	(498,824)	(832,855)
– Preventive maint of T&D system.	P0000360	48,963	42,933	(6,030)	89,656	138,664	49,008	42,978
– Preventive inspection of T&D system.	P0000361	500,555	1,402,419	901,864	887,583	2,321,820	1,434,237	2,336,100
– Corrective inspection of T&D system.	P0000362	223,933	115,691	(108,242)	307,643	175,167	(132,477)	(240,719)
– PTM switching operations.	P0000740	1,560,753	2,144,531	583,777	1,936,795	2,609,578	672,783	1,256,560
– Preventive OH tsf repl.	P1789000	14,424	61,336	46,912	19,283	78,485	59,202	106,113
– Preventive UG tsf repl.	P1793000	15,307	26,171	10,864	21,081	36,063	14,982	25,846
– Preventive miscellaneous cable failure repl.	P1810000	15,332	0	(15,332)	33,248	100,632	67,383	52,051
– Preventive OH distribution repls.	P3400000	301,411	464,865	163,453	258,385	623,599	365,213	528,667
– Preventive OH subtransmission repls.	P3401000	145,053	117,962	(27,092)	224,286	184,453	(39,833)	(66,925)
– Preventive OH transmission repls.	P3402000	95,123	104,474	9,351	150,393	225,526	75,134	84,485
GRAND TOTAL		**5,848,222**	**6,933,155**	**1,084,933**	**12,155,733**	**16,310,665**	**4,154,932**	**5,239,865**

* All program totals include oncosts for Non-productive Wages, Energy Delivery, Corporate Administration, Employee Benefits and Payroll Taxes.

DESCRIPTION	PROJECT NUMBER	2003 ACTUAL	2004 ACTUAL	2005 ACTUAL	2006 ACTUAL	2007 ACTUAL	2008 BUDGET	2009 ESTIMATE
– Corrective OH transformer repl program.	P0000120	128,679	187,420	265,302	233,251	201,878	212,954	217,072
– Corrective UG transformer repl program	P0000121	96,501	135,579	146,735	158,285	119,088	170,735	163,374
– Corrective miscellaneous cable failures.	P0000122	104,177	257,406	315,748	2,617,134	2,614,541	3,377,255	3,593,262
– Corrective OH distribution repls.	P0000123	331,769	624,447	1,074,911	1,691,780	2,139,383	1,861,805	2,099,444
– Corrective OH subtransmission repls.	P0000124	120,400	110,388	138,691	163,681	305,413	137,359	177,394
– Corrective OH transmission repls.	P0000125	0	0	432	0	0	0	0
– Vegetation management.	P0000126	2,384,558	2,289,940	2,206,549	3,082,736	4,226,184	4,457,522	5,076,215
– Test and treat wood poles.	P0000127	204,857	257,694	280,285	469,515	503,977	520,612	731,266
– Corrective maint of T&D system.	P0000359	2,476,398	4,047,311	5,505,626	1,111,155	1,044,282	234,481	211,427
– Preventive maint of T&D system.	P0000360	373,962	117,500	94,322	186,924	138,619	220,038	181,597
– Preventive inspection of T&D system.	P0000361	1,533,435	2,130,278	1,918,200	1,433,645	1,388,138	2,083,955	3,724,239
– Corrective inspection of T&D system.	P0000362	151,462	-2,095	179,720	487,279	531,576	328,675	290,857
– PTM switching operations.	P0000740	1,307,852	1,980,646	2,277,592	3,207,833	3,497,548	3,764,974	4,754,109
– Preventive OH tsf repl.	P1789000	44,908	31,590	53,335	41,194	33,707	151,021	139,820
– Preventive UG tsf repl.	P1793000	70,629	99,404	74,021	123,077	36,388	71,953	62,234
– Preventive miscellaneous cable failure repl.	P1810000	364,281	12,443	178,422	27,218	48,581	30,967	100,632
– Preventive OH distribution repls.	P3400000	490,672	532,907	562,981	879,070	559,796	811,445	1,088,463
– Preventive OH subtransmission repls.	P3401000	169,755	153,086	174,414	281,821	369,340	328,547	302,415
– Preventive OH transmission repls.	P3402000	144,042	170,508	456,059	186,313	245,516	283,743	330,001
TOTAL O&M		10,498,337	13,136,452	15,903,343	16,381,909	18,003,955	19,048,040	23,243,820

Description of C&M Programs

The purpose of the following programs is to maintain or improve system reliability, power quality and customer satisfaction by restoring service or the system to its prior or an upgraded condition.

P0000120 – Corrective overhead transformer replacement program. The purpose of the program is the repair or replacement of overhead transformers that have been identified as failed due to being rusted, leaking, overloaded or damaged by an outside party.

P0000121 – Corrective underground transformer replacement program. The purpose of the program is the repair or replacement of underground padmount transformers that have been identified as failed due to being rusted, leaking, overloaded or damaged by an outside party.

P0000122 – Corrective miscellaneous cable failures. The purpose of the program is the corrective repair or replacement of underground primary, secondary, service and transmission cables, including damages due to a dig-in by outside parties. The replacement cable may be of greater capacity and/or higher voltage rating to accommodate future conditions

P0000123 – Corrective overhead distribution replacements. The purpose of the program is the repair or replacement of overhead distribution poles and associated equipment, including cutouts, aerial cables, conductors and fixtures that have been identified as broken, rusted, corroded, rotten or damaged. This is to restore service or the system to its original condition or an upgraded condition.

P0000124 – Corrective overhead subtransmission replacements. The purpose of the program is the repair or replacement of overhead subtransmission poles and associated equipment, including anchors, conductors and fixtures that have been identified as broken, rusted, corroded, rotten or damaged. This is to restore service or the system to its original condition or an upgraded condition.

P0000125 – Corrective overhead transmission replacements. The purpose of the program is the repair or replacement of overhead transmission poles and associated equipment, including anchors, conductors and fixtures that have been identified as broken, rusted, corroded, rotten or damaged. This is to restore service or the system to its original condition or an upgraded condition.

P0000126 – Vegetation management. This program is to manage vegetation along HECO roadside, right-of-way and other facilities to ensure safe and reliable service can be provided. This includes cutting, trimming and controlling trees, vines and other

Description of C&M Programs

undesirable vegetation to ensure easy and safe access for inspections, maintenance and repairs of facilities.

P0000127 – Test and treat wood poles. This program involves the inspection of wood poles by sounding and boring to determine the condition of the poles and the treatment of the poles with insecticide or fungicide. The program will identify and correct any potential damage by termites or wood rot, which will prolong the life of the pole and reduce replacement costs and outages caused by pole failures.

P0000359 – Corrective maintenance of T&D system. The program is to make minor miscellaneous temporary or permanent repairs or adjustments to unsafe equipment that has failed and poses a danger to customers.

P0000360 – Preventive maintenance of T&D system. The program is to make minor miscellaneous planned repairs, replacements or improvements of overhead and underground equipment that has been identified as deteriorated or damage and not up to standard.

P0000361 – Preventive inspection of T&D system. The purpose of the program is the overhead and underground inspections of the transmission and distribution system to identify potential repairs, replacements or improvements of equipment. This program should identify deteriorated and/or broken equipment before it fails and leads to outages.

P0000362 – Corrective inspection of T&D system. The purpose of the program is the corrective inspection to determine the cause of interruptions or outages to improve system reliability and power quality.

P0000740 – PTM switching operations. This program is being created to capture PTM responsibilities not related to a specific program or project, including emergency or accident investigations, minor repairs and trouble calls.

P1789000 – Preventive overhead transformer replacement. The purpose of the program is the planned repairs or replacement of overhead transformers that have been identified due to rusting, potential future overloading conditions or as part of a planned pole replacement/upgrade.

P1793000 – Preventive underground transformer replacement. The purpose of the program is the planned repairs or replacement of underground padmount transformers that have been identified due to rusting, potential future overloading conditions or as part of a planned pole replacement/upgrade.

Description of C&M Programs

P181000 – Preventive miscellaneous cable failure replacement. The purpose of the program is the planned replacement of underground cables that have been identified as needing replacement due to excessive faulting.

P3400000 – Preventive overhead distribution replacements. The purpose of the program is the repair or replacement of overhead distribution poles and associated equipment, including cutouts, aerial cables, conductors and fixtures prior to failure.

P3401000 – Preventive overhead subtransmission replacements. The purpose of the program is the repair or replacement of overhead subtransmission poles and associated equipment, including anchors, conductors and fixtures prior to failure.

P3402000 – Preventive overhead transmission replacements. The purpose of the program is the repair or replacement of overhead transmission poles and associated equipment, including anchors, conductors and fixtures prior to failure.

Hawaiian Electric Company, Inc.
2009 TEST YEAR

TRANSMISSION OPERATION AND
MAINTENANCE EXPENSE ADJUSTMENTS

	BUDGET	BUD ADJ		NORM	DIRECT
TRANSMISSION OPER					
LABOR	2,902				2,902
NON-LABOR	4,114	(65)	(1)		4,048
TOTAL	7,016	(65)		0	6,950
TRANSMISSION MAINT					
LABOR	2,083				2,083
NON-LABOR	4,926	7	(2)		4,933
TOTAL	7,009	7		0	7,016
TRANSMISSION - TOTAL					
LABOR	4,985	0		0	4,985
NON-LABOR	9,040	(58)		0	8,982
TOTAL	14,025	(58)		0	13,967

(1) Remove incentive plans <$59K> and restricted stock <$8K>; Abandoned projects expense +$2K.
(2) Abandoned projects expense +$7K.

Hawaiian Electric Company, Inc.
2009 TEST YEAR

DISTRIBUTION OPERATION AND MAINTENANCE EXPENSE ADJUSTMENTS

	BUDGET	BUD ADJ		NORM	DIRECT
DISTRIBUTION OPER					
LABOR	6,712				6,712
NON-LABOR	6,945	(44)	(1)		6,901
TOTAL	13,657	(44)		0	13,613
DISTRIBUTION MAINT					
LABOR	5,760				5,760
NON-LABOR	11,094	25	(2)		11,119
TOTAL	16,854	25		0	16,879
DISTRIBUTION - TOTAL					
LABOR	12,472	0		0	12,472
NON-LABOR	18,039	(19)		0	18,020
TOTAL	30,511	(19)		0	30,492

(1) Remove incentive plans <$143K>; Abandoned projects expenses +$99K.
(2) Abandoned projects expenses +$25K

Hawaiian Electric Company, Inc.
2009 Test Year

OUTAGE MANAGEMENT SYSTEM (OMS) PROJECT COSTS

	Description of Cost	Initial Project Forecast				Project Actuals-to-date as of 3-31-2008			
		Capital	**Deferred**	**Expense**	**Total Estimate**	**Capital Actuals**	**Deferred Actuals**	**Expense Actuals**	**Total Actuals**
1	Pre-selection/evaluation and PUC reporting			$276,341	**$276,341**			$613,762	**$613,762**
2	Convert data from current system to new			$686,451	**$686,451**			$529,289	**$529,289**
3	Maintenance on Software (added)							$218,577	**$218,577**
4	Training material development & training sessions			$85,873	**$85,873**			$209,141	**$209,141**
5	Overhead on Expense Items			$92,035	**$92,035**			$596,270	**$596,270**
	Expense subtotal				**$1,140,701**			**$2,167,039**	**$2,167,039**
6	Software license fees		$1,274,366		**$1,274,366**		$767,425		**$767,425**
7	Other costs		$66,010		**$66,010**		$0		**$0**
8	AFUDC on Deferred Items		$398,565		**$398,565**		$339,177		**$339,177**
9	Other internal & external labor costs		$291,204		**$291,204**		$874,195		**$874,195**
10	Outside services (relabeled from interisland travel etc.)		$1,771,599		**$1,771,599**		$2,218,919		**$2,218,919**
11	Overhead on Deferred Items		$504,721		**$504,721**		$331,905		**$331,905**
	Deferred subtotal				**$4,306,466**		**$4,531,621**		**$4,531,621**
12	Hardware	$353,436			**$353,436**	$576,018			**$576,018**
13	Other costs	$19,980			**$19,980**	$0			**$0**
14	AFUDC on Capital Items	$21,300			**$21,300**	$0			**$0**
	Captial subtotal				**$394,716**	**$576,018**			**$576,018**
	Total	$394,716	$4,306,466	$1,140,701	**$5,841,882**	$576,018	$4,531,621	$2,167,039	**$7,274,678**

	CAPITAL	DEFERRED	EXPENSE	**TOTAL**
Project Actuals-to-date as of 3-31-2008	$576,018	$4,531,621	$2,167,039	**$7,274,678**
Remaining Forecast: 4/08-12/08				
Software Maintenance			$77,139	
Training (Labor & Outside Services)			$0	
Data Clean Up			$48,000	
AFUDC on deferred expense		$0		
SPL Software License		$61,657		
Outside Services (including SPL and Kema)		$527,115		
HECO labor including overheads		$8,465	$14,626	
Remaining Forecast: 4/08 - 12/08 Total	$0	$597,237	$139,765	**$737,002**
TOTAL REVISED ESTIMATE:	$576,018	$5,128,858	$2,306,804	**$8,011,680**

Hawaiian Electric Company, Inc.
2009 Test Year

OUTAGE MANAGEMENT SYSTEM (OMS) PROJECT COSTS

	Description of Cost	Actual	Actual	Actual	Actual	Actual	Actual	Project Actuals-to-date as of 03-31-08:			
		2003 Subtotal	**2004 Subtotal**	**2005 Subtotal**	**2006 Subtotal**	**2007 Subtotal**	**2008 Jan-Mar Subtotal**	**Capital Actuals**	**Deferred Actuals**	**Expense Actuals**	**Total Actuals**
1	Pre-selection/evaluation and PUC reporting	$17,339	230,195	335,466	28,035	2,727				$613,762	**$613,762**
2	Convert data from current system to new			79,441	198,696	247,009	4,143			$529,289	**$529,289**
3	Maintenance on Software			80,225	89,564	43,463	5,325			$218,577	**$218,577**
4	Training material development & training sessions			23,864	59,704	125,507	66			$209,141	**$209,141**
5	Overhead on Expense Items			40,427	222,319	310,850	22,674			$596,270	**$596,270**
6	Software license fees			192,379	482,631	92,415			$767,425		**$767,425**
7	Other costs								$0		**$0**
8	AFUDC on Deferred Items			11,153	149,836	178,188			$339,177		**$339,177**
9	Other internal & external labor costs			244,681	302,712	300,227	26,575		$874,195		**$874,195**
10	Outside services (relabeled from interisland travel ect.)			243,120	1,433,100	503,328	39,371		$2,218,919		**$2,218,919**
11	Overhead on Deferred Items				159,220	159,456	13,229		$331,905		**$331,905**
12	Hardware			8,055	488,153	79,726	84	$576,018			**$576,018**
13	Other costs							$0			**$0**
14	AFUDC on Capital Items							$0			**$0**
	Total	$17,339	230,195	1,258,811	3,613,970	2,042,896	111,467	$576,018	$4,531,621	$2,167,039	**$7,274,678**