✓BKK

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAIIAN ELECTRIC COMPANY, INC.	)	Docket No. 05-0069
	)	
For Approval and/or Modification of Demand-Side and Load Management Programs and Recovery of Program Costs and DSM Utility Incentives.	)	

FILED

2006 JUL 14 A 9:27

PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN INSTITUTE'S RESPONSES TO

INFORMATION REQUESTS FROM

HAWAIIAN ELECTRIC COMPANY,

THE CONSUMER ADVOCATE,

HAWAII SOLAR ENERGY ASSOCIATION,

HAWAII RENEWABLE ENERGY ALLIANCE,

KAUAI ISLAND UTILITY COOPERATIVE

AND THE GAS COMPANY

AND

CERTIFICATE OF SERVICE

E. Kyle Datta, Managing Director
Rocky Mountain Institute
P. O. Box 390303
Keauhou, HI 96739

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAIIAN ELECTRIC COMPANY, INC.	)	Docket No. 05-0069
	)	
For Approval and/or Modification of Demand-Side and Load Management Programs and Recovery of Program Costs and DSM Utility Incentives.	)	

ROCKY MOUNTAIN INSTITUTE'S RESPONSES TO

INFORMATION REQUESTS FROM

THE HAWAIIAN ELECTRIC COMPANY

In accordance with the Schedule of Proceedings in Docket No. 05-0069 (as amended) Rocky Mountain Institute (RMI) respectfully submits its responses to the information requests by the Hawaiian Electric Company (HECO).

HECO/RMI-FSOP-IR-101

Ref: RMI FSOP, page 7. "If the current growth rate continues and we assume the level of efficiency in the utility's most current plans and current renewable projects, then the state's oil dependence will increase to 78.5% by 2015."

Please provide the workpapers upon which the 78.5% is based.

RMI RESPONSE (**Kyle Datta):**

See attached table.

The supporting Excel Spreadsheet is not in a format that is practical to print and is provided in electronic format.

STATEWIDE ENERGYMIX

Source: DBEDT Data

Includes expected power generation capacity additions, 60 MW wind, 10 MW solar PV and 42 MW biomas

Growth Rate 2.0% *With Efficiency (estimated vs 2.6% without)*

Untis: **trillion Btus**

Year	Petroleum	Coal	Biomass	Municipal Soli	Solar Hot Wa	Geothermal	Hydroelectric	Wind	Photovoltaic	Total	% Renewable	Year	% Oil
1970	197.2279		26.9020				1.1000			225.2	12.43%	1970	
1980	248.0109		24.2000		0.7700		0.9000			273.9	9.45%	1980	
1985	238.6470	0.9560	23.1430		2.1327	0.1886	0.9808	0.1697		266.2	10.00%	1985	
1990	284.4906	0.8900	18.1200	4.9298	2.3400	0.0000	1.0700	0.2900		312.1	8.57%	1990	91%
1995	273.9590	16.5249	11.8232	6.3688	2.8386	2.3045	1.0632	0.2364	0.0003	315.1	7.82%	1995	87%
2000	290.2354	15.4724	7.1331	5.1086	3.5483	2.5855	0.9481	0.1794	0.0043	325.2	6.00%	2000	89%
2001	273.7797	15.7719	3.4243	4.5234	3.6792	2.1356	1.0439	0.1809	0.0110	304.5	4.92%	2001	90%
2002	272.8375	17.1440	5.5584	4.6602	4.0214	0.7637	1.0318	0.1354	0.0110	306.2	5.29%	2002	89%
2003	284.4207	18.2279	6.2769	4.6545	4.0687	1.8181	0.7962	0.1137	0.0193	320.4	5.54%	2003	89%
2004	290.55815	18.22790	6.444279	4.6545	4.1643	1.8181	0.7962	0.1137	0.0268	326.8	5.51%	2004	89%
2005	296.82152	18.22790	6.611658	4.6545	4.2622	1.8181	0.7962	0.1137	0.0342	333.3	5.49%	2005	89%
2006	302.67431	18.22790	7.318037	4.6545	4.3623	1.8181	0.7962	0.1137	0.0417	340.0	5.62%	2006	89%
2007	308.34424	18.22790	8.024416	4.6545	4.4649	1.8181	0.7962	0.4275	0.0492	346.8	5.83%	**2007**	89%
2008	314.14777	18.22790	8.730795	4.6545	4.5698	1.8181	0.7962	0.7414	0.0567	353.7	6.04%	2008	89%
2009	320.40139	18.22790	9.437174	4.6545	4.6772	1.8181	0.7962	0.7414	0.0641	360.8	6.15%	2009	89%
2010	326.96136	18.22790	9.976174	4.6545	4.7871	1.8181	0.7962	0.7414	0.0716	368.0	6.21%	2010	89%
2011	333.66308	18.22790	10.515174	4.6545	4.8996	1.8181	0.7962	0.7414	0.0791	375.4	6.26%	2011	89%
2012	341.04837	18.22790	10.515174	4.6545	5.0147	1.8181	0.7962	0.7414	0.0866	382.9	6.17%	2012	89%
2013	348.58111	18.22790	10.5152	4.6545	5.1326	1.8181	0.7962	0.7414	0.0940	390.6	6.08%	2013	89%
2014	356.27171	18.22790	10.5152	4.6545	5.2532	1.8181	0.7962	0.7414	0.0940	398.4	5.99%	2014	89%
2015	364.11570	18.22790	10.5152	4.6545	5.3766	1.8181	0.7962	0.7414	0.0940	406.3	5.91%	2015	90%
2016	372.11614	18.22790	10.5152	4.6545	5.5030	1.8181	0.7962	0.7414	0.0940	414.5	5.82%	2016	90%
2017	380.27615	18.22790	10.5152	4.6545	5.6323	1.8181	0.7962	0.7414	0.0940	422.8	5.74%	2017	90%
2018	388.59891	18.22790	10.5152	4.6545	5.7647	1.8181	0.7962	0.7414	0.0940	431.2	5.65%	2018	90%
2019	397.08765	18.22790	10.5152	4.6545	5.9001	1.8181	0.7962	0.7414	0.0940	439.8	5.57%	2019	90%
2020	405.74570	18.22790	10.5152	4.6545	6.0388	1.8181	0.7962	0.7414	0.0940	448.6	5.50%	2020	90%

HECO/RMI-FSOP-IR-102:

RMI FSOP, page 10. "HECO, in its recent IRP filing, is already proposing an effective reduction of 0.6% of gross sales."
Please provide workpapers and cites upon which the 0.6% is based.

RMI RESPONSE (Kyle Datta):

See attached excel spreadsheet

HECO - DSM Programs
Accomplishments and Surcharges Report, 3/31/2003
DBEDT DATA BOOK

Table 17.13-- SERVICE PROVIDED BY HAWAIIAN ELECTRIC COMPANY, IN ON OAHU: 1991 TO 2001

Year	Total Customers	Residential Customers Only	Net input (1,000 kWh) *	Electricity sales (1,000 kWh)	Average annual residential	A res
1991	255,176	223,304	6,876,964	6,538,952	7,610	0
1992	257,442	225,229	7,061,157	6,650,449	7,711	0
1993	263,478	230,192	7,029,839	6,607,424	7,581	0
1994	264,992	232,115	7,222,978	6,797,364	7,681	0
1995	269,307	235,905	7,359,195	6,962,794	7,732	0
1996	271,602	237,860	7,499,202	7,091,147	7,868	0
1997	271,801	238,825	7,424,259	7,040,291	7,773	0
1998	272,675	239,945	7,299,149	6,938,326	7,603	0
1999	275,467	242,579	7,356,725	6,997,936	7,654	0
2000	278,260	245,027	7,589,409	7,211,760	7,793	0
2001	280,911	247,672	7,643,288	7,276,681	7,816	0

* Net generation plus purchased power.
** Based on average number of customers during the year.
*** Includes firm purchase power.
Source: Hawaiian Electric Company, Inc., records.

1996 - 2004 Historical DSM Program Energy Savings and Lost Margins

Incremental Energy Savings (kWh) - net of free riders a the customer level

Year	Total (kWh)	Total (GWh)
1996	13,704,530	13.705
1997	27,661,529	27.662
1998	19,251,090	19.251
1999	19,212,162	19.212
2000	19,917,527	19.918
2001	29,074,196	29.074
2002	22,416,554	22.417
2003	24,526,554	24.527
2004	17,118,312	17.118

Source: DOD-IR-5-4.xls, DOD / HECO-IR-5-4, Docket NO. 04-0113, Page 4 of 7

Hawaiian Electric Company Cumulative DSM Impacts

Incremental DSM Program Impacts	**2005**	**2006**	**2007**	**2008**
Energy (GWh - Cust Level*)	48.60	48.60	48.60	48.60
Demand (MW - Net to Sys Level)**	19.60	19.60	18.90	17.30
Energy (gWh - Grs Gen Level)	54.70	109.50	164.20	219.00
Energy (gWh - Cust Level*)	48.60	97.30	145.90	194.50
Demand (MW - Grs Gen Level)	21.00	42.00	62.20	80.80
Demand (MW - Net to Sys Level**)	19.60	39.20	58.10	75.40

* Customer Level, inlcuding free riders, annualized. 11.17% loosses from the Grs Gen Level

** Net to Sysem Level, net of Free Riders. 4.864% losses to the Customer Level

Source: "The Big White Binder" T-10 Exhibits 11-04-04 rev 1.xls, HECO - 1015, Docket NO. 04-0113, Page 1 of 1

Year	% per year
2005	0.006308084
2009	0.006086819

HECO/RMI-FSOP-IR-103:

Ref: RMI FSOP, Page 10. "RMI observes that independent, third-party administrators, such as Efficiency Vermont, . . . as reported by ACEEE in their 2006 study are achieving a 1% reduction of energy reductions in electrical sales each year."

Please provide a copy of the study referenced in footnote 8 on page 10 and identify whether each program administrator's reported reductions include free-riders, and the generation level (gross generation, net-to-system level, or customer level) at which the reductions are reported.

RMI RESONSE (Natalie Mims under the direction of Kyle Datta):

"Many of the leading programs are targeting and achieving savings of 1% of covered electricity and natural gas use each year from end-use energy efficiency programs. This includes programs in California, Connecticut, New Jersey, and Vermont."[1]

The current trend in measurement and verification of energy efficiency is to create standardized protocol for individual or groups of programs. In January 2006, the Northeast Energy Efficiency Partnership ("NEEP") published "The Need for and Approaches to Developing Common Protocols to Measure, Verify and Report Energy Efficiency Savings in the Northeast."[2] NEEP looked at the measurement and verification protocols in CT, ME, MA, NH, NH, NY, RI, and VT. In April 2006, California adopted standardized measurement and verification protocols.

<u>New England</u>

NEEP's 2006 report found that "the majority of program administrators in the region report savings to their regulatory commissions at the net customer meter level, except New

[1] Nadel, Steven, "Energy Efficiency Resource Standards: Experience and Recommendations." ACEEE Report EO63, March 2006, p29.
[2] Available at: www.neep.org/policy_and_outreach/policy_outreach.html

effects (i.e., the difference between spillover and free-ridership) in their reported energy and demand savings, while others include them only in their cost-effectiveness analyses.

Table 1. Spillover and Free-ridership in Select States.

State	Summary of Spillover (Participant)[7]	Summary of Spillover (Non-participant)[8]	Free-ridership[9]
CT	Yes	Yes	Yes
NJ	No	No	No
NY	Yes	Yes	Yes
VT	No	Yes	Yes

In summary, Connecticut and New York report savings at the net customer meter level and New Jersey and Vermont report savings at the net generator level. New Jersey is the only of the four states that does not account for spillover or free-ridership in some form.

California

In April 2006, the California Public Utility Commission (CPUC) and the California Energy Commission (CEC) established protocols that together comprise the primary evaluation guidance document for energy efficiency program and program portfolio evaluation efforts.[10] The CPUC's evaluation goal with the Evaluation Protocols is to assess net program-specific energy impacts or the market level impacts of the portfolio of energy efficiency services and to compare those results with the assigned energy savings goals.

[7] "Participant spillover are the additional energy efficiency actions that program participants take outside a program as a result of having participated in the program." NEEP p19.
[8] "Non-participant spillover are changes in the energy use of non-participants as a result of a program." NEEP p19.
[9] "Free-ridership is the fraction of gross program savings that would have occurred despite the program, where a freerider is a non-participant who adopted a particular efficiency measure or practice but would have done so anyway absent the EE program." NEEP p19.
[10] TecMarket Works Team, "California Energy Efficiency Evaluation Protocols: Technical, Methodological and Reporting Requirements for Evaluation Professionals." Prepared for CPUC April 2006.

The Participant Net Impact Protocol (one of the Protocols in the Impact Protocol Evaluation) states that, "All participant net impact analysis must be designed to estimate the proportion of savings that is program-induced and net of free-ridership estimates…"[11] A free-rider is defined as a "program participant who would have implemented the program measure or practice in the absence of the program." [12] Thus, California's standard does not include free-ridership in it's evaluation of assigned energy savings goals.

The California Evaluation Framework[13] ("Framework") mandated by the CPUC recommends several methods for evaluating assigned energy savings goals. Chapter 6 and 7 of the Framework focus on estimating the gross and net effects from the implementation of ones or more energy efficiency programs. Most program impact projections contain ex-ante estimates of savings. These estimates are what the program is expected to save as a result of its implementation efforts. These estimates are used for program planning and contracting purposes and for prioritizing program funding choices.

The impact evaluation focuses on identifying and estimating the amount of energy and demand the program actually provides. Estimates of actual savings are ex-post savings; program savings that can be documented after the program has made the changes that are to produce the savings.

In summary, California has recently adopted standardized protocols that collectively comprise the primary evaluation guidance document for energy efficiency program and program portfolio evaluation efforts. These protocols evaluate energy efficiency net of free-ridership.

---

[11] California Energy Efficiency Evaluation Protocols: Technical, Methodological and Reporting Requirements for Evaluation Professionals, p 36.
[12] California Energy Efficiency Evaluation Protocols: Technical, Methodological and Reporting Requirements for Evaluation Professionals, p242.
[13] TecMarket Works Team, "The California Evaluation Framework." Prepared for the CPUC June 2004.

California also has an Evaluation Framework that has several methods for evaluating energy savings that includes, but is not limited to gross and net effects. The methods serve different purposes for system planning.

A copy of the requested study will be provided in electronic format.

HECO/RMI-FSOP-IR-106:

Ref: RMI FSOP, page 12. Regarding the statement "If agreement cannot be reached with a utility regarding reasonable DSM financial recovery mechanisms or if these mechanisms prove too expensive or cumbersome…", what financial recovery mechanisms would then apply to non-utility DSM administrators and who would develop such mechanisms?

RMI RESPONSE (Carl Freedman):

The financial mechanisms that would apply to non-utility DSM administrators would be mechanisms for (1) recovery of direct expenses of DSM program implementation and administration and (2) possible incentives or penalties for attainment of program objectives and any established goals or thresholds. Mechanisms to address host utility revenue erosion (lost margins) would not apply to non-utility DSM administrators.

HECO/RMI-FSOP-IR-107: Ref:

RMI FSOP, page 12. What level of utility incentives is RMI proposing (e.g., if the proposed DSM programs represent an investment in DSM resources of $15 million, what level of compensation to the utility and/or a third party administrator would be reasonable to aggressively pursue the successful implementation of cost-effective DSM programs)?

RMI RESPONSE (Kyle Datta):

See RMI's response to HECO/RMI-FSOP-IR-142. Note that RMI's proposed incentives are defined by the total resource test savings, not based on cost. RMI may be able supplement its response based on necessary information provided to HECO responses to RMI's information requests.

HECO/RMI-FSOP-IR-108:

Ref: RMI FSOP, page 13. "Utility administration and utility implementation of DSM programs (existing structure)." HECO currently uses non-utility third-parties to install all DSM measures. Would RMI still consider HECO to be implementing the DSM programs?

RMI RESPONSE (Carl Freedman):

See footnote #6 at the bottom of page 13 of the RMI FSOP regarding the distinction between DSM program administration and implementation. HECO employees do not install DSM measures but HECO is still responsible for carrying out the delivery mechanisms (disbursing incentives, determining qualifying installers, tracking and reporting, associated advertising, etc.) therefore HECO is still performing functions of implementing the DSM programs.

HECO/RMI-FSOP-IR-109:

Ref: RMI FSOP, page 19. "Regarding HECO's proposed DSM programs specifically, the utility-incurred costs are not normal and ongoing in nature."

a. If the company intends to make DSM part of its normal and on-going activity, why would it not be realistic to include prospective staff and program costs a test year calculation of base rates?

b. If the company could not ramp up to the normal on-going level of DSM activity within one year, would it be prudent to include the ramped portion in base rates and the remaining full year costs through a DSM surcharge in future years?

RMI RESPONSE (Carl Freedman):

a. The normal and ongoing nature of DSM program expenses is one of several concerns identified by RMI regarding including DSM expenses in base rates. Several other reasons are identified in the bulleted text starting on page 18 of the RMI FSOP continuing to the top of page 20. Note that for purposes of HECO's proposals in this docket, RMI holds that HECO's DSM program expenses are not normal and ongoing because they represent a severalfold increase in magnitude compared to previous expenditures.

b. No. See response to part a. above and bulleted text on pages 18 to 20 of the RMI FSOP.

HECO/RMI-FSOP-IR-110:

Ref: RMI FSOP, page 26. "RMI's decoupling mechanism proposed in this docket (energy revenue decoupling for selected customer classes recoupled by an index of number of customers)"

Please demonstrate the correlation of RMI's index of number of customers to HECO's fixed costs using historical data.

RMI RESPONSE (Carl Freedman):

RMI does not have access to the required information and has not performed this correlation.

HECO/RMI-FSOP-IR-111: Ref: RMI FSOP, pages 28 -29. "Lost margins are the difference between what the utility loses by way of reduced revenue due to reduced energy consumption and what it saves by not having to generate and deliver the incremental energy."

This definition of lost margins is different from the following definition of net revenue loss in Section III. F. 2. a. of the IRP Framework: "The net revenue loss is the revenue loss less the variable fuel and operating expenses saved by the utility as a result of not having to generate the unsold energy." Please explain how HECO's historical use of average base energy costs to calculate its lost margins is not consistent with the definition in the IRP Framework.

RMI RESPONSE (Carl Freedman): The quotation above from the RMI FSOP is a paraphrase of the definition quoted above from the IRP Framework. The words are different but the meaning is the same. The RMI FSOP phrase "what the utility loses by way of reduced revenue due to reduced energy consumption" is equivalent to the IRP Framework phrase "the revenue loss." The RMI FSOP phrase "what it saves by not having to generate and deliver the incremental energy" is equivalent to the IRP Framework phrase "the variable fuel and operating expenses saved by the utility as a result of not having to generate the unsold energy." In both cases lost margins are defined as the difference between these two terms.

HECO's use of average base energy costs to calculate lost margins is not consistent with the IRP Framework definition because average base energy costs are significantly less than the fuel and operating expenses saved by the utility as a result of not having to generate the unsold energy. The fuel costs saved by not having to generate the unsold energy are the marginal generation costs not the average base energy costs. Both the IRP Framework formula and HECO's application of the lost margins mechanism are portrayed in the following tables based on HECO's 2005 rate case test year and HECO's 2005 DSM Accomplishments and Surcharge Report dated May 31, 2005. The tables show the unit impacts per kilowatt-hour of energy being avoided by implementation of utility DSM programs for each rate class. The first table is based

RMI Response to HECO/RMI-FSOP-IR-111

Example of Revenue, Cost and Net Revenue for One Kilowatt-Hour Sales Reduction Due to DSM

Marginal Costs Based on HECO Estimates of DSM Avoided Energy Costs

This demonstrates the difference between HECO's lost margins methods and IRP Framework specification.
Based on HECO Rate Application in Docket No. 04-0113; Data cited from RMI FSOP Exhibit E are derived from HECO-WP-2202 and HECO-2218 thru 2225
Marginal costs are from HECO FSOP Exhibits 10 and 12 based on 2006 cost ($.117) with adjustment to sales level based on HECO-403
Rate Application Data are for 2005 Test Year.

Line		SOURCE	Schedule R	Schedule G	Schedule J	Schedule PT	Schedule PP	Schedule PS
	Source Components of Volumetric (Energy) Tariff							
A	Fuel and Purchased Energy Costs (w/taxes)	RMI FSOP Exh.E	$0.0679	$0.0685	$0.0684	$0.0667	$0.0664	$0.0679
B	Non-Fuel/Purch.Energy in Energy Charges (fixed costs)	RMI FSOP Exh.E	$0.0805	$0.0697	$0.0407	$0.0219	$0.0228	$0.0221
C	Total Unit Volumetric Energy Tariff	A + B	$0.1484	$0.1382	$0.1091	$0.0886	$0.0892	$0.0900
D	Revenue Loss Due to Sales Reduction	C	$0.1484	$0.1382	$0.1091	$0.0886	$0.0892	$0.0900
E	Variable Fuel and Operating Expenses Saved	HECO FSOP Exhibit 12	$0.1113	$0.1113	$0.1113	$0.1113	$0.1113	$0.1113
F	**Revenue Erosion without Lost Margins Mechanism**	D - E	**$0.0371**	**$0.0269**	**-$0.0022**	**-$0.0227**	**-$0.0221**	**-$0.0213**
	Lost Margins Adjustment per IRP Framework							
G	Revenue Loss Due to Sales Reduction	D	$0.1484	$0.1382	$0.1091	$0.0886	$0.0892	$0.0900
H	Variable Fuel and Operating Expenses Saved	HECO FSOP Exhibit 12	$0.1113	$0.1113	$0.1113	$0.1113	$0.1113	$0.1113
J	*Net Lost Margins Adjustment*	G - H	$0.0371	$0.0269	-$0.0022	-$0.0227	-$0.0221	-$0.0213
K	**Resulting Revenue Effect (neg. is loss, pos. is windfall)**	J - F	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**
	Lost Margins Adjustment Implemented by HECO (2005)							
L	Base Energy Rate	HECO 2005 A&S Report	$0.1130	$0.1116	$0.0816	$0.0643	$0.0657	$0.0673
M	ECAC Adjustment	HECO-1032	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259
N	Revenue Loss Due to Sales Reduction	L + M	$0.1388	$0.1374	$0.1075	$0.0901	$0.0916	$0.0932
L2	Variable Non-Fuel O&M	HECO 2005 A&S Report	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008
P	Base Energy Costs, Generation Level, Not Price Adjusted	HECO 2005 A&S Report	$0.0351	$0.0351	$0.0351	$0.0351	$0.0351	$0.0351
Q	Net Lost Margins Adjustment	L - P - L2	$0.0770	$0.0757	$0.0457	$0.0284	$0.0298	$0.0314
R	**Resulting Revenue Effect (neg. is loss, pos. is windfall)**	Q - N + E	**$0.0495**	**$0.0495**	**$0.0495**	**$0.0495**	**$0.0495**	**$0.0495**
	Lost Margins Adj. *Based on Sales Level*, Current Base Energy Costs							
S	Revenue Loss Due to Sales Reduction	C	$0.1484	$0.1382	$0.1091	$0.0886	$0.0892	$0.0900
T	Base Energy Costs, Sales Level per 2005 Test Year	A	$0.0679	$0.0685	$0.0684	$0.0667	$0.0664	$0.0679
U	Net Lost Margins Adjustment	S - T	$0.0805	$0.0697	$0.0407	$0.0219	$0.0228	$0.0221
V	**Resulting Revenue Effect (neg. is loss, pos. is windfall)**	U - F	**$0.0434**	**$0.0428**	**$0.0429**	**$0.0446**	**$0.0449**	**$0.0434**

that will hopefully be explained or resolved by HECO's responses to RMI's information requests.

One estimate of HECO's marginal costs is provided in HECO's marginal cost of service study in its rate case application. The nature and basis for these marginal costs is provided in HECO T-22 in Docket No. 0-0113 starting at page 15:

> the Marginal Cost Study is a tool used to quantify the unit change in the utility's costs of providing service due to a unit change in the system load or number of customers served by the system. ...
>
> The marginal energy cost is the unit change in energy cost associated with a unit change in kWh produced by the system. ...
>
> The marginal energy costs are based on the hourly running costs for the six-year period from 2004 to 2009, from the production simulation model.

The marginal costs from HECO's marginal cost study are provided in HECO-WP-2217 pages 90 through 95 which identify estimated marginal energy costs by costing period for the years 2004 through 2009 for priority peak, mid-peak, off-peak and average periods. The marginal energy costs reported in HECO-WP-2217 are also summarized as an average for the years 2004 – 2009 equal to 8.14 cents per kWh. HECO-2211 includes a direct comparison of average embedded and marginal costs by function. As shown in HECO-2211 HECO's marginal costs (8.14 cents per kWh) are higher than its proposed base energy costs including taxes (6.751 cents per kWh).

HECO also identifies the marginal energy costs associated with implementing its proposed DSM programs in its FSOP. HECO FSOP Exhibit 12 explains HECO's calculation of the reduction in HECO's production costs that result from implementation of its DSM programs. The amount that each KWH of DSM program impact saves HECO in fuel and variable operations costs is shown for each year in colume 11 on page 5 of Exhibit 12. The application of these avoided energy costs to determine the benefits of HECO's DSM programs (and to calculate associated shareholder incentives) is portrayed in HECO FSOP Exhibit 10. For the year 2006 HECO estimates that it would save 11.7 cents per kilowatt-hour for reductions in production (net to system) resulting from DSM implementation. Adjusting this amount to sales level from net-to-system level based on HECO's test year sales and net-to-system estimates shown in HECO 403 this equates to a marginal cost of 11.1 cents per kilowatt-hour.

b. Average costs are imbedded in base rates. No, the utility does not recover the difference between marginal costs and average costs through its rates. The utility rates are determined by average test year costs.

The pertinent fact is that the when the utility reduces sales by implementation of DSM programs (1) its revenues decrease because less energy is sold (2) its costs decrease because it has to generate less energy and (3) its earnings decrease by the difference between these two reductions. The applicable revenue loss in (1) above is governed by the tariffs which are based on average test year costs and may include both fixed and variable costs in volumetrically applied rates. The applicable cost decrease in (2) above is governed by the unit marginal cost to generate energy including line and transformation losses.

c. Yes, marginal costs of generation vary during the day. Yes, it would be possible that for limited periods of time marginal costs could in some circumstances be lower than average base energy costs but not with HECO's existing generation system and current demand pattern. HECO's system marginal costs exceed average base energy costs during all periods of the day. See the response to part a. of this information request above and the HECO exhibits cited. On HELCO's system where minimum loads are small with respect to baseload generation (and resulting curtailment of as-available resources is a concern) it is more likely that marginal costs could be less than average costs for limited periods of time. It is possible in some circumstances

HECO/RMI-FSOP-IR-113:

Ref: RMI FSOP, page 30. "A procedure to adjust the marginal costs used to calculate the unit fixed margin could be implemented although this may not be necessary if the current implementation of the Energy Cost Adjustment Clause is continued."

Please explain the relationship between the Energy Cost Adjustment Clause and marginal costs.

RMI RESPONSE (Carl Freedman):

The relationship between the Energy Cost Adjustment Clause (ECAC) and marginal costs as referred to in the quotation above is simply that the existing ECAC makes adjustments in HECO's recovery of energy production costs based on changes in the price of fuel and purchased power and that this reduces the need for adjustment for variations in HECO's marginal costs as applied in the proposed decoupling mechanism. Note that the quotation states that adjustments "may" not be necessary. This is a possibility that could be explored. For example, it would be possible to make adjustments to the marginal costs used in the determination of the unit fixed margin based on changes in energy prices.

See RMI's response to HECO/RMI-FSOP-IR-132 for discussion of the similarity of the depicted decoupling mechanism and its transparency to the existing ECAC.

HECO/RMI-FSOP-IR-114:

Ref: RMI FSOP, page 31. "Although the initial establishment of a decoupling mechanism would require some careful consideration and some conceptually difficult determinations, it would be simpler to implement in the long term."

a. Please detail the data requirements, design criteria, and implementation steps necessary to implement a decoupling mechanism.

b. In RMI's decoupling proposal would the decoupling parameters (e.g., number of customers, fixed revenue per customer) differ by rate schedule?

RMI RESPONSE (Carl Freedman):

a. The data requirements to implement the decoupling mechanism proposed by RMI on an ongoing basis would be, for each applicable customer class, the test year and current period sales and index of the number of customers. The index of the number of customers would require tracking of changes to accounts to determine which are additional customers according to the criteria identified at pages 7 and 8 of RMI FSOP – Exhibit B. The data requirements necessary during a rate case are identified at pages 5 and 6 of RMI FSOP – Exhibit B. The design criteria and steps necessary are described generally in RMI FSOP – Exhibit B at pages 2 through 14 and in RMI FSOP at pages 24 through 35.

b. Yes.

HECO/RMI-FSOP-IR-115:

Ref: RMI FSOP, page 31. "The effort and expense to implement a decoupling mechanism like the one proposed by RMI on an ongoing basis would be approximately similar in difficulty and costs (as well as in several other respects) to the existing Energy Cost Adjustment Clause."

a. Please identify the "several other respects" in which the decoupling mechanism "would be approximately similar" to the existing Energy Cost Adjustment Clause. Please provide the basis for the response.

b. Please state RMI's understanding of the "difficulty" to implement the existing Energy Cost Adjustment Clause. Please provide the basis for the response.

c. Please state RMI's understanding of the "costs" to implement existing Energy Cost Adjustment Clause. Please provide the basis for the response.

RMI RESPONSE (Carl Freedman):

a. RMI's proposed decoupling mechanism is similar to HECO's existing ECAC in the following respects:

- Both make adjustments to volumetric energy charges.
- Both require unbundling of energy charges into source components to calculate adjustments.
- Both would be automatic adjustment mechanisms that would be reviewed and approved in a rate case and be implemented without formal review until the next rate case.
- Both are determined by discrete statistics that are simply determined and are essentially beyond the control of the utility.
- Both are based on comparisons of test year estimates to actual statistics to adjust energy rates.
- Both are designed to reduce the need for frequent rate cases by adjusting energy charges for exogenous factors.

- Both are more complicated and difficult to conceptualize and establish than to actually implement.
- Both can be expressed, reviewed and approved by development of a spreadsheet that can be applied to determine adjustments on a periodic basis. See Response to HECO/RMI-FSOP-IR-132.
- The decoupling mechanism could be implemented using an energy cost adder approach very similar to the ECAC approach. See Response to HECO/RMI-FSOP-IR-132.
- Both result in adjustments that may increase or decrease rates at certain times but are not designed to skew rates on the average or in the long run.

b. The "difficulty" of implementing the ECAC is characterized by the complexity of the calculations necessary each period, the amount of information needed each period to perform the adjustment and the extent to which the periodically required information is available, discrete and possible to determine without controversy or subjective argument.

c. The costs of implementing the ECAC are characterized according to the same factors identified in response to paragraph "b" above.

HECO/RMI-FSOP-IR-116:

Ref: RMI FSOP, page 35. "Decoupling mechanisms have been implemented in several mainland jurisdictions."

a. How many jurisdictions currently use RMI's proposed index of the number of customers as the basis to recouple revenues?"

b. What has been the history of success for jurisdictions that are using, or have used, the number of customers as a basis for recoupling?

RMI RESPONSE (Natalie Mims under the direction of Kyle Datta):

a. RMI is familiar with one jurisdiction (California) that uses a customer indexing mechanism as the basis to recouple revenues. Southern California Gas Company has operated under a margin per customer indexing mechanism since 1998. In 2005, the margin per customer index was extended to for Southern California Gas Company until 2008. San Diego Gas & Electric was also granted permission to use a margin per customer index from 2005-2008.[1] Please note that RMI does not base its mechanism or rely on implementations in other jurisdictions.

b. What has been the history of success for jurisdictions that are using, or have used, the number of customers as a basis for recoupling?

Southern California Gas Company (SoCal Gas) filed an application in December 2002 to extend the margin per customer index for an additional five years, which was granted in 2005. SDG&E also joined SoCal Gas in using the margin per customer index in 2005.

[1] California Public Utility Commission, Decision 05-03-023, March 17, 2005.

HECO/RMI-FSOP-IR-117:

Ref: RMI FSOP, page 38. "Because utility profits would be contingent upon independent ex poste evaluation of actual program implementation the PUC could allow more flexibility in DSM program implementation knowing that the utility has a strong incentive to diligently attain program goals."

Please specify the additional DSM program "flexibility" that the PUC could allow.

RMI RESPONSE (Carl Freedman):

The original DSM program regulatory compact requires substantial ex ante review and approval of the details of program implementation in order to provide assurance that ratepayer funds will be prudently used. In order to determine that programs will be cost effective many details of program implementation must be defined prior to program approval and implementation. Approval of the programs includes specification of many specific characteristics of the programs including delivery mechanisms, rebate levels, program participant qualifications, etc. Since the reasonableness and prudence of the programs is established based on these details in the program application and review, any subsequent changes to these details requires review and approval by the Commission. Additional flexibility could be provided to the utility regarding changes to program implementation details if sufficient incentives and/or penalties would be determined based on ex poste evaluation of utility performance. In this case the regulatory compact would rely to a greater extent on ex poste evaluation with associated incentives and/or penalties to ensure diligent use of ratepayer funds rather than ex ante review of details in the program application and review process.

The amount and type of flexibility that could be allowed with ex poste evaluation would depend on the scope of ex poste evaluation and the magnitude of incentives and/or penalties at stake. In one extreme, if the ex poste evaluation is rigorous and thorough in scope, evaluating all aspects of the utility's DSM performance and if the incentives and/or penalties are substantial the utility could be allowed to implement its DSM programs however it decides without rigorous ex ante review and approval since the utility would be highly motivated to meet the objectives of the ultimate performance evaluation.

The extent to which flexibility would be provided to the utility would be determined in the DSM program application review and approval process. This determination should take into consideration the incentives that a utility will have on an ongoing basis to make decisions about expenditures of DSM funds that are prudent and consistent with the IRP and DSM program objectives. For example, if it is determined in the DSM program application proceeding that the shareholder incentive mechanism provides sufficient incentives for the utility to optimize DSM program participant rebate levels, then the utility could be provided commensurate flexibility in adjusting rebate levels without prior Commission approval.

HECO/RMI-FSOP-IR-118:

Ref: RMI FSOP, page 39. "In addition, RMI believes that two additional programs should be offered, a Pay As you Save (PAYS) program (as defined in Act 96, but expanded to include solar photovoltaic) and an Affordable Housing Residential New Construction program (AFRNC), for developers of affordable housing."

a. Please provide a suggested amount that should be budgeted annually for the revolving loan and whether the loan would be at market rates or low interest rates.

b. With this type of program, where do you see the boundaries on how the developer could spend the loan funds? Would the design cost be paid using these funds too?

c. Currently, the City and County of Honolulu has a loan program where the City needs to pre-approve what the funds will be used for. After installation, the City will directly reimburse the installing contractor. Would that be the case here, to ensure that only qualified measures are installed?

d. Would the loan amount be just for the cost differential of the energy efficiency measures (standard verses high efficiency) or the entire cost?

e. Would the loan replace the customer rebate or be in addition to the rebates?

RMI RESPONSE (Kyle Datta):

a. RMI has not yet calculated the total amount that would need to be budgeted based on the affordable housing demands in Oahu, and projected building over the next two years.

b. The developers could pay for the incremental costs of constructing more efficient housing and the design and engineering required to modify current housing designs to be more efficient.

c. Yes. In addition, if developers were able to avoid HVAC systems due to other efficiency measures in the building envelop, these building envelop measurs would be included.

d. Yes, the load amount is for the differential cost only.

e. The loan would be in addition to the rebates, where the rebates do not cover the entire costs.

CALCULATIONS FOR SOLAR PAYBACK TIME

Solar System		2	kW
Cost/kW		9000	$/kW
Total Cost	$	18,000	
Federal tax credit		30%	
State Tax Credit		35%	Sunbject to $7,500 cap
Federal tax Credit	$	5,400	
State Tax Credit	$	6,300	
Net Cost After Tax Credits	$	6,300	
Capacity Factor		22%	
Kwh Generated		3854.4	Kwh/yr
HECO Rate	$	0.1897	Effective Schedule R rate 2/1/06
Rate Inrease	$	0.0109	
New HECO Rate	$	0.2005	
Net Meter Savings	$	773	$/yr
Payback (simple)		8.2	

HECO/RMI-FSOP-IR-121:

Ref: RMI FSOP, page 44. "RMI recommends that the Commission use this docket to implement Act 96 and extend the PAYS program to include solar photovoltaic as well, in combination with the AFRNC program discussed above."

a. What is the typical payback period for a residential photovoltaic installation?

b. Assuming the payback period is an extended period of time, (i.e. ten years of greater), is it appropriate to create a program where the customer payment stream may extend for this extended period of time? Please explain.

c. How should the program handle changes in ownership of the residence where the photovoltaic measure is installed?

RMI RESPONSE (Kyle Datta):

a. The payback of the solar system depends on the electricity rates. As oil prices rise and are passed through to the consumer, the payback time is reduced. If we take HECO's 2006 effective electricity rates of $0.189697 (as per 2/1/06) and assume the current proposed rate increase of ~$0.0106, then the simple payback period, would be 8.2 years assuming that there was no increase in oil prices vs. 2/1/06. (see attached spreadsheet)

b. It is precisely for long payback periods that loans of this nature are needed for those within the lower income brackets that can not afford the higher fixed cost despite the long run benefits.

c. The loan conditions would require that the loan is paid back by the existing customers or assumed by the new owner of the residence. The issue is no different than the installation of other devices on the home, such as solar water heaters, or load control devices.

HECO/RMI-FSOP-IR-123:

Ref: RMI FSOP, page 49. With respect to RMI's statement "The amount of shareholder incentives proposed is excessive", for HECO's DSM programs estimated costs and energy and demand savings, as provided in its FSOP, what level of shareholder incentives does RMI maintain to be reasonable?

RMI RESPONSE (Carl Freedman): See RMI's Response to HECO/RMI-FSOP-IR-142.

HECO/RMI-FSOP-IR-125:

Ref: RMI FSOP, Exhibit A, page 2. "Alternate market structures would move some combination of these phases to non-utility entities: Determination of utility system DSM objectives:..."

Does RMI envision any circumstance under which the determination of utility system DSM objectives would be moved to a non-utility entity?

RMI RESPONSE (Kyle Datta):

The utility will always be responsible for defining the overall system needs for both supply and demand since it bears the obligation to serve. Thus, the utility system level DSM objectives (e.g how many MW and Mwh, and the desired impact on load shape) would be determined within the IRP process. However, if a third party administrator was implementing the DSM programs, this non-utility entity would then have the responsibility to define the cost effective suite of DSM programs and how they would be executed in order to meet the program objective.

HECO/RMI-FSOP-IR-126:

Ref: RMI FSOP, Exhibit A, page 4. "If a "fund administrator" is established pursuant to the provision of Chapter 269 as amended in the 2006 legislative session (SB3185), the fund administrator would automatically be a party to the utility IRP proceedings."

a. Does RMI envision a single third-party administrator or several third-party administrators, each with its own DSM program?

b. If several third-party administrators, would each one be a party to the utility IRP proceedings?

RMI RESPONSE: (Carl Freedman):

a. Both would be possibilities.

b. Yes, although the scope of participation and standing could be limited to the appropriate issues.

HECO/RMI-FSOP-IR-127:

Ref: RMI FSOP, Exhibit A, page 7. "Utility incentives and any non-utility administrator incentives would be determined and distributed based on ex poste evaluation of DSM program performance conducted by an independent firm retained by the Commission."

a. Would payment of incentives be withheld until the ex poste evaluation by the independent firm is complete, or would there be payments in advance of the evaluation completion subject to reconciliation based on the results of the evaluation?

b. How often would the ex poste evaluation be conducted?

c. Who would pay for the "independent firm retained by the Commission"? The Commission?

RMI RESPONSE (Carl Freedman):

a. Some portion of the incentives could be disbursed at the time or in the year following measure implementation similar to the original shareholder incentives and surcharge recovery mechanisms. At lease some significant portion of the shareholder incentive would be disbursed only upon completion of the ex poste evaluation.

b. The timing of the ex poste evaluation would be determined at the time of the approval of the DSM programs based on the characteristics of the program, program measures and measurement and evaluation plans. The ex poste evaluation would take place only after the results of the utility (or non-utility administrator) measurement and evaluation studies are available. c. The evaluation would be a DSM expense paid for by the same source of funding as other DSM expenses.

HECO/RMI-FSOP-IR-128:

Ref: RMI FSOP, Exhibit A, page 9. "For some DSM programs the utility would continue to function as the administrator. Several important components of the market structure for these programs are the . . . procedures and standards for measurement and evaluation..."

Please distinguish the measurement and evaluation efforts conducted by the utility from the evaluation efforts conducted by the independent firm retained by the Commission.

RMI RESPONSE (Carl Freedman):

The measurement and evaluation efforts that would be conducted by the utility are those that are currently conducted by the utility. These measurement and evaluation efforts would not be reduced or displaced by the ex poste evaluation used to determine shareholder incentives. The independent firm retained by the Commission would use the results of the utility measurement and evaluation studies (in addition to any additional necessary studies) specifically to determine the disbursement of utility incentives based on the attainment of program objectives.

HECO/RMI-FSOP-IR-129:

Ref: RMI FSOP, Exhibit A, page 11. For the non-utility administrator of DSM, does RMI believe that measurement and evaluation activities should be performed by an independent entity in order to preclude the possibility of gaming?

RMI RESPONSE (Carl Freedman):

The standards for independent performance of measurement and evaluation activities should be the same for utility and non-utility entities. To the extent that there is a possibility of gaming this should be addressed. To the extent that the measurement and evaluation activities are used directly to determine incentives (or lost margins) the results should be performed by independent entities or should be closely monitored and reviewed by the Commission.

HECO/RMI-FSOP-IR-131:

Ref: RMI FSOP, Exhibit B, pages 5-6. The RMI proposed Energy Charge would recover marginal fuel costs in the Fuel Energy Charge and recover fixed costs in the Non-Fuel Energy Charge. Please provide examples of decoupling rate design from other regulated jurisdictions that are similar to this RMI proposal.

RMI RESPONSE (Carl Freedman):

RMI's proposed decoupling mechanism is not based on rate designs from other jurisdictions.

See response to HECO/RMI-FSOP-IR-116.

quarterly basis. The third and fourth tables show the resulting revenue streams that result from the mechanism depicted. Explanatory notes are provided on the tables.

The mechanism depicted implements the decoupling method and equations described in the RMI FSOP and exhibits except that (1) the equations in the mechanism depicted here have been put in the form of energy charge adjustments similar in form and application to HECO's existing ECAC mechanism and (2) necessary detail in the form of the equations has been added in implementing equations. Putting the equations in the form of an energy charge adjustment provides a method of implementing the mechanism that is transparent to other rate design features (including the ECAC), is generally familiar to the Hawaii utilities and regulators and is feasible to implement by existing billing formats and procedures.

Alternate mechanisms have been developed by RMI. The particular method depicted here follows most closely to the principle described in the RMI FSOP and exhibits that net recovery of test year non-fuel expenses included in the energy charge (after production costs are covered) will track and increase in proportion with an index of the number of customers. Sales volumes do not affect the net revenues of the utility. This is demonstrated on the third and fourth tables.

The data in these tables are the subject of RMI's pending information requests to HECO and may need to be amended or supplemented based on HECO's responses.

Comparison of Resulting Energy Charge Revenues — Method #1

Hawaiian Electric Company - Fixed Margin Based on Marginal Energy Costs

Source information based on original rate case application in Docket No. 04-0113 (Revenue at Proposed Rates)

Customer Class =>	**R/E**	**G**	**J**
Assumptions:			
Ratio of Actual Sales to Test Year Sales	**1.05**	**1.05**	**1.05**
Ratio of Actual Customers to Test Year Customers	**1.03**	**1.03**	**1.03**
Test Year Revenue Using Existing Charges			
Fuel Charge Revenues	$145,725	$25,816	$137,910
Non-Fuel Charge Revenues	$172,652	$26,299	$82,100
Total Energy Charge Revenues	$318,377	$52,115	$220,010
Production Costs	$145,725	$25,816	$137,910
Net Revenue (For Fixed Costs)	$172,652	$26,299	$82,100
Test Year Revenue Using Decoupled Charges			
Fuel Charge Revenues	$174,660	$30,696	$164,176
Non-Fuel Charge Revenues	$143,717	$21,419	$55,834
Decoupling Energy Charge Adjustment Revenues	$0	$0	$0
Total Energy Charge Revenues	$318,377	$52,115	$220,010
Production Costs	$145,725	$25,816	$137,910
Net Revenue (For Fixed Costs)	$172,652	$26,299	$82,100
Actual Revenue Using Traditional Tariff Design			
Fuel Charge Revenues	$153,011	$27,107	$144,806
Non-Fuel Charge Revenues	$181,285	$27,614	$86,205
Total Energy Charge Revenues	$334,296	$54,721	$231,011
Production Costs	$154,458	$27,351	$146,119
Net Revenue (For Fixed Costs)	$179,838	$27,370	$84,892
Actual Revenue Using Decoupled Charges			
Fuel Charge Revenues	$183,393	$32,231	$172,384
Non-Fuel Charge Revenues	$150,903	$22,490	$58,626
Decoupling Energy Charge Adjustment Revenues	-$2,006	-$282	-$329
Total Energy Charge Revenues	$332,290	$54,439	$230,682
Production Costs	$154,458	$27,351	$146,119
Net Revenue (For Fixed Costs)	**$177,832**	**$27,088**	**$84,563**
Check			
Test Year Non-Fuel Revenues	$172,652	$26,299	$82,100
Index of Customers Growth Factor	1.03	1.03	1.03
Test Year Non-Fuel Revs. Times Customer Factor	**$177,832**	**$27,088**	**$84,563**

Comparison of Resulting Energy Charge Revenues

Method #1

Hawaiian Electric Company - Fixed Margin Based on Marginal Energy Costs

Source information based on original rate case application in Docket No. 04-0113 (Revenue at Proposed Rates)

Customer Class =>	**R/E**	**R/E**	**R/E**	**R/E**	**R/E**
Assumptions:					
Ratio of Actual Sales to Test Year Sales	**1**	**1.05**	**1.05**	**1**	**1.1**
Ratio of Actual Customers to Test Year Customers	**1**	**1.05**	**1.03**	**1.03**	**1.03**
Test Year Revenue Using Existing Charges					
Fuel Charge Revenues	$145,725	$145,725	$145,725	$145,725	$145,725
Non-Fuel Charge Revenues	$172,652	$172,652	$172,652	$172,652	$172,652
Total Energy Charge Revenues	**$318,377**	$318,377	$318,377	$318,377	$318,377
Production Costs	$145,725	$145,725	$145,725	$145,725	$145,725
Net Revenue (For Fixed Costs)	**$172,652**	$172,652	$172,652	$172,652	$172,652
Test Year Revenue Using Decoupled Charges					
Fuel Charge Revenues	$174,660	$174,660	$174,660	$174,660	$174,660
Non-Fuel Charge Revenues	$143,717	$143,717	$143,717	$143,717	$143,717
Decoupling Energy Charge Adjustment Revenues	$0	$0	$0	$0	$0
Total Energy Charge Revenues	**$318,377**	$318,377	$318,377	$318,377	$318,377
Production Costs	$145,725	$145,725	$145,725	$145,725	$145,725
Net Revenue (For Fixed Costs)	**$172,652**	$172,652	$172,652	$172,652	$172,652
Actual Revenue Using Traditional Tariff Design					
Fuel Charge Revenues	$145,725	$153,011	$153,011	$145,725	$160,298
Non-Fuel Charge Revenues	$172,652	$181,285	$181,285	$172,652	$189,917
Total Energy Charge Revenues	**$318,377**	$334,296	$334,296	$318,377	$350,215
Production Costs	$145,725	$154,458	$154,458	$145,725	$163,191
Net Revenue (For Fixed Costs)	**$172,652**	$179,838	$179,838	$172,652	$187,024
Actual Revenue Using Decoupled Charges					
Fuel Charge Revenues	$174,660	$183,393	$183,393	$174,660	$192,126
Non-Fuel Charge Revenues	$143,717	$150,903	$150,903	$143,717	$158,089
Decoupling Energy Charge Adjustment Revenues	$0	$1,447	-$2,006	$5,180	-$9,192
Total Energy Charge Revenues	**$318,377**	$335,743	$332,290	$323,557	$341,023
Production Costs	$145,725	$154,458	$154,458	$145,725	$163,191
Net Revenue (For Fixed Costs)	**$172,652**	**$181,285**	**$177,832**	**$177,832**	**$177,832**
Check					
Test Year Non-Fuel Revenues	$172,652	$172,652	$172,652	$172,652	$172,652
Index of Customers Growth Factor	1	1.05	1.03	1.03	1.03
Test Year Non-Fuel Revs. Times Customer Factor	**$172,652**	**$181,285**	**$177,832**	**$177,832**	**$177,832**

HECO/RMI-FSOP-IR-133:

Ref: RMI FSOP, Exhibit B, page 7. "For purposes of implementing the decoupling mechanism the index of the number of customers would not be the same as the number of accounts."

a. At what frequency would the number of customers be needed?

b. Would new customers at existing premises that were previously vacant be counted in the number of customers for this purpose?

c. Would the utility need to keep track of which customer locations were originally occupied, and not count the occupant when re-occupied? Also, would the utility need to keep track of which customer locations were originally vacant, and count the occupant when occupied?

d. If a customer were to move from an occupied unit to a unit that was originally vacant, would the number of customers increase?

e. At what point in time would the vintage of unit vacancy or occupancy be set? At what point in time would the vintage be reset?

RMI RESPONSE (Carl Freedman):

a. RMI has not specified the period for application of the proposed decoupling mechanism. The index of the number of customers would be needed once per adjustment period. If the adjustment period is quarterly the index would be needed four times per year.

b. The specifications for determining the index of the number of customers were devised by RMI to be simple to implement and to avoid opportunity for gaming or spurious circumstances. RMI is open to suggestions for alternate or additional specifications that would meet these objectives. According to the specification in the RMI FSOP (1) for each customer class the index of the number of customers would be the test year number of customers plus new customers at new premises. The pertinent question is whether the premise ever had a previous account or whether this is a new premises that has never received service. In most circumstances a building permit for a new building would be associated with each new customer addition to the

HECO/RMI-FSOP-IR-134:

Ref: RMI FSOP, Exhibit B, page 9. Lines 20-23. When there is system growth during the periods between rate cases, the revenue stream provided by existing tariffs is expected to increase in total dollars. Please explain and or illustrate how the proposed decoupling mechanism replicates "the **value** of the revenue stream provided by existing tariffs associated with system growth during the periods between rate cases." If the value is intended to be something other than dollar value, please explain.

RMI RESPONSE (Carl Freedman):

See RMI FSOP - Exhibit B at page 7, lines 7 – 15 for discussion that if use per customer remains constant the decoupling mechanism would not change the amount of utility cost recovery between rate cases from what is collected by the existing rate structure. See RMI FSOP – Exhibit B at pages 10 to 11 including footnote 9 for discussion of the value of stability of the revenue stream provided by the decoupling mechanism. The value of the revenue stability provided by the decoupling mechanism has a dollar value in the same sense that stability versus volatility in the utility's revenue stream affects the utility's costs of capital that are associated with financial risk.

HECO/RMI-FSOP-IR-135:

Ref: RMI FSOP, Exhibit B, page 10. "The proposed decoupling mechanism does not attempt to improve upon the accuracy of the existing regulatory compact in this respect, but rather to preserve the approximate magnitude of the value of the revenue stream."

Is the regulatory compact referred to the existing lost margins mechanism? If not, what is the regulatory compact?

RMI RESPONSE (Carl Freedman):

The baseline "regulatory compact" referred to in the quotation above is without the original (no longer existing) lost margins mechanism and without implementation of DSM. The proposed mechanism is designed to preserve the value of the revenue stream so that it is not affected by DSM implementation.

HECO/RMI-FSOP-IR-136:

Ref: Decoupling. Please quantify the effect of RMI's decoupling proposal on HECO's revenue historically, 2000-2005.

RMI RESPONSE (Carl Freedman):

RMI has not performed this quantification.

HECO/RMI-FSOP-IR-139:

Ref: RMI FSOP, Exhibit B, page 11. "RMI's proposed mechanism recouples the fixed margin revenues to an index of the number of customers. some alternatives that have been considered as a basis for recoupling are:"

a. Please identify decoupling mechanisms in other regulated jurisdictions that recouple fixed margin revenues to an index of number of customers.

b. Why did RMI reject the four alternatives identified on this page and propose an index of the number of customers instead?

RMI RESPONSE (Carl Freedman):

a. RMI's decoupling proposal does not rely on the existence of form of decoupling mechanisms in other jurisdictions.

b. RMI selected an index of the number of customers as the basis for recoupling because it is a good proxy for the growth of the utility system, would preserve the approximate value of the cost stream between rate cases (compared to the existing regulatory compact). RMI is open to discussing other the other identified alternatives as a basis for recoupling.

HECO/RMI-FSOP-IR-140:

Ref: RMI FSOP, Exhibit B, pages 14-18. Please provide a numerical illustration of how the proposed performance based utility mechanism would be calculated and implemented.

RMI RESPONSE (Kyle Datta):

See RMI's response to HECO/RMI-FSOP-IR-142.

capital avoided over 15 years for a program starting in 2006 to be $543/kW. HECO is allowed to earn a weighted 5.98% on this levelized capital cost of $32.5/kW. This would represent the shareholder incentive that would equal HECO's avoided supply side earnings opportunity and make HECO indifferent between additional demand without the DSM programs, assuming that a revenue decoupling mechanism was in place to pay for all existing fixed costs (including shareholder returns on these costs). See Attached Spreadsheet for illustrative calculations. Please note that the numbers used in this response and the attached spreadsheet are supplied for illustrative purposes and may be amended or supplemented based on HECO's responses to RMI's information requests.

1. CALCULATION OF HECO EARNINGS FROM AVOIDED COST INFORMATION
FROM HECO FSOP SPREADSHEET CE Analysis DOCKET (05-30-06).xls, tab avoided cost

Levelized Avoided Cost	$/kW	$543.94	Applies A/T levelization factor over 2006-2025 values
Levelized Energy Cost	$/Kwh	$0.0427	Applies A/T levelization factor over 2006-2025 values

2. CALCULATION OF HECO COST OF CAPITAL (WACC)
Source: 2004 PURPA filing

	% of Total	%Earning Requirement	% Pre Tax Weighted Requirement	% After Tax Weighted Requirement
Short Term Debt	3%	1.20%	0.04%	0.02%
Long Term Debt	38%	6.25%	2.38%	1.45%
Preferred Stock	7%	6.35%	0.44%	4.40%
Common Stock	52%	11.50%	5.98%	5.98%
Composite Cost of Capital			8.84%	7.90%
% Equity Portion of WACC			67.6%	75.7%

15 Year Levelization Factor 11.612%

3. Utility Shareholder Earnings from Avoided Costs

Utiliy Earnings on Energy Cost — Zero — 100% Pass through via ECAC
Assumes Revenue Decoupling is in Place

Utility Earnings on Avoided Capacity
HECO Avoided Capacity Costs

Levelized Avoided Cost	$/kW	543.94	
Common Equity Earnings	$/kW	32.53	Applies Weighted Equity Return for each year
Percent of Levelized Cost		5.98%	

4. Example: CIEE Program

			2006	2007	2008	2009	2010	2011	2012
Cumulative Savings (Net System Level)									
Peak Demand Reduction (kW)			2,284	4,567	6,851	9,135	11,418	13,697	15,661
Energy Savings (kWh)			15,266,176	30,532,351	45,798,527	61,064,703	76,330,878	91,575,903	105,015,883
Utility Earnings (levelized)	$/kW		32.53	32.53	32.53	32.53	32.53	32.53	32.53
Utility earnings ($)			$ 74,281	$ 148,562	$ 222,843	$ 297,124	$ 371,404	$ 445,536	$ 509,429
NPV Utility Earnings		$4,996,688							
Maximum Shareholder Incentive		$4,996,688							

5. Shareholder Incentive Percentage of TRC Calculations CIEE Program

Benefits	Costs	Net Benefits	B/C Ratio
$181,715,611	$88,144,874	$93,570,736	2.06

4. Example: CIEE Program

Cumulative Savings (Net System Level)		2013	2014	2015	2016	2017	2018
Peak Demand Reduction (kW)		17,590	19,493	21,396	22,384	23,373	24,361
Energy Savings (kWh)		118,281,870	131,429,865	144,577,860	151,432,516	158,287,172	165,141,829
Utility Earning $/kW		32.53	32.53	32.53	32.53	32.53	32.53
Utility earnings ($)							
NPV Utility Earnings	$4,996,688	$ 572,165	$ 634,061	$ 695,957	$ 728,104	$ 760,251	$ 792,397
Max.Shareholder Incentive	$4,996,688						

4. Example: CIEE Program

Cumulative Savings (Net System Level)		2019	2020	2021	2022	2023	2024	2025
Peak Demand Reduction (kW)		25,349	26,337	27,273	27,305	27,337	27,369	27,401
Energy Savings (kWh)		171,996,485	178,851,141	185,418,506	185,775,374	186,132,243	186,489,111	186,845,980
Utility Earnings ($/kW		32.53	32.53	32.53	32.53	32.53	32.53	32.53
Utility earnings ($)		$ 824,544	$ 856,691	$ 887,138	$ 888,177	$ 889,217	$ 890,256	$ 891,296
NPV Utility Earnings	$4,996,688							
Max. Shareholder Incentive	$4,996,688							

HECO/RMI-FSOP-IR-144:

Ref: RMI FSOP, Exhibit B, page 16. "The utility incentive percentage share of the shared savings used in each program would be set so that the amount of potential incentives for each program is the same percentage of the total amount of the DSM portfolio utility incentives as the percentage of each program's contribution to total DSM portfolio gross TRC benefits."

Please provide a numerical example of how the program percentage shares would work.

RMI RESPONSE (Kyle Datta):

To avoid cream skimming behavior, the entire portfolio of DSM programs would be evaluated as an integrated package to determine the total amount of shareholder incentive. For illustrative purposes, let is assume the total amount of shareholder incentives for all proposed programs in this docket is 100 units. The total TRC net benefits for all the programs proposed in this docket is $375.007,232. However, one program (REWH) is TRC negative by ($2,817,756). Therefore, this program is excluded, making the total net TRC benefits equal to $377,825,028. The CIEE net TRC benefits are $93,570,736. Therefore, the CIEE share of the shareholder incentive = $93,570,736$377,825,028 or 24.7656%. The CINC net TRC benefits are $32,872,955. Therefore, the CINC share of the shareholder incentive = $32,872,955/$377,825,028 or 8.7006%. Other program shares would be calculated in a similar manner. Note that the quantities used in this response are used for illustrative purposes and may be amended based on responses to RMI's information requests.

HECO/RMI-FSOP-IR-145:

Ref: RMI FSOP, Exhibit B, pages 15-16. Please show an example of the calculation of the shareholder earnings that are the return on equity portion of the capacity costs avoided by the DSM portfolio. Is it possible for the total quantity of potential shareholder earnings to be greater than 100% of the total resource cost (TRC) net benefits of the portfolio of DSM measures? If not, why not? Describe how the TRC net benefits are related to the return on equity portion of the capacity costs avoided by the DSM portfolio.

RMI RESPONSE (Kyle Datta):

Yes, it is possible for a program to pass the TRC test and have shareholder earnings greater than 100% of the TRC net benefits. For example, a program that barely passes the TRC test could have a net TRC benefit of $1. In such a case, the maximum shareholder earnings would most likely be greater than net TRC benefits. The amount of utility shareholder incentives is clearly capped in RMI's formulation by the net TRC benefits. However, we observe from HECO's proposed portfolio that the programs proposed have healthly B/C ratios, and this is not the situation at hand. The calculation and relationship of TRC net benefits are shown in the answers to the prior question and the illustrative spreadsheet for the CIEE program.

HECO/RMI-FSOP-IR-147:

Ref: RMI FSOP, Exhibit B, page 18. "The incentive would be adjusted to account for free riders, market penetration, and persistence of DSM measures."
How would market penetration and persistence of DSM be measured and determined, and how would the incentive be adjusted to account for them?

RMI RESPONSE (Carl Freedman):

Market penetration would be measured by the DSM tracking and reporting conventions currently used. Persistance would be measured along with measure efficicacy and verification of unit measure impacts by studies for this purpose. These studies and DSM program tracking and reporting would ordinarily be performed by the utility or non-utility program administrator. For purposes of determining the disbursement of shareholder incentives a separate ex poste evaluation would be performed under the supervision of the Commission. This ex poste evaluation would be specifically for the purpose of determining whether the objectives established for each program are met for purposes of determining disbursement of shareholder incentives. This ex poste evaluation would rely on the DSM program tracking, measurement and evaluation activities performed by the utility or non-utility program administrators with verification and separate studies performed only as necessary.

HECO/RMI-FSOP-IR-149:

Ref: RMI FSOP, Exhibit C, page 3. How does the RMI Financial Mechanisms Proposal (i.e., shared savings based on TRC test) encourage:

1. measure efficacy,
2. measure persistence, and
3. free-ridership control?

RMI RESPONSE (Kyle Datta):

The total resource test defines the net benefits based on the total benefits (avoided capacity and energy) vs. the costs incurred by the utility and the customer. Thus, a percentage the the net TRC benefits aligns the utility to focus on the programs that have the greatest savings to society overall. As stated in the prior questions, the choice of the TRC test, per se, has no bearing on measure persistence and free ridership control. These are calculations that must modify the values within the TRC test.

Furthermore the disbursement of the shareholder incentive would be contingent upon ex poste evaluation of program performance that could include specific criteria for these and other program performance characteristics as a basis for determining incentives.

HECO/RMI-FSOP-IR-150:

Ref: RMI FSOP, Exhibit D. Utility Incentives.
How does full ex poste performance in the RMI Strawmodel differ from the true-up in the original HECO DSM Financial Recovery?

RMI RESPONSE (Carl Freedman):

The original HECO shareholder incentive mechanism was not implemented with any true up based on ex poste evaluation. This was a difference between the implementation of HECO's original lost margins mechanism and its shareholder incentives mechanism.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAIIAN ELECTRIC COMPANY, INC.	)	Docket No. 05-0069
	)	
For Approval and/or Modification of Demand-Side and Load Management Programs and Recovery of Program Costs and DSM Utility Incentives.	)	
	)	

ROCKY MOUNTAIN INSTITUTE'S RESPONSES TO

INFORMATION REQUESTS FROM

THE CONSUMER ADVOCATE

In accordance with the Schedule of Proceedings in Docket No. 05-0069 (as amended) Rocky Mountain Institute (RMI) respectfully submits its responses to the information requests by the Consumer Advocate (CA).

CA/RMI-FSOP-IR-1:

Ref: Final Statement of Position. On page 20, RMI states that it "would be appropriate for a utility to recover actual costs of implementing any approved utility-administered DSM programs." Is it correct to assume that RMI would qualify this statement to refer to prudently incurred costs?

RMI RESPONSE (Carl Freedman):

Yes.

CA/RMI-FSOP-IR-2:

Ref: Final Statement of Position. On pages 23 and 24, RMI discusses its perceived need to provide positive incentives for utilities to pursue DSM. The ability to earn more from building supply side assets is noted.

a. Does RMI agree that the installation of DSM is less risky financially than the construction of supply side resources?

b. If so, how does RMI recommend that the Commission take the lower DSM risk into consideration?

c. If not, please explain RMI's reasoning.

RMI RESPONSE (Kyle Datta):

a. The question of risk depends on who bears the risk. From society's perspective, efficiency investments are indeed less risky that the construction of fossil fuel side resources, because they do not bear fossil fuel risks. However, RMI understands the question to relate to the risks borne by the utility. From the utility's perspective, construction of supply side resources are under its control, as opposed to the customers, and thus are perceived to be less risky financially to them, even if the financial incentives to shareholders for both were exactly the same.

b. RMI believes the commission should incorporate the volatility of fossil fuels into the consideration of avoided costs. Since efficiency (and for that matter renewables) create a hedge of fossil fuels, the value of this hedge should be quantified and added to the price of fossil fuels (or deducted from the costs of renewables or efficiency) when determining cost benefit.

In terms of allowed rate of return, we believe the methodology proposed by RMI fairly compensates the utility for the risk of undertaking DSM since the revenue decoupling takes out the volatility of earnings and ensures 100% certainty of recover of fixed costs.

c. See above.

CA/RMI-FSOP-IR-3:

Ref: Final Statement of Position.
On page 35, RMI states that decoupling has "been implemented in several mainland jurisdictions."

a. Please identify which jurisdictions and provide the specifics of each mechanism.

b. For each jurisdiction, please state the period for which the decoupling mechanism has been in effect.

c. For each jurisdiction, please state the period for which the decoupling mechanism has been in effect.

RMI RESPONSE (Natalie Mims under the direction of Kyle Datta):

a. There are six states that RMI is aware of that are implementing or planning to implement a decoupling mechanism. (CA, ID, OR, MD, CT and NY).

California

In September 2003, Pacific Gas & Electric reached a settlement agreement with parties in its general rate case, which included a new revenue decoupling mechanism to remove the disincentive to invest in energy efficiency.[1] Southern California Edison has had a distribution-only revenue decoupling mechanism in place since April 2002.[2] Southern California Gas (SoCal Gas) has operated under a decoupling mechanism 1998.[3]

Oregon

In 2002, the Public Utility Commission of Oregon adopted a settlement agreement signed by a number of parties to the Commission's established a decoupling mechanism for

[1] Bachrach, D., S. Carter and S. Jaffe, "Do Portfolio Managers Have An *Inherent* Conflict of Interest with Energy Efficiency?" *The Electricity Journal,* Volume 17, Issue 8, October 2004, pp. 52-62

[2] *Id.*

[3] *Id.*

calculation of the billing adjustment are filed monthly with the Public Service Commission."

b. See response to part a. above.

c. See response to part a. above.

CA/RMI-FSOP-IR-4:

Ref: Final Statement of Position. Please compare RMI's proposed decoupling mechanism with decoupling mechanisms implemented elsewhere. In doing so, please state RMI's opinion as to which jurisdiction's mechanism is most similar to RMI's proposal.

RMI RESPONSE (Carl Freedman):

See response to CA/RMI-IR-3. Please note that RMI's decoupling mechanism was not based and does not rely on any specific mechanism implemented in other jurisdictions.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAIIAN ELECTRIC COMPANY, INC.	)	Docket No. 05-0069
	)	
For Approval and/or Modification of	)	
Demand-Side and Load Management	)	
Programs and Recovery of Program	)	
Costs and DSM Utility Incentives.	)	
	)	

ROCKY MOUNTAIN INSTITUTE'S RESPONSES TO

INFORMATION REQUESTS FROM

HAWAII RENEWABLE ENERGY ALLIANCE

In accordance with the Schedule of Proceedings in Docket No. 05-0069 (as amended) Rocky Mountain Institute (RMI) respectfully submits its responses to the information requests by the Hawaii Renewable Energy Alliance (HREA).

HSEA/RMI-IR-1:

Ref: RMI FSOP page 39: RMI recommends that A Pay As You Save (PAYS) program, including both solar and hot water and photovoltaic solar electric systems (PV) should be included in the DSM package. HSEA's written testimony in support of SB2957, Act 96, establishing the pilot PAYS program, also supported the inclusion of residential PV. Does RMI believe that the combination of quantitative and qualitative system benefits provided by PV make this technology conventionally cost-effective, or would RMI use some other metrics in arguing for the inclusion of PV in the residential PAYS program.

RMI RESPONSE (Kyle Datta):

RMI believes that PV is cost effective under today's rates and current tax credits. RMI calculates an 8 year payback on residential PV systems, (see response to HECO/RMI-FSOP-IR 120. This means the PV technology is already cost effective, the problem is affordability for low income customers that can not afford the first cost nor can they wait for an 8 year payback.

HREA/RMI-FSOP-IR-2.

On page 13, regarding market structures, there have been a number of states looking at third party utility approaches and some with implementation, e.g., Vermont, Oregon, New York and Texas. Also, HREA has learned recently about a proposal from the California Coalition For Energy Efficiency (CCEE), based on the Texas program, which we believe deserves consideration for Hawaii. The CCEE proposal can be found at: http://www.womensenergymatters.org/currentcampaigns/CCEE/CCEEAdminProposal.pdf. Does RMI have any comments on the CCEE proposal or the Texas program?

RMI RESPONSE (Kyle Datta):

RMI has not reviewed the CCEE proposal or Texas program in depth for its applicability to Hawaii, so declines to comment at this time.

HREA/RMI-FSOP-IR-3.

On pages 26 to 30, regarding RMI's discussion on revenue erosion and proposals for decoupling, is RMI saying that the utility will always experience revenue erosion when conducting DSM programs? For example, is there revenue erosion when the utility's increase in sales exceeds its revenue losses due to DSM measures? Furthermore, is RMI saying that the utility is entitled to sales growth, or would it be more correct to say that the utility has an opportunity for profits through sales growth? For example, it is HREA's view that the utility has revenue opportunities, while DSM providers should have opportunities to provide energy savings to consumers.

RMI RESPONSE (Kyle Datta):

By definition, utilities will have lower revenues due to the implementation of DSM programs. When DSM programs reduce sales utility revenues are less than they would otherwise be. This is true with or without general system load growth. Between rate cases increased load growth generally results in higher utility revenues. RMI is not saying anything about a utility's entitlement to load growth except to note that, in order to make the utility revenue-neutral with respect to the implementation of DSM programs the effects of load growth should be decoupled from utility revenues.

HREA/RMI-FSOP-IR-4.

On pages 35 to 38, regarding incentives (for whoever administers DSM), would RMI support a "fixed price" mechanism for delivery of specific programs and measures? For example, the incentives could b performance-based on a figure of merit, such as cost/kWh/year for each DSM program, and would necessarily vary from program to program?

RMI RESPONSE (Kyle Datta):

RMI assumes this question is proposing a shareholder incentive based on a fixed quantum per kwh for saved energy. While this approach has merit in the administrative simplicity, and therefore deserves consideration, it assumes that the value to society of a kWh saved is constant across all programs, which may not necessarily be accurate.

KIUC-SOP-IR-8:

Ref: RMI Final SOP, page 12.In its Final SOP, RMI states, in relevant part:

> The existing utility-only market structure should apply to Kauai Island Utility Cooperative (KIUC) rather than any alternative market structure except that, if a statewide non-utility DSM administrator (or fund administrator) is established, KIUC should work in partnership to the extent that benefits to KIUC's customers can best benefit.

In connection with the above, the following summarizes KIUC's understanding of the consensus reached by the parties/participants present at the May 11, 2006 settlement meeting, including RMI, on four of the five issues established for this proceeding as they pertain to KIUC, together with some background on each issue:

Docket Issue No. 2: What market structure(s) is the most appropriate for providing these or other DSM programs (e.g., utility-only, utility in competition with non-utility providers, non-utility providers)?

Consensus: As it pertains to KIUC, an electric cooperative essentially owned by its customers, there should be no change to the market structure by which KIUC currently develops and administers its DSM programs, provided that, as recommended by HREA and agreed upon by KIUC, KIUC hire a DSM consultant and/or consult with a third party or fund administrator if and when appropriate.

Background:

- Under the current structure, KIUC, at its discretion, either conducts its own DSM/energy services programs or contracts it out to a third party as appropriate. During the meeting, KIUC stated that this structure best supports the cooperative model, whereby DSM could be integrated with other energy services offerings.

- KIUC also noted that it strives to provide a level of service to its members even higher than that allowed or established by the current DSM evaluation criteria, and as such, KIUC is currently implementing programs that go beyond simple cost effectiveness. Examples given were: (1) KIUC's current appliance rebate program, whereby KIUC pays a rebate to any member that purchases a qualifying energy efficient appliance, and (2) KIUC's current solar rebate and loan program whereby KIUC either pays rebates or provides (through third-party lending institutions) no-interest loans for the installation of solar water heating systems. In both examples, KIUC does not screen for cost effectiveness and the programs are funded by the program budget approved by KIUC's Board of Directors (who are elected directly by KIUC's customer/members to represent their interests).

- KIUC also noted that the direct install DSM programs offered by KIUC during the past 7 years have significantly penetrated the residential markets. As a result, the current remaining markets may be too small to overcome the fixed cost associated with a full-scale DSM-type program. KIUC stated that they believe that these small markets can best be served with energy efficiency programs that combine DSM programs with other energy service programs.

- KIUC also stated that the commercial programs are an integral part of its Commercial Enhanced Energy Services offering and Key Accounts program, through which solutions to commercial customer's high-energy costs are achieved through a mix of DSM-type measures with other energy service-type measures, such as power factor correction.

Docket Issue No. 3: For utility-incurred costs, what cost recovery mechanism(s) is appropriate (e.g., base rates, fuel clause, IRP Clause)?

Consensus: As it pertains to KIUC, KIUC should be able to recover its utility-incurred costs from its members and customers via cost recovery mechanisms that are deemed most appropriate for KIUC's situation and cooperative structure.

Background: As a not-for-profit, member-owned cooperative for which the traditional rate base method of ratemaking is not applicable, KIUC anticipates working with the Commission and the Consumer Advocate at some point in the future to determine the most appropriate cost recovery mechanism that should apply not only to energy efficiency costs, but to all of its costs of operation in general. This is a matter that should be decided at the time of KIUC's first rate case or deregulation proceeding, and is outside of the context of the subject proceeding.

Docket Issue No. 4: For utility-incurred costs, what types of costs are appropriate for recovery?

Consensus: As it pertains to KIUC, KIUC should be able to recover all of its incurred costs associated with energy efficiency programs.

Background: During the meeting, KIUC explained that this cost recovery issue seems to involve whether DSM program costs should be recovered from the utility's ratepayers or instead paid for by the utility's shareholders. KIUC explained that this is not applicable to KIUC (i.e., a not-for-profit, member-owned cooperative with the ratepayers and the shareholders essentially being one and the same). In the end, it is our understanding that all parties present agreed that KIUC should be allowed to recover its costs associated with energy efficiency programs.

As a side note, during the meeting, we also understand that the parties considered whether there should be a revenue erosion mechanism and if so, what should this mechanism be. For the same reasons as Docket Issue No. 3, it is our understanding that the parties present agreed that this issue does not apply to a not-for-profit, member-owned cooperative such as KIUC.

Docket Issue No. 5: Whether DSM incentive mechanisms are appropriate to encourage the implementation of DSM programs, and, if so, what is the appropriate mechanism(s) for such DSM incentives?

b. See response to paragraph “a” above. The process should certainly include identification of supply side risks and the degree to which energy efficiency measures mitigate those risks should be quantified and, where possible valued. This will aid in the determination of the how much energy efficiency is cost effective, and therefore the appropriate goals for the state.

c. For each goal that is adopted the meaning should be clear. If it is necessary to provide specific definitions to clarify the meaning of any goal then appropriate definitions should be provided. RMI has not identified any definitions that would apply to specific goals.

CERTIFICATE OF SERVICE

I hereby certify that I have on this date served a copy of the foregoing Responses to Information Requests upon the following parties and participant, by hand delivery or by causing a copy hereof to be mailed, postage prepaid, and properly addressed to each such party or participant.

DIVISION OF CONSUMER ADVOCACY
DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS
P.O. Box 541
Honolulu, HI 96809

WILLIAM A. BONNET
VICE PRESIDENT
HAWAIIAN ELECTRIC COMPANY, INC.
HAWAII ELECTRIC LIGHT COMPANY, INC.
MAUI ELECTRIC COMPANY, LIMITED
P. O. Box 2750
Honolulu, HI 96840-0001

DEAN K. MATSUURA
DIRECTOR, REGULATORY AFFAIRS
HAWAIIAN ELECTRIC COMPANY, INC.
P. O. Box 2750
Honolulu, HI 96840-0001

EDWARD REINHARDT
PRESIDENT
MAUI ELECTRIC COMPANY, LTD.
P.O. Box 398
Kahului, HI 96733-6898

WARREN LEE
PRESIDENT
HAWAII ELECTRIC LIGHT COMPANY, INC.
P.O. Box 1027
Hilo, HI 96721-1027

RANDALL Y. K. YOUNG
NAVAL FACILITIES ENGINEERING COMMAND PACIFIC
258 Makalapa Drive, Suite 100
Pearl Harbor, HI 96860

Counsel for Department of the Navy

RICHARD R. REED
PRESIDENT
HAWAII SOLAR ENERGY ASSOCIATION
c/o INTER-ISLAND SOLAR SUPPLY
761 Ahua Street
Honolulu, HI 96819

WARREN S. BOLLMEIER II
PRESIDENT
HAWAII RENEWABLE ENERGY ALLIANCE
46-040 Konane Place, #3816
Kaneohe, HI 96744

HENRY Q CURTIS
VICE PRESIDENT FOR CONSUMER ISSUES
LIFE OF THE LAND
76 North King Street, Suite 203
Honolulu, HI 96817

BRIAN T. MOTO
CINDY Y. YOUNG
DEPARTMENT OF THE CORPORATION COUNSEL
COUNTY OF MAUI
200 South High Street
Wailuku, HI 96793

Counsel for County of Maui

KAL KOBAYASHI
ENERGY COORDINATOR
DEPARTMENT OF MANAGEMENT
COUNTY OF MAUI
200 South High Street
Wailuku, HI 96793

LANI D. H. NAKAZAWA, ESQ.
LAUREL LOO, ESQ.
JAMES K. TAGUPA, ESQ.
OFFICE OF THE COUNTY ATTORNEY

COUNTY OF KAUAI
4444 Rice Street, Suite 220
Lihue, HI 96766-1300

Counsel for the County of Kauai

E. Kyle Datta

E. Kyle Datta

DATED: ___________________________