CA-IR-340

Ref: T-15, page 12 & HECO-1506 (FAS106 OPEB Costs).

Please provide the following information:

a. Please provide a complete copy of the Watson Wyatt actuarial study supporting the 2004 actual FAS106 costs recorded by HECO and the 2005 test year projection set forth on HECO-1506.

b. Referring to item (a) above, please confirm that the studies were based on January 1, 2003 employee demographics and assumptions. If this cannot be confirmed, please explain.

c. Please provide complete copy of the 2004 Watson Wyatt actuarial study, including any reforecast of the 2005 projection. If the study is not yet available, please provide the requested information immediately upon receipt.

HECO Response:

a. Watson Wyatt, the plan's actuary, provided the attached set of exhibits on pages 2 to 21 to

HEI FAS 106
01/01/2004
0
TOTAL
ALL
01/01/2004

DISCOUNT:	6.25%	MED TR:	10.0--->4.25%
Assets:BU401(h)=	9.00%	VIS TR:	3.25%
Assets:ElecDisc=	5.50%	DEN TR:	4.25%
Assets:NBVEBA=	5.00%	MCR TR:	0.00%
		INS TR:	0.00%
		ELC TR:	v

INPUT **********	HECO	HELCO	MECO	SUBTOTAL	HEI	TOTAL
SVC COST						
MED/VIS/DEN 100%Drug						
MED/VIS/DEN 0% Drug						
MED/VIS/DEN 75% Drug	2,343,118	510,271	511,341	3,364,730	94,900	3,459,630
MEDICARE	72,287	16,410	14,472	103,169	3,412	106,581
GROUP LIFE INS	137,783	32,228	29,604	199,563	4,903	204,466
EXEC LIFE INS	90,175	17,839	5,202	113,216	5,249	118,465
ELEC DISC	188,474	56,149	51,180	295,803	0	295,803
TOTAL	2,831,817	632,896	611,799	4,076,511	108,464	4,184,975
APBO						
MED/VIS/DEN 100%Drug						
MED/VIS/DEN 0% Drug						
MED/VIS/DEN 75% Drug	91,906,170	21,365,004	17,938,759	131,209,933	2,077,790	133,287,723
MEDICARE	4,526,249	844,324	736,106	6,106,679	98,540	6,205,219
GROUP LIFE INS	11,554,315	2,138,001	1,871,273	15,563,589	188,259	15,751,848
EXEC LIFE INS	7,091,149	703,657	706,691	8,501,497	1,594,708	10,096,205
ELEC DISC	6,798,752	2,150,565	1,649,493	10,598,810	0	10,598,810
TOTAL	121,876,635	27,201,561	22,902,322	171,980,508	3,959,297	175,939,805
EXP DISTRIB						
MED/VIS/DEN 100%Drug						
MED/VIS/DEN 0% Drug						
MED/VIS/DEN 75% Drug	4,356,957	933,234	640,019	5,930,210	55,470	[illegible]
MEDICARE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

HEI OPEB PLANS
Electric Discount Trust
1/1/2004
Market Related Value for FAS106 - 15% MV Corridor

Expected asset return: 5.50%

Gain or Loss - Prior Year

	Actual	Weighted	
(1) Market Value on 1/1 PY	39,799		
(2) Contributions	441,000	268,878	actual
(3) Benefit Payments	(431,022)	(215,511)	0.5000
(4) Admin Expenses	(166)	(83)	0.5000
(5) Expected Income	5,120		
(6) Expected Asset Value	54,731		
(7) Market Value on 12/31 PY	61,844		
(8) Gain/(Loss) for Year	7,113		
Actual Return:	12,233	13.14%	

Unrecognized Portion of Gains and Losses

December 31	Gain/(Loss)	Recognized	Unrecognized	Gain/(Loss)
2000	(7,587)	75%	25%	(1,897)
2001	(14,879)	50%	50%	(7,440)
2002	(19,449)	25%	75%	(14,587)
2003	7,113	0%	100%	7,113
	Unrecognized Gain/(Loss):			(16,811)

Adjusted Assets

	HECO	HELCO	MECO	HEI	TOTAL
(0) Market Value 1/1 PY	16,349	8,142	15,308	0	39,799
contributions	300,000	85,000	56,000	0	441,000
distributions	(302,049)	(76,332)	(52,641)	0	(431,022)
expenses	(85)	(41)	(40)	0	(166)
transfers	(3,161)	8,008	(4,847)	0	0
(1) Market Value 1/1 CY	16,790	27,912	17,142	0	61,844
(2) Unrecognized Gain/(Loss)	(4,564)	(7,587)	(4,660)	0	(16,811)
(3) Market Related Value (1)-(2)	21,354	35,499	21,802	0	[illegible]

HEI OPEB PLANS
BU VEBA
1/1/2004
Market Related Value for FAS106 - 15% MV Corridor

Expected asset return: 9.00%

Gain or Loss - Prior Year

	Actual	Weighted	
(1) Market Value on 1/1 PY	52,742,300		
(2) Contributions	5,299,904	1,832,930	actual
(3) Benefit Payments	(3,571,559)	(1,785,780)	0.5000
(4) Admin Expenses	(19,943)	(9,972)	0.5000
(5) Expected Income	4,750,153		
(6) Expected Asset Value	59,200,855		
(7) Market Value on 12/31 PY	67,996,838		
(8) Gain/(Loss) for Year	8,795,983		
Actual Return:	13,546,136	25.67%	

Unrecognized Portion of Gains and Losses

December 31	Gain/(Loss)	Recognized	Unrecognized	Gain/(Loss)
2000	(13,330,329)	75%	25%	(3,332,582)
2001	(16,126,275)	50%	50%	(8,063,138)
2002	(16,632,327)	25%	75%	(12,474,245)
2003	8,795,983	0%	100%	8,795,983
	Unrecognized Gain/(Loss):			(15,073,982)

Adjusted Assets

	HECO	HELCO	MECO	HEI	TOTAL
(0) Market Value 1/1 PY	37,843,843	7,803,834	7,094,623	0	52,742,300
contributions	3,677,037	829,384	793,483	0	5,299,904
distributions	(2,612,431)	(596,193)	(362,935)	0	(3,571,559)
expenses	(14,293)	(2,957)	(2,693)	0	(19,943)
transfers	(23,097)	147,030	(123,933)	0	0
(1) Market Value 1/1 CY	48,568,400	10,183,572	9,244,866	0	67,996,838
(2) Unrecognized Gain/(Loss)	(10,766,959)	(2,257,561)	(2,049,462)	0	(15,073,982)
(3) Market Related Value (1)-(2)	59,335,359	12,441,133	11,294,328	0	83,070,820
(4) 85% of Mkt Value	41,283,140	8,656,036	7,858,136	0	57,797,312
(5) 115% of Mkt Value	55,853,660	11,711,108	10,631,596	0	78,196,364
(6) Adjusted MRV (4) < [(3)] < (5)	55,853,660	11,711,108	10,631,596	0	78,196,364

HEI OPEB PLANS
NBU VEBA
1/1/2004
Market Related Value for FAS106 - 15% MV Corridor

Expected asset return: 5.00%

Gain or Loss - Prior Year

	Actual	Weighted	
(1) Market Value on 1/1 PY	5,698,767		
(2) Contributions	4,478,028	1,656,005	actual
(3) Benefit Payments	(2,354,493)	(1,177,247)	0.5000
(4) Admin Expenses	46,334	23,167	0.5000
(5) Expected Income	310,035		
(6) Expected Asset Value	8,178,671		
(7) Market Value on 12/31 PY	9,551,580		
(8) Gain/(Loss) for Year	1,372,909		
Actual Return:	1,682,944	27.14%	

Unrecognized Portion of Gains and Losses

December 31	Gain/(Loss)	Recognized	Unrecognized	Gain/(Loss)
2000	(726,040)	75%	25%	(181,510)
2001	(575,785)	50%	50%	(287,893)
2002	(1,257,278)	25%	75%	(942,959)
2003	1,372,909	0%	100%	1,372,909
	Unrecognized Gain/(Loss):			(39,453)

Adjusted Assets

	HECO	HELCO	MECO	HEI	TOTAL
(0) Market Value 1/1 PY	3,340,074	990,580	809,490	558,623	5,698,767
contributions	3,386,518	501,233	508,359	81,918	4,478,028
distributions	(1,861,571)	(258,126)	(208,646)	(26,150)	(2,354,493)
expenses	19,707	10,877	8,311	7,439	46,334
transfers	42,177	0	3,683	(45,860)	0
(1) Market Value 1/1 CY	5,927,995	1,525,519	1,369,747	728,319	9,551,580
(2) Unrecognized Gain/(Loss)	(24,486)	(6,301)	(5,658)	(3,008)	(39,453)
(3) Market Related Value (1)-(2)	5,952,481	1,531,820	1,375,405	731,327	9,591,033
(4) 85% of Mkt Value	5,038,796	1,296,691	1,164,285	619,071	8,118,843
(5) 115% of Mkt Value	6,817,194	1,754,347	1,575,209	837,567	10,984,317
(6) Adjusted MRV (4) < [(3)] < (5)	5,952,481	1,531,820	1,375,405	731,327	9,591,033

HEI OPEB PLANS
401(h) Account
1/1/2004
Market Related Value for FAS106 - 15% MV Corridor

Expected asset return: 9.00%

Gain or Loss - Prior Year

	Actual	Weighted	
(1) Market Value on 1/1 PY	17,442,258		
(2) Contributions	0	0	actual
(3) Benefit Payments	(821,289)	(410,645)	0.5000
(4) Admin Expenses	(16,145)	(8,073)	0.5000
(5) Expected Income	1,532,119		
(6) Expected Asset Value	18,136,943		
(7) Market Value on 12/31 PY	20,578,390		
(8) Gain/(Loss) for Year	2,441,447		
Actual Return:	3,973,566	23.34%	

Unrecognized Portion of Gains and Losses

December 31	Gain/(Loss)	Recognized	Unrecognized	Gain/(Loss)
2000	(3,180,958)	75%	25%	(795,240)

HEI FAS 106		DISCOUNT:	6.25%	MED TR:	10.0-->4.25%	
1/1/2005 proj from 1/1/2004		Assets:BU401(h)=	9.00%	VIS TR:	3.25%	
0		Assets:ElecDisc=	5.50%	DEN TR:	4.25%	
TOTAL		Assets:NBVEBA=	5.00%	MCR TR:	0.00%	
ALL				INS TR:	0.00%	
01/01/2005				ELC TR:	v	
INPUT **********	HECO	HELCO	MECO	SUBTOTAL	HEI	TOTAL
SVC COST						
MED/VIS/DEN 100%Drug						
MED/VIS/DEN 0% Drug						
MED/VIS/DEN 75% Drug	2,544,611	548,959	574,876	3,668,446	109,722	3,778,168
MEDICARE	71,662	16,813	14,220	102,695	2,804	105,499
GROUP LIFE INS	136,386	32,749	28,718	197,853	4,291	202,144
EXEC LIFE INS	94,290	18,954	5,527	118,771	5,577	124,348
ELEC DISC	194,430	58,089	53,091	305,610	0	305,610
TOTAL	3,041,379	675,564	676,432	4,393,375	122,394	4,515,769
APBO						
MED/VIS/DEN 100%Drug						
MED/VIS/DEN 0% Drug						
MED/VIS/DEN 75% Drug	97,258,857	22,701,748	19,427,543	139,388,148	2,321,860	141,710,008
MEDICARE	4,622,773	882,472	753,560	6,258,805	106,420	6,375,225
GROUP LIFE INS	11,816,939	2,216,768	1,941,616	15,975,323	201,965	16,177,288
EXEC LIFE INS	7,291,451	744,184	737,541	8,773,176	1,677,357	10,450,533
ELEC DISC	7,129,178	2,267,706	1,750,233	11,147,117	0	11,147,117
TOTAL	128,119,198	28,812,878	24,620,493	181,552,569	4,307,602	185,860,171
EXP DISTRIB						
MED/VIS/DEN 100%Drug						
MED/VIS/DEN 0% Drug						
MED/VIS/DEN 75% Drug	4,826,761	1,067,498	715,044	6,609,303	71,438	6,680,741
MEDICARE	262,388	32,073	35,064	329,525	2,285	331,810
GROUP LIFE INS	609,002	90,431	79,953	779,386	3,993	783,379
EXEC LIFE INS	407,929	28,718	27,088	463,735	54,639	518,374
ELEC DISC	295,549	78,690	57,833	432,072	0	432,072
TOTAL	6,401,629	1,297,410	914,982	8,614,021	132,355	8,746,376
GAIN/LOSS CALC						
APBO	128,119,198	28,812,878	24,620,493	181,552,569	4,307,602	185,860,171
MRV ASSETS	79,005,271	18,432,359	16,083,598	113,521,228	1,938,374	115,459,602
UNREC TRANS	19,203,031	2,984,146	2,849,262	25,036,439	67,621	25,104,060
UNREC PRIOR SVC	0	0	0	0	0	0
(ACCRUED)/PREPD	(17,837,153)	(2,733,932)	(2,710,254)	(23,281,339)	(1,404,284)	(24,685,623)
(GAIN)/LOSS	12,073,743	4,662,441	2,977,379	19,713,563	897,323	20,610,886
MAX(PBO,MRV)	128,119,198	28,812,878	24,620,493	181,552,569	4,307,602	185,860,171
10%	12,811,920	2,881,288	2,462,049	18,155,257	430,760	18,586,017
(G)/L AMORT.	0	1,781,153	515,330	2,296,483	466,563	2,024,869
FUTURE SERVICE	11.03	11.03	11.03		11.03	11.03
AMORTIZATION	0	161,483	46,721	208,203	42,299	183,578
Excess to Include	0	1,983,200	1,100,006	3,083,206	526,756	3,609,962
TOTAL AMORT						183,578
ALLOC AMORT.	0	118,341	34,239	152,580	30,999	183,578

NET PER BEN COST 1/1/2005 proj from 1/1/2004 HEI FAS 106

NPOPBC	TOTAL ALL					
1) SERVICE COST						
A. SERVICE COST	3,041,379	675,564	676,432	4,393,375	122,394	4,515,769
B. EXPENSE ASSUMPTION	50,940	9,830	10,030	70,800	5,200	76,000
C. INTEREST	193,269	42,838	42,904	279,011	7,975	286,986
D. TOTAL SVC COST	3,285,588	728,232	729,366	4,743,186	135,569	4,878,755
2) INTEREST COST						
A. APBO	128,119,198	28,812,878	24,620,493	181,552,569	4,307,602	185,860,171
B. EXP DIST.	6,401,629	1,297,410	914,982	8,614,021	132,355	8,746,376
C. WEIGHTED 1/2	3,200,816	648,705	457,493	4,307,014	66,179	4,373,193

HEI OPEB PLANS
Electric Discount Trust
Estimated 1/1/2005
Market Related Value for FAS106 - 15% MV Corridor

Expected asset return: 5.50%
Actual asset return: 5.50%

Gain or Loss - Prior Year

	Actual	Weighted	
(1) Market Value on 1/1 PY	61,844		
(2) Contributions	422,699	211,350	0.5000
(3) Benefit Payments	(421,699)	(210,850)	0.5000
(4) Admin Expenses	(1,000)	(500)	0.5000
(5) Expected Income	3,401		
(6) Expected Asset Value	65,245		
(7) Market Value on 12/31 PY	65,245		
(8) Gain/(Loss) for Year	0		
Actual Return:	3,401	5.50%	

Unrecognized Portion of Gains and Losses

December 31	Gain/(Loss)	Recognized	Unrecognized	Gain/(Loss)
2001	(14,879)	75%	25%	(3,720)
2002	(19,449)	50%	50%	(9,725)
2003	7,113	25%	75%	5,335
2004	0	0%	100%	0
	Unrecognized Gain/(Loss):			(8,110)

Adjusted Assets

	HECO	HELCO	MECO	HEI	TOTAL
(1) Market Value 1/1 CY	17,713	29,447	18,085	0	65,245
(2) Unrecognized Gain/(Loss)	(2,202)	(3,660)	(2,248)	0	(8,110)
(3) Market Related Value (1)-(2)	19,915	33,107	20,333	0	73,355
(4) 85% of Mkt Value	15,056	25,030	15,372	0	55,458
(5) 115% of Mkt Value	20,370	33,864	20,798	0	75,032
(6) Adjusted MRV (4) < [(3)] < (5)	19,915	33,107	20,333	0	73,355

HEI OPEB PLANS
BU VEBA
Estimated 1/1/2005
Market Related Value for FAS106 - 15% MV Corridor

Expected asset return:	9.00%
Actual asset return:	9.00%

Gain or Loss - Prior Year

	Actual	Weighted	
(1) Market Value on 1/1 PY	67,996,838		
(2) Contributions	2,431,417	1,215,709	0.5000
(3) Benefit Payments	(3,756,342)	(1,878,171)	0.5000
(4) Admin Expenses	(25,000)	(12,500)	0.5000
(5) Expected Income	6,058,969		
(6) Expected Asset Value	72,705,882		
(7) Market Value on 12/31 PY	72,705,882		
(8) Gain/(Loss) for Year	0		
Actual Return:	6,058,969	9.00%	

Unrecognized Portion of Gains and Losses

December 31	Gain/(Loss)	Recognized	Unrecognized	Gain/(Loss)
2001	(16,126,275)	75%	25%	(4,031,569)
2002	(16,632,327)	50%	50%	(8,316,164)
2003	8,795,983	25%	75%	6,596,987
2004	0	0%	100%	0
	Unrecognized Gain/(Loss):			(5,750,746)

Adjusted Assets

	HECO	HELCO	MECO	HEI	TOTAL
(1) Market Value 1/1 CY	51,372,332	11,135,835	10,197,715	0	72,705,882
(2) Unrecognized Gain/(Loss)	(4,063,347)	(880,800)	(806,599)	0	(5,750,746)
(3) Market Related Value (1)-(2)	55,435,679	12,016,635	11,004,314	0	78,456,628
(4) 85% of Mkt Value	43,666,482	9,465,460	8,668,058	0	61,800,000
(5) 115% of Mkt Value	59,078,182	12,806,210	11,727,372	0	83,611,764
(6) Adjusted MRV (4) < [(3)] < (5)	55,435,679	12,016,635	11,004,314	0	78,456,628

HEI OPEB PLANS
NBU VEBA
Estimated 1/1/2005
Market Related Value for FAS106 - 15% MV Corridor

Expected asset return:	5.00%
Actual asset return:	5.00%

Gain or Loss - Prior Year

	Actual	Weighted	
(1) Market Value on 1/1 PY	9,551,580		
(2) Contributions	5,117,270	2,558,635	0.5000
(3) Benefit Payments	(2,434,867)	(1,217,434)	0.5000
(4) Admin Expenses	(25,000)	(12,500)	0.5000
(5) Expected Income	544,014		
(6) Expected Asset Value	12,752,997		
(7) Market Value on 12/31 PY	12,752,997		
(8) Gain/(Loss) for Year	0		
Actual Return:	544,014	5.00%	

Unrecognized Portion of Gains and Losses

December 31	Gain/(Loss)	Recognized	Unrecognized	Gain/(Loss)
2001	(575,785)	75%	25%	(143,946)
2002	(1,257,278)	50%	50%	(628,639)
2003	1,372,909	25%	75%	1,029,682
2004	0	0%	100%	0
	Unrecognized Gain/(Loss):			257,097

Adjusted Assets

	HECO	HELCO	MECO	HEI	TOTAL
(1) Market Value 1/1 CY	8,393,867	1,815,291	1,743,196	800,643	12,752,997
(2) Unrecognized Gain/(Loss)	169,218	36,596	35,142	16,141	257,097
(3) Market Related Value (1)-(2)	8,224,649	1,778,695	1,708,054	784,502	12,495,900
(4) 85% of Mkt Value	7,134,787	1,542,997	1,481,717	680,547	10,840,048
(5) 115% of Mkt Value	9,652,947	2,087,585	2,004,675	920,739	14,665,946
(6) Adjusted MRV (4) < [(3)] < (5)	8,224,649	1,778,695	1,708,054	784,502	12,495,900

HEI OPEB PLANS
401(h) Account
Estimated 1/1/2005
Market Related Value for FAS106 - 15% MV Corridor

Expected asset return: 9.00%
Actual asset return: 9.00%

Gain or Loss - Prior Year

	Actual	Weighted	
(1) Market Value on 1/1 PY	20,578,390		
(2) Contributions	1,069,043	534,522	0.5000
(3) Benefit Payments	(872,463)	(436,232)	0.5000
(4) Admin Expenses	(25,000)	(12,500)	0.5000
(5) Expected Income	1,859,776		
(6) Expected Asset Value	22,609,746		
(7) Market Value on 12/31 PY	22,609,746		
(8) Gain/(Loss) for Year	0		
Actual Return:	1,859,776	9.00%	

Unrecognized Portion of Gains and Losses

December 31	Gain/(Loss)	Recognized	Unrecognized	Gain/(Loss)
2001	(4,751,695)	75%	25%	(1,187,924)
2002	(4,934,268)	50%	50%	(2,467,134)
2003	2,441,447	25%	75%	1,831,085
2004	0	0%	100%	0
	Unrecognized Gain/(Loss):			(1,823,973)

Adjusted Assets

	HECO	HELCO	MECO	HEI	TOTAL
(1) Market Value 1/1 CY	14,181,017	4,260,240	3,100,753	1,067,736	22,609,746
(2) Unrecognized Gain/(Loss)	(1,144,011)	(343,682)	(250,144)	(86,136)	(1,823,973)
(3) Market Related Value (1)-(2)	15,325,028	4,603,922	3,350,897	1,153,872	24,433,719
(4) 85% of Mkt Value	12,053,864	3,621,204	2,635,640	907,576	19,218,284
(5) 115% of Mkt Value	16,308,170	4,899,276	3,565,866	1,227,896	26,001,208
(6) Adjusted MRV (4) < [(3)] < (5)	15,325,028	4,603,922	3,350,897	1,153,872	24,433,719

Section V: Basic Data

Source of Data

The participant data used in the calculations was supplied by Hawaiian Electric Company, Inc. Included were computer files providing the active data and a retiree file showing plan coverages and other relevant information. Hawaiian Electric Company also provided premium information for the various health benefits.

Basic Participant Data

A summary of the basic participant data is shown below.

	1/1/2003	1/1/2004
(1) Number of Covered Employees		
(a) Active Employees		
• BU	1,133	1,095
• NBU	805	796
• Total	1,938	1,891
(b) Retirees	1,201	1,253
(c) Beneficiaries of Deceased Retirees	17	16
(d) Disabled Employees on LTD	16	11
(e) Total	3,172	3,171
(2) Approximate Annual Base Payroll	$123,191,365	$124,403,643
(3) Averages for Active Employees		
(a) Years of Past Service	14.95	14.80
(b) Attained Age	45.24	45.53
(c) Retirement Age	59.16	59.23
(4) Retiree Averages		
(a) Retirement Age	58.55	58.44
(b) Attained Age	69.22	69.21

Basic Data by Participating Company as of January 1, 2004

Basic Data	HECO	HELCO	MECO	HEI	Total
(1) Number of Covered Participants					
(a) Active Employees					
BU	685	205	205	0	1,095
NBU	588	78	86	44	796
Total	1,273	283	291	44	1,891
(b) Retirees	938	170	137	8	1,253
(2) Approximate Annual Base Payroll	$84,026,264	$17,385,410	$18,463,133	$4,528,836	$124,403,643
(3) Averages for Active Employees					
(a) Years of Past Service	14.99	15.14	14.04	12.26	14.80
(b) Attained Age	45.54	45.80	44.94	47.55	45.53
(c) Retirement Age	59.27	59.11	59.06	59.77	59.23
(4) Retiree Averages					
(a) Retirement Age	58.26	58.10	60.10	58.43	58.44

Basic Premium Data (Monthly)

	1/1/2002	1/1/2003	1/1/2004
(1) Medical Plans – Retirees Under 65			
(a) HMSA – Preferred Provider Plan			
– single	$ 326.96	$ 314.49	$ 326.95
– 2 party	654.78	629.71	654.57
(b) HMSA – HealthLink			
– single	387.88	428.38	438.10
– 2 party	776.77	857.82	877.19
(c) HMSA – Health Plan Hawaii Plus			
– single	387.88	428.38	438.10
– 2 party	776.77	857.82	877.19
(d) Kaiser			
– single	267.59	321.16	373.05
– 2 party	535.18	642.32	746.10
(2) Senior Plans (per capita) – 65 and Over			
(a) HMSA 65C+	75.76	81.50	86.50
(b) Kaiser Senior	72.00	84.68	98.02
(3) Dental Plan (composite)	54.42	55.78	59.02
(4) Vision Plan (composite)	12.50	12.50	12.50
(5) Senior Drug Plan (per capita)	216.96	249.93	292.17

Section VI: Summary of Plan Benefits

(1) Medical Benefits

(a) Eligibility

Retirement after attaining age 50 with 5 years of service and 65 points (points equals age plus service) or attainment of age 55 with 5 years of service. Beginning January 1, 1994, the plan provides the following percentage of the medical plan premiums described below for the retiree and spouse, to the extent the spouse does not have comparable coverage available from a former employer, based upon the retiree's years of service at retirement:

Years of Service	Percentage
Less than 6	0%
6 - 9	25
10 - 14	50
15 - 19	75
20 and Over	100

Employees with at least 11 years of service as of December 31, 1993 shall be grandfathered at 100%.

For retirements between 1/1/92 and 12/31/93, the following percentages apply:

Years of Service	Percentage
Less than 5	0%
6 - 10	50
11 and Over	100

The percentage for retirements prior to 1/1/92 is 100%.

For employees hired after 12/31/98, the following percentages apply:

Years of Service	Pre-Medicare Percentage	Post-Medicare Percentage
N/A	50%	100%

(b) Benefits

The plan provides medical coverage for eligible retirees, their eligible spouses, and unmarried dependent children under age 19. Several alternative plans are available. Upon attainment of age 65, the plan provides a Medicare supplement.

Benefits for retirees continue for their lifetimes. Benefits for eligible dependents or spouses continue for two years following the death of the retiree.

(2) Vision Benefits

(a) Eligibility

Same as (1)(a) above.

(b) Benefits

The plan provides vision coverage for eligible retirees, their eligible spouses, and unmarried dependent children under the age of 19 (currently Vision Services Plan).

Benefits for retirees continue for their lifetimes. Benefits for eligible dependents or spouses continue for two years following the death of the retiree.

(3) Dental Benefits

(a) Eligibility

Same as (1)(a) above.

(b) Benefits

The plan provides dental coverage for eligible retirees, their eligible spouses, and unmarried dependent children under the age of 19 (currently through Hawaii Dental Service).

Benefits for retirees continue for their lifetimes. Benefits for eligible dependents or spouses continue for two years following the death of the retiree.

Maximum Company Contributions

For employees retiring after 12/31/1998, aggregate Company-paid premium amounts associated with benefits (1), (2), and (3), will be limited to the following maximum annual amounts:

	Maximum Annual Company-Paid Premiums	
	Hired Before 1/1/1999	Hired After 12/31/1998
Under 65		
▪ Retiree, Spouse, and Dependents	$ 15,000	$10,000
▪ Single Retiree or Single Spouse	7,500	5,000
Over 65		
▪ Retiree and Spouse (per individual)	3,000	2,500*

* Includes drug

(4) Drug Benefits

For employees retiring after 12/31/1998, dental and vision coverages terminate upon eligibility for Medicare and are replaced by drug coverage with the following limits:

Years of Service	Company-Paid Percent of Premium	Maximum Company-Paid Premium*
Less than 6	0 %	$ 0
6 – 9	25	400
10 – 14	50	800
15 – 19	75	1,200
20 and over	100	1,600

*Applies to employee and spouse separately.

For employees hired after 12/31/1998, the maximum shown in (4) above applies to the combined medical and drug premiums.

		Benefits for retirees continue for their lifetimes. Benefits for eligible spouses continue for two years following the death of the retiree.
(6)	Group Life Insurance	
	(a) Eligibility	Retirement after attainment of age 50 with 5 years of service and 65 points or after attainment of age 55 with 5 years of service.
	(b) Benefits	A benefit of $20,000 ($15,000 for retirement between 11/1/1981 and 12/31/1993, $10,000 for retirement between 11/1/1977 and 10/31/1981, and smaller amounts for retirement prior to 11/1/1977) is paid to the retiree's beneficiary upon the retiree's death. Spouses and dependents are not covered under the life insurance program.
(7)	Medicare Part B Premiums	
	(a) Eligibility	Retirement after attainment of age 50 with 5 years of service and 65 points or after attainment of age 55 with 5 years of service.
	(b) Benefits	The plan reimburses the eligible retiree and his eligible spouse in an amount up to $24.80 per month, per individual, for Medicare Part B premiums. Benefits for retirees start at age 65 (or at retirement, if later) and continue for their lifetimes. Benefits for spouses start at the spouses' age 65 and continue for two years following the death of the retiree.

Benefits Included in VEBAs and 401(h) Account

The benefits provided by the plan are funded through three vehicles: a VEBA for bargaining unit employees, a VEBA for nonbargaining (or "merit") employees, and a 401(h) account, which is a separate account in the Retirement Plan for Employees of Hawaiian Electric Industries, Inc. and Participating Subsidiaries.

Because the 401(h) account funding limits are rather low (limited to one third of the retirement plan normal cost), the benefits are funded through the VEBAs to the extent possible. The benefits which cannot be funded through the VEBAs are then funded through the 401(h) account. Generally, deductible contributions to VEBAs are limited to current health care costs (not including future increases in benefits due to health care cost trending). However there are

no such limits for bargained VEBAs. Thus, the full postretirement benefits for bargaining employees, including future health care cost increases, are included in the bargaining VEBA. The VEBA for nonbargaining employees includes life insurance and health care benefits based on current benefit costs. Therefore, the future benefit increases above current costs for nonbargaining employees are funded through the 401(h) account.

Assumptions Related to Plan Benefits

Development of Baseline Health Care Costs

Claims costs were based on a weighted average of 2002, 2003, and 2004 composite premiums (with trending applied to prior years) to estimate net 2004 claims costs. The annual claims costs developed for the 2004 plan year are:

Health Care Cost Trend Rates

Assumed rates by which health care costs are expected to increase annually:

Medical: 10.0% for 2004, grading down to 4.25% over 6 years.
Dental: 4.25% per year
Vision: 3.25% per year

Other Actuarial Assumptions

(1)(a) Discount Rate: 6.25%

(1)(b) Long Term Asset Return Rate:

BU VEBA	9.00%
NBU VEBA	5.00%
401(h) Account	9.00%

The 5.00% interest rate used for the Non-Bargaining group VEBA reflects investment return after taxes.

(2) Salary Increases: Not applicable.

(3) Mortality: The 1983 Group Annuity Mortality Table with separate rates for males and females.

(4) Withdrawal: The following schedule shows representative rates at selected ages.

Age	Rates Males	Rates Females
20	7.4%	6.2%
25	4.9	3.7
30	3.4	2.5
35	2.4	1.7
40	1.3	1.2
45	0.7	0.7
50	0.0	0.3
55 and over	0.0	0.0

(5) Retirement Age:

The following schedule shows the assumed rates of retirement.

Age	Rate
Below 50	0%
50	2
51	2
52	2
53	2
54	4
55	15
56	15
57	15
58	15
59	15
60	15
61	15
62	30
63	25
64	30
65	50
66	50
67	50
68 and over	100

(6) Marital Status:

79% of male participants and 66% of female participants are assumed to be married, with female spouses three years younger than male spouses.

(7) Administrative Expenses (not including investment-related expenses)

BU VEBA	$25,000 per year
NBU VEBA	25,000 per year
401(h) Account	25,000 per year

CA-IR-341

Ref: T-15, pages 11-12 & HECO-1506 (FAS106 OPEB Costs).

The referenced testimony indicates, in part, that the HPUC allowed HECO to adopt FAS106 effective January 1, 1995 and that HECO funds the entire postretirement cost to tax advantaged funding vehicles, to the maximum extent possible. Please provide the following information.

a. Referring to HECO-1506, please provide a schedule showing comparable FAS106 cost data for each year since adoption in 1995.

b. To the extent that the amount of annual FAS106 cost exceeds the amount contributed to tax advantaged funding vehicles, please explain how HECO has accounted for any difference (e.g., internal funding commingled with other corporate assets, external non-deductible fund, etc.) and provide a breakdown of the cumulative balance by year since adoption of FAS106.

c. For each year (e.g., 1995-2005) referenced in item (a) above, please provide the following information since adoption of FAS106:

   1. Discount rate.

   2. Expected return on plan assets.

   3. Actual return on plan assets.

HECO Response:

a. The information of comparable FAS 106 data as provided by the actuary for 1995-2004 is attached.

b. The updated HECO-1504 attached to the response to CA-IR-337 includes the FAS 106 cost and contribution amounts. The difference between the FAS 106 cost and amounts contributed to tax advantaged funding vehicles for 1996-2004 represents the cost for the executive life portion which has been deleted from this case. See HECO T-15, page 11, lines 13-18.

c. The 1995-2003 asset returns for the HEI Retirement Plan are also shown on the updated HECO-1504 attached to the response to CA-IR-337. The returns for the OPEB plan are roughly the same as those for the retirement plan. The asset method for the funding

valuation has been changed effective January 1, 2004. Consequently, the value shown on the updated HECO-1504 for column q (2003) in the row labeled "Actual Returns for Valuation" was changed from 22.13% to 2.29%. The asset return values for 2004 have also been included in the updated HECO-1504, provided in response to CA-IR-337.

Periodic Postretirement Benefit Cost

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
unt										
	85,040	110,732	174,024	191,158	203,060	134,613	155,647	167,995	173,082	201,040
	322,548	308,646	414,854	438,724	446,264	400,680	418,169	413,408	399,260	415,853
rn	131	17,312	5,170	3,347	1,434	2,708	1,330	2,932	1,014	1,042
Oblig	144,616	126,644	126,644	126,644	126,644	126,644	126,644	126,644	126,644	126,644
Svc Cost	0	0	0	0	0	0	0	0	0	0
/Loss	0	0	0	0	0	0	0	0	0	0
	552,073	528,710	710,352	753,179	774,534	659,229	699,130	705,115	697,972	742,495
Ins										
	25,906	38,850	36,099	36,688	41,604	34,085	43,363	20,222	85,964	95,811
	240,276	275,185	291,908	305,477	301,122	343,534	364,247	388,202	414,941	431,019
rn	0	0	0	0	0	0	0	0	0	14,580
Oblig	343,145	343,145	343,145	343,145	343,145	343,145	343,145	343,145	343,145	343,145
Svc Cost	0	0	0	0	0	0	0	0	0	0
/Loss	0	0	0	-144,888	-167,186	-262,342	-199,305	-114,155	0	0
	609,327	657,180	671,152	540,422	518,685	458,422	551,450	637,414	844,050	855,395
	1,896,453	2,155,788	2,204,835	1,543,994	1,008,229	858,157	909,647	947,166	1,048,259	1,349,449
	4,208,295	4,408,164	4,506,458	3,690,284	2,627,410	3,033,386	3,054,519	3,382,387	3,391,021	3,492,213
rn	119,871	1,032,381	2,109,300	3,609,315	4,322,281	5,054,057	5,334,610	5,240,362	3,944,717	4,966,068
Oblig	2,445,089	2,445,089	2,445,089	2,129,026	1,192,556	1,192,556	1,192,556	1,192,556	1,192,556	1,117,592
Svc Cost	0	0	0	0	0	0	0	0	0	0
/Loss	0	0	0	-375,470	-629,662	-1,393,776	-1,206,207	-283,282	0	0
	8,429,966	7,976,660	7,047,082	3,378,519	-123,748	-1,363,734	-1,384,095	-1,535	1,687,119	993,186

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
IBU VEBA										
ervice Cost	319,398	366,003	378,680	454,683	378,796	344,920	382,333	445,072	514,032	564,790
nterest Cost	1,673,398	1,609,244	1,594,268	1,607,715	1,339,749	1,485,680	1,572,113	1,599,883	1,611,910	1,533,177
xp Asset Return	135,653	212,984	70,873	-11,871	7,134	84,866	127,780	183,727	227,303	350,166
mort of Trans Oblig	931,440	931,440	931,440	923,412	812,998	812,998	812,998	812,998	812,998	812,998
mort of Prior Svc Cost	0	0	0	0	0	0	0	0	0	0
mort of (Gain)/Loss	0	0	0	0	0	-21,354	0	0	0	0
PPC	2,788,583	2,693,703	2,833,515	2,997,681	2,524,409	2,537,378	2,639,664	2,674,226	2,711,637	2,560,799
01(h) Account										
ervice Cost	1,039,915	1,148,312	1,212,680	842,430	503,899	471,210	514,384	520,949	589,024	851,839
nterest Cost	1,653,013	1,761,300	1,850,402	1,362,246	819,981	998,822	1,100,652	1,343,820	1,446,934	1,561,202
xp Asset Return	179,724	661,697	763,292	938,688	1,077,163	1,324,134	1,457,431	1,481,650	1,084,030	1,331,429
mort of Trans Oblig	831,459	831,459	831,459	621,532	13,060	13,060	13,060	13,060	13,060	0
mort of Prior Svc Cost	0	0	0	0	0	0	0	0	0	0
mort of (Gain)/Loss	0	0	0	-272,536	-379,531	-689,057	-569,848	-148,668	0	0
PPC	3,344,663	3,079,374	3,131,249	1,614,984	-119,754	-530,099	-399,183	247,511	964,988	1,081,612
otal										
ervice Cost	3,366,712	3,819,685	4,006,318	3,068,953	2,135,588	1,842,985	2,005,374	2,101,404	2,410,361	3,062,929
nterest Cost	8,097,530	8,362,539	8,657,890	7,404,446	5,534,526	6,262,102	6,509,700	7,127,700	7,264,066	7,433,464
xp Asset Return	435,379	1,924,374	2,948,635	4,539,479	5,408,012	6,465,765	6,921,151	6,908,671	5,257,064	6,663,285
mort of Trans Oblig	4,695,749	4,677,777	4,677,777	4,143,759	2,488,403	2,488,403	2,488,403	2,488,403	2,488,403	2,400,379
mort of Prior Svc Cost	0	0	0	0	0	0	0	0	0	0
mort of (Gain)/Loss	0	0	0	-792,894	-1,176,379	-2,366,529	-1,975,360	-546,105	0	0
PPC	15,724,612	14,935,627	14,393,350	9,284,785	3,574,126	1,761,196	2,106,966	4,262,731	6,905,766	6,233,487

CA-IR-342

Ref: T-15, pages 11-12 & HECO-1506 (FAS106 OPEB Costs).

Please confirm that HECO has not transferred any "excess" pension funds for purposes of paying retiree OPEB benefits via transfer provisions under IRC Section 401(h). If such transfers have

occurred, please provide the amount thereof by calendar year since adoption of FAS106.

CA-IR-343

Ref: T-15, page 15 (FAS106 OPEB Costs).

At lines 11-20, the referenced testimony discusses reductions in postretirement benefit costs as a result of the 1998 and 2003 union negotiations, changes in plan provisions and changes in drug plan provisions. Please provide the following:

a. Please provide an estimate of the impact of the identified changes.

b. Does the FAS106 actuarial study consider the estimated impact of the new Medicare Reform Act (MRA) on retiree prescription drug costs?

   1. If so, please provide an estimate of the impact on the 2005 test year forecast.

   2. If not, please explain why the actuarial study does not consider the MRA and provide any estimates of the savings of such program provided to HECO.

HECO Response:

a. The 1998 changes resulted in a reduction in HECO's accumulated postretirement benefit obligation of approximately $31.2 million as of December 31, 1998. The impact of the 2003 plan changes was a reduction of approximately $856,000 as of January 1, 2004.

b. The impact of the new MRA on retiree prescription drug costs was not considered.

   1. Not applicable.

   2. See attached page 2 which is an excerpt from the HEI/HECO 2004 Form 10-K, Footnote 1 of the HECO Notes to Consolidated Financial Statements.

Footnote 1

Medicare Prescription Drug, Improvement and Modernization Act of 2003. The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the 2003 Act) was signed into law on December 8, 2003. The 2003 Act expanded Medicare to include for the first time coverage for prescription drugs. The 2003 Act provides that persons eligible for Medicare benefits can enroll in Part D, prescription drug coverage, for a monthly premium. Alternatively, if an employer sponsors a retiree health plan that provides benefits determined to be actuarially equivalent to those covered under the Medicare standard prescription drug benefit, the employer will be paid a subsidy of 28 percent of a participant's drug costs between $250 and $5,000 if the participant waives coverage under Medicare Part D.

In May 2004, the FASB issued FSP No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." When an employer is able to determine that benefits provided by its plan are actuarially equivalent to the Medicare Part D benefits, the FSP requires (a) treatment of the effects of the federal subsidy as an actuarial gain like similar gains and losses, and (b) certain financial statement disclosures related to the impact of the 2003 Act for employers that sponsor postretirement health care plans providing prescription drug benefits. The FASB's related initial guidance, FSP No. 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," was superseded upon the effective date of FSP No. 106-2, which was the first interim or annual period beginning after June 15, 2004.

In the Company's current disclosure, the accumulated postretirement benefit obligation and net periodic postretirement benefit cost do not reflect any amount associated with the federal subsidy because, although the Company has concluded that the benefits the plan provides are actuarially equivalent to Medicare Part D benefits under the 2003 Act, the Company may not be eligible for any employer sponsored qualified plan subsidy, partly due to caps on the Company's costs for these benefits and the sharing of premiums between the Company and retirees. If the Company is eligible, it expects the impact to be immaterial.

The new Medicare legislation could impact the Company's future measures of accumulated postretirement benefit obligation and net periodic postretirement benefit cost in three ways: (1) as described above, the subsidy would reduce the obligation for benefits provided by the postretirement health plan, (2) to the extent election into Medicare Part D coverage causes retirees to elect out of the Company's plan, such measures will be lower, and (3) the Company will review the plan design for alternative ways to capture savings from the 2003 Act.

CA-IR-344

Ref: T-15, page 16 (Long-Term Disability).

Please provide the following:

a. Please explain why HECO changed from a partially self-insured basis for long-term disability to a fully insured basis.

b. Referring to the decision referenced in item (a) above, did the Company prepare any cost/benefit studies in assessing the economics of the change?

   1. If so, please provide a copy of any such studies.

   2. If not, please explain why such studies were not undertaken.

HECO Response:

a. The decision to change from a partially self-insured basis to a fully insured basis for long-term disability was made by HECO primarily due to administrative issues. Under the partially self-insured contract between MetLife and HEI, there is one bank account covering HEI and the utilities making the reconciliation of claims paid by company extremely difficult due to timing differences. While partially self-insured arrangements were once prevalent, they had become an exception to the carrier's administrative structure. HECO

was also interested in a fully insured arrangement with known premium costs.

b. No cost/benefit studies were made in conjunction with this change.

   2. The change was made since MetLife provided a competitive rate for the fully insured

CA-IR-345

Ref: T-15, page 17 & HECO-1507 (Long-Term Disability).

HECO-1507 provides the calculation of long-term disability for the forecast test year. [Note: If the information requested below has been previously provided in response to CA-IR-2 or another interrogatory, please provide a pinpoint reference to the responsive data.] Please provide the following:

[redacted]

arrangement prior to January 1, 2003. As indicated in the response to part c. above, the claims estimate has been updated to reflect actual claims remaining. The worksheet for the $161,418 annualized claims estimate was provided in response to CA-IR-2, HECO T-15, Attachment 8, pages 1 to 7 filed with the Consumer Advocate on January 11, 2005. Attached at page 10 to this response is the worksheet used to determine the updated estimate.

Metropolitan Life Insurance Company
4380 SW Macadam Ave, Suite 200, Portland, OR 97239
Tel 503 494-1053 800 884-3916
Fax 503 227-2799 jpenosh@metlife.com

John E. Penosh
Account Executive

Registered Representative

MetLife

February 10, 2004

Lorraine Nakasone
Aon Consulting
P. O. Box 201
Honolulu, HI 96810

Dear Lorraine:

Thank you for the opportunity to present some plan design options for the consideration of the staff at **Hawaiian Electric Industries**. I am pleased to present our response to a variety of these changes.

We are quoting options for the management/non-bargained group of employees. The options that we can offer fall into two categories. We can provide plan options under a group insurance arrangement, or we can offer an employee "buy-up" through individual disability insurance. I will address the group insurance options first.

The current group plan provides benefits of 60% after an elimination period of 180 days. The current rate for this plan is $.42/$100 of Covered Payroll. While we do not track the rates separately by class, this is certainly an option. So, in the table below, I am presenting the rate impact for each plan change on the rate of the management/non-bargained class only, as well as the impact to the overall rate.

	Impact to Management Only	Impact to Composite Rate
* Increase benefit to 65% of pay	+24%	+12%
Increase benefit to 66 2/3% of pay	+30%	+15%
* Add terminal illness benefit at 80% of pay for 12 months	+14%	+7%
Add terminal illness benefit at 100% of pay for 12 months	+18%	+9%
Change to a 36 month "Own Occupation" definition	+7%	+3%
Change to a 60 month "Own Occupation" definition	+15%	+7%

For example, if the staff at HEI elect to change the management employee plan to feature a 65% benefit, then they could increase the rate for all employees by 12% to $.47/$100. Alternately, they can break out the rates for the two groups and pay $.42/$100 for the non-management and $.52/$100 for the management plan (+24%).

Variable annuities and variable life insurance offered by Metropolitan Life Insurance Company, One Madison Avenue, New York, NY 10010.
Mutual funds offered by MetLife Securities, Inc., One Madison Avenue, New York, NY 10010

MetLife

Lorraine Nakasone
Aon Consulting
February 10, 2004

Also note that these plan changes are applied as a multiple, so that if they select both the 65% benefit (worth 12% overall) and the 80% terminal illness benefit (worth 7% overall), then the rate would be $.42/$100 X 1.12 X 1.07, or $.50/$100. Finally, these options are offered on an employer-paid basis. As such, any benefit payable under the plan is considered taxable income to the employees.

As an alternative to these employer-paid programs, we are proud to offer an employee-paid option through our Individual Disability Insurance (IDI) product. This IDI program has advantages over group programs, including:

- Fixed premium for the life of the coverage, unless changed by class
- Fully portable
- Guaranteed Issue to $7,000 of coverage
- Benefits up to 75% of pre-disability income
- Riders to allow guaranteed future purchase of Long Term Care coverage and Catastrophic disability riders
- Premiums paid on after-tax basis makes plan benefits non-taxable

I urge you to carefully review the IDI quote, as it does represent a significant increase in benefit to employees at a competitive cost. Better yet, it increases the value of the benefit program with little or no cost to the employer, unless they wish to subsidize a portion of the plan's cost.

One item we noted on the census was that there were several employees who appeared to not match the job descriptions of the class. For example, we did see some system workers in the ineligible class, and some "technicians" in the eligible class. We would like to confirm that these employees are classed correctly for purposes of eligibility. I look forward to discussing these options and related issues with you in more detail. Please let me know a convenient time to get together.

Thank you again for the opportunity to present our findings and recommendations, and I look forward to hearing from you soon.

Sincerely,

John Panosh

Employee Benefits Consulting

Lorraine P. Nakasone
Consultant
Aon Consulting
Direct Line (808) 540-4357
E-mail: lorraine_nakasone@aonsoc.com

October 5, 2004

Mr. John Panosh
Account Executive
MetLife
4380 SW Macadam Avenue, Suite 200
Portland, OR 97201

RE: HAWAIIAN ELECTRIC INDUSTRIES

Dear John:

We are pleased to inform you of Hawaiian Electric Industries, Inc.'s decision regarding their LTD renewal for the 2005 and 2006 Plan Years. The accepted terms of the two-year agreement are as follows:

For 2005:

Insured LTD Plan – BU	$.42 per $100 of covered payroll
Insured LTD Plan – NBU	$.59 per $100 of covered payroll

For the 2006 Plan Year, HEI has accepted a maximum increase/decrease of 5.0%

ASO Runout Claim Fees

Claims inforce greater than 2 years	$41.97 per claim
Claims inforce less than 2 years	$58.67 per claim

Banking Charge	$376.33 per month

The ASO Runout Claim Fees and the Banking Charge are guaranteed for one year.

The updated certificates for all classes (merit/salaried, subsidiaries and bargaining) are being reviewed. We will contact you to discuss and finalize.

On behalf of Hawaiian Electric Industries, Inc., thank you for your assistance with this renewal. Should you have any questions, please feel free to contact me at (808) 540-4357.

Sincerely,

Lorraine P. Nakasone

Lorraine P. Nakasone
Consultant

cc: Myra O'Brien/Hawaiian Electric Industries, Inc.
Malcolm Tajiri/Aon Consulting

Enrollment Counts as of

Enrollment in:	1/1/2004 HECO		1/1/2005 HECO	
Medical Waive	64		80	
HPH				
Single	128	10.1%	142	10.6%
Sin Par	41	3.2%	43	3.2%
Couple	88	6.9%	92	6.9%
Family	244	19.2%	272	20.3%
	501		549	
Kaiser				
Single	54	4.3%	49	3.7%
Sin Par	11	0.9%	8	0.6%
Couple	37	2.9%	39	2.9%
Family	65	5.1%	74	5.5%
	167		170	
HealthLink				
Single	10	0.8%		0.0%
Sin Par	2	0.2%		0.0%
Couple	6	0.5%		0.0%
Family	21	1.7%		0.0%
	39		0	
PPP				
Single	100	7.9%	118	8.8%
Sin Par	32	2.5%	35	2.6%
Couple	110	8.7%	111	8.3%
Family	255	20.1%	277	20.7%
	497		541	
Vision				
Single	292	23.0%	309	23.1%
Couple	241	19.0%	242	18.1%
Family	671	52.9%	709	52.9%
	1204		1260	
Dental Waive	35		41	
Preventive				
Single	12	0.9%		0.0%
Couple	3	0.2%		0.0%
Family	4	0.3%		0.0%
	19		0	
Major Care				
Single	279	22.0%	309	23.1%
Couple	251	19.8%	252	18.8%
Family	684	53.9%	738	55.1%
	1214		1299	

Enrollment Counts as of

Enrollment In:	1/1/2004 HECO		1/1/2005 HECO	
Supplemental L25				
0-29	1	0.1%	3	0.3%
30-34	10	1.1%	7	0.8%
35-39	14	1.6%	13	1.4%
40-44	26	3.0%	27	3.0%
45-49	24	2.7%	31	3.4%
50-54	22	2.5%	24	2.7%
55-59	23	2.6%	22	2.4%
60-64	15	1.7%	15	1.7%
65 +	2	0.2%	4	0.4%
Supplemental L35				
0-29	8	0.9%	15	1.7%
30-34	39	4.4%	46	5.1%
35-39	136	15.5%	129	14.3%
40-44	181	20.6%	177	19.6%
45-49	147	16.7%	160	17.7%
50-54	133	15.1%	135	14.9%
55-59	76	8.6%	74	8.2%
60-64	17	1.9%	15	1.7%
65 +	3	0.3%	3	0.3%
Supplemental L50				
0-29	0	0.0%	0	0.0%
30-34	1	0.1%	1	0.1%
35-39	1	0.1%	0	0.0%
40-44	0	0.0%	1	0.1%
45-49	1	0.1%	2	0.2%
50-54	0	0.0%	0	0.0%
55-59	0	0.0%	0	0.0%
60-64	0	0.0%	0	0.0%
65 +	0	0.0%	0	0.0%
	880		904	
Spending Accounts				
$Health Care	315,444		328,347	
$Dependent Care	299,309		332,238	
No HC	375		375	
Avg $	841		876	
Part. %	29.6%		28.0%	
No DC	112		113	
Avg $	2,672		2,940	
Part. %	8.8%		8.4%	
Employee Count (based on medical)				
Merit	584	46.1%	658	49.1%
BU	684	53.9%	682	50.9%
	1268	100.0%	1340	100.0%

BeneStats2004.xls
02/21/2004

Enrollment Counts as of

Enrollment in:	1/1/2004 HECO		1/1/2005 HECO	
Dependent Life				
10K	89	7.0%	79	5.9%
25K	559	44.1%	595	44.4%
Waive	620	48.9%	666	49.7%
	1268		1340	
AD&D				
Single	360	28.4%	385	28.7%
Family	683	53.9%	711	53.1%
Waive	225	17.7%	244	18.2%
	1268		1340	
Supplemental				
Avg Merit Sal	74,139		73,284	
Avg BU Wage	57,387		57,595	
Avg Merit 50,000 Cov	0		147	
Avg BU 50,000 Cov	775		244	
AD&D				
Avg Mrt Sin Cov	184,933		176,138	
Avg Mrt Fam Cov	220,475		217,552	
Avg BU Sin Cov	162,454		167,652	
Avg BU Fam Cov	187,644		191,500	
Avg Life Credit	6.53		10.57	
			0.87	
			12.33	

Your company determines the projected salary/wage increase to use on this worksheet. For the utilities that is provided to you by the Budgets Dept.
LTD is from your own records.

HECO-1507 Updated (3-22-05)

Hawaiian Electric Co., Inc.

CALCULATION OF LONG TERM DISABILITY

2005

				MERIT		BU		TOTAL
Average Salary for	January	2004	Enrollment	73,284		57,595		
				x 1.0000				
				73,284				
Salary/Wage Adjustment		*(see note)*		x 1.0000		x 1.0000		
				73,284		57,595		
Projected No. of Merit and BU Employees				x 733		x 762		
Projected Compensation for	2005			53,717,172		43,887,390		
2004	Premium rate per $100 Compensation * eff 7/1/2004	BU	$0.42					
		MERIT*	$0.59	x $0.0059		x $0.0042		
				$316,931.31		$184,327		501,258
Administrative fee			$0.00	per employee (annualized)			+	0
				ASA admin fee plus banking fees			+	5,600
				Annual Premium				506,858
Plus Claims	(incurred as of		04/01/04	& annualized)			+	91,000
					2005	Forecast		597,858

780 PHE NE NPFZZZZZ 509 **597,858**

No. of Merit Employees	49%
No. of BU Employees	51%

LTD CLAIM PAYMENTS
JANUARY 2005

Company	Date	Name	Amount	Federal	State	FICA	Mcare	Total
HECO	1/31/2005	A	$663.76					$663.76
HECO		B						$0.00
HECO		B						$0.00
HECO	1/31/2005	C	$747.10	11.33	21.57			$780.00
HECO	1/13/2005	D	($200.00)					($200.00)
HECO		D						$0.00
HECO		E						$0.00
HECO		F						$0.00
HECO		G						$0.00
HECO	1/31/2005	H	$2,584.73	297.96	167.62			$3,050.31
HECO		I						$0.00
HECO	1/4/2005	I	$833.00					$833.00
HECO		J						$0.00
HECO	1/31/2005	K	$1,015.59					$1,015.59
HECO	1/3/2005	K	$1,015.59	116.35	60.41			$1,192.35
HECO		L						$0.00
HECO	1/4/2005	L	$196.00					$196.00
		TOTAL	$6,855.77	$425.64	$249.60	$0.00	$0.00	$7,531.01
			Total Taxes	$675.24				

Names deleted for confidentiality. Each letter represents an individual.

CA-IR-346

Ref: T-15, page 23 (Administration Costs).

The referenced testimony indicates that the $400,700 estimate included in the test year was based on prior year costs. Please provide the historical data on which this estimate was based and provide a detailed breakdown of the various components or expense elements comprising this amount. [Note: If this information has previously been supplied in response to CA-IR-1 or CA-IR-2, please provide a pinpoint reference thereto.]

HECO Response:

See attached for requested breakdown. The amount of administrative costs will be adjusted in rebuttal testimony to reflect changes in the HEI inter-company billing amount as noted on the attached.

CA-IR-346

Breakdown of Administration Costs

Expense Element	TY Est	2004 Budget	2003 Actual	Description
501	625	625	625	Registration fees
	47,679	46,893	76,129	Consulting, telephone, transp., meetings
	44,467	44,080	38,680	Trustee fees, Pre-Ret Workshop, Pension System
	625	625	4,160	attend training
	600	600	525	Shredding
516	959	929	50	Ee memberships
520	1,500	1,500	0	Mainland travel
521	250	250	0	Meals/Ent
550	232,946 [1]	184,750	194,335	HEI inter-company billings
205	6,778	6,778	8,524	Subscriptions, printing
301	960	1,056	8	Vehicles
462	1,094	1,120	4	Software purchases
502	25,653	25,402	26,451	Legal Services
451	35,928	42,684	33,228	ISD-Prod & Dev
	400,064 [2]	357,292	382,719	Total

Note:

[1] Amount will be adjusted to delete incentive compensation
Corrected amount is 167,375. See HECO-1310, page 2 (25,469+141,906)

[2] Total on HECO T-15, page 18, line 2 is 400,700. Difference is due to G/L codes reversal.

CA-IR-347

Ref: T-15, page 28 & HECO-1509 (Group Medical).

At line 18, the referenced testimony indicates that actual group medical rates for 2005 were established in October 2004. Please update HECO-1509 to reflect the actual 2005 rates.

HECO Response:

[redacted]

HECO-1509 Updated (3-22-05)

Hawaiian Electric Co., Inc.

Flex Plan Premiums & Prices

2005

Plan Options	Premium Per Month 2004 Medical	Premium Per Month 2005	Medical % Increase	FlexPlan Price per Pay Pd 2004	FlexPlan Price per Pay Pd 2005
Credits				67.54	67.54
HealthLink [1]					
Single	232.15	0.00	0.00	65.68	0.00
Single Parent	437.50	0.00	0.00	69.49	0.00
Couple	526.37	0.00	0.00	75.46	0.00
Family	571.11	0.00	0.00	79.99	0.00
PPP					
Single	207.65	208.46	0.39	65.68	66.68
Single Parent	405.67	417.76	2.98	69.49	70.49
Couple	488.05	502.72	3.01	75.46	77.46
Family	526.15	542.86	3.18	79.99	82.49
HPH Plus					
Single	232.15	237.19	2.17	65.68	66.68
Single Parent	437.50	456.20	4.27	69.49	70.49
Couple	526.37	548.96	4.29	75.46	77.46
Family	571.11	596.88	4.51	79.99	82.49
Kaiser					
Single	286.96	249.01	-13.23	65.68	66.68
Single Parent	550.96	478.10	-13.22	69.49	70.49
Couple	662.88	575.22	-13.22	75.46	77.46
Family	723.14	627.51	-13.22	79.99	82.49
Vision					
Single	5.85	4.86	-16.92	2.75	2.75
Couple	11.70	9.71	-17.00	3.00	3.00
Family	16.97	14.09	-16.97	3.00	3.00
Preventive [1]					
Single	8.92	0.00	0.00	1.23	0.00
Couple	17.84	0.00	0.00	2.44	0.00
Family	20.67	0.00	0.00	3.67	0.00
Major Care					
Single	29.44	31.21	6.01	4.11	4.11
Couple	58.86	62.39	6.00	5.08	5.08
Family	84.24	89.29	6.00	6.05	6.05

[1] discontinued effective 1/1/2005

Note:

Medical prices based on employee contribution per 2003 Negotiations
No price increase for Vision and Dental

	Single	SingleParent	Couple	Family
Medical	66.68	70.49	77.46	82.49
Vision	2.75	3.00	3.00	3.00
Dental	4.11	6.05	5.08	6.05
Total Prices	73.54	79.54	85.54	91.54
Less Credits	67.54	67.54	67.54	67.54
Employee Cont.	6.00	12.00	18.00	24.00

CA-IR-348

Ref: T-15, page 27 & HECO-1510 (Medical Expense).

Please update HECO-1510 to reflect the following:

a. Actual January 2005 employee participation by available plan.

b. Actual 2005 premium rates.

HECO Response:

a. Attached as page 2 to this response is HECO-1510 which has been updated to reflect January 1, 2005 enrollment data, and actual 2005 premium rates (as provided in response to CA-IR-347).

b. See response to part a. above.

HECO-1510 Updated (3-22-05)

Hawaiian Electric Co., Inc.

Calculation of Medical Expense

2005

PLAN	COVERAG	1 % OF PARTICIPATION 1/1/2005	2 PROJECTED PARTICIPATION 2005	3 2005 MONTHLY PREMIUM RATES	4 MONTHLY PREMIUM FOR 2005 PARTICIPATION (2 x 3)	5 2005 ANNUAL PREMIUM
HealthLink [1] (HMSA)	Single	0.0%	0.0	0.00	0	0
	S. Parent	0.0%	0.0	0.00	0	0
	Couple	0.0%	0.0	0.00	0	0
	Family	0.0%	0.0	0.00	0	0
					0	0
PPP (HMSA)	Single	8.8%	131.6	208.46	27,433	329,196
	S. Parent	2.6%	38.9	417.76	16,251	195,012
	Couple	8.3%	124.1	502.72	62,388	748,656
	Family	20.7%	309.5	542.86	168,015	2,016,180
					274,087	3,289,044
HPH Plus (HMSA)	Single	10.6%	158.5	237.19	37,595	451,140
	S. Parent	3.2%	47.8	456.20	21,806	261,672
	Couple	6.9%	103.2	548.96	56,653	679,836
	Family	20.3%	303.5	596.88	181,153	2,173,836
					297,207	3,566,484
Kaiser	Single	3.7%	55.3	249.01	13,770	165,240
	S. Parent	0.6%	9.0	478.10	4,303	51,636
	Couple	2.9%	43.4	575.22	24,965	299,580
	Family	5.5%	82.2	627.51	51,581	618,972
					94,619	1,135,428
Waive		5.9%	88.0			
		100.0%	1,495		665,913	7,990,956

[1] discontinued effective 1/1/2005

778 PHE NE NPFZZZZZ 509	TOTAL	6,855,528
778 PHE NE NPFZZZZZ 509	TOTAL	1,135,428

CA-IR-349

Ref: T-15, page 29 & HECO-1511 (Group Dental).

At lines 14-17, the referenced testimony describes how the premium rates were determined for the 2005 test year. If the 2005 actual premium rates are available, please update HECO-1511 to reflect the actual 2005 rates.

HECO Response:

Attached as page 2 to this response, is HECO-1511 which has been updated to include

January 1, 2005 enrollment data, and actual 2005 premium rates.

HECO-1511 Updated (3-22-05)

Hawaiian Electric Co., Inc.

Calculation of Dental Expense

2005

PLAN	COVERAG	1 % OF PARTICIPATION 1/1/2005	2 PROJECTED PARTICIPATION 2005	3 2005 MONTHLY PREMIUM RATES	4 MONTHLY PREMIUM FOR 2005 PARTICIPATION (2 x 3)	5 2005 PROJECTED ANNUAL PREMIUM
Preventive [1] (HDS)	Single	0.0%	0.0	0.00	0	0
	2 Party	0.0%	0.0	0.00	0	0
	Family	0.0%	0.0	0.00	0	0
					0	0
Major Care (HDS)	Single	23.1%	345.3	31.21	10,777	129,324
	2 Party	18.8%	281.1	62.39	17,538	210,456
	Family	55.1%	823.7	89.29	73,548	882,576
					101,863	1,222,356
Waive		3.0%	44.9		203,726	
		100.0%	1,495		203,726	1,222,356

[1] discontinued effective 1/1/2005

778 PHE NE NPFZZZZZ 509 TOTAL 1,222,356

CA-IR-350

Ref: T-15, page 30 & HECO-1512 (Group Vision).

At lines 4-12, the referenced testimony describes how the premium rates were determined for the

HECO-1512 Updated (3-22-05)

Hawaiian Electric Co., Inc.

Calculation of Vision Expense

2005

PLAN	COVERAG	1 % OF PARTICIPATION 1/1/2005	2 PROJECTED PARTICIPATION 2005	3 2005 MONTHLY PREMIUM RATES	4 MONTHLY PREMIUM FOR 2005 PARTICIPATION (2 x 3)	5 2005 PROJECTED ANNUAL PREMIUM
VISION (VSP)	Single	23.1%	345.3	4.86	1,678	20,136
	Couple	18.1%	270.6	9.71	2,628	31,536
	Family	52.9%	790.9	14.09	11,144	133,728
Waive		5.9%	88.2			
		100.0%	1,495		15,450	185,400

778 PHE NE NPFZZZZZ 509 TOTAL 185,400

CA-IR-351

Ref: T-15, pages 34-35 (Labor Market).

The referenced testimony describes the merit increases included in the 2005 test year forecast and generally discusses the labor markets in which HECO competes for employees. Please provide a copy of any studies, analyses or other documentation prepared by, or for, HECO that addresses the competitive labor market and how the Company's pay rates compare to comparable positions of those competitors.

HECO Response:

HECO uses market based survey information to determine pay rates for its non-bargaining positions. The surveys are confidential, proprietary and voluminous (total 10 binders), but can be made available for review on a confidential basis at HECO Regulatory Affairs Department by contacting Irene Sekiya at 543-4778. The following is a list of organizations whose salary surveys were used to forecast market rates for 2005:

1. Foushee Group Inc.
2. Hawaii Employers Council
3. Mercer HR Consulting,
4. Towers Perrin Human Resources Services
5. Watson Wyatt

CA-IR-352

Ref: T-15, page 36 (Human Resources Suite).

Please discuss the current status of HECO's plans to file an application for approval of this

HECO Response:

HECO is currently in the process of developing the application to the Commission for approval of this project. A Request for Proposal has been sent out, interested vendors have submitted responses, interviews were conducted with potential vendors and an evaluation has been

CA-IR-353

Ref: T-19, page 11 (Pension Asset)

At line 12, Ms. Ohashi states: "In theory, ratepayers provide the funds based on the NPPC and investors provide the funds contributed to the pension fund." Please provide the following:

a. Please provide a copy of all documentation relied upon that supports this regulatory "theory," including any pinpoint citations to HPUC rules, Hawaii statutes, regulatory decisions (other than the referenced HELCO and MECO decisions) or other authoritative literature.

b. Please explain how ratepayers provide pension costs based on the NPPC, identifying and describing any cost recovery mechanisms or assumptions associated with this treatment.

c. Please explain how investors provide the funds contributed to the pension fund, indicating how such amounts are collected from investors.

HECO Response:

a. HECO did not rely on any documents other than the referenced HELCO and MECO decisions in making the statement.

b. The NPPC is used to determine the administrative and general expenses charged to O&M and used to determine revenue requirements. See testimony of Ms. Julie Price, HECO T-15, pages 5 and 6 and HECO-1502.

c. Cash contributions to the pension fund are provided by the net cash provided by operating activities and the net cash flow from financing activities.

CA-IR-354

Ref: T-19, page 11 (Pension Asset)

At line 12, Ms. Ohashi states: "In theory, ratepayers provide the funds based on the NPPC and investors provide the funds contributed to the pension fund." Please provide the following:

a. Does the Company believe that expenses that increase between rate proceedings (e.g., positive NPPC, storm damage costs, abandoned projects, outside services, etc.) are automatically recovered from ratepayers as recorded by HECO? If so, please explain.

b. Does the Company believe that act of recording negative NPPC results in those credits automatically being flowed through to the benefit of customers? If so, please explain.

HECO Response:

a. No, the Company does not believe that there is any automatic recovery from ratepayers of expenses.

b. No, the Company does not believe that there is any automatic flow through to ratepayers of any negative NPPC.

CA-IR-355

Ref: T-19, page 11 (Pension Asset)

At line 15, Ms. Ohashi states: "Since the test year estimates forecast that the NPPC and fund contributions will result in a net asset, investors are providing the net amount." Please provide the following:

[redacted]

statement is based.

b. Please provide the amount of NPPC included in the test year forecast in HECO's last rate proceeding.

c. Please provide the amount of pension fund contributions forecast for the test year in HECO's last rate proceeding.

HECO Response:

(REVISED 5-26-05)

CA-IR-356

Ref: HECO-1904 (Pension Asset).

In a format comparable to HECO-1904, please provide the accumulated deferred income tax reserve balance HECO has included in rate base associated with the prepaid pension asset.

HECO Response:

See page 2 to this response for the corrected 12/31/03 recorded balance and the updated deferred taxes on pension. See also HECO's response to CA-IR-691.

CA-IR-356

Re: HECO-1904 (Pension Asset).

In a format comparable to HECO-1904, please provide the accumulated deferred income tax reserve balance HECO has included in rate base associated with the prepaid pension asset.

HECO Response:

See page 2 to this response.

(REVISED 5-26-05)

Hawaiian Electric Company, Inc.
Deferred Taxes on Pension
($ in thousands)

RECORDED BALANCE - 12/31/03	21,431
Accrual	631
Payments	7,312
ACTUAL BALANCE - 12/31/04	29,374
Accrual	(1,718)
Payments	0
ESTIMATED BALANCE - 12/31/05	27,656
AVERAGE 2005 BALANCE	28,515

NOTE: Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Deferred Taxes on Pension

($ in thousands)

RECORDED BALANCE - 12/31/03	3,322
Accrual	0
Payments	0
ESTIMATED BALANCE - 12/31/04	3,322
Accrual	0
Payments	0
ESTIMATED BALANCE - 12/31/05	3,322
AVERAGE 2005 BALANCE	3,322

NOTE: Totals may not add exactly due to rounding.

CA-IR-357

Please provide the following information regarding HECO tariff provisions within Schedules R and G that provide for minimum charges:

a. Explain the origin of this tariff element, if known, and the purpose it is believed to serve today that is not served by the Customer Charge within the tariff.

b. What specific pricing or efficiency goals are believed to be achieved by maintaining a Minimum Charge provision that charges customers for certain amounts of energy, whether such energy is used or not?

c. To what extent are the Company's demand side management goals in conflict with tariff provisions that tend to encourage customers to use energy because of Minimum Charge tariff provisions that work like take or pay pricing?

d. Provide the amount of kwh and revenues (present and proposed rates) that are billed under the Minimum Charge provisions of each rate having such provisions.

e. State each reason why HECO or Ms. Seese believes the Minimum Charge tariff elements should not be eliminated from each of the Company's tariffs.

HECO Response:

a. The Schedule R minimum charge was set equal to the customer charge until July 15, 1981 when the minimum charge was set higher than the customer charge as ordered by the PUC in its Decision & Order No. 6696 in Docket No. 3874. The PUC's decision and order found

6531, in order to align rates closer to costs.

The customer charges both at present rates and at proposed rates are lower than the customer-related costs, especially the Schedule R customer charges. The remainder of the customer costs that is not recovered in the customer charges is recovered in the energy rates. Furthermore, all of the demand-related costs of providing service to Schedules R and G which the Company incurs regardless of whether or not the customers consume kWh, are embedded and recovered in the energy rates. For instance, the Company continues to incur the costs of reading the meters, billing the customers, operating and maintaining the plant facilities regardless of customer's kWh consumption, even when the customers do not

6531, in order to align rates closer to costs.

The customer charges both at present rates and at proposed rates are lower than the customer-related costs, especially the Schedule R customer charges. The remainder of the customer costs that is not recovered in the customer charges is recovered in the energy rates. Furthermore, all of the demand-related costs of providing service to Schedules R and G which the Company incurs regardless of whether or not the customers consume kWh, are embedded and recovered in the energy rates. For instance, the Company continues to incur the costs of reading the meters, billing the customers, operating and maintaining the plant facilities regardless of customers' kWh consumption, even when the customer does not consume any kWh. When customers do not use any kWh, or use only nominal amount of kWh, they are not paying their fair share of these fixed costs even with the minimum charge provision, as these charges do not recover the full customer costs and demand costs of serving these customer classes.

b. The minimum charge provisions in Schedules R and G are aimed at aligning rates closer to costs. Although the minimum charges do not fully recover the total customer costs and demand costs from zero-energy users or from minimal energy users, the minimum charge provision provides a pricing mechanism relative to not having a minimum charge provision at all, by minimizing the intra-class subsidization, and by providing recovery of some of the utility's fixed costs. Aligning rates closer to cost provides more efficient pricing since cost-

average energy usage of the minimum bill customers. For instance, when the current rates which became effective in January 1, 1997 were designed, the average kWh usage of the minimum bill customers was 29 kWh per customer per month. (See HECO Transmittal Letter dated December 21, 1995, Exhibit 8, page 6, in Docket No. 7766.) In this instant docket, the average kWh usage of minimum bill customers is 24 kWh per customer per month at present rates which is about 17% lower than in 1997. (See Docket No. 04-0113, HECO-WP-304, page 3.)

As discussed in HECO T-22, page 17, HECO's rate design such as the inclusion of minimum charge provision in the tariffs, takes into account many different factors such as the recovery of the Company's revenue requirements or costs of providing service, aligning rates closers to costs, providing revenue stability to the Company, providing fair and equitable rates and minimizing intra-class subsidy, as well as encourage customer load management. The revenue recovery and revenue stability considerations in the Company's rate design, such as with the inclusion of the minimum charge provision, do not necessarily conflict with the Company's demand side management goals. The amount of kWh that the minimum charges in Schedules R and G would buy is very minimal as to conflict with the Company's demand side management goals. For Schedule R, the proposed minimum charge for 1-Phase service will buy 67 kWh per month, and the proposed minimum charge for 3-Phase service will buy 33 kWh per month. (See Docket No. 04-0113, HECO-WP-304, page 2.) For Schedule G, the proposed minimum charge for 1-Phase service will buy 36 kWh per month. The 3-Phase service, the proposed minimum charge is set equal to the proposed customer charge. (See Docket No. 04-0113, HECO-WP-304, page 12.)

d. Please see the following workpapers for the amount of kWh and revenues at present rates

and at proposed rates that are billed under the minimum charge provisions: (1) for Schedule R, please see HECO-WP-304, pages 2-4, (2) for Schedule G, please see HECO-WP-304, pages 12-14, and (3) for Schedule F, please see HECO-WP-304, pages 152-153.

e. Please see HECO response to parts b. and c. above. The minimum charge provision in the tariff should not be eliminated, and in fact, should be moved closer to costs in future rate cases for the following reasons:

1. The minimum charge provisions in the tariffs are aimed at ensuring cost recovery and revenue stability. The rate elements in Schedules R, G, and F only include the monthly customer charge and the energy rates. As discussed in the response to part b. above, the customer charges are set lower than the customer-related costs. The energy rates are set higher than the energy-related costs to recover the remainder of the customer costs that are not recovered from the customer charge, as well as to recover all of the demand-related costs. The customer costs and the demand costs are fixed costs, in that, they do not vary with the customers' energy consumption. These costs are incurred by HECO whether the customer does not consume kWh or consume only minimal kWh. The minimum charge provision allows the Company to recover some of these fixed costs

tourists, and/or dwelling units owned by part-time island residents.

CA-IR-358

Ref: T-22, Page 19 Base Fuel Charge.

Please provide detailed calculations and references into supporting documentation associated with the Company's proposed 6.052 cents/KWH Base Fuel Charge.

HECO Response:

The calculation of the proposed 6.052 ¢/kWh Base Fuel Charge is provided on page 2 of this response.

Hawaiian Electric Company, Inc.
Docket No. 04-0113, Test-Year 2005
Determination of Base Fuel Energy Charge At Proposed Rates

Line No.			Reference
L1	Weighted Base Generation Cost, ¢/kWh	3.66345	HECO-1032, page 2, line 20
L2	Revenue Tax Factor	1.0975	HECO-1032, page 2, line 22
L3 = L1 x L2	Generation Fuel Cost Component, ¢/ kWh	4.0206	
L4	Weighted Base CHP Energy Cost, ¢/kWh	0.00996	HECO-1032, page 2, line 29
L5	Loss Factor	1.052	HECO-1032, page 2, line 31
L6 = L4 x L5 x L2	CHP Fuel Cost Component, ¢/kWh	0.0115	
L7	Weighted Base Purchased Energy Cost, ¢/kWh	1.74947	HECO-1032, page 2, line 60
L8	Loss Factor	1.052	HECO-1032, page 2, line 62
L9 = L7 x L9 x L2	Purchased Energy Cost Component, ¢/kWh	2.0199	
L10 = L3 + L7 + L9	**Base Fuel Energy Charge At Proposed, ¢/kWh**	**6.0520**	

CA-IR-359

Ref: T-22, Page 26 Schedule J Proposed Maximum Load.

Please provide the following information regarding the Company's proposal to define a maximum qualifying load for Schedule J:

a. For the 208 customers that "will be grandfathered," describe whether they would generally pay higher or lower prices for service if they migrated to large power rates PS, PP or PT.

b. State whether any migration has been modeled or assumed in pricing out revenues at present and/or proposed rates in the Company's filing.

c. Provide calculations and references into (or copies of) supporting documentation associated with your response to part (b).

d. Explain HECO's procedures for working with customers to optimize their tariff selection, including descriptions of the frequency of customer contacts that are made, information that is provided to customers and policies that are followed with respect to customer migrations among rates.

HECO Response:

a. Based on the customers' recorded billing loads for 2003, all of the Schedule J customers with maximum load equal to, or greater than 300 kW, that will be grandfathered under the proposed Schedule J would pay higher prices for service if they migrated to the large power rates PS, PP, or PT – except for one (1) customer. In other words, all the large customers with loads equal to or greater than 300 kW and who are currently served under Schedule J are better off staying under Schedule J, except for one (1) customer. The one customer who will pay lower price under Schedule PS is presently considering taking curtailable service under Rider M (Option B), in which case, he will be better off remaining under Schedule J. These customers would generally pay higher prices if they migrated to the applicable rate schedule "P" because these customers are low load-factor customers with high kW demands but relatively little energy consumption. The higher demand and customer charges in

Schedule PS, PP, or PT relative to Schedule J, more than offset the amount of savings generated from the lower energy charges in these large power rate schedules for these low load factor customers.

b. No rate migration between Schedule J and PS, PP, or PT was assumed or modeled in the calculation of the test-year revenues or in the determination of the proposed rates. However, potential Rider M (Option B), and Rider I customers, in addition to the existing rider customers, were assumed and modeled in the determination of the test-year revenues at present and proposed rates. The potential rider customers include customers who are currently considering or have expressed interest in taking service under the rider. The determination of revenues for Schedule J included three (3) potential Rider M (Option B) customers. These are the customers listed as "Rider Mb11", "Rider Mb12", and "Rider Mb13" in HECO-WP-304, page 55. The determination of revenues for Schedule PS included one (1) potential Rider I customer listed as "Rider I PS1" in HECO-WP-304, page 111; and the determination of revenues for Schedule PP included two (2) potential Rider M (B) customers listed as "Rider I PP3" and "Rider I PP4" in HECO-WP-304, page 126.

c. Please see HECO response to part b. above.

d. HECO's procedures for working with customers to ensure that they are served under the best applicable rate schedule include the following:

   1. Each of the 400 largest customers which include customers served under Schedules PS, PP, and PT and Schedule J are assigned an Account Manager. The Account Managers contact each of their assigned clients at least once a year either by phone, by e-mail, or in person. In addition, customer contacts are made in many different forums such as in workshops, flyers about new or existing initiatives, executive visits, etc. At any time,

the customers can call their Account Manager on any rate or tariff inquiry including a verification of whether they are being served under the best applicable rate schedule, or about taking service under any of the riders (e.g., Rider T, M, or I). When an Account Manager receives a rate or tariff inquiry from a customer, HECO's Pricing Division prepares the rate analysis to respond to the customer inquiry. The rate analysis results are forwarded to the Account Manager who then presents and discusses them with the customer. Depending on the results of the analysis, the customer may elect to change or not change his/her rate schedule.

2. HECO's Account Managers on their own initiative and based on information they receive regarding changes in their client's operations and/or load level and usage pattern, also request rate analysis from HECO's Pricing Division to verify if a customer is still served under best applicable rate schedule. Depending on the analysis' results, the Account Manager presents/discusses the information with the customer, and the customer can elect whether or not to change his/her rate schedule.

3. HECO's Pricing Division prepares an annual rate analysis for each of the large customers to verify and monitor that they are being served under the best applicable rate and/or rider. The results of the analysis are presented to and discussed with the Account Managers. The analysis identifies the customers who are better under another rate schedule based on their recorded billing loads. The Account Managers would normally meet with these customers to present/discuss the analysis results, and the customer can elect to change or not change his/her rate schedule.

CA-IR-360

Ref: T-22, Page 20 Schedule E Employee Service.

Please provide the following information regarding the Company's employee discount for electric service:

a. Explain the origin of this tariff, if known, and the purpose it is believed to serve today that is not served by other offered employee benefit programs.

b. To what extent are the Company's demand side management goals in conflict with tariff provisions that tend to distort the pricing cues associated with energy usage?

c. Why is it thought reasonable to increase the value of this employee benefit by over nine percent (the approximate proposed residential rate increase), rather than limiting the benefit to a fixed monthly credit amount on employee bills?

d. Please explain why the Company has included $57,100 of employee discount negative revenue for rate Schedule G (embedded in HECO 304, page 2, proposed rates "Miscellaneous", according to the "assumptions" tab of file "HECO_RateG_Draft_ proposed_final_110704efile.xls").

e. Provide the number of employee "commercial" customers being served under General Service Schedule G and explain the circumstances of all such service.

f. Is the Company aware of any other electric utility that provides discounted electric service as an employee benefit?

g. If your response to part f is affirmative, please identify each other utility's employee

company's products and/or services are common employee benefits offered by most types of businesses. For instance, one communication company provides employee rate plans that are 20% less than the regular plans for wireless service, 50% discount on land line service, and 10% discount on phones and accessories. A cable company's employee discount benefits include free TV cable service, and 50% to 75% discount on internet service. The retail businesses' employee discounts range from 20% to 30% off of the regular price and sale price. The airline companies' employee benefits include free fares on standby travels. In the hotel industry, some hotels' employee benefits include discounts on hotel rooms as well as discounts on food and beverage in restaurant dining. In the banking industry, some of the financial institutions offer employee discounts on the mortgage rates, and discounts on banking services. The Company's employee rate discount is not served by any other offered employee benefit program.

b. The Company's Schedule E does not "distort the pricing cues associated with energy usage" as implied in the information request, and it is not in conflict with the Company's demand side management (DSM) goals. Schedule E reflects an inverted rate form which provides higher price for any kWh consumed above 825 kWh per month, and therefore provides an appropriate price signal which is in concert with the Company's DSM goals.

More importantly, Schedule E does not inhibit nor discourage nor lessen the employees' energy efficiency efforts to reduce their electricity consumption as evidenced by the relatively higher employee participation in the Company's Residential DSM programs. Since the inception of the Company's DSM programs in 1996 through 2004, a total of 335 employees or **23.7%** of the recorded number of employees of 1416 as of 12/31/04 have participated in HECO's Residential DSM Programs (279 employees in the REWH program,

44 employees in the RNC program, and 12 employees in the RCFL program). In comparison, the residential customers (Schedule R only) who have participated in HECO's Residential DSM programs from 1996 to 2004 total 41,825 or only **16.6%** of the recorded number of Schedule R customers in 2004. A large percentage of employees participate in the Company's DSM programs in spite of the rate discount provided in Schedule E than the percentage of general Schedule R customers.

c. HECO is not proposing any changes to the current Schedule E which provides residential service rates to HECO employees that are one-third less than the rates for non-employee residential customers, for the 1st 825 kWh/month. All kWh in excess of 825 are charged the full residential rates. By maintaining the current Schedule E structure, employees are effectively assigned the same rate increase of 9.4% as the non-employee residential customers.

HECO is not proposing any changes to the current Schedule E at this time because the employee discount is a contractual obligation between HECO and its bargaining unit employees. Replacing the discount with an alternative compensation benefit will result in additional employee benefits costs due to the tax impact, which in turn will increase the company's revenue requirements. For instance, it would cost the Company $1.86 in additional salary or benefit cost to replace a $1.00 discount in employees' electric bill.

The termination of the employee discount was extensively explored in the last union negotiations. But the issue was a highly emotionally-charged issue with the union that no change was made to the employee discount.

d. The $57,100 negative revenue adjustment [illegible]

discount that is allocated to Schedule G. The Company allocated the cost of the employee discount to all the rate classes per the CA's proposal in Docket No. 6998, rather than just

recovering it from Schedule R. The Company has followed the same allocation of the cost of the employee discount in all prior rate cases following Docket No. 6998. (See Docket No. 6998, HECO RT-14, pages 12, 16-17 and CA-T-9, pages 33-34. See also response to CA-IR-333.)

e. There are no employees being served under Schedule G. See HECO response to part d. above.

f. The following electric utilities provide discounted electric service as an employee benefit that the witness is currently aware of, and is not an all inclusive list of utilities with employee discount:

1. Appalachian Power Company (Virginia)
2. American Electric Power (Kentucky)
3. Kingsport Power Company d/b/a AEP (Tennessee)
4. Indiana Michigan Power Company (Indiana)
5. Sierra Pacific Power Co. (Nevada)
6. Southern California Edison (California)
7. San Diego Gas & electric Company (California)
8. Montana-Dakota Utilities Company (Montana)

13. Pacific Gas & Electric (California)

14. Portland General Electric (Oregon)

g. A copy of the employee electric service tariffs of the above listed utilities, except Ohio Power Company, is attached as pages 6 to 39 of this response. The employee discount provided by the Ohio Power Company is included in the employee benefits package, but is not provided in a published tariff.

APPALACHIAN POWER COMPANY

Third Revision of Sheet No. 5-1

VA. S.C.C. TARIFF NO. 18

SCHEDULE R.S.-E.
(Residential Service-Employee)

This Schedule is limited to regular and retired employees of the Company as of December 31, 2001.

AVAILABILITY OF SERVICE

Available for electric service to regular and retired employees of the Company for electric service through one meter who take Standard Service from the Company.

MONTHLY RATE (Schedule Code 020)

	Generation	OATT Transmission	Retail Transmission	Distribution	Total
Customer Charge ($)				7.00	7.00
Energy Charge (¢/kWh)	0.976	0.419	(0.034)	1.495	2.856
Levelized Fuel Factor (¢/kWh)	1.420				1.420

MINIMUM CHARGE

This Schedule is subject to a minimum monthly charge equal to the Customer Charge.

PAYMENT

Bills are due upon presentation and payable by mail, checkless payment plan, electronic payment plan, or at authorized payment agents of the Company to be received by the Company within twenty (20) days of the bill preparation date. A charge of 1½% per month will be applied to any account balances, excluding local consumer utility taxes, not received by the Company by the next bill preparation date.

TERM

Written agreements may be required pursuant to the Extension of Service provision of the Company's Terms and Conditions of Standard Service.

SPECIAL TERMS AND CONDITIONS

This Schedule is subject to the Company's Terms and Conditions of Standard Service.

This Schedule is available to rural domestic customers engaged principally in agricultural pursuits where service is taken through one meter for residential purposes, as well as for the usual farm uses outside the home, but service under this Schedule shall not be extended to operations of a commercial nature or operations such as processing, preparing or distributing products not raised or produced on the farm, unless such operation is incidental to the usual residential and farm uses.

This Schedule is available for single-phase residential service. Where the residential customer requests three-phase service, this Schedule will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service Standard Schedule will apply to such service.

Customers with cogeneration and/or small power production facilities shall take service under Schedule COGEN/SPP, Schedule N.M.S. or by special agreement with the Company.

Issued: December 2, 2004
Pursuant to Order
Dated November 16, 2004
Case No. PUE-2004-00128

Effective: January 1, 2005

APPALACHIAN POWER COMPANY

Sheet No. 5-2

VA. S.C.C. TARIFF NO. 18

SCHEDULE R.S.-E.
(Residential Service-Employee)
(continued)

LOAD MANAGEMENT WATER HEATING PROVISION (Schedule Code 051)

For residential customers who install a Company-approved load management water-heating system which consumes electrical energy primarily during off-peak hours specified by the Company and stores hot water for use during on-peak

APPALACHIAN POWER COMPANY

Third Revision of Sheet No. 4-1

VA. S.C.C. TARIFF NO. 18

SCHEDULE R.S.
(Residential Service)

AVAILABILITY OF SERVICE

Available for electric service through one meter to individual residential customers, including rural residential customers engaged principally in agricultural pursuits, who take Standard Service from the Company.

MONTHLY RATE (Schedule Code 015)

	Generation	OATT Transmission	Retail Transmission	Distribution	Total
Customer Charge ($)				7.00	7.00
Energy Charge (¢/kWh)					
First 900 kWh	1.778	0.419	(0.025)	1.576	3.748
All Over 900 kWh	1.136	0.419	(0.025)	1.453	2.983
Levelized Fuel Factor (¢/kWh)	1.420				1.420

MINIMUM CHARGE

This Schedule is subject to a minimum monthly charge equal to the Customer Charge.

PAYMENT

Bills are due upon presentation and payable by mail, checkless payment plan, electronic payment plan, or at authorized payment agents of the Company to be received by the Company within twenty (20) days of the bill preparation date. A charge of 1½% per month will be applied to any account balances, excluding local consumer utility taxes, not received by the Company by the next bill preparation date.

TERM

Written agreements may be required pursuant to the Extension of Service provision of the Company's Terms and Conditions of Standard Service.

SPECIAL TERMS AND CONDITIONS

This Schedule is subject to the Company's Terms and Conditions of Standard Service.

This Schedule is available to rural domestic customers engaged principally in agricultural pursuits where service is taken through one meter for residential purposes, as well as for the usual farm uses outside the home, but service under this Schedule shall not be extended to operations of a commercial nature or operations such as processing, preparing or distributing products not raised or produced on the farm, unless such operation is incidental to the usual residential and farm uses.

This Schedule is available for single-phase residential service. Where the residential customer requests three-phase service, this Schedule will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service Standard Schedule will apply to such service.

Customers with cogeneration and/or small power production facilities shall take service under Schedule COGEN/SPP, Schedule N.M.S. or by special agreement with the Company.

Issued: December 2, 2004
Pursuant to Order
Dated November 16, 2004
Case No. PUE-2004-00128

Effective: January 1, 2005

SCHEDULE R.S.
(Residential Service)
(continued)

LOAD MANAGEMENT WATER HEATING PROVISION (Schedule Code 011)

For residential customers who install a Company-approved load management water-heating system which consumes electrical energy primarily during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 KWH of use in any month shall be billed at a generation energy charge of 1.226¢/KWH.

This provision, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "MONTHLY RATE" as set forth above.

For the purpose of this provision, the on-peak billing period is defined as 7 a.m. to 8 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as 8 p.m. to 7 a.m., local time, for all weekdays, all hours of the day on Saturdays and Sundays, and the legally observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

The Company reserves the right to inspect at all reasonable times the load management water heating system(s) and devices which qualify the residence for service under the Load Management Water Heating Provision. If the Company finds that, in its sole judgment, the availability conditions of this provision are being violated, it may discontinue billing the customer under this provision and commence billing under the standard monthly rate.

P.S.C. ELECTRIC NO. 7
CANCELS P.S.C. ELECTRIC NO. 6

Cancels and Supersedes all Previous Schedules

AMERICAN ELECTRIC POWER

SCHEDULE OF TARIFFS, TERMS AND CONDITIONS OF SERVICE GOVERNING SALE OF ELECTRICITY

In the Kentucky territory served
by American Electric Power
as stated on Sheet No. 1

Issued by
Errol K. Wagner, Director of Rates
Ashland, Kentucky

Issued: January 30, 1996

Effective: April 1, 1991

AMERICAN ELECTRIC POWER

CANCELING 4TH REVISED SHEET NO. 1-1
3RD REVISED SHEET NO. 1-1

P.S.C. ELECTRIC NO. 7

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THE ABOVE TARIFFS ARE APPLICABLE TO THE ENTIRE TERRITORY SERVED BY KENTUCKY POWER COMPANY AS ON FILE WITH THE PUBLIC SERVICE COMMISSION

DATE OF ISSUE February 22, 2000 DATE EFFECTIVE Service rendered on and after July 9, 1998

ISSUED BY E. K. WAGNER (NAME) DIRECTOR OF REGULATORY AFFAIRS (TITLE) ASHLAND, KENTUCKY (ADDRESS)

Issued by authority of an order of the Public Service Commission in Case No. 99-271 dated June 29, 1999

TERMS AND CONDITIONS OF SERVICE

1. APPLICATION.

A copy of the tariffs and standard terms and conditions under which service is to be rendered to the Customer will be furnished upon request at the Company's office and the Customer shall elect upon which tariff applicable to his service his application shall be based.

A written agreement may be required from each Customer before service will be commenced. A copy of the agreement will be furnished to the Customer upon request.

When the Customer desires delivery of energy at more than one point, a separate agreement will be required for each separate point of delivery. Service delivered at each point of delivery will be billed separately under the applicable tariff.

2. INSPECTION.

It is to the interest of the Customer to properly install and maintain his wiring and electrical equipment and he shall at all times be responsible for the character and condition thereof. The Company makes no inspection thereof and in no event shall be responsible therefor.

Where a Customer's premises are located in a municipality or other governmental subdivision where inspection laws or ordinances are in effect, the Company may withhold furnishing service to new installations until it has received evidence that the inspection laws or ordinances have been complied with.

Where a Customer's premises are located outside of an area where inspection service is in effect, the Company may require the delivery by the Customer to the Company of an agreement duly signed by the owner and tenant of the premises authorizing the connection to the wiring system of the Customer and assuming responsibility therefor. No responsibility shall attach to the Company because of any waiver of this requirement.

3. SERVICE CONNECTIONS.

Service connections will be provided in accordance with 807 KAR 5:041, Section 10.

The Customer should in all cases consult the Company before his premises are wired to determine the location of Company's point of service connection.

The Company will, when requested to furnish service, designate the location of its service connection. The Customer's wiring must, except for those cases listed below, be brought outside the building wall nearest the Company's service wires so as to be readily accessible thereto. When service is from an overhead system, the Customer's wiring must extend at least 18 inches beyond the building. Where Customers install service entrance facilities which have capacity and layout specified by the Company and/or install and use certain utilization equipment specified by the Company, the Company may provide or offer to own certain facilities on the Customer's side of the point where the service wires attach to the building.

All inside wiring must be grounded in accordance with the requirements of the National Electrical Code or the requirements of any local inspection service authorized

AMERICAN ELECTRIC POWER

Canceling 1st Revised Sheet No. 2-2
Original Sheet No. 2-2

P.S.C. ELECTRIC NO. 7

TERMS AND CONDITIONS OF SERVICE

4. DEPOSITS.

The Company may require a minimum cash deposit or other guaranty to secure payment of bills except for customer's qualifying for service reconnection pursuant to 807 KAR 5:006, Section 15, Winter Hardship Reconnection. Service may be refused or discontinued for failure to pay the requested deposit. Upon request from a residential customer the deposit will be returned after 18 months if the customer has established a satisfactory payment record; but commercial deposits will be retained during the entire time that the account remains active.

A. Interest

Interest will be paid on all sums held on deposit at the rate indicated in KRS 278.460. The interest will be applied as a credit to the Customer's bill or will be paid to the Customer on an annual basis. If the deposit is refunded or credited to the Customer's bill prior to the deposit anniversary date, interest will be paid or credited to the Customer's bill on a pro-rated basis.

The Company will not pay interest on deposits after discontinuance of service to the Customer. Retention by the Company, prior to final settlement of any deposit or guaranty is not a payment or part payment of any bill for service. The Company shall have a reasonable time in which to obtain a final reading and to ascertain that the obligations of the Customer have been fully performed before being required to return any deposits.

B. Criteria for Waiver of Deposit Requirement

The Company may waive any deposit requirement based upon the following criteria which shall be considered by the Company cumulatively.

1. Satisfactory payment history.
2. Statement from another utility showing satisfactory payment history.
3. Another customer with satisfactory payment history is willing to sign as a guarantor for an amount equal to the required deposit.
4. Providing evidence of Surety Bond.

C. Method of Determination

1. Calculated Deposits

a. Residential customers shall pay a calculated amount based upon actual usage data of the customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the average bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the customer's actual or estimated annual bill.

b. Commercial customers shall pay a calculated amount based upon actual usage data of the customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the typical bills of similar customers and premises in the customer class. The deposit shall not exceed [illegible]

American Electric Power

1st REVISED SHEET NO. 2-3
CANCELING ORIGINAL SHEET NO. 2-3

P.S.C. ELECTRIC NO. 7

TERMS AND CONDITIONS OF SERVICE (cont'd)

4. DEPOSITS. (Cont'd.)

E. Recalculation of Customers Deposit

When a deposit is held longer than 18 months, the customer may request that the deposit be recalculated based on the customer's actual usage. If the amount of deposit on the account differs from the recalculated amount by more than $10.00 for a residential customer or 10 percent for a non-residential customer, the Company may collect any underpayment and shall refund any overpayment by check or credit to the customer's bill. No refund will be made if the customer's bill is delinquent at the time of the recalculation.

5. PAYMENTS.

Bills will be rendered by the Company to the Customer monthly or in accordance with the tariff selected applicable to the Customer's service.

A. Equal Payment Plan

Residential Customers have the option of paying a fixed amount each month under the Company's Equal Payment Plan. The monthly payment amount will be based on one-twelfth of the Customers

AMERICAN ELECTRIC POWER

CANCELING ORIGINAL SHEET NO. 2-4
SHEET NO. _____

P.S.C. ELECTRIC NO. 7

TERMS AND CONDITIONS OF SERVICE (Cont'd)

6. UNDERGROUND SERVICE.

When a real estate developer desires an underground distribution system within the property which he is developing and/or a Customer desires an underground service, the real estate [illegible]

AMERICAN ELECTRIC POWER

CANCELING ORIGINAL SHEET NO. 2-5
_____ SHEET NO. _____

P.S.C. ELECTRIIC NO. 7

TERMS AND CONDITIONS OF SERVICE (Cont'd)

9. EXTENSION OF SERVICE.

The electric facilities of the Company shall be extended or expanded to supply electric service to all residential Customers and small commercial Customers which require single phase line where the installed transformer capacity does not exceed 25 KVA in accordance with 807 KAR 5:041, Section 11.

The electric facilities of the Company shall be extended or expanded to supply electric service to Customer's other than those named in the above paragraph when the estimated revenue is sufficient to justify the estimated cost of making such extensions or expansions as set forth below.

For service to be delivered to Commercial, Industrial, Mining and multiple housing project Customers up to and including estimated demands of 500 KW requiring new facilities, the Company will: (a) where the estimated revenue for one year exceeds the estimated installed cost of new local facilities required, provide service at no cost to the Customer; (b) where the estimated revenue for one year is less than the installed cost of new local facilities required, the Customer will be required to pay a contribution in aid of construction equal to the difference between the installed cost of the new facilities required to serve the load and the estimated revenue for one year; (c) where the Company

TERMS AND CONDITIONS OF SERVICE (Cont'd)

10. EXTENSION OF SERVICE TO MOBILE HOME.

The electrical facilities of the Company will be extended or expanded to supply electric service to mobile homes in accordance with 807 KAR 5:041, Section 12.

11. LOCATION AND MAINTENANCE OF COMPANY'S EQUIPMENT.

The Company shall have the right to construct its poles, lines and circuits on the property, and to place its transformers and other apparatus on the property or within the building of the Customer, at a point or points convenient for such purposes, as required to serve such Customer, and the Customer shall provide suitable space for the installation of necessary measuring instruments so that the latter may be protected from injury by the elements or through the negligence or deliberate acts of the Customer or of any employee of the same.

12. BILLING FORM.

Pursuant to 807 KAR 5:006, Section 6(3) copies of the billing forms used by the Company is shown on Sheet Nos. 2-9, 2-10 and 2-11.

13. RATE SCHEDULE SELECTION.

When more than one rate schedule is available for the service requested, Customer shall designate the rate schedule on which the application or contract shall be based. Company will assist Customer in the selection of the rate schedule best adapted to Customer's service requirements, provided, however, that Company does not assume responsibility for the selection or that Customer will at all times be served under the most favorable rate schedule.

Customer may change his initial rate schedule selection to another applicable rate schedule at any time by either written notice to Company and/or by executing a new contract for the rate schedule selected, provided that the application of such subsequent selection shall continue for 12 months before any other selection may be made. In no case will the Company refund any monetary difference between the rate schedule under which service was billed in prior periods and the newly selected rate schedule.

14. MONITORING USAGE.

At least once annually the Company will monitor the usage of each customer according to the following procedure:

1. The customer's monthly usage will be compared with the usage of the corresponding period of the previous year.

2. If the monthly usage for the two periods are substantially the same or if any difference is known to be attributed to unique circumstances, such as unusual weather conditions, common to all customers, no further review will be made.

3. If the monthly usage is not substantially the same and cannot be attributed to a readily identified common cause, the Company will compare the customer's monthly usage records for the 12-month period with the monthly usage for the same months of the preceding year.

4. If the cause for the usage deviation cannot be determined from analysis of the customer's meter reading and billing records, the Company will contact the customer to determine whether there have been changes that explain the increased usage.

5. Where the deviation is not otherwise explained, the Company will test the customer's meter to determine whether it shows an average error greater than 2 percent fast or slow.

6. The Company will notify the customers of the investigation, its findings, and any refunds or backbilling in accordance with 807 KAR 5:006, Section 10(4) and (5).

In addition to the annual monitoring, the Company will immediately investigate usage deviations brought to its attention as a result of its on-going meter reading or billing processes or customer inquiry.

(Cont'd on Sheet No. 2-7)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

15. USE OF ENERGY BY CUSTOMER.

The tariffs for electric energy given herein are classified by the character of use of such energy and are not available for service except as provided herein.

With particular reference to power Customers it shall be understood that upon the expiration of a contract the Customer may elect to renew the contract upon the same or another tariff published by the Company available in the division in which the Customer resides or operates and applicable to the Customer's requirements, except that in no case shall the Company be required to maintain transmission, switching or transformation equipment (either for voltage or form of current change) different from or in addition to that generally furnished to other Customers receiving electrical supply under the terms of the tariff elected by the Customer.

The service connections, transformers, meters and appliances supplied by the Company for each Customer have a definite capacity and no additions to the equipment, or load connected thereto, will be allowed except by consent of the Company.

The Customer shall install only motors, apparatus or appliances which are suitable for operation with the character of the service supplied by the Company, and which shall not be detrimental to same, and the electric power must not be used in such a manner as to cause unprovided for voltage fluctuations or disturbances in the Company's transmission or distribution system. The Company shall be the sole judge as to the suitability of apparatus or appliances, and also as to whether the operation of such apparatus or appliances is or will be detrimental to its general service.

No attachment of any kind whatsoever may be made to the Company's lines, poles, crossarms, structures or other facilities without the express written consent of the Company.

All apparatus used by the Customer shall be of such type as to secure the highest practicable commercial efficiency, power factor and the proper balancing of phases. Motors which are frequently started or motors arranged for automatic control must be of a type to give maximum starting torque with minimum current flow, and must be of a type, and equipped with controlling devises, approved by the Company. The Customer agrees to notify the Company of any increase or decrease in his connected load.

The Company will not supply service to Customers who have other sources of electrical energy supply except under tariffs which specifically provide for same.

The Customer shall not be permitted to operate his own generating equipment in [illegible]

TERMS AND CONDITIONS OF SERVICE (Cont'd)

17. DENIAL OR DISCONTINUANCE OF SERVICE.

The Company reserves the right to refuse to serve any applicant for service or to discontinue to serve any Customer if the applicant or Customer is indebted to the Company for any service theretofore rendered at any location; provided however, the Customer shall be notified in writing in accordance with 807 KAR 5:006, Section 14, before disconnection of service.

The Company reserves the right to discontinue to serve any Customer for failure to provide and maintain adequate security for the payment of bills as requested by the Company, for failure to comply with these terms and conditions or to prevent fraud upon the Company.

Any discontinuance of service shall not terminate the contract between the Company and the Customer nor shall it abrogate any minimum charge which may be effective.

18. EMPLOYEES' DISCOUNT.

Regular employees who have been in the Company's employ for 6 months or more may, at the discretion of the Company, receive a reduction in their residence electric bills for the premises occupied by the employee.

19. SPECIAL CHARGES.

A. Reconnection and Disconnect Charges

In cases where the Company has discontinued service as herein provided for, the Company reserves the right to take a reconnection charge pursuant to 807 KAR 5:006, Section 8 (3)(b), payable in advance, in accordance with the following schedule. However, those customers qualifying for Winter Hardship Reconnection under Section 15 shall be exempt from the reconnect charges.

1. Reconnect for nonpayment during regular hours ..... $ 9.00
2. Reconnect for nonpayment when work continues into overtime at the end of the day (No "Call Out" required). $12.00
3. Reconnect for nonpayment when a "Call Out" is required (A "Call Out" is when an employee must be called in to work On an overtime basis to make the reconnect trip) $25.00
4. Reconnect for nonpayment when double time is required (Sunday and Holiday). $31.00
5. Termination or field collection trip ..... $ 6.00

The reconnection charge for all Customers where service has been disconnected for fraudulent use of electricity will be the actual cost of the reconnection.

B. Returned Check Charge

In cases where a Customer pays by check, which is later returned as unpaid by the bank for any reason, the Customer will be charged a fee of $5.00 to cover the handling costs.

C. Meter Test Charge

Where test of a meter is made upon written request of the Customer pursuant to 807 KAR 5:006, Section 18, the Customer will be charged $10.00 if such tests shows that the meter was not more than two percent (2%) fast.

(Cont'd on Sheet No. 2-9)

AMERICAN ELECTRIC POWER

CANCELING 1ST REVISED SHEET NO. 2-9
ORIGINAL SHEET NO. 2-9

S.C. ELECTRIC NO. 7

TERMS AND CONDITIONS OF SERVICE (Cont'd)

19. SPECIAL CHARGES (Cont'd).

D. Work Performed on Company's Facilities at Customer's Request

Whenever, at the request and for the benefit of the customer, work is performed on the Company's facilities, including the relocation, covering or replacement of the Company's facilities, the customer shall pay to the Company in advance the estimated total cost of such work. This cost shall be itemized by major categories and shall include the Company's overheads and shall be credited with the net value of any salvageable material. The actual cost for the work performed shall be calculated at the completion of the work and the appropriate charge or refund will be made to the customer.

Reasonable notice of not less than three working days shall be given to the Company for all requested work except for the covering of the Company's lines. Notice of any request for the Company to cover its lines shall be given at least two days in advance. The Company will use its best efforts to comply with all timely requests, but work may be delayed because of demands on the Company's personnel and equipment.

If the cost, as calculated above, is $500 or less, no charge will be imposed for covering the Company's distribution facilities. The customer shall pay the Company, in advance, all estimated costs greater than $500. The actual cost for the work performed shall be calculated at the completion of the work and the appropriate charge or refund will be made to the customer.

(Cont'd on Sheet No. 2-10)

DATE OF ISSUE June 19, 1998 DATE EFFECTIVE July 19, 1998

ISSUED BY E. K. WAGNER DIRECTOR OF RATES ASHLAND, KENTUCKY
NAME TITLE ADDRESS

Issued pursuant to Public Service Commission July 19, 1998

AMERICAN ELECTRIC POWER

1ST REVISED SHEET NO. 5-2
CANCELING ORIGINAL SHEET NO. 5-2

PSC ELECTRIC NO. 7

FUEL ADJUSTMENT CLAUSE (Cont'd)

7. At the time the fuel clause is initially filed, the utility shall submit copies of each fossil fuel purchase contract not otherwise on file with the Commission and all other agreements, options or similar such documents, and all amendments and modifications thereof related to the procurement of fuel supply and purchased power. Incorporation by reference is permissible. Any changes in the documents, including price escalations, or any new agreements entered into after the initial submission, shall be submitted at the time they are entered into. Where fuel is purchased from utility-owned or controlled sources, or the contract contains a price escalation clause, those facts shall be noted and the utility shall explain and justify them in writing. Fuel charges which are unreasonable shall be disallowed and may result in the suspension of the fuel adjustment clause. The Commission on its own motion may investigate any aspect of fuel purchasing activities covered by this regulation.

8. Any tariff filing which contains a fuel clause shall conform that clause with this regulation within three (3) months of the effective date of this regulation. The tariff filing shall contain a description of the fuel clause with detailed cost support.

9 The monthly fuel adjustment shall be filed with the Commission ten (10) days before it is scheduled to

KINGSPORT POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
Kingsport, Tennessee

1st Revised Sheet Number 3
T.R.A. Tariff Number 1
Cancels Original Sheet Number 3

TARIFF R. S.
(Residential Electric Service)

AVAILABILITY OF SERVICE

Available for residential electric service through one meter to individual residential customers including rural residential customers engaged principally in agricultural pursuits.

MONTHLY RATE (Tariff Code 015)

Service Charge	$ 7.30 per customer
Energy Charge	4.873 cents per KWH

MINIMUM CHARGE

This tariff is subject to a minimum monthly charge equal to the service charge.

FUEL CLAUSE

When the unit cost of fuel in the charges for power purchased from Appalachian Power Company under Federal Energy Regulatory Commission rate schedule No. 23 is above or below a base unit price of 15.8563 mills per KWH, adjusted for losses, the bill for service shall be increased or decreased respectively at a rate per KWH equal to the amount that such cost of fuel is above or below the unit base cost of 15.8563 mills per KWH, adjusted for losses, applied to the KWH measured in the period for which the bill is rendered. The adjustment shall be based on the most recent calendar month for which fuel cost data is available.

PROMPT PAYMENT DISCOUNT

A discount of 1.5 percent will be allowed if account is paid in full within 15 days of date of bill.

LOAD MANAGEMENT WATER HEATING PROVISION

For residential customers who install a Company-approved load management water heating system which consumes electrical energy primarily during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 KWH of use in any month shall be billed at 2.755 cents per KWH.

This provision, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "MONTHLY RATE" as set forth above.

For the purpose of this provision, the on-peak billing period is defined as 6:00 a.m. to 9:00 p.m. local time for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 p.m. to 6:00 a.m. for all weekdays, all hours of the day on Saturdays and Sundays, and the legal holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

The Company reserves the right to inspect at all reasonable times the load management water heating system and devices which qualify the residence for service under the load management water heating provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgment the availability conditions of this provision are being violated, it may discontinue billing the customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the service charge as stated in the above monthly rate.

TERM OF CONTRACT

A written contract may, at the Company's option, be required to fulfill the provisions of the Terms and Conditions of Service.

SPECIAL TERMS AND CONDITIONS

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for single-phase residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

KINGSPORT POWER COMPANY
Kingsport, Tennessee

Original Sheet Number 5-1
T.P.S.C. Tariff Number 1

TARIFF R. S. - L. M. - T. O. D.
(Residential Load Management Time-Of-Day Electric Service)

AVAILABILITY OF SERVICE

Available to residential customers who use energy storage devices with time-differentiated load characteristics approved by the Company, such as electric thermal storage space heating and/or cooling systems and water heaters which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours.

Households eligible to be served under this Tariff shall be metered through one single-phase multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods.

MONTHLY RATE (Tariff Code 032)

Service Charge ..... $ 13.35 per customer

Energy Charge:
For all KWH used during the on-peak billing period ..... 7.541 cents per KWH
For all KWH used during the off-peak billing period..... 2.755 cents per KWH

For the purpose of this Tariff, the on-peak billing period is defined as 6:00 a.m. to 9:00 p.m. local time for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 p.m. to 6:00 a.m. for all weekdays, all hours of the day on Saturdays and Sundays, and the legal holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

CONSERVATION AND LOAD MANAGEMENT CREDIT

For the combination of an approved electric thermal storage space heating and/or coolingbsystem and water heater, all of which are designed to consume electrical energy only during the off peak billing period as previously described in this tariff, each residence will be credited 0.937 cents per KWH for all KWH used during the off-peak billing period, for a total of 60 monthly billing periods following the installation and use of these devices in such residence.

MINIMUM CHARGE

This tariff is subject to a minimum monthly charge equal to the service charge.

FUEL CLAUSE

When the unit cost of fuel in the charges for power purchased from Appalachian Power Company under Federal Energy Regulatory Commission rate schedule No. 23 is above or below a base unit price of 15.8563 mills per KWH, adjusted for losses, the bill for service shall be increased or decreased respectively at a rate per KWH equal to the amount that such cost of fuel is above or below the unit base cost of 15.8563 mills per KWH, adjusted for losses, applied to the KWH measured in the period for which the bill is rendered. The adjustment shall be based on the most recent calendar month for which fuel cost data is available.

PROMPT PAYMENT DISCOUNT

A discount of 1.5 percent will be allowed if account is paid in full within 15 days of date of bill.

SEPARATE METERING PROVISION

Customers shall have the option of receiving service under the R.S. or R.S. [illegible]

TARIFF R. S. - L. M. - T. O. D.
(Residential Load Management Time-Of-Day Electric Service)

SPECIAL TERMS AND CONDITIONS

This tariff is subject to the Company's Terms and Conditions of Service.

The Company reserves the right to inspect at all reasonable times the energy storage devices which qualify the residence for service and for conservation and load management credits under this Tariff, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds, that in its sole judgment the availability conditions of this Tariff are being violated, it may discontinue billing the customer under this Tariff and commence billing under the appropriate Residential Service Tariff.

This tariff is available for single-phase residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

KINGSPORT POWER COMPANY
Kingsport, Tennessee

Original Sheet Number 6
T.P.S.C. Tariff Number 1

TARIFF R.S. - T.O.D.
(Residential Time-of-Day Electric Service)

AVAILABILITY OF SERVICE

Available for residential electric service through one single-phase multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods to individual residential customers. Availability is limited to the first 250 customers applying for service under this tariff.

MONTHLY RATE

Service Charge ..... $ 13.35 per customer

Energy Charge:
Tariff Code 030 For all KWH used during the on-peak billing period .... 7.541 cents per KWH
Tariff Code 031 For all KWH used during the off-peak billing period ... 2.755 cents per KWH

For the purpose of this tariff, the on-peak billing period is defined as 6:00 a.m. to 9:00 p.m. local time for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 p.m. to 6:00 a.m. for all weekdays, all hours of the day on Saturdays and Sundays, and the legal holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

MINIMUM CHARGE

This tariff is subject to a minimum monthly charge equal to the service charge.

FUEL CLAUSE

When the unit cost of fuel in the charges for power purchased from Appalachian Power Company under Federal Energy Regulatory Commission rate schedule No. 23 is above or below a base unit price of 15.8563 mills per KWH, adjusted for losses, the bill for service shall be increased or decreased respectively at a rate per KWH equal to the amount that such cost of fuel is above or below the unit base cost of 15.8563 mills per KWH, adjusted for losses, applied to the KWH measured in the period for which the bill is rendered. The adjustment shall be based on the most recent calendar month for which fuel cost data is available.

PROMPT PAYMENT DISCOUNT

A discount of 1.5 percent will be allowed if account is paid in full within 15 days of date of bill.

TERM OF CONTRACT

A written contract may, at the Company's option, be required to fulfill the provisions of the Terms and Conditions of Service.

SPECIAL TERMS AND CONDITIONS

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is intended for single-phase residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

TERMS AND CONDITIONS OF SERVICE

(Cont'd from Sheet No. 3.16)

22. Employees Discount.

Regular employees who have been in the Company employ for six months or more and are the head of the family or mainly responsible for maintenance of the premises they occupy may, at the discretion of the Company, secure a reduction in their residential electric bills. The rate for standard electric service shall consist of a monthly service charge of $6.65 plus 5.104¢/kWh for

Employees who install a Company-approved storage water-heating system will be subject to a rate of 1.474¢/kWh under the conditions set forth in the storage water-heating provision or load management water-heating provision of Tariff RS.

Employees who use energy-storage or other load-management devices with time-differentiated load characteristics approved by the Company may receive service under the provisions of Tariff RS-OPES. The TOD rate shall be

SIERRA PACIFIC POWER CO.
RENO, NEVADA

Revised CPUC Sheet No. 1868-E
Canceling Revised CPUC Sheet No. 1799-E

SCHEDULE NO. DE
DOMESTIC SERVICE TO COMPANY EMPLOYEES

APPLICABILITY

Electricity for domestic and water heating purposes is available upon application, under this schedule to regular bargaining unit and pensioned employees of the Company, (married or unmarried) provided they reside in their own home (single family dwelling, separately-metered flat or apartment) and are supplied directly by the Company.

TERRITORY

Entire service Territory.

RATES

The regular filed rate schedules applicable to domestic service in the territory where service is supplied, less 50% discount.

Minimum Charge:

$2.25 per month. (R)

SPECIAL CONDITIONS

1. This rate applied to employees living with, and constituting the support of , a mother and/or father or other relatives.

2. The service must be billed to and paid by the employee.

3. A regular employee is defined, for the purpose of this schedule, as one who has been continuously employed by the Company for more than six months and is paid on a weekly or monthly basis.

4. This schedule is not applicable to probationary, casual or temporary employees.

5. **Rate Reduction Credit.** The customer charge and energy charges reflect a ten percent reduction as required by the Commission's decision addressing the application of AB 1890 to smaller and multi-jurisdictional utilities. (N) | (N)

(To be inserted by utility)	Issued by	(To be inserted by CPUC)
Advice Letter No. 255-E	Walter M. Higgins (Name)	Date Filed December 23, 1997
Decision No.	President (Title)	Effective January 1, 1998
		Resolution No.

SIERRA PACIFIC POWER COMPANY
6100 Neil Road, Reno, Nevada
Tariff No. **Electric No. 1** Cancelling **2nd Revised** PUCN Sheet No. **63F**
1st Revised PUCN Sheet No. **63F**

SCHEDULE NO. SCE

SERVICE TO COMPANY EMPLOYEES

APPLICABILITY

Electricity for domestic purposes is available, upon application, under this schedule to regular and pensioned employees of the Utility (married or unmarried) provided (1) they reside in their own home (single family dwelling, flat or apartment); (2) are supplied directly by Utility; and (3) meet the requirements as set forth in the Special Conditions below.

AVAILABILITY

Service is available hereunder in Utility's electric service area in Reno and Sparks, Nevada, and adjacent territory.

RATE

50% discount based on all charges applicable under the appropriate domestic rate schedules.

Late Charge

1% on any amount in arrears from previous billings.

Tax Adjustment Charge

2% of total bill within incorporated areas.

Universal Energy Charge (UEC) (N)

All kWh per kWh $0.00039 (N)

MINIMUM CHARGE

The minimum charge for service hereunder shall consist of one-half (1/2) of the minimum charge otherwise applicable under the appropriate domestic rate schedules plus the late charge, tax adjustment charge and UEC. (N)

(Continued)

Issued: **07-24-01** Effective: **07-17-01** Advice No.: **409-E**	Issued By: Mary O. Simmons Vice President	

SIERRA PACIFIC POWER COMPANY
6100 Neil Road, Reno, Nevada
Tariff No. **Electric No. 1** Cancelling **1st Revised** PUCN Sheet No. **63F(1)**
Cancelling **Original** PUCN Sheet No. **63F(1)**

SCHEDULE NO. SCE

SERVICE TO COMPANY EMPLOYEES
(Continued)

SPECIAL CONDITIONS

1. This rate applies to employees living with and constituting the support of a mother and/or father or other relatives. (L) (L)

2. The service must be billed to and paid by the employee.

3. A regular employee is defined, for the purpose of this schedule, as one who has been continuously employed by the Utility for more than six months and is paid on a weekly or monthly basis.

4. This schedule is not applicable to probationary, casual or temporary employees.

5. Effective January 1, 1981, this schedule is limited only to those regular and pensioned employees who are classified as Bargaining Unit employees and meet the eligibility requirements as set forth in SPECIAL CONDITIONS 1, 2, 3, and 4.

6. Pensioned employees who were classified as Management, Professional and Administrative (MPA) employees and who were receiving pension benefits prior to January 1, 1981 are eligible for this rate schedule.

7. The UEC as mandated by AB 661, passed by the 2001 Legislature, will go to fund the Nevada fund for energy assistance and conservation. Under certain circumstances, Customers will be refunded amounts paid in excess of $25,000 per calendar quarter. The Commission will administer the collection of the UEC, certify exemptions, and administer refunds. Exemptions are generally kWh sold to: (N)
   a) Any governmental agency, including the State of Nevada and any political subdivision thereof, and
   b) Any Customer using electrolytic-manufacturing processes.

   Except as provided above, all kWh sold are subject to the charge.

8. The UEC is not subject to the Tax Adjustment Charge. (N)

Issued: **07-24-01** Effective: **07-17-01** Advice No.: **409-E-R**	Issued By: Mary O. Simmons Vice President	

SOUTHERN CALIFORNIA EDISON
Southern California Edison
Rosemead, California

Revised Cal. PUC Sheet No. 34726-E**
Cancelling Revised Cal. PUC Sheet No. 33647-E*
30859-E, 30861-E

Schedule DE
DOMESTIC SERVICE TO UTILITY EMPLOYEES

APPLICABILITY

Applicable to domestic service SCE employees for lighting, heating, cooking, water heating, and power service, or combination thereof, in a single-family accommodation, separately metered by SCE. (T)

TERRITORY

Within the entire territory served directly by SCE. (T)

RATES

The bill as determined under a regularly filed schedule for domestic service which would otherwise be applicable, less the following:

Regular Employee Discount	Retiree Discount
5/1/96 - 25.00%	5/1/96 - 25.0%
1/1/97 - 16.67%*	1/1/97 - 22.5%*
1/1/98 - 8.33%*	1/1/98 - 20.0%*
6/1/98 - 0%*	1/1/99 - 17.5%*
	1/1/00 - 15.0%*
	1/1/01 - 12.5%*
	1/1/02 - 10.0%*
	1/1/03 - 7.5%*
	1/1/04 - 5.0%*
	1/1/05 - 2.5%*
	1/1/06 - 0%*

* These changes are suspended with Commission Resolution E-3765. Until modified or eliminated in SCE's next General Rate Case, scheduled for late 2003, the 5/1/96 percentage shown above is the effective percentage. (D)

SPECIAL CONDITIONS

1. This Schedule shall be available only to regular employees and to retired employees who were retired under SCE's pension plan. This Schedule is not applicable to new, part-time, intermittent, or contract employees, nor to regular employees on leave of absence in excess of thirty (30) days. (T) (T)

2. This Schedule will apply only to the single-family accommodation which is the place of residence of the employee or retiree, where such eligible person is head of the household served (or that person's spouse), or where he or she lives with and constitutes the support of a mother, father, or other immediate family. (T)

3. Service under this Schedule is available only upon written application made by the employee or retiree, and the discount will be discontinued upon termination of eligibility of such person or upon cessation of payment of bills directly by the employee or retiree. (T)

4. Regular Employees who retire on or before May 1, 2001, are eligible for the Retiree Discount as of the effective date of the employee's retirement. (D)

Schedule No. DE
DOMESTIC SERVICE TO UTILITY EMPLOYEES

Sheet 1

APPLICABILITY

Applicable to domestic service to utility employees for heating, cooking, water heating, refrigeration, and other residential use, or combination thereof, in a single-family accommodation, separately metered by utility.

TERRITORY

Santa Catalina island, Los Angeles County.

RATES

The bill as determined under a regularly filed schedule which applies to the

SDGE
San Diego Gas & Electric Company
San Diego, California

Revised Cal. P.U.C. Sheet No. 10777.1-E
Canceling Revised Cal. P.U.C. Sheet No. 4524-E

SCHEDULE DE

Sheet 1

DOMESTIC SERVICE TO UTILITY EMPLOYEES

APPLICABILITY

Applicable to single-phase residential service to utility employees for lighting, heating, cooking, water heating, and power service, or combination thereof, in single-family dwellings, flats, and bungalow court units, separately metered by the utility.

TERRITORY

Within the entire territory served by the utility.

RATE

The bill as determined under a regularly filed schedule for domestic service would otherwise be applicable, less 25% discount.

The 25% discount will be given based on the total bill as determined for UDC Bundled Service Customers under a regularly filed schedule for domestic service which would otherwise be applicable, by way of a reduction to the distribution rate component.

SPECIAL CONDITIONS

1. All special conditions contained in the applicable domestic schedule are applicable to service under this schedule.

2. This schedule shall be available only to regular employees who have been continuously employed by the utility for more than twelve (12) months, and to retired employees who were employed by the utility for more than ten (10) years and were retired under the utility's pension plan. This schedule is not applicable to provisional, temporary, short-term, part-time or call-in employees, nor to regular employees on leave of absence in excess of thirty (30) days. This schedule is not applicable to employees or annuitants who, during the 12 months prior to application for service under this schedule, had his service discontinued for nonpayment of a bill for service.

3. This schedule will apply only to a single dwelling unit which is the place of residence of the employee or annuitant, where such eligible person is head of the household served (or that person's spouse), or where he or she lives with and constitutes the support of a mother and/or father or other immediate family.

4. Service under this schedule is available only upon written application made by the employee or annuitant, and the discount will be discontinued upon termination of eligibility of such person or upon cessation of payment of bills directly by the employee or annuitant.

5. If service to an employee or annuitant is discontinued for nonpayment of a bill for service, the employee or annuitant shall become ineligible for service under this schedule for 12 monthly billing periods after the date service is discontinued. Reinstatement of the discount will be in accordance with Special Condition 2.

Public Service Commission of Montana

MONTANA-DAKOTA UTILITIES CO
A Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501

		Volume No.	3
	1st Revised	Sheet No.	54
Cancelling	Vol 1, Orig	Sheet No.	34

Electric Service

RATE FOR RESIDENTIAL ELECTRIC SERVICE
FOR PERMANENT EMPLOYEES OF MONTANA-DAKOTA UTILITIES CO.
A DIVISION OF MDU RESOURCES GROUP, INC.
AND WHOLLY-OWNED SUBSIDIARIES Rate 102

AVAILABLE FOR:
Residential use only in a single family unit served by Montana-Dakota Utilities Co. to a full time permanent employee who has been continuously employed by the Company at least six months and is the principal support of the household in which he resides, or is the spouse of the principal support.

RATE:
The employee's bill shall be computed at the applicable rate, and the amount reduced by 33 1/3%.

Issued: September 27, 1994 (Date) By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

FOR OFFICE USE ONLY - DO NOT PRINT BELOW THIS LINE

Date Approved: September 6, 1994
Docket No. 94.8.36
Order No. Final Order #5801

Effective for bills rendered on or after October 1, 1994

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501

STATE OF SOUTH DAKOTA
ELECTRIC RATE SCHEDULE

SD P.U.C	3rd Revised	Volume	5
Cancelling	1st Revised	Sheet No.	2
		Sheet No.	2

RATE FOR RESIDENTIAL ELECTRIC SERVICE FOR PERMANENT EMPLOYEES OF MONTANA-DAKOTA UTILITIES CO., A DIVISION OF MDU RESOURCES GROUP, INC. AND WHOLLY-OWNED SUBSIDIARIES Rate 102 (T)

Available for: Residential use only in a single family unit serviced by Montana-Dakota Utilities Co. to a full time permanent employee who has been continuously employed by the Company at least six months and is the principal support of the household in which he resides, or is the spouse of the principal support.

Rate: The employee's bill shall be computed at the applicable rate, and the amount reduced by 33 1/3%.

Date Filed: May 16, 1986 Effective Date: June 1, 1986

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

MONTANA-DAKOTA UTILITIES CO

STATE OF WYOMING
ELECTRIC RATE SCHEDULE

W.P.S.C		Tariff No.	4
	Original	Sheet No.	145
Cancelling		Sheet No.	

RATE FOR RESIDENTIAL ELECTRIC SERVICE FOR REGULAR EMPLOYEES
OF MONTANA-DAKOTA UTILITIES CO., MDU RESOURCES GROUP, INC.
AND WHOLLY-OWNED SUBSIDIARIES OF MDU RESOURCES GROUP, INC. Rate 102

The rate for residential electric service for regular employees of Montana-Dakota Utilities Co., MDU Resources Group, Inc., and all wholly-owned subsidiaries of MDU Resources Group, Inc., shall be computed at the applicable rate, and the amount reduced by 33 1/3%. This is available only for residential use, in a single family unit, served by the Company to a regular employee who has been continuously employed at least six months and is the principal support of the household in which employee resides, or is the spouse of the principal support.

Date Filed: March 10, 1995 Effective Date: Implemented with bills rendered April 3, 1995

Issued By: C. Wayne Fox, Vice President - Regulatory Affairs & General Services

Docket No. 20004-ET-95-25

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Electric Rate Schedule

NDPSC Volume 4
Original Sheet No. 51

RESIDENTIAL ELECTRIC SERVICE FOR PERMANENT EMPLOYEES Rate 102

Available for:

Residential use only in a single family unit served by Montana-Dakota Utilities Co. to a full time permanent employee who has been continuously employed by the Company at least six months and is the principal support of the household in which he resides, or is the spouse of the principal support.

Rate:

The employee's bill shall be computed at the applicable rate, and the amount reduced by 33 1/3%.

Date Filed:	January 7, 2004	**Effective Date:**	Service rendered on and after January 23, 2004
Issued By:	Donald R. Ball Assistant Vice President - Regulatory Affairs	**Case No.:**	PU-399-03-296

Pacific Gas and Electric Company
San Francisco, California

Cancelling Revised Cal. P.U.C. Sheet No. 20872-E
Revised Cal. P.U.C. Sheet No. 18188-E

SCHEDULE EE—SERVICE TO COMPANY EMPLOYEES

APPLICABILITY: Electricity for domestic purposes is available, upon application, under this schedule to regular and pensioned employees of the Utility, provided they reside in their own home (single family dwelling, separately-metered flat or apartment) and are supplied directly by the Utility.

TABLE 2
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2005 COS ONLY

CATEGORY	RATE SCHEDULE	Forecast SOCT04G05 CONSUMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT w/ all adjustments except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED w/ all adjustments except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	680,961	7,608,114	$607,762,235	$609,836,545	$2,074,310	0.3%
Employee Discount				($649,254)	($654,827)	($5,572)	
Subtotal				$607,112,981	$609,181,718	$2,068,737	0.3%
Outdoor Area Lighting	15	0	23,832	$3,819,184	$3,824,094	$4,910	0.1%
General Service <30 kW	32	78,816	1,434,689	$118,048,908	$117,220,080	($828,827)	-0.7%
Opt. Time-of-Day G.S. >30 kW	38	192	49,089	$3,865,405	$3,934,015	$68,610	1.8%
Irrig. & Drain. Pump. < 30 kW	47	1,711	23,275	$1,739,532	$1,646,245	($93,287)	-5.4%
Irrig. & Drain. Pump. > 30 kW	49	840	65,339	$3,679,335	$3,512,127	($167,208)	-4.5%
General Service >30 kW Secondary	83-S	12,461	5,550,205	$356,825,334	$368,428,189	$11,602,855	3.3%
Primary	83-P	201	1,720,776	$96,120,641	$99,581,951	$3,461,310	3.6%
Subtransmission	83-T	6	643,979	$30,938,558	$32,024,463	$1,085,905	3.5%
Street & Highway Lighting	91	205	94,918	$13,895,137	$14,013,782	$118,645	0.9%
Traffic Signals	92	14	6,412	$395,919	$402,010	$6,091	1.5%
Recreational Field Lighting	93	28	568	$80,042	$79,997	($45)	-0.1%
Drainage Districts	97	2	1,316	$95,162	$96,399	$1,237	1.3%
TOTAL (CYCLE YEAR BASIS)		775,436	17,222,509	$1,236,616,137	$1,253,945,070	$17,328,932	1.4%
CONVERSION ADJUSTMENT			32,125	$2,306,683	$2,339,007		
TOTAL (CALENDAR YEAR BASIS)			17,254,634	$1,238,922,820	$1,256,284,076	$17,361,256	1.4%

CA-IR-361

Ref: HECO Rule No. 16, Interruption of Service

According to the Rule, the Company is to provide semiannual notification of the customers' right to file compensation claims associated with any interruption of service and any such customer claims must be filed within 30 days of the interruption to be valid. Please provide a statement of all submitted customer claims pursuant to this Rule since January 1, 2000 and explain the resolution of each such claim, indicating any charges by NARUC account that were incurred by the Company.

HECO Response:

Costs for these liability claims are included in the totals for NARUC Account 925.02 shown in HECO-1401, page 3 and HECO-1404, page 1, Docket No. 04-0113. A listing by claim of all requested information are provided on pages 2 to 177. Since the list is voluminous, only one copy each will be provided to the Consumer Advocate and Commission under separate transmittal. Annual totals as of March 22, 2005 are:

YEAR	No. Claims	No. Paid	Amount Incurred	Amount Paid
2000	814	380	$356,826	$356,826
2001	1,076	562	$317,601	$317,601
2002	811	362	$412,044	$326,544
2003	933	499	$448,139	$353,501
2004	1,355	400	$508,578	$317,181
2005	143	32	$103,113	$26,107

Due to the voluminous nature of the information, one copy (pages 2-177) will be provided to the Consumer Advocate and the Public Utilities Commission under separate transmittal

CA-IR-362

Ref: HECO-305, AES Capacity Rate Adjustment.

Please explain and reconcile why the calculated rate adjustment on this Schedule is -0.401%, when the actual tariff provision at HECO-105, page 5, actually specifies a "Rate Adjustment of 0.406%."

HECO Response:

Both the calculated rate adjustment described at HECO-305 and the Rate Adjustment, effective January 1, 2004, shown at HECO-105, page 5 are based on refunding the same amount to customers, $3,187,140, as shown at L3 of HECO-305. This is consistent with Decision and Order No. 20292 and Order No. 20310 issued by the Commission in Docket No. 03-0126. The difference in the refund percentages results because the calculated rate adjustment in HECO-305 is based on the forecast of base electric revenues in test year 2005, while the rate adjustment

CA-IR-363

Ref: HECO-WP-304, page 8 and page 15 Time of Use Revenue.

Regarding the accounting in Company workpapers for time of TOU-R and TOU-C revenue impacts, please provide the following information:

a. Please explain the assumptions and analyses employed to estimate the number of customers that could benefit from TOU rates and the revenue effect of such participation.

b. Provide a monthly breakdown for all available months of 2003 and 2004 of the actual number of TOU-R and TOU-C participants and the experienced actual revenue impacts of such participation.

c. Provide complete copies of all studies performed (or references if filed with the PUC) to evaluate the performance of HECO's TOU pilot programs.

d. State whether HECO has assumed that all customers who might benefit from TOU rates will, in fact, participate in the formulation of the adjustments shown at pages 8 and 15 of HECO-WP-304, and explain the basis for such assumption.

HECO Response:

a. The 500 Schedule TOU-R participants shown at HECO-WP-304, page 8 and the 200 Schedule TOU-C non-demand service participants shown at HECO-WP-304, page 15, represent the estimated number of customers in test year 2005 for the estimate of test year revenues. The Company has not made an analysis of the number of customers that could benefit from TOU rates. For the proposed Schedule TOU-R, the estimate of 500 customers in test year 2005 assumes a phased-in participation of 50% of the proposed 1,000 customer limit. The 1,000 customer limit for Schedule TOU-R represents about 0.39% of total Schedule R customers. The estimated number of Schedule TOU-C non-demand service customers in test year 2005 is 200, which is about 0.78% of total Schedule G customers, or about two times the estimated percentage participation of the Schedule TOU-R customer limit. The estimated average Schedule TOU-R customer savings of $18.80 per customer per

year shown on HECO-WP-304, page 8 is based on taking time-of-use kWh consumption data for Schedule TOU-R pilot program participants, billing the consumption at both proposed Schedule R and proposed Schedule TOU-R rates, and calculating the annualized average bill difference per customer. The estimated average Schedule TOU-C non-demand service customer savings of $214.80 per customer per year shown on HECO-WP-304, page 15 is based on taking time-of-use kWh consumption data for Schedule G class load study participants that would save under Schedule TOU-C non-demand service, billing the consumption at both proposed Schedule G and proposed Schedule TOU-C non-demand service rates, and calculating the average bill difference per customer.

b. See HECO-2237 for the available results of the Schedule TOU-R pilot program. See also HECO's response to CA-IR-232, part a. There is no approved Schedule TOU-C program at this time.

c. The requested information is not yet available. See HECO's response to CA-IR-232, part a.

d. The Company has not made an analysis of the number of customers that would benefit from TOU rates and participate in TOU rate programs. See HECO's response to part a. above.

CA-IR-364

Ref: HECO-WP-304.

Please confirm that 2003 billing information was extracted from automated systems for purposes of preparing this workpaper and provide copies of the "recorded" supporting billing unit data documentation (MWH, KW demand, Bills, etc.) for each rate schedule that was used to distribute projected MWH sales volumes among rate blocks throughout the referenced workpaper.

HECO Response:

Yes, 2003 billing information from the HECO billing system was used to prepare HECO-WP-304. The billing information summaries are voluminous (the Schedule J, Schedule PS, Schedule PP, Schedule PT, and Schedule F billing summaries are filed in a total of 31 binders) but are available for review at HECO's Regulatory Affairs Department. Please contact Irene Sekiya at 543-4778 to arrange for review.

CA-IR-365

Ref: T-22, page 23, Unmetered Schedule G Service.

Please provide the following information regarding HECO's proposal to offer unmetered Schedule G Service:

a. Summarize the number of accounts/meters that are expected to be eligible for and to actually take unmetered service.

b. Explain HECO's plan to notify customers of this service offering, negotiate unmetered service agreements, remove meters and the timeline for transition to such service.

c. What, if any, customer bill impacts are expected to result from transitioning to unmetered [redacted] service (please respond for representative types of anticipated loads)?

d. Provide the incremental amount of bills, kwh and revenues (present and proposed rates) that are expected to result from the proposed implementation of unmetered service.

e. Provide references to, or copies of, all analyses associated with your responses to parts (a) through (d), above.

HECO Response:

a. HECO plans to withdraw its proposal to include a provision for unmetered service in

b. Please see response to part a above.

c. Please see response to part a. above. The requested information is not available. To ascertain the customer bill impact in transitioning to unmetered service requires information on the customer's equipment nameplate ratings – which the Company currently does not have. In general, it is expected that the customer may ask to change an account to unmetered service if it will not be adversely affected by the change through increases in its energy bill or operating budget.

d. See HECO response to part c. above.

e. See HECO responses to parts a. and c. above.

CA-IR-366

Ref: HECO-2220, Schedule E Adjustments.

Please explain the basis for, and provide calculations supportive of, the employee discount adjustment taken to each of the following rates:

a. Schedule J proposed revenues of $184,900,

b. Schedule H proposed revenues of $5,500,

c. Schedule PS proposed revenues of $68,000,

d. Schedule PP proposed revenues of $150,000,

e. Schedule PT proposed revenues of $9,000, and

f. Schedule F proposed revenues of $5,400.

HECO Response:

Please see HECO response to CA-IR-333 and to CA-IR-360, part d.

CA-IR-367

Ref: HECO-2218, Schedule R Apartment House Discount.

Please provide the following information regarding the Company's tariff provision for a 10 percent bill credit (up to $5.00 per month per apartment) for apartment owners willing to accept the three listed terms and conditions:

a. Explain when this tariff provision was initiated and provide copies of, or reference to associated testimony and exhibits.

CA-IR-368

Ref: HECO-2220, HECO-2222, HECO-2223 and HECO-2224, Power Factor Adjustment

Please provide the following information regarding the Company's tariff provision for a 0.1 percent demand and energy charge adjustment for each full one percentage departure from an 85 percent power factor:

a. Explain when this tariff provision was initiated and provide copies of, or reference to associated testimony and exhibits.

b. State whether the discount terms are thought to be cost-based or economically justified.

c. Provide complete copies of all studies and other documentation associated with your response to part (b) of this information request.

HECO Response:

a. The power factor adjustment provision has been in HECO's tariffs since before the 1930's. The demand and energy adjustment was changed from 0.15% to 0.10% effective July 22, 1980, per PUC Decision & Order No. 6275 in Docket No. 3705.

b. See HECO response to part a. above. The power factor adjustment is economically justified as it provides incentives to customers to install capacitors and reduce the kvar that they require from the system, thereby reducing the utility system costs. The power factor adjustment is a common provision in utilities' tariffs for large power service.

c. Copies of other utilities' tariffs with power factor provisions are available but are voluminous. One copy each will be provided to the Consumer Advocate and the Commission under separate transmittal.

Due to the voluminous nature of the information, one copy (pages 2 to 197) will be provided to the Consumer Advocate and the Public Utilities Commission under separate transmittal.

CA-IR-369

Ref: T-22, page 27, HECO-2220 and HECO-2222, Network Adjustment.

Please provide the following information regarding the Company's new tariff provision adding a 0.9 percent demand and energy charge increase for customers served on the downtown underground network:

a. Explain why this tariff provision is needed now and describe any changes in operations or facilities associated with the change.

b. State whether the proposed pricing differential is thought to be cost-based or economically justified.

c. Provide complete copies of all studies and other documentation associated with your response to part (b) of this information request.

d. Define what is meant by "the inherent operating conditions in the downtown area supplied by the Company's underground network system," as referenced in HECO-106, page 12 (proposed tariff sheet 54B).

e. Explain and quantify how customers are thought to benefit from the "multiple redundancy of the circuits" on the Iwilei Network, as noted in the testimony.

HECO Response:

a. Please see HECO response to CA-IR-227. The proposed inclusion of the Network Adjustment provision in Schedule J will not require any changes in operations or the facilities of these customers.

b. Please see HECO response to CA-IR-227.

c. Please see HECO response to CA-IR-227.

d. Please see HECO response to CA-IR-227.

e. Please see HECO response to CA-IR-227.

CA-IR-370

Ref: T-22, pages 25, 31, 33 and 36, Proposed Demand Charge Levels.

Please explain why the existing and proposed demand charges for Schedule J are so much lower than corresponding demand charge levels (existing and proposed) for Schedules PS, PP and PT. Provide copies of all studies and other documentation associated with your response.

HECO Response:

The lower demand charges for Schedule J than the demand charge levels for Schedules PS, PP

and PT are consistent with the fact that the unit demand costs for Schedule J are lower than the

unit demand costs for Schedule PS, PP, and PT at present rates and at

CA-IR-371

Ref: T-22, pages 25, 31, 33 and 36, and HECO-2211; Proposed Demand Charge Levels

Please provide the following information regarding existing and proposed demand charge levels for Rate Schedules J, PS, PP and PT:

a. Confirm and explain why none of the existing or proposed demand charge levels meet or exceed HECO's calculated Unit Marginal Cost values for "Demand Costs."

b. Explain why the Schedule J existing and proposed demand charge levels fail to meet either the Unit Embedded Demand Costs or Unit Marginal Demand Costs.

c. Explain the basis for maintaining declining block demand charge rates for Schedule PS, PP and PT customers.

d. Provide complete copies of any studies or other documentation associated with your responses to parts (a) through (c) of this information request.

HECO Response:

a. The existing and proposed demand charge levels are not based on HECO's calculated unit marginal cost values for demand costs. The embedded cost of service study which allocates the Company's total revenue requirements to the various rate classes is the main basis of HECO's present rates and proposed rates, and the marginal cost study is one of the considerations in the rate design process. This is consistent with the PUC's Decision & Order No. 6034 in Docket No. 2793, Decision & Order No. 6696 in Docket No. 3874, Decision & Order No. 6697 in Docket No. 3705, and Decision & Order No. 11317 in Docket No. 6531.

b. The basis and determination of the Schedule J demand charge at present rates which became

HECO's response to part a. above, the main basis of the proposed Schedule J demand charge, as well as the elements of HECO's proposed rates in this instant docket is the Company's embedded cost of service study, and taking into account the various factors listed in HECO T-22, page 17, lines 13-25. As discussed in HECO T-22, page 25, HECO is proposing to increase the Schedule J demand charge from the current $5.75 per billing kW to $8.50 per billing kW – which reflects an increase of 48%. The proposed $8.50 per billing kW is based on 45% of Schedule J's full unit demand cost including DSM costs of $19.01 per kW. To increase the proposed demand charge in Schedule J from the current $5.75 per billing kW to the class's full unit embedded demand cost of $19.01 per kW could result in rate shock to customers. Rate continuity, impact on customers, and revenue stability are equally important considerations in HECO's rate design besides cost recovery.

c. The multi-step demand charge for Schedules PS, PP, and PT is reasonable and should be maintained for the following reasons:

1. There is a wide range in the kW load of the customers served under these rate schedules, ranging from less than 300 kW to 56,400 kW. The multi-step demand rate structure minimizes the intra-class subsidy.

2. The multi-step demand charge in Schedules PS, PP, and PT is designed to reflect the

and revenue stability.

4. The CA was a party in all the dockets referenced in the HECO Response to subpart a. above, and therefore, the CA must have copies of the PUC decisions & orders in those dockets. There are no other documentation associated with HECO responses to parts b. and c. above.

CA-IR-372

Ref: Iolani Court Plaza.

By letter dated February 24, 2005, Mr. William Bonnet advised the Commission of certain transactions regarding the sale of leased fee interest in residential units. Please provide a summary of the overall status of Iolani Court Plaza transactions, reconciling the Total Net Gain on Sale realized by HECO overall to date into the amounts shown in HECO-1320 and HECO-WP-303 page 2 for the test period.

HECO Response:

Reference the attached copy of Mr. Bonnet's letter to the Commission dated February 24, 2005 regarding sales of leased fee interests in four residential units of the Iolani Court Plaza. The amounts shown in HECO-1320 and in HECO-WP-303, page 2 reflect the results of sales shown on Attachment A of the referenced letter for units #1009 and #1700. The results of sales shown for units #2706 (sold 12/3/04) and #3109 (sold 11/16/04) are not reflected on HECO-1320 and in HECO-WP-303, page 2, because these sales took place subsequent to HECO's filing of testimonies, exhibits, and workpapers in the instant docket. The Total Net Gain on Sale realized by HECO for the sum of all four sales transactions is $333,236. HECO's revised estimate of the

2005 amortization of gain on sale for the Iolani Court Plaza sales transactions is $66,647. HECO's revised estimates of the unamortized balance of the gain on sale for Iolani Court Plaza sales transactions are $283,503 at 12/31/04 and $216,856 at 12/31/05. The sales of the Iolani Court Plaza units referenced in Mr. Bonnet's letter of February 24, 2005 are the only Iolani Court Plaza sales transactions with remaining unamortized balances of gain on sale. These revised estimates will be included in HECO's next determination of revenue requirements.

Hawaiian Electric Co

William A. Bonnet
Vice President
Government and Community Affairs

February 24, 2005

FILED
2005 FEB 24 P 4: 15
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street, First Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket 98-0170
Iolani Court Plaza

This is to inform the Commission that HECO successfully sold the leased fee interest in four residential units of the Iolani Court Plaza Condominium Project, together with the limited common elements appurtenant to those units.[1] Detailed results of the sales are provided in Attachment A.

HECO will keep the Commission informed of any new sales of the leased fee interest in the remaining residential units.

Sincerely,

Attachment

cc: Division of Consumer Advocacy

[1] By letter dated November 22, 1999, HECO informed the Commission of the last prior sales at the Iolani Court Plaza.

ATTACHMENT A

RESULTS OF SALES				
IOLANI COURT PLAZA				
Unit Description	**1009**	**1700**	**2706**	**3109**
Cost of Leased Fee Interest Sold	$7,957.74	$4,803.12	$3,265.36	$7,957.74
Date Sold	12/8/2003	6/7/2002	12/3/2004	11/16/2004
Selling Price	$117,793.00	$58,492.00	$53,289.00	$129,867.00
Sales Expenses	$0.00	$2,221.04	$0.00	$0.00
Total Net Gain	$109,835.26	$51,467.84	$50,023.64	$121,909.26
(Selling Price - Sales Expenses - Cost of Leased Fee Interest Sold)				
Starting month of 5-year amortization	1/04	7/02	1/05	12/04

CA-IR-373

Ref: HECO Responses to CA-IR-222 and CA-IR-230, page 3; HECO-WP-304, pages 69 and 135-138 Rider I billing determinants.

Please provide the following information for each Rider I customer:

a. Actual 2003 billing determinants.

b. Any adjustments to the part a actual information in deriving the "Billing Units" used in HECO-WP-304 calculations.

c. Explanations and copies of documentation for each adjustment provided in your response to part b.

d. State the contract period, any assumptions and provide calculations used to determine the billing kw in HECO-WP-304.

e. Explain whether any adjustments were made in the CA-IR-222 Class Load Study to account for interruptible demands measured during 2003.

HECO Response:

a. See the attached sheets, pages 2 through 9. Included are two customers that have both Rider I and Rider M, option B.

b. See the attached sheets, pages 2 through 9.

c. See the attached sheets, pages 2 through 9.

d. See the attached sheets, pages 2 through 9.

e. There were no adjustments made to the Class Load Study to account for interruptible demands.

RIDER I J1
From HECO-WP-304, Page 69

2003 Billing Parameters

	kW measured	kWh	Power Factor %	kWb at proposed Sch. J kWb
Jan-03	2,515.2	259,200	92	2,515.2
Feb-03	2,385.6	283,200	92	2,450.4
Mar-03	2,175.6	247,200	93	2,345.4
Apr-03	2,366.4	265,200	92	2,440.8
May-03	2,490.0	285,600	92	2,502.6
Jun-03	2,608.8	291,600	91	2,608.8
Jul-03	2,434.8	236,400	92	2,521.8
Aug-03	2,409.6	314,400	89	2,509.2
Sep-03	2,227.2	240,000	95	2,418.0
Oct-03	2,229.6	226,800	94	2,419.2
Nov-03	2,142.0	194,400	95	2,375.4
Dec-03	2,250.0	219,600	93	2,429.4
2003 Average/Mo.	2,352.9	255,300	93	2,461.4

Used for Schedule J
Billing At Present Rates/Mo. 2,350.0 255,000 93
(Test Year forecast rounds 2003 avg/mo to nearest 10 kW and nearest 1,000 kWh)
Customer started Rider I service in August 2004.

Used for Rider I
Billing At Present Rates/Mo.
(Assumes 2,350 kW
is interruptible) 1,645.0 255,000 93

Used for Schedule J
Billing At Proposed Rates/Mo. 255,000 93 2,461.4

Used for Rider I
Billing At Proposed Rates/Mo.
(Assumes 2,350 kW
is interruptible) 255,000 93 1,756.4

RIDER Mbl J1
From HECO-WP-304, Page 94

2003 Billing Parameters

	Sch J	Rider Mbl		Power	kWb at proposed	kWb at proposed
Jan-03	3,120.0	424.8	62,400	54	3,482.4	787.2
Feb-03	3,283.2	341.5	103,200	53	3,564.0	622.3
Mar-03	3,033.6	373.0	74,400	64	3,439.2	778.6
Apr-03	3,818.4	504.2	218,400	64	3,831.6	517.4
May-03	3,818.4	504.2	151,200	63	3,831.6	517.4
Jun-03	3,818.4	504.2	144,000	62	3,831.6	517.4
Jul-03	3,948.0	480.0	156,000	63	3,948.0	480.0
Aug-03	3,432.0	374.4	151,200	60	3,690.0	632.4
Sep-03	3,434.4	374.6	124,800	57	3,691.2	631.4
Oct-03	4,084.8	433.7	218,400	67	4,084.8	433.7
Nov-03	3,792.0	656.4	235,200	69	3,938.4	802.8
Dec-03	3,782.4	402.2	192,000	67	3,933.6	553.4
2003 Average/Mo.	3,613.8	447.8	152,600	62	3,772.2	606.2
Used for Billing At Present Rates/Mo.	3,613.8	447.8	152,600	62		
Used for Billing At Proposed Rates/Mo.			152,600	62	3,772.2	606.2

RIDER I PS1
From HECO-WP-304, Page 116

2003 Billing Parameters

	kW measured	kWh	Power Factor %
Jan-03	530.4	268,560	83
Feb-03	538.8	285,840	84
Mar-03	563.3	288,960	84
Apr-03	564.5	319,200	84
May-03	581.3	310,560	84
Jun-03	577.0	306,720	84
Jul-03	582.0	341,040	84
Aug-03	598.8	324,960	85
Sep-03	588.7	339,360	84
Oct-03	583.0	327,840	85
Nov-03	570.2	314,160	85
Dec-03	529.0	310,800	84
Jan-04	555.8	283,200	84
Feb-04	600.5	324,240	84
Mar-04	554.2	289,680	84
Apr-04	576.7	309,840	84
May-04	572.9	299,520	84
2003 Average/Mo.	567.3	311,500	84
12 Months ending May-04	574.1	3,771,360	84
- -Rounded Values Used	574.0	3,770,000	84
Used for Schedule PS Billing/Mo. At Present and Proposed Rates	574.0	314,167	85

Forecast New Rider I Customer in 2005. Estimate of TY 2005 billing based on 12 Months ending May-04 with zero power factor adjustment.

Used for Rider I Billing/Mo. At Present and Proposed Rates (Assumes 100% Load Interruptible)	401.8	314,167	85

RIDER I PP1
From HECO-WP-304, Page 135

2003 Billing Parameters

	Sch PP kWb	Rider I kWb	kWh	Power Factor %
Jan-03	1,196.4	996.5	746,400	95
Feb-03	1,192.8	995.0	649,200	95
Mar-03	1,198.2	997.2	738,000	95
Apr-03	1,204.8	999.8	685,200	95
May-03	1,195.2	996.0	705,600	95
Jun-03	1,202.4	998.9	758,400	95
Jul-03	1,226.4	1,008.5	693,600	95
Aug-03	1,209.0	1,001.5	727,200	95
Sep-03	1,224.0	1,007.5	799,200	95
Oct-03	1,254.0	1,027.8	715,200	94
Nov-03	1,263.6	1,034.5	750,000	94
Dec-03	1,243.8	1,026.6	787,200	95
2003 Average/Mo.	1,217.6	1,007.5	729,600	95
Used for Billing Per Month At Present and Proposed Rates	1,217.6	1,007.5	729,600	95

RIDER I PP2
From HECO-WP-304, Page 136

2003 Billing Parameters

	Sch PP kWb	Rider I kWb	kWh	Power Factor %
Jan-03	2,515.5	1,842.1	921,600	89
Feb-03	2,341.8	1,772.6	905,400	87
Mar-03	2,406.6	1,798.6	894,600	89
Apr-03	2,424.6	1,805.8	930,600	91
May-03	2,351.7	1,776.6	858,600	91
Jun-03	2,447.1	1,814.8	891,000	91
Jul-03	2,444.4	1,813.7	1,040,400	92
Aug-03	2,625.3	1,886.0	1,072,800	89
Sep-03	2,541.6	1,852.6	1,063,800	90
Oct-03	2,604.6	1,877.8	970,200	90
Nov-03	2,503.8	1,763.5	1,081,800	89
Dec-03	2,439.0	1,715.9	1,173,600	91
2003 Average/Mo.	2,470.5	1,810.0	983,700	90
Used for Billing Per Month At Present and Proposed Rates	2,470.5	1,810.0	983,700	90

RIDER I PP3
From HECO-WP-304, Page 137

2003 Billing Parameters

	kW measured	kWh	Power Factor %
Jan-03	68.8	22,400	85
Feb-03	65.6	20,800	85
Mar-03	68.8	22,400	85
Apr-03	88.0	24,000	85
May-03	86.4	27,200	85
Jun-03	84.8	27,200	85
Jul-03	83.2	24,000	85
Aug-03	78.4	28,800	85
Sep-03	81.6	28,800	85
Oct-03	83.2	25,600	85
Nov-03	83.2	28,800	85
Dec-03	96.0	28,800	85
Jan-04	84.8	25,600	85
Feb-04	84.8	25,600	85
Mar-04	86.4	25,600	85
Apr-04	1,571.2	344,000	87
May-04	1,505.6	528,000	88
Jun-04	1,542.4	587,200	88
2003 Average/Mo.	80.7	25,733	85
3 Mo Avg or 2 Mo Avg ending Jun-04	1,539.7	557,600	88
- -Rounded Values Used	1,540.0	550,000	88
Used for Schedule PP Billing/Mo. At Present and Proposed Rates	1,540.0	550,000	88

Forecast New Rider I Customer in 2005. Estimate of TY 2005 billing based on 3 Months ending Jun-04 (2 Months ending Jun-04 for kWh).

Used for Rider I Billing/Mo. At Present and Proposed Rates (Assumes 100% Load Interruptible)	1,078.0	550,000	88

RIDER I PP4
From HECO-WP-304, Page 138

2003 Billing Parameters
(this is not a current customer)

	kW measured	kWh	Power Factor %
Used for Schedule PP Billing/Mo. At Present and Proposed Rates	1,000.0	180,000	85

Forecast New Rider I Customer in 2005. Test Year 2005 billing loads estimated based on account manager assumptions.

Used for Rider I Billing/Mo. At Present and Proposed Rates (Assumes 800 kW Load Interruptible)	760.0	180,000	85

RIDERMult PP2
From HECO-WP-304, Page 140

2003 Billing Parameters

	Sch PP kWb	Rider Mb & I kWb	kWh	Power Factor %
Jan-03	1,809.9	1,352.3	1,161,000	93
Feb-03	1,800.9	1,357.6	1,112,400	93
Mar-03	1,920.6	1,419.4	1,204,200	93
Apr-03	1,875.6	1,377.6	1,144,800	93
May-03	1,904.4	1,404.5	1,224,000	93
Jun-03	1,817.1	1,378.0	1,123,200	93
Jul-03	1,824.3	1,380.9	1,072,800	93
Aug-03	1,854.9	1,380.2	1,222,200	93
Sep-03	1,913.4	1,362.0	1,240,200	92
Oct-03	1,863.0	1,375.3	1,114,200	93
Nov-03	1,918.8	1,350.9	1,200,600	92
Dec-03	1,931.4	1,356.2	1,227,600	92
2003 Average/Mo.	1,869.5	1,374.6	1,170,600	93
Used for Billing Per Month At Present and Proposed Rates	1,869.5	1,374.6	1,170,600	93

CA-IR-374

Ref: HECO WP-304, pages 126 through 143.

Regarding each of the following Schedule PP Rider customers, please provide a copy of the customer's service contract and the actual 2003 monthly detailed billing determinants, as well as explanations and calculations supporting the specific amounts used for test year billing determinants (if different from the 2003 actual values):

a. Rider Mb PP4 (page 130).

b. RiderMult PP2 (page 140).

c. Rider CHP PP1 (page 141).

d. Rider CHP PP2 (page 142).

e. Rider CHP PP3 (page 143).

HECO Response:

Attached as page 2 of this response is a copy of the Rider M – Option B service contract form that is used for Rider M customers, including customers Rider Mb PP4 and RiderMult PP2. The Rider M service contract simply implements the terms of the Rider M tariff and does not require separate Commission approval for each contract. The Rider I contract for customer RiderMult PP2 was approved by the Commission (Decision and Order No. 12208) on February 25, 1993 in Docket No. 7570. There are no existing contracts for customers Rider CHP PP1, Rider CHP PP2, and Rider CHP PP3, as these are potential customers anticipated in test year 2005 in direct testimony. HECO has since decided to remove CHP projects from this docket, so these potential Rider CHP customers and their associated impacts will also be removed from the test year revenue estimates.

The actual 2003 monthly billing determinants for customer Rider Mb PP4 are shown on page 3 of this response. The 2003 monthly billing determinants for customer RiderMult PP2 were presented in this docket at page 9 of HECO's response to CA-IR-373.

RIDER M - Option B
Curtailable Service Contract

This Contract covers electric service provided by HAWAIIAN ELECTRIC COMPANY, INC. (HECO) to:

Customer: _____

Account Number: _____

Service Address: _____

Under this Contract, the electric service provided by HECO to the customer's service location shall be served on rate Schedule ___ and Rider M, Option B. All terms of Schedule ___ shall apply, except as specifically modified by Rider M, Option B and/or further specified in this Contract.

Under this Rider "M" Option "B" contract, the customer shall curtail between _____ kW and _____ kW during the selected curtailment option. For billing purposes, the curtailed load cannot be greater than _____ kW. The billing demand under this Rider M - Option B contract shall be the billing demand as determined under the applicable rate schedule reduced by (select one):

___ 1. 75% of curtailed kW demand if the curtailment period is fixed throughout the year from 5 p.m. to 9 p.m., Monday through Friday, or

___ 2. 40% of curtailed kW demand if the curtailment period is two (2) consecutive hours as specified by the Company.

This Contract shall become effective at the beginning of the first regular billing cycle following _____(date) or the first billing period after the installation of a HECO time-of-use meter, whichever occurs later.

Service under this Rider shall not be less than three (3) years, and shall continue thereafter on a year-to-year basis until terminated by either party with a 30-day written notice. The Customer may terminate service under this Rider during the first six (6) months without penalty. If the customer terminates service after the first six months but before the end of the initial three-year

RIDER Mb PP4
From HECO-WP-304, Page 130

2003 Billing Parameters

	Sch PP kWb	Rider Mb kWb	kWh	Power Factor %
Jan-03	52,800.0	48,480.0	29,832,000	98
Feb-03	53,040.0	48,000.0	24,768,000	99
Mar-03	52,200.0	48,240.0	28,800,000	99
Apr-03	51,480.0	49,140.0	23,808,000	99
May-03	52,560.0	47,700.0	25,248,000	99
Jun-03	54,360.0	48,960.0	31,800,000	98
Jul-03	53,160.0	48,840.0	26,832,000	99
Aug-03	54,840.0	48,180.0	27,360,000	98
Sep-03	56,400.0	50,640.0	34,080,000	98
Oct-03	56,040.0	49,380.0	29,976,000	98
Nov-03	54,708.0	49,092.0	27,768,000	98
Dec-03	55,512.0	50,454.0	32,928,000	97
2003 Average/Mo.	53,925.0	48,925.5	28,600,000	98
Used for Billing Per Month At Present and Proposed Rates	53,925.0	48,925.5	28,600,000	98

CA-IR-375

Ref: HECO-WP-304, pages 55 through 100.

For each of the following Schedule J Rider customers, please provide a copy of the customer's service contract and the actual 2003 monthly detailed billing determinants, as well as explanations and calculations supporting the specific amounts used for the test year billing determinants (if different from 2003 actual values):

a. Rider Mb J1 (page 56).

b. Rider Mb J2 (page 57).

c. Rider Mb J8 (page 63).

d. Rider Mb J11 (page 66).

e. Rider Mb J12 (page 67).

f. Rider Mb J13 (page 68).

g. Rider T J7 (page 76).

h. Rider T J8 (page 77).

i. Rider T J16 (page 85.)

j. Rider T J17 (page 86).

k. Rider Mbl J1 (page 94.)

l. Rider U J4 (page 98).

m. Rider EDR J1 (page 99).

n. Rider CHP J1 (page 100).

HECO Response:

A copy of the Rider M – Option B service contract form that is used for Rider M customers, including customers Rider Mb J1, Rider Mb J2, Rider Mb J8, and Rider MbI J1 was submitted at page 2 of HECO's response to CA-IR-374 in this docket. Note that customers Rider Mb J11, Rider Mb J12, and Rider Mb J13 are potential customers anticipated in test year 2005 for which HECO does not yet have Rider M service contracts. The Rider M service contract simply implements the terms of the Rider M tariff and does not require separate Commission approval

for each contract. Attached as page 3 of this response is a copy of the Rider T service contract

form that is used for Rider T customers, including customers Rider T J7, Rider T J8, Rider T J16, and Rider T J17. The Rider T service contract simply implements the terms of the Rider T tariff

customer Rider MbI J1 was approved by the Commission on February 14, 1991 (Decision and Order No. 10978) in Docket No. 6790. The Schedule U contract for customer Sch U J4 was approved by the Commission on January 6, 2004 (Decision and Order No. 20732) in Docket No.

HAWAIIAN ELECTRIC COMPANY
P.O. BOX 2750, Honolulu, Hawaii 96840

RIDER T
TIME-OF-DAY RIDER

This Contract covers the electric service provided by HAWAIIAN ELECTRIC COMPANY, INC. (HECO) to:

Customer:

Account Number:

Service Address:

Under this Contract, the electric service provided by HECO to the customer's service location shall be served on rate Schedule PS and Rider T. All terms of Schedule PS shall apply, except as specifically modified by Rider T, and/or further specified in this Contract. The time-of-day rating periods under this Rider shall be as follows:

On-Peak Period: 7:00 a.m. – 9:00 p.m., Daily

Off-Peak Period: 9:00 p.m. – 7:00 a.m., Daily

This Contract shall become effective at the beginning of the first regular billing cycle following _____(date) or the first billing period after the installation of a HECO time-of-use meter, whichever occurs later.

Service under this Rider shall not be less than five (5) years, and shall continue thereafter on a year-to-year basis until terminated by either party with a 30-day written notice. The Customer may terminate service under this Rider during the first six (6) months without penalty. If the customer terminates service after the first six months but before the end of the initial five-year term which begins from the start date of the customer's service under this Rider, the Customer shall be assessed a termination fee equal to the savings received by the customer under this Rider during the last six months prior to the service termination date.

Authorizing Signature & Title:		HECO Representative:	
Name		Name	
Title	Date	Title	Date

RIDER Mb J1
From HECO-WP-304, Page 56

2003 Billing Parameters

	Sch J kWb	Rider Mb kWb	kWh	Power Factor %	kWb at proposed Sch. J kWb	kWb at proposed Rider Mb
Jan-03	123.4	31.7	25,520	85	124.1	32.4
Feb-03	123.8	31.8	23,040	85	124.3	32.3
Mar-03	123.4	31.7	25,760	85	124.1	32.4
Apr-03	123.5	31.7	24,400	85	124.1	32.3
May-03	136.7	35.2	22,480	85	136.7	35.2
Jun-03	123.1	31.6	29,680	85	129.9	38.4
Jul-03	123.3	121.6	24,800	85	130.0	128.3
Aug-03	123.3	32.8	27,440	85	130.0	39.5
Sep-03	123.2	31.6	27,920	85	130.0	38.4
Oct-03	123.1	31.6	25,360	85	129.9	38.4
Nov-03	122.8	31.5	25,840	85	129.8	38.5
Dec-03	123.1	31.6	25,120	85	129.9	38.4
2003 Average/Mo.	124.4	39.5	25,613	85	128.5	43.7
Used for Billing At Present Rates/Mo.	124.4	39.5	25,613	85		
Used for Billing At Proposed Rates/Mo.			25,613	85	128.5	43.7

HECO-WP-304, Page 56 uses 39.6 kW for Rider Mb kWb at present rates; difference due to rounding.

RIDER Mb J2
From HECO-WP-304, Page 57

2003 Billing Parameters

	Sch J kWb	Rider Mb kWb	kWh	Power Factor %	kWb at proposed Sch. J kWb	kWb at proposed Rider Mb
Jan-03	174.9	44.9	68,960	85	175.4	45.4
Feb-03	175.0	45.0	58,320	85	175.4	45.4
Mar-03	175.0	45.0	68,560	85	175.4	45.4
Apr-03	174.9	44.9	55,840	85	175.4	45.4
May-03	176.3	45.4	57,680	85	176.3	45.4
Jun-03	174.9	45.0	72,000	85	175.6	45.7
Jul-03	175.4	45.0	60,640	85	175.9	45.5
Aug-03	175.4	45.1	64,560	85	175.9	45.6
Sep-03	174.1	44.8	66,160	85	175.2	45.9
Oct-03	174.3	44.8	70,240	85	175.3	45.8
Nov-03	181.0	46.5	60,640	85	181.0	46.5
Dec-03	174.9	45.0	64,960	85	178.0	48.1
2003 Average/Mo.	175.5	45.1	64,047	85	176.2	45.8
Used for Billing At Present Rates/Mo.	175.5	45.1	64,047	85		
Used for Billing At Proposed Rates/Mo.			64,047	85	176.2	45.8

RIDER Mb J8
From HECO-WP-304, Page 63

2003 Billing Parameters

	Sch J kWb	Rider Mb kWb	kWh	Power Factor %	kWb at proposed Sch. J kWb	kWb at proposed Rider Mb
Sep-03	523.8	301.0	182,400	88	523.8	301.0
Oct-03	524.4	330.4	187,200	89	524.4	330.4
Nov-03	522.6	287.2	178,800	90	523.5	288.1
Dec-03	504.6	280.0	184,200	89	514.5	289.9
Jan-04	517.8	297.3	160,200	87	521.1	300.6
Feb-04	537.6	314.8	216,600	89	537.6	314.8
6 mos. Average/Mo.	521.8	301.8	184,900	89	524.2	304.1
Used for Billing At Present Rates/Mo.	521.8	301.8	184,900	89		
Used for Billing At Proposed Rates/Mo.			184,900	89	524.2	304.1

HECO-WP-304, Page 63 uses 304.2 kW for Rider Mb kWb at proposed rates; difference due to rounding.
Customer began Rider M Service in August 2003.
Test year estimate based on data available at the time the estimate was made.

RIDER T J7
From HECO-WP-304, Page 76

2003 Billing Parameters

	Max Measured kW	Max On-Peak kW	Sch J kWb	Rider T kWb	On-Peak kWh	Off-Peak kWh	Power Factor %	kWb at proposed Sch. J kWb	kWb at proposed Rider T
Jan-03	1.2	1.2	718.8	25.0	0	0		360.0	25.0
Feb-03	1.2	1.2	539.1	25.0	0	1,200		360.0	25.0
Mar-03	1.2	1.2	539.1	25.0	1,200	0		360.0	25.0
Apr-03	1.2	1.2	718.8	25.0	0	0		360.0	25.0
May-03	1.2	1.2	718.8	25.0	0	0		360.0	25.0
Jun-03	718.8	1.2	718.8	25.0	1,200	3,600	97	718.8	25.0
Jul-03	1.2	1.2	718.8	25.0	0	0		360.0	25.0
Aug-03	1.2	1.2	539.1	25.0	0	1,200	100	360.0	25.0
Sep-03	1.2	1.2	539.1	25.0	1,200	0	100	360.0	25.0
Oct-03	1.2	1.2	718.8	25.0	0	0		360.0	25.0
Nov-03	1.2	1.2	539.1	25.0	1,200	0		360.0	25.0
Dec-03	1.2	1.2	539.1	25.0	0	1,200		360.0	25.0
2003 Average/Mo.	61.0	1.2	629.0	25.0	400	600	99	389.9	25.0
Used for Billing At Present Rates/Mo.			539.1	25.0	400	600	100		
Used for Billing At Proposed Rates/Mo.					400	600	100	359.4	25.0

Schedule J 2003 kWb: Customer is paying minimum bill in several months, based on 718.8 kW - measured in last 12 months.
Schedule J kWb at present rates assumes Schedule J ratchet on 718.8 kW = 75% x 718.8 = 539.1 kWb.
Schedule J kWb at proposed rates assumes proposed Schedule J ratchet on 718.8 kW with current month 0 kW = 50% x (718.8 + 0) = 359.4 kWb.
Power Factor assumed to be 100 every month.

RIDER T J8
From HECO-WP-304, Page 77

2003 Billing Parameters

	Max Measured kW	Max On-Peak kW	Sch J kWb	Rider T kWb	On-Peak kWh	Off-Peak kWh	Power Factor %	kWb at proposed Sch. J kWb	kWb at proposed Rider T
Jan-03	4.8	4.8	598.8	25.0	0	1,600	85	401.6	25.0
Feb-03	4.8	4.8	798.4	25.0	0	0	85	401.6	25.0
Mar-03	3.2	3.2	598.8	25.0	1,600	0	85	400.8	25.0
Apr-03	3.2	3.2	598.8	25.0	0	1,600	85	400.8	25.0
May-03	3.2	3.2	798.4	25.0	0	0	85	400.8	25.0
Jun-03	0.0	0.0	798.4	25.0	0	0	85	399.2	25.0
Jul-03	0.0	0.0	798.4	25.0	0	0	85	399.2	25.0
Aug-03	0.0	0.0	25.0	25.0	0	0	85	25.0	25.0
Sep-03	1.6	1.6	25.0	25.0	0	0	85	25.0	25.0
Oct-03	3.2	3.2	25.0	25.0	1,600	0	85	25.0	25.0
Nov-03	3.2	3.2	25.0	25.0	0	0	85	25.0	25.0
Dec-03	3.2	3.2	25.0	25.0	0	0	85	25.0	25.0
2003 Average/Mo.	2.5	2.5	426.3	25.0	267	267	85	244.1	25.0
Used for Billing At Present Rates/Mo.			598.8	25.0	267	266	85		
Used for Billing At Proposed Rates/Mo.					267	[illegible]	[illegible]	[illegible]	[illegible]

Schedule J 2003 kWb: Customer is paying minimum bill in several months, based on 798.4 kW - measured in last 12 months.
Schedule J kWb at present rates assumes Schedule J ratchet on 798.4 kW = 75% x 798.4 = 598.8 kWb.
Schedule J kWb at proposed rates assumes proposed Schedule J ratchet on 798.4 kW with current month 0 kW = 50% x (798.4 + 0) = 399.2 kWb.
Off-Peak kWh at present and proposed rates adjusted 1 kWh for rounding.

RIDER T J16
From HECO-WP-304, Page 85

2003 Billing Parameters

	Max Measured kW	Max On-Peak kW	Sch J kWb	Rider T kWb	On-Peak kWh	Off-Peak kWh	Power Factor %	kWb at proposed Sch. J kWb	kWb at proposed Rider T
Jan-03	237.7	1.5	237.7	25.0	640	48,560	82	257.6	25.0
Feb-03	236.3	1.4	236.3	25.0	560	48,080	82	256.9	25.0
Mar-03	238.1	1.4	238.1	25.0	560	56,160	83	257.8	25.0
Apr-03	245.3	1.4	245.3	25.0	640	65,440	83	261.0	25.0
May-03	247.0	1.5	247.0	25.0	560	58,320	83	261.9	25.0
Jun-03	257.2	1.5	257.2	25.0	1,040	62,480	83	267.0	25.0
Jul-03	254.0	1.6	254.0	25.0	640	67,760	83	265.4	25.0
Aug-03	257.2	1.5	257.2	25.0	560	64,800	83	267.0	25.0
Sep-03	256.5	1.5	256.5	25.0	640	66,080	84	263.4	25.0
Oct-03	259.2	4.9	259.2	25.0	640	73,840	83	259.2	25.0
Nov-03	258.6	1.7	258.6	25.0	560	57,360	82	258.9	25.0
Dec-03	225.0	1.5	225.0	25.0	560	50,080	80	242.1	25.0
2003 Average/Mo.	247.7	1.8	247.7	25.0	633	59,913	83	259.9	25.0
Used for Billing At Present Rates/Mo.			247.7	25.0	633	59,914	83		
Used for Billing At Proposed Rates/Mo.					633	59,914	83	259.8	25.0

Off-Peak kWh at present and proposed rates adjusted 1 kWh for rounding.
Schedule J kWb at proposed rates adjusted for rounding.

RIDER T J17
From HECO-WP-304, Page 86

2003 Billing Parameters

	Max Measured kW	Max On-Peak kW	Sch J kWb	Rider T kWb	On-Peak kWh	Off-Peak kWh	Power Factor %	kWb at proposed Sch. J kWb	kWb at proposed Rider T
Jan-03	215.2	211.2	215.2	211.2	560	21,600	82	241.5	211.2
Feb-03	216.2	6.7	216.2	158.4	80	28,240	83	242.0	109.0
Mar-03	215.0	1.4	215.0	158.4	80	36,400	82	241.4	106.3
Apr-03	228.0	6.2	228.0	158.4	80	34,080	83	247.9	108.7
May-03	0.2	0.2	200.9	158.4	80	36,880	84	134.0	105.7
Jun-03	214.9	0.2	214.9	158.4	2,320	30,400	84	241.4	105.7
Jul-03	226.5	0.2	226.5	158.4	80	37,360	84	247.2	105.7
Aug-03	226.1	0.2	226.1	158.4	2,880	38,480	85	247.0	105.7
Sep-03	225.0	0.2	225.0	158.4	80	49,120	85	246.4	105.7
Oct-03	232.5	0.2	232.5	158.4	80	48,400	85	232.5	105.7
Nov-03	220.0	17.1	220.0	158.4	80	43,120	82	226.3	114.2
Dec-03	215.4	0.2	215.4	158.4	80	36,000	82	224.0	105.7
2003 Average/Mo.	202.9	20.3	219.6	162.8	540	36,673	83	230.9	115.8
Used for Billing At Present Rates/Mo.			219.6	25.0	540	36,673	83		
Used for Billing At Proposed Rates/Mo.					540	36,673	83	230.9	25.0

Rider T kWb at present and proposed rates assumes that this customer will not operate significantly in the on-peak hours.
The January 2003 on-peak kW is assumed to be a correctable exception to normal operations.

SCH U J4
From HECO-WP-304, Page 98

2003 Billing Parameters

	Max Measured kW	Max On-Peak kW	Sch J kWb	Sch U kWb	On-Peak kWh	Off-Peak kWh	Power Factor %
Feb-04	605.0	1.4	605.0	25.0	240	107,280	94
Mar-04	600.2	1.4	600.2	25.0	240	128,880	94
Apr-04	599.5	1.4	599.5	25.0	240	144,720	94
May-04	599.5	1.2	599.5	25.0	240	139,920	94
Four Months Average/Mo.	601.1	1.4	601.1	25.0	240	130,200	94
Used for Billing Per Month At Present and Proposed Rates			601.1	25.0	240	130,200	94

Estimates for this Schedule U customer were made based on the data available at the time the estimate was made.
This customer commenced Schedule U service in January 2004 and was first billed on Schedule U in February 2004.

CA-IR-376

Ref: HECO Response to CA-IR-228, Schedule H Service.

Please provide the following information regarding HECO's Schedule H Service:

a. Regarding the "very small size and continued decline in the number of Schedule H customers" (response part a(1)), please explain any problems that would be caused by grandfathering existing customers' participation in the rate, but closing the rate to any new customers prospectively.

b. Regarding the site inspections on the customers' premises explained in response to part c, please provide an estimate of the annual Field Service Division labor hours expended to administer this end-use rate.

c. Provide references to, or copies of, all analyses associated with your responses to parts a through d, above.

HECO Response:

a. Closing Schedule H to new customers prospectively could result to the following issues/problems:

1. If a new tenant who is a current customer in a different service location, moves to a service site with existing Schedule H meter, this customer would have to incur costs to re-wire the site to be served with one meter under the other applicable rate schedule. If the customer does not re-wire its location, it could end up with more than one meter being served under the same rate schedule, such as 2 Schedule G meters, increasing the customer's electric bill and such customer could end up in a variance with the HECO's tariffs. Small customers normally do not have the funds to re-wire their location to be served with one meter as required by HECO's tariffs, such as by the Availability Clause of HECO's rate schedules.

2. The definition of "new customer" will have to be clarified. For instance, would an

existing customer choosing to re-locate to another service location with an existing "H" meter be considered "new customer" such that it will not be allowed to receive service under Schedule H.

b. The estimated annual Field Service Division labor hours expended to administer Schedule H is about 2,600 hours/year. This estimate is based on one full time equivalent senior investigator plus associated administrative hours.

c. There are no other references or analyses associated with responses to parts a. and b. above.

CA-IR-377

Ref: HECO's Response to CA-IR-229 DSM Allocations and C-8 Allocation Factor.

Please provide the following information:

a. The actual class allocation of test year DSM costs, if different from the percentage values set forth at the bottom of page 3 of the response.

b. Copies of supporting documentation and calculations supportive of the response to part a, above, if different from page 3 of the response.

c. A revised page 144 for HECO-WP-2202, supportive of the actual C8 allocation factors employed in the Company's embedded cost of service study (for example, 53.56% to R on the "HAFDATA" tab, cell C14 of the Excel model).

d. Complete calculations and underlying data **if** any revisions to the customer service allocation factor C8 percentage values, have been identified as needed by the Company.

HECO Response:

a. The actual class allocation of test year DSM costs is attached as page 2 to this response. This same worksheet was provided to the CA on January 11, 2005, in the EXCEL file labeled "HECO_TY_2005_COS_Cust_Allo_Fct.xls".

b. The allocation was based on the recorded DSM program rebates for 2003 which is shown at the bottom of page 3 of the HECO Response to CA-IR-229, and also attached as page 3 to this response.

c. The revised page 144 or HECO-WP-2202 is attached as page 4 to this response. This worksheet was provided to the CA on January 11, 2005, in the EXCEL file labeled "HECO_TY_2005_COS_Cust_Allo_Fct.xls"

STS ($000s)

NC, DLC	TOTAL DSM
$0.0	$16,096.4
130.0	$130.0
997.7	$4,997.7
$8.1	$8.1
104.8	$3,104.8
286.1	$5,923.3
$13.5	$13.5
$0.0	$0.0
540.2	$30,273.8
540.2	$30,273.8

CA on January 11, 2005.

HAWAIIAN ELECTRIC COMPANY, INC.
Docket No. 04-0113, Test-Year 2005
Summary Allocation of DSM Program Rebates, 2000 - 2003

Year 2000

Rate Class	REWH	RNC	CIEE	CINC	CICR	Total
Schedule R	$1,072,268.18	$405,535.53	$0.00	$0.00	$0.00	$1,477,803.71
Schedule E	$13,264.15	$1,602.31	$0.00	$0.00	$0.00	$14,866.46
Schedule G	$711.03	$49,892.04	$7,874.00	$53,710.00	$414.00	$112,601.06
Schedule J - Sec	$40.06	$0.00	$124,215.00	$241,684.00	$64,012.00	$429,951.06
Schedule J - Pri	$0.00	$0.00	$15,218.00	$0.00	$2,180.00	$17,398.00
Schedule H	$0.00	$0.00	$369.00	$0.00	$8,119.00	$8,488.00
Schedule PS	$0.00	$0.00	$51,738.00	$3,226.00	$159,753.00	$214,717.00
Schedule PP	$71,993.95	$688,574.19	$290,436.00	$273,589.00	$220,708.00	$1,545,301.14
Schedule PT	$0.00	$98,742.57	$15,377.00	$2,307.00	$144,407.00	$260,833.57
Total	$1,158,277.36	$1,244,346.64	$505,227.00	$574,516.00	$599,593.00	$4,081,960.00

Year 2001

	REWH	RNC	CIEE	CINC	CICR	Total
Schedule R	$550,818.07	$526,222.40	$0.00	$0.00	$0.00	$1,077,040.47
Schedule E	$5,645.78	$2,658.71	$0.00	$0.00	$0.00	$8,304.48
Schedule G	$762.66	$6,641.47	$16,290.00	$37,846.00	$246.00	$61,786.12
Schedule J - Sec	$42.37	$0.00	$160,449.00	$220,592.00	$138,755.00	$519,838.37
Schedule J - Pri	$0.00	$0.00	$27,071.00	$55,912.00	$14,675.00	$97,658.00
Schedule H	$116.52	$0.00	$2,627.00	$915.00	$0.00	$3,658.52
Schedule PS	$0.00	$0.00	$61,718.00	$2,723.00	$128,842.00	$193,283.00
Schedule PP	$101,094.36	$104,865.27	$651,073.00	$145,339.00	$350,942.00	$1,353,313.63
Schedule PT	$68,956.86	$17,477.55	$0.00	$15,392.00	$0.00	$101,826.40
Total	$727,436.61	$657,865.39	$919,228.00	$478,719.00	$633,460.00	$3,416,709.00

Year 2002

	REWH	RNC	CIEE	CINC	CICR	Total
Schedule R	$790,891.20	$321,640.75	$0.00	$0.00	$0.00	$1,112,531.95
Schedule E	$5,392.12	$2,014.05	$0.00	$0.00	$0.00	$7,406.17
Schedule G	$937.76	$15,238.59	$10,729.00	$223.00	$161,751.00	$188,879.35
Schedule J - Sec	$799.23	$0.00	$267,621.00	$75,498.00	$14,670.00	$358,588.23
Schedule J - Pri	$32,768.29	$0.00	$26,482.00	$0.00	$12,615.00	$71,865.29
Schedule H	$42.63	$0.00	$0.00	$0.00	$0.00	$42.63
Schedule PS	$0.00	$0.00	$130,230.00	$540.00	$88,355.00	$219,125.00
Schedule PP	$392,420.26	$217,219.13	$334,739.00	$143,538.00	$365,779.00	$1,453,695.39
Schedule PT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$1,223,251.48	$556,112.52	$769,801.00	$219,799.00	$643,170.00	$3,412,134.00

Year 2003

	REWH	RNC	CIEE	CINC	CICR	Total
Schedule R	$1,165,752.08	$472,090.96	$0.00	$0.00	$0.00	$1,637,843.04
Schedule E	$10,022.40	$2,878.66	$0.00	$0.00	$0.00	$12,901.06
Schedule G	$1,068.91	$8,710.07	$17,760.44	$232.53	$396.49	$28,168.43
Schedule J - Sec	$52.92	$0.00	$397,196.62	$175,693.48	$74,261.34	$647,204.35
Schedule J - Pri	$0.00	$0.00	$43,093.88	$2,754.54	$17,601.44	$63,449.86
Schedule H	$52.92	$0.00	$1,207.35	$0.00	$28.82	$1,289.08
Schedule PS	$0.00	$0.00	$256,624.55	$33,876.30	$150,859.87	$441,360.71
Schedule PP	$0.00	$230,187.09	$239,507.03	$146,806.56	$365,285.86	$981,786.55
Schedule PT	$0.00	$0.00	$0.00	$500.83	$1,406.09	$1,906.91
Total	$1,176,949.22	$713,866.78	$955,389.86	$359,864.23	$609,839.91	$3,815,910.00

Rate Schedule	Total Residential Programs		Total C&I Programs	
	($)	(%)	($)	(%)
Schedule R/E	$1,660,628.91	87.83%	$0.00	0.00%
Schedule G	$0.00	0.00%	$18,389.45	0.96%
Schedule J	$0.00	0.00%	$710,601.30	36.91%
Schedule H	$0.00	0.00%	$1,236.17	0.06%
Schedule PS	$0.00	0.00%	$441,360.71	22.93%
Schedule PP	$230,187.09	12.17%	$751,599.46	39.04%
Schedule PT	$0.00	0.00%	$1,906.91	0.10%
Schedule F	$0.00	0.00%	$0.00	0.00%
Total	$1,890,816.00	100.00%	$1,925,094.00	100.00%

Source File: HECO_TY_2005_COS_Cust_Allo_Fct.xls/C8 - Acct 910 DSM. Electronic copy of the source file was provided to the CA on January 11, 2005.

Pricing/Es:3-28-05
CA-IR-377.xls
Recorded DSM Rebates

Hawaiian Electric Company, Inc.
Docket No. 04-0113, Test-Year 2005

	No. Cust.	% of Total Customers	Account 909 ESD[1]	Account 909 Total	Account 910 - DSM	Account 910 - NON-DSM ALL Div Excl Ed & Cons Affairs, SN, SR Divs.[1]	Account 910 - NON-DSM Ed & Cons Affairs[2]	Account 910 - NON-DSM ESD - SN & SR Divs[3]	Account 910 - NON-DSM Total	Account 911 Corp Comm, Environ, ESD[1]	Account 911 Total	Account 912 CSD[1]	Account 912 Total	Cust Serv Ex Account 909-912 Total DSM	Cust Serv Ex Account 909-912 NON-DSM ($000s)	Cust Serv Ex Account 909-912 Total DSM ($000s)	TOTAL CUST SERV EXP ($000s)	TOTAL CUST SERV EXP (C8 FCT. %)
Schedule R/E	257,519																	
	129																	
	257,648	88.307%	$27.4		$16,096.4	$1,375.3	$391.9		$1,767.2	$292.4		$30.0		$2,117.0		$16,096.4	$18,213.4	53.557%
Schedule G	16,121																	
	9,508																	
	25,629	8.784%	$2.7		$130.0	$136.8			$136.8	$29.1		$3.0		$171.6		$130.0	$301.6	0.887%
Schedule J - DP	4																	
	127																	
	131																	
Schedule J - DS	1																	
	22																	
	23																	
Schedule J - Pri	5																	
	149																	
	154																	
Schedule J - Sec	547																	
	5,953																	
	6,500																	
Schedule J - Nwk	0																	
	24																	
	24																	
Schedule J - Sec	547																	
	5,977																	
	6,524																	
Schedule J Total	552																	
	6,128																	
	6,680	2.290%	$0.7		$4,997.7	$35.7		$1,317.1	$1,352.8	$7.6		$0.8		$1,361.9		$4,997.7	$6,359.6	18.701%
Schedule H/K	332																	
	710																	
	1,042	0.357%	$0.1		$8.1	$5.6			$5.6	$1.2		$0.1		$7.0		$8.1	$15.1	0.044%
Schedule PS	190	0.065%	$0.0		$3,104.8	$1.0		$37.5	$38.5	$0.2		$0.0		$38.7		$3,104.8	$3,143.5	9.244%
Schedule PP	166	0.057%	$0.0		$5,923.3	$0.9		$32.7	$33.6	$0.2		$0.0		$33.8		$5,923.3	$5,957.1	17.517%
Schedule PT	4	0.001%	$0.0		$13.5	$0.0		$0.8	$0.8	$0.0		$0.0		$0.8		$13.5	$14.3	0.042%
	360																	
Schedule F - Pri																		
Metered	52																	
Unmetered	275																	
	327																	
Schedule F - Sec																		
Metered	79																	
Flat	0																	
	79																	
Schedule F - Total																		
Metered	131																	
Unmetered	275																	
	406	0.139%	$0.0		$0.0	$2.2			$2.2	$0.5		$0.0		$2.7		$0.0	$2.7	0.008%
TOTAL	291,765	100.000%	$31.0		$30,273.8	$1,557.4	$391.9	$1,388.1	$3,337.4	$331.1		$34.0		$3,733.5		$30,273.8	$34,007.3	100.000%
			$30.9			$1,557.5		$1,388.1	$3,337.5	$331.2		$33.9		$3,733.5		$30,273.8		

[1] Allocation basis - % of customers (all rate classes).
[2] Allocation basis - 100% residential class. See e-mail from K. DeSilva dated 3/26/04.
[3] Allocate to Schedules J, PS, PP, and PT.

Source File: HECO_TY_2005_COS_Cust_Allo_Fct.xls/C8 - Acct 910 DSM. Electronic copy of the source file was provided to the CA on January 11, 2005.

Pricing/Ex:3-28-05
CA-IR-377.xls
C8 - Cust Serv-P1

CA-IR-377
DOCKET NO. 04-0113
PAGE 4 OF 4

REVISED HECO-WP-2202
PAGE 144 of 173 (3/31/05)

CA-IR-378

Ref: HECO Response to CA-IR-225 civil defense siren billing kWh.

Please provide a complete statement and copies of supporting documentation for any changes HECO intends to make to its proposed 730 hours per month billing kWh level, so as to allow the Consumer Advocate an opportunity to evaluate such revisions (if any).

HECO Response:

The proposed 730 hours per month for use in determining the billing kWh for the proposed unmetered service option in Schedule G is based on the total number of hours per year divided by 12 months: 730 hours/month = (365 days per year x 24 hours per day) ÷ (12 months per year). The analysis of the metered data for the one civil defense siren account on Molokai supports the reasonableness of the proposed 730 hours per month and no changes will be made in the Company's rebuttal testimony for the following reasons:

1. The metered data for the referenced civil defense siren account on Molokai for the period from October 9, 2004 to March 2, 2005, confirms that this type of load is fairly constant and is on 24/7. The data is voluminous and is being provided in an electronic file labeled "CA-IR-378.xls" and provided under separate transmittal.

2. The proposed 730 hours per month is based on the total number of hours in a year which ensures that the customer is not overcharged or undercharged in any given year. For the proposed unmetered service, the unmetered accounts can be scheduled to be billed every 30 to 31 days, and equal 365 bill days in a year.
3. The proposed 730 hours per month provides the customer with a fairly stable and predictable electric bill every month and every year which may be useful for their budgeting purposes.

CA-IR-379

Ref: HECO response to CA-IR-224, page 2.

Please explain the methodology employed and calculations used to determine the values in the "Variable O&M $/MWH" column. Provide copies of all studies and other documentation associated with your response.

HECO Response:

The "Variable O&M $/MWH" for the HECO units is based upon HECO's avoided consumable costs submitted in Docket 7310, Avoided Cost Docket and have been escalated to 2004 dollars. These rates for the HECO units can be found in HECO's "Stipulation to Resolve Proceeding" filed on March 4, 1994 with the PUC, the avoided O&M methodology was described in pages 9-10 and shown in Exhibit J for HECO pages 1-7.

The "Variable O&M $/MWH" for HPOWER is based upon the historical 2001 actual HPOWER cost ($24,678,419.65) and energy (282,002 MWH) to derive the cost per MWH that has been escalated to 2004 dollars.

The escalation factors are based upon the GDPIPD forecast from the US DOE "annual Energy Outlook 2002," Table A20. The URL is as follows:

http://www.eia.doe.gov/oiaf/archive/aeo02/pdf/0383(2002).pdf

CA-IR-380

Ref: HECO response to CA-IR-220.

Please provide the following information regarding the classification of non-fuel production O&M costs:

a. Explain the basis for HECO's "demand-related" classification of all such costs (part a), given the admission in part f that, "the Company has not made a determination of the percentage of recorded expenses in each NARUC Production O&M expense account other than fuel that is variable in relation to kWh generation, as opposed to being fixed cost…."

b. Explain whether the Company views such a "determination" to be reasonable, in order to facilitate a more accurate classification of non-fuel production O&M expenses.

c. Identify and provide copies of any authority relied upon by HECO for its "demand-related" classification of these costs in the absence of any study or other "determination" of cost causation.

HECO Response:

a. The Company's embedded cost of service study classifies costs that are related to energy usage or costs that vary with kWh, as energy-related costs. These include all fuel costs such as the fuel expense and purchased energy cost included in the test-year production o&m costs as energy-related. These energy-related costs have been identified and estimated for the test-year 2005. If there are other production o&m other than fuel and the purchased energy costs, identified as related to energy usage, these costs will also be classified as energy-related costs in the Company's cost of service study.

b. Such determination of production costs other than fuel [illegible]

method used in prior rate cases and approved by the Commission.

CA-IR-381

Ref: HECO-2103 and HECO-WP-1702 regarding the Interest Deduction for Income Tax Calculation.

a. Please confirm, or explain and quantify to the contrary if applicable, that there are no planned long-term debt issuances projected for calendar year 2005.

b. Please confirm, or explain and quantify to the contrary, if applicable, that there were no additional long-term debt issuances during calendar year 2004 that were not forecasted or predicted when developing the "Net Proceeds" amount shown on HECO-2103.

c. Please confirm, or explain and illustrate to the contrary as applicable, that the "Annual Amortization" amount (consisting of Issuance and Redemption Costs, Investment Income Differential and Discount) shown in Column (D) on HECO 2103, are not reflected or considered in any amount or to any degree within the simplified top down federal and state cost of service income tax calculation developed on HECO-1702.

d. If not confirmed, please state and show specifically where such amortization amount has been considered in the development of federal/state cost-of-service taxable income.

e. With regard to each subcomponent of the "Annual Amortization" amount shown within Column (D) of HECO 2103 (i.e., Issuance and Redemption Costs, Investment Income Differential and Discount), please state when such amount is deductible for purposes of developing federal and state taxable income. To the extent any component is never deductible, please specifically and identify each appropriate amortization component as a permanent book/tax difference.

f. Assuming 1) that it is confirmed in part (c) to this request that the Annual Amortization shown within Column (D) of HECO 2103 is not considered in the development of cost of service federal/state taxable income, and 2) that is confirmed in part (e) to this request

4.8% Refunding Series 2005A revenue bonds. The possibility of refunding the Series 1995A revenue bonds was mentioned on page 32 of T-21.

b. There were no additional long-term debt issuances during the calendar year 2004 that were not forecasted or predicted when developing the "Net Proceeds" amount shown in HECO-2103.

c. The annual amortization is not included in the simplified top down federal and state cost of service income tax calculation. The amortization should have been included as part of the interest expense deduction in the federal and state cost of service income tax calculation. We will adjust this in our rebuttal testimony.

d. See c. above.

e. For tax purposes, issuance costs are amortized over the life of the bond. If a bond is redeemed early, the remaining unamortized issuance costs are deducted in the year of early redemption. Redemption costs are deducted in the year of redemption.

The investment differential is the difference between the actual earnings and the interest costs attributable to the undrawn proceeds in the construction fund. The actual earnings and the interest cost of the undrawn proceeds are included in taxable income as earned or incurred. The issuance discount is amortized over the life of the bond.

f. We will include the annual amortization in our cost-of-service federal and state income tax calculation in rebuttal.

CA-IR-382

Ref: Response to CA-IR-91 providing *permanent* book/tax differences for calendar year 2004.

Please provide the following regarding the permanent book/tax difference entitled "Keyman Insurance:"

a. A complete descriptive explanation of this insurance, including purpose, insurable interest (if applicable), beneficiaries, and initial date of purchase.

b. A complete description of the income statement and balance sheet impact of such transaction (i.e., NARUC income statement accounts charged/credited and any balance sheet accounting related to this program).

c. A description of the cost incurrence by, or assignment/allocation of costs between, parent/subsidiaries/affiliates.

d. Comparable 2005 estimate of such permanent difference by parent and subsidiaries. If no difference is forecasted for 2005, please explain why not.

e. Total HECO above-the-line cost of service impact of this transaction in the 2005 test year, if applicable. If there is no impact please explain how this can occur.

HECO Response:

a. There are two separate life insurance permanent differences. First, American Savings Bank invested in a bank-owned life insurance policy, covering a large group of officers above a certain level. They are not participants in HEI's executive life deferred compensation plan. Second, keyman insurance was purchased to fund HECO's Executive Life Deferred Compensation Plan. Keyman insurance policies generally cover manager level positions and above, and the Company is the beneficiary of these policies. Policies have been purchased at various times since the inception of the plan in 1986. Note that the permanent difference is made to eliminate the income or expense associated with the insurance policies.

b. The journal entries for keyman insurance are:

Debit: Executive Life Insurance Expense (#92600000)

Credit: Prepaid Keyman Insurance (#16608000)

To accrue executive life insurance premiums.

Debit: Prepaid Keyman Insurance (#16608000)

Credit: Cash

To record the payment of executive life insurance premiums.

Debit: Cash Surrender Value – Executive life insurance (#18605000)

Credit: Executive Life Insurance Expense (#92600000)

To record the increase in cash surrender value.

c. Income and expenses are broken down by individual covered employees and allocated specifically to the company by which the covered individual is employed.

d. The 2005 estimate of the permanent difference for HEI and its subsidiaries is an additional deduction of $4,276,148. The decrease is due primarily to ASB's bank-owned life insurance, which is totally unrelated to utility operations.

e. The cost of this deferred compensation plan was never included in cost of service for ratemaking purposes. See HECO T-15, Page 11 of 39.

CA-IR-383

Ref: Response to CA-IR-91 providing *permanent* book/tax differences for calendar year 2004.

Please provide the following regarding the permanent book/tax difference entitled "Flex Dividend Deduction:"

a. A complete descriptive explanation of this permanent difference.

b. A complete description of the income statement and balance sheet impact of such transaction (i.e., NARUC income statement accounts charged/credited and any balance sheet accounting related to this program).

c. Describe why this is considered an "HEI" or "non-utility" transaction.

d. Comparable 2005 estimate of such permanent difference. If no difference is forecasted for 2005, please explain why not.

e. Total HECO above-the-line cost of service impact of this transaction in the 2005 test year, if applicable, or alternatively, confirmation that there is no above-the-line cost of service impact from this transaction included within the 2005 test year.

HECO Response:

a. Flex dividend deduction refers to the deduction HEI is entitled to under IRC §404(k)(2) for

HEI common stock dividends paid to the 401k plan for HEI [illegible]

CA-IR-384

Ref: Response to CA-IR-91 providing *permanent* book/tax differences for calendar year 2004.

Please provide the following regarding the permanent book/tax difference entitled "Nonqualifed Stock Option Exercise:"

a. A complete descriptive explanation of this permanent difference.

b. A complete description of the income statement and balance sheet impact of such transaction (i.e., NARUC income statement accounts charged/credited and any balance sheet accounting related to this program).

c. Describe why this is considered an "HEI" or "non-utility" transaction.

d. Comparable 2005 estimate of such permanent difference. If no difference is forecasted for 2005, please explain why not.

e. Total HECO above-the-line cost of service impact of this transaction in the 2005 test year, if applicable, or alternatively, confirmation that there is no above-the-line cost of service impact from this transaction included within the 2005 test year.

HECO Response:

a. HEI and its subsidiaries have a shareholder-approved stock option and incentive plan to provide a means to attract and retain high caliber personnel and to provide participating employees long-term incentives for sustained high levels of performance. HECO recognizes

when the options are exercised.

b. For book purposes, HECO records stock option expense as a deferred charge via HEI intercompany billings and amortizes this cost into income over the 4 year vesting period.

When the executive exercises the options, HEI recognizes the additional stock option deduction as a permanent difference related to the stock option value received.

c. This permanent difference is treated as an HEI deduction because the difference between the book expense and the value of the stock options realized is not paid by HECO.

d. We do not forecast this item, as it is difficult to predict when the executives will exercise their options and at what price.

e. None, it is not included in HECO's cost of service.

CA-IR-385

Ref: Response to CA-IR-91 providing *permanent* book/tax differences for calendar year 2004.

Please provide the following regarding the permanent book/tax difference entitled "Preferred Dividends:"

a. A complete descriptive explanation of this permanent difference.

b. A complete description of the income statement and balance sheet impact of such

accounting related to this program).

Credit: Preferred Dividends Payable (#23800000)

To accrue dividends paid.

Debit: Preferred Dividends Payable (#23800000)

Credit: Cash

To record payment of preferred dividends.

c. HEI and HEIDI receive the dividends and are entitled to take the dividends received deduction which prevents the double counting of income within the consolidated group.

d. The 2005 estimate is the same as the 2004 accrual of $5,505,000.

e. There is no above-the-line cost of service impact in the 2005 test year.

CA-IR-386

Ref: Response to CA-IR-91 providing *permanent* book/tax differences for calendar year 2004.

Please provide the following regarding the permanent book/tax difference entitled "Real Estate Partnership Leveraged Lease Book NI:"

a. A complete descriptive explanation of this permanent difference.

b. A complete description of the income statement and balance sheet impact of such transaction (i.e., NARUC income statement accounts charged/credited and any balance sheet accounts related to this transaction)

c. Describe why this is an "HEI" or "non-utility" transaction.

d. Comparable 2005 estimate of such permanent difference. If no difference is forecasted for 2005, please explain why not.

e. Total HECO above-the-line cost of service impact of this transaction in the 2005 test year, if applicable, or alternatively, confirmation that there is no above-the-line cost of service impact from this transaction included within the 2005 test year.

HECO Response:

a. HEI Investments Inc. (HEIII), an unregulated subsidiary under HEI invested in several leveraged leases. Book income is based on the projected cash flow from the lease pursuant to FAS 13, accounting for leases. This total book income is spread over the lease period, based on relative net investment in the lease for each year during the lease period. On the other hand, taxable income is determined as if the asset is owned and leased, recognizing rental income accrued for the year and depreciating the asset under the tax guidelines.

is treated as a temporary difference.

c. See explanation in a. HEIII, a non utility company, invests in the leveraged leases outside of Hawaii. The income and expense are totally unrelated to utility operations.

d. Not applicable as this amount is not included in above-the-line cost of service.

e. None.

CA-IR-387

Ref: Response to CA-IR-91 providing *permanent* book/tax differences for calendar year 2004.

Please provide the following regarding the permanent book/tax difference entitled "Franchise Tax Payment:"

a. A complete descriptive explanation of this permanent difference.

b. A complete description of the income statement and balance sheet impact of such transaction (i.e., NARUC income statement accounts charged/credited and any balance sheet accounting related to this program).

c. Describe why this is an "HEI" or "non-utility" transaction.

d. Comparable 2005 estimate of such permanent difference. If no difference is forecasted for 2005, please explain why not.

e. Total HECO above-the-line cost of service impact of this transaction in the 2005 test year, if applicable, or alternatively, confirmation that there is no above-the-line cost of service impact from this transaction included within the 2005 test year.

HECO Response:

a. HEI Diversified Inc. (HEIDI) and its subsidiary, American Savings Bank (ASB) are subject to Hawaii franchise tax, which is unrelated to HECO and any electric utility activities. The franchise tax is the net income tax imposed on financial institutions in Hawaii. The amount deducted as a permanent difference in the 2004 tax calculation relates to additional taxes paid in conjunction with a settlement agreement with the State of Hawaii.

b. Not applicable as it does not relate to HECO.

c. See response to part a. above.

d. Not applicable as it does not relate to HECO.

e. None.

CA-IR-388

Ref: Response to CA-IR-91 providing *permanent* book/tax differences for calendar year 2004.

Please provide the following regarding the *federal* permanent book/tax difference entitled "Research Tax Credit - 2003:"

a. A complete descriptive explanation of this permanent difference.

b. A complete description of the income statement and balance sheet impact of such transaction (i.e., NARUC income statement accounts charged/credited and any balance sheet accounting related to this program).

c. Comparable 2005 estimate of such permanent difference. If no difference is forecasted for 2005, please explain why not.

d. Total HECO above-the-line cost of service impact of this transaction in the 2005 test year, if applicable, or alternatively, confirmation that there is no above-the-line cost of service impact from this transaction included within the 2005 test year.

HECO Response:

a. Hawaii Revised Statutes §235-110.91 allows a tax credit for research activities. The 2003 research tax credit was calculated after the 2003 federal tax return was filed, but before the 2003 Hawaii tax return was filed. Thus, the 2003 research credit was included only in the 2003 Hawaii tax return and was not accounted for in the [illegible]

included in the 2005 test year estimate.

CA-IR-389

Ref: HECO-WP-1705 (Federal and State Accumulated Deferred Income Tax Schedule).

Please update HECO-WP-1705a and HECO-WP-1705b for *actual* 2004-ending federal and state accumulated deferred income tax balances and most-recently-revised end-of-2005 estimated federal and state accumulated deferred income tax balances.

HECO Response:

The requested information is attached on pages 2 to 13 to this response. The plant deferred taxes (account 282) for 2004 increased because book depreciation rates changed in September 2004. This was approved by the Commission in HECO's latest depreciation study Decision and Order ("D&O") No. 21331 (September 4, 2004) in Docket No. 02-0391.

Hawaiian Electric Company, Inc.
Deferred Income Taxes
FEDERAL

LIAB (DR)CR		Actual 12-31-00	Actual 2001	Actual 12-31-01	Actual 2002	Actual 12-31-02	Actual 2003
28310	State ITC	(6,377,132.54)	(503,722.00)	(6,880,854.54)	(348,009.64)	(7,228,864.18)	(147,639.77)
28311	Unearned Lease	(112,548.20)	2,225.00	(110,323.20)	2,225.49	(108,097.71)	2,264.82
28312	Accrued Vacation	989,672.21	(53,367.00)	936,305.21	(7,279.70)	929,025.51	166,488.02
28313	Uncollectible Acct	(569,244.87)	6,790.00	(562,454.87)	24,796.08	(537,658.79)	(40,999.86)
28314	Directors Def Comp	(24,302.85)	11,021.00	(13,281.85)	1,307.70	(11,974.15)	9,721.00
28315	Computer Conv	8,721.00	0.00	8,721.00	0.00	8,721.00	0.00
28317	Discounted Work Comp	(1,141,636.73)	103,915.00	(1,037,721.73)	113,527.63	(924,194.10)	188,991.78
28319	Cap to Construction	22,081,853.51	589,764.20	22,671,617.71	1,315,665.17	23,987,282.88	1,752,698.12
28320	Gain HIRI Sub/misc	(161.00)	0.00	(161.00)	0.00	(161.00)	0.00
28321	Excess Pension	5,019,089.11	6,731,946.00	11,751,035.11	5,149,814.47	16,900,849.58	1,208,791.34
28322	Sec 189 Interest	(3,388.68)	0.00	(3,388.68)	0.00	(3,388.68)	0.00
28323	Excess Benefit Plan	(42,585.00)	41,860.00	(725.00)	29,363.12	28,638.12	4,411.51
28324	Nonop Deferred Gain	1,475.68	0.00	1,475.68	0.00	1,475.68	0.00
28326	Def Exec Comp	(143,960.86)	0.00	(143,960.86)	0.00	(143,960.86)	0.00
28327	Software	(306,904.59)	130,408.11	(176,496.48)	27,691.81	(148,804.67)	(93,906.99)
28328	G/L ACRS Retirements	4,324,390.89	50,754.42	4,375,145.31	514,708.40	4,889,853.71	1,255,645.16
28329	Series U Exp (Bonds)	311,323.79	(46,568.00)	264,755.79	(46,568.05)	218,187.74	(46,568.05)
28330	EICP	(521,691.25)	114,393.00	(407,298.25)	47,886.84	(359,411.41)	20,450.38
28331	CIAC	(18,028,820.17)	1,452,260.07	(16,576,560.10)	1,080,056.06	(15,496,504.04)	1,582,917.43
28332	Customer Advances	(344,078.29)	(38,494.00)	(382,572.29)	142,151.00	(240,421.29)	(44,360.53)
28333	Capitalized Interest	(13,267,923.40)	(435,214.07)	(13,703,137.47)	(406,755.67)	(14,109,893.14)	62,838.88
28335	Connection Fees	10,365.27	(1,940.00)	8,425.27	0.00	8,425.27	0.00
28336	Nondeductible Interest	13,237.68	0.00	13,237.68	0.00	13,237.68	(117,047.47)
28337	Supplemt Benefits	(52,021.00)	(22,123.00)	(74,144.00)	(25,194.08)	(99,338.08)	(55,148.03)
28338	Nondeductible Vac	(1,059,752.00)	0.00	(1,059,752.00)	0.00	(1,059,752.00)	0.00
28339	System Devel Cost	178,118.00	0.00	178,118.00	0.00	178,118.00	0.00
28340	LTIP	40,914.42	29,632.00	70,546.42	36,685.89	107,232.31	35,397.54
28341	Waipahu Baseyard Int	(108,655.95)	0.00	(108,655.95)	0.00	(108,655.95)	0.00
28342	1990 Rate Case Exp	(96.00)	0.00	(96.00)	0.00	(96.00)	0.00
28345	Ross Cap/Legal Fees	(1,021.00)	0.00	(1,021.00)	0.00	(1,021.00)	0.00
28346	Ser V Redmp Premium	66,292.70	(20,384.00)	45,908.70	(20,384.21)	25,524.49	(20,384.21)
28347	Waiau Water Well Pmts	(504,255.13)	21,243.00	(483,012.13)	21,242.72	(461,769.41)	28,028.72
28348	Nonutil Bad Debt	329,141.43	0.00	329,141.43	0.00	329,141.43	0.00
28349	Cap Corp Logo	163.24	0.00	163.24	0.00	163.24	0.00
28350	Loss Adj Exp	79,260.02	8,081.00	87,341.02	0.00	87,341.02	141,400.00
28400	92 Rate Case	1,357.45	0.00	1,357.45	0.00	1,357.45	0.00
28401	Genl/Auto (& Accidents)	(51,456.72)	(60,132.00)	(111,588.72)	(176,381.58)	(287,970.30)	47,697.37
28402	Ser Q Redmp Premium	(31,502.56)	0.00	(31,502.56)	0.00	(31,502.56)	0.00
28403	CWIP Debt Transition	612,502.80	(20,891.70)	591,611.10	(20,888.47)	570,722.63	(20,889.47)
28404	CWIP Equity Trans	1,937,655.66	(68,627.03)	1,869,028.63	(74,698.30)	1,794,330.33	(76,252.30)
28405	Iolani Ct Plaza Sale	26,568.60	26,403.00	52,971.60	27,037.36	80,008.96	(21,309.79)
28406	Kaonohi Sale	37,751.68	0.00	37,751.68	0.00	37,751.68	0.00
28407	FAS 109 Flow Through	4,137,893.00	(275,856.56)	3,862,036.44	(275,858.23)	3,586,178.21	(275,858.23)
28408	Plant Transition	21,630,427.00	(864,825.85)	20,765,601.15	(864,810.41)	19,899,781.74	(864,810.41)

Hawaiian Electric Company, Inc.
Deferred Income Taxes
FEDERAL

LIAB (DR)CR		Actual 12-31-00	Actual 2001	Actual 12-31-01	Actual 2002	Actual 12-31-02	Actual 2003
28428	94 Rate Case Costs	(238.95)	0.00	(238.95)	0.00	(238.95)	0.00
28429	95 Rate Case Costs	(0.46)	0.00	(0.46)	0.00	(0.46)	0.00
28430	FMB X Premium	481,153.86	(21,919.00)	459,234.86	(21,918.75)	437,316.11	(21,918.75)
28431	EV Demo Costs	0.00	0.00	0.00	0.00	0.00	0.00
28432	Coal Gasif Costs	(61,649.00)	0.00	(61,649.00)	0.00	(61,649.00)	65,594.00
28433	Def PTI Costs	(126,806.78)	0.00	(126,806.78)	0.00	(126,806.78)	0.00
28434	EEO Claims	(113,155.19)	(38,765.00)	(151,920.19)	133,616.37	(18,303.82)	4,741.27
28435	Differential	977,776.42	76,540.00	1,054,316.42	87,878.57	1,142,194.99	126,616.86
28436	TIP	(17,701.56)	(231,548.00)	(249,249.56)	277,862.79	28,613.23	8,678.94
28437	HACOA	(9,502.00)	0.00	(9,502.00)	0.00	(9,502.00)	8,764.00
28438	BONY Rev	(2,594.00)	0.00	(2,594.00)	0.00	(2,594.00)	1,247.00
28439	GAQS Tel	(1,452.00)	0.00	(1,452.00)	0.00	(1,452.00)	1,451.00
28440	Kalaeloa	(377,798.00)	0.00	(377,798.00)	0.00	(377,798.00)	72,982.00
28441	Sun Power	(9,019.91)	0.00	(9,019.91)	0.00	(9,019.91)	0.00
28442	Overhaul	(198,935.00)	0.00	(198,935.00)	0.00	(198,935.00)	0.00
28443	EV Tax Credit	131.00	(132.00)	(1.00)	0.00	(1.00)	0.00
28444	FMB S Premium	10,190.04	(9,487.00)	703.04	(8,696.57)	(7,993.53)	0.00
28445	HMSA Reserve	0.23	0.00	0.23	0.00	0.23	0.00
28500	Sec. 481(a) Adjustment	861,336.00	430,668.00	1,292,004.00	0.00	1,292,004.00	0.00
28502	Sec. 481(a) Adjustment - Depr	0.00	0.00	0.00	0.00	0.00	0.00
28504	Barbers Point	93,843.00	(95,528.00)	(1,685.00)	59,580.92	57,895.92	46,862.50
28506	Substation land - Makiki	(135,348.00)	34,623.00	(100,725.00)	37,771.34	(62,953.66)	37,771.34
28508	Substation land - Wilder	(31,351.00)	8,689.00	(22,662.00)	8,898.46	(13,763.54)	8,898.01
28510	Substation land - Lilipuna	(29,037.00)	6,832.00	(22,205.00)	6,832.11	(15,372.89)	6,832.11
28512	Revenue Bond Cost Amort	276,493.00	651,776.00	928,269.00	(96,384.11)	831,884.89	337,556.54
28514	APPRISE Software		449,084.53	449,084.53	976,304.09	1,425,388.62	(1,548,725.10)
28516	Honolulu Harbor Reserve		(360,855.00)	(360,855.00)	80,808.71	(280,046.29)	(33,652.95)
28518	D&T Fee Accrual		0.00	0.00	(54,551.00)	(54,551.00)	(27,189.14)
28520	Deferred Comp - restricted stock		0.00	0.00	(3,173.00)	(3,173.00)	25,818.42
28522	Knapp lawsuit			0.00	0.00	0.00	(15,575.66)
28524	Software (E-business only)			0.00	0.00	0.00	0.00
28526	Emissions Fees			0.00	0.00	0.00	0.00
28528	Substation land - Kuliouou			0.00	0.00	0.00	0.00
28530	AES Hawaii PPA			0.00	0.00	0.00	0.00
28532	CIS Project Costs			0.00	0.00	0.00	0.00
28534	Substation land - Queen Emma			0.00	0.00	0.00	0.00
	OCI - NQ Pension			0.00	(46,524.34)	(46,524.34)	(50,164.00)
	Insurance Reserve *	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCOUNT 283.01	37,260,922.49	9,596,795.44	46,857,717.93	9,479,253.44	56,336,971.37	6,235,878.13
	ACCOUNT 282 DEPR	60,923,786.70	(4,221,116.36)	56,702,670.34	(1,440,941.76)	55,261,728.58	(697,562.06)
	TOTAL FEDERAL DEFERRED BALANCE (before rate year adjustments)	98,184,709.19	5,375,679.08	103,560,388.27	8,038,311.68	111,598,699.95	5,538,316.07

Hawaiian Electric Company, Inc.
Deferred Income Taxes
FEDERAL

LIAB (DR)CR		Actual 12-31-00	Actual 2001	Actual 12-31-01	Actual 2002	Actual 12-31-02	Actual 2003
28326	Def Exec Comp (Def LTIP)	(143,960.86)	0.00	(143,960.86)	0.00	(143,960.86)	0.00
28330	EICP	(521,691.25)	114,393.00	(407,298.25)	47,886.84	(359,411.41)	20,450.38
28336	Nondeductible Interest	13,237.68	0.00	13,237.68	0.00	13,237.68	(117,047.47)
28337	Supplemental Benefits -SERP	(52,021.00)	(22,123.00)	(74,144.00)	(25,194.08)	(99,338.08)	(55,148.03)
28338	Nondeductible Vacation	(1,059,752.00)	0.00	(1,059,752.00)	0.00	(1,059,752.00)	0.00
28340	LTIP	40,914.42	29,632.00	70,546.42	36,685.89	107,232.31	35,397.54
28341	Waipahu Baseyard Int	(108,655.95)	0.00	(108,655.95)	0.00	(108,655.95)	0.00
28342	1990 Rate Case Exp	(96.00)	0.00	(96.00)	0.00	(96.00)	0.00
28345	Ross Cap Legal Fees	(1,021.00)	0.00	(1,021.00)	0.00	(1,021.00)	0.00
28348	Nonutil Bad Debt	329,141.43	0.00	329,141.43	0.00	329,141.43	0.00
28349	Cap Corp Logo	163.24	0.00	163.24	0.00	163.24	0.00
28350	Outage Loss Adj Exp	79,260.02	8,081.00	87,341.02	0.00	87,341.02	141,400.00
28400	92 Rate Case	1,357.45	0.00	1,357.45	0.00	1,357.45	0.00
28401	Genl/Auto (&Accidents)	(51,456.72)	(60,132.00)	(111,588.72)	(176,381.58)	(287,970.30)	47,697.37
28412	Genl/Auto Legal	(23,790.62)	(31,402.00)	(55,192.62)	(32,467.11)	(87,659.73)	37,236.84
28436	TIP	(17,701.56)	(231,548.00)	(249,249.56)	277,862.79	28,613.23	8,678.94
28520	Deferred Comp - restricted sto	0.00	0.00	0.00	(3,173.00)	(3,173.00)	25,818.42
	OCI - NQ Pension	0.00	0.00	0.00	(46,524.34)	(46,524.34)	(50,164.00)
	AFUDC in CWIP	4,438,732.80	(227,128.04)	4,211,604.76	48,845.71	4,260,450.47	701,863.28
	TCI in CWIP	(2,866,352.04)	(258,030.31)	(3,124,382.35)	(386,737.86)	(3,511,120.21)	(523,064.31)
	"OTHER ITEMS" FED DEFD TAX LIABILITY	44,359,808.55	10,668,555.79	55,028,364.34	9,924,744.99	64,953,109.33	5,781,786.40

ACCOUNT 282.02 DEPR	13,398,255.73	(4,221,116.36)	56,702,670.34	(1,440,941.76)	55,261,728.58	(697,562.06)
Less: Nonutil Act 28210	0.00	0.00	0.00	0.00	0.00	0.00
DEFD TAX LIABILITY ACCELERATED DEPR	13,398,255.73	(4,221,116.36)	56,702,670.34	(1,440,941.76)	55,261,728.58	(697,562.06)

Hawaiian Electric Company, Inc.
Deferred Income Taxes
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LIAB (DR)CR		Actual 12-31-03	Actual 2004	Actual 12-31-04	Estimate 2005	Estimate 12-31-05
28310	State ITC	(7,376,503.95)	(826,950.68)	(8,203,454.63)	(641,490.13)	(8,844,944.76)
28311	Unearned Lease	(105,832.89)	99,030.07	(6,802.82)	1,226.57	(5,576.25)
28312	Accrued Vacation	1,095,513.53	(2,081.21)	1,093,432.32	0.00	1,093,432.32
28313	Uncollectible Acct	(578,658.65)	377,856.49	(200,802.16)	0.00	(200,802.16)
28314	Directors Def Comp	(2,253.15)	14,851.30	12,598.15	(3,618.42)	8,979.73
28315	Computer Conv	8,721.00	(8,721.00)	0.00	0.00	0.00
28317	Discounted Work Comp	(735,202.32)	(44,878.66)	(780,080.98)	0.00	(780,080.98)
28319	Cap to Construction	25,739,981.00	86,243.05	25,826,224.05	1,615,484.87	27,441,708.92
28320	Gain HIRI Sub/misc	(161.00)	161.00	0.00	0.00	0.00
28321	Excess Pension	18,109,640.92	6,721,377.32	24,831,018.24	0.00	24,831,018.24
28322	Sec 189 Interest	(3,388.68)	3,388.68	0.00	0.00	0.00
28323	Excess Benefit Plan	33,049.63	(63,371.64)	(30,322.01)	0.00	(30,322.01)
28324	Nonop Deferred Gain	1,475.68	43.53	1,519.21	0.00	1,519.21
28326	Def Exec Comp	(143,960.86)	87,445.84	(56,515.02)	0.00	(56,515.02)
28327	Software	(242,711.66)	305,484.01	62,772.35	46,767.90	109,540.25
28328	G/L ACRS Retirements	6,145,498.87	(212,265.74)	5,933,233.13	0.00	5,933,233.13
28329	Series U Exp (Bonds)	171,619.69	(170,731.48)	888.21	0.00	888.21
28330	EICP	(338,961.03)	344,677.48	5,716.45	(4,116.12)	1,600.33
28331	CIAC	(13,913,586.61)	1,102,021.10	(12,811,565.51)	883,949.39	(11,927,616.12)
28332	Customer Advances	(284,781.82)	(13,510.68)	(298,292.50)	0.00	(298,292.50)
28333	Capitalized Interest	(14,047,054.26)	(2,027,539.49)	(16,074,593.75)	(1,057,157.46)	(17,131,751.21)
28335	Connection Fees	8,425.27	7,594.58	16,019.85	0.00	16,019.85
28336	Nondeductible Interest	(103,809.79)	(80,729.49)	(184,539.28)	0.00	(184,539.28)
28337	Supplemt Benefits	(154,486.11)	(79,748.16)	(234,234.27)	0.00	(234,234.27)
28338	Nondeductible Vac	(1,059,752.00)	(24,444.31)	(1,084,196.31)	0.00	(1,084,196.31)
28339	System Devel Cost	178,118.00	(178,118.00)	0.00	0.00	0.00
28340	LTIP	142,629.85	(267,156.03)	(124,526.18)	0.00	(124,526.18)
28341	Waipahu Baseyard Int	(108,655.95)	(3,205.60)	(111,861.55)	0.00	(111,861.55)
28342	1990 Rate Case Exp	(96.00)	96.00	0.00	0.00	0.00
28345	Ross Cap Legal Fees	(1,021.00)	1,021.00	0.00	0.00	0.00
28346	Ser V Redmp Premium	5,140.28	6,744.91	11,885.19	(11,890.79)	(5.60)
28347	Waiau Water Well Prmts	(433,740.69)	4,607.93	(429,132.76)	21,242.72	(407,890.04)
28348	Nonutil Bad Debt	329,141.43	(321,094.14)	8,047.29	0.00	8,047.29
28349	Cap Corp Logo	163.24	72.14	235.38	0.00	235.38
28350	Loss Adj Exp	228,741.02	(228,741.02)	0.00	0.00	0.00
28400	92 Rate Case	1,357.45	(1,357.45)	0.00	0.00	0.00
28401	Genl/Auto (& Accidents)	(240,272.93)	(312,029.12)	(552,302.05)	0.00	(552,302.05)
28402	Ser Q Redmp Premium	(31,502.56)	31,502.56	0.00	0.00	0.00
28403	CWIP Debt Transition	549,833.16	(20,889.47)	528,943.69	(20,889.47)	508,054.22
28404	CWIP Equity Trans	1,718,078.03	(76,248.30)	1,641,829.73	(76,252.30)	1,565,577.43
28405	Iolani Ct Plaza Sale	58,699.17	(154,321.43)	(95,622.26)	10,612.07	(85,010.19)
28406	Kaonohi Sale	37,751.68	0.00	37,751.68	0.00	37,751.68
28407	FAS 109 Flow Through	3,310,319.98	(275,858.23)	3,034,461.75	(275,858.23)	2,758,603.52
28408	Plant Transition	19,025,962.33	(864,819.41)	18,161,142.92	(864,819.41)	17,296,323.51
28409	CWIP Equity Net	13,430,891.31	1,321,410.90	14,752,302.21	1,399,595.39	16,151,897.60
28410	CWIP Equity Grossup	8,550,876.72	841,638.41	9,392,515.13	891,434.52	10,283,949.65
28411	CWIP Debt	6,929,067.80	574,622.37	7,503,690.17	639,114.80	8,142,804.97
28412	Genl/Auto Liability - Legal	(50,422.89)	(21,254.69)	(71,677.58)	0.00	(71,677.58)
28413	Post Retirement Ben	(972,735.36)	(521,071.49)	(1,493,806.85)	0.00	(1,493,806.85)
28414	Reg Liab Federal ITC	(3,558,384.62)	525,807.21	(3,032,577.41)	512,665.09	(2,519,912.32)
28417	Series R &T Exp (Bonds)	(38,869.03)	38,869.03	0.00	0.00	0.00
28418	IRP & DSM Costs	397,292.34	(187,628.16)	209,664.18	0.00	209,664.18
28419	Reg Liab Excess 283	(503,292.75)	18,947.37	(484,345.38)	18,947.37	(465,398.01)
28420	Reg Liab Deficit 283	(24,116.52)	12,730.26	(11,386.26)	12,730.26	1,344.00
28421	UFAMS Costs	(3,440.86)	3,440.86	0.00	0.00	0.00
28422	Miscellaneous	(2,196,985.59)	2,168,473.99	(28,511.60)	0.00	(28,511.60)
28424	Access Costs	(12,289.94)	12,289.94	0.00	0.00	0.00

Hawaiian Electric Company, Inc.
Deferred Income Taxes
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LIAB (DR)CR		Actual 12-31-03	Actual 2004	Actual 12-31-04	Estimate 2005	Estimate 12-31-05
28428	94 Rate Case Costs	(238.95)	238.95	0.00	0.00	0.00
28429	95 Rate Case Costs	(0.46)	0.46	0.00	0.00	0.00
28430	FMB X Premium	415,397.36	(154,201.75)	261,195.61	(21,918.75)	239,276.86
28431	EV Demo Costs	0.00	0.00	0.00	0.00	0.00
28432	Coal Gasif Costs	3,945.00	(3,945.00)	0.00	0.00	0.00
28433	Def PTI Costs	(126,806.78)	126,806.78	0.00	0.00	0.00
28434	EEO Claims	(13,562.55)	(51,577.02)	(65,139.57)	(48,519.74)	(113,659.31)
28435	Differential	1,268,811.85	(332,442.86)	936,368.99	(43,676.59)	892,692.40
28436	TIP	37,292.17	(207,771.16)	(170,478.99)	0.00	(170,478.99)
28437	HACOA	(738.00)	(2,193.00)	(2,931.00)	0.00	(2,931.00)
28438	BONY Rev	(1,347.00)	(3,428.00)	(4,775.00)	0.00	(4,775.00)
28439	GAQS Tel	(1.00)	1.00	0.00	0.00	0.00
28440	Kalaeloa	(304,816.00)	(19,349.00)	(324,165.00)	0.00	(324,165.00)
28441	Sun Power	(9,019.91)	9,597.00	577.09	0.00	577.09
28442	Overhaul	(198,935.00)	0.00	(198,935.00)	0.00	(198,935.00)
28443	EV Tax Credit	(1.00)	1.00	0.00	0.00	0.00
28444	FMB S Premium	(7,993.53)	7,993.53	0.00	0.00	0.00
28445	HMSA Reserve	0.23	(0.23)	0.00	0.00	0.00
28500	Sec. 481(a) Adjustment	1,292,004.00	(1,292,004.00)	0.00	0.00	0.00
28502	Sec. 481(a) Adjustment - Depr	0.00	0.00	0.00	0.00	0.00
28504	Barbers Point	104,758.42	(128,877.36)	(24,118.94)	113,611.84	89,492.90
28506	Substation land - Makiki	(25,182.32)	25,182.32	0.00	0.00	0.00
28508	Substation land - Wilder	(4,865.53)	4,865.53	0.00	0.00	0.00
28510	Substation land - Lilipuna	(8,540.78)	6,832.11	(1,708.67)	1,708.03	(0.64)
28512	Revenue Bond Cost Amort	1,169,441.43	(119,324.38)	1,050,117.05	(119,324.71)	930,792.34
28514	APPRISE Software	(123,336.48)	123,336.48	0.00	0.00	0.00
28516	Honolulu Harbor Reserve	(313,699.24)	25,949.00	(287,750.24)	0.00	(287,750.24)
28518	D&T Fee Accrual	(81,740.14)	81,740.46	0.32	0.00	0.32
28520	Deferred Comp - restricted sto	22,645.42	(11,806.58)	10,838.84	(11,172.04)	(333.20)
28522	Knapp lawsuit	(15,575.66)	2,418.06	(13,157.60)	(103.95)	(13,261.55)
28524	Software (E-business only)	0.00	46,173.65	46,173.65	(13,644.23)	32,529.42
28526	Emissions Fees	0.00	(285,315.17)	(285,315.17)	0.00	(285,315.17)
28528	Substation land - Kuliouou	0.00	(59,777.31)	(59,777.31)	13,042.32	(46,734.99)
28530	AES Hawaii PPA	0.00	(50,866.72)	(50,866.72)	0.00	(50,866.72)
28532	CIS Project Costs	0.00	(103,162.49)	(103,162.49)	0.00	(103,162.49)
28534	Substation land - Queen Emma	0.00	0.00	0.00	(375,570.40)	(375,570.40)
	OCI - NQ Pension	(96,688.34)	(51,627.00)	(148,315.34)	0.00	(148,315.34)
	Insurance Reserve *	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCOUNT 283.01	62,572,849.50	5,237,139.51	67,809,989.01	2,592,110.40	70,402,099.41
	ACCOUNT 282 DEPR	54,564,166.52	5,001,295.59	59,565,462.11	(4,599,705.02)	54,965,757.09
	TOTAL FEDERAL DEFERRED BALANCE (before rate case adjustments)	117,137,016.02	10,238,435.10	127,375,451.12	(2,007,594.62)	125,367,856.50
	TOTAL ACCOUNT 283.01	62,572,849.50	5,237,139.51	67,809,989.01	2,592,110.40	70,402,099.41
	Less Rate Case Adjustments *1					
28310	State ITC	(7,376,503.95)	(826,950.68)	(8,203,454.63)	(641,490.13)	(8,844,944.76)
28312	Accrued Vacation	1,095,513.53	(2,081.21)	1,093,432.32	0.00	1,093,432.32
28313	Uncollectible Account	(578,658.65)	377,856.49	(200,802.16)	0.00	(200,802.16)
28314	Directors Def Comp	(2,253.15)	14,851.30	12,598.15	(3,618.42)	8,979.73
28315	Computer Conversion Costs	8,721.00	(8,721.00)	0.00	0.00	0.00
28317	Discounted Work Comp	(735,202.32)	(44,878.66)	(780,080.98)	0.00	(780,080.98)
28320	Gain HIRI Sub/misc	(161.00)	161.00	0.00	0.00	0.00
28323	Excess Benefit Plan	33,049.63	(63,371.64)	(30,322.01)	0.00	(30,322.01)
28324	Nonop Deferred Gain	1,475.68	43.53	1,519.21	0.00	1,519.21

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LIAB (DR)CR		Actual 12-31-03	Actual 2004	Actual 12-31-04	Estimate 2005	Estimate 12-31-05
28326	Def Exec Comp (Def LTIP)	(143,960.86)	87,445.84	(56,515.02)	0.00	(56,515.02)
28330	EICP	(338,961.03)	344,677.48	5,716.45	(4,116.12)	1,600.33
28336	Nondeductible Interest	(103,809.79)	(80,729.49)	(184,539.28)	0.00	(184,539.28)
28337	Supplemental Benefits -SERP	(154,486.11)	(79,748.16)	(234,234.27)	0.00	(234,234.27)
28338	Nondeductible Vacation	(1,059,752.00)	(24,444.31)	(1,084,196.31)	0.00	(1,084,196.31)
28340	LTIP	142,629.85	(267,156.03)	(124,526.18)	0.00	(124,526.18)
28341	Waipahu Baseyard Int	(108,655.95)	(3,205.60)	(111,861.55)	0.00	(111,861.55)
28342	1990 Rate Case Exp	(96.00)	96.00	0.00	0.00	0.00
28345	Ross Cap Legal Fees	(1,021.00)	1,021.00	0.00	0.00	0.00
28348	Nonutil Bad Debt	329,141.43	(321,094.14)	8,047.29	0.00	8,047.29
28349	Cap Corp Logo	163.24	72.14	235.38	0.00	235.38
28350	Outage Loss Adj Exp	228,741.02	(228,741.02)	0.00	0.00	0.00
28400	92 Rate Case	1,357.45	(1,357.45)	0.00	0.00	0.00
28401	Genl/Auto (&Accidents)	(240,272.93)	(312,029.12)	(552,302.05)	0.00	(552,302.05)
28412	Genl/Auto Legal	(50,422.89)	(21,254.69)	(71,677.58)	0.00	(71,677.58)
28436	TIP	37,292.17	(207,771.16)	(170,478.99)	0.00	(170,478.99)
28520	Deferred Comp - restricted sto	22,645.42	(11,806.58)	10,838.84	(11,172.04)	(333.20)
	OCI - NQ Pension	(96,688.34)	(51,627.00)	(148,315.34)	0.00	(148,315.34)
	TCI in CWIP	(4,034,184.52)	(881,047.06)	(4,915,231.58)	(700,247.23)	(5,615,478.81)
	"OTHER ITEMS" FED DEF'D TAX LIABILITY	70,734,895.82	7,357,346.29	78,092,242.11	3,771,741.06	81,863,983.17
	ACCOUNT 282.02 DEPR	54,564,166.52	5,001,295.59	59,565,462.11	(4,599,705.02)	54,965,757.09
	Less: Nonutil Act 28210	0.00	0.00	0.00	0.00	0.00

Hawaiian Electric Company, Inc.
Deferred Income Taxes
STATE

LIAB (DR)CR		Actual 12-31-00	Actual 2001	Actual 12-31-01	Actual 2002	Actual 12-31-02	Actual 2003
28310	State ITC	2,321.67	(684.00)	1,637.67	(2,616.00)	(978.33)	1,000.00
28311	Unearned Lease	(2,683.00)	407.00	(2,276.00)	406.95	(1,869.05)	414.14
28312	Accrued Vacation	186,190.70	(9,759.00)	176,431.70	(1,331.58)	175,100.12	2,216.96
28313	Uncollectible Acct	(102,375.64)	1,242.00	(101,133.64)	4,534.60	(96,599.04)	(5,052.11)
28314	Directors Def Comp	(1,811.05)	2,016.00	204.95	239.29	444.24	(667.43)
28315	Computer Conv	(25,651.00)	0.00	(25,651.00)	0.00	(25,651.00)	0.00
28317	Discounted Work Comp	(213,104.81)	19,002.00	(194,102.81)	20,759.34	(173,343.47)	34,558.50
28319	Cap to Construction	3,782,082.08	107,842.53	3,889,924.61	240,578.98	4,130,503.59	320,493.37
28320	Gain HIRI Sub/misc	(18.00)	0.00	(18.00)	0.00	(18.00)	0.00
28321	Excess Pension	928,386.10	1,230,984.00	2,159,370.10	941,680.36	3,101,050.46	221,036.45
28322	Sec 189 Interest	0.00	0.00	0.00	0.00	0.00	0.00
28323	Excess Benefit Plan	(7,787.00)	7,654.00	(133.00)	7,185.26	7,052.26	131.43
28324	Nonop Deferred Gain	277.79	0.00	277.79	0.00	277.79	0.00
28326	Def Exec Comp	(24,620.41)	0.00	(24,620.41)	0.00	(24,620.41)	0.00
28327	Software	37,910.18	23,645.43	61,555.61	5,063.99	66,619.60	(56,616.59)
28328	G/L ACRS Retirements	784,298.19	9,281.67	793,579.86	94,117.80	887,697.66	229,603.68
28329	Series U Exp (Bonds)	25,096.13	(8,515.00)	16,581.13	(8,515.30)	8,065.83	(8,515.30)
28330	EICP	(94,436.98)	20,918.00	(73,518.98)	8,755.45	(64,763.53)	(13,151.93)
28331	CIAC	(3,491,902.60)	265,556.11	(3,226,346.49)	197,496.01	(3,028,850.48)	281,099.23
28332	Customer Advances	(67,633.68)	(7,039.00)	(74,672.68)	25,994.00	(48,678.68)	(8,111.64)
28333	Capitalized Interest	(2,450,238.81)	(79,582.10)	(2,529,820.91)	(92,556.83)	(2,622,377.74)	(59,909.34)
28335	Connection Fees	7,981.14	(355.00)	7,626.14	0.00	7,626.14	0.00
28336	Nondeductible Interest	954.62	0.00	954.62	0.00	954.62	(21,402.97)
28337	Supplemt Benefits	(9,513.00)	(4,045.00)	(13,558.00)	(4,606.92)	(18,164.92)	69,241.20
28338	Nondeductible Vac	(195,605.00)	0.00	(195,605.00)	0.00	(195,605.00)	0.00
28339	System Devel Cost	0.00	0.00	0.00	0.00	0.00	0.00
28340	LTTP	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
28341	Waipahu Baseyard Int	(20,452.91)	0.00	(20,452.91)	0.00	(20,452.91)	0.00
28342	1990 Rate Case Exp	(0.48)	0.00	(0.48)	0.00	(0.48)	0.00
28345	Ross Cap Legal Fees	0.00	0.00	0.00	0.00	0.00	0.00
28346	Ser V Redmp Premium	13,356.36	(3,727.00)	9,629.36	(3,727.40)	5,901.96	(3,727.40)
28347	Waiau Water Well Pmts	(84,161.96)	3,884.00	(80,277.96)	3,884.38	(76,393.58)	4,285.38
28348	Nonutil Bad Debt	60,054.69	0.00	60,054.69	0.00	60,054.69	0.00
28349	Cap Corp Logo	460.09	0.00	460.09	0.00	460.09	0.00
28350	Loss Adj Exp	13,787.52	1,478.00	15,265.52	0.00	15,265.52	0.00
28400	92 Rate Case	340.20	0.00	340.20	0.00	340.20	0.00
28401	Genl/Auto (& Accidents)	(9,984.70)	(10,995.00)	(20,979.70)	(32,252.63)	(53,232.33)	8,721.80
28402	Ser Q Redmp Premium	(4,829.08)	0.00	(4,829.08)	0.00	(4,829.08)	0.00
28403	CWIP Debt Transition	112,002.27	(3,820.00)	108,182.27	(3,819.79)	104,362.48	(3,819.79)
28404	CWIP Equity Trans	354,314.68	(12,549.00)	341,765.68	(13,659.28)	328,106.40	(13,943.28)
28405	Iolani Ct Plaza Sale	(8,190.67)	4,828.00	(3,362.67)	6,639.04	3,276.37	(4,711.32)
28406	Kaonohi Sale	6,942.61	0.00	6,942.61	0.00	6,942.61	0.00
28407	FAS 109 Flow Through	756,602.00	(50,446.65)	706,155.35	(50,442.65)	655,712.70	(50,442.65)

Hawaiian Electric Company, Inc.
Deferred Income Taxes
STATE

LIAB (DR)CR		Actual 12-31-00	Actual 2001	Actual 12-31-01	Actual 2002	Actual 12-31-02	Actual 2003
28428	94 Rate Case Costs	(43.53)	0.00	(43.53)	0.00	(43.53)	0.00
28429	95 Rate Case Costs	(0.21)	0.00	(0.21)	0.00	(0.21)	0.00
28430	FMB X Premium	87,982.59	(4,008.00)	83,974.59	(4,008.00)	79,966.59	(4,008.00)
28431	EV Demo Costs	0.00	0.00	0.00	0.00	0.00	0.00
28432	Coal Gasif Costs	(11,273.00)	0.00	(11,273.00)	0.00	(11,273.00)	0.00
28433	Def PTI Costs	(23,187.48)	0.00	(23,187.48)	0.00	(23,187.48)	0.00
28434	EEO Claims	(20,691.77)	(7,089.00)	(27,780.77)	24,432.71	(3,348.06)	866.97
28435	Differential	178,792.69	13,996.00	192,788.69	16,069.22	208,857.91	23,152.80
28436	TIP	(3,236.82)	(42,341.00)	(45,577.82)	50,809.32	5,231.50	1,587.01
28437	HACOA			0.00		0.00	
28438	BONY Rev			0.00		0.00	
28439	GAQS Tel			0.00		0.00	
28440	Kalaeloa			0.00		0.00	1,486.00
28441	Sun Power	(1,649.28)	0.00	(1,649.28)	0.00	(1,649.28)	0.00
28442	Overhaul	(36,377.00)	0.00	(36,377.00)	0.00	(36,377.00)	0.00
28443	EV Tax Credit			0.00		0.00	74.00
28444	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
28445	HMSA Reserve	0.16	0.00	0.16	0.00	0.16	0.00
28500	Sec. 481(a) Adjustment	157,502.00	78,751.00	236,253.00	0.00	236,253.00	0.00
28502	Sec. 481(a) Adjustment - Depr	0.00	0.00	0.00	0.00	0.00	0.00
28504	Barbers Point	17,160.00	(17,468.00)	(308.00)	10,894.80	10,586.80	8,569.14
28506	Substation land - Makiki	(25,325.00)	6,907.00	(18,418.00)	7,482.76	(10,935.24)	6,906.76
28508	Substation land - Wilder	(2,881.00)	1,589.00	(1,292.00)	2,184.93	892.93	993.08
28510	Substation land - Lilipuna	(5,309.00)	1,249.00	(4,060.00)	1,249.30	(2,810.70)	1,249.30
28512	Revenue Bond Cost Amort	50,558.00	119,182.00	169,740.00	(17,624.52)	152,115.48	61,724.63
28514	APPRISE Software		82,318.54	82,318.54	178,524.09	260,842.63	(283,397.10)
28516	Honolulu Harbor Reserve		(65,985.00)	(65,985.00)	14,776.45	(51,208.55)	(6,153.68)
28518	D&T Fee Accrual			0.00	(9,975.00)	(9,975.00)	(4,971.73)
28520	Deferred Comp - restricted stock			0.00	(580.00)	(580.00)	4,721.08
28522	Knapp lawsuit			0.00		0.00	(2,848.12)
28524	Software (E-business only)			0.00		0.00	
28526	Emissions Fees			0.00		0.00	
28528	Substation land - Kuliouou			0.00		0.00	
28530	AES Hawaii PPA					0.00	
28532	CIS Project Costs					0.00	
28534	Substation land - Queen Emma			0.00		0.00	
	OCI - NQ Pension			0.00	(8,507.31)	(8,507.31)	(9,173.00)
	Insurance Reserve *			0.00		0.00	
	TOTAL ACCOUNT 283.02	7,989,487.87	1,846,860.71	9,836,348.58	1,779,017.43	11,615,366.01	932,756.36

Hawaiian Electric Company, Inc.
Deferred Income Taxes
STATE

LIAB (DR)CR		Actual 12-31-00	Actual 2001	Actual 12-31-01	Actual 2002	Actual 12-31-02	Actual 2003
28326	Def Exec Comp (Def LTIP)	(24,620.41)	0.00	(24,620.41)	0.00	(24,620.41)	0.00
28330	EICP	(94,436.98)	20,918.00	(73,518.98)	8,755.45	(64,763.53)	(13,151.93)
28336	Nondeductible Interest	954.62	0.00	954.62	0.00	954.62	(21,402.97)
28337	Supplemental Benefits -SERP	(9,513.00)	(4,045.00)	(13,558.00)	(4,606.92)	(18,164.92)	69,241.20
28338	Nondeductible Vacation	(195,605.00)	0.00	(195,605.00)	0.00	(195,605.00)	0.00
28340	LTIP	6,926.82	5,417.00	12,343.82	6,707.73	19,051.55	6,472.69
28341	Waipahu Baseyard Int	(20,452.91)	0.00	(20,452.91)	0.00	(20,452.91)	0.00
28342	1990 Rate Case Exp	(0.48)	0.00	(0.48)	0.00	(0.48)	0.00
28345	Ross Cap Legal Fees	0.00	0.00	0.00	0.00	0.00	0.00
28348	Nonutil Bad Debt	60,054.69	0.00	60,054.69	0.00	60,054.69	0.00
28349	Cap Corp Logo	460.09	0.00	460.09	0.00	460.09	0.00
28350	Outage Loss Adj Exp	13,787.52	1,478.00	15,265.52	0.00	15,265.52	0.00
28400	92 Rate Case	340.20	0.00	340.20	0.00	340.20	0.00
28401	Genl/Auto (&Accidents)	(9,984.70)	(10,995.00)	(20,979.70)	(32,252.63)	(53,232.33)	8,721.80
28412	Genl/Auto Legal	(4,598.34)	(5,742.00)	(10,340.34)	(5,936.84)	(16,277.18)	6,809.02
28436	TIP	(3,236.82)	(42,341.00)	(45,577.82)	50,809.32	5,231.50	1,587.01
28520	Deferred Comp - restricted stock			0.00	(580.00)	(580.00)	4,721.08
	OCI - NQ Pension	0.00	0.00	0.00	(8,507.31)	(8,507.31)	(9,173.00)
	AFUDC in CWIP	811,649.83	(41,531.77)	770,118.06	8,931.74	779,049.80	128,340.06
	TCI in CWIP	(524,130.26)	(47,182.44)	(571,312.70)	(70,717.42)	(642,030.12)	(95,645.55)
	"OTHER ITEMS" STATE DEF'D TAX LIABILITY	8,143,850.34	1,951,413.92	10,095,264.26	1,797,643.40	11,892,907.66	814,049.60
	ACCOUNT 282.02 DEPR	13,398,255.73	(771,870.61)	9,343,145.79	(754,685.11)	8,588,460.68	(678,186.27)
	Less: Nonutil Act 28210	0.00	0.00	0.00	0.00	0.00	0.00
	DEF'D TAX LIABILITY ACCELERATED DEPR	13,398,255.73	(771,870.61)	9,343,145.79	(754,685.11)	8,588,460.68	(678,186.27)

Hawaiian Electric Company, Inc.
Deferred Income Taxes
STATE

LIAB (DR)CR		Actual 12-31-03	Actual 2004	Actual 12-31-04	Estimate 2005	Estimate 12-31-05
28310	State ITC	21.67	(1,489,256.71)	(1,489,235.04)	0.00	(1,489,235.04)
28311	Unearned Lease	(1,454.91)	288.77	(1,166.14)	224.29	(941.85)
28312	Accrued Vacation	177,317.08	(380.97)	176,936.11	0.00	176,936.11
28313	Uncollectible Acct	(101,651.15)	69,571.26	(32,079.89)	0.00	(32,079.89)
28314	Directors Def Comp	(223.19)	(2,230.34)	(2,453.53)	(661.65)	(3,115.18)
28315	Computer Conv	(25,651.00)	25,651.00	0.00	0.00	0.00
28317	Discounted Work Comp	(138,784.97)	(3,857.64)	(142,642.61)	0.00	(142,642.61)
28319	Cap to Construction	4,450,996.96	279,603.49	4,730,600.45	295,402.94	5,026,003.39
28320	Gain HIRI Sub/misc	(18.00)	18.00	0.00	0.00	0.00
28321	Excess Pension	3,322,086.91	1,221,540.66	4,543,627.57	0.00	4,543,627.57
28322	Sec 189 Interest	0.00	0.00	0.00	0.00	0.00
28323	Excess Benefit Plan	7,183.69	(10,312.02)	(3,128.33)	0.00	(3,128.33)
28324	Nonop Deferred Gain	277.79	0.00	277.79	0.00	277.79
28326	Def Exec Comp	(24,620.41)	14,286.32	(10,334.09)	0.00	(10,334.09)
28327	Software	10,003.01	2,049.47	12,052.48	10,803.02	22,855.50
28328	G/L ACRS Retirements	1,117,301.34	(44,810.06)	1,072,491.28	0.00	1,072,491.28
28329	Series U Exp (Bonds)	(449.47)	611.88	162.41	0.00	162.41
28330	EICP	(77,915.46)	78,960.75	1,045.29	(752.66)	292.63
28331	CIAC	(2,747,751.25)	186,918.03	(2,560,833.22)	150,767.69	(2,410,065.53)
28332	Customer Advances	(56,790.32)	2,908.00	(53,882.32)	0.00	(53,882.32)
28333	Capitalized Interest	(2,682,287.08)	(371,100.96)	(3,053,388.04)	(203,677.07)	(3,257,065.11)
28335	Connection Fees	7,626.14	818.00	8,444.14	0.00	8,444.14
28336	Nondeductible Interest	(20,448.35)	(13,295.82)	(33,744.17)	0.00	(33,744.17)
28337	Supplemt Benefits	51,076.28	(97,027.10)	(45,950.82)	0.00	(45,950.82)
28338	Nondeductible Vac	(195,605.00)	0.00	(195,605.00)	0.00	(195,605.00)
28339	System Devel Cost	0.00	0.00	0.00	0.00	0.00
28340	LTIP	25,524.24	(48,294.63)	(22,770.39)	0.00	(22,770.39)
28341	Waipahu Baseyard Int	(20,452.91)	0.00	(20,452.91)	0.00	(20,452.91)
28342	1990 Rate Case Exp	(0.48)	0.48	0.00	0.00	0.00
28345	Ross Cap Legal Fees	0.00	0.00	0.00	0.00	0.00
28346	Ser V Redmp Premium	2,174.56	0.49	2,175.05	(2,174.32)	0.73
28347	Waiau Water Well Prmts	(72,108.20)	(7,845.62)	(79,953.82)	3,884.38	(76,069.44)
28348	Nonutil Bad Debt	60,054.69	(58,737.00)	1,317.69	0.00	1,317.69
28349	Cap Corp Logo	460.09	240.00	700.09	0.00	700.09
28350	Loss Adj Exp	15,265.52	(15,265.52)	0.00	0.00	0.00
28400	92 Rate Case	340.20	(340.20)	0.00	0.00	0.00
28401	Genl/Auto (& Accidents)	(44,510.53)	(56,481.36)	(100,991.89)	0.00	(100,991.89)
28402	Ser Q Redmp Premium	(4,829.08)	4,829.08	0.00	0.00	0.00
28403	CWIP Debt Transition	100,542.69	(3,819.79)	96,722.90	(3,819.79)	92,903.11
28404	CWIP Equity Trans	314,163.12	(13,942.28)	300,220.84	(13,943.28)	286,277.56
28405	Iolani Ct Plaza Sale	(1,434.95)	(6,315.76)	(7,750.71)	1,940.49	(5,810.22)
28406	Kaonohi Sale	6,942.61	0.00	6,942.61	0.00	6,942.61
28407	FAS 109 Flow Through	605,270.05	(50,442.65)	554,827.40	(50,442.65)	504,384.75
28408	Plant Transition	3,479,060.77	(158,138.41)	3,320,922.36	(158,138.41)	3,162,783.95
28409	CWIP Equity Net	2,455,925.25	241,629.42	2,697,554.67	255,926.01	2,953,480.68
28410	CWIP Equity Grossup	1,563,582.13	153,899.59	1,717,481.72	163,005.16	1,880,486.88
28411	CWIP Debt	1,270,566.74	105,073.51	1,375,640.25	116,866.71	1,492,506.96
28412	Genl/Auto Liability - Legal	(9,468.16)	(3,638.55)	(13,106.71)	0.00	(13,106.71)
28413	Post Retirement Ben	(179,011.56)	(96,557.04)	(275,568.60)	0.00	(275,568.60)
28414	Reg Liab Federal ITC	(651,511.68)	96,147.28	(555,364.40)	93,744.47	(461,619.93)
28417	Series R &T Exp (Bonds)	(6,346.52)	6,346.52	0.00	0.00	0.00
28418	IRP & DSM Costs	78,716.05	(40,356.56)	38,359.49	0.00	38,359.49
28419	Reg Liab Excess 283	(92,670.62)	3,464.66	(89,205.96)	3,464.66	(85,741.30)
28420	Reg Liab Deficit 283	(4,017.16)	2,327.82	(1,689.34)	2,327.82	638.48
28421	UFAMS Costs	(642.43)	642.43	0.00	0.00	0.00
28422	Miscellaneous	(49,614.56)	50,225.56	611.00	0.00	611.00
28424	Access Costs	0.04	(0.04)	0.00	0.00	0.00
28426	WMS Dev Costs	0.00	0.00	0.00	0.00	0.00
27427	Prepaid Expenses	41,743.12	64,418.05	106,161.17	0.00	106,161.17

Hawaiian Electric Company, Inc.
Deferred Income Taxes
STATE

LIAB (DR)CR		Actual 12-31-03	Actual 2004	Actual 12-31-04	Estimate 2005	Estimate 12-31-05
28428	94 Rate Case Costs	(43.53)	43.53	0.00	0.00	0.00
28429	95 Rate Case Costs	(0.21)	0.21	0.00	0.00	0.00
28430	FMB X Premium	75,958.59	(28,196.00)	47,762.59	(4,008.00)	43,754.59
28431	EV Demo Costs	0.00	0.00	0.00	0.00	0.00
28432	Coal Gasif Costs	(11,273.00)	11,273.00	0.00	0.00	0.00
28433	Def PTI Costs	(23,187.48)	23,187.48	0.00	0.00	0.00
28434	EEO Claims	(2,481.09)	(9,430.08)	(11,911.17)	(8,872.18)	(20,783.35)
28435	Differential	232,010.71	(60,789.85)	171,220.86	(7,986.58)	163,234.28
28436	TIP	6,818.51	(42,292.98)	(35,474.47)	0.00	(35,474.47)
28437	HACOA	0.00	(588.00)	(588.00)	0.00	(588.00)
28438	BONY Rev	0.00	74.00	74.00	0.00	74.00
28439	GAQS Tel	0.00	178.00	178.00	0.00	178.00
28440	Kalaeloa	1,486.00	(19,375.00)	(17,889.00)	0.00	(17,889.00)
28441	Sun Power	(1,649.28)	0.00	(1,649.28)	0.00	(1,649.28)
28442	Overhaul	(36,377.00)	0.00	(36,377.00)	0.00	(36,377.00)
28443	EV Tax Credit	74.00	0.00	74.00	0.00	74.00
28444	FMB S Premium	(1,461.75)	1,461.75	0.00	0.00	0.00
28445	HMSA Reserve	0.16	(0.16)	0.00	0.00	0.00
28500	Sec. 481(a) Adjustment	236,253.00	(236,253.00)	0.00	0.00	0.00
28502	Sec. 481(a) Adjustment - Depr	0.00	0.00	0.00	0.00	0.00
28504	Barbers Point	19,155.94	(23,566.23)	(4,410.29)	20,774.88	16,364.59
28506	Substation land - Makiki	(4,028.48)	4,028.48	0.00	0.00	0.00
28508	Substation land - Wilder	1,886.01	(1,886.01)	0.00	0.00	0.00
28510	Substation land - Lilipuna	(1,561.40)	1,249.30	(312.10)	312.32	0.22
28512	Revenue Bond Cost Amort	213,840.11	(21,819.32)	192,020.79	(21,819.38)	170,201.41
28514	APPRISE Software	(22,554.47)	22,554.47	0.00	0.00	0.00
28516	Honolulu Harbor Reserve	(57,362.23)	4,745.00	(52,617.23)	0.00	(52,617.23)
28518	D&T Fee Accrual	(14,946.73)	14,946.83	0.10	0.00	0.10
28520	Deferred Comp - restricted sto	4,141.08	(2,158.92)	1,982.16	(2,042.89)	(60.73)
28522	Knapp lawsuit	(2,848.12)	442.06	(2,406.06)	(19.01)	(2,425.07)
28524	Software (E-business only)	0.00	9,413.97	9,413.97	(2,271.89)	7,142.08
28526	Emissions Fees	0.00	(52,172.18)	(52,172.18)	0.00	(52,172.18)
28528	Substation land - Kuliouou	0.00	(10,930.71)	(10,930.71)	2,384.88	(8,545.83)
28530	AES Hawaii PPA	0.00	(9,301.50)	(9,301.50)	0.00	(9,301.50)
28532	CIS Project Costs	0.00	(18,863.89)	(18,863.89)	0.00	(18,863.89)
28534	Substation land - Queen Emma	0.00	0.00	0.00	(68,675.73)	(68,675.73)
	OCI - NQ Pension	(17,680.31)	(9,440.00)	(27,120.31)	0.00	(27,120.31)
	Insurance Reserve *	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCOUNT 283.02	12,548,122.37	(433,442.26)	12,114,680.11	572,524.23	12,687,204.34
	ACCOUNT 282 DEPR	7,910,274.41	(880,865.71)	7,029,408.70	(1,134,318.02)	5,895,090.68
	TOTAL STATE DEFERRED BALANCE (before rate case adjustments)	20,458,396.78	(1,314,307.97)	19,144,088.81	(561,793.79)	18,582,295.02
	TOTAL ACCOUNT 283.02	12,548,122.37	(433,442.26)	12,114,680.11	572,524.23	12,687,204.34
	Less Rate Case Adjustments *					
28310	State ITC	21.67	(1,489,256.71)	(1,489,235.04)	0.00	(1,489,235.04)
28312	Accrued Vacation	177,317.08	(380.97)	176,936.11	0.00	176,936.11
28313	Uncollectible Account	(101,651.15)	69,571.26	(32,079.89)	0.00	(32,079.89)
28314	Directors Def Comp	(223.19)	(2,230.34)	(2,453.53)	(661.65)	(3,115.18)
28315	Computer Conversion Costs	(25,651.00)	25,651.00	0.00	0.00	0.00
28317	Discounted Work Comp	(138,784.97)	(3,857.64)	(142,642.61)	0.00	(142,642.61)
28320	Gain HIRI Sub/misc	(18.00)	18.00	0.00	0.00	0.00
28323	Excess Benefit Plan	7,183.69	(10,312.02)	(3,128.33)	0.00	(3,128.33)
28324	Nonop Deferred Gain	277.79	0.00	277.79	0.00	277.79

Hawaiian Electric Company, Inc.
Deferred Income Taxes
STATE

LIAB (DR)CR		Actual 12-31-03	Actual 2004	Actual 12-31-04	Estimate 2005	Estimate 12-31-05
28326	Def Exec Comp (Def LTIP)	(24,620.41)	14,286.32	(10,334.09)	0.00	(10,334.09)
28330	EICP	(77,915.46)	78,960.75	1,045.29	(752.66)	292.63
28336	Nondeductible Interest	(20,448.35)	(13,295.82)	(33,744.17)	0.00	(33,744.17)
28337	Supplemental Benefits -SERP	51,076.28	(97,027.10)	(45,950.82)	0.00	(45,950.82)
28338	Nondeductible Vacation	(195,605.00)	0.00	(195,605.00)	0.00	(195,605.00)
28340	LTIP	25,524.24	(48,294.63)	(22,770.39)	0.00	(22,770.39)
28341	Waipahu Baseyard Int	(20,452.91)	0.00	(20,452.91)	0.00	(20,452.91)
28342	1990 Rate Case Exp	(0.48)	0.48	0.00	0.00	0.00
28345	Ross Cap Legal Fees	0.00	0.00	0.00	0.00	0.00
28348	Nonutil Bad Debt	60,054.69	(58,737.00)	1,317.69	0.00	1,317.69
28349	Cap Corp Logo	460.09	240.00	700.09	0.00	700.09
28350	Outage Loss Adj Exp	15,265.52	(15,265.52)	0.00	0.00	0.00
28400	92 Rate Case	340.20	(340.20)	0.00	0.00	0.00
28401	Genl/Auto (&Accidents)	(44,510.53)	(56,481.36)	(100,991.89)	0.00	(100,991.89)
28412	Genl/Auto Legal	(9,468.16)	(3,638.55)	(13,106.71)	0.00	(13,106.71)
28436	TIP	6,818.51	(42,292.98)	(35,474.47)	0.00	(35,474.47)
28520	Deferred Comp - restricted sto	4,141.08	(2,158.92)	1,982.16	(2,042.89)	(60.73)
	OCI - NQ Pension	(17,680.31)	(9,440.00)	(27,120.31)	0.00	(27,120.31)
	AFUDC in CWIP	907,389.86	89,889.08	997,278.94	33,099.40	1,030,378.34
	TCI in CWIP	(737,675.67)	(161,104.92)	(898,780.59)	(128,044.55)	(1,026,825.14)
	"OTHER ITEMS" STATE DEF'D TAX LIABILITY	12,706,957.26	1,302,055.53	14,009,012.79	670,926.58	14,679,939.37
	ACCOUNT 282.02 DEPR	7,910,274.41	(880,865.71)	7,029,408.70	(1,134,318.02)	5,895,090.68
	Less: Nonutil Act 28210	0.00	0.00	0.00	0.00	0.00
	DEF'D TAX LIABILITY ACCELERATED DEPR	7,910,274.41	(880,865.71)	7,029,408.70	(1,134,318.02)	5,895,090.68

CA-IR-390

Ref: CIP Docket No. 04-0278 Ford Island Substation.

Please provide the following regarding the Ford Island Substation Project:

a. Were the long-lead-time materials noted at page 15 of the application ordered in January 2005? If no, when were they/will they be ordered and how has this impacted the expected timing for completion of the project?

b. Are there any penalty provisions in any contracts with the Navy/federal government for not completing the substation by December 2005 as now anticipated? If yes, please note and describe such penalty provisions.

c. Describe, discuss and quantify the first loads anticipated to be served immediately following the completion of the Ford Island substation.

d. Describe, discuss and quantify the expected/anticipated annual increases in load anticipated to be served in the subsequent annual periods following the completion of the Ford Island substation.

HECO Response:

a. Long-lead items noted on page 15 of the application were not ordered in January 2005. HECO chose to wait for the PUC D&O approval (received recently on March 10, 2005) prior to committing funds for material and construction. Upon receipt of executive approval, HECO recently ordered the materials. Because the long-lead materials were not ordered earlier, HECO has compressed the construction schedule to maintain the Navy's service date of December 2005.

b. There are no penalty provisions in the Navy contract if HECO does not meet the December 2005 service date.

c. In addition to existing loads, the first new load anticipated to be served immediately following the completion of the Ford Island substation is the Navy's Pacific Warfighting Center (FY05 MCON P-113 project) which is scheduled for completion in early 2006 and is

Fluor Hawaii, LLC Private Developments which will provide an additional 2,205 kVA of demand. For further information on projected Ford Island loads, see the response to CA-IR-2 in Docket No. 04-0278, Ford Island Substation.

d. See response to part c above.

CA-IR-391

Ref: HECO-WP-1801 2004 Plant Additions.

The following Project Nos. show significant construction expenditures beyond 2004 even though the Company projected to have plant closings for these noted projects by the end of 2004.

- P0000562 Mokuone 46-12KV Line Ext
- P0000143 Salt Lake Blvd Widening Ph2
- P0000423 Kailua Rd UG Conversion
- P0000530 Ka lwi 12kV UG, Ph 1 Inc 2
- P0000575 Nimitz Hwy Rehab-UA # 1691
- P0000597 Diamond Head Rd OH/UG Imp

Please provide the following regarding the above-noted Project Nos.:

a. Confirm, or explain and quantify to the contrary if applicable, that all amounts included in the column entitled "Project to Date Recorded 12/31/03" were recorded as Construction Work in Progress as of 12/31/03 and were not included in Plant in Service as of that date.

b. The actual construction costs closed to plant in service at December 2004.

c. For each project, narratively describe how elements of the projects – though not the totality of the projects -- are deemed to be in service, and the criteria for determining in service status for individual components/phases.

HECO Response:

a. All projects listed above and its associated amounts included in the column "Project to Date Recorded 12/31/03" on HECO-WP-1801 were recorded as Construction Work in Progress as of 12/31/03 and were not included in Plant in Service as of 12/31/03.

b. P0000423, Kailua Rd UG Conversion, was placed in service in August 2004 with costs as of December 2004 of $534,559. P0000575, Nimitz Hwy Rehab-UA # 1691, was placed in service in September 2004 with costs as of December 2004 of $206,232.

c. Generally, projects are deemed to be in service based on the guidelines provided in "Accounting for Capital Project Costs" which was provided as Exhibit HECO-1318 (see pages 2-3).

CA-IR-392

Ref: HECO-WP-1801 2005 Plant Additions.

The following Project Nos. show significant construction expenditures beyond 2005 even though the Company projected to have plant closings for these noted projects by the end of 2005.

- P0000834 46 kV Fdrs to Mamala Sub
- P0000836 Ford Island Substation
- P0000838 46 kV Fdrs to FI Sub
- P0000951 Ocean Pointe 46 kV Lines
- P0000829 W4 Main Xfmr Replacement

Please provide the following regarding the above-noted Project Nos.:

a. Confirm, or explain and quantify to the contrary if applicable, that all amounts included in the column entitled "Project to Date Recorded 12/31/03" were recorded as Construction Work in Progress as of 12/31/03 and were not included in Plant in Service.

b. Actual construction costs closed to plant in service at December 2004, if applicable.

c. For each project, narratively describe how elements of the projects – though not the totality of the projects – are deemed to be in service, and the criteria for determining in service status for individual components/phases.

HECO Response:

a. All projects listed above and its associated amounts included in the column "Project to Date Recorded 12/31/03" on HECO-WP-1801 were recorded as Construction Work in Progress as of 12/31/03 and were not included in Plant in Service as of 12/31/03.

CA-IR-393

Ref: HECO-1800 and HECO-WP-1801 Quantification of Projected Plant Additions.

In an interview held with Lorie Nagata and other HECO representatives on February 8, 2005, the various representatives discussed how the Company undertook a "construction expenditures update" approximately on a quarterly basis with the next "update" anticipated to begin around

April 1. Please provide the results of the update and the expected impact by program and project costs as now summarized on HECO-1800 and HECO WP 1801, as soon as such exercise has been completed.

HECO Response:

The Company will provide the requested information as soon as the update process is completed, which is anticipated to be around April 15, 2005.

CA-IR-394

Ref: T-21, HECO-WP-2103, page 2, regarding Series 2002A Special Purpose Revenue Bonds.

Please provide a complete description of the intended uses/purpose of such bonds and complete description of the accounting for such transactions, including without limitation the following:

a. Specific delineation of purposes for which such bond proceeds may be used and/or a delineation of purposes for which the bond proceeds cannot be used.

b. Investments made by trust with undrawn construction funds.

c. Actual amounts of undrawn construction funds invested, as well as actual earnings on such undrawn construction funds, in each month since issuance of the bonds

d. Accounting for the Investment Income Differential on the undrawn balance of bond proceeds invested in temporary investments. Specifically state/describe/quantify to which accounts such Differential is initially charged and what event occurs or what time intervals pass before amortization of specific amounts begin.

e. To the extent not explained in response to previous subparts of this request, state how and to what extent the drawn and undrawn balances of the bond proceeds were considered in the development of the AFUDC rate applied to construction projects in each year since issuance of the bonds.

f. State, quantify and describe the extent to which AFUDC accounting may differ for construction projects ultimately deemed to be financed by the Special Purpose Revenue bond proceeds versus all other projects not eligible for Special Purpose Revenue Bond financing.

g. Describe and explain, if applicable, how the accounting for the Series 2002A Special Purpose Revenue Bonds may have differed from policies and procedures employed for other series of Special Purpose Revenue Bonds.

HECO Response:

a. See the Series 2002A Trust Indenture (Article V) that was filed as part of Exhibit 3 to the letter filed with the Commission on November 15, 2002 in Docket No. 99-0120.

b. For guidelines regarding the permitted investments see the Series 2002A Trust Indenture (Sections 6.04 and 14.01) that was filed as part of Exhibit 3 to the letter filed with the Commission on November 15, 2002 in Docket No. 99-0120.

c. See attached schedule on page 4 to this response.

d. The investment income differential is initially charged to general ledger account 25345000 and amortized in general ledger account 40303015. The investment income differential is amortized when a bond has net expense or when excess earnings are not required to be rebated to the IRS. However, since amortization is booked only on the amount attributable to the drawn portion of the construction fund, no amortization is booked until funds are drawn.

e. The calculation of the AFUDC rate applied to construction projects in each year only considers the drawn portion of the Special Purpose Revenue Bond, as shown in response to CA-IR-205 which shows the calculation of the AFUDC rate for 2004 and 2005.

f. AFUDC accounting does not differ between construction projects financed by Special Purpose Revenue Bond proceeds and construction projects not eligible for Special Purpose Revenue Bond financing.

g. The Series 2002A Special Purpose Revenue Bond is accounted for in the same manner as the other outstanding revenue bonds.

The accounting treatment of certain items relating to revenue bonds changed in 1994. Prior to 1994, issuing expenses were amortized once it was determined that most of the issuing expenses were recorded. The costs were amortized over the life of the bond and allocated proportionately based on the ratio of drawn or undrawn funds to the total amount of the proceeds. The portion of the amortization related to the drawn funds was reflected as an expense while the portion related to the undrawn funds was recorded as an amortization differential. The offsetting credit was to unamortized issuing expense account for the total amortized issuing cost. Bonds issued subsequent to 1994 record

only the amortization expense attributable to the drawn funds with an offset to unamortized issuing expense. Therefore no amortization differential is recorded.

For bonds without arbitrage calculation requirements issued prior to 1994, there was no amortization of the investment income and amortization differentials until 1994. For bonds with arbitrage calculation requirements issued prior to 1994 (specifically the 1982 & 1987 Series), investment income differentials were amortized over the remaining life of these bonds once it was determined that no arbitrage was due. Beginning in 1994, these items were amortized in proportion to the funds drawn over the remaining life of the bonds.

CA-IR-394 (c)

Hawaiian Electric Company Inc.
Series 2002A Bond
For the Period: September 2002 to February 2005

Date	*Invested Undrawn Balance*	*Actual Investment Income **
September 30, 2002	39,687,728.56	2,737.58
October 31, 2002	18,952,435.83	37,207.28
November 30, 2002	17,080,713.67	15,298.75
December 31, 2002	16,128,575.77	112,061.49
January 31, 2003	15,572,107.48	15,844.46
February 28, 2003	15,340,766.72	12,730.69
March 31, 2003	15,187,652.85	20,278.81
April 30, 2003	15,200,285.97	13,042.82
May 31, 2003	15,214,281.47	14,580.48
June 30, 2003	14,982,606.10	123,441.45
July 31, 2003	14,787,640.32	15,036.08
August 31, 2003	14,745,021.37	21,613.43
September 30, 2003	14,665,596.92	18,182.05
October 31, 2003	14,533,234.13	19,868.12
November 30, 2003	14,371,798.11	13,653.34
December 31, 2003	14,025,472.26	115,481.63
January 31, 2004	13,806,043.47	5,981.67
February 29, 2004	13,756,706.14	3,086.17
March 31, 2004	13,693,940.32	4,808.03
April 30, 2004	13,570,653.00	12,518.53
May 31, 2004	13,526,441.87	5,235.41
June 30, 2004	13,496,662.90	10,342.15
July 31, 2004	13,371,492.36	46,971.53
August 31, 2004	13,253,478.05	4,797.01
September 30, 2004	13,039,014.20	4,538.09
October 31, 2004	12,839,706.53	10,494.43
November 30, 2004	12,597,478.09	8,074.00
December 31, 2004	12,477,093.22	15,017.72
January 31, 2005	12,369,112.92	82,009.27
February 28, 2005	12,048,074.25	7,169.47

* Does not included accrued investment earnings.

CA-IR-395

Ref: Page 3.

Describe how KW impacts are adjusted for their coincidence with HECO's peak. Provide all assumptions and calculations.

HECO Response:

HECO originally started its DSM program in 1996 with engineering estimates of the kW impacts of each DSM measure promoted including its coincidence with HECO's peak. (See Demand-Side Management Resource Assessment Final Report filed in HECO's initial IRP Plan, Volume 6, filed July 1, 1993, Docket No. 7257.) For residential measures these impacts and coincidence factors also varied by single family or multi-family end use and by new construction or existing construction. In the commercial and industrial market segment the impact of each DSM measure also varied by the business structure where it was installed. HECO used the load profiles from 12 different commercial and industrial business types, e.g., offices, warehouses, retail, education, hotel/motel and miscellaneous commercial, to estimate the effects of different DSM measures on both the impacts and the coincidence factors.

HECO has conducted three complete impact evaluations, filed in its Annual Program Modifications and Evaluation Reports ("M&E Reports"), where the impacts and coincidence with HECO's peak was actually measured. A sample of projects from the years 1996 and 1997 were actually metered in the first impact analysis, filed in HECO's M&E Reports in 1998 and 1999. The second impact evaluation covered projects installed in the years 1998 and 1999. The individual reports from the second impact evaluation were filed in HECO's M&E Reports in 2000 and 2001. HECO's third impact evaluation was filed in the 2004 M&E Report, and included metered results from projects installed in 2001 through 2003. Statistical analysis was

used to apply the results of the metered data of the sample groups to the overall population of participants in HECO's DSM programs. Using this method, the impact on HECO's peak of each measure and its implicit coincidence factor was actually measured through onsite metering. However, not all measures in all 12 commercial market segments could cost-effectively be metered. Therefore, in the cases where a DSM measure was installed but not specifically metered in one commercial market segment, the results of the metered data from another market segment were adjusted by using the relationship of original load profiles from the 12 different market segments to determine the impact on HECO's peak of the measure in these market segments.

CA-IR-396

Ref: Page 3.

Describe how kwh impacts are adjusted for system losses. Provide all assumptions and calculations, and explain in detail how losses are measured.

HECO Response:

The kWh impacts are grossed up to account for line losses in transmission and for auxiliary losses at the power plant by multiplying the energy savings as measured at the customers' meter by 11.17%. The loss factors by installation year are filed in Attachment E, page 125 in HECO's 2004 A&S Report. This factor was developed by taking a three-year average of losses from the generating station auxiliaries and line losses. The attached spreadsheet shows the calculations.

	kWh	
96	1995	3-year Total
00	4,568,601,200	13,790,783,600
00	279,517,720	850,354,743
00	4,289,083,480	12,940,428,857
90	3,070,111,278	9,342,227,268
90	7,359,194,758	22,282,656,125
01	379,462,880	1,139,771,026
59	16,937,721	48,652,701
60	396,400,601	1,188,423,727
66	231,030,069	690,165,149
30	6,962,794,157	21,094,232,398
		3-year Average
4%	5.39%	**5.33%**
4%	5.19%	**5.14%**
8%	11.18%	11.17%

CA-IR-397

Ref: Page 4.

Why do net-to-gross ratios, which used to adjust for system losses, range from 60% to 89%, while HECO's 2003 FERC Form 1 (page 401a) shows a system-wide net-to-gross ratio of 95%?

HECO Response:

The referenced net-to-gross ratios do not adjust for system losses. These net-to-gross ratio adjust the impacts of the DSM programs by netting out the effects of freeriders. Freeriders are the customers who participate in a DSM program and receive the financial incentive, but would have installed the DSM measure even if the utility did not have the DSM programs. Another term for this is naturally occurring conservation. Even without utility sponsored DSM programs some customers would purchase and install energy efficiency measures. A well designed and implemented DSM program will encourage a greater number of customers to install these measures, but some of the measures would have been installed without the program. Therefore, when calculating the net benefit of the DSM programs the impacts of the programs are reduced by the effect of customers that would have installed the DSM measures even without the existence of the programs.

Conversely, the system-wide net-to-gross ratio of 95% is a ratio of MWh sales to customers to net-generation at the power plants, excluding station use. This ratio, therefore, does represent a measure of system line losses during transmission and distribution.

CA-IR-398

Ref: Page 7.

a. Why are evaluation costs subtracted from the UC test when calculating shareholder incentives?

b. Were evaluation costs included in the original benefit / cost analyses that determined that the programs were economic? Explain why or why not.

HECO Response:

a. Evaluation costs are subtracted from the UC test when calculating shareholder incentives because this is consistent with the shareholder incentive mechanism approved by the Commission in Decision and Order No. 14638, filed on April 22, 1996, in Docket Nos. 94-0010, 94-0011 and 4-0012 (Consolidated). The mechanism is a shared savings approach, which provides HECO's shareholders with 10 percent of the net benefits of the DSM programs, on an after-tax basis. The benefits are the present value of the estimated energy and demand costs avoided as a result of the DSM programs over the lives of the installed measures. The net benefits are the benefits less the costs included in the "modified UC test". The costs in the modified UC test are the costs the utility incurs in providing the DSM measures, exclusive of evaluation costs. Evaluation costs are excluded in the calculation of shareholders incentives to discourage any tendency to minimize evaluation efforts.

Evaluation activities are critical to the success of its DSM programs. Evaluation provides reliable evidence to all interested parties of the resource value of HECO's DSM programs. However, evaluation can be a very expensive activity. Since evaluation activities alone provide no additional net benefits to the DSM program, evaluation costs act (without modification) to reduce the cost-effectiveness of the programs. The tendency may be to

maximize shareholder incentives by minimizing evaluation expense which would be inappropriate given the acknowledged value of evaluation activities. Consequently, HECO proposed in its IRP-1 that shareholder incentives be based on a modified UC test where evaluation expenses where excluded from the test. See HECO IRP-1, Summary Report, Volume I, Appendix I, pages 26-28, filed July 1, 1993, Docket No. 7257.

b. Evaluation costs are included when HECO calculates the benefit/costs ratios for each program. As discussed above, the reason evaluation costs are not included in the shareholder incentive calculation is to discourage any tendency to minimize evaluation expenses, thereby increasing the level of shareholder incentives.

CA-IR-399

Ref: Page 7.

Please explain why the TRC test can be problematic when testing an on-going program.

HECO Response:

The TRC test can be problematic when testing an on-going program because of the difficulty of getting actual installed cost information from the customer. For instance, in a energy efficient lighting retrofit, one customer may retain the services of an electrical contractor to complete the entire installation of the energy efficient lighting fixtures, whereas another customer may use their own in-house staff to do the installation. In the first example, the cost of the labor would be included in the total measure cost for inclusion in the benefit/cost calculations, whereas in the second example the customer would probably not report the time that its in-house electrician spent on the installation for inclusion in the benefit/cost calculations. Similarly, some energy efficiency projects at customers' facilities include multiple energy efficiency measures. For example, when a customer installs a new chiller in many cases they might also install variable speed drives on the chiller itself or on the cooling tower. Under HECO's existing DSM programs, the incentive and impacts for the chiller would be assigned to the CIEE program, and the incentive and impacts for the variable speed drive would be assigned to the CICR program. As with the lighting example, it may be easy to get information from the customer on the equipment cost for these two measures, but it may be very difficult to get accurate information on the labor cost for the installation of each respective measure. In addition, some customers and contractors may be reluctant to share actual measure cost information for competitive reasons. Another problem arises when a customer replaces failed equipment. In this case, only the

incremental cost of replacing the equipment with an energy efficient measure should be used in the TRC calculation. For example, when replacing a failed water heater with an efficient water heater, only the incremental cost of higher efficiency water heater above and beyond the cost of a standard water heater should be included in the TRC test. However, it may be difficult to get accurate information from the customer on what the actual incremental increase in cost of the efficient installation was over a standard installation.

Another limitation to the TRC test occurs in residential programs. While most business decisions are based on expected financial returns, residential customers often make purchases for other reasons. A residential customer may purchase energy efficient equipment, such as a solar water heating system, based on his/her personal environmental concerns. Other customers may purchase the same product because it is different or new and they want to be in the forefront of new technologies. A residential customer with only two people in the family may also purchase a solar water heating system in anticipation of a growing family in the future, however, the increase in future savings cannot be factored into the current cost effectiveness of the residential programs.

A further limitation of the TRC occurs in the CICR Program. In this program, a prohibition on projects with a two-year or less payback eliminates projects with high TRC results. These higher TRC projects could be used to offset customized projects whose TRC results are less. However, when only the marginally cost-effective projects are included in the program and when labor costs are added for analysis of increasingly complex projects and other general program administrative costs are included, the TRC results for the entire CICR Program can fall below 1.0. (See HECO's Annual Program Accomplishments and Surcharge Report, filed April 30, 2004, pages 7-8.)

CA-IR-400

Ref: Page 8.

Does HECO have a position on whether or not DSM programs should also pass the RIM test? Please explain.

HECO Response:

The RIM test includes the lost revenues from the reduced electricity sales as a cost component. Because of this, and since average rates tend to exceed marginal avoided costs, nearly all energy efficiency DSM programs will fail the RIM test. In fact, in the portfolio of DSM programs proposed in this proceeding, only the two load management programs (i.e., the Commercial and Industrial Direct Load Control Program and the Residential Direct Load Control Program) pass the RIM test. Therefore, HECO's position is not to require an energy efficiency DSM program to pass the RIM test to be considered "cost-effective".

CA-IR-401

Ref: Page 12.

Please provide the electronic files supporting the results of the 2001 M&E Report referenced, with all formula and cell references intact. Also provide the electronic files for the 2002 M&E Report results. If HECO has this report itself in electronic media, please provide a copy of that file.

HECO Response:

The requested electronic files will be provided under a separate transmittal.

CA-IR-402

Ref: Page 12.

Please provide the electronic files supporting the results of the Impact Evaluation Reports referenced with all formula and cell references intact. If HECO has this report itself in electronic media, please provide a copy of that file.

HECO Response:

Please see HECO response to CA-IR-401.

CA-IR-403

Ref: page 13.

Please provide a copy of the updated avoided costs. Also provide all assumptions, workpapers, calculations, spreadsheets, and computer model output uses in developing these costs.

HECO Response:

Please see attached. The electronic files will be provided under a separate transmittal.

SYSTPL 6
HECO DSM
YP

INTEROFFICE CORRESPONDENCE

Hawaiian Electric Co., Inc.

March 24, 2000

To: Norris Creveston
George Willoughby

From: Gary Hashiro

Subject: DSM Avoided cost for HECO DSM Program Extension

Attached are the DSM Avoided costs and the Unit Addition Timing for plans with and without future 20 year DSM programs. This analysis was based on future DSM programs provided by Energy Services on March 15, 2000, with revised residential programs provided on March 21, 2000.

Sheet 1 of Attachement 1 provides the avoided energy costs, and Sheet 2 of Attachment 1 provides the avoided capital and fixed O&M costs.

The DSM avoided cost calucation methodology is consistent with historical calculations. A slight variation to the calculation is that the base plan represents "No Future DSM" as opposed to "No DSM". Therefore, the base plan includes embedded and approved DSM (5 years) to evaluate only the future DSM programs in the avoided cost calculation.

The DSM avoided cost spreadsheet will be provided to you via e-mail for your use in your calculation of shareholder incentives. If there are any questions, please contact me at (x7767) or Michelle Fukuji (x4464).

Attachments

cc: K. Block
A. Tam
R. Sakuda
D. Schwartz
A. Goto
M. Fukuji

July 1999 Sales and Peak Fore t; May 1998 Fuel Price Forecast
ATTACHMEN (Sheet 1 of 2)
DSM Avoided Cost 20 year DSM

	Production Revenue Requirements							Energy Requirements			
	with EE DSM - 20 yr			without DSM							
	Total Production Rev. Req. ($000) (1)	Fixed O&M Rev. Req. ($000) (2)	Fuel, Var O&M and Purchased Power ($000) (3)	Total Production Rev. Req. ($000) (4)	Fixed O&M Rev. Req. ($000) (5)	Fuel, Var O&M and Purchased Power ($000) (6)	Avoided Production Costs ($000) (7)	with DSM (GWh) (8)	w/o DSM (GWh) (9)	Avoided Energy (GWh) (10)	Avoided Energy Costs ($/MWh) (11)
1998	423,707	35,046	388,662	423,707	35,046	388,662	-	7,299	7,299	-	-
1999	435,716	35,691	400,025	435,716	35,691	400,025	-	7,410	7,410	-	-
2000	452,059	37,040	415,019	452,059	37,040	415,019	-	7,514	7,514	-	-
2001	463,726	38,032	425,693	464,341	38,032	426,309	561	7,593	7,611	18	31.96
2002	477,804	39,052	438,752	479,529	39,052	440,477	1,572	7,679	7,727	47	33.21
2003	491,646	40,098	451,548	494,414	40,098	454,316	2,522	7,775	7,850	75	33.57
2004	506,756	41,173	465,583	510,690	41,173	469,517	3,585	7,861	7,965	104	34.42
2005	526,845	42,276	484,569	532,389	42,276	490,112	5,051	7,999	8,134	134	37.58
2006	544,565	43,553	501,012	551,592	43,553	508,039	6,403	8,118	8,284	166	38.58
2007	563,572	44,868	518,703	572,118	44,868	527,249	7,787	8,238	8,436	198	39.33
2008	584,256	46,223	538,033	595,032	46,223	548,808	9,818	8,360	8,591	231	42.54
2009	605,696	47,619	558,076	620,822	49,447	571,375	12,117	8,483	8,748	265	45.71
2010	629,607	49,057	580,550	647,875	50,941	596,935	14,929	8,608	8,909	301	49.61
2011	657,372	52,673	604,700	676,821	52,673	624,148	17,721	8,748	9,087	338	52.36
2012	684,883	54,463	630,420	708,107	54,463	653,643	21,160	8,891	9,268	378	56.02
2013	713,396	56,315	657,081	740,927	56,362	684,565	25,042	9,034	9,453	419	59.79
2014	746,781	58,230	688,551	780,201	58,278	721,923	30,408	9,202	9,664	462	65.83
2015	785,612	60,259	725,353	818,178	61,771	756,407	28,295	9,373	9,880	507	55.81
2016	796,768	66,306	730,462	836,495	68,613	767,882	34,095	9,538	10,076	538	63.43
2017	823,195	71,117	752,078	867,994	71,171	796,823	40,770	9,718	10,275	557	73.21
2018	867,694	73,713	793,980	918,659	73,768	844,891	46,387	9,898	10,479	581	79.83
2019	917,935	76,404	841,532	975,650	76,461	899,190	52,535	10,081	10,687	607	86.61
2020	972,847	79,252	893,595	1,025,224	81,060	944,164	46,076	10,266	10,899	633	72.74
2021	1,025,111	82,144	942,967	1,079,655	86,736	992,919	45,514	10,487	11,116	629	72.41
2022	1,087,557	85,143	1,002,414	1,135,909	89,902	1,046,007	39,719	10,740	11,336	596	66.59
2023	1,068,107	96,214	971,893	1,129,439	96,214	1,033,224	55,883	10,997	11,561	564	99.13
2024	1,144,227	99,726	1,044,500	1,190,546	101,814	1,088,732	40,302	11,261	11,791	529	76.13
2025	1,209,484	97,022	1,112,462	1,265,954	100,158	1,165,795	48,595	11,531	12,025	494	98.46

General Notes:
Load forecast July 1999 (short-term) for 1998-2004, extrapolated 2005+ using the percent increase per the March 1995 (long-term) forecast (revised May 1995)
Fuel price forecast May 1998
DSM Impacts from Energy Services on 3/15/00 and revised residential on 3/21/00

Notes:
1 GAF Utility Costs (fixed & variable O&M, fuel, emissions and purchase power expenses) from PRV System Cost Report for WDSMEE20.sav w/ 20-year EE DSM in 1998
2 Fixed O&M Costs from GAF System Report for WDSMEE20.sav
3 Column (1) minus column (2)
4 GAF Utility Costs from PRV System Cost Report for NDSM00FR.sav
5 Fixed O&M Costs from GAF System Report for NDSM00FR.sav.
6 Column (4) minus column (5)
7 Column (6) minus column (3) with the 9.751% revenue tax removed
8 Energy Required from GAF System Report (including losses) WDSMEE20.sav
9 Energy Required from GAF System Report (including losses) NDSM00FR.sav.
10 Column (9) minus column (8)
11 Column (7) divided by column (10)

July 1999 Sales and Peak Fore[illegible]; May 1998 Fuel Price Forecast
ATTACHMEN[illegible] (Sheet 2 of 2)
DSM Avoided Cost 20 year DSM

	Revenue Requirements						Coincident Peak Demand			
	with DSM ($000) (12)	w/o DSM ($000) (13)	Net Avoided Revenue Requirements ($000) (14)	DSM Revenue Requirements ($000) (15)	Avoided Revenue Requirements ($000) (16)	Avoided Capital and Fixed O&M Costs ($000) (17)	with DSM (MW) (18)	w/o DSM (MW) (19)	Peak Reduction (MW) (20)	Avoided Capital and Fixed O&M Costs ($/kW-yr) (21)
1998	433,459	433,459	-	-	-	-	1,148.0	1,148.0	-	-
1999	445,182	445,182	-	-	-	-	1,170.9	1,170.9	-	-
2000	461,929	461,929	-	-	-	-	1,187.0	1,187.0	-	-
2001	473,288	467,881	(5,407)	6,022	615	-	1,198.7	1,203.6	4.9	-
2002	484,099	479,979	(4,120)	5,845	1,725	-	1,211.7	1,221.6	9.9	-
2003	499,083	495,339	(3,744)	6,512	2,768	-	1,226.9	1,241.6	14.6	-
2004	514,501	512,181	(2,319)	6,254	3,934	-	1,240.0	1,259.5	19.5	-
2005	535,079	534,052	(1,027)	6,570	5,543	-	1,259.0	1,283.5	24.5	-
2006	553,504	553,573	69	6,958	7,027	-	1,275.5	1,305.3	29.8	-
2007	571,322	573,778	2,456	6,090	8,546	-	1,292.4	1,327.3	34.9	-
2008	593,213	597,535	4,321	6,455	10,776	-	1,309.7	1,349.8	40.1	-
2009	615,292	643,662	28,370	6,844	35,214	19,968	1,327.2	1,372.7	45.5	439
2010	640,025	675,359	35,334	7,258	42,592	23,878	1,344.7	1,395.9	51.1	467
2011	689,523	703,156	13,634	7,704	21,338	1,721	1,365.3	1,422.3	57.0	30
2012	721,648	733,198	11,550	8,180	19,730	(3,183)	1,386.1	1,449.2	63.1	(50)
2013	749,544	774,645	25,101	8,687	33,788	5,743	1,407.3	1,476.7	69.5	83
2014	782,578	815,165	32,587	9,227	41,814	7,692	1,432.5	1,508.6	76.1	101
2015	831,478	873,577	42,099	9,802	51,901	18,995	1,457.9	1,540.9	83.0	229
2016	886,437	940,575	54,138	10,417	64,555	24,724	1,484.4	1,570.1	85.7	289
2017	947,744	990,607	42,864	11,070	53,934	8,373	1,511.2	1,599.7	88.5	95
2018	995,439	1,039,552	44,112	11,769	55,882	4,530	1,537.8	1,629.9	92.0	49
2019	1,042,233	1,092,103	49,870	12,515	62,385	4,307	1,564.8	1,660.5	95.7	45
2020	1,106,236	1,163,197	56,962	13,312	70,273	17,954	1,592.2	1,691.9	99.6	180
2021	1,144,140	1,239,415	95,276	342	95,618	41,608	1,627.1	1,723.8	96.7	430
2022	1,202,068	1,294,581	92,513	324	92,836	44,869	1,664.7	1,756.3	91.6	490
2023	1,275,531	1,328,325	52,794	306	53,100	(7,501)	1,703.1	1,789.4	86.4	(87)
2024	1,367,256	1,422,509	55,253	288	55,541	10,305	1,742.2	1,823.2	81.0	127
2025	1,478,264	1,543,379	65,115	270	65,385	10,981	1,782.2	1,857.6	75.3	146

Cost of Capital 8.092% Total (98-25) 956,823 NPV (98$) $222,854

NPV (98$) $794.22
Levelized (98$) 67.0452

Notes:

12 Utility Cost from PRV System Cost Report for WDSMEE20.sav.
13 Utility Cost from PRV System Cost Report for NDSM00FR.sav.
14 Columns (13) minus column (12)
15 Difference in DSM cost for energy efficiency DSM programs (excluding adjustments for T&D avoided costs) from LFA Utility Cost from PRV System Cost Reports for WDSMEE20.sav and NDSM00FR.sav.
16 Column (14) plus Column (15)
17 Column (16) minus column (7) with the 9.751%revenue tax removed
18 Final Peak from GAF Loads and Resources Detail Report for WDSMEE20.sav less rider I, CBB, and RDLC
19 Final Peak from GAF Loads and Resources Detail Report for NDSM00FR.sav less rider I, CBB, and RDLC
20 Column (19) minus column (18)
21 Column (17) divided by column (20)
22 Feb 9, 1999 after tax Cost of capital forecast = 8.092%.
23 Levelized Avoided capital & fixed o&m over period 1998-2025

20-year Future DSM programs
July 1999 Sales and Peak Forecast
May 1998 Fuel Price Forecast

ATTACHMENT 2

Unit Addition Timing With and Without future EE DSM Programs

	Plan - 20 yr DSM Only	
	Base Plan	Alternate Plan

1999		
2000		

CA-IR-404

Ref: page 21.

a. Please provide details on each of the options listed in the last paragraph, including HECO efforts to identify additional CHP sites and increasing the output of HECO's existing units.

b. Other than amendments 5 and 6 for the Kalaeloa PPA, are there any other options to increase output from IPPs?

c. If so, please describe in detail each option and provide the amount of energy/capacity to be received from each option in terms of MW, the cost of each option, the timing of the option, etc.

HECO Response:

a. Please refer to HECO's response to CA-IR-273.

b. From time to time, other IPPs have inquired about the possibility of providing more energy or capacity to HECO, and HECO has reviewed these inquiries. At this time, HECO is not in negotiations with any IPPs for additional energy or capacity.

c. Not applicable.

CA-IR-405

Ref: Attachment A.

a. How does HECO track the monthly quantity of individual measures installed (i.e., light fixtures, motors, etc.)?

b. Are these quantities entered into DSMIS as installations are actually made? Explain why or why not.

c. How frequently does HECO conduct field visits to verify that the measures installed in prior years are still in-service?

HECO Response:

a. When a financial incentive is paid to a customer for the installation of an energy efficiency measure, HECO records the quantity, type of measure, location of installation, installation date and various other attributes, depending on the specific measure(s) installed, in its DSMIS system. The DSMIS system will then sum the monthly quantities of measures installed from all the projects where an incentive was paid for a given month.

b. The quantities enter into DSMIS are rarely entered as the installations are actually made. The reason for this is HECO depends on the customer to submit applications and other information specific to the installation prior to making an incentive payment. In addition, in a larger percentage of the projects inspections and field verification of the installation are required before an incentive payment can be made. Therefore, only after all the required information is received and verified is an incentive paid and information on the measure installed entered into the DSMIS system.

c. To date HECO has conducted three impact evaluations of all its DSM programs. In the process of the impact evaluation, site visits are made to a sample of customers who have installed energy efficient equipment as part of a DSM program. In most cases, these

installations have occurred in prior years. For example, in HECO's most recent impact evaluation completed in October 2004, filed as Attachment B in HECO's 2004 M&E Report on November 30, 2004, the energy efficient installation evaluated were all from the previous years 2001 through 2003.

CA-IR-406

a. How does HECO determine the kw savings from each measure?

b. Are these calculated or metered?

c. How frequently does HECO conduct field measurements of savings?

HECO Response:

a. Please see HECO response to CA-IR-395.

b. Please see HECO response to CA-IR-395.

c. Please see HECO response to CA-IR-395.

CA-IR-407

Ref: Attachment C.

Please explain the Arch Wireless invoices for the RNC program.

HECO Response:

Arch Wireless provides the 900 MHz commercial paging communications for the load control switched installed on 80 gallon high efficiency electric water heaters in the RNC Program as part of the "Tank and Timer" DSM measure. When HECO first introduced the Tank and Timer, HECO was using autonomous timers to turn the water heaters off from 5 pm to 9 pm each weeknight. HECO anticipated that at some point the inflexibility of the autonomous timer would require that it be replaced with a more advanced solution. In the 1998 M&E Report, filed November 30, 1998, page 21, HECO reported that it would be conducting a pilot to examine the advantages of converting the Tank and Timer to a system based on 900 MHz commercial paging communications. After some initial start-up problems, which were reported in the 1999 M&E Report, filed November 30, 1999, page 24, HECO has conducted a successful test of the 900 MHz system. In fact, this system was adopted for full scale roll-out of HECO newly implemented RDLC program, approved in Decision and Order No. 21415, Docket No. 03-0166.

CA-IR-408

Ref: Attachment D, page 1.

a. Please explain the tax benefit item, and provide any calculations.

b. Who receives this tax benefit?

HECO Response:

a. The State of Hawaii currently has a Renewable Energy Tax Credit that provides a 35% tax credit to customers who install solar water heating systems. The tax credit is based on the net cost of the installed system after the HECO rebate is deducted. Consequently, the credit is calculated as 35% of the incremental cost shown in the preceding column minus the number of participants multiplied by the amount of the current solar rebate. In the referenced calculation the amount of the solar rebate was inadvertently not adjusted from the previous rebate of $800 per system to the current $750. Consequently the correct tax benefit

CA-IR-409

Ref: Attachment D, page 3.

Why are lost revenues valued in $/kw, instead of $/kwh?

HECO Response:

The referenced spreadsheet uses a very simplistic method for forecasting the lost revenues in future years of HECO's existing DSM program. The assumption behind this method is if an existing program resulted in a certain level of lost revenue in a recently completed year, then the same program should produce the same level of lost revenue on a $/kW basis in a future year. For instance, if a program's impacts were expected to grow by ten percent measured by its effect on kW reductions, then the resulting lost revenue should also increase by approximately ten percent. Therefore, this spreadsheet used the relationship between actual kW impacts in a previous year compared to the program's expected impact on kW saving in a future year to represent the estimated lost revenue. This method could have also used the relationship between actual kWh impacts and future forecasts. The column labeled $/kW was not intended to represent an actual lost revenue. This column only represents a unitized value which is then multiplied by the kW impact in the future year to get the forecast of lost revenue in that year.

It is important to note that HECO uses this method in these spreadsheets to forecast the future benefit/cost ratios for each program. Actual benefit/cost calculation using the actual lost revenue are calculated and reported to the Commission in HECO's A&S Report for the previous year. Additionally, HECO only collects the lost margins for actual lost sales resulting from its DSM programs. The actual lost revenue is also adjusted for two factors. The first adjustment is

customers who would have installed the DSM measures without the existence of HECO's DSM programs. The second adjustment reflects the ramping effect of the lost margins. This adjustment reflects the fact that margins lost in January are lost for twelve months of the year. Margins lost in December are lost for only one month of the year. These lost margins are then trued-up based on the results of the impact evaluations conducted for each DSM program.

CA-IR-410

Ref: Attachment D, pages 5 – 7.

a. What are the bases for the decay rates for energy and capacity?

b. Do these ever get adjusted for actual field verifications? Explain why or why not.

HECO Response:

a. HECO calculates the decay rates for energy and capacity based on the life expectancies of the measures installed in each program. For example, in the REWH program the two main DSM measures being installed are solar water heating systems with a life expectancy of 15 years and high efficiency electric water heaters with a life expectancy of ten years. Consequently, the energy and capacity impacts will decay in the eleventh year by the amount of impacts resulting from the number of high efficiency electric water heaters installed in the program in the current year. The life expectancy of each DSM measure was based on industry experience and introduced to all parties in HECO's IRP-1, Demand Side

Management Programs, adopted by the California Public Utilities Commission in Decision 93-05-063, and revised in February 1996 pursuant to Decision 94-05-063, 94-10-059, 94-12-021 and 95-12-054.

CA-IR-411

Ref: Attachment D, page 4.

Explain the difference between the 2003 Resource cost for the CICR program of $4,662,832 versus the $7,233,132 figure shown on page 1.

HECO Response:

The resource cost for the CICR program of $7,233,132 appearing on page 1 is in error. The value should have been $4,662,832 as it appears on page 4. The correct value of $4,662,832 was used for the cost-effectiveness results reported on pages 8 and 12.

CA-IR-412

Ref: Attachment D, pages 8 and 9.

a. Please provide copies of the workpapers and electronic files containing the spreadsheets that perform the calculations for the entries, including NPV estimates. Leave all formula and cell references intact.

b. Also explain how the program costs listed on page 1 translate or comport with the costs listed on page 8.

HECO Response:

a. The requested Excel files labeled "CA-IR-412 03 A&S Cost Tests w/Tax.xls", "CA-IR-412 CI Shareholder Incentives.xls", "CA-IR-412 RES Shareholder Incentives.xls" and "CA-IR-412 si for k.block-2003.xls" will be provided under separate transmittal. In the referenced

8.092%	Weight	Rate
Short-term debt	5%	6.0%
Long-term debt	40%	6.5%
[redacted]	[redacted]	[redacted]
[redacted]		
Common stock	48%	12%

Federal tax rate of 35%

State tax rate of 6.4%

The formula for the NPV factor is:

(ST Weight*ST Rate)*(1-Composite Tax Rate)+(LT Weight*LT Rate)*(1-Composite Tax Rate)+(PS Weight*PS Rate)+(Common Weight*Common Rate),

where Composite Tax Rate = (State Tax Rate/(1+State Tax Rate))+Federal Tax Rate*(1-State Tax Rate/(1+State Tax Rate)) = 38.91%

b. The program measure costs calculated on page 1 are the total costs of the DSM measures installed in each program. They are derived by multiplying the total number of DSM units expressed in either individual unit, as is the case with residential water heaters and solar systems, or in kWh of impacts in the case of commercial and industrial DSM measures, by the results of Hawaii Measure Cost Study that was filed as Attachment G in the 1998 M&E Report.

CA-IR-413

Ref: Response to CA-IR-264.
In order to clarify technical issues regarding the referenced response, the Consumer Advocate contacted Ms. Hazama. By email sent on March 10, 2005, Ms. Hazama provided the following clarification:

In response to your telephone request, the following is to clarify the response to CA-IR-264:

Question: On pages 8 and 9 of CA-IR-264, the number of observations are both 26, even if page

HECO Response:

Previous IR responses were provided based on discussions with Itron, the MetrixND software vendor. Clarifications were provided by Itron after further discussions and after the vendor researched the software code. According to the initial response from Itron, any observations with missing values are not considered for the regression. However, after researching the code, Itron responded that it appears that even though 1976 is missing a value, the data for the independent variables are being used by the nonlinear optimization algorithm to form a residual that feeds the AR process. On page 8, the 1976 data is dropped from the initial regression to get the starting points for the structural parameters due to a missing value for lagprice resulting in 26 observations to fit the model. On page 9, the 1976 data is included as part of the initial data

The model on page 9, on the other hand, is fit on 1976 – 2002 data (27 observations) and with the AR(1) specification, the initial observation (1976) is used to calculate the error

term and fits the model using 1977 – 2002 data (26 observations) for the regression.

b. The iterations are determined by MetrixND based on a convergence criterion, details of which are not in the MetrixND Users' Guide (see also HECO's response to CA-IR-302).

c. No, the model on page 9 has 26 observations and 22 degrees of freedom.

d. The model on page 9 is fitted over the 1976 – 2002 period resulting in 26 observations after the initial data point is lost for the AR(1) specification and 22 degrees of freedom (26 – constant – A/C – lagprice – AR).

CA-IR-414

Ref: HECO-WP-1705a and 1705b.

Please provide the following for each "Rate Case Adjustment" except for "Account 28310 State ITC:"

a. Provide a brief explanation as to the reason for excluding the ADIT balance from rate base determination.

b. State whether there is a balance sheet account related to the accumulated deferred income tax balance being excluded from rate base determination. If a related balance sheet account exists, provide the account number, account description and projected beginning and end of 2005 balances, and state whether such related balance sheet amount has been included within the Company's proposed rate base determination.

c. Identify, as applicable and appropriate, whether the timing difference is related to an above-the-line *or* below-the-line expense item. If related to an above-the-line expense item, provide the 2005 projected cost-of-service expense amount and the related 2005 projected tax deduction.

HECO Response:

Accrued Vacation (#28312) and Nondeductible Vacation (#28338)

a. In prior rate cases, the PUC ruled that HECO's cost of service may include only vacation paid during the year. For tax purposes, an accelerated deduction is allowed for the vacation taken between January 1 and March 15 of the subsequent year.

b. The beginning 2005 balance of Regulatory Asset – Vacation Liability (#18670800) is $3,466,616.20. The beginning 2005 balance of Accrued Vacation Liability (#24203000) is ($3,466,616.20). They completely offset each other. We do not forecast an ending balance. Both of these accounts are excluded from rate base.

c. The timing difference relates to an expense item not included in cost of service.

Uncollectible Account (#28313) and Nonutility Bad Debt (#28348)

liability balance is excluded, deferred taxes are excluded.

b. The beginning 2005 balance of Allowance for Bad Debts (#144) is ($361,323.32). We do not forecast an ending balance. However, the balance at March 31, 2005 is ($310,442.70). This is not included in the proposed rate base calculation.

c. The timing difference relates to an accrual of a reserve which is not included in cost of service.

Directors Deferred Compensation (#28314)

a. To simplify and limit issues, we are not seeking cost recovery for nonqualified pension plans. See HECO T-1, page 26 of 34.

b. The beginning 2005 balance of Nonemployee Nonqualified Pension – Directors (#24206400) is ($99,926). The projected ending 2005 balance is ($111,926). This is not included in the proposed rate base calculation.

c. The timing difference relates to an expense item not included in cost of service.

Computer Conversion Costs (#28315)

a. The balance is zero, so there is no impact on rate base in the current test year.

b. None.

c. None.

Discounted Worker's Compensation (#28317)

a. The deferred taxes track the rate base treatment of the related liability balance. Since the liability balance is excluded, deferred taxes are excluded.

b. The beginning 2005 balance of Other Deferred Credits – Work Comp (#25322000) is ($2,371,449). We do not forecast the ending balance. However, the balance at March 31, 2005 is ($2,457,123). This is not included in the proposed rate base calculation.

c. The timing difference relates to an above-the-line expense item. See HECO-1401, page 2 for the 2005 projected cost-of-service.

Gain HIRI Sub/misc (#28320)

a. The balance is zero, so there is no impact on rate base in the current test year.

b. None.

c. None.

Excess Benefit Plan (#28323)

a. To simplify and limit issues, we are not seeking cost recovery for nonqualified pension plans. See HECO T-1, page 26 of 34.

b. The beginning 2005 balance of Nonemployee Nonqualified Pension – Excess Plans (#24206100) is ($1,369,316.53). The projected ending 2005 balance is ($1,489,316.53). This is not included in the proposed rate base calculation.

c. The timing difference relates to an expense item not included in cost of service.

Nonoperating Deferred Gain (#28324)

a. The balance should be zero, and therefore we will adjust in rebuttal testimony.

b. None.

c. None.

Deferred Executive Compensation (#28326)

a. To simplify and limit issues, we are not seeking cost recovery for incentive compensation for employees and executives. See HECO T-1, page 26 of 34.

b. The beginning 2005 balance of Deferred Executive Incentive Compensation Plans (#25311000) is ($287,483.49). The projected ending 2005 balance is ($158,947.02). This is not included in the proposed rate base calculation.

c. The timing difference relates to an expense item not included in cost of service.

Executive Incentive Compensation Plan (EICP) (#28330)

a. To simplify and limit issues, we are not seeking cost recovery for incentive compensation for employees and executives. See HECO T-1, page 26 of 34.

b. The beginning 2005 balance of Executive Incentive Plan (#242210) is ($845,733). The projected ending 2005 balance is ($860,937). This is not included in the proposed rate base calculation.

c. The timing difference relates to an expense item not included in cost of service.

Nondeductible Interest (#28336)

a. In D&O No. 11699, Docket No. 6998, the PUC ruled that the company, not the ratepayer, should pay for any costs resulting from an audit. The nondeductible interest is interest accrued on prior year's IRS potential audit adjustments.

b. The beginning 2005 balance of Interest Payable (#23700000) is ($561,000). We do not forecast the ending balance. However, the balance at March 31, 2005 is ($591,700). This is not included in the proposed rate base calculation.

c. The timing difference relates to potential tax liabilities not yet resolved with the government tax authorities and is not included in the interest expense calculation.

Supplemental Benefits – SERP (#28337)

a. To simplify and limit issues, we are not seeking cost recovery for incentive compensation for employees and executives. See HECO T-1, page 26 of 34.

b. The beginning 2005 balance of Nonemployee Nonqualified Pension – SERP (#24206200) is ($1,858,925.04). The projected ending 2005 balance is ($2,157,425.04). This is not included in the proposed rate base calculation.

c. The timing difference relates to an expense item not included in cost of service.

Long Term Incentive Plan (LTIP) (#28340)

a. To simplify and limit issues, we are not seeking cost recovery for incentive compensation for employees and executives. See HECO T-1, page 26 of 34.

b. The beginning 2005 balance of Long Term Incentive Plan (#253100) is ($661,960). The projected ending 2005 balance is ($943,019). This is not included in the proposed rate base calculation.

c. The timing difference relates to an expense item not included in cost of service.

Waipahu Baseyard Interest (#28341)

a. In D&O No. 11699, Docket No. 6998, the PUC ruled that negative deferred income taxes associated with the Waipahu Baseyard should be excluded from rate base.

b. None.

c. None.

1990 Rate Case Expense (#28342) and 1992 Rate Case Expense (#28400)

a. The balance is zero, so there is no impact on rate base in the current test year.

b. None.

c. None.

Ross Capitalized Legal Fees (#28345)

a. The balance is zero, so there is no impact on rate base in the current test year.

b. None.

c. None.

Capitalized Corporate Logo (#28349)

a. The balance should be zero, and therefore we will adjust in rebuttal testimony.

b. None.

c. None.

Outage Loss Adjusting Expense (#28350)

a. The balance is zero, so there is no impact on rate base in the current test year.

b. None.

c. None.

General / Auto & Accidents (#28401)

a. The deferred taxes track the rate base treatment of the related liability balance. Since the

liability balance is excluded, deferred taxes are excluded.

a. To simplify and limit issues, we are not seeking cost recovery for incentive compensation for employees and executives. See HECO T-1, page 26 of 34.

b. The beginning 2005 balance of Team Incentive Plan (#242200) is ($788,000). The projected ending 2005 balance is ($1,098,200). This is not included in the proposed rate base calculation.

c. The timing difference relates to an expense item not included in cost of service.

Restricted Stock (#28520)

a. To simplify and limit issues, we are not seeking cost recovery for incentive compensation for employees and executives. See HECO T-1, page 26 of 34.

b. The beginning 2005 balance of Deferred Compensation Expense (#18616000) is $71,531. The projected ending 2005 balance is $37,568. This is not included in the proposed rate base calculation.

c. The timing difference relates to an expense item not included in cost of service.

Other Comprehensive Income (OCI) – Nonqualified Pension

a. To simplify and limit issues, we are not seeking cost recovery for incentive compensation for employees and executives. See HECO T-1, page 26 of 34.

b. The beginning 2005 balance of Accumulated OCI (#21101000) is $450,878. The projected ending 2005 balance is $45,356. This is not included in the proposed rate base calculation.

c. The book accrual does not affect book expense since it is charged to a shareholder equity account. There is no impact on cost of service.

AFUDC in CWIP

a. Since construction work-in-progress is not included in rate base, the deferred tax related to AFUDC incurred in CWIP and not yet closed to plant is similarly excluded from rate base.

b. The balance sheet account related to the deferred taxes is included in CWIP (#107). The beginning 2005 balance of AFUDC in CWIP is $16,579,866. The projected ending 2005 balance of AFUDC in CWIP is $17,130,147.

c. AFUDC incurred and charged to CWIP is not included in cost of service.

Tax Capitalized Interest (TCI) in CWIP

a. Tax Capitalized Interest is the tax equivalent of AFUDC. See AFUDC in CWIP above.

b. None.

c. None.

CA-IR-415

Capital versus Expense Accounting for Production Facility Repairs.

Since HECO's last rate case (Docket No. 7766) please provide the following regarding every instance wherein the Company elected to capitalize the replacement of a minor item of property (i.e., less than a property unit) that would have been expensed pursuant to Utility Plant Instructions contained in the NARUC Uniform System of Accounts, but for the fact that the replacement purportedly resulted in a substantial betterment:

a. Project number, project title and brief description of the repair and replacement.

b. Date replacement was capitalized.

c. Total cost capitalized.

d. A detailed description of the "substantial betterment" achieved as a result of the replacement.

e. CIP docket number in which addressed, if applicable.

HECO Response:

Beginning 2004, the Company has agreed to modify its betterment accounting practice to be fully consistent with the NARUC Instructions (only the difference between the cost of replacement with betterment and the cost of replacement without betterment is capitalized) beginning with betterment projects commencing in 2004. Refer to the agreement letter, dated March 29, 2005 (Docket No. 03-0206), between the Company and the Consumer Advocate.

Without having to perform an extensive research effort from as far back as HECO's last rate case, the Company knows of the following project, prior to 2004, wherein the Company elected to capitalize the replacement of a minor item of property that would have been expensed pursuant to Utility Plant Instructions contained in the NARUC Uniform System of Accounts, but for the fact the replacement purportedly resulted in a substantial betterment.

a. Refer to attached table on page 3.

b. Refer to attached table on page 3.

c. Refer to attached table on page 3.

d. Refer to attached table on page 3.

e. Refer to attached table on page 3.

Attachment to CA-IR-415 (Revised 5-24-05)
Capital versus Expense Accounting for Production Facility Repairs

Item a.			Item b.	Item c.	Item d.	Item e.
Project Number	Project Title	Brief Description of Project	Date of replacement capitalized	Total cost capitalized (as of April 7, 2005)	A detailed description of the "substantial betterment".	CIP docket number.
P0000204	W7 BFP (Boiler Feed Pump) Rec Ctrl Valves Upg	Install piping modifications	Apr-04	$37,969 ($7,000 would have been expensed under betterment accounting.)	Property unit will have an increased capacity and improved heat rate.	Not applicable.
P0000254	W3 Stack & Breeching Rpl	Reinforce stack and install a liner in the stack and breeching	Aug-04	$290,940 ($140,000 would have been expensed under betterment accounting.)	Property unit's life will be substantially extended.	Not applicable.
P0000638	W3 Air Heater Tube Replmnt	Install modern grade H tubes	Oct-04	$792,551 ($753,000 would have been expensed under betterment accounting.)	Property unit's life will be substantially extended.	Not applicable.
P0000651	K5 AEH Limit Switch Upgrade	Install new limit switches	Jun-04	$105,700 ($97,000 would have been expensed under betterment accounting.)	Property unit will be substantially more efficient.	Not applicable.
P0000893	H8 Generator Rotor Rewind	Rewind generator rotor with new and reinsulated rotor coils	Dec-03	$522,056 (would have been expensed under betterment accounting.)	Property unit's life will be substantially extended.	03-0206

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	Item b.	Item c.	Item d.	Item e.
ject	Date of replacement capitalized	Total cost capitalized (as of April 7, 2005)	A detailed description of the "substantial betterment".	CIP docket number.
ons	Apr-04	$37,969 ($7,000 would be expensed under betterment accounting based on cursory review)	Property unit will have an increased capacity and improved heat rate.	Not applicable.
iner in the	Aug-04	$290,940 ($140,000 would be expensed under betterment accounting based on cursory review.)	Property unit's life will be substantially extended.	Not applicable.
ubes	Oct-04	$792,[illegible] ($753,000 would be expensed under betterment accounting based on cursory review.)	Property unit's life will be substantially extended.	Not applicable.
es	Ju[illegible]	$105,700 ($97,000 would be expensed under betterment accounting based on cursory review.)	Property unit will be substantially more efficient.	Not applicable.
nd	Dec-03	$522,056 (would be expensed under betterment accounting based on cursory review.)	Property unit's life will be substantially extended.	03-0206

CA-IR-416

Please provide the following regarding every instance wherein the Company has forecasted within the 2005 test year to capitalize the replacement of a minor item of property (i.e., less than a property unit) that would be expensed pursuant to Utility Plant Instructions contained in the NARUC Uniform System of Accounts, but for the fact that the replacement purportedly will result in a substantial betterment:

a. Project number, project title and brief description of the projected repair and replacement.

b. Date of expected replacement.

c. Total forecasted cost capitalized.

d. A detailed description of the "substantial betterment" expected as a result of the replacement.

projects that will be expensed, and the test year production maintenance expense will be

(REVISED 5-24-05)

Attachment to CA-IR-416
Capital versus Expense Accounting for Production Facility Repairs

Item a.			Item b.	Item c.	Item d.	Item e.
Project Number	Project Title	Brief Description of Project	Date of expected replacement (Direct testimony)	Total forecasted cost capitalized. (Direct testimony plant addition)	A detailed description of the "substantial betterment".	CIP docket number.
P0000641	K6 AEH Limit Switch Upgrade	Replacement of limit switches on the turbine steam valves.	2005	$95,647 ($9,000 will be capitalized under betterment accounting.)	Property unit will be substantially more efficient.	Not applicable.
P0000299	W9 Compressor Blade Coating (Revised to W9 Compressor Wash)	Compressor blade coating (Revised to only include compressor wash systems).	2005	$323,074 (Project is expected to be completed in 2005. $117,015 will be capitalized under betterment accounting.)	Property unit's life will be substantially extended.	Not applicable.
P0000300	W10 Compressor Blade Coating (Revised to W10 Compressor Wash)	Compressor blade coating (Revised to only include compressor wash systems).	2005	$322,683 (Project is expected to be completed in 2005. $122,791 will be capitalized under betterment accounting.)	Property unit's life will be substantially extended.	Not applicable.

Attachment to CA-IR-416
Capital versus Expense Accounting for Production Facility Repairs

Item a.			Item b.	Item c.	Item d.	Item e.
Project Number	Project Title	Brief Description of Project	Date of expected replacement (Direct testimony)	Total forecasted cost capitalized. (Direct testimony plant addition)	Detailed description of the "substantial betterment".	CIP docket number.
P0000641	K6 AEH Limit Switch Upgrade	Replacement of limit switches on the turbine steam valves.	2005	$95,647 ($9,000 will be capitalized under betterment accounting based on cursory review.)	Property unit will be substantially more efficient.	Not applicable.
P0000299	W9 Compressor Blade Coating (Revised to W9 Compressor Wash)	Compressor blade coating (Revised to only include compressor wash systems).	2005	$323,074 (Project is expected to be completed in 2005. $117,015 will be capitalized under betterment accounting based on cursory review.)	Property unit's life will be substantially extended.	Not applicable.
P0000300	W10 Compressor Blade Coating (Revised to W10 Compressor Wash)	Compressor blade coating (Revised to only include compressor wash systems).	2005	$322,683 (Project is expected to be completed in 2005. $122,791 will be capitalized under betterment accounting based on cursory review.)	Property unit's life will be substantially extended.	Not applicable.

Attachment to CA-IR-416
Capital versus Expense Accounting for Production Facility Repairs

Item a.			Item b.	Item c.	Item d.	Item e.
Project Number	Project Title	Brief Description of Project	Date of expected replacement (Direct testimony)	Total forecasted cost capitalized. (Direct testimony plant addition)	A detailed description of the "substantial betterment".	CIP docket number.
P0000641	K6 AEH Limit Switch Upgrade	Replacement of limit switches on the turbine steam valves.	2005	$95,647 (estimated $9,000 will be capitalized under betterment accounting)	Property unit will be substantially more efficient.	Not applicable.
P0000299	W9 Compressor Blade Coating (Revised to W9 Compressor Wash)	Compressor blade coating (Revised to only include compressor wash systems).	2005	$323,074 (Project is expected to be completed in 2005. Estimated $117,015 will be capitalized under betterment accounting.)	Property unit's life will be substantially extended.	Not applicable.
P0000300	W10 Compressor Blade Coating (Revised to W10 Compressor Wash)	Compressor blade coating (Revised to only include compressor wash systems).	2005	$322,683 (Project is expected to be completed in 2005. Estimated $122,791 will be capitalized under betterment accounting.)	Property unit's life will be substantially extended.	Not applicable.
P0000870	H9 Generator Rotor Rewind	Rewind generator rotor with new and reinsulated rotor coils.	2005	$9[illegible]805 (Project is expected to be completed in 2006 and will be expensed under betterment accounting.)	Property unit's life will be substantially extended.	Not applicable.

CA-IR-417

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

HECO provided a copy of the Excel spreadsheet file supporting HECO-1310 in response to CA-IR-251(a). The spreadsheet file contains hard inputs for direct/ indirect labor hours and labor dollars. Further, the spreadsheet file does not contain any algorithms that apply the various allocation factors to total labor/ nonlabor dollars to derive HECO's allocated share. Please provide the following:

a. Does a version of the spreadsheet file exist that contains cell formulae showing the application of standard labor rates to labor hours in quantifying labor dollars? Please explain.

b. Does a version of the spreadsheet file exist that applies the allocation factors to total indirect labor and non-labor costs to derive HECO's allocated share? Please explain.

c. Referring to items (a) and (b) above, please provide additional linked spreadsheet files or a revised spreadsheet that shows all underlying calculations and algorithms.

HECO Response:

a. Yes, please see HECO's response to CA-IR-251 pages 3 – 159 which supports the spreadsheet file HECO-1310 showing the application of standard labor rates to labor hours in quantifying labor dollars.

b. Yes, please see HECO's response to CA-IR-251 pages 3 – 159 which supports the spreadsheet file HECO-1310 showing the application of the allocation factors to indirect labor and non-labor costs to derive HECO's allocated share.

c. Please see HECO's response to CA-IR-251 pages 3 – 159 which supports the spreadsheet file HECO-1310 and shows all underlying calculations.

CA-IR-418

Ref: HECO response to CA-IR-252 & HECO-1310 (HEI Billings).

a. Does HECO plan on updating the HEI billings to HECO included in the 2005 test year forecast to reflect more current allocation factors?

b. If not, why not?

c. If so, please provide the revised amounts proposed for inclusion in the 2005 test year forecast, showing all calculations and workpapers.

HECO Response:

a. Yes, HECO will update the HEI billings to HECO included in the 2005 test year estimate to reflect more current allocation factors and more current estimates.

b. Not applicable.

c. Please see response to CA-IR-419.

CA-IR-419

Ref: HECO-1310 (HEI Billings).

a. Does HECO plan on updating the HEI billings to HECO included more currents estimates of HEI's 2005 test year forecast?

b. If not, why not?

c. If so, please provide the revised amounts proposed for inclusion in the 2005 test year forecast, showing all calculations and workpapers.

HECO Response:

a. Yes, HECO will update the HEI billings to HECO included in the 2005 test year estimate to reflect more current allocation factors and more current estimates.

b. Not applicable.

c. The revised 2005 HEI billings to HECO is $1,827,046.92. The impact of using the 2004 actual data for labor hours and nonlabor dollars (instead of the 2003 actual data for labor hours and nonlabor dollars which was the basis for the 2005 test year estimate shown on HECO-1310), updated allocation factors (which are actually being used in the 2005 billings to the subsidiaries) and higher SOX costs primarily due to higher auditor attestation fees than originally anticipated is $94,756.35 ($1,827,046.92 revised amount versus the 2005 test year amount shown on HECO-1310 of $1,732,290.57 = $94,756.35). See pages 3 to 6 for the workpapers (similar to HECO-1310) supporting the revised amount of $1,827,046.92. However, due to the confidential nature of employee salary information, the detailed bill that supports the workpapers shown on pages 3 to 6 is only available for review at the HEI Controller's office. Please contact Irene Sekiya at (808) 543-4778 to arrange to review this information.

The $94,756.35 increase is primarily due to higher auditor attestation fees related to SOX, higher reporting, pension, stock transfer, board of directors and community relations costs based upon HEI updating its 2005 test year estimate with more current information.

HECO
EXCLUDING INCENTIVE COMPENSATION

Activity code	ACTIVITY CODE DESCRIPTIONS	Direct Charges-2004: Direct Labor Hours	Direct Labor Dollars	Direct Nonlabor Dollars	Shared Charges-2004: Shared Labor Hours	2005 Allocation Factor	Shared Labor Dollars	Shared Nonlabor Dollars	2004 Actual	2005 Adjustments	2005 Estimate (1)
ACC	**Accounting**										
ACC 001	Research accounting issues				4.00	40.0%	184.51		184.51		188.38
ACC 004	Maintain general ledger	314.00	16,668.24						16,668.24		17,018.27
ACC 008	Analyze financial results	2.00	1,466.67						1,466.67		1,497.47
ACC 009	Monitor accounting and reporting standards	13.75	3,138.76	7,000.00	59.00	40.0%	2,200.93		12,339.69	(7,000.00) (2)	5,451.82
ACC 018	Intercompany billing administration				453.25	40.9%	8,523.07		8,523.07		8,702.05
		329.75	21,273.67	7,000.00	516.25		10,908.51	0.00	39,182.18	(7,000.00)	32,857.99
ADM	**Administrative**										
ADM 006	Assist on rate cases	380.00	29,792.11						29,792.11	(29,792.11) (3)	0.00
ADM 007	Corporate risk review				17.50	40.9%	4,288.43		4,288.43		4,378.49
ADM 011	Telephone charges			3,056.32					3,056.32		3,120.50
ADM 012	Rent - ASB Tower (formerly Pacific Tower)			54,667.90					54,667.90	(1,124.41) (4)	54,667.90
ADM 013	Supplies			2,000.00					2,000.00		2,042.00
ADM 014	Rent - Central Pacific			41,194.25					41,194.25		42,059.33
ADM 112	Sarbanes-Oxley Section 302	2.00	271.46						271.46		277.16
		382.00	30,063.57	100,918.47	17.50		4,288.43	0.00	135,270.47	(30,916.52)	106,545.38
ANN	**Annual meeting**										
ANN 001	Annual shareholder meeting planning & coordination				105.25	39.7%	5,138.99	4,737.18	9,876.17		10,083.57
		0.00	0.00	0.00	105.25		5,138.99	4,737.18	9,876.17	0.00	10,083.57
AUD	**Audits**										
AUD 005	Audit Committee meeting attendance					63.3%		224.74	224.74		229.46
		0.00	0.00	0.00	0.00		0.00	224.74	224.74	0.00	229.46
BOD	**Board of Directors**										
BOD 001	Board of Directors meetings	314.75	18,013.77	282.79					18,296.56		18,680.79
BOD 002	Attendance (presentations)	42.50	30,679.35						30,679.35		31,323.62
BOD 005	Misc. board matters	2.30	1,152.36	380.96					1,533.32		1,565.52
		359.55	49,845.48	663.75	0.00		0.00	0.00	50,509.23	0.00	51,569.93
BUD	**Budgets**										
BUD 001	Preparation	0.25	19.99						19.99		20.41
		0.25	19.99	0.00	0.00		0.00	0.00	19.99	0.00	20.41
CAS	**Cash Management**										
CAS 006	Cash disbursements (wire confirmations)	5.67	249.98						249.98		255.23
		5.67	249.98	0.00	0.00		0.00	0.00	249.98	0.00	255.23
COM	**Community Relations**										
COM 001	Media relations and communications	1.50	1,114.14						1,114.14	7,798.98 (5)	9,100.30
		1.50	1,114.14	0.00	0.00		0.00	0.00	1,114.14	7,798.98	9,100.30
CON	**Consulting - general**										
CON 002	Meetings	24.25	17,828.16						17,828.16		18,202.55
CON 004	Other	28.50	20,464.24	2,081.27					22,545.51		23,018.97
		52.75	38,292.40	2,081.27	0.00		0.00	0.00	40,373.67	0.00	41,221.52

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HECO
EXCLUDING INCENTIVE COMPENSATION

Activity code	ACTIVITY CODE DESCRIPTIONS	Direct Charges-2004 Direct Labor Hours	Direct Labor Dollars	Direct Nonlabor Dollars	Shared Charges-2004 Shared Labor Hours	2005 Allocation Factor	Shared Labor Dollars	Shared Nonlabor Dollars	2004 Actual	2005 Adjustments	2005 Estimate (1)
FIN	**Financing**										
FIN 001	Debt financing planning and coordination	17.75	2,386.48	109.37					2,495.85	(2,495.85) (6)	0.00
FIN 002	Debt financing due diligence	11.75	1,452.88						1,452.88		1,483.39
FIN 100	Stock split				18.75	39.7%	1,477.69	110,864.05	112,341.74	(112,341.74) (7)	0.00
		29.50	3,839.36	109.37	18.75		1,477.69	110,864.05	116,290.47	(114,837.59)	1,483.39
HUM	**Human Resources**										
HUM 001	Benefits consulting services	1.00	232.48		2.75	41.8%	265.50		497.98		508.44
HUM 002	Compensation consulting services	1.75	399.63		0.50	43.3%	49.44		449.07		458.50
HUM 008	Code of Conduct development and administrative assistance				0.75	41.8%	71.59		71.59		73.09
HUM 009	Code of Conduct review				5.25	41.8%	508.01	6,455.51	6,963.52	(6,455.51) (8)	518.68
HUM 010	Compensation committee meetings				135.50	43.3%	9,187.09		9,187.09		9,380.02
HUM 011	Long-term incentive plan (LTIP)	1.25	79.09		26.50	21.0%	439.94		519.03 (a)	(519.03) (9)	0.00
HUM 012	Executive incentive compensation plan (EICP)				56.00	26.6%	1,257.36		1,257.36 (b)	(1,257.36) (9)	0.00
HUM 013	Stock options with dividend equivalents	22.00	1,195.61		186.50	33.4%	5,499.80	4,824.07	11,519.48 (c)	(11,519.48) (9)	0.00
HUM 014	Stock options	16.00	712.50						712.50 (d)	(712.50) (9)	0.00
HUM 015	Executives deferred compensation				7.25	60.0%	296.21	60.53	356.74 (e)	(356.74) (9)	0.00
		42.00	2,619.31	0.00	421.00		17,574.94	11,340.11	31,534.36	(20,820.62)	10,938.73
INT	**Internet**										
INT 001	Frontbridge (spam filtering)			7,805.00		90.0%		3,664.67	11,469.67	(11,469.67) (10)	0.00
INT 002	Firewall services					32.0%		29,661.42	29,661.42	(13,515.48) (10)	16,485.00
INT 003	Internet services					33.0%		3,317.56	3,317.56	1,921.42 (10)	5,349.00
INT 004	Shared internet connection					58.6%		24,877.98	24,877.98	14,982.94 (10)	40,698.00
INT 005	File Transfer Protocol (FTP) server					90.0%		312.50	312.50	645.38 (10)	978.00
INT 006	Disaster recovery (ISDN line)			2,129.43					2,129.43	(2,129.43) (10)	0.00
		0.00	0.00	9,934.43	0.00		0.00	61,834.13	71,768.56	(9,564.84)	63,510.00
INV	**Investor Relations**										
INV 001	Analyst/media communications				134.50	39.7%	5,278.83		5,278.83		5,389.69
INV 003	Fact sheet				4.50	39.7%	147.87		147.87		150.98
INV 004	Financial mailing list				38.00	39.7%	840.53	3,628.49	4,469.02		4,562.87
INV 005	Financial news releases			98.80	184.50	39.7%	8,117.10	3,560.83	11,776.73		12,024.04
INV 006	Group analyst meetings				768.50	39.7%	48,352.00	106,447.46	154,799.46		158,050.25
INV 007	HEI stock - share forecast				4.00	39.7%	88.91		88.91		90.78
INV 008	Investor base/stockholder monitoring				18.50	39.7%	729.40	15,573.52	16,302.92		16,645.28
INV 009	Investor relations planning				68.00	39.7%	1,612.40	671.91	2,284.31		2,332.28
INV 011	National Association of Investors Corporation (NAIC)					39.7%		825.76	825.76		843.10
INV 012	One-on-one meetings/visits with analysts				82.00	39.7%	9,712.40		9,712.40		9,916.36
INV 013	Other investor relations activities				118.00	39.7%	4,211.05	30,988.84	35,199.89		35,939.09
INV 015	Retail/broker/shareholder communications				33.50	39.7%	1,302.41		1,302.41		1,329.76
INV 018	Statistical supplement				18.50	39.7%	556.63		556.63		568.32
INV 019	Surveys	0.50	34.39		10.50	47.6%	369.24		403.63		412.11
INV 020	Teleconferencing				14.00	39.7%	1,102.60		1,102.60		1,125.75
INV 022	Investor Relations-Sarbanes Oxley Related Chgs					39.7%			0.00	2,475.08 (14)	2,527.06
		0.50	34.39	98.80	1,497.00		82,421.37	161,696.81	244,251.37	2,475.08	251,907.72
PEN	**Pension plan**										
PEN 005	HEIRS	2.60	145.63		426.20	46.2%	12,265.85	15,421.43	27,832.91		28,417.40
PEN 007	HEI Retirement Plan	6.50	364.07		7.25	72.0%	398.52		762.59		778.60
PEN 009	Master pension trust				773.00	66.9%	83,667.24	1,540.80	85,208.04		86,997.41
PEN 010	Pension-Sarbanes Oxley Related Charges					66.9%			0.00	3,311.94 (14)	3,381.49
PEN 022	Supplemental Exec. Retirement plan					50.0%		1,495.00	1,495.00		1,526.40
PEN 026	OPEB funded plans/trusts				648.50	68.3%	39,160.92	1,573.11	40,734.03		41,589.44
PEN 028	HECO OPEB Plan	43.50	2,484.61		84.50	68.4%	3,601.38		6,085.99		6,213.80
PEN 030	HEI postretirement electric discount trust	1.50	119.94		1.00	18.5%	14.46		134.40		137.22
		54.10	3,114.25	0.00	1,940.45		139,108.37	20,030.34	162,252.96	3,311.94	169,041.76

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HECO
EXCLUDING INCENTIVE COMPENSATION

Activity code	ACTIVITY CODE DESCRIPTIONS	Direct Charges-2004 Direct Labor Hours	Direct Labor Dollars	Direct Nonlabor Dollars	Shared Charges-2004 Shared Labor Hours	2005 Allocation Factor	Shared Labor Dollars	Shared Nonlabor Dollars	2004 Actual	2005 Adjustments	2005 Estimate (1)
RPT	**Reports**										
RPT 001	10K preparation	1.00	52.34		306.75	40.0%	11,572.42	15,861.71	27,486.47		28,063.69
RPT 011	10Q preparation	23.71	1,738.99	904.80	859.25	40.0%	31,913.98	33,089.49	67,647.26		69,067.85
RPT 015	10Q printing and mailing					37.4%		323.32	323.32		330.11
RPT 021	8K preparation	25.00	2,237.16	11,305.59	139.75	40.0%	3,670.23	6,882.67	24,095.65		24,601.66
RPT 041	Proxy preparation				71.70	39.7%	3,621.78	17,572.80	21,194.58		21,639.67
RPT 045	Proxy printing and mailing					37.1%		92,022.74	92,022.74		93,955.22
RPT 051	Annual report preparation	75.00	4,411.95		985.80	40.0%	36,413.67	125,274.05	166,099.67		169,587.76
RPT 055	Annual report printing and mailing					37.4%		53,974.46	53,974.46		55,107.92
RPT 098	Financial Reporting-Sarbanes Oxley Related Charges					40.0%		54,582.99	54,582.99	34,072.91 (14)	90,517.67
		124.71	8,440.44	12,210.39	2,363.25		87,192.08	399,564.23	507,427.14	34,072.91	552,871.55
STO	**Stock Transfer activities**										
STO 001	Preferred stock dividend payments	14.55	785.28						785.28		801.77
STO 003	Form 1099 (for preferred stockholders)	3.00	141.96						141.96		144.94
STO 004	Preferred stockholder database maintenance	17.30	755.36						755.36		771.22
STO 005	Other preferred stock communications	1.25	55.70						55.70		56.87
STO 006	Preferred stock transfer administrative activities	50.90	2,789.06	152.58					2,941.64		3,003.41
STO 011	Common stock dividend payments				61.80	37.1%	1,188.58	1,887.63	3,076.21		3,140.81
STO 012	HEI dividend reinvestment program administration				2,769.85	37.1%	48,862.17	37,747.68	86,609.85		88,428.66
STO 013	Form 1099 Dividends				25.50	37.1%	454.76	797.15	1,251.91		1,278.20
STO 014	Common stockholder database maintenance				1,197.80	37.1%	19,329.16	448.07	19,777.23		20,192.55
STO 015	Other common stock communications				1,950.75	37.1%	35,265.13		35,265.13		36,005.70
STO 016	Common stock transfer administrative activities				2,309.65	37.1%	47,605.38	12,742.86	60,348.24		61,615.55
STO 018	Stock transfer system				150.30	37.1%	2,662.92	48,613.43	51,276.35		52,353.15
STO 019	Stock transfer division expenses					37.1%		40,814.62	40,814.62	14,071.29 (11)	66,455.98
										10,203.20 (12)	
STO 020	Stock transfer division miscellaneous income					37.1%		(32,976.02)	(32,976.02)		(33,668.52)
STO 021	Stock Transfer-Sarbanes Oxley Related Chgs					37.1%			0.00	5,671.80 (14)	5,790.91
		87.00	4,527.36	152.58	8,465.65		155,368.10	110,075.42	270,123.46	29,946.29	306,371.20

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2004				
ıared abor ɔllars	Shared Nonlabor Dollars	2004 Actual	2005 Adjustments	2005 Estimate (1)
,258.95	5,156.22	24,928.93	20,500.00 (13)	46,382.94
,377.46		10,333.04	6,740.31 (13)	17,431.89
,881.26		20,587.69		21,020.03
149.12		10,507.25	15,349.77 (13)	26,400.02
687.01		17,524.43	21,230.61 (13)	39,568.90
36.05		2,667.11		2,723.12
,806.90		17,338.99	14,504.14 (13)	32,511.84
		4,451.80		4,545.29
		1,178.07		1,202.81
53.49		1,091.61		1,114.53
		222.13		226.79
		3,728.20		3,806.49
		2,701.18		2,757.90
		1,042.97		1,064.87
		16,086.57	(11,455.15) (13)	10,172.70
			5,332.05 (14)	
		17,942.01	(10,000.13) (13)	8,108.66
250.24	5,156.22	152,331.98	82,201.60	219,038.78
728.72	885,543.23	1,832,800.87	(43,332.77)	1,827,046.92
		(519.03) (a)		
		(1,257.36) (b)		
		(11,519.48) (c)		
		(712.50) (d)		
		(356.74) (e)		
		1,818,435.76		

to this rate case only.
ixed until March 31, 2006 (see CA-IR-253, Item 3).
ıng Committee.
'apital Trust III.

nd beyond.
ıed to this rate case only.

k split.

ɜntation on tax items as a result

Sarbanes-Oxley Section 404

CJJ 4/5/05

CA-IR-420

Ref: HECO response to CA-IR-252 & HECO-1310 (HEI Billings).

In response to CA-IR-252, the Company provided documentation supporting the development of the numerous allocation factors used to quantify the amount of HEI billings to HECO included in the 2005 test year forecast. The following questions point to specific pages of the response to CA-IR-252 and request additional information and/ or explanation:

a. Pages 11, 16, 45 and 49. Please provide additional documentation showing the split of "HEI Diversified, Inc. and subsidiary" amounts between ASB and HEIDI, by income statement and balance sheet line item.

b. Pages 12 and 46. As of year-end 2003 and 2004, the "Hycap Management, Inc." common equity balance declined from $18.7 million to $234,000. Please describe the business purpose of this entity and the apparent write-off of its equity investments in subsidiaries during 2004.

c. Pages 16-20 and 49-51. For each entity, please provide a more detailed breakdown of the reported expenses for 2003 and 2004. If a more detailed income statement for each entity is not readily available, please segregate the reported expenses between the following broad expense categories: fuel & purchased power; depreciation & amortization; labor; benefits; and other.

d. Pages 27 and 57. It is unclear how Bishop Insurance of Hawaii is considered in the development of the HEI allocation factors. Please explain in general how Bishop Insurance was considered, specifically referring to the gross payroll data.

e. Pages 16-20, 30, 49-51, and 60.

   1. Please explain why pages 30 and 60 only show month-end employees for HECO, HELCO, MECO, ASB, PECS and HEI Corporate when pages 16-20 and 49-51 present operating results for additional subsidiaries.

   2. If each of the subsidiaries reporting operating results in 2003 and/ or 2004 do not have employees, please explain how each entity's day-to-day work requirements are met (e.g., work performed by parent or affiliate employees whose labor/ benefit costs are allocated to subsidiary, work performed by outside contractor, etc.).

f. Pages 7 and 44.

1. Please explain the disproportionate attribution of "executives" to HECO in relation to HELCO, MECO and HEI.

2. Does HECO directly assign or allocate a portion of its executive time to HELCO, MECO and/ or HEI? Please explain.

g. Page 14. The notations showing the calculation of short term borrowings attribute negative short term debt ($4.8 million) to HECO in 2003 that was then assigned to HELCO.

1. Please explain how HECO can have negative short term debt.

2. Please explain why HECO was assigned zero short term debt with the negative $4.8 million assigned to HELCO.

h. Pages 15, 19-20, 47 and 51. In 2003, the common equity and pre-tax income attributed to HECO included HECO Capital Trusts I and II. In 2004, these trusts do not appear, at least separately, in the summary financial statements.

1. Please describe the business purpose of each of these trusts.

2. Why were these Trusts included in the HECO numbers for purposes of developing the 2003 allocation factors? Please explain.

3. Were these Trusts included in HECO's financial reports for 2004, such that it was unnecessary to separately add them in? Please explain.

i. Pages 13 and 18. In 2003, separate financial data is presented for Hawaiian Electric Industries Capital Trust I and subsidiary. Similar financial data is not show in 2004.

1. Please describe the business purpose of the Hawaiian Electric Industries Capital Trust I and subsidiary.

2. Please explain why the Hawaiian Electric Industries Capital Trust I and subsidiary financial results were not considered in developing the 2003 allocation factors. If they where, please provide a pinpoint reference to such consideration.

3. Why was financial data for Hawaiian Electric Industries Capital Trust I and subsidiary not provided for 2004? Please explain.

j. Pages 3 and 4. The estimated common equity results for December 31, 2004 used by the Company in HECO-1310 are not supported by the workpapers provided in response to

CA-IR-252 (pages 3-7). In addition, these common equity amounts were hard inputs in Excel spreadsheet file provided by HECO ("CA-IR-2a TY allocation factors.xls").

1. Please explain how the 12/31/04 estimates were determined.

2. Please provide a copy of any supporting workpapers, as requested by CA-IR-252(a).

HECO Response:

a. See pages 9 to 12 for the additional documentation showing the split of "HEI Diversified, Inc. and subsidiary" amounts between ASB and HEIDI, by income statement and balance sheet line item.

b. Hycap Management, Inc., HEI Preferred Funding, LP (a limited partnership in which Hycap Management, Inc. was the sole general partner), and Hawaiian Electric Industries Capital Trust I (a Delaware statutory trust in which HEI owned all the common securities) were formed to effect the issuance of $100 million of 8.36% HEI-obligated trust preferred securities in 1997, which securities were redeemed in April 2004. Hawaiian Electric Industries Capital Trust I and HEI Preferred Funding, LP were dissolved and terminated in 2004, and Hycap Management, Inc. began dissolution in 2004 for a period of three years, after which period Hycap will be terminated. The decline in the common equity balance was due to the return of capital to HEI, its parent company during 2004 in connection with the dissolution process.

c. A more detailed breakdown of the reported expenses for 2003 and 2004 for HEI, the holding company was provided in response to CA-IR-254, page 4. See pages 13 and 14, respectively for the 2003 and 2004 consolidating statements of income for Hawaiian Electric Company, Inc. and subsidiaries excerpted from the 12/31/04 SEC Form 10-K. The detailed

breakdown of the reported expenses for the other HEI subsidiaries would not be relevant for purposes of HECO's 2005 rate case.

d. American Savings Bank, F.S.B. (ASB) is the parent company of American Savings Investment Services Corp. (ASISC). ASISC is the parent company of Bishop Insurance Agency of Hawaii, Inc. and hence, its gross payroll data was included in the allocation factor for ASB.

e. Pages 30 and 60 only show employees for the HEI subsidiaries which have employees. The consolidating schedule of income information shown on pages 16-20 and 49-51 reflect all the HEI subsidiaries that have income information. The HEI subsidiaries without employees are HEI Diversified, Inc. (HEIDI), parent company of ASB, which currently conducts no business, HEI Investments Inc. (HEIII) which currently holds investments in leveraged leases, HEI Properties, Inc. (HEIPI) which currently holds venture capital investments, HEI Leasing Inc. (dissolved in 2003), Hycap Management, Inc. (discussed in question b. above and currently in dissolution), and The Old Oahu Tug Service, Inc. (TOOTS) which was formerly known as Hawaiian Tug & Barge but changed its name when it sold substantially all of its operating assets and the stock of Young Brothers in 1999. These companies with no employees manage its work requirements by utilizing HEI services, HECO services and/or outside contractors.

f. 1. HEI is involved in administering compensation matters (which are approved by the HEI Compensation Committee) related to the senior executive positions of the companies. Senior executive positions for the utilities and HEI include the Presidents' positions at HECO, HELCO and MECO and HEI, the Vice Presidents' positions at HECO (12 positions as of 1/1/05; 10 positions as of 1/1/04) and HEI (4 positions), the Controller's

position at both HECO and HEI, the Treasurer's position at HECO and the Secretary's position at HECO. Hence, HECO has the indicated number of senior executives as reflected on CA-IR-252 pages 7 and 44, whereas at HELCO and MECO only the respective company Presidents' compensation is approved by the HEI Compensation Committee. Certain of the HECO senior executives are also senior executives at HELCO and MECO. See HECO's response to part 2 below on how it charges its executive time to HELCO, MECO and/or HEI.

2. Yes, HECO Executives direct charge their time to the extent possible and practical to all [redacted]

HEI affiliates, including HELCO, MECO and HEI.

g. Please refer to CA-IR-252, page 5, which is the supporting workpaper for the development of the allocation factors for short-term debt. As indicated on CA-IR-252, page 5, HELCO is the only company attributed with $6 million of short-term debt as of 12/31/03. The derivation of the $6 million of HELCO short-term debt is based upon the following analysis and supported by what is shown on CA-IR-252, pages 14 and 15:

As of December 31, 2003, HECO had short-term borrowings of $25.5 million from MECO and $6 million from HEI (note the [illegible]

$4.8 million) so that the electric utilities do not reflect more short-term borrowings than exists at the consolidated HECO level.

h. 1. HECO Capital Trust I and HECO Capital Trust II were formed to effect the issuances of $50 million of 8.05% cumulative quarterly income preferred securities in March 1997 (redeemed in 2004) and $50 million of 7.3% cumulative quarterly income preferred securities in December 1998 (redeemed in 2004), respectively.

2. Both HECO Capital Trusts I and II were included in the HECO consolidated financial statements as of 12/31/03 and were financing entities under HECO; therefore, they were included in the HECO numbers for purposes of developing the 2003 allocation factors.

3. In December 2003, the Financial Accounting Standards Board (FASB) issued revised Interpretation No. 46 (FIN 46R), "Consolidation of Variable Interest Entities," which addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and accordingly should consolidate the entity. As of January 1, 2004, HEI and its subsidiaries (the Company) adopted the provisions of FIN 46R and deconsolidated HECO Capital Trust I and HECO Capital Trust II from its consolidated financial statements. The Company was not required to restate previously issued financial statements. HECO Capital Trusts I and II were dissolved and terminated in 2004.

In 2004, before their dissolution, the Trusts were not consolidated, but included in HECO's financial reports as equity investments, and thus, it was unnecessary to separately add them in.

i. 1. Hawaiian Electric Industries (HEI) Capital Trust I was formed to effect the issuance of $100 million of 8.36% HEI-obligated trust preferred securities in 1997 (redeemed in 2004).

2. HEI Capital Trust I and its subsidiary are financing subsidiaries of HEI, formed to effect the issuance of $100 million of 8.36% HEI-obligated trust preferred securities, the proceeds of which were used by HEI for the paydown of its existing debt and for general corporate purposes.

HEI Capital Trust I and its subsidiary are not included in the development of the HEI allocation factors to subsidiaries because in substance, these companies were formed to facilitate a financing transaction of HEI. Consequently, these subsidiaries were considered part of the HEI holding company for intercompany billing purposes.

3. HEI Capital Trust I was dissolved and terminated in 2004 since the $100 million of 8.36% HEI-obligated trust preferred securities were redeemed in April 2004. In addition, HEI and its subsidiaries adopted the provisions of FIN 46R as of January 1, 2004 and deconsolidated HEI Capital Trust I from its consolidated financial statements. The Company was not required to restate previously issued financial statements. In 2004,

estimate shown on HECO-1310 was 39.0% (see HECO-1310 and CA-IR-252, page 3) whereas the actual common equity percentage allocation to HECO that should have been used is 39.7% (see CA-IR-252, page 40).

HEI DIVERSIFIED, INC. AND SUBSIDIARY
Consolidating Schedule - Balance Sheet Information
December 31, 2003
(Unaudited)
(in thousands)

	HEI Diversified, Inc.	American Savings Bank, F.S.B. and subsidiaries	Reclassifications and Eliminations Dr. (Cr.)	Consolidated
ASSETS				
Cash and equivalents	$ 122	209,598	–	$ 209,720
Federal funds sold	–	56,678	–	56,678
Notes receivable from affiliated companies	1,320	–	–	1,320
Accounts receivable and unbilled revenues, net	2	23,136	–	23,138
Available-for-sale investment and mortgage-related securities	–	1,775,053	–	1,775,053
Available-for-sale mortgage-related securities pledged for repurchase agreements	–	941,571	–	941,571
Held-to-maturity investment securities	–	94,624	–	94,624
Loans receivable, net	–	3,121,979	–	3,121,979
Property, plant and equipment, net	–	69,703	–	69,703
Other	20,394	128,879	(3,304)	145,969
Goodwill and other intangibles	–	93,987	–	93,987
Investment in subsidiary, at equity	539,724	–	(539,724)	–
	$ 561,562	6,515,208	(543,028)	$ 6,533,742
LIABILITIES AND STOCKHOLDER'S EQUITY				
Liabilities				
Accounts payable	$ 597	42,628	–	$ 43,225
Deposit liabilities	–	4,026,250	–	4,026,250
Securities sold under agreements to repurchase	–	831,335	–	831,335
Advances from Federal Home Loan Bank	–	1,017,053	–	1,017,053
Long-term debt, net	17,073	–	–	17,073
Deferred income taxes	–	30,796	–	30,796
Other	(1,016)	24,005	–	22,989
	16,654	5,972,067	–	5,988,721
Preferred stock of bank subsidiary	–	113	–	113
Minority interests	–	3,304	3,304	–
Stockholder's equity				
Preferred stock	–	75,000	75,000	–
Common stock	331,072	244,568	244,568	331,072
Retained earnings	214,789	221,109	221,109	214,789
Accumulated other comprehensive loss	(953)	(953)	(953)	(953)
	544,908	539,724	539,724	544,908
	$ 561,562	6,515,208	543,028	$ 6,533,742

ASB

464,724

Agrees to CA-IR-252, p 11

544,908 - 464,724 = 80,184

HEID /

Agrees to CA-IR-252, p.1

HEI DIVERSIFIED, INC. AND SUBSIDIARY
Consolidating Schedule - Income Information
Year ended December 31, 2003
(Unaudited)
(in thousands)

	HEI Diversified, Inc.	American Savings Bank, F.S.B. and subsidiaries	Reclassifications and Eliminations Dr. (Cr.)	Consolidated
Revenues				
Bank	$ –	371,320	–	$ 371,320
Other	5,640	–	5,400	240
Equity in net income of subsidiary/ minority interest	56,385	–	56,385	–
	62,025	371,320	61,785	371,560
Expenses				
Bank	–	278,565	–	278,565
Other	1,391	–	–	1,391
	1,391	278,565	–	279,956
Operating income				
Bank	–	92,755	–	92,755
Other	60,634	–	61,785	(1,151)
	60,634	92,755	61,785	91,604
Interest expense–other than bank	(1,428)	–	–	(1,428)
Preferred stock dividends of subsidiaries	–	–	11	(11)
Income from continuing operations before income taxes and minority interest	59,206	4 92,755	61,796	3 90,165
Income tax expense (benefit)	(959)	30,959	–	30,000
Income from continuing operations before minority interest	60,165	61,796	61,796	60,165
Minority interest in net income of subsidiary	–	5 124	(124)	–
Income from continuing operations	60,165	61,672	61,672	60,165
Preferred stock dividends	–	2 5,411	(5,411)	–
Net income for common stock	$ 60,165	56,261	56,261	$ 60,165

2 92,755
2 5,411
002
ASB 4 87,344 Agrees to CA-IR-252 p. 16

3 90,165
4 87,344
002
2,821

5 124
003
HEIDI 2,945 Agrees to CA-IR-252 p. 16

HEI DIVERSIFIED, INC. AND SUBSIDIARY
Consolidating Schedule - Balance Sheet Information
December 31, 2004
(Unaudited)
(in thousands)

ASSETS	HEI Diversified, Inc.	American Savings Bank, F.S.B. and subsidiaries	Reclassifi-cations and Eliminations Dr. (Cr.)	Consolidated
Cash and equivalents	$ 1	120,295	–	$ 120,296
Federal funds sold	–	41,491	–	41,491
Notes receivable from affiliated companies	2,602	–	–	2,602
Accounts receivable and unbilled revenues, net	1,051	23,704	–	24,755
Available-for-sale investment and mortgage-related securities	–	2,034,091	–	2,034,091
Available-for-sale mortgage-related securities pledged for repurchase agreements	–	919,281	–	919,281
Held-to-maturity investment securities	–	97,365	–	97,365
Loans receivable, net	–	3,249,191	–	3,249,191
Property, plant and equipment, net	–	72,330	–	72,330
Other	17,377	117,494	(3,303)	131,568
Goodwill and other intangibles	–	91,263	–	91,263
Investment in subsidiary, at equity	556,311	–	(556,311)	–
	$ 577,342	6,766,505	(559,614)	$ 6,784,233
LIABILITIES AND STOCKHOLDER'S EQUITY				
Liabilities				
Accounts payable	$ 930	44,163	–	$ 45,093
Deposit liabilities	–	4,296,172	–	4,296,172
Securities sold under agreements to repurchase	–	811,438	–	811,438
Advances from Federal Home Loan Bank	–	988,231	–	988,231
Long-term debt, net	–	–	–	–
Deferred income taxes	1	19,297	–	19,298
Other	(436)	47,478	–	47,042
	495	6,206,779	–	6,207,274
Preferred stock of bank subsidiary	–	112	–	112
Minority interests	–	3,303	3,303	–
Stockholder's equity				
Common stock	331,071	320,501	320,501	331,071
Retained earnings	252,967	243,001	243,001	252,967
Accumulated other comprehensive loss	(7,191)	(7,191)	(7,191)	(7,191)
	576,847	(2) 556,311	556,311	(1) 576,847
	$ 577,342	6,766,505	559,614	$ 6,784,233

ASB
Agrees to
CA-IR-252, p 45.

(1) 576,847 · * +
(2) 556,311 · -

002

HEIDI 20,536 · *

Agrees to CA-IR-252 p. 45.

HEI DIVERSIFIED, INC. AND SUBSIDIARY
Consolidating Schedule - Income Information
Year ended December 31, 2004
(Unaudited)
(in thousands)

	HEI Diversified, Inc.	American Savings Bank, F.S.B. and subsidiaries	Reclassifications and Eliminations Dr. (Cr.)	Consolidated
Revenues				
Bank	$ –	364,284	–	$ 364,284
Other	5,492	–	5,400	92
Equity in net income of subsidiary/ minority interest	41,159	–	41,159	–
	46,651	364,284	46,559	364,376
Expenses				
Bank	–	259,310	–	259,310
Other	811	–	–	811
	811	259,310	–	260,121
Operating income				
Bank	–	104,974	–	104,974
Other	45,840	–	46,559	(719)
	45,840	104,974	46,559	104,255
Interest expense–other than bank	(437)	–	–	(437)
Preferred stock dividends of subsidiaries	–	–	11	(11)
Income from continuing operations before income taxes and minority interest	45,403	(1) 104,974	46,570	(3) 103,807
Income tax expense (benefit)	(923)	58,404	–	57,481
Income from continuing operations before minority interest	46,326	46,570	46,570	46,326
Minority interest in net income of subsidiary	–	(5) 97	(97)	–
Income from continuing operations	46,326	46,473	46,473	46,326
Preferred stock dividends	–	(2) 5,411	(5,411)	–
Income from continuing operations	46,326	41,062	41,062	46,326
Income from discontinued operations	66	–	–	66
Net income for common stock	$ 46,392	41,062	41,062	$ 46,392

(1) 104,974. *+
(2) 5,411. –
002
ASB (4) 99,563. * Agrees to CA-IR-252 p. 49

(3) 103,807. *+
(4) 99,563. –
002
4,244. ◊

(5) 97. +
003
HEID 4,341. * Agrees to CA-IR-252 p. 49

Consolidating statement of income

(in thousands)	HECO	HELCO	MECO	Renewable Hawaii, Inc.	HECO Capital Trust I	HECO Capital Trust II	Reclassifications and Eliminations		HECO Consolidated
	Year ended December 31, 2003								
Operating revenues	$963,500	214,243	215,295	–	–	–	–		$1,393,038
Operating expenses									
Fuel oil	273,905	31,853	82,802	–	–	–	–		388,560
Purchased power	284,549	75,042	8,485	–	–	–	–		368,076
Other operation	102,441	25,643	27,447	–	–	–	–		155,531
Maintenance	38,505	13,737	12,379	–	–	–	–		64,621
Depreciation	67,121	20,293	23,146	–	–	–	–		110,560
Taxes, other than income taxes	90,150	20,105	20,422	–	–	–	–		130,677
Income taxes	31,113	7,120	11,942	–	–	–	–		50,175
	887,784	193,793	186,623	–	–	–	–		1,268,200
Operating income	75,716	20,450	28,672	–	–	–	–		124,838
Other income									
Allowance for equity funds used during construction	3,652	170	445	–	–	–	–		4,267
Equity in earnings of subsidiaries	29,459	–	–	–	–	–	(29,459)	[2]	–
Other, net	2,667	315	(557)	(133)	4,149	3,763	(8,301)	[1]	1,903
	35,778	485	(112)	(133)	4,149	3,763	(37,760)		6,170
Income before interest and other charges	111,494	20,935	28,560	(133)	4,149	3,763	(37,760)		131,008
Interest and other charges									
Interest on long-term debt	25,284	7,016	8,398	–	–	–	–		40,698
Amortization of net bond premium and expense	1,371	364	396	–	–	–	–		2,131
Preferred securities distributions of trust subsidiaries	–	–	–	–	–	–	7,675	[3]	7,675
Other interest charges	6,506	1,952	1,354	1	–	–	(8,301)	[1]	1,512
Allowance for borrowed funds used during construction	(1,658)	(80)	(176)	–	–	–	–		(1,914)
Preferred stock dividends of subsidiaries	–	–	–	–	–	–	915	[3]	915
	31,503	9,252	9,972	1	–	–	289		51,017
Income before preferred stock dividends of HECO	79,991	11,683	18,588	(134)	4,149	3,763	(38,049)		79,991
Preferred stock dividends of HECO	1,080	534	381	–	4,025	3,650	(8,590)	[3]	1,080
Net income for common stock	$ 78,911	11,149	18,207	(134)	124	113	(29,459)		$ 78,911

Consolidating statement of income

(in thousands)	HECO	HELCO	MECO	Renewable Hawaii, Inc.	Reclassifications and Eliminations		HECO Consolidated
	Year ended December 31, 2004						
Operating revenues	$1,053,100	241,630	252,145	–	–		$1,546,875
Operating expenses							
Fuel oil	335,281	38,072	110,070	–	–		483,423
Purchased power	295,963	91,024	11,849	–	–		398,836
Other operation	106,138	24,572	26,488	–	–		157,198
Maintenance	47,847	15,145	14,321	–	–		77,313
Depreciation	69,467	21,163	24,290	–	–		114,920
Taxes, other than income taxes	97,974	22,391	23,469	–	–		143,834
Income taxes	29,484	8,204	12,371	–	–		50,059
	982,154	220,571	222,858	–	–		1,425,583
Operating income	70,946	21,059	29,287	–	–		121,292
Other income							
Allowance for equity funds used during construction	5,226	162	406	–	–		5,794
Equity in earnings of subsidiaries	31,746	–	–	–	(31,746)	[2]	–
Other, net	3,652	210	(43)	(53)	(634)	[1]	3,132
	40,624	372	363	(53)	(32,380)		8,926
Income before interest and other charges	111,570	21,431	29,650	(53)	(32,380)		130,218
Interest and other charges							
Interest on long-term debt	26,566	7,184	8,793	–	–		42,543
Amortization of net bond premium and expense	1,464	403	422	–	–		2,289
Other interest charges	3,595	1,083	712	–	(634)	[1]	4,756
Allowance for borrowed funds used during construction	(2,312)	(75)	(155)	–	–		(2,542)
Preferred stock dividends of subsidiaries	–	–	–	–	915	[3]	915
	29,313	8,595	9,772	–	281		47,961
Income before preferred stock dividends of HECO	82,257	12,836	19,878	(53)	(32,661)		82,257
Preferred stock dividends of HECO	1,080	534	381	–	(915)	[3]	1,080
Net income for common stock	$ 81,177	12,302	19,497	(53)	(31,746)		$ 81,177

HECO

COMPANY NAME - HAWAIIAN ELECTRIC COMPANY
CAPITAL STRUCTURE
DECEMBER 31
in thousands)

CAPITALIZATION BALANCES ($)	ACTUAL 2003	BUDGET 2004
PREFERRED STOCK	22,293	22,293
COMMON EQUITY	582,562	637,323

Agrees to CA-IR-252, pg 3

4/5/2004

RHI

COMPANY NAME - RENEWABLE HAWAII, INC. (RHI)
CAPITAL STRUCTURE
DECEMBER 31
In thousands)

CAPITALIZATION BALANCES ($)	ACTUAL 2003	BUDGET 2004
PREFERRED STOCK	0	0
COMMON EQUITY	47	1,047

Agrees to CA-IR-252, pg 3

4/5/2004

HELCO

COMPANY NAME - HAWAII ELECTRIC LIGHT COMPANY, INC.
CAPITAL STRUCTURE
DECEMBER 31
in thousands)

CAPITALIZATION BALANCES ($)	ACTUAL 2003	BUDGET 2004
PREFERRED STOCK	7,000	7,000
COMMON EQUITY	174,639	186,450

Agrees to CA-IR-252, pg 3

MECO

COMPANY NAME - MAUI ELECTRIC COMPANY, LTD.
CAPITAL STRUCTURE
DECEMBER 31
in thousands)

CAPITALIZATION BALANCES ($)	ACTUAL 2003	BUDGET 2004
PREFERRED STOCK	5,000	5,000
COMMON EQUITY	187,194	193,696

Agrees to CA-IR-252, pg 3

4/5/2004

AMERICAN SAVINGS BANK, F.S.B. AND SUBSIDIARIES (ASB)
CAPITAL STRUCTURE
DECEMBER 31,
($ in thousands)

	Budget 2004
CAPITALIZATION - YEAR-END:	
PREFERRED STOCK	75,000
COMMON EQUITY	494,934
TOTAL CAPITALIZATION	569,934
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	10,471

505,405
Agrees to CA-IR-252, pg 3

Description	HECO	RHI	HELCO	MECO	ASB	TOOTS	HEIDI	HEIII	HEIPI	PECS	TOTAL	
12/31/03 actual ending common equity						1,978	80,184	14,984	3,949	31		Agrees to CA-IR-252, pages 11-13
2004 estimated net income (loss)						(13)	5,193	1,858	(73)	(60)		See page ___
2004 estimated equity infusion						0	0	0	100	60		
12/31/04 estimated ending common equity	637,323	1,047	186,450	193,696	505,405	1,965	85,377	16,842	3,976	31	1,632,112	Agrees to CA-IR-252, page 3
	See p _	See p _	See p _	See p _	See p _							
12/31/04 estimated common equity % (used for developing the 2005 HECO test year estimate)	39.0%	0.1%	11.4%	11.9%	31.0%	0.1%	5.2%	1.0%	0.3%	0.0%	100.0%	Agrees to CA-IR-252, page 3
12/31/04 actual ending common equity	640,892	294	186,505	189,413	556,311	2,164	20,536	16,805	3,035	0	1,615,955	Agrees to CA-IR-252, page 40
12/31/04 actual common equity %	39.7%	0.0%	11.6%	11.7%	34.4%	0.1%	1.3%	1.0%	0.2%	0.0%	100.0%	Agrees to CA-IR-252, page 40
Difference in %s between actual and estimated	0.7%	(0.1%)	0.2%	(0.2%)	3.4%	0.0%	(3.9%)	0.0%	(0.1%)	0.0%	0.0%	

CA-IR-421

Ref: HECO responses to CA-IR-252, CA-IR-253 & HECO-1310 (HEI Billings).

In response to CA-IR-252, the Company provided documentation supporting the development of the numerous allocation factors used to quantify the amount of HEI billings to HECO included in the 2005 test year forecast. Item 7 of the response to CA-IR-253 described the Company's elimination of incentive compensation costs from the HEI charges to simplify issues in the rate case. The following questions point to specific [illegible] of the [illegible] to CA-IR-252 [illegible]

additional information and/ or explanation:

a. Pages 5, 21, 29, 42, and 55-59. The development of the Gross Payroll allocation factor

IR-252, page 5 based upon the 12/31/03 results and 40.9% (see page 4) versus the 40.2% shown on CA-IR-252, page 42 based upon the 12/31/04 results. Hence, the allocations to HECO would have been higher than what is currently reflected in the 2005 test year estimate to HECO shown on HECO-1310.

oted) used for determining HEI's 2005 estimate of shared charges to HECO shown on HECO-1310

CO	RHI	HELCO	MECO	ASB	TOOTS	HEIDI	HEIII	HEIPI	PECS	TOTAL	ADJ	HEI Corp., (and its financing subs HEI Captial Trust I Hycap) & Elim	CONS.
847	0	21,882	21,975	57,781	0	0	0	0	181	200,666		6,657	207,323
313)	0	(181)	(231)	(10,719)	0	0	0	0	(3)	(12,947)		(2,056)	(15,003)
034	0	21,701	21,744	47,062	0	0	0	0	178	187,719		4,601	192,320
.6%	0.0%	10.6%	10.6%	27.9%	0.0%	0.0%	0.0%	0.0%	0.1%	96.8%		3.2%	100.0%
.8%	0.0%	0.7%	0.7%	(3.4%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%		(0.8%)	(0.0%)
.4%	0.0%	11.3%	11.3%	24.5%	0.0%	0.0%	0.0%	0.0%	0.1%	97.6%		2.4%	100.0%
.6%	0.0%	11.6%	12.4%	30.8%	0.1%	5.3%	1.0%	0.2%	0.0%	100.0%			100.0%
.3%	0.1%	8.2%	13.6%	39.5%	0.0%	1.3%	0.9%	0.1%	0.0%	100.0%			100.0%
.6%	0.0%	10.6%	10.6%	27.9%	0.0%	0.0%	0.0%	0.0%	0.1%	96.8%	0.0%	3.2%	100.0%
.8%	0.0%	10.1%	12.2%	32.8%	(0.0%)	2.2%	0.7%	0.1%	0.0%	98.9%	0.0%	1.1%	100.0%
compensation:													
6%	0.0%	11.6%	12.4%	30.8%	0.1%	5.3%	1.0%	0.2%	0.0%	100.0%			100.0%
3%	0.1%	8.2%	13.6%	39.5%	0.0%	1.3%	0.9%	0.1%	0.0%	100.0%			100.0%
4%	0.0%	11.3%	11.3%	24.5%	0.0%	0.0%	0.0%	0.0%	0.1%	97.6%	0.0%	2.4%	100.0%
8%	0.0%	10.4%	12.4%	31.6%	0.0%	2.2%	0.7%	0.1%	0.0%	99.2%	0.0%	0.8%	100.0%
0%	0.0%	0.3%	0.2%	(1.2%)	(0.0%)	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%	(0.3%)	0.0%

Allocation Factors

Actual results as of 12/31/04 to be used in HEI's 2005 actual billings to HECO

(in thousands of dollars, except as noted)

	Ref	Source	HECO	RHI	HELCO	MECO	ASB	TOOTS	HEIDI	HEIII	HEIPI	PECS	TOTAL	ADJ	HEI Corp., (and its financing subs HEI Captial Trust I Hycap) & Elim	CONS.
Employee related:																
Gross payroll (per CA-IR-252 page 42)			102,067	0	23,174	23,341	56,897	0	0	0	0	174	205,653		7,193	212,846
Excluding bonus & incentive compensation			(1,794)	0	(181)	(170)	(8,224)	0	0	0	0	(5)	(10,374)		(2,611)	(12,985)
Gross payroll (excl. bonus/incentive comp)			100,273	0	22,993	23,171	48,673	0	0	0	0	169	195,279		4,582	199,861
Gross payroll % (per CA-IR-252 page 42)			47.9%	0.0%	10.9%	11.0%	26.7%	0.0%	0.0%	0.0%	0.0%	0.1%	96.6%		3.4%	100.0%
Adj due to exclusion of bonus & incentive comp			2.2%	0.0%	0.6%	0.6%	(2.3%)	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%		(1.1%)	0.0%
Gross payroll % (excl. bonus/incentive comp)			50.1%	0.0%	11.5%	11.6%	24.4%	0.0%	0.0%	0.0%	0.0%	0.1%	97.7%		2.3%	100.0%
General (3 factor formula) per CA-IR-252 page 42:																
Common equity			39.7%	0.0%	11.6%	11.7%	34.4%	0.1%	1.3%	1.0%	0.2%	0.0%	100.0%			100.0%
Pretax income			33.0%	0.0%	8.6%	13.3%	41.8%	0.1%	1.8%	0.9%	0.4%	0.1%	100.0%			100.0%
Gross payroll			47.9%	0.0%	10.9%	11.0%	26.7%	0.0%	0.0%	0.0%	0.0%	0.1%	96.6%	0.0%	3.4%	100.0%
Average			40.2%	0.0%	10.4%	12.0%	34.3%	0.1%	1.0%	0.6%	0.2%	0.1%	98.9%	0.0%	1.1%	100.0%
General (3 factor formula) excluding bonus/incentive compensation:																
Common equity			39.7%	0.0%	11.6%	11.7%	34.4%	0.1%	1.3%	1.0%	0.2%	0.0%	100.0%			100.0%
Pretax income			33.0%	0.0%	8.6%	13.3%	41.8%	0.1%	1.8%	0.9%	0.4%	0.1%	100.0%			100.0%
Gross payroll (excl. bonus/incentive comp)			50.1%	0.0%	11.5%	11.6%	24.4%	0.0%	0.0%	0.0%	0.0%	0.1%	97.7%	0.0%	2.3%	100.0%
Average (excl. bonus/incentive comp)			40.9%	0.0%	10.5%	12.2%	33.6%	0.1%	1.0%	0.7%	0.2%	0.0%	99.2%	0.0%	0.8%	100.0%
Difference % due to exclusion of			0.7%	0.0%	0.1%	0.2%	(0.7%)	0.0%	0.0%	0.1%	0.0%	(0.1%)	0.3%		(0.3%)	0.0%

CA-IR-422

Ref: HECO responses to CA-IR-6 & CA-IR-252 (HEI Billings).

Page 4 of the response to CA-IR-6 represents a corporate organizational chart for Hawaiian Electric Industries, Inc. Please identify each of the subsidiary operations listed below that have been excluded from the development of the allocation factors used to apportion shared HEI costs, as presented in the response to CA-IR-252, and provide a detailed explanation of the rationale for each property excluded therefrom:

a. HEI Properties, Inc.

b. HYCAP Management, Inc.

c. HEI Diversified, Inc.

   1. American Savings Bank, FSB.

   2. Adcommunications, Inc.

   3. American Savings Investment Services Corp.

   4. Bishop Insurance Agency.

   5. ASB Realty Corporation.

d. Hawaiian Electric Company, Inc.

   1. Hawaii Electric Light, Inc.

   2. Maui Electric Company, Ltd.

   3. HECO Capital Trust III.

   4. Renewable Hawaii, Inc.

e. The Old Oahu Tug Service, Inc.

f. HEI Power Corp.

   1. HEI Investments, Inc.

   2. HEI Power Corp. International.

      (a) HEIPC China.

(b) United Power Pacific Co., Ltd.

g. Pacific Energy Conservations Services, Inc.

h. HEI Capital Trust II, III.

HECO Response:

Discussed below are only those companies that are excluded from the development of the allocation factors and the rationale for their exclusion:

From inception, HYCAP Management, Inc. (HYCAP) was not included in the development of the allocation factors because in substance, this company was formed to facilitate a financing transaction of HEI. Consequently, this subsidiary is considered part of the HEI holding company for intercompany billing purposes. As discussed in CA-IR-420, Item b., HYCAP, HEI Preferred Funding, LP (a limited partnership in which HYCAP was the sole general partner), and Hawaiian Electric Industries Capital Trust I (a Delaware statutory trust in which HEI owned all the common securities) were formed to effect the issuance of $100 million of 8.36% HEI-obligated trust preferred securities in 1997, which securities were redeemed in April 2004. Hawaiian Electric Industries Capital Trust I and HEI Preferred Funding, LP were dissolved and terminated

HEIPC intends to transfer ownership of HEIII to HEI. HEIII will then operate as a direct subsidiary of HEI for the foreseeable future. Consequently, HEIII has been included in the development of the common equity and other allocation factors.

HEI Capital Trusts II and III were formed to be used in connection with possible future trust preferred financings and from inception through December 31, 2004 have been inactive. These Trusts have no capital and they are not included in the development of the allocation factors.

CA-IR-423

Ref: HECO response to CA-IR-252 & HECO-1310 (HEI Billings).

In response to CA-IR-252(c), the Company indicated that common equity based allocation factors are used to allocate approximately 80% of the total HEI shared charges. Please provide a detailed explanation of the rationale for using common stock and cumulative equity earnings (i.e., common equity) as the basis for apportioning shared cost responsibility between the regulated and non-regulated entities included in the HEI portfolio.

HECO Response:

The HEI shared costs allocated to its subsidiaries using the common equity allocator consist primarily of shared costs related to stock transfer, investor relations and reporting activities. Based upon the principle that if each of the HEI subsidiaries were a stand-alone publicly-traded company, each would conduct these types of activities. HEI allocates these shared costs to its subsidiaries based upon this logical measure of cost causation.

Subsidiaries derive their equity from two sources: parent company equity infusions

In addition, allocation of these shared costs based upon relative common equity is also reasonable based upon the logic that the tendency would be for corporate resources to be utilized relative to those subsidiaries in which the holding company has a greater investment, or equity.

All of HEI's attribution methods were independently reviewed by the former Arthur

CA-IR-424

Ref: HECO T-13, page 38, response to CA-IR-253 and HECO-1310 (HEI Billings).

In response to CA-IR-253, Item 9 refers to Footnote 12 of HECO-1310 and describes certain HEI adjustments to 2004 for inclusion in the 2005 test year forecast related to Sarbanes-Oxley ("SOX"). The adjustments are primarily associated with an additional 1,304 labor hours related to SOX that were converted into labor dollars and partially allocated to HECO. Additional external auditor charges were also allocated to HECO. Please provide the following:

a. During or subsequent to 2003, did HEI hire additional full time or part-time employees to whom the 1,304 hours are attributable?

   1. If so, please identify those new employment positions, annual pay rates and dates of hire.

   2. If not, please explain whether the additional labor hours relate to pre-existing HEI employees.

b. Referring to page 9 of the response to CA-IR-253, please provide additional support showing the development of the December 31, 2003 labor rates included in column (b), showing all labor loading calculations.

c. Are the $48,954 in additional "external auditor attestation fees" for SOX compliance an annually recurring cost? Please explain.

d. At page 38 of HECO T-13, the $128,000 increase in KPMG audit fees between 2003 and 2005 is generally attributed to additional work to comply with SOX, including internal controls. The response to CA-IR-2, Attachment 6 (pages 4-5), provides additional support for the HECO SOX audit fees. Are the HEI SOX audit fees ($48,954) duplicative of the increased audit fees directly incurred by HECO ($128,000)? Please explain.

e. Referring to page 38 of HECO T-13 and CA-IR-2, Attachment 6 (pages 4-5), is the increase in SOX audit fees incurred by HECO partially allocable to HELCO and MECO?

HECO Response:

a. 1. & 2. During or subsequent to 2003 (but prior to March 2005), HEI did not hire any additional full or part-time employees to whom the additional 1,304 labor hours are attributable. Instead, HEI retained outside consultants to assist in its Sarbanes-Oxley Act of 2002 (SOX) compliance effort. In 2004, HEI recorded $0.6 million of fees to external vendors (excluding $0.1 million of audit fees) related to its SOX compliance effort.

In March 2005, HEI added one full-time position in connection with its SOX compliance effort (due to the confidential nature of employee salary information, the pay rate for this new employee is only available for review at the HEI Controller's office. Please contact Irene Sekiya at (808) 543-4778 to arrange to review this information). In 2005, the HEI internal audit department will assist management in its testing of its internal control over financial reporting. Management may also retain outside consultants to assist in its testing.

b. Due to the confidential nature of employee salary and benefit information, the actual loaded

financial statements included in the annual report has issued an attestation report on management's assessment of the company's internal control over financial reporting.

d. No, the HEI SOX audit fees of ($48,954) of which ($18,821) is estimated to be allocated to HECO is not duplicative of the increased audit fees directly incurred by HECO ($128,000). HEI and HECO are billed separately by KPMG LLP for the SOX audit work they perform for each Company, based on hours spent auditing each Company. See page 9 of HECO's response to CA-IR-253 for KPMG charges to HEI allocated to HECO. HECO's estimated SOX audit fee was based only on the amounts estimated to be billed by KPMG LLP directly to HECO.

e. KPMG LLP bills HECO, HELCO and MECO separately for SOX audit work performed for each company, based on hours spent auditing each Company. As such, the amounts billed to HECO were not allocated to HELCO and MECO.

f. The cost of KPMG LLP's SOX audit for HECO for the year 2004 totaled $464,000, excluding general excise tax. Of this amount, $206,000 was expensed in 2004 and $258,000 was expensed in 2005. KPMG LLP has not yet developed its fee estimate for their 2005 SOX audit, but it is expected to be substantially higher than the original rate case estimate.
The actual cost of KPMG LLP's SOX audit for HEI for the year 2004 totaled $203,000. Of this amount, $136,000 was expensed in 2004 and $67,000 was expensed in 2005. KPMG LLP has not yet developed its fee estimate for their 2005 SOX audit, but preliminary discussions with KPMG LLP indicate that the fee estimate will be at least $203,000.

CA-IR-425

Ref: HECO response to CA-IR-254 & HECO-1310 (HEI Billings).

In response to CA-IR-254, the Company provided total HEI expenses (excluding intercompany billings) for 2001-2004 and the 2005 Forecast. Please provide the following:

a. Do the amounts for 2004 represent actual or budgeted expenses? Please explain.

b. Do the amounts for the 2005 Forecast represent the results of HEI's normal budget/ forecast process as opposed to the test year forecast process? Please explain.

c. For calendar years 2003, 2004 and 2005 Forecast, please provide a detailed breakdown of the HEI expenses by Activity Code, regardless whether the costs are retained or billed by HEI.

d. Referring to item (c) above and the response to CA-iR-254(b), please identify each activity code that is retained (i.e., not billed) by HEI.

HECO Response:

a. The amounts shown on CA-IR-254, pages 4 and 6, represent actual 2004 expenses in the column designated as "2004".

b. Yes, the amounts for the 2005 Forecast represent HEI's normal budget/ forecast process.

c. See page 3 for the 2003, 2004 and 2005 Forecast of the HEI expenses.

d. HEI's forecast process is not based upon capturing costs by activity code that is retained versus billed. HEI's forecast process for developing its intercompany billing amounts to its subsidiaries are based upon reviewing the prior year actual historical billings to its subsidiaries and increasing the billings by an inflation factor with certain adjustments similar to what are shown on HECO-1310, page 4. The adjustments are based upon the reviews performed by the respective HEI departments that provide chargeable services to HEI's subsidiaries. The respective HEI departments review the prior year's actual labor

hours and nonlabor dollars for the activities being charged to the subsidiaries (see CA-IR-251, pages 3-159 for a copy of the report the HEI departments review) and determine whether the labor hours and nonlabor dollars should be increased or decreased for the upcoming year's forecast based upon their knowledge at that time.

HAWAIIAN ELECTRIC INDUSTRIES, INC.

MAIN ACCOUNT	DESCRIPTION		2005 Forecast	2004 Forecast	2003 Forecast
	ADMINISTRATIVE & GENERAL EXPENSE				
55000	Labor Expense		7,417,778	7,190,680	6,563,696
(55100 TO 55110)	Nonlabor Expense		686,946	612,966	587,512
(55200 TO 55204)	Intercompany Billing to Subs	(a)	(4,405,311)	(3,744,798)	(3,428,040)
(55500 TO 55509)	Advertising/Public Relations/Communications		197,268	205,818	200,998
56001	Legal Services		202,200	202,200	160,020
56002	Services From Associated Companies		218,458	260,970	332,863
(56032 TO 56070)	Other Outside Services		927,385	743,726	657,580
57000	Insurance Expense		1,214,270	1,447,543	273,268
57500	Employee Benefits		1,070,056	984,706	1,426,145
57600	Other Employee Benefits		1,710,777	1,485,937	1,180,056
58500	Rent-Building		888,500	849,900	888,936
(59002 TO 59099)	Misc A&G Expense		3,474,364	3,104,628	6,587,816
(59105 TO 59150)	Investor Relations		743,644	729,906	762,763
(59201 TO 59203)	Common Stock Expense		424,817	204,460	197,577
(59300 TO 59318)	HEI Info Tech Expense		312,087	298,620	323,567
	TOTAL ADMINISTRATIVE & GENERAL EXPENSE		**15,083,239**	**14,577,262**	**16,714,757**
	DEPRECIATION & AMORTIZATION				
(60000 TO 60011)	Depreciation Expense		275,876	346,271	432,497
61000	Amortization		33,965	22,745	1,534
	TOTAL DEPRECIATION & AMORTIZATION		**309,841**	**369,016**	**434,031**
	TAXES, OTHER THAN INCOME TAXES				
80000	Payroll Tax Expense		315,426	454,241	465,789
81000	State General Excise Tax & Use Tax		8,217	10,000	10,000
85000	Other Taxes		0	0	0
	TOTAL TAXES, OTHER THAN INCOME TAXES		**323,643**	**464,241**	**475,789**
	TOTAL ESTIMATED EXPENSES		**15,716,723**	**15,410,519**	**17,624,577**
(55200 TO 55204)	Add back: Intercompany Billings to Subs	(a)	4,405,311	3,744,798	3,428,040
	TOTAL ESTIMATED EXPENSES excluding Interco Billings	(b)	**20,122,034**	**19,155,317**	**21,052,617**
	% billed to subs for management service fees (including interco. borrowing	**(c) = (a) / (b)**	**21.9%**	**19.5%**	**16.3%**
	% of costs retained by HEI (excluding interest and income taxes)	**1- (c)**	**78.1%**	**80.5%**	**83.7%**

CA-IR-426

Ref: HECO response to CA-IR-254 & HECO-1310 (HEI Billings).

In response to CA-IR-254(b)(3), the Company indicated that of the estimated 21.9% of costs billed by HEI to its subsidiaries, HECO's 2005 test year amount of $1.7 million (HECO-1310) represents approximately 39% of the estimated costs billed. Using 2003 actual data from HECO-1310 and CA-IR-254, HEI billed approximately 24.8% of $22.17 million of which $1.67 million or 30.4% (i.e., $1.67 million ÷ ($22.17 x 24.8%) = 30.4%) was billed to HECO. Please provide the following:

a. Referring to page 4 of the response to CA-IR-254, the total HEI expenses (excluding interco billings) decreased from 2003 ($22.17 million) to the 2005 Forecast ($20.12 million). Please explain and reconcile the decline in total HEI costs with the increase in HEI costs charged to HECO, as supported by HECO-1310.

b. Please explain and reconcile the increase in HECO's share of HEI's billed cost from 30.4% in 2003 to approximately 39% in the 2005 test year estimate.

HECO Response:

a. See page 2 that explains and reconciles the decline in HEI expenses from 2003 ($22.2 million) to the 2005 forecast ($20.1 million).

b. After excluding the one-time nonrecurring items that are included in the 2003 actual results and billings to the subs, HECO's adjusted share of HEI's billed costs is 38.8% in 2003 (as shown on page 2), which is close to the 39% in the 2005 test year estimate.

Hawaiian Electric Industries, Inc.
(in millions of $)

2003 Actual		$ 22.2	Per CA-IR-254, p 4
2005 Forecast		$ 20.1	Per CA-IR-254, p 4
Difference		$ 2.1	
Explanation for the difference:			
Income note litigation expenses in 2003 only which were not billed to subs (Misc A&G exp)		$ 3.5	
Less: nonrecurring intercompany billing to HEIDI & true-up in 2003 only		$ (1.2)	
Other		$ (0.2)	
		$ 2.1	
2003 intercompany billings to HECO	(a)	$ 1.67	Per HECO-1310
2003 intercompany billings to subs		$ 5.5	Per CA-IR-254, p 4
Less: nonrecurring intercompany billing to HEIDI & true-up in 2003 only		$ (1.2)	
	(b)	$ 4.3	
	(a) / (b)	38.8%	

CA-IR-427

Ref: HECO response to CA-IR-249 (Standard Labor Rates).

[illegible]

provided, in part, the "standard labor rates used to derive the 2005 test year labor expenses." The referenced interrogatory sought additional documentation supporting the development of the Standard Labor Rates used in the 2005 test year forecast. A comparison of the labor rates set forth in these documents indicates that the rates set forth on Attachment A are about 2.8% to 5.9% higher than the CA-IR-249 rates. Please provide the following:

[illegible]

CA-IR-428

		Data	
BU/Merit	LAB_COST_CL_L	Sum of Amount	Sum of Hours
Police	POLICE	378,579	15,958
Police Total		378,579	15,958
BU	BUOC	5,577,691	248,586
	BUOCB	315,194	14,544
	BUOCED	403,297	19,181
	BUOCI	218,103	10,306
	BUOCW	224,770	9,622
	BUOCY	65,938	3,501
	BUTC	2,950,907	114,966
	BUTCED	604,379	19,716
	BUTCI	6,825,429	212,322
	COMELE	355,675	11,669
	CONCRW	208,392	5,975
	CUPLNR	144,346	5,076
	DEPLNR	186,764	5,752
	ENGMAP	274,648	10,425
	HPPMNT	492,457	14,932
	INSCRW	241,169	7,703
	JPCORD	56,535	2,037
	JRPLNR	240,195	9,650
	KPPMNT	1,751,098	51,510
	MTELEC	358,549	12,032
	OHCREW	8,564,974	244,003
	OPEDIS	630,518	18,537
	PPDRAF	105,900	3,438
	PTM	1,569,889	44,320
	RELCRW	366,300	11,572
	RESHER	93,897	3,618
	STRDFT	121,527	3,969
	SUBCRW	1,570,498	47,952
	SUBDFT	123,546	3,840
	SURVBU	90,952	3,574
	TECDFT	52,972	1,845
	TNDDFT	133,330	4,221
	TVLBLR	2,314,291	69,888
	TVLELC	814,710	22,111
	TVLMCH	859,288	24,481
	TVLTCH	369,688	10,542
	UGCREW	2,148,690	58,731
	WHMAID	53,997	1,785
	WPPMNT	1,363,736	39,986
BU Total		42,844,238	1,407,916
Merit	AIRSCI	309,185	8,847
	AIRSPE	31,306	1,296
	CHEMST	326,155	11,221
	COMENG	63,512	1,860
	COMSUP	70,127	2,033
	CONSUP	25,156	665

		Data	
BU/Merit	LAB_COST_CL_L	Sum of Amount	Sum of Hours
Merit	CUDGNR	121,097	3,592
	CUENGR	219,090	6,475
	E	1,194,436	24,046
	E-B	92,384	1,964
	E-ED	195,297	3,754
	E-I	101,882	2,126
	ENGSRE	77,069	2,063
	ENGSTF	233,276	7,503
	ENGSUP	47,992	1,898
	E-W	93,666	1,817
	EXEC	2,264,565	23,782
	EXEC2	350,031	6,221
	E-Y	110,535	1,812
	F	828,387	19,027
	FS	2,565,374	66,390
	FS-B	404,291	9,002
	FS-ED	237,191	6,278
	FS-I	395,571	8,930
	FS-W	74,874	1,877
	GENPLN	490,245	14,255
	I	2,538,053	113,325
	I-B	32,829	1,705
	I-ED	112,112	4,070
	I-I	68,448	3,062
	INSENG	71,141	1,970
	INSSUP	69,684	1,992
	IRP	180,263	5,072
	I-W	37,573	1,774
	I-Y	33,450	1,828
	MTENGR	122,389	3,684
	MTSUPV	59,610	1,802
	OPESPT	88,315	2,210
	OPESTF	340,249	10,091
	OPESUP	414,018	11,062
	PDSUPV	265,022	7,377
	PPELEC	314,828	10,774
	PPENGR	561,849	18,795
	PPMECH	488,063	13,894
	PPPLAN	131,845	4,220
	PPPROJ	304,923	7,975
	PPSPVR	303,872	8,322
	PRJMGT	170,914	5,652
	PRJSUP	108,368	3,813
	PROTEC	177,877	5,439
	RELENG	144,792	3,950
	RELSUP	61,150	1,794
	SSENG	439,172	13,311
	STRENG	425,491	13,095

		Data	
BU/Merit	LAB_COST_CL_L	Sum of Amount	Sum of Hours
Merit	SUBENG	60,175	1,793
	SUBPLN	119,649	3,781
	SUBSUP	151,643	4,558
	SURVEY	239,224	8,283
	TC	11,067,094	371,710
	TC-B	49,121	1,713
	TC-ED	625,431	21,532
	TCENGR	176,922	5,476
	TC-I	512,883	16,038
	TCS	683,198	23,362
	TCS-B	53,039	1,773
	TCS-ED	769,414	25,131
	TCSENG	69,005	1,836
	TCS-I	1,754,994	50,018
	TCS-W	58,212	2,101
	TCS-Y	57,198	1,789
	TC-W	108,360	3,537
	TECENG	554,620	14,478
	TECHSV	527,555	14,770
	TECSPT	82,321	1,784
	TNDENG	909,372	28,454
	TRNPLN	478,021	14,238
	TVLSPV	305,245	8,294
	WHMSCI	359,399	11,428
Merit Total		38,761,087	1,158,663
Grand Total		81,983,904	2,582,536

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Ref: HECO response to CA-IR-249 (Standard Labor Rates).

In calculating the 2003 standard labor rates, the referenced response generally discusses certain adjustments to merit unpaid overtime hours, because merit overtime is not compensated. Please provide the following:

a. Referring to Column C of response pages 4-5, please provide additional data showing the

b. Referring to Column D of response pages 4-5, please provide additional data showing the

Labor class	Employee No	Productive hours	Nonproductive hours	Total hours	OT factor
EXEC	0000008695	2,026.00	300	2,326.00	1.11
EXEC	0000008923	2,316.50	343	2,659.50	1.27
EXEC	0000010002	2,271.00	243	2,514.00	1.20
EXEC	0000010161	2,161.00	267	2,428.00	1.16
EXEC	0000010165	2,338.00	216	2,554.00	1.22
EXEC	0000010166	2,304.25	104	2,408.25	1.15
EXEC	0000010170	1,976.50	348	2,324.50	1.11
EXEC	0000010177	2,007.50	256	2,263.50	1.08
EXEC	0000020938	2,320.00	298	2,618.00	1.25
EXEC	0000034060	1,946.00	254	2,200.00	1.05
EXEC	0000034185	2,115.25	304	2,419.25	1.16
EXEC2	0000009437	2,139.33	272	2,411.33	1.15
EXEC2	0000010156	2,136.67	360	2,496.67	1.20
EXEC2	0000010174	1,944.75	325	2,269.75	1.09
				Average Executive	**1.16**
E-Y	0000009562	1,812.00	300	2,112.00	1.01
E	0000008397	1,869.50	276	2,145.50	1.03
E	0000008518	1,632.00	519	2,151.00	1.03
E	0000009253	1,951.50	396	2,347.50	1.12
E	0000010173	1,895.50	260	2,155.50	1.03
E	0000020036	2,189.00	319	2,508.00	1.20
E	0000020166	1,853.00	259.5	2,112.50	1.01
E	0000020263	1,949.00	196	2,145.00	1.03
E	0000020354	1,965.75	266.5	2,232.25	1.07
E	0000020481	2,097.00	229	2,326.00	1.11
E	0000020616	1,877.50	234.5	2,112.00	1.01
E	0000020803	2,754.00	293.5	3,047.50	1.46
E	0000021124	1,683.50	245.75	1,929.25	0.92
E-B	0000009311	1,964.00	356	2,320.00	1.11
E-ED	0000009027	1,876.25	348	2,224.25	1.07
E-ED	0000009701	1,878.00	320	2,198.00	1.05
E-I	0000009235	2,126.00	356	2,482.00	1.19
E-W	0000020883	1,817.00	326	2,143.00	1.03
				Average Enabler	**1.08**
F	0000009388	1,805.00	301	2,106.00	1.01
F	0000020099	1,538.25	716	2,254.25	1.08
F	0000020237	2,005.00	257.5	2,262.50	1.08
F	0000020454	2,362.25	262.75	2,625.00	1.26
F	0000020673	1,856.00	252	2,108.00	1.01
F	0000021181	1,844.50	280	2,124.50	1.02
F	0000033776	1,920.00	241.75	2,161.75	1.04
F	0000033902	2,588.50	180	2,768.50	1.33
F	0000034053	1,881.25	265	2,146.25	1.03
FS	0000009099	1,796.00	332	2,128.00	1.02

Labor class	Employee No	Productive hours	Nonproductive hours	Total hours	OT factor
FS	0000009268	1,805.75	328	2,133.75	1.02
FS	0000009328	2,070.67	282	2,352.67	1.13
FS	0000009379	1,950.00	276	2,226.00	1.07
FS	0000009527	2,326.00	308	2,634.00	1.26
FS	0000009602	2,416.83	279.5	2,696.33	1.29
FS	0000009636	1,784.00	376	2,160.00	1.03
FS	0000009664	1,911.00	205	2,116.00	1.01
FS	0000009747	1,846.97	304	2,150.97	1.03
FS	0000009758	2,069.00	336	2,405.00	1.15
FS	0000020099	396.50	319.5	716.00	0.34
FS	0000020321	1,852.50	328	2,180.50	1.04
FS	0000020401	2,532.00	343	2,875.00	1.38
FS	0000020432	1,887.50	268	2,155.50	1.03
FS	0000020451	2,158.75	257	2,415.75	1.16
FS	0000020582	1,930.00	256	2,186.00	1.05
FS	0000020630	1,759.00	357	2,116.00	1.01
FS	0000020700	2,096.00	239	2,335.00	1.12
FS	0000020736	2,070.00	268	2,338.00	1.12
FS	0000020746	1,848.50	302	2,150.50	1.03
FS	0000020848	2,424.25	320	2,744.25	1.31
FS	0000020894	2,428.75	202.5	2,631.25	1.26
FS	0000020901	1,931.00	212	2,143.00	1.03
FS	0000021016	1,732.00	376	2,108.00	1.01
FS	0000021042	2,031.50	256	2,287.50	1.10
FS	0000021138	1,871.00	244	2,115.00	1.01
FS	0000033234	2,406.00	241	2,647.00	1.27
FS	0000033441	1,926.75	281	2,207.75	1.06
FS	0000033592	2,034.00	280	2,314.00	1.11
FS	0000034181	2,648.50	156	2,804.50	1.34
FS	0000034221	2,356.50	156	2,512.50	1.20
FS	0000034404	1,950.00	170	2,120.00	1.02
FS	0000034461	1,403.50	391.5	1,795.00	0.86
FS	0000008810	1,759.00	376	2,135.00	1.02
FS	0000009337	1,849.50	350	2,199.50	1.05
FS	0000009378	1,914.00	331.5	2,245.50	1.08
FS	0000020152	1,808.00	284	2,092.00	1.00
FS-ED	0000008472	2,535.50	332	2,867.50	1.37
FS-ED	0000008974	1,905.25	348	2,253.25	1.08
FS-ED	0000009442	1,837.50	367.5	2,205.00	1.06
FS-ED	0000009021	1,815.00	356	2,171.00	1.04
FS-ED	0000009627	1,800.00	300	2,100.00	1.01
FS-ED	0000020750	1,772.50	343.5	2,116.00	1.01
FS-ED	0000021110	2,716.50	292	3,008.50	1.44
FS-W	0000020333	1,876.50	322	2,198.50	1.05
IRP	0000020500	1,210.00	266	1,476.00	0.71
IRP	0000020624	1,728.00	394	2,122.00	1.02
IRP	0000020682	1,845.83	264	2,109.83	1.01
IRP	0000020886	288.00	308	596.00	0.29
MTENGR	0000020049	1,837.00	299	2,136.00	1.02

Labor class	Employee No	Productive hours	Nonproductive hours	Total hours	OT factor
MTENGR	0000020878	1,846.50	266	2,112.50	1.01
MTSUPV	0000009048	1,802.00	330	2,132.00	1.02
OPESPT	0000009575	2,209.75	293.5	2,503.25	1.20
OPESTF	0000008896	2,049.58	372.5	2,422.08	1.16
OPESTF	0000008977	1,765.00	372.5	2,137.50	1.02
TC	0000008353	1,666.50	512.00	2,178.50	1.04
TC	0000008752	1,758.92	376.50	2,135.42	1.02
TC	0000008759	1,697.83	456.00	2,153.83	1.03
TC	0000008816	1,961.00	328.00	2,289.00	1.10
				Average other merit	**1.07**

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		Employee Count													
_LbrClass	grp	FY05	5-Jan	5-Feb	5-Mar	5-Apr	5-May	5-Jun	5-Jul	5-Aug	5-Sep	5-Oct	5-Nov	5-Dec	Average Empt Ct
__EXEC	eme	132	11	11	11	11	11	11	11	11	11	11	11	11	11
__EXEC2	eme	36	3	3	3	3	3	3	3	3	3	3	3	3	3
													To Hours sheet		14
__E	mme	132	11	11	11	11	11	11	11	11	11	11	11	11	11
__E-B	mme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
__E-ED	mme	36	3	3	3	3	3	3	3	3	3	3	3	3	3
__E-I	mme	24	2	2	2	2	2	2	2	2	2	2	2	2	2
__E-W	mme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
__E-Y	mme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
													To Hours sheet		19
__F	nmme	120	10	10	10	10	10	10	10	10	10	10	10	10	10
__FS	nmme	432	36	36	36	36	36	36	36	36	36	36	36	36	36
__FS-B	nmme	60	5	5	5	5	5	5	5	5	5	5	5	5	5
__FS-ED	nmme	36	3	3	3	3	3	3	3	3	3	3	3	3	3
__FS-I	nmme	72	6	6	6	6	6	6	6	6	6	6	6	6	6
__FS-W	nmme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
__TC	nmme	2704	262	222	222	222	222	222	222	222	222	222	222	222	225.3333333
__TC-ED	nmme	156	13	13	13	13	13	13	13	13	13	13	13	13	13
__TC-I	nmme	144	12	12	12	12	12	12	12	12	12	12	12	12	12
__TCS	nmme	144	12	12	12	12	12	12	12	12	12	12	12	12	12
__TCS-B	nmme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
__TCS-ED	nmme	180	15	15	15	15	15	15	15	15	15	15	15	15	15
__TCS-I	nmme	312	26	26	26	26	26	26	26	26	26	26	26	26	26
__TCS-W	nmme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
__TCS-Y	nmme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
__TC-W	nmme	24	2	2	2	2	2	2	2	2	2	2	2	2	2
B_PRJMGT	nmme	36	3	3	3	3	3	3	3	3	3	3	3	3	3
B_PRJSUP	nmme	46	3	3	4	4	4	4	4	4	4	4	4	4	3.833333333
B_PROTEC	nmme	48	4	4	4	4	4	4	4	4	4	4	4	4	4
B_SSENG	nmme	96	8	8	8	8	8	8	8	8	8	8	8	8	8
B_STRENG	nmme	96	8	8	8	8	8	8	8	8	8	8	8	8	8
B_SURVEY	nmme	48	4	4	4	4	4	4	4	4	4	4	4	4	4
B_TCENGR	nmme	46	3	3	4	4	4	4	4	4	4	4	4	4	3.833333333
B_TCSENG	nmme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
B_TECENG	nmme	108	9	9	9	9	9	9	9	9	9	9	9	9	9
B_TNDENG	nmme	204	17	17	17	17	17	17	17	17	17	17	17	17	17
I_PPENGR	nmme	156	13	13	13	13	13	13	13	13	13	13	13	13	13
I_PPPLAN	nmme	60	5	5	5	5	5	5	5	5	5	5	5	5	5
I_PPSPVR	nmme	84	7	7	7	7	7	7	7	7	7	7	7	7	7
I_TVLSPV	nmme	48	4	4	4	4	4	4	4	4	4	4	4	4	4
J_AIRSCI	nmme	60	5	5	5	5	5	5	5	5	5	5	5	5	5
J_CHEMST	nmme	72	6	6	6	6	6	6	6	6	6	6	6	6	6
J_WHMSCI	nmme	84	7	7	7	7	7	7	7	7	7	7	7	7	7
R_COMENG	nmme	12	1	1	1	1	1	1	1	1	1	1	1	1	1

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_LbrClass	grp	FY05	5-Jan	5-Feb	5-Mar	5-Apr	5-May	5-Jun	5-Jul	5-Aug	5-Sep	5-Oct	5-Nov	5-Dec	Average Empt Ct
R_COMSUP	nmme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
R_ENGSRE	nmme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
R_ENGSTF	nmme	72	6	6	6	6	6	6	6	6	6	6	6	6	6
R_ENGSUP	nmme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
R_INSENG	nmme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
R_INSSUP	nmme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
R_OPESPT	nmme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
R_OPESTF	nmme	60	5	5	5	5	5	5	5	5	5	5	5	5	5
R_OPESUP	nmme	72	6	6	6	6	6	6	6	6	6	6	6	6	6
R_RELENG	nmme	24	2	2	2	2	2	2	2	2	2	2	2	2	2
R_RELSUP	nmme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
R_SUBENG	nmme	24	2	2	2	2	2	2	2	2	2	2	2	2	2
R_SUBPLN	nmme	24	2	2	2	2	2	2	2	2	2	2	2	2	2
R_SUBSUP	nmme	24	2	2	2	2	2	2	2	2	2	2	2	2	2
R_TECSPT	nmme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
W_CUENGR	nmme	72	6	6	6	6	6	6	6	6	6	6	6	6	6
W_MTENGR	nmme	24	2	2	2	2	2	2	2	2	2	2	2	2	2
W_MTSUPV	nmme	12	1	1	1	1	1	1	1	1	1	1	1	1	1
W_PDSUPV	nmme	48	4	4	4	4	4	4	4	4	4	4	4	4	4
Y_GENPLN	nmme	120	10	10	10	10	10	10	10	10	10	10	10	10	10
Y_IRP	nmme	36	3	3	3	3	3	3	3	3	3	3	3	3	3
Y_PPELEC	nmme	96	8	8	8	8	8	8	8	8	8	8	8	8	8
Y_PPMECH	nmme	108	9	9	9	9	9	9	9	9	9	9	9	9	9
Y_PPPROJ	nmme	48	4	4	4	4	4	4	4	4	4	4	4	4	4
Y_TECHSV	nmme	108	9	9	9	9	9	9	9	9	9	9	9	9	9
Y_TRNPLN	nmme	96	8	8	8	8	8	8	8	8	8	8	8	8	8
														To Hours sheet	576

	5-Oct	5-Nov	5-Dec	FY05	avg emp ct (from Emp Count sheet)	ttl hrs div by avg emp ct div by 2080
36	-2155	-2025	-2172	-25641		
79	-562	-584	-622	-7179		
				-32820	14	-1.13
15	-1954	-2042	-2045	-24696		
62	-177	-192	-177	-2514		
90	-579	-636	-649	-7050		
47	-366	-345	-334	-4531		
76	-168	-176	-176	-2080		
76	-168	-176	-176	-2080		
				-42951	19	-1.09
82	-1663	-1778	-1778	-20822		
0	0	0	0	0		
58	-6477	-6750	-6699	-79992		
52	-1057	-1111	-1115	-13088		
60	-510	-623	-473	-6314		
90	-1189	-1159	-1128	-13792		
74	-174	-174	-174	-2088		
41	-39164	-40476	-41155	-481822		
67	-3260	-2935	-2721	-35800		
52	-2158	-2171	-2128	-25670		
34	-2390	-2676	-2208	-28301		
68	-176	-168	-205	-2128		
75	-3669	-3818	-3853	-43567		
17	-5503	-5180	-4979	-62453		
76	-168	-176	-176	-2128		
76	-168	-176	-176	-2080		
52	-336	-352	-352	-4160		
32	-380	-396	-422	-5145		
74	-594	-666	-652	-7519		
67	-700	-757	-744	-9333		
39	-1904	-1834	-1587	-25874		
23	-1322	-1519	-1388	-19766		
67	-837	-879	-839	-10308		
55	-572	-618	-597	-9316		
36	-247	-213	-204	-2853		
13	-1787	-1815	-1722	-21357		
07	-3115	-3271	-3239	-39314		
64	-2703	-2593	-2463	-31658		
35	-996	-971	-930	-11505		
47	-1373	-1335	-1279	-15870		
38	-761	-815	-753	-9925		
93	-1093	-1093	-983	-12784		

Hours

_LbrClass	grp	5-Jan	5-Feb	5-Mar	5-Apr	5-May	5-Jun	5-Jul	5-Aug	5-Sep	5-Oct	5-Nov	5-Dec	FY05	avg emp ct (from Emp Count sheet)	ttl hrs div by avg emp ct div by 2080
J_CHEMS	nmme	-1008	-960	-1104	-1008	-1056	-1056	-1008	-1104	-1008	-1008	-1056	-1056	-12432		
J_WHMSC	nmme	-1229	-1336	-1258	-1204	-1299	-1256	-1258	-1285	-1253	-1292	-1321	-1363	-15354		
R_COMEN	nmme	-162	-208	-170	-170	-186	-232	-170	-174	-170	-208	-187	-151	-2188		
R_COMSL	nmme	-194	-242	-218	-223	-234	-282	-267	-277	-318	-209	-216	-183	-2863		
R_CONSU	nmme	0	0	0	0	0	0	0	0	0	0	0	0	0		
R_ENGSR	nmme	-197	-181	-205	-189	-197	-197	-235	-223	-215	-264	-256	-292	-2651		
R_ENGST	nmme	-1493	-1520	-1588	-1494	-1501	-1542	-1840	-1972	-1904	-2425	-2432	-2322	-22033		
R_ENGSU	nmme	-170	-200	-188	-170	-200	-202	-180	-200	-180	-172	-208	-180	-2250		
R_INSENC	nmme	-414	-422	-323	-412	-284	-469	-330	-500	-373	-490	-385	-471	-4873		
R_INSSUF	nmme	-236	-257	-218	-253	-199	-264	-244	-258	-199	-239	-260	-324	-2951		
R_OPESP	nmme	-172	-196	-180	-164	-180	-204	-172	-204	-172	-180	-180	-220	-2224		
R_OPESTI	nmme	-895	-895	-855	-895	-895	-895	-895	-895	-940	-1070	-1110	-1170	-11410		
R_OPESU	nmme	-1136	-1136	-1088	-1136	-1136	-1136	-1136	-1136	-1136	-1223	-1271	-1271	-13941		
R_RELEN	nmme	-394	-416	-504	-427	-470	-431	-420	-562	-533	-343	-364	-639	-5503		
R_RELSUI	nmme	-162	-176	-196	-172	-180	-186	-187	-267	-190	-176	-186	-265	-2343		
R_SUBEN	nmme	-336	-356	-346	-336	-336	-360	-350	-350	-336	-357	-355	-356	-4174		
R_SUBPLI	nmme	-328	-353	-328	-318	-318	-386	-367	-361	-318	-379	-362	-354	-4172		
R_SUBSU	nmme	-355	-355	-355	-331	-331	-370	-368	-362	-326	-365	-371	-365	-4254		
R_TECSP	nmme	-178	-170	-170	-146	-194	-181	-181	-181	-194	-181	-205	-189	-2170		
W_CUENC	nmme	-1030	-1029	-1029	-1020	-1009	-1009	-1010	-1039	-1027	-1028	-1027	-1027	-12284		
W_MTENC	nmme	-256	-265	-268	-284	-397	-334	-444	-364	-519	-406	-487	-292	-4316		
W_MTSUF	nmme	-180	-192	-189	-177	-183	-183	-182	-187	-186	-185	-194	-194	-2232		
W_PDSUF	nmme	-706	-706	-705	-706	-705	-706	-706	-706	-705	-706	-706	-706	-8469		
Y_GENPLI	nmme	-1811	-1811	-1770	-1731	-1832	-1812	-1813	-1813	-1713	-1682	-1662	-1662	-21112		
Y_IRP	nmme	-504	-480	-552	-504	-528	-528	-504	-552	-528	-504	-528	-528	-6240		
Y_PPELEC	nmme	-1797	-1827	-1770	-1674	-1561	-1532	-1653	-1483	-1634	-1556	-1591	-1400	-19478		
Y_PPMEC	nmme	-2012	-1795	-1844	-1726	-1606	-1906	-1612	-1806	-1607	-1222	-1109	-1095	-19340		
Y_PPPRO	nmme	-811	-811	-813	-813	-813	-843	-760	-793	-770	-770	-770	-770	-9537		
Y_TECHS	nmme	-1763	-1721	-1957	-1739	-1835	-1941	-1897	-2007	-1910	-1760	-1820	-1830	-22180		
Y_TRNPLI	nmme	-1391	-1391	-1391	-1391	-1392	-1392	-1387	-1379	-1377	-1377	-1378	-1378	-16624		
														-1316330	576	-1.10

CA-IR-430

Ref: HECO response to CA-IR-249 (Standard Labor Rates).

According to "Note 1", the 2003 recorded merit OT factors are based on the sum of productive and nonproductive hours, which total 2,088 annual base hours. The 2005 budget merit OT factors are based on 2,080 annual base hours. Please provide the following:

a. Since calendar year 2003 was not a "leap year," please explain why the 2003 recorded average merit unpaid OT factor (Column C) was based on 2,088 annual base hours, while 2005 has 2,080 base hours.

b. According to the responses to CA-IR-249 (c) and (e), neither nonproductive pay nor nonproductive hours were considered in the development of the standard labor rates. Please explain HECO's accounting for nonproductive pay, identifying accounts charged/ credited and any related clearings or distributions to ultimate accounts.

HECO Response:

a. Page 2 of this response provides the calculation of the annual base hours for 2003 and 2005.

b. Nonproductive wages, which include vacation, holiday, sick pay and other excused absences, are charged to account 184030 Clearings – Nonproductive Wages. Non-productive wages are then allocated by applying an on-cost dollar amount to productive labor hours, crediting account 184030 Clearings – Nonproductive Wages and debiting the same account that the productive labor is charged.

		2003		2005
Number of weekdays in the month				
January		23		21
February		20		20
March		21		23
April		22		21
May		22		22
June		21		22
July		23		21
August		21		23
September		22		22
October		23		21
November		20		22
December		23		22
Total days		261		260
Hours per day	×	8	×	8
Total Hours		2088		2080

CA-IR-431

Ref: HECO response to CA-IR-250 (Standard Labor Rates).

The referenced response did not provide the requested straight time or overtime data (hours or dollars) embedded in the development of the standard labor rates for calendar years 2002 and 2003. For each year, please provide the following:

a. Please provide a breakdown of the recorded labor pay between merit and bargaining employee groups, separately showing regular pay and overtime/ premium pay for each group.

b. Please provide a breakdown of the labor hours between merit and bargaining employee groups, separately showing regular hours and overtime/ premium hours for each group.

HECO Response:

a. The breakdown of the labor dollars used in the development of the standard labor rates for 2002 and 2003 between merit and bargaining unit employee labor classes is provided on pages 2-7 of this response. The electronic file will be submitted under separate transmittal. As stated previously in HECO's response to part b of CA-IR-249, the breakdown of the labor dollars between regular pay and overtime/premium pay is not available since straight time and overtime dollars are not identifiable in the distributed labor dollars.

b. The breakdown of the labor hours used in the development of the standard labor rates for 2002 and 2003 between merit and bargaining unit employee labor classes is provided on pages 2-7 of this response. The electronic file will be submitted under separate transmittal. As stated previously in HECO's response to part d of CA-IR-249, the breakdown of the labor hours between regular hours and overtime/premium hours is not available since straight time and overtime hours are not identifiable in the distributed labor hours.

Labor dollars and hours used in calculation of 2002 standard labor rates

		Data	
BU/Merit	Labor Class	Sum of 2000 Recorded Amount	Sum of 2000 Recorded Hours
Police/Summer	POLICE	198,334.68	9,889.73
	SUMMER	7,907.78	1,432.17
Police/Summer Total		206,242.46	11,321.90
BU	BUOC	5,710,352.49	274,445.68
	BUOCB	305,273.73	15,233.92
	BUOCED	375,111.93	18,690.83
	BUOCI	213,288.28	11,060.00
	BUOCW	186,445.49	8,617.00
	BUOCY	64,987.20	3,771.00
	BUTC	2,696,299.60	106,098.57
	BUTCED	725,796.52	29,610.00
	BUTCI	6,722,112.61	221,308.14
	COMELE	264,609.67	8,517.17
	COMTEC	25,021.43	849.50
	CONCRW	243,424.65	8,231.45
	CUPLNR	246,874.54	9,090.33
	DEPLNR	52,689.62	1,772.00
	ENGMAP	316,833.28	13,527.50
	HPPMNT	433,448.47	13,843.25
	INSCRW	261,561.26	8,996.00
	JPCORD	39,992.47	1,646.00
	JRPLNR	252,615.92	11,191.16
	KPPMNT	1,499,521.27	48,704.75
	MTELEC	519,536.17	18,864.92
	OHCREW	8,606,147.57	273,705.80
	OPEDIS	665,591.99	20,684.13
	PPDRAF	120,882.94	3,970.00
	PTM	1,227,194.84	37,639.37
	RELCRW	335,067.38	11,327.00
	RESHER	91,310.34	3,758.00
	STRDFT	112,586.97	3,948.00
	SUBCRW	1,834,589.93	58,401.97
	SUBDFT	156,929.17	5,245.33
	SURVBU	84,645.83	3,550.00
	TECDFT	53,848.65	1,967.83
	TNDDFT	67,750.67	2,228.67
	TVLBLR	2,313,441.23	74,582.00
	TVLELC	707,451.05	20,862.50
	TVLMCH	824,493.88	23,147.25
	TVLTCH	514,021.03	14,075.00
	UGCREW	2,449,775.42	67,740.43
	WHMAID	49,727.67	1,731.00
	WPPMNT	1,378,623.28	44,059.50
BU Total		42,749,876.44	1,506,692.95

Labor dollars and hours used in calculation of 2002 standard labor rates

		Data	
BU/Merit	Labor Class	Sum of 2000 Recorded Amount	Sum of 2000 Recorded Hours
Merit	AIRSCI	186,522.34	5,893.50
	AIRSPE	69,647.28	3,115.50
	CHEMST	297,948.72	11,024.00
	COMENG	55,100.23	1,813.00
	COMSUP	70,782.17	2,224.50
	CONSUP	61,744.69	1,794.50
	CUDGNR	223,450.52	7,177.00
	CUENGR	91,463.48	3,109.00
	DISPLN	362,982.90	11,976.50
	E	811,948.95	20,041.00
	E-B	44,444.43	1,050.00
	ENGSRE	66,621.34	1,876.58
	ENGSTF	191,193.11	6,443.90
	ENGSUP	51,492.83	1,856.00
	E-V	197,244.32	4,255.00
	E-V-ED	200,720.15	4,992.00
	E-V-I	281,594.73	6,115.50
	E-W	78,808.33	1,752.00
	EXEC	1,485,223.40	18,478.58
	EXEC2	111,840.28	2,246.00
	E-Y	102,277.90	1,772.00
	F	487,116.81	13,373.90
	FS	2,241,641.85	61,733.67
	FS-B	507,986.22	12,305.67
	FS-ED	407,007.27	12,108.25
	FS-I	422,813.42	10,413.00
	FS-W	43,405.65	1,266.50
	FS-Y	64,998.96	1,552.00
	F-Y	9,784.69	263.50
	GENPLN	411,402.70	13,376.50
	I	2,541,896.31	120,841.81
	I-B	52,501.14	2,995.00
	I-ED	222,041.93	10,497.00
	I-I	184,058.49	8,933.83
	INSENG	59,158.71	1,813.00
	INSSUP	56,648.92	1,806.50
	IRP	218,658.02	7,002.00
	I-W	36,578.78	1,676.00
	I-Y	25,799.16	1,356.00
	MTENGR	107,863.80	3,633.00
	MTSUPV	58,273.90	1,952.50
	NOCOST	0.00	261.33
	OPESPT	77,402.66	1,949.00
	OPESTF	245,125.38	7,569.50
	OPESUP	427,744.56	12,227.50
	PDSUPV	211,129.49	6,618.08

Labor dollars and hours used in calculation of 2002 standard labor rates

	Data
[redacted]	[redacted]

Labor dollars and hours used in calculation of 2003 standard labor rates

		Data	
BU/Merit	LAB_COST_CL_L	Sum of TRAN_AMOUNT	Sum of NO_OF_HOURS_L
Police/Summe	POLICE	231,821.65	11,461.58
	SUMMER	10,753.11	2,017.50
Police/Summer Total		242,574.76	13,479.08
BU	BUOC	5,786,047.11	274,808.34
	BUOCB	286,063.10	13,851.50
	BUOCED	322,187.65	15,899.00
	BUOCI	193,975.45	10,268.50
	BUOCW	184,681.28	8,241.83
	BUOCY	66,665.01	3,729.00
	BUTC	2,600,340.32	107,500.87
	BUTCED	727,567.16	24,505.00
	BUTCI	6,438,035.00	212,381.52
	COMELE	297,707.39	10,605.00
	CONCRW	242,389.98	7,636.50
	CUPLNR	200,021.52	7,291.17
	DEPLNR	101,976.82	3,409.33
	ENGMAP	331,339.11	13,873.50
	HPPMNT	398,708.75	12,837.00
	INSCRW	243,521.40	8,398.50
	JPCORD	42,817.80	1,724.00
	JRPLNR	224,047.63	9,351.58
	KPPMNT	1,506,104.42	47,600.00
	MTELEC	485,948.66	17,089.00
	OHCREW	8,869,070.27	271,431.19
	OPEDIS	746,211.05	22,931.48
	PPDRAF	127,867.79	4,108.83
	PTM	1,214,202.49	35,831.82
	RELCRW	324,735.14	11,126.00
	RESHER	98,059.19	3,867.92
	STRDFT	111,660.08	3,860.00
	SUBCRW	1,815,441.93	60,494.73
	SUBDFT	176,108.25	5,671.00
	SURVBU	86,484.35	3,566.00
	TECDFT	51,090.90	1,836.50
	TNDDFT	72,798.36	2,359.50
	TVLBLR	2,150,257.79	73,345.08
	TVLELC	804,680.91	24,773.00
	TVLMCH	699,876.21	21,016.25
	TVLTCH	401,603.43	11,898.00
	UGCREW	2,364,738.06	66,393.86
	WHMAID	43,657.95	1,516.00
	WPPMNT	1,332,423.26	44,322.25
BU Total		42,171,112.97	1,481,350.55
Merit	AIRSCI	273,849.80	8,334.00

Labor dollars and hours used in calculation of 2003 standard labor rates

		Data	
BU/Merit	LAB_COST_CL_L	Sum of TRAN_AMOUNT	Sum of NO_OF_HOURS_L
Merit	AIRSPE	39,894.99	1,776.00
	CHEMST	312,476.11	11,303.48
	COMENG	58,964.41	1,866.75
	COMSUP	60,736.55	1,852.00
	CONSUP	63,806.22	1,785.67
	CUDGNR	162,184.39	5,133.50
	CUENGR	141,091.05	4,505.67
	DISPLN	351,654.61	11,228.50
	E	629,971.28	15,168.15
	E-B	86,983.57	2,066.00
	ENGSRE	67,761.71	1,900.50
	ENGSTF	188,843.52	6,326.00
	ENGSUP	53,641.51	1,913.00
	E-V	361,209.94	7,547.00
	E-V-ED	186,837.82	4,579.50
	E-V-I	290,572.42	6,001.75
	E-W	81,004.82	1,766.50
	EXEC	1,612,708.30	20,372.75
	EXEC2	209,168.48	3,983.75
	E-Y	103,038.92	1,809.50
	F	638,968.08	17,621.75
	FS	2,429,660.33	64,266.98
	FS-B	553,401.01	13,035.42
	FS-ED	361,930.10	10,053.00
	FS-I	460,032.40	11,277.00
	FS-W	72,105.16	2,066.00
	FS-Y	21,949.94	520.00
	GENPLN	451,253.03	14,297.00
	I	2,617,392.32	123,201.31
	I-B	48,428.45	2,638.50
	I-ED	177,623.36	7,406.00
	I-I	188,276.26	9,060.00
	INSENG	60,966.52	1,809.50
	INSSUP	58,074.85	1,789.50
	IRP	302,343.37	9,894.83
	I-W	23,315.90	1,266.00
	I-Y	32,361.73	1,888.00
	MTENGR	114,092.98	3,708.00
	MTSUPV	57,695.79	1,872.00
	OPESPT	80,046.12	1,940.25
	OPESTF	252,800.83	7,488.92
	OPESUP	394,325.52	11,011.42
	PDSUPV	237,485.26	7,328.33
	PPELEC	246,287.04	8,362.00
	PPENGR	851,478.28	27,579.40
	PPMECH	427,959.07	12,970.00

Labor dollars and hours used in calculation of 2003 standard labor rates

		Data	
BU/Merit	LAB_COST_CL_L	Sum of TRAN_AMOUNT	Sum of NO_OF_HOURS_L
Merit	PPPLAN	155,858.09	5,422.00
	PPPROJ	266,902.66	7,750.00
	PPSPVR	396,526.27	12,233.50
	PRJMGT	199,509.22	5,625.00
	PRJSUP	132,838.38	5,403.17
	PROTEC	170,337.41	5,457.00
	RELENG	128,944.33	3,782.50
	RELSUP	56,905.80	1,779.50
	SSENG	452,471.95	14,618.17
	STRENG	369,756.10	12,207.42
	SUBENG	57,653.09	1,835.00
	SUBPLN	59,314.38	1,945.42
	SUBSUP	136,518.85	3,963.25
	SURVEY	241,458.46	8,902.00
	TC	9,084,134.13	329,700.84
	TCBUSM	59,924.26	1,655.83
	TC-ED	522,812.97	17,373.67
	TCENGR	185,778.53	6,111.00
	TC-I	538,113.30	18,104.25
	TCPMGR	111,637.34	3,464.75
	TCS	948,443.54	34,072.60
	TCS-B	51,046.21	1,813.25
	TCS-ED	696,022.20	22,744.48
	TCSENG	61,012.26	1,677.67
	TCS-I	1,451,199.46	43,823.00
	TCS-W	45,922.83	1,794.50
	TCS-Y	55,934.10	1,831.00
	TC-W	176,437.09	6,254.67
	TECENG	338,392.23	10,089.50
	TECHSV	526,440.30	15,730.07
	TECSPT	74,864.72	1,752.00
	TNDENG	660,937.03	22,233.00
	TRNPLN	334,554.97	10,511.67
	TVLSPV	245,634.53	7,033.00
	WHMSCI	309,528.28	10,905.25
Merit Total		35,800,419.39	1,155,171.00
Grand Total		78,214,107.12	2,650,000.63

The following Information Requests are directed to HECO's Accomplishments and Surcharge Report, April 30, 2004:

CA-IR-432

Ref: AOS 2005 Appendix 1, at 2.

a. What is the capacity (MW) rating of each of the cogen units at Tesoro, Chevron, and Pearl Harbor?

b. What is the maximum amount of MWs that each unit can deliver to HECO?

HECO Response:

a. The capacity ratings of the Tesoro and Chevron cogen units are 18.5 MW and 9.6 MW, respectively. HECO does not have a power purchase contract with Pearl Harbor. HECO does not have the requested information on the cogen units at Pearl Harbor.

b. Tesoro and Chevron installed their cogen units to supply electrical and thermal power to their facilities. Any excess electrical power produced by the cogen units and not used by their facilities is sold to HECO under the terms of their power purchase contracts on an "as-available" basis. If these facilities did not use any electrical power produced by the cogen units, then the maximum amount of MWs that the Tesoro and Chevron cogen units can deliver to HECO are 18.5 MW and 9.6 MW, respectively.

CA-IR-433

Ref: AOS 2005, at 2.

Please provide a table that lists all individual generating units that comprise the 1615 MW identified at the top of the page as "HECO's 2004 total generating capability." Include for each (a) unit name, (b) year entered into commercial service, (c) type, (d) primary fuel, (e) capability (MWs), (f) ownership, (g) whether dispatchable, (h) whether capable of load following and/or providing spinning Reserve, (i) equivalent forced outage rate assumed for Reliability purposes, and (j) annual maintenance "down time" Requirements.

HECO Response:

Tabular data for items (a) through (i) are provided on page 2 of this response. Annual maintenance "down time" requirements for each unit varies by year and depends on the capital and maintenance work that needs to be performed during the planned outages. Examples of the type of work that are performed during planned outages are given in HECO's response to CA-IR-43 and -129.

Unit Name (a)	Service Date (b)	Type [Operation] (c-1)	Type [Prime Mover] (c-2)	Primary Fuel (d)	Normal Net Capability, MW (e)	Ownership (f)	Dispatchable? (g)	Capable of Load Following and/or Spinning Reserve? (h)	EFOR Estimate (i)
Honolulu 8	1954	Cycling	Steam Turbine	LSFO	52.9	Utility	Yes	Both	5.7%
Honolulu 9	1957	Cycling	Steam Turbine	LSFO	54.4	Utility	Yes	Both	5.7%
			Honolulu Power Plant:		107.3				
Waiau 3	1947	Cycling	Steam Turbine	LSFO	46.2	Utility	Yes	Both	9.2%
Waiau 4	1950	Cycling	Steam Turbine	LSFO	46.4	Utility	Yes	Both	7.9%
Waiau 5	1959	Cycling	Steam Turbine	LSFO	54.6	Utility	Yes	Both	2.3%
Waiau 6	1961	Cycling	Steam Turbine	LSFO	55.6	Utility	Yes	Both	2.3%
Waiau 7	1966	Baseload	Steam Turbine	LSFO	88.1	Utility	Yes	Both	1.2%
Waiau 8	1968	Baseload	Steam Turbine	LSFO	88.1	Utility	Yes	Both	2.9%
Waiau 9	1973	Peaking	Combustion Turbine	Diesel	51.9	Utility	Yes	Both	10.0%
Waiau 10	1973	Peaking	Combustion Turbine	Diesel	49.9	Utility	Yes	Both	10.0%
			Waiau Power Plant:		480.8				
Kahe 1	1963	Baseload	Steam Turbine	LSFO	88.2	Utility	Yes	Both	2.6%
Kahe 2	1964	Baseload	Steam Turbine	LSFO	86.3	Utility	Yes	Both	2.9%
Kahe 3	1970	Baseload	Steam Turbine	LSFO	88.2	Utility	Yes	Both	3.3%
Kahe 4	1972	Baseload	Steam Turbine	LSFO	89.2	Utility	Yes	Both	2.6%
Kahe 5	1974	Baseload	Steam Turbine	LSFO	134.7	Utility	Yes	Both	2.4%
Kahe 6	1981	Baseload	Steam Turbine	LSFO	133.9	Utility	Yes	Both	2.4%
			Kahe Power Plant:		620.5				
HECO Generation					1208.6				
H-POWER (1990)		Baseload	Steam Turbine	MSW	46.0	IPP	Yes[1]	Both[2]	10.0%
Kalaeloa Partners, L.P. (1991)		Baseload	Combined Cycle	LSFO	180.0	IPP	Yes	Both	1.0%
AES Hawaii (1992)		Baseload	Steam Turbine	Coal	180.0	IPP	Yes	Both	1.0%
Total Generation:					1614.6				

Notes:
1. Ability to dispatch the unit can be affected by MSW fuel constraints.
2. Ability to load follow can be affected by MSW fuel constraints.

CA-IR-434

Ref: AOS 2005, at 10, Table 1.

Please provide key data, assumptions and all supporting documentation for the June 2004 forecast of peak loads.

HECO Response:

The June 2004 Update peak projections were developed using sales load factors from the February 2004 Sales Forecast. Attached on page 2 of this response is the worksheet used to develop the June 2004 peak forecast. The derivation of sales load factors from the February 2004 Forecast is shown on page 3 of this response. The file for this response is provided electronically in MS Excel format on a CD in a folder labeled CA-IR-434 filed under separate transmittal. Customer specific identifications have been removed from the attachments and the electronic file. In addition, the June 2004 Update report was submitted as HECO-WP-201 and additional workpapers for the June 2004 Update were included in the voluminous workpapers requested by Ms. Sharon Nishi on January 25, 2005. The February 2004 Forecast, including the peak derivation, was also provided in the above referenced voluminous workpapers.

The peak loads shown in Table 1, page 10 of the AOS have been adjusted from the workpapers referred to in this response to exclude the impact of future enhanced energy efficiency DSM, load management DSM, utility CHP and Impacts of Non-utility CHP. The derivation of the peak loads shown in Table 1 of the AOS is shown on page 4 of this response using the information shown on pages 2 and 3 of this response.

May 2004 Sales Update
Peak Forecast

rty	HECO				New Construction					Adjusted
P	CHP	Proj 1	Proj 2	Proj 3	Proj 4	Proj 5	Proj 6	Proj 7	Total	Gwh
0.3	0.0	1.6	4.3	8.0	0.0	30.0	0.0	0.0	43.9	7790.0
5.6	-1.4	9.4	23.5	31.9	0.0	20.0	4.7	8.2	97.7	7960.3
3.0	-10.2	9.4	33.3	31.9	6.5	20.0	48.7	19.8	169.6	8131.1
8.6	-18.4	9.4	33.3	45.2	29.3	20.0	53.8	22.2	213.2	8274.6
6.6	-25.8	9.4	33.3	46.5	39.1	20.0	56.1	23.0	227.4	8380.8
3.6	-33.7	9.4	33.3	46.5	39.1	33.6	57.0	23.6	242.5	8483.9

rty	HECO				New Construction							Feb-04
P	CHP	Proj 1	Proj 2	Proj 3	Proj 4	Proj 5	Proj 6	Proj 7	Total	Standby	New Grs MW	SLF
0.0	0.0	0.0	2.4	5.1	0.0	2.0	0.0	0.0	9.5	21	1330.4	0.6666
0.9	-0.3	1.6	6.0	5.1	0.0	2.0	1.5	3.0	19.2	21	1364.9	0.6658
1.9	-2.3	1.6	6.0	5.1	5.7	2.0	8.9	4.4	33.7	21	1390.4	0.6676
2.8	-2.8	1.6	6.0	7.0	5.7	2.0	8.9	4.7	35.9	21	1416.1	0.6670
3.8	-3.9	1.6	6.0	7.0	5.7	2.0	9.3	4.7	36.3	21	1430.4	0.6670
4.3	-5.0	1.6	6.0	7.0	5.7	10.8	9.3	5.1	45.5	21	1452.3	0.6668

rty	HECO				New Construction							Feb-04
	CHP	Proj 1	Proj 2	Proj 3	Proj 4	Proj 5	Proj 6	Proj 7	Total	Standby	New Grs MW	SLF
0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	2.0	24	1286.7	0.6893
0.9	-0.1	1.6	6.0	5.1	0.0	2.0	1.5	3.0	19.2	24	1319.8	0.6885
1.9	-1.1	1.6	6.0	5.1	5.7	2.0	8.9	4.4	33.7	24	1351.4	0.6869
2.3	-2.7	1.6	6.0	7.0	5.7	2.0	8.9	4.7	35.9	24	1375.3	0.6868
3.3	-3.9	1.6	6.0	7.0	5.7	2.0	9.3	4.7	36.3	24	1388.6	0.6871
4.3	-5.0	1.6	6.0	7.0	5.7	10.8	9.3	5.1	45.5	24	1410.4	0.6867

ty	HECO				New Construction							Feb-04
	CHP	Proj 1	Proj 2	Proj 3	Proj 4	Proj 5	Proj 6	Proj 7	Total	Standby	New Net MW	SLF
0.0	0.0	0.0	2.4	5.1	0.0	2.0	0.0	0.0	9.5	21	1284.6	0.6904
0.9	-0.3	1.6	6.0	5.1	0.0	2.0	1.5	3.0	19.2	21	1318.2	0.6893
1.9	-2.3	1.6	6.0	5.1	5.7	2.0	8.9	4.4	33.7	21	1343.7	0.6908
2.8	-2.8	1.6	6.0	7.0	5.7	2.0	8.9	4.7	35.9	21	1369.3	0.6898
3.8	-3.9	1.6	6.0	7.0	5.7	2.0	9.3	4.7	36.3	21	1381.6	0.6906
4.3	-5.0	1.6	6.0	7.0	5.7	10.8	9.3	5.1	45.5	21	1401.5	0.6910

ty	HECO				New Construction							Feb-04
	CHP	Proj 1	Proj 2	Proj 3	Proj 4	Proj 5	Proj 6	Proj 7	Total	Standby	New Net MW	SLF
0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	2.0	24	1245.8	0.7118
0.9	-0.1	1.6	6.0	5.1	0.0	2.0	1.5	3.0	19.2	24	1278.1	0.7110
1.9	-1.1	1.6	6.0	5.1	5.7	2.0	8.9	4.4	33.7	24	1306.6	0.7104
2.3	-2.7	1.6	6.0	7.0	5.7	2.0	8.9	4.7	35.9	24	1330.4	0.7100
3.3	-3.9	1.6	6.0	7.0	5.7	2.0	9.3	4.7	36.3	24	1342.8	0.7105
4.3	-5.0	1.6	6.0	7.0	5.7	10.8	9.3	5.1	45.5	24	1363.6	0.7103

ty	HECO				New Construction							Feb-04
	CHP	Proj 1	Proj 2	Proj 3	Proj 4	Proj 5	Proj 6	Proj 7	Total	Standby	New Grs MW	SLF
0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	2.0	0	576.3	1.5388
0.4	0.0	0.0	0.0	2.6	0.0	2.0	0.0	0.0	4.6	0	592.2	1.5345
0.9	-0.8	0.0	0.0	2.6	0.0	2.0	3.7	1.8	10.1	0	606.0	1.5317
.9	-2.4	0.0	0.0	3.5	5.7	2.0	4.5	2.2	17.9	0	615.8	1.5340
.8	-3.7	0.0	0.0	3.5	5.7	2.0	4.5	2.4	18.0	0	621.2	1.5359
.8	-4.9	0.0	0.0	3.5	5.7	2.0	4.7	2.4	18.2	0	630.7	1.5355

February 2004 Sales Update
Peak Forecast

Sales

	Gwh	Future DSM	Acquired DSM	3rd Party CHP	HECO CHP	Proj 1	Proj 2	Proj 3	New Construction Proj 4	Proj 5	Proj 6	Proj 7	Total	Adjusted Gwh
2004	7685.6	-11.3	-159.0	-3.0	-1.9	1.6	15.0	8.0	0.0	10.2	0.0	0.0	34.8	7826.0
2005	7916.5	-32.6	-158.9	-5.6	-4.8	9.4	26.0	37.9	0.0	20.3	3.3	4.7	101.6	8016.8
2006	8124.4	-54.8	-156.2	-13.0	-7.5	9.4	33.3	46.5	6.5	20.3	43.9	17.8	177.7	8178.2
2007	8274.0	-77.4	-147.5	-18.6	-11.5	9.4	33.3	46.5	29.3	20.3	53.8	33.4	226.0	8303.0
2008	8366.1	-99.9	-145.3	-26.6	-15.7	9.4	33.3	46.5	39.1	20.3	56.1	34.3	239.0	8414.6
2009	8449.6	-122.5	-142.8	-35.5	-21.4	9.4	33.3	46.5	39.1	44.5	57.0	34.3	264.1	8507.7

Gross Evening Peak

	Gross MW	Future DSM	Acquired DSM	3rd Party CHP	HECO CHP	Proj 1	Proj 2	Proj 3	New Construction Proj 4	Proj 5	Proj 6	Proj 7	Total	Standby	Adjusted **Grs** MW	SLF
2004	1334	-3	-31	0	0	0.0	3.4	5.1	0.0	2.0	0.0	0.0	10.5	21	1337	0.667
2005	1375	-8	-31	-1	-1	1.6	6.0	7.0	0.0	2.0	1.1	2.7	20.4	21	1375	0.666
2006	1410	-12	-29	-2	-1	1.6	6.0	7.0	5.7	2.0	8.9	3.3	34.5	21	1399	0.668
2007	1435	-16	-28	-3	-2	1.6	6.0	7.0	5.7	2.0	8.9	10.8	42.0	21	1421	0.667
2008	1447	-19	-28	-4	-2	1.6	6.0	7.0	5.7	2.0	9.3	11.2	42.8	21	1436	0.667
2009	1471	-24	-27	-4	-3	1.6	6.0	7.0	5.7	10.8	9.3	11.2	51.6	21	1456	0.667

Gross Day Peak

	Gross MW	Future DSM	Acquired DSM	3rd Party CHP	HECO CHP	Proj 1	Proj 2	Proj 3	New Construction Proj 4	Proj 5	Proj 6	Proj 7	Total	Standby	Adjusted **Grs** MW	SLF
2004	1294	-3	-25	0	0	0.0	3.4	0.0	0.0	2.0	0.0	0.0	5.4	24	1293	0.689
2005	1337	-6	-25	-1	-1	1.6	6.0	7.0	0.0	2.0	0.0	0.2	16.8	24	1329	0.689
2006	1377	-11	-26	-2	-1	1.6	6.0	7.0	5.7	2.0	8.2	3.3	33.8	24	1359	0.687
2007	1403	-15	-24	-2	-2	1.6	6.0	7.0	5.7	2.0	8.9	10.8	42.0	24	1380	0.687
2008	1412	-20	-24	-3	-2	1.6	6.0	7.0	5.7	2.0	9.3	11.2	42.8	24	1394	0.687
2009	1434	-25	-24	-4	-3	1.6	6.0	7.0	5.7	10.8	9.3	11.2	51.6	24	1414	0.687

Net Evening Peak

	Net MW	Future DSM	Acquired DSM	3rd Party CHP	HECO CHP	Proj 1	Proj 2	Proj 3	New Construction Proj 4	Proj 5	Proj 6	Proj 7	Total	Standby	Adjusted **Net** MW	SLF
2004	1290	-3	-29	0	0	0.0	3.4	5.1	0.0	2.0	0.0	0.0	10.5	21	1291	0.690
2005	1331	-7	-29	-1	-1	1.6	6.0	7.0	0.0	2.0	1.1	2.7	20.4	21	1328	0.689
2006	1366	-11	-27	-2	-1	1.6	6.0	7.0	5.7	2.0	8.9	3.3	34.5	21	1352	0.691
2007	1391	-15	-26	-3	-2	1.6	6.0	7.0	5.7	2.0	8.9	10.8	42.0	21	1374	0.690
2008	1401	-18	-26	-4	-2	1.6	6.0	7.0	5.7	2.0	9.3	11.2	42.8	21	1387	0.691
2009	1424	-22	-25	-4	-3	1.6	6.0	7.0	5.7	10.8	9.3	11.2	51.6	21	1405	0.691

Net Day Peak

	Net MW	Future DSM	Acquired DSM	3rd Party CHP	HECO CHP	Proj 1	Proj 2	Proj 3	New Construction Proj 4	Proj 5	Proj 6	Proj 7	Total	Standby	Adjusted **Net** MW	SLF
2004	1254	-3	-24	0	0	0.0	3.4	0.0	0.0	2.0	0.0	0.0	5.4	24	1252	0.712
2005	1296	-6	-24	-1	-1	1.6	6.0	7.0	0.0	2.0	0.0	0.2	16.8	24	1287	0.711
2006	1335	-10	-24	-2	-1	1.6	6.0	7.0	5.7	2.0	8.2	3.3	33.8	24	1314	0.710
2007	1360	-14	-23	-2	-2	1.6	6.0	7.0	5.7	2.0	8.9	10.8	42.0	24	1335	0.710
2008	1368	-19	-23	-3	-2	1.6	6.0	7.0	5.7	2.0	9.3	11.2	42.8	24	1348	0.711
2009	1390	-23	-23	-4	-3	1.6	6.0	7.0	5.7	10.8	9.3	11.2	51.6	24	1367	0.710

Minimum

	Grs MW	Future DSM	Acquired DSM	3rd Party CHP	HECO CHP	Proj 1	Proj 2	Proj 3	New Construction Proj 4	Proj 5	Proj 6	Proj 7	Total	Standby	Adjusted **Grs** MW	SLF
2004	571	0	-8	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	579	1.539
2005	591	0	-10	0	0	0.0	0.0	2.6	0.0	2.0	0.0	0.0	4.6	0	596	1.534
2006	607	0	-10	-1	-1	0.0	0.0	3.5	0.0	2.0	2.3	1.7	9.5	0	610	1.532
2007	627	0	-9	-2	-1	0.0	0.0	3.5	5.7	2.0	4.5	5.4	21.1	0	618	1.534
2008	633	0	-7	-3	-2	0.0	0.0	3.5	5.7	2.0	4.5	5.6	21.3	0	624	1.536
2009	640	0	-7	-4	-3	0.0	0.0	3.5	5.7	2.0	4.7	5.6	21.5	0	633	1.535

ca-ir-434 peak fcst 0405.xls
4/5/2005

Hawaiian Electric Company, Inc.

June 2004 Sales & Peak Update

	Net MW Peak *	Addback Future DSM	Addback 3rd Party CHP	Addback Utility CHP	AOS Table 1
2004	1,282	3	0	0	1,286
2005	1,316	12	1	0	1,329
2006	1,345	21	2	2	1,370
2007	1,364	30	3	3	1,399
2008	1,365	40	4	4	1,413
2009	1,384	49	4	5	1,442

February 2004 Sales & Peak Forecast

	Net MW Peak *	Addback Future DSM	Addback 3rd Party CHP	Addback Utility CHP	AOS Table 1
2004	1,290	3	0	0	1,294
2005	1,331	7	1	1	1,340
2006	1,366	11	2	1	1,380
2007	1,391	15	3	2	1,411
2008	1,401	18	4	2	1,425
2009	1,424	22	4	3	1,453

* Does not include load management program impacts

CA-IR-435

Ref: AOS 2005, at 8, n.5.

Please provide a ten-year forecast of the amount of interruptible load on the HECO system.

HECO Response:

Ten-year forecasts for interruptible load on the HECO system are provided below. The data for years 2005 through 2007 were also provided in Table A1 on Appendix 1, page 1, Columns [C] and [E] of HECO's Adequacy of Supply Report filed with the PUC and the CA on March 10, 2005.

	Interruptible Load (net kW)	
Year	Without Future DSM (Includes Acquired DSM)	With Future DSM (Includes Acquired DSM)
2005	5,200	11,300
2006	5,200	22,200
2007	5,200	31,400
2008	5,200	38,900
2009	5,200	40,100
2010	5,200	40,100
2011	5,200	40,100
2012	5,200	40,100
2013	5,200	40,100
2014	5,200	40,100

CA-IR-436

Ref: AOS 2005, at 5.

What is the likely maximum generating station capacity (MW) that the Campbell Industrial Park site can sustain (i.e., assuming no change in output of the existing generation in the aRefa and no transmission constraints)?

HECO Response:

HECO's Barbers Point Tank Farm site in Campbell Industrial Park can accommodate the installation of two single-train combined-cycle generating units of approximately 115 MW to 170 MW each, resulting in a total site capacity of 230 MW to 340 MW. This assumes installation of commercially available combustion turbines in the nominal 100 MW range with their associated steam turbines providing approximately 50% additional capacity. The available combustion turbines in this rating range vary from approximately 76 MW to 112 MW when burning diesel fuel oil.

CA-IR-437

Ref: AOS 2005, at 2.

Please provide the following information on the "two as-available energy producers" on the HECO system:

a. unit name;

b. in-service date;

c. type of unit;

d. primary fuel;

e. capability (MW);

f. ownership;

g. equivalent forced outage rate assumed for reliability purposes; and

h. annual maintenance (downtime) requirements.

HECO Response:

	Chevron	Tesoro
a. Unit Name:	Chevron U.S.A. Hawaiian Refinery	Tesoro Cogeneration Unit
b. In-service Date:	August 2, 1990	December 28, 1983
c. Type of Unit:	Combustion turbine	Combustion turbine
d. Primary fuel:	Refinery gas	Refinery gas
e. Capability (MW):	9.6	18.5
f. Ownership:	Chevron U.S.A., Inc.	Tesoro Hawaii Corporation
g. Equivalent Forced Outage Rate:	Not applicable	Not applicable
h. Annual maintenance requirements	Not applicable	Not applicable

The Chevron and Tesoro facilities are as-available energy producers, and not firm capacity

producers. As such, there are no requirements in their power purchase contracts relating to Equivalent Forced Outage Rate or Annual maintenance requirements.

CA-IR-438

Ref: AOS 2005, at 3-4.

a. Has HECO taken any steps to encourage the installation of CHP units by non-utility vendors at customer sites?

b. If so, please describe.

c. If no, please explain why not.

HECO Response

a. HECO has taken limited steps to encourage the installation of CHP units by non-utility vendors at customer sites.

b. HECO provides general information of the benefits of CHP to its customers. For example, at the October 2004 HECO Energy Expo, generic information was presented by HECO about distributed generation and CHP, and mention was made of both non-utility and utility CHP ownership models. Cummins West and Hawthorne Pacific are competing vendors offering CHP systems and both had exhibits at the 2004 Energy Expo where they had the opportunity to meet with numerous large power users.

Additionally, although HECO does not have a systematic effort in place to encourage non-utility CHP, it has taken the opportunity in certain instances to do so. For example, in the course of recent discussions with Pacific Allied Products, after Pacific Allied decided to terminate its CHP agreement with HECO due to schedule delays, HECO offered to put Pacific Allied in touch with HECO's pre-qualified non-utility CHP vendors Hess Microgen, Hawthorne Pacific, and Cummins West, in the event that Pacific Allied was still interested in developing CHP with a third party.

c. Not applicable.

CA-IR-439

Ref: AOS 2005, at 4-5, 24-25.

a. Has HECO conducted in the last three years any studies of opportunities to improve the availability levels of its owned generating facilities.

b. If so, please provide a copy of the results of those studies.

c. If no, please explain why not.

HECO Response:

a. Yes, HECO has conducted studies through its maintenance programs, practices and application of various technologies and testing techniques. The studies primarily focus on critical pieces of equipment such as the boiler, generator and turbine that significantly impact unit availability.

For example, ultrasonic shear wave, video probe, and wet fluorescent magnetic particle testing techniques were applied to precisely inspect and document cracks in the H8 and H9 high pressure turbine cylinders and rotors, and to determine whether the cracks were active or dormant. The results of the analysis led to a decision to attempt major crack repairs never before attempted in HECO's history. Both repairs were successful and both turbines were returned to service with a high confidence level of reliability and availability. The alternative was to order new cylinders with an estimated lead time of two years.

Boiler internal inspections which includes metalurgical analysis on major boiler components such as headers, waterwall tubes, steam tubes and high energy piping (steam pipes that connect the boiler to the turbine) have been ongoing since the mid 1980's and have been refined over the years. CA-IR-44, Attachment 2, filed with the Consumer

Advocate and the Department of Defense on April 14, 2005, shows the Boiler internal inspection record as of February 10, 2005, for all HECO steam units.

Also, special techniques and processes were developed by employees to replace critical superheater tubes and avoid longer unit outages required to perform an extensive and complex flushing process referred to as a steam blow. This non-steam blow technique was first successfully applied in 2004 on Kahe Unit 5 during the replacement of the reheater steam tubes in the boiler. The result was the avoidance of a 2 plus week extension to allow sufficient time to modify the boiler to accommodate steam blowing, performing the steam blow process, and restoring the boiler for normal operation. A similar non-steam blow process will be used to replace the superheater section on Kahe Unit 6 in 2005.

Generators have undergone major inspection and testing on both the armature (stator) and field (rotor) based on advances in technology that can detect and locate degraded insulation in the generator armature, and other technologies such as flux probe testing to monitor the condition of the field.

Balance of plant components such as pumps, motors, breakers, heat exchangers, transformers, etc. are monitored utilizing technologies discussed in HECO's response to CA-IR-46 filed with the Consumer Advocate and the Department of Defense on April 14, 2005.

b. Examples of turbine, boiler and generator analysis reports are provided below. While the information is very technical, this is the level of knowledge and expertise required to understand the condition of HECO's aging fleet of generating units, and to take appropriate corrective action to maintain availability and reliability.

1. Preliminary Report on the Results of the Nondestructive Evaluation (NDE) and

Engineering Analysis of Honolulu Unit 8 Generator Rotor (Reference: R&A C-7058) on pages 4 to 18.

2. Field Report – Nondestructive Examinations Results performed at Honolulu - Hicks Generating Station Unit 9 Generator/Turbine components (Reference: R&A C-7028) on pages 19 to 45.

3. Waiau Unit 5 Generator Final Post Restack and Rewind Summary dated 2/19/03, on pages 46 to 53.

4. February, 2004, Integrity and Condition Assessment of Selected Areas on the Main Steam and Hot Reheat Piping Systems - Kahe Unit 5. Report issued on June 29, 2004 on pages 54 to 70.

c. Not applicable.

Due to the voluminous nature of the information, one copy (pages 4 to 70) will be provided to the Consumer Advocate, Department of Defense and the Public Utilities Commission under separate transmittal.

CA-IR-440

Ref: AOS 2005, at 7.

What is the date on which HECO expects to file its "preferred plan for IRP-3"?

HECO Response:

HECO is currently preparing a draft of its IRP-3 report and will review the draft report with its public Advisory Group before finalizing and filing it with the PUC. HECO expects to file its IRP-3 report before October 31, 2005. However, this is dependent on the number and nature of comments it receives on the draft IRP-3 report.

CA-IR-441

Ref: AOS 2005, at 6.

a. Please provide a copy of all documents (memoranda, correspondence, reports, etc.) that pertain to HECO's consideration of "portable, leased DG units at HECO-controlled substation sites and other sites." Include documents that identify or discuss related potential savings in transmission and distribution investments.

b. Please identify the sites for which such DG units have been considered, and identify the anticipated maximum output (MWs) of generation facilities located on those sites.

HECO Response

a. HECO objects to the request to provide "all" documents pertaining to HECO's consideration of portable, leased DG units at HECO-controlled substation sites and other sites, on the grounds that (1) requests that the Companies produce "all" documents are overly broad and unduly burdensome given the volume of documents (including e-mails, agendas, power point presentations, etc.); (2) internal communications contain information subject to the attorney-client and attorney work product privileges; (3) information produced pursuant to such requests could include preliminary and/or outdated analyses, which have been superseded by later analyses; and (4) documents may contain confidential vendor pricing and other related information.

Without waiving this objection, attached are relevant documents that pertain to HECO's consideration and evaluation of temporary rental DG units at HECO-controlled substation sites. The attachments (Attachment 1 to Attachment 6) are voluminous and therefore one copy each will be provided to the Consumer Advocate, Department of Defense and the Commission under separate transmittal. Also, vendor confidential and HECO confidential information has been redacted and will be provided to the PUC, CA and Department of Defense under protective order. The documents are separated into the following major

groups:

- Attachment 1: Background documents,
- Attachment 2: Temporary DG site selection,
- Attachment 3: Mobile diesel generator bid request,
- Attachment 4: Hawthorne Power Systems bid response
- Attachment 5: Cummins West bid response
- Attachment 6: Bid evaluation and recommendation

HECO is developing a detailed cost estimate of the capital and O&M costs associated with the deployment of portable leased DG units. This information will be submitted as part of a comprehensive update of HECO's 2005 test year costs.

HECO did not consider potential savings in T&D investments in its consideration of deploying portable leased DG units.

b. HECO considered all substation sites on the island of Oahu, and other properties owned by HECO. Five have been identified as leading candidate sites for installation of temporary DG, although other sites may also be viable. These sites are (1) Helemano Substation, (2) Ewa Nui Substation, (3) Hoaeae Substation, (4) Uwapo Substation, and (5) Iwilei Tank Yard. (See Attachment 2 of the documentation submitted in response to subpart a.) For each site with the exception of Hoaeae Substation, up to three temporary DG units, each rated at 1.64 MW, would be installed totaling a maximum 4.92 MW per site. Hoaeae Substation would be limited because of physical space constraints to two units, totaling 3.28 MW.

CA-IR-442

Ref: AOS 2005, at 6.

Please provide copies of all documents (memoranda, correspondence, reports, etc.) that pertain to HECO's consideration of permanent DG units at HECO-controlled substation sites and other sites.

HECO Response:

HECO objects to the request to provide "all" documents pertaining to HECO's consideration of "permanent DG units at HECO-controlled substation sites and other sites", on the grounds that (1) requests that the Companies produce "all" documents are overly broad and unduly burdensome given the volume of documents (including e-mails, agendas, power point presentations, etc.); (2) internal communications contain information subject to the attorney-client and attorney work product privileges; (3) information produced pursuant to such requests could include preliminary and/or outdated analyses, which have been superseded by later analyses; and (4) documents may contain confidential vendor pricing and other related information.

Without waiving its objection, HECO considered permanent DG units at HECO-controlled substations only to the point of obtaining pricing information for purchase of DG units via the RFP referenced in HECO's response to CA-IR-441. Upon receiving the pricing information, HECO decided to pursue installation of temporary units at HECO substations to provide additional near term generating capacity.

in Docket No. 03-0371. HECO plans to continue its evaluation of these mainland DG programs to assess whether any aspects of the programs might be feasible for application at HECO. HECO has also been approached by the Department of Defense to explore DG opportunities for Oahu military installations. Preliminary discussions are underway between HECO and the Department of Defense on what the scope of work would be for this effort, but nothing has been finalized and no analysis has been initiated.

CA-IR-443

Ref: AOS 2005, at 22.

a. Please identify the load forecast that was operable (i.e., provide both the date that the forecast was produced and peak load projections for each year through 2009) in July 2003 when HECO started its IRP 3 planning process.

b. Please state whether the HECO IRP 3 process started in July 2003 at any time considered a scenario in which projected loads might reach levels consistent with those of the June 2004 forecast.

c. If Part (b) above is answered in the affirmative, please provide a copy of the relevant scenario analysis (i.e., provide both the date that the forecast was produced and peak load projections for each year through 2009).

d. Please state whether HECO at any time prior to 2004 considered a scenario in which projected loads might reach levels consistent with those of the June 2004 forecast.

e. If Part (d) is answered in the affirmative, please provide a copy of the relevant scenario analysis (i.e., provide both the date that the forecast was produced and peak load projections for each year through 2009).

HECO Response:

a. The June 2003 peak forecast was the most recently adopted forecast at the time the HECO IRP-3 process was started in July 2003. The June 2003 forecast was a short-term forecast with a horizon of 5 years extending through 2008. The peaks forecasted are shown on page 3 of this response in the column labeled Jun-03.

b. Yes, the HECO IRP-3 process was based on projected loads from the February 2004 forecast. The projected peaks from the February 2004 forecast were higher than those projected in the June 2004 update (see Table 1, page 10 of the AOS).

c. The projected peaks from the February 2004 forecast are shown on page 3 of this response in the column labeled Feb-04.

d. Yes, the peaks from the June 2001 forecast were comparable for the years 2004 – 2005 and

the peaks projected for the October 2003 forecast and the February 2004 forecast were comparable over the forecast horizon to the June 2004 update projections.

e. The June 2001, October 2003, and February 2004 projections are shown on page 3 of this response, along with the recorded peaks for 1999 – 2004, and the June 2004 update.

Hawaiian Electric Company, Inc.

Including Standby Loads, Future DSM, 3rd Party CHP, and Utility CHP (Net MW)

	Net MW Peak *	Forecast Adopted				
		Jun-01	Jun-03	Oct-03	Feb-04	**Jun-04**
1999	1137					
2000	1185					
2001	1213	1207				
2002	1224	1232				
2003	1262	1254	1239	1242		
2004	1299	1285	1272	1290	1290	**1282**
2005		1311	1299	1318	1331	**1316**
2006		1334	1324	1352	1366	**1345**
2007			1340	1373	1391	**1363**
2008			1353	1389	1401	**1365**
2009					1424	**1384**

* Recorded peaks adjusted assuming standby co-gens were off-line (i.e., loads were on HECO's system).

Note: The June 2004 peak forecast includes the impact of enhanced DSM program future impacts. Previous forecasts included the impact of existing program impacts. Adjusting the forecasts to exclude future DSM impacts would result in numbers that are not comparable due to the impact of acquired DSM impacts. For example, the June 2004 forecast excluding future DSM would still include installations that occurred from 1996 - 2003, whereas the June 2001 forecast excluding future DSM would only include installations that occurred from 1996 - 2000.

CA-IR-444

Ref: AOS 2005, at 6.

a. Please identify the date on which HECO first communicated to the Commission that it expected a capacity shortfall during 2005 (i.e., that it would need additional resources during 2005 "to maintain generation system reliability at or above HECO's reliability guideline").

b. Please provide a copy of the document in which this information was communicated to the Commission.

c. Please identify the date on which it became apparent to HECO's senior management that the company would required additional resources during 2005 "to maintain generation system reliability at or above HECO's reliability guideline."

HECO Response:

a. HECO does not expect a capacity shortfall in 2005. A capacity (or generation) shortfall would occur when there is not enough capacity on the system to meet the expected load. Rather, HECO has a reserve capacity shortfall, which is defined as not having enough reserve capacity from firm capacity resources on the system to maintain generating system reliability at or above HECO's 4.5 years per day reliability guideline in a given year. Please refer to the discussion in Appendix 6 of HECO's March 10, 2005 Adequacy of Supply report.

In HECO's March 31, 2004 Adequacy of Supply report, HECO indicated on pages 5 and 6 that:

"With the February 2004 forecast, which is higher than the August 2002 forecast as

indicated in Table 1, HECO's analysis indicates that generating system reliability will fall below the 4.5 years per day reliability guideline beginning in 2006, assuming that no new central-station generating capacity is added from 2004 through 2006, even if:

1. forecasted peak reduction benefits (estimated at 11 MW for 2004 – 2006)

from continuation of existing energy efficiency DSM programs are acquired,

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

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

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

Therefore, HECO had indicated as early as March 2004 that a reserve margin shortfall was expected to occur sooner than 2006 if the peak reduction benefits from the energy efficiency DSM, load management DSM and CHP Programs did not occur as forecast. By the fourth quarter of 2004, it was apparent that the peak reduction benefits from the CHP and load management DSM Programs would not be realized as forecasted because HECO's CHP Program application continued to be suspended by the Commission, and Commission approval of the load management DSM Programs was received in October 2004 such that there was not enough time for the programs to be implemented and peak reduction benefits

efficiency and load management DSM program impacts, new firm capacity would be needed in 2006. With the firm capacity from the CHP Program, new firm capacity would be needed even sooner."

On September 24, 2004, HECO briefed the Commission, the Consumer Advocate, and other government officials that HECO was already experiencing a shortage of generation reserve.

In its March 10, 2005 Adequacy of Supply report, HECO explicitly stated to the Commission that a reserve capacity shortfall is expected in 2005. HECO stated on pages 5 and 6 that "HECO anticipates reserve capacity shortfalls in 2005 and projects these shortfalls to continue at least until 2009, which is the earliest that HECO expects to be able to permit, acquire and install and place into commercial operation its next central station generating unit."

b. Copies of HECO's March 31, 2004 and March 10, 2005 Adequacy of Supply reports were submitted to the Consumer Advocate at the same time they were filed with the Commission.

c. HECO is unable to identify a specific date on which it became apparent to HECO's senior management that the company would require additional resources during 2005 "to maintain generation system reliability at or above HECO's reliability guideline." HECO's senior management is kept apprised of the amount of reserve capacity available. (The reports provided to them are in terms of reserve capacity available and not in terms of the

day reliability guideline from 2005 to at least 2009 was not made until about February 2005.

CA-IR-445

Ref: AOS 2005, at 6.

Please provide a copy of all documents (including, but not limited to scenario analyses) that address the risk (or eventuality) that HECO might experience a capacity shortfall during 2005 (i.e., that it would need additional resources during 2005 "to maintain generation system reliability at or above HECO's reliability guideline").

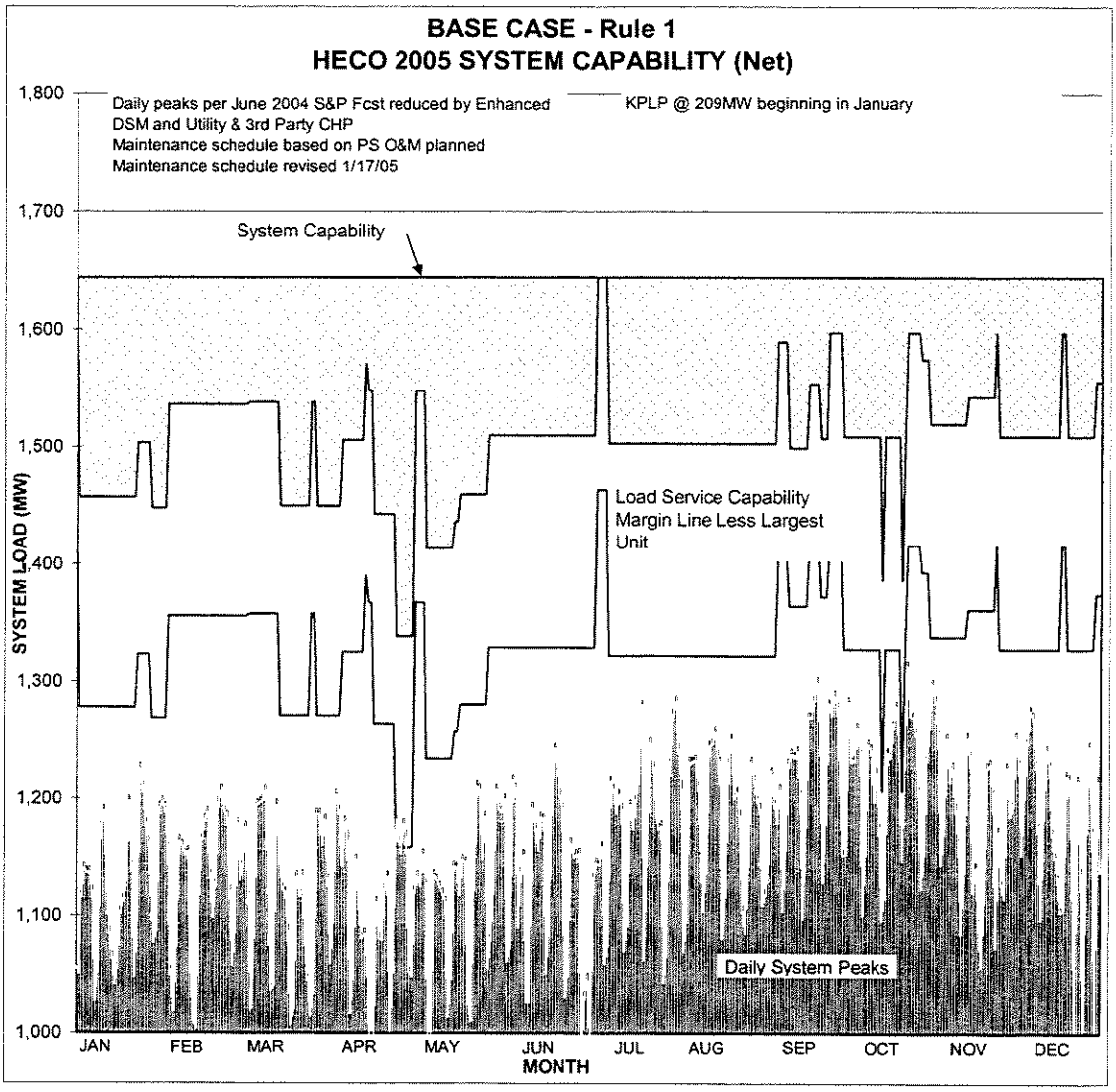
HECO Response:

In order to assess generating system reliability outlook, HECO evaluated the following scenarios:

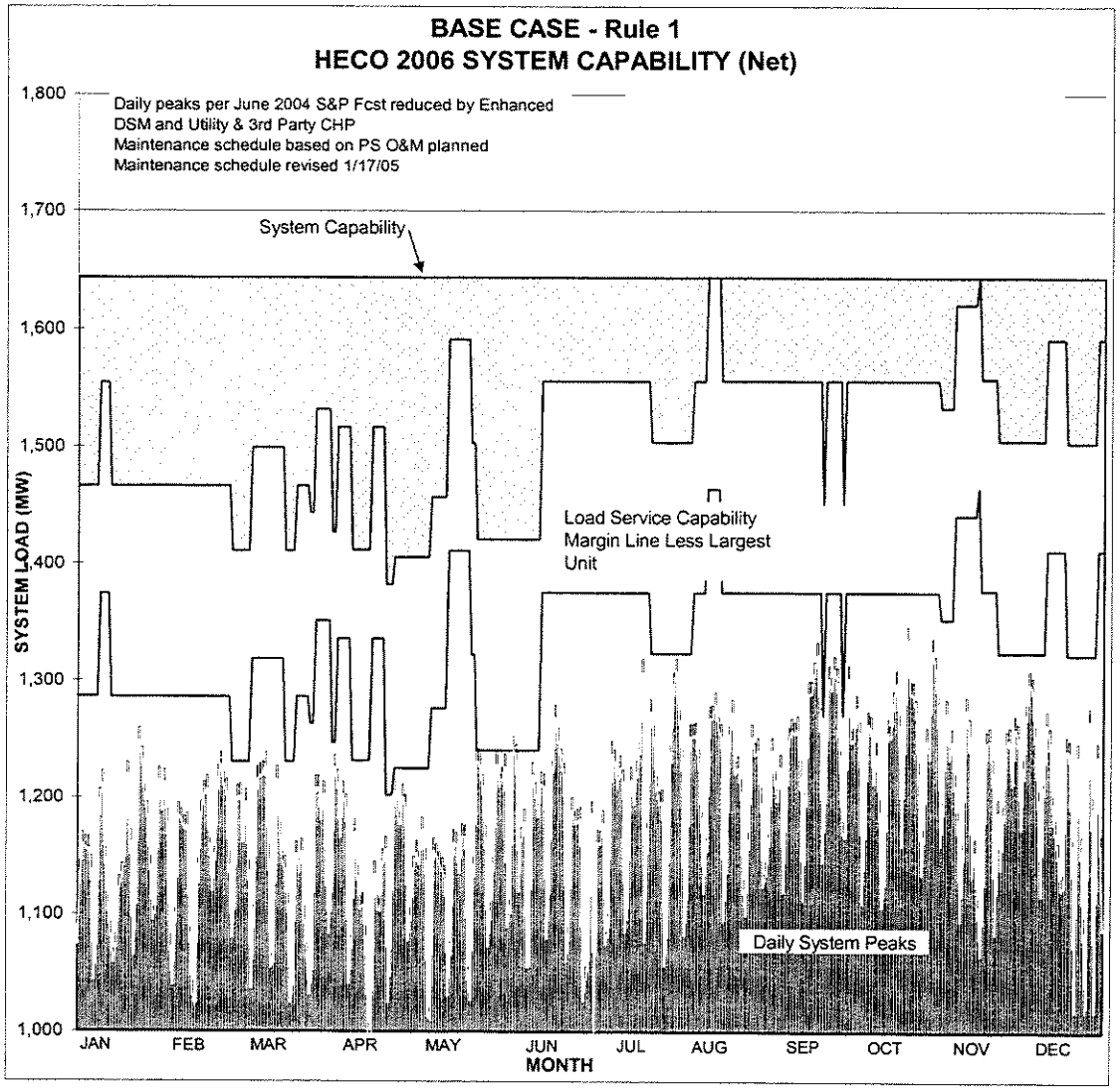
1. Reliability under a base set of assumptions for the peak forecast, the peak reduction benefits of energy efficiency and load management DSM, the amount of third party and utility CHP, and the Equivalent Forced Outage Rates of HECO's generating units. These base assumptions are given in Table 1 on page 10 (June 2004 forecast), Table A2 in Appendix 2, page 1 (Load Management Impacts; 2005 Projections), Table A3 Appendix 2, page 3 (Energy Efficiency DSM; 2005 Projections), Table A4 in Appendix 2, page 4 (Utility and Non-utility CHP; 2005 Projections), and in Section 3.5 on page 13 (base system composite EFOR of 2.89%) of the Adequacy of Supply report. The results of the reliability analyses are shown in Tables 3 and 4 on pages 17 and 18, respectively. Table 5 page 18 shows the Rule 1 and Rule 2 analyses.
2. Reliability under a scenario where residential and commercial load management impacts are lower than the base case by 25% and CHP impacts are 20% lower than the base case, as described in Section 4.3.2, on page 19 of the Adequacy of Supply report. The numerical values for the difference in cumulative DSM and CHP impacts are shown in Tables 6 (page 20) and A6 (Appendix 5, page 1). The results of the reliability analyses are shown in Tables

7 (page 21) and A7 (Appendix 5, page 2). Tables 8 (page 21) and A8 (Appendix 5, page 2) show the Rule 1 and Rule 2 analyses.

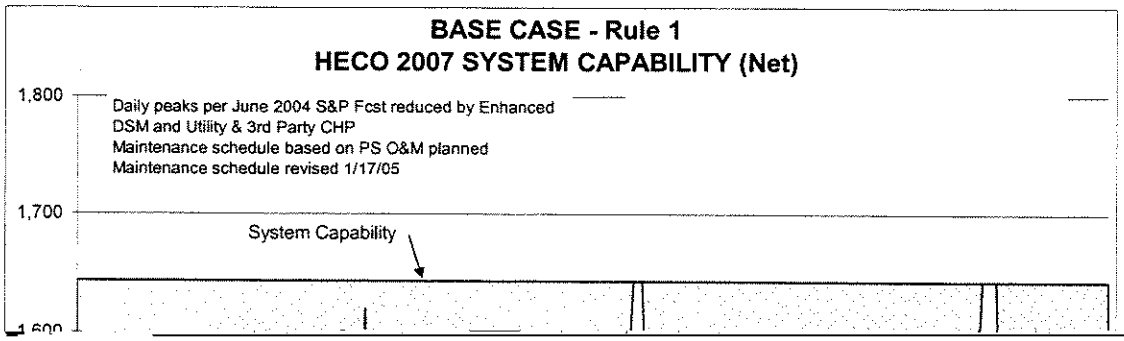
3. Reliability under a scenario the same as in Item 2 above, except that the forecasted EFORs for existing generating units (both HECO and IPP) are increased by 20%, as described on page 20 of the 2005 Adequacy of Supply report. (The 20% higher EFOR on the individual generating units result in a system composite EFOR of 3.47%). The results of this analysis

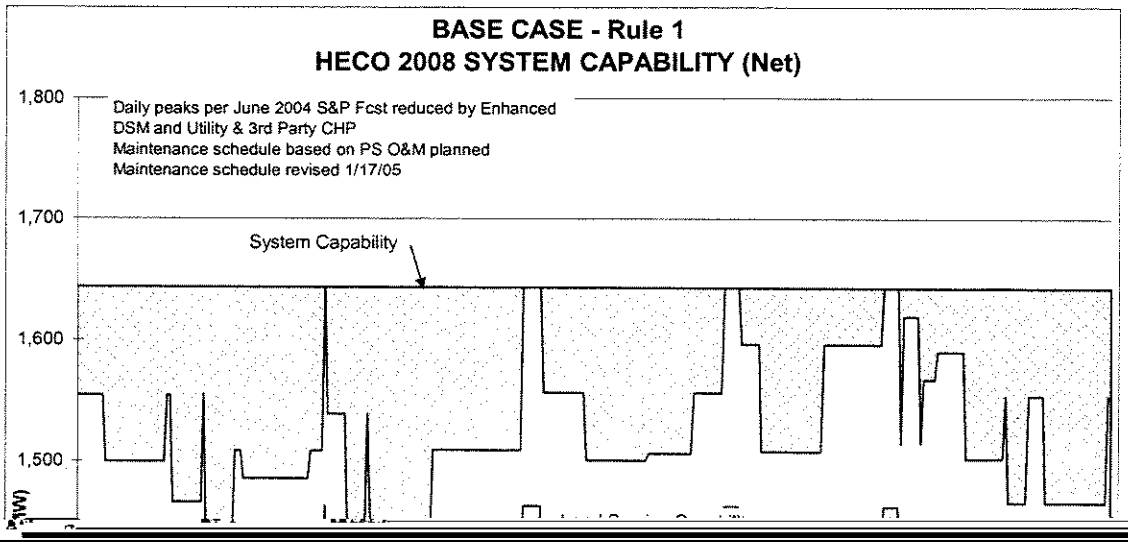


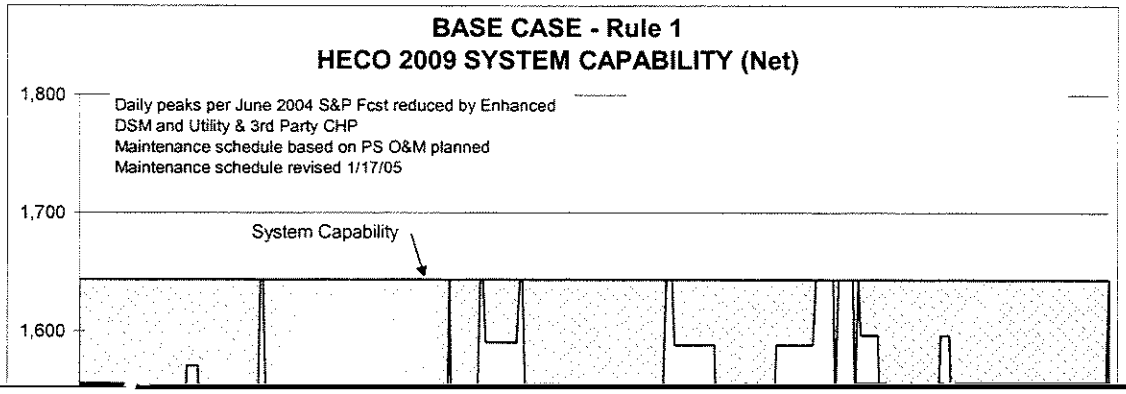
Month	Without Load Management		With Load Management	
	Minimum LSC Diff	# of days in violation	Minimum LSC Diff	# of days in violation
JAN	70.7	0	75.9	0
FEB	66.0	0	71.2	0
MAR	78.4	0	83.6	0
APR	(28.5)	4	(23.3)	4
MAY	63.9	0	69.1	0
JUN	82.1	0	87.3	0
JUL	38.1	0	43.3	0
AUG	33.9	0	39.1	0
SEP	95.7	0	100.9	0
OCT	40.6	0	45.8	0
NOV	35.9	0	41.1	0
DEC	49.2	0	54.4	0

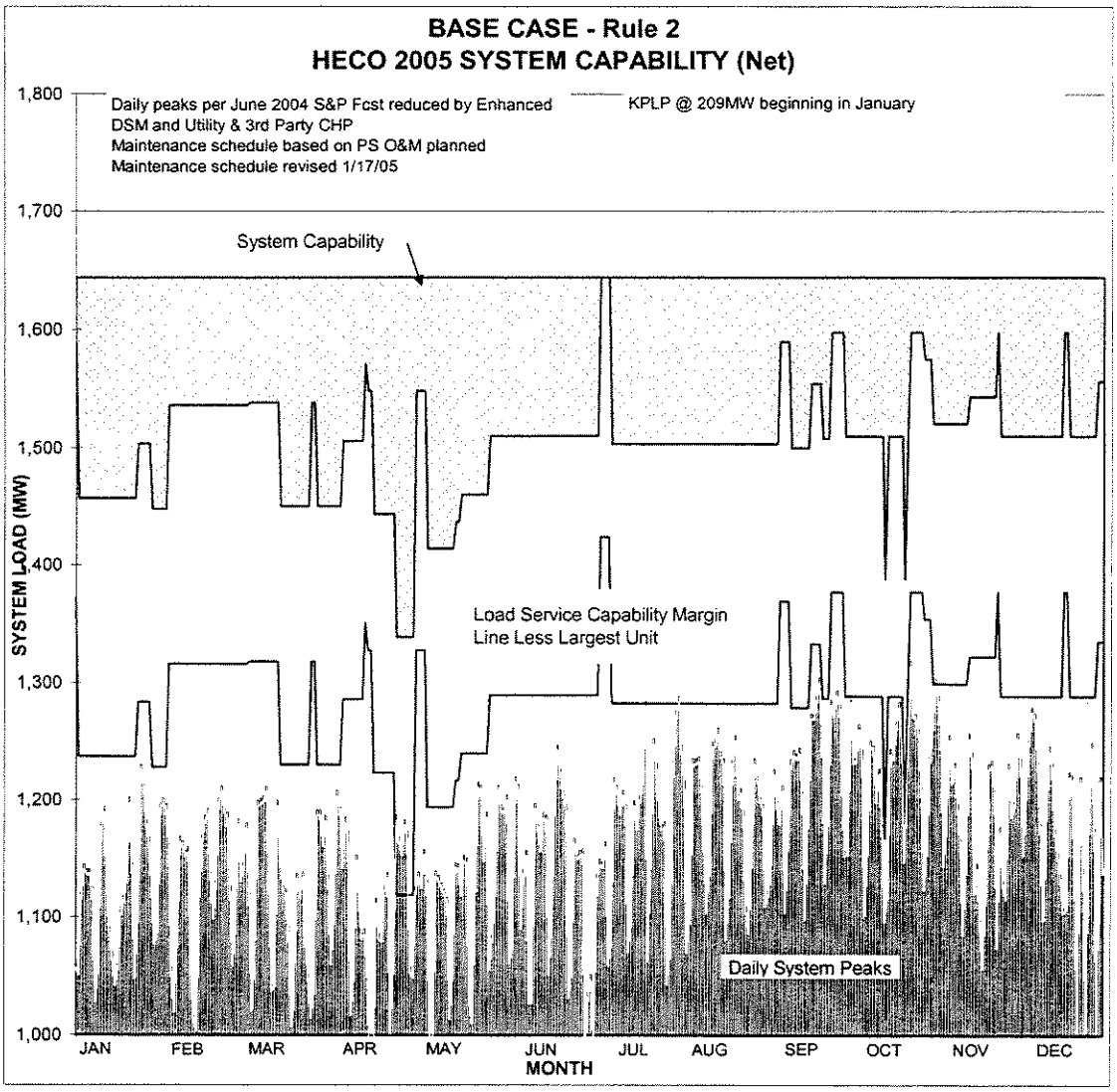


Month	Without Load Management		With Load Management	
	Minimum LSC Diff	# of days in violation	Minimum LSC Diff	# of days in violation
JAN	26.2	0	37.6	0
FEB	18.6	0	30.0	0
MAR	23.6	0	35.0	0
APR	9.2	0	20.6	0
MAY	(2.3)	1	9.1	0
JUN	(12.3)	2	(0.9)	1
JUL	38.5	0	49.9	0
AUG	3.5	0	14.9	0
SEP	41.5	0	52.9	0
OCT	28.5	0	39.9	0
NOV	38.5	0	49.9	0
DEC	15.4	0	26.8	0

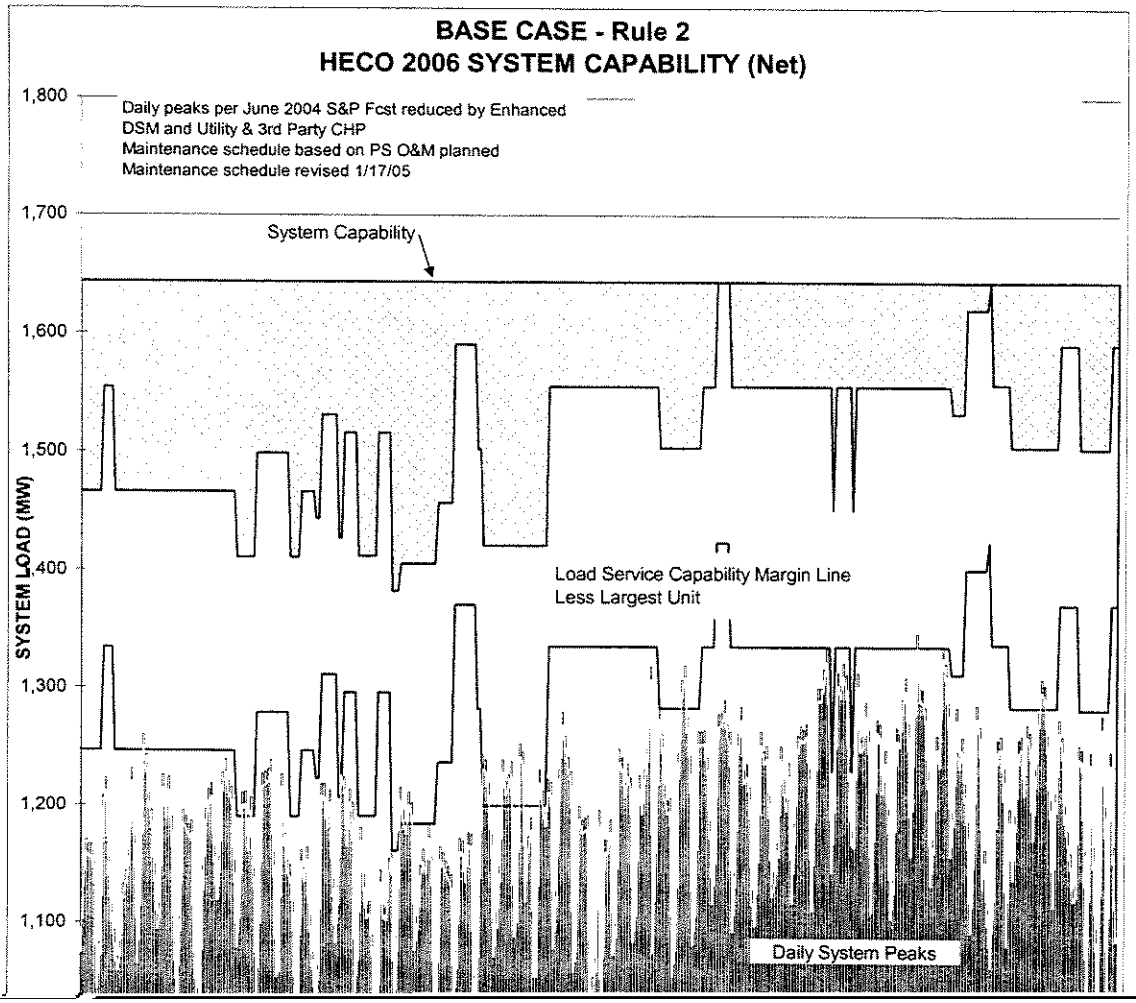

BASE CASE - Rule 1
HECO 2007 SYSTEM CAPABILITY (Net)
1,800
Daily peaks per June 2004 S&P Fcst reduced by Enhanced
DSM and Utility & 3rd Party CHP
Maintenance schedule based on PS O&M planned
Maintenance schedule revised 1/17/05
1,700
System Capability

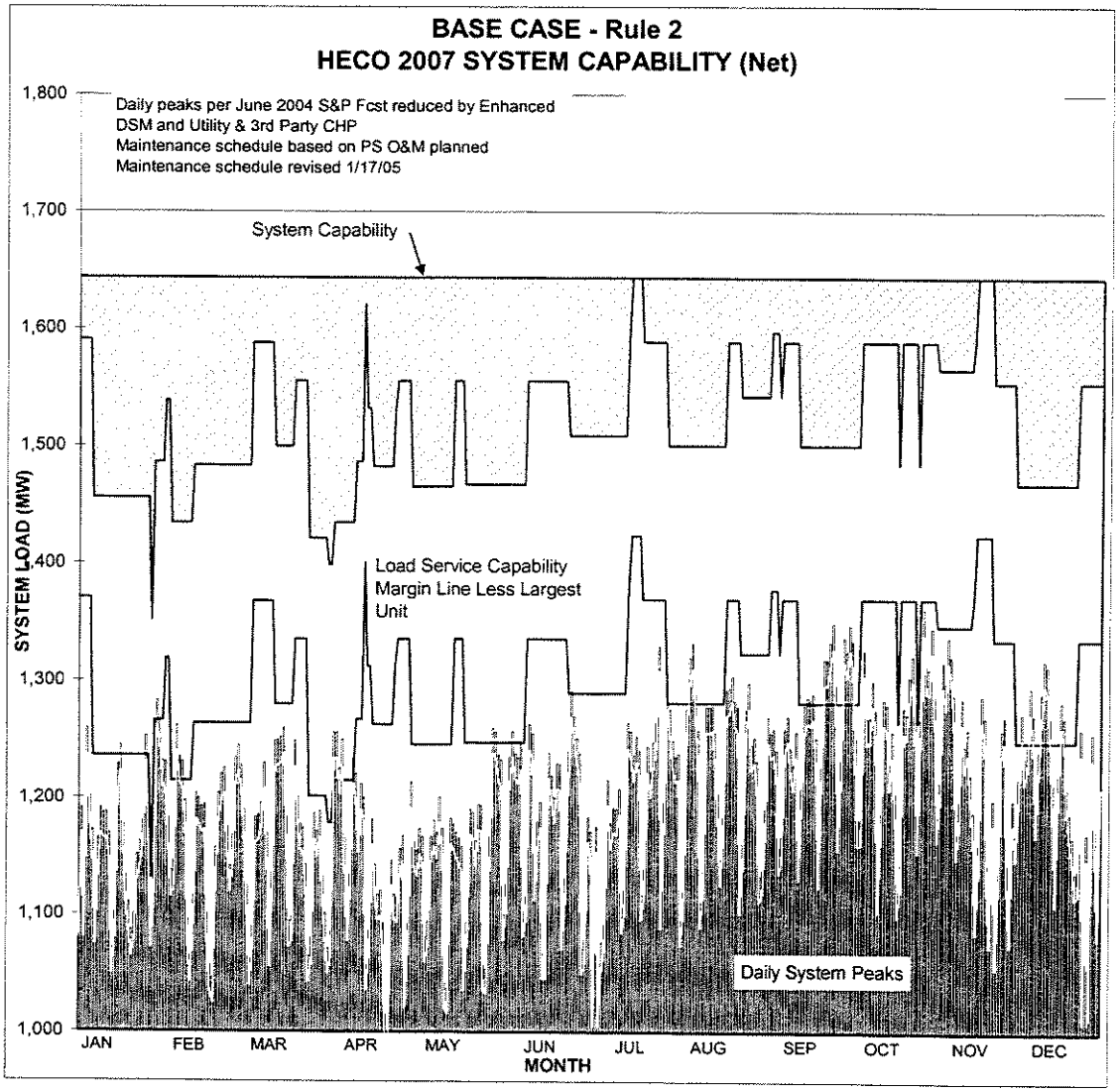

BASE CASE - Rule 1
HECO 2008 SYSTEM CAPABILITY (Net)
1,800
1,700
1,600
1,500
(MW)
Daily peaks per June 2004 S&P Fcst reduced by Enhanced
DSM and Utility & 3rd Party CHP
Maintenance schedule based on PS O&M planned
Maintenance schedule revised 1/17/05
System Capability


BASE CASE - Rule 1
HECO 2009 SYSTEM CAPABILITY (Net)
1,800
1,700
1,600
Daily peaks per June 2004 S&P Fcst reduced by Enhanced
DSM and Utility & 3rd Party CHP
Maintenance schedule based on PS O&M planned
Maintenance schedule revised 1/17/05
System Capability

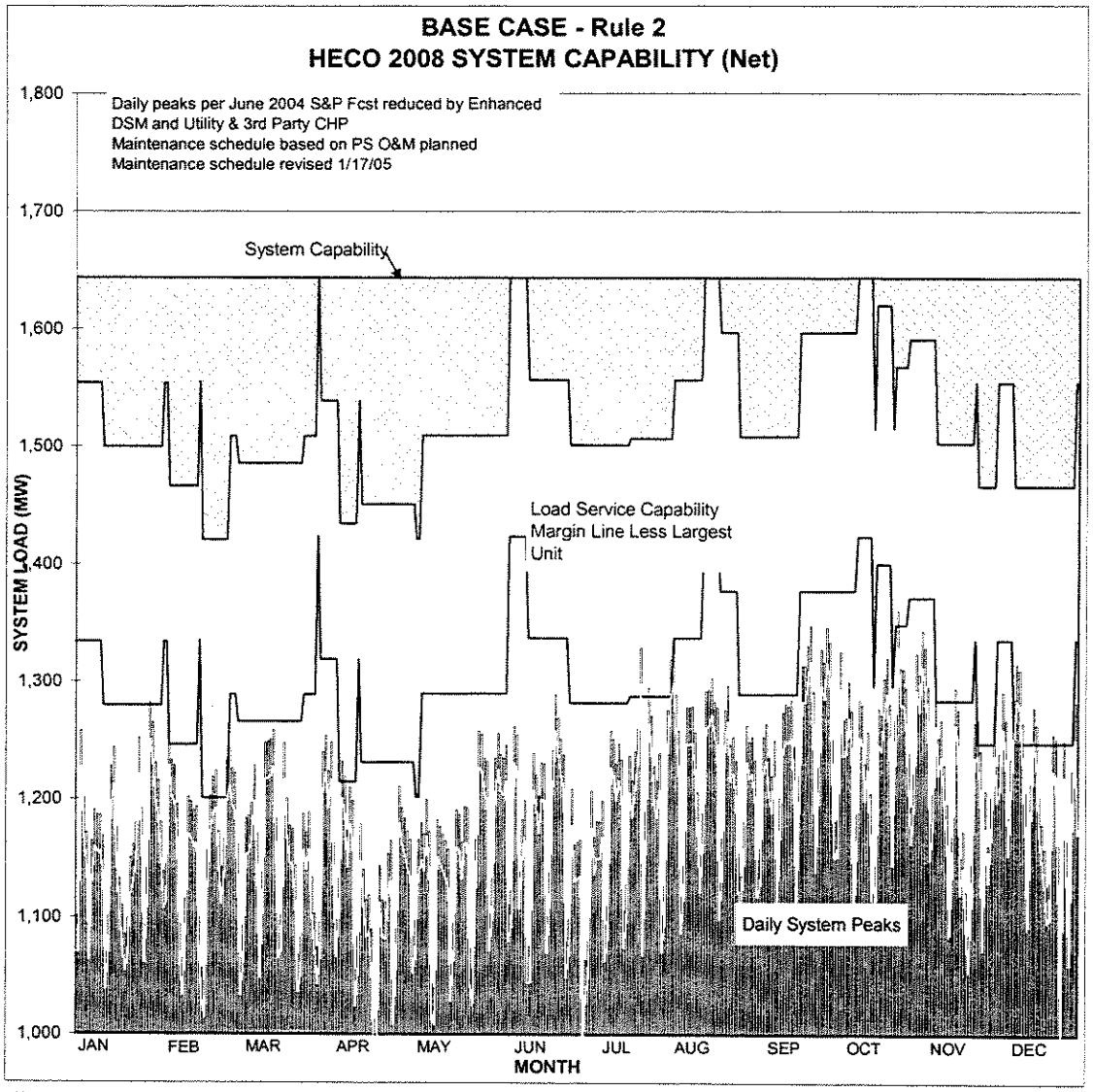


Month	Without Load Management		With Load Management	
	Minimum LSC Diff	# of days in violation	Minimum LSC Diff	# of days in violation
JAN	30.7	0	35.9	0
FEB	26.0	0	31.2	0
MAR	38.4	0	43.6	0
APR	(68.5)	5	(63.3)	5
MAY	23.9	0	29.1	0
JUN	42.1	0	47.3	0
JUL	(1.9)	1	3.3	0
AUG	(6.1)	1	(0.9)	1
SEP	28.4	0	33.6	0
OCT	0.6	0	5.8	0
NOV	(4.1)	1	1.1	0
DEC	9.2	0	14.4	0

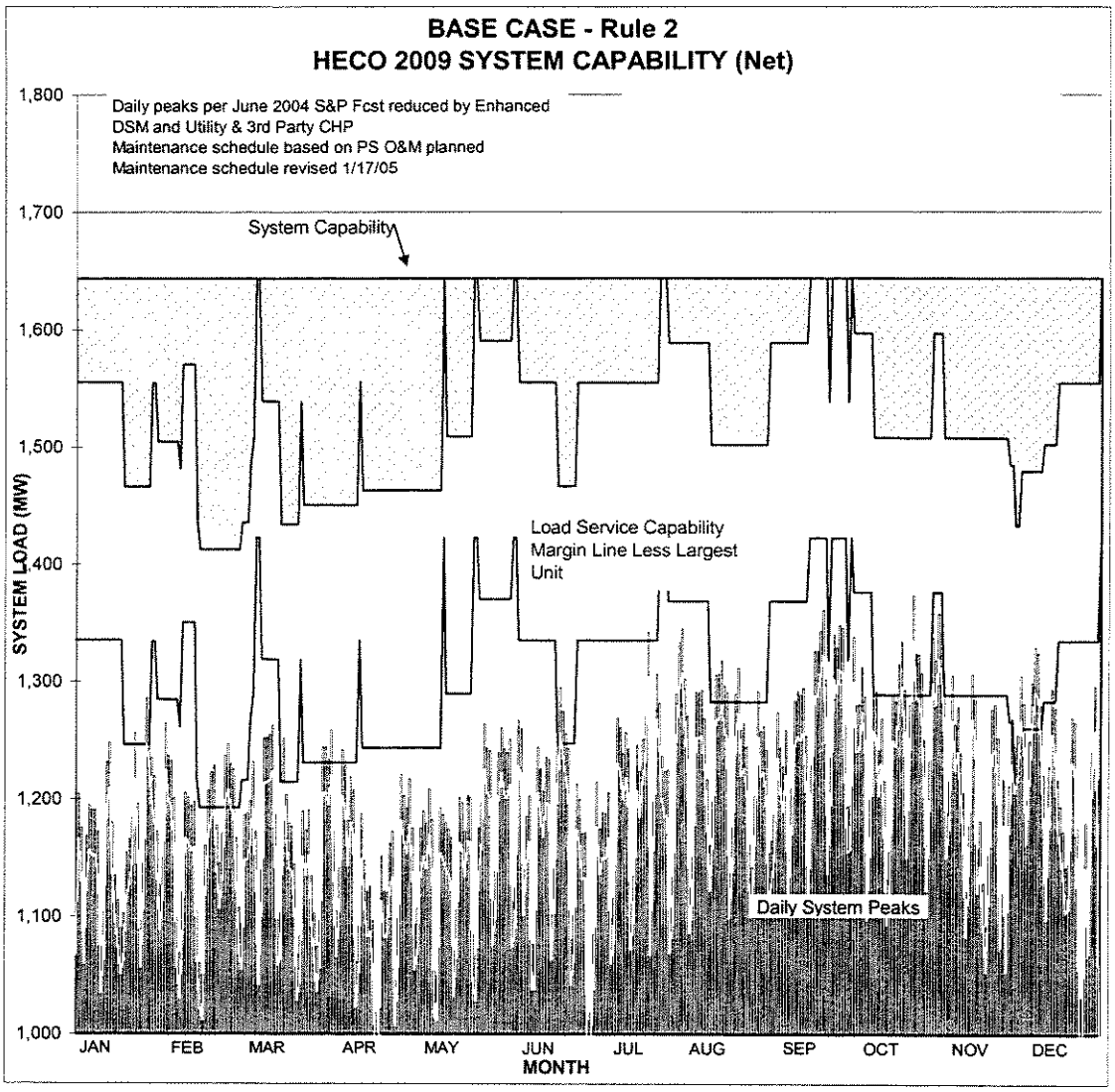

BASE CASE - Rule 2
HECO 2006 SYSTEM CAPABILITY (Net)
Daily peaks per June 2004 S&P Fcst reduced by Enhanced
DSM and Utility & 3rd Party CHP
Maintenance schedule based on PS O&M planned
Maintenance schedule revised 1/17/05
System Capability
Load Service Capability Margin Line
Less Largest Unit
Daily System Peaks
SYSTEM LOAD (MW)
1,800
1,700
1,600
1,500
1,400
1,300
1,200
1,100



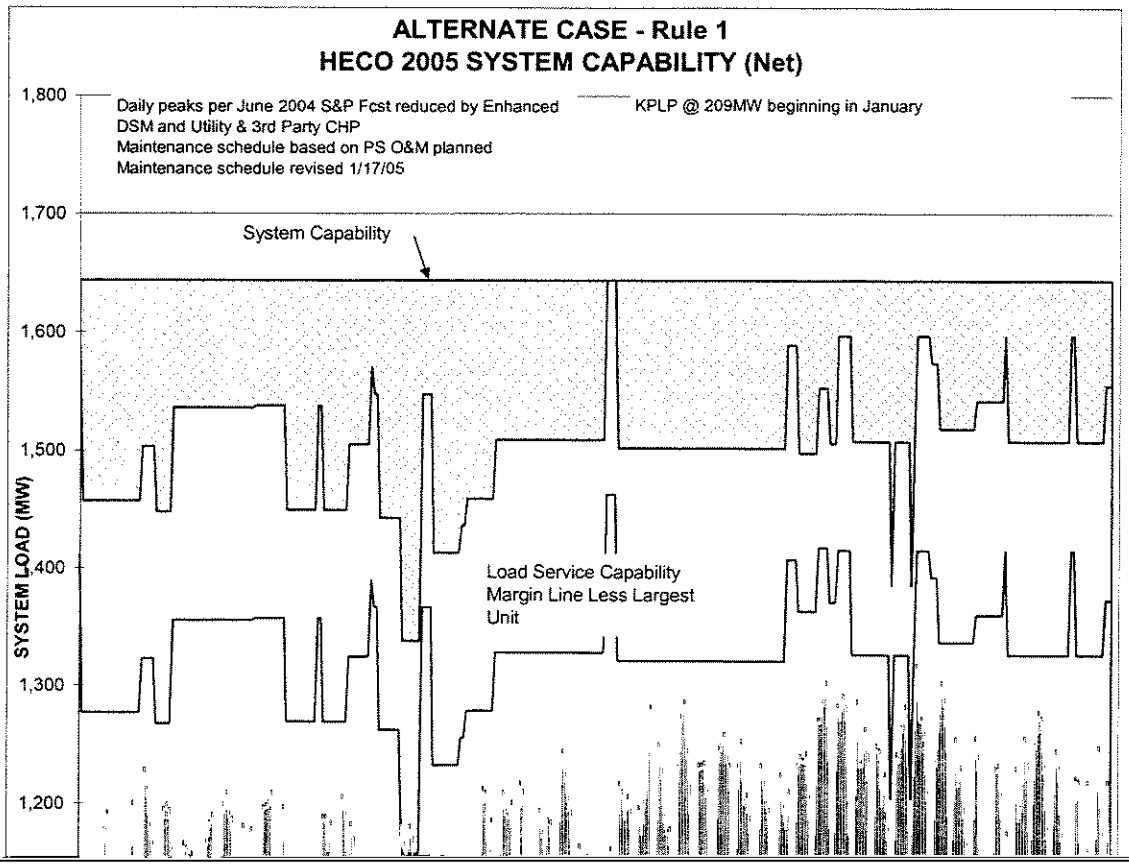
Month	Without Load Management		With Load Management	
	Minimum LSC Diff	# of days in violation	Minimum LSC Diff	# of days in violation
JAN	(17.0)	3	5.2	0
FEB	(47.4)	3	(25.2)	1
MAR	12.6	0	34.8	0
APR	(41.2)	5	(19.0)	3
MAY	(12.7)	2	9.5	0
JUN	(9.7)	2	12.5	0
JUL	(17.1)	1	5.1	0
AUG	(51.1)	3	(28.9)	2
SEP	(68.0)	8	(45.8)	4
OCT	(66.0)	4	(43.8)	4
NOV	9.2	0	31.4	0
DEC	(68.9)	9	(46.7)	7

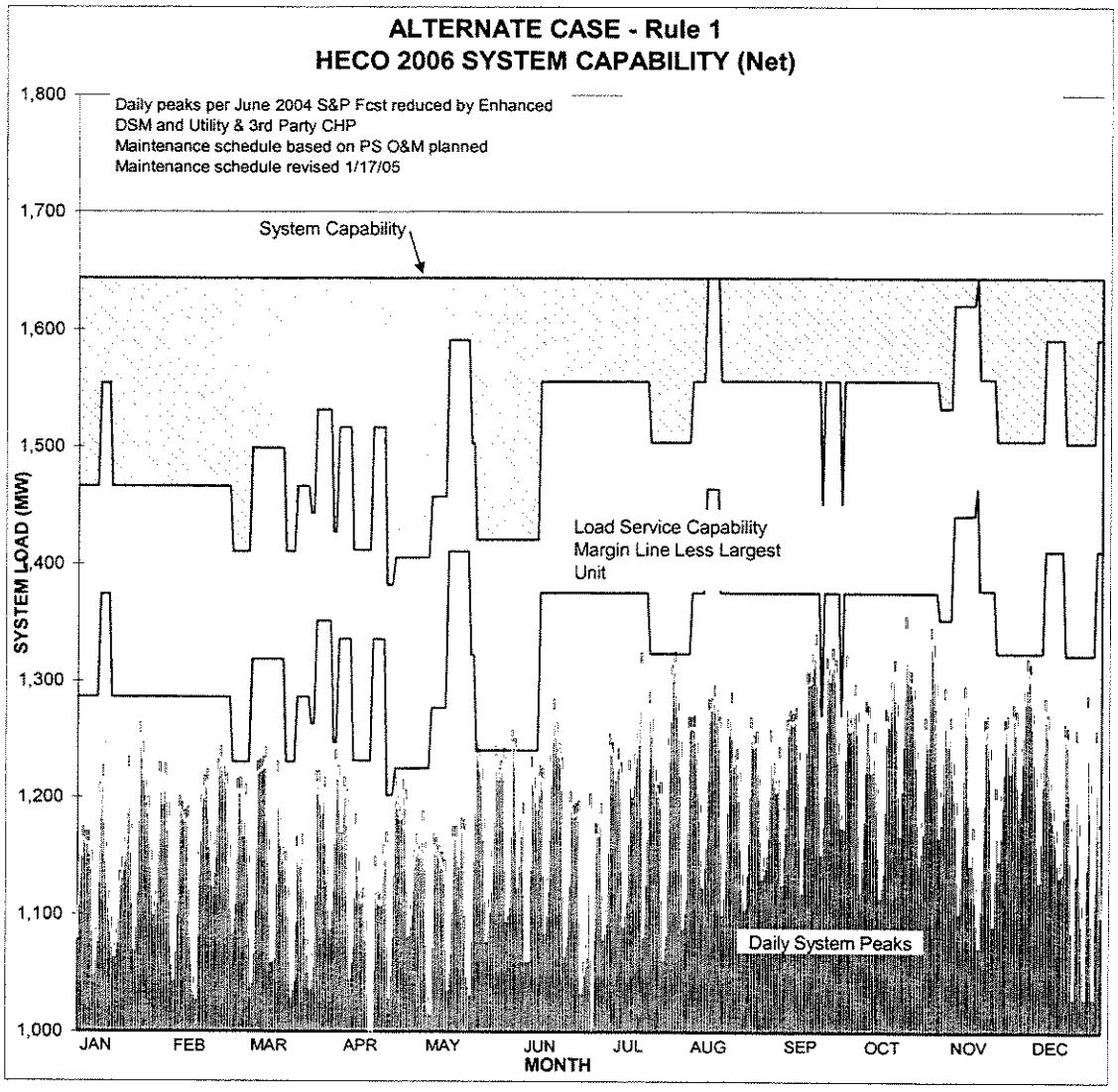


Month	Without Load Management		With Load Management	
	Minimum LSC Diff	# of days in violation	Minimum LSC Diff	# of days in violation
JAN	(2.2)	1	29.3	0
FEB	(32.2)	5	(0.7)	1
MAR	6.9	0	38.4	0
APR	(17.4)	2	14.1	0
MAY	31.7	0	63.2	0
JUN	33.7	0	65.2	0
JUL	(41.6)	2	(10.1)	1
AUG	(31.6)	1	(0.1)	1
SEP	5.2	0	36.7	0
OCT	(12.3)	1	19.2	0
NOV	(20.7)	3	10.8	0
DEC	(67.7)	10	(36.2)	3

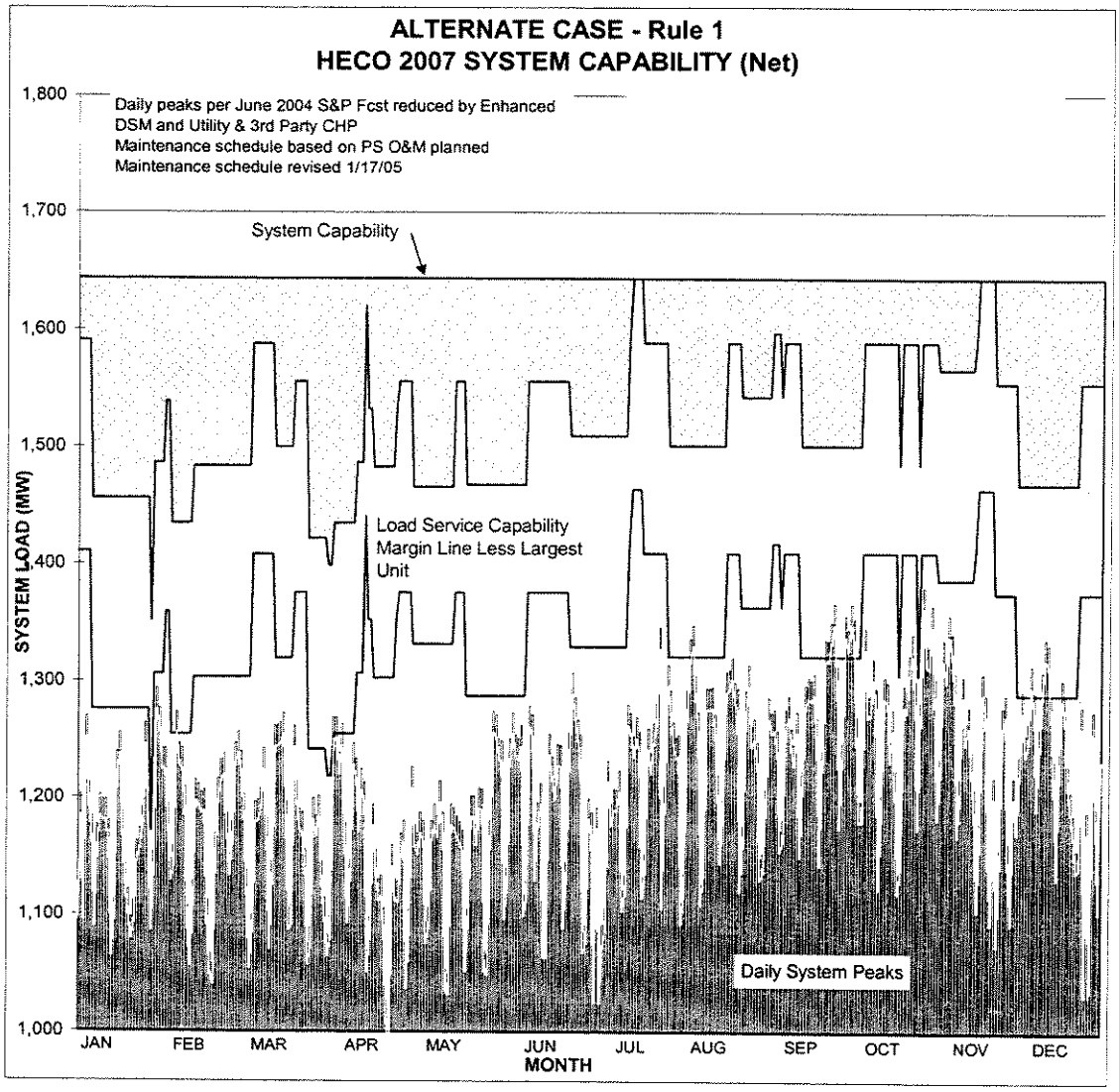


Month	Without Load Management		With Load Management	
	Minimum LSC Diff	# of days in violation	Minimum LSC Diff	# of days in violation
JAN	(39.8)	3	(0.9)	1
FEB	(54.0)	7	(15.1)	2
MAR	(37.4)	3	1.5	0
APR	(28.0)	3	10.9	0
MAY	34.6	0	73.5	0
JUN	(47.7)	3	(8.8)	1
JUL	(7.6)	1	31.3	0
AUG	(35.3)	7	3.6	0
SEP	(9.3)	1	29.6	0
OCT	(85.9)	9	(47.0)	2
NOV	(19.9)	4	19.0	0
DEC	(69.4)	9	(30.5)	5

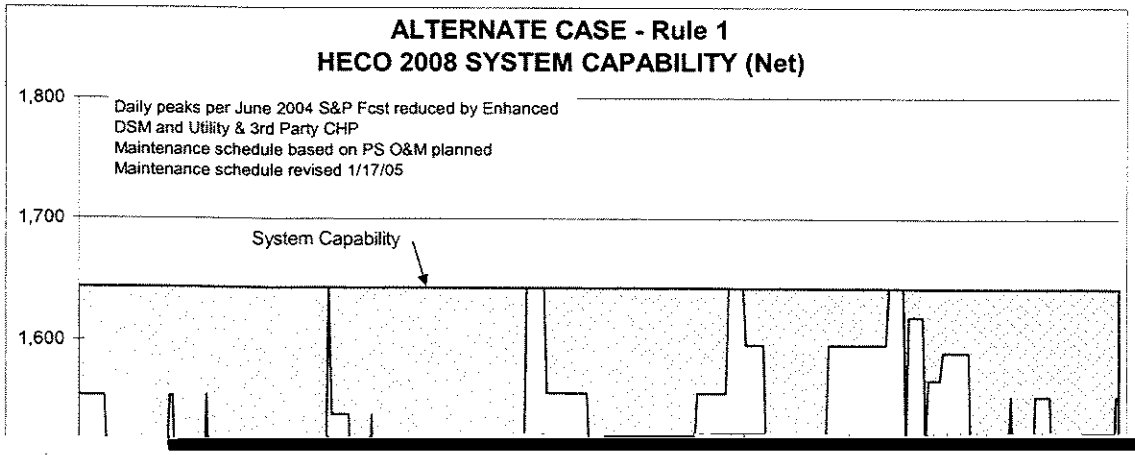

ALTERNATE CASE - Rule 1
HECO 2005 SYSTEM CAPABILITY (Net)
Daily peaks per June 2004 S&P Fcst reduced by Enhanced DSM and Utility & 3rd Party CHP
Maintenance schedule based on PS O&M planned
Maintenance schedule revised 1/17/05
KPLP @ 209MW beginning in January
System Capability
Load Service Capability Margin Line Less Largest Unit
SYSTEM LOAD (MW)
1,800
1,700
1,600
1,500
1,400
1,300
1,200



Month	Without Load Management		With Load Management	
	Minimum LSC Diff	# of days in violation	Minimum LSC Diff	# of days in violation
JAN	22.2	0	32.3	0
FEB	13.6	0	23.7	0
MAR	19.6	0	29.7	0
APR	5.2	0	15.3	0
MAY	(7.3)	3	2.8	0
JUN	(17.3)	3	(7.2)	2
JUL	32.5	0	42.6	0
AUG	(2.5)	1	7.6	0
SEP	34.5	0	44.6	0
OCT	19.5	0	29.6	0
NOV	28.5	0	38.6	0
DEC	4.4	0	14.5	0



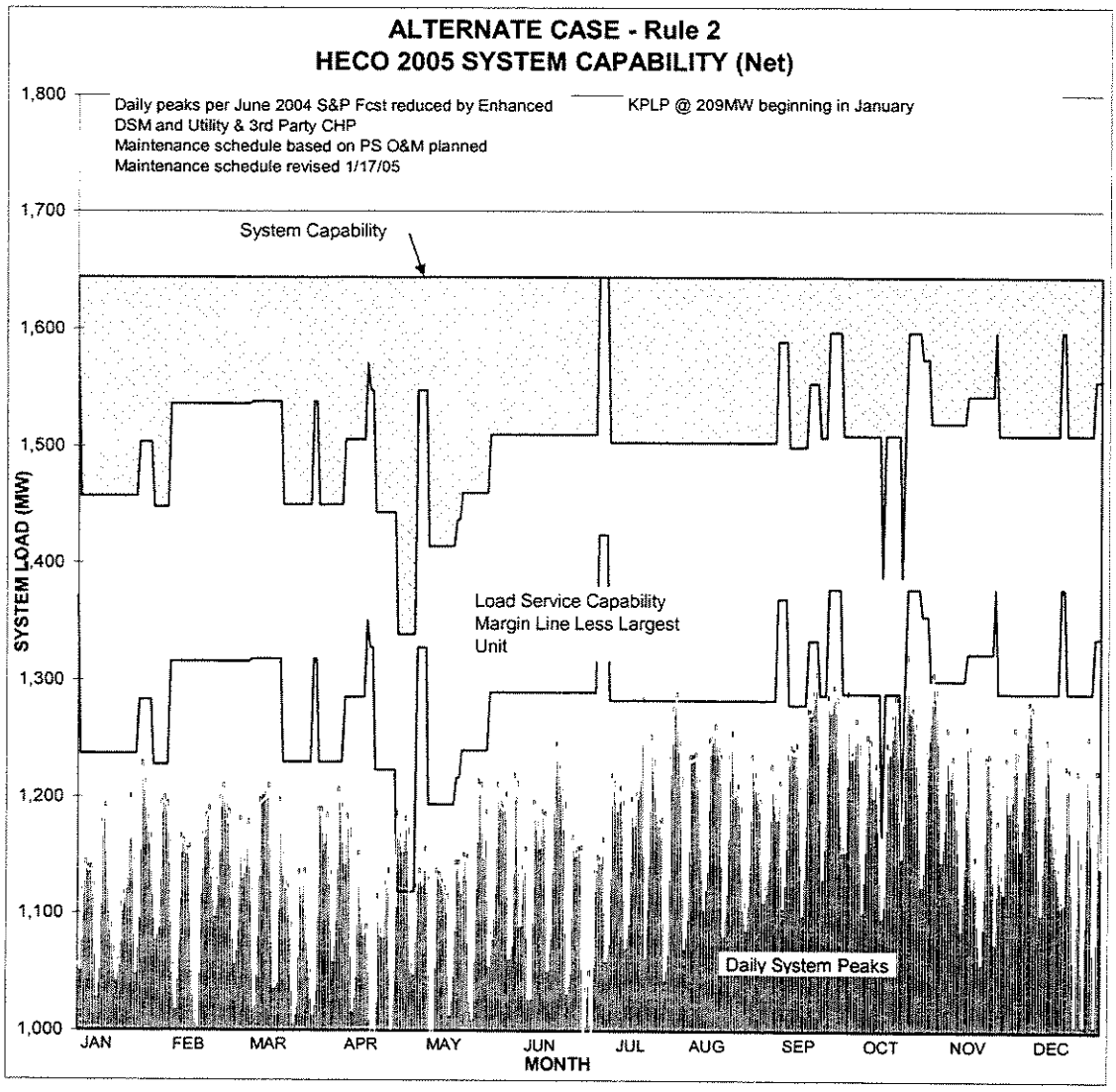
Month	Without Load Management		With Load Management	
	Minimum LSC Diff	# of days in violation	Minimum LSC Diff	# of days in violation
JAN	12.0	0	30.4	0
FEB	(19.4)	1	(1.0)	1
MAR	39.6	0	58.0	0
APR	(14.2)	3	4.2	0
MAY	13.3	0	31.7	0
JUN	14.3	0	32.7	0
JUL	6.9	0	25.3	0
AUG	(27.1)	2	(8.7)	1
SEP	(45.0)	4	(26.6)	2
OCT	(45.0)	4	(26.6)	4
NOV	30.2	0	48.6	0
DEC	(47.9)	7	(29.5)	4


ALTERNATE CASE - Rule 1
HECO 2008 SYSTEM CAPABILITY (Net)
1,800
1,700
1,600
Daily peaks per June 2004 S&P Fcst reduced by Enhanced
DSM and Utility & 3rd Party CHP
Maintenance schedule based on PS O&M planned
Maintenance schedule revised 1/17/05
System Capability

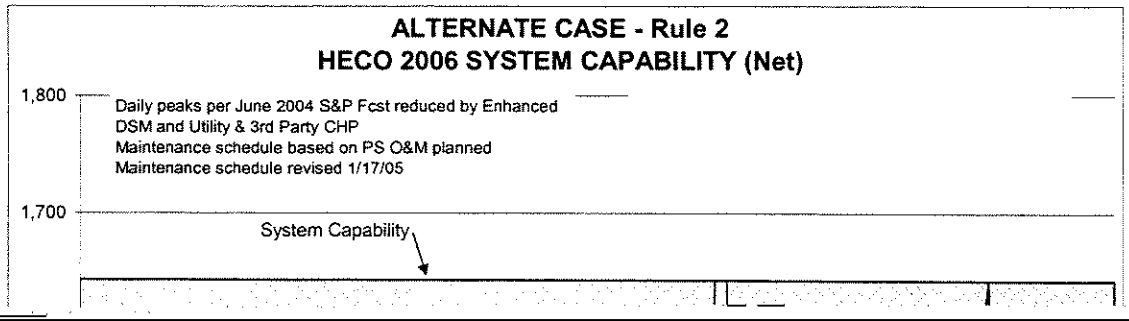
ALTERNATE CASE - Rule 1
HECO 2009 SYSTEM CAPABILITY (Net)

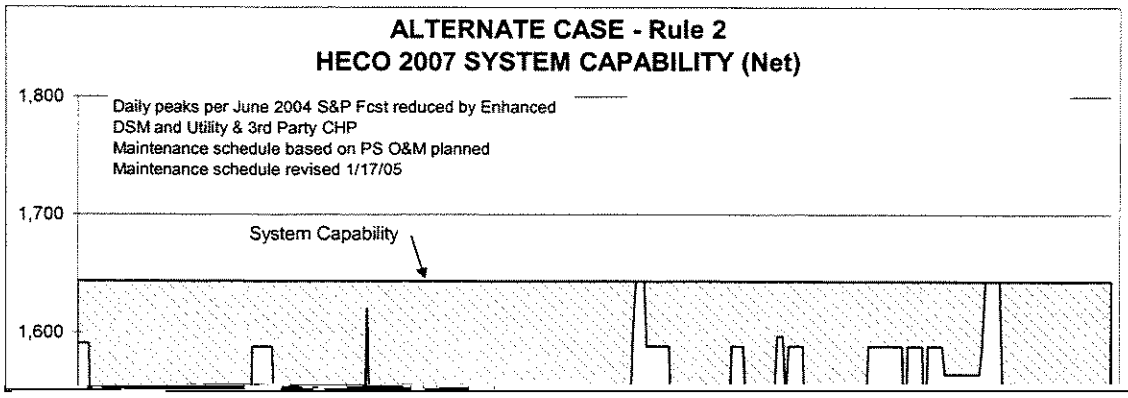
1,800

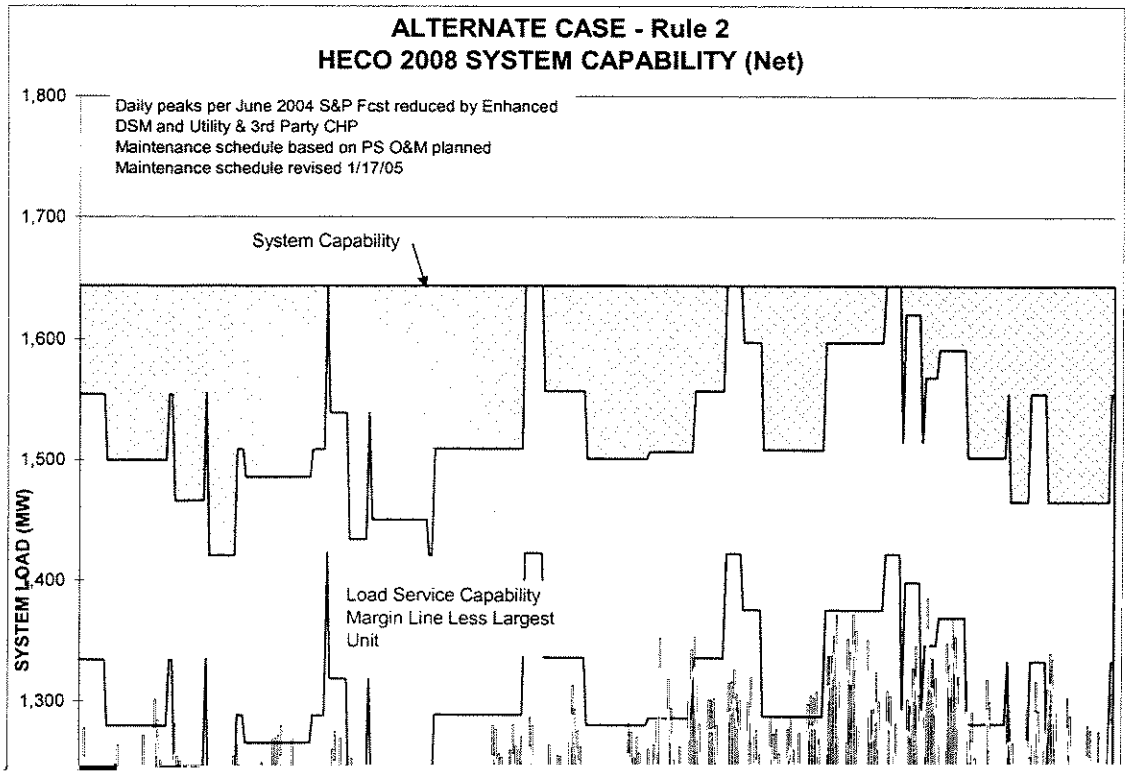
1,700

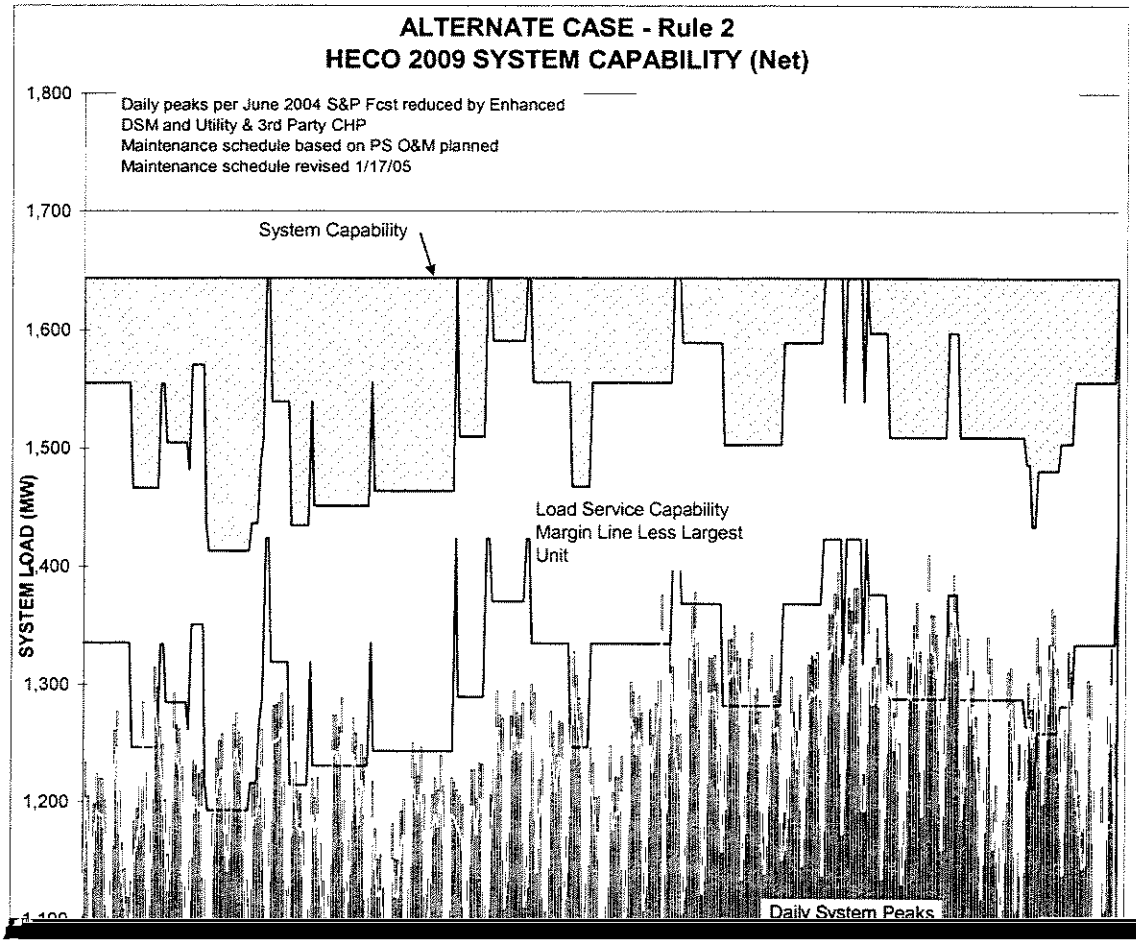


Month	Without Load Management		With Load Management	
	Minimum LSC Diff	# of days in violation	Minimum LSC Diff	# of days in violation
JAN	29.9	0	35.1	0
FEB	25.9	0	31.1	0
MAR	38.0	0	43.2	0
APR	(69.3)	5	(64.1)	5
MAY	23.8	0	29.0	0
JUN	41.7	0	46.9	0
JUL	(3.1)	1	2.1	0
AUG	(7.1)	1	(1.9)	1
SEP	26.6	0	31.8	0
OCT	(2.0)	1	3.2	0
NOV	(7.4)	1	(2.2)	1
DEC	6.1	0	11.3	0


ALTERNATE CASE - Rule 2
HECO 2006 SYSTEM CAPABILITY (Net)
1,800
1,700
Daily peaks per June 2004 S&P Fcst reduced by Enhanced
DSM and Utility & 3rd Party CHP
Maintenance schedule based on PS O&M planned
Maintenance schedule revised 1/17/05
System Capability


ALTERNATE CASE - Rule 2
HECO 2007 SYSTEM CAPABILITY (Net)
1,800
1,700
1,600
Daily peaks per June 2004 S&P Fcst reduced by Enhanced
DSM and Utility & 3rd Party CHP
Maintenance schedule based on PS O&M planned
Maintenance schedule revised 1/17/05
System Capability


ALTERNATE CASE - Rule 2
HECO 2008 SYSTEM CAPABILITY (Net)
Daily peaks per June 2004 S&P Fcst reduced by Enhanced DSM and Utility & 3rd Party CHP
Maintenance schedule based on PS O&M planned
Maintenance schedule revised 1/17/05
System Capability
Load Service Capability Margin Line Less Largest Unit
SYSTEM LOAD (MW)
1,800
1,700
1,600
1,500
1,400
1,300


ALTERNATE CASE - Rule 2
HECO 2009 SYSTEM CAPABILITY (Net)
Daily peaks per June 2004 S&P Fcst reduced by Enhanced DSM and Utility & 3rd Party CHP
Maintenance schedule based on PS O&M planned
Maintenance schedule revised 1/17/05
System Capability
Load Service Capability Margin Line Less Largest Unit
Daily System Peaks
SYSTEM LOAD (MW)
1,800
1,700
1,600
1,500
1,400
1,300
1,200

CA-IR-446

Ref: AOS 2005, at 7, 24.

a. Please provide a copy of all documents that address the mitigation of the risk (or eventuality) that HECO might experience a capacity shortfall during 2005.

b. Has HECO considered issuing an RFP to secure needed capacity from competitive markets?

c. If the response to Part (b) is in the affirmative, please provide a copy of all documents that address a potential RFP?

d. Please state whether HECO believes that a competitive solicitation for needed power supplies would not resolve its capacity deficiency (i.e., it reserve capacity shortfall as shown in Table 4) at reasonable cost.

HECO Response:

a. Please note that the March 10, 2005 Adequacy of Supply letter ("AOS report") refers to "reserve capacity shortfalls" rather than "capacity shortfalls." For example, on page 27, the AOS report concludes that:

> HECO expects to have sufficient generation capacity to meet the forecasted peak demands of electricity use. However, HECO anticipates reserve capacity shortfalls in 2005 and projects these shortfalls to continue at least until 2009, which is the earliest that HECO expects to be able to permit, acquire, install and place into commercial operation its next central station generating unit.

HECO also objects to this information request (1) to the extent that it requests information about actions or projects to be completed well beyond the end of the 2005 test year and/or that are not reasonably related to the 2005 test year, (2) on the grounds that it is overly broad and unduly burdensome in that it requests "all documents," and (3) on the grounds that some of the documents requested would be subject to the attorney-client privilege. Without waiving the objections, HECO's responses with respect to each of the various activities or programs identified in the AOS report are as follows:

1. Load Management DSM. See documents filed in Docket No. 03-0166, regarding the Residential Direct Load Control Program, and in Docket No. 03-0415, regarding the Commercial & Industrial Direct Load Control Program. Additional information was filed in the Annual Surcharge & Accomplishments Report on May 31, 2005.

As indicated in the updates to the revenue requirements inputs filed May 5, 2005 (Attachment 4, page 2), HECO at that time proposed to include approximately $493,000 in base rates for the RDLC and CIDLC Programs as a reasonable estimate for the expenses necessary to achieve Year 1 (2005) peak impacts, which includes $100,000 more than the sum of the direct labor, advertising, and miscellaneous budgets stipulated to and approved by the Commission in 2004 in Docket Nos. 03-0166 (RDLC Program) and 03-0415 (CIDLC Program).

The additional $100,000 was the estimated amount to be used to conduct a follow-up telemarketing campaign to increase the participation rate of customers receiving the targeted RDLC direct mailings from the current 5% to an estimated initial 10%-15%. Based on discussions with a couple of companies who are potential providers of telemarketing services since the filing of the May 5, 2005 letter, however, $125,000 is a more reasonable estimate of the cost of telemarketing for the 6 remaining months of 2005. Moreover, the telemarketing campaign is expected to continue into the following year (2006) and for the foreseeable future, because RDLC Program enrollment is expected to become more challenging in the years ahead. Therefore, HECO is increasing its test year estimate of RDLC advertising expenses by $175,000, from $150,000 to $325,000, to reflect a full year direct mail campaign ($50,000), telemarketing ($250,000), and the addition of a customer recognition campaign

($25,000) to retain previously enrolled customers. See response to CA-IR-533.

Achievement of RDLC Program load reductions and enrollment of RDLC Program participants will become increasingly more challenging for the following reasons: (1) First year direct mailings will have covered most of the island-wide eligible customers and signed up those that are the most highly motivated to enroll in the program. Customers approached in following years will be those that were unwilling or unable to participate during the first year. (2) The target for program participants will increase. As indicated in Attachment A of the Commission's Decision and Order No. 21415, dated October 14, 2004, in Docket No. 03-0166, the number of participants increases in Year 2 and 3 to 7,500 from the Year 1 target of 5,000.

HECO expects that the energy awareness and education campaign (see 2. below) will have a positive effect on the participation and retention rates in the RDLC Program. However, the Company must still provide the means for customers to enroll in the program. Those means will continue to be direct mailings and the telemarketing campaign.

CIDLC program participants once enrolled must also be retained. Therefore, HECO proposes to add an advertising component of $25,000 to the CIDLC budget included in base rates. The CIDLC Program advertising component will recognize commercial and industrial participants in print and radio, provide materials for display in their offices and/or storefronts identifying them as CIDLC Program participants, and any other advertising focused on reinforcing participation and/or recognizing participants. One of the major purposes of the advertising is to (1) publicly recognize the contributions that participants are making to maintaining electrical system reliability

for everyone, and (2) assure residential customers that the commercial and industrial sector is also contributing to demand reductions. See response to CA-IR-533.

to be used (in conjunction with much of the existing corporate advertising "budget") to encourage energy conservation, through "behavioral changes" on the part of residential customers, in addition to their implementation of DSM measures included in the Residential DSM Programs. The net result, however, would still be somewhat lower impacts than if the Enhanced EE DSM Programs had been implemented beginning in July 2005, as was assumed for purposes of the AOS report.

One of the DSM programs included in the rate case application was the proposed Residential Conservation Energy Awareness ("RCEA") program, for which an application was filed for a two-year pilot program in Docket No. 03-0142. The stated purpose of the proposed pilot program was to determine if an aggressive communications program can change the level of customer energy awareness of energy options, and encourage customers to adopt energy efficient appliances and behavior, with the objective of helping to achieve energy savings and peak load reductions. By Decision and Order No. 21756, issued April 20, 2005, the Commission denied the application, as revised on October 7, 2004, without prejudice (based on concerns raised by the Consumer Advocate). At the same time, the Commission noted that (1) it "understands HECO's need and desire to educate its residential customers about energy matters, including conservation," and (2) "[a]n educational program, such as the RCEA Pilot Program may be better suited as one component of a portfolio of DSM measures, which may be considered in other proceedings before the Commission, if HECO so chooses."

In light of the concerns raised by the Consumer Advocate, the Commission's decision, and the critical need to encourage residential customers to adopt cost-effective

conservation resources and practices, HECO intends to add $750,000 to its test year general advertising budget in order to enhance the Company's ability to educate and inform its customers about ways that they can save energy and reduce their peak demands. See response to CA-IR-533.

Given current conditions, HECO has developed plans for a three-layered conservation and energy efficiency message, which will be critical through at least the year 2008. The first message revolves around the importance of using energy wisely at all times; the second emphasizes that it makes special sense to reduce energy use at peak; and the third creates a basis for dramatically cutting the use of electricity during an emergency. HECO would expand and enhance its efforts to educate customers about the need to conserve at these three levels. Additional messages would be developed and produced, and HECO would procure an expanded presence in print and broadcast media (including television and radio). Participation in HECO's DSM Programs (programs that these messages will refer to by name) will be identified as one of the actions our newly energy-aware customers can take to implement energy efficiency. Details about the Company's DSM Programs, however, will continue to be provided under HECO's separate DSM Program advertising budgets.

In conjunction with its integrated advertising campaign, HECO would work with the EPA to promote Energy Star as a residential and commercial solution for energy efficiency. For the residential market, HECO would develop educational advertisement and point of sale collateral materials. HECO would explore partnerships with appliance retailers and distributors. Commercial efforts would focus on design assistance and educational workshops and seminars for operations and facility managers. In addition,

HECO would undertake a complete redesign and consolidation of the conservation and energy efficiency sections of our website.

As indicated above, HECO plans to launch a new lighting initiative, aimed at the residential market, to accelerate the adoption of energy efficient lighting solutions. HECO would seek interim approval, probably in the Energy Efficiency Docket, to recover the measure implementation and evaluation costs through the DSM component of the IRP surcharge. HECO does not currently [illegible]

[redacted]

provides incentives for efficient lighting measures. At the same time, energy efficient compact fluorescent lamps also will be one of the measures specifically identified in the general advertising campaign. The initiative would be conducted in concert with lighting distributors and manufacturers' representatives.

6. HECO's Next Generating Unit. As is indicated in the AOS report, HECO has commenced the permitting process for a combustion turbine, in the 100 MW range, to be installed at its Campbell Industrial Park, Barbers Point Tank Farm site. See documents filed in Docket No. 95-0347, HECO's second cycle IRP process ("IRP-2") docket, and the response to CA-IR-448 in this docket. Additional information will be included in the draft IRP-3 Preferred Resource Plan to be provided to the Advisory Group in or about June 2005. Documents related to the preliminary activities

[redacted]

referenced in the AOS report, such as the air permit application and the amended air permit application, are voluminous (and some are a matter of public record on file with the Department of Health, Air Branch), but will be made available for review at HECO Regulatory Affairs Division. Please contact Irene Sekiya at 543-4778 to arrange for review. HECO issued a Request For Proposals for a nominal 100 MW combustion turbine on April 8, 2005, to three vendors including Alstom, Siemens-Westinghouse,

DG units at substations was provided in response to CA-IR-441, as well as with the updates to the revenue requirements inputs filed May 5, 2005 (Attachment 1A).

8. Demand Load Response Program. HECO has retained a consultant to develop a demand load response program and expects to file an application with the Commission by mid-2005. Documentation regarding a proposed program will be available at that time. HECO does not expect that the demand load response program will impact its 2005 test year expenses, since HECO would seek recovery of incremental costs under the DSM surcharge.

9. Residential Air Conditioning Load Control Program. Following the filing of the Demand Load Response Program, HECO will pursue the development of a residential air conditioning load control program. HECO's Residential Direct Load Control (RDLC) Program, approved by the Commission in 2004, focuses on interrupting electric resistance water heaters only. HECO does not expect that the residential air conditioning load control program will impact its 2005 test year expenses, since HECO would seek recovery of incremental costs under the DSM surcharge.

10. Public Notification Program. The Public Notification Program is discussed in Section 5.6.4 of the AOS letter, on page 26. HECO does not expect that the program will impact its 2005 test year expenses since these costs are part of the Company's on-going communication efforts with our customers.

b. At this time, HECO does not plan to issue an RFP specifically designed to acquire capacity based on the expected 2005 – 2009 reserve capacity shortfall. The steps currently being taken and/or planned by HECO to partially offset load growth and to add firm capacity are addressed in subpart a. above. HECO has had discussions with existing providers of firm

capacity, such as H-Power, and is aware of their capabilities and plans. However, the time to add firm capacity in Hawaii (unless it can be done without a major air permit modification, as Kalaeloa was able to do through its "M" upgrade) is substantial, due to the time required to do air permitting, the need for an EIS for generation greater than 5 MW, the

need for land use permits and approvals at many sites, and the time required for other regulatory approval proceedings. (HECO does not have the option of "importing" power from other jurisdictions.)

HECO also meets with large customers from time-to-time regarding their ability and/or plans to take advantage of energy efficiency and load management demand-side management measures, interruptible and off-peak rate options, and even combined heat and power systems and distributed generation. Further, HECO is marketing its demand-side management programs addressed to its residential customers. Thus, HECO is and has been addressing the market possibilities for additional peak load reduction impacts and firm capacity, albeit not through the mechanism of a formal RFP.

In addition, Renewable Hawaii, Inc. ("RHI"), a non-regulated subsidiary of HECO, has issued RFPs to seek passive investment opportunities in commercial renewable energy projects greater than 1 MW in Hawaii (which could include firm capacity and as-available energy). RHI issued its first RFP in May 2003 for renewable energy projects on the island of Oahu. The intent of the renewable energy RFP is to stimulate the addition of cost-effective renewable energy in Hawaii, promote viable projects that will integrate positively with the utility grid on Oahu, and encourage renewable energy generation activity where such is lacking in targeted categories. Please see HECO response to CA-IR-6, pages 4 and 5, in Docket No. 04-0320 (Kalaeloa Amendments Nos. 5 and 6) filed on February 23, 2005,

for information on the potential renewable energy options.

On October 21, 2003, the Commission issued Order No. 20583 in Docket No. 03-0372 instituting a proceeding to investigate competitive bidding for new generating capacity in Hawaii. The parties[1] to the docket filed Statements of Position on March 14, 2005. HECO has not issued an RFP for firm fossil-fueled capacity. Please refer to HECO's Statement of Position, Exhibit A, Issue 2 (Whether a competitive bidding system should be developed for acquiring or building new generation in Hawaii?), pages 15 to 43. As HECO stated on page 15, "HECO has reservations about the effectiveness of competitive bidding in an island system such as Hawaii. If competitive bidding is implemented, there are a number of potential shortcomings or pitfalls that need to be addressed to ensure that competitive bidding system provides benefits to customers and shareholders. HECO [illegible]

Administrative rules 6-74, "Standards for Small Power Production and Cogeneration" to HECO at any time. Please see HECO response to CA-IR-404, part b. In addition, for the combustion turbine targeted for installation in 2009, all major equipment as well as construction services will be secured through a competitive procurement process. The engineering design services that will be performed by a consultant have already been secured through a competitive solicitation process.

RENEWABLE ENERGY REQUEST FOR PROJECT PROPOSALS

(ISLAND OF OAHU)

Issued by

Renewable Hawaii, Inc.

May 22, 2003

Renewable
HAWAII
A HECO SUBSIDIARY

RENEWABLE ENERGY
REQUEST FOR PROJECT PROPOSALS
(ISLAND OF OAHU)

Renewable Hawaii, Inc.

May 22, 2003

I. INTRODUCTION

Renewable Hawaii, Inc. issues this Renewable Energy Request for Project Proposals (RE RFPP) to solicit competitive proposals for investment opportunities in projects to supply renewable energy on the island of Oahu. The island of Oahu represents nearly 80% of the total peak electrical demand of the islands of Oahu, Maui, Molokai, Lanai, and the Big Island of Hawaii. Hence, the island of Oahu has the highest need for renewable energy development.

The intent of this RE RFPP is to stimulate the addition of cost-effective renewable energy in Hawaii, promote viable projects that will integrate positively with the utility grid on Oahu, and encourage renewable energy generation activity where such is lacking in targeted categories. Projects proposed for the grid system of Hawaiian Electric Company, Inc. (HECO), also referred to as the "applicable utility," are eligible under this RE RFPP.

Renewable Hawaii, Inc. seeks passive equity investment opportunities with respondents to this RE RFPP. A Memorandum of Understanding (MOU) will be developed with each successful bidder to reflect the negotiated agreement between Renewable Hawaii, Inc. and that entity. The exact nature of this negotiation will be handled on a case-by-case basis with the successful bidder. Once an MOU has been executed, it is the responsibility of the bidder to subsequently approach the applicable utility for a Power Purchase Agreement (PPA) for the sale of electricity. This RE RFPP is being issued by Renewable Hawaii, Inc., and not by or on behalf of the applicable utility. Renewable Hawaii, Inc. does not guarantee the process or outcome of the PPA negotiations with the applicable utility and will not participate in that process.

At a later date, separate RE RFPPs will be released to cover the service territory of each subsidiary utility of HECO. It is expected that a RE RFPP for the service territory of Maui Electric Company, Limited (MECO), which comprises the islands of Maui, Molokai, and Lanai, will be issued in the third quarter of 2003. In addition, a RE RFPP for the service territory of Hawaii Electric Light Company, Inc. (HELCO), or the Big Island of Hawaii, will be issued in the fourth quarter of 2003.

A. SCOPE

This RE RFPP is open to parties seeking to develop generating facility(ies) that produce electricity by wind, solar energy, hydropower, pumped storage hydroelectric, landfill gas, waste to energy, geothermal resources, ocean thermal energy conversion, wave energy, biomass including municipal solid waste, biofuels or fuels derived entirely from organic sources, hydrogen fuels derived from renewable energy, fuel cells where the fuel is derived entirely from renewable sources, or other technologies deemed to be renewable in nature.

Respondents are requested to provide proposals for projects supplying renewable energy (firm capacity and/or as-available energy as defined in Section V) that will contribute toward the total amounts, and

during the timeframes, specified in Section I-B. The rated generation capacity of the proposed project shall exceed 1,000 kW.

Renewable Hawaii, Inc. will not entertain, at this time, proposals for wind projects located between Kahuku and Haleiwa, on the north shore of Oahu. Renewable Hawaii, Inc. will issue a separate announcement regarding wind development within this defined Oahu north shore geographical area at a later date.

B. RENEWABLE ENERGY REQUIREMENTS

By this RE RFPP, Renewable Hawaii, Inc. seeks renewable energy to satisfy all or a portion of the renewable energy requirements forecast shown in the table below.

Year	2003	2005	2010
Renewable Energy Requirements, MWh	35,000	160,000	345,000

The renewable energy requirements stated above are applicable to the islands of Oahu, Maui, Molokai, Lanai, and the Big Island of Hawaii. In addition, the requirements are incremental and therefore do not include existing renewable energy generation and electrical energy savings (solar water heating and heat pump systems) in the service territories of HECO, HELCO, and MECO. In addition, it is assumed that the renewable energy achieved from existing systems during calendar year 2002 is maintained in 2003, 2005, and 2010.

Renewable Hawaii, Inc. provides notice that the forecast of renewable energy requirements may be modified as a result of changes in the forecast requirements at any point during the Renewable Hawaii, Inc. RE RFPP process or during negotiations with bidders and any such change may increase, reduce, or eliminate the amount of renewable energy sought.

All project proposals shall contain delivery schedules with a commercial date of operation no later than December 31, 2008.

II. BIDDER REQUIREMENTS

A. PROPOSAL REQUIREMENTS

The bidder shall provide proposal information listed in Sections II-A.1, II-A.2 and II-A.3. If an item is not applicable, the bidder should so indicate by specifying "N/A" for "Not Applicable" and provide an explanation why the item is not applicable. Failure to do so may render the proposal incomplete such that it will not be evaluated further.

1. Completed "Proposal Summary" provided in Appendix A.

2. Completed "Supplemental Proposal Information" as delineated in Appendix B.

3. Provide evidence of Federal Energy Regulatory Commission (FERC) certification or self-certification, or State of Hawaii Public Utilities Commission (PUC) order, indicating that bidder's proposed project is a qualifying small power production facility (QF) (see definition in Section V).

B. CHANGES TO RE RFPP

Renewable Hawaii, Inc. reserves the right to revise, suspend or terminate this RE RFPP and any schedule related thereto at its sole discretion at any time and for any reason without liability to the bidder. It shall be the responsibility of each potential bidder to regularly access Renewable Hawaii, Inc.'s website at www.renewablehawaii.com to investigate any and all changes and addendums to this RE RFPP.

C. SAMPLE POWER PURCHASE AGREEMENT

A sample Power Purchase Agreement (PPA) for as-available energy, entitled "Power Purchase Contract for As-available Energy," may be obtained upon request of the RE RFPP Contact (see Section III-G). This document indicates, for information purposes only, the terms and conditions that may be negotiated in a contract for the sale of electricity to be executed with the applicable utility. The terms and conditions that may be offered by the applicable utility in an as-available energy PPA may be modified to reflect factors such as different renewable technologies, project specifics, changes in applicable rules, guidance from the PUC in proceedings regulating the approval or negotiation of such PPAs, and negotiated terms and conditions. Firm power PPAs are complex and developed in accordance with the specifics of each individual renewable technology. Any final executed PPA between the bidder and the applicable utility shall be submitted by the applicable utility to the PUC for review and approval.

D. RENEWABLE ENERGY SITE LOCATION AND INTERCONNECTION POINT(S)

Renewable Hawaii, Inc. may invest in projects situated on the island of Oahu. Preferred locations are described in Section IV-A.4. Pursuant to negotiations between the bidder and the applicable utility, the latter may accept some or all of bidder's firm capacity and/or as-available energy.

III. INSTRUCTIONS TO BIDDERS

The following sections provide instructions to bidders of the RE RFPP

A. The anticipated schedule for proposal solicitation and evaluation is as follows:

RE RFPP for Oahu Issued	May 22, 2003
RE RFPP Proposals for Oahu Due	August 22, 2003

D. Bidders should, at the time of submittal, supply any additional information not included in the forms if such information may be needed for a thorough understanding or evaluation of the proposal. All responses will be considered commitments to be used in developing the MOU between Renewable Hawaii, Inc. and the bidder that may arise from this RE RFPP.

E. A signed written original plus eight (8) hard bound copies, and an electronic copy including all attachments, must be submitted to the address as noted in Section III-G below.

F. A duly authorized signatory of the bidder must sign the proposal.

G. All proposals, including all attachments, must be properly completed and submitted by: (1) courier or Registered or Certified Mail, Return Receipt Requested, in hard copy and (2) electronic version, to Renewable Hawaii, Inc.'s RE RFPP Contact:

Arthur Seki
Mail: P.O. Box 2750
Honolulu, Hawaii 96840-0001
Delivery: 820 Ward Avenue
Honolulu, Hawaii 96814
Subject: Renewable Hawaii, Inc. RE RFPP – Oahu
Phone: (808) 543-7987
Facsimile: (808) 543-7519
E-mail: aseki@hei.com

H. All proposals must be received by Renewable Hawaii, Inc.'s RE RFPP Contact by no later than 4:00 P.M. (Hawaii Standard Time) on August 22, 2003. Late proposals may or may not be considered at Renewable Hawaii, Inc.'s sole discretion.

I. Dollar figures quoted must be clearly stated in $US as nominal for the calendar year in which they occur. Escalation rate assumptions used should be clearly stated.

J. None of the material received by Renewable Hawaii, Inc. from the bidder in response to this RE RFPP will be returned to the bidder, even if no MOU is consummated between the parties. All materials and proposals submitted by the bidder will become the property of Renewable Hawaii, Inc. and may be used by Renewable Hawaii, Inc. for the purpose of evaluating proposals, executing any agreements, providing background and non-confidential information for regulatory and/or legislative hearings, or other related activities.

K. If the bidder is negotiating for a PPA with the applicable utility regarding the renewable energy project proposal (or a substantially similar proposal) submitted to Renewable Hawaii, Inc. in response to this RE RFPP, Renewable Hawaii, Inc. will not simultaneously consider that project proposal in this RE RFPP process.

L. Unsuccessful participants in the RE RFPP process may submit proposals directly to the applicable utility without Renewable Hawaii, Inc. investment. Non-participants in the RE RFPP process may submit proposals directly to the applicable utility.

IV. PROPOSAL EVALUATION

A. EVALUATION PROCESS

The following major steps will be taken as part of the proposal evaluation process.

1. Eligibility Requirements Pre-Screening
   Proposals will be pre-screened to determine if eligibility requirements are met.

   In order for a proposal to be eligible for evaluation by Renewable Hawaii, Inc., the proposal must meet minimum eligibility criteria. The eligibility criteria are listed below:

   - Substantially complete proposal meeting requirements of this RE RFPP received by specified due date and time.
   - Proposal generates electrical power from one of the renewable resources listed in Section I-A.
   - Project exceeds the minimum net design capacity (greater than 1,000 kW).
   - Proposal information contained in Sections II-A.1, II-A.2, and II-A.3 is complete.
   - Proposal is not currently under negotiations for a PPA with the applicable utility.

   Proposals that do not meet the eligibility criteria listed above will not be evaluated; provided that proposals deemed by Renewable Hawaii, Inc. to be substantially complete after clarification of outstanding issues and/or receipt of additional information it requests may be considered at Renewable Hawaii, Inc.'s sole discretion. Upon notification by Renewable Hawaii, Inc., bidders are provided five (5) working days to clarify any outstanding items in their proposal.

2. Proposal Categorization
   Based on the information provided in the bidder's proposal, an eligible proposal will be categorized by project type (i.e., either firm capacity or as-available energy), and if applicable, by technology.

3. Screening
   Proposals will be evaluated for passive equity investment to identify and eliminate any proposals that are clearly not technologically feasible or not financially competitive with other proposals, or are submitted by bidders that lack appropriate creditworthiness, sufficient financial resources, or management qualifications. These proposals will be screened out from further evaluation.

4. Detailed Evaluation
   The remaining proposals will undergo detailed evaluation for passive equity investment. The detailed evaluation criteria utilized in the RE RFPP include:

   - Viable proposals at or below avoided costs.
   - Proposed project must be a qualifying facility (see definition in Section V).
   - Location and project type preference (in order of priority):

     1. Oahu – firm power
     2. Oahu – as-available energy, excluding wind projects on Oahu located between Kahuku and Haleiwa

   The remaining proposals will be evaluated on qualitative and quantitative criteria.

- Renewable Hawaii, Inc. is interested in investing in viable projects with pricing proposals that are at or below the avoided costs of the applicable electric utility.
- Renewable Hawaii, Inc. is interested in investing in viable projects with project teams, technologies, performance guarantees, siting, and schedules that optimize the likelihood of timely attainment of an executed PPA with the applicable utility. Renewable Hawaii, Inc. will review and evaluate the background of each bidder and its principals and associated team, the proposed resource and technology, status of required permits and approvals, plans for site acquisition and control, project flexibility and viability, project financing, project schedule, operation and maintenance plans, environmental factors, and plans for community support.

The result of the evaluation will be a relative ranking of proposals, for passive investment purposes, within the firm capacity and as-available energy project type categories.

5. Memorandum of Understanding
Bidders that propose projects that meet eligibility requirements pre-screening, screening and detailed evaluation and are deemed viable based on evaluations conducted by Renewable Hawaii, Inc. have the opportunity to (a) enter into discussions for passive equity investment by Renewable Hawaii, Inc. and (b) sign an MOU with Renewable Hawaii, Inc. that reflects negotiated agreements. The exact nature of this negotiation will be handled on a case-by-case basis with the successful bidder.

It is envisioned that bidders with completed MOUs with Renewable Hawaii, Inc. will timely approach the applicable utility and enter into PPA negotiations for the sale of electricity.

B. EVALUATION CONSIDERATIONS

The following considerations apply in the proposal evaluation process.

1. Renewable Hawaii, Inc., at its sole discretion, shall evaluate responsive proposals and select projects, if any, which (a) provide the best investment value to Renewable Hawaii, Inc., and (b) promote the timely and cost-effective addition of renewable energy in Hawaii.

2. Renewable Hawaii, Inc. shall perform an initial screening evaluation to identify and eliminate non-

6. Those bidders who submit proposals agree to do so at their own risk and without legal recourse against Renewable Hawaii, Inc., its parent or affiliates, or their directors, officers, employees and agents. Renewable Hawaii, Inc. shall not be liable to any bidder or party in law or equity for any reason whatsoever for any acts or omissions arising out of or in connection with this RE RFPP.

7. The bidder shall be liable for all its costs and Renewable Hawaii, Inc. shall not be responsible for any of the bidder's costs incurred to prepare, submit, or negotiate its proposal or for any other activity related thereto.

C. CONFIDENTIALITY

Renewable Hawaii, Inc. will take reasonable precautions and use reasonable efforts to protect any claimed proprietary and confidential information contained in a proposal provided that such information is clearly identified by the bidder as "Proprietary and Confidential" on the page on which proprietary and confidential information appears. Such information may, however, be made available under applicable state or federal law to regulatory commission(s), their staff(s), or other governmental agencies having an interest or jurisdiction in these matters and in accordance with the guidelines delineated in Section III-J.

Renewable Hawaii, Inc. also reserves the right to release such information to its agents or contractors for the purpose of evaluating the bidder's proposal but such agents or contractors will be required to observe the same care with respect to disclosure as Renewable Hawaii, Inc. Under no circumstances will Renewable Hawaii, Inc., its parent or affiliates, or their directors, officers, employees, agents or contractors, be liable for any damages resulting from any disclosure of the bidder's claimed confidential information during or after the solicitation process.

V. DEFINITIONS

A. FIRM CAPACITY

"Firm capacity" refers to scheduled amounts of capacity in kilowatts made available from a generating unit to an electric utility under utility dispatch within particular time periods pursuant to a power purchase agreement with the utility.

The value of the firm capacity and energy provided by a generating unit generally will be determined based on the utility's long-term avoided capacity and energy costs estimated at the time the power purchase agreement is negotiated, and will be impacted by factors such as constraints on the utility's ability to dispatch the unit, the unit's reliability and availability, and contractual sanctions for not meeting minimum reliability and availability standards, and the utility's ability to coordinate scheduled outages of the unit.

B. AS–AVAILABLE ENERGY

"As-available energy" refers to energy from non-firm generation sources. As-available energy is provided to the utility from a generating unit when the energy is determined to be available for purchase by the utility, subject to the utility's ability to accept the energy (i.e., subject to the utility's curtailment rights). The value of the energy provided by a unit generating as-available energy generally will be based on the utility's short-term avoided energy costs determined at the time the energy is delivered, but may be based on the utility's long-term avoided energy costs estimated at the time the power purchase agreement is negotiated if the utility accepts fixed or formula energy prices set for the term of the agreement.

C. UTILITY DISPATCH

"Utility dispatch" means the utility's right, through supervisory equipment (such as the utility's Energy Management System) or otherwise, to control, from moment to moment, within the limits of sound engineering practices, both the capacity and the energy output of a generating unit. Dispatch includes control, within established ranges, of a generation unit's real power, reactive power, voltage, frequency, cycling on and off-line, droop control setting, ramp rate setting, and other characteristics of energy output whose parameters are normally controlled or accounted for in a utility dispatching system.

D. QUALIFYING FACILITY

"Qualifying facility" (QF) means a cogeneration facility or a small power production facility which is a qualifying facility under Title 6, Chapter 74 of the Hawaii Administrative Rules, sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. sections 796 and 824i, and the regulations of the United States Federal Energy Regulatory Commission (FERC) regarding qualifying cogeneration and small power production facilities, 18 C.F.R. Part 29.

APPENDIX A

Proposal Summary

APPENDIX A

Proposal Summary

Fill out this form completely, using separate copies to describe each proposed project. Use separate sheets or schedules as necessary to provide the required information, referencing the numbered sections on this form. Indicate N/A if not applicable

Proposal applicable to service territory of Hawaiian Electric Company, Inc. (HECO)

Section I General Information

(Note: Throughout this form, "net" refers to "net TO THE UTILITY," unless otherwise indicated.)

I.1 Project Name

I.2 Technology employed

I.3 Fuel Type

I.4 Specific Site (for determining transmission requirements and avoided costs). Attach documents to support site acquisition.

I.5 Unit Capacity

	Net (MW) (to utility system)	Corresponding Gross (MW)
Minimum (normal operations)		
Minimum + [25% x (Normal Top Load - Minimum)] (normal operations)		
Minimum + [50% x (Normal Top Load - Minimum)] (normal operations)		
Minimum + [75% x (Normal Top Load - Minimum)] (normal operations)		
Normal Top Load (normal operations)		
Emergency		

Duration of Emergency Capacity (e.g., 10% above Normal Top Load capacity for 2 hours only in a 24-hour period)

I.6 In-Service Date(s) (month & year). Attach a detailed schedule to support the in-service date.

I.7 Estimated Plant Service Life _____ Years

I.8 Power Purchase Agreement Duration _____ Years
(As a normal practice, Power Purchase Agreement Duration should not exceed the Estimated Plant Service Life.)

I.9 Interconnection point, metering location, required modifications to HECO/HELCO/MECO system to integrate proposed NUG project

I.10 Name of Contact _____
telephone no. _____ facsimile no. _____

I.11 Conflict of Interest - list all principal parties and contractors and state any conflicts of interest they may have between this proposed project and any other alternative projects, either with a competitor or HECO/HELCO/MECO. If there are no conflicts of interest, so indicate.

Section II Operational Information

II.1 Full dispatchability (Unit must load follow between Normal Top Load and Minimum capacities.
_____ Yes _____ No

The utility will consider Qualifying Facilities without full dispatchability and will consider the degree of dispatchability in determining the value of the firm capacity. The value will depend upon the extent to which the capacity can be utilized by the utility's system. Each bidder shall describe any operating or dispatch constraint and the source of the constraint (e.g., equipment limitations, environmental permits, fuel resource availability, or other sources). It should be noted that the constraints might impact the value of the firm capacity (if any) provided by the facility and the ability of the utility's system to accept the capacity.

Operating or Dispatch Constraints:

Source of Constraints:

II.2 Cycling capability (Complete shutdown or turn down to 0 MW net to system) on a daily basis?
_____ Yes _____ No

The utility will consider Qualifying Facilities without full cycling capability and will consider the degree of cycling capability in determining the value of the firm capacity. The value will depend upon the extent to which the capacity

II.4 Expected Capacity Factor for Each Month (or provide dispatch table by hour for every month)

_____ (expected energy generated in January) x 100 _____ %
(rated capacity) x hours in January _____

_____ (expected energy generated in February) x 100 _____ %
(rated capacity) x hours in February _____

_____ (expected energy generated in March) x 100 _____ %
(rated capacity) x hours in March _____

_____ (expected energy generated in April) x 100 _____ %
(rated capacity) x hours in April _____

_____ (expected energy generated in May) x 100 _____ %
(rated capacity) x hours in May _____

_____ (expected energy generated in June) x 100 _____ %
(rated capacity) x hours in June _____

_____ (expected energy generated in July) x 100 _____ %
(rated capacity) x hours in July _____

_____ (expected energy generated in August) x 100 _____ %
(rated capacity) x hours in August _____

_____ (expected energy generated in September) x 100 _____ %
(rated capacity) x hours in September _____

_____ (expected energy generated in October) x 100 _____ %
(rated capacity) x hours in October _____

_____ (expected energy generated in November) x 100 _____ %
(rated capacity) x hours in November _____

_____ (expected energy generated in December) x 100 _____ %
(rated capacity) x hours in December _____

II.5 Expected Equivalent Availability Factor (NERC Definition)
(annual equivalent hours available/8760) _____ %

II.6 Equivalent Forced Outage Rate (NERC Definition)
_____ (forced out hours + equivalent forced derated hours)
(forced out hrs + svc hrs + equiv. forced derated hrs during reserve shutdown)
_____ %

II.7 Ramp rate

	Net (MW/minute)	Gross (MW/minute)
Ramp Rate	_____	_____

II.8 Quick Load Pick-Up (QLPU) (for HECO only If bidder is for a firm capacity QF, then this section N/A) - the amount of additional load that the unit could pick up in 3 seconds in response to a system frequency decrease when the unit is not at full load. (HELCO & MECO currently have no QLPU criteria.)

	Net MW	Net QLPU Available MW	Corresponding Gross QLPU Available MW
Minimum Net Capacity	_____	_____	_____
Min Net Cap+25% x (Normal Top Load Net Cap - Min Net Cap)	_____	_____	_____
Min Net Cap+50% x (Normal Top Load Net Cap - Min Net Cap)	_____	_____	_____
Min Net Cap+75% x (Normal Top Load Net Cap - Min Net Cap)	_____	_____	_____

II.9 Maintenance Outage Requirements - Specify partial and complete outage requirements in weeks for the number of years required for the cycle to repeat (For example, list time interval of major overhauls and the duration of overhauls)

II.10 Cold start heat input requirement in MBTU _____

II.11 Hot start heat input requirement in MBTU _____

II.12 Number of hours the unit stays hot after shutdown _____

II.13 Specify all other operating constraints

Section III Contract Terms

III.1 Capacity Charge

Generation Capital (normally levelized)	_____	($/kW-yr, net)			
Fixed Operations & Maintenance	_____	($/kW-yr, net)	(in calendar year	_____	dollars)
Other (specify) _____	_____	($/kW-yr, net)	(in calendar year	_____	dollars)
Total Capacity Charge	_____	($/kW-yr, net)	(in calendar year	_____	dollars)

III.2 Energy Charge

Each bidder shall provide a formula that describes the pricing for the energy provided by the bidder's unit as a function of unit output.

Fuel cost is in calendar year _____ dollars

Variable Operations & Maintenance	_____	(¢/kWh)	(in calendar year	_____	cents)
Other (specify) _____	_____	(¢/kWh)	(in calendar year	_____	cents)

III.3 Type of Capacity (firm or non-firm) _____

(See definition for firm capacity in Section V-A of the RE RFPP. See also Sections II.1 and II.2 of this Appendix A and response to Frequently Asked Question Q13.)

III.4 Escalation terms (specifically state what indices to use for escalation, if any)

Fixed Operations & Maintenance _____

Fuel _____
(As a normal practice, the Fuel charge is escalated using actual fossil fuel prices for fossil fuel technologies.)

Variable Operations & Maintenance _____

Other _____

III.5 Reliability terms or adjustments (if any) _____

(Provide details on terms or adjustments)

III.6 Options, such as black start, future fuel conversions, etc. and their pricing

III.7 Payment Terms (describe when invoices will be rendered, when payments are due, period of time covered by invoice, and any other special terms regarding payments)

III.8 Any other charge items from NUG to HECO/HELCO/MECO

III.9 Specify all other special needs and/or provisions

(Use separate sheets as necessary)

APPENDIX B

Supplemental Proposal Information

APPENDIX B

SUPPLEMENTAL PROPOSAL INFORMATION

All bidders to the RE RFPP must provide the following information regarding their proposal(s). If an item is not applicable to the bidder, the bidder must so indicate by specifying "N/A" for "Not Applicable." Failure to do so may render the proposal incomplete such that it will not be evaluated further.

Background on Bidder

- Provide bidder's legal name, structure (e.g., sole ownership, corporation, joint venture, partnership, LLC, LLP, etc.), nature of business and description, number of years in business, number of permanent employees, address, federal tax identification number, legal names of parent company and/or subsidiaries, organizational structure of each entity, and state or country

- Provide information on commitments for supply and transportation of renewable resources, if applicable;
- Provide technical data on the renewable technology, including any studies or reports regarding the technology;
- Provide information on the proposed renewable technology as used in other locations;
- Provide an update on the status of the vendor(s) of the renewable technology; and
- Describe conceptual designs and major equipment list.

Permits and Approvals

- List all major permits required, including environmental assessments or environmental impact statements;
- Describe land and use rights for proposed project, such as location, ownership, current zoning, size, and cost of project site;
- Provide status and copies of any agreements for obtainment of any necessary land lease and easements, air and water permits, rights of way, and the like;
- Describe and provide all licenses received or description of plans to obtain licenses; and
- Describe and provide all approvals required for completion of the project.

Project Flexibility and Viability

- Describe ability to conform to the commercial date of operation specified by Renewable Hawaii, Inc. (December 31, 2008);
- Describe ability to expand at the proposed site;
- Describe proposed role of Renewable Hawaii, Inc.;
- Provide location of known substation and transmission and distribution lines near the project location;
- Identify provisions offered by the bidder for providing liquidated damages and payment for replacement power in the event of failure-to-perform by the bidder for proposals containing firm power deliveries;

Project Schedule

- Provide project schedule with key milestones (include permitting, land lease, major equipment purchase, etc).

Operation and Maintenance

- Provide description of operation and maintenance (O&M) plan.

Environmental

- Describe projected emissions and waste streams, environmental impacts, including any studies or reports regarding the environmental impacts.

Community Support

- Describe level of community support and provide the communications plan to gain public support for the proposed project.

FREQUENTLY ASKED QUESTIONS

Renewable Hawaii, Inc.
Renewable Energy Request for Project Proposals (RE RFPP) – Island of Oahu

Q1: I am currently negotiating a renewable energy power purchase agreement (PPA) with Hawaiian Electric Company, Inc. for a project in the HECO service territory. How will the RE RFPP affect my project?

A1: You may continue to negotiate with HECO for a PPA. It is Renewable Hawaii's understanding that all renewable energy project proposals submitted to HECO will be treated similarly, without predisposed priorities or separate treatment, whether those proposals are received through the PURPA process or as a result of Renewable Hawaii's RE RFPP process.

You must decide, however, whether to submit your project proposal to Renewable Hawaii, Inc. in response to its RE RFPP, or to continue negotiating a PPA with HECO. If the bidder is negotiating directly for a PPA with HECO regarding the renewable energy project proposal (or a substantially similar proposal) that was also submitted to Renewable Hawaii, Inc. in response to this RE RFPP, Renewable Hawaii, Inc. will not simultaneously consider that project proposal in this RE RFPP process.

Q2: Will Renewable Hawaii, Inc. invest in a project with pricing terms that are above avoided costs?

A2: No. Renewable Hawaii, Inc. is interested in investing in viable projects that are at or below avoided cost, offer the best investment value for Renewable Hawaii, Inc., and support the attainment of renewable energy goals for the State of Hawaii. Renewable Hawaii, Inc. will review and evaluate the cost of the project, background of the respondent and its principals and associated team, the proposed resource and technology, permits and approvals, project flexibility and viability, project financing, project schedule, operation and maintenance plans, environmental factors, and plans for community support.

Q3: Will Renewable Hawaii, Inc. invest in renewable projects on Kauai, Maui, Molokai, Lanai,, the Big Island of Hawaii or on the mainland?

A3: Not at this time. The general intent of this RE RFPP is to solicit proposals for potential projects that are located on the island of Oahu, in accordance with the scope and priorities described in the RE RFPP.

The island of Oahu represents nearly 80% of the total peak electrical demand of the islands of Oahu, Maui, Molokai, Lanai, and the Big Island of Hawaii. Hence, the island of Oahu has the highest need for renewable energy development.

It is expected that a RE RFPP for the service territory of Maui Electric Company, Limited (MECO), which comprises the islands of Maui, Molokai, and Lanai, will be

issued in the third quarter of 2003. In addition, a RE RFPP for the service territory of Hawaii Electric Light Company, Inc. (HELCO), or the Big Island of Hawaii, will be issued in the fourth quarter of 2003.

Q4: Will production of energy from my renewable project be subject to performance standards or to curtailment?

A4: The electric utility systems serving the islands of Oahu, Maui, Molokai and Lanai and Hawaii (the "Big Island of Hawaii") are not interconnected with each other. The peak load served by HECO in 2002 was 1,204 MW (on Oahu). The minimum load served by HECO in 2002 was 496 MW.

As a result of the lack of interconnections, and the relatively small size of the systems, the electric utilities require that new generation meet applicable performance standards related to power quality and system reliability, and may exercise their PPA rights to curtail or interrupt as-available energy deliveries when necessary. For example, during low load periods, base loaded generation is backed down to minimum load levels consistent with the operating characteristics of the units, minimum dispatch constraints in firm PPAs and the need to maintain operating reserves (to address sudden load reductions, or sudden increases and/or fluctuations in as-available energy output). The difference between the system load, and the minimum load levels of base loaded generation (and any other generation that must be on line to ensure system stability and reliability), generally will determine the amount of as-available energy that can be accepted by the utility's system at any time.

The utilities cannot predict in advance the degree to which curtailment will be necessary, since that will depend on factors such as the number and size of as-available energy and firm capacity projects added, and the utilities' future minimum system loads. Some degree of curtailment may be anticipated, however, particularly on the Big Island. HELCO currently receives as-available energy deliveries from a number of renewable energy producers, and curtails the output of producers from time-to-time, primarily during minimum load periods in accordance with the curtailment priorities in its PPAs with the producers.

Q5: Are there any transmission and distribution constraints that may limit the amount of energy into the utility system?

A5: Yes. Utility transmission and distribution systems have various constraints that may limit the amount of energy that could be accepted into the utility's grid. Transmission and distribution lines have maximum MVA ratings, which can limit the amount of power flowing through the lines. Injecting more energy than the lines are rated for will cause the lines to overload, which will result in line sagging or line failure.

During PPA negotiations between the bidder and utility, the bidder will be requested to provide a preliminary single-line diagram or rough schematic describing the anticipated electrical interconnection for the proposed project.

There may also be limitations on the amount of intermittent generation on the transmission and distributions systems. Injecting large amounts of fluctuating, intermittent power in one location can result in voltage fluctuations, which can damage sensitive electrical equipment or result in power outages.

As part of the process of negotiating a PPA, the bidder will coordinate with the utility to conduct an interconnection requirements study (IRS) in a timely manner. The study will be conducted by utility transmission planners or contracted to previously approved outside consultants under the terms of an IRS letter agreement negotiated prior to the IRS. The cost of the IRS shall be the sole responsibility of the bidder. Depending on the renewable technology and location of the project, the cost of an IRS could total $60,000 or more.

In addition, the PPA negotiated with an applicable utility will require that other interconnection costs (generally, the costs of transmission and distribution facilities and service required to deliver power from the proposed project to the utility's interconnection point) shall be the sole responsibility of the bidder.

Q6: If Renewable Hawaii, Inc. enters into a Memorandum of Understanding (MOU) and binding agreement for equity investment in my project, will Renewable Hawaii, Inc. participate in the power purchase agreement negotiations or other activities?

A6: No. After the MOU and contract are executed, the bidder will have sole responsibility to complete all actions and agreements to meet the commercial date of operation.

Q7: If my project is not suitable for Renewable Hawaii, Inc. investment, can I still pursue a power purchase agreement with the utility?

A7: Yes. As a qualifying facility, the bidder may pursue a power purchase agreement directly with the applicable utility.

Q8: If I have a question on the RE RFPP, when will I get a response?

A8: All questions should be directed to the RE RFPP Contact. Responses will be provided to bidders in a uniform and consistent basis, to the extent possible. Bidders should regularly check the Renewable Hawaii, Inc. website for RE RFPP and Frequently Asked Questions updates and announcements.

Q9: What are the potential generation capacities (in MW) that can satisfy the renewable energy requirements specified in Section I-B of the RE RFPP?

A9: Assuming a capacity factor (percentage of hours in a 8,760-hour year that a facility produces energy at its rated capacity) of 83% for a firm generation facility and 35% for a non-firm (as-available) generation facility, the generation potentials for the 2003, 2005, and 2010 renewable energy requirements specified in Section I-B of the RE RFPP are estimated to be:

- 2003 (35,000 MWh): 5 MW of firm generation or 11 MW of as-available generation;
- 2005 (160,000 MWh): 22 MW of firm generation or 52 MW of as-available generation; and
- 2010 (345,000 MWh): 47 MW of firm generation or 113 MW of as-available generation.

Q10: How will Renewable Hawaii, Inc. determine whether a project proposal will be at or below avoided costs?

A10: For firm capacity proposals and certain as-available energy proposals, Renewable Hawaii, Inc. will obtain an estimate of the avoided costs for your proposal during screening of the proposals. A more detailed calculation of avoided costs will be made by the applicable utility during power purchase agreement negotiations. (The utility generally performs one calculation for a completed proposal free of charge.)

Q11: How are avoided costs determined by the utility?

A11: Avoided costs for firm capacity proposals and certain as-available energy proposals are the costs that the utility would avoid by purchasing capacity and energy from a qualifying facility (QF). Avoided costs are comprised of two major components: avoided capacity costs (for firm power projects) and avoided energy costs. Typical avoided capacity costs include firm generating capital costs, generation capital working cash, transmission capital costs, transmission capacity losses, fixed operation and maintenance (O&M) costs, fixed O&M working cash, land costs, and insurance costs. Typical avoided energy costs include fuel costs, fuel working cash, fuel inventory, transmission energy losses, variable O&M costs, and variable O&M working cash.

Avoided costs generally are calculated using the differential revenue requirements (DRR) method. The DRR method uses a base plan to determine what the capacity, fuel, and O&M costs would be without the QF. An alternate plan is developed with the QF unit installed based on the QF developer's proposal and on criteria for dispatch of all units on the system, including the QF. The difference in the utility's cost between the base plan and alternate plan represents the cost that the utility can avoid by implementing the QF alternative. The dispatch of the QF (for firm power projects) in the production simulation is dependent on the energy price proposal (determines economic dispatch), duty cycle (determines how QF would be operated), and location (determines interconnection requirements, voltage support, transmission losses).

The use of the DRR method to calculate avoided costs for HECO, HELCO and MECO is explained in the applicable utility's system cost data filing filed with the State of Hawaii Public Utilities Commission (PUC) on July 1, 2002. The base plan used by the utility to calculate avoided costs will be based upon the latest information available at the time the calculation is performed, which may be different from the utility's system cost data filing. HECO filed updated information regarding its base

plan in December 2002 (Integrated Resource Plan 1998-2017: 2002 Evaluation Report).

For as-available energy purchases, the utility also files short-term avoided energy costs with the PUC on a quarterly basis.

Q12: What is the "quarterly avoided energy cost" filing?

A12: The quarterly avoided energy cost filing is a report that HECO, HELCO and MECO file each quarter with the PUC. The report provides the rates during that quarter at which the utilities will purchase as-available energy during on-peak and off-peak hours. The latest quarterly avoided energy costs for HECO, HELCO, and MECO may be obtained by request of the RE RFPP Contact.

Q13: When are avoided costs based on the differential revenue requirements (DRR) method and when are "quarterly avoided energy costs" used?

A13: The DRR method is used when purchase rates are tied to the utility's long-run avoided capacity and/or avoided energy costs. They may apply to long-term power purchase agreements for firm capacity and associated energy, or to as-available energy agreements, where pre-determined fixed formula purchase rates are desired. Quarterly avoided energy costs generally are used for short-term power purchase agreements or for as-available energy power purchase agreements, where rates of purchase are determined at the time the energy is delivered.

Q14: Is there any new wind resource data available?

A14: Yes. Hawaiian Electric Company, Inc. (HECO) and Maui Electric Company, Limited (MECO) have recently completed high resolution wind resource maps (wind speed and wind power densities) for the islands of Oahu, Maui, Molokai, and Lanai. These maps can be found on HECO's website at www.heco.com. A high resolution wind resource map for the Big Island of Hawaii will be available at a later date.

CA-IR-447

Ref: AOS 2005, at 5.

a. How will the Hawaii Renewable Portfolio Standard (RPS) Requirements be met on Oahu "if . . . renewable energy program imports are not fully realized"?

b. Has HECO considered renewable capacity that can help meet the capacity shortfall in the interim?

HECO Response:

a. Please refer to the HECO, HELCO and MECO Renewable Portfolio Standards Status Report that was filed with the Commission (and a copy provided to the Consumer Advocate) on February 27, 2004. There are numerous renewable energy projects that have been identified that have the potential to contribute to meeting the RPS. Under the State of Hawaii RPS law (HRS-269.91 – 94), an electric utility company and its electric utility affiliates may aggregate their renewable portfolios in order to achieve the RPS. Please also refer to HECO's response to CA-IR-295.

b. Yes, HECO considered renewable capacity that can help meet the capacity shortfall in the interim. As stated in HECO's response to CA-IR-6, in Docket No. 04-0320 (Kalaeloa PPA Amendment Nos. 5 and 6), filed on February 23, 2005, Renewable Hawaii Inc. ("RHI"), a subsidiary of HECO, is currently considering three proposals (for possible passive investment) selected from among eight received in response to RHI's Request For Project Proposals issued in May 2003. The proposals include a landfill gas generating unit, a municipal solid waste generating unit, and a wind farm. The first two renewable energy options may provide firm capacity, at some time in the future, but not until the projects are developed, permitted and constructed, and PPAs are negotiated with HECO by the project developer and approved by the Commission. The wind farm would provide as-available energy and would not provide firm capacity.

CA-IR-448

Ref: AOS 2005, at 5-6.

a. How did HECO determine that the identified simple-cycle combustion turbine is the best option to pursue in 2009 (i.e., "the earliest that HECO expects to be able to permit, acquire, install and place into commercial operation" such facility)?

b. What other options has HECO explored?

c. Please provide copies of all documents that address the other options that have been explored.

HECO Response:

a. Since 1998, HECO has consistently maintained that the next firm capacity central-station generating unit on the system should be a simple cycle combustion turbine installed in 2009.[1] HECO performed rigorous integration analyses in its IRP-2 process (in Docket No. 95-0347) and concluded that the next unit that should be installed as part of the Preferred Plan should be a 107 MW simple cycle combustion turbine.[2] The integration analysis compared the Total Resource Costs of plans which had a baseloaded biomass unit as the next unit, a baseloaded coal-fired unit as the next unit, and a peaking combustion turbine as the next unit. The plans with the peaking combustion turbine as the next unit were lower in cost compared to the plans with the biomass or coal-fired unit as the next unit.[3] A primary driver in the analysis was that the unit is needed to operate for only short periods of time to provide spinning reserve during the peak period periods of the day. A peaking unit best fits this system need. Other plan attributes, such as emissions, fuel diversity and rate impact

[1] As early as 1996, HECO indicated that the next generating unit should be a simple cycle peaking unit. See HECO IRP-1 Evaluation Report, filed August 1, 1996, in Docket No. 7257, Table 2.2.5.1, on page 40. At the

were also considered.[4]

By Order No. 18340, filed on January 29, 2001, in Docket No. 95-0347, the Commission indicated that HECO's 2nd IRP and Action Plans were sufficient to meet HECO's responsibilities under Sections II.C.1. and II.C.2. of the IRP Framework and that it was not necessary under the circumstances for the Commission to issue a final decision and order under Section II.D.2. of the IRP Framework.

In HECO's 2002 IRP-2 Evaluation Report, filed on December 31, 2002, in Docket No. 95-0347, HECO again concluded that the next central-station generating unit that should be installed as part of the Updated IRP-2 Plan should be a 107 MW simple cycle combustion turbine installed in 2009.[5]

In HECO's currently on-going IRP-3 process, HECO again evaluated which type of unit would be the most appropriate next unit. In a process similar to that used in IRP-2, a simple cycle combustion turbine and a coal-fired plant were tested as the next generating unit in the long-term plan and the Total Resource Costs of the plans were compared. Based on the assumptions being used in the IRP-3 process, including, but not limited to, the sales

coal-fired steam unit), additional capacity from existing Independent Power Producer ("IPP") units, Combined Heat and Power ("CHP"), firm capacity renewable generation (such as biomass and municipal solid waste generation) and as-available renewable generation (such as photovoltaic and wind energy). HECO is pursuing a number of these

options, including energy efficiency and load management DSM, CHP, firm and as-available renewable energy, as well as a simple cycle peaking unit. No one option will satisfy the forecasted need for firm capacity. Please refer to HECO's response to CA-IR-6, in Docket No. 04-0320 (Kalaeloa PPA Amendment Nos. 5 and 6), filed on February 23,

would not be able to provide capacity any sooner than a peaking unit could.

With respect to additional capacity from existing IPP units, please refer to HECO's submittals in Docket No. 04-0320 for the additional 29 MW of capacity from Kalaeloa. Please also refer to HECO's response to CA-IR-404, part b. regarding additional capacity from other IPPs.

With respect to CHP, please refer to the application of HECO, HELCO and MECO for the Companies' proposed CHP Program in Docket No. 03-0366, filed on October 10, 2003, and also to HECO's submittals in the Distributed Generation Docket in Docket No. 03-0371.

With respect to firm capacity renewable generation, Renewables Hawaii Inc. ("RHI") is evaluating proposals for a landfill gas generating unit and a municipal solid waste generating unit. Documentation for these projects is in the possession of RHI. Due to the "conflict screen" between HECO and RHI, HECO does not have access to these documents.

With respect to as-available renewable generation, Renewables Hawaii Inc. ("RHI") is evaluating a proposal for a wind farm. Documentation for these projects are in the possession of RHI. Due to the conflict screen between HECO and RHI, HECO does not have access to these documents. Please also refer to HECO's response to CA-IR-447, part b.

Please also refer to HECO's response to CA-IR-6, in Docket No. 04-0320 (Kalaeloa PPA Amendment Nos. 5 and 6), filed on February 23, 2005, for information on measures HECO is pursing to maintain generating system reliability. See also responses and objections to CA-IR-446, which are incorporated herein by reference.

CA-IR-449

Ref: AOS 2005, at 13, Section 3.5.

a. Please explain why the system average generating unit EFORs will not continue to be higher than the identified "forward looking system average EFOR for the 2005-2009 period," given that load is expected to grow and capacity is expected to be short in coming years?

b. Why would growing loads and short capacity not be expected to result in more planned outages for the coming years or more derates?

c. What maintenance plans are in place to address issues associated with wear and tear of the units?

HECO Response:

a. In estimating future EFORs for its generating units, HECO considered the historical reliability of the units as well as the recent work performed on the units. (See the Adequacy of Supply Report, Appendix 4, Section 7, pages 3 and 4.) For example, Honolulu Unit 8 has a five-year (2000-2004) average EFOR of 11.6% while Honolulu Unit 9 has a five year average EFOR of 5.7%. As indicated in HECO's response to CA-IR-129, a substantial amount of boiler, turbine, generator and other work was done to Honolulu Unit 8 to restore its condition. Therefore, HECO estimates that Honolulu Unit 8's future EFOR will be about the same as Honolulu Unit 9's historical average EFOR of 5.7%. Another example is Waiau Unit 9. It has a five-year (2000-2004) average EFOR of 26.2%. The unit suffered a major force outage in October 2004 due to considerable blade damage in the compressor. (See HECO's response to CA-IR-129.) A substantial amount of work is being done on the unit to restore its condition. HECO estimates that its future EFOR will be about 10%. Waiau Unit 10 has a five-year average EFOR of 14.5%, but that unit is scheduled for a lengthy planned outage in 2005 to restore its condition. Therefore, HECO estimates that that unit will also have a future EFOR of 10%.

b. In estimating future EFORs, HECO also considered the effect higher loads and the reserve capacity shortfall may have on unit reliability. While these may cause EFORs to be higher (with all other factors being equal), HECO believes they will be offset by the work being performed on the generating units.

c. HECO plans its unit maintenance schedules up to five years in advance. The work that is planned for each outage on each unit depends on known problems (if any) that need to be

CA-IR-450

Ref: Response to CA-IR-274.

The response to Part (b) of CA-IR-274 discusses the possible retirement of the Honolulu Power plant and "Replacement of the Honolulu Power Plant capacity with capacity from a power plant at an alternative site."

a. Please provide copies of all resource planning documents that address this retirement, as either a "plan" or a "contingency" scenario.

b. Has the possible retirement of the Honolulu Power Plant been incorporated into the planning (to-date) for HECO's IRP-3?

c. If the response to Part (b) is in the affirmative, please explain how and provide supporting documentation.

HECO Response:

a. A copy of the planning scenarios with the possible retirement of Honolulu Power Plant is provided on pages 3 and 4 of this response.

b. Yes, the possible retirement of the Honolulu Power Plant has been incorporated into the planning (to-date) for HECO's IRP-3.

c. On August 31, 2004, HECO presented to the IRP-3 Integration Technical Committee ("ITC") the scenarios that HECO would be analyzing as part of the integration analysis. A scenario with the possible retirement of Honolulu Power Plant was included, as shown on the attached excerpt Powerpoint slide (Slide 54) that was shown to the ITC. The scenario analysis considered the changes in resource timing and total resource costs based on retiring Honolulu Power Plant in 2015[1], maintaining generating system reliability throughout the 20-

[1] The 2015 retirement date was based on the requirement that replacement generation would need to be permitted, constructed and fully operational before Honolulu Power Plant could be retired. Please see HECO's response to CA-IR-451, part c. HECO estimated that the time needed to permit, install and place into service a power plant capable of baseload or cycling duty (as Honolulu Power Plant is capable of) and permit, install and place into service all other substation, transmission and distribution infrastructure to replace that which would

year planning period, and meeting the objectives in each plan concept. On September 27, 2004, HECO presented the preliminary results of the scenario analysis, and on November 8, 2004, HECO presented the final results of the scenario analysis. These results are summarized on pages 3 and 4 of this response. The documents from the November 8, 2004 ITC meeting were placed on HECO's IRP website (http://irp.heco.com) after the meeting. On November 15, 2004, the materials presented at the November 8, 2004 ITC meeting were presented to the full IRP-3 Advisory Group. On December 6, 2004, an Advisory Group meeting was held to review the candidate plans and the input received at a public IRP meeting held on November 17, 2004. The Consumer Advocate participated as a member of the IRP-3 Advisory Group and the ITC.[2]

be removed with the Honolulu Power Plant, was approximately 10 years for the purposes of the scenario analysis.

[2] The Consumer Advocate ("CA") attended the August 31, 2004 meeting. The CA was unable to attend the

HECO IRP-3 FINALIST PLANS SCENARIO ANALYSIS - HONOLULU POWER PLANT RETIRES

	A **Finalist Plan 1** **Least Cost Plan**	B **Finalist Plan 2** **20% of Oahu Sales from RE by 2020** **(RE defined by SB2474) Plan**	C **Finalist Plan 3** **Maximize RE (RE defined by SB2474) Plan**
Year	Supply Side Resource	Supply Side Resource	Supply Side Resource
2006			
2007			
2008			Add 100 kW Fixed PV systems (4 MW = 40 units)
2009	Add GE PG7121 Simple Cycle CT (76 MW)	Add GE PG7121 Simple Cycle CT (76 MW)	Add GE PG7121 Simple Cycle CT (76 MW) Add Wind at Kahe (50 MW) Add 100 kW Fixed PV systems (4 MW = 40 units)
2010			Add 100 kW Fixed PV systems (4 MW = 40 units) Add 2 kW Fixed PV systems (4 MW = 2,000 units) Add 100 kW Tracking PV systems (2 MW = 20 units)
2011		Add 100 kW Fixed PV systems (4 MW = 40 units)	Add Wind at Kahuku (20 MW) Add 100 kW Fixed PV systems (4 MW = 40 units) Add 2 kW Fixed PV systems (4 MW = 2,000 units) Add 100 kW Tracking PV systems (2 MW = 20 units)
2012		Add 100 kW Fixed PV systems (4 MW = 40 units)	Add 100 kW Fixed PV systems (4 MW = 40 units) Add 2 kW Fixed PV systems (4 MW = 2,000 units) Add 100 kW Tracking PV systems (2 MW = 20 units)
2013		Add 100 kW Fixed PV systems (4 MW = 40 units)	Add 100 kW Fixed PV systems (4 MW = 40 units) Add 2 kW Fixed PV systems (4 MW = 2,000 units) Add 100 kW Tracking PV systems (2 MW = 20 units)
2014	Add Single Train Combined Cycle GE PG7121 (120 MW)	Add Single Train Combined Cycle GE PG7121 (120 MW) Add 100 kW Fixed PV systems (4 MW = 40 units)	Add Single Train Combined Cycle GE PG7121 (120 MW) Add Wind at Kaena Point (15 MW) Add 100 kW Fixed PV systems (4 MW = 40 units) Add 2 kW Fixed PV systems (4 MW = 2,000 units) Add 100 kW Tracking PV systems (2 MW = 20 units)
2015	Honolulu Power Plant retires 12/31/2015 (-107 MW)	Honolulu Power Plant retires 12/31/2015 (-107 MW) Add Wind at Kahe (50 MW) Add MSW (16 MW) Add 100 kW Fixed PV systems (4 MW = 40 units)	Honolulu Power Plant retires 12/31/2015 (-107 MW) Add MSW (16 MW) Add Biomass (25 MW) Add 100 kW Fixed PV systems (4 MW =40 units) Add 2 kW Fixed PV systems (4 MW = 2,000 units) Add 100 kW Tracking PV systems (2 MW = 20 units)
2016		Add 2 kW Fixed PV systems (4 MW = 2,000 units) Add 100 kW Fixed PV systems (4 MW = 40 units) Add 100 kW Tracking PV systems (2 MW = 20 units)	Add 100 kW Fixed PV systems (4 MW =40 units) Add 2 kW Fixed PV systems (4 MW = 2,000 units) Add 100 kW Tracking PV systems (2 MW = 20 units)
2017		Add 2 kW Fixed PV systems (4 MW = 2,000 units) Add 100 kW Fixed PV systems (4 MW = 40 units) Add 100 kW Tracking PV systems (2 MW = 20 units)	Add 100 kW Fixed PV systems (4 MW =40 units) Add 2 kW Fixed PV systems (4 MW = 2,000 units) Add 100 kW Tracking PV systems (2 MW = 20 units)
2018		Add 2 kW Fixed PV systems (4 MW = 2,000 units) Add 100 kW Fixed PV systems (4 MW = 40 units) Add 100 kW Tracking PV systems (2 MW = 20 units)	Add 2 kW Fixed PV systems (4 MW = 2,000 units) Add 100 kW Tracking PV systems (2 MW = 20 units)
2019		Add 2 kW Fixed PV systems (4 MW = 2,000 units) Add 100 kW Fixed PV systems (4 MW = 40 units) Add 100 kW Tracking PV systems (2 MW = 20 units)	Add 2 kW Fixed PV systems (4 MW = 2,000 units) Add 100 kW Tracking PV systems (2 MW = 20 units)
2020		Add Biomass (25 MW) Add Wind at Kahuku (20 MW) Add Wind at Kaena Point (15 MW) Add 2 kW Fixed PV systems (4 MW = 2,000 units) Add 100 kW Fixed PV systems (4 MW = 40 units) Add 100 kW Tracking PV systems (2 MW = 20 units)	Add 2 kW Fixed PV systems (4 MW = 2,000 units)
2021			Add 2 kW Fixed PV systems (4 MW = 2,000 units)
2022	Add GE PG7121 Simple Cycle CT (76 MW)		Add 2 kW Fixed PV systems (4 MW = 2,000 units)
2023			Add 2 kW Fixed PV systems (4 MW = 2,000 units)
2024			Add 2 kW Fixed PV systems (4 MW = 2,000 units)
2025			Add 2 kW Fixed PV systems (4 MW = 2,000 units)
P. V. TOTAL COST ($000):			
Planning Period	7,283,932	7,772,873	8,275,976
End Effects Period	3,320,265	3,593,544	3,790,349
Study Period	10,604,197	11,366,416	12,066,324
P.V. Societal Cost ($000):	7,350,083	7,837,309	8,338,826

HECO IRP-3 FINALIST PLANS SCENARIO ANALYSIS - HONOLULU POWER PLANT RETIRES

D **Finalist Plan 4** **HECO w/contribution from HELCO/MECO to conform to SB2474 Plan**	E **Finalist Plan 5** **Maximize Fuel Diversity Plan**	F **Finalist Plan 6** **Combined Plan**	
Supply Side Resource	Supply Side Resource	Supply Side Resource	Year
			2006
			2007
			2008
Add GE PG7121 Simple Cycle CT (76 MW)	Add GE PG7121 Simple Cycle CT (76 MW) Add Wind at Kahe (50 MW)	Add GE PG7121 Simple Cycle CT (76 MW) Add Wind at Kahe (50 MW)	2009
			2010
			2011
			2012
			2013
Add Single Train Combined Cycle GE PG7121 (120 MW)	Add Single Train Combined Cycle GE PG7121 (120 MW)	Add Single Train Combined Cycle GE PG7121 (120 MW)	2014
Honolulu Power Plant retires 12/31/2015 (-107 MW)	Honolulu Power Plant retires 12/31/2015 (-107 MW)	Honolulu Power Plant retires 12/31/2015 (-107 MW) Add 100 kW Fixed PV systems (300 kW = 3 units)	2015
	Add Coal unit (180 MW)		2016
			2017
			2018
			2019
Add Wind at Kahe (25 MW)		Add 100 kW Fixed PV systems (300 kW = 3 units)	2020
			2021
Add GE PG7121 Simple Cycle CT (76 MW)		Add Coal unit (180 MW)	2022
			2023
			2024
		Add 100 kW Fixed PV systems (300 kW = 3 units)	2025
			:P. V. TOTAL COST ($000)
7,294,067	7,374,433	7,377,073	Planning Period
3,326,458	3,367,397	3,315,757	End Effects Period
10,620,525	10,741,830	10,692,830	Study Period
7,360,070	7,436,389	7,440,656	:P.V. Societal Cost ($000)

Sensitivity Analysis to be Performed as Part of ITC Meeting #4

- Lower level of energy efficiency DSM impacts
- No utility participation in CHP market
- High/low sales and peak impacts
- Honolulu Power Plant retirement
- Combustion turbine sizes
- High fuel price scenarios

CA-IR-451

Ref: Response to CA-IR-274.

The response to Part (b) of CA-IR-274 discusses the possible retirement of the Honolulu Power Plant. The November 14, 2004 article provided states that "operating generators would be taken down in 2008."

a. Please provide a copy of all company documents that discuss a possible date for the retirement of the Honolulu Power Plant.

b. If no such documents exist beyond those already provided, please state HECO's knowledge regarding the source of this date.

c. Please state what HECO has indicated about possible retirement dates to the parties with

which it has been discussing the possible retirement of the Honolulu Power Plant.

- HECO response to CA-IR-32, in Docket No. 95-0347, regarding the Remaining Useful Life Assessments for Honolulu Units 8 and 9 and other HECO units.
- HECO 2002 IRP-2 Evaluation Report, filed with the Commission on December 31, 2002, page 71: "The updated IRP-2 plan includes the continued operation of all of HECO's existing generating resources throughout the planning period [2002-2017]."
- HECO IRP-3 presentation by HECO to the Integration Technical Committee on August 31, 2004, Slide 10 (copy attached as page 4 to this response) of 55: Base Analysis Assumptions: "Continuation of IPP and HECO generating units through planning period."

All of these documents have previously been submitted to the Consumer Advocate at earlier dates.

b. Aside from the article provided in response to Part (b) of CA-IR-274, HECO does not know the source of this date.

c. HECO informed the other parties[1] in the discussion on Honolulu Power Plant that HECO needs the capacity from Honolulu Power Plant (as well as the voltage support provided by

down. HECO's primary concern was maintaining sufficient generating capacity (as well as the voltage support and other benefits provided by the plant) on the system to meet growing demand. HECO did not put forth any specific timeframe in which the plant could be shut down. Rather, HECO advised the parties that the plant could be shut down only after replacement capacity is fully operational on the system. On April 25, 2004, HECO submitted the attached document (on pages 5 to 7 to this response), dated April 25, 2004, titled "Site Requirements for Honolulu Power Plant," to the State of Hawaii, Office of Planning, to inform them of the general requirements for siting a new power plant to replace the generation from Honolulu Power Plant if it were to be shut down. The second to the last bullet on page 6 indicates "The new power plant must be fully permitted, constructed and operational before the Honolulu Power Plant can be shut down."

Base Analysis Assumptions

- Base electric sales and peaks
- Continuation of IPP and HECO generating units through planning period
- Energy efficiency DSM developed in conjunction with DSM Technical Committee
- Load management DSM consistent with program applications
- CHP market impact developed in conjunction with CHP Technical Committee
- Base fuel prices from forecast filed with PUC September 11, 2003

Site Requirements for Power Plant

- Minimum 110 MW baseloaded facility with the ability to cycle.
- Easements, permits and approvals for 46kV or 138kV transmission lines from the power plant to the existing grid must be available.
- Two 138 kV transmission lines to interconnect the relocated power plant to the 138 kV transmission system.
- If interconnection to the HECO system is at the 46 kV level, a minimum of four 46 kV cables may be needed in order to export the full output of the plant.
- Sufficient cooling water source must be available from seawater or extraction wells.
- Sufficient potable water source must be available from the Board of Water Supply or extraction wells.
- Area must be zoned for industrial use (I-2).
- All land use permits and approvals can be obtained to construct and operate a baseloaded power plant. (See attached list of permits.)
- Area must allow for a Prevention of Significant Deterioration/Covered Source Permit (air permit) to be obtained - available airshed.
- Power plant must be able to comply with noise ordinances in the area.
- Area must be below the UIC line to allow for treated wastewater injection wells or discharge to the ocean.
- Site must accommodate fuel delivery by trucks, pipeline or conveyor.
- Site must be away from military lands, airports, etc. that may impose restriction on use of land. Must be away from aircraft flight path.
- Slope of site shall be less than 4%.
- Site must be large enough to accommodate:
  - generating unit
  - fuel storage (30-day supply) with sufficient containment capacity
  - cooling tower (if applicable)
  - water treatment facility
  - wastewater treatment facility
  - switchyard
  - warehouse
  - control building
  - water storage
  - maintenance shop
  - miscellaneous equipment
  - waste storage area
  - employee, contractor and visitor parking
  - staging areas for overhaul and maintenance operations

- Site must be a minimum of 5 to 6 acres - as much as 9 acres or more depending upon type of unit installed, conditions of the site, and zoning or use of adjacent properties.
- Requires access roads to and from site that can accommodate large trucks.
- Must be able to accommodate exhaust stack 210 feet or higher.
- HECO prefers to own the land upon which facility will be situated.
- Must have unobstructed line-of-sight for power plant microwave communications.
- Location of the site must be such that the system benefits now provided by Honolulu Power Plant can be replicated by the new power plant at the new site. Examples of these system benefits include:
  - are voltage support near the load center;
  - preventing of transmission and distribution system overloads;
  - sub-transmission and distribution system switching and protection as provided by the Halekauwila Substation; and
  - reduced vulnerability to total system outage in the event of a terrorist attack or natural disaster.
- Environmental Site assessment should be performed and the site must be free from environmental defects.
- Site must be outside of tsunami inundation zone.
- Environmental Impact Statement must be prepared for new power plant and all relevant issues must be addressed in the document.
- The new power plant must be fully permitted, constructed and operational before the Honolulu Power Plant can be shut down.
- Replacement downtown office space for the Environmental Department must be found.

List of Permits Needed to Construct and Operation a Power Plant

Permits/Approvals	Permitting Agency
PUC Application	State PUC
Public Infrastructure Map Amendment (PIMA)	C&C DPP /City Council
Conditional Use Permit (Minor)	C&C DPP
Zoning Variance for tank heights - possibly	C&C DPP
Water Use Permit	CWRM
Air Permit	State DOH/U.S. EPA
Building Permit	C&C DPP
Certificate of Occupancy	C&C DPP
Construction Dewatering Permit (Temporary)	C&C DPP
Grubbing, Grading, and Stockpiling Permit	C&C DPP
Sign Permit	C&C DPP
Flammable and Combustible Liquids (Tanks)	C&C Fire Department
Well Construction Permit	CWRM
Pump Installation Permit	CWRM
Underground Injection Control (UIC) Permit	State DOH
Wastewater Systems (Treatment)	State DOH
Construction Stormwater Permit (NPDES)	State DOH
Airport Hazard Area Zone Permit	State DOT
Noise Variance (Construction)	State DOH
Shoreline Management Area	C&C DPP
Conservation District Use Area	State DLNR
National Pollution Discharge Elimination System	State DOH
Sanitary waste disposal permits	State DOH
FAA Permit for Stack	FAA

PUC = Public Utilities Commission
C&C DPP = City & County Department of Planning & Permitting
CWRM = Commission on Water Resources Management
DOH = Department of Health
DOT = Department of Transportation

CA-IR-452

Ref: Response to CA-IR-278.

The response to Part (c) of CA-IR-278 appears non-responsive.

a. Please verify that there are no "workpapers, reports and other materials" used to develop the need projection contained in HECO's March 10, 2005 Adequacy of Supply Report.

b. Otherwise, please provide the most recent simulation of HECO's program used to calculate its capacity (MW) need during each year through 2009. Include all input assumptions and any work papers and calculations? Where supporting electronic spreadsheet are available, please provide copies of those spreadsheets with all formulas and cell references intact.

CA-IR-453

Ref: Response to CA-IR-279(b).

Please provide copies of all contingency analyses performed by the company that are not out-of-

HECO Response:

and 6 with Kalaeloa Partners, L.P. to provide up to an additional 29 MW of firm capacity. HECO is seeking Commission approval of the Amendments in Docket No. 04-0320. Addition of the 29 MW is not considered a contingency option as it is needed not in lieu of the next generating unit but as part of a total package of resources, including the next generating unit, to meet the growing demand. Please also refer to HECO's response to CA-IR-404 on other options to increase output from IPPs.

With respect to implementing interruptible DSM programs, HECO is currently implementing its Residential Direct Load Control Program in Docket No. 03-0166 and its Commercial and Industrial Direct Load Control Program in Docket No. 03-0415. These programs are not considered contingency options as they are needed not in lieu of the next generating unit but as part of a total package of resources, including the next generating unit, to meet the growing demand. See response to CA-IR-446, part a. with respect to HECO's plans for a demand load response program.

With respect to deferring unit retirements as a contingency option, there are no units that HECO is considering for retirement. Therefore, deferring retirements is not available as a contingency option.

The mitigation measures that HECO is considering are discussed in Section 5, pages 24 to 27, of HECO's March 10, 2005 Adequacy of Supply Report. Among the mitigation measures discussed are DGs[1] at HECO substation sites, a Demand Load Response Program and a Residential Air Conditioning Load Control Program. See response to CA-IR-446. These measures are intended to lessen the adverse impacts of the reserve capacity shortfall.

[1] The DGs at HECO substation sites are planned to be temporary and will be removed when it is determined that they are no longer needed to maintain generating system reliability. See responses to CA-IR-441 and CA-IR-442.

CA-IR-454

a. Has HECO prepared any forecasts, budgets or projections of its anticipated sales or revenues, operating expenses, capital investment or other financial performance parameters for calendar year 2006?

b. If affirmative, please provide complete copies of the most detailed available documentation associated with all such forecasts, budgets or projections.

HECO Response:

a. The Company has prepared projections of sales and capital expenditures, and a financing plan for 2006. For purposes of putting together HECO's 2006 financing plan, HECO assumed an overall level of operating expenses, but did not prepare an itemized projection of operating expenses.

b. Without waiving any of the objections stated below, please refer to HECO-WP-201, page 15, for the sales forecast for 2006. Refer to the responses to CA-IR-201 and DOD/HECO-IR-3-9 for a listing of the 2006 capital expenditures and 2006 financing plan, respectively. Also, in general, HECO has provided the forecast information that it is required to provide under the Commission's rules. (The Commission's rules specify where five-year utility forecasts are required.) In accordance with the Commission's rules, HECO provides the Commission and the CA with five-year capital expenditures estimates each December (see the 2005 Capital Expenditures Budget filed with the Commission on December 30, 2004), and provide five-year financing plans in financing dockets (unless the requirement is waived). While the Company has prepared projected financial performance parameters for 2006, such as net income (earnings) and return on common equity, the Company objects to providing such information, even under a protective order, on the grounds that the information contains privileged commercial and

financial information that are non-public, confidential information and disclosure of such information could trigger requirements under rules and guidelines of the Securities and Exchange Commission and/or the New York Stock Exchange. The disclosure of forecast information related to income, earnings, and return on common equity could trigger requirements under the rules and guidelines of the Securities and Exchange Commission and/or the New York Stock Exchange that information that would be meaningful to an investor (such as earnings estimates) be released to all investors, if the information is disclosed beyond a limited number of "insiders." Forecasts of earnings and returns, etc. are the types of information that, if selectively released, could violate such requirements.

In addition, HECO objects to providing such financial performance parameters for 2006, as provision of such information without explanations of how the financial parameters were derived (including the assumptions that were made to derive such information as well as the basis for such assumptions) would be meaningless and confusing, and preparation of such explanation for post-test year estimates would be unduly burdensome. If HECO is required to produce such internally generated documents at the time of rate cases, then the information will have to be generated in a fashion suitable for external publication, rather than in its present form used for internal management purposes. This would be unduly burdensome as well as counterproductive. As set forth in the objection to CA-IR-242, the CA's request fails to balance the CA's need for this information against HECO's need to manage. HECO also objects to disclosure of such financial performance parameters under protective order. The value of the internal documents will be diminished for the reasons stated above if HECO is

required to provide the documents to the CA, even if the documents are provided

pursuant to a protective order.

CA-IR-455

a. Has HECO prepared any budget variance reports or other accounting reports that compare actual revenues, operating expenses and plant investment expenditures to forecasted amounts for year to date 2005?

b. If affirmative, please provide complete copies of the most detailed available documentation associated with all such reports, including all narrative discussions of the reasons for experienced variances.

HECO Response:

a. Yes, the Company prepares various reports that compare actual revenues, operating expenses and capital expenditures to the budget for year-to-date 2005.

b. HECO objects to providing such reports on the grounds stated in the response to CA-IR-242.

CA-IR-456

Ref: HECO Response to CA-IR-156 and CA-IR-157, parts (d) and (e) Commercial Sales Sector Analysis.

Please provide detailed calculations supporting each revision to test period commercial sales by rate schedule (billing determinants and revenue $) that HECO believes to be appropriate as a result of its re-evaluation of commercial sales level estimates (if any).

HECO Response:

As indicated in the response to CA-IR-157 part (e), the complicated and time consuming re-evaluation of HECO's commercial sales projections is currently underway and a new forecast is expected to be presented to HECO's executive staff by the end of May 2005. Sufficient progress on the forecast has not been made at this time to revise test year commercial sales by rate schedule.

CA-IR-457

Ref: HECO Response to CA-IR-158 Residential Sales Market Analysis.

Please provide the following information in consideration of updated permit data and residential customer count information:

a. Actual monthly 2004 and to-date 2005 residential customer count information.

b. Actual monthly 2005 private building permit data, as available.

c. Explain the revisions to HECO's assumed residential customer additions of 2,700 that

should be made to fully account for actual customer level information through December 2004.

d. Given the strong positive correlation between permits and customers added, as shown on the graph at page 3 of the response, please explain why/if the 3,811 permits granted in 2004 should not produce an upward revision in the assumed 3,000 customer added during 2005.

e. Provide detailed calculations supporting any revision to its filing that HECO views as appropriate to consider updated residential customer count and permit information.

HECO Response:

a. The monthly residential customer count for 2004 was provided in response to CA-IR-162 (see the electronic file *CA-IR-162 RES MONTHLY SALES AND CUSTOMERS.XLS*). The monthly residential customer count for year-to-date 2005 is as follows:

January 2005	255,270
February 2005	255,086

b. HECO has not received any additional building permit data from the Department of Business and Economic Development & Tourism for 2005.

c. Through December 2004, HECO's average number of residential customers increased by 2,422 customers over 2003, which is lower than the 2,700 expected in the June 2004 sales update. Given this lower than expected growth and the average increase of 2,320 customers February year-to-date 2005, it is likely that the projected customer addition of 3,000 in 2005 may be optimistic. In addition, the 2004 average number of customers of 253,670 was 279

lower than the 253,948 expected for 2004 in the June 2004 update and would lower the average number of customers projected for the test year even if the additions were kept at 3,000. The residential customer projection for 2005 is currently being re-evaluated as part of the annual sales forecast effort expected to be presented to HECO's executive staff in May.

d. While there does appear to be a correlation between the number of permits issued and the number of customer additions, the number of additions is not necessarily readily predicted by the number of permits issued. For example, in the data on page 3 of the response to CA-IR-158, customer additions were lower than the previous year's permits, 25 out of the 33 years (76%) of the time, and for those years the customer additions were on average 33% lower than the previous year's permits. Also, a regression fitted on the data indicates that the 3,811 permits issued in 2004 would result in a predicted 2,960 customer additions for 2005.

Other factors should also be considered when evaluating permits issued and their relationship to customer additions. It appears as though Oahu in recent years has been experiencing slower residential project completions because of concerns such as the skilled labor shortages in the construction industry, inability of subcontractors to keep up with construction schedules due to high demand for services, and scarce resources especially in light of the level of residential construction being undertaken on military property. These concerns are likely to continue to have an impact on the number of residential customer additions that will be feasible even if permits have been issued for projects.

e. The residential customer projection for 2005 is currently being re-evaluated as part of the annual sales forecast effort expected to be presented to HECO's executive staff in May.

CA-IR-458

Ref: Response to CA-IR-222 (2003 Class Load Study, pages 14 to 16), HECO T-2 (pages 20 to 22), and Adequacy of Supply report filed March 10, 2005, page 3.

According to the Class Load Study, to support long-range forecasting and renewable portfolio standards, the residential sample was stratified by the fuel used for water heating. HECO T-2 and the Adequacy of Supply report, however, note that air conditioning is a major factor influencing residential sales and the impact on the peak.

a. Did HECO determine the number of residential customers in the samples with air-conditioning?

b. If yes,

   1. Please provide the data.

   2. Please explain if the proportion of air-conditioned homes in the 2003 study is comparable to the saturation rate (0.5115) used to forecast residential energy sales in HECO T 2.

c. If not, why was air-conditioning was not considered since HECO has determined that air-conditioning is a major factor in residential energy sales and demand?

HECO Response:

a. No, HECO did not survey the residential customers as part of the 2003 Class Load Study to determine the number of customers with air-conditioning.

b. However, the sample frame in the Class Load Study consisted of the residences occupied by the respondents to the 2000 Residential Appliance Saturation Survey. Since the survey included questions on air-conditioning, HECO is able to determine which Class Load Study participants had air-conditioning at the time of the 2000 survey. The following is based on the responses to the 2000 appliance survey from the participants in the Class Load Study:

   1. 34 of 70 sample locations in the Class Load Study had some type of air-conditioning in the 2000 residential appliance survey.

   2. The Class Load Study sample proportion was 0.4857 based on the data gathered in

2000. This appears to be comparable to the projected 2003 saturation rate of 0.5115.

c. Traditionally, water heating has been the major user of electricity in the residential class. Recently, it appears that air-conditioning has become more of a factor influencing residential sales and demand because of residential development growth in normally hotter and drier areas such as the Ewa plains and because of the increasing availability and lower prices of residential air-conditioning technology. HECO only began to try to incorporate the saturation of air-conditioning into its residential econometric use forecast at the end of 2003 and the statement in the Adequacy of Supply report filed March 10, 2005: "It is likely that extremely warm and humid weather, combined with the growing use of air-conditioning across the island, contributed to the October 2004 system peak demand." was based on anecdotal observations and has not yet been empirically determined. Future class load studies may consider air-conditioning in the sample design.

CA-IR-459

Witness T-6, Mr. Fujinaka

Ref: HECO Response to CA-IR-38, page 7.

O&M non-labor costs for Actual 2004 and Test Year 2005 that are associated with "Complia

with Regulations and Safety" are identified on page 7 by RA#. Non-labor O&M within RA PJB "Air Quality and Noise" is projected to increase from $336,389 in 2004 to $1,140,454 in 2005 with no explanation of any changed regulations affecting such activities. Please explain and justify this increase, describing all individual projects and payees that were active in 2004 and that are planned in 2005.

HECO Response: