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PUBLIC UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
MAUI ELECTRIC COMPANY, LIMITED	)	**DOCKET NO. 2006-0387**
	)	
For Approval of Rate Increases and Revised Rate Schedules.	)	

DIVISION OF CONSUMER ADVOCACY'S

DIRECT TESTIMONIES, EXHIBITS, AND WORKPAPERS

October 25, 2007

108.

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DIVISION OF CONSUMER ADVOCACY
Department of Commerce and
Consumer Affairs
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Honolulu, Hawaii 96813
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FILED

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PUBLIC UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
	)	
MAUI ELECTRIC COMPANY, LIMITED	)	DOCKET NO. 2006-0387
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Approval of Rate Increase and Revised Rate Schedules.	)	

DIVISION OF CONSUMER ADVOCACY'S
DIRECT TESTIMONIES, EXHIBITS, AND WORKPAPERS

Pursuant to the Schedule of Proceedings in Order No. 23496, the Division of Consumer Advocacy submits its **DIRECT TESTIMONIES, EXHIBITS, AND WORKPAPERS** in the above docketed matter.

DATED: Honolulu, Hawaii, October 25, 2007.

Respectfully submitted,

By Cheryl S Kikuta
CHERYL S. KIKUTA
Utilities Administrator
DIVISION OF CONSUMER ADVOCACY

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing **DIVISION OF CONSUMER ADVOCACY'S DIRECT TESTIMONIES, EXHIBITS, AND WORKPAPERS** was duly served upon the following parties, by personal service, hand delivery, and/or U.S. mail, postage prepaid, and properly addressed pursuant to HAR § 6-61-21(d).

EDWARD L. REINHARDT PRESIDENT MAUI ELECTRIC COMPANY, LIMITED P. O. Box 398 Kahului, Hawaii 96733-6898	1 copy by U.S. mail
DEAN K. MATSUURA DIRECTOR - REGULATORY AFFAIRS HAWAIIAN ELECTRIC COMPANY, INC. P. O. Box 2750 Honolulu, Hawaii 96840-0001	1 copy by hand delivery
PETER Y. KIKUTA, ESQ. GOODSILL, ANDERSON, QUINN & STIFEL 1800 Alii Place 1099 Alakea Street Honolulu, Hawaii 96813	1 copy by hand delivery

DATED: Honolulu, Hawaii, October 25, 2007.

Desiree Loesch

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CA-T-1
DOCKET NO. 2006-0387

DIRECT TESTIMONY AND EXHIBITS

OF

STEVEN C. CARVER

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: Overall Revenue Requirement, Test Year Concept, MECO Updates and Revisions, Pension Asset, Labor & Benefit Costs, Research & Development, Expiring Software Amortization, T&D Outside Services, Ho'omaika'i Costs, Cash Working Capital

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CA-101	Consumer Advocate Joint Accounting Schedules – Consolidated
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CA-104	Consumer Advocate Joint Accounting Schedules – Molokai Division
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DIRECT TESTIMONY OF STEVEN C. CARVER

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven C. Carver. My business address is 740 NW Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am a principal in the firm Utilitech, Inc., which specializes in providing consulting services for clients who actively participate in the process surrounding the regulation of public utility companies. Our work includes the review of utility rate applications, as well as the performance of special investigations and analyses related to utility operations, cost allocation and ratemaking issues.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. Maui Electric Company, Limited (hereinafter "MECO" or "Company") filed an application seeking the Public Utilities Commission of the State of Hawaii's ("Commission" or "HPUC") approval for an overall increase in the tariff rates and charges under which it provides regulated electric service on the island of Oahu. The HPUC opened Docket No. 2006-0387 to review and address this application.

Utilitech was retained by the Department of Commerce and Consumer Affairs, Division of Consumer Advocacy (hereinafter "Consumer Advocate" or "CA") to review and respond to that rate case filing and to prepare direct

1 testimony for filing with this Commission regarding the issues identified during
2 the course of our review. Consequently, I am appearing on behalf of the
3 Consumer Advocate.
4
5 Q. PLEASE SUMMARIZE THE PURPOSE OF YOUR TESTIMONY.
6 A. Generally, my responsibilities in this docket encompass sponsorship of the
7 Consumer Advocate's overall revenue requirement recommendation along
8 with the review and evaluation of various elements of rate base and operating
9 income included within revenue requirement. The specific functional expense
10 categories I address include: transmission & distribution, administrative and
11 general, and depreciation expense. I will discuss various adjustments to rate
12 base and operating income (CA Adjustments B-1, B-2, B-5, C-1 and C-13
13 through C-20) and jointly sponsor the Consumer Advocate's proposed capital
14 structure (Schedule D) with Mr. David Parcell (CA-T-4). The additional
15 ratemaking adjustments proposed by the Consumer Advocate, which I do not
16 sponsor, are separately addressed in the direct testimony of Mr. Michael
17 Brosch (CA-T-3). The revenue requirement effect of the various Consumer
18 Advocate adjustments and recommendations are reflected within the
19 Consumer Advocate's Joint Accounting Schedules identified as Exhibit
20 CA-101 through Exhibit CA-104, which are provided separately.
21

Q. HOW ARE THE CONSUMER ADVOCATE'S JOINT ACCOUNTING SCHEDULES ORGANIZED?

A. Because MECO maintains separate rates and tariffs for each island (i.e., Maui, Lanai and Molokai) on which it provides regulated electric service, overall revenue requirement has been presented separately for each island segment, as well as for the Company's consolidated operations. Exhibit CA-101 through Exhibit CA-104 represent the Consumer Advocate's Joint Accounting Schedules for MECO's Consolidated operations, the Maui Division, the Lanai Division and the Molokai Division, respectively.

Within each of these exhibits, the Consumer Advocate's joint accounting schedules are organized into sections, using the following framework:

Schedule A	Change in Gross Revenue Requirement
Schedule B	Rate Base Summary & Adjustments
Schedule C	Operating Income Summary & Adjustments
Schedule D	Capital Structure & Cost Rates (CA T-4)
Schedule E	Reconciliation of CA and MECO Filings

As indicated previously, the joint accounting schedules are sponsored by several Consumer Advocate witnesses. The witness sponsoring each schedule and adjustment is listed on the schedule index located at the front of the joint accounting schedules and identified in the upper left-hand corner of each schedule and adjustment. Each recommended adjustment to rate base

1 and operating income is supported by individual adjustment schedules, also
2 contained within Exhibit CA-101 through Exhibit CA-104.
3
4 Q. HOW WILL YOU IDENTIFY AND REFER TO THE INDIVIDUAL
5 ACCOUNTING ADJUSTMENTS?
6 A. The adjustments to both rate base and operating income have been
7 numbered sequentially, but separately, beginning with the number "one." In
8 order to distinguish the first rate base adjustment from the first operating
9 income adjustment, the adjustment number is preceded by a reference to the
10 "schedule" on which the adjustment was posted. For example, the posting
11 schedule for the rate base adjustments is Schedule B. So, the first rate base
12 adjustment would then be referenced as Schedule (or Adjustment) B-1.
13 Similarly, the first operating income adjustment would be identified as
14 Schedule (or Adjustment) C-1, since Schedule C is the posting schedule for
15 the income statement adjustments. For purposes of testimony presentation in
16 this proceeding, Mr. Brosch and I may use the words "schedule" and
17 "adjustment" interchangeably when referring to the individual adjustments
18 proposed by the Consumer Advocate.
19
20 Q. DO THE JOINT ACCOUNTING SCHEDULES PROVIDE CALCULATION
21 DETAIL SUPPORTING EACH CONSUMER ADVOCATE ADJUSTMENT?
22 A. Generally, yes. The joint accounting schedules contain individual adjustment
23 "schedules" that provide support for the quantification of each test year

adjustment, including footnote references to additional workpapers or other supporting documentation. Since virtually all information relied upon by the Consumer Advocate in developing these adjustments was supplied by the Company in response to written discovery, the adjustment schedules will often refer to relevant data sources already in MECO's possession, representing the primary support for the adjustments affecting overall revenue requirement.

Q. PLEASE DESCRIBE HOW THE REMAINDER OF YOUR TESTIMONY IS ORGANIZED.

A. The remainder of my testimony is arranged by topical section, following the table index presented previously. This index identifies the specific areas I address in testimony and references the testimony pages, as well as any related adjustment or schedule number located in the joint accounting schedules.

I. EDUCATION AND EXPERIENCE.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I graduated from State Fair Community College, where I received an Associate of Arts Degree with an emphasis in Accounting. I also graduated from Central Missouri State University with a Bachelor of Science Degree in Business Administration, majoring in Accounting.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE IN THE FIELD OF UTILITY REGULATION.

A. My entire professional career has been associated with the regulation of public utilities. From 1977 to 1987, I was employed by the Missouri Public Service Commission ("MoPSC") in various professional auditing positions, including a promotion by the Missouri Commissioners to the position of Chief Accountant in April 1983. Since my employment with Utilitech in June 1987, I have been associated with various regulatory projects on behalf of clients in multiple State jurisdictions (Arizona, California, Florida, Hawaii, Kansas, Illinois, Iowa, Indiana, Mississippi, Missouri, Nevada, New Mexico, New York, Oklahoma, Pennsylvania, Texas, Utah, Washington, West Virginia and Wyoming) and have conducted revenue requirement and special studies involving various regulated industries (i.e., electric, gas, telephone and water). Additional information regarding my professional experience and qualifications are summarized in Exhibit CA-100, which was prepared for this purpose.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION IN PROCEEDINGS THAT INVOLVED MECO OR ITS AFFILIATES?

A. Yes. Mr. Michael Brosch, also of Utilitech, and I prepared and presented revenue requirement recommendations in HECO's 1994 rate case (Docket No. 7700), 2005 rate case (Docket No. 04-0113) and 2007 rate case (Docket No. 2006-0386) on behalf of the Consumer Advocate. I have also prepared testimony in three proceedings involving Hawaii Electric Light Company, a

HECO subsidiary (Docket Nos. 98-0013, 99-0207 and 05-0315), representing the Consumer Advocate.

In addition, I have prepared testimony in several other Hawaii regulatory proceedings, including: Kauai Electric, then a Division of Citizens Communications Company (Docket No. 94-0097); GTE Hawaiian Telephone Company, Inc. (fna Verizon Hawaii, nka Hawaiian Telcom) (Docket No. 94-0298); The Gas Company (Docket No. 00-0309); as well as a self-insured property damage reserve generic proceeding (Docket No. 95-0051), in which HECO and its subsidiaries participated.

Finally, I have assisted the Consumer Advocate in its analysis of the acquisition of The Gas Company by Citizens Communications Company from Broken Hill Proprietary Company, Ltd. (Docket No. 97-0035) and the subsequent acquisition of The Gas Company, a Division of Citizens Communications Company by K-1 USA Ventures, Inc. (Docket No. 03-0051), as well as the analysis of the sale of Verizon Hawaii to entities controlled by the Carlyle Group (Docket No. 04-0140).

II. EXECUTIVE SUMMARY & OVERALL REVENUE REQUIREMENT.

Q. WHAT IS THE CONSUMER ADVOCATE'S PROPOSED REVENUE REQUIREMENT FOR THE 2007 TEST YEAR?

A. Based on a 2007 forecast test year, the Company quantified an overall, consolidated revenue deficiency of $18.977 million.[1] As a result of MECO's June 2007 Update, the overall revenue deficiency has been revised to about $18.326 million.[2] In comparison, the Consumer Advocate has assembled a revenue requirement recommendation for the Company's electric operations, based on an internally consistent test year approach, supporting an overall revenue deficiency of approximately $8.9 million. The following table summarizes the Consumer Advocate's proposed rate change and exhibit reference for each segment within the Joint Accounting Schedules:

	Proposed Rate Change	Exhibit Ref. (Sch. A)
Consolidated	$ 8,877,000	CA-101
Maui Division	$ 8,311,000	CA-102
Lanai Division	$ 251,000	CA-103
Molokai Division	$ 315,000	CA-104

[1] See the direct testimony of Company witness Edward L. Reinhardt (MECO T-20, p. 1), and MECO-2001, p. 1.

[2] See MECO's response to CA-IR-304, Attachment A.

Q. COULD YOU SUMMARIZE THE MAJOR ISSUES CONTRIBUTING TO THE DIFFERENCE IN THE REVENUE REQUIREMENT RECOMMENDATIONS OF THE CONSUMER ADVOCATE AND MECO?

A. Yes. The six (6) largest revenue requirement issues, set forth in the in the following table, represent about $7.67 million of the difference between the recommendations of MECO and the Consumer Advocate on a Consolidated basis:

Revenue Requirement Issue	Consolidated Exhibit CA-101	Estimated Value (millions)
Recommended Cost of Capital	D	$ 4.75
Pension Asset Rate Base & Amort.	B-2, C-16	.56
Fuel Inventory	B-3	.54
Fuel, Purchased Power & ECAC	C-3	.55
Payroll-Average Employees	C-13, C-14, C-15	.64
T&D Outside Services	C-19	.63

The Consumer Advocate's weighted cost of capital, specifically the return on equity, recommendation represents the single largest issue, which is addressed by Mr. Parcell (CA-T-4).

Q. PLEASE DESCRIBE THE CONSUMER ADVOCATE'S APPROACH TO QUANTIFYING REVENUE REQUIREMENT IN THIS PROCEEDING.

A. The Consumer Advocate's Joint Accounting Schedules use MECO's "prefiled" amounts for rate base, operating revenues and expenses as a starting point. The Company's proposed amounts were then adjusted to reflect the impact of the MECO's June 2007 Update and various other adjustments sponsored by Consumer Advocate witnesses.

Q. WHY DO THE CONSUMER ADVOCATE'S JOINT ACCOUNTING SCHEDULES USE MECO'S "PREFILED" AMOUNTS AS THE STARTING POINT FOR PURPOSES OF QUANTIFYING REVENUE REQUIREMENT?

A. By starting with the Company's prefiled amounts, each ratemaking adjustment proposed by Consumer Advocate witnesses represents a reconciling difference, positive or negative, between the overall revenue requirement recommendations of the Consumer Advocate and MECO. In fact, CA Schedule E represents a reconciliation of the individual revenue requirement differences between the Company and the Consumer Advocate. While the same overall revenue requirement could have been quantified using other methodologies, the approach used by the Consumer Advocate serves to streamline the presentation of issues by focusing attention on the specific areas at issue.

Q. WOULD YOU PLEASE SUMMARIZE YOUR RESPONSIBILITIES IN THIS PROCEEDING?

A. The ratemaking adjustment areas I address include: the pension asset and the pension tracking mechanism, cash working capital, payroll expense (average employees), employee benefit costs, research and development, expiring software amortization, T&D outside services, Ho'omaika'i costs, and cash working capital. The specific adjustments are more fully listed in the index to my testimony.

1 Q. DO YOU HAVE ANY OTHER GENERAL COMMENTS REGARDING THE
2 CONSUMER ADVOCATE'S PARTICIPATION IN THIS DOCKET?
3 A. Yes. *In direct testimony, each Consumer Advocate witness will specifically*
4 *discuss any recommended adjustments, changes or modifications to MECO's*
5 quantification of overall revenue requirement. However, it should be noted
6 that the Consumer Advocate typically submits discovery questions on a variety
7 of topics and areas of interest that may not result in rate base or operating
8 income adjustments sponsored by a Consumer Advocate witness. For
9 example, a number of information requests were submitted regarding MECO's
10 forecast of 2007 plant additions, as well as related customer advances and
11 contributions in aid of construction. Due to changes identified in various
12 responses to the Consumer Advocate's discovery and subsequent forecast
13 revisions presented by MECO in a series of June 2007 Update submissions,
14 the Consumer Advocate may have concluded that no separate adjustment
15 was necessary in these and other areas.
16
17 ***III.*** ***<u>TEST YEAR CONCEPT</u>.***
18 Q. PLEASE BRIEFLY DESCRIBE THE "TEST YEAR" CONCEPT, AS USED
19 FOR UTILITY RATEMAKING PURPOSES.
20 A. In general terms, a "test year" is a twelve month period of time adopted by
21 regulatory agencies and used for ratemaking purposes to determine pro forma
22 rate base, operating revenues, operating expenses and operating income. As
23 a result of Sections 6-61-87(4) and 6-61-88(3) of the Commission's

1 Administrative Rules, this Commission requires the use of an average
2 forecasted test year, rather than a historical test year, for ratemaking
3 purposes. However, even when a forecast test year is employed, it may be
4 necessary to identify and recognize various ratemaking adjustments
5 (e.g., annualization, normalization and disallowance adjustments) to the
6 forecast values set forth by the utility in order to set rates that are based on
7 reasonable, ongoing investment and cost levels. In determining overall
8 revenue requirement, it is also critically important that all elements of the
9 ratemaking equation be balanced, internally consistent and comparable.

10 The ratemaking equation commonly employed by this Commission, and
11 other regulatory agencies, compares a required return on rate base to the
12 return on investment generated by adjusted test year operating results
13 (i.e., operating revenues less operating expenses, depreciation and taxes). If
14 the return indicated by the adjusted operating results (i.e., adjusted test year
15 net operating income divided by rate base) is deficient, an increase in
16 revenues is required to provide the utility an opportunity to earn a "reasonable"
17 return on its investment. Conversely, an excessive return would support a
18 reduction in utility revenues and rates.

1 The following formulae depict the ratemaking equation and the
2 quantification of the required change in utility rates:

3 **Revenue Requirement = (RB x ROR) + E**

4 Where,

5 RB = Rate Base
6 ROR = Rate of Return
7 E = Expenses, including depreciation & income taxes
8 Then,

9 **Rate Change = Revenue Requirement – Revenues at Present Rates**

10 CA Schedule A, included within the joint accounting schedules (Exhibit
11 CA-101 through Exhibit CA-104), combines both of these formulae so as to
12 quantify the "rate change" – identified as the gross "Revenue Deficiency
13 (Excess)." CA Schedule A also provides a reference to the source of each of
14 the elements of the ratemaking equation: rate base, rate of return and
15 expenses.

16

17 Q. WHAT TEST YEAR HAS MECO EMPLOYED TO DETERMINE REVENUE
18 REQUIREMENT IN THIS PROCEEDING?

19 A. MECO used a calendar 2007 forecast test year in assembling its rate filing,
20 which has also been employed by the Consumer Advocate. In general terms,
21 MECO's proposed test year is based upon average rate base, customer and
22 sales levels and, for the most part, average expenses. However, MECO
23 departed from this average approach in quantifying certain labor cost
24 elements, which the Consumer Advocate recommends be adjusted to reflect

average headcounts. The Company should not be allowed to selectively depart from the average test year approach to capture the annualized effect of increasing cost elements, while inconsistently leaving other ratemaking elements at average levels.

Q. SHOULD EACH ELEMENT OF THE RATEMAKING EQUATION BE DEVELOPED IN AN IDENTICAL MANNER OR BE EXPECTED TO REFLECT THE PRECISE AMOUNTS LIKELY TO BE REALIZED BY THE UTILITY DURING FUTURE YEARS WHEN THE NEW RATES WILL BE IN EFFECT?

A. No. In the ratemaking process, it is neither possible nor desirable to employ a stringent or mechanical method or approach to quantify each element of the ratemaking equation. Because the overall revenue requirement is comprised of various dissimilar yet necessary elements, the technique employed to determine rate base and the ongoing level of revenues and expenses must be unique to the facts and circumstances underlying each element. The test year approach should be balanced and consistently applied to the various ratemaking elements, such that the resulting revenue requirement contains minimal quantification distortions.

For the ratemaking equation to function properly, the components comprising the equation (i.e., rate base, revenues, expenses and rate of return) must be reasonably representative of ongoing levels, internally consistent and comparable – within the context of test period parameters. To the extent that these components are not properly synchronized, a utility may

1 not have the opportunity to earn its authorized return or, alternatively, may
2 have the opportunity to earn in excess of the return authorized. By
3 synchronizing or maintaining the comparability of revenues, expenses and
4 investment, the integrity of the test year can be maintained with the
5 reasonable expectation that the resulting rates will not significantly misstate
6 the ongoing cost of providing utility service.

7 Because the ratemaking process is a periodic exercise, not a
8 continuous process, the objective of setting rates is not to determine precise
9 amounts that will be realized in future periods. The regulatory reliance on a
10 defined test year for ratemaking purposes is to determine overall revenue
11 requirement based upon the relationship between the elements of the
12 ratemaking equation during a common period, rather than attempt to
13 determine absolute values of those elements in future periods.

14 All components of the ratemaking equation change over time. It is only
15 by consistently analyzing the relationship of the major cost of service
16 components that a determination can be made as to whether the overall
17 revenue requirement has changed materially. The key issue is whether
18 revenues grow faster or slower than the overall costs (i.e., operating expense
19 and return on and of investment) necessary to support those revenues. As
20 long as the relationships between the ratemaking formula elements remain in
21 relative balance during the effective period, the utility should have a
22 reasonable opportunity to earn the authorized return.
23

Q. WHAT TYPES OF ADJUSTMENTS MIGHT BE REQUIRED RELATIVE TO A FORECAST TEST YEAR?

A. Utility forecasts typically focus on quantifying amounts (i.e., revenues, expenses, plant additions and retirements, etc.) that might reasonably be achievable in the forecast year. However, unusual, one-time, non-recurring or extraordinary amounts might be expected to occur and be included in the forecast used for ratemaking purposes. If so, it is essential that the ratemaking process identify and adjust such amounts so that the quantification of the overall revenue requirement recognizes only normal, ongoing amounts. If such normalization adjustments are not made, utility rates may be set at abnormal levels resulting in the over or under-recovery of costs to the disadvantage of either ratepayers or shareholders.

Just as a test year might employ a historic or forecast period, the test year can also be based upon either a <u>year-end</u> or any <u>average</u> approach. Under the average approach adopted by this Commission, the ratemaking elements of rate base and operating income should consistently reflect average prices and average volumes for the test year. Similarly, if a year-end test year approach were employed, the material elements of the ratemaking equation should reflect year-end prices and volumes. While neither test year approach is technically superior, it is critically important that the valuation of the ratemaking elements (e.g., rate base, customers and sales/revenue levels, employee headcounts and wage rates, depreciation expenses, etc.) consistently comply with the selected test year. Consequently, ratemaking

adjustments may be necessary to avoid distortions that might result if an inconsistent test year approach were employed (i.e., use of average customer sales and rate base but year-end, employee headcounts, wage levels and benefit costs).

Q. IF COSTS ARE EXPECTED TO INCREASE NEAR THE END OF THE FORECAST TEST YEAR, WOULD IT BE NECESSARY TO RECOGNIZE THE FULL ANNUAL LEVEL OF SUCH COSTS IN SETTING RATES FOR THE UTILITY TO BE ABLE TO RECOVER THOSE COSTS?

A. No. This is a common misconception about the ratemaking process. As I previously indicated, all elements of the ratemaking equation change over time. Revenues may increase after the mid-point of the average test year in an amount that may be sufficient to materially offset the increasing costs. Similarly, other offsetting cost reductions may also be expected to occur late in the test year. Proposals to annualize isolated cost increases expected to occur late in the test year should be denied, particularly when such increases are not reasonably balanced or matched with offsetting factors occurring within the average test year.

Otherwise, a distorted view of the cost of service can lead to improper rate adjustments. A consistent matching of both price and quantity changes is necessary to achieve this balance, particularly in an average, forecast test year where volume changes may offset price level increases.

1 Q. COULD YOU EXPLAIN THE CONCEPTUAL DIFFERENCE BETWEEN
2 "NORMALIZING" AND "ANNUALIZING" A REVENUE OR EXPENSE
3 ELEMENT FOR RATEMAKING PURPOSES?
4 A. Yes. The concept of normalization concerns the removal of an abnormality
5 from the test year. For example, the test year could include an abnormally
6 high or low amount for a certain component of operating revenues or
7 expenses (e.g., late payment fees, uncollectible expense, power plant
8 maintenance, research and development, etc.). If so, it would be appropriate
9 to adjust such amounts so that the test year activity is "normalized" to reflect a
10 "normal" ongoing revenue or cost level for this particular element of the
11 revenue requirement. Absent such an adjustment, the test year inclusion of
12 the abnormally high or low amount creates an over or under-recovery of such
13 revenue or cost in future periods when more normal levels are expected to be
14 incurred.
15 In contrast, the annualization concept focuses on translating known or
16 identifiable changes in either prices or quantities (i.e., transaction data)
17 occurring at defined points in time into a full year equivalent (i.e., "annualized")
18 amount. If the Company expected to hire new employees or planned to grant
19 an across-the-board wage increase late in the test year, an annualization
20 adjustment could be employed to increase labor expense as if the new
21 employees or wage increases had been in effect throughout the full twelve
22 months of the test year. Similarly, an annualization adjustment could be used
23 to capture the full annual effect of growth in the number of customers through

1 year-end beyond the "average" level included in the Company's filing.
2 Annualization adjustments, which can either increase or decrease the test
3 year revenue requirement, are typically employed to transform the test year
4 results from an average approach to a year-end approach.
5
6 Q. WHAT HAS BEEN THE CONSUMER ADVOCATE'S APPROACH IN THIS
7 DOCKET REGARDING THE "AVERAGE" VERSUS "YEAR-END" TEST
8 YEAR CONCEPT?
9 A. The Consumer Advocate's filing consistently employs the average approach
10 for material, identifiable elements of cost of service. Although the Company's
11 test year forecast may have the effect of annualizing certain items to year-end
12 levels, Mr. Brosch and I have attempted to maintain the average test year
13 concept throughout our adjustments. In doing so, we seek to avoid or
14 minimize revenue requirement distortions that can occur if only certain
15 elements of the revenue requirement formula are "annualized." Sales and
16 revenues, rate base, staffing levels and operating expenses are all quantified
17 throughout the 2007 test year on an average basis, so as to properly match
18 the elements of the ratemaking equation.
19
20 **IV. MECO JUNE 2007 TEST YEAR UPDATES.**
21 Q. PLEASE DESCRIBE CA ADJUSTMENTS B-1 AND C-1.
22 A. During the course of this proceeding, MECO identified various changes to its
23 original filing due to revised forecast assumptions or corrections identified in

response to Consumer Advocate discovery. These forecast changes or revisions are presented in a series of "June 2007 Update" submissions sponsored by individual MECO witnesses. In response to CA-IR-304, the Company revised its calculation of overall revenue requirement (i.e., Consolidated, Maui Division, Lanai Division and Molokai Division) to incorporate the June 2007 Update revisions.

Since MECO's original revenue requirement submission represents the starting point for Exhibits CA-101 through CA-104, CA Adjustments B-1 and C-1 simply post the rate base and operating income effect of the updates and revisions that MECO intends to make to its original filing. Assuming we have accurately compiled this information, it is our expectation that the Company will agree with the changes reflected by both adjustments unless further revisions are deemed necessary. Such an approach allows the Consumer Advocate to incorporate the latest known Company positions in our presentation of test year revenue requirement.

Q. WHAT IS THE IMPACT OF THESE "JUNE 2007 UPDATES" ON MECO'S OVERALL REVENUE REQUIREMENT?

A. The overall impact of MECO'S proposed June 2007 Update reduces rate base by about $490,000 and increases operating income by about $318,000. The combined effect of these changes is a $.6 million decrease to revenue

requirement, on a consolidated basis using the Consumer Advocate's proposed overall rate of return.[3]

V. PREPAID PENSION ASSET.

Q. WHAT IS THE PURPOSE OF CA ADJUSTMENTS B-2 AND C-16?

A. CA Adjustment B-2 eliminates from rate base MECO's proposed pension asset, net of the related accumulated deferred income tax ("ADIT") reserve.[4] CA Adjustment C-16 reverses or eliminates MECO's proposed amortization of the estimated pension asset balance, at December 2007, over a five year period. This amortization was part of the Company's June 2007 Update (MECO T-9) which sought to implement a pension tracking mechanism.[5]

Q. WHAT PENSION ASSET AMOUNT IS MECO PROPOSING TO INCLUDE IN RATE BASE?

A. In direct testimony, Company witness Ohashi (MECO T-15, p. 12) summarized the Company's rate base recommendation, which includes an estimated

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3 The sum of lines 5 and 16 on Schedule E of Exhibit CA-101.

4 The pension asset (MECO-928 as revised by MECO T-9 June 2007 Update, Attachment 5, and Exhibit CA-105) is gross of the related ADIT reserve. For consistency, if the pension asset is excluded from rate base, the companion ADIT reserve should also be removed.

5 The proposed pension tracking mechanism is similar to a mechanism agreed to by the Consumer Advocate and Hawaii Electric Light Company in Docket No. 05-0315. In Docket No. 2006-0386, the Consumer Advocate and HECO also agreed to implement a pension tracking mechanism which, unlike the HELCO mechanism, did not provide for any amortization of the estimated pension asset balance at test year end.

average net pension asset balance of about $3.3 million. MECO subsequently revised its test year forecast of the average pension asset, resulting in the average rate base amounts summarized below:[6]

	Average Rate Base	Reference
Maui Division	$ 2,989,000	MECO T-15 June Update, p. 6.
Lanai Division	84,000	MECO T-15 June Update, p. 12.
Molokai Division	143,000	MECO T-15 June Update, p. 18.
Consolidated	$ 3,216,000	MECO T-15 June Update, p. 5.

The above amounts do not include the average test year ADIT reserves of approximately $1.251 million. These reserves represent deferred income taxes attributable to the differing amounts that are recorded as pension costs on the Company's financial statements and deductible for income tax purposes. The net increase to the test year rate base associated with the pension asset is approximately 1.965 million.[7]

For the reasons discussed in Sections V.B. and V.C. below, the Consumer Advocate recommends that the Commission not include: (a) the pension asset and related ADIT reserve in the test year rate base; and (b) the amortization of such asset in the test year expense.

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6 Also, see MECO's June 2007 Update, Attachment 5 (MECO-928).

7 See CA Adjustment B-2 (Exhibits CA-101 through CA-104) for the calculation of and related sources for the components these amounts.

Q. HAVE YOU ADDRESSED THIS ISSUE IN PAST RATE PROCEEDINGS?

A. Yes. I have sponsored testimony in various jurisdictions opposing the inclusion of a pension asset in rate base, including:

Jurisdiction	Case / Docket	
Arizona Corporation Commission	E-1051-93-183	(a)
	T-1051B-99-105	(a)
	T-1051B-03-0454	(c)
Hawaii Public Utilities Commission	04-0113	(g)
	05-0315	(h)
	2006-0386	(g)
Missouri Public Service Commission	2007-0002	(i)
Public Utilities Commission of Hawaii	94-0298	(e)
Oklahoma Corporation Commission	PUD 001151	(d)
Utah Public Service Commission	97-049-08	(a)
Washington Utilities & Transportation Commission	UT-930074	(b)
	UT-040788	(f)

Note (a): Qwest Corp. rate case.
Note (b): Qwest Corp. AFOR – sharing.
Note (c): Qwest price cap review.
Note (d): Oklahoma Natural Gas.
Note (e): GTE Hawaiian Tel.
Note (f): Verizon Northwest rate case.
Note (g): Hawaiian Electric Company.
Note (h): Hawaii Electric Light Company.
Note (i): Union Electric Company.

Q. IN THE PROCEEDINGS IDENTIFIED IN THIS TABLE, DID YOU RECOMMEND THE COMPLETE ELIMINATION OF THE PENSION ASSET FROM RATE BASE?

A. Yes, except for three relatively recent rate case proceedings (i.e., Qwest Corporation, ACC Docket No. T-1051B-03-0454; Union Electric,[8] MoPSC

[8] Union Electric Company did not propose rate base inclusion of the pension asset, as recorded on its financial statements, for ratemaking purposes.

1 Case No. ER-2007-0002; and HELCO, HPUC Docket No. 05-0315[9]), my
2 pension asset analyses resulted in recommendations to exclude the pension
3 asset from rate base for rate setting purposes.
4
5 Q. WHY DID YOUR RECOMMENDATION DIFFER FOR THREE OF THE
6 PROCEEDINGS IN WHICH YOU ADDRESSED THIS ISSUE?
7 A. The proper ratemaking treatment of the pension asset issue must consider the
8 unique facts and circumstance relevant to each utility. The unique facts
9 pertaining to HELCO supported rate base inclusion of the pension asset and
10 proposed implementation of a pension tracker mechanism, whereas the facts
11 pertaining to HECO[10] and MECO do **not** support rate base inclusion of the
12 pension asset. In Docket No. 2006-0386 (HECO's most recent rate
13 proceeding), I recommended the implementation of a pension tracking
14 mechanism without any catch-up amortization.[11] The position proposed by the

---

9 In the 2005 HELCO rate case, my analyses supported the inclusion of a pension asset in rate base, which accompanied a Consumer Advocate proposal to implement a pension tracking mechanism. The Consumer Advocate and HELCO entered into a stipulation and agreement that, among other provisions, reflected the parties' concurrence in a pension tracking mechanism substantially similar to the mechanism proposed by the Consumer Advocate (CA-T-3 at 13-48; CA-302 through CA-306).

10 In Docket No. 04-0113, I recommended exclusion of the pension asset in rate base, but did not propose a pension tracking mechanism at that time. As a result, no pension tracking mechanism was considered for implementation in Docket No. 04-0113.

11 Although the parties reached a negotiated settlement agreement in the HECO rate case (Docket No. 2006-0386), the parties agreed to submit proposed orders and findings of fact on the pension asset issue, without the need for hearings. HECO has requested an extension of time for the parties to file their initial proposed orders and findings of fact with the Commission from October 5, 2007 to October 26, 2007. That request is still pending before the Commission.

1 Consumer Advocate in this docket is similar to the recommendation set forth in
2 Docket No. 2006-0386.
3 In light of the complexity of this issue, I want to avoid any
4 misinterpretation of the position taken on this issue in each of the pending
5 HECO and MECO rate cases with the recommendation set forth in the recent
6 HELCO rate case. The recommendation in Docket No. 05-0315 (the pending
7 HELCO rate case) should **not** be viewed as a global shift in the Consumer
8 Advocate's or my position on the propriety of including the pension asset in
9 rate base for the pending HECO rate cases (i.e., Docket Nos. 04-0113 and
10 05-0386) and the instant docket. The facts pertaining to each of the three
11 utilities resulted in one recommendation (HELCO) for including the pension
12 asset in rate base and three recommendations (HECO and MECO) excluding
13 the pension asset from rate base.
14
15 Q. HAVE YOU USED THE SAME METHODOLOGY IN THE CURRENT MECO
16 RATE CASE, AS COMPARED TO THE HECO AND HELCO RATE CASES,
17 IN ORDER TO ASSESS WHETHER IT IS REASONABLE TO INCLUDE OR
18 EXCLUDE THE PENSION ASSET FROM MECO'S RATE BASE?
19 A. Yes, however the unique differences between the accounting and ratemaking
20 history of HELCO, HECO and MECO, at the time the pension issue arose,
21 resulted in the different recommendations.
22

Q. WOULD IT BE ACCURATE TO STATE THAT YOU DO NOT BELIEVE A PENSION ASSET SHOULD AUTOMATICALLY BE INCLUDED IN RATE BASE EVEN THOUGH A PENSION TRACKING MECHANISM IS IMPLEMENTED?

A. Yes, that is a fair statement. Absent a demonstration that the cumulative pension credits have been materially provided to ratepayers, or that ratepayers have substantially realized the benefits of the reduced pension costs associated with the pension asset in the rates paid for utility service, my analyses have consistently questioned whether the alleged benefits were instead enjoyed by investors, not ratepayers. In the absence of a utility demonstrating ratepayer benefit, I believe that it would be inappropriate to include a pension asset in rate base.

Q. HAS THIS COMMISSION PREVIOUSLY ADDRESSED THE RATE BASE INCLUSION OF A PENSION ASSET?

A. Yes, on two occasions. In Interim Decision and Order filed in HECO's 2005 rate case, the Commission stated:

> For the purposes of this Interim Decision and Order, we find that HECO is probably entitled to include the $78,791,000 in prepaid pension asset in rate base, with a corresponding adjustment of $28,483,000 for the ADIT reserve. At this juncture, a cursory review of the record appears to indicate that the amounts contributed to the pension plan were not imprudent.[12]

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[12] Interim Decision & Order No. 22050 , Docket No. 04-0113, p. 9, dated September 27, 2005.

The Commission went on to state that:

> . . . the findings and adoption here of the various amounts reflected in Exhibits A and B is for the purposes of this Interim Decision and Order, only. It does not, in any way, commit the commission to accept any of these amounts in its final decision. The commission's final decision will reflect a detailed review and analysis of all estimates and proposals of the Parties. HECO will be required to refund to its customers any excess collected under this interim decision, together with such interest as provided for by HRS § 269-16(d), if the final increase approved by the commission is less than the total interim increase granted by this Interim Decision and Order.[13]

In Proposed Decision and Order No. 23748 filed in this same HECO rate case, the Commission proposes to reverse its interim decision, stating in part:

> The specific facts in this record do not adequately demonstrate that HECO's shareholders, *in fact, provided the funds* represented in the prepaid pension asset, such that HECO's shareholders should now be entitled to earn a return on the asset. Rather, it appears that that [sic] the majority of the funds constituting the prepaid pension asset resulted from favorable market conditions during 1999 to 2002, and not from investor contributions. In particular, from 1999 through 2002, HECO recorded negative pension costs and made no contributions to the pension trust fund ... Thus, the favorable market conditions and the SFAS 87 pension accounting requirements resulted in a reduced NPPC, a growing asset, and presumably less expense and greater investor return for HECO's shareholders. Under these circumstances, the commission will not require HECO's ratepayers to pay for a return on such an asset by placing the asset in rate base. [14]

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13 Interim Decision and Order No. 22050 at 11.

14 Proposed Decision and Order No. 23748 at 14 to15 (Docket No. 04-0113), filed October 22, 2007.

Proposed Decision and Order No. 23748 (at 16) also directs HECO to provide the Commission with a refund plan within ten days from the date of the Commission's final Decision and Order in that proceeding.

Q. DO YOU AGREE WITH PROPOSED DECISION AND ORDER NO. 23748 THAT THE PENSION ASSET SHOULD BE EXCLUDED FROM RATE BASE?

A. Yes. The prudency of making contributions to the pension trust fund is **not** the appropriate factor upon which to determine whether the pension asset should be included in the test year rate base and revenue requirement. Rather, the regulator must focus on who benefited from the transactions that gave rise to the creation of the pension asset, as the Commission did in Proposed Decision and Order No. 23748.

Q. HOW DOES ONE MAKE SUCH A DETERMINATION?

A. Consistent with my positions in the recent HELCO and HECO rate cases, rate base inclusion of the recorded pension asset balance would only be appropriate if it can be reasonably demonstrated that reduced FAS87 pension costs, in a cumulative amount at least equal to the pension asset sought to be included in rate base, have been flowed through to the benefit of utility ratepayers.[15]

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[15] *See HELCO Docket No. 05-0315, Carver Direct Testimony (CA-T-3) at 26-27; HECO Docket* No. 04-0113, Carver Direct Testimony (CA-T-2) at 16-17; and HECO Docket No. 2006-0386, Carver Direct Testimony (CA-T-3) at 21-23.

Q. IS THE FACT SITUATION FOR MECO SIMILAR TO THAT OF HECO, AS SUMMARIZED BY THE COMMISSION IN PROPOSED DECISION AND ORDER NO. 23748?

A. Yes. Referring to Exhibit CA-105, the primary reason for MECO's pension asset is because of the significant pension credits recorded during calendar years 2000-2002 – much like HECO.

A. BACKGROUND REGARDING PENSION ACCOUNTING.

Q. PLEASE DESCRIBE THE EVENTS OR CIRCUMSTANCES GIVING RISE TO THE PENSION ASSET.

A. In December 1985, the Financial Accounting Standards Board ("FASB") issued FAS87. FAS87 provided guidance as to how companies would recognize pension costs for financial statement reporting purposes, effective for fiscal years beginning after December 15, 1986. FAS87 did not address how one determines the amounts to be contributed to the pension fund.[16] This determination is based on actuarial analyses that consider various factors including pension trust earnings, the life expectancy of the present and future retirees and the amounts that are needed in the pension fund to meet the present and future pension obligation to retirees.

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[16] The pension fund is **separate** from the utility's financial statements. The monies in the *pension fund are held by the pension trustee. The utility's contributions (i.e., monies* deposited) to the pension fund are invested by the pension trustee to ensure that the fund balances are sufficient to pay future pension obligations to the utility's employees.

1 Prior to the issuance of FAS87, the amount of pension costs recorded
2 by a company for financial statement purposes equaled the level of
3 contributions actually made to the pension fund. Subsequent to FAS87, the
4 FASB determined that pension costs reported for financial statements
5 purposes would not automatically equal the pension fund contribution,
6 breaking the historical linkage between financial reporting of net periodic
7 pension costs (expense and capital)[17] and pension contributions to the
8 pension fund.

9 If the pension fund contribution exceeded the pension costs recorded
10 for financial statement purposes,[18] FAS87 required the difference to be
11 recorded on the balance sheet in a pension asset account. If the contribution
12 to the pension fund was less than the recorded pension cost, the company
13 would record a pension obligation or liability. In sum, FAS87 required
14 companies to record either a pension asset or pension liability for the
15 difference between accrual basis pension costs that are recorded for financial
16 statement purposes and the amount of any contributions to the pension fund.
17 As indicated previously, this accounting is commonly referred to as "net
18 periodic pension cost" ("NPPC") accounting.

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17 The full amount of NPPC determined by the Company's actuary is initially recorded in expense Account No. 926000, Employee Pensions and Benefits. The portion of NPPC that is capitalized to plant or billed to others is recorded in a contra-expense Account No. 926020, Employee Benefits Transfer. This latter account recognizes that a pro-rata portion of employee benefits are attributable to the labor costs that are charged to plant in service.

18 Pension costs recorded for financial statement purposes pursuant to FAS87 are also referred to as NPPC.

1 Q. HOW DID THE ISSUANCE OF FAS87 AFFECT THE PENSION COSTS
2 RECORDED ON THE COMPANY'S FINANCIAL STATEMENTS?
3 A. Subsequent to the adoption of FAS87, MECO's pension costs continued to
4 roughly equal the amounts contributed to the pension fund in each year until
5 about 1995.[19] Beginning in 1995, the contributions to the fund continued to be
6 less than the amount recorded for financial statement purposes under NPPC
7 accounting, thereby causing MECO to record a growing pension liability
8 through 1999. During this period, the pension liability recorded by MECO
9 grew to about $1.5 million by 1999.
10 In calendar year 2000, however, the pension costs recorded for
11 financial statement purposes pursuant to FAS87 became negative
12 (i.e., pension credits), rather than "positive" amounts, as were recorded in prior
13 years. From 2000 through 2002, the Company recorded about $6.041 million
14 in negative pension costs under FAS87, but made **no** contribution to the
15 pension fund.[20] The following chart illustrates the annual variation in the
16 actual NPPC accruals for financial statement purposes and pension fund
17 contributions.

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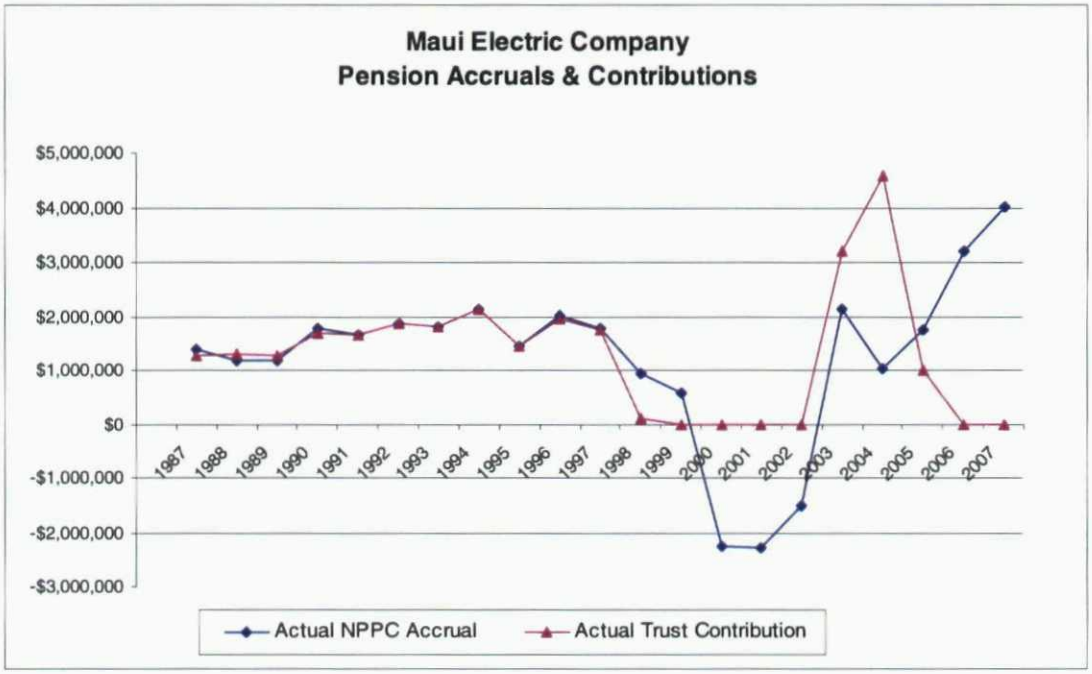
19 MECO's pension asset accounting is summarized on Exhibit CA-105.

20 The $6.041 million in negative NPPC represents approximately 188% of the average pension asset balance MECO seeks to include in the test year rate base.



Even though MECO made **no** contribution to the pension fund during the period 1999-2002, the "zero" contribution in three of those years still exceeded the significantly "negative" pension costs or NPPC,[21] which directly caused the reversal of the pension liability and the significant escalation in the prepaid pension asset account balance during this period. Thus, under FAS87 accounting, the pension liability of $(1,524,000) at December 1999 grew to a peak pension asset of $9,178,000 at December 2004, then proceeded to drop to an estimated $1,209,000 at December 2007, as illustrated by the following chart:

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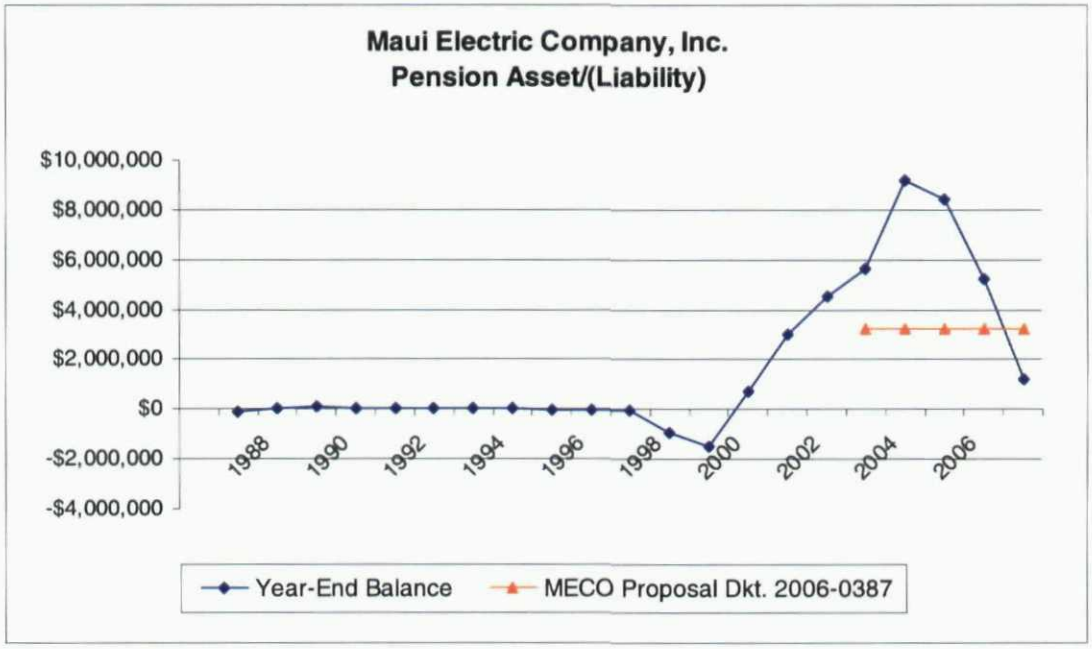
21 As set forth on Exhibit CA-105, the primary factor causing MECO's large pension asset balance was the recording of negative NPPC, or pension credits, during the period 2000-2002.



As shown on Exhibit CA-105, the cumulative contributions to the pension fund (i.e., a contribution of "zero" is still a contribution for pension accounting purposes) in excess of FAS87 determined pension costs resulted in the pension asset balance, which averaged $3.2 million in the 2007 forecast test year -- down from a peak of almost $9.2 million at December 2004. The dramatic decline in the pension asset balance since 2004 is due to the marked increase in NPPC in 2006 and 2007 coupled with "zero" pension contributions in each of those years.

Based on this information, it is clear that the pension asset that MECO seeks to include in the test year rate base was created by the achieved returns on pension fund assets[22] resulting in MECO recording negative pension costs,

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22 MECO-1003 provides FAS87 actuarial study assumptions, including the asset return rate, and actual achieved asset returns.

or credits, for financial accounting purposes and has nothing to do with whether MECO's pension fund contributions were prudent in amount or "who" (ratepayers or investors) provided the monies contributed to the pension fund in any year.

Considering the facts and circumstances unique to MECO, these years of negative NPPC represent accounting periods that fell **between** the Company's 1999 and 2007 rate case test years. Thus, MECO's ratepayers did not receive any of the benefits in the form of reduced rates resulting from the negative NPPC. Consequently, the Consumer Advocate contends that the facts and circumstances unique to MECO fail to support the rate base inclusion of the pension asset.

B. PROPOSED MECO APPROACH.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM THAT THE PREPAID PENSION ASSET SHOULD BE INCLUDED IN RATE BASE?

A. Beginning at page 101, MECO T-9 summarizes the Company's basis for seeking rate base inclusion as follows:

> Q. Why is it proper to include the prepaid pension asset in rate base?
> A. Including the pension asset in rate base is proper because: (1) the pension asset reflects a prudent investment, funded by investors, that is used or useful in providing electric utility service, (2) the pension asset benefits the ratepayers and (3) other jurisdictions have allowed a pension asset to be included in rate base.

Q. DO YOU AGREE WITH THESE POINTS RAISED BY MECO T-9 TO SUPPORT THE RATE BASE INCLUSION OF THE PREPAID PENSION ASSET FOR RATEMAKING PURPOSES?

A. No, for the reasons discussed below.

Q. DO YOU BELIEVE THAT THE PENSION ASSET REPRESENTS A PRUDENT INVESTMENT FUNDED BY INVESTORS?

A. No. As previously discussed, the pension asset simply represents the cumulative **difference** between FAS87 NPPC and the contributions to the pension fund. Unlike the Company's investment in other assets (e.g., fuel oil inventory, prepaid insurance, electric poles, generating plants, overhead lines, etc.), MECO did not expend any funds to construct, purchase or acquire the pension asset. While the contributions to the pension fund do represent a disbursement of cash (i.e., a check or wire transfer of funds to the pension trust), the cumulative "difference" between the pension fund contributions and NPPC accruals (i.e., the pension asset that MECO seeks to include in rate base) *does not represent a cash transaction, much less an investment* necessarily funded by investors.

Furthermore, the pension asset is **not** directly analogous to other types of assets included on the Company's balance sheet that are recognized for rate base purposes since the asset represents an accounting entry, as opposed to a physical asset that is used in the provision of the regulated service.

The following table represents a hypothetical example that is representative of the annual valuation fluctuations experienced by MECO and serves to illustrate the interaction between NPPC accruals and pension fund contributions giving rise to the creation of the cumulative pension asset balance:

Year	NPPC Accrual	Contribution	Difference	Pension Asset
	(a)	(b)	(c)	(d)
1	$ 0	$ 2,000,000	$ 2,000,000	$ 2,000,000
2	(2,000,000)	0	2,000,000	4,000,000
3	4,000,000	0	(4,000,000)	0
Totals	$2,000,000	$2,000,000	$ 0	

- Year 1: The $2 million pension fund contribution exceeds the $0 NPPC accrual, resulting in a $2 million pension asset. The contribution represents a cash disbursement.

- Year 2: Because the company recorded negative NPPC of $2 million and made no contribution ($0) to the pension fund, the pension asset increased by the difference, reaching $4 million by year end. The company neither received cash in the amount of the negative expense from the pension fund nor disbursed cash to the pension fund.

- Year 3: NPPC accrual is a positive $4 million. With no pension contribution, the pension asset balance is reduced to "zero" by the amount of the difference. No cash is disbursed.

Although $2 million was contributed to the pension fund in this hypothetical example, MECO's proposed rate base treatment would also attribute the negative NPPC as an "investment" by its investors and would include the following amounts in rate base, using an average rate base concept:

1 Year 1 -- $1.0 million (average of $0 & $2 million)

2 Year 2 -- $3 million (average of $2 million & $4 million)

3 Year 3 -- $2 million (average of $4 million & $0)

4

5 Q. DO YOU BELIEVE THAT THE NEGATIVE NPPC IN THE ABOVE EXAMPLE
6 SHOULD BE CONSIDERED AN "INVESTMENT" BY THE COMPANY'S
7 INVESTORS THAT MERITS RATE BASE INCLUSION?

8 A. No. Outside the context of a rate case, there is no required use of cash
9 funded by investors regardless of whether the NPPC accrual recorded by the
10 Company is: (a) positive, (b) negative or (c) zero in amount. Unless the
11 $2 million of negative NPPC in Year 2 was explicitly recognized in setting
12 utility rates or specifically flowed through to the benefit of customers, it is my
13 opinion that the positive financial benefits of recording the negative expense
14 accrual would be retained by the utility. In other words, the negative NPPC
15 would increase Year 2 earnings in relation to the earnings that would have
16 been reported in the absence of the negative NPPC accrual. As such, no rate
17 base treatment of the negative NPPC accrual would be warranted.

18

Q. AT PAGE 104, MECO T-9 STATES:

> Furthermore, ratepayers benefited directly in 2002 when MECO recorded a negative $1,496,000 NPPC accrual in the same year in which MECO also reduced its recovery of DSM shareholder incentives by $631,400 (net of revenue taxes) in order to not exceed its allowed rate of return as a result of the earnings cap that was implemented with the Commission's Order No. 19093, filed on November 30, 2001, in Docket Nos. 95-0173, 95-0174, 95-0175 and 95-0176.

DO YOU HAVE ANY COMMENTS REGARDING THIS STATEMENT?

A. Yes. First, it should be noted that the negative NPPC of $1,496,000 is **not** the amount that would have increased MECO's earnings in 2002. This amount represents 100% of the NPPC accrual – an amount that is gross of transfers to construction or billed to third parties.[23] In response to part (a) of CA-IR-163, MECO estimated the amount of NPPC net of such transfers to be $1,062,600, not $1,496,000.

Second, the $1,062,600 net of transfer amount does not represent the impact on 2002 achieved earnings because MECO would have recorded offsetting income tax expense in 2002, further reducing the earnings impact by the composite tax rate of about 38.91%.[24]

Finally, this statement on its face appears to directly link or attribute the reduction in DSM shareholder incentives recovered from ratepayers to the recording of negative NPPC in calendar year 2002. However, this linkage is

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[23] According to MECO's response to CA-IR-172, the percentage of employee benefits transferred to capital and billed to outside third parties in 2002 was 28.94%.

[24] About $649,144, all else remaining equal or $1,062,600 times "one" minus the composite tax rate (i.e., 100%-38.90975%).

severed by MECO's responses to CA-IR-163 and CA-IR-256. In response to part (f) of the response to CA-IR-163, the Company stated that **no** reductions have been implemented to any cost tracking mechanisms, including the 2002 DSM earnings cap adjustment, for the purpose of flowing negative pension costs back to ratepayers.

As indicated in the response to CA-IR-256, the Commission implemented a DSM earnings cap of 8.83% on average rate base (Order No. 19093), which limited the amount of DSM shareholder incentives recovered from ratepayers. In response to part (b) of CA-IR-256, MECO completely severs the implied linkage of negative NPPC to ratepayer benefits vis-à-vis the DSM earnings cap adjustment, as follows:

> If it is assumed that all other things are equal, one could perhaps take the position that the large negative NPPC accrual in 2002 reduced the recoverable amount of DSM shareholder incentives collected from ratepayers. If the 2002 NPPC accrual had been a smaller negative amount or a positive amount, then the recoverable amount of DSM shareholder incentives collected from ratepayers would have been larger, again, assuming that all other things are equal. However, because MECO's 2002 rate of return on average rate base calculation, prior to the DSM earnings cap adjustment, included all of the components of operating income and rate base, it is not meaningful to attempt to attribute all or a portion of the DSM earnings cap adjustment to a single component item of revenue, expense, or rate base.

Q. AT THE BOTTOM OF PAGE 104, MECO T-9 ALSO INDICATES THAT RATEPAYERS HAVE BENEFITED FROM NEGATIVE NPPC TRANSFERRED TO CONSTRUCTION, RESULTING IN LOWER AFUDC

1 AND LOWER RATE BASE. DO YOU CARE TO COMMENT ON THIS
2 POINT?
3 A. Yes. First, while that testimony is accurate that MECO transferred a portion of
4 the negative NPPC recorded in 2000-2002 to construction, it only conveys part
5 of the story. The Commission should recognize that the NPPC included in
6 revenue requirement in the three MECO rate cases since the adoption of
7 FAS87 for ratemaking purposes have been positive, not negative, amounts.[25]
8 Second, it is true that, during 2000-2002, MECO recorded negative
9 NPPC of which a portion (16%-29%) was capitalized or billed to third-parties.[26]
10 Any amounts capitalized would have reduced both AFUDC and plant
11 investment. However, this is not unique to negative NPPC. A portion of all
12 NPPC, whether positive or negative in amount or whether higher or lower than
13 the amount recognized in setting rates, would be capitalized in the normal
14 course of business. It bears mention that MECO is not proposing to limit the
15 pension asset balance it seeks to include in rate base to that portion of the
16 negative NPPC that was capitalized during 2000-2002.
17 Furthermore, the capitalized element of the negative NPPC is not
18 translated into an immediate ratepayer benefit, as the reduced plant in service
19 amount only impacts revenue requirements through the return on rate base

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25 Exhibit CA-106 identifies the amount of NPPC recognized in the 1993 rate case (Docket No. 7000) as about $1.9 million, $2.0 million in the 2005 rate case (Docket No. 94-0345) and $.9 million in the 1997 rate case (Docket No. 97-0346).

26 See MECO's response to CA-IR-172.

and return of investment (i.e., depreciation) in the years subsequent to the in-service date of the related plant asset. In fact, the currently pending rate case is the first such proceeding to arise since MECO recorded negative NPPC in 2000-2002. As such, any benefit ratepayers might see from the alleged reductions to plant and rate base have yet to be recognized in setting utility rates.

Q. HAVE YOU ATTEMPTED TO EVALUATE THE EXTENT TO WHICH RATEPAYERS MAY HAVE BENEFITED FROM THE NEGATIVE NPPC ACCRUALS OR FROM NPPC ACCRUALS THAT ARE LESS THAN PENSION CONTRIBUTIONS?

A. Yes. Referring to Exhibit CA-105, the Company's contributions to the pension trust fund since 1993, which FAS87 was first recognized for ratemaking purposes in MECO's 1993 rate case test year, have totaled $18 million. Actual NPPC during this period was about $16.8 million, with the resulting difference of $1.2 million approximating the recorded pension asset balance at December 2007. If ratepayers have received the benefit of the negative pension credits recorded in 2000-2002, the cumulative amount of NPPC included in rates should be equal to or less than the $16.8 million actual NPPC.

Exhibit CA-106 represents an analysis comparing the actual amount of NPPC included in utility rates with MECO's actual NPPC. Noting a one-month

1 prorate difference in 1993,[27] the cumulative NPPC included in rates since
2 1993 is about $18.5 million, which exceeds the actual NPPC during this same
3 period by $1.9 million – an amount greater than the $1.2 million pension asset
4 balance at December 2007.
5 Exhibit CA-107 compares that amount of NPPC included in rates with
6 pension contributions since 1993. During this period, the amount of NPPC in
7 rates exceeds pension contributions, supporting an implied pension liability
8 rather than pension asset.
9
10 Q. DO EXHIBITS CA-106 AND CA-107 EXPLICITLY CONSIDER THE
11 RATEPAYER BENEFIT OF THE CAPITALIZED PORTION OF THE
12 NEGATIVE NPPC ADDRESSED BY MECO T-9?
13 A. These exhibits intentionally recognize 100% of the NPPC included in rates for
14 comparison with 100% of MECO's actual NPPC and actual pension
15 contributions. If Exhibit CA-106 was modified to capture the effect of the
16 actual NPPC capitalization percentage, the resulting change would have a
17 negligible impact on the results, as both Columns G and H would be adjusted
18 downward by the same proportion. However, any downward adjustment to the
19 NPPC in rates (Column C) on Exhibit CA-107 would be improper, as the trust

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27 *Interim Decision and Order No. 12163 (Docket No. 7000) was effective on February 1, 1993,* representing the first Commission rate order in which FAS87 was recognized in setting MECO's rates.

1 contribution (Column D) would not be similarly apportioned, leading to an
2 improper "apples and oranges" comparison.
3
4 Q. DO YOU BELIEVE THAT RATEPAYERS RECEIVE THE BENEFIT OF
5 PENSION CREDITS, OR REDUCED PENSION COSTS, MERELY AS A
6 RESULT OF A UTILITY HAVING RECORDED THE NEGATIVE, OR
7 REDUCED, PENSION COSTS?
8 A. No. The mere recording of NPPC, whether positive or negative in amount, at
9 levels lower than pension contributions does not conclusively demonstrate
10 "who" (ratepayers or investors) may have funded, or benefited from, the lower
11 recorded pension costs. MECO T-9 fails to cite to any negative NPPC
12 amounts recognized in past rate case revenue requirement calculations or
13 explicitly refunded to customers.[28] Other than a historical comparison of
14 pension costs and contributions comprising the pension asset balance set
15 forth on MECO-928,[29] the Company has provided no quantification of the
16 cumulative benefits ratepayers are alleged to have received to support the
17 proposed rate base inclusion of the pension asset. Furthermore, the
18 Company's reference to the fact that a portion of the negative NPPC accruals

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28 The years in which MECO recorded negative NPPC occurred during the interval between MECO's 1999 (Docket No.97-0346) and 2007 (Docket No. 2006-0387) rate case test years. Also, MECO has not provided any refunds or credits to ratepayers to match the negative NPPC accruals.

29 MECO-928 has been updated to reflect revised 2007 activity by MECO T-9's June 2007 Update, Attachment 5, p. 1. The revised amounts are reflected on both Exhibit CA-105 and Exhibit CA-106.

has been capitalized does not justify full inclusion of the recorded prepaid pension asset in rate base. Such reference or analysis is woefully deficient as it fails to comprehensively consider the amount of FAS87-determined NPPC collected in rates versus total NPPC recorded by MECO.

Q. THE THIRD POINT RAISED BY MECO T-9 TO SUPPORT THE RATE BASE INCLUSION OF THE PENSION ASSET IS THAT "OTHER JURISDICTIONS HAVE ALLOWED A PENSION ASSET TO BE INCLUDED IN RATE BASE." DO YOU HAVE ANY COMMENTS ON THIS POINT?

A. Yes. MECO T-9 does not discuss the treatment of other jurisdictions, other than to observe that this subject was discussed in the opening and reply briefs of the parties in HECO's 2005 test year rate case (Docket No. 04-0113).[30] The Consumer Advocate is not aware of any additional research undertaken by MECO for the instant docket.

With respect to HECO's referenced research in other jurisdictions, it is of particular note that, during the December 2005 hearings (Docket No. 04-0113) on the pension asset issue, HECO witness Tayne Sekimura (HECO T-16) referred to a pension tracking mechanism of some potential interest. The mechanism was set forth in a settlement agreement in a then recent Empire District Electric Company rate case (Missouri Case No. ER-2004-0570). Although HECO T-16 indicated that the tracking

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30 See MECO T-9 at 106.

mechanism had some appeal to the Company, more research and review would be required to determine whether HECO would find such a mechanism to be acceptable. The referenced Missouri pension tracking mechanism served as the basis for the pension tracking mechanism the Consumer Advocate proposed in the recent HELCO rate case (Docket No. 05-0315) and HECO rate case (Docket No. 2006-0386) that was substantially adopted and agreed to by HELCO, HECO and the Consumer Advocate.

Q. IN YOUR OPINION, DO THE ANALYSES SET FORTH AS EXHIBITS CA-106 AND CA-107 EVALUATE THE PROPRIETY OF EXCLUDING A PENSION ASSET IN RATE BASE BY ASSESSING WHETHER RATEPAYERS HAVE BENEFITED FROM NPPC ACCRUALS LESS THAN PENSION CONTRIBUTIONS?

A. Yes. My conclusion from this analysis is that the pension asset recorded by MECO should be excluded from rate base.

1 **C. PROPOSED CONSUMER ADVOCATE APPROACH.**

2 Q. HOW DOES THE AMOUNT OF THE PENSION ASSET, GROSS OF THE
3 ADIT RESERVE, THAT MECO PROPOSES TO INCLUDE IN TEST YEAR
4 RATE BASE COMPARE WITH YOUR ESTIMATE OF RATEPAYER
5 PARTICIPATION IN THE NET BENEFITS RESULTING FROM MECO
6 HAVING RECORDED PENSION CREDITS IN PRIOR YEARS?

7 A. In direct testimony, Company witness Matsunaga (MECO T-9) discusses the
8 basis[31] for the Company's proposal to include in rate base an estimated
9 average pension asset balance of about $3.321 million, gross of the related
10 ADIT reserve balance, which was subsequently revised to about
11 $3.216 million in MECO's June 2007 Update.[32]

12 Although MECO adopted FAS87 for accounting purposes in 1987, the
13 Company's utility rates did not explicitly include FAS87-determined net
14 periodic pension costs until the issuance of the Commission's February 1993
15 interim decision in Docket No. 7000.[33] The following points summarize the
16 history of MECO's pension accounting as well as an overview of the results of
17 the analyses set forth on Exhibits CA-105, CA-106 and CA-107:

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31 See MECO T-9 at 93-106.

32 See MECO-928 (original filing) and June 2007 Update (MECO T-9, Attachment 5 at 1).

33 See MECO response to CA-IR-161. FAS87 adopted for accounting purposes in 1987; FAS87 first adopted for ratemaking purposes in Docket No. 7000 (Interim Decision No. 12163 effective February 1, 1993).

- During calendar years 1993-2007, the cumulative amount of actual NPPC recorded by MECO is about $16.8 million and the comparable amount of pension contributions is $18 million – the $1.2 million difference (i.e., contributions in excess of NPPC) approximates the estimated pension asset balance as of December 2007. (See Exhibit CA-105.)
- MECO proposed rate base inclusion of a test year average pension asset balance of about $3.2 million. (See Exhibit CA-105.)
- Since February 1993, the date when FAS87 pension costs were first included in MECO's rates:
  - The estimated amount of total NPPC included in utility rates ($18.5 million) exceeds actual recorded NPPC ($16.6 million) by about $1.9 million. (See Exhibit CA-106, line 19.)
  - The estimated amount of total NPPC included in utility rates ($18.5 million) exceeds the total pension contributions ($17.8 million) by about $.7 million. (See Exhibit CA-107.)

Rather than demonstrate that ratepayers have benefited from reduced pension costs through the ratemaking process, I believe that these analyses raise serious questions about ratepayers having potentially paid more pension costs through rates than either the amount of NPPC recorded by the Company or the amount contributed to the pension fund. Consequently, it would seem more appropriate to reduce rate base for the excess support MECO has received from ratepayers, rather than penalize ratepayers by including the

1 pension asset in rate base. While the Consumer Advocate is not proposing
2 such a rate base reduction, the Company's proposed addition to rate base, net
3 of the related ADIT reserve balance, should be rejected for purposes of this
4 proceeding.
5
6 Q. IF THE ANALYSIS SET FORTH ON EXHIBIT CA-106 HAD SHOWN THAT
7 THE NPPC INCLUDED IN UTILITY RATES WAS EQUAL TO OR LOWER
8 THAN ACTUAL NPPC, WOULD YOU HAVE PROPOSED TO INCLUDE THE
9 PREPAID PENSION ASSET IN RATE BASE?
10 A. Depending on the results of such an analysis, it is possible that I would have
11 recommended that all or some portion of the recorded pension asset be
12 included in rate base.[34] Obviously, the results of such an analysis would be
13 dependent on the unique facts and circumstances of each utility at the time
14 such an analysis was prepared. In MECO's current case, the key factor
15 causing the analysis to support <u>excluding</u> the pension asset from rate base is
16 the infrequency of rate case activity during the period in which MECO
17 recorded *significant pension credits* (i.e., *negative* NPPC) *in relation to the*
18 positive NPPC amounts embedded in utility rates throughout that same period
19 (i.e., calendar years 2000-2002).

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34 In fact, this was the very result from a similar analysis that lead to the Consumer Advocate's recommendation that the pension asset was appropriately included in rate base in the recent HELCO rate case, Docket No. 05-0315. However, MECO's regulatory history causes the analysis to produce a result that does not support rate base inclusion.

More specifically, during that three-year period (2000-2002), MECO's utility rates included positive annual NPPC of about $.877 million per year, equating to $2.631 million collected from customers. However, a pension liability and related ADIT reserves were included in rate base in MECO's 1999 test year rate case. Consequently, the net cost to ratepayers has been reduced for purposes of Exhibits CA-106 and CA-107 to recognize the revenue requirement of the rate base offset, which reduces the annual NPPC in rates to about $.787 million or $2.36 million over three years. During that same period, the Company recorded negative NPPC of $6.041 million – a difference of $8.4 million more NPPC embedded in utility rates than the NPPC recorded by MECO.

Contrary to the Consumer Advocate's conclusion in the recent HELCO rate case, the facts and circumstances as they exist in MECO's current rate case do not support rate base inclusion of the pension asset for MECO. While such a conclusion could change in future MECO rate cases as the analysis is updated over time, the facts and circumstances relevant to the amount of NPPC embedded in utility rates should be expected to yield a different, but consistent, conclusion in any given rate case and for any particular utility.

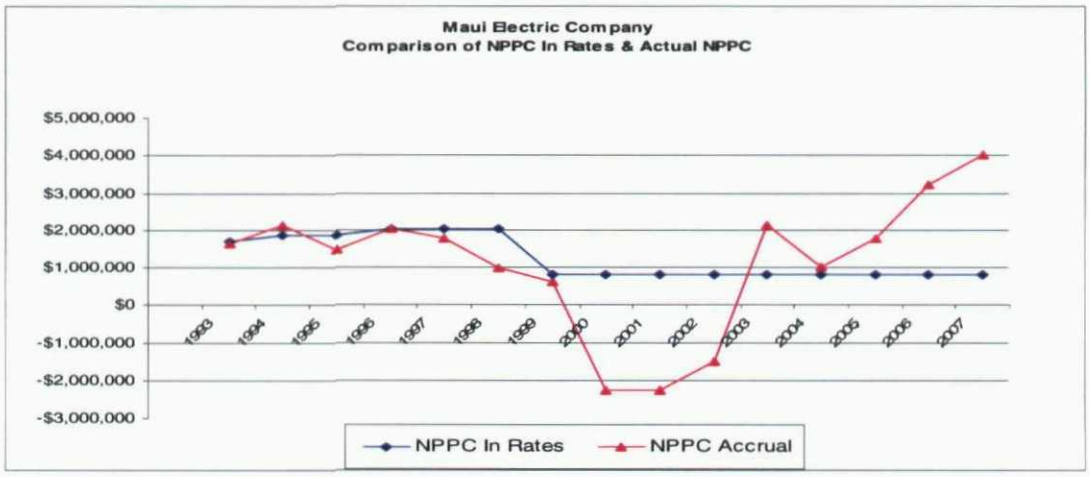
Q. STATED ANOTHER WAY, ARE YOU SAYING THAT THE CONCEPT OF "CONSISTENCY" DOES NOT NECESSARILY RESULT IN A CONCLUSION THAT THE PENSION ASSET SHOULD ALWAYS BE INCLUDED IN OR

EXCLUDED FROM RATE BASE FOR ALL UTILITIES REGULATED BY THIS COMMISSION?

A. Yes, that is correct.

Q. EARLIER, YOU PROVIDED CHARTS SHOWING ANNUAL NPPC ACCRUALS, PENSION FUND CONTRIBUTIONS AND THE YEAR-END PENSION ASSET BALANCE. HAVE YOU PREPARED A SIMILAR COMPARISON OF THE ACTUAL NPPC ACCRUALS WITH YOUR ESTIMATE OF NPPC INCLUDED IN MECO'S UTILITY RATES?

A. Yes. From a conceptual framework, it can be difficult to appreciate the distinctive difference in amounts between the actual NPPC recorded by MECO and the NPPC included in utility rates. Using data from Exhibit CA-106, the following chart shows the difference between these amounts.[35]



35 As noted previously, the amount reflected in this chart for NPPC in rates is not the full NPPC of $877,000 allowed in the last rate case. Instead, the NPPC in rates depicted in this chart have been reduced by the revenue requirement effect of the net pension liability recognized as a rate base offset in MECO's 1999 rate case test year.

1 As mentioned previously, the pension asset MECO proposes to include
2 in rate base represents the difference between the actual NPPC accruals and
3 pension contributions – with the "negative" NPPC accruals shown above
4 representing the key driver in the large increase in the pension asset balance
5 starting in 2000. The above chart very clearly highlights the distinctive
6 difference between the amounts of NPPC in rates and NPPC accruals
7 recorded by the Company, underpinning the Consumer Advocate's concern
8 regarding the equitable treatment of MECO's ratepayers.

9 If the Commission determines that utility rates do not and have not
10 changed on an annual basis (i.e., between rate cases), concurs that MECO
11 has not refunded or otherwise returned the negative NPPC to customers, and
12 concurs with my estimate of the amount of NPPC historically included in utility
13 rates, then the pension asset should be properly excluded from rate base, as
14 recommended by the Consumer Advocate. However, if the Commission finds
15 that utility rates do change between rate cases or the Company has somehow
16 explicitly flowed through the negative pension costs to the benefit of its
17 ratepayers, then the pension asset should be included in rate base – however,
18 the Consumer Advocate does not believe that the facts of this case would
19 support such a conclusion
20
21 Q. REFERRING TO MECO'S RESPONSES TO CA-IR-171 AND CA-IR-255, DO
22 YOU AGREE THAT REGULATORS SHOULD CONSIDER ALL FACTORS
23 (I.E., CHANGES IN SALES, REVENUES, EXPENSES, INVESTMENT,

1 CAPITAL COSTS, ETC.) IN DETERMINING OVERALL REVENUE
2 REQUIREMENT DURING A RATE CASE – NOT JUST CHANGES IN A
3 SINGLE ELEMENT, LIKE NPPC?
4 A. It has been my position for many years that it is critically important, in
5 determining overall revenue requirement, to properly consider and balance all
6 elements of the ratemaking equation. However, it is not uncommon for
7 regulators to address various issues associated with changes that arise
8 between rate cases. For example, utility companies often propose to deviate
9 from this general framework, that all elements of the ratemaking formula must
10 be consistently considered and balanced, by seeking regulatory authority to
11 defer or capitalize significant costs that arise and would otherwise be charged
12 to expense between rate cases, such as:
13 • changes in accounting method (e.g., transition from pay-as-you-go to
14 FAS106 accrual accounting for OPEB costs);
15 • deferral of one-time or infrequently occurring costs (e.g., storm damage,
16 demand-side management costs, software development costs);
17 • proposals to amortize costs (e.g., storm damage, workforce reduction
18 program costs, software development costs); and
19 • implementation of cost tracking mechanisms (e.g., fuel adjustment
20 clause, integrated resource planning costs, demand-side management
21 costs).
22 If the mere act of <u>recording</u> a transaction (i.e., whether negative NPPC
23 or positive software development costs) meant that ratepayers symmetrically

1 funded the cost increases and benefited from decreases in expense, there
2 would be no need for the many cost deferral, cost tracker or cost amortization
3 issues that frequently arise in utility regulation – most often initiated by utility
4 companies seeking Commission approval of such actions.

5 The fact is that such issues do arise and have existed for many years.
6 Rather than dismissively reject these requests, regulators typically review the
7 facts and circumstances unique to each situation and determine whether the
8 regulatory treatment requested by the utility should be accepted, rejected or
9 modified.[36] Changes in NPPC and the pension asset are no different.

10 While negative NPPC has been periodically recorded by utilities since
11 the late 1980's, the rate base question should focus on whether and to what
12 extent utility ratepayers have tangibly benefited from the reduced pension
13 costs. If ratepayers have not benefited from the reduced level of pension
14 costs, as compared to the contributions to the pension fund, then the
15 Company and its investors are the only remaining parties that could have
16 benefited from the reduced costs (i.e., through higher earnings than would
17 have otherwise been achieved).

18 While the Company has proposed to include the pension asset in rate
19 base, MECO has provided no factual support to quantify the extent of any

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36 For example, the implementation of a new accounting software system might result in additional costs not previously included in utility rates. In order to mitigate the negative earnings effect of charging such costs to expense as incurred, a utility company might seek authority to defer and amortize such costs over future periods, allowing recovery from ratepayers and mitigating the negative earnings impact.

ratepayer benefits to the detriment of MECO's investors. Rate base inclusion is appropriate only if it can be reasonably demonstrated that reduced FAS87 pension costs, including the pension credits, on a cumulative basis have been flowed through to the benefit of MECO's ratepayers in an amount at least equal to the pension asset to be included in rate base. However, in the current case, it is the analysis prepared by the Consumer Advocate,[37] not MECO, that produces factual support to evaluate the Company's request to include the pension asset in rate base.

Q. HAVE THE PENSION CREDITS, OR PENSION COSTS BELOW CONTRIBUTIONS, RESULTED IN HIGHER EARNINGS?

A. Yes. Under FAS87, regulated utilities record pension costs in an amount equal to NPPC, unless ordered otherwise by regulators. If reduced or even negative levels of NPPC are not automatically flowed through to the benefit of customers via bill credits or rate reduction, the resulting decrease to operating expense would increase MECO's net operating income above levels that would have been realized in the absence of the FAS87 pension credits.

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[37] See Exhibits CA-105 through CA-107.

Q. REFERRING TO EXHIBIT CA-106, ARE YOUR CALCULATIONS OF RECOVERIES FROM RATEPAYERS "EXACT" IN AMOUNT?

A. No. It is not possible to precisely quantify the "exact" amount of cumulative net pension recoveries from or benefits provided to ratepayers, particularly over the decades predating or following the adoption of FAS87. However, it is reasonable to consider relevant, available information to assess regulatory intent and estimate the amount of cumulative NPPC that might have been reasonably recovered from or otherwise flowed through to the benefit of ratepayers, in the context of MECO's stated theoretical basis for including the pension asset in rate base. After all, MECO first recorded a pension liability and then began recording a pension asset in 2000 resulting from the decoupling of pension cost and pension contributions, pursuant to FAS87.

Q. BY ATTEMPTING TO ASSESS RATEPAYER PARTICIPATION IN THE REDUCED PENSION COSTS RECORDED BY THE COMPANY, ARE YOU SUGGESTING THAT THE COMMISSION ENGAGE IN RETROACTIVE RATEMAKING?

A. No, I neither propose nor suggest that MECO pay back past excessive profits or recoup past operating losses, as implied by that concept. Instead, the retrospective analysis or review that I propose would solely be used to gauge the extent of benefits received by ratepayers, or retained by investors, in determining whether the pension asset balance should be included in rate base.

Q. HAS YOUR APPROACH BEEN USED FOR ANY OTHER ELEMENT OF RATE BASE?

A. No, it has not. However, such a criticism fails to address the key points of concern relative to this issue:

- Have ratepayers benefited from the pension credits or recorded NPPC less than contribution levels?
- If so, by how much?
- Is the cumulative extent of any benefits enjoyed by ratepayers sufficient to include the pension asset in rate base?

The implementation of FAS87 resulted in a significant shift in the accounting method for pension costs from the cash basis to an accrual basis. Because this shift caused MECO to record cumulative NPPC at levels less than pension contributions, I believe that it is responsible and reasonable for regulators to question the extent to which ratepayers, not the Company and its investors, have enjoyed the benefits of those annual pension credits – before allowing the pension asset in rate base.

Q. WHY IS THAT?

A. All components of the ratemaking equation change over time – revenues, expenses and investment. As each component changes, a utility should have a reasonable opportunity to achieve its authorized return (i.e., not materially over or under earn), so long as the components remain in relative balance or changes to one component are mitigated or offset by changes in other components. I generally agree that the prohibition against retroactive

1 ratemaking presumes that recorded costs are assumed to be recovered,
2 regardless of explicit inclusion in cost of service. This presumption holds the
3 utility accountable for incurred costs and prevents a potentially abusive
4 process of collecting past earnings deficiencies from current and future
5 ratepayers.

6 Since adoption of FAS87, the amount of pension costs and pension
7 credits recorded by MECO has varied significantly from year-to-year.[38] In the
8 absence of rate case activity or some mechanism to flow changes in NPPC
9 through to the benefit ratepayers, FAS87 pension accounting has resulted in
10 the reduced NPPC increasing utility income and investor returns.

11 Contrary to any implications otherwise, the evaluation of this issue is
12 not designed, intended nor does it result in a retrospective inquiry of past
13 earnings to impose a surcharge for past under-recoveries or a refund for past
14 over-recoveries. Instead, this approach is designed to evaluate, based on
15 available information, whether it is reasonable to assume that ratepayers have
16 sufficiently enjoyed the benefits of the ever fluctuating NPPC (supporting rate
17 base inclusion of some portion of the pension asset) or whether the resulting
18 earnings benefits have been retained by investors (supporting the rate base
19 exclusion). Exhibit CA-105 compares the amount of actual NPPC accruals
20 with pension contributions, dating back to 1987, while Exhibit CA-107

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38 The amount of actual NPPC since 1987 has ranged from $4 million included in the 2007 test year forecast to $(2.279) million in 2001 (Exhibit CA-105).

compares the amount of NPPC included in rates with pension contributions, dating back to February 1993 – producing different results.

Q. DO YOU BELIEVE THAT ALL ELEMENTS OF THE COST OF SERVICE INCLUDED IN PAST RATES SHOULD BE RECONCILED WITH CURRENT COST LEVELS TO DETERMINE PROSPECTIVE RATE TREATMENT FOR EACH ITEM?

A. No. As a matter of ratemaking policy, I do not generally recommend that the Commission rely solely on, or otherwise reconcile past decisions in establishing cost of service for future periods. However, the consideration of past rate orders is indeed relevant in assessing whether investors have some reasonable claim to inclusion of the pension asset in rate base. After all, the pension asset represents a "non-cash" asset recorded on the Company's balance sheet in that no funds have been expended nor have any checks been written for the amount MECO seeks to include in rate base. As discussed above, I recommend that the Commission <u>exclude</u> the pension asset from rate base.

Q. IN THE 2007 TEST YEAR FORECAST, HAS MECO ESTIMATED NPPC TO BE POSITIVE OR NEGATIVE AND HOW DOES THAT AMOUNT COMPARE TO THE ESTIMATED PENSION CONTRIBUTION?

A. According to MECO T-9's June 2007 Update (see Attachment 5 at 1), MECO currently forecasts the 2007 NPPC to be a positive $4.013 million and

1 anticipates a pension fund contribution of "zero." The amount of NPPC
2 included in overall revenue requirement significantly exceeds planned
3 contributions for the year, which caused the December 2007 estimated
4 pension asset balance ($1.209 million) to be materially lower than the
5 December 2006 actual balance ($5.223 million).
6
7 **D. PENSION TRACKING MECHANISM.**
8 Q. ARE YOU AWARE OF THE FACT THAT MECO T-9 PROPOSED THE
9 IMPLEMENTATION OF A PENSION TRACKING MECHANISM AS PART OF
10 THE COMPANY'S JUNE 2007 UPDATE?
11 A. Yes.
12
13 Q. ARE YOU ALSO AWARE THAT THE CONSUMER ADVOCATE AGREED TO
14 A SIMILAR PENSION TRACKING MECHANISM IN THE RECENT HELCO
15 (DOCKET NO. 05-0315) AND HECO (DOCKET NO. 2006-0386) RATE
16 CASES?
17 A. Yes. I was the Consumer Advocate witness (CA-T-3) in both of these dockets
18 who sponsored the pension tracking mechanism. Following discussions and
19 negotiations between the Parties to those dockets, the pension tracker was
20 implemented substantially in the form recommended by the Consumer
21 Advocate.
22 Although the Parties also agreed to implement an OPEB tracking
23 mechanism patterned after the pension mechanism, it should be noted that the

Consumer Advocate viewed the OPEB tracker largely as a non-event, because of the relative stability of the Net Periodic Benefit Costs ("NPBC") in recent years and the fact that HELCO and HECO were already required to fund NPBC.[39] Consequently, there was no net OPEB asset or liability whose rate base treatment was in dispute among the parties in those proceedings.

Q. BECAUSE OF YOUR INVOLVEMENT IN THE HELCO RATE CASE AND SPONSORSHIP OF THE PENSION TRACKING MECHANISM, ARE YOU ALSO AWARE THAT HELCO'S PENSION ASSET WAS INCLUDED IN RATE BASE AND THE PENSION TRACKING MECHANISM ALLOWED A FIVE-YEAR AMORTIZATION OF THE YEAR END BALANCE?

A. Yes. I conducted analyses for HELCO that were virtually identical to the MECO analyses discussed previously.[40] My analyses for the recent HELCO rate case application considered the ratemaking history and other facts and circumstances unique to HELCO. Based on the results of those analyses and as an integral component of the pension tracking mechanism, I recommended the rate base inclusion of the average test year pension asset, net of accumulated deferred income tax reserves, and proposed that HELCO's test year-end pension asset balance be amortized over a five-year period.

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39 Decision and Order No. 13659, Docket No. 7233, dated November 29, 1994. At page 30, the Commission determined that "any utility adopting, for ratemaking purposes, the accrual method of accounting for the cost of postretirement benefits other than pensions shall fund the full SFAS 106 cost amounts."

40 Analyses comparable to Exhibits CA-105 and CA-106 attached hereto.

However, for the same reasons that the Consumer advocate opposes rate base inclusion of MECO's pension asset, the Consumer Advocate must also oppose those provisions of MECO's proposed pension tracking mechanism that would allow a "catch-up" amortization of the year-end pension asset balance. Consequently, the Consumer Advocate will not endorse the portions of MECO's proposed pension tracking mechanism that discuss rate base inclusion of the $1.2 million pension asset, or the amortization of said balance over a five-year period.[41] These provisions of the pension tracker proposed by MECO should be rejected and excluded from any pension tracker that might be implemented by the Commission for MECO.

Q. REFERRING TO ATTACHMENT 2, PAGE 2 OF THE JUNE 2007 UPDATE SPONSORED BY MECO T-9, THE FOLLOWING STATEMENT APPEARS: "IN THE HELCO RATE CASE, THE CONSUMER ADVOCATE INDICATED THAT IT WOULD PROPOSE THE TRACKING MECHANISM FOR HELCO'S AFFILIATES." IS THAT AN ACCURATE REPRESENTATION?

A. In a document entitled "Comments & Clarifications Regarding the Consumer Advocate's Proposed Pension Tracking Mechanism," paragraph 7 does contain language indicating that the Consumer Advocate will propose a substantially similar pension tracking mechanism for HELCO's affiliates.

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[41] See MECO T-9 June 2007 Update, Attachment 3.

Q. BY FAILING TO ENDORSE THE RATE BASE INCLUSION OF THE PENSION ASSET OR MECO'S PROPOSED AMORTIZATION OF THE YEAR-END PENSION ASSET BALANCE, IS THE CONSUMER ADVOCATE FAILING TO MEET THAT COMMITMENT?

A. No. It was very clear, between the representatives of both HELCO and the Consumer Advocate, that the Parties disagreed on the criteria that should be applied to determine whether a pension asset is properly includable in rate base. In fact, even HECO agreed to this view in response to CA-IR-442 (Docket No. 2006-0386), acknowledging that the Company and witness HECO T-10 do <u>not</u> take the position that the Consumer Advocate's support of HELCO's pension tracking mechanism for HECO requires the Consumer Advocate to support rate base inclusion and amortization of HECO's pension asset.

Q. DOES THE CONSUMER ADVOCATE RECOMMEND THAT A PENSION TRACKING MECHANISM BE IMPLEMENTED FOR MECO?

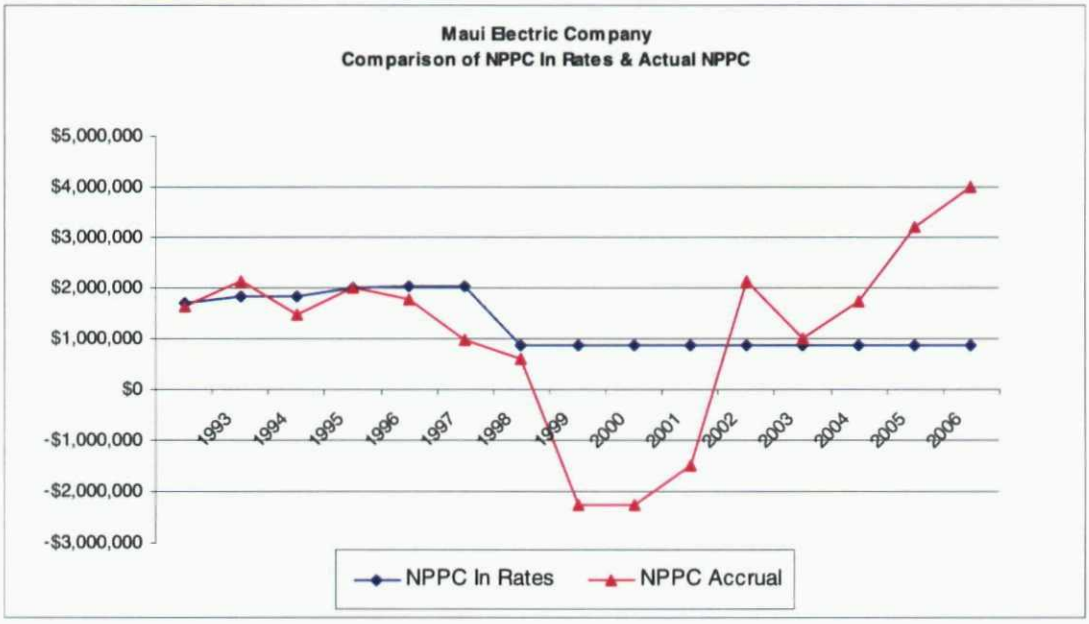
A. Yes. Exhibits CA-108 and CA-109 represent a pension tracking mechanism that the Consumer Advocate recommends be implemented for MECO. Notably, this tracking mechanism is to only be applied on a <u>prospective</u> basis in that there are no provisions for a catch-up or true-up amortization of the embedded pension asset balance recorded by MECO. For reference proposes, Exhibits CA-110 and CA-111 represent MECO's proposed pension

1 tracker showing strike-out and additional language that are set forth as
2 Exhibits CA-108 and CA-109.
3
4 Q. IN THE ABSENCE OF SUCH A CATCH-UP PROVISION, IS THERE ANY
5 VALUE IN IMPLEMENTING A PENSION TRACKING MECHANISM?
6 A. Yes. The rates resulting from MECO's 1999 rate case test year included
7 about $.877 million of NPPC, excluding the effect of the pension liability rate
8 base offset. Since the Commission's issuance of Decision & Order No. 16922
9 (Docket No. 97-0346) in April 1999, the amount of NPPC recorded by MECO
10 has fluctuated from $(2.279) million in calendar year 2001 to $4 million in
11 MECO's 2007 test year forecast.[42]
12 Had a pension tracking mechanism been in place since 1999, MECO
13 would have tracked the difference between the $.877 million NPPC included in
14 rates and the actual NPPC recorded in each year. Any difference between
15 these amounts would have been recorded as a regulatory asset and
16 recovered from ratepayers in future years, pursuant to the provisions of the
17 pension tracking mechanism. Under this mechanism, had NPPC declined
18 from the level included in rates from the last rate case, the excess NPPC
19 "difference" would have been returned to ratepayers via the pension tracking
20 mechanism.

---

42 See Exhibit CA-105.

For convenience and reference purposes, the following chart is reproduced from an earlier subsection of my pension asset testimony, with one exception,[43] so as to reemphasize the historical volatility in the amount of NPPC recorded by MECO pursuant to generally accepted accounting principles and how starkly divergent such recorded amounts are from the NPPC included in rates, also based on the very same generally accepted accounting principles – namely FAS87, as amended and revised from time to time:



As shown on Exhibit CA-105, the marked increase in actual NPPC in 2006 and 2007, coupled with "zero" funding in those years, caused the

---

43 In order for the Consumer Advocate's analysis to credit MECO for the revenue requirement effect of the rate base reduction (pension liability) in the 1999 rate case, the NPPC in rates included in the earlier chart was reduced by about $90,260 per year. Since the purpose of the following chart is to demonstrate the historical volatility in actual NPPC versus NPPC in rates, the rate base reduction impact has been removed from this chart.

1 pension asset to decline from $8.4 million at December 2005 to about
2 $1.2 million forecasted for December 2007. While it is unlikely that MECO and
3 I can agree as to whether the $1.2 million should be recovered from
4 ratepayers, the implementation of a prospective-only pension tracking
5 mechanism will address ongoing variances between future NPPC to be
6 recorded by MECO, that is likely to remain volatile, and the NPPC included in
7 utility rates. At least prospectively, the pension tracking mechanism would
8 fairly and equitably balance the interests of the ratepayers with those of the
9 Company and its investors – specifically, the reconciliation mechanism would
10 ensure that neither ratepayers nor MECO (and its investors) would
11 unnecessarily gain (or lose) to the detriment (or benefit) of the other party.
12
13 Q. DO YOU HAVE ANY FURTHER COMMENTS ON THE SUBJECT OF
14 PENSION ACCOUNTING THAT IS RELEVANT TO THE IMPLEMENTATION
15 OF A PENSION TRACKING MECHANISM OR THE INCLUSION OF THE
16 PENSION ASSET IN RATE BASE?
17 A. Yes. By Decision and Order No. 23223 (Docket No. 05-0310), the
18 Commission denied a joint application filed by HECO, HELCO and MECO
19 seeking Commission authorization to record as a regulatory asset, pursuant to
20 Financial Accounting Standards No. 71 ("FAS71"), the amount that would

otherwise be charged to equity as required under provisions of FAS87 or FAS158, as a result of recording a minimum pension liability.[44]

At page 29 of Decision and Order No. 23223, the Commission recognized that a charge to AOCI, if required, would represent a non-cash transaction. Citing to page 10 of the Consumer Advocate's Statement of Position in that proceeding, the Commission further explained the reference to a non-cash transaction, as follows:

> In other words, the regulatory asset created under the FASB requirement for pension accounting does not constitute a monetary expenditure or the application of cash.

I concur that the AOCI charge represents a non-cash transaction and agree with the Commission's decision to deny the relief sought by the joint applicants in Docket No. 05-0310. While addressing a seemingly different aspect of pension accounting, the "non-cash" element of the AOCI charge is directly on point with regard to the pension asset MECO seeks to include in rate base. There is no monetary expenditure of cash related to the pension asset. As discussed earlier herein, the pension asset merely represents the cumulative difference between the NPPC MECO has recorded for financial statement purposes and pension contributions.

---

[44] The charge to equity pursuant to FAS87 and FAS158 is commonly identified as a charge to accumulated other comprehensive income or "AOCI."

1 **VI. PAYROLL EXPENSE.**

2 Q. PLEASE DESCRIBE CA ADJUSTMENT C-13.

3 A. CA Adjustment C-13 revises the Company's salary and wage expense
4 forecast to recognize average employee counts for the 2007 forecast period.
5 This labor adjustment encompasses all MECO expense account blocks,
6 including production, transmission and distribution, customer service,
7 customer accounts, and administrative and general.[45]

8

9 Q. WHY DOES CA ADJUSTMENT C-13 REVISE MECO'S LABOR FORECAST
10 TO REFLECT AVERAGE 2007 EMPLOYEE COUNTS?

11 A. In direct testimony, Company witness Andrew Herrera (MECO T-6) discusses
12 the Company's historical and forecast staffing level for the Transmission and
13 Distribution ("T&D") Department and the Engineering Department.[46]
14 According to MECO T-6, the actual employee count at December 2006 was 96
15 for the T&D Department and 29 for the Engineering Department, compared to
16 forecast levels of 111 and 31, respectively.[47] However, MECO's rate case is

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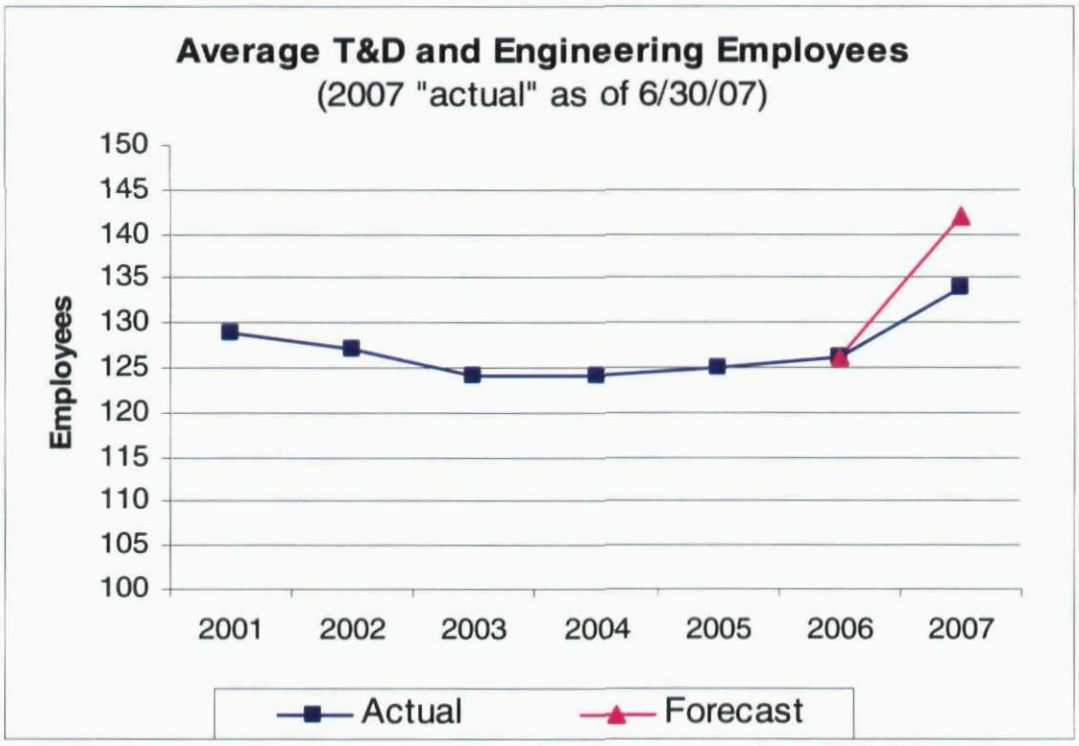
45 See the direct testimony of Consumer Advocate witness Brosch (CA-T-3) for additional discussion regarding MECO's forecast labor costs in production, customer service and customer accounts.

46 MECO T-6 at 33-41. MECO-616 compares the 2007 forecast of T&D and Engineering employees (111 and 31, respectively) with actual, average staffing levels in calendar years 2001-2006.

47 MECO T-6 at 33 and MECO response to CA-IR-112.

based on the assumption that the forecast employee count would be achieved and maintained throughout the 2007 test year.[48]

In order to provide some perspective to the magnitude of MECO's 2007 employee count forecast, the following chart compares MECO's forecast with average actual T&D and engineering employees in calendar years 2001-2006 (i.e., from MECO-616) and the actual employee count at June 2007 (i.e., the mid-point of the 2007 test year).



Source: MECO-616 & CA-IR-112.

In the context of the material employee count increase proposed by MECO, it is clear that the Company was unable to hire new employees and retain existing employees in sufficient numbers to achieve the forecast level by

48 MECO responses to CA-IR-112 and CA-IR-133.

June 30, 2007, much less January 1, 2007, as assumed in the rate case forecast. Employee turnover, which leads to "vacant" or "unfilled" positions, is inevitable for large business enterprises.

Since the Company was unable to achieve and maintain the forecast level of T&D and engineering employees throughout the first six months of 2007, CA Adjustment C-13 reduces MECO's T&D O&M labor costs to reflect average 2007 staffing levels. Consistent with the recommendation of Mr. Brosch (CA-T-3),[49] CA Adjustment C-13 is based on the average of the beginning of year actual (December 31, 2006) and MECO's end of year forecast (December 31, 2007) employee levels for all departments, including T&D and engineering.

Q. DID MECO EXPERIENCE DIFFICULTIES IN HIRING AND MAINTAINING THE FORECASTED EMPLOYEE COUNTS IN AREAS WHOSE LABOR COSTS ARE INCLUDED IN A&G ACCOUNTS?

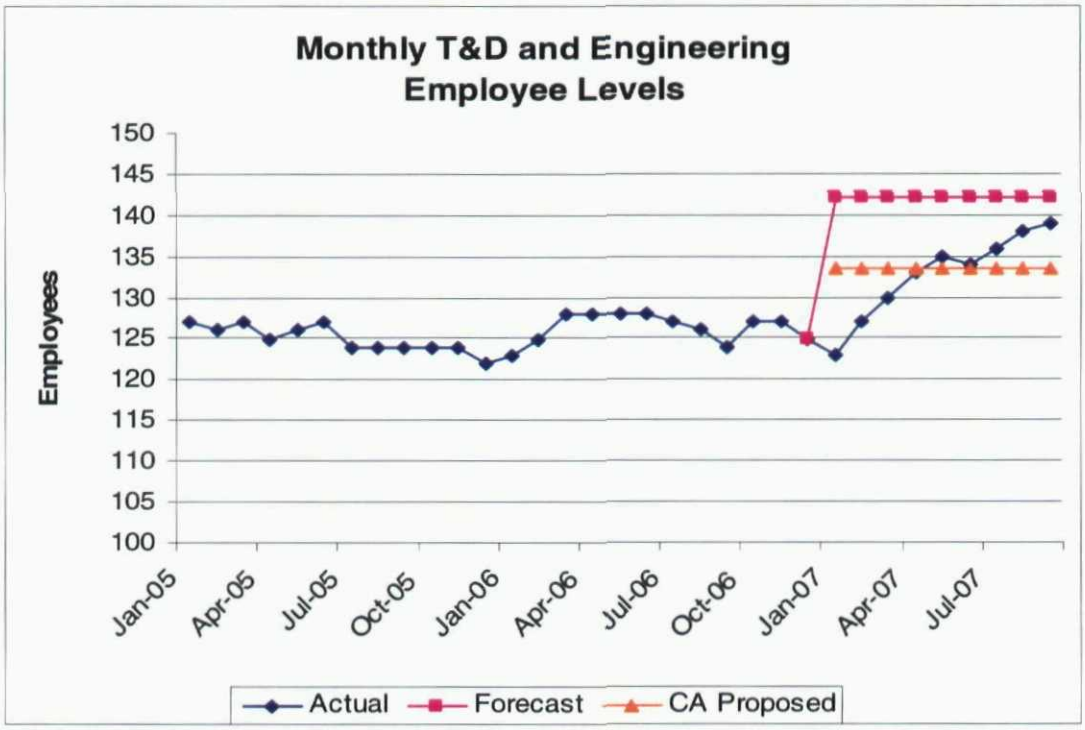
A. Yes.

---

49 Labor and employee counts for production, customer service and customer accounts.

Q. THE EARLIER GRAPH COMPARED MECO'S "AVERAGE" ACTUAL T&D AND ENGINEERING EMPLOYEE COUNT WITH MECO'S 2007 TEST YEAR FORECAST. HOW HAVE THOSE EMPLOYEE LEVELS CHANGED ON A MONTHLY BASIS DURING RECENT YEARS?

A. The following chart compares MECO's historical and forecast monthly T&D and engineering employee count with the test year average recommended by the Consumer Advocate:



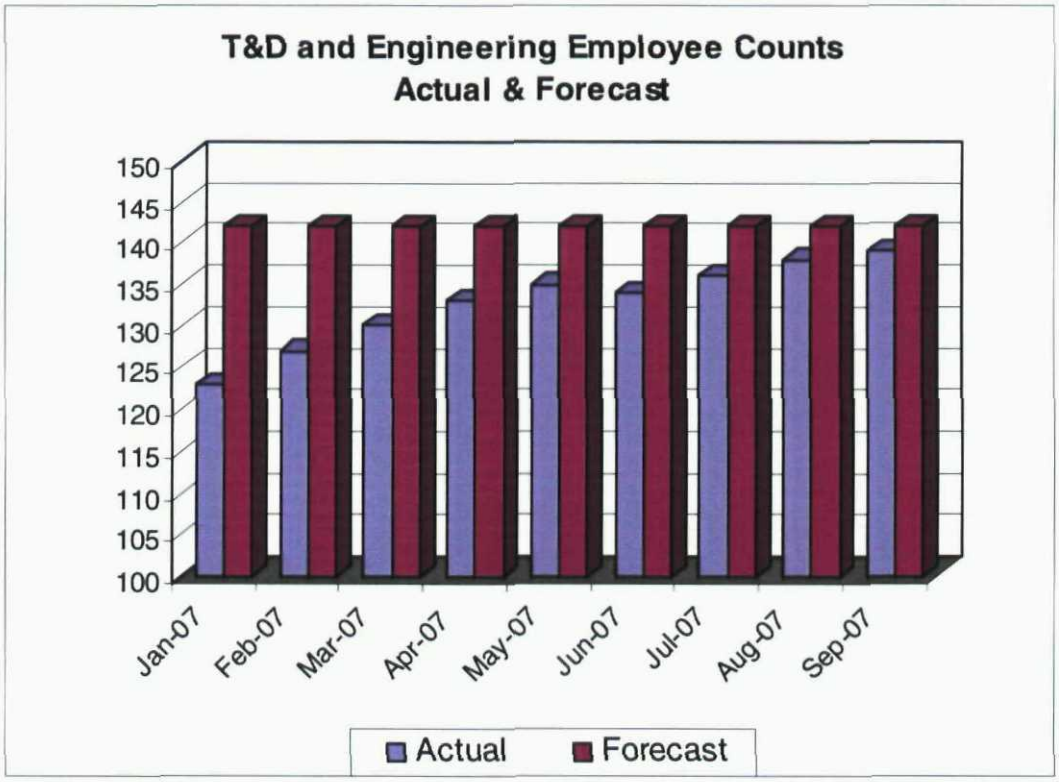
Source: CA-IR-112.

Actual employee counts fluctuated around 125 from January 2005 through the first quarter of 2007. Beginning in April 2007, actual employee counts began a steady increase, as open positions were filled and employees started working for MECO. By September 2007, the monthly staffing count (139) approached the employee level (142) MECO had forecast continuously

1 throughout 2007. By comparison, the average test year employee count
2 proposed by the Consumer Advocate (133.5) approximates the actual number
3 of employees at June 2007 (134). There is no question that actual T&D and
4 engineering employee counts remained relatively static during 2005, 2006 and
5 early 2007, but then began increasing throughout the second and third
6 quarters of 2007.
7
8 Q. WHY WOULD IT NOT BE APPROPRIATE TO RECOGNIZE MECO'S
9 HIGHER FORECAST LEVEL FOR RATEMAKING PURPOSES?
10 A. First, the monthly employee chart clearly shows that MECO did not attain the
11 forecast employee level throughout 2007 – contrary to the Company's test
12 year forecast assumption. It is common for employee vacancies and the hiring
13 of new employees to result in overall headcount levels that fluctuate from
14 month-to-month.
15 Second, just as customer levels and other expenses fluctuate from
16 month-to-month, so do employee levels. It would be highly inconsistent and
17 improper to intentionally set utility rates on an overall cost of service that fixes
18 employee counts at a hypothetical end-of-period forecast level, while not
19 similarly and consistently annualizing customer growth, changes in energy
20 usage or changes in other expenses that are expected to occur in the forecast
21 year. Overall revenue requirement should consistently reflect either an
22 average or end-of-period test year approach – not merely represent a result

that relies on selectively choosing between both test year approaches for discrete elements of the ratemaking equation.

Further, most large entities experience recurring employee turnover and a normal "lag" in the hiring process. It would be wholly inappropriate to ignore these workforce realities in the ratemaking process. Using monthly employee data provided by MECO, the following chart highlights the disconnect between the actual T&D and engineering employee count and the comparable forecast level MECO proposes to include in the 2007 test year forecast.[50]



50 MECO response to CA-IR-112.

Q. HOW DID YOU QUANTIFY CA ADJUSTMENT C-13?

A. During the course of this proceeding, the Consumer Advocate submitted numerous information requests in order to evaluate various factors influencing overall labor costs, including work requirements, employee vacancies, and the status of filling open positions.

Although serious consideration was given to recognizing only those employee positions actually filled as of the mid-point of the forecast test year (134 T&D and engineering employees at June 30, 2007), CA Adjustment C-13 is based on a simple average of MECO's forecast employee count at December 31, 2007, and the actual employee count as of December 31, 2006. While my testimony and the foregoing graphs primarily focus on T&D and engineering positions, CA Adjustment C-13 applies a similar methodology to all MECO departments.

Specifically, CA Adjustment C-13 revises MECO's O&M labor expense using an adjustment factor calculated by comparing the average test year employee count with MECO's forecasted test year level.[51] This adjustment factor was then multiplied by MECO's proposed T&D direct labor expense by RA, including straight time and overtime pay, to quantify CA Adjustment C-13.

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[51] This adjustment factor was developed for each Responsibility Area (or "RA") within each MECO department.

1 Q. DID YOU GIVE ANY CONSIDERATION TO WHETHER REDUCING MECO'S
2 T&D EMPLOYEE LEVEL WOULD HAVE A MATERIAL EFFECT ON EITHER
3 OVERTIME REQUIREMENTS OR OUTSIDE CONTRACTOR NEEDS?
4 A. Yes. The Company explains the proposed increase in staffing for T&D and
5 engineering as being necessary to address increased system requirements
6 due to continued growth and increasing age of utility plant, growing customer
7 demand, loss of experienced staff, and new projects related to system
8 reliability.[52] Changes in perceived system requirements not only effect
9 assessments of staffing needs, but can also influence the need for outside
10 contractor services.
11 In direct testimony, MECO attributes one of the primary reasons for
12 higher forecast T&D O&M expense to increased vegetation management
13 efforts.[53] At page 18, MECO T-6 refers to vegetation management expense in
14 2005 being lower than historical averages and indicates that the 2007
15 estimate is "inline with historical trending" – citing to MECO-622 and
16 MECO-WP-622.
17 Given MECO's discussion of system requirements, vacancies and
18 hiring needs,[54] questions certainly arose as to whether an increase or a
19 decrease in T&D staffing levels would materially affect overtime levels or

---

52 MECO T-6 at 38.

53 MECO T-6 at 2 and 6.

54 For example, see MECO T-6 at 33-41, regarding the T&D and engineering departments.

reliance on outside contractors, particularly in light of MECO's proposed staffing increase. MECO witness Eileen Wachi (HECO T-11, pp. 4-5) discussed the Company's view that there is not a direct relationship between the number of employees and O&M labor expenses. At page 4, MECO T-11 states:

> While there is a general relationship between the number of employees and labor costs incurred, it should not be presumed that there is a direct relationship between employee count and the level of O&M labor expenses incurred. The O&M labor expenses included in MECO's test year estimates reflect the required level of MECO operations, regardless of the number of employees on MECO's payroll. Even if the Company is unable to fill all of the positions needed during the test year, the Company must still get the necessary work done. Therefore, the Company may make up for the unfilled positions by: (1) incurring additional overtime and increasing the number of temporary hires with which MECO supplements its work force during peak manpower requirement periods, and (2) increasing the amount of work performed by outside contractors, such as agency temporaries and technical service representatives. The increased overtime and number of temporary hires translate into increased labor costs. Additional contract services also translate into increased costs, but such costs are recorded as non-labor costs.

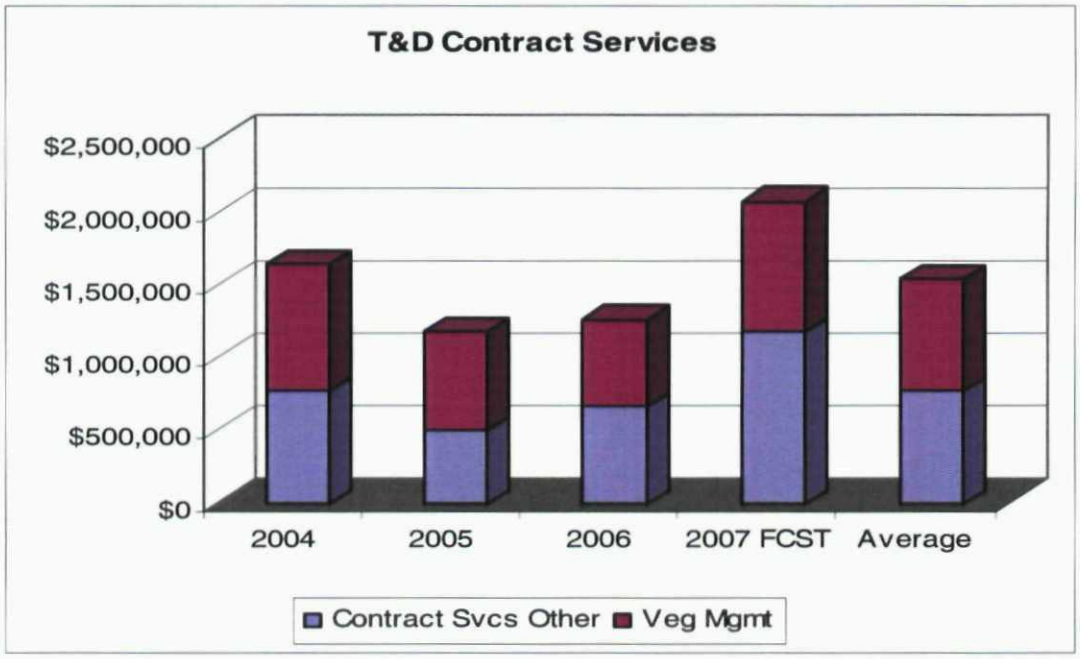
However, in response to CA-IR-117, MECO indicated that additional employee positions would not have materially reduced the Company's historical reliance on outside contractors or reduced O&M outside services expense and will have a minimal impact on reducing project deferrals.

Given the Company's forecasted increase in employee count, the Consumer Advocate's initial concern was whether MECO's 2007 forecast recognized adequate <u>reductions</u> to historical levels of overtime and contract services that are reasonably expected to result from the forecasted staff

increase. In response to CA-IR-135, MECO confirmed that no formal studies or analyses have been prepared specifically evaluating the historical relationship between employee levels, overtime levels, contract services and project deferrals.

Q. IN LIGHT OF THE REPRESENTATION BY MECO T-6, AT PAGE 18, THAT THE 2007 ESTIMATE OF VEGETATION MANAGEMENT EXPENSE IS "INLINE WITH HISTORICAL TRENDING," DO YOU BELIEVE THAT MECO'S 2007 TEST YEAR FORECAST OF T&D CONTRACT SERVICES SHOULD BE INCREASED, IF THE COMMISSION WERE TO ACCEPT THE CONSUMER ADVOCATE'S ADJUSTMENT TO T&D STAFFING LEVELS?

A. No. It should be noted that MECO's graph of vegetation management expenses (MECO-622) is limited to the distribution expense for the Maui Division, excluding Maui transmission and the Lanai and Molokai Divisions. Further, MECO-622 excludes all T&D outside services expense that is not related to vegetation management. As shown by the following chart, MECO's total 2007 forecast of T&D outside services is significantly higher than recent historical levels, in spite of the forecast increase in T&D employees.

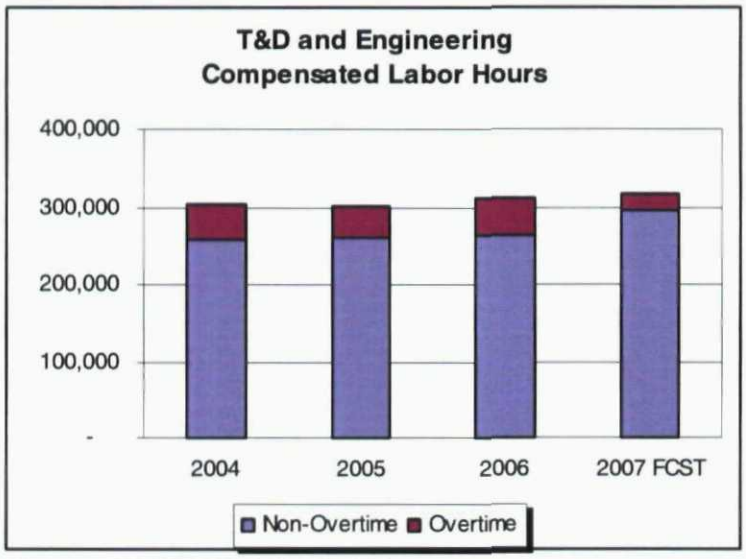


Source: CA-IR-338, updated 9/18/07.

There are several points of note with regard to this graph. First, the "average" bar on the chart represents a four-year average including the 2007 test year forecast. Second, as illustrated in the earlier graph showing monthly employee levels, MECO's average T&D and engineering employee counts were relatively static from 2005 through 2006, mostly fluctuating around 125 employees. The T&D and engineering employee count then spikes to 142 in the 2007 test year forecast – the very year in which total outside services expense also spikes.

Rather than incurring higher contract services when employee counts are low and reduced contract services as employee levels increase, the above chart shows a different pattern, possibly indicating that factors other than the availability of employees to meet work requirements may also materially influence decisions to retain outside contractor services. A separate testimony

1 section will discuss the Consumer Advocate's proposed adjustment
2 (CA Adjustment C-19) to normalize MECO's 2007 T&D outside services
3 forecast.
4
5 Q. DID YOU ALSO REVIEW MECO'S T&D OVERTIME LEVELS IN ORDER TO
6 ASSESS WHETHER FURTHER REVISIONS WOULD BE NECESSARY?
7 A. Yes. As a general matter, the need for overtime work is a function of multiple
8 factors, including: changing work requirements, which are difficult to define;
9 changing employee count; and changing experience mix of staff personnel.
10 As indicated by an earlier chart, average employee counts increased
11 slightly during 2004-2006 (124, 125 and 126, respectively), so did straight time
12 and total labor hours. While compensated overtime hours fluctuated during
13 this period and decreased with the 2007 increase in headcounts, total labor
14 hours continued to increase throughout this period.



15
16 Source: CA-IR-236 & CA-IR-406.

1 Because MECO uses standard labor rates, which combine straight time
2 and overtime pay into a composite hourly rate by labor class, to develop the
3 Company's test year labor forecast, it is difficult to focus solely on labor hours
4 in order to assess the precise amount of overtime compensation embedded in
5 O&M expense. In addition, the changing distribution of labor costs allocated
6 between expense and capital accounts also complicates the translation of
7 labor hours into the related O&M expense impact. In the aggregate, the total
8 T&D and engineering hours do not appear to be overstated, given the planned
9 increase in employee levels.
10
11 Q. YOU PREVIOUSLY INDICATED THAT THE CONSUMER ADVOCATE'S
12 LABOR O&M ADJUSTMENT WAS THE SAME FOR PRODUCTION,
13 CUSTOMER SERVICE, CUSTOMER ACCOUNTS, T&D AND A&G. DO YOU
14 CONCUR WITH MR. BROSCH'S ASSESSMENT THAT THIS
15 METHODOLOGY IS CONSERVATIVE?
16 A. Yes. This methodology assumes that MECO will achieve and maintain the
17 forecast employee count by December 31, 2007 – a presumption that has not
18 yet been attained.
19
20 **VII. <u>EMPLOYEE BENEFITS & PAYROLL TAXES</u>.**
21 Q. WHAT IS THE PURPOSE OF CA ADJUSTMENTS C-14 AND C-15?
22 A. CA Adjustment C-14 reduces MECO's revised forecast of employee benefit
23 expense to recognize the net effect of the Consumer Advocate's

1 recommended employee count adjustments (CA Adjustment C-13). Since
2 CA Adjustment C-1 recognizes the cumulative forecast revisions provided by
3 Company witness Price (MECO T-10),[55] CA Adjustment C-14 is limited to the
4 net effect of the employee average headcount recommendations discussed by
5 Mr. Brosch and myself.
6 CA Adjustment C-15 recognizes the estimated effect of the Consumer
7 Advocate's employee headcount adjustment on related payroll tax expense.
8
9 Q. WHAT METHODOLOGY WAS EMPLOYED FOR PURPOSES OF
10 QUANTIFYING CA ADJUSTMENT C-14?
11 A. CA Adjustment C-14 was quantified using MECO's forecast methodology,
12 including the June 2007 Update revisions, and the net reduction in employee
13 counts due to the difference between end-of-period and average forecast
14 levels.
15

---

55 See MECO T-10 June 2007 Update which revised the forecast of employee benefits to recognize various changes, including updated participant data, premium rates and actuarial results studies.

1 Q. ARE THERE ANY KNOWN DIFFERENCES IN MEDICAL PREMIUM RATES
2 OR OTHER KEY ASSUMPTIONS BETWEEN THE DETAILS UNDERLYING
3 CA ADJUSTMENT C-14 AND MECO'S CURRENT FORECAST OF
4 EMPLOYEE BENEFITS?
5 A. No. Other than the roll-out effect of the employee count reduction, I am not
6 aware of any other differences between the parties concerning Flex Credits,
7 Group Medical, Group Dental, Group Vision or Group Life insurance.
8
9 Q. PLEASE EXPLAIN HOW CA ADJUSTMENT C-15 WAS QUANTIFIED.
10 A. Since CA Adjustment C-13 only adjusts test year labor expense for the effect
11 of the difference between year-end and average headcounts, no employee
12 positions were completely eliminated or removed from the 2007 test year
13 forecast. In order to quantify the related payroll tax effect associated with this
14 Consumer Advocate's labor cost adjustment, CA Adjustment C-15 was
15 calculated by multiplying the composite payroll tax rate from MECO-WP-1301
16 to the labor adjustment amount.
17
18 **VIII. <u>RESEARCH & DEVELOPMENT</u>.**
19 Q. PLEASE DESCRIBE CA ADJUSTMENT C-17.
20 A. CA Adjustment C-17 normalizes the amount of research and development
21 expense (i.e., non-labor, non-EPRI dues charged to NARUC Account 930.2)
22 based on a three-year average, including MECO's updated 2007 test year
23 forecast.

Q. WHAT TYPES OF R&D PROJECT COSTS ARE RECORDED IN ADMINISTRATIVE AND GENERAL ("AG") EXPENSE ACCOUNT 930.2?

A. As generally discussed by Company witness Matsunaga (MECO T-9, page 68), the R&D activities included in A&G expense include MECO's membership in the Electric Power Research Institute ("EPRI") and local R&D activities.

Q. WHY IS IT NECESSARY TO NORMALIZE R&D EXPENSE INCLUDABLE IN MECO'S A&G EXPENSE FORECAST?

A. Over the years, MECO reviews, evaluates and participates in a changing mix of R&D projects and activities. While a particular project (e.g., Sun Power for Schools, BIPB demonstration, etc.) may not be annually reoccurring, MECO typically engages in some level of R&D activity on an annual basis. So the question focuses on "how much" R&D expense should be considered in setting utility rates. As mentioned previously, the Consumer Advocate recommends that R&D expense charged to A&G expense be normalized based on a three year average – actual costs for 2005 and 2006 as well as MECO's revised 2007 test year forecast.[56]

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[56] MECO's response to CA-IR-435, Attachment 1, represents the most recent revised R&D forecast.

Q. HOW DOES MECO'S 2007 REVISED TEST YEAR FORECAST COMPARE TO RECENT ACTUAL EXPERIENCE?

A. During the course of this proceeding, MECO provided responses to various information requests, including revisions to the 2007 test year forecast, from which the following recent historical comparison was based:

	2004 Actual	2005 Actual	2006 Actual	2007 FCST
R&D Charged to A/C 930.24				
R&D (excluding EPRI)	$ 99,944	$ 137,621	$ (9,985)	$ 247,379
EPRI Dues	237,718	198,708	527	222,200
Other (labor, on cost)	20,610	9,845	4,073	12,958
Total	$ 358,272	$ 346,174	$ (5,385)	$ 482,537

Source: CA-IR-432.
Note: The "Other" amount for 2005 excludes $42,635 charged to A/C 930.2 in error (see MECO's response to CA-IR-428).

While the above table does not identify the changing mix of MECO's R&D activity from year-to-year, it clearly demonstrates the annual fluctuation in R&D expenditures. During the three years of actual data in the above table, the level of EPRI due and non-EPRI R&D activity fluctuated materially from $(5,385) in 2006 to $358,272 in 2004. However, in the 2007 rate case test year, MECO is proposing to recognize $482,537 of R&D related costs charged to A&G expense.

With regard to MECO's EPRI dues, the amounts incurred in 2004 and 2005 and forecasted for 2007 are materially above the amount incurred in 2006. Virtually no EPRI costs were incurred in 2006 because the Company

chose to not renew its EPRI membership and paid no dues in 2006, due to budget constraints and a loss of flexibility in the use of EPRI allocated funds.[57]

Q. HOW DID YOU EMPLOY THIS DATA TO CALCULATE THE NORMALIZED R&D AMOUNT ON WHICH CA ADJUSTMENT C-17 WAS BASED?

A. The normalization adjustment was limited to the non-EPRI R&D amounts and excluded the "other" charges, primarily labor and on costs. The three-year average was based on the actual amounts for 2005 and 2006 plus MECO's 2007 revised forecast. Even though MECO chose to not participate in EPRI during 2006, the Consumer Advocate has not proposed any adjustment to the Company's 2007 EPRI forecast estimate.

Q. WITH REGARD TO THE NON-EPRI R&D COSTS, HOW DOES THIS THREE-YEAR AVERAGE NORMALIZATION METHOD COMPARE TO THE HISTORICAL COST LEVELS INCURRED BY MECO?

A. In order to further evaluate the reasonableness of MECO's proposed forecast level of non-EPRI R&D costs, historical information was reviewed for several years prior to 2004. The following chart compares the Consumer Advocate's proposed normalized level with actual historical amounts and MECO's 2007 test year forecast.

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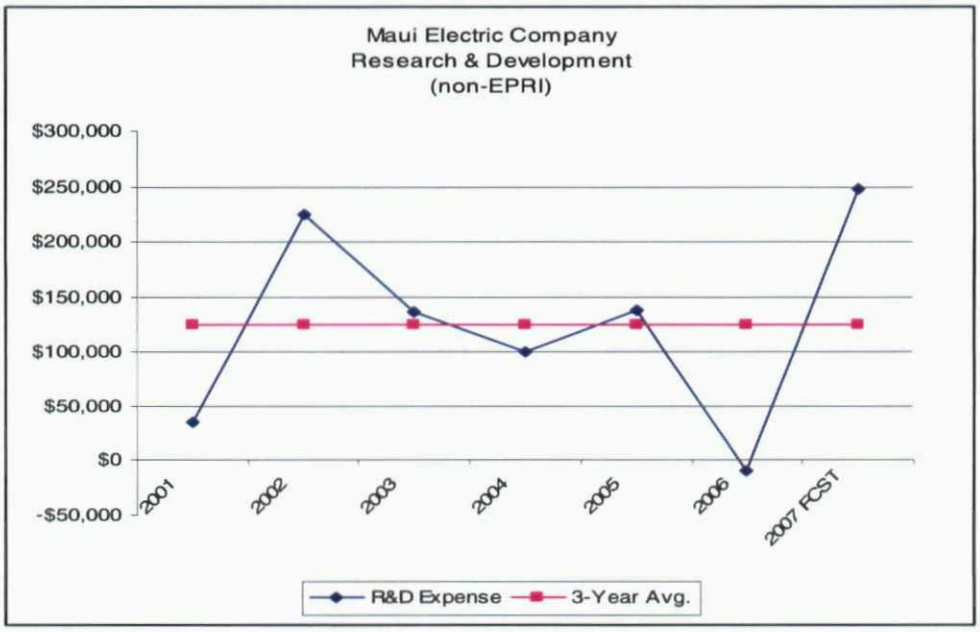
57 See HECO T-9 at 69.



Q. YOU PREVIOUSLY INDICATED THAT THE CONSUMER ADVOCATE'S NORMALIZATION METHOD WAS BASED ON A THREE-YEAR AVERAGE OF 2005, 2006 AND MECO'S 2007 REVISED FORECAST. DOES THE FACT THAT THE 2006 ACTUAL AMOUNT WAS NEGATIVE MATERIALLY EFFECT THE NORMALIZATION RESULTS?

A. No. This specific averaging period was not the only approach considered for normalization purposes. I also calculated average non-EPRI R&D costs for the entire period 2001-2006 and the 2007 forecast ($124,515), as well as only 2003-2005 ($124,739). Each of these approaches produced nearly identical results, with the selected averaging period resulting in a slightly higher normalization amount ($125,505). Although 2006 was negative, MECO's 2007 test year forecast is so exceptionally high that the three-year average produced a reasonable, normalized level.

1 Q. WHY WAS NON-EPRI R&D "NEGATIVE" IN 2006?

2 A. As indicated in the response to part (a) of CA-IR-366, R&D expenditures were
3 negative in 2006 due to two basic factors. First, overall R&D expense was at
4 a reduced level in 2006. Second, MECO also received specific project
5 reimbursements from EPRI and contributions for Sun Power for Schools.
6 Since the reimbursements and contributions exceeded project expenditures,
7 the non-EPRI dues R&D expenses were negative in 2006.

8

9 Q. BEFORE DECIDING TO EMPLOY AN AVERAGING TECHNIQUE TO
10 DETERMINE A NORMALIZED FORECAST AMOUNT, DID YOU REVIEW
11 THE SPECIFIC FORECAST DOCUMENTATION DEVELOPED BY MECO TO
12 SUPPORT THE $247,000 REVISED 2007 FORECAST AMOUNT?

13 A. No, not specifically. In response to CA-IR-2, each MECO witness provided
14 additional documentation supporting their test year forecast of non-labor
15 expenses. Support for almost the entire 2007 non-EPRI R&D forecast was
16 provided by MECO T-8.[58] Since those workpapers failed to contain any
17 support showing how the forecast amounts were specifically determined,
18 separate information requests[59] were submitted seeking copies of any
19 additional documentation for the three largest R&D items, which comprised

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58 MECO T-8 response to CA-IR-2, Attachment B, pp. 39 ($109,500), 41 ($25,000), 48 ($10,000) and 49 ($100,000).

59 CA-IR-418, CA-IR-419 and CA-IR-420.

1 $234,500 of the non-EPRI forecast. Although the responses provided general
2 references to specific prior R&D projects undertaken by the Company, these
3 responses basically state that no additional forecast workpapers or supporting
4 calculations exist.

5 In response to CA-IR-429, MECO explained that actual spending on
6 non-EPRI R&D was affected by several factors, including:

7 • The availability of viable projects or programs which have the
8 potential to benefit MECO's ratepayers.

9 • The inability to predict when MECO might reach agreement with
10 external parties involved in viable projects or programs.

11 • The unpredictable nature of viable projects decreases the
12 predictability of the timing of R&D expenditures.

13 The response to part (a) of CA-IR-429 also conveys MECO's belief that
14 the test year forecast is reasonable, because the Company intends to
15 "generally fund future year research and development activities at the test year
16 level of expenditures." However, given the wide fluctuation in historical
17 expenditures, the significant ramp up MECO has forecast for 2007 and the
18 absence of any meaningful documentation supporting the level forecast, the
19 Consumer Advocate determined that it was necessary to develop a
20 normalization method for purposes of this rate case.

21

1 Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING R&D
2 ACTIVITIES?
3 A. Yes. The Consumer Advocate understands the need for, and importance of
4 rational participation in long term and strategic R&D projects for the benefit of
5 MECO and its customers. However, the Consumer Advocate is also
6 concerned about the seemingly discretionary nature of MECO's recent
7 R&D commitment.
8 Because of the importance of MECO's ongoing participation in
9 R&D projects, the Consumer Advocate does not desire to present the
10 Company with an unnecessary or unreasonable disincentive to actively
11 participate in needed R&D. However, the 2006 experience[60] introduces a fair
12 degree of caution in the evaluation of MECO's 2007 R&D expenditure forecast
13 (including EPRI), especially when MECO seeks financial support from
14 ratepayers for $482,000 [61] of R&D expenditures on an annual basis.
15 As a condition of the Consumer Advocate's proposed inclusion of about
16 $360,000 of A&G-related R&D expense in the 2007 test year rate case
17 (i.e., EPRI dues of $222,200, non-EPRI R&D of $125,005 and labor/on-costs
18 of $12,958), which compares quite favorably with recent actual experience, the
19 Consumer Advocate recommends that the Commission's Decision and Order

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60 Termination of EPRI participation and negative non-EPRI R&D expense.

61 Sum of $222,200 EPRI dues and $260,337 non-EPRI R&D and labor/on-cost that MECO has proposed to include in the 2007 test year forecast. See CA-IR-435.

in this proceeding require MECO to provide a full and complete accounting of its R&D expenditures in its next rate case filing, specifically explaining the basis for any shortfall in actual R&D funding relative to the amount included in utility rates. Such a reporting requirement would facilitate a review of MECO's commitment to the level of R&D funding included in revenue requirement.

IX. EXPIRING SOFTWARE AMORTIZATION.

Q. WHAT IS THE PURPOSE OF CA ADJUSTMENT C-18?

A. CA Adjustment C-18 reduces MECO's test year expense forecast to remove the amortization of certain Ellipse/Mincom Buy-Down Fees that will expire in September 2007.

Q. PLEASE EXPLAIN THE BASIS OF THIS AMORTIZATION.

A. As discussed by MECO T-9 (page 19), the Company's core business software system is called ELLIPSE. The cost of this business software system was initially paid for by HECO and then partially allocated to MECO through the intercompany billing process, including the Ellipse/Mincom Buy-Down Fees.

Although MECO's direct testimony does not specifically discuss the Ellipse/Mincom amortization, the subject was addressed in HECO's 2005 (Docket No. 04-0113) and 2007 (Docket No. 2006-0386) test year rate cases. In developing its 2005 test year forecast, HECO proposed to amortize $1.1 million in prepaid expense to Mincom over a two-year period, which would have expired in May 2006. Pursuant to the Stipulated Settlement Letter

accepted by the Hawaii Public Utilities Commission for purposes of Interim Decision and Order No. 22050 (Docket No. 04-0113), the amortization period was revised to extend through September 2007 – the next software upgrade then planned by the software vendor.

In HECO's 2007 test year rate case, HECO T-13 briefly described the history of and sponsored the Company's inclusion of this amortization in the 2007 test year forecast.[62] I also sponsored testimony in both of these HECO rate cases,[63] most recently opposing the inclusion of the Buy-Down fee Amortization of $17,187 per month, which is scheduled to expire or terminate in September 2007.[64] When the amortization is completed in September 2007, MECO will cease or terminate the amortization accrual of that particular software prepayment.

Q. WHY IS CA ADJUSTMENT C-18 NECESSARY?

A. While 2007 is the forecast test year selected for this rate proceeding, it is important that the components of the ratemaking equation be internally

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62 As discussed by HECO T-13, page 19, in HECO's 2007 test year rate case (Docket No. 2006-0386), Mincom is HECO's Ellipse software vendor. HECO made two payments of $550,000 in June 2004 and January 2005. These prepayments entitled HECO to reduced future software maintenance pursuant to Amendment No. 17 to the Mincom software license agreement.

63 CA-T-2, pp. 39-43 (Docket No. 04-0113) and CA-T-3, pp. 70-72 (Docket No. 2006-0386).

64 The monthly amortization of $17,187 is before allocation between HECO (70%), HELCO (15%), and MECO (15%). See MECO T-9 response to CA-IR-2, Attachment B and MECO's response to CA-IR-371.

consistent and reasonably representative of ongoing conditions. While it is true that this software amortization will be recorded for nine (9) months of the 2007 test year, it is equally true that the amortization will terminate in September 2007. It is necessary and appropriate to remove this amortization expense that will not continue beyond September 30, 2007.

Q. WHY SHOULD THIS SOON TO EXPIRE AMORTIZATION BE REMOVED FROM TEST YEAR EXPENSE?

A. At the time of HECO's 2005 test year rate case, HECO was allowed to defer and amortize these prepaid software buy-down costs over a defined time period. In September 2007, the amortization period negotiated in HECO's 2005 rate case will expire. Although MECO was not a party to HECO's 2005 rate case, MECO similarly deferred the amortization to conform to the HECO settlement agreement – causing MECO's amortization to terminate a few months prior to the end of the 2007 test year and the scheduled date for the Statement of Probable Entitlement.[65]

If the soon to expire amortization is not eliminated from the test year expense, MECO will effectively be allowed to recover this amortization during the entire term that the rates resulting from the pending case are in effect. One could argue that the settlement agreement with HECO, extending the

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65 Pursuant to Order No. 23496, MECO's Statement of Probable Entitlement is scheduled for filing on December 14, 2007.

amortization period through September 2007, only applied to HECO and that MECO's amortization should have expired in May 2006 and should not have been included in MECO's 2007 rate case forecast. In any event, MECO should not be allowed to recover this expiring amortization through utility rates well beyond 2007. CA Adjustment C-18 properly removes these costs from test year expense.

X. T&D OUTSIDE SERVICES.

Q. PLEASE DESCRIBE CA ADJUSTMENT C-19.

A. CA Adjustment C-19 normalizes the outside contract services costs included in the T&D O&M forecast, as sponsored by Company witness Herrera (T-6).[66]

Q. DOES THE COMPANY'S FILED EVIDENCE PROVIDE A COMPARATIVE OVERVIEW OF THE TOTAL T&D OUTSIDE CONTRACT SERVICE COSTS CHARGED TO O&M EXPENSE?

A. No. MECO's direct filing does not provide a global overview of the Company's outside services costs, which include both vegetation management and other outside services costs. The only specific information presented by the Company is set forth on MECO-622 and MECO-WP-622, but this data only

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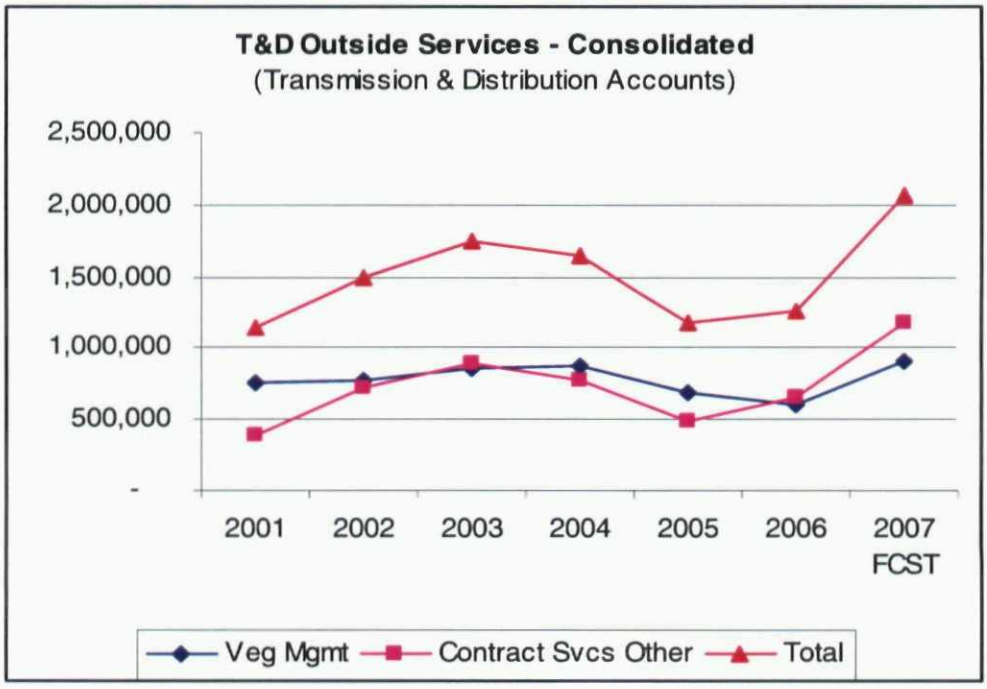
66 MECO T-6 generally discusses the Company's reliance on vegetation management contractor and other outside services at various points through his direct testimony, with specific references to MECO-622 and MECO-WP-622.

contains vegetation management related costs charged to distribution expense for the Maui Division.[67]

Q. HAVE YOU COMPILED A COMPARATIVE OVERVIEW OF T&D OUTSIDE CONTRACT SERVICE COSTS THAT INCLUDES ALL THREE MECO DIVISIONS?

A. Yes. Using data supplied by MECO (i.e., CA-IR-114 and CA-IR-135), the following line chart illustrates the historical year to year fluctuation in vegetation management and other outside services:[68]



Source: CA-IR-114 & CA-IR-135 (revised 9/11/07), plus the steel pole project.

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67 See MECO's response to CA-IR-114.

68 The 2007 forecast for other contract services costs has been adjusted to include $150,000 for the steel pole project, which was excluded from the data supplied in response to CA-IR-135, as revised on 9/11/07.

Clearly, the amount of total T&D contract services MECO has proposed to include in the 2007 forecast test year is higher than any level experienced during the period 2001-2006. Notably, the component making the largest contribution to this increase relates to "other" contract services, rather than vegetation management.

Q. WHY DO YOU CONSIDER IT NOTABLE THAT THE "OTHER" COMPONENT OF OUTSIDE SERVICES IS MORE OF A CONTRIBUTOR TO THE 2007 FORECAST THAN VEGETATION MANAGEMENT?

A. In direct testimony, MECO T-6 specifically identified vegetation management as a major driver to explain why the 2007 T&D forecast is higher than 2005 actual results.[69] While the Steel Pole project is also identified as a primary driver, the Company's testimony offers limited information about the non-vegetation contract services. As illustrated by the following table, the 2007 forecast for vegetation management is only about 32% higher (i.e., a multiplier of 1.32 times) than the 2005 actual amount, but comparable amounts for MECO's other T&D contract services indicate that the 2007 test year is 140% higher (a multiplier of 2.4 times).

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69 MECO T-6 at 2 and 8.

	Vegetation Management	Contract Svcs Other	Total
2005	$ 682,777	$ 488,999	$1,171,776
2006	597,701	659,680	1,257,381
2007 FCST	898,023	1,173,432	2,071,455
2007 v. 2005	1.32	2.40	

Sources: CA-IR-114 & CA-IR-135 (revised 9/11/07).

Q. DURING THE COURSE OF THIS PROCEEDING, HAS THE COMPANY PROVIDED DETAILED SUPPORT FOR ITS T&D OUTSIDE SERVICES FORECAST?

A. Yes, for some items but not others. In response to CA-IR-2, MECO T-6 provided about two inches of duplexed documentation to support the 2007 T&D non-labor forecast. Attachment 5 of that response represents a detailed line item listing of direct non-labor expense amounts (by RA and block of account) and includes references to additional supporting documentation located in other attachments to that response. Of the 173 non-labor line items, about 65 relate to vegetation management and other outside contract services (expense element 501). Upon reviewing the supporting documentation, I observed that no supporting quantification data was provided for a large number of the outside services line items. Instead, a number of the supporting schedules contained general statements such as "prior year actuals," "trending" or similar statements.

1 Q. WHY IS THE ABSENCE OF DETAILED DOCUMENTATION RELEVANT TO
2 THE REVIEW OF THE T&D FORECAST?
3 A. As supported by the earlier graph, outside services costs have fluctuated
4 significantly from year to year since 2001. MECO's 2007 test year forecast
5 represents a substantial increase above these historical levels. With detailed
6 forecast documentation, it is possible for the approach and methodology to be
7 critically reviewed and evaluated by the Consumer Advocate and the
8 Commission. In the absence of detailed forecast support, the analyst is left
9 with broader review and evaluation techniques to assess the reasonableness
10 of the forecast cost level. Based on my review, I have concluded that the T&D
11 outside services forecast is excessive and merits downward revision.
12
13 Q. HAVE YOU CONSIDERED MECO'S ACTUAL 2007 EXPENDITURES FOR
14 T&D CONTRACT SERVICES?
15 A. Yes. I am aware that MECO's actual 2007 contract services expenditures are
16 under-running the 2007 forecast,[70] but that information was not a factor in
17 developing CA Adjustment C-19.
18
19 Q. WHY NOT?
20 A. While comparisons of actual and forecast amounts can be useful, particularly
21 when reviewing rate base components, the fact remains that this Commission

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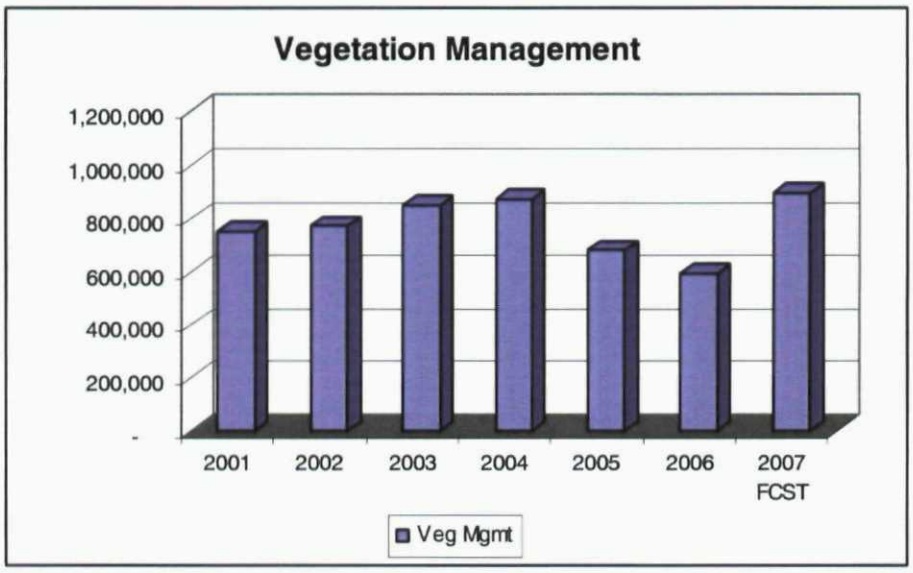
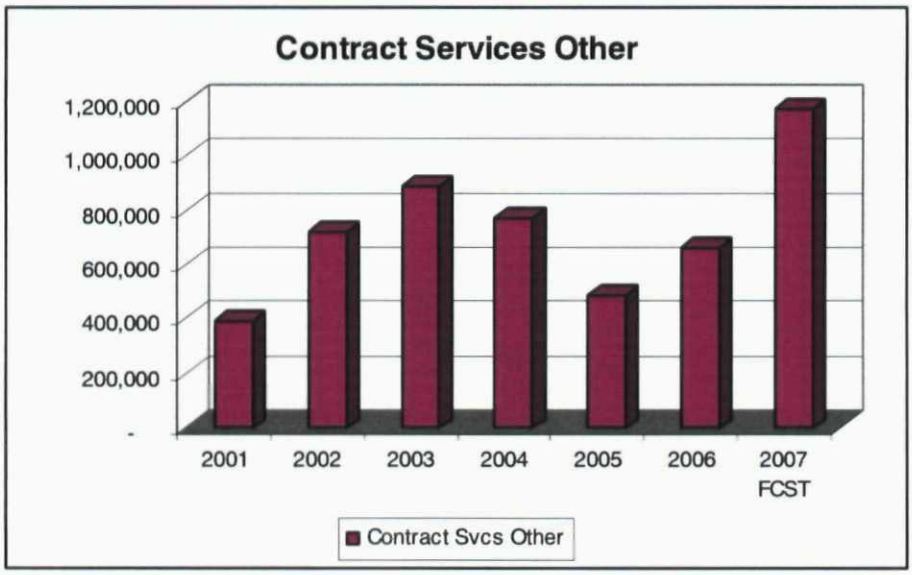
70 See MECO's response to CA-IR-404.

relies on a forecast test year, not a historical test year. While it is of interest that MECO's 2007 year-to-date actual expenditures on T&D contract services are under forecast, such information does not provide a sufficient base line for purposes of determining an appropriate forecast level.

Q. HOW DID YOU QUANTIFY THE CONSUMER ADVOCATE'S RECOMMENDED LEVEL OF T&D OUTSIDE CONTRACT SERVICES?

A. During the course of this proceeding, I reviewed a variety of information supplied by MECO – from the Company's forecast workpapers to rainfall statistics (vegetation management) to specific revised calculation inputs (sidewalk repairs and steel pole project). The ultimate challenge is whether the aggregate forecast amount appears reasonable, based on the available information. Since detailed forecast information was not supplied for a number of the outside services line items included in the Company's forecast, historical expenditure levels appeared to serve as a better quantification basis for developing a reasonable test year forecast, as evidenced by the following charts.





After considering multiple averaging and calculation techniques, I concluded that a three-year average, including actual data for 2005 and 2006 plus MECO's 2007 forecast, was both relatively straight forward and resulted in comparable results to longer average periods or other methods that

1 attempted to isolate certain forecast elements.[71] Using this approach, I
2 quantified a normalized level of total outside contract services of about
3 $1.5 million as compared to the $2.1 million requested by MECO.[72]
4
5 Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING T&D OUTSIDE
6 CONTRACT SERVICES?
7 A. Yes. In direct testimony, MECO T-6 (page 34) stated that the T&D and
8 Engineering departments manage staffing level shortfalls through the use of
9 outside contract services, deferral of projects, use of overtime and through
10 recruitment to backfill positions. In this context, CA-IR-135 inquired of any
11 related studies undertaken by the Company to quantify these relationships. In
12 response, MECO indicated that no formal studies or analyses have been
13 prepared to evaluate the historical relationship between employee levels,
14 overtime, contract services and project deferrals.
15 In a separate testimony section, I sponsor CA Adjustment C-13, which
16 recognizes average test year headcounts for all departments, including T&D.
17 Mindful of MECO's reliance on outside services to help manage staffing
18 shortfalls, CA-IR-117 was submitted in part to assess the extent to which
19 MECO's historical reliance on outside services would have been effected if the

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71 The reference to isolating forecast elements pertains to the steel pole project, sidewalk repair and oil disposal services. Insufficient data existed to attempt any vegetation normalization based on rain fall or other weather related statistics.

72 See CA Adjustment C-19, Consolidated.

employee positions added to T&D and Engineering in 2007 had instead been added in 2004. In response, MECO indicated that such employee additions would not have materially reduced the historical reliance on outside contractors nor reduced outside services O&M expense during 2004-2006, even if the positions had been added in 2004, as discussed in the following excerpt:

> The primary drivers for utilizing outside services are that the work can be more economically executed by outside contractors (e.g., vegetation management, hole digging, concrete, etc.), the work is beyond MECO's expertise (e.g., relay work, legal work, large studies, etc.), and the work can be better accomplished or performed by affiliated companies due to level of expertise or to take advantage of economies of scale that can provide lower costs or improved efficiencies. The positions that were added in 2007 are not in areas where MECO traditionally utilizes outside services and instead are in technical areas where outside services are either not available, unreliable, or too costly.

Based on this information, I concluded that the Consumer Advocate's recommendation to recognize average employee levels for purposes of developing the 2007 test year forecast would have no material effect on the required level of T&D outside contract services.

XI. HO'OMAIKA'I COSTS.

Q. WHAT IS THE PURPOSE OF CA ADJUSTMENT C-20?

A. CA Adjustment C-20 adjusts the amount of Ho'omaika'i Awards costs MECO has proposed to include in the 2007 test year forecast in order to recognize a more normal level of such costs, based on historical experience.

Q. WHAT DO THE HO'OMAIKA'I AWARDS REPRESENT?

A. As indicated in the response to CA-IR-372 (Attachment A), the Ho'omaika'i awards are part of MECO's Safety Recognition Awards Program. Provided Company employees meet established safety goals (e.g., below targeted lost time hours, no industrial and preventive vehicle accidents, etc.) and other employment eligibility requirements, qualifying employees attend a Ho'omaika'i Awards Banquet, receive Process Area Team Awards (gifts) and receive limited Special Recognition Awards (cash).

Q. PLEASE EXPLAIN HOW MECO QUANTIFIED THE AMOUNT OF HO'OMAIKA'I COSTS INCLUDED IN THE COMPANY'S 2007 TEST YEAR FORECAST.

A. In the forecast workpapers provided by the Company,[73] MECO has proposed to include $56,800 in the 2007 test year for Ho'omaika'i Awards costs, summarized as follows:

	2007 Forecast Amount
Ho'omaika'i Awards Banquet	$ 22,350
Process Team Awards	29,450
Special Recognition Awards	5,000
Total	$ 56,800

Source: MECO T-9, response to CA-IR-2, Attachment C.

[73] *MECO T-9 response to CA-IR-2, Attachment C. Although this workpaper also includes* $36,850 for Ho'okina Awards, MECO T-9 removes this amount from the forecast in the June 2007 Update because the program was terminated.

1 These forecast amounts assume 335 employees (plus 335 guests)
2 attend a Ho'omaika'i banquet, 335 employees receive gifts ($50 to $100
3 value), and 6 employees receive cash awards ($500 to $1,000).
4
5 Q. WHY IS IT NECESSARY TO ADJUST MECO'S FORECAST ESTIMATE TO A
6 MORE NORMAL LEVEL?
7 A. In response to CA-IR-438, the Company explained the basis for the 2007
8 forecast estimate, as follows:

9 The 2007 test year estimate of $56,800 for the Ho'omaika'i
10 program is reasonable because the Company expects to
11 achieve the goals identified for this program in the test year as
12 well as in subsequent years in which the rates approved by the
13 Commission in this docket are expected to be in effect. As of
14 September 30, 2007, the Company's lost time severity rate
15 was 121, well below the targeted goal of 150. Company safety
16 programs, training and procedures are continually reviewed
17 and, if necessary, improved. The Company's goal each year is
18 not simply to meet the stated corporate safety goal but rather to
19 strive to attain MECO's best safety goal ever.
20
21 As a matter of policy, the Consumer Advocate is not opposed to the use
22 of awards programs to encourage safety in the workplace and reward good
23 safety records. However, in response to CA-IR-372, MECO provided
24 documentation outlining the 2001 Safety Recognition Awards Program[74] and
25 supplied actual program costs for the Ho'omaika'i Awards Banquet and the
26 Process Area Team Awards for the 2004, 2005 and 2006 program years.

---

[74] *According to the response to CA-IR-372, the 2001 awards program documentation remains* applicable to the program in 2007.

1 Based on a review of this information and the response to CA-IR-438, MECO
2 did not meet all safety goals in two of the three years. The following table
3 summarizes actual costs by program year:

	2004	2005	2006
Ho'omaika'I Awards Banquet	$ 0	$ 22,803	$ 0
Process Team Awards	5,381	29,260	0
Total	$ 5,381	$ 52,063	$ 0

4
5 Based on this recent experience, it is clear that the safety goals are not
6 achieved each and every year, contrary to the assumption underlying the 2007
7 forecast estimate.
8
9 Q. PLEASE EXPLAIN HOW THE CONSUMER ADVOCATE USED THIS
10 RECENT HISTORICAL DATA TO QUANTIFY A MORE NORMAL LEVEL OF
11 HO'OMAIKA'I AWARD COSTS.
12 A. While the Company's presumption that the safety goals will be attained on an
13 annually recurring basis has not been true historically, it is unclear whether the
14 recent experience of attaining those goals in only one out of three years is
15 reasonable. Consequently, CA Adjustment C-20 is based on a normalized
16 forecast level based on a four-year average of awards costs – the three
17 historical years (2004-2006) and MECO's 2007 forecast estimate.
18 The Consumer Advocate certainly looks forward to MECO's rebuttal
19 testimony on this matter for more information as to the reasonableness of a
20 50% program year attainment rate. However, based on the information

1 presently available, the Consumer Advocate believes that the recommended
2 normalization approach is reasonable for purposes of this rate case.
3
4 **XII. EEI DUES & VEHICLE ON-COST.**
5 Q. HAS THE CONSUMER ADVOCATE PROPOSED AN ADJUSTMENT TO
6 MECO'S CURRENT FORECAST LEVEL FOR EITHER EEI DUES OR
7 VEHICLE DEPRECIATION?
8 A. No. The Consumer Advocate has not proposed an adjustment for either EEI
9 Dues or Vehicle Depreciation at the present time.
10
11 Q. DO YOU BELIEVE THAT AN ADJUSTMENT TO EEI DUES IS
12 WARRANTED?
13 A. In the recent HECO rate case, the Company proposed to exclude a portion of
14 the 2007 forecast of EEI Dues as being attributable to government lobbying.[75]
15 The Department of Defense applied a larger exclusion percentage based on
16 amounts EEI spent on legislative and regulatory advocacy, advertising,
17 marketing and public relations – in 2005. For settlement purposes, the Parties
18 to that docket agreed to a disallowance similar to that proposed by the
19 Department of Defense, but updated to reflect the percentage of comparable
20 EEI expenditures in 2006.

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[75] The HECO exclusion was 15% of Membership Dues for Regular Activities and 70% of the Mutual Assistance Program fees (HECO-1304, p. 5).

Because MECO's forecast exclusion (see MECO-917, p. 2) mirrors the exclusion presented by HECO in direct testimony, it would be reasonable to employ the HECO settlement methodology in the MECO rate case. However, the Consumer Advocate has quantified that adjustment to be only about $8,500, before allocation between the three MECO divisions. In light of this limited adjustment value, the Consumer Advocate has not proposed an adjustment at this time, since such adjustment would have a negligible impact on the resulting test year revenue requirement and resulting rates.

Q. SHOULD MECO'S VEHICLE DEPRECIATION FORECAST BE REVISED?

A. Possibly. CA-IR-346 and CA-IR-370 were submitted seeking additional support for the vehicle costs included in MECO's rate case forecast. In response to these information requests, MECO indicated that the vehicle on-cost rates used in the 2007 forecast were incorrect and understated total vehicle costs by as much as $202,000.

Subsequently, CA-IR-439 and CA-IR-440 were submitted for additional information to allow the Consumer Advocate to further evaluate the identified revisions.[76] Because vehicle on-costs are not charged 100% to O&M expense and the Company's response to CA-IR-439 did not contain the requested allocation of vehicle on-costs between expense, capital and billable work, the

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[76] The response to CA-IR-439 also disclosed that the calculated understatement ($202,000) was also incorrect as vehicle depreciation had been overstated by about $30,000.

1 Consumer Advocate was unable to fully evaluate or fashion an accurate
2 adjustment to correct MECO's vehicle expense forecast. Although MECO did
3 not clearly state whether it intended to correct this element of the rate case
4 forecast, the Consumer Advocate will review any subsequent revisions and
5 workpapers proposed by the Company, but reserves the right to request any
6 additional supporting documentation that might be required.
7
8 **XIII. CASH WORKING CAPITAL.**
9 Q. PLEASE DESCRIBE CA ADJUSTMENT B-5.
10 A. CA Adjustment B-5 eliminates non-cash items (i.e., pension accruals and
11 pension asset amortization) from MECO's updated lead lag study results and
12 incorporates the Consumer Advocate's adjusted income statement
13 projections, consistent with prior Commission decisions.[77]
14
15 Q. DOES CA ADJUSTMENT B-5 CALCULATE WORKING CASH AT
16 PROPOSED RATE LEVELS, SIMILAR TO THE COMPANY'S WORKING
17 CASH PRESENTATION?
18 A. Yes. CA Adjustment B-5 quantifies Cash Working Capital at both present and
19 the Consumer Advocate's proposed rate levels.
20

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[77] The Company's study properly excluded other non-cash items such as depreciation expense and deferred income tax expense.

1 Q. WHAT IS CASH WORKING CAPITAL AND WHY SHOULD IT BE
2 RECOGNIZED IN RATE BASE?
3 A. Cash working capital, or working cash as referenced by MECO, is commonly
4 defined as the amount of cash needed by a utility to pay its day-to-day
5 expenses incurred in providing service in relation to the timing of the collection
6 of revenues for those services. In applying this definition, if the timing of a
7 company's cash expenditures, in the aggregate, precedes the cash recovery
8 of those expenses, investors must provide cash working capital. On the other
9 hand, ratepayers are considered the providers of cash working capital in
10 instances where their remittances, on average, precede the company's cash
11 disbursements for expenses. Whether "positive" or "negative" in amount, cash
12 working capital is typically included in utility rate base to recognize the timing
13 of cash flows through the utility.
14
15 Q. IN YOUR OPINION, HOW SHOULD CASH WORKING CAPITAL BE
16 QUANTIFIED FOR INCLUSION IN RATE BASE?
17 A. In my opinion, sample-based lead lag studies represent the best available
18 method for quantifying the revenue and expense component lags that are
19 used in determining cash working capital. Although it may not be feasible to
20 completely update such studies when a utility routinely seeks an annual rate
21 increase, due to the complex and detailed nature of such an undertaking,
22 major components of the lead lag study should be updated periodically to
23 ensure that the revenue and expense lag calculations reasonably represent

current operational conditions and reflect the effects of recent changes in corporate policies, as well as organizational structure.

The study prepared by MECO[78] uses the same basic methodology, including the common revenue and/or expense lags presented in HECO's 2005 and 2007 test year rate case. While a sampling methodology was not specifically used to determine the lead lag days that are unique to MECO, MECO's current study results did include additional analyses to identify actual payment dates for certain transactions.

Q. PLEASE IDENTIFY THE MAJOR CASH FLOWS OF A TYPICAL PUBLIC UTILITY, INDICATING WHICH CASH FLOWS ARE RELEVANT TO THE MEASUREMENT OF CASH WORKING CAPITAL REQUIREMENTS.

A. The major sources and uses of cash typically observable in a utility's statement of cash flows, or its equivalent, include:

<u>Sources of cash for a utility ordinarily</u>:

- Operating revenues.
- Non-operating and non-jurisdictional revenues.
- Proceeds from outside financings or debt/ equity infusions from parent.
- Asset sales.

---

78 MECO witness Gayle Ohasi (MECO T-15, pp.15-33) sponsors an analysis of working cash using a lead lag study of cash flow. The original study results, summarized by MECO-1507, MECO-1513 and MECO-1519, were subsequently updated by MECO T-15 June 2007 Update.

1 Uses of utility cash:
2 • Payment of utility expenses.
3 • Utility plant construction expenditures.
4 • Payment of non-operating or non-jurisdictional costs.
5 • Net change in other assets (inventory, cash, prepayments).
6 • Retirement of debt or equity.
7
8 Given the definition of cash working capital discussed previously
9 (i.e., "the amount of cash needed by a utility to pay its day-to-day expenses"),
10 cash flow timing and measurement is properly focused solely on the first cash
11 "source" and the first cash "use" listed above. All other sources and uses are
12 either separately considered in the ratemaking process or are non-operational,
13 financing or investing functions – not transactions related to the day-to-day
14 payment of operating expenses. It is also important to note that some
15 operating revenues represent a utility's recovery of recorded "non-cash"
16 expenses, such as depreciation, amortization, deferred income tax and other
17 recorded expenses that do not entail a near-term expenditure of cash. While
18 these accrued expenses are properly included in determining overall revenue
19 requirements, the expenses do not require the current expenditure of cash.
20 Therefore, these "non-cash" expenses fall outside the scope of a properly
21 prepared lead lag study.
22

1 Q. HAS MECO PROPOSED TO INCLUDE THESE VARIOUS NON-CASH
2 ITEMS IN THE QUANTIFICATION OF THE AMOUNT OF CASH WORKING
3 CAPITAL?
4 A. MECO's study properly excludes depreciation and deferred income tax
5 expenses from the overall calculation of cash working capital. However, the
6 Company has included the following non-cash amounts in its updated study
7 results:
8 • Pension asset amortization; and
9 • Pension expense.
10 While the pension asset amortization appears as a separate line item in
11 the Company's revised CWC study, pension expense was embedded in the
12 "O&M Nonlabor" line set forth on revised MECO-1507, MECO-1513 and
13 MECO-1519.[79]
14
15 Q. COULD YOU SUMMARIZE THE REVENUE AND EXPENSE LAG
16 TREATMENT THAT MECO HAS PROPOSED FOR EACH OF THESE
17 NON-CASH ITEMS?
18 A. Referring to the MECO T-15 June 2007 Update, the following table
19 summarizes MECO's most recent proposals regarding the revenue lag and
20 expense lag treatment attributed to each of non-cash item:
21

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[79] See MECO T-15 June 2007 Update.

	Revenue Lag	Expense Lag	Net Lag
Pension Asset Amortization	36	0	36
Pension Expense			
With Tracker	36	14	23
Without Tracker	36	0	36
OPEB			
With Tracker	36	84	-48
Without Tracker	36	0	36

Q. PLEASE SUMMARIZE THE CONSUMER ADVOCATE'S PROPOSED TREATMENT OF THESE ITEMS.

A. With the exception of OPEBs, I consider each of these items to represent non-cash accruals recorded by the Company. As a matter of longstanding policy and practice, the Commission has determined that non-cash expenses not requiring current period cash payments[80] should be excluded from cash working capital studies. MECO T-15 (page 18) contends that "all payments should be included in the calculation of working cash sources from payment lags," but the Company "excluded those items that have been excluded by the Commission in previous decisions" – specifically referring to the Commission's decision and order in MECO's 1999 rate case.[81]

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80 Non-cash items include accrual-basis items, such as depreciation and amortization expenses, return on investment (i.e., operating income) and deferred income tax expenses.

81 In Amended Decision and Order No. 16922 at 28-29, the Commission stated that it had approved the inclusion of six expense components (fuel oil, purchase power, O&M labor, O&M non-labor, revenue taxes and income taxes) in the calculation of working cash in the last several MECO rate cases. This order also observed that MECO revised the working cash payment lags for O&M non-labor to exclude nonfunded pensions subsequent to rebuttal testimony. Further, the Commission revised the working cash calculation to reflect the level of expense it approved.

1 Consistent with past Commission decisions on this issue, all non-cash
2 accrued expenses recorded by the Company should be excluded from any
3 lead lag study of cash flows, unless MECO is required to disburse cash or
4 otherwise make cash funding contributions to its external pension or OPEB
5 funding vehicles.
6 For purposes of the current proceeding, MECO has proposed a 14-day
7 pension lag and an 84-day OPEB lag, if the Commission approves the pension
8 and OPEB tracking mechanisms recommended by Mr. Matsunaga
9 (MECO T-9) in the June 2007 Update, since the proposed trackers include
10 funding requirements. Otherwise, the Company would assign a "zero"
11 expense lag to both pension and OPEB accrued expenses.
12
13 Q. DO YOU AGREE WITH THE LINKAGE OF MECO'S EXPENSE LAG
14 TREATMENT WITH THE COMMISSION'S ACCEPTANCE OF THE
15 REFERENCED TRACKING MECHANISMS?
16 A. No. First, the Consumer Advocate does not object to assigning an expense
17 lag to pension accruals for that portion of the expense that is supported by
18 recurring fund contributions. Absent linked contributions, the pension accrual
19 is nothing more that another non-cash expense – that is, the expense is
20 recorded on the income statement, but no cash disbursement is made to a
21 third party entity. Recognizing that MECO does not anticipate making a

1 pension contribution in 2007,[82] the Consumer Advocate recommends removal
2 of this item from the lead lag study by assigning a "zero" revenue lag and a
3 "zero" expense lag to pensions, absent plans or a study specifically analyzing
4 pension cash flows.

5 Second, as observed by Company witness Ms. Julie Price
6 (MECO T-10, page 18), Commission Decision and Order No. 13659 required
7 MECO to fund its entire postretirement benefit costs (i.e., OPEB accruals) to
8 the maximum extent possible using tax advantaged funding vehicles.
9 Referring to MECO T-9 June 2007 Update, Attachment 6, MECO has made
10 recurring annual contributions to external funds since the issuance of Decision
11 and Order No. 13659. In light of this recurring funding history, MECO's
12 attempt to link the value of the OPEB expense lag (i.e., "zero" days or
13 84 days) to whether the Commission adopts the OPEB tracking mechanism is
14 inappropriate and should be rejected. CA Adjustment B-5 recognizes an
15 84 day expense lag for the OPEB expense, a component of the
16 "O&M Nonlabor" category. The full 36 day revenue lag is also assigned to the
17 "O&M Nonlabor" category.
18

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82 See MECO T-9 June 2007 Update, Attachment 5.

1 Q. YOU EARLIER MENTIONED THAT CA ADJUSTMENT B-5 REMOVED NON-
2 CASH ITEMS FROM THE LEAD LAG STUDY BY ASSIGNING A "ZERO"
3 REVENUE LAG AND "ZERO" EXPENSE LAG. IS THAT CORRECT?
4 A. Yes. For presentation purposes, CA Adjustment B-5 continues to show the
5 pension expense amount for this non-cash item, with no revenue lag or
6 expense lag. However, the overall effect of removing these items from
7 influencing the lead lag study results could have also been accomplished by
8 showing the expense value at "zero."
9
10 **XIV. <u>CAPITAL STRUCTURE & COST RATES</u>.**
11 Q. COULD YOU BRIEFLY IDENTIFY THE CAPITAL STRUCTURE AND COST
12 RATES PROPOSED BY CONSUMER ADVOCATE IN THIS CAUSE?
13 A. Yes. CA Schedule D of the CA Joint Accounting Schedules sets forth the
14 capital structure and cost rates recommended by both MECO[83] and the
15 Consumer Advocate, including the return on equity recommended by
16 Consumer Advocate witness Parcell (CA-T-4). For purposes of the Consumer
17 Advocate's direct testimony and revenue requirement recommendation,
18 CA Schedules A and D employ the capital structure and cost rates sponsored
19 by Mr. Parcell.

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83 The MECO forecast capital structure set forth on CA Schedule D represents the Company's original filed balances and cost rates, per MECO-2001 and CA-IR-304, Attachment A, p.2. While MECO's June 2007 Update did not update or revise its consolidated capital structure or cost rates, the Company's original filing adjusted the weighted cost of capital for each division so as to create a "return" subsidy between divisions. In the update, this divisional shift was not employed.

XV. CONCLUSION.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

STEVEN C. CARVER

Summary of Qualifications

EMPLOYER: Utilitech, Inc.
Regulatory and Management Consultants

POSITION: Vice-President

ADDRESS: 740 North Blue Parkway, Suite 204
Lee's Summit, Missouri 64086

PRIOR EXPERIENCE:

6/87 - Present	Utilitech, Inc.
4/83 - 6/87	Missouri Public Service Commission, Chief Accountant
10/79 - 4/83	Missouri Public Service Commission, Accounting Manager
6/77 -10/79	Missouri Public Service Commission, Regulatory Auditor

EDUCATION:

Central Missouri State University
Bachelor of Science Degree in Business Administration
Accounting Major (1977)

State Fair Community College
Associate of Arts Degree - Emphasis in Accounting (1975)

OTHER QUALIFICATIONS:

Speaker - 1988 Missouri Public Service Commission Workshop
- 1990 Annual NASUCA/NARUC Convention (Orlando)
- 1996 Mid-Year NASUCA Meeting (Chicago)

Instructor - 1994 Hawaii Consumer Advocate Regulatory Training Program
- 1997 Hawaii Consumer Advocate Telecommunications Training Program
- 1999 Overview of Utility Regulation (Hawaii)
- 2000 Telecommunications: Overview of Regulation (Arizona)

PRIOR TESTIMONIES: (See listings attached as Exhibit CA-301.)

STEVEN C. CARVER

SUMMARY OF QUALIFICATIONS

Education and Experience

I graduated from State Fair Community College where I received an Associate of Arts Degree with an emphasis in Accounting. I also graduated from Central Missouri State University with a Bachelor of Science Degree in Business Administration, majoring in Accounting. Subsequent to the completion of formal education, my entire professional career has been dedicated to public utility investigations, regulatory analysis and consulting.

From 1977 to 1987, I was employed by the Missouri Public Service Commission in various professional auditing positions associated with the regulation of public utilities. In that capacity, I participated in and supervised various accounting compliance and rate case audits (including earnings reviews) of electric, gas and telephone utility companies and was responsible for the submission of expert testimony as a Staff witness.

In October 1979, I was promoted to the position of Accounting Manager of the Kansas City Office of the Commission Staff and assumed supervisory responsibilities for a staff of regulatory auditors, directing numerous rate case audits of large electric, gas and telephone utility companies operating in the State of Missouri. In April 1983, I was promoted by the Commission to the position of Chief Accountant and assumed overall management and policy responsibilities for the Accounting Department, providing guidance and assistance in the technical development of Staff issues in major rate cases and coordinating the general audit and administrative activities of the Department.

During 1986-1987, I was actively involved in a docket established by the Missouri Public Service Commission to investigate the revenue requirement impact of the Tax Reform Act of 1986 on Missouri utilities. In 1986, I prepared the comments of the Missouri Public Service Commission respecting the Proposed Amendment to FAS

Statement No. 71 (relating to phase-in plans, plant abandonments, plant cost disallowances, etc.) as well as the Proposed Statement of Financial Accounting Standards for Accounting for Income Taxes. I actively participated in the discussions of a subcommittee responsible for drafting the comments of the National Association of Regulatory Utility Commissioners ("NARUC") on the Proposed Amendment to FAS Statement No. 71 and subsequently appeared before the Financial Accounting Standards Board with a Missouri Commissioner to present the positions of NARUC and the Missouri Commission.

In July of 1983 and in addition to my duties as Chief Accountant, I was appointed Project Manager of the Commission Staff's construction audits of two nuclear power plants owned by electric utilities regulated by the Missouri Public Service Commission. As Project Manager, I was involved in the staffing and coordination of the construction audits and in the development and preparation of the Staff's audit findings for presentation to the Commission. In this capacity, I coordinated and supervised a matrix organization of Staff accountants, engineers, attorneys and consultants.

Since commencing employment with Utilitech in June 1987, I have conducted revenue requirement and special studies involving various regulated industries (i.e., electric, gas, telephone and water) and have been associated with regulatory projects on behalf of clients in twenty State regulatory jurisdictions.

Previous Expert Testimony

I have continued to appear as an expert witness before the Missouri Public Service Commission on behalf of various clients, including the Commission Staff. I have filed testimony before utility regulatory agencies in Arizona, California, Florida, Hawaii, Kansas, Indiana, Nevada, New Mexico, Oklahoma, Pennsylvania, Utah, and Washington. My previous experience involving major electric company proceedings includes: PSI Energy, Union Electric (now Ameren), Kansas City Power & Light, Missouri Public Service/ UtiliCorp United (now Aquila), Public Service Company of

Oklahoma, Oklahoma Gas and Electric, Hawaiian Electric, and Sierra Pacific Power/Nevada Power.

Exhibit CA-301 summarizes the various regulatory proceedings in which I have filed testimony.

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2007 (October)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Kansas City Power & Light	Missouri	PSC	ER-78-252	Staff	1978	Rate Base, Operating Income
Gas Service Company	Missouri	PSC	GR-79-114	Staff	1979	Rate Base, Operating Income
United Telephone of Missouri	Missouri	PSC	TO-79-227	Staff	1979	Rate Base, Operating Income, Affiliated Interest
Kansas City Power & Light	Missouri	PSC	ER-80-48	Staff	1980	Operating Income, Fuel Cost
Gas Service Company	Missouri	PSC	GR-80-173	Staff	1980	Operating Income
Southwestern Bell Telephone	Missouri	PSC	TR-80-256	Staff	1980	Operating Income
Missouri Public Service	Missouri	PSC	ER-81-85	Staff	1981	Operating Income
Missouri Public Service	Missouri	PSC	ER-81-154	Staff	1981	Interim Rates
Gas Service Company	Missouri	PSC	GR-81-155	Staff	1981	Operating Income
Gas Service Company	Missouri	PSC	GR-81-257	Staff	1981	Interim Rates
Union Electric Company	Missouri	PSC	ER-82-52	Staff	1982	Operating Income, Fuel Cost
Southwestern Bell Telephone	Missouri	PSC	TR-82-199	Staff	1982	Operating Income
Union Electric Company	Missouri	PSC	ER-83-163	Staff	1983	Rate Base, Plant Cancellation Costs
Gas Service Company	Missouri	PSC	GR-83-207	Staff	1983	Interim Rates
Union Electric Company	Missouri	PSC	ER-84-168/ EO-85-17	Staff	1984 1985	Construction Audit, Operating Income
Kansas City Power & Light	Missouri	PSC	ER-85-128/ EO-85-185	Staff	1983 1985	Construction Audit, Rate Base, Operating Income
St. Joseph Light & Power	Missouri	PSC	EC-88-107	Public Counsel	1987	Rate Base, Operating Income
Northern Indiana Public Service	Indiana	IURC	38380	Consumer Counsel	1988	Operating Income
US West Communications	Arizona	ACC	E-1051-88-146	Staff	1989	Rate Base, Operating Income

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2007 (October)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Dauphin Consol. Water Supply Co.	Pennsylvania	PUC	R-891259	Staff	1989	Rate Base, Operating Income, Rate Design
Southwest Gas Corporation	Arizona	ACC	E-1551-89-102 E-1551-89-103	Staff	1989	Rate Base, Operating Income
Southwestern Bell Telephone	Missouri	PSC	TO-89-56	Public Counsel	1989 1990	Intrastate Cost Accounting Manual
Missouri Public Service	Missouri	PSC	ER-90-101	Public Counsel/ Staff	1990	UtiliCorp United Corporate Structure/ Diversification
City Gas Company	Florida	PSC	891175-GU	Public Counsel	1990	Rate Base, Operating Income, Acquisition Adjustment
Capital City Water Company	Missouri	PSC	WR-90-118	Jefferson City	1991	Rehearing - Water Storage Contract
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1991	Rate Base, Operating Income
Public Service of New Mexico	New Mexico	PSC	2437	USEA	1992	Franchise Taxes
Citizens Utilities Company	Arizona	ACC	ER-1032-92-073	Staff	1992 1993	Rate Base, Operating Income
Missouri Public Service Company	Missouri	PSC	ER-93-37	Staff	1993	Accounting Authority Order
Public Service Company of Oklahoma	Oklahoma	OCC	PUD-1342	Staff	1993	Rate Base, Operating Income, Acquisition Adjustment
Hawaiian Electric Company	Hawaii	PUC	7700	Consumer Advocate	1993	Rate Base, Operating Income
US West Communications	Washington	WUTC	UT-930074, 0307	Public Counsel/ TRACER	1994	Sharing Plan Modifications
US West Communications	Arizona	ACC	E-1051-93-183	Staff	1994	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	IURC	39584	Consumer Counselor	1994	Operating Income, Capital Structure

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2007 (October)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Arkla, a Division of NORAM Energy	Oklahoma	OCC	PUD-940000354	Attorney General	1994	Rate Base, Operating Income
Kauai Electric Division of Citizens Utilities Company	Hawaii	PUC	94-0097	Consumer Advocate	1995	Hurricane Iniki Storm Damage Restoration
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-940000477	Attorney General	1995	Rate Base, Operating Income
US West Communications	Washington	WUTC	UT-950200	Attorney General/ TRACER	1995	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	IURC	40003	Consumer Counselor	1995	Rate Base, Operating Income
GTE Hawaiian Tel; Kauai Electric - Citizens Utilities Co.; Hawaiian Electric Co.; Hawaii Electric Light Co.; Maui Electric Company	Hawaii	PUC	95-0051	Consumer Advocate	1996	Self-Insured Property Damage Reserve
GTE Hawaiian Telephone Co., Inc.	Hawaii	PUC	94-0298	Consumer Advocate	1996	Rate Base, Operating Income
Oklahoma Gas and Electric Company	Oklahoma	OCC	PUD-960000116	Attorney General	1996	Rate Base, Operating Income
Public Service Company	Oklahoma	OCC	PUD-0000214	Attorney General	1997	Rate Base, Operating Income
Arizona Telephone Company (TDS)	Arizona	ACC	U-2063-97-329	Staff	1997	Rate Base, Operating Income, Affiliate Transactions
US West Communications	Utah	UPSC	97-049-08	Committee of Consumer Services	1997	Rate Base, Operating Income

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2007 (October)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Missouri Gas Energy	Missouri	PSC	GR-98-140	Public Counsel	1998	Revenues, Uncollectibles
Sierra Pacific Power Company	Nevada	PUCN	98-4062 98-4063	Utility Consumers Advocate	1999	Sharing Plan
Hawaii Electric Light Co., Power Purchase Agreement (Encogen)	Hawaii	PUC	98-0013	Consumer Advocate	1999	Keahole CT-4/CT-5 AFUDC, Avoided Cost
Kansas City Power & Light Company	Missouri	MoPSC	EC-99-553	GST Steel Company	1999	Complaint Investigation
US West Communications	New Mexico	NM PRC	3008	PRC Staff	2000	Rate Base, Operating Income
Hawaii Electric Light Company	Hawaii	PUC	99-0207	Consumer Advocate	2000	Keahole pre-PSD Common Facilities
US West/ Qwest Communications	Arizona	ACC	T-1051B-99-105	Staff	2000	Rate Base, Operating Income
The Gas Company	Hawaii	PUC	00-0309	Consumer Advocate	2001	Rate Base, Operating Income, Nonreg Svcs.
Craw-Kan Telephone Cooperative, Inc.	Kansas	KCC	01-CRKT-713-AUD	KCC Staff	2001	Rate Base, Operating Income
Home Telephone Company, Inc.	Kansas	KCC	02-HOMT-209-AUD	KCC Staff	2002	Rate Base, Operating Income
Wilson Telephone Company, Inc.	Kansas	KCC	02-WLST-210-AUD	KCC Staff	2002	Rate Base, Operating Income
SBC Pacific Bell	California	PUC	01-09-001 / 01-09-002	Office of Ratepayer Advocate	2002	New Regulatory Framework / Earnings Sharing Investigation

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2007 (October)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
JBN Telephone Company	Kansas	KCC	02-JBNT-846-AUD	KCC Staff	2002	Rate Base, Operating Income
Kerman Telephone Company	California	PUC	02-01-004	Office of Ratepayer Advocate	2002	General Rate Case, Affiliate Lease, Nonregulated Transactions
S&A Telephone Company	Kansas	KCC	03-S&AT-160-AUD	KCC Staff	2003	Rate Base, Operating Income, Nonreg Alloc
PSI Energy, Inc.	Indiana	IURC	42359	Consumer Counselor	2003	Rate Base, Operating Income, Nonreg Alloc
Arizona Public Service Company	Arizona	ACC	E-10345A-03-0437	ACC Staff	2004	Rate Base, Operating Income
Qwest Corporation	Arizona	ACC	T-01051B-03-0454 & T-00000D-00-0672	ACC Staff	2004	Rate Base, Operating Income, Nonreg Alloc
Verizon Northwest Inc.	Washington	WUTC	UT-040788	Attorney General/ AARP/ WeBTEC	2004	Rate Base, Operating Income
Public Service Company	Oklahoma	OCC	PUD-200300076	Attorney General	2005	Operating Income
Hawaiian Electric Company	Hawaii	PUC	04-0113	Consumer Advocate	2005	Rate Base, Operating Income
Citizens Gas & Coke Utility	Indiana	IURC	42767	Consumer Counselor	2005	Operating Income, Benchmarking Study
AmerenUE d/b/a Union Electric Co.	Missouri	MoPSC	ER-2007-0002	State of Missouri	2006	Revenue Requirement
Hawaii Electric Light Company	Hawaii	PUC	05-0315	Consumer Advocate	2007	Rate Base, Operating Income & Keahole Units
Hawaii Electric Company	Hawaii	PUC	2006-0386	Consumer Advocate	2007	Rate Base, Operating Income

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2007 (October)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Maui Electric Company	Hawaii	PUC	2006-0387	Consumer Advocate	2007	Rate Base, Operating Income

CA-101 to CA-104

are being submitted under

Joint Accounting Exhibits and Supporting Schedules

MAUI ELECTRIC COMPANY, LIMITED
DOCKET NO. 2006-0387
HISTORICAL COMPARISON OF PENSION COSTS, CONTRIBUTIONS & PREPAID PENSION ASSET BALANCES

Year	Beginning Pension Asset Balance	Actual		Ending Pension Asset Balance
		NPPC Accrual	Trust Contribution	
(A)	(B)	(C)	(D)	(E)
1987	$ -	$ 1,375,000	$ 1,255,000	$ (120,000)
1988	(120,000)	1,167,000	1,287,000	-
1989	-	1,173,000	1,272,000	99,000
1990	99,000	1,785,000	1,686,000	-
1991	-	1,644,000	1,644,000	-
1992	-	1,864,000	1,863,000	(1,000)
1993	(1,000)	1,802,000	1,798,000	(5,000)
1994	(5,000)	2,140,000	2,138,000	(7,000)
1995	(7,000)	1,461,000	1,441,000	(27,000)
1996	(27,000)	2,009,000	1,970,000	(66,000)
1997	(66,000)	1,765,000	1,755,000	(76,000)
1998	(76,000)	952,000	95,000	(933,000)
1999	(933,000)	591,000	-	(1,524,000)
2000	(1,524,000)	(2,266,000)	-	742,000
2001	742,000	(2,279,000)	-	3,021,000
2002	3,021,000	(1,496,000)	-	4,517,000
2003	4,517,000	2,127,000	3,223,000	5,613,000
2004	5,613,000	1,016,000	4,581,000	9,178,000
2005	9,178,000	1,745,000	1,000,000	8,433,000
2006	8,433,000	3,210,000	-	5,223,000
2007	5,223,000	4,013,000	-	1,209,000
Totals		$ 25,798,000	$ 27,008,000	
2006-2007 Average Balance				$ 3,216,000
% Of Test Year Average Pension Asset Balance Arising from Negative NPPC				187.84%
Totals:				
1993-2007		$ 16,790,000	$ 18,001,000	$ 1,211,000
1998-2007		$ 7,613,000	$ 8,899,000	$ 1,286,000
2000-2007		$ 6,070,000	$ 8,804,000	$ 2,734,000

Source: MECO-928 & MECO response to CA-IR-156, p. 17

MAUI ELECTRIC COMPANY, LIMITED
DOCKET NO. 2006-0387
HISTORICAL ANALYSIS OF PENSION COSTS
INCLUDED IN REVENUE REQUIREMENT

						Total NPPC -- Before Allocation Between Expense & Capital/Other			
Line No.	Year	HPUC Dkt./Dec. No.	Test Year	D&O Effective Date	Assumed Months in Effect	Total NPPC Rate Case Allowance	Prorated NPPC In Rates	Prorated NPPC Accrual	"( )" Denotes NPPC Net Ratepayer Benefit
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	1993	7000/12163 (I)	1993	02/01/93	10.95	**$1,850,000**	$1,687,808	$ 1,644,016	$ 43,792
2	1994				12.00	1,850,000	1,850,000	2,140,000	(290,000)
3	1995				12.00	1,850,000	1,850,000	1,461,000	389,000
4					1.02	1,850,000	156,694	170,161	(13,467)
5	1996	94-0345/14509 (I)	1996	01/31/96	10.98	**2,027,300**	1,855,589	1,838,839	16,750
6		94-0345/15544 (F)		04/25/97					
7	1997	96-0040/16134	1997	N/C	12.00	2,027,300	2,027,300	1,765,000	262,300
8					11.90	2,027,300	2,010,637	944,175	1,066,462
9	1998	97-0346/16768 (I)	1999	12/28/98	0.10	**786,740**	6,466	7,825	(1,358)
10	1999	97-0346/16922(F)		04/09/99	12.00	786,740	786,740	591,000	195,740
11	2000				12.00	786,740	786,740	(2,266,000)	3,052,740
12	2001				12.00	786,740	786,740	(2,279,000)	3,065,740
13	2002				12.00	786,740	786,740	(1,496,000)	2,282,740
14	2003				12.00	786,740	786,740	2,127,000	(1,340,260)
15	2004				12.00	786,740	786,740	1,016,000	(229,260)
16	2005				12.00	786,740	786,740	1,745,000	(958,260)
17	2006				12.00	786,740	786,740	3,210,000	(2,423,260)
18	2007				12.00	786,740	786,740	4,013,000	(3,226,260)
19		1993-2007 Totals Since Ratemaking Recognition of FAS87					$18,525,158	$16,632,016	$ 1,893,141
20		1998-2007 Totals Since Pension Asset ~ $1 Million in 1998					$ 9,097,767	$ 7,613,000	$ 1,484,767
21		2000-2007 Totals Since NPPC Materially Negative in 2000					$ 6,293,923	$ 6,070,000	$ 223,923

Col. B HPUC Docket/Decision No. Reference:

(I) =Interim Rate Order.

(F) =Final Rate Order.

Col. B-D Source: MECO response to CA-IR-161 & HPUC decisions.

Col. E Number of months rates are in effect based on interim dates.

Col. F Source: MECO response to CA-IR-161. Note: The 1999 rate case test year amount is NPPC of $887,000 less the revenue requirement effect of the net pension liability included in rate base of about $90,260 (i.e., $733,385 pension liability times 12.3%).

Col. G "NPPC Rate Case Allowance" (Col. F) times number of months in effect (Col. E) divided by 12.

Col. H "NPPC Accrual" (from Exhibit CA-105, Col. C) times number of months in effect (Col. E) divided by 12.

[NPPC Accrual represents total FAS87 accrual, before allocation to capital and billed to others.]

Col. I "NPPC in Rates" (Col. G) less "NPPC Accrual" (Col. H). Ratepayer benefit arises when "NPPC in Rates" is less than "NPPC Accrual."

-- Ratepayer benefit arises when "NPPC in Rates" is less than "NPPC Accrual."

-- Ratepayer detriment arises when "NPPC in Rates" is greater than "NPPC Accrual."

MAUI ELECTRIC COMPANY, LIMITED
DOCKET NO. 2006-0387
COMPARISON OF PENSION COSTS IN RATES
& PENSION CONTRIBUTIONS

Year	Beginning Cumulative Difference	Prorated NPPC In Rates	Trust Contributions	Ending Cumulative Difference
(A)	(B)	(C)	(D)	(E)
1993	$ -	$ 1,687,808	$ 1,640,367	$ (47,441)
1994	(47,441)	1,850,000	2,138,000	240,559
1995	240,559	1,850,000	1,441,000	(168,441)
1996	(168,441)	2,012,283	1,970,000	(210,724)
1997	(210,724)	2,027,300	1,755,000	(483,024)
1998	(483,024)	2,017,104	95,000	(2,405,128)
1999	(2,405,128)	786,740	-	(3,191,868)
2000	(3,191,868)	786,740	-	(3,978,608)
2001	(3,978,608)	786,740	-	(4,765,349)
2002	(4,765,349)	786,740	-	(5,552,089)
2003	(5,552,089)	786,740	3,223,000	(3,115,829)
2004	(3,115,829)	786,740	4,581,000	678,430
2005	678,430	786,740	1,000,000	891,690
2006	891,690	786,740	-	104,950
2007	104,950	786,740	-	(681,791)
1993-2007		$ 18,525,158	$ 17,843,367	$ (681,791)
1998-2007		$ 9,097,767	$ 8,899,000	$ (198,767)
2000-2007		$ 6,293,923	$ 8,804,000	$ 2,510,077

Source : MECO-928 & Exhibit CA-106.
"( )" Denotes implied liability to ratepayers due to "NPPC in Rates" in excess of "Trust Contributions."

CONSUMER ADVOCATE
PROPOSED PENSION TRACKING MECHANISM

Purpose: The proposed pension tracking mechanism is designed to achieve the following objectives:

A. Ensure that the pension costs recovered through rates are based on the FAS87 NPPC, as reported for financial reporting purposes;

B. Ensure that all amounts contributed to the pension trust funds (subject to the exceptions in Item 3 below) are in an amount equal to actual NPPC and are recoverable through rates; and

C. Clarify the future treatment of any charges that would otherwise be recorded to equity (e.g., increases/decreases to other comprehensive income) as required by FAS87, FAS158 or any other FASB statement or procedure relative to the recognition of pension costs and/or liabilities.

Procedure:

1. The amount of FAS 87 NPPC included in rates shall be equal to the amount recognized for financial reporting purposes.

2. Except when limited by the ERISA minimum contributions requirements or the maximum contribution imposed by the IRC, or the contribution exceeds the NPPC for a reason provided in Item 3, the annual contribution to the pension trust fund will be equal to the amount of FAS87 NPPC.

3. The utility will be allowed to recover through rates the amount of any contributions to the pension trust in excess of the FAS87 NPPC that were made for the following reasons[1]:

- the minimum required contribution is greater than the FAS 87 NPPC,
- the increased contribution was made to avoid a significant increase in Pension Benefit Guaranty Corporation (PBGC) variable premiums,
- the increased contribution was made to avoid a charge to other comprehensive income, or
- the increased contribution was made to avoid: (i) higher minimum contribution requirements under the Pension Protection Act,[2] or (ii) other adverse funding requirements under federal pension regulations (provided funding does not exceed 100% of the PBO as a result). The recoverability *of any discretionary contributions (as described under this bullet item) shall be subject to review in the Company's next rate case*

Any such "excess" contributions shall be recorded in a separate regulatory asset account, which will be included in rate base.

4. A regulatory asset (or liability) will be established on the Company's books to track the difference between the level of actual FAS87 NPPC during the rate effective period and the level of FAS87 NPPC included in rates during that same period.

---

1 The Company or the Consumer Advocate (jointly, the "Parties") may initiate discussions with the Parties and the Hawaii Public Utilities Commission to modify these provisions between rate cases (with Commission approval) if there are future changes in accounting standards, federal tax law or federal tax regulations that materially impact the costs otherwise recoverable through this tracking mechanism.

2 Transitional relief applies under the Pension Protection Act if the plan's target liability funded level meets the prescribed phase-in percentages for 2008 through 2011. The Parties recognize that such transitional relief or related requirements may be subject to change or revision in future years.

- The unamortized cumulative net ratepayer benefit of approximately $0 ("zero" dollars), as of December 2007, shall be included in rate base and amortized over a five year period.

- If the actual FAS87-determined NPPC recorded during a given rate-effective period is greater than the FAS87 NPPC included in rates during the immediately preceding rate case, the Company will establish a separate regulatory asset account to accumulate such difference, but only to the extent that such amount is not used to reduce a regulatory liability recorded pursuant to Item 5.

- If the actual FAS87-determined NPPC recorded during the rate-effective period, adjusted for any amount of such expense used to reduce a regulatory liability maintained pursuant to Item 5, is less than the expense built into rates, the Company will establish a separate regulatory liability account to accumulate such difference.

- If the actual FAS87 NPPC becomes negative, the regulatory liability will be increased by the difference between the level of FAS87 NPPC included in rates for that period and "zero" (i.e., $0).

- Since this is considered to be a cash item under the tracking mechanism, the regulatory asset or liability will be included in rate base and amortized over a five (5) year period at the time of the next following rate case.

5. If the FAS87 NPPC becomes negative, the Company will set up a regulatory liability to offset the prepaid pension asset created by the negative amount. This regulatory liability will increase by the amount of any negative NPPC, or decrease by the amount of positive NPPC, in each subsequent year. Positive NPPC in each subsequent year will be used to reduce the regulatory liability before being used to establish a regulatory asset pursuant to Item 4.

- If NPPC is negative at the time of the next rate case, the amount included in rates will be "zero" (i.e., $0).

- If NPPC is positive at the time of the next rate case, the positive expense will not be included in rates and the Company will not be required to make contributions to the trust until any regulatory liability created under this Item 5 has been reduced to "zero" (i.e., $0).

- Since this regulatory liability is considered to be a non-cash item under the tracking mechanism, it is not subjected to amortization and should not be recognized in determining rate base in future years.

6. The objective of this tracking mechanism is that, over time, the Company will recover through rates FAS87-based NPPC, including the amortization of unrecognized amounts as set forth above.

- The Company will establish a separate regulatory asset/liability account to offset any charge, or credit, that would otherwise be recorded against equity (e.g., decreases to other comprehensive income) caused by applying the provisions of FAS87, FAS158 or any other FASB statement or procedure that requires accounting adjustments due to the funded status or other attributes of the Company's pension plan.

- This regulatory asset/liability will not be amortized into rates or included in rate base, because any such charges are expected to be recovered in rates through the valuation of FAS87 NPPC in future accounting periods, which will be subject to the true-up process described herein. In other words, this regulatory asset/liability will automatically be reversed through the mechanics of FAS87 and, pursuant to other provisions of this tracking mechanism, all FAS87-determined NPPC will over time ultimately be recovered from ratepayers.

- The regulatory asset/liability will increase or decrease each year by the same amount that the equity charge increases or decreases.

7. Recognizing that rate cases do not typically occur on a five-year cycle, the Company will continue to record any amortizations allowed herein throughout the effective term that the approved rates remain in effect, regardless whether the term is longer or shorter than five years.

- If the rate effective period is less than five years, the Company will be allowed to recover any unamortized and unrecovered amounts in the next following rate case over a five year period and any unamortized balance shall be included in rate base.

- If the rate effective period is greater than five years, the Company will be required to establish a separate regulatory asset or liability to accumulate

any excess amortization, which shall be included in rate base and amortized over a five year period in the next following rate case.

8. Any prepaid pension asset or accrued liability recorded pursuant to the terms and conditions of FAS87 (as opposed to regulatory assets arising from the provisions of this proposed tracking mechanism) will not be included in Rate Base in any future rate case, except for the unamortized portion of the $0 ("zero" dollars)_of cumulative net ratepayer benefits previously identified. The regulatory assets/liabilities discussed herein specifically identify all rate base includable amounts for pension differences.

Comments & Clarifications
Regarding the Consumer Advocate's
Proposed Pension Tracking Mechanism

1. The proposed tracking mechanism refers to "NPPC" in explaining how the mechanism operates, which is intended to represent actuarially determined total FAS87 net periodic costs.
2. "NPPC" intentionally encompasses total actuarially determined amounts without regard to any expense allocation or capitalization accounting the Company may recognize on its books and records.
3. Unless limited by IRC maximum contributions or ERISA minimum contributions, the proposed tracking mechanism requires the Company to make annual fund contributions in an amount equal to the total FAS87 net periodic costs determined for each calendar year.
4. The proposed tracking mechanism requires the Company to establish a regulatory asset or liability for the difference between the total FAS87 net periodic costs determined for a given year and the amount of such costs included in then-existing utility rates.
5. The provisions of FAS87 may require a company to record a prepaid pension asset in the normal course of business, without regard to any regulatory agreements or orders adopting a tracking mechanism:
   a. The proposed tracking mechanism would exclude from rate base for ratemaking purposes any current or future prepaid pension asset resulting from an actuarial study that resulted in "negative" net periodic costs.

b. The proposed tracking mechanism would exclude, or not recognize, any "negative" net periodic costs for ratemaking purposes, instead setting the amount equal to "zero" (i.e., $0).

6. If the utility is allocated a portion of the FAS87 net periodic costs from an affiliated entity in the normal course of business and the tracking mechanism is approved by the Commission, the Company would be required to commit to funding 100% of the FAS87 net periodic costs for both MECO and the affiliate **or** to maintain segregated pension trust fund accounting for each entity in order to avoid any funding conflicts or issues that might arise in the future.

7. Any commitment by MECO to fund 100% of its FAS87 net periodic costs (as limited under item 3) will not be contingent on implementing a substantially similar tracking mechanism for each MECO affiliate.

8. When an order is issued by the Commission which: 1) adopts the tracking mechanism and 2) establishes new rates that explicitly incorporate the provisions of the mechanism in the new rates, MECO will fund the NPPC for the calendar year of the date of the order based on a monthly proration of the annual NPPC.

CONSUMER ADVOCATE
PROPOSED PENSION TRACKING MECHANISM

Purpose: The proposed pension tracking mechanism is designed to achieve the following objectives:

A. Ensure that the pension costs recovered through rates are based on the FAS87 NPPC, as reported for financial reporting purposes;

B. Ensure that all amounts contributed to the pension trust funds (subject to the exceptions in Item 3 below) are in an amount equal to actual NPPC and are recoverable through rates; and

C. Clarify the future treatment of any charges that would otherwise be recorded to equity (e.g., increases/decreases to other comprehensive income) as required by FAS87, FAS158 or any other FASB statement or procedure relative to the recognition of pension costs and/or liabilities.

Procedure:

1. The amount of FAS 87 NPPC included in rates shall be equal to the amount recognized for financial reporting purposes.

2. Except when limited by the ERISA minimum contributions requirements or the maximum contribution imposed by the IRC, or the contribution exceeds the NPPC for a reason provided in Item 3, the annual contribution to the pension trust fund will be equal to the amount of FAS87 NPPC.

3. The utility will be allowed to recover through rates the amount of any contributions to the pension trust in excess of the FAS87 NPPC that were made for the following reasons[1]:

- the minimum required contribution is greater than the FAS 87 NPPC,
- the increased contribution was made to avoid a significant increase in Pension Benefit Guaranty Corporation (PBGC) variable premiums,
- the increased contribution was made to avoid a charge to other comprehensive income, or
- the increased contribution was made to avoid: (i) higher minimum contribution requirements under the Pension Protection Act,[2] or (ii) other adverse funding requirements under federal pension regulations (provided funding does not exceed 100% of the PBO as a result). The recoverability of any discretionary contributions (as described under this bullet item) shall be subject to review in the Company's next rate case

Any such "excess" contributions shall be recorded in a separate regulatory asset account, which will be included in rate base.

4. A regulatory asset (or liability) will be established on the Company's books to track the difference between the level of actual FAS87 NPPC during the rate effective period and the level of FAS87 NPPC included in rates during that same period.

---

1 The Company or the Consumer Advocate (jointly, the "Parties") may initiate discussions with the Parties and the Hawaii Public Utilities Commission to modify these provisions between rate cases (with Commission approval) if there are future changes in accounting standards, federal tax law or federal tax regulations that materially impact the costs otherwise recoverable through this tracking mechanism.

2 Transitional relief applies under the Pension Protection Act if the plan's target liability funded level meets the prescribed phase-in percentages for 2008 through 2011. The Parties recognize that such transitional relief or related requirements may be subject to change or revision in future years.

- The unamortized cumulative net ratepayer benefit of approximately ~~$1.2 million~~ ~~$0 ("zero" dollars)~~, as of December 2007, shall be included in rate base and amortized over a five year period.

- If the actual FAS87-determined NPPC recorded during a given rate-effective period is greater than the FAS87 NPPC included in rates during the immediately preceding rate case, the Company will establish a separate regulatory asset account to accumulate such difference, but only to the extent that such amount is not used to reduce a regulatory liability recorded pursuant to Item 5.

- If the actual FAS87-determined NPPC recorded during the rate-effective period, adjusted for any amount of such expense used to reduce a regulatory liability maintained pursuant to Item 5, is less than the expense built into rates, the Company will establish a separate regulatory liability account to accumulate such difference.

- If the actual FAS87 NPPC becomes negative, the regulatory liability will be increased by the difference between the level of FAS87 NPPC included in rates for that period and "zero" (i.e., $0).

- Since this is considered to be a cash item under the tracking mechanism, the regulatory asset or liability will be included in rate base and amortized over a five (5) year period at the time of the next following rate case.

5. If the FAS87 NPPC becomes negative, the Company will set up a regulatory liability to offset the prepaid pension asset created by the negative amount. This regulatory liability will increase by the amount of any negative NPPC, or decrease by the amount of positive NPPC, in each subsequent year. Positive NPPC in each subsequent year will be used to reduce the regulatory liability before being used to establish a regulatory asset pursuant to Item 4.

- If NPPC is negative at the time of the next rate case, the amount included in rates will be "zero" (i.e., $0).

- If NPPC is positive at the time of the next rate case, the positive expense will not be included in rates and the Company will not be required to make contributions to the trust until any regulatory liability created under this Item 5 has been reduced to "zero" (i.e., $0).

- Since this regulatory liability is considered to be a non-cash item under the tracking mechanism, it is not subjected to amortization and should not be recognized in determining rate base in future years.

6. The objective of this tracking mechanism is that, over time, the Company will recover through rates FAS87-based NPPC, including the amortization of unrecognized amounts as set forth above.

- The Company will establish a separate regulatory asset/liability account to offset any charge, or credit, that would otherwise be recorded against equity (e.g., decreases to other comprehensive income) caused by applying the provisions of FAS87, FAS158 or any other FASB statement or procedure that requires accounting adjustments due to the funded status or other attributes of the Company's pension plan.

- This regulatory asset/liability will not be amortized into rates or included in *rate base, because any such charges are expected to be recovered in* rates through the valuation of FAS87 NPPC in future accounting periods, which will be subject to the true-up process described herein. In other words, this regulatory asset/liability will automatically be reversed through the mechanics of FAS87 and, pursuant to other provisions of this proposal tracking mechanism, all FAS87-determined NPPC will over time ultimately be recovered from ratepayers.

- The regulatory asset/liability will increase or decrease each year by the same amount that the equity charge increases or decreases.

7. Recognizing that rate cases do not typically occur on a five-year cycle, the Company will continue to record any amortizations allowed herein throughout the effective term that the approved rates remain in effect, regardless whether the term is longer or shorter than five years.

- ~~The amortization established at the adoption of the tracking mechanism shall continue over a five-year period. This amortization will not change over the five-year period and will be included in costs in any rate case in the five-year period. Any unamortized balance shall be included in rate base in any rate case in the five-year period.~~ If the rate effective period is less than five years, the Company will be allowed to recover any unamortized and unrecovered amounts in the next following rate case

over a five year period and any unamortized balance shall be included in rate base.

- The Company will be required to establish a separate regulatory asset or liability to accumulate any excess negative amortization or amortization (separate from the initial pension asset discussed in the preceding bullet), which shall be included in rate base and amortized over a five year period in the next following rate case. If the rate effective period is greater than five years, the Company will be required to establish a separate regulatory asset or liability to accumulate any excess amortization, which shall be included in rate base and amortized over a five year period in the next following rate case.

8. Any prepaid pension asset or accrued liability recorded pursuant to the terms and conditions of FAS87 (as opposed to regulatory assets arising from the provisions of this proposed tracking mechanism) will not be included in Rate Base in any future rate case, *except for the unamortized portion of the* $1.2 million $0 ("zero" dollars) of cumulative net ratepayer benefits previously identified. The regulatory assets/liabilities discussed herein specifically identify all rate base includable amounts for pension differences.

Comments & Clarifications
Regarding the Consumer Advocate's
Proposed Pension Tracking Mechanism

1. The proposed tracking mechanism refers to "NPPC" in explaining how the mechanism operates, which is intended to represent actuarially determined total FAS87 net periodic costs.

2. "NPPC" intentionally encompasses total actuarially determined amounts without regard to any expense allocation or capitalization accounting the Company may recognize on its books and records.

3. Unless limited by IRC maximum contributions or ERISA minimum contributions, the proposed tracking mechanism requires the Company to make annual fund contributions in an amount equal to the total FAS87 net periodic costs determined for each calendar year.

4. *The proposed tracking mechanism requires the Company to establish a* regulatory asset or liability for the difference between the total FAS87 net periodic costs determined for a given year and the amount of such costs included in then-existing utility rates.

5. The provisions of FAS87 may require a company to record a prepaid pension asset in the normal course of business, without regard to any regulatory agreements or orders adopting a tracking mechanism:

   a. The proposed tracking mechanism would exclude from rate base for ratemaking purposes any current or future prepaid pension asset

resulting from an actuarial study that resulted in "negative" net periodic costs.

b. The proposed tracking mechanism would exclude, or not recognize, any "negative" net periodic costs for ratemaking purposes, instead setting the amount equal to "zero" (i.e., $0).

6. If the utility is allocated a portion of the FAS87 net periodic costs from an affiliated entity in the normal course of business and the tracking mechanism is approved by the Commission, the Company would be required to commit to funding 100% of the FAS87 net periodic costs for both MECO and the affiliate **or** to maintain segregated pension trust fund accounting for each entity in order to avoid any funding conflicts or issues that might arise in the future.

7. Any commitment by MECO to fund 100% of its FAS87 net periodic costs (as limited under item 3) will not be contingent on implementing a substantially similar tracking mechanism for each MECO affiliate.

8. When an order is issued by the Commission which: 1) adopts the tracking mechanism and 2) establishes new rates that explicitly incorporate the provisions of the mechanism in the new rates, MECO will fund the NPPC for the calendar year of the date of the order based on a monthly proration of the annual NPPC.

CA-T-2
DOCKET NO. 2006-0387

DIRECT TESTIMONY AND EXHIBITS

OF

JOSEPH A. HERZ

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: Fuel and Purchased Power Expense, Generation Efficiency Factor (Sales Heat Rate), Fuel Inventory, Energy Cost Adjustment Factor and Power Factor Adjustment in Rate Design

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DIRECT TESTIMONY OF JOSEPH A. HERZ, P.E.

I. INTRODUCTION.

Q. PLEASE STATE YOUR NAME, POSITION AND PLACE OF EMPLOYMENT.

A. My name is Joseph A. Herz. I am employed by Sawvel and Associates, Inc. (Sawvel). I am an owner and Vice President of Sawvel, which is an independent consulting firm. Sawvel is located at 100 East Main Cross Street, Suite 300, Findlay, Ohio 45840.

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. Exhibit CA-200 summarizes my professional experience and educational background.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Division of Consumer Advocacy ("Consumer Advocate" or "CA"), who is a participant in this proceeding to represent, advance and protect the interests of Hawaii's electric utility ratepayers.

Q. HAVE YOU PREVIOUSLY PARTICIPATED IN REGULATORY ENGAGEMENTS BEFORE THE HAWAII PUBLIC UTILITIES COMMISSION ("COMMISSION") ON BEHALF OF THE CONSUMER ADVOCATE?

A. Yes. I testified on behalf of the Consumer Advocate in rate case proceedings involving Hawaiian Electric Company, Inc. ("HECO" or "Company") Docket Nos. 7766, 04-0113 and 2006-0386, Hawaii Electric Light Company, Inc. ("HELCO") Docket Nos. 7764, 97-0420, 99-0207, and 05-0315 and Kauai Electric Division ("KED") (nka Kauai Island Utility Cooperative) Docket No. 94-0097. In addition to these rate case engagements, I assisted the Consumer Advocate with its analysis, Statement of Position and/or testimony in various independent power producer ("IPP") purchase power agreements, Integrated Resource Plan ("IRP") proposals, need for resource additions and transmission improvements involving HELCO (Docket Nos. 7623, 97-0349, 98-0013, 99-0346 and 99-0355) and avoided energy cost calculation for a proposed wind facility on Kauai (Docket No. 01-0005). I testified on behalf of the Consumer Advocate in the Commission's generic investigation of distributed generation ("DG") in Hawaii (Docket No. 03-0371). I testified on behalf of the Consumer Advocate in HECO's application to commit funds for a 110 MW Combustion Turbine to be sited in the Campbell Industrial Park area (Docket No. 05-0145) and assisted the Consumer Advocate in reaching a stipulated agreement with HECO and the Department of Defense in Docket No. 7310.

Q. WHAT ARE THE FUNCTIONAL AREAS OF THE CONSUMER ADVOCATE'S PRESENTATION IN THIS DOCKET, FOR WHICH YOU ARE DIRECTLY RESPONSIBLE?

A. My direct testimony provides the Consumer Advocate's position on MECO's 2007 estimated test year fuel and purchased power expense, generation efficiency factor (sales heat rate), fuel inventory and energy cost factor at current rates based on the production simulation results described later in this testimony.

Q. WHAT MATERIALS DID YOU REVIEW AS PART OF YOUR PREPARATION FOR THIS FILING?

A. The materials that I have reviewed are MECO's application, written direct testimonies, exhibits and workpapers, as well as the responses to various information requests submitted by the Consumer Advocate.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes, I am sponsoring Exhibits CA-201 through CA-219. A listing and description of my exhibits is provided in the table of contents at the beginning of this testimony.

II. SUMMARY OF RECOMMENDATIONS.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. It is my recommendation, based on the results of the independent production simulation that I conducted of MECO's system, that the Commission adopt the adjustments shown in Exhibit CA-201, and summarized below, to MECO's 2007 test year direct testimony projections:

1. Maui Division Fuel and Purchased Power Expenses – The recommended fuel expense for the 2007 test year should be decreased by $654,000. The recommended purchased power expense should be increased $6,000. (See CA-201, page 1.)

2. Maui Division Sales Heat Rate – Based on the production cost simulation which the Consumer Advocate has conducted using the estimated 2007 test-year data described above, the fixed sales heat rates for the 2007 test year should be as follows:

Fixed Efficiency Factors	mmBtu/kWh sales	Adjustment
Sales Heat Rate - LFSO	0.015295	(0.000016)
Sales Heat Rate - Diesel	0.009418	(0.000042)
Sales Heat Rate - Other	0.010614	(0.000034)

Source: CA-201, Line 7

The fixed sales heat rates should also be incorporated in the Energy Cost Adjustment Clause ("ECAC") resulting from this proceeding (see CA-201, page 1).

3. Maui Division Fuel Inventory – Utilizing a 30-day industrial fuel oil supply level and a 22-day diesel fuel oil inventory level, which includes an allowance for the Hana DG diesels, the Consumer Advocate's recommended test year fuel consumption and MECO's September 2006 fuel prices, the recommended fuel inventory to be included in the test year rate base is $11,027,000, a decrease of $3,602,000 to MECO's direct testimony filing of $14,629,000 (see CA-201, page 1).

4. Maui Division Energy Cost Acquisition ("ECA") Factor at Current Rates – Based on the adjustments for fuel and purchased power expenses, MECO's direct testimony test year filing ECA factor at current rates of 13.954 cents per kWh should be adjusted and decreased by 0.013 cents per kWh to 13.941 cents per kWh (see CA-201, page 1).

III. MAUI DIVISION FUEL AND PURCHASED POWER EXPENSES.

Q. WHAT IS THE CONSUMER ADVOCATE'S TEST YEAR ESTIMATE OF FUEL EXPENSE?

A. As shown in CA-201, page 1, the Consumer Advocate recommends a test year projection of $166,383,000, which is comprised of fuel oil expense (see CA-204, page 1) and fuel related expense (see CA-205, page 1). CA-204, page 1 shows the derivation of the Consumer Advocate's recommended test year fuel oil expense of $165,872,000. The test year fuel

related expense consists of fuel additives, Petrospect and Ocean Cargo Insurance expenses and is $511,000 as shown in CA-205, page 1.

Q. EXPLAIN HOW YOU DETERMINED YOUR RECOMMENDED TEST YEAR FUEL EXPENSE.

A. Fuel oil expense is derived by multiplying the estimated test year fuel consumption (in barrels) at each of MECO's generating plants by the September 2006 fuel prices for the type of fuel consumed at that plant (see CA-204, page 1). With the exception of the fuel handling component of the fuel related expense, fuel additives, Petrospect and Ocean Cargo Insurance costs (in dollars per barrel) are also applied to the estimated fuel consumption (in barrels) at each of MECO's generating plants (see CA-205). The fuel handling component of fuel related expenses is the value reflected in MECO's direct testimony (see CA-205, page 1).

To determine the test year fuel consumption at each MECO generating plant, I must first determine MECO's estimated 2007 test year energy requirements. Next, I must determine the portion of the energy requirements that will be provided by MECO's purchases from the as-available resources. The balance of MECO's estimated 2007 test year energy requirements, after such purchases, are assumed to be provided by MECO's generating plants and purchases from Hawaiian Commercial & Sugar Company ("HC&S").

To determine the amount of generation that will be produced by all of MECO's generating units, as opposed to the specific generation of HC&S, I needed to simulate the economic dispatch of the as-available generation from MECO, Kaheawa Wind Partners (KWP), Makila Hydroelectric Plant (Makila) and HC&S. This was done using a production simulation model.

The above analysis resulted in the estimated test year fuel consumption of MECO's generation and the associated quantity of fuel that will be consumed at each of MECO's generating plants, as well as the amount of test year energy purchases from the independent power producers (i.e., the as-available and HC&S).

Q. WERE YOU ABLE TO USE THE RESULTS OF THE PRODUCTION SIMULATION MODEL WITHOUT FURTHER ADJUSTMENTS?

A. No, the production simulation model results needed to be adjusted to account for differences in operation that cannot be captured in the model. This adjustment is known as the calibration factor, which is used to adjust the Btu output and subsequently the amount of fuel burned at each MECO generating plant as shown in CA-WP-204, page 2. As described above and shown in CA-204 and CA-205, an estimated fuel oil price, and estimated fuel additives and Petrospect costs, are applied to the estimated test year fuel consumption (determined from the prior step) to arrive at the estimated 2007 test year fuel expense.

A. DETERMINATION OF THE TEST YEAR ENERGY REQUIREMENTS AND SOURCES OF ENERGY SUPPLY.

Q. HOW DID YOU DETERMINE MECO'S ESTIMATED 2007 TEST YEAR ENERGY REQUIREMENTS?

A. The determination of MECO's estimated 2007 test year energy requirements is set forth on CA-203. As shown on CA-203, the starting point of the process is MECO's forecasted sales for the test year. Next, the amount of energy that the Company will use at its buildings and facilities (referred to as "Company Use" and also referred to as "No Charge") is determined. Finally, the amount of energy that will be lost in the system as the power is transformed into the voltages required for transmission and distribution throughout the Company's system (referred to as MECO system losses (5.95%)) must be determined. The sum of the above three items represents the total system energy requirements, or the amount of power that must be generated by MECO's generation and the generation of the independent power producers who sell power to the Company.

1. The Consumer Advocate's 2007 Test Year forecasted sales for MECO.

Q. WHAT ARE MECO'S TEST YEAR FORECASTED SALES?

A. CA-203 contains MECO's direct testimony sales forecast. MECO's estimated 2007 test year energy requirements are based on a forecasted sales level of 1,212.9 GWh.

Q. WHAT IS THE CONSUMER ADVOCATE'S ESTIMATE OF MECO FORECASTED SALES?

A. As discussed in CA-T-3, the Consumer Advocate adopted the MECO test year sales projection reflected in the Company's direct testimony filing.

2. The Consumer Advocate's estimated Company Use or No Charge for the 2007 test year.

Q. WHAT EXACTLY IS THIS COMPANY USE ENERGY THAT IS ADDED TO FORECASTED SALES?

A. Company Use energy involves electric energy use at MECO's buildings and facilities. Such energy use at MECO's buildings and facilities is included with forecasted sales and system losses to determine the amount of energy to be generated by MECO's generating units and purchased from others. Since the cost of supplying this "Company Use" is included in MECO's revenue requirements to be recovered from ratepayers, the amount of estimated test year energy use at MECO's buildings and facilities has an impact on the revenue deficiency and level of rate increase to be established in this proceeding. As shown in MECO-403, MECO included an estimate of 16.6 GWh of Company Use in its test year energy requirements.

Q. WHAT IS THE CONSUMER ADVOCATE'S TEST YEAR ESTIMATE OF COMPANY USE OR NO CHARGE?

A. The Consumer Advocate used MECO's estimate of Company Use and believes the amount represents a reasonable estimate as calculated by MECO in MECO-WP-403, pages 1 through 3. The following table shows MECO Historical Company Use from MECO-WP-403, page 2.

	Company Use (MWh)	Total Recorded Sales (MWh)	No Charge % of Sales (%)
2001	1,690	1,071,486	0.16%
2002	1,611	1,096,739	0.15%
2003	1,647	1,142,689	0.14%
2004	1,655	1,184,544	0.14%
2005	1,709	1,188,253	0.14%
	8,312		0.15%
Average	1,662		

This table indicates an average Company Use of 1,662 MWh for the historical period of 2001 through 2005. This level of use is 0.15% of sales to customers over the five-year historical period. MECO's Company Use of 16.6 GWh is consistent with the method used in the last MECO rate case and is reasonable.

1 **3. Estimate of System Losses for the test year.**

2 Q. WHAT ARE SYSTEM LOSSES AND HOW ARE THEY INCURRED BY
3 MECO?

4 A. During the transmission, distribution and transformation of electricity from
5 MECO's power supply resources to MECO's customers, losses are incurred
6 on the transmission and distribution systems. In addition, MECO incurs
7 step-up transformation losses for power produced at its generating facilities.
8 The purpose of the system loss factor is to estimate the amount of energy loss
9 that must be added to forecasted sales and Company Use to determine
10 MECO's total system energy requirements.

11

12 Q. HOW WAS THE SYSTEM LOSS FACTOR UTILIZED?

13 A. Forecasted sales and Company Use were adjusted by the system loss factor
14 to arrive at the test year energy requirements to be provided by MECO's
15 generating and purchase power resources. System losses are shown on
16 Line 4 of Exhibit CA-203.

17

18 Q. PLEASE DESCRIBE THE LOSS FACTOR USED BY MECO.

19 A. As shown in MECO-403, system losses were computed at 5.95% of Net
20 Energy to System. This loss factor is based on historical losses for the 5-year
21 period of 2001 through 2005 shown in MECO-WP-403, page 2. The range of
22 losses during the five-year period was 5.73% to 6.08%. The five-year average

approach is reasonable to ensure that extraordinarily high or low losses are not used in the test year and is a fair and reasonable approach.

Q. DOES THE CONSUMER ADVOCATE HAVE ANY CONCERNS WITH THE METHODOLOGY USED BY MECO TO DETERMINE THE TEST YEAR SYSTEM LOSS PROJECTIONS?

A. No, the Consumer Advocate agrees that MECO's methodology is reasonable for purposes of determining the total system losses for production simulation modeling purposes.

Q. WHAT LOSS FACTOR IS THE CONSUMER ADVOCATE RECOMMENDING BE USED FOR PURPOSES OF DETERMINING THE TEST YEAR FUEL AND PURCHASED POWER EXPENSE?

A. The Consumer Advocate used MECO's estimated loss factor of 5.95%. MECO's actual average loss factor for the five-year period 2001 through 2005 was 5.91%

4. Projected As-Available Energy for the test year.

Q. WHAT IS AS-AVAILABLE ENERGY?

A. As-available energy is that which is provided only when the resource is available. In the instant proceeding, the energy is provided by independent power producers, when such producers have the energy available for sale to

MECO. In addition to the as-available producers, MECO purchases energy from the HC&S facility.

Q. WHAT IS THE AMOUNT OF TEST YEAR ENERGY ANTICIPATED TO BE PROVIDED BY THE AS-AVAILABLE RESOURCES AND HC&S?

A. MECO estimated that the as-available resources consisting of KWP and Makila will provide 14,159,946 and 170,923 kWh, respectively, in the 2007 test year (see MECO-507). MECO's estimate of as-available energy purchased from KWP was based on KWP's estimated plant capacity factor that was based on wind studies performed for the location of the wind farm. MECO's estimate of as-available energy purchased from Makila was based on conversations with Makila and past experience with Pioneer Mill. (See MECO T-5, page 32 and 33 and MECO-507).

Q. DOES THE CONSUMER ADVOCATE HAVE ANY CONCERNS WITH MECO'S TEST PROJECTION FOR THESE TWO ITEMS?

A. No, the Consumer Advocate reviewed the information in the testimony and concluded that MECO's estimates are reasonable. Thus, the Consumer Advocate has adopted MECO's energy estimate of as-available resources for purposes of this proceeding.

Q. WHAT IS THE AMOUNT OF TEST YEAR ENERGY ANTICIPATED TO BE PROVIDED BY HC&S?

A. MECO used purchase power contract provisions and historical trends to forecast the test year energy from HC&S (see MECO T-5, page 31). MECO's test year forecast of purchased energy from HC&S assumes that the plant is shut down for 262 hours in January for routine maintenance. In addition, HC&S is scheduled to reduce their on-peak capacity from 12 MW to 8MW on January 30, February 21, February 22 and February 23. According to the MECO-HC&S PPA, HC&S has the right to designate a period or periods totaling a maximum of 437 hours per contract year during which firm capacity will be 8 MW. HC&S informed MECO that they will be exercising this right on the dates mentioned. MECO anticipates that HC&S test year estimate of "regular energy" to be purchased is 12 MW during the 14-hour on-peak period (7:00am to 9:00pm) and 8 MW during the off-peak period (9:00pm to 7:00am). HC&S is expected to provide "optional additional energy" and "supplement schedule power" during the on-peak period as shown in CA-WP-110. MECO's estimate of 2007 test year energy to be available from HC&S is 90 GWh (see MECO-507).

Later in my testimony, I will describe MECO's energy cost adjustment clause that provides a pass through to MECO's ratepayers of MECO's actual purchased energy mix and prices. Accordingly, the cost associated with any deviations in HC&S's actual energy purchases versus that estimated for the

test year will be passed through to MECO's ratepayers. For purposes of this proceeding, I believe that MECO's estimate of test year energy purchases from HC&S is reasonable and the Consumer Advocate has adopted MECO's estimate for HC&S as presented in its filing.

5. Determination of the energy to be provided by MECO's generation and the generation from the independent power producers (i.e., KWP and Makila).

Q. HOW ARE MECO'S GENERATING PLANT FUEL CONSUMPTION ESTIMATED FOR THE TEST YEAR?

A. MECO's estimated fuel consumption for the test year is determined through the use of a computer production simulation model. The purpose of this model is to simulate the hour-by-hour operation of MECO's generation system by allocating forecasted generation energy requirements among the available MECO dispatchable generating units to determine the amount of energy to be produced by each such unit to serve the balance of MECO's energy requirements and associated costs.

The computer model, utilizing MECO's pre-defined unit commitment, economically dispatches MECO's generating units to be loaded in order of lowest to highest incremental cost of production for each unit. The computer model thus calculates the quantity of fuel that will be consumed by each generating unit based on the load to be carried by each unit and each unit's efficiency characteristics. The total consumption for each MECO generating

unit is the sum of fuel consumed for each hour of operation at that unit's hourly loading.

Q. PLEASE DESCRIBE THE COMPUTER MODEL USED BY THE CONSUMER ADVOCATE TO ESTIMATE THE QUANTITY OF TEST YEAR FUEL CONSUMPTION.

A. The computer production simulation model I have utilized is the P-Month model developed by the P-Plus Corporation to assess the reasonableness of the fuel and purchased power projections. This program is capable of modeling Monte Carlo simulations in the same manner as modeled by MECO. I compared the MECO dispatch model output reports to the independent results from my P-Month model to assess the reasonableness of the MECO model results. MECO also uses the P-Month Production Simulation Model to calculate its fuel and purchase power costs.

Q. HOW DID YOU GO ABOUT DETERMINING THE REASONABLENESS OF MECO'S PRODUCTION SIMULATION MODEL RESULTS?

A. First, I requested generating unit and capacity and energy purchase information used by MECO as inputs to the Company's energy dispatch production simulation model through numerous information requests. I also requested copies of MECO dispatch model output reports and summaries to

obtain the dispatch model results, as well as several other information requests that were issued to the Company.

Next, MECO's production simulation inputs from the Company's direct testimony filing was input to our production simulation model to benchmark our production simulation model results against MECO's own production simulation model results. The purpose of doing so was to confirm and verify that my production cost simulation model would produce similar results as presented by the Company.

Q. PLEASE DESCRIBE THE RESULTS OF YOUR COMPARISON.

A. Exhibit CA-201, page 1 provides a comparison of production simulation results using MECO's direct testimony filing inputs (see Lines 1 through 6, Columns (a) and (b)). MECO's production simulation results in an estimated test year fuel expense that is $654,000 greater, and purchased power expense that is $6,000 less than my production simulation results under the same load and resource conditions. My production simulation results were similar to the MECO results although several generating units were dispatched differently than the MECO dispatch model. CA-WP-204 provides a comparison of the Consumer Advocate dispatch results to MECO's dispatch results. These production simulation results represent a difference of 0.32% of estimated test year fuel and purchased power expenses.

Q. WHAT MECO INPUTS WERE REVIEWED TO ARRIVE AT THE ABOVE CONCLUSION?

A. The following are several items that are important to achieve an accurate dispatch model result: generating unit minimum and maximum capacities, forced outage rates, generating unit maintenance schedules, unit efficiency (heat rate) and variable operation and maintenance costs. The results of my review of each of these items will be discussed in the following sections of my testimony.

Q. BEFORE CONTINUING, DID YOU MODIFY ANY OF THE COMPANY'S INPUTS TO THE DISPATCH MODEL?

A. No, the inputs to my initial model were not modified because I wanted to independently assess the reasonableness of MECO dispatch results in its rate filing.

(a) Need to calibrate the production model results.

Q. DOES MECO ADJUST ITS DISPATCH MODEL RESULTS TO CALIBRATE THEM TO ACTUAL HISTORICAL COSTS?

A. Yes. MECO applies a calibration factor to the generating unit heat rates for IFO and diesel.

Q. WHY DOES MECO USE A CALIBRATION FACTOR?

A. MECO witness T-4 indicates that the calibration factor is used to adjust fuel consumption results from the production simulation modeling for actual operating conditions that cannot be completely duplicated by the computer model (see MECO-T-4, page 31).

Q. HOW DOES MECO DETERMINE THE CALIBRATION FACTORS?

A. MECO divides the actual generating plant net heat rate for a year by the simulated net heat rate determined from the production simulation modeling results for that same year. Then the Company uses the computed calibration factor to adjust its generating plant heat rates and fuel consumption as calculated by the production simulation model to determine the fuel expense for the year.

Q. WHAT YEAR DID MECO USE TO CALCULATE THE CALIBRATION FACTOR?

A. For MECO's direct testimony filing, the Company calculated calibration factors for 2005.

Q. DO YOU AGREE THAT THE 2005 CALIBRATION FACTORS WOULD BE APPROPRIATE FOR MECO'S 2007 ESTIMATED TEST YEAR IN THIS PROCEEDING?

A. Yes. The 2005 energy generation mix is very similar to the energy generation mix projected for test year 2007. Thus, I agree that the 2005 Calibration Factor would be appropriate for determining MECO's 2007 estimated test year fuel and purchased power expense in this proceeding and incorporated these factors in my simulation model results. However, I recommend that the Commission continue to require MECO, and the other utilities under its jurisdiction, to provide annual calibration reports. This reporting will allow the Commission and Consumer Advocate to monitor the difference between the actual results and the estimated results produced from the use of the production simulation model.

(b) Variable O&M costs.

Q. DID YOU INCLUDE VARIABLE OPERATION AND MAINTENANCE COSTS IN THE SIMULATION MODEL DISPATCH?

A. Yes, my model was designed to dispatch in the same manner as the MECO model.

Q. PLEASE SUMMARIZE YOUR POSITION REGARDING THE ESTIMATED TEST YEAR FUEL OIL EXPENSE.

A. My recommended test year total fuel oil expense of $166,383,000 and purchased power expense of $33,988,000 are based on the September 2006 fuel oil prices provided by MECO in its direct testimony filing. Test year fuel consumption is based on my production simulation model results. My production simulation utilized MECO's direct testimony filing.

B. PURCHASE POWER EXPENSE FOR THE 2007 TEST YEAR.

Q. WHAT IS PURCHASED POWER AND WHY MUST IT BE CONSIDERED IN DETERMINING THE TEST YEAR REVENUE REQUIREMENTS?

A. Over 17% of MECO's estimated 2007 test year energy requirements is projected to be purchased from independent power producers ("IPP") at an estimated cost of $33,988,000 (see CA-201, page 1). The amount of energy estimated to be purchased by MECO from each IPP for the 2007 test year is summarized below:

IPP Provider	Estimated Test Year Energy Purchases by MECO (MWh)
HC&S	90,420
KWP	122,930
Makila	876
Total	214,214

Source: CA-210.

MECO's payments to the IPPs represent a purchase power expense incurred by the Company to meet its service obligations to its customers, i.e., the ratepayers. Accordingly, MECO's purchase power expenditures are included in MECO's test year revenue requirements for purposes of evaluating and setting rates for the Company.

Q. HOW IS PURCHASED POWER EXPENSE DETERMINED?

A. Each IPP has a purchase power agreement ("PPA") with MECO that sets forth the payment rates and the manner to determine the amount of MECO's payment to the IPP. Some of the IPP providers are considered firm capacity resources in MECO's power supply firm capacity resource planning and receive capacity payments from MECO in addition to energy payments for the energy output of the IPP's facility that is purchased by MECO. Other IPP providers are considered "as-available" resources and are not considered as a capacity resource and receive energy only payments. The following tabulation provides the type of resource, and the amount of MECO estimated test year energy and capacity payment, if applicable for each IPP under their PPA:

IPP Provider	Capacity (MW)	Capacity Payment ($000)	Energy Payment ($000)	Total Payment ($000)
Firm				
HC&S		1,839	17,813	19,652
As Available				
KWP	N/A	N/A	14,165	14,165
Makila	N/A	N/A	171	171
Total	0	1,839	32,149	33,988

Sources: CA-210

The HC&S capacity payment terms and the KWP and Makila energy payment terms are established by their respective PPA and are summarized in MECO-507, page 1.

Q. DID YOU REVIEW THE CHARGES FOR PURCHASED POWER INCLUDED IN MECO'S DIRECT TESTIMONY?

A. Yes. I reviewed charges associated with MECO's firm power purchases from HC&S. I also reviewed charges for as-available energy purchases from KWP and Makila. In particular I reviewed the testimony of MECO witness Michael P. Ribao (MECO T-5), Manager of Power Supply Department.

Q. HOW IS PURCHASE POWER CHARGES CALCULATED FOR THE HC&S AND MAKILA PURCHASES?

A. Purchase power charges for these purchases are calculated in CA-WP-210. Based on my review, these charges are consistent with the terms of the PPA between MECO and each IPP.

Q. DO YOU RECOMMEND ANY CHANGES TO THE MECO DIRECT TESTIMONY PURCHASED POWER CHARGES?

A. Although I did not make any changes to the method by which MECO computed its estimated 2007 test year purchase power expense, my recommended purchase power expense of $33,988,000 is $6,000 greater

than MECO's direct testimony filing of estimated purchase power of $33,982,000. This is due primarily to MECO's estimate of different amounts of purchased energy.

IV. GENERATION EFFICIENCY FACTOR (SALES HEAT RATE).

Q. WHAT IS THE GENERATION EFFICIENCY FACTOR OR SALES HEAT RATE?

A. The generation efficiency factor or sales heat rate is a measure, expressed in terms of Btu per kWh or MBtu per kWh, of the amount of fuel consumed in MECO's generation facilities to provide a kWh of energy measured at the customer's meter. The sales heat rate is used in the ECAC to pass through increases and decreases in the composite weighted average cost of fuel consumed at MECO's generating plants (expressed in terms of cents per MMBtu) from that included in MECO's base rates to MECO's customers. Basically, the ECAC is an energy rate adjustment mechanism that passes through, after conclusion of a rate case, price changes in the Company's fuel and purchased energy cost and changes in the Company's generation and purchased energy mix from that used in arriving at the Company's test year revenue requirements and base rates in the rate case, without the need for the Company to file a new rate case.

Q. PLEASE DESCRIBE THE ECAC USED BY MECO.

A. The ECAC is a provision in the Company's rate schedule that allows MECO to apply a factor, referred to as the energy cost adjustment ("ECA") Factor, expressed in terms of cents per kWh, that increases or decreases ratepayer charges resulting from the Company's monthly ECAC calculations. MECO files its ECA Factor calculations with the Commission on a monthly basis. The two major components in the monthly ECA Factor calculation are the generation factor and the purchased energy factor, both of which are expressed in terms of cents per kWh. Exhibit CA-212 provides the test year ECA Factor calculation under MECO's present rates.

The purchased energy factor is determined as the difference between MECO's weighted composite cost of purchased energy (computed as MECO's average cost of purchased energy prices multiplied by the percentage of sales provided by purchased energy) and the base weighted composite cost of purchased energy embedded in MECO's base rates. Similarly, the generation factor is the difference between MECO's weighted composite cost of fuel prices and the base weighted composite cost embedded in MECO's base rates. The calculation of the generation factor, however, is not as straight-forward as the purchased energy factor in that MECO's composite fuel price of fuel consumed at the Company's generating plants is expressed in terms of cents per MMBtu, which needs to be converted to cents per kWh for the ECA Factor to be applied to MECO's ratepayers. As previously stated,

1 MECO's composite purchased energy prices are already expressed in terms
2 of cents per kWh and therefore the calculation of the purchased energy factor
3 does not require the interim conversion step needed for determining the
4 generation factor.
5
6 Q. HOW IS THE SALES HEAT RATE UTILIZED IN THE ECA CLAUSE?
7 A. The sales heat rate is utilized to convert MECO's composite fuel prices of fuel
8 consumed at the Company's generating plants, expressed in terms of cents
9 per MBtu, to a composite cost of generation, in terms of cents per kWh, for
10 determining the generation factor. The sales heat rate is essentially a
11 measure of MECO's generation efficiency conversion of fuel consumed,
12 expressed in terms of MBtu, to electricity produced and delivered by the
13 Company's generating units to MECO's customers, expressed in terms of
14 kWh. Accordingly, this generation efficiency factor or sales heat rate,
15 expressed in terms of MBtu per kWh, is utilized to pass through fuel price
16 increases or decreases experienced by MECO to the ratepayers. As a result,
17 the sales heat rate has an impact on future customer billings.
18
19 Q. HOW IS THE SALES HEAT RATE DETERMINED?
20 A. The sales heat rate is determined by dividing test year fuel consumption by
21 forecasted sales attributable to MECO's generation (see CA-206). Test year
22 fuel consumption is taken directly from the results of the production simulation

used to determine fuel expense. The amount of forecasted sales attributable to MECO's generation is calculated by multiplying forecasted sales by the ratio of MECO's system generation to total (i.e., net to system) energy requirements. In other words, the calculation of MECO's sales heat rate in this rate case proceeding will establish the fixed generation efficiency factor to be utilized in MECO's ECAC. Thus, the sales heat rate to be implemented in MECO's ECAC will correspond to test year resource mix utilized to determine MECO's revenue requirements and new rates in this proceeding.

Q. WHAT EFFECT DOES THE SELECTION OF THE SALES HEAT RATE HAVE ON FUTURE CUSTOMER BILLINGS?

A. The sales heat rate implemented as a result of this proceeding will have an impact on what MECO's customers will be charged for fluctuations in fuel prices in the future. Also, since the sales heat rate is determined by dividing fuel consumption by energy sales, the estimated Company Use energy and the estimated system loss energy discussed previously are implicitly incorporated into the sales heat rate. Accordingly, the charges to ratepayers for fluctuations in fuel prices will be based on the estimated Company Use and estimated system losses utilized to develop the sales heat rate. To the extent that the sales heat rate utilized in MECO's ECA clause is inconsistent with the actual operating conditions, the cost of fuel passed on to MECO's customers

1 will likewise not be consistent with, or track the basis on which such charges
2 for electric service were developed.
3
4 Q. WHY IS IT IMPORTANT TO DETERMINE A NORMALIZED HEAT RATE FOR
5 RATE SETTING PURPOSES WHEN A COMPANY LIKE MECO IS
6 ALLOWED TO USE THE ECAC TO RECOVER THE COSTS ASSOCIATED
7 WITH CHANGES IN THE PRICE OF FUEL OIL?
8 A. The sales heat rate will determine the amount to be paid by MECO's
9 ratepayers (in cents per kWh) when MECO's composite generation fuel cost
10 (in cents per MMBtu) is different than that used to set rates, and the base cost
11 in MECO's ECAC. If MECO's actual sales heat rate is different than that used
12 in the ECAC, the change in MECO's fuel expense will not match on a
13 dollar-for-dollar basis the change in MECO's ECAC revenues. Thus, if the
14 heat rate as determined in the instant rate proceeding overstates the actual
15 heat rate experienced by MECO, MECO will be able to recover, through the
16 ECAC, monies that are in excess of the actual fuel expense incurred to meet
17 customers' energy needs. On the other hand, if the heat rate established in a
18 rate proceeding understates the actual heat rate, MECO will not be provided
19 an opportunity to recover the fuel cost associated with the higher actual heat
20 rate. In effect, the fixed heat rate utilized in the Company's existing ECAC
21 provides some level of risk that the Company will not be able to recover from
22 or pass through to ratepayers, the actual deviation in fuel expense from the

estimate reflected in the instant docket. The Company will only be able to recover or pass through the effects of the deviation in the price of fuel through the ECAC.

V. FUEL INVENTORY.

Q. PLEASE DESCRIBE WHAT IS SET FORTH ON EXHIBIT CA-208.

A. Exhibit CA-208 provides the derivation of test-year fuel inventory amounts based on my production simulation model results and MECO's September 2006 fuel prices. The methodology that I used for determining fuel inventory is shown in Exhibits CA-208 and CA-209 and is the same methodology utilized by the Company in its direct testimony filing.

Q. DID YOU REVIEW AND ASSESS MECO'S FUEL INVENTORY CALCULATIONS?

A. Yes. MECO maintains an inventory for Low Sulphur Fuel Oil (LSFO) that is used in MECO's steam generating units and for diesel fuel that is used in its combustion turbines and reciprocating diesel engine generating units.

Q. WHAT DOES MECO PROPOSE AS AN INVENTORY LEVEL FOR LSFO IN ITS DIRECT TESTIMONY FILING?

A. MECO proposes a 37-day inventory that is equivalent to an average daily LSFO consumption of 50,599 barrels of LSFO resulting in an inventory of 53,248 barrels of LSFO (See MECO-408).

Q. DO YOU AGREE WITH THIS LEVEL OF INVENTORY?

A. No. I independently calculated LSFO inventory in CA-208, page 2. Based on a 30-day inventory level, the number of barrels of LSFO is 41,112, which is 9,487 barrels less than MECO's filed inventory level.

Q. DO YOU AGREE WITH MECO'S STATED GOAL OF A 37-DAY INVENTORY LEVEL?

A. No. It is unclear from the testimony and supporting documents that LSFO inventory needs to be greater than 30 days.

Q. WHAT INVENTORY LEVEL DO YOU RECOMMEND FOR LSFO?

A. I recommend an inventory level of no more than 30 days for LSFO.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I estimated a fuel inventory level using information provided by R. H. Sakuda in MECO T-4. My estimate is explained as follows:

1. Dead storage is 2,649 barrels as set forth in MECO T-4, page 48.
2. I estimated the minimum amount of fuel oil that is required to operate the Kahului plant continuously for a five-day period to transfer the fuel oil into the storage tanks and to test the fuel oil at the average fuel burn rate of 1,370 bpd,[1] which results in 6,850 barrels.
3. I estimated the minimum amount of fuel oil that is required for a pipeline outage to operate the Kahului plant continuously for an eleven-day period at a the average fuel burn rate of 1,370 bpd, which results in 15,070 barrels.
4. I summed numbers 1, 2 and 3 above for the minimum fuel volume, which results in 24,569 barrels.
5. I used an average fuel shipment volume of 21,667 barrels. The average fuel shipment volume is based on one shipment at full capacity of 25,000 barrels and two shipments of 20,000 barrels to account for pier docking limitations as set forth in MECO T-4, page 43.
6. I calculated the maximum fuel volume as the sum of the minimum fuel volume of 24,569 barrels and the average fuel shipment volume of 21,667 barrels, which results in 46,236 barrels.

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[1] MECO estimated that its test year burn rates were 1,370 bpd for LSFO (See MECO-408). The results of my production simulation model estimated that the test year average burn rates would be 1,370 bpd for LSFO (see CA-208).

7. I calculated the average fuel volume as the average of the minimum fuel volume of 24,569 barrels and the maximum fuel volume of 46,236 barrels, which results in 35,402 barrels.

8. I calculated the average number of days of inventory as the average fuel volume of 35,402 barrels divided by the average fuel burned rate of 1,370 bpd, which results in 26 days.

This method resulted in approximately 26 days of LSFO fuel inventory. An inventory level of 26 days is similar to the inventory level of 30 days. In MECO T-4, page 45, MECO states that fuel deliveries occur approximately every seven to ten days but may be as long as 19 days if the barge must be taken out of service. I believe a 30-day fuel inventory would cover this occurrence. Therefore, I conclude that an LSFO inventory level of 30-days as approved by the Commission in the previous rate case is reasonable for the instant docket.

Q. HOW DOES THIS INVENTORY LEVEL COMPARE TO ACTUAL MECO INVENTORY LEVELS?

A. MECO maintained an average LSFO inventory level of 37 days from 2001 through 2005. The maximum inventory during this period was 38 days in 2001, 2002 and 2005 and the minimum level was 36 days in 2003.

Q. IF MECO HAS MAINTAINED ACTUAL INVENTORY LEVELS THAT EXCEED THE 30-DAY SUPPLY YOU RECOMMEND, WHY SHOULD THE COMMISSION ACCEPT YOUR RECOMMENDATION FOR A 30-DAY LSFO FUEL INVENTORY?

A. As noted above, my recommended fuel inventory is based on the computed volume of oil required to maintain operation of the generating units until the next fuel shipment is delivered to Maui. MECO, on the other hand, has not supported the actual higher fuel inventory levels. I thus recommend that the Commission not accept MECO's recommendation for a higher LSFO inventory level unless the Company can demonstrate the need to maintain higher inventory levels.

Q. WHY IS IT IMPORTANT TO DETERMINE THE APPROPRIATE FUEL INVENTORY LEVELS FOR THE TEST YEAR?

A. Since the fuel inventory in reflected in the Company's test year rate base, overstatement of the fuel inventory will result in an overstatement in the test year revenue requirement and resulting rates.

Q. WHAT DOES MECO PROPOSE AS AN INVENTORY LEVEL FOR DIESEL FUEL IN ITS DIRECT TESTIMONY FILING?

A. MECO proposed a 30-day inventory that is equivalent to an average daily diesel consumption of 107,003 barrels of diesel (See MECO-408).

Q. DO YOU AGREE WITH THIS LEVEL OF INVENTORY?

A. No, I independently calculated the diesel fuel inventory in CA-208, page 3. Based on a 22-day inventory level, the number of barrels of diesel fuel inventory is 78,049, which is 28,954 barrels less than MECO's filed inventory level.

Q. PLEASE EXPLAIN YOUR CALCULATION.

A. My estimated diesel fuel inventory level uses information provided by R. H. Sakuda in MECO T-4. My estimate is explained as follows:

1. Dead storage is 2,094 barrels as set forth in MECO T-4, page 42.
2. I estimated the minimum amount of fuel oil that is required to operate the Maalaea plant continuously to transfer the diesel fuel into the storage tanks and to test the diesel fuel for a four-day period at a the average fuel burn rate of 3,548 bpd, which results in 14,192 barrels.
3. I summed numbers 1 and 2 above for the minimum fuel volume, which results in 16,286 barrels.
4. I used an average fuel shipment volume of 38,667 barrels. The average fuel shipment volume is based on one shipment at full capacity of 42,000 barrels and two shipments of 37,000 barrels to account for pier docking limitations as set forth in MECO T-4, page 43.

5. I calculated the maximum fuel volume as the sum of the minimum fuel volume of 16,286 barrels and the average fuel shipment volume of 38,667 barrels, which results in 54,953 barrels.

6. I calculated the average fuel volume as the average of the minimum fuel volume of 16,286 barrels and the maximum fuel volume of 54,953 barrels, which results in 35,619 barrels.

7. I calculated the average number of days of inventory as the average fuel volume of 35,619 barrels divided by the average fuel burned rate of 3,548 bpd, which results in 10 days.

8. This method resulted in approximately 10 days of diesel fuel inventory. In MECO T-4, page 45, MECO states that fuel deliveries occur approximately every seven to ten days but may be as long as 19 days if the barge must be taken out of service. Therefore, I believe a minimum of 19 days should be maintained to cover this occurrence. I added three days of diesel fuel inventory to account for unexpected loss of energy as a result of a failure of one of MECO's LSFO units for a period of 30 days which resulted in approximately 7,790 MWh and 11,575 barrels of diesel fuel. Therefore, I conclude that a diesel fuel inventory level of 22 days is reasonable.

Q. HOW IS THE TEST YEAR NORMALIZED FUEL INVENTORY DETERMINED?

A. As shown in Exhibit CA-208, fuel inventory is determined separately for residual fuel oil (also referred to as "LSFO") and diesel oil. The residual fuel oil inventory is determined by using the estimated average daily fuel burn rate for LSFO from the production simulation model results (see Exhibit CA-208, page 2). The average daily LSFO burn rate, expressed in terms of number of barrels per day (bpd), is then multiplied by the desired number of days of supply (i.e., 30 days; see CA-208, page 2, line 2) to arrive at the average quantity of fuel to be maintained in inventory. Dead storage is added to the average quantity of fuel to be maintained in inventory for total fuel inventory. This total LSFO fuel inventory quantity is then multiplied by test year fuel prices (see Exhibit CA-208, page 2, line 5) to arrive at the amount of residual fuel oil inventory to be included in the rate base (see Exhibit CA-208, page 2, line 6). The diesel fuel inventory is based upon the Consumer Advocate recommended inventory level.

Q. WHAT FUEL PRICES WERE USED FOR PURPOSES OF DETERMINING TEST YEAR FUEL INVENTORY AMOUNTS?

A. I used MECO's September 2006 fuel prices in the direct testimony filing.

1 VI. **ECA FACTOR AT CURRENT RATES.**

2 Q. DID YOU CALCULATE WHAT THE ECA FACTOR UNDER CURRENT
3 RATES WOULD BE FOR THE ESTIMATED 2007 TEST YEAR BASED ON
4 YOUR ESTIMATED FUEL ENERGY PRICES AND RESOURCE MIX?

5 A. Yes, I did. The calculation of the ECA Factor under current rates based on my
6 production simulation results for the estimated 2007 test year is provided as
7 Exhibit CA-212. As shown by that exhibit, the ECA Factor at current rates that
8 corresponds with my test year estimates of fuel and purchase power expenses
9 is 13.941 cents per kWh.

10

11 Q. DID YOU CALCULATE ANY OTHER ECAC RELATED RATES OR
12 CHARGES?

13 A. No.

14

15 Q. ARE THERE ANY PROPOSED MODIFICATIONS TO MECO'S ECAC
16 OTHER THAN THOSE ITEMS ASSOCIATED WITH UPDATES TO THE
17 ECAC FOR THE ESTIMATED 2007 TEST YEAR AND THE CHANGES
18 PREVIOUSLY DESCRIBED IN YOUR TESTIMONEY?

19 A. No, although there are other matters that relate to the ECAC that are
20 associated with Act 162 considerations discussed later in my testimony.

21

Q. WHAT ARE YOUR RECOMMENDED FIXED EFFICIENCY FACTORS AND HOW DO THEY COMPARE WITH THAT PROPOSED BY THE COMPANY?

A. The fixed efficiency factors that I am recommending are provided in Workpaper WP-215 and the weighted average is provided in Exhibit CA-215. A comparison of the fixed efficiency factors that I am recommending with that proposed by HECO are provided in Exhibit CA-201 and summarized in the following tabulation:

Fixed Efficiency Factors	mmBtu/kWh sales	Adjustment
Sales Heat Rate - LFSO	0.015295	(0.000016)
Sales Heat Rate - Diesel	0.009418	(0.000042)
Sales Heat Rate - Other	0.010614	(0.000034)

Source: CA-201, Line 7

The Consumer Advocate's fixed efficiency factors are based on the availability, resource mix and use of various IPP and HECO generating resources, as described earlier in this testimony, used to develop estimated 2007 test year revenue requirements.

VII. MOLOKAI DIVISION FUEL AND PURCHASED POWER EXPENSES.

Q. WHAT IS THE CONSUMER ADVOCATE'S TEST YEAR ESTIMATE OF FUEL EXPENSE FOR MOLOKAI?

A. As shown in CA-201, page 2, the Consumer Advocate recommends a test year projection of $7,253,000, which is comprised of fuel oil expense

(see CA-204, page 1) and fuel related expense consists of Petrospect expenses amounting to $5,500,000 (see CA-205, page 1).

Q. EXPLAIN HOW YOU DETERMINED YOUR RECOMMENDED TEST YEAR FUEL EXPENSE FOR MOLOKAI.

A. Fuel oil expense is derived by multiplying the estimated test year fuel consumption (in barrels) at the Molokai generating plant by the September 2006 fuel prices for diesel fuel consumed at that plant (see CA-204, page 1). Petrospect costs (in dollars per barrel) are also applied to the estimated fuel consumption (in barrels) at Molokai Division generating plant (see CA-205).

To determine the test year fuel consumption at Molokai Division generating plant, I must first determine Molokai Division's estimated 2007 test year energy requirements.

A. DETERMINATION OF THE TEST YEAR ENERGY REQUIREMENTS AND SOURCES OF ENERGY SUPPLY.

Q. HOW DID YOU DETERMINE MOLOKAI'S ESTIMATED 2007 TEST YEAR ENERGY REQUIREMENTS?

A. The determination of Molokai's estimated 2007 test year energy requirements is set forth on CA-WP-204, Lines 1 through 11. As shown on CA-WP-204, the starting point of the process is Molokai's forecasted sales for the test year. Next, the amount of energy that the Company will use at its buildings and facilities (referred to as "Company Use" and also referred to as "No Charge") is

determined. Finally, the amount of energy that will be lost in the system as the power is transformed into the voltages required for transmission and distribution throughout the Company's system (referred to as Molokai system losses (8.75%)) must be determined. The sum of the above three items represents the total system energy requirements, or the amount of power that must be generated by Molokai's generation.

1. The Consumer Advocate's 2007 Test Year forecasted sales for Molokai.

Q. WHAT ARE MOLOKAI'S TEST YEAR FORECASTED SALES?

A. CA-WP-204 contains MECO's direct testimony sales forecast for Molokai. MECO's estimated 2007 test year energy requirements for Molokai are based on a forecasted sales level of 36,547.8 GWh.

Q. WHAT IS THE CONSUMER ADVOCATE'S ESTIMATE OF MOLOKAI FORECASTED SALES?

A. As discussed in CA-T-3, the Consumer Advocate adopted the MECO test year sales projection reflected in the Company's direct testimony filing.

2. The Consumer Advocate's estimated Company Use or No Charge for the 2007 test year for Molokai.

Q. WHAT EXACTLY IS THIS COMPANY USE ENERGY THAT IS ADDED TO FORECASTED SALES?

A. Company Use energy involves electric energy use at Molokai's buildings and facilities. Such energy use at Molokai's buildings and facilities is included with forecasted sales and system losses to determine the amount of energy to be generated by Molokai's generating units and purchased from others. Since the cost of supplying this "Company Use" is included in Molokai's revenue requirements to be recovered from ratepayers, the amount of estimated test year energy use at Molokai's buildings and facilities has an impact on the revenue deficiency and level of rate increase to be established in this proceeding. As shown in MECO-403, MECO included an estimate of 131.6 MWh of Company Use in its test year energy requirements for Molokai.

Q. WHAT IS THE CONSUMER ADVOCATE'S TEST YEAR ESTIMATE OF COMPANY USE OR NO CHARGE FOR MOLOKAI?

A. The Consumer Advocate used MECO's estimate of Company Use for Molokai and believes the amount represents a reasonable estimate as calculated by MECO in MECO-WP-404, page 1.

The following table shows MECO Historical Company Use from MECO-WP-404, page 94.

2001	135	35,681	0.38%
2002	129	34,942	0.37%
2003	133	35,894	0.37%
2004	123	35,344	0.35%
2005	122	35,918	0.34%
	641		0.36%
Average	128		

This table indicates an average Company Use of 128 MWh for the historical period of 2001 through 2005. This level of use is 0.36% of sales to customers over the five-year historical period. Molokai's Company Use of 131.6 MWh is consistent with the method used in the last MECO rate case and is reasonable.

3. Estimate of System Losses for the test year for Molokai.

Q. WHAT ARE SYSTEM LOSSES AND HOW ARE THEY INCURRED BY MOLOKAI?

A. During the transmission, distribution and transformation of electricity from Molokai's power supply resources to Molokai's customers, losses are incurred on the transmission and distribution systems. In addition, Molokai incurs step-up transformation losses for power produced at its generating facilities. The purpose of the system loss factor is to estimate the amount of energy loss

that must be added to forecasted sales and Company Use to determine Molokai's total system energy requirements.

Q. HOW WAS THE SYSTEM LOSS FACTOR UTILIZED?

A. Forecasted sales and Company Use were adjusted by the system loss factor to arrive at the test year energy requirements to be provided by Molokai's generating and purchase power resources. System losses are shown on Line 6 of Exhibit CA-WP-204, page 5.

Q. PLEASE DESCRIBE THE LOSS FACTOR USED BY MECO FOR MOLOKAI.

A. As shown in MECO-WP-404, page 96, system losses were computed at 8.75% of Net Energy to System. This loss factor is based on historical losses for the 5-year period of 2001 through 2005 shown in MECO-WP-404, page 98. The range of losses during the five-year period was 8.38% to 9.14%. The five-year average approach is reasonable to ensure that extraordinarily high or low losses are not used in the test year and is a fair and reasonable approach.

Q. DOES THE CONSUMER ADVOCATE HAVE ANY CONCERNS WITH THE METHODOLOGY USED BY MECO TO DETERMINE THE TEST YEAR SYSTEM LOSS PROJECTIONS FOR MOLOKAI?

A. No, the Consumer Advocate agrees that MECO's methodology is reasonable for purposes of determining the total system losses for production simulation modeling purposes.

Q. WHAT LOSS FACTOR IS THE CONSUMER ADVOCATE RECOMMENDING BE USED FOR PURPOSES OF DETERMINING THE TEST YEAR FUEL EXPENSE?

A. The Consumer Advocate adopted MECO's estimated loss factor of 8.75% for Molokai.

Q. WHAT IS MECO'S ESTIMATED TEST YEAR GROSS GENERATION HEAT RATE FOR MOLOKAI?

A. MECO's estimated test year gross generation heat rate for Molokai is 9,840 Btu/kWh as shown in MECO-406, line 11.

Q. HOW DID MECO ESTIMATE THE TEST YEAR GROSS GENERATION HEAT RATE FOR MOLOKAI?

A. MECO estimated the test year gross generation heat rate for Molokai based on a five-year historical average as shown in MECO-407.

Q. DOES THE CONSUMER ADVOCATE HAVE ANY CONCERNS WITH THE METHODOLOGY USED BY MECO TO DETERMINE THE TEST YEAR GROSS GENERATION HEAT RATE FOR MOLOKAI?

A. No, the Consumer Advocate agrees that MECO's methodology of using a five-year average is reasonable because it takes into account major maintenance and overhauls. If MECO had used a historical year that included generating unit major maintenance, the test year heat rate would be higher. Likewise, if MECO had used a calendar year with little or no maintenance the heat rate would be lower than normal. Thus, this approach used by MECO in the instant proceeding is more representative of a normal or average year of operation.

VIII. MOLOKAI DIVISION ECA FACTOR AT CURRENT RATES.

Q. DID YOU CALCULATE WHAT THE ECA FACTOR UNDER CURRENT RATES WOULD BE FOR THE ESTIMATED 2007 TEST YEAR BASED ON YOUR ESTIMATED FUEL ENERGY PRICES AND RESOURCE MIX?

A. Yes, I did. The calculation of the ECA Factor under current rates based on my production simulation results for the estimated 2007 test year is provided as Exhibit CA-218. As shown by that exhibit, the ECA Factor at current rates that corresponds with my test year estimates of fuel expenses is 15.774 cents per kWh. The ECA factor is the same as the ECA Factor in the Company's direct testimony filing.

Q. DID YOU CALCULATE ANY OTHER ECAC RELATED RATES OR CHARGES?

A. No.

Q. ARE THERE ANY PROPOSED MODIFICATIONS TO MECO'S ECAC OTHER THAN THOSE ITEMS ASSOCIATED WITH UPDATES TO THE ECAC FOR THE ESTIMATED 2007 TEST YEAR AND THE CHANGES PREVIOUSLY DESCRIBED IN YOUR TESTIMONEY?

A. No, although there are other matters that relate to the ECAC that are associated with Act 162 considerations discussed later in my testimony.

Q. WHAT IS YOUR RECOMMENDED CENTRAL STATION FIXED EFFICIENCY FACTOR AND HOW DOES IT COMPARE WITH THAT PROPOSED BY THE COMPANY?

A. The Consumer Advocate test year fixed efficiency factor is 0.010823 MMBtu/kWh sales, the same as MECO's (see CA-WP-216, page 2 line 5).

IX. LANAI DIVISION FUEL AND PURCHASED POWER EXPENSES.

Q. WHAT IS THE CONSUMER ADVOCATE'S TEST YEAR ESTIMATE OF FUEL EXPENSE FOR LANAI?

A. As shown in CA-201, page 3, the Consumer Advocate recommends a test year projection of $6,175,000 which is comprised of fuel oil expense

(see CA-204, page 1) and fuel related expense consisting of Petrospect expenses amounting to $3,000 (see CA-205, page 1).

Q. EXPLAIN HOW YOU DETERMINED YOUR RECOMMENDED TEST YEAR FUEL EXPENSE FOR LANAI.

A. Fuel oil expense is derived by multiplying the estimated test year fuel consumption (in barrels) at the Lanai generating plant by the September 2006 fuel prices for diesel fuel consumed at that plant (see CA-204, page 1). Petrospect costs (in dollars per barrel) are also applied to the estimated fuel consumption (in barrels) at the Lanai Division generating plant (see CA-205).

To determine the test year fuel consumption at the Lanai Division generating plant, I must first determine the Lanai Division estimated 2007 test year energy requirements.

A. DETERMINATION OF THE TEST YEAR ENERGY REQUIREMENTS AND SOURCES OF ENERGY SUPPLY FOR LANAI.

Q. HOW DID YOU DETERMINE MECO'S ESTIMATED 2007 TEST YEAR ENERGY REQUIREMENTS?

A. The determination of MECO's estimated 2007 test year energy requirements is set forth on CA-WP-204, page 4, Lines 1 through 11. As shown on CA-204, the starting point of the process is MECO's forecasted sales for the test year. Next, the amount of energy that the Company will use at its buildings and facilities (referred to as "Company Use" and also referred to as "No Charge") is

determined. Finally, the amount of energy that will be lost in the system as the power is transformed into the voltages required for transmission and distribution throughout the Company's system (referred to as MECO system losses (5.11%)) must be determined. The sum of the above three items represents the total system energy requirements, or the amount of power that must be generated by Lanai Division generation and the generation of the independent power producers who sell power to the Company.

1. The Consumer Advocate's 2007 Test Year forecasted sales for Lanai.

Q. WHAT ARE LANAI'S TEST YEAR FORECASTED SALES?

A. CA-WP-204 contains MECO's direct testimony sales forecast for Lanai. MECO's estimated 2007 test year energy requirements for Lanai are based on a forecasted sales level of 29,780 MWh.

Q. WHAT IS THE CONSUMER ADVOCATE'S ESTIMATE OF LANAI FORECASTED SALES?

A. As discussed in CA-T-3, the Consumer Advocate adopted the MECO test year sales projection reflected in the Company's direct testimony filing.

2. The Consumer Advocate's estimated Company Use or No Charge for the 2007 test year for Lanai.

Q. WHAT EXACTLY IS THIS COMPANY USE ENERGY THAT IS ADDED TO THE TEST YEAR FORECASTED SALES?

A. Company Use energy involves electric energy use at Lanai's buildings and facilities. Such energy use at Lanai's buildings and facilities is included with forecasted sales and system losses to determine the amount of energy to be generated by MECO's generating units and purchased from others. Since the cost of supplying this "Company Use" is included in Lanai's revenue requirements to be recovered from ratepayers, the amount of estimated test year energy use at Lanai's buildings and facilities has an impact on the revenue deficiency and level of rate increase to be established in this proceeding. As shown in MECO-403, MECO included an estimate of 7.6 MWh of Company Use in its test year energy requirements for Lanai.

Q. WHAT IS THE CONSUMER ADVOCATE'S TEST YEAR ESTIMATE OF COMPANY USE OR NO CHARGE FOR LANAI?

A. The Consumer Advocate used MECO's estimate of Company Use for Lanai and believes that the amount represents a reasonable estimate as calculated by MECO in MECO-WP-404, page 1 through 95. The following table shows MECO Historical Company Use from MECO-WP-404, page 95.

	Company Use (MWh)	Total Recorded Sales (MWh)	No Charge % of Sales (%)
2001	4	26,905	0.013%
2002	6	27,036	0.022%
2003	7	28,136	0.024%
2004	8	27,802	0.029%
2005	11	27,942	0.039%
	35		0.025%
Average	7		

This table indicates an average Company Use of 7.6 MWh for the historical period of 2001 through 2005. This level of use is 0.026% of sales to customers over the five-year historical period. The Lanai's Company Use of 7.6 MWh is consistent with the method used in the last MECO rate case and is reasonable.

3. Estimate of System Losses for the test year for Lanai.

Q. WHAT ARE SYSTEM LOSSES AND HOW ARE THEY INCURRED BY LANAI?

A. During the transmission, distribution and transformation of electricity from Lanai's power supply resources to Lanai's customers, losses are incurred on the transmission and distribution systems. In addition, Lanai incurs step-up transformation losses for power produced at its generating facilities. The purpose of the system loss factor is to estimate the amount of energy loss that must be added to forecasted sales and Company Use to determine Lanai's total system energy requirements.

Q. HOW WAS THE SYSTEM LOSS FACTOR UTILIZED FOR LANAI?

A. Forecasted sales and Company Use were adjusted by the system loss factor to arrive at the test year energy requirements to be provided by MECO's generating and purchase power resources. System losses are shown on Line 6 of CA-WP-204, page 4.

Q. PLEASE DESCRIBE THE LOSS FACTOR USED BY MECO.

A. As shown in MECO-WP-404, page 95, system losses were computed at 5.11% of Net Energy to System. This loss factor is based on historical losses for the 5-year period of 2001 through 2005 shown in MECO-WP-404, page 95. The range of losses during the five-year period was 4.94% to 5.47%. The five-year average approach is reasonable to ensure that extraordinarily high or low losses are not used in the test year and is a fair and reasonable approach. This approach was also used in the last MECO rate case.

Q. DOES THE CONSUMER ADVOCATE HAVE ANY CONCERNS WITH THE METHODOLOGY USED BY MECO TO DETERMINE THE TEST YEAR SYSTEM LOSS PROJECTIONS FOR LANAI?

A. No, the Consumer Advocate agrees that MECO's methodology is reasonable for purposes of determining the total system losses for production simulation modeling purposes in this proceeding.

Q. WHAT LOSS FACTOR IS THE CONSUMER ADVOCATE RECOMMENDING BE USED FOR PURPOSES OF DETERMINING THE TEST YEAR FUEL EXPENSE?

A. The Consumer Advocate used MECO's estimated loss factor of 5.11% for Lanai.

Q. WHAT IS MECO'S ESTIMATED TEST YEAR GROSS GENERATION HEAT RATE FOR Lanai?

A. MECO's estimated test year gross generation heat rate for Lanai is 10,034 Btu/kWh as shown in MECO-406, line 11.

Q. HOW DID MECO ESTIMATE THE TEST YEAR GROSS GENERATION HEAT RATE FOR Lanai?

A. MECO estimated the test year gross generation heat rate for Lanai based on a five-year historical average as shown in MECO-407.

Q. DOES THE CONSUMER ADVOCATE HAVE ANY CONCERNS WITH THE METHODOLOGY USED BY MECO TO DETERMINE THE TEST YEAR GROSS GENERATION HEAT RATE FOR LANAI?

A. No, the Consumer Advocate agrees that MECO's methodology of using a five-year average is reasonable because it takes into account major maintenance and overhauls. If MECO had used a historical year that included

generating unit major maintenance, the test year heat rate would be higher. Likewise, if MECO had used a calendar year with little or no maintenance the heat rate would be lower than normal. Thus, the approach used by MECO for this docket is more representative of a normal or average year of operation.

X. LANAI DIVISION ECA FACTOR AT CURRENT RATES.

Q. DID YOU CALCULATE WHAT THE ECA FACTOR UNDER CURRENT RATES WOULD BE FOR THE ESTIMATED 2007 TEST YEAR BASED ON YOUR ESTIMATED FUEL ENERGY PRICES AND RESOURCE MIX?

A. Yes, I did. The calculation of the ECA Factor under current rates for the estimated 2007 test year is provided as Exhibit CA-216. As shown by that exhibit, the ECA Factor at current rates that corresponds with my test year estimates of fuel expenses is 13.913 cents per kWh. The ECA factor is the same as the ECA Factor in the Company's direct testimony filing.

Q. ARE THERE ANY PROPOSED MODIFICATIONS TO MECO'S ECAC OTHER THAN THOSE ITEMS ASSOCIATED WITH UPDATES TO THE ECAC FOR THE ESTIMATED 2007 TEST YEAR AND THE CHANGES PREVIOUSLY DESCRIBED IN YOUR TESTIMONEY?

A. No, although there are other matters that relate to the ECAC that are associated with Act 162 considerations discussed later in my testimony.

Q. WHAT IS YOUR RECOMMENDED CENTRAL STATION FIXED EFFICIENCY FACTOR AND HOW DOES IT COMPARE WITH THAT PROPOSED BY THE COMPANY?

A. The Consumer Advocate adopted the MECO test year fixed efficiency factor is 0.010577 MMBtu/kWh sales, the same as MECO's (see CA-WP-216, page 2, line 5).

XI. ACT 162 CONSIDERATIONS.

Q. HOW DOES ACT 162 AFFECT THE ECAC?

A. Act 162, in part, states the following:

> Any automatic fuel rate adjustment clause requested by a public utility in an application filed with the commission shall be designed, as determined in the commission's discretion, to:
>
> (1) Fairly share the risk of fuel cost changes between the public utility and its customers;
>
> (2) Provide the public utility with sufficient incentive to reasonably manage or lower it fuel costs and encourage greater use of renewable energy;
>
> (3) Allow the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as through fuel hedging contracts;
>
> (4) Preserve, to the extents reasonably possible, the public utility's financial integrity; and
>
> (5) Minimize, to the extent reasonably possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs.

1 Q. WITH RESPECT TO THE FIRST CONSIDERATION, DOES MECO'S
2 PROPOSED ECAC "FAIRLY SHARE THE RISK OF FUEL COST CHANGES
3 BETWEEN THE PUBLIC UTILITY AND ITS CUSTOMERS?"
4 A. The sharing of the risk of fuel cost changes first requires an understanding of
5 how the ECAC handles fuel cost changes, and how the ECAC shares the risks
6 of cost changes between the Company and its ratepayers. The Company's
7 fuel costs are the result of: (a) prices paid by MECO for the quantity of fuel
8 consumed in its generating plants; and (b) the quantity of fuel consumed,
9 which is determined by the efficiency of the operation and performance of
10 MECO's generating units to convert the fuel into electricity delivered to
11 ratepayers. The risks of fuel cost changes are primarily associated with the
12 fluctuations in fuel prices (item (a) above) and to lesser extent MECO's
13 performance and operation of generating units (item (b) above).
14 As previously explained, the Company's ECAC has fixed efficiency
15 factors to determine the amount of MECO's fuel cost changes that are passed
16 through to ratepayers. Essentially, the ECAC's fixed efficiency factors place
17 on MECO, the risk of fuel cost changes due to changes in the Company's
18 generating unit operation and performance (item (b) above). MECO bears the
19 cost of, or benefits from, fuel cost changes between rate case filings due to the
20 generation and performance of its generating units (i.e., the fuel costs
21 associated with the actual versus fixed heat rate). Since the operation and
22 performance of MECO's generating units are generally viewed as being within

1 the Company's control, fuel cost changes associated with such risks are
2 considered appropriate to be borne by the Company and its shareholders, not
3 ratepayers. If the Company's generating system does not achieve the level of
4 efficiency established in the last rate case and used to set MECO's rates, the
5 Company and its shareholders bear the risk and associated fuel costs of not
6 achieving that level of efficiency. On the other hand, if MECO's generating
7 units do better than the efficiency level established in the last rate case, the
8 Company and its shareholders receive the benefits of such fuel cost savings.
9 The ECAC's fixed efficiency factors are thus an effective means of sharing the
10 operating and performance risks between MECO's ratepayers and
11 shareholders.

12 With respect to the risk of fuel cost changes due to changes in fuel
13 prices, the ECAC passes such risks in price changes through to ratepayers.
14 Because fuel prices are not within MECO's control and MECO is a price taker,
15 it is not considered appropriate for MECO to bear the risks of fuel cost
16 changes due to price changes established by a global market. The question
17 then becomes whether there should be some incentive or risk sharing
18 regarding decisions as to when and how much fuel should be purchased at
19 the prices established by a global market.
20

1 Q, SHOULD THE COMPANY BEAR ANY RISK OF FUEL PRICES?

2 A. The Company should be required to prove that it has taken appropriate
3 actions to acquire fuel at reasonable costs. This could be done through a
4 process, which requires the Company to periodically file a fuel plan with the
5 Commission. The purpose of the plan would be to assume that the Company
6 is taking appropriate measures to acquire fuel at the lowest cost possible on
7 behalf of its customers. We understand that the Company files its fuel
8 contracts with the Commission for approval.

9

10 Q. DOES THE COMPANY'S ECAC "PROVIDE THE PUBLIC UTILITY WITH
11 SUFFICIENT INCENTIVES TO REASONABLY MANAGE OR LOWER ITS
12 FUEL COSTS AND ENCOURAGE GREATER USE OF RENEWABLE
13 ENERGY."

14 A. As previously indicated, the Company's fuel costs are a function of (a) fuel
15 prices and (b) the efficiency of the Company's operation and performance of
16 its generating units. The ECAC's fixed efficiency factors are effectively an
17 incentive in place for MECO's generating unit operations and performance.
18 Fuel cost changes due to changes in fuel prices are passed through the ECAC
19 to ratepayers. As previously indicated, fuel prices are not within the
20 Company's control and therefore are not manageable by the Company.

21 With regard to renewables, the ECAC provides MECO with the
22 opportunity to recover or pass through to ratepayers the Company's

1 purchased energy costs for generation provided by independent producers of
2 renewable energy. Accordingly, there is not a ratemaking or ECAC preference
3 to MECO favoring the recovery of the Company's fuel cost for its own
4 generation over the purchased energy cost of renewables. It is not clear to me
5 why or how the ECAC should be modified to encourage greater use of
6 renewable energy. The IRP process is the venue where decisions should be
7 made regarding the appropriate balance of reliable resource diversity,
8 compliance with state energy policy and compliance with renewable resource
9 portfolio standards at lowest reasonable cost, rather than using the ECAC to
10 achieve these objectives. The ECAC essentially should be the risk sharing
11 pass through mechanism for the Company's fuel costs and purchased energy
12 costs (including energy provided by renewable resources) resulting from the
13 implementation of the Company's IRP plan. It is not clear to me how the
14 ECAC can be used to encourage greater use of renewables without either
15 imposing penalties on MECO or increasing costs to ratepayers. An evaluation
16 or a determination must be made as to: (1) whether such punitive measures to
17 the Company and/or ratepayers could reasonably be expected to have the
18 desired effect (i.e., encourage greater use of renewable resources) and
19 (2) that it would be worth the punitive affect borne by MECO and/or
20 ratepayers. Such an evaluation or determination of whether the Company is
21 reasonably considering renewable resource options to meet the customer's
22 energy needs, and whether penalties should be assessed for

1 non-performance should be done in the context of the IRP process. The
2 Commission has established the IRP Framework and the Company's submit
3 their IRPs to the Commission for review and approval. If the Commission
4 determines that the IRP submitted does not pursue an appropriate amount of
5 renewable resources, the Commission has the authority to modify the IRP.
6
7 Q. DOES THE COMPANY'S ECAC "ALLOW THE PUBLIC UTILITY TO
8 MITIGATE THE RISK OF SUDDEN OR FREQUENT FUEL COST CHANGES
9 THAT CANNOT OTHERWISE BE REASONABLY MITIGATED THROUGH
10 OTHER COMMERCIALLY AVAILABLE MEANS, SUCH AS THROUGH FUEL
11 HEDGING CONTRACTS?"
12 A. The Company's direct testimony points out that hedging, either by physical
13 means or financial instructions, provides a means for locking in a known price
14 at an added cost and that such costs should be passed on to ratepayers (see
15 MECO T-19, pages 14 and 15). MECO proposes budget billing and fixed rate
16 billing as alternatives for smoothing the impact of fuel cost changes on the
17 electric rates charged ratepayers (see MECO T-19, page 15). If the Company
18 cannot achieve non-volatile fuel prices through its fuel purchasing plan, it
19 would seem reasonable that customers who desire less month-to-month
20 fluctuation in their electric charges would have the option of levelizing their
21 payments through budget billing that would not charge the customer more
22 than it otherwise would pay over a period of one year.

1 Q. WITH RESPECT TO THE FOURTH ITEM "PRESERVE, TO THE EXTENT
2 REASONABLY POSSIBLE, THE PUBLIC UTILITY'S FINANCIAL INTEGRITY
3 AND THE FIFTH ITEM "MINIMIZE, TO THE EXTENT REASONABLY
4 POSSIBLE, THE PUBLIC UTILITY'S NEED TO APPLY FOR FREQUENT
5 APPLICATIONS FOR GENERAL RATE INCREASES TO ACCOUNT FOR
6 THE CHANGES TO ITS FUEL COSTS," IS THE COMPANY'S ECAC
7 APPROPRIATE FOR CONSIDERATION OF THESE MATTERS?
8 A. I do not believe there is any question that an ECAC is needed to preserve the
9 Company's financial integrity given the fact that fuel and purchase power
10 expense represents approximately 80 percent[2] of the Company's total
11 operating expenses. MECO should be provided a reasonable opportunity to
12 recover the fuel cost and purchased energy expenses incurred with providing
13 electric service to ratepayers without the need to process back-to-back rate
14 applications. MECO's ECAC provides a means for the Company to timely
15 pass through to ratepayers the changes in fuel and purchased energy costs,
16 as such changes occur, between rate case filings. Absent such an ECAC, the
17 Company would need to have more frequent rate case filings during periods of
18 rising fuel prices to recover the increased cost of fuel and purchased energy
19 and maintain the financial integrity of the Company. Even so, the time that it
20 takes to prepare, fully consider and prosecute a rate case filing would put

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2 Per MECO 2001 ($180,465 +$33,982) ÷ $262,476 = 81.7% rounded to 80%

1 some additional financial risk exposure on the Company. On the flip side,
2 during periods of falling fuel prices the Company would experience a windfall,
3 absent an Order to Show Cause why the rates should not be reduced to
4 recognize the lower fuel costs and the Commission and the Consumer
5 Advocate would be hard pressed to monitor the Company's financial situation
6 and find a method to provide timely rate relief for ratepayers. In either
7 situation, the administrative burdens on the Company, the Commission and
8 the Consumer Advocate are avoided with the Company's ECAC.
9
10 Q. WHAT CONCLUSIONS SHOULD BE REACHED WITH RESPECT TO THE
11 ACT 162 CONSIDERATIONS OF THE COMPANY'S ECAC?
12 A. The Company's ECAC provides a fair sharing of the risks of fuel costs
13 changes between the Company and its ratepayers in a manner that preserves
14 the financial integrity of the Company without the need for frequent rate filings.
15
16 **XII. <u>CONCLUSION</u>.**
17 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?
18 A. Yes, it does.

JOSEPH A. HERZ

Mr. Herz has over 30 years of experience in the areas of public utility planning, financing, operations and management for electric, natural gas, steam, water and wastewater utilities.

He is a registered Professional Engineer. His professional experience includes planning and analytical studies related to electric power supply, transmission arrangements, feasibility studies, economic analyses and rate studies and contract negotiations. He has conducted detailed cost-of-service, rate, financial, power supply and transmission studies involving various investor, municipal and cooperative-owned systems.

Mr. Herz has testified on numerous occasions as an expert witness concerning regulatory matters. He has participated in more than 100 regulatory proceedings and has testified before 14 state regulatory commissions and the FERC on electric, gas, steam and water utility services.

He is experienced in long-range planning for acquisition and/or expansion of utility systems, engineering, financial and economic feasibility investigations and analyses. Power supply experience includes evaluating the technical and financial feasibility of transmission and power supply resources and related arrangements; power pooling, including integration of transmission and generating facilities; and, preparation and negotiation of related power supply and transmission contracts. Mr. Herz has served as an independent arbitrator on power supply contract disputes.

Education

University of Nebraska
B.S., Electrical Engineering, 1971

Registration

Professional Engineer — Ohio

Professional Organizations

American Gas Association
American Public Power Association
American Water Works Association
The Institute of Electrical and Electronics Engineers, Inc.
National Society of Professional Engineers
Ohio Society of Professional Engineers

PROJECTS INVOLVING REGULATORY FILINGS

Joseph A. Herz, P.E.

Utility	Docket No.	Issues and/or Scope	Client	Year
Federal Energy Regulatory Commission				
Westar Energy, Inc.	ER05-925-000	Open Access Transmission Tariff rate revisions for transmission and ancillary services	Kansas Municipal Utilities. Kansas Power Pool, Unified Government of Wyandotte County/Kansas City, Kansas, Board of Public Utilities and Kansas Municipal Energy Agency	2005
Westar Energy, Inc. Kansas Gas and Electric Company	ER03-9-002, -003, -004, -005 ER98-2157-002, -003, -004 EL05-64-000	Westar Energy and KGE market power mitigation proposal	Kansas Municipal Utilities and Unified Government of Wyandotte County/Kansas City, Kansas, Board of Public Utilities	2005
Kansas City Power & Light Company and Great Plains Power, Inc.	ER99-1005-000 ER02-725-000 EL05-3-000	Ability of KCP&L to exercise market power	Unified Government of Wyandotte County/Kansas City, Kansas, Board of Public Utilities	2005
Dayton Power & Light Company	EL00-24-000	*Contract dispute and interpretation of* certain pricing provisions	*Arcanum, Eldorado, Jackson Center,* Lakeview, Mendon, Minster, New Bremen, Tipp City, Waynesfield and Yellow Springs, Ohio	2000
Western Resources and Kansas City Power & Light	EC97-56-000	Western Resources Merger Intervention and other related relief	Kansas City, Kansas Board of Public Utilities	1999
Western Resources and Kansas City Power & Light	ER97-4669-000	Western Resources Merger Intervention and other related relief	Kansas City, Kansas Board of Public Utilities	1999
FirstEnergy Operating Companies	EC97-5-000	IEU/FirstEnergy Merger Intervention and other related relief	Industrial Energy Users of Ohio	1997
FirstEnergy Operating Companies	EC97-413-000	IEU/FirstEnergy Merger Intervention and other related relief	Industrial Energy Users of Ohio	1997

PROJECTS INVOLVING REGULATORY FILINGS

Joseph A. Herz, P.E.

Public Utility District No. 2 of Grant County Washington	EL95-35-000	Determine appropriate allocation of power from Priest Rapids Project	Kootenai Electric Cooperative, Inc., Clearwater Power Company, Idaho County Light & Power Cooperative Association, Inc., and Northern Lights, Inc.	1995
PacifiCorp	ER96-8-000	Transmission, cost of service and rate design	Utah Municipal Power Agency Deseret Generation and Transmission Cooperative, Inc.	1995
Dayton Power & Light Company	ER95-83-000	Transmission power services and rates	Arcanum, Eldorado, Jackson Center, Lakeview, Mendon, Minster, New Bremen, Tipp City, Waynesfield and Yellow Springs, Ohio	1995
Dayton Power & Light Company	94-1469-000	Transmission/interconnection/power services and rates	City of Piqua, Ohio	1994
Cincinnati Gas & Electric Company	ER94-1637-000	Transmission service and rates	City of Hamilton, Ohio	1994
Public Service Company of New Mexico	EL-94-6-000	Fuel inventory practices and expense accounting	Plains Electric Generation and Transmission Cooperative	1994
CINergy (merger of Cincinnati Gas & Electric Company and PSI Energy, Inc.)	ER93-6-000	Transmission issues, cost of service and rate design	City of Hamilton, Ohio	1993
American Electric Power Company	ER93-540-000	Transmission issues, cost of service and rate design	City of Hamilton, Ohio	1993
Ohio Power Company and Kentucky Power Company	ER93-295-001	Transmission loss factors	City of Hamilton, Ohio	1993
PacifiCorp Electric Operations	ER93-675-0000	Transmission issues, cost of service and rate design	Utah Municipal Power Agency	1993

PROJECTS INVOLVING REGULATORY FILINGS

Joseph A. Herz, P.E.

PacifiCorp Electric Operations	ER91-494-0000	Transmission issues, cost of service and rate design	Utah Municipal Power Agency	1991
PacifiCorp Electric Operations	ER91-471-0000	Transmission issues, cost of service and rate design	Utah Municipal Power Agency	1991
Ohio Power Company	EL91-1-000 and EL90-42-000	Interconnected utility operations and scheduling matters	City of Hamilton, Ohio	1990
Arizona Public Service Company	ER89-265-000	Transmission issues, cost of service and rate design	Plains Electric Generation and Transmission Cooperative	1989
Cincinnati Gas & Electric Company	ER89-17-000 and ER89-19-000	Transmission service, schedule restrictions and billing for transmission service	City of Hamilton, Ohio	1989
Utah Power and Light Company	EL85-12	PURPA wheeling under Sections 210, 211 and 212 of the Federal Power Act	Utah Municipal Power Agency and City of Manti, Utah	1985
Utah Power and Light Company	ER84-571/572	Transmission issues, cost of service and rate design	Utah Municipal Power Agency and the Cities of Manti and Provo, Utah	1985
Northern Indiana Public Service Company	ER83-396-000	Transmission issues, price squeeze, cost of service and rate design	Argos, Bremen, Brookston, Chalmers, Etna Green, Kingsford Heights, Walkerton and Winamac, Indiana	1983
Utah Power and Light Company	ER83-427-000	Transmission issues, revenue requirement, cost of service and rate design	Manti, Utah	1983
Ohio Power Company	ER82-553-000	Engineering issues, cost of service and rate design	Ohio Power Municipals	1982
Arizona Public Service Company	ER82-481-000	Transmission issues, cost of service and rate design	Plains Electric Generation and Transmission Cooperative	1982
Arizona Public Service Company	ER81-179-000	Wholesale and transmission issues, cost of service and rate design	Plains Electric Generation and Transmission Cooperative	1981

PROJECTS INVOLVING REGULATORY FILINGS

Joseph A. Herz, P.E.

Public Service Company of New Mexico	ER80-313	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1981
Public Service Company of New Mexico	ER79-478/479	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1981
Public Service Company of New Mexico	ER78-337/338	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1980
Northern Indiana Public Service Company	ER78-509	Price squeeze and rate design	Argos, Bremen, Brookston, Chalmers, Etna Green, Kingsford Heights, Walkerton and Winamac, Indiana	1979
Federal Power Commission:				
Ohio Edison Company	E-9497	Engineering issues, cost of service	The Wholesale Consumers of Ohio Edison Company	1976
Colorado Public Utilities Commission:				
Public Service Company of Colorado	1425 Phase II	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1981
Florida Public Service Commission:				
Florida Power Corporation	80119-EU	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1980
Gulf Power	010949-EI	Engineering and cost of service issues that have an actual or potential impact on the FEA	The Executive Agencies of the United States	2001

PROJECTS INVOLVING REGULATORY FILINGS

Joseph A. Herz, P.E.

Hawaii Public Utilities Commission:

Hawaiian Electric Company, Inc.	2006-0386	HECO 2007 Rate Case	Division of Consumer Advocacy, State of Hawaii	2007
Hawaiian Electric Light Company, Inc.	05-0315	HELCO 2005 – 2006 Rate Case	Division of Consumer Advocacy, State of Hawaii	2007
Hawaiian Electric Company, Inc.	05-0145	HECO CIP Project Application	Division of Consumer Advocacy, State of Hawaii	2006
Hawaiian Electric Company, Inc.	7310	HECO Utilities Avoided Cost Investigation	Division of Consumer Advocacy, State of Hawaii	2005
Hawaiian Electric Company, Inc.	04-0113	Evaluation of application for an increase in rates using a 2005 test year, cost of service and rate design issues	Division of Consumer Advocacy, State of Hawaii	2004
Commission Initiated Generic Investigation	03-0371	Commission initiated generic investigation of distributed generation in Hawaii	Division of Consumer Advocacy, State of Hawaii	2004
Kauai Electric Division	01-0005	Avoided energy costs associated with an Energy Purchase Agreement with Kauai Winds Inc. and inclusion in ERAC	Division of Consumer Advocacy, State of Hawaii	2001
Hawaii Electric Light Company, Inc.	99-0355	Transmission system improvements with IPP purchase power addition	Division of Consumer Advocacy, State of Hawaii	2000
Hawaii Electric Light Company, Inc.	99-0207	Generation and purchase power, operation and maintenance expenses, system losses and engineering issues	Division of Consumer Advocacy, State of Hawaii	2000

PROJECTS INVOLVING REGULATORY FILINGS

Joseph A. Herz, P.E.

Hawaii Electric Light Company, Inc.	99-0346	Need for capacity additions/review of IPP Purchase Power Agreement	Division of Consumer Advocacy, State of Hawaii	1999
Hawaii Electric Light Company, Inc.	98-0013	Need for capacity resource additions, IPP purchase power agreement	Division of Consumer Advocacy, State of Hawaii	1999
Hawaii Electric Light Company, Inc	97-0420	Generation and purchase power, operation and maintenance expenses, system losses and engineering issues	Division of Consumer Advocacy, State of Hawaii	1999
Hawaii Electric Light Company, Inc	97-0349	Integrated resource planning	Division of Consumer Advocacy, State of Hawaii	1999
Kauai Electric Division	KE94-0097	Engineering issues, generation and purchase power, operation and maintenance expenses, system losses and cost of service and rate design	Division of Consumer Advocacy, State of Hawaii	1994
Hawaiian Electric Company, Inc.	7766	Engineering issues, generation and purchase power, operation and maintenance expenses, system losses and cost of service and rate design	Division of Consumer Advocacy, State of Hawaii	1994
Hawaii Electric Light Company, Inc.	7623	Need for capacity resource additions and purchase power contracts	Division of Consumer Advocacy, State of Hawaii	1994
Hawaii Electric Light Company, Inc.	7764	Engineering issues, generation and purchase power, operation and maintenance expenses and system losses	Division of Consumer Advocacy, State of Hawaii	1994
Indiana Public Service Commission				
Wayne County Rural Electric Membership Cooperative	39048	Engineering issues, cost of service and rate design	Wayne County Rural Electric Membership Cooperative	1990

PROJECTS INVOLVING REGULATORY FILINGS

Joseph A. Herz, P.E.

New Carlisle, Indiana	Unknown	Engineering issues, revenue requirements, cost of service and rate design	New Carlisle, Indiana	1975
Kansas Corporation Commission:				
Southwest Power Pool, Inc.	06-SPP-202-COC	Application for the limited purpose of managing and coordinating the use of certain transmission facilities located within the State of Kansas	Kansas Municipal Utilities, Inc. Kansas Municipal Electric Agency Kansas Corporation Commission Kansas Public Power	2006
Westar Energy, Inc. Kansas Gas and Electric Company The Empire District Electric Company Kansas City Power & Light Company Aquila, Inc. D/B/A Aquila Networks-WPK Midwest Energy, Inc. Southwestern Public Service Company	06-WSEE-203-MIS	Joint Application for authority to transfer functional control of certain transmission facilities to the Southwest Power Pool, Inc.	Kansas Municipal Utilities, Inc. Kansas Municipal Electric Agency Kansas Corporation Commission Kansas Public Power	2006
Western Resources and Kansas City Power & Light	97-WSRE-676-MER	Western Resources Merger Intervention and other related relief	Kansas City, Kansas Board of Public Utilities	1999
Kansas Gas and Electric Company	142-098-U	Engineering issues, cost of service and rate design	McConnell Air Force Base	1985
Michigan Public Service Commission:				
Detroit Thermal	Case No. U-13691	Implement initial default tariff rates *for steam service*	Detroit Thermal	2004

PROJECTS INVOLVING REGULATORY FILINGS

Joseph A. Herz, P.E.

Michigan Consolidated Gas Company	Case No. U-7895	Engineering issues, cost of service and rate design	Traverse City Light and Power Board	1984
Indiana and Michigan Electric Company	Case No. U-7791	Engineering issues, cost of service and rate design	Auto Specialties, Southern Michigan Cold Storage, Waterville Paper Company, and Whirlpool Corporation	1984
Detroit Edison Company	Case No. U-7232	Interconnection agreements and power sales contract	Michigan Attorney General	1983
Consumers Power Company	Case No. U-6923	Cost of service, rate design and price elasticity	Clark Equipment Company	1982
Indiana and Michigan Electric Company	Case No. U-6927	Engineering issues, cost of service and rate design	Auto Specialties, Clark Equipment Company, and Whirlpool Corporation	1981
Upper Peninsula Power Company	Case No. U-6785	Engineering issues, cost of service and rate design	Michigan Technological University	1981
Upper Peninsula Power Company	Case No. U-6485	Engineering issues, cost of service and rate design	Michigan Technological University	1980
Indiana and Michigan Electric Company	Case No. U-6148	Engineering issues, cost of service and rate design	Auto Specialties, Clark Equipment Company, and Whirlpool Corporation	1980
Missouri Public Service Commission:				
Kansas City Power and Light Company	ER-2007-0291	Rate Design and Discounted Rates for Space-heating	Trigen-Kansas City Energy Corp.	2007
Kansas City Power and Light Company	ER-2006-0314	Rate Design and special rates for space heating.	Trigen-Kansas City Energy Corp.	2006
Kansas City Power and Light Company	Case No. ER83-49	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1983

PROJECTS INVOLVING REGULATORY FILINGS

Joseph A. Herz, P.E.

Kansas City Power and Light Company	Case No. EO-78-161	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1980
Montana Public Service Commission:				
Malmstrom Air Force Base	D2001.10.144	Rate design for customers receiving default power supply and transmission services, and limitations on the ability of qualified customers to return to the default supply services	The Executive Agencies of the United States	2001
New Mexico Service Commission:				
Public Service Company Of New Mexico	Case No. 03-00352-UT	Appropriateness of underground projects Rate Rider	Rio Rancho, New Mexico	2004
Otero Electric Cooperative	Case No. 2048	Demand metering and rate design	Otero Electric Cooperative	1987
Gas Company of New Mexico	Case No. 1875	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1984
Gas Company of New Mexico	Case No. 1787	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1983
Gas Company of New Mexico	Case No. 1710	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1982
Gas Company of New Mexico	Case No. 1568	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1982
Ohio Public Utilities Commission:				
FirstEnergy Operating Companies	Case No. 98-1636-EL-UNC	Transmission system reliability - sale and transfer of generating assets	Industrial Energy Users of Ohio	1999

PROJECTS INVOLVING REGULATORY FILINGS

Joseph A. Herz, P.E.

Ohio Edison Company	Case No. 93-1048-EL-CSS	Cost of service and predatory pricing	Youngstown Thermal, Limited Partnership	1994
Cincinnati Gas & Electric Company	Case No. 87-593-GA-CSS	Metering and billing dispute	Sheraton/Springdale Hotel	1987
Dayton Power and Light Company	Case No. 82-517-EL-AIR	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1983
Dayton Power and Light Company	Case No. 81-1256-EL-AIR	Revenue requirements, cost of service and rate design	The Executive Agencies of the United States	1982
Dayton Power and Light Company	Case No. 81-1237-EL-CSS	Billing procedures and practices	The Dayton Tire and Rubber Company	1982
Toledo Edison Company	Case No. 81-620-EL-AIR	Determination of billing units and rate design	Seaway Food Town, Inc.	1982
Ohio American Water Company	Case Nos. 81-385-WW-AIR and 81-739-WW-CMR	Engineering issues, cost of service and rate design	City of Tiffin, Ohio	1982
Dayton Power and Light Company	Case No. 81-21-EL-AIR	Engineering issues, revenue requirements, cost of service and rate design	The Executive Agencies of the United States	1981
Dayton Power and Light Company	Case No. 80-687-EL-AIR	Engineering issues, revenue requirements, cost of service and rate design	The Executive Agencies of the United States	1981
Ohio American Water Company	Case No. 79-3143-WW-AIR	Engineering issues, revenue requirements, cost of service and rate design	Cities of Marion and Tiffin, Ohio	1980
Dayton Power and Light Company	Case No. 79-510-EL-AIR	Engineering issues, revenue requirements, cost of service and rate design	The Executive Agencies of the United States	1980

PROJECTS INVOLVING REGULATORY FILINGS

Joseph A. Herz, P.E.

Cincinnati Gas & Electric Company	Case No. 79-11-EL-AIR	Cost of service and rate design	The Ohio Council of Retail Merchants	1979
Columbus and Southern Ohio Electric Company	Case No. 78-1438-EL-AIR	Cost of service and rate design	The Ohio Council of Retail Merchants	1979
Seneca Utilities, Inc.	Case No. 78-287-WW-AIR	Engineering issues, revenue requirements, cost of service and rate design	Lake Seneca Property Owners Association	1979
Dayton Power and Light Company	Case No. 78-92-EL-AIR	Engineering issues, revenue requirements, cost of service and rate design	The Executive Agencies of the United States	1979
Texas Public Utility Commission:				
Houston Lighting & Power Company	5779	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1984
Utah Public Service Commission:				
Hill Air Force Base	01-035-01	Revenue requirements, cost of service, rate design	The Executive Agencies of the United States	2001
Hill Air Force Base	01-035-23	Revenue requirements, cost of service, rate design	The Executive Agencies of the United States	2001
Hill Air Force Base	01-035-35	Revenue requirements, cost of service, rate design	The Executive Agencies of the United States	2001
Hill Air Force Base	01-035-36	Evaluate power cost adjustment mechanism to determine if it is non-discriminatory, accurately reflects the actual cost of providing the service, and is necessary under the circumstances	The Executive Agencies of the United States	2001

PROJECTS INVOLVING REGULATORY FILINGS

Joseph A. Herz, P.E.

Hill Air Force Base	00-035-15	Revenue requirements, cost of service, rate design	The Executive Agencies of the United States	2001
Wisconsin Public Service Commission:				
Barron Electric Cooperative	Case No. 380-EI-1	Transmission wheeling charges	Barron Electric Cooperative	1982
Wyoming Public Service Commission:				
PacifiCorp	20000-ER-95-99	Revenue requirements, cost of service, rate design and jurisdictional allocations	Marathon Oil Company	1996

Maui Electric Company, Inc.
Maui Division
COMPARISON OF TEST YEAR ESTIMATES FOR FUEL EXPENSE, PURCHASE POWER EXPENSE, EFFICIENCY FACTOR (SALES HEAT RATE) AND FUEL INVENTORY

Line	Description	CA Reference	Units	Production Simulation Results using MECO DT Inputs: MECO DT Filing (a)	Production Simulation Results using MECO DT Inputs: CA Output Results (b)	CA DT Position (c)	CA Adjustments to MECO DT Filing (c -a) (d)
	FUEL EXPENSE						
1.	**Fuel Oil Expense**	CA-204, page 1	$000s	166,525.3	165,872.1	165,872.1	(653.2)
2.	**Fuel Related Expense**	CA-205, page 1	$000s	511.4	510.6	510.6	(0.9)
3.	**Total Fuel Expense**		$000s	167,036.7	166,382.6	166,382.6	(654.0)
	PURCHASED POWER EXPENSE						
4.	**Energy Payments**	CA-210, page 1	$000s	32,142.6	32,149.0	32,149.0	6.4
5.	**Firm Capacity Payments**	CA-210, page 1	$000s	1,839.1	1,839.3	1,839.3	0.2
6.	**Total Purchased Power Expense**		$000s	33,981.7	33,988.2	33,988.2	6.6
	FIXED EFFICIENCY FACTORS						
7.	**Sales Heat Rate - Steam**	CA-215	MMBTU/kWh Sales	0.015311	0.015295	0.015295	(0.000016)
	Sales Heat Rate - Diesel		MMBTU/kWh Sales	0.009460	0.009418	0.009418	(0.000042)
	Sales Heat Rate - Other		MMBTU/kWh Sales	0.010648	0.010614	0.010614	(0.000034)
	WEIGHTED EFFICIENCY FACTOR		MMBTU/kWh Sales	0.010648	0.010614	0.010614	(0.000034)
8.	**FUEL INVENTORY**	CA-208, page 1	$000s	14,628.9	11,026.8	11,026.8	(3,602.0)
	ENERGY COST ADJUSTMENT CLAUSE						
9.	**ECA Factor at Current Rates**	CA-212, page 1	¢/kWh	13.954	13.941	13.941	(0.0130)
10.	**Base Fuel Energy Charge at Proposed Rates**	CA-214, page 1	¢/kWh	13.7479	13.6924	13.6924	(0.0556)

Note: Totals may not add exactly due to rounding.

Maui Electric Company, Inc.
Molokai Division
COMPARISON OF TEST YEAR ESTIMATES FOR FUEL EXPENSE, PURCHASE POWER EXPENSE, EFFICIENCY FACTOR (SALES HEAT RATE) AND FUEL INVENTORY

Line	Description	CA Reference	Units	MECO DT Filing (a)	CA Output Results (b)	CA DT Position (c)	CA Adjustments to MECO DT Filing (c -a) (d)
	FUEL EXPENSE						
1.	Fuel Oil Expense	CA-204, page 1	$000s	7,247.2	7,247.2	7,247.2	-
2.	Fuel Related Expense	CA-205, page 1	$000s	5.5	5.5	5.5	-
3.	Total Fuel Expense		$000s	7,252.7	7,252.7	7,252.7	-
	PURCHASED POWER EXPENSE						
4.	Energy Payments	CA-210, page 1	$000s	-	-	-	-
5.	Firm Capacity Payments	CA-210, page 1	$000s	-	-	-	-
6.	Total Purchased Power Expense		$000s	-	-	-	-
	FIXED EFFICIENCY FACTORS						
7.	Sales Heat Rate - Steam		MMBTU/kWh Sales	-	-	-	-
	Sales Heat Rate - Diesel	CA-WP-216	MMBTU/kWh Sales	0.010823	0.010823	0.010823	(0.000000)
	Sales Heat Rate - Other		MMBTU/kWh Sales			-	-
	WEIGHTED EFFICIENCY FACTOR		MMBTU/kWh Sales			-	-
8.	FUEL INVENTORY	CA-208, page 1	$000s	632.3	632.3	632.3	-
	ENERGY COST ADJUSTMENT CLAUSE						
9.	ECA Factor at Current Rates	CA-218, page 1	¢/kWh	15.774	15.774	15.774	0.000
10.	Base Fuel Energy Charge at Proposed Rates	CA-219, page 1	¢/kWh	19.8440	19.8440	19.8440	0.0000

Note: Totals may not add exactly due to rounding.

Maui Electric Company, Inc.
Lanai Division
COMPARISON OF TEST YEAR ESTIMATES FOR FUEL EXPENSE, PURCHASE POWER EXPENSE, EFFICIENCY FACTOR (SALES HEAT RATE) AND FUEL INVENTORY

Line	Description	CA Reference	Units	MECO DT Filing (a)	CA Output Results (b)	CA DT Position (c)	CA Adjustments to MECO DT Filing (c -a) (d)
	FUEL EXPENSE						
1.	**Fuel Oil Expense**	CA-204, page 1	$000s	6,172.6	6,172.6	6,172.6	-
2.	**Fuel Related Expense**	CA-205, page 1	$000s	2.7	2.7	2.7	-
3.	**Total Fuel Expense**		$000s	6,175.3	6,175.3	6,175.3	-
	PURCHASED POWER EXPENSE						
4.	**Energy Payments**	CA-210, page 1	$000s	-	-	-	-
5.	**Firm Capacity Payments**	CA-210, page 1	$000s	-	-	-	-
6.	**Total Purchased Power Expense**		$000s	-	-	-	-
	FIXED EFFICIENCY FACTORS						
7.	**Sales Heat Rate - Steam**		MMBTU/kWh Sales	-	-	-	-
	Sales Heat Rate - Diesel	CA-WP-216	MMBTU/kWh Sales	0.010577	0.010577	0.010577	0.000000
	Sales Heat Rate - Other		MMBTU/kWh Sales			-	-
	WEIGHTED EFFICIENCY FACTOR		MMBTU/kWh Sales			-	-
8.	**FUEL INVENTORY**	CA-208, page 1	$000s	549.9	549.9	549.9	-
	ENERGY COST ADJUSTMENT CLAUSE						
9.	**ECA Factor at Current Rates**	CA-212, page 1	¢/kWh	13.913	13.913	13.913	0.000
10.	**Base Fuel Energy Charge at Proposed Rates**	CA-217, page 1	¢/kWh	20.7356	20.7356	20.7356	0.0000

Note: Totals may not add exactly due to rounding.

Maui Electric Company, Limited

TEST YEAR 2007 FUEL EXPENSE
Direct Testimony

Line		MECO DT Test Year 2007 ($000)	CA DT Test Year 2007 ($000)
1	**Total Fuel Oil Expense**		
2	Maui	166,525.3	165,872.1
3	Lanai	6,172.6	6,172.6
4	*Molokai*	7,247.2	7,247.2
5	Total	179,945.0	179,291.8
6	**Total Fuel Related Expense**		
7	Maui	511.4	510.6
8	Lanai	2.7	2.7
9	Molokai	5.5	5.5
10	Total	519.6	518.7
11	**Total Fuel Expenses**		
12	Maui	167,036.7	166,382.6
13	Lanai	6,175.3	6,175.3
14	Molokai	7,252.7	7,252.7
15	**Total**	180,464.6	179,810.6

CA Reference:
Lines 2-4: CA-204
Lines 7-9: CA-205

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Maui Electric Company, Limited

TEST YEAR 2007 FUEL OIL PRICES

Direct Testimony

Line		*MECO DT* Delivered-to-plant Weighted Fuel Price ($/BBL)	*CA DT* Delivered-to-plant Weighted Fuel Price ($/BBL)
	Maui Division		
1	Kahului (IFO)	59.6359	59.6359
2	Maalaea (Diesel)	104.8621	104.8621
3	Maalaea (Biodiesel)	109.2000	109.2000
4	Hana (Diesel)	115.8105	115.8105
	Lanai Division		
5	Miki Basin (Diesel)	114.8311	114.8311
	Molokai Division		
6	Paalau (Diesel)	107.3613	107.3613

CA Reference:
MECO-402

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Maui Electric Company, Limited

TEST YEAR 2007 NET GENERATION
Direct Testimony

(Maui Division)

Line		MECO DT (A) Energy (MWh)	MECO DT (B) Percent of Net System Input	CA DT (C) Energy (MWh)	CA DT (D) Percent of Net System Input
1	Test Year Sales	1,212,929		1,212,929	
2	+ No Charge (@ 1662 MWh)	1,662		1,662	
3	Sales + No Charge	1,214,591		1,214,591	
4	+ Losses (@ 5.95%)	76,840		76,840	
5	Net-To-System Input	1,291,431	100.00%	1,291,431	100.00%
6	- Purchase Power	214,173	16.58%	214,226	16.59%
7	Net MECO	1,077,258	83.42%	1,077,205	83.41%

CA Reference:
Line 1: MECO-403
Line 2: MECO-403
Line 4: MECO-403
Line 6: CA-210

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Maui Electric Company, Limited

TEST YEAR 2007 FUEL OIL EXPENSE SUMMARY
Direct Testimony

		MECO DT			CA DT		
Line	Division	(A) Fuel Consumption (BBLs)	(B) Fuel Prices ($/BBL)	(C) = (A) x (B) Fuel Expense ($000)	(D) Fuel Consumption (BBLs)	(E) Fuel Prices ($/BBL)	(F) = (D) x (E) Fuel Expense ($000)
	Maui						
1	Kahului (IFO)	499,157	59.6359	29,767.7	500,190	59.6359	29,829.3
2	Maalaea (Diesel)	1,301,713	104.8621	136,500.3	1,294,744	104.8621	135,769.5
3	Maalaea (Biodiesel	2,193	109.2000	239.5	2,339	109.2000	255.5
4	Hana	154	115.8105	17.8	154	115.8105	17.8
5	Total Maui	1,803,217		166,525.3	1,797,427		165,872.1
6	**Lanai**	53,754	114.8311	6,172.6	53,754	114.8311	6,172.6
7	**Molokai**	67,503	107.3613	7,247.2	67,503	107.3613	7,247.2
8	**TOTAL MECO**	1,924,473		179,945.0	1,918,683		179,291.8

CA Reference:
Lines 1-4: CA-WP-204, page 3
Line 6: MECO-WP-404, page 94
Line 7: MECO-WP-404, page 97

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Maui Electric Company, Limited

TEST YEAR 2007 FUEL RELATED EXPENSES
($000)
Direct Testimony

Line		MECO DT	CA DT
	Maui Division		
1	Ignition Start Up and Fuel Handling Expenses	26.1	26.1
2	Fuel Additives Expenses	155.7	156.0
3	Petroleum Inspection Expenses	134.3	133.9
4	Ocean Cargo Insurance	195.4	194.6
5	Total Maui Division	511.4	510.6
	Lanai Division		
6	Petroleum Inspection Expenses	2.7	2.7
	Molokai Division		
7	Petroleum Inspection Expenses	5.5	5.5
8	Total	519.6	518.7

Reference:
Line 1: MECO-WP-405, page 1
Line 2: MECO-WP-405, page 2 and CA-WP-212
Line 3: MECO-WP-405, page 2 and CA-WP-212
Line 4: MECO-WP-405, page 3 and CA-WP-212
Line 6: MECO-WP-405, page 5
Line 7: MECO-WP-405, page 6

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Maui Electric Company, Limited

TEST YEAR 2007 FUEL EFFICIENCY
Direct Testimony

Line			MECO DT			CA DT		
			Maui	Lanai	Molokai	Maui	Lanai	Molokai
1	Cental Station Generated Energy	(Net GWH)	1,077.3	31.4	40.2	1,077.3	31.4	40.2
2	IFO Generated Energy	(Net GWH)	218.7			219.4		
3	Diesel Generated Energy	(Net GWH)	858.6	31.4	40.2	857.9	31.4	40.2
4	Test Year Sales	(GWH)	1,212.9	29.8	36.5	1,212.9	29.8	36.5
5	Total Central Station Fuel Consumed	(000 BBLs)	1,801	53.8	67.5	1,795	53.8	67.5
6		(000 MBTUs)	10,774	315.0	395.6	10,739	315.0	395.6
7	IFO Fuel Consumed	(000 BBLs)	499			500		
8		(000 MBTUs)	3,145			3,151		
9	Diesel Fuel Consumed	(000 BBLs)	1,302	53.8	67.5	1,295	53.8	67.5
10		(000 MBTUs)	7,629	315.0	395.6	7,588	315.0	395.6
11	Total Central Station Net Heat Rate	(BTU / Net KWH)	10,001	10,034	9,840	9,969	10,034	9,840
12		(Net KWH / BBL)	598	584	596	600	584	596
13	IFO Net Heat Rate	(BTU / Net KWH)	14,380			14,364		
14		(Net KWH / BBL)	438			439		
15	Maalaea Diesel Net Heat Rate	(BTU / Net KWH)	8,885			8,845		
16		(Net KWH / BBL)	660			663		
17	Hana Diesel Net Heat Rate	(BTU / Net KWH)	11,275			11,275		
18		(Net KWH / BBL)	519			519		
19	IFO Sales Heat Rate	(MBTU / KWH Sales)	0.015310			0.015294		
20	Diesel Sales Heat Rate	(MBTU / KWH Sales)	0.009460	0.010577	0.010823	0.009417	0.010577	0.010823
21	Diesel Sales Heat Rate (Hana)	(MBTU / KWH Sales)	0.012005			0.012005		

Reference
Lines 1-16: Maui Division, MECO-WP-404, page 2 and CA-WP-204, page 2
Lines 1-10: Lanai Division, MECO-WP-404, page 93
Lines 1-10: Molokai Division, MECO-WP-404, page 96
Lines 11, 20: Lanai Division, MECO-WP-406, page 4
Lines 11, 20: Molokai Division, MECO-WP-406, page 5
Line 15: Maui Division, MECO-WP-404, page 2 and CA-WP-204, page 2
Line 17: Maui Division, MECO-WP-404, page 2 and CA-WP-204, page 2

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Maui Electric Company, Limited

HISTORICAL FUEL EFFICIENCY
Direct Testimony
(Maui Division)

							MECO DT			CA DT		
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
							Test Year	TY vs. 2005		Test Year	TY vs. 2005	
Line		2001	2002	2003	2004	2005	2007	Diff	%	2007	Diff	%
Maui Division												
1	Maui Net Heat Rate (BTU / KWH)	10,578	10,404	10,434	10,441	10,516	10,001	-515	-4.9	9,969	-547	-5.2
2	IFO Net Heat Rate (BTU / KWH)	14,398	14,059	14,440	14,539	14,598	14,380	-218	-1.5	14,364	-234	-1.6
3	Diesel Net Heat Rate (BTU / KWH)	9,594	9,379	9,441	9,450	9,544	8,885	-659	-6.9	8,845	-699	-7.3
Lanai Division												
4	Diesel Net Heat Rate (BTU / KWH)	10,085	9,897	9,874	10,025	10,288	10,034	-254	-2.5	10,034	-254	-2.5
Molokai Division												
5	Diesel Net Heat Rate (BTU / KWH)	9,737	9,684	9,803	10,004	9,974	9,840	-134	-1.3	9,840	-133	-1.3

Reference:
CA-106
Columns A - E: Maui Division, MECO-WP-407, page 1
Columns A - E: Lanai Division, MECO-WP-407, page 2
Columns A - E: Molokai Division, MECO-WP-407, page 2
Column F: MECO-406
Column G: Column F - Column E
Column H: Column G ÷ Column E

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Maui Electric Company, Limited

DERIVATION OF FUEL INVENTORY
TEST YEAR 2007
Direct Testimony

Line		MECO DT (A) Fuel Inventory (BBLs)	MECO DT (B) Fuel Inventory ($)	CA DT (C) Fuel Inventory (BBLs)	CA DT (D) Fuel Inventory ($)
	Maui				
1	Industrial Fuel Oil Inventory	53,248	$ 3,175,519	43,761	$ 2,609,695
2	Diesel Fuel Inventory				
	Maalaea	109,097	$ 11,440,113	80,143	$ 8,403,924
	Hana	114	$ 13,230	114	$ 13,230
3	Total Maui	162,459	$ 14,628,862	124,017	$ 11,026,849
4	**Lanai**	4,789	$ 549,917	4,789	$ 549,917
5	**Molokai**	5,890	$ 632,339	5,890	$ 632,339
6	**TOTAL MECO**	173,138	$ 15,811,118	134,696	$ 12,209,105

Reference:
Line 1: MECO-408, page 2 and CA-208, page 2
Line 2: MECO-408, page 3-4 and CA-208, page 3-4
Line 4: MECO-408, page 5 and CA-208, page 5
Line 5: MECO-408, page 6 and CA-208, page 6

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Maui Electric Company, Limited

DERIVATION OF INDUSTRIAL FUEL OIL INVENTORY
TEST YEAR 2007
Direct Testimony

(Maui Division)

Line		MECO DT Test Year 2007	CA DT Test Year 2007	
1	Test Year Industrial Fuel Burn Rate	1,368	1,370	BBL / Day
2	30 Day Inventory (Line 1 x 30 Days)	50,599	41,112	BBLs
3	+ Dead Storage	2,649	2,649	BBLs
4	Total Industrial Fuel Oil BBL Inventory (Line 2 + Line 3)	53,248	43,761	BBLs
5	Fuel Price	$ 59.6359	$ 59.6359	/ BBL
6	Industrial Fuel Oil Inventory (Line 4 x Line 5)	$ 3,175,519	$ 2,609,695	

Reference:
Line 1: MECO-WP-408, page 5 and CA-WP-208, page 1
Line 2: MECO-409, page 1
Line 3: MECO-WP-408, page 1
Line 5: MECO-402, page 1

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Maui Electric Company, Limited

DERIVATION OF DIESEL FUEL INVENTORY
TEST YEAR 2007
Direct Testimony

(Maui Division)

Line		MECO DT Test Year 2007	CA DT Test Year 2007	
1	Test Year Diesel Burn Rate	3,567	3,548	BBL / Day
2	22 Day Inventory (Line 1 x 22 Days)	107,003	78,049	BBLs
3	+ Dead Storage	2,094	2,094	BBLs
4	Total Diesel Fuel BBL Inventory (Line 2 + Line 3)	109,097	80,143	BBLs
5	Fuel Price	$ 104.8621	$ 104.8621	/ BBL
6	Diesel Fuel Inventory (Line 4 x Line 5)	$ 11,440,113	$ 8,403,924	

Reference:
Line 1: MECO-WP-408, page 5 and CA-WP-208, page 1
Line 3: MECO-WP-408, page 1
Line 5: MECO-WP-402, page 1

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Maui Electric Company, Limited

DERIVATION OF DIESEL FUEL INVENTORY - HANA
TEST YEAR 2007
Direct Testimony

(Maui Division)

Line		MECO DT Test Year 2007	CA DT Test Year 2007
1	5-year End Of Month Average Inventory	114	114 BBLs
2	Fuel Price	115.8105	115.8105 / BBL
3	Diesel Fuel Inventory (Line 1 x Line 2)	$ 13,230	$ 13,230

Reference:
Line 1: MECO-WP-408, page 8
Line 2: MECO-WP-402, page 1

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Maui Electric Company, Limited

DERIVATION OF DIESEL FUEL INVENTORY
TEST YEAR 2007
Direct Testimony

(Lanai Division)

Line		MECO DT Test Year 2007	CA DT Test Year 2007
1	Test Year Diesel Burn Rate	147	147 BBL / Day
2	30 Day Inventory (Line 1 x 30 Days)	4,418	4,418 BBLs
3	+ Dead Storage	371	371 BBLs
4	Total Diesel Fuel BBL Inventory (Line 2 + Line 3)	4,789	4,789 BBLs
5	Fuel Price	$ 114.8311	$ 114.8311 / BBL
6	Diesel Fuel Inventory (Line 4 x Line 5)	$ 549,917	$ 549,917

Reference:
Line 1: MECO-WP-408, page 9
Line 3: MECO-WP-408, page 2
Line 5: MECO-402, page 1

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Maui Electric Company, Limited

DERIVATION OF DIESEL FUEL INVENTORY
TEST YEAR 2007
Direct Testimony

(Molokai Division)

Line		MECO DT Test Year 2007	CA DT Test Year 2007	
1	Test Year Diesel Burn Rate	185	185	BBL / Day
2	30 Day Inventory (Line 1 x 30 Days)	5,548	5,548	BBLs
3	+ Dead Storage	342	342	BBLs
4	Total Diesel Fuel BBL Inventory (Line 2 + Line 3)	5,890	5,890	BBLs
5	Fuel Price	$ 107.3613	$ 107.3613	/ BBL
6	Diesel Fuel Inventory (Line 4 x Line 5)	$ 632,339	$ 632,339	

Reference:
Line 1: MECO-WP-408, page 10
Line 3: MECO-WP-408, page 3
Line 5: MECO-402, page 1

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Maui Electric Company, Limited

HISTORICAL AVERAGE FUEL INVENTORY
(Barrels)
Direct Testimony

(Maui Division)

Line		(A) 2001	(B) 2002	(C) 2003	(D) 2004	(E) 2005	MECO DT (F) Test Year 2007	MECO DT (G) TY vs. 2005 Diff	MECO DT (H) TY vs. 2005 %	CA DT (I) Test Year 2007	CA DT (J) TY vs. 2005 Diff	CA DT (K) TY vs. 2005 %
	Industrial Fuel Oil											
1	Avg Inventory	53,508	54,231	50,819	52,341	54,008	53,248	-760	-1.4	41,112	-12,897	-23.9
2	Avg Daily Burn Rate	1,390	1,445	1,414	1,433	1,423	1,368			1,370		
3	Avg No. of Days of Supply	38	38	36	37	38	39			30		
	Diesel Fuel [1]											
4	Avg Inventory	112,988	112,137	111,093	113,233	119,835	107,117	-12,719	-10.6	78,163	-41,672	-34.8
5	Avg Daily Burn Rate	3,863	3,697	4,008	4,143	4,199	3,567			3,548		
6	Avg No. of Days	29	30	28	27	29	30			22		

Reference:
CA-208
Line 1: Average of recorded month-ending inventories
Line 2: Average of recorded annual consumption divided by 365 days
Line 3: Line 1 ÷ Line 2
Line 4: Average of recorded month-ending inventories
Line 5: Average of recorded annual consumption divided by 365 days
Line 6: Line 4 ÷ Line 6
Column G: Column F - Column E
Column H: Column G ÷ Column E
Column J: Column I - Column E
Column K: Column J ÷ Column E

Note:
1. Diesel fuel averages include Hana diesel inventory starting from 2003

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Maui Electric Company, Limited

HISTORICAL AVERAGE FUEL INVENTORY
(Barrels)
Direct Testimony

(Lanai Division)

							MECO DT			CA DT		
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
							Test Year	TY vs. 2005		Test Year	TY vs. 2005	
Line		2001	2002	2003	2004	2005	2007	Diff	%	2007	Diff	%
	Diesel Fuel											
1	Avg Inventory	5,089	5,038	3,213	4,241	3,070	4,418	1,348	43.9	4,418	1,348	43.9
2	Avg Daily Burn Rate	134	132	137	137	141	147			147		
3	Avg No. of Days	38	38	24	31	22	30			30		

Reference:
CA-208, pg 5
Line 1: Average of recorded month-ending inventories
Line 2: Average of recorded annual consumption divided by 365 days
Line 3: Line 1 ÷ Line 2
Column G: Column F - Column E
Column H: Column G ÷ Column E
Column J: Column I - Column E
Column K: Column J ÷ Column E

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Maui Electric Company, Limited

HISTORICAL AVERAGE FUEL INVENTORY
(Barrels)
Direct Testimony

(Molokai Division)

							MECO DT			CA DT		
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
							Test Year	TY vs. 2005		Test Year	TY vs. 2005	
Line		2001	2002	2003	2004	2005	2007	Diff	%	2007	Diff	%
	Diesel Fuel											
1	Avg Inventory	8,835	8,167	7,473	8,255	7,643	5,548	-2,095	-27.4	5,548	-2,095	-27.4
2	Avg Daily Burn Rate	178	174	182	182	184	185			185		
3	Avg No. of Days	50	47	41	45	42	30			30		

Reference:
CA-208, pg 6
Line 1: Average of recorded month-ending inventories
Line 2: Average of recorded annual consumption divided by 365 days
Line 3: Line 1 ÷ Line 2
Column G: Column F - Column E
Column H: Column G ÷ Column E
Column J: Column I - Column E
Column K: Column J ÷ Column E

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Maui Electric Company, Limited

PURCHASED POWER EXPENSE

		MECO DT				CA DT			
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line		KWHs	ENERGY COST ($)	CAPACITY COST ($)	TOTAL COST ($)	KWHs	ENERGY COST ($)	CAPACITY COST ($)	TOTAL COST ($)
	FIRM POWER								
1	2004 HC&S	94,498,100	10,119,878	1,834,116	11,953,994	94,498,100	10,119,878	1,834,116	11,953,994
2	2005 HC&S	97,083,300	14,456,543	1,846,910	16,303,453	97,083,300	14,456,543	1,846,910	16,303,453
3	2007 HC&S (fcst)	90,415,000	17,811,697	1,839,097	19,650,793	90,420,000	17,812,710	1,839,285	19,651,995
	AS-AVAILABLE POWER								
4	2007 KWP (fcst)	122,882,000	14,159,946	0	14,159,946	122,930,000	14,165,321	0	14,165,321
5	2007 Makila (fcst)	876,000	170,922	0	170,922	876,000	170,922	0	170,922
6	*Sub-total 2007 Forecast*	*123,758,000*	*14,330,868*	0	*14,330,868*	*123,806,000*	*14,336,243*	*0*	*14,336,243*
7	**TOTAL 2007 CONSOLIDATED**	214,173,000	32,142,564	1,839,097	33,981,661	214,226,000	32,148,953	1,839,285	33,988,238

Source: Column A: MECO-WP-507-a
Column B: MECO-WP-507-b
Column C: MECO-WP-507-b
Column D: Column B + Column C

Column E: CA-WP-210, page 1
Column F: CA-WP-210, page 3
Column G: CA-WP-210, page 3
Column H: Column F + Column G

Reference:
HC&S (Hawaiian Commercial & Sugar Co.)
KWP (Kaheawa Wind Partners)
Makila (Hydroelectric Plant)

Maui Electric Company, Ltd.

BASE FUEL ENERGY CHARGE AND
FIXED EFFICIENCY FACTOR (OR SALES HEAT RATE)

Rate Proceeding Docket No. 97-0346, Apr 1999

Line		Maui	Lanai	Molokai
1	Base Fuel Energy, ¢/kWh	4.5937	9.0620	5.3991
	Fuel Price			
2	Industrial, $/bbl	14.21	- - - -	- - - -
3	Diesel, $/bbl	25.78	45.31	27.40
	Base Composite Cost			
4	Generation , ¢/MBtu	369.60	773.27	467.54
5	Purchased Energy, ¢/kWh	5.028	- - - -	- - - -
	Fixed Efficiency Factor or			
6	Sales Heat Rate, Btu/kWh of sales	11,032	10,678	10,522

Source:
MECO-1902

MAUI ELECTRIC COMPANY, LTD.
MAUI DIVISION
ENERGY COST ADJUSTMENT FILING

PRESENT RATES

Line

1 Effective Date 2007 Test Year - Direct
Supersedes Factor of

OIL-FIRED GENERATION COMPONENT

Line		
	OIL PRICES, ¢/MBTU	
2	Industrial	948.90
3	Diesel	1,792.83
3a	Hana DG	0.00
	OIL BTU MIX, %	
4	Industrial	29.34%
5	Diesel	70.65%
5a	Hana DG	0.01%
6	COMPOSITE GENERATION COST, ¢/MBTU, {Lines (2x4) + Lines (3x5)}	1,545.04
7	% Input to System kWh Mix	83.41%
8	Efficiency Factor, mbtu/kWh	0.011032
9	WEIGHTED COMPOSITE GEN. COST, ¢/KWH, {Lines (6x7x8)}	14.21714
10	BASE GENERATION COST, ¢/MBTU	369.60
11	Base % Input to System kWh Mix	91.79
12	Efficiency Factor, mbtu/kWh	0.011032
13	WEIGHTED BASE GEN. COST ¢/KWH, {Lines (10x11x12)}	3.74267
14	COST LESS BASE { Line 9-13 }	10.47447
15	Multiplier to Include Rev. Tax Requirement	1.0975
16	GENERATION FACTOR, ¢/KWH { Lines (14x15) }	11.49573

PURCHASED POWER COMPONENT

Line			
	PURCHASED POWER PRICES, ¢/KWH		
17	HC&S - Regular	- On Peak	20.270
18		- Off Peak	18.450
19	HC&S - Emergency	- On Peak	20.270
20		- Off Peak	18.450
21	HC&S - Unschedule	- On Peak	20.270
22		- Off Peak	18.450
23	Kaheawa Wind	- On Peak	12.0884
24		- Off Peak	10.8333
25	Makila Hydro	- On Peak	20.270
26		- Off Peak	18.450
27	Other (<100 kW)		0.000
	PURCHASED POWER KWH MIX, %		
28	HC&S - Regular	- On Peak	27.67%
29		- Off Peak	13.22%
30	HC&S - Emergency	- On Peak	0.00%
31		- Off Peak	0.00%
32	HC&S - Unschedule	- On Peak	1.32%
33		- Off Peak	0.00%
34	Kaheawa Wind	- On Peak	31.54%
35		- Off Peak	25.85%
	Makila Hydro	- On Peak	0.24%
		- Off Peak	0.17%
36	Other (<100 kW)		0.00%
37	COMPOSITE COST OF PURCHASE ENERGY, ¢/KWH		15.007
38	% Input to System kWh Mix		16.59%
39	WEIGHTED COMP. PURCH. ENERGY COST, ¢/KWH, {Lines (37x38)}		2.48966
40	BASE PURCHASED ENERGY COMPOSITE COST, ¢/KWH		5.028
41	Base % Input to System kWh Mix		8.21
42	WEIGHTED BASE PURCH. ENERGY COST, ¢/KWH, Lines {40x41}		0.41280
43	COST LESS BASE {LINE (39-42)}		2.07686
44	Loss Factor		1.073
45	Multiplier to Include Rev. Tax Requirement		1.0975
46	PURCHASED ENERGY FCTR, ¢/KWH {Lines (43+44+45}		2.44575

SYSTEM COMPOSITE CALCULATIONS

Line		
45	FUEL AND PURCHASED ENERGY FACTOR, ¢/KWH {Lines 16+46}	13.941
46	ADJUSTMENT, ¢/KWH	0.000
47	ECA RECONCILIATION ADJUSTMENT, ¢/KWH	0.000
48	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH {Lines 45+46+47}	13.941

Reference: CA-WP-212

MAUI ELECTRIC COMPANY, LTD. - MAUI DIVISION
Comparison of Composite Costs of Central Station Generation
at Present and Proposed Rates

2007 Test Year - Direct Testimony

Line		MECO DT (A) At Current Effective Rates	MECO DT (B) At Proposed Rates	MECO DT (C) Difference (B) - (A)	CA DT (D) At Current Effective Rates	CA DT (E) At Proposed Rates	CA DT (F) Difference (E) - (D)
	FUEL PRICES, ¢/mmbtu						
1	Industrial	948.90	953.85	4.95	948.90	953.85	4.95
2	Diesel	1,792.83	1,792.83	0.00	1,792.83	1,792.83	0.00
3	DG	0.00	0.00	0.00	0.00	0.00	0.00
	BTU MIX, %						
4	Industrial	29.19	29.19	0.00	29.34	29.35	0.01
5	Diesel	70.80	70.81	0.01	70.65	70.65	0.00
6	DG	0.01	0.00	(0.01)	0.01	0.00	(0.01)
		100.00	100.00	0.00	100.00	100.00	0.00
7	COMPOSITE COST OF GENERATION ¢/mmbtu	1,546.31	1,547.93	1.62	1,545.04	1,546.59	1.55

Source:
Col (A) : MECO-1904
Col (B) : MECO-1906
Col (D) : CA-WP-212
Col (E) : CA-WP-214

MAUI ELECTRIC COMPANY, LTD. - MAUI DIVISION
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Rates

ENERGY COST ADJUSTMENT (ECA) FILING - 2007 Test Year - Direct

Line		
1	*Effective Date*	*2007 Test Year - Direct*
2	Supercedes Factors of	

GENERATION COMPONENT

CENTRAL STATION

	FUEL PRICES, ¢/mmbtu	
3	Industrial	953.85
4	Diesel	1,792.83
5	Other	0.00
	BTU MIX, %	
6	Industrial	29.35
7	Diesel	70.65
8	Other	0.00
		100.00
9	COMPOSITE COST OF GENERATION, *CNTRL STN + OTHER ¢/mmbtu*	1,546.59
10	% Input to System kWh Mix	83.40

EFFICIENCY FACTOR, mmbtu/kWh

	(A)	(B)	(C)	(D)
	Fuel Type	Eff Factor mmbtu/kwh	Percent of Centrl Stn + Other	Weighted Eff Factor
11	Industrial	0.015295	20.37	0.003115
12	Diesel	0.009418	79.63	0.007500
13	Other	0.010614	0.00	0.000000

(Lines 15, 16, 17): Col(B) x Col(C) = Col(D)

14	Weighted Efficiency Factor, mmbtu/kWh [lines 15(D) + 16(D) + 17(D)]	0.010615
15	WGTD. COMPOSITE CNTRL STN + OTHER GEN COST, ¢/kWh (lines (13x14x18))	13.69245
16	BASE CNTRL STN + OTHER GEN. COST, ¢/mmbtu	1,546.59
17	Base % Input to Sys kWh Mix	83.41
18	Efficiency Factor, mmbtu/kwh	0.010614
19	WEIGHTED BASE CNTRL STN + OTHER GEN COST ¢/kWh (lines (20x21x22))	13.69239
20	COST LESS BASE (line(19-23))	0.00006
21	Revenue Tax Req Multiplier	1.0975
22	CNTRL STN + OTHER GENERATION FACTOR, ¢/kWh (line (24x25))	0.00007

DG ENERGY COMPONENT

23	COMPOSITE COST OF DG ENERGY, ¢/kWh	22.294
24	% Input to System kWh Mix	0.01
25	WTD COMP DG ENRGY COST, ¢/kWh (Lines 27 x 28)	0.00138
26	BASE DG ENERGY COMP COST	22.294
27	Base % Input to System kWh Mix	0.01
28	WTD BASE DG ENERGY COST, ¢/kWh (Line 30 x 31)	0.00138
29	Cost Less Base (Line 29 - 32)	0.00000
30	Loss Factor	1.065
31	Revenue Tax Req Multiplier	1.0975
32	DG FACTOR, ¢/kWh (Line 33 x 34 x 35)	0.00000

SUMMARY OF TOTAL GENERATION FACTOR, ¢/kWh

33	Cntrl Stn+Other (line 26)	0.00007
34	DG (line 36)	0.00000
35	TOTAL GENERATION FACTOR, ¢/kWh (lines 37 + 38)	0.00007

MAUI ELECTRIC COMPANY, LTD. - MAUI DIVISION
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Rates

ENERGY COST ADJUSTMENT (ECA) FILING - 2007 Test Year - Direct

Line	PURCHASED ENERGY COMPONENT		
	PURCHASED ENERGY PRICE, ¢/kWh		
36	HC&S - Regular	- On Peak	20.270
37		- Off Peak	18.450
38	HC&S - Emergency	- On Peak	20.270
39		- Off Peak	18.450
40	HC&S - Unscheduled	- On Peak	20.270
41		- Off Peak	18.450
42	Kaheawa Wind	- On Peak	12.088
43		- Off Peak	10.833
44	Makila Hydro	- On Peak	20.270
45		- Off Peak	18.450
	PURCHASED ENERGY KWH MIX, %		
46	HC&S - Regular	- On Peak	27.67
47		- Off Peak	13.22
48	HC&S - Emergency	- On Peak	0.00
49		- Off Peak	0.00
50	HC&S - Unscheduled	- On Peak	1.32
51		- Off Peak	0.00
52	Kaheawa Wind	- On Peak	31.54
53		- Off Peak	25.85
54	Makila Hydro	- On Peak	0.24
55		- Off Peak	0.17
			100.00
56	COMPOSITE COST OF PURCHASED ENERGY, ¢/kWh		15.007
57	% Input to System kWh Mix		16.59 ok
58	WEIGHTED COMP. PURCH. ENERGY COST, ¢/kWh (lines (60x61))		2.48966
59	BASE PURCHASED ENERGY COMPOSITE COST, ¢/kWh		15.007
60	Base % Input to Sys kWh Mix		16.59
61	WEIGHTED BASE PURCH ENERGY COST, ¢/kWh (lines (63 x 64))		2.48966
62	COST LESS BASE(lines (62 - 65))		0.00000
63	Loss Factor		1.065
64	Revenue Tax Req Multiplier		1.0975
65	PURCHSD ENERGY FCTR, ¢/kWh (lines (66 x 67 x 68))		0.00000

Line	SYSTEM COMPOSITE	
66	GEN AND PURCHASED ENERGY FACTOR, ¢/kWh (lines (39 + 69))	0.00007
67	Adjustment, ¢/kWh	0.000
68	ECA Reconciliation Adjustment	0.000
69	ECA FACTOR, ¢/kWh (lines (70 + 71 + 72))	0.000

Reference: MECO-1907, MECO-WP-1904, pp. 1 and 5, MECO-WP-1906

Maui Electric Company, Ltd. - Maui Division

FIXED AND WEIGHTED EFFICIENCY FACTORS
2007 Test Year - Direct Testimony
At Proposed Rates

	Industrial	Diesel	Other	Total	
1 **Fixed Efficiency Factor**	**0.015295**	**0.009418**	**0.010614**		mbtu/kwh
2 Gen Mwh %	20.37	79.63	0.00	100.00	%
3 Weighted Efficiency Factor (line 1 x line 2)	0.003115	0.007500	0.000000	0.010615	mbtu/kwh

Reference:
1 CA-WP-215
2 CA-WP-214, page 4

MAUI ELECTRIC COMPANY, LTD.
LANAI DIVISION
ENERGY COST ADJUSTMENT FILING

PRESENT RATES

Line			Line		
1	*Effective Date* *2007 Test Year - Direct*				
	Supersedes Factor of				
	OIL-FIRED GENERATION COMPONENT			**PURCHASED POWER COMPONENT**	
	OIL PRICES, ¢/MBTU			PURCHASED POWER PRICES, ¢/KWH	
2	Industrial	0.00			
3	Diesel	1,960.44	17	- Off Peak	0.000
			18	- On Peak	0.000
	OIL BTU MIX, %				
4	Industrial	0.00	19	Schedule Q	0.000
5	Diesel	100.00			
				PURCHASED POWER KWH MIX, %	
			20	- Off Peak	0.000
			21	- On Peak	0.000
			22	Schedule Q	0.000
6	COMPOSITE GENERATION COST, ¢/MB {Lines (2X4) + Lines (3X5)}	1,960.44		COMPOSITE COST OF	
7	% Input to System kWh Mix	100.00%	23	PURCHASED POWER, ¢/KWH	0.00000
8	Efficiency Factor, Mbtu/kWh	0.01068	24	% Input to System kWh Mix	0.00%
9	WEIGHTED COMPOSITE GEN. COST, ¢/KWH {Lines (6X7X8)}	20.93358	25	WEIGHTED BASE PURCH ENERGY COST, ¢/KWH {Lines (23X24)}	0.00000
10	BASE GENERATION COST, ¢/MBTU	773.27		BASE PURCHASED POWER	
11	Base % Input to System kWh Mix	100.00%	26	COMPOSITE COST ¢/KWH	7.695
12	Efficiency Factor, Mbtu/kWh	0.01068	27	Base % Input to System kWh Mix	0.00%
13	WEIGHTED BASE GEN. COST, ¢/KWH, {Lines (10X11X12)}	8.25698	28	WEIGHTED BASE PURCH ENERGY COST ¢/KWH {Lines (26x27)}	0.00000
14	COST LESS BASE {Lines (9-13)}	12.6766	29	COST LESS BASE {LINES (25-28)}	0.000
15	Multiplier to Include Rev. Tax Requirement	1.0975	30	Loss Factor	1.073
			31	Multiplier to Include Rev. Tax Requirement	1.0975
16	GENERATION FACTOR, ¢/KWH Lines (14X15)	13.9126	32	PURCHASED POWER FACTOR, ¢/KWH {Lines (29X30X31)}	0.00000

Line	**SYSTEM COMPOSITE CALCULATIONS**	
33	FUEL AND PURCHASED ENERGY FACTOR, ¢/KWH {Lines (16+32)}	13.913
34	ADJUSTMENT, ¢/KWH	0.000
35	ECA RECONCILIATION ADJUSTMENT, ¢/KWH	0.000
36	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH	13.913

Reference: MECO-1902, MECO-WP-1909

MAUI ELECTRIC COMPANY, LTD. - LANAI DIVISION
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Weighted Generation Efficiency Factor & DG Component

ENERGY COST ADJUSTMENT (ECA) FILING - 2007 Test Year - Direct

Line		
1	Effective Date	2007 Test Year - Direct
2	Supercedes Factors of	

GENERATION COMPONENT

CENTRAL STATION

	FUEL PRICES, ¢/mmbtu	
3	Industrial	0.00
4	Diesel	1,960.44
5	Other	0.00
	BTU MIX, %	
6	Industrial	0.00
7	Diesel	100.00
8	Other	0.00
		100.00
9	COMPOSITE COST OF GENERATION, CNTRL STN + OTHER ¢/mmbtu	1,960.44
10	% Input to System kWh Mix	100.00

EFFICIENCY FACTOR, mmbtu/kWh

	(A) Fuel Type	(B) Eff Factor mmbtu/kwh	(C) Percent of Centrl Stn + Other	(D) Weighted Eff Factor
11	Industrial	0.000000	0.00	0.000000
12	Diesel	0.010577	100.00	0.010577
13	Other	0.010577	0.00	0.000000

(Lines 11, 12, 13): Col(B) x Col(C) = Col(D)

14	Weighted Efficiency Factor, mmbtu/kWh [lines 11(D) + 12(D) + 13(D)]	0.010577
15	WGTD. COMPOSITE CNTRL STN + OTHER GEN COST, ¢/kWh (lines (9x10x14))	20.73557
16	BASE CNTRL STN + OTHER GEN. COST, ¢/mmbtu	1,960.44
17	Base % Input to Sys kWh Mix	100.00
18	Efficiency Factor, mmbtu/kwh	0.010577
19	WEIGHTED BASE CNTRL STN + OTHER GEN COST ¢/kWh (lines (16x17x18))	20.73557
20	COST LESS BASE (line(15-19))	0.00000
21	Revenue Tax Req Multiplier	1.0975
22	CNTRL STN + OTHER GENERATION FACTOR, ¢/kWh (line (20x21))	0.00000

DG ENERGY COMPONENT

23	COMPOSITE COST OF DG ENERGY, ¢/kWh	0.000
24	% Input to System kWh Mix	0.00
25	WTD COMP DG ENRGY COST, ¢/kWh (Lines 23 x 2	0.00000
26	BASE DG ENERGY COMP COS	0.000
27	Base % Input to System kWh Mix	0.00
28	WTD BASE DG ENERGY COST, ¢/kWh (Line 26 x 27	0.00000
29	Cost Less Base (Line 25 - 28)	0.00000
30	Loss Factor	1.054
31	Revenue Tax Req Multiplier	1.0975
32	DG FACTOR, ¢/kWh (Line 29 x 30 x 31)	0.00000

SUMMARY OF TOTAL GENERATION FACTOR, ¢/kWh

33	Cntrl Stn+Other (line 22)	0.00000
34	DG (line 32)	0.00000
35	TOTAL GENERATION FACTOR, ¢/kWh (lines 33 + 34)	0.00000

MAUI ELECTRIC COMPANY, LTD. - LANAI DIVISION
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Weighted Generation Efficiency Factor & DG Component

ENERGY COST ADJUSTMENT (ECA) FILING - 2007 Test Year - Direct

Line	PURCHASED ENERGY COMPONENT	
	PURCHASED ENERGY PRICE, ¢/kWh	
36	- On Peak	0.000
37	- Off Peak	0.000
38	Sch Q	0.000
	PURCHASED ENERGY KWH MIX, %	
39	- On Peak	0.00
40	- Off Peak	0.00
41	Sch Q	0.000
42	COMPOSITE COST OF PURCHASED ENERGY, ¢/kWh	0.000
43	% Input to System kWh Mix	0.00
44	WEIGHTED COMP. PURCH. ENERGY COST, ¢/kWh (lines (42x43))	0.00000
45	BASE PURCHASED ENERGY COMPOSITE COST, ¢/kWh	0.000
46	Base % Input to Sys kWh Mix	0.00
47	WEIGHTED BASE PURCH ENERGY COST, ¢/kWh (lines (45 x 46))	0.00000
48	COST LESS BASE(lines (44 - 47))	0.00000
49	Loss Factor	1.054
50	Revenue Tax Req Multiplier	1.0975
51	PURCHSD ENERGY FCTR, ¢/kWh (lines (48 x 49 x 50))	0.00000

Line	SYSTEM COMPOSITE	
52	GEN AND PURCHASED ENERGY FACTOR, ¢/kWh (lines (35 + 51))	0.00000
53	Adjustment, ¢/kWh	0.000
54	ECA Reconciliation Adjustment	0.000
55	ECA FACTOR, ¢/kWh (lines (52 + 53 + 54))	0.000

Reference: MECO-WP-1909, 1910

MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION
ENERGY COST ADJUSTMENT FILING

PRESENT RATES

Line		
1	Effective Date 2007 Test Year - Direct Supersedes Factor of	
	OIL-FIRED GENERATION COMPONENT	
	OIL PRICES, ¢/MBTU	
2	Industrial	0.00
3	Diesel	1,833.50
	OIL BTU MIX, %	
4	Industrial	0.00%
5	Diesel	100.00%
6	COMPOSITE GENERATION COST, ¢/MBTU {Line(2X4)+Line(3X5)}	1,833.50
7	% Input to System kWh Mix	100.0%
8	Efficiency Factor, mbtu/kWh	0.010522
9	WEIGHTED COMPOSITE GEN. COST, ¢/KWH {LINES (6X7X8)}	19.29209
10	BASE GENERATION COST, ¢/MBTU	467.54
11	Base % Input to System kWh Mix	100.00%
12	Efficiency Factor, mbtu/kWh	0.010522
13	WEIGHTED BASE GEN. COST, ¢/KWH {LINES (10X11X12)}	4.91946
14	COST LESS BASE {LINES (9-13)}	14.37263
15	Multiplier to include Rev. Tax Requirement	1.09750
16	GENERATION FACTOR, ¢/KWH LINES (14X15)	15.77396

Line		
	PURCHASED POWER COMPONENT	
	PURCHASED POWER PRICES, ¢/KWH	
17	- Off Peak	0.000
18	- On Peak	0.000
19	Schedule Q	0.000
	PURCHASED POWER KWH MIX, %	
20	- Off Peak	0.000%
21	- On Peak	0.000%
22	Schedule Q	0.000%
	COMPOSITE COST OF	
23	PURCHASED POWER ¢/KWH	0.000
24	% Input to System kWh Mix	0.0%
25	WEIGHTED COMP. PURCH ENERGY COST, ¢/KWH {Lines (23X24)}	0.00000
	BASE PURCHASED POWER	
26	COMPOSITE COST ¢/KWH	4.448
27	Base % Input to System kWh Mix	0.00%
28	WEIGHTED BASE PURCH ENERGY COST, ¢/KWH {Lines (26X27)}	0.00000
29	COST LESS BASE {Lines (25-28)}	0.00000
30	Loss Factor	1.106
31	Multiplier to Include Rev. Tax Requirement	1.0975
32	PURCHASED POWER FACTOR, ¢/KWH {Lines (29X30X31)}	0.00000

Line	**SYSTEM COMPOSITE CALCULATIONS**	
33	FUEL AND PURCHASED ENERGY FACTOR, ¢/KWH {Lines (16+32)}	15.77396
34	ADJUSTMENT, ¢/KWH	0.000
35	ECA RECONCILIATION ADJUSTMENT, ¢/KWH	0.000
36	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH	15.774

Reference: MECO-1902, MECO-WP-1909

MAUI ELECTRIC COMPANY, LTD. - MOLOKAI DIVISION
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Weighted Generation Efficiency Factor & DG Component

ENERGY COST ADJUSTMENT (ECA) FILING - 2007 Test Year - Direct

Line		
1	Effective Date	2007 Test Year - Direct
2	Supercedes Factors of	

GENERATION COMPONENT

CENTRAL STATION

	FUEL PRICES, ¢/mmbtu	
3	Industrial	0.00
4	Diesel	1,833.50
5	Other	0.00
	BTU MIX, %	
6	Industrial	0.00
7	Diesel	100.00
8	Other	0.00
		100.00
9	COMPOSITE COST OF GENERATION, CNTRL STN + OTHER ¢/mmbtu	1,833.50
10	% Input to System kWh Mix	100.00

EFFICIENCY FACTOR, mmbtu/kWh

	(A) Fuel Type	(B) Eff Factor mmbtu/kwh	(C) Percent of Centrl Stn + Other	(D) Weighted Eff Factor
11	Industrial	0.000000	0.00	0.000000
12	Diesel	0.010823	100.00	0.010823
13	Other	0.010823	0.00	0.000000

(Lines 11, 12, 13): Col(B) x Col(C) = Col(D)

14	Weighted Efficiency Factor, mmbtu/kWh [lines 11(D) + 12(D) + 13(D)]	0.010823
15	WGTD. COMPOSITE CNTRL STN + OTHER GEN COST, ¢/kWh (lines (9x10x14))	19.84397
16	BASE CNTRL STN + OTHER GEN. COST, ¢/mmbtu	1,833.50
17	Base % Input to Sys kWh Mix	100.00
18	Efficiency Factor, mmbtu/kwh	0.010823
19	WEIGHTED BASE CNTRL STN + OTHER GEN COST ¢/kWh (lines (16x17x18))	19.84397
20	COST LESS BASE (line(15-19))	0.00000
21	Revenue Tax Req Multiplier	1.0975
22	CNTRL STN + OTHER GENERATION FACTOR, ¢/kWh (line (20x21))	0.00000

DG ENERGY COMPONENT

23	COMPOSITE COST OF DG ENERGY, ¢/kWh	0.000
24	% Input to System kWh Mix	0.00
25	WTD COMP DG ENRGY COST, ¢/kWh (Lines 23 x 2	0.00000
26	BASE DG ENERGY COMP COS	0.000
27	Base % Input to System kWh Mix	0.00
28	WTD BASE DG ENERGY COST, ¢/kWh (Line 26 x 27	0.00000
29	Cost Less Base (Line 25 - 28)	0.00000
30	Loss Factor	1.100
31	Revenue Tax Req Multiplier	1.0975
32	DG FACTOR, ¢/kWh (Line 29 x 30 x 31)	0.00000

SUMMARY OF TOTAL GENERATION FACTOR, ¢/kWh

33	Cntrl Stn+Other (line 22)	0.00000
34	DG (line 32)	0.00000
35	TOTAL GENERATION FACTOR, ¢/kWh (lines 33 + 34)	0.00000

MAUI ELECTRIC COMPANY, LTD. - MOLOKAI DIVISION
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Weighted Generation Efficiency Factor & DG Component

ENERGY COST ADJUSTMENT (ECA) FILING - 2007 Test Year - Direct

Line	PURCHASED ENERGY COMPONENT	
	PURCHASED ENERGY PRICE, ¢/kWh	
36	- On Peak	0.000
37	- Off Peak	0.000
38	Sch Q	0.000
	PURCHASED ENERGY KWH MIX, %	
39	- On Peak	0.00
40	- Off Peak	0.00
41	Sch Q	0.000
42	COMPOSITE COST OF PURCHASED ENERGY, ¢/kWh	0.000
43	% Input to System kWh Mix	0.00
44	WEIGHTED COMP. PURCH. ENERGY COST, ¢/kWh (lines (42x43))	0.00000
45	BASE PURCHASED ENERGY COMPOSITE COST, ¢/kWh	0.000
46	Base % Input to Sys kWh Mix	0.00
47	*WEIGHTED BASE PURCH ENERGY* COST, ¢/kWh (lines (45 x 46))	0.00000
48	COST LESS BASE(lines (44 - 47))	0.00000
49	Loss Factor	1.100
50	Revenue Tax Req Multiplier	1.0975
51	PURCHSD ENERGY FCTR, ¢/kWh (lines (48 x 49 x 50))	0.00000

Line	SYSTEM COMPOSITE	
52	GEN AND PURCHASED ENERGY FACTOR, ¢/kWh (lines (35 + 51))	0.00000
53	Adjustment, ¢/kWh	0.000
54	*ECA Reconciliation Adjustment*	*0.000*
55	ECA FACTOR, ¢/kWh (lines (52 + 53 + 54))	0.000

Reference: MECO-WP-1909, 1912

Maui Electric Company, Limited

TEST YEAR 2007 PRODUCTION SIMULATION
SUMMARY (UNADJUSTED)
Direct Testimony

(Maui Division)

Location	Unit No.	MECO Production Simulation				CA Production Simulation			
		Hours Run	Net MWHs	Fuel Consumption BBL	Fuel Consumption MBTU	Hours Run	Net MWHs	Fuel Consumption BBL	Fuel Consumption MBTU
		PMONTH	*PMONTH*		*PMONTH*	*PMONTH*	*PMONTH*		*PMONTH*
Kahului	1	4,576	17,043	45,143	284,400	4,339	16,390	43,429	273,600
	2	4,698	20,159	52,921	333,400	4,499	20,050	52,556	331,100
	3	8,076	87,886	183,079	1,153,400	8,076	88,160	183,619	1,156,800
	4	8,076	93,600	209,794	1,321,700	8,075	94,780	212,349	1,337,800
	Total	25,426	218,688	490,937	3,092,900	24,988	219,380	491,952	3,099,300
Maalaea	X1	1	3	0	0	0.30	0	0	0
	X2	1	2	0	0	0.10	0	0	0
	1	2	6	17	100	0.50	0	0	0
	2	4	11	17	100	1.20	0	0	0
	3	8	21	34	200	2.10	10	17	100
	sub total	17	43	68	400	4	10	17	100
	4	132	464	802	4,700	43	150	256	1,500
	5	20	69	119	700	8	30	51	300
	6	465	1,626	2,833	16,600	120	420	734	4,300
	7	50	175	307	1,800	19	70	119	700
	sub total	667	2,334	4,061	23,800	190	670	1,160	6,800
	8	912	3,181	5,273	30,900	419	1,470	2,440	14,300
	9	1,479	5,163	8,567	50,200	851	2,970	4,932	28,900
	sub total	2,391	8,344	13,840	81,100	1,270	4,440	7,372	43,200
	10	3,103	26,105	40,324	236,300	2,250	19,810	30,546	179,000
	11	4,437	37,221	57,509	337,000	3,868	32,750	50,563	296,300
	12	4,490	37,645	58,157	340,800	4,263	35,820	55,341	324,300
	13	6,095	50,845	78,618	460,700	5,583	46,820	72,338	423,900
	sub total	18,125	151,816	234,608	1,374,800	15,964	135,200	208,788	1,223,500
	M14&15	8,225	197,723	290,512	1,702,400	8,225	199,500	292,884	1,716,300
	M15&16	8,177	189,056	278,925	1,634,500	8,177	192,530	283,481	1,661,200
	M17&18	8,579	219,021	320,137	1,876,000	8,579	223,350	325,802	1,909,200
	M18&19	7,032	90,194	139,352	816,600	6,423	102,140	155,137	909,100
	sub total	32,013	695,994	1,028,925	6,029,500	31,404	717,520	1,057,304	6,195,800
	Total	53,212	858,531	1,281,502	7,509,600	48,832	857,840	1,274,642	7,469,400
Hana	H1	40	40	75	442	40	40	75	442
	H2	40	40	75	442	40	40	75	442
	Total	80	80	151	885	80	80	151	885
IPP									
HC&S			90,427				90,420		
KWP			122,912				122,910		
Makila Hydro			875				880		
	Total		214,214				214,210		
IPP Total			214,214				214,210		
MECO Total		78,718	1,077,299	1,772,589	10,603,385	73,900	1,077,300	1,766,745	10,569,585
SYSTEM TOTAL		78,718	1,291,513	0	0	73,900	1,291,510		

Maui Electric Company, Limited

TEST YEAR 2007 FUEL CONSUMPTION
PRODUCTION SIMULATION
Direct Testimony

(Maui Division)

Adjustment for Calibration Factor:

Steam	Net MWHs	Prod Sim Barrels	Calibration Factor	Adjusted Barrels	Net KWH / Barrel	Barrels Per Day	MBTU @ 6.30 MBTU / BBL	Net Heat Rate (MBTU/KWH
K1	16,390	43,429	1.016743	44,156	371	121	278,183	16,973
K2	20,050	52,556	1.016743	53,436	375	146	336,647	16,790
K3	88,160	183,619	1.016743	186,693	472	511	1,176,166	13,341
K4	94,780	212,349	1.016743	215,905	439	592	1,360,202	14,351
Kahului Total	219,380	491,952		500,190	439	1,370	3,151,197	14,364

Diesel	Net MWHs	Prod Sim Barrels	*p. 54* Calibration Factor	Adjusted Barrels	Net KWH / Barrel	Barrels Per Day	*MBTU @* 5.86 MBTU / BBL	*Net* Heat Rate (MBTU/KWH
M1-3, X1-2	10	17	1.015772	17	588	0	100	10,000
M 4-7	670	1,160	1.015772	1,179	568	3	6,909	10,312
M 8-9	4,440	7,372	1.015772	7,488	593	21	43,880	9,883
M10-13	135,200	208,788	1.015772	212,081	637	581	1,242,795	9,192
M14&15	199,500	292,884	1.015772	297,503	671	815	1,743,368	8,739
M15&16	192,530	283,481	1.015772	287,952	669	789	1,687,399	8,764
M17&18	223,350	325,802	1.015772	330,941	675	907	1,939,314	8,683
M18&19	102,140	155,137	1.015772	157,583	648	432	923,436	9,041
Maalaea Total	857,840	1,274,642		1,294,744	663	3,547	7,587,200	8,845
H1	40	75	1.015772	77	519	0.2	451	11,275
H2	40	75	1.015772	77	519	0.2	451	11,275
Hana Total	80	151		154	519	0.4	902	11,275
Diesel total	857,920	1,274,793		1,294,898	663		7,588,102	8,845

Plant	Net MWHs		Adjusted Barrels	Barrels Per Day	Adjusted MBTU	Net HR (MBTU/KWH
Kahului	219,380		500,190	1,370	3,151,197	14,364
Maalaea (incl Hana)	857,920		1,294,898	3,548	7,588,102	8,845
IPP	214,210	MECO Only MWH				
System	1,291,510	1,077,300	1,795,088	4,918	10,739,299	9,969

Notes:
Industrial Fuel Oil (IFO) heat content = 6.3 million Btu per barrel
Diesel fuel oil het content = 5.86 million Btu per barrel

Maui Electric Company, Limited

TEST YEAR 2007 FUEL OIL EXPENSE
Direct Testimony

(Maui Division)

Plant	(A) Fuel Consumption (BBLs)	(B) Fuel Prices ($/BBL)	(C) = (A) x (B) Fuel Expense ($000)
Kahului	500,190	59.6359	29,829.3
Maalaea	1,294,744	104.8621	135,769.5
Maalaea Biodiesel	2,339	109.2000	255.5
Hana	154	115.8105	17.8
	1,797,427		165,872.1
	COMPOSITE FUEL PRICE ($ / BBL)		92.2831

CA Reference
Column A: CA-WP-204, page 2
Maalaea Biodiesel: Start Ups for Maalaea 12 and 13 multiplied by 150 divided by 42.
Column B: MECO-WP-402, page 1

Maui Electric Company, Limited
Generation and Purchased Power
TEST YEAR 2007
Direct Testimony
(Lanai Division)

Line		MECO DT 2007 Test Year (MWh)	CA DT 2007 Test Year (MWh)
1	Unadjusted Sales	29,779.9	29,779.9
2	- Future DSM Impact	0.0	0.0
3	Test Year Sales	29,779.9	29,779.9
4	+ No Charge (0.026% of sales)	7.6	7.6
5	Sales - DSM + No Charge	29,787.5	29,787.5
6	+ Losses (5.11%)	1,604.7	1,604.7
7	Net-To-System	31,392.2	31,392.2
8	- Purchased Energy	0.0	0.0
9	Net Company Generation	31,392.2	31,392.2
10	+ Station Power (Gross/Net Ratio = 1.0322)	1,011.5	1,011.5
11	Gross Company Generation	32,403.7	32,403.7

CA Reference:
Lines 1 - 4: MECO-WP-404, page 93
Line 5: Line 3 - Line 2 + Line 4
Line 6: MECO-WP-404, page 93
Line 7: Line 5 + Line 6
Line 10: MECO-WP-404, page 93
Line11: Line 9 + Line 10

Maui Electric Company, Limited
Generation and Purchased Power
TEST YEAR 2007
Direct Testimony
(Molokai Division)

Line		MECO DT 2007 Test Year MWh	CA DT 2007 Test Year MWh
1	Unadjusted Sales	36,547.8	36,547.8
2	- Future DSM Impact	0.0	0.0
3	Test Year Sales	36,547.8	36,547.8
4	+ No Charge (0.36% of sales)	131.6	131.6
5	Sales - DSM + No Charge	36,679.4	36,679.4
6	+ Losses (8.75%)	3,518.7	3,518.7
7	Net-To-System	40,198.1	40,198.1
8	- Purchased Energy	0.0	0.0
9	Net Company Generation	40,198.1	40,198.1
10	+ Station Power (Gross/Net Ratio = 1.0329)	1,322.4	1,322.4
11	Gross Company Generation	41,520.5	41,520.5

CA Reference:
Lines 1 - 4: MECO-WP-404, page 96
Line 5: Line 3 - Line 2 + Line 4
Line 6: MECO-WP-404, page 96
Line 7: Line 5 + Line 6
Line 10: MECO-WP-404, page 96
Line 11: Line 9 + Line 10

Maui Electric Company, Limited
TEST YEAR 2007 OCEAN CARGO INSURANCE
Direct Testimony
(Maui Division)

Plant	(A) Fuel Expense ($)	(B) Ocean Cargo Insurance Rate	(C) = (A) x (B) Total ($)
Kahului	29,829,261	0.1175%	35,049
Maalaea	135,769,537	0.1175%	159,529
Total	165,598,798		194,579

CA Reference
Column A: CA-WP-204, page 3

Maui Electric Company, Limited
TEST YEAR 2007 SALES FUEL EFFICIENCY
Direct Testimony
(Maui Division)

	Net Gen (MWH)	Fuel (BBL)	Fuel (MBTU)	Net Heat Rate (BTU/KWH)
IFO	219,380	500,190	3,151,197	14,364
Diesel - Maalea	857,840	1,294,744	7,587,200	8,845
Diesel - Hana	80	154	902	11,275
Total MECO	1,077,300	1,795,088	10,739,299	

SALES PROVIDED BY COMPANY GENERATION

1,212.9	GWH Sales				
83.42%	1,077.300	/	1,291.431	=	net gen / net system input
1,011.8	GWH Sales Provided by Company Generation				

SALES PROVIDED BY IFO GENERATION

1,212.9	GWH Sales				
16.99%	219.380	/	1,291.431	=	net gen / net system input
206.0	GWH Sales Provided by Steam Generation				

SALES FUEL EFFICIENCY FOR IFO GENERATION

=	MBTU	÷	(GWH Steam Generated Sales	x	1,000,000)
=	3,151,197	÷	206,044,518		
=	0.015294	MBTU / KWH Sales			

CA Reference
CA-WP-204, page 2

Maui Electric Company, Limited
TEST YEAR 2007 SALES FUEL EFFICIENCY
Direct Testimony
(Maui Division - MAALAEA)

	Net Gen (MWH)	Fuel (BBL)	Fuel (MBTU)	Heat Rate (BTU/KWH)
IFO	219,380	500,190	3,151,197	14,364
Diesel - Maalea	857,840	1,294,744	7,587,200	8,845
Diesel - Hana	80	154	902	11,275
Total MECO	1,077,300	1,795,088	10,739,299	

SALES PROVIDED BY DIESEL GENERATION

1,212.9	GWH Sales				
66.43%	857.840	/	1,291.431	=	net gen / net system input
805.7	GWH Sales Provided by Diesel Generation				

SALES FUEL EFFICIENCY FOR DIESEL GENERATION

=	MBTU	÷	(GWH Diesel Generated Sales	x	1,000,000)
=	7,587,200	÷	805,694.361		
=	0.009417	MBTU / KWH Sales			

CA Reference
CA-WP-204, page 2

Maui Electric Company, Limited
TEST YEAR 2007 HANA SALES FUEL EFFICIENCY
Direct Testimony
(Maui Division - HANA)

	Net Gen (MWH)	Fuel (BBL)	Fuel (MBTU)	Heat Rate (BTU/KWH)
IFO	219,380	500,190	3,151,197	14,364
Diesel - Maalea	857,840	1,294,744	7,587,200	8,845
Diesel - Hana	80	154	902	11,275
Total MECO	1,077,300	1,795,088	10,739,299	

SALES PROVIDED BY DIESEL GENERATION

1,212.9	GWH Sales				
0.01%	0.080	/	1,291.431	=	net gen / net system input
0.1	GWH Sales Provided by Diesel Generation				

SALES FUEL EFFICIENCY FOR DIESEL GENERATION

=	MBTU	÷	(GWH Diesel Generated Sales	x	1,000,000)
=	902	÷	75,137		
=	0.012005	MBTU / KWH Sales			

CA Reference:
CA-WP-204, page 2

Maui Electric Company, Limited
TEST YEAR 2007 SALES FUEL EFFICIENCY
Direct Testimony
(Lanai Division)

	Net Gen (MWH)	Fuel (BBL)	Fuel (MBTU)	Net Heat Rate (BTU/KWH)
Diesel	31,392	53,754	314,996	10,034

SALES PROVIDED BY COMPANY GENERATION

29.8	GWH Sales			
100.00%	31.392	/	31.392	= net gen / net system input
29.8	MWH Sales Provided by Company Generation			

SALES FUEL EFFICIENCY

=	MBTU	÷	(GWH Diesel Generated Sales	x 1,000,000)
=	314,996	÷	29,779,900	
=	0.010577	MBTU / KWH Sales		

Maui Electric Company, Limited
TEST YEAR 2007 SALES FUEL EFFICIENCY
Direct Testimony
(Molokai Division)

	Net Gen (MWH)	Fuel (BBL)	Fuel (MBTU)	Net Heat Rate (BTU/KWH)
Diesel	40,198	67,503	395,565	9,840

SALES PROVIDED BY COMPANY GENERATION

	36.5	GWH Sales			
	100.00%	40.198	/	40.198	= net gen / net system input
	36.5	GWH Sales Provided by Company Generation			

SALES FUEL EFFICIENCY

=	MBTU	÷	(GWH Diesel Generated Sales	x	1,000,000)
=	395,565	÷	36,547,800		
=	0.010823	MBTU / KWH Sales			

Maui Electric Company, Limited
TEST YEAR 2007 AVERAGE BURN RATE FOR FUEL INVENTORY
Direct Testimony
(Maui Division)

Line		Industrial Fuel Oil (Barrels)	Diesel (Barrels)	TOTAL (Barrels)
1	Total Test Year Fuel Consumption	500,190	1,294,898	1,795,088
2	Days per year	365	365	
3	Test Year Burn Rate	1,370	3,548	4,918

CA Reference:
Line 1: CA-WP-204, page 2
Line 3: Line 1 ÷ Line 2

Maui Electric Company, Limited
TEST YEAR 2007 BIODIESEL FUEL CONSUMPTION
Direct Testimony

Line		(A)	(B)	(A+B) = (C)	
1	Unit	Maalaea M12	Maalaea M13		
2	Number of Starts	301	354	655	
3	Fuel Consumption Per Start	150	150		gallons
4	Total Consumption	45,150	53,100	98,250	gallons
5	Fuel Price	$2.60	$2.60	$2.60	/ gallon
6	Total	$117,390.00	$138,060.00	$255,450.00	

CA Reference:
Line 4: Line 2 x Line 3
Line 5: MECO-WP-402, page 1
Line 6: Line 4 x Line 5

Maui Electric Company, Limited
TEST YEAR 2007 AVERAGE BURN RATE FOR FUEL INVENTORY
Direct Testimony
(Lanai Division)

Line		Diesel (Barrels)
1	Total Test Year Fuel Consumption	53,754
2	Days per year	365
3	Test Year Burn Rate	147

CA Reference:
Line 1: MECO-WP-404, page 94
Line 3: Line 1 ÷ Line 2

Maui Electric Company, Limited

TEST YEAR 2007 AVERAGE BURN RATE FOR FUEL INVENTORY
Direct Testimony
(Molokai Division)

Line		Diesel (Barrels)
1	Total Test Year Fuel Consumption	67,503
2	Days per year	365
3	Test Year Burn Rate	185

CA Reference:
Line 1: MECO-WP-404, page 97
Line 3: Line 1 ÷ Line 2

Maui Electric Company, Limited
PURCHASED POWER ENERGY
(kWh)

	ON PEAK (kWh)				OFF PEAK (kWh)			
	Scheduled	Supl	Optional	Emerg	Scheduled	Supl	Optional	Total
FIRM POWER								
2004 HC&S	58,875,482	302,625	2,197,803	7,990	33,114,200	0	0	94,498,100
2005 HC&S	59,924,164	32,456	3,140,488	4,492	33,981,700	0	0	97,083,300
TY 2007 HC&S	59,266,000	147,000	2,687,000	0	28,320,000	0	0	90,420,000

	kWh		
	ON PEAK	OFF-PEAK	Total
AS AVAILABLE POWER			
TY 2007 Kaheawa	67,560,000	55,370,000	122,930,000
TY 2007 Makila	511,000	365,000	876,000

Scheduled Energy - Scheduled energy up to 12MW on-peak (14 hours/day) and 8MW off-peak (10 hours/day) to meet contract obligations.
Supplemental Energy - Additional scheduled energy above scheduled 12MW contract amount on-peak or 8MW off-peak requested by utilty.
Optional Energy - Additional energy above 12MW on-peak or 8MW off-peak that supplier wants to sell utility.
Emergency Energy - Unscheduled energy requested by utility to meet system demand.

Note: Supplemental and/or Optional schedule usually take place during on peak hours.

CA Reference
CA-WP-204, page 2

Maui Electric Company, Limited

PURCHASED POWER ENERGY
(KWHRs)

TEST YEAR 2007 FORECAST - FIRM POWER

	ON PEAK				OFF PEAK			Total
Month	Contract	Supl	Optional	Emerg	Contract	Supl	Optional	(On & Off Peak)
J	3,318,000		32,000		1,600,000			4,950,000
F	4,540,000		-		2,240,000			6,780,000
M	5,208,000		212,000		2,480,000			7,900,000
A	5,040,000		460,000		2,400,000			7,900,000
M	5,208,000	56,000	346,000		2,480,000			8,090,000
J	5,040,000		260,000		2,400,000			7,700,000
J	5,208,000		2,000		2,480,000			7,690,000
A	5,208,000	15,000	(3,000)		2,480,000			7,700,000
S	5,040,000	9,000	71,000		2,400,000			7,520,000
O	5,208,000	60,000	362,000		2,480,000			8,110,000
N	5,040,000		520,000		2,400,000			7,960,000
D	5,208,000	7,000	425,000		2,480,000			8,120,000
YEAR	59,266,000	147,000	2,687,000	-	28,320,000	-	-	90,420,000

Regular energy assumes 12MW on-peak (14 hours/day) and 8MW off-peak (10 hours/day)
Optional Additional energy estimated using Jan 2004 through December 2005 actuals. (Ref. PP8806 xls'HC&S)
Supplemental energy estimated using Jan 2004 through December 2005 actuals. (Ref. PP8806 xls"HC&S PkAvg),D/HCS/KWHR.xls

TEST YEAR 2007 FORECAST - AS AVAILABLE POWER

	ON PEAK		OFF PEAK			
	KWP	Makila	KWP	Makila		
Month	As-Available	As-Available	As-Available	As-Available	KWP Total	Makila Total
J	4,040,000	43,400	3,130,000	31,000	7,170,000	74,400
F	3,430,000	39,200	3,380,000	28,000	6,810,000	67,200
M	5,300,000	43,400	4,090,000	31,000	9,390,000	74,400
A	5,470,000	42,000	4,670,000	30,000	10,140,000	72,000
M	6,060,000	43,400	4,840,000	31,000	10,900,000	74,400
J	7,370,000	42,000	5,690,000	30,000	13,060,000	72,000
J	7,620,000	43,400	6,350,000	31,000	13,970,000	74,400
A	5,400,000	43,400	5,150,000	31,000	10,550,000	74,400
S	5,790,000	42,000	4,870,000	30,000	10,660,000	72,000
O	5,820,000	43,400	4,630,000	31,000	10,450,000	74,400
N	5,800,000	42,000	4,460,000	30,000	10,260,000	72,000
D	5,460,000	43,400	4,110,000	31,000	9,570,000	74,400
YEAR	67,560,000	511,000	55,370,000	365,000	122,930,000	876,000

Assumes On-Peak (14 hours/day) and Off-Peak (10 hours/day).
KWP energy based on KWP preliminary estimates (Confidential and Proprietary)
Makila energy based on 100Kw continuous for 24hrs per day.

Maui Electric Company, Limited
PURCHASED POWER EXPENSE
(Dollars)

	ON PEAK PAYMENTS				OFF PEAK PAYMENTS			
FIRM ENERGY	**Scheduled**	**Supl**	**Optional**	**Emerg**	**Scheduled**	**Supl**	**Optional**	**Total**
2004 HC&S	6,503,368	35,017	236,222	2,908	3,342,364	0	0	10,119,878
2005 HC&S	9,173,661	4,976	524,627	1,839	4,751,439	0	0	14,456,543
TY 2007 HC&S	12,013,218	29,797	544,655	0	5,225,040	0	0	17,812,710

CAPACITY PAYMENTS	**Scheduled**	**Supl**	**Optional**	**Total Capacity**
2004 HC&S	1,790,880	4,498	38,737	1,834,116
2005 HC&S	1,790,880	554	55,476	1,846,910
TY 2007 HC&S	1,790,880	2,511	45,894	1,839,285

AS-AVAILABLE ENERGY	**On-Peak**	**Off-Peak**	**Total**
TY 2007 Kaheawa	8,166,923	5,998,398	14,165,321
TY 2007 Makila	103,580	67,343	170,922

Source: MECO-WP-404

Reference:

2007 HC&S (fcst)

On-Peak Scheduled	59,262,000 kwh (forecast) x $0.2027 (on-peak avoided cost, fcst) =$12,012,407
On-Peak Supplemental	147,000 kwh (forecast) x $0.2027 (on-peak avoided cost, fcst) = $29,797
On-Peak Optional	2,696,000 kwh (forecast) x $0.2027 (on-peak avoided cost, fcst) = $546,479
Off-Peak Scheduled	28,320,000 kwh (forecast) x $0.1845 (off-peak avoided cost, fcst) = $5,225,040
Capacity Payments (Scheduled)	$1,790,880 (fixed contract amount)
Capacity Payments (Supplemental)	147,000 kwh (forecast) x $0.01708 (fixed contract amount) = $2,511
Capacity Payments (Optional)	2,696,000 kwh (forecast) x $0.01708 (fixed contract amount) = $46,048

2007 Kaheawa (fcst)

On-Peak As-Available	67,550,000 kwh (forecast) x ((0.7 (70%) x $0.08582 (fixed on-peak contract amount, Table D-1) + 0.3 (30%) x $0.2027 (on-peak avoided cost, fcst)) = $8,165,714
Off-Peak As-Available	55,363,000 kwh (forecast) x ((0.7 (70%) x $0.07569 (fixed off-peak contract amount, Table D-1) + 0.3 (30%) x $0.1845 (off-peak avoided cost, fcst)) = $5,997,640

2007 Makila (fcst)

On-Peak As-Available	511,000 kwh (forecast) x 0.2027 (on-peak avoided cost, fcst) = $103,580
Off-Peak As-Available	365,000 kwh (forecast) x 0.1845 (off-peak avoided cost, fcst) = $67,343

Maui Electric Company, Limited

PURCHASED POWER EXPENSE

(Dollars)

TEST YEAR 2007 FORECAST - FIRM ENERGY

ENERGY	ON PEAK				OFF PEAK			Total
Month	Scheduled	Supl	Optional	Emerg	Scheduled	Supl	Optional	(On & Off Peak)
J	672,559	0	6,486	0	295,200	0	0	974,245
F	920,258	0	0	0	413,280	0	0	1,333,538
M	1,055,662	0	42,972	0	457,560	0	0	1,556,194
A	1,021,608	0	93,242	0	442,800	0	0	1,557,650
M	1,055,662	11,351	70,134	0	457,560	0	0	1,594,707
J	1,021,608	0	52,702	0	442,800	0	0	1,517,110
J	1,055,662	0	405	0	457,560	0	0	1,513,627
A	1,055,662	3,041	(608)	0	457,560	0	0	1,515,654
S	1,021,608	1,824	14,392	0	442,800	0	0	1,480,624
O	1,055,662	12,162	73,377	0	457,560	0	0	1,598,761
N	1,021,608	0	105,404	0	442,800	0	0	1,569,812
D	1,055,662	1,419	86,148	0	457,560	0	0	1,600,788
YEAR	12,013,218	29,797	544,655	0	5,225,040	0	0	17,812,710

CAPACITY				
Month	Scheduled	Supl	Optional	Total
J	149,240	0	547	149,787
F	149,240	0	0	149,240
M	149,240	0	3,621	152,861
A	149,240	0	7,857	157,097
M	149,240	956	5,910	156,106
J	149,240	0	4,441	153,681
J	149,240	0	34	149,274
A	149,240	256	(51)	149,445
S	149,240	154	1,213	150,606
O	149,240	1,025	6,183	156,448
N	149,240	0	8,882	158,122
D	149,240	120	7,259	156,619
YEAR	1,790,880	2,511	45,894	1,839,285

TEST YEAR 2007 FORECAST - AS-AVAILABLE ENERGY

ENERGY	ON PEAK		OFF PEAK		Total	Total
Month	KWP As-Available	Makila As-Available	KWP As-Available	Makila As-Available	KWP	Makila
J	488,371	8,797	339,082	5,720	827,454	14,517
F	414,632	7,946	366,166	5,166	780,798	13,112
M	640,685	8,797	443,082	5,720	1,083,767	14,517
A	661,235	8,513	505,915	5,535	1,167,151	14,048
M	732,557	8,797	524,332	5,720	1,256,889	14,517
J	890,915	8,513	616,415	5,535	1,507,330	14,048
J	921,136	8,797	687,915	5,720	1,609,051	14,517
A	652,774	8,797	557,915	5,720	1,210,689	14,517
S	699,918	8,513	527,582	5,535	1,227,500	14,048
O	703,545	8,797	501,582	5,720	1,205,127	14,517
N	701,127	8,513	483,165	5,535	1,184,292	14,048
D	660,027	8,797	445,249	5,720	1,105,275	14,517
YEAR	8,166,923	103,580	5,998,398	67,343	14,165,321	170,922

Maui Electric Company, Ltd. - Maui Division
Fuel Price for ECAC Calculations
2007 Test Year - Direct Testimony

	Description	(A) Central Station Kahului Industrial	(B) Central Station Maalaea Diesel	(C) Central Station Total	(D) Hana DG
1	MBtu Consumed	3,151,197	7,587,200	10,738,397	902
2	No. of Barrels Consumed	500,190	1,294,744	1,794,934	154
3	Wgt Fuel Oil Price ($/bbl)	59.6359	104.8621		115.8105
4	Inspection Cost per bbl	0.0746	0.0746		0.0000
5	Ocean Cargo Insur. Cost per bbl	0.0701	0.1232		0.0000
6	Fuel Additive Cost per bbl	0.3119	0.0000		0.0000
	Fuel Expense ($000)				
7	Fuel Oil Expense	29,829.3	135,769.5	165,598.8	17.8
8	Inspection Expense	37.3	96.6	133.9	0.0
9	Ocean Cargo Insurance Expense	35.1	159.5	194.6	0.0
10	Fuel Additive Expense	156.0	0.0	156.0	0.0
11	Total Fuel Expense ($000)	30,057.7	136,025.6	166,083.3	17.8
12	Heat Content (MBtu/bbl)	6.3	5.86		5.86
	Fuel Expense at Present Rates				
13	Fuel Oil	29,829.3	135,769.5		0.0
14	Inspection	37.3	96.6		0.0
15	Ocean Cargo Insurance	35.1	159.5		0.0
16	Fuel Additive	0.0	0.0		0.0
17	Fuel Expense at Present Rates	29,901.7	136,025.6		0.0
18	Fuel Price per MBtu (¢/MBtu)	948.90	1,792.83		0.00
	Fuel Expense at Proposed Rates				
19	Fuel Oil	29,829.3	135,769.5		17.8
20	Inspection	37.3	96.6		0.0
21	Ocean Cargo Insurance	35.1	159.5		0.0
22	Fuel Additive	156.0	0.0		0.0
23	Fuel Expense at Proposed Rates	30,057.7	136,025.6		17.8
24	Fuel Price per MBtu (¢/MBtu)	953.85	1,792.83		1,973.39

CA Reference
Line 1: CA-WP-204, pg 2
Line 2: CA-WP-204, pg 2
Line 3: MECO-402
Line 4: MECO-WP-1904, page 1
Line 5: CA-WP-205 ÷ line 2
Line 6: MECO-WP-1904, page 1
Line 7: line 2 x line 3
Line 8: line 2 x line 4
Line 9: line 2 x line 5
Line 10: line 2 x line 6
Line 18: line 17 ÷ line 1 x 10
Line 24: line 23 ÷ line 1 x 10

Maui Electric Company, Ltd. - Maui Division
Determination of Percent of Generation MBTU Mix

2007 Test Year - Direct Testimony
At Present Rates

Line	Generation	(A) MBTU	(B) % to Total Generation
1	Kahului - Industrial	3,151,197	29.34
2	Maalaea - Diesel	7,587,200	70.65
3	DG	902	0.01
4	Total	10,739,299	100.00

CA Reference
CA-WP-204, page 2

MAUI ELECTRIC COMPANY, LTD. - MAUI DIVISION
Composite Cost of Generation
2007 Test Year - Direct Testimony
At Present Rates

Line	GENERATION COMPONENT	
	FUEL PRICES, ¢/mmbtu	
1	Industrial	948.90
2	Diesel	1,792.83
3	DG	0.00
	BTU MIX, %	
4	Industrial	29.34
5	Diesel	70.65
6	DG	0.01
		100.00
7	COMPOSITE COST OF GENERATION, ¢/mmbtu	1,545.04

Line 7: (Line 1x4 + line 2x5 + line 3x6)

CA Reference

Lines 1-3: CA-WP-212 page 1, line 18
Lines 4-6: CA-WP-212, page 1-2

Maui Electric Company, Ltd. - Maui Division
Net System Percent Mix

2007 Test Year - Direct Testimony
At Present Rates

Line		(A) 2007 Norm Energy (Mwh)	(B) % to Total System
	Generation (Mwh)		
1	Kahului - Industrial	219,380	
2	Maalaea - Diesel	857,840	
3	DG	80	
4	Total Generation	1,077,300	83.41
	Purchased Power (Mwh)		
5	HC&S	90,420	
6	Kaheawa	122,910	
7	Makila Hydro	880	
8	Total Purchased Power	214,210	16.59
13	Total Net System	1,291,510	100.00

CA Reference
Column A: CA-WP-204, page 2

Maui Electric Company, Ltd. - Maui Division
Determination of Percent of Purchased Energy Mix,
Payment Rate (in ¢/kwh) and
Composite Cost of Purchased Energy (in ¢/kwh)

2007 Test Year - Direct Testimony
At Present and Proposed Rates

	(A)	(B)	(C)	(D)	(E)	(F)
No.	Producer	Mwh Purchased	% to Total PP	Payment Rate (¢/kwh)	Weighted Cost (¢/kwh) [(colF ÷ colB) * colC * 1000]	Purch Pwr Fuel Expense ($ thous)
1	**HC&S**					
	Regular					
	On Peak	59,266	27.67	20.270	5.608	12,013.2
	Off Peak	28,320	13.22	18.450	2.439	5,225.0
	Optional Addt'l					
	On Peak	2,687	1.25	20.270	0.254	544.7
	Off Peak	0	0.00	18.450	0.000	0.0
	Supplemental					
	On Peak	147	0.07	20.270	0.014	29.8
	Off Peak	0	0.00	18.450	0.000	0.0
	Total	90,420				17,812.7
2	**Kaheawa**					
	On Peak	67,560	31.54	12.0884	3.812	8,166.9
	Off Peak	55,370	25.85	10.8333	2.800	5,998.4
	Total	122,930				14,165.3
3	**Makila Hydro**					
	On Peak	511	0.24	20.270	0.048	103.6
	Off Peak	365	0.17	18.450	0.031	67.3
	Total	876				170.9
4	**Other**	-	0.00	0.000	0.000	-
5	Total	214,226	100.00		15.007	32,148.9
6	Composite Cost of Purchased Energy				15.007 ¢/kwh	

Column B: CA-WP-210, page 2
Column C: Column B ÷ Column B line 5
Column D: CA-WP-214, page 8
Column F: CA-WP-210, page 2

Maui Electric Company, Ltd. - Maui Division
Determination of Percent of Central Station Generation MBTU Mix

2007 Test Year - Direct Testimony
At Proposed Rates

Line	Central Station Plant	(A) MBTU	(B) % to Total Generation
1	Kahului - Industrial	3,151,197	29.35
2	Maalaea - Diesel	7,587,200	70.65
4	Total	10,738,397	100.00

CA Reference
CA-WP-204, page 2

MAUI ELECTRIC COMPANY, LTD. - MAUI DIVISION
Composite Cost of Central Station Generation

2007 Test Year - Direct Testimony
At Proposed Rates

Line	GENERATION COMPONENT Central Station and Other	
	FUEL PRICES, ¢/mmbtu	
1	Industrial	953.85
2	Diesel	1,792.83
	BTU MIX, %	
3	Industrial	29.35
4	Diesel	70.65
		100.00
5	COMPOSITE COST OF GENERATION, Central Stn + Other ¢/mmbtu	1,546.59

CA Reference

Lines 1-2: CA-WP-212, page 1
Lines 3-4: CA-WP-214, page 1
Line 5: (Line 1 x 3 + Line 2 x 4)

Maui Electric Company, Ltd. - Maui Division
Net System Percent Mix
2007 Test Year - Direct Testimony
At Proposed Rates

		(A) 2007 Norm Energy (Mwh)	(B) % to Total System
	Central Station Generation		
	Industrial	219,380	16.99
	Diesel	857,840	66.42
12	Tot Central Station Generation	1,077,220	83.41
13	DG	80	0.01
14	Purchase Power	214,210	16.59
15	Total Net System	1,291,510	100.00

CA Reference
CA-WP-204, page 2

Maui Electric Company, Ltd. - Maui Division
Percent of Central Station Industrial and Diesel Kwh Mix
2007 Test Year - Direct Testimony
At Proposed Rates

Line		(A) 2007 Norm Energy (Mwh)	(B) Percent of Central Stn Generation	Reference
1	Kahului - Industrial	219,380	20.37	CA-WP-104, page 2
2	Maalaea - Diesel	857,840	79.63	CA-WP-104, page 2
3	Total	1,077,220	100.00	

CA Reference
CA-WP-204, page 2

Maui Electric Company, Ltd. - Maui Division
Determination of Composite Cost of DG Energy

2007 Test Year - Direct Testimony
At Proposed Rates

	(A)	(B)	(C)	(D)	(E)	(F)
Line	DG Unit Location	Net to System (kWh)	Fuel Consumed (MBtu)	Fuel Expense ($)	Fuel Cost (¢/MBtu)	Fuel Cost (¢/kWh)
1	Hana DG	80,000	902	17,835	1977.25	22.294
2					0.00	0.000
3					0.00	0.000
4					0.00	0.000
5	Total	80,000	902	17,835	1977.25	22.294

6	Composite DG Fuel Cost	1977.25 ¢/MBtu
7	Composite Cost of DG Energy	22.294 ¢/kWh

CA Reference
Column B: CA-WP-204, page 2
Column C: CA-WP-204, page 2
Column D: CA-WP-204, page 3
Column E: (D) ÷ (C) x 100
Column F: (D) ÷ (B) x 100

Maui Electric Company, Ltd. - Maui Division
Determination of Central Station and DG Percent to
Total Generation Mbtu Mix
2007 Test Year - Direct Testimony
At Proposed Rates

		(A) 2007 MBtu Consumed	(B) % to Total MBtu Consumed
1	Central Station Generation	10,738,397	99.99
2	DG	902	0.01
3	Total Generation	10,739,299	100.00

CA Reference
CA-WP-206, page 1

Maui Electric Company, Ltd. - Maui Division
Determination of Composite Cost of Total (Central Station and DG) Generation
For Avoided Cost Calculation Purposes

2007 Test Year - Direct Testimony
At Proposed Rates

Line	CENTRAL STATION ENERGY COMPONENT		Line	DG ENERGY COMPONENT	
1	Composite Cost of Centrl Stn Gen.	1546.59 ¢/Mbtu	4	Composite Cost of DG Generation	1977.25 ¢/Mbtu
2	Percent of Centrl Stn Gen. Btu Mix	99.99 %	5	Percent of DG Gen. Btu Mix	0.01 %
3	Weighted Composite Cost of Central Station	1546.4353 ¢/Mbtu	6	Weighted Composite Cost of DG	0.1977 ¢/Mbtu

Line	Total Generation Composite Cost	
7	Composite Cost of Central Station and DG	1546.63 ¢/Mbtu

CA Reference
Line 1: CA-WP-214, page 2
Line 2: CA-WP-214, page 6
Line 3: Line 1 x Line 2
Line 4: CA-WP-214, page 5
Line 5: CA-WP-214, page 6
Line 6: Line 4 x Line 5
Line 7: Line 3 + Line 6

Maui Electric Company, Ltd.
Maui Division

DERIVATION OF TEST YEAR 2007
AVOIDED ENERGY COST PAYMENT RATES
Avoided Energy Rate - over 100 KW

At Proposed Rates

LINE		ON-PEAK	OFF-PEAK	SOURCE
1	*Heat Rate*	*12,856 BTU/NET KWH*	*11,600 BTU/NET KWH*	*Docket #4569, HECO-101*
2	Composite Fuel Cost of Total Generation (Centrl Stn & DG)	1,546.63 ¢ / MMBTU	1,546.63 ¢ / MMBTU	Test Year 2007 Composite Fuel Cost, CA-WP-114, p. 7
3	1 MMBTU / 1,000,000 BTU	1000000 BTU/MMBTU	1000000 BTU/MMBTU	
4	Unadjusted Payment Rate (line 1 x 2) / line 3	19.88 ¢ / NET KWH	17.94 ¢ / NET KWH	
5	O&M Adjustment	0.37 ¢ / NET KWH	0.49 ¢ / NET KWH	Appendix C, D&O 8298
6	BASE Avoided Energy Payment Rate (line 4 + 5)	20.25 ¢ / NET KWH	18.43 ¢ / NET KWH	

Maui Electric Company, Ltd.
Maui Division

DERIVATION OF TEST YEAR 2007
SCHEDULE "Q" PAYMENT RATES
Schedule "Q" Rate - Under 100 KW

2007 Test Year - Direct Testimony
At Proposed Rates

LINE		ON-PEAK	OFF-PEAK	SOURCE
1	Heat Rate	12,856 BTU/NET KWH	11,600 BTU/NET KWH	Docket #4569, HECO-101
2	Composite Fuel Cost of Total Generation (Centrl Stn & DG)	1,546.63 ¢/MMBTU	1,546.63 ¢/MMBTU	Test Year 2007 Composite Fuel Cost, CA-WP-114, p. 7
3	1 MMBTU / 1,000,000 BTU	1000000 BTU/MMBTU	1000000 BTU/MMBTU	
4	Unadjusted Payment Rate (line 1 x 2) / line 3	19.88 ¢ / NET KWH	17.94 ¢ / NET KWH	
5	Power Factor Adjustment	-0.12 ¢ / NET KWH	-0.28 ¢ / NET KWH	Appendix C, D&O 8298
6	O&M Adjustment	0.37 ¢ / NET KWH	0.49 ¢ / NET KWH	Appendix C, D&O 8298
7	Pre Time-weighted "Q" Payment Rate (line 4 + 5 + 6)	20.13 ¢ / NET KWH	18.15 ¢ / NET KWH	
8	Hour Weighting	x 14/24 HOURS/HOURS	x 10/24 HOURS/HOURS	
9	Time-weighted Peak Time-related Schedule "Q" Energy Payment Rate (line 7 x 8)	11.74 ¢ / NET KWH	7.56 ¢ / NET KWH	
10	Time-weighted "Q" ON PEAK Payment Rate	11.74 ¢ / NET KWH		
11	Time-weighted "Q" OFF PEAK Payment Rate	7.56 ¢ / NET KWH		
12	Schedule "Q" Energy Payment Rate (line 10 + 11)	19.30 ¢ / NET KWH		
13	Base 1999 Schedule "Q" Energy Payment Rate	4.80 ¢ / NET KWH		Docket 97-0346, D&O 16922
14	Difference Between Test Year 2007 Direct and Base Sch "Q" Rates (line 12 - line 13)	14.50 ¢ / NET KWH		

Maui Electric Company, Ltd. -Maui Division
DG and Purchased Energy Loss Factor Calculations

2007 Test Year - Direct Testimony
At Proposed Rates

Line		
1	Net to System (MWh)	1,291,510
2	Sales (MWh)	1,212,929
3	DG & Purchase Power Loss Factor	1.065

CA Reference
Line 1: CA-WP-214, page 3
Line 2: MECO-403
Line 3: Line 1 ÷ Line 2

Maui Electric Company, Ltd. - Maui Division
Determination of Fixed Efficiency Factor or Sales Heat Rate (Mbtu / Kwh Sales)
2007 Test Year - Direct Testimony
At Proposed Rates

Line				CA Reference
	Total Central Station Fuel Sales Heat Rate			
1	Total Central Station Fuel Consumed	10,738,397	Mbtu	CA-WP-106, page 1
2	Sales	1,212,929	Mwh	MECO-403
3	% of Central Stn to Total System	83.41	Percent	CA-WP-114, page 3
4	Kwh/Mwh Conversion	1,000	kwh/mwh	
5	Sales Heat Rate [line 1 ÷ (line 2 x line 3 x line 4)]	0.010614	Mbtu/Kwh Sales	
	Industrial Fuel Sales Heat Rate			
6	Industrial Fuel Consumed	3,151,197	Mbtu	CA-WP-106, page 1
7	Sales	1,212,929	Mwh	MECO-403
8	% of Industrial Fuel Generation to Total System	16.99	Percent	CA-WP-114, page 3
9	Kwh/Mwh Conversion	1,000	kwh/mwh	
10	Sales Heat Rate [line 6 ÷ (line 7 x line 8 x line 9)]	0.015295	Mbtu/Kwh Sales	
	Diesel Fuel Sales Heat Rate			
11	Diesel Fuel Consumed	7,587,200	Mbtu	CA-WP-106, page 1
12	Sales	1,212,929	Mwh	MECO-403
13	% of Diesel Fuel Generation to Total System	66.42	Percent	CA-WP-114, page 3
14	Kwh/mwh Conversion	1,000	kwh/mwh	
15	Sales Heat Rate [line 11 ÷ (line 12 x line 13 x line 14)]	0.009418	Mbtu/Kwh Sales	
	MECO-Maui Other Sales Heat Rate			
16	Total Central Station Fuel Consumed	10,738,397	Mbtu	
17	Sales	1,212,929	Gwh	
18	% of Central Stn to Total System	83.41	Percent	
19	Kwh/mwh Conversion	1,000	kwh/mwh	
20	Sales Heat Rate [line 16 ÷ (line 17 x line 18 x line 19)]	0.010614	Mbtu/Kwh Sales	

Maui Electric Company, Ltd.
Lanai Division and Molokai Division
Fuel Price for ECAC Calculations
2007 Test Year - Direct Testimony

	Description	LANAI Diesel	MOLOKAI Diesel
1	MBtu Consumed	314,996	395,565
2	No. of Barrels Consumed	53,754	67,503
3	Net Generation (mwh)	31,392.2	40,198.1
4	Wgt Fuel Oil Price ($/bbl)	114.8311	107.3613
5	Inspection Cost per bbl	0.0496	0.0815
6	Ocean Cargo Insur. Cost per bbl	0.0000	0.0000
7	Fuel Additive Cost per bbl	0.0000	0.0000
	Fuel Expense ($)		
8	Fuel Oil Expense	6,172.6	7,247.2
9	Inspection Expense	2.7	5.5
10	Ocean Cargo Insurance Expense	0.0	0.0
11	Fuel Additive Expense	0.0	0.0
12	Total Fuel Expense ($)	6,175.3	7,252.7
13	Heat Content (MBtu/bbl)	5.86	5.86
	Fuel Expense at Present Rates		
14	Fuel Oil	6,172.6	7,247.2
15	Inspection	2.7	5.5
16	Ocean Cargo Insurance	0.0	0.0
17	Fuel Additive	0.0	0.0
18	Fuel Expense at Present Rates	6,175.3	7,252.7
19	Fuel Price per MBtu (¢/MBtu)	1,960.44	1,833.50
	Fuel Expense at Proposed Rates		
20	Fuel Oil	6,172.6	7,247.2
21	Inspection	2.7	5.5
22	Ocean Cargo Insurance	0.0	0.0
23	Fuel Additive	0.0	0.0
24	Fuel Expense at Proposed Rates	6,175.3	7,252.7
25	Fuel Price per MBtu (¢/MBtu)	1,960.44	1,833.50

CA Reference
Lines 1-3: CA-WP-206, pages 4 - 5
Line 4: MECO-402, lines 5, 6
Line 5: Line 9 ÷ Line 2
Line 8: CA-204
Line 9: MECO-405
Line 10: CA-WP-205
Line11: MECO-405
Line 19: Line 18 ÷ Line 1
Line 25: Line 24 ÷ Line 1

Maui Electric Company, Ltd.
Lanai Division and Molokai Division
Determination of Fixed Efficiency Factor or Sales Heat Rate (Mbtu / Kwh Sales)
2007 Test Year - Direct Testimony
At Proposed Rates

Line			Lanai	Molokai	Reference
1	Total Fuel Consumed	Mbtu	314,996	395,565	MECO-WP-406, pgs 4,5
2	Sales	Mwh	29,779.9	36,547.8	MECO-WP-404, pg 93 & 96
3	% of Total System	Percent	100.00	100.00	MECO-WP-406, pgs 4,5
4	Kwh/Gwh Conversion	kwh/gwh	1,000	1,000	
5	Sales Heat Rate [line 1 ÷ (line 2 x line 3 x line 4)]	Mbtu/Kwh Sales	0.010577	0.010823	MECO-WP-406, pg 4, 5

Maui Electric Company, Ltd.
Lanai Division and Molokai Division
DG and Purchased Energy Loss Factor Calculations
2007 Test Year - Direct Testimony
At Proposed Rates

Line		Lanai	Molokai	Reference
1	Net to System (mwh)	31,392.2	40,198.1	MECO-WP-404, pg 93 & 96
2	Sales (mwh)	29,779.9	36,547.8	MECO-WP-404, pg 93 & 96
3	DG & Purchase Power Loss Factor	1.054	1.100	

Maui Electric Company, Ltd. - Lanai Division
Determination of Composite Cost of Total (Central Station and DG) Generation
For Avoided Cost Calculation Purposes
2007 Test Year - Direct Testimony
At Proposed Rates

Line	CENTRAL STATION ENERGY COMPONENT		Line	DG ENERGY COMPONENT	
1	Composite Cost of Centrl Stn Gen.	1960.44 ¢/MBtu	4	Composite Cost of DG Generation	0.00 ¢/MBtu
2	Percent of Centrl Stn Gen. Btu Mix	100.00 %	5	Percent of DG Gen. Btu Mix	0.00 %
3	Weighted Composite Cost of Central Station	1960.4400 ¢/MBtu	6	Weighted Composite Cost of DG	0.0000 ¢/MBtu

Line	Total Generation Composite Cost	
7	Composite Cost of Central Station and DG	1960.44 ¢/MBbtu

CA Reference
Line 1: CA-WP-216, page 1
Line 3: Line 1 x Line 2
Line 6: Line 4 x Line 5
Line 7: Line 3 + Line 6

Maui Electric Company, Ltd.
Lanai Division

DERIVATION OF TEST YEAR 2007
AVOIDED ENERGY COST PAYMENT RATES
Avoided Energy Rate - over 100 KW

At Proposed Rates

LINE		ON-PEAK		OFF-PEAK		SOURCE
1	Heat Rate	11002	Btu/NET kWh	11002	Btu/NET kWh	
2	Composite Fuel Cost of Total Generation (Centrl Stn & DG)	1,960.44	¢/MMBtu	1,960.44	¢/MMBtu	Test Year 2007 Composite Fuel Cost, MECO-WP-1910, p.1
3	1 MMBtu / 1,000,000 Btu	1000000	Btu/MMBtu	1000000	Btu/MMBtu	
4	Unadjusted Payment Rate (line 1 x 2) / line 3	21.57	¢/NET kWh	21.57	¢/NET kWh	
5	O&M Adjustment	0.42	¢/NET kWh	0.42	¢/NET kWh	Appendix C, D&O 8298 Composite
6	BASE Avoided Energy Payment Rate (line 4 + 5)	21.99	¢/NET kWh	21.99	¢/NET kWh	

Maui Electric Company, Ltd.
Lanai Division

DERIVATION OF TEST YEAR 2007
SCHEDULE "Q" PAYMENT RATES
Schedule "Q" Rate - Under 100 KW

2007 Test Year - Direct Testimony
At Proposed Rates

LINE		ON-PEAK	OFF-PEAK	SOURCE
1	Heat Rate	11002 Btu/NET kWh	11002 Btu/NET kWh	
2	Composite Fuel Cost of Total Generation (Centrl Stn & DG)	1,960.44 ¢/MMBtu	1,960.44 ¢/MMBtu	Test Year 2007 Composite Fuel Cost, MECO-WP-1911, p.1
3	1 MMBtu / 1,000,000 Btu	1000000 Btu/MMBtu	1000000 Btu/MMBtu	
4	Unadjusted Payment Rate (line 1 x 2) / line 3	21.57 ¢/NET kWh	21.57 ¢/NET kWh	
5	Power Factor Adjustment	-0.12 ¢/NET kWh	-0.28 ¢/NET kWh	Appendix C, D&O 8298
6	O&M Adjustment	0.42 ¢/NET kWh	0.42 ¢/NET kWh	Appendix C, D&O 8298 Composite
7	Pre Time-weighted "Q" Payment Rate (line 4 + 5 + 6)	21.87 ¢/NET kWh	21.71 ¢/NET kWh	
8	Hour Weighting	x 14/24 HOURS/HOURS	x 10/24 HOURS/HOURS	
9	Time-weighted Peak Time-related Schedule "Q" Energy Payment Rate (line 7 x 8)	12 76 ¢/NET kWh	9.05 ¢/NET kWh	
10	Time-weighted "Q" ON PEAK Payment Rate	12.76 ¢/NET kWh		
11	Time-weighted "Q" OFF PEAK Payment Rate	9.05 ¢/NET kWh		
12	Schedule "Q" Energy Payment Rate (line 10 + 11)	21.81 ¢/NET kWh		
13	Base 1999 Schedule "Q" Energy Payment Rate	8.74 ¢/NET kWh		Docket 97-0346, D&O 16922
14	Difference Between Test Year 2007 Direct and Base Sch "Q" Rates (line 12 - line 13)	13.07 ¢/NET kWh		

Maui Electric Company, Ltd. - Molokai Division
Determination of Composite Cost of Total (Central Station and DG) Generation
For Avoided Cost Calculation Purposes

2007 Test Year - Direct Testimony
At Proposed Rates

Line	CENTRAL STATION ENERGY COMPONENT		Line	DG ENERGY COMPONENT	
1	Composite Cost of Centrl Stn Gen.	1833.50 ¢/Mbtu	4	Composite Cost of DG Generation	0.00 ¢/Mbtu
2	Percent of Centrl Stn Gen. Btu Mix	100.00 %	5	Percent of DG Gen. Btu Mix	0.00 %
3	Weighted Composite Cost of Central Station	1833.5000 ¢/Mbtu	6	Weighted Composite Cost of DG	0.0000 ¢/Mbtu

Line	Total Generation Composite Cost	
7	Composite Cost of Central Station and DG	1833.50 ¢/Mbtu

CA Reference
Line 1: CA-WP-216, page 1
Line 3: Line 1 x Line 2
Line 6: Line 4 x Line 5
Line 7: Line 3 + Line 6

Maui Electric Company, Ltd.
Molokai Division

DERIVATION OF TEST YEAR 2007
AVOIDED ENERGY COST PAYMENT RATES
Avoided Energy Rate - over 100 KW

At Proposed Rates

LINE		ON-PEAK		OFF-PEAK		SOURCE
1	Heat Rate	11006	Btu/NET kWh	11006	Btu/NET kWh	Adjusted 1989 Actual
2	Composite Fuel Cost of Total Generation (Centrl Stn & DG)	1,833.50	¢/MMBtu	1,833.50	¢/MMBtu	Test Year 2007 Composite Fuel Cost, MECO-WP-1911, p.1
3	1 MMBtu / 1,000,000 Btu	1000000	Btu/MMBtu	1000000	Btu/MMBtu	
4	Unadjusted Payment Rate (line 1 x 2) / line 3	20.18	¢/NET kWh	20.18	¢/NET kWh	
5	O&M Adjustment	0.64	¢/NET kWh	0.64	¢/NET kWh	Actual 1989
6	BASE Avoided Energy Payment Rate (line 4 + 5)	20.82	¢/NET kWh	20.82	¢/NET kWh	

Maui Electric Company, Ltd.
Molokai Division

DERIVATION OF TEST YEAR 2007
SCHEDULE "Q" PAYMENT RATES
Schedule "Q" Rate - Under 100 KW

2007 Test Year - Direct Testimony
At Proposed Rates

LINE		ON-PEAK		OFF-PEAK		SOURCE
1	Heat Rate	11006	Btu/NET kWh	11006	Btu/NET kWh	Adjusted 1989 Actual
2	Composite Fuel Cost of Total Generation (Centrl Stn & DG)	1,833.50	¢/MMBtu	1,833.50	¢/MMBtu	Test Year 2007 Composite Fuel Cost, MECO-WP-1911, p.1
3	1 MMBtu / 1,000,000 Btu	1000000	Btu/MMBtu	1000000	Btu/MMBtu	
4	Unadjusted Payment Rate (line 1 x 2) / line 3	20.18	¢/NET kWh	20.18	¢/NET kWh	
5	Power Factor Adjustment	-0.12	¢/NET kWh	-0.28	¢/NET kWh	Appendix B, D&O 8298
6	O&M Adjustment	0.64	¢/NET kWh	0.64	¢/NET kWh	1989 Actual
7	Pre Time-weighted "Q" Payment Rate (line 4 + 5 + 6)	20.70	¢/NET kWh	20.54	¢/NET kWh	
8	Hour Weighting	x 14/24	HOURS/HOURS	x 10/24	HOURS/HOURS	
9	Time-weighted Peak Time-related Schedule "Q" Energy Payment Rate (line 7 x 8)	12.08	¢/NET kWh	8 56	¢/NET kWh	
10	Time-weighted "Q" ON PEAK Payment Rate		12.08	¢/NET kWh		
11	Time-weighted "Q" OFF PEAK Payment Rate		8.56	¢/NET kWh		
12	Schedule "Q" Energy Payment Rate (line 10 + 11)		20.64	¢/NET kWh		
13	Base 1999 Schedule "Q" Energy Payment Rate		5.61	¢/NET kWh		Docket 97-0346, D&O 16922
14	Difference Between Test Year 2007 Direct and Base Sch "Q" Rates (line 12 - line 13)		15.03	¢/NET kWh		

CA-T-3
DOCKET NO. 2006-0387

DIRECT TESTIMONY AND EXHIBITS

OF

MICHAEL L. BROSCH

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: Sales Revenues, Miscellaneous Revenues, Fuel & Purchased Power Adjustments, Production Operations and Maintenance Expense, Customer Accounts Expense, Customer Service Expense, Income and Other Tax Expenses, Accumulated Deferred Income Taxes and Fuel Inventory.

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Summary of Brosch Qualifications	CA-300

1 **DIRECT TESTIMONY OF MICHAEL L. BROSCH**

2 I. **INTRODUCTION.**

3 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

4 A. My name is Michael L. Brosch. My business address is 740 Northwest Blue
5 Parkway, Suite 204, Lee's Summit, Missouri 64086.

6

7 Q. WHAT IS YOUR PRESENT OCCUPATION?

8 A. I am a principal and the President of Utilitech, Inc. The firm's business and my
9 responsibilities are primarily related to special services work for utility
10 regulatory clients, including rate case reviews, cost of service analyses,
11 jurisdictional and class cost allocations, financial studies, rate design analyses,
12 and special investigations of utility operations and ratemaking issues.

13

14 Q. WILL YOU SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND
15 PROFESSIONAL EXPERIENCE IN THE FIELD OF UTILITY REGULATION?

16 A. I have prepared Exhibit CA-300 for this purpose.

17

18 Q. HAVE YOU PREVIOUSLY PARTICIPATED IN REGULATORY
19 ENGAGEMENTS BEFORE THE HAWAII PUBLIC UTILITIES COMMISSION?

20 A. Yes. I submitted written direct testimony on behalf of the Hawaii Department
21 of Commerce and Consumer Affairs, Division of Consumer Advocacy

("Consumer Advocate" or "CA") in numerous rate case proceedings involving most of the largest Hawaii utility companies, including:

- Hawaii Electric Light Company, Inc. Docket Nos. 6999 and 05-0315,
- Maui Electric Company, Limited Docket No. 7000,
- Hawaiian Electric Company, Inc. ("HECO") Docket Nos. 7700, 04-0113 and 2006-0386,
- GTE Hawaiian Telephone Company (now Hawaiian Telcom) Docket No. 94-0298,
- The Gas Company Docket No. 00-0309.

In addition to these rate case engagements, I assisted the Consumer Advocate in the following:

- Analysis and Statement of Position preparation regarding the sale of the Gas Company by Broken Hill Proprietary Company, Ltd. to Citizens Utilities in Docket No. 97-0035,
- Analysis and Statement of Position preparation in Docket No. 03-0051 involving the subsequent sale of The Gas Company by Citizens Communications Company to K-1 USA Ventures, Inc.,
- Analysis and Statement of Position preparation in the most recent sale of The Gas Company to Macquarie Infrastructure Company in Docket No. 05-0242.

- Analysis and Statement of Position preparation regarding the sale of the Kauai Electric Division by Citizens in Docket Nos. 00-0352 and 02-0060.
- Analysis and Statement of Position preparation in the sale of Verizon Hawaii to entities controlled by the Carlyle Group in Docket No. 04-0140.
- Analysis and Statement of Position preparation in the recently proposed sale of the Hawaii Directory Publishing in Docket No. 2007-0123.
- Analysis and testimony in the HECO Community Benefits proceeding, Docket No. 05-0146.

Q. ON WHOSE BEHALF ARE YOU NOW APPEARING?

A. I am testifying on behalf of the Consumer Advocate in this proceeding.

Q. WHAT ARE THE FUNCTIONAL AREAS OF THE CONSUMER ADVOCATE'S PRESENTATION IN THIS DOCKET, FOR WHICH YOU ARE DIRECTLY RESPONSIBLE?

A. My testimony explains the Consumer Advocate's recommended test year sales revenues and miscellaneous revenue levels, non-fuel production O&M expenses, customer accounts expenses, customer service expenses, income and other tax expense amounts and the accumulated deferred tax balances includable in the test year rate base. My testimony also addresses the

adjustments that are proposed by CA-T-2, Mr. Herz for fuel and purchased power and fuel inventory. In a separately filed testimony designated CA-T-5, I discuss MECO's proposed cost of service allocation studies, proposed revenue distribution among rate classes, and certain rate design issues.

Q. HOW ARE THE CONSUMER ADVOCATE ACCOUNTING SCHEDULES ORGANIZED?

A. The Consumer Advocate's Accounting Schedules are organized within Exhibit CA-101 through CA-104, which contains all of the revenue requirements calculations for MECO's 2007 Test Year for the consolidated business and each island system, respectively. These Exhibits are jointly sponsored with other witnesses testifying on behalf of the Consumer Advocate and their organization and overall results are explained in greater detail within Mr. Carver's (CA-T-1) testimony. Throughout my testimony, I will refer to individual Consumer Advocate adjustments that I sponsor by indicating the Consumer Advocate "Accounting Schedule" or the "CA Adjustment Schedule" that corresponds to the testimony discussion.

1 II. **SALES REVENUES.**

2 Q. HOW DID MECO DEVELOP ITS TEST YEAR 2007 SALES AND REVENUE
3 PROJECTIONS?

4 A. Ms. Ide, MECO T-2, explains that the test year sales estimate is based on
5 MECO's Sales and Peaks forecast that was formally adopted in July of 2006.
6 This sales forecast was based upon a series of key assumptions derived from
7 MECO's assessment of the economic outlook, known changes and future
8 projects planned by individually significant customers and MECO's own
9 historical customer and electricity usage series data, as more fully explained at
10 pages 4 through 7 of Ms. Ide's testimony. A blending of results from five
11 different forecasting methodologies was utilized to develop various elements
12 of the rate case projections of customer and KWH sales levels for each
13 customer class. The results of MECO sales projections are summarized by
14 island and for the consolidated business in MECO-201 and the projections are
15 compared to historical data for each island in MECO-203 (Maui Division),
16 MECO-204 (Lanai Division) and MECO-205 (Molokai Division).

17 The kilowatthour sales projections sponsored by Mrs. Ide in MECO T-2
18 are then priced out to derive sales revenue values at present and proposed
19 rates by Mr. Young (MECO T-3), using certain assumptions about the
20 distribution of projected test year 2007 sales volumes and customer levels
21 among the specific rate schedule demand and energy blocks, rate riders and
22 other tariff provisions. The resulting projected test year 2007 Sales Revenues

at Present Rates and at Proposed Rates are summarized in MECO-301 through MECO-304 for the consolidated business, Maui, Lanai and Molokai, respectively.

Q. HAS MECO PROPOSED ANY UPDATES OR REVISIONS TO ITS TEST YEAR SALES FORECAST?

A. No. The Company's June 2007 update to the rate case filing did not change the sales forecast or Sales Revenue amounts included in the Company's initial filing.

Q. DOES THE CONSUMER ADVOCATE OBJECT TO THE SALES VOLUME PROJECTIONS SPONSORED BY MECO T-2?

A. No. According to the Company's updated response to CA-IR-309, actual test year 2007 sales volumes through August are tracking very closely with projected levels. Actual sales are somewhat higher than projected for commercial customers on Schedules J and P, but are lower than projected for residential customers, commercial Schedule H and Lighting Schedule F customers, with an overall variance in total gigawatthours of only 5,697 MWH or about 0.7 percent of forecasted levels through August of 2007. Moreover, much of this small positive sales variance appears to relate to water pumping loads, which have been above forecast thus far in 2007 because of unusual

drought conditions in Maui County, conditions that may not be indicative of normal ongoing sales levels.[1]

Q. WHAT IS THE PURPOSE OF THE ADJUSTMENT APPEARING AT CA SCHEDULE C-2?

A. This adjustment sets forth a very small update to sales revenues to account for known changes in tariff rider participation as of December 31, 2006. Two additional customers have been added to Schedule J, Rider T and the revenue effect of these changes is quantified in the response to CA-IR-206, which serves as the basis for the CA Adjustment Schedule C-2. This adjustment was apparently overlooked by MECO when the Company assembled its June 2007 Update filing.

Q. IF MECO IS NOT REVISING ITS SALES PROJECTIONS FOR THE TEST YEAR, WHY ARE YOU PROPOSING THE REVENUE ADJUSTMENTS SET FORTH IN CA-101, SCHEDULE C-3?

A. CA Accounting Schedule C-3 sets forth, for each island, at lines 8 through 15, the estimated sales revenue impact of differences in energy cost adjustment clause ("ECAC") revenues associated with fuel and purchased power adjustments being made by Consumer Advocate witness CA-T-2, along with

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[1] See MECO responses to CA-IR-201, 203, 204 and 309 for additional details regarding sales variances experienced in 2007.

the corresponding adjustments to fuel and purchased power expenses. In its filing, MECO's adjusted sales revenues at present rates included ECAC revenues calculated at 13.954 cents per KWH for Maui, 13.9130 cents per KWH for Lanai and 15.774 cents per KWH for Molokai.[2] These pro-forma ECAC rates were derived from the Company's fuel and energy cost simulation calculations, so as to synchronize energy costs with ECAC revenues at present rates.

Mr. Herz, CA-T-2, is proposing further adjustments to fuel and purchased power expenses and to related ECAC revenues that are summarized at CA Adjustment Schedule C-3. This further adjustment recalculates the ECAC revenues in the Consumer Advocate's revenue requirement presentation using a modified ECAC factor of 13.941 cents per KWH (Maui), while retaining the Company's 13.913 cents per KWH (Lanai) and 15.774 cents per KWH (Molokai) factors, so as to reflect the revised Maui energy costs calculated by Mr. Herz at Exhibit CA-201 that impact the ECAC factor for Maui.[3] This adjustment is necessary to properly synchronize the Consumer Advocate's calculated fuel and purchase power costs with the energy cost adjustment revenues that would be recoverable through the

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2 See MECO-WP-302, page 1; MECO-WP-303, page 1 and MECO-WP-304, page 1. See MECO 1904, 1909 and 1911 for the calculations of these ECAC factors.

3 CA-201 Total Fuel Expense of $179,811,000 [$166,383,000 (Maui) + $6,175,000 (Lanai) + $7,253,000 (Molokai)] plus Purchased Power Energy Payments of $33,988,000.

ECAC at such higher incurred cost levels. The related fuel and purchased power adjustments are discussed in a subsequent section of my testimony.

III. MISCELLANEOUS REVENUES.

Q. WHAT IS INCLUDED IN MECO'S MISCELLANEOUS REVENUES FOR THE TEST YEAR?

A. Miscellaneous Revenues include various types of Non-sales Electric Utility revenues collected from customers for late payment charges, service establishment charges, returned check charges and other tariff terms and conditions, as summarized in MECO-712. Also included within Miscellaneous Other Revenues are the Company's rent revenues.

Q. IS ANY ADJUSTMENT NECESSARY FOR MECO'S PROPOSED TEST YEAR MISCELLANEOUS REVENUES?

A. No. The Consumer Advocate's analysis of miscellaneous revenues proposed by the Company supports a conclusion that such amounts are reasonable and no further adjustment is proposed by the Consumer Advocate.

1 **IV. FUEL AND PURCHASED POWER EXPENSE.**

2 Q. HOW HAS MECO DETERMINED ITS PROPOSED FUEL AND PURCHASED
3 POWER EXPENSES FOR RATEMAKING PURPOSES?

4 A. In its filing, the Company calculated pro-forma fuel and purchased power
5 expenses using a dispatch simulation program with input data associated with
6 MECO generating units, fuel prices, purchase power contracts and adjusted
7 demand levels. These calculations were reviewed by Consumer Advocate
8 witness Mr. Joseph Herz and are addressed in detail within CA-T-2.

9

10 Q. HOW ARE THE RESULTS OF MR. HERZ'S ANALYSIS INCORPORATED
11 INTO THE CONSUMER ADVOCATE'S REVENUE REQUIREMENT?

12 A. CA Adjustment Schedule C-3 sets forth the ratemaking adjustments required
13 to include adjusted fuel expense and purchased energy expenses based upon
14 the analysis performed by Mr. Herz for each island system, as summarized in
15 Exhibit CA-201, pages 1 through 3. In Exhibits CA-212, 216, and 218,
16 Mr. Herz calculates the ECAC factor that corresponds with the Consumer
17 Advocate's test year fuel and purchased power expense levels, system heat
18 rate and sales levels for the Maui, Lanai and Molokai divisions, respectively.
19 This ECAC value is then used to calculate annualized fuel adjustment
20 revenues at present rates which are incorporated into CA Adjustment
21 Schedule C-3 at lines 9 through 14 to properly synchronize ECAC revenues
22 and the related energy expenses for the test year, as referenced in my earlier

testimony regarding Sales Revenues. Finally, lines 18 through 20 calculate the incremental revenue taxes associated with the additional ECAC revenues to be collected at the somewhat lower Consumer Advocate proposed fuel and higher purchased energy cost levels for Maui Division. This process is repeated for each of the MECO Divisions; Maui, Lanai and Molokai using input amounts specific to each island.

Q. AT PAGES 23 THROUGH 28 OF MECO T-1, MR. REINHARDT TESTIFIES IN FAVOR OF CONTINUED UTILIZATION OF THE ECAC AND THE COMPANY'S POSITION REGARDING ACT 162. IS THE CONSUMER ADVOCATE IN AGREEMENT WITH MECO THAT THE ECAC SHOULD CONTINUE TO BE EMPLOYED?

A. Yes. Mr. Reinhardt states at page 23 that MECO fuel and purchased energy costs represent 82 percent of total O&M expenses and represent costs that are "largely beyond the Company's control." Fuel price volatility in international fuel markets and MECO's dependence upon such markets makes ECAC continuation important to the Company and its ability to timely recover fluctuating costs for the most significant operating expenses (i.e., fuel and purchased energy) thereby minimizing earnings volatility and the risk of reduced access to capital markets on reasonable terms. On the other hand, continued utilization of ECAC shifts virtually all energy cost risk onto ratepayers and the rate of return awarded by the Commission in this Docket

should fully account for this energy cost risk distribution between shareholders and ratepayers.

Q. DOES THE CONSUMER ADVOCATE OBJECT TO THE CONTINUATION OF THE ECAC TO PROVIDE MECO WITH FULL RECOVERY OF CHANGES IN ENERGY COSTS?

A. No. However, it should be recognized that the ECAC effectively transfers operating risks associated with energy cost fluctuations to MECO's customers. When the ratemaking cost of equity capital to be allowed MECO is being considered, this transfer of commodity price risk exposure to customers should be found to directly reduce the business risk facing MECO and its shareholders. In addition, the Commission must remain vigilant in monitoring MECO's fuel procurement and operational performance because of the diminished financial incentives that result from automatic rate recovery of fuel price changes. Mr. Herz explains in greater detail how the ECAC should be administered and how Act 162 impacts this issue.

Q. IS ANY MODIFICATION TO MECO'S PROPOSED SALES HEAT RATE BEING PROPOSED BY THE CONSUMER ADVOCATE?

A. Yes, I understand that Mr. Herz is also recommending that the Maui Sales Heat Rate for future ECAC administration be revised, as summarized in his Exhibit CA-215.

1 V. **PRODUCTION O&M EXPENSE.**

2 Q. BEYOND FUEL EXPENSES, DOES MECO INCUR OTHER EXPENSES FOR
3 THE OPERATION AND MAINTENANCE OF THE COMPANY'S
4 GENERATING UNITS?

5 A. Yes. The Company incurs significant non-fuel Production Operations and
6 Maintenance ("O&M") expenses to operate and maintain the power production
7 facilities located on each island. These Production O&M expenses are
8 recorded in expense accounts, ranging from NARUC Account Nos. 500
9 through 557 and include the costs of employee labor, materials, contract labor,
10 engineering, environmental and other administrative functions and services
11 incurred to operate and maintain the Company's generating facilities at the
12 Kahalui and Maalaea Power Plants and two small generating units at Hana on
13 Maui, as well as at the Miki Basin station on Lanai and the Palaau station on
14 Molokai.

15

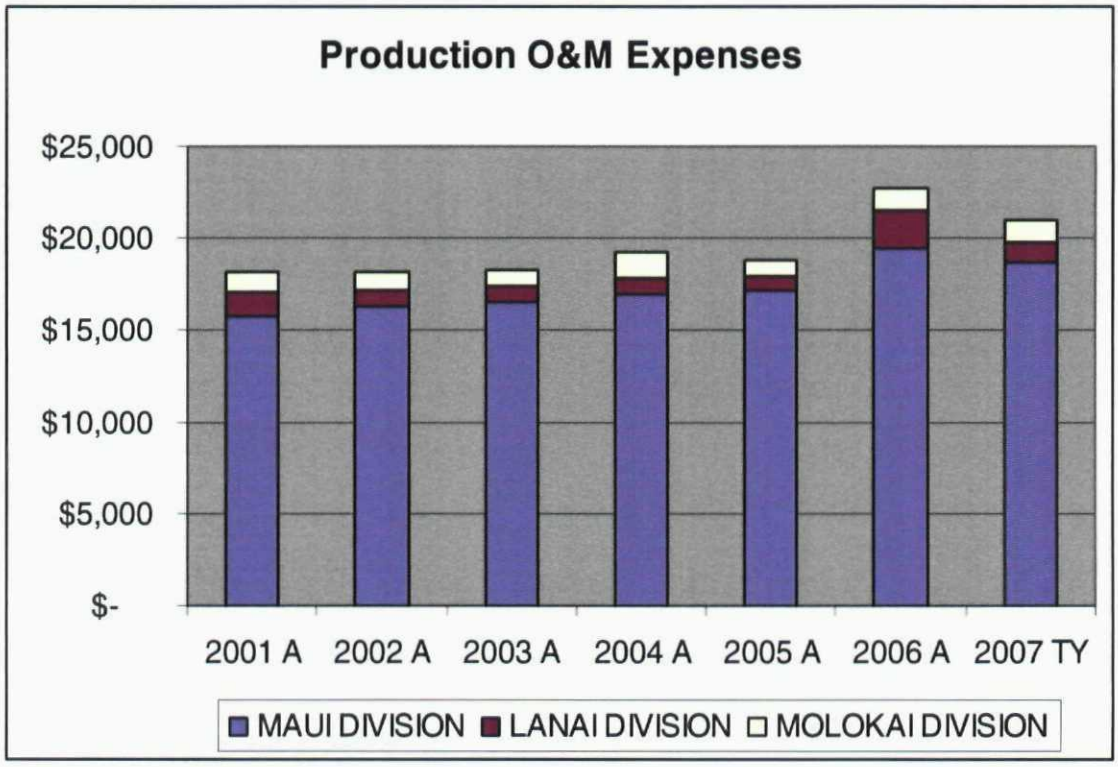
16 Q. WHAT IS MECO'S ESTIMATED LEVEL OF PRODUCTION OPERATIONS
17 AND MAINTENANCE EXPENSE FOR THE 2007 TEST YEAR?

18 A. As shown at MECO-502, MECO's proposed test year Production Operations
19 expense is $9.67 million with another $11.34 million for Production
20 Maintenance expenses, for a combined non-fuel production O&M level of
21 $21.01 million.

22

Q. HOW DOES MECO'S 2007 TEST YEAR PROJECTION FOR PRODUCTION O&M EXPENSES COMPARE TO RECENT HISTORICAL EXPENSE LEVELS FOR THIS BLOCK OF ACCOUNTS?

A. As shown in the following table, the Company's 2007 test year projection is moderately higher than comparable actual Production O&M expenses incurred in the years 2001 through 2005.



Sources: MECO-506 and CA-IR-82.

From this historical information, one can observe that MECO's Non-fuel Production O&M expenses have been relatively stable in the past several years, with an increase in actual spending in 2006. This graph illustrates that the Company's projected 2007 expense levels are expected to be lower than

2006 actual expenses, but somewhat higher than historical periods prior to 2006.

Q. HAS THE COMPANY PROPOSED SIGNIFICANT ADJUSTMENTS TO NORMALIZE THE PRODUCTION O&M EXPENSES THAT ARE FORECASTED TO BE INCURRED IN THE 2007 TEST YEAR?

A. Yes. The budgeted 2007 test year expenses that are expected to be incurred by MECO are much higher than the amounts proposed by the Company for inclusion in the rate case. MECO-505 sets forth the Company's Overhaul Normalization Summary, which represents MECO's re-calculation of generating unit non-labor overhaul expenses based upon established overhaul intervals (operating run-time hours or years) and dispatch simulation test year unit utilization. This adjustment is explained by MECO T-5 at pages 23-25 and has the effect of significantly reducing test year projected overhaul expenses by approximately $3.4 million, as shown in column B of MECO-505. If this adjustment to normalize overhaul expenses was not made, test year 2007 production O&M expenses would have exceeded all prior recorded years shown in the graph (above) because more overhaul work activity and

spending is planned by MECO in the 2007 test year than is "normal" when long-term overhaul intervals and unit running rates are considered.[4]

Q. DOES THE CONSUMER ADVOCATE AGREE WITH THE COMPANY'S APPROACH OF NORMALIZING GENERATING UNIT OVERHAUL FREQUENCY AND COST FOR THE TEST YEAR?

A. Yes. Where individually large overhaul projects can have a dramatic impact upon expenses incurred in a particular period, it is important to analyze and normalize the costs of such projects for ratemaking purposes. The calculations at MECO-WP-505 that support the 2007 Overhaul Normalization adjustment made by the Company reflect a systematic and rational approach to developing an adjusted normal overhaul expense level for ratemaking purposes. These adjustments have been accepted by the Consumer Advocate as necessary to establish a normalized, ongoing expense level for such overhaul non-labor costs.

Other MECO ratemaking adjustments were made by the Company to reclassify, restate or normalize 2007 budgeted amounts for fuel additives, biodiesel, lube oil and Nitrogen Oxide ("Nox") water expenses and some of these adjustments require revisions that are discussed in more detail below.

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[4] MECO T-5, at page 25, states that a "significant portion of MECO's 2007 overhaul expense [was] removed from the test year estimate" and "should the concept of overhaul frequency normalization be deemed unreasonable for whatever reason, the expenses which were removed in the normalization process should be re-included in the test year estimate when determining reasonable costs."

Q. HAS THE COMPANY MODIFIED ITS PREFILED CASE WITH RESPECT TO THE PROPOSED LEVEL OF TEST YEAR 2007 NON-FUEL PRODUCTION O&M EXPENSES?

A. Yes. As part of its June 2007 update, MECO proposed an update adjustment to its prefiled Production O&M expenses that would increase the test year Production O&M expenses by $471,558 for additional expenses anticipated to be billed by HECO through inter-company billing procedures primarily for the new HECO Power Supply Competitive Bidding Division. These expenses include MECO's allocated share of these higher anticipated labor costs for Generation Bidding, Fuel Infrastructure and Administrative staff additions. This update proposed by MECO to its test year Production O&M expense is set forth at lines 8 through 10 of CA Adjustment Schedule C-1. In addition to increased HECO staffing and labor costs that are allocable to MECO and are included in this adjustment, MECO has also included an allocated share of anticipated future higher costs through the year 2009 associated with competitive bidding for future generation resources in an amount that is disputed by the Consumer Advocate, as more fully explained below.

Q. DO YOU RECOMMEND THAT THE COMMISSION APPROVE MECO'S PROJECTED TEST YEAR 2007 NON-FUEL PRODUCTION O&M EXPENSE LEVELS, AS MODIFIED BY THE JUNE 2007 UPDATES?

A. Not entirely. MECO's proposed test year level of O&M expense is overstated and should be adjusted as explained in the testimony that follows. Ratemaking adjustments to MECO's recommended 2007 Production O&M expenses are proposed by the Consumer Advocate for the following reasons.

- Projected labor costs are overstated because of new employee positions included in the test year forecast that have not been filled and because MECO has assumed full staffing (no vacancies) throughout the test year for the entire production department workforce. Mr. Carver (CA-T-1) has proposed an adjustment to account for Company-wide overstatement of staffing levels by recognizing actual staff levels as of the beginning of the test year, including staffing within the MECO Production Department.
- MECO has, in its June 2007 test year updates, proposed an excessive estimate of non-labor consulting and legal expenses to support the competitive bidding process.
- MECO has proposed adjustments to restate the 2007 forecast for lubricating oil ("lube oil") expenses,[5] for which specific further

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5 See MECO-WP-504b and MECO-WP-504e.

adjustments are proposed by the Consumer Advocate to correct an error in the Company's lube oil consumption rate and to reflect last known actual prices of lube oil.

- While the Company has calculated structural maintenance normalization adjustments for the Maalaea and Palaau stations,[6] no comparable adjustment was proposed for the Kahului station. A structural maintenance normalization adjustment is also appropriate for Kahului station and is proposed by the Consumer Advocate.
- MECO has failed to account for the periodic waivers in emission fees that have been granted historically and that should be considered in calculating a normalized test year emission fee expense amount for ratemaking purposes.
- Water treatment expenses incurred to purify water used for Nox emission control at the Maalaea station were normalized by MECO, as described at MECO T-5 at page 16,[7] but further adjustment is needed to update and refine this calculation.

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6 See MECO-WP-504f and MECO-WP-504g.

7 Calculations supporting the MECO adjustment appear at MECO-WP-504d.

Q. ARE ADDITIONAL EMPLOYEE POSITIONS INCLUDED WITHIN MR. RIBAO'S PROJECTED TEST YEAR PRODUCTION O&M EXPENSES?

A. Yes. According to MECO T-5 at pages 17 and 29, several new positions have been fully included in the Company's test year labor cost projections. Some of these proposed new employee positions were not filled at the beginning of the test year, as shown in the Company's response to CA-IR-1, MECO T-5, Attachment 15.

A. PRODUCTION O&M LABOR EXPENSE ADJUSTMENTS.

Q. HOW DID THE COMPANY DETERMINE THE LEVEL OF STRAIGHT TIME AND OVERTIME LABOR HOURS AND RESULTING LABOR EXPENSES THAT ARE INCLUDED IN ITS RATE CASE PROJECTIONS FOR TEST YEAR 2007?

A. Mr. Ribao (MECO T-5) sponsors MECO's proposed Production O&M labor expenses. According to page 17 of this testimony, MECO's 2007 test year Production Operations labor expense estimate of $5.4 million is close to the amount of recorded 2005 cost, but at page 29 of his testimony, Mr. Ribao indicates that, "production maintenance labor expense is expected to increase from $3,401,400 to $3,902,300 between 2005 and test year 2007." This increase is said by Mr. Ribao to be attributable in part to "three additional employees; a Senior Helper at Kahului Power Plant, an Electrician at Maalaea

1 Power Plant, and an Operator Helper at Lanai Power Plant" that are proposed
2 to be added by MECO.
3 At page 36 of MECO T-5, Mr. Ribao states, "[t]he 2007 Power Supply
4 staffing level is estimated at 123 employees, as compared to 121 employees
5 in 2005 (See MECO-1102 in Ms. Eileen Wachi's T-11 testimony)." Then, at
6 page 38 he states, "[t]he Power Supply Department's actual year end
7 employee count was 118."
8
9 Q. HAS MECO ACCOUNTED FOR THE VACANCIES IN STAFFING THAT
10 ROUTINELY OCCUR AS A RESULT OF NORMAL WORKFORCE
11 TURNOVER?
12 A. No. Mr. Ribao's test year labor expense estimate assumes that all
13 123 positions are filled throughout 2007.
14
15 Q. DOES THE CONSUMER ADVOCATE OBJECT TO THE INCLUSION OF
16 THE COSTS ASSOCIATED WITH MECO'S ASSUMED FULL STAFFING
17 FOR RATEMAKING PURPOSES?
18 A. Yes. There is no factual support for an assumption that MECO will never
19 experience vacancies in its workforce. So as to not intentionally overstate the
20 test year labor costs, I have asked Mr. Carver (CA-T-1) to include the Power
21 Supply employees within his Company-wide adjustment to account for
22 average test year employees at CA Adjustment Schedule C-13. The effect of

1 such inclusion is to adjust labor expenses based upon a weighted average of
2 actual employee levels at the beginning of the test year with proposed
3 employee levels at the end of the test year, which implicitly assumes that
4 MECO may achieve full staffing by year-end. This assumption renders the
5 Consumer Advocate adjustment conservative in its impact, because of the
6 likelihood that even by year-end MECO may not achieve the full staffing levels
7 that are assumed in its rate case filing.
8
9 **B. PRODUCTION O&M NON-LABOR EXPENSE ADJUSTMENTS.**
10 Q. ASIDE FROM THE LABOR COST PROJECTION ISSUES YOU HAVE
11 DESCRIBED, ARE THERE ALSO PROBLEMS WITH MECO'S PROPOSED
12 NON-LABOR PRODUCTION OPERATIONS EXPENSES?
13 A. Yes. The following sections of this testimony describe several adjustments
14 proposed by the Consumer Advocate to correct and normalize elements of
15 MECO's proposed Production O&M Non-labor expenses.
16
17 Q. IN MECO'S PROPOSED JUNE 2007 UPDATE IN THE PRODUCTION O&M
18 AREA, HAS THE COMPANY ADDED NEW EXPENSES TO SUPPORT NEW
19 "GENERATION BIDDING" ACTIVITES?
20 A. Yes. MECO has proposed increasing test year labor expenses by $57,724 to
21 account for reorganization and staffing increases needed to implement the
22 Commission's competitive bidding framework requirements. Additionally,

1 MECO seeks to add $413,834 to non-labor test year expenses for competitive
2 bidding related work.
3
4 Q. DOES THE CONSUMER ADVOCATE OBJECT TO THESE NEW LABOR
5 AND NON-LABOR ADJUSTMENTS?
6 A. The Consumer Advocate does not object to the inclusion of additional labor
7 expenses for staffing additions that are occurring in connection with the
8 reorganization and creation of MECO's Power Supply System Planning
9 Department, as explained in the Company's response to CA-IR-317,
10 Attachment A. The new positions created by this reorganization either have
11 been or will be filled by mid-year and MECO has included labor costs
12 employing a half-year convention, which is more consistent with the Consumer
13 Advocate approach to average staffing labor expense quantification.
14 However, MECO has clearly overstated the additional non-labor expenses
15 associated with competitive bidding that will be incurred in 2007 and an
16 adjustment is required to reduce MECO's updated proposed expenses in this
17 area.
18
19 Q. WHAT IS THE PURPOSE OF CONSUMER ADVOCATE ADJUSTMENT
20 SCHEDULE C-4?
21 A. CA Adjustment Schedule C-4 is proposed to reduce MECO's proposed June
22 2007 update adjustment to its filing that seeks to add $413,834 into Production

O&M expenses for anticipated higher future spending to implement competitive bidding for generation resources. This adjustment reduces proposed expenses in the Company's updated filing (as included in CA Schedule C-1) from $413,834 to $138,150 to recognize only the cost level that is likely to be incurred in 2007 for competitive bidding activity.

Q. HOW DID MECO QUANTIFY THE ADDITIONAL NON-LABOR EXPENSES IT HAS ADDED INTO ITS RATE FILING FOR COMPETITIVE BIDDING ACTIVITIES?

A. According to MECO's response to CA-IR-317 at Attachment A, page 3, the Company anticipates that it may spend $276,300 in 2007, $482,600 in 2008 and another $482,600 in 2009 for outside legal and consulting assistance to implement competitive bidding. MECO is now proposing that a three-year average of these future cost estimates be averaged and added into the 2007 test year expenses. Thus, MECO would reach beyond the end of the 2007 test year to incorporate potentially higher future expenses in 2008 and 2009 into ratemaking expenses.

Q. HOW DOES THE CONSUMER ADVOCATE RECOMMEND THAT COMPETITIVE BIDDING COSTS BE TREATED FOR RATEMAKING PURPOSES?

A. The Consumer Advocate believes that only a reasonable estimate of expenses that are likely to be incurred within 2007 should be recognized for this proceeding. A rate case test year should contain only reasonable estimates of normal, ongoing expenses that would be performed in that year. Reaching beyond the end of the test year to include certain types of expenses that may increase in the future is inappropriate because such inclusion distorts test year matching that is an essential element of utility rate regulation. It is quite possible that continuing customer and sales growth or cost reductions arising from productivity improvements may be available to MECO <u>after</u> 2007 to offset some, or all of the cost increases that may be experienced at that time. Piecemeal post test year adjustments should be discouraged by the Commission, so as to maintain a consistent test year matching of the test year revenues, expenses and rate base, while avoiding a process that may encourage cherry-picking of certain cost items by parties to regulatory proceedings.

Q. HOW MUCH NON-LABOR EXPENSE HAS MECO ACTUALLY INCURRED IN 2007 TO SUPPORT COMPETITIVE BIDDING, TO-DATE?

A. Total MECO expenditures to-date for competitive bidding total only $27,114.[8] This is less than 10 percent of the $276,300 projected to be spent in all of 2007 and considerably less than the $413,834 being requested as test year operating expenses based upon the three-year period ending in 2009. According to the response to CA-IR-317, part c:

> MECO does not have direct contractually committed spending for competitive bidding work. On September 5, 2007 HECO Generation Bidding Division (HGBD) authorized Merrimack to assist with the development of the MECO RFP. The commitment is for $150,000 in 2007 but due to timing and limited resources, a good portion of the actual expenditures will likely carry over into 2008. HGBD is also working on retaining an Independent Observer to assist with issues related to the competitive bidding and parallel plan work we are about to engage in. It will likely take another month before an agreement can be reached and a contract signed.

Thus, the activities and non-labor expenses chargeable to MECO for competitive bidding support appear to be gradually increasing within the test year, but not at the levels proposed for inclusion by MECO.

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8 MECO response to CA-IR-317, Attachment B.

Q. WHAT AMOUNT IS RECOMMENDED FOR TEST YEAR COMPETITIVE BIDDING NON-LABOR EXPENSES FOR MECO BY THE CONSUMER ADVOCATE?

A. The Consumer Advocate has included one-half of the Company's estimated non-labor expenses projected to be incurred in 2007, which results in $138,150 being added to MECO's Production O&M expenses (one-half of the $276,300 from CA-IR-317, Attachment A, page 3). This amount is about five times what has actually been incurred through September 25, 2007 and provides an ample allowance for consulting support, **if** commitments are reached with vendors before year-end. This amount is also reasonable in comparison to the $175,000 allowed by the Consumer Advocate for HECO in Docket No. 2006-0386 which also employed a 2007 total test year.

Q. TURNING NEXT TO LUBRICATION OIL EXPENSES ("LUBE OIL"), PLEASE EXPLAIN WHAT IS SHOWN IN CONSUMER ADVOCATE ADJUSTMENT SCHEDULE C-5.

A. This Schedule contains an adjustment required to correct the Company's calculation of lube oil expenses for the Mitsubishi diesel units, because an error was made in calculating the lube oil consumption rates for these units. According to the response to CA-IR-326, part a, "[t]here was an error in the lube oil consumption for all the Mitsubishi units in CA-IR-217, Attachment 1," *which is the calculation supporting the Company's normalized level of lube oil*

expense for the test year. In addition, 2007 updated unit prices from the Company's confidential response to CA-IR-326, Exhibit 3 are employed to recalculate the lube oil adjustment. This Consumer Advocate adjustment is to correct the consumption rate error and to reflect last known actual unit prices as set forth in the confidential calculations shown at lines 2 through 21 within Schedule C-5 for Maui Division, based upon the confidential detailed information contained in response to CA-IR-326. Comparable adjustments for Lanai and Molokai are presented in Schedule C-5, using lube oil consumption rates for power plants on each island at current unit costs for lube oil on each island.

Q. PLEASE EXPLAIN THE REASON FOR THE CONSUMER ADVOCATE'S NEXT ADJUSTMENT APPEARING ON SCHEDULE C-6.

A. MECO incurs significant costs to periodically overhaul its generating units, as well as ongoing costs to perform preventative and miscellaneous minor maintenance on the units. In addition to these unit maintenance activities, the buildings and other structures associated with each generating station also require periodic inspection, painting and repairs. Such "structural maintenance" activities and costs tend to fluctuate from year-to-year, as discrete large projects occur only occasionally that require maintenance. For the Maalaea and Palaau generating stations, MECO has analyzed historical expenditure levels for this "structural" station-wide maintenance and calculated

normalized expense amounts to be used for ratemaking purposes (See MECO-WP-504f and MECO-WP-504g). For each of these stations, the MECO-proposed normalized level of expenses exceeds the expected 2007 spending in the Company's Operating Budget, so a ratemaking adjustment is proposed to increase budgeted cost levels for ratemaking purposes.

The Kahului Power Plant ("KPP") 2007 Operating Budget expenditure levels, however, were much higher than the expenditures incurred in most historical years and no normalization adjustment was calculated or proposed by the Company for the 2007 expense projections. The Consumer Advocate does not agree with the Company's position that no normalization should be performed for Kahului structural maintenance. As a result, in CA-IR-226 MECO was asked to apply the same logic and calculations it used at Maalaea and Palaau to its recorded and expected expenses for structural maintenance at Kahului. In response to CA-IR-226 the Company prepared a normalization adjustment. The Consumer Advocate accepts the adjustment for ratemaking purposes as shown in Consumer Advocate Schedule C-6.

Q. FOR WHAT REASONS HAS MECO NOT INCLUDED A STRUCTURAL MAINTENANCE NORMALIZATION ADJUSTMENT FOR THE KAHULUI STATION?

A. According to the narrative response to CA-IR-226, part b:

> A rate case normalization adjustment is not appropriate, based on the timing and level of future structural maintenance

expenses at KPP. In each of the next three years (2008, 2009, and 2010), one of the three KPP bulk fuel tanks will undergo an out-of-service inspection/repair, at an average cost of $274K (See Attachment 1, lines 79-81 for cost estimates). In the 2011-2012 time period, MECO expects to incur $200K for the next phase of the berm wall repair. Given the level and consistency of these future KPP structural maintenance costs, MECO believes the 2007 Operating Budget forecast for KPP structural maintenance is appropriate for the years over which the rates determined in this case will be in effect.

Q. WHY HAS THE CONSUMER ADVOCATE NOT ACCEPTED THIS RATIONALE FOR RETAINING THE HIGHER BUDGETED 2007 EXPENSES AND NOT NORMALIZING KPP STATION STRUCTURAL MAINTENANCE EXPENSES?

A. Structural maintenance activity and cost levels for KPP have fluctuated significantly over the past six years. The Consumer Advocate does not dispute MECO's view that significant structural maintenance costs will be concentrated in the near term because of the anticipated multiple bulk fuel tank inspections and the berm wall repairs that are now underway. But the bulk fuel tank inspections are only performed every ten years and were last performed in the 1998 through 2000 time frame and the KPP berm wall has not been substantially repaired in the last ten years.[9] It is unreasonable to build an excessive level of such non-recurring types of costs into a single test year.

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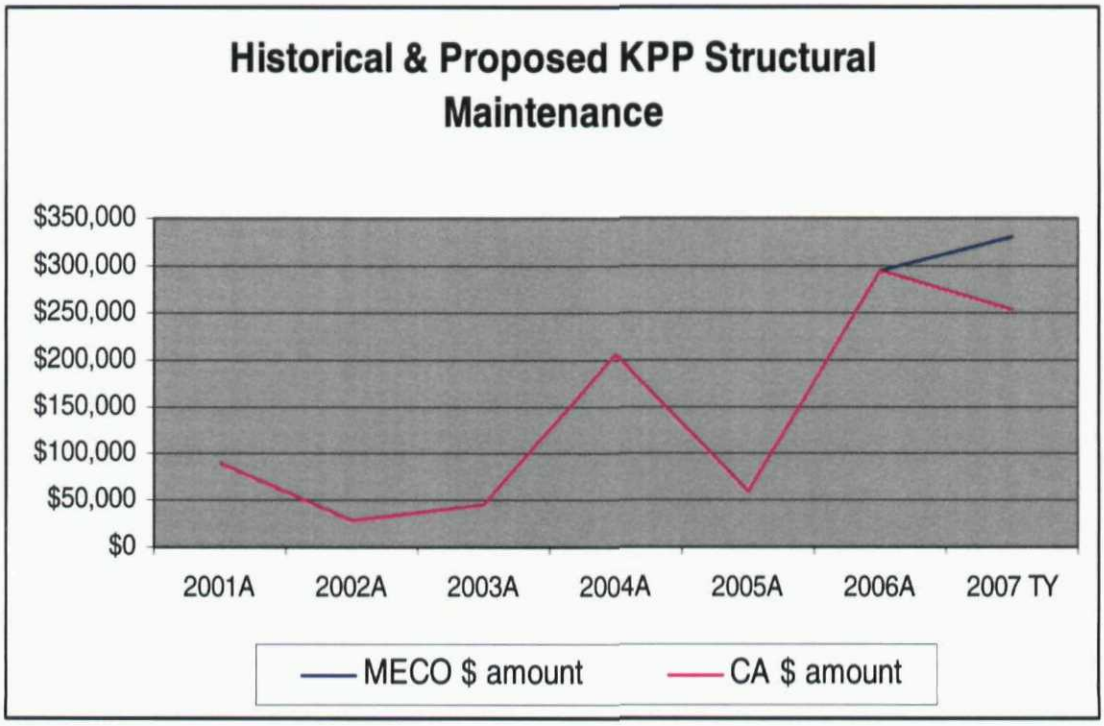
[9] See MECO response to CA-IR-282.

The normalization calculations prepared by MECO in response to CA-IR-226 provide for a one-tenth normalization of all needed KPP fuel tank inspections, as well as recognition of estimated costs to repair the entire berm wall spread over a normalized 10-year interval. The resulting normalized cost level is higher than historical actual expenditure levels in most recent years and is more reasonable for ratemaking purposes than the Company's proposed level which would inappropriately recover the KPP structural maintenance costs within only a few years.

The following graph summarizes actual historical KPP structural maintenance spending and the MECO-proposed 2007 test year amount, versus the Consumer Advocate's recommended normalized spending levels, using information in the Company's response to CA-IR-226, Attachment 1:



This graph illustrates how the Consumer Advocate's recommended "2007 TY" normalized amount of approximately $250,000 for KPP structural maintenance expense is more consistent with average historical spending levels and is likely to be more representative of ongoing spending levels.

Q. WHAT IS THE NEXT PRODUCTION O&M NON-LABOR EXPENSE ADJUSTMENT YOU PROPOSE, AS SET FORTH IN CONSUMER ADVOCATE SCHEDULE C-7?

A. To control emission levels at the Maalaea Power Plant, MECO uses a water injection system that requires large amounts of purified water. Water purification facilities and expenses are referred to by MECO as "Nox water costs" and the Company derived its test year normalized level of such costs in MECO-WP-504d, by calculating water treatment expenses as a ratio of fuel burn quantities for the test year. The Company's adjustment relies upon the average incurred Nox water treatment expenses from 2003 through 2005, factored up for an assumed inflation increase and then divided by the actual fuel burned during 2003-2005, to derive an estimated 2007 Nox water cost factor per barrel of fuel burned. This estimated cost factor is then multiplied by the test year projected fuel burn barrels to calculate an adjusted test year expense of $293,291 as shown at the line captioned "Adjusted '07 Nox Water Cost ($)" of MECO-WP-504d.

Q. WHAT IS WRONG WITH THE COMPANY'S NORMALIZATION ADJUSTMENT FOR MAALAEA NOX WATER TREATMENT COSTS?

A. The Company's adjustment appears to be based upon two flawed assumptions: 1) that Nox water treatment expenses are subject to inflation, and 2) that Nox water treatment expenses always vary directly with the amount of fuel being burned, with no efficiency gains achievable through improved technology. The assumptions implicit in the Company's calculations are inconsistent with actual historical expense levels. The following table compares historical actual Nox water treatment expenses and fuel burn quantities at Maalaea to illustrate the problem with the Company's methodology and to show how these costs have fluctuated:

Historical Maalaea Nox Water Costs	Actual Nox Water Expenses	Maalaea Fuel Burn (barrels)	Nox Water Expense per Barrel
2003 A	$ 288,857	857,574	$ 0.3368
2004 A	$ 280,010	906,074	$ 0.3090
2005 A	$ 156,442	924,407	$ 0.1692
2006 A	$ 97,338	981,408	$ 0.0992
May Year to date 2007 A	$ 98,543	434,932	$ 0.2266
MECO Position	$ 293,291	1,045,153	$ 0.2806
CA Position (MECO Original Budget)	$ 248,452	1,045,153	$ 0.2377

Source: MECO-WP-504-d and CA-IR-85.

This table clearly shows that the "MECO Position" calculated in MECO-WP-504-d yields an excessive Nox water ratio and expense, because water treatment costs have <u>not</u> been steadily increasing in proportion to fuel burned quantities as assumed by the Company.

In contrast, the Consumer Advocate position, which is based upon acceptance of the initial MECO Operating Budget expense for 2007, represents an expense result that is more consistent with historical expense levels and is relatively close to costs actually being incurred to date in 2007 on a per fuel barrel burned basis ($.2377 versus $.2266).

Q. HAS MECO RECENTLY MADE CHANGES TO ITS NOX WATER FACILITIES THAT CAUSE HISTORICAL WATER TREATMENT COSTS, AS USED IN THE COMPANY'S NORMALIZATION CALCULATIONS, TO BE POTENTIALLY UNRELIABLE IN PREDICTING ONGOING FUTURE COST LEVELS?

A. Yes. With the new generating unit M18 operational and the second combined cycle train in service, 100 gallons per minute ("GPM") of purified water is needed on a continuous basis. To accommodate this increased demand, MECO has installed a new 100 GPM E-cell water treatment system to replace its less reliable Osmonics mixed bed demineralizer system. Some of the historical operating costs associated with the Osmonic demineralizer, such as costs of acids and caustic chemicals to regenerate the demineralizer, will no longer be incurred because the new E-cell system uses electricity instead of chemicals to continuously regenerate the resins.[10]

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[10] MECO response to CA-IR-324, Attachment 4, page 65. The new E-cell project was indicated to be completed in the Company's test year update, MECO T-14, Attachment 1, page 3.

Q. PLEASE EXPLAIN THE FINAL PRODUCTION O&M NON-LABOR ADJUSTMENT YOU PROPOSE, AS SET FORTH AT CONSUMER ADVOCATE SCHEDULE C-8.

A. MECO pays emission fees to the Hawaii Department of Health ("DOH") as a contribution to the State's clean air fund, based upon the utility's calculated quantities of air pollution emissions at a dollar per ton rate that is established by the DOH. While in most historical years the calculated fees are assessed by and paid to the DOH, in some prior years such fees have been entirely waived. For the test year, MECO estimated the 2007 rate at $55.92 per ton applied to the fuel burn quantities taken from the Company's latest 2007 fuel expense forecast. The calculated emission fees for each generating station were <u>not</u> reduced by MECO to normalize for the periodic fee waivers that have been granted by the DOH, "[b]ecause emission fees have been paid for the last three years (2004, 2005, and 2006), [and] MECO does not believe historical waivers should be considered in determining the test year estimate."[11] A history of emission fee payments for MECO reveals that emission fees were paid in most of the years 1997 through 2006, but for the years 1998, 2001 and 2003 such fees were waived and not required to be paid to the DOH.

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[11] MECO response to CA-IR-104.

In its 2005 and 2007 test year rate case filings, HECO calculated its emission fees based upon an assumption that periodic fee waivers may continue to occur, by using a 10/13th prorate of calculated fees to recognize that waivers can be expected to occur on average in three out of thirteen years. This was explained in the testimony of HECO witness Mr. Giovanni (HECO T-6) at page 58:

> HECO proposes a normalization of ten thirteenths (10/13th) for emissions Fees based on HECO's payment of emission fees in 10 of the past 13 years. HECO maintains that the administration of the fee by the Department of Health is not predictable, however, for 2007 test year HECO is utilizing the 10/13th's methodology to determine the Emission Fee adjustment.

In its last rate case, HELCO made a similar normalizing adjustment to recognize the occasional, but unpredictable emission fee waivers in its filing.[12] The Consumer Advocate believes that MECO should not ignore the historical fee waivers that have been experienced and that may be experienced in the future, particularly since a normalization for such waivers was proposed by HECO and HELCO and used to set rates in their most recent rate cases. Therefore, a normalization adjustment is being proposed by the Consumer Advocate to recalculate emission fees using the same 10/13th factor that was employed by HECO in Docket No. 2006-0386.

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12 In Docket No. 05-0315, HELCO witness T-5 stated at page 57 that, "[w]ithin the last 10 years (1995-2005), HELCO was granted waivers for two of the 10 years. The granting of waivers is not predictable. Thus, for ratemaking purposes, the normalized amount was based on taking 80% of the 2006 forecast amount to derive the 2006 TY normalization cost of $245,000."

In the Consumer Advocate's recalculation of emission fees for MECO, a somewhat higher per ton rate of $57.14, rather than the $55.92 value in the Company's forecast, is also being employed by the Consumer Advocate to recognize that the actual fees most recently assessed were at $55.15 per ton for 2006 operations and that the fee rate is subject to DOH escalation based upon changes in the Consumer Price Index. The $57.14 rate being used by the Consumer Advocate is based upon an assumed change in CPI of 3.6 percent over 2006 price levels.[13]

Q. WHAT IS THE SOURCE OF THE EMISSION TONNAGE ESTIMATES REFLECTED AS INPUTS WITHIN SCHEDULE C-8?

A. The emission tonnage amounts shown for each generating station were provided by MECO based upon their test year production simulation runs (or budget estimates for Lanai and Molokai). The Consumer Advocate adjustment recalculates emission fees using these tonnage values at the higher $57.14 per ton emission fee rate in the Company's response to CA-IR-327 for each of the Company's generating stations on Maui and for the Lanai and Molokai generation in total. All the calculated emission fee amounts are then multiplied by the 10/13th factor to account for periodic fee waivers by the DOH.

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13 See responses to CA-IR-215 and CA-IR-327.

1 **VI. CUSTOMER ACCOUNTS EXPENSE.**

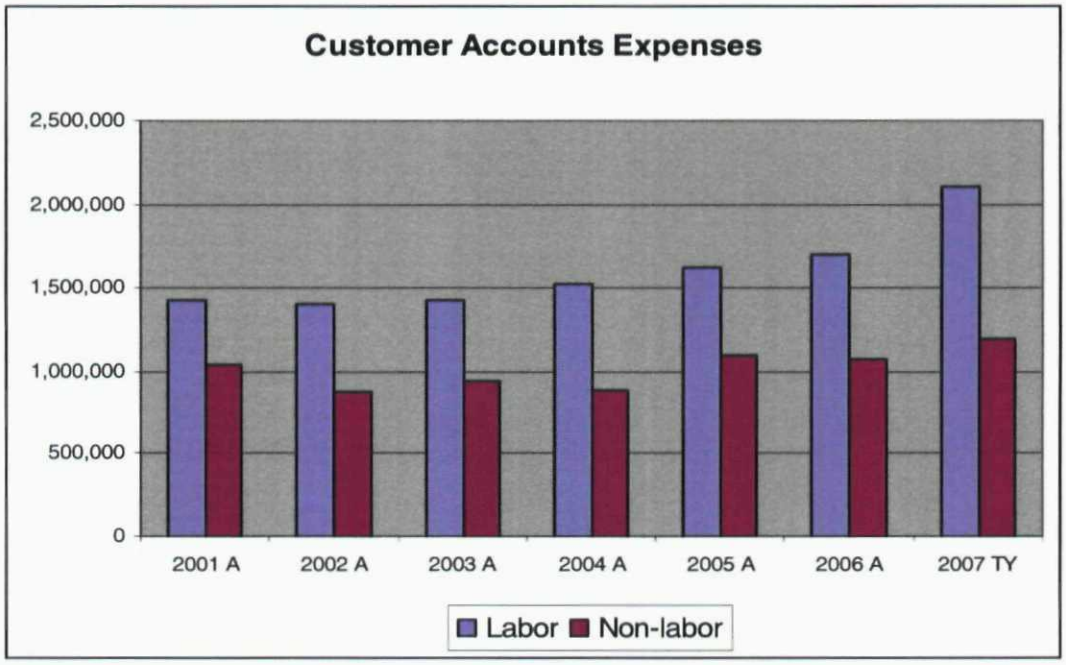
2 Q. WHAT TYPES OF EXPENSES ARE INCLUDED WITHIN MECO'S
3 CUSTOMER ACCOUNTS EXPENSES?

4 A. Customer Accounts Expenses include the labor and non-labor costs
5 associated with customer records, meter reading, billing, collections and
6 remittance processing, as well as the supervisory and information systems
7 functions supporting such activities. In addition, Customer Accounts expenses
8 include Account 904 Uncollectibles expenses. MECO witness T-7, Ms. Suzuki
9 explains and sponsors the Company's proposal to include $3.3 million of
10 Customer Accounts expenses in the 2007 test year, as shown in MECO-701 in
11 the column labeled "2007 Test Year @ Present Rates."

12

13 Q. HOW DOES THE MECO-PROPOSED LEVEL OF TEST YEAR PROJECTED
14 CUSTOMER ACCOUNTS EXPENSE COMPARE TO PRIOR YEAR ACTUAL
15 EXPENSE LEVELS?

16 A. MECO-WP-701 at page 6, line 33, shows "Test Year Estimate 2007" expenses
17 of $3.3 million to be significantly higher than prior year actual expense levels.
18 If this comparison is made separately for labor and non-labor elements of
19 Customer Accounts Expenses, the proposed increases in test year expenses
20 are concentrated within the labor expense category, as shown in the following
21 graph:



This comparison shows that Non-labor customer accounts expenses have been gradually increasing from $0.8 to $1.1 million on an actual basis historically, while the test year proposed level is only modestly higher at $1.2 million. In contrast, MECO has proposed substantially higher labor expenses for Customer Accounts activities, where the proposed labor expense amount of $2.1 million vastly exceeds prior year expense levels.

A. CUSTOMER ACCOUNTS LABOR EXPENSE.

Q. ARE THERE PROBLEMS WITH MECO'S STAFFING ASSUMPTIONS USED IN ESTIMATING TEST YEAR LABOR EXPENSES FOR THE CUSTOMER ACCOUNTS EXPENSE BLOCK?

A. Yes. The Customer Accounts labor cost projections prepared by Ms. Suzuki are based upon an expanded Customer Service Department staffing level that

is assumed to be fully staffed with no vacancies throughout the test year. At MECO-WP-715, page 1 illustrates how increased staffing to 34 employees is embedded within test year expense estimates. The effect of expanded staffing at these levels, as well as high levels of estimated overtime hours, is an increase in projected labor expenses for the Maui Division Customer Accounts Expenses of 27.5 percent above 2006 actual labor expense levels.[14]

The assumption of full staffing at the proposed levels is unrealistic, because there will always be some level of vacancy among approved positions resulting from employee resignations, retirements, disabilities and normal turnover of personnel. Thus, a ratemaking adjustment is needed and is being proposed by Mr. Carver to account for actual staffing levels at the beginning of the test year, averaged with assumed full employment by year end at proposed levels. The mechanics of this adjustment are described in greater detail by Mr. Carver (CA-T-1).

Q. IS MECO MAKING PROGRESS TOWARD ACHIEVEMENT OF THE CUSTOMER SERVICE DEPARTMENT STAFFING AT RATE CASE PROPOSED LEVELS?

A. Yes. Some progress is being made by the Company, as shown in Attachment A to MECO's response to CA-IR-148. A total of 43 positions were

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[14] MECO-WP-704, page 1 of 2, Updated April 2007, at line 13. MECO-704, page 3 shows MECO's test year overtime hours estimated for the Customer Service Department, at line 12 in column H, that are much higher than prior recorded levels in all prior years.

proposed by the Company and included throughout the test year expense projections. At year-end 2006, actual staffing levels totaled 40 employees, but as of May 2007 the Company had hired additional employees to achieve actual staffing of 42 positions. While it is conceivable that MECO is deliberately focused upon hiring to achieve full staffing because of the pending rate case, it should be recognized that some periodic vacancies will occur naturally from time to time that will contribute to labor cost savings. The labor cost savings achieved because of structural vacancies among the planned workforce should not be ignored when the revenue requirement is determined.

Q. HAS MECO INCURRED ANY TEMPORARY SERVICE LABOR COSTS BECAUSE OF VACANCIES THAT HAVE EXISTED THUS FAR IN THE TEST YEAR?

A. Yes. According to the response to CA-IR-354, part b and Attachment B, agency temporary service contractors were employed at a cost of $22,220.52 through July of 2007 and these costs "were not included in the test year forecast." These temporary service agency workers were used to cover for a vacant meter reader position and to allow for two additional clerical workers to aid in improving customer service levels.[15]

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[15] MECO response to CA-IR-354, part c.

1 Q. SHOULD MECO BE ALLOWED ADDITIONAL EXPENSES FOR
2 TEMPORARY SERVICE CONTRACTOR CHARGES AS AN OFFSET TO
3 THE EMPLOYEE LEVEL ADJUSTMENT MR. CARVER IS SPONSORING,
4 SINCE THAT CONSUMER ADVOCATE ADJUSTMENT REDUCES TEST
5 YEAR PROJECTED LABOR EXPENSES TO ACCOUNT FOR VACANT
6 POSITIONS AND SUCH VACANCIES MAY CONTRIBUTE TO MECO'S
7 NEED IN 2007 FOR TEMPORARY CONTRACT EMPLOYEES?
8 A. No. The Customer Accounts portion of Mr. Carver's adjustment reduces test
9 year expenses by only about $70,000, which is only a small portion of the
10 overall labor increase that MECO has included in its test year projections and
11 is only a portion of the labor cost savings MECO is actually experiencing as a
12 result of vacancies in 2007. The Company's response to CA-IR-410 at
13 Attachment B shows that actual labor hours charged to Customer Accounts
14 expenses are running more than 5,200 labor hours below projected levels
15 through September 2007. At the standard labor rates used by MECO for the
16 test year,[16] this labor hour variance implies an expense savings being
17 experienced by MECO in 2007 that is much larger than Mr. Carver has
18 captured by averaging employee headcounts for the test year. If temporary
19 contract employee charges are allowed into test year expenses, an even

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16 MECO's response to CA-IR-57 at page 8 shows hourly labor rates ranging from $21.44 for meter readers to $30.01 for customer account representatives. Using an average rate of $25 per hour, the 5,213 labor hour variance through September 2007 should have produced Customer Accounts expense labor savings of more than $130,000 so far in 2007.

1 larger labor cost vacancy adjustment is needed to fully account for
2 vacancy-related savings, beyond the amounts calculated and sponsored by
3 Mr. Carver. Instead of making larger a larger employee level adjustment,
4 offset by inclusion of contract temporary labor charges, Mr. Carver has applied
5 a uniform average test year calculation approach in Adjustment
6 Schedule C-13 that provides a reasonable overall test year expense level for
7 the labor requirements within MECO's Customer Accounts function.
8
9 **B. CUSTOMER ACCOUNTS NON-LABOR EXPENSE ADJUSTMENTS.**
10 Q. IN EARLIER TESTIMONY YOU PROVIDED A GRAPH OF HISTORICAL
11 VERSUS TEST YEAR CUSTOMER ACCOUNTS LABOR AND NON-LABOR
12 EXPENSES AND COMMENTED THAT MECO'S PROPOSED NON-LABOR
13 EXPENSES COMPARE REASONABLY TO HISTORICAL LEVELS. IS THE
14 CONSUMER ADVOCATE PROPOSING ANY ADJUSTMENTS TO TEST
15 YEAR CUSTOMER ACCOUNTS NON-LABOR EXPENSES?
16 A. No. The Consumer Advocate's analysis of test year estimated non-labor
17 Customer Accounts expenses supports a conclusion that the overall non-labor
18 expenses proposed by MECO in this area are reasonable and any
19 adjustments that might be considered would be insignificant in amount.[17] The

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[17] According to MECO's responses to CA-IR-246 and CA-IR-409, actual intercompany charges from HECO to MECO have fluctuated from estimated levels, in part due to anticipated postage rate increases being effective at the beginning of the test year when the actual increases did not occur until May 2007.

only disputed non-labor Customer Accounts expense item is a minor difference regarding uncollectible expense associated with the proposed rate increase.

Q. WHAT AMOUNT OF UNCOLLECTIBLE EXPENSE IS BEING PROPOSED BY MECO?

A. For the test year, MECO has calculated uncollectibles at present rate levels for the consolidated business (all islands) of $214,000, as shown at MECO-711, page 1, line 1. This proposed amount is based upon application of an "Uncollectible Factor" of 0.06% to test year revenues at present rate levels. The Consumer Advocate is accepting this $214,000 expense amount as reasonable, as it is consistent with recently incurred amounts of uncollectibles actually written off by MECO.[18] However, MECO has also projected a somewhat higher uncollectible amount under "Proposed Rates" based upon the unproven assumption that the rate increase will directly increase future uncollectibles. The incremental uncollectibles amount being proposed by MECO due to the rate increase total only $11,000, as shown on MECO-711 when Line 5 is compared to Line 1.

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[18] MECO response to CA-IR-352, Attachment A shows 12 months ended net write-offs of uncollectibles staying within a range from a low of $187,197 to a high of $220,820 over the last six months.

1 Q. IS ANY ADJUSTMENT NEEDED IN THE CONSUMER ADVOCATE'S
2 REVENUE REQUIREMENT CALCULATION TO ELIMINATE THIS EXTRA
3 $11,000 OF UNCOLLECTIBLES THAT IS PRESUMED TO OCCUR
4 BECAUSE OF THE RATE INCREASE?
5 A. No adjustment is required. The Consumer Advocate's revenue requirement
6 calculations are prepared starting from MECO's exhibits prepared on a
7 "Present Rates" basis. The incremental rate-increase uncollectibles in
8 MECO's filing arise from application of a "Revenue Conversion Factor" that
9 calculates incremental taxes and other expenses that are directly impacted by
10 any rate increase. Schedule A-1 within Exhibits CA-101 through CA-104
11 contains this Revenue Conversion Factor and the only substantive difference
12 between the Company and Consumer can be observed at line 7, where the
13 Company has included a 0.06% factor for uncollectibles that has been reset to
14 zero in the Consumer Advocate's calculated conversion factor.
15
16 Q. WHY SHOULD UNCOLLECTIBLES NOT BE INCLUDED WITHIN THE
17 REVENUE CONVERSION FACTOR AT LINE 7 OF SCHEDULE A-1.
18 A. MECO has assumed that every dollar of rate change in this Docket will result
19 in ratable increases in uncollectible expense, by applying its 0.06 percent
20 uncollectible factor to the rate increase being proposed. This is demonstrated
21 at line 7 in the "Company Proposed" column of the Revenue Conversion
22 Factor and can also be observed at MECO-2001 page 1 where the middle

1 column showing proposed rate changes has an entry at the line captioned
2 "Allowance for Uncoll. Accounts" increasing expense associated with the rate
3 change being proposed. The Consumer Advocate does not believe that
4 MECO can demonstrate that its uncollectibles do, in fact, vary directly with the
5 level of rates or revenues. In fact, the calculations performed by MECO at
6 MECO-WP-711 in column G show a continuously variable relationship
7 between uncollectible write-off levels and sales revenues. This variability is
8 the reason why the Consumer Advocate opposes any inclusion of assumed
9 uncollectibles arising from the rate increase. Because of the absence of a
10 linear relationship between revenues and uncollectibles, the Consumer
11 Advocate recommends that the rate increase granted in this proceeding not be
12 factored up for presumed increases in uncollectibles and has included a zero
13 value at line 7 of Schedule A-1 to this end.
14
15 **VII. <u>CUSTOMER SERVICE EXPENSES</u>.**
16 Q. WHAT ACTIVITIES ARE UNDERTAKEN BY MECO FOR WHICH COSTS
17 ARE CHARGED TO CUSTOMER SERVICE EXPENSES?
18 A. Customer Service includes virtually all customer contact activities that do not
19 relate to service order processing or account billing issues. Thus, Customer
20 Service expenses include labor and non-labor costs incurred in connection
21 with consultation with individual customers or meetings with community groups
22 regarding rate matters, load management efforts, energy conservation and

efficiency measures, integrated resource planning ("IRP") and demand side management ("DSM") as well as the events and advertising supportive of such efforts.

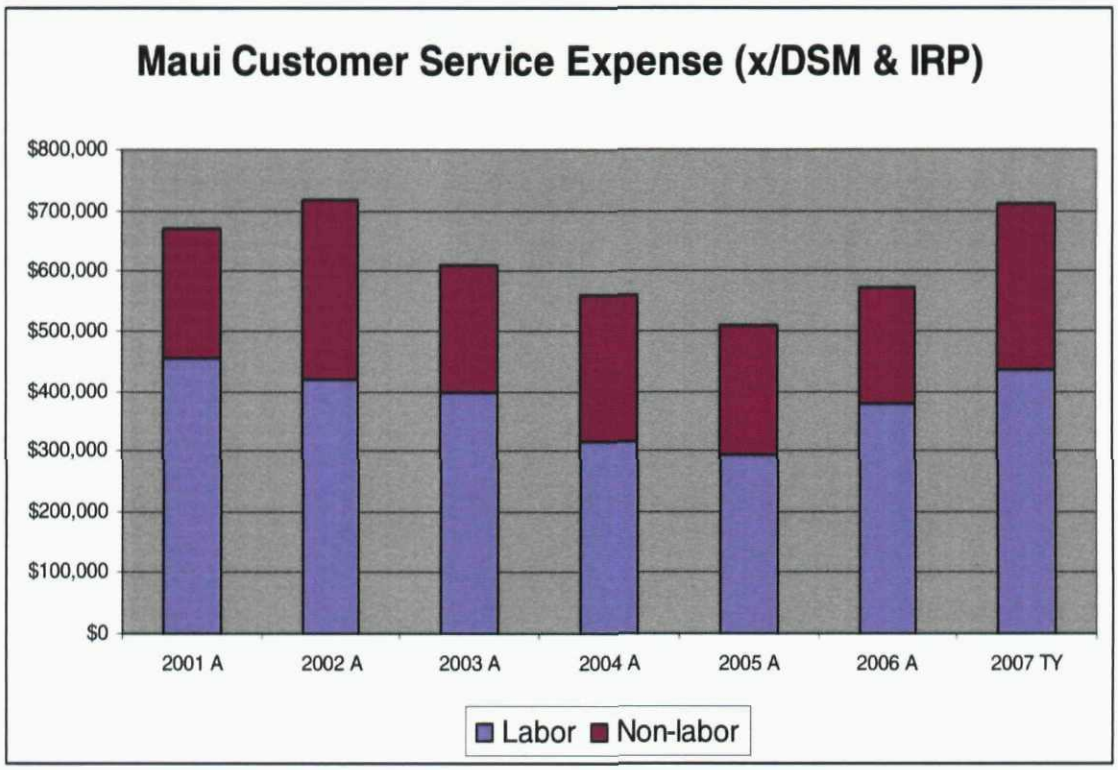
Q. HOW DID MECO DETERMINE ITS PROPOSED TEST PERIOD CUSTOMER SERVICES EXPENSE?

A. MECO-803 summarizes the Company's test year proposed Customer Service O&M expenses of $ 1.5 million, after adjustments are made by MECO to remove projected incremental DSM expenses for separate recovery through the IRP surcharge mechanism (in column B) and to include a normalized level of incremental costs associated with Integrated Resource Planning (in column C) for base rate recovery. Column D then shows this amount to be comprised of about 1/3 labor expenses and 2/3 non-labor expense elements.

Q. HOW DOES THE MECO-PROPOSED TEST YEAR LEVEL OF ADJUSTED CUSTOMER SERVICE EXPENSE COMPARE TO PRIOR YEAR EXPENDITURE LEVELS?

A. The estimated test year expenses proposed by MECO should be viewed on a basis that excludes the DSM and IRP amounts that are subject to ratemaking adjustment in the Company's filing. Using MECO-804, page 2 information, as updated in MECO's response to CA-IR-155, Attachment A, the following graph

compares the test year Customer Service Expenses proposed by MECO for the Maui Division, exclusive of DSM and IRP expenses, to prior periods:[19]



Test year Customer Service expenses, as proposed by MECO excluding DSM and IRP costs, are higher than all prior years shown except 2002. Notably the amounts shown in the "2007 TY" column do not include an additional $796,000 of expenses that are separately added by MECO in MECO-812 (and column H of MECO-804) to include a normalized level of "Incremental

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19 Lanai and Molokai amounts are excluded as insignificant, since they are only $1,000 and $2,000, respectively for the test year, as shown in MECO-807 and MECO-808.

Integrated Resource Planning Costs" in base rate expenses. This normalization is separately discussed in testimony that follows.

Q. HAS THE COMPANY FURTHER REVISED ITS PROPOSED TEST YEAR CUSTOMER SERVICE EXPENSE LEVEL FOR THE TEST YEAR WITHIN UPDATED FILING INFORMATION?

A. Yes. In its June 2007 update, MECO T-8 (Ms. Suzuki) proposes to increase Customer Service O&M expenses by $202,000 to a total of $1.743 million to increase labor costs for three regular MECO employees whose compensation was previously classified in Direct Testimony as incremental labor costs to be recovered through the IRP surcharge (outside of base rates). Labor overheads (corporate overheads, benefits and payroll taxes) add another $117,000 to the direct labor costs associated with this reclassification, making the total value of this Company update an expense increase of $319,000.[20]

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[20] See MECO June 2007 Update, MECO T-8, Attachment A.

1 Q DOES THE CONSUMER ADVOCATE AGREE WITH MECO'S PROPOSED
2 TEST YEAR LEVEL OF CUSTOMER SERVICES EXPENSES, AFTER
3 REFLECTION OF THE JUNE UPDATE INCREASE FOR DSM COST
4 RECOVERY RECLASSIFICATION?
5 A. Not entirely. The Consumer Advocate has reviewed MECO's test year
6 proposed Customer Service expenses, and agrees with most of the
7 Company's proposed expense amounts. However, four adjustments to the
8 Company's expense proposals are needed:
9 1. A labor expense adjustment is included in Mr. Carver's Schedule C-13
10 calculations to account for certain vacant positions in the Company's
11 Customer Service Department that charges expenses to Customer
12 Service accounts,
13 2. MECO's proposed update filing reclassification of DSM program
14 expenses to be treated as "base rate" costs is <u>not</u> accepted by the
15 Consumer Advocate. Instead these costs were properly treated as
16 "incremental" in the Company's initial filing and should continue to be
17 excluded from base rates, for recovery through the DSM surcharge, in
18 order to prepare for the Commission-ordered third party administration
19 of DSM activities,
20 3. MECO's proposed normalization of incremental IRP general planning
21 expenses results in an overstatement of such costs and an adjustment

is needed to better quantify a normal ongoing level of IRP general planning expenses, and

4. MECO has overstated the estimated test year costs for support needed from HECO for Customer Service expenses that are provided by the HECO Marketing Support Organization.

These four adjustments are described in the testimony sections that follow.

A. CUSTOMER SERVICE LABOR EXPENSES.

Q. DID MS. SUZUKI ASSUME THAT ALL OF THE EMPLOYEE POSITIONS INCLUDED IN THE TEST YEAR O&M FORECAST WERE FILLED THROUGHOUT THE YEAR (NO VACANCIES)?

A Yes. MECO-WP-702 shows the full available labor hours were input for each Customer Service Department employee position throughout all months of the test year. Ms. Suzuki references the "additions of the Supervisor of Commercial Services and the IRP Specialist positions, and the full staffing of the Commercial Account Manager positions" at page 16 of MECO T-8 to explain the significantly higher labor expenses projected for Customer Service expenses in Account 910.

1 Q. IS THE ASSUMPTION OF FULL STAFFING AT PROPOSED LEVELS WITH
2 NO VACANCIES FACTUALLY ACCURATE?
3 A. No. Two of the employee positions that charge labor costs to Customer
4 Service and that were included in MECO's test year projections were vacant at
5 the beginning of the test year.[21] Moreover, it is unreasonable to assume that a
6 threshold level of employee vacancies will not occur as a result of normal
7 employee turnover due to resignations, retirements, disability and other
8 causes.
9
10 Q. HAS THE CONSUMER ADVOCATE PREPARED AN ADJUSTMENT TO
11 ACCOUNT FOR VACANCIES AND TO BETTER CONFORM THE
12 CUSTOMER SERVICE LABOR EXPENSES TO THE AVERAGE TEST YEAR
13 CONCEPT USED IN THIS DOCKET?
14 A Yes. Mr. Carver has included the Customer Service expenses within the
15 scope of his adjustment to restate the MECO-proposed test year labor
16 expenses to reflect an average staffing level at Schedule C-13. This
17 adjustment assumes that MECO will fully achieve its desired staffing by
18 year-end 2007 and uses that staff count for employee statistics at the end of
19 the 2007 test year, combining actual employee counts as of December 31,
20 2006, so as to calculate a two-point average staffing for the test year.

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21 See CA-WP-101-C13, page 4 for detailed calculations of Mr. Carver's average staffing adjustment for this expense block.

Q. WHAT IS THE PURPOSE OF SCHEDULE C-9?

A. Consumer Advocate Adjustment Schedule C-9 reclassifies the test year proposed levels of DSM Program Costs, to reverse the Company's proposed June 2007 Update adjustment that was discussed previously. By reversing the Company's proposed change in position reflected in its proposed June update, the Consumer Advocate removes the costs of DSM Program labor from base rates so such costs can continue to be recovered through the IRP surcharge.

Q. WHY SHOULD THESE DSM PROGRAM LABOR COSTS CONTINUE TO BE RECOVERED THROUGH THE SURCHARGE MECHANISM AT THIS TIME?

A. In Decision and Order No. 23258, issued in Docket No. 05-0069, the Commission Ordered that "[a]ll of the HECO Companies' Energy Efficiency DSM programs shall transition from the HECO Companies to the Non-Utility Market Structure, by January 2009, unless otherwise ordered by the Commission."[22] That Order also provides that, "[u]nder the Utility Market Structure, the Existing Cost Recovery Mechanism shall continue to apply, such that labor costs shall be recovered through base rates and all other DSM-related utility-incurred costs shall be recovered through a surcharge."[23]

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22 See Decision and Order No. 23258, Ordering Paragraph No. 4 at 144.

23 Id. Ordering Paragraph No. 6.

Q. WOULD THE COMPANY'S PROPOSED DSM LABOR COST RECOVERY THROUGH BASE RATES, UNTIL THE TRANSITION TO A NON-UTILITY MARKET STRUCTURE IS COMPLETED, CREATE ANY PROBLEMS WITH REGARD TO UTILITY RATEMAKING?

A. Yes. When responsibility for DSM program administration is transferred from the utility to a third party administrator, there is no ability to remove the utility DSM program costs that are embedded in the base rates established in this docket, but will no longer be incurred by the utilities in the absence of a utility rate case that occurs coincident with such transfer. Absent the filing of a rate application to remove the costs that will no longer be incurred by MECO, the utility will continue to collect DSM program costs in its rates at the same time newly incurred labor costs of the third party provider will become chargeable to ratepayers through the public benefits charge that will be established to fund the operations of the third party administrator.

Q. HOW SHOULD THIS PROBLEM BE ADDRESSED?

A. I recommend that test year estimated labor and labor overhead costs for DSM programs be included within the surcharge recovery mechanism rather than within new base rates. Then, when the transition to the Non-utility market structure is completed, it will be possible to discontinue ratepayer funding of utility labor costs to administer DSM programs. While this approach is not entirely consistent with the Commission's findings in D&O 23258 regarding the

1 intended continuation of base rate recovery of DSM labor, it is the only way
2 that double recovery of future labor costs can be avoided.
3
4 Q. BY CLASSIFYING THESE DSM COSTS AS SURCHARGE RECOVERABLE
5 AND REMOVING THEM FROM THE BASE RATE REVENUE
6 REQUIREMENT, WILL MECO BE DENIED AN ABILITY TO RECOVER
7 SUCH COSTS?
8 A. No. After reclassification, MECO can continue to incur and collect the
9 reclassified categories of cost through the IRP surcharge tariff until actual cost
10 reductions are possible to implement.
11
12 **B. CUSTOMER SERVICE NON-LABOR EXPENSES.**
13 Q. WHAT IS THE PURPOSE OF YOUR NEXT CUSTOMER SERVICE
14 EXPENSE ADJUSTMENT, APPEARING AT SCHEDULE C-10?
15 A. Schedule C-10 reflects the Consumer Advocate's proposed reduction in the
16 Company's proposed test year IRP expenses. MECO has proposed a
17 normalized $889,000 amount of base rate expenses for IRP expenses in the
18 test year, as shown in MECO-811, with supporting details in MECO-812 and
19 the related MECO-WP-811 and 812. Ms. Suzuki's testimony (MECO T-8)
20 explains, at pages 23-29, how she calculated a ratemaking adjustment to
21 reflect changed accounting to recover incremental IRP expenses, including
22 consultant and legal services, information services, labor and on-costs and

other miscellaneous costs through base rates rather than through the IRP clause. MECO-812 and MECO-WP-812 reflect the calculation of a three year average of actual 2005 amounts, with budgeted 2006 amounts and budgeted 2007 amounts of incremental IRP expenses, as explained at MECO T-8, pages 27-28 under the "Normalization Methodology" heading in Ms. Suzuki's testimony.

Q. ARE YOU DISPUTING THE LABOR PORTION OF THE NORMALIZATION ADJUSTMENT TO TRANSFER INCREMENTAL IRP EXPENSES INTO BASE RATES?

A. No. The $100,000 adjustment for labor proposed by MECO is to reclassify the Company's full time IRP Specialist employee from historical IRP clause recovery into base rate recovery, including salary and related on-cost expenses. The Consumer Advocate has accepted the Company's assertion in its response to CA-IR-248, part c, that, "A full-time IRP Specialist should be included each year to perform the work" that is required because of the ongoing nature of the IRP process. However, the Company's non-labor expense calculations produce an overstated estimate of required HECO support services, outside consulting and legal support for ongoing IRP activities.

Q. HOW DID THE COMPANY CALCULATE THE NORMALIZED AMOUNT OF NON-LABOR INCREMENTAL IRP EXPENSES THAT ARE PROPOSED TO BE INCLUDED WITHIN BASE RATES?

A. MECO-WP-812 indicates, at page 2, that a three-year average of actual and estimated costs was used, but only in 2005 and part of 2006 were actual expenditure levels used in this average calculation. When budgeted spending in 2006 and the first part of 2007 is replaced with actual expenditure levels that are now available, a much lower average of non-labor expenses is shown to be required by MECO. According to the Company's response to CA-IR-411, at Attachment C, non-labor actual IRP expenses incurred by MECO in 2006 were only $604,191,[24] which is significantly lower than the $767,839 "2006 July YTD + Fcst" value assumed by MECO at line 32, column J of MECO WP-812, page 1. That same Attachment shows actual spending through August of 2007 to be running well below the "Budget 2007" value of $728,881 used by MECO, as shown in MECO-WP-812 at column K.[25]

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24 CA-IR-411, Attachment C shows total 2006 IRP expenses of $664,188 including "Labor" of $33,374 and "Overhead of $26,623. When Labor and Overhead is removed, the remaining non-labor expenses total $604,191. In Docket No. 05-0273, the Consumer Advocate recommended that, based upon the above, MECO's request to recover $664,188 in general IRP costs [should] be reduced by $12,700 to remove the allocated legal costs associated with the processing of HECO's request to implement DSM programs that was the subject of Docket No. 05-0069.

25 Actual non-labor spending through August 2007 was designated as confidential by MECO in its response to CA-IR-411, Attachment C and was only $249,602 and after reduction for labor and overheads of $28,371 and $22,646, respectively, indicates non-labor spending of only $198,585.

1 Q. HOW DID THE CONSUMER ADVOCATE DEVELOP THE ALTERNATIVE
2 AMOUNT OF NON-LABOR IRP EXPENSE FOR MECO, AS REFLECTED IN
3 CONSUMER ADVOCATE ADJUSTMENT SCHEDULE C-10?
4 A. The Consumer Advocate has accepted the three-year averaging approach
5 that has been employed in past rate cases and is advocated for use by MECO
6 in this case, but proposes the substitution of known actual spending levels in
7 place of the overstated budgeted amounts used by MECO for the 2006 and
8 2007 years included in the Company's calculated three year average.
9 Schedule C-10 sets forth a revised three-year average of non-labor IRP
10 expenses based upon actual 2005 and actual 2006 spending levels, plus
11 assumed ratable continued spending in 2007, based upon actual year-to-date
12 August 2007 spending by MECO so far this year. This revised calculation is
13 then compared to the non-labor IRP expenses calculated in MECO's three
14 year average that depended completely upon budgeted higher spending after
15 2005, to derive the difference that is proposed as the Consumer Advocate's
16 adjustment.
17
18 Q. PLEASE DESCRIBE YOUR FINAL ADJUSTMENT TO CUSTOMER
19 SERVICE NON-LABOR EXPENSES AT SCHEDULE C-11.
20 A. MECO included within its Customer Service test year expense budget
21 estimated expenses for intercompany charges from HECO's Marketing
22 Support organization in the estimated amount of $47,531 in Maui Division

Account 910. This amount is significantly higher than actual HECO Marketing Support charges in any of the past three years. These comparable prior period actual expense amounts are shown at lines 2 through 4 of Schedule C-11. The Consumer Advocate proposed amount of allocated HECO expense for these activities is calculated as a three year average of actual annual spending in the years 2004, 2005 and 2006.

Q. WHAT CAUSES THE FLUCTUATION IN ANNUAL SPENDING FOR HECO MARKETING SUPPORT TO MECO?

A. The work being performed is technical support and is project oriented, such that spending fluctuates as project needs vary from year to year. According to the Company's response to CA-IR-415, part a, the expense for PNG Marketing Support is to "assist with providing information concerning various types of potential electrotechnology projects and programs. More specifically, the Energy Projects Department is expected to further explore the potential of dispatchable standby generation ("DSG") at major commercial customer facilities, and to work with MECO to develop a green pricing tariff." Attachment A to the same IR response shows that actual spending through June of 2007 totals only $417, which is less than one percent of the test year proposed expense level.

1 Q. HAS MECO PROVIDED ANY SUPPORTING INFORMATION TO INDICATE
2 SPECIFIC PLANS FOR ACTIVITIES THAT WOULD CAUSE THE COMPANY
3 TO INCUR HECO INTERCOMPANY CHARGES FOR THE OTHER
4 99 PERCENT OF PROJECTED TEST YEAR EXPENSES IN WHAT
5 REMAINS OF TEST YEAR 2007?
6 A. No. In fact, in response to CA-IR-415, part c, MECO stated, "Costs related to
7 the DSG and green pricing projects mentioned in part a. above are expected
8 to be charged to the Company later this year. However, the updated estimate
9 for these projects is expected to be approximately $20,000 - $25,000 at
10 year-end." This statement implies that the adjustment proposed by the
11 Consumer Advocate reducing such estimated charges from HECO to about
12 $19,000 is consistent with the Company's revised marketing project activity
13 and spending plans.
14
15 **VIII. <u>INCOME AND OTHER TAX EXPENSE</u>.**
16 Q. HAVE YOU REVIEWED THE UPDATED CALCULATIONS OF INCOME AND
17 OTHER TAXES INCLUDED IN THE COMPANY'S UPDATE FILINGS?
18 A. Yes. Updates were submitted on August 24, 2007 by Mr. Okada (MECO
19 T-13) containing a comprehensive update of payroll, revenue and income tax
20 calculations. Upon review of these calculations, I was able to confirm that the
21 Company has properly reflected several needed changes that were identified
22 through the submission and analysis of Consumer Advocate information

1 requests. These changes include revision of State Unemployment expenses
2 to current tax base and rate inputs and the inclusion of an estimated Section
3 199 Federal Income Tax deduction for Qualified Production Activity Income.[26]
4
5 Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO INCOME OR OTHER
6 TAXES, AS CALCULATED BY MECO IN ITS UPDATE?
7 A. No. There are small remaining differences arising from the overly
8 conservative Section 199 deduction calculation assumptions performed by
9 MECO in its Update filing, particularly with regard to allocations of Interest
10 Expense, Customer Accounts and Customer Service expenses in the
11 estimation of income arising from generation activity, but to simplify the issues
12 in this proceeding I have proposed no further adjustment in this area. In its
13 response to CA-IR-260 in August of 2007, MECO stated, "The Company has
14 not yet filed its 2006 federal and state income tax returns and the Company is
15 awaiting further guidance with regard to the allocation of deductions.
16 However, pursuant to Proposed Treas. Reg §1.861-8T(b)(3), it is expected
17 that the Company will be required to allocate expenses that are supportive in
18 function to production activity in its determination of QPAI." Then, in response
19 to a later data request, CA-IR-376 part b, the Company provided a copy of the
20 Section 199 deduction that was actually used in the HEI 2006 filed tax return.

---

26 These needed changes were identified and quantified in responses to CA-IR-177 (SUTA tax rate and base), and CA-IR-260 and 376 for the Section 199 Qualified Production Activity Income deduction.

1 Several methodology differences were identified in that tax-basis calculation,
2 relative to calculations used for ratemaking purposes, including inclusion of
3 additional HEI parent interest expense and a different method for interest
4 allocations to production activity (using tax basis values rather than rate base
5 values).

6 The potential overstatement of income tax expense associated with the
7 aforementioned Section 199 allocation issues would likely be offset by any
8 Commission-ordered reduction in MECO's proposed rate of return that would
9 negatively impact qualified production activities income used to calculate the
10 Section 199 deduction. For this reason I have accepted MECO's estimated
11 $394,000 reduction to consolidated MECO income tax expenses in its June
12 Update filing and recommend that this value be fixed and not be revised for
13 later changes in input values or the rate of return awarded by the Commission,
14 because multiple complex and potentially offsetting adjustments are actually
15 required to fully update the Section 199 deduction to mirror the methods used
16 to actually calculate the deduction taken by the Company on its tax return.
17
18 Q. HOW ARE THE TAX IMPACTS OF THE VARIOUS CONSUMER ADVOCATE
19 PROPOSED RATEMAKING ADJUSTMENTS REFLECTED IN EXHIBIT
20 CA-101?
21 A. Each adjustment is posted to a summary Schedule C, where income and other
22 tax effects are added, so as to reflect each ratemaking adjustment, as well as

1 its impact on utility Operating Income. This approach facilitates a
2 reconciliation of issue values, as shown in Schedule E of Exhibit CA-101,
3 because the entire income and revenue requirement impact of the issue can
4 be seen in Schedule C and Schedule E, respectively.
5
6 **IX. <u>ACCUMULATED DEFERRED INCOME TAXES</u>.**
7 Q. PLEASE EXPLAIN THE ADJUSTMENT TO MECO'S ACCUMULATED
8 DEFERRED INCOME TAXES, AS SET FORTH IN CA ADJUSTMENT
9 SCHEDULE B-4.
10 A. This adjustment is required to correct three separate problems that exist within
11 the MECO June 2007 updated level of Accumulated Deferred Income Taxes
12 that are included in rate base by the Company. Each of these three problems
13 has the effect of overstating rate base, by understating deferred tax balances
14 that are subtracted in calculating rate base.
15
16 Q. WHAT IS THE BASIS FOR THE FIRST OF THE THREE ADJUSTMENTS
17 APPEARING ON SCHEDULE B-4?
18 A. In its response to CA-IR-377, the Company stated, "MECO has changed its
19 position with respect to the deferred taxes related to AFUDC in CWIP and TCI
20 in light of the settlement position in HECO Docket No. 2006-0386. In that
21 case, HECO agreed to include in rate base all the deferred taxes associated
22 with AFUDC and to similarly include all the deferred taxes associated with

TCI." This was a matter of dispute between the Consumer Advocate, the Department of Defense and HECO in the 2007 test year HECO rate case that was resolved in the manner described. The adjustment now being proposed by the Consumer Advocate accepts the MECO revisions needed to restore the AFUDC and tax capitalized interest ("TCI") deferred tax balances that were still being eliminated in the MECO June 2007 update filing. This adjustment is understood to be acceptable to MECO, as necessary to consistently resolve this issue for MECO using the principles established for HECO, as more fully explained in the Company's response to CA-IR-377.

Q. IS THE SECOND ADJUSTMENT ON SCHEDULE B-4 THAT CORRECTS DEFERRED TAXES FOR EMISSION FEES ALSO A CHANGE THAT MECO HAS AGREED WITH IN RESPONDING TO INFORMATION REQUESTS?

A. Yes. In its response to CA-IR-379, the Company stated, "In the process of updating MECO's deferred tax balances, the estimated amount of deferred taxes accrued for the 2007 test year emission fees was incorrectly calculated. The correct test year calculation for the change in deferred taxes should have been the tax effect of the difference between the test year estimated emission fees of $404,998 and the amount actually paid of $518,430. Based on these numbers...the estimated federal and state deferred income tax balances associated with emission fees at December 3, 2007 should have been debit balances of $127,351 and $23,286, respectively. A correction to the test year

1 estimates for this error will be included when deferred income taxes are
2 updated at the next opportunity." The Consumer Advocate is recognizing this
3 needed update in its filing to correct these deferred tax balances.
4
5 Q. DOES THE CONSUMER ADVOCATE'S ADJUSTMENT TO MECO'S
6 PROPOSED TEST YEAR EMISSION FEES IMPACT THE CORRECTION
7 NEEDED FOR THIS ITEM?
8 A. No. The normalized ratemaking level of emission fees is actually comparable
9 to amounts payable after the test year and will ultimately be paid in a different
10 amount than was allowed, because of changes in simulated versus actual
11 generation dispatch. In contrast, the book/tax timing difference associated
12 with emission fees that existed during the test year is a function of amounts
13 actually expected to be recorded in 2007 for book purposes, compared with
14 actual amounts paid in 2007 associated with accrued book expenses in 2006.
15 Thus, there is no need to attempt to synchronize the timing difference amounts
16 with the ongoing differences associated with ratemaking normalization
17 calculations that impact only booked expense amounts.
18
19 Q. WHAT IS THE FINAL ADJUSTMENT TO ACCUMULATED DEFERRED
20 TAXES THAT IS CONTAINED IN SCHEDULE B-4?
21 A. MECO has proposed a change to its rate case treatment of deferred tax
22 balances arising from differences between book and tax recognition of IRP

and DSM program costs. According to the Company's response to CA-IR-378, part c, "MECO included deferred taxes related to IRP/DSM program costs in its last (test year 1999) rate case, Docket No. 97-0346. However, MECO is proposing to exclude deferred taxes related to IRP/DSM program costs in the current case. As over- and under-recovered balances of deferred IRP/DSM costs are not included in rate base, consistency dictates that any related deferred taxes should also be excluded from rate base. This is consistent with HELCO's treatment of its DSM and IRP deferred taxes in Docket No. 05-0315, HELCO's test year 2006 rate case."

Q. WHY DOES THE CONSUMER ADVOCATE DISAGREE WITH THIS PROPOSED CHANGE IN TREATMENT FOR IRP/DSM DEFERRED TAXES?

A. Deferred taxes arising from IRP/DSM program costs recovery timing differences should be fully included in rate base because, even though the deferred expense balances associated with over and under-recoveries of program costs are not included in rate base, MECO is allowed to earn a return on investment in the form of interest added to the deferred cost balances. These interest accruals allow MECO to earn a return on the full amount of program costs while awaiting recovery from customers, but the interest calculations do not recognize the income tax deferral benefit arising from IRP/DSM costs that are currently deductible for tax purposes as paid. To fully account for the economic impact of IRP/DSM program spending and cost

recovery, given the allowance of interest on gross pretax deferred costs, the deferred tax impacts must also be treated as jurisdictional and included in rate base (because they are not recognized when interest is accrued).

Q. DID HECO INCLUDE IRP/DSM RELATED DEFERRED TAXES IN ITS CALCULATION OF RATE BASE IN THAT COMPANY'S MOST RECENT RATE CASE, DOCKET NO. 2006-0386?

A. Yes.

X. <u>FUEL INVENTORY</u>.

Q. WHAT IS PROPOSED BY THE COMPANY WITH RESPECT TO FUEL INVENTORIES INCLUDED IN RATE BASE?

A. The Company has included an allowance for fuel oil inventory balances within its asserted rate base, as described by Mr. Sakuda in MECO T-4 at pages 41-49 (Maui), 52-54 (Molokai) and 57-58 (Lanai).

Q. DOES THE CONSUMER ADVOCATE PROPOSE ANY MODIFICATIONS TO THE COMPANY'S PROPOSED FUEL INVENTORY ALLOWANCE?

A. Yes. As more fully described by Mr. Herz (CA-T-2), the Consumer Advocate has calculated an updated fuel inventory balance consistent with its calculations underlying test year fuel expense.

Q. WHAT IS THE PURPOSE OF CA SCHEDULE B-3, THE ADJUSTMENT TO TEST PERIOD FUEL INVENTORY BALANCES?

A. This schedule incorporates the fuel inventory allowance that should be included in MECO's rate base, using the value recommended by Mr. Herz at CA-208. The Consumer Advocate's recommended fuel inventory allowance is compared to the Company's prefiled fuel inventory request to derive the adjustment required to increase fuel inventory to the Consumer Advocate's proposed level.

XI. CONCLUSION.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. It does. My additional Direct Testimony addressing cost of service and rate design issues is designated CA-T-5.

MICHAEL L. BROSCH

Summary of Qualifications

EMPLOYER:	Utilitech, Inc. Regulatory and Management Consultants
POSITION:	President
ADDRESS:	740 NW Blue Parkway, Suite 204 Lee's Summit, Missouri 64086

PRIOR EXPERIENCE:

1978-1982	Missouri Public Service Commission, Senior Accountant
1982-1983	Troupe, Kehoe, Whiteaker & Kent CPA's, Regulatory Consultant
1983-1985	Lubow, McKay, Stevens and Lewis, Project Manager
1985-Present	Utilitech, Principal and President

DEGREES:
University of Missouri – Kansas City
Bachelor – Business Administration (Accounting 1978) "with distinction"

OTHER QUALIFICATIONS:
Certified Public Accountant – Certification in Kansas and Missouri

Member	American Institute of Certified Public Accountants Missouri Society of Certified Public Accountants Kansas Society of Certified Public Accountants Beta Alpha Psi, professional accounting scholastic fraternity
Seminars	Iowa State Regulatory Conference 1981, 1985 Regulated Industries Symposium 1979, 1980 Michigan State Regulatory Conference 1981 United States Telephone Association Round Table 1984 NARUC/NASUCA Annual Meeting 1988, Speaker NARUC/NASUCA Annual Meeting 2000, Speaker NASUCA Mid-Year Consumer Protection Meeting 2007, Speaker
Instructor	INFOCAST Ratemaking Courses Arizona Staff Training Hawaii Staff Training

PRIOR TESTIMONIES: (See listings attached)

Utility	Jurisdiction	Agency	Docket/Case Number	Represented	Year	Addressed
Kansas City Power and Light Co.	Missouri	PSC	ER-81-42	Staff	1981	Rate Base, Operating Income
Southwestern Bell Telephone	Missouri	PSC	TR-81-208	Staff	1981	Rate Base, Operating Income, Affiliated Interest
Northern Indiana Public Service	Indiana	PSC	36689	Consumers Counsel	1982	Rate Base, Operating Income
Northern Indiana Public Service	Indiana	URC	37023	Consumers Counsel	1983	Rate Base, Operating Income, Cost Allocations
Mountain Bell Telephone	Arizona	ACC	9981-E1051-81-406	Staff	1982	Affiliated Interest
Sun City Water	Arizona	ACC	U-1656-81-332	Staff	1982	Rate Base, Operating Income
Sun City Sewer	Arizona	ACC	U-1656-81-331	Staff	1982	Rate Base, Operating Income
El Paso Water	Kansas	City Counsel	Unknown	Company	1982	Rate Base, Operating Income, Rate of Return
Ohio Power Company	Ohio	PUCO	83-98-EL-AIR	Consumer Counsel	1983	Operating Income, Rate Design, Cost Allocations
Dayton Power & Light Company	Ohio	PUCO	83-777-GA-AIR	Consumer Counsel	1983	Rate Base
Walnut Hill Telephone	Arkansas	PSC	83-010-U	Company	1983	Operating Income, Rate Base
Cleveland Electric Illum.	Ohio	PUCO	84-188-EL-AIR	Consumer Counsel	1984	Rate Base, Operating Income, Cost Allocations
Cincinnati Gas & Electric	Ohio	PUCO	84-13-EL-EFC	Consumer Counsel	1984	Fuel Clause
Cincinnati Gas & Electric	Ohio	PUCO	84-13-EL-EFC (Subfile A)	Consumer Counsel	1984	Fuel Clause
General Telephone - Ohio	Ohio	PUCO	84-1026-TP-AIR	Consumer Counsel	1984	Rate Base
Cincinnati Bell Telephone	Ohio	PUCO	84-1272-TP-AIR	Consumer Counsel	1985	Rate Base
Ohio Bell Telephone	Ohio	PUCO	84-1535-TP-AIR	Consumer Counsel	1985	Rate Base
United Telephone - Missouri	Missouri	PSC	TR-85-179	Staff	1985	Rate Base, Operating Income
Wisconsin Gas	Wisconsin	PSC	05-UI-18	Staff	1985	Diversification-Restructuring
United Telephone - Indiana	Indiana	URC	37927	Consumer Counsel	1986	Rate Base, Affiliated Interest
Indianapolis Power & Light	Indiana	URC	37837	Consumer Counsel	1986	Rate Base
Northern Indiana Public Service	Indiana	URC	37972	Consumer Counsel	1986	Plant Cancellation Costs
Northern Indiana Public Service	Indiana	URC	38045	Consumer Counsel	1986	Rate Base, Operating Income, Cost Allocations, Capital Costs
Arizona Public Service	Arizona	ACC	U-1435-85-367	Staff	1987	Rate Base, Operating Income, Cost Allocations
Kansas City, KS Board of Public Utilities	Kansas	BPU	87-1	Municipal Utility	1987	Operating Income, Capital Costs
Detroit Edison	Michigan	PSC	U-8683	Industrial Customers	1987	Income Taxes
Consumers Power	Michigan	PSC	U-8681	Industrial Customers	1987	Income Taxes

Consumers Power	Michigan	PSC	U-8680	Industrial Customers	1987	Income Taxes
Northern Indiana Public Service	Indiana	URC	38365	Consumer Counsel	1987	Rate Design
Indiana Gas	Indiana	URC	38080	Consumer Counsel	1987	Rate Base
Northern Indiana Public Service	Indiana	URC	38380	Consumers Counsel	1988	Rate Base, Operating Income, Rate Design, Capital Costs
Terre Haute Gas	Indiana	URC	38515	Consumers Counsel	1988	Rate Base, Operating Income, Capital Costs
United Telephone -Kansas	Kansas	KCC	162,044-U	Consumers Counsel	1989	Rate Base, Capital Costs, Affiliated Interest
US West Communications	Arizona	ACC	E-1051-88-146	Staff	1989	Rate Base, Operating Income, Affiliate Interest
All Kansas Electrics	Kansas	KCC	140,718-U	Consumers Counsel	1989	Generic Fuel Adjustment Hearing
Southwest Gas	Arizona	ACC	E-1551-89-102 E-1551-89-103	Staff	1989	Rate Base, Operating Income, Affiliated Interest
American Telephone and Telegraph	Kansas	KCC	167,493-U	Consumers Counsel	1990	Price/Flexible Regulation, Competition, Revenue Requirements
Indiana Michigan Power	Indiana	URC	38728	Consumer Counsel	1989	Rate Base, Operating Income, Rate Design
People Gas, Light and Coke Company	Illinois	ICC	90-0007	Public Counsel	1990	Rate Base, Operating Income
United Telephone Company	Florida	PSC	891239-TL	Public Counsel	1990	Affiliated Interest
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1990	Rate Base, Operating Income (Testimony not admitted)
Arizona Public Service Company	Arizona	ACC	U-1345-90-007	Staff	1991	Rate Base, Operating Income
Indiana Bell Telephone Company	Indiana	URC	39017	Consumer Counsel	1991	Test Year, Discovery, Schedule
Southwestern Bell Telephone Company	Oklahoma	OCC	39321	Attorney General	1991	Remand Issues
UtiliCorp United/ Centel	Kansas	KCC	175,476-U	Consumer Counsel	1991	Merger/Acquisition
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1991	Rate Base, Operating Income
United Telephone - Florida	Florida	PSC	910980-TL	Public Counsel	1992	Affiliated Interest
Hawaii Electric Light Company	Hawaii	PUC	6999	Consumer Advocate	1992	Rate Base, Operating Income, Budgets/Forecasts
Maui Electric Company	Hawaii	PUC	7000	Consumer Advocate	1992	Rate Base, Operating Income, Budgets/Forecasts
Southern Bell Telephone Company	Florida	PSC	920260-TL	Public Counsel	1992	Affiliated Interest
US West Communications	Washington	WUTC	U-89-3245-P	Attorney General	1992	Alternative Regulation
UtiliCorp United/ MPS	Missouri	PSC	ER-93-37	Staff	1993	Affiliated Interest
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-1151, 1144, 1190	Attorney General	1993	Rate Base, Operating Income, Take or Pay, Rate Design
Public S2ervice Company of Oklahoma	Oklahoma	OCC	PUD-1342	Staff	1993	Rate Base, Operating Income, Affiliated Interest

Illinois Bell Telephone	Illinois	ICC	92-0448 92-0239	Citizens Board	1993	Rate Base, Operating Income, Alt. Regulation, Forecasts, Affiliated Interest
Hawaiian Electric Company	Hawaii	PUC	7700	Consumer Advocate	1993	Rate Base, Operating Income
US West Communications	Arizona	ACC	E-1051-93-183	Staff	1994	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	URC	39584	Consumer Counselor	1994	Rate Base, Operating Income, Alt. Regulation, Forecasts, Affiliated Interest
Arkla, a Division of NORAM Energy	Oklahoma	OCC	PUD-940000354	Attorney General	1994	Cost Allocations, Rate Design
PSI Energy, Inc.	Indiana	URC	39584-S2	Consumer Counselor	1994	Merger Costs and Cost Savings, Non-Traditional Ratemaking
Transok, Inc.	Oklahoma	OCC	PUD-1342	Staff	1994	Rate Base, Operating Income, Affiliated Interest, Allocations
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-940000477	Attorney General	1995	Rate Base, Operating Income, Cost of Service, Rate Design
US West Communications	Washington	WUTC	UT-950200	Attorney General/ TRACER	1995	Operating Income, Affiliate Interest, Service Quality
PSI Energy, Inc.	Indiana	URC	40003	Consumer Counselor	1995	Rate Base, Operating Income
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-880000598	Attorney General	1995	Stand-by Tariff
GTE Hawaiian Telephone Co., Inc.	Hawaii	PUC	PUC 94-0298	Consumer Advocate	1996	Rate Base, Operating Income, Affiliate Interest, Cost Allocations
Mid-American Energy Company	Iowa	ICC	APP-96-1	Consumer Advocate	1996	Non-Traditional Ratemaking
Oklahoma Gas and Electric Company	Oklahoma	OCC	PUD-960000116	Attorney General	1996	Rate Base, Operating Income, Rate Design, Non-Traditional Ratemaking
Southwest Gas Corporation	Arizona	ACC	U-1551-96-596	Staff	1997	Operating Income, Affiliated Interest, Gas Supply
Utilicorp United - Missouri Public Service Division	Missouri	PSC	EO-97-144	Staff	1997	Operating Income
US West Communications	Utah	PSC	97-049-08	Consumer Advocate	1997	Rate Base, Operating Income, Affiliate Interest, Cost Allocations
US West Communications	Washington	WUTC	UT-970766	Attorney General	1997	Rate Base, Operating Income
Missouri Gas Energy	Missouri	PSC	GR 98-140	Public Counsel	1998	Affiliated Interest
ONEOK	Oklahoma	OCC	PUD980000177	Attorney General	1998	Gas Restructuring, rate Design, Unbundling
Nevada Power/Sierra Pacific Power Merger	Nevada	PSC	98-7023	Consumer Advocate	1998	Merger Savings, Rate Plan and Accounting
PacifiCorp / Utah Power	Utah	PSC	97-035-1	Consumer Advocate	1998	Affiliated Interest
MidAmerican Energy / CalEnergy Merger	Iowa	PUB	SPU-98-8	Consumer Advocate	1998	Merger Savings, Rate Plan and Accounting
American Electric Power / Central and South West Merger	Oklahoma	OCC	980000444	Attorney General	1998	Merger Savings, Rate Plan and Accounting

ONEOK Gas Transportation	Oklahoma	OCC	970000088	Attorney General	1998	Cost of Service, Rate Design, Special Contract
U S West Communications	Washington	WUTC	UT-98048	Attorney General	1999	Directory Imputation and Business Valuation
U S West / Qwest Merger	Iowa	PUB	SPU 99-27	Consumer Advocate	1999	Merger Impacts, Service Quality and Accounting
U S West / Qwest Merger	Washington	WUTC	UT-991358	Attorney General	2000	Merger Impacts, Service Quality and Accounting
U S West / Qwest Merger	Utah	PSC	99-049-41	Consumer Advocate	2000	Merger Impacts, Service Quality and Accounting
PacifiCorp / Utah Power	Utah	PSC	99-035-10	Consumer Advocate	2000	Affiliated Interest
Oklahoma Natural Gas, ONEOK Gas Transportation	Oklahoma	OCC	980000683, 980000570, 990000166	Attorney General	2000	Operating Income, Rate Base, Cost of Service, Rate Design, Special Contract
U S West Communications	New Mexico	PRC	3008	Staff	2000	Operating Income, Directory Imputation
U S West Communications	Arizona	ACC	T-0105B-99-0105	Staff	2000	Operating Income, Rate Base, Directory Imputation
Northern Indiana Public Service Company	Indiana	IURC	41746	Consumer Counsel	2001	Operating Income, Rate Base, Affiliate Transactions
Nevada Power Company	Nevada	PUCN	01-10001	Attorney General-BCP	2001	Operating Income, Rate Base, Merger Costs, Affiliates
Sierra Pacific Power Company	Nevada	PUCN	01-11030	Attorney General-BCP	2002	Operating Income, Rate Base, Merger Costs, Affiliates
The Gas Company, Division of Citizens Communications	Hawaii	PUC	00-0309	Consumer Advocate	2001	Operating Income, Rate Base, Cost of Service, Rate Design
SBC Pacific Bell	California	PUC	I.01-09-002 R.01-09-001	Office of Ratepayer Advocate	2002	Depreciation, Income Taxes and Affiliates
Qwest Communications – Dex Sale	Utah	PSC	02-049-76 02-049-82 01-2383-01	Consumer Advocate	2003	Directory Publishing
Qwest Communications – Dex Sale	Washington	WUTC	UT-021120	Attorney General	2003	Directory Publishing
Qwest Communications – Dex Sale	Arizona	ACC	T-0105B-02-0666	Staff	2003	Directory Publishing
PSI Energy, Inc.	Indiana	IURC	42359	Consumer Counsel	2003	Operating Income, Rate Trackers, Cost of Service, Rate Design
Qwest Communications	Arizona	ACC	T-0105B-03-0454	Staff	2004	Operating Income, Rate Base
Verizon Northwest	Washington	WUTC	UT-040788A	Attorney General	2004	Operating Income, Rate Base, Directory Imputation
Public Service Company of Oklahoma	Oklahoma	OCC	Cause No. 200300076	Attorney General	2005	Operating Income, Rate Base, Cost of Service, Rate Design
Hawaiian Electric Company, Inc.	Hawaii	PUC	04-0113	Consumer Advocate	2005	Operating Income, Rate Base, Cost of Service, Rate Design
Citizens Gas & Coke Utility	Indiana	IURC	42767	Consumer Counsel	2005	Operating Income, Debt Service, Ratemaking Policy, Working Capital
Puget Sound Energy	Washington	WUTC	UE-060266 et al	Attorney General	2006	Ratemaking Policy, Rate Trackers
Cascade Natural Gas	Washington	WUTC	UG-060256	Attorney General	2006	Ratemaking Policy, Rate Trackers

Arizona Public Service	Arizona	ACC	E-01345A-05-0816	Staff	2006	Operating Income, Cost of Service
Hawaiian Electric Company	Hawaii	HPUC	05-0146	Consumer Advocate	2006	Capital Improvements and Discounted Rates
Hawaii Electric Light Company	Hawaii	HPUC	05-0315	Consumer Advocate	2006	Operating Income, Rate Base, Cost of Service, Rate Design
Union Electric Company d/b/a AmerenUE	Missouri	PSC	2007-0002	Attorney General	2007	Operating Income, Rate Base, Fuel Adjustment Clause
Hawaiian Electric Company, Inc.	Hawaii	PUC	2006-0386	Consumer Advocate	2007	Operating Income, Rate Base, Cost of Service, Rate Design
Peoples Gas Light & Coke Company	Illinois	ICC	07-0241	Attorney General, City	2007	Ratemaking Policy, Rate Trackers
North Shore Gas Company	Illinois	ICC	07-0242	Attorney General, City	2007	Ratemaking Policy, Rate Trackers

CA-T-4
DOCKET NO. 2006-0387

DIRECT TESTIMONY AND EXHIBITS

OF

DAVID C. PARCELL

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: RATE OF RETURN

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DIRECT TESTIMONY OF DAVID C. PARCELL

I. INTRODUCTION.

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings dating back to 1972. In connection with this, I have previously filed testimony and/or testified in about 400 utility proceedings before some 40 regulatory agencies in the United States and Canada.

In connection with these proceedings, I filed testimony written direct testimony on behalf of the Division of Consumer Advocacy, Department of Commerce and Consumer Affairs ("Consumer Advocate" or "CA") in:

- Maui Electric Company, Limited's ("MECO") last three rate proceedings (i.e., Docket Nos. 94-0345, 96-0040 and 97-0346) wherein the cost of capital issues in the first two cases were settled prior to the evidentiary hearing and I was required to testify in the third case;

- Hawaii Electric Light Company's ("HELCO") last two litigated rate proceedings (Docket Nos. 94-0140 and 99-0207) and its latest proceeding which was settled prior to hearing (i.e., Docket No. 05-0315);

- Hawaiian Electric Company, Inc.'s ("HECO") last two rate proceedings (i.e., Docket Nos. 04-0113 and 2006-0386 in which the cost of capital issues were settled prior to hearing);

- Young Brothers, Ltd.'s 1997 litigated rate proceeding (i.e., Docket No. 96-0483) and its latest proceeding which was settled prior to the hearing (i.e., Docket No. 2006-0396);

- The Gas Company's 2001 rate proceeding (i.e., Docket No. 00-0309 in which the cost of capital issues were settled prior to hearing); and,

- West Hawaii Utility Company's last rate proceeding (i.e., Docket No. 2006-0409) which is pending before the Commission.

CA-400 provides a more complete description of my background and experience.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been retained by the Consumer Advocate to evaluate the cost of capital aspects of the current filing of Maui Electric Company ("MECO" or "Company"). I have performed independent studies and will provide a recommendation of the current cost of capital for MECO for this proceeding. In addition, since MECO is a subsidiary of Hawaiian Electric Company ("HECO"), which in turn is a subsidiary of Hawaiian Electric Industries, Inc. ("HEI"), I have also evaluated these entities in my analyses.

Q. HAVE YOU PREPARED EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I have prepared 16 exhibits, identified as CA-400 through CA-415. These exhibits were prepared either by me or under my direction. The information contained in these exhibits is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY.

Q. WHAT ARE YOUR RECOMMENDATIONS IN THIS PROCEEDING?

A. My overall cost of capital recommendations for MECO are as follows:

Item	Percent	Cost Rate	Weighted Cost
Short-Term Debt	1.27%	5.00%	0.06%
Long-Term Debt	40.15%	6.11%	2.45%
Hybrid Securities	2.45%	7.47%	0.18%
Preferred Stock	1.25%	8.34%	0.10%
Common Equity	54.89%	9.5%-10.5%	5.21%-5.76%
Total	100.00%		8.02%-8.57%
			8.29% (mid-point)

MECO's application requests a return on common equity of 11.25 percent and overall rate of return of 8.98 percent. The only difference between my recommendation and MECO's application is the cost of common equity. I propose a return on common equity in the range of 9.5 percent to 10.5 percent, resulting in an overall rate of return in the range of 8.02 percent to 8.57 percent.

Q. PLEASE SUMMARIZE YOUR COST ANALYSES AND RELATED CONCLUSIONS FOR MECO.

A. This proceeding is concerned with MECO's regulated electric utility operations in Hawaii, relative to its 2007 test year. My analyses are concerned with the Company's total cost of capital. The first step in performing an analysis of the Company's cost of capital is the development of the appropriate capital structure. MECO's proposed capital structure is its 2006 actual capital structure adjusted for expected changes in 2007. I also use the same capital structure in my cost of capital analyses.

The second step in a cost of capital calculation is a determination of the embedded cost rates of debt and other fixed-cost capital. I have used the cost rates for long-term debt and other fixed-cost capital contained in MECO's application.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for MECO. Each of these methodologies is applied to two groups of proxy electric utilities. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow	9.0-10.75% (9.9% mid-point)
Capital Asset Pricing Model	10.0-11.0% (10.5% mid-point)
Comparable Earnings	9.0-10.0% (9.5% mid-point)

Based upon these findings, I conclude that the cost of common equity for MECO is within a broad range of 9.0 percent to 11 percent (10 percent

mid-point). For the purposes of my recommendation, I propose to use the middle portion of this range, or 9.5 percent to 10.5 percent.

Combining these three steps into a weighted cost of capital results in an overall rate of return range of 8.02 percent to 8.57 percent (8.29 percent mid-point, which incorporates a cost of common equity of 10.0 percent). My specific cost of capital recommendation for MECO is 8.29 percent.

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES.

Q. WHAT ARE THE PRIMARY ECONOMIC AND LEGAL PRINCIPLES THAT ESTABLISH THE STANDARDS FOR DETERMINING A FAIR RATE OF RETURN FOR A REGULATED UTILITY?

A. *Public utility rates are normally established in a manner designed to allow the* recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base - rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (i.e., rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. The

1 revenue impact of the cost of capital is thus derived by multiplying the rate
2 base by the rate of return (including income taxes).

3 The rate of return is developed from the cost of capital, which is
4 estimated by weighting the capital structure components (i.e., debt, preferred
5 stock, and common equity) by their percentages in the capital structure and
6 multiplying these by their cost rates. This is also known as the weighted cost
7 of capital.

8 Technically, "fair rate of return" is a legal and accounting concept that
9 refers to an ex post (after the fact) earned return on an asset base, while the
10 cost of capital is an economic and financial concept which refers to an ex ante
11 (before the fact) expected or required return on a liability base. In regulatory
12 proceedings, however, the two terms are often used interchangeably. I have
13 not distinguished between the two concepts in my testimony.

14 From an economic standpoint, a fair rate of return is normally
15 interpreted to mean that an efficient and economically managed utility will be
16 able to maintain its financial integrity, attract capital, and establish comparable
17 returns for similar risk investments. These concepts are derived from
18 economic and financial theory and are generally implemented using financial
19 models and economic concepts.

20 Although I am not a lawyer and I do not offer a legal opinion, my
21 testimony is based on my understanding that two United States Supreme
22 Court decisions are universally cited as providing the standards for a fair rate

of return. The first is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of fair and enlightened judgment, having regard to all *relevant facts. A public utility is entitled to such rates as will* permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

It is my understanding that the Bluefield decision established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time, as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and consumer interests . . . From the investor or

> company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

The Hope case is also frequently credited with establishing the "end result" doctrine, which maintains that the methods utilized to develop a fair return are not important as long as the end result is reasonable.

The three economic and financial parameters in the Bluefield and Hope decisions - comparable earnings, financial integrity, and capital attraction - reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise on which regulation rests, namely, that regulation is intended to act as a surrogate for competition.

Q. HOW CAN THESE PARAMETERS BE EMPLOYED TO ESTIMATE THE COST OF CAPITAL FOR A UTILITY?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is

1 the case because the cost of capital is an opportunity cost and is
2 prospective-looking, which dictates that it must be estimated.
3 There are several useful models that can be employed to assist in
4 estimating the cost of equity capital, which is the capital structure item that is
5 the most difficult to determine. These include the discounted cash flow
6 ("DCF"), capital asset pricing model ("CAPM"), comparable earnings ("CE")
7 and risk premium ("RP") methods. Each of these methods (or models) differs
8 from the others and each, if properly employed, can be a useful tool in
9 estimating the cost of common equity for a regulated utility.
10
11 Q. WHICH METHODS HAVE YOU EMPLOYED IN YOUR ANALYSES OF THE
12 COST OF COMMON EQUITY IN THIS PROCEEDING?
13 A. I have utilized three methodologies to determine MECO's cost of common
14 equity: the DCF, CAPM, and CE methods. Each of these methodologies will
15 be described in more detail in my testimony that follows.
16
17 **IV. <u>GENERAL ECONOMIC CONDITIONS</u>.**
18 Q. WHY ARE ECONOMIC AND FINANCIAL CONDITIONS IMPORTANT IN
19 DETERMINING THE COSTS OF CAPITAL?
20 A. The costs of capital, for both fixed-cost (debt and preferred stock) components
21 and common equity, are determined in part by current and prospective
22 economic and financial conditions. At any given time, each of the following

factors has an influence on the costs of capital: the level of economic activity (i.e., growth rate of the economy), the stage of the business cycle (i.e., recession, expansion, or transition), and the level of inflation. My understanding is that use of these factors is consistent with the Supreme Court's Bluefield decision, which noted that "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally."

Q. WHAT INDICATORS OF ECONOMIC AND FINANCIAL ACTIVITY HAVE YOU EVALUATED IN YOUR ANALYSES?

A. I have examined several sets of economic statistics for the period 1975 to present. I chose this period because it permits the evaluation of economic conditions over three full business cycles plus the current cycle to-date, and thus makes it possible to assess changes in long-term trends. This period also approximates the beginning and continuation of active rate case activities by public utilities.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical

(i.e., stage of business cycle) influences and thus permits a comparison of structural (or long-term) trends.

Q. PLEASE DESCRIBE THE TIMEFRAME OF THE THREE PRIOR BUSINESS CYCLES AND THE MOST CURRENT CYCLE.

A. The three prior complete cycles and current cycle cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
Current	Dec. 2001-Present	

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS CONCERNING THE CHANGING TRENDS IN ECONOMIC CONDITIONS AND THEIR IMPACT ON COSTS OVER THIS BROAD PERIOD?

A. Yes, I do. As I will describe below, the U.S. economy has enjoyed general prosperity and stability over the period since the early 1980s. This period has been characterized by longer economic expansions, relatively tame contractions, relatively low and declining inflation, and declining interest rates and other capital costs. The current business cycle began in late 2001, following a somewhat modest recession in 2001. During the recession and early in the succeeding expansion, the Federal Reserve lowered interest rates (i.e., Federal Funds rate) eleven times in 2001 and twice in 2003 in an effort to stimulate the economy.

Q. PLEASE DESCRIBE RECENT AND CURRENT ECONOMIC AND FINANCIAL CONDITIONS AND THEIR IMPACT ON THE COSTS OF CAPITAL.

A. CA-401 shows several sets of economic data. Pages 1 and 2 contain general macroeconomic statistics, while pages 3 through 6 contain financial market statistics. Pages 1 and 2 of CA-401 show that the U.S. economy is currently in the sixth year of an economic expansion. This is indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product, industrial production, and the reduction in the unemployment rate. This current expansion has generally been characterized as slower growth, in comparison to prior expansions. This has resulted in lower inflationary pressures and interest rates, as well as slower growth in corporate profits.

The rate of inflation is also shown on pages 1 and 2 of CA-401. As is reflected in the Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially in 1981 and remained at or below 6.1 percent during the 1983-1991 business cycle. Since 1991, the CPI has been 3.4 percent or lower. The 2.5 percent rate of inflation in 2006 was similar to the levels since 2000, but was well below the levels of the past thirty years.

Q. WHAT HAVE BEEN THE TRENDS IN INTEREST RATES?

A. Pages 3 and 4 of CA-401 show several series of interest rates. Rates rose sharply to record levels in 1975-1981 when the inflation rate was high and generally rising. Interest rates then fell substantially in conjunction with inflation rates throughout the remainder of the 1980s throughout the 1990s. Interest rates declined even further from 2000-2005 and generally recorded their lowest levels since the 1960s.

This low level of interest rates, in conjunction with the recent strength of the U.S. economy, may have created an expectation over the past few years that any near-term movement of interest rates will be upward. In fact, the Federal Reserve has, since the middle of 2004, increased short-term interest rates on 17 occasions, although each time by only 0.25 percent, in an attempt to insure that any perceived inflationary expectations will not stifle continued economic growth. Nevertheless, the economic recovery and Federal Reserve actions to date have not resulted in a pronounced increase in long-term rates. Most recently, however, the Federal Reserve has lowered the Federal Funds rate (i.e., short-term rate) by 50 basis points.

Q. WHAT HAVE BEEN THE TRENDS IN COMMON SHARE PRICES?

A. Pages 5 and 6 of CA-401 show several series of common stock prices and ratios. These rates indicate that share prices were basically stagnant during the high inflation/high interest rate environment of the late 1970s and early

1980s. On the other hand, the 1983-1991 business cycle and the most recent cycle have witnessed a significant upward trend in stock prices. During the initial years of the current expansion, however, stock prices were volatile and declined substantially from the highs reached in 1999 and early 2000. Share prices have increased somewhat since 2003 and currently stand at near record high levels.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS DISCUSSION OF ECONOMIC AND FINANCIAL CONDITIONS?

A. It is apparent that capital costs are currently low in comparison to the levels that have prevailed over the past three decades. In addition, even a moderate increase in interest rates, as well as other capital costs, would still result in capital costs that are low by historic standards. Therefore, it can reasonably be expected that cost of equity models currently will produce returns that are lower than was the case in prior years.

V. MECO'S OPERATIONS AND RISKS.

Q. PLEASE SUMMARIZE MECO AND ITS OPERATIONS.

A. MECO is an operating electric utility which is in the business of generating, purchasing, transmitting, distributing, and selling electric energy. Its service area is the islands of Maui, Lanai and Molokai. MECO is owned by HECO, which also owns HELCO.

Q. PLEASE BRIEFLY DESCRIBE HEI'S BUSINESS OPERATIONS

A. HEI was incorporated in 1981 and, as part of a corporate restructuring in 1983, became the parent company of HECO, HELCO and MECO. HEI is a holding company with subsidiaries engaged in the provision of electric energy (i.e., HECO, HELCO, and MECO), financial services (i.e., American Savings Bank, F.S.B.), and other businesses.

Q. WHAT ARE HEI'S BUSINESS SEGMENT RATIOS?

A. The major operations of HEI are shown on CA-402. The electric utility percentages can be summarized as follows:

	2003	2004	2005	2006
Revenues	78.4%	80.6%	81.5%	83.5%
Income	66.8%	75.3%	57.1%	69.4%
Capital Expenditures	90.2%	93.7%	97.3%	92.7%
Assets	28.9%	29.6%	31.0%	31.0%

As this indicates, the electric utility operations have remained dominant in terms of revenues, operating income and capital expenditures. The "other" operations have remained small and, as a group, unprofitable.

Q. PLEASE DESCRIBE THE NATURE OF HEI'S ELECTRIC ENERGY OPERATIONS.

A. HECO constitutes HEI's electric energy operations, which are carried out through its own operations (i.e., the island of Oahu) and the operations of HELCO (i.e., the island of Hawaii) and MECO (i.e., the islands of Maui,

Molokai, and Lanai), which it owns. As noted above, the electric energy operations account for about 80 percent of the revenues of HEI.

Q. HOW ARE HECO, HELCO AND MECO FINANCED?

A. All of the common stock of HELCO and MECO is owned by HECO. HECO's common stock, in turn, is owned by HEI. The debt, preferred stock and hybrid securities capital of HELCO and MECO are arranged by HECO, although each subsidiary does have its own debt, preferred stock, and hybrid securities. However, the debt and hybrid securities of HELCO and MECO are guaranteed by HECO and the debt and hybrid securities ratings of each subsidiary are derived from HECO's consolidated financial standing. As a result, HELCO and MECO carry the same debt and hybrid security ratings as HECO.

Q. ARE THE FINANCING AND COSTS OF CAPITAL OF HELCO, MECO, AND HECO INDEPENDENT OF HEI?

A. No. The debt ratings of HECO (and, thus, HELCO and MECO) are partially tied to the risks and operations of HEI. This has long been recognized by Standard & Poor's, which noted in an October 11, 1993 CreditWeek):

> Parent Hawaiian Electric Industries Inc.'s **aggressive diversification activities** -- in financial services, freight transportation, and real estate development (representing around 20% of total earnings) – have **intensified consolidated financial risk**. In view of parent debt financing, the **utility** is **not fully insulated** from **higher-risk affiliates**. [Emphasis added.]

Subsequent statements by Standard & Poor's indicate that this concern persisted. In a November 1995 Global Sector Review), S&P noted:

> HEI's **diversification** -- in financial services, freight transportation, real estate, and passive investments (25% of electric utility and savings bank net income) **intensifies consolidated financial risk**. In view of HEI debt, HECO is **not fully insulated from higher-risk affiliates**. [Emphasis added.]

Standard & Poor's November 4, 1997 CreditWire:

> HEI's ratings largely reflect the credit worthiness of HECO, adjusted for **higher-risk non-utility units**. HECO's ratings reflect an average business profile and gradually improving financials. [Emphasis added.]

Standard & Poor's September 1999 Utility Credit Report:

> HEI's aggressive **diversification intensifies consolidated financial risk**. Given parent debt, HECO is **not fully insulated from higher risk non-utility affiliates**. [Emphasis added.]

Even though HEI has, in recent years, divested itself of its more risky non-utility affiliates (e.g., international power and freight transportation), it remains that the utility operations are least risky. This is demonstrated in a July 9, 2004 Standard & Poor's Ratings Direct report:

> The corporate credit rating of HEI reflects the credit fundamentals of HECO as well as the **higher-risk financial services operations** of American Savings Bank. However, Standard & Poor's does not accord any credit uplift to American Savings Bank as a result of its affiliation with HEI.
>
> In most circumstances, Standard & Poor's will not rate the debt of a wholly owned subsidiary higher than the rating of the parent. However, exceptions can be made on the basis of structural protections and/or regulatory insulation. In HECO's case, Standard & Poor's believes that there are adequate insulating conditions in Hawaii's statutory and regulatory framework, including orders issued by the Hawaii Public Utilities

> Commission (PUC) regarding the formation of the HEI's holding company structure, that insulate the utility from the parent's activities. The conditions imposed on HECO, and the PUC's ability, intent, and demonstrated willingness to protect HECO's creditworthiness provide Standard & Poor's with sufficient confidence to separate the corporate credit ratings of HEI and HECO by one notch. [Emphasis added.]

On a more recent basis, Standard & Poor's made the following statements in a March 26, 2007 Ratings Direct report on HEI:

> The ratings on diversified holding company Hawaiian Electric Industries Inc. (HEI) are based on the **consolidated credit profile of HEI's units, which include the electric utility, Hawaiian Electric Co. Inc and its two subsidiaries Hawaiian Electric Light Co. (HELCO) and Maui Electric Co.** (83% of core revenues and 65% of operating income as of Dec. 31, 2006) **and the riskier financial services operations** of American Savings Bank FSB (17% of core revenues and 35% of operating income). Standard & Poor's Ratings Services does not accord any credit uplift to American Savings Bank as a *result of its affiliation with HEI.*
>
> . . .
>
> **HEI and Hawaiian Electric have satisfactory business profiles** of '6' and '5', respectively, (business profiles are ranked from '1'(excellent) to '10' (vulnerable)) and somewhat weak financial measures. **HEI's business position is characterized by limited competitive threats due to the utility's geographic isolation, nominal stranded-asset risk, a currently excellent fuel clause, and relatively steady banking operations.** These strengths are tempered by Hawaii's economic dependence on a limited number of industries, reliance on fuel oil, strained capacity reserve margins, significant purchased power obligations, and support of the somewhat riskier banking business. **Hawaiian Electric's business profile is slightly stronger than that of the parent due to the absence of nonutility operations.** With regard to the bank, its earnings have been challenged by margin compression and rising interest costs. [Emphasis added.]

This assessment was largely mirrored by Moody's, which made the following comments in a December 21, 2006 Credit Opinion:

> HEI's Baa2 senior unsecured rating reflects the relatively stable earnings and cash flow provided by its vertically integrated utility business and from the market position held by ASB, the third largest financial institution in Hawaii. The rating further reflects the relatively **strong economic growth** that continues within the state, which indirectly benefits both subsidiary businesses, the company's conservative financial management, including its **back-to-basics business strategy**, and the **historically strong financial metrics** that have resulted for this medium size utility. The rating also recognizes the concentration risk that exists for this enterprise, the increasing size of the company's capital programs, the need for timely regulatory support to help finance capital investment and to maintain credit quality at HECO and at HEI, and the associated challenges to implement rate increases at HECO in a state where retail electric rates are high. [Emphasis added.]

This relationship is further demonstrated by the higher bond ratings which MECO maintains relative to HEI. At the current time, MECO's corporate credit rating is Baa1 by Moody's and BBB by Standard & Poor's, while HEI's corporate credit is rated lower at Baa2 by Moody's and BBB by Standard & Poor's (see CA-403).

Q. WHAT ARE THE CURRENT SECURITY RATINGS OF MECO?

A. As shown in CA-403, Page 1, the current ratings of MECO are:

	Moody's	S&P
Revenue Bonds	Baa1	BBB
Preferred Stock	baa2	BB+
Commercial Paper	P-2	A-2

As this Exhibit indicates, MECO's most senior securities (i.e., revenue bonds), presently carry "high" or "mid" triple B ratings by the two major rating agencies.

Q. WHAT HAS BEEN THE TREND IN MECO'S DEBT RATINGS?

A. As CA-403, page 2 indicates, prior to 1990 MECO's most prominent debt (i.e., revenue bonds) was rated A by each of the rating agencies. Moody's reduced MECO's ratings in 1989, 1990, and 1991, while S&P also reduced the ratings in 1990. The Moody's ratings have remained the same since 1991. In May of 2007, S&P reduced MECO's ratings one "notch," to BBB.

Q. WHERE DOES MECO RANK WITHIN THE 'BUSINESS POSITION' CATEGORIES THAT THE RATING AGENCIES HAVE ESTABLISHED?

A. Standard & Poor's has established a "business profile" system, ranging from "1" (strong) to "10" (weak). MECO has a business profile of "5." Since this business profile is in the middle of the range, it follows that the perceived business risk of companies in this category, including MECO, are average. In addition, as noted previously, S&P described this business position as "satisfactory."

Q. HOW IS THE REGULATORY CLIMATE IN HAWAII VIEWED?

A. Hawaii's regulatory climate is "Above Average," according to Value Line.[1] It is noteworthy that only 10 of 50 states have "above average" Regulatory Climate designations.

It is also apparent that the regulatory process in Hawaii serves to minimize the risk of rate base disallowances. This is the case since the Commission's procedures provide for **four opportunities** to review major construction projects prior to their appearance in a rate proceeding. First, the Company annually submits a 5-year capital budget, which generally identifies generation and transmission projects due to the cost of these projects. Second, a 3-year financing plan is submitted when the Company seeks Commission approval to issue securities. Third, the resource planning process and related IRP hearings evaluate and approve both planned construction and DSM programs for the 20-year planning horizon with emphasis on the upcoming five-year period. The Commission requires a filing of annual updates to the latest approved plan and a major review and new filing of the IRP plan for Commission review and approval every three years. Fourth, the Commission's G.O. #7 Standards provide for a submission of capital improvements application seeking Commission approval to commit or

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1 See Value Line Investment Survey of May 12, 2006, page 1774.

1 expend funds for any single project over $2,500,000.[2] Commission approval
2 (or failure to act within 90 days of filing)[3] implies that the project will likely be
3 included in rate base. From a practical standpoint, following Commission
4 review at these steps the likelihood of rate base disapproval of the entire
5 project cost is significantly reduced. Thus, the Company's business risk is
6 also reduced. In addition, allowing MECO to continue recovering the fuel
7 costs associated with the change in the price of fuel through the Energy Cost
8 Adjustment Clause ("ECAC") also reduces the risk of the Company, since the
9 ECAC effectively shifts all risk associated with changes in fuel prices from
10 stockholders to ratepayers.
11
12 Q. HOW DO THE BOND RATINGS OF MECO COMPARE TO OTHER
13 ELECTRIC UTILITIES?
14 A. As I indicated in a previous answer, MECO has triple B bond ratings, which
15 are investment grade (i.e., triple-B or above). Of the 65 electric utilities and
16 combination gas and electric utilities covered by AUS Utilities Reports, the
17 following number of bond ratings currently exists:

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2 In Decision and Order No. 21002 filed on May 27, 2004 in Docket No. 03-0257, the Commission granted, among other things, a request by the electric utilities to increase the $500,000 threshold for seeking Commission approval to commit funds for capital improvement projects to $2,500,000.

3 Such action may result in the suspension of the application to allow the Commission and/or parties to the proceeding additional time to review the merits of the utility's proposal.

	Moody's	S&P
Aa/AA	1	3
A/A	16	20
Baa/BBB	40	35
Ba/BB or Below	4	2
Not Rated	4	4

This comparison indicates that MECO's ratings are in the most common rating category of electric utilities.

VI. CAPITAL STRUCTURE AND COSTS OF DEBT, HYBRID SECURITIES AND PREFERRED STOCK.

Q. WHAT IS THE IMPORTANCE OF DETERMINING A PROPER CAPITAL STRUCTURE IN A REGULATORY FRAMEWORK?

A. A utility's capital structure is important because the concept of rate base – rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help ascertain its capital costs. The rate base – rate of return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the cost of capital is derived from the

liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the dollar values of the capital structure and the rate base are approximately equal and the former is utilized to finance the latter.

The common equity ratio (i.e., the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case because common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and (3) causes the most controversy since its cost cannot be precisely determined.

Q. HOW HAVE YOU EVALUATED THE CAPITAL STRUCTURES OF MECO, HECO, AND HEI?

A. I have first examined the five year historic (2002-2006) capital structure ratios of MECO, HECO and HEI. Page 1 of CA-404 shows the capital structures of MECO. The common equity ratios of this company are shown below:

	Including S-T Debt	Excluding S-T Debt
2002	50.7%	50.7%
2003	52.6%	52.6%
2004	54.4%	54.4%
2005	55.0%	55.0%
2006	54.0%	54.7%

These generally indicate a recent, historic capital structure for MECO of about 51 percent to 55 percent common equity (including short-term debt).

Q. HOW DO MECO'S CAPITAL STRUCTURE RATIOS COMPARE TO THOSE OF HECO (CONSOLIDATED)?

A. HECO's capital structure ratios are shown on page 2 of CA-404. The common equity ratios of HECO on a consolidated basis are shown below:

	Including S-T Debt	Excluding S-T Debt
2002	52.2%	52.4%
2003	52.9%	53.1%
2004	53.7%	56.4%
2005	52.9%	56.8%
2006	51.2%	54.5%

The common equity ratios of HECO consolidated are generally lower than those of MECO since 2004.

Q. WHAT ARE THE CAPITAL STRUCTURE RATIOS OF HEI?

A. These are shown on Page 3 of CA-404. The common equity ratios of HEI, on a consolidated basis, are summarized below:

	Including S-T Debt	Excluding S-T Debt
2002	43.8%	43.8%
2003	45.6%	45.6%
2004	48.7%	50.2%
2005	48.0%	50.8%
2006	44.9%	48.4%

These are somewhat lower than those of MECO and HECO.

Q. IS THERE ANYTHING UNIQUE ABOUT MECO'S CAPITAL STRUCTURE?

A. Yes. A significant potion of MECO's debt is revenue bonds, which are issued in conjunction with the Department of Budget and Finance of the state of Hawaii. This is a source of funding not generally available to many other utilities and represents a favorable circumstance of MECO.

Q. HOW DO THESE CAPITAL STRUCTURES COMPARE TO THOSE OF INVESTOR-OWNED ELECTRIC UTILITIES?

A. CA-405 shows the common equity ratios (including short-term debt in capitalization) for the two groups of electric utilities covered by AUS Utility Reports. These are:

	Electric	Combination Gas & Electric
2002	38%	36%
2003	42%	38%
2004	47%	43%
2005	44%	47%
2006	45%	44%

These common equity ratios are generally lower than those of MECO over the 2002-2006 period.

Q. WHAT CAPITAL STRUCTURE RATIOS HAS MECO REQUESTED IN THIS PROCEEDING?

A. Per MECO-1701, the Company requests use of the following capital structure:

Capital Item	Percent
Short-Term Debt	1.27%
Long-Term Debt	40.15%
Hybrid Securities	2.45%
Preferred Stock	1.25%
Common Equity	54.89%

According to Company witness Tayne Sekimura, this capital structure was derived by taking the 2006 capital structure of the Company and adjusting it for expected changes in 2007. Ms. Sekimura states that this capital structure has been derived using the same methodology employed by HELCO, MECO and HECO in their recent rate proceedings.[4]

Q. HAVE YOU REVIEWED THE COMMISSION'S ORDERS IN THE MOST RECENT MECO RATE PROCEEDINGS?

A. Yes, I have. Since Docket No. 7000, the Commission has used MECO's projected average capital structures for the purpose of setting a rate of return for the Company. The dockets since this time incorporated the following capital structure ratios:

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4 See MECO T-17, page 4.

Capital Item	Docket No. 7000	Docket No. 94-0345	Docket No. 96-0040	Docket No. 97-0346
Short-Term Debt	6.50%	5.49%	1.23%	0.00%
Long-Term Debt	37.69%	38.96%	42.91%	44.18%
Preferred Stock	7.13%	6.43%	7.28%	6.84%
Common Equity	48.68%	49.12%	48.58%	48.97%

The proposed ratios are higher than those in the earlier proceedings.

Q. WHAT CAPITAL STRUCTURE DO YOU PROPOSE TO USE IN THIS PROCEEDING?

A. I will also employ the projected 2007 capital structure. Furthermore, I note that if MECO updates its capital structure later in the proceeding, I may have further comments at that time.

Q. WHAT ARE THE COSTS OF FIXED-COST CAPITAL IN THE COMPANY'S APPLICATION?

A. The Company's Application (see MECO-1701) contains the following cost rates:

Capital Item	Percent
Short-Term Debt	5.00%
Long-Term Debt	6.11%
Hybrid Securities	7.47%
Preferred Stock	8.34%

Since it appears from the Application that these rates are calculated using the same methodology as in prior proceedings, I will also use these cost rates in

my analyses. The Company may also update these rates later in this proceeding. As a result, I may have further comments at that time.

Q. CAN THE COST OF COMMON EQUITY BE DETERMINED WITH THE SAME DEGREE OF PRECISION AS THE COST OF DEBT AND OTHER FIXED COST SECURITIES?

A. No. The cost rates of debt and other fixed-cost securities are largely determined by interest payments, issue prices, and related expenses. The cost of common equity, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. There are, however, several models which can be employed to estimate the cost of common equity. Three of the primary methods - DCF, CAPM, and CE - are developed in the following sections of my testimony.

VII. SELECTION OF PROXY GROUPS.

Q. HOW HAVE YOU ESTIMATED THE COST OF COMMON EQUITY FOR MECO?

A. MECO is not a publicly traded company; rather, it is a subsidiary of HECO and HEI. As a result, it is not possible to conduct direct analyses of the cost of common equity for MECO. It is possible to conduct studies of HEI's cost of equity; however, the diversified nature of this company's operations indicate that it is not an adequate proxy, standing alone, for the cost of equity for

1 MECO. I note that the Commission concurred with this assessment in
2 Decision and Order No. 16922 filed on April 6, 1999 in Docket No. 97-0346 (In
3 RE MECO), on page 40, wherein the Commission stated that it did not
4 consider HEI an appropriate proxy for MECO and thus did not consider the
5 HEI results. It is, however, useful to analyze groups of comparison or "proxy"
6 companies as a substitute for MECO to determine its cost of common equity. I
7 have examined two such groups for comparison to MECO.
8
9 Q. HOW HAVE YOU SELECTED THE GROUPS OF COMPARISON
10 COMPANIES?
11 A. My first group of comparison companies was selected using criteria similar to
12 that cited by the Commission in a recent HELCO (Decision and Order
13 No. 18365 dated February 8, 2001 in Docket No. 99-0207) and MECO
14 (Decision and Order No. 16922 dated April 6, 1999 in Docket No. 97-0346)
15 Decisions. As I interpret these Decisions, the Commission has noted that it is
16 appropriate to select comparison companies based upon the following criteria:
17 (1) primarily an electric utility, with electric revenues providing most of the
18 company's total revenues;
19 (2) publicly-traded common stock on New York Stock Exchange;
20 (3) substantially regulated entity;
21 (4) Value Line safety rating of 1 or 2;
22 (5) first mortgage bonds rated within one rating increment of HECO;

1 (6) if a holding company, have only one subsidiary;

2 (7) common equity ratio in the 35 percent to 50 percent range; and

3 (8) be small (total market value of outstanding common equity within

4 $0.45 billion to $3.0 billion range).[5]

5 The Commission has also identified, in some cases

6 (e.g., [In RE HELCO] Decision and Order No. 13762 dated February 10, 1995

7 in Docket No. 7764 on page 53) a criterion of nuclear risk (i.e., no nuclear

8 construction) similar to HECO. The Commission further has noted

9 (e.g., [In RE HECO] Decision and Order No. 14412 dated December 11, 1995

10 in Docket No. 7766 on page 54) that in future cases these selection criteria

11 may "be applied advisedly."

12 I have selected a group of nine comparison companies based upon

13 these criteria. Page 1 of CA-406 lists the nine comparison companies and

14 identifies the selection criteria. I note that I have included companies with a

15 market cap up to $5 million (reflecting growth in HEI's market cap) and equity

16 ratios up to 60 percent (also reflecting an increase in the equity ratio of HEI

17 and MECO).

18 In addition to this group, I also selected a group of six electric

19 companies using alternative selection criteria that I normally employ in electric

---

5 The Commission initially endorsed $2.0 billion as the top end of the market value of common stock range. In Docket No. 97-0346, I proposed the market value criteria be expanded to $3 billion. In its Decision and Order No. 16922, the Commission accepted my proxy group as "reasonable."

1 utility cases. I have selected a group of six companies based upon the
2 following criteria:
3 (1) Net utility plant of about $5 billion or less;
4 (2) No nuclear generation;
5 (3) Electric revenues of 50 percent or greater of total revenues;
6 (4) Common equity ratio in the 40 percent to 55 percent range;
7 (5) Standard & Poor's stock ranking of B+ or A-; and
8 (6) Moody's bond rating of A or Baa.
9 These companies are identified on page 2 of CA-406. I note that I have
10 included HEI in my proxy group, notwithstanding the fact that the Commission
11 has previously indicated this Company is not an adequate proxy. The
12 movement of HEI's operations toward a traditional utility structure makes this
13 company more appropriate for a proxy company at this time.
14
15 Q. HOW DO THESE PROXY GROUPS COMPARE TO THE GROUPS THAT
16 MECO WITNESS MORIN USES IN HIS COST OF CAPITAL ANALYSES?
17 A. MECO's cost of capital witness (Dr. Roger A. Morin) has not selected proxy
18 groups based upon any criteria specifically designed for comparison to HECO
19 or the previously-cited Commission criteria. Rather, Dr. Morin has used broad
20 industry groups, such as Moody's Electric Utilities and vertically integrated
21 electric utilities. In Section XIII of my testimony, I will discuss the deficiencies
22 with Dr. Morin's proxy group of companies.

VIII. DISCOUNTED CASH FLOW ANALYSIS.

Q. WHAT IS THE THEORY AND METHODOLOGICAL BASIS OF THE DISCOUNTED CASH FLOW MODEL?

A. The DCF model is one of the oldest, as well as the most commonly-used, models for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework, cost of capital is derived by the following formula:

$$K = \frac{D}{P} + g$$

where: K = discount rate (cost of capital)

P = current price

D = current dividend rate

g = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. PLEASE EXPLAIN HOW YOU HAVE EMPLOYED THE DCF MODEL.

A. For purposes of my analysis I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for each group of proxy utility stocks described in the previous section with several indicators of expected dividend growth.

Q. HOW DID YOU DERIVE THE DIVIDEND YIELD COMPONENT OF THE DCF EQUATION?

A. There are several methods that can be used for calculating the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed; i.e., current versus future dividends or annual versus quarterly compounding of dividends. I believe the most appropriate dividend yield component is a quarterly compounding variant, which is expressed as follows:

$$Yield = \frac{D_0(1+0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average (of high and low) stock price for each proxy company for the most recent three month period (July-September 2007). The D_0 is the current annualized dividend rate for each proxy company.

Q. HOW HAVE YOU ESTIMATED THE DIVIDEND GROWTH COMPONENT OF THE DCF EQUATION?

A. The dividend growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to sell that stock.

A wide array of indicators exists for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of dividend growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

(1) 2002-2006 (5-year average) earnings retention, or fundamental growth (per Value Line);

(2) 5-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS) (per Value Line);

(3) 2007, 2008, and 2010-2012 projections of earnings retention growth per Value Line);

(4) 2004-2006 to 2010-2012 projections of EPS, DPS, and BVPS (per Value Line); and

(5) 5-year projections of EPS growth as reported in First Call (per Yahoo! Finance).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which should be expected to have some impact on their decision-making process.

Q. PLEASE DESCRIBE YOUR INITIAL DCF CALCULATIONS.

A. CA-407 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rate for the groups of proxy companies.

Page 4 shows the "raw" DCF calculations, which are presented on several bases: mean, median, and range of low/high values. These results can be summarized as follows:

	Mean	Median	High[6]
Comparison Groups			
Commission Criteria	8.0%	8.1%	10.8%
Parcell Criteria	7.6%	7.8%	9.7%

I note that the individual DCF calculations shown on CA-407 should not be interpreted to reflect the expected cost of capital for the proxy groups; rather, the individual values shown should be interpreted as alternative information considered by investors.

The DCF results in CA-407 indicate average (mean and median) DCF cost rates of about 8 percent or less. The highest DCF rates (i.e., using the highest growth rates only) are 9.7 percent to 10.8 percent for two proxy groups.

Q. WHAT DO YOU CONCLUDE FROM YOUR DCF ANALYSES?

A. Based upon my analyses, I believe a broad range of 8 percent to 10¾ percent represents the current DCF cost of equity for MECO. This cost of equity recommendation is approximated by the upper portion of the average/mean values, as well as the top DCF calculations for the proxy groups examined in the previous analysis. I recommend a 9 percent to 10¾ percent range for

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6 Using only the highest growth rate.

MECO, which focuses on the upper portion of the DCF ranges describes above.

IX. CAPITAL ASSET PRICING MODEL ANALYSIS.

Q. PLEASE DESCRIBE THE THEORY AND METHODOLOGICAL BASIS OF THE CAPITAL ASSET PRICING MODEL.

A. The CAPM is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory (MPT), which studies the relationships among risk, diversification, and expected returns.

Q. HOW IS THE CAPM DERIVED?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where: K = cost of equity

R_f = risk free rate

R_m = return on market

β = beta

R_m-R_f = market risk premium

As noted previously, the CAPM is a variant of the risk premium method. I believe the CAPM is generally superior to the simple risk premium method

because the CAPM specifically recognizes the risk of a particular company or industry (i.e., beta), whereas the simple risk premium method assumes the same cost of equity for all companies exhibiting similar bond ratings.

Q. WHAT GROUPS OF COMPANIES HAVE YOU UTILIZED TO PERFORM YOUR CAPM ANALYSES?

A. I have performed CAPM analyses for the same groups of proxy utilities evaluated in my DCF analyses.

Q. WHAT RATE DID YOU USE FOR THE RISK-FREE RATE?

A. The first term of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any risk.

In CAPM applications, the risk-free rate is generally recognized by using the U.S. Treasury securities' rate. Two general types of U.S. Treasury securities are often utilized as the R_f component - short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

I have performed CAPM calculations using the three-month average yield (July-September 2007) for 20-year U.S. Treasury bonds. Over this three- month period, these bonds had an average yield of 5.01 percent.

Q. WHAT IS BETA AND WHAT BETAS DID YOU EMPLOY IN YOUR CAPM?

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas of less than 1 are considered less risky than the market, whereas betas greater than 1 are more risky. Utility stocks traditionally have had betas below 1. I utilized the most recent Value Line betas for each company in the groups of proxy utilities.

Q. HOW DID YOU ESTIMATE THE MARKET RISK PREMIUM COMPONENT?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or government bonds. For the purpose of estimating the market risk premium, I considered alternative measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

First, I have compared the actual annual returns on equity of the S&P 500 with the actual annual yields of U.S. Treasury bonds. CA-408 shows the return on equity for the S&P 500 group for the period 1978-2005 (all available years reported by S&P). This exhibit also indicates the annual yields on 20-year U.S. Treasury bonds, as well as the annual differentials (i.e., risk premiums) between the S&P 500 and U.S. Treasury 20-year bonds. Based upon these returns, I conclude that this version of the risk premium is about 6.2 percent.

I have also considered the total returns (i.e., dividends/interest plus capital gains/losses) for the S&P 500 group, as well as for long-term government bonds, as tabulated by Morning Star (previously Ibbotson Associates), using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2006 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	12.3%	5.8%	6.5%
Geometric	10.4%	5.4%	5.0%

I conclude from these total returns that the expected risk premium is about 5.9 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate because investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Page 1 of CA-409 shows my CAPM calculations. The results are:

	Mean	Median
Comparison Groups		
PUC Criteria	10.4%	10.3%
Parcell Criteria	10.2%	10.0%

Q. HAVE YOU PERFORMED AN ALTERNATIVE SET OF CAPM CALCULATIONS?

A. Yes. I have performed an alternative set of CAPM calculations in order to address the Commission's preference for use of the risk premium from

Ibbotson & Associates. I have developed such a risk premium by comparing the 1926-2006 total returns based on arithmetic returns, or 6.5 percent. I focus on the arithmetic return since the Commission has expressed a preference for use of the Ibbotson returns as the CAPM R_m.[7]

Page 2 of CA-409 shows my CAPM calculations using this risk premium. The results are:

	Mean	Median
Comparison Groups		
PUC Criteria	10.9%	10.9%
Parcell Criteria	10.7%	10.5%

Q. WHAT IS YOUR CONCLUSION CONCERNING THE CAPM COST OF EQUITY?

A. The CAPM results collectively indicate a cost of about 10 percent to 11 percent for the two groups of comparison utilities. I conclude that the CAPM cost of equity for MECO is within a range of 10 percent to 11 percent.

X. COMPARABLE EARNINGS ("CE") ANALYSIS.

Q. PLEASE DESCRIBE THE BASIS OF THE CE METHODOLOGY.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is thus based upon the economic

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7 See, for example [In RE MECO], Decision and Order No. 16134 dated December 31, 1997 in Docket No. 96-0040 at page 28.

1 concept of opportunity cost. As previously noted, the cost of capital is an
2 opportunity cost: the prospective return available to investors from alternative
3 investments of similar risk.

4 The CE method is designed to measure the returns expected to be
5 earned on the original cost book value of similar risk enterprises. Thus, this
6 method provides a direct measure of the fair return, because the CE method
7 translates into practice the competitive principle upon which regulation is
8 based.

9 The CE method normally examines the experienced and/or projected
10 returns on book common equity. The logic for examining returns on book
11 equity follows from the use of original cost rate base regulation for public
12 utilities, which uses a utility's book common equity to determine the cost of
13 capital. This cost of capital is, in turn, used as the fair rate of return which is
14 then applied (multiplied) to the book value of rate base to establish the dollar
15 level of capital costs to be recovered by the utility. This technique is thus
16 consistent with the rate base methodology used to set utility rates.

17

18 Q. HOW HAVE YOU EMPLOYED THE CE METHODOLOGY IN YOUR
19 ANALYSIS OF MECO'S COMMON EQUITY COST?

20 A. I conducted the CE methodology by examining realized returns on equity for
21 several groups of companies and evaluating the investor acceptance of these
22 returns by reference to the resulting market-to-book ratios. In this manner it is

1 possible to assess the degree to which a given level of return equates to the
2 cost of capital. It is generally recognized for utilities that market-to-book ratios
3 of greater than one (i.e., 100%) reflect a situation where a company is able to
4 attract new equity capital without dilution (i.e., above book value). As a result,
5 one objective of a fair cost of equity is the maintenance of stock prices above
6 book value.

7 I would further note that the CE analysis, as I have employed it, is
8 based upon market data (through the use of market-to-book ratios) and is thus
9 essentially a market test. As a result, my CE analysis is not subject to the
10 criticisms occasionally made by some who maintain that past earned returns
11 do not represent the cost of capital. In addition, my CE analysis uses
12 prospective returns and thus is not backward looking.
13
14 Q. WHAT TIME PERIODS HAVE YOU EXAMINED IN YOUR CE ANALYSIS?
15 A. My CE analysis considers the experienced equity returns of the proxy groups
16 of utilities for the period 1992-2006 (i.e., last fifteen years). The CE analysis
17 requires that I examine a relatively long period of time in order to determine
18 trends in earnings over at least a full business cycle. Further, in estimating a
19 fair level of return for a future period, it is important to examine earnings over a
20 diverse period of time in order to avoid any undue influence from unusual or
21 abnormal conditions that may occur in a single year or shorter period.
22 Therefore, in forming my judgment of the current cost of equity I have focused

on two periods: 2002-2006 (the last five years - the average length of a business cycle) and 1992-2001 (the most recent complete business cycle).

Q. PLEASE DESCRIBE YOUR CE ANALYSIS.

A. CA-410 and CA-411 contain summaries of experienced returns on equity for several groups of companies, while CA-412 presents a risk comparison of utilities versus unregulated firms.

CA-410 shows the earned returns on average common equity and market-to-book ratios for the two groups of proxy utilities. These can be summarized as follows:

	Historic		Prospective
Group	ROE	M/B	ROE
Comparison Groups			
PUC Criteria	8.1-10.3%	129-141%	8.6-9.2%
Parcell Criteria	8.6-10.8%	141-148%	8.5-9.8%

These results indicate that historic returns of 8.1-10.8 percent have been adequate to produce market-to-book ratios of 129-148 percent for the groups of proxy utilities. Furthermore, projected returns on equity for 2007, 2008, and 2010-2012 are within a range of 8.5 percent to 9.8 percent for the utility groups. These relate to 2006 market-to-book ratios of 145 percent or higher.

Q. HAVE YOU ALSO REVIEWED EARNINGS OF UNREGULATED FIRMS?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, because this is a

1 well recognized group of firms that is widely utilized in the investment
2 community and the composite group is indicative of the competitive sector of
3 the economy. CA-411 presents the earned returns on equity and
4 market to-book ratios for the S&P 500 group over the past fourteen years. As
5 this exhibit indicates, over the two stated periods this group's average earned
6 returns ranged from 12.2-14.7 percent with market-to-book ratios ranging
7 between 299 percent and 341 percent.
8
9 Q. HOW CAN THE ABOVE INFORMATION BE USED TO ESTIMATE THE
10 COST OF EQUITY FOR MECO?
11 A. The recent earnings of the proxy utility and S&P 500 groups can be utilized as
12 an indication of the level of return realized and expected in the regulated and
13 competitive sectors of the economy. In order to apply these returns to the cost
14 of equity for proxy utilities, however, it is necessary to compare the risk levels
15 of the electric utility industries with those of the competitive sector. I have
16 done this in CA-412, which compares several risk indicators for the S&P 500
17 group and the utility groups. The information in this exhibit indicates that the
18 S&P 500 group is slightly more risky than the utility proxy groups.
19
20 Q. WHAT RETURN ON EQUITY IS INDICATED BY THE CE ANALYSIS?
21 A. Based on the recent earnings and market-to-book ratios, I believe the
22 CE analysis indicates that the cost of equity for the proxy utilities is no more

than 9 percent to 10 percent. Recent returns of 8.1-10.8 percent have resulted in market-to-book ratios of 129 and greater. Prospective returns of 8.5-9.8 percent have been accompanied by market-to-book ratios of over 140 percent. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. An earned return of 9 percent to 10 percent should thus result in a market-to-book ratio of at least 100 percent. As I indicated earlier, the fact that market-to-book ratios substantially exceed 100 percent indicates that historic and prospective returns of 9 percent to 10 percent reflect earnings levels that exceed the cost of equity for those regulated companies.

XI. RETURN ON EQUITY RECOMMENDATION.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR THREE EQUITY COST ANALYSES.

A. My three methodologies produce the following:

Discounted Cash Flow	9.0-10.75% (9.9% mid-point)
Capital Asset Pricing Model	10.0-11.0 (10.5% mid-point)
Comparable Earnings	9.0-10.0% (9.5% mid-point)

These result in a broad cost of equity range of 9.0 percent to 11.0 percent. For the purpose of my recommendation, I propose to use the middle portion of this range. My overall conclusion from these results is thus an overall range of 9.5 percent to 10.5 percent. I recommend a cost of equity rate of 9.5 percent to 10.5 percent for MECO.

1 **XII. TOTAL COST OF CAPITAL.**

2 Q. WHAT IS THE TOTAL COST OF CAPITAL FOR MECO?

3 A. CA-413 reflects the total cost of capital for the Company using the
4 December 31, 2007 capital structure and costs of long-term debt, short-term
5 debt, preferred stock, and my common equity cost recommendations. The
6 resulting total cost of capital is a range of 8.02 percent to 8.57 percent, with a
7 mid-point of 8.29 percent. I recommend that this 8.29 total cost of capital be
8 established for MECO.

9

10 Q. DOES YOUR COST OF CAPITAL RECOMMENDATION PROVIDE THE
11 COMPANY WITH A SUFFICIENT LEVEL OF EARNINGS TO MAINTAIN ITS
12 FINANCIAL INTEGRITY?

13 A. Yes, it does. CA-414 shows the pre-tax coverage that would result if MECO
14 earned the mid-point of my cost of capital recommendation. As the results
15 indicate, the mid-point of my recommended range would produce a coverage
16 level within the benchmark range for a BBB rated utility. In addition, the debt
17 ratio (which reflects the capital structure as proposed by the Company) is
18 within that benchmark for a BBB rated utility.

19

XIII. COMMENTS ON COMPANY TESTIMONY.

Q. HAVE YOU REVIEWED THE TESTIMONY OF MECO WITNESS ROGER MORIN?

A. Yes, I have.

Q. WHAT IS YOUR UNDERSTANDING OF DR. MORIN'S COST OF EQUITY RECOMMENDATION FOR MECO?

A. Dr. Morin is recommending an 11.25 percent cost of common equity for MECO. This recommendation is based upon his implementation of the following cost of equity models:

	Morin Conclusions		
CAPM			
Traditional	11.6%		
Empirical	11.8%		
Average		11.7%	
Risk Premium			
Historical Electric Utility	10.8%		
Allowed Returns	10.8%		
Average		10.8%	
DCF			
Electric Value Line	9.7%		
Electric Zacks	10.7%		
Moody's Electric Value Line	10.8%		
Moody's Electric Zacks	10.4%		
Average		10.4%	
Overall Average			11.0%

Based upon these results, he concludes that 11.0 percent is the cost of equity for an average risk electric utility. He recommends an 11.25 percent return on

1 equity for MECO, reflecting his perception that MECO faces above average
2 risks on its electric utility operations.
3
4 Q. YOU PREVIOUSLY NOTED THAT DR. MORIN'S PROXY GROUPS WERE
5 NOT SELECTED USING CRITERIA CONSISTENT WITH PAST
6 COMMISSION PRECEDENT. WHAT ARE THE IMPLICATIONS OF THIS?
7 A. Over the past several rate proceedings involving HECO, HELCO, and MECO,
8 the Commission has provided some rather precise definitions of what it
9 considers to be appropriate proxy companies for use in determining the cost of
10 equity for these companies. My testimony, as indicated in a prior section,
11 follows these guidelines. Dr. Morin's analyses, on the other hand, do not.
12 Instead, he simply applies his cost of equity analyses to two broad groups of
13 utilities. Neither of his proxy groups is selected based upon an analysis of the
14 factors that make these companies similar to MECO. As a result, I believe
15 that Dr. Morin's cost of equity analyses do not properly address MECO's risks
16 and required returns. Use of these broad proxy groups does not provide the
17 required risk profiles and specific recognition of MECO's required returns.
18
19 Q. WHAT IS YOUR UNDERSTANDING OF DR. MORIN'S CAPM ANALYSES?
20 A. Dr. Morin performs CAPM analyses for a group of electric utilities
21 (0.86 average beta). He combines a 0.86 beta with a 4.9 percent level cost of

1 long-term (30-year) Treasury bonds and a 7.4 percent risk premium to get the
2 following CAPM results:

3 $$K = RF + \beta(RP) = 4.9\% + .86\ (7.4\%) = 11.3\%$$

4 $$= 4.9\% + .86\ (7.4\%) = 11.3\%$$

5 He then adds a 0.3 percent flotation costs adjustment to this to get an
6 11.6 percent CAPM result.
7
8 Q. DO YOU AGREE WITH THIS CAPM ANALYSIS?
9 A. No, I do not.
10
11 Q. WITH WHICH COMPONENTS OF HIS CAPM ANALYSIS DO YOU
12 DISAGREE?
13 A. I disagree with the risk premium component.
14
15 Q. WHAT IS YOUR DISAGREEMENT WITH DR. MORIN'S MARKET RISK
16 PREMIUM COMPONENT?
17 A. Dr. Morin's 7.4 percent risk premium is derived from two studies – the
18 1926-2005 Ibbotson Associates study showing a 7.1 percent differential
19 between common stocks and the "income component" of Treasury bonds and
20 a DCF analysis he performed for Value Line's aggregate stock market index
21 and growth forecasts versus long-term Treasury bonds that produced a
22 7.8 percent differential. I disagree with both his studies.

1 I disagree with the first study since Dr. Morin improperly used "income
2 returns" from the Ibbotson Associates study rather than "total returns." What
3 Dr. Morin did was compare the differential between total returns for common
4 stocks (i.e., dividends and capital gains) and only income returns for Treasury
5 bonds. As such, he has ignored the capital gains component of the Treasury
6 bonds return. As I indicated in my earlier testimony, the differential between
7 total returns of common stocks and Treasury bonds is 6.5 percent (a figure
8 Dr. Morin acknowledges on page 32).

9 Dr. Morin's second study relies upon his conclusion that the "expected
10 return on the aggregate equity market" is 12.7 percent, which he derives by
11 performing DCF analyses for the Value Line aggregate market. He combines
12 a 1.2 percent dividend yield with a projected growth rate of 11.2 percent to
13 arrive at a 12.4 percent return. He then adjusted the dividend yield by the
14 growth rate to arrive at his 12.7 percent DCF cost, which he in turn compared
15 to the 4.9 percent 30-year Treasury bond yields to arrive at a 7.8 percent risk
16 premium.

17 I do not believe this is an appropriate method by which to estimate the
18 risk premium. Dr. Morin has not attempted to verify that the Value Line group
19 of some 1,800 stocks is an appropriate standard for the risk premium (which is
20 normally performed by using a smaller sample of large companies, such as
21 the S&P 500). I note that historic returns for the S&P 500 have been

1 10.4 percent on a geometric basis and 12.3 percent on an arithmetic basis,
2 both of which are less than the 12.7 percent conclusion of Dr. Morin.
3
4 Q. PLEASE DESCRIBE DR. MORIN'S "EMPIRICAL" CAPM ANALYSIS.
5 A. Dr. Morin also employs what he describes as an "empirical" CAPM analysis.
6 This form of the CAPM assumes that beta for an industry understates the
7 industry's volatility and thus risk and it is necessary to substitute the overall
8 market's beta (i.e., 1.0) for one-fourth of the industry's actual beta. Dr. Morin
9 assumed that the appropriate beta in a CAPM analysis is a combination of the
10 actual industry beta with a 75 percent weight and a beta of 1 with a 25 percent
11 weight.
12 The use of an empirical CAPM overstates the cost of equity for
13 companies with betas below that of the market. What the empirical CAPM
14 actually does is inflate the CAPM cost for the selected company or industry on
15 one-fourth of its equity and assumes that one-fourth of the company has the
16 risk of the overall market. This is not appropriate for MECO or for other
17 utilities.
18 I note that Dr. Morin's "empirical" CAPM is similar to a "zero beta"
19 CAPM proposed by MECO witness Paul R. Moul in a 1999 proceeding before

this Commission. In its decision in that proceeding (Docket No. 97-0346, In Re (MECO)), the Commission did not accept MECO's proposed CAPM.[8]

Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF DR. MORIN'S RISK PREMIUM ANALYSIS.

A. Dr. Morin performs two sets of risk premium analyses. Each of these involved the estimation of an equity risk premium over the 4.9 percent long-term Treasury bond yields used as the risk-free rate in his CAPM analyses. The two risk premiums he developed are:

- Historic risk premium for the electric utility industry; and,
- Allowed risk premiums for the electric utility industry.

Q. PLEASE DESCRIBE DR. MORIN'S HISTORIC RISK PREMIUM FOR THE ELECTRIC UTILITY INDUSTRY.

A. Dr. Morin's historic risk premium for the electric utility industry involves an examination of the total returns of 20-year Treasury bonds (capital gains/losses plus interest) and Moody's Electric Utility Index (capital gains/losses plus dividend yield) over the period 1932-2005. The average historical difference between the electric utility returns and the Treasury bond returns was 5.6. His historic risk premium for the electric utility industry simply added the 4.9 percent Treasury bond yield to the 5.6 percent historic risk

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8 See Decision and Order No. 16922, in Docket No. 97-0346, page 50.

premium to get a 10.5 percent result. To this he added 0.3 percent for flotation cost.

Q. DO YOU AGREE WITH THIS METHODOLOGY FOR ESTIMATING THE COST OF EQUITY FOR MECO?

A. No, I do not. Dr. Morin's historic risk premium of 5.6 percent is simply an examination of historical events going back to 1932. He has made no demonstration that economic and financial conditions in 2007 are similar to those over the past eighty plus years. The use of such a methodology implicitly assumes that the events of each of these years can have the same influences at the current time.

In addition, the risk premiums developed by Dr. Morin are generally dominated by the influence of capital gains in many years. For example, the year 1935 stock return of 72.01 percent reflects a 71.23 percent capital gain component. I do not believe it is proper to assign MECO's cost of equity based upon a methodology which is dominated by stock market changes and bond market changes.

It is also apparent that the risk premium level has been very volatile over the 1932-2005 period. The highest risk premium was 72.01 percent in 1935 and the lowest was -37.48 percent in 1937. The averages by decade have also been quite different, as is shown on my CA-415. This indicates that the decade of the 1950's dominates the risk premium averages with a

14.17 percent premium. The decade of the 1990's, in contrast, shows a 0.03 percent risk premium. Dr. Morin's methodology weights these equally. It is doubtful that investors place equal weight on events in the 1930's and 1990's in making investment decisions, yet Dr. Morin's risk premium analysis implicitly assumes this is the case.

Q. PLEASE DESCRIBE DR. MORIN'S ANALYSIS OF ALLOWED RISK PREMIUMS FOR THE ELECTRIC UTILITY INDUSTRY.

A. In this phase of his risk premium testimony, Dr. Morin compares the differential between allowed returns on equity for electric utilities and long-term Treasury bonds over the 1997-2006 period (i.e., last 10 years). The average spread over this period was 5.6 percent, but Dr. Morin does not utilize this differential as his risk premium. Instead, he performs regression analyses to track the risk premium in terms of rising and falling interest rates. He then concludes that a 5.9 percent risk premium is appropriate in conjunction with a 4.9 percent treasury bond yield. This adjustment is not consistent with Dr. Morin's historic risk premium analyses where he simply took the average risk premium over the entire 1932-2005 period and applied it to the current level of Treasury bond yields.

I also note that there has been a downward trend in allowed returns on equity for electric utilities in recent years. According to the source of Dr. Morin's allowed risk premium analysis, Regulatory Focus (published by

Regulatory Research Associates), the annual average return on equity awards have been:

2000	11.43%
2001	11.09%
2002	11.16%
2003	10.97%
2004	10.75%
2005	10.54%
2006	10.36%
2007 (6 months)	10.27%

Q. WHAT IS YOUR UNDERSTANDING OF DR. MORIN'S DCF ANALYSES?

A. Dr. Morin performs several sets of DCF analyses for two groups of electric utilities. In these analyses, he uses "spot" dividend yields for each company as of October 2006. For the growth rates, he used two indicators of growth - Zacks 5-year EPS growth projections and Value Line projections of EPS growth.

The major problem with Dr. Morin's DCF analyses is the fact that he has used only one indicator of growth – projections of EPS growth. As I indicated in my DCF analysis, it is customary and proper to use alternative measures of growth.

Dr. Morin's DCF analyses implicitly assume that investors rely exclusively on EPS projections in making investment decisions. This is a very dubious assumption and Dr. Morin has offered no evidence that it is correct. I note, for example, that Value Line – one of the sources of his growth rate estimates – contains many statistics, both of a historic and projected nature,

1 for the benefit of investors who subscribe to this publication and presumably
2 make investment decisions based at least in part from the information
3 contained in Value Line. Yet, Dr. Morin would have us believe that Value Line
4 subscribers and investors focus exclusively on one single number from this
5 publication.
6 I note in this regard that the DCF model is a "cash flow" model. The
7 cash flow to investors in a DCF framework is dividends. Dr. Morin's DCF
8 model, in contrast, does not even consider dividend growth rates.
9
10 Q. WHAT COMMENTS DO YOU HAVE CONCERNING DR. MORIN'S
11 FLOTATION COST ADJUSTMENT?
12 A. Dr. Morin increases each of his cost of equity estimates by 30 basis points as
13 a flotation cost adjustment. There is no need to make a flotation adjustment,
14 as Dr. Morin recommends. A utility should only be allowed to recover from
15 ratepayers its actual, quantifiable levels of issuance costs. Neither Dr. Morin
16 nor MECO has made any demonstration that the company has incurred any
17 issuance costs. In addition, as my CA-410 reflects, my two proxy groups have
18 2006 market-to-book ratios of over 145 percent. To make a market-to-book
19 adjustment for companies whose market-to-book ratio already exceeds
20 145 percent is unnecessary and inappropriate, since any common stock
21 issuance would actually increase the book value of existing stockholders'
22 stock.

1 Q. IN SOME PAST HECO, HELCO AND MECO PROCEEDINGS, THE
2 COMMISSION HAS MADE AN ADJUSTMENT ABOVE THE COST OF
3 EQUITY FOR COMPARISON ELECTRIC UTILITIES. DO YOU HAVE ANY
4 COMMENTS ON THIS?
5 A. Yes, I do. The Commission has, in some past cases (e.g., Docket
6 No. 99-0207 for HELCO and Docket No. 97-0346 for MECO) added an
7 adjustment of 50 basis points to the cost of equity for comparison companies.
8 The Commission's decisions in these proceedings cited higher business risk
9 (higher operating ratio, lower quality of earnings, and weak level of internally
10 generated funds for construction), current national and local economic
11 conditions, and MECO's minimal investment grade bond rating as matters of
12 concern.
13 MECO has requested a 25 basis point adjustment in this proceeding,
14 based upon Dr. Morin's conclusions that MECO is more risky than his
15 comparison groups.
16
17 Q. DO YOU AGREE THAT THIS TYPE OF ADJUSTMENT IS WARRANTED?
18 A. No. I do not believe that current circumstances warrant an upward adjustment
19 to the cost of equity for the comparison groups.
20 It is important to review the history of MECO's cost of equity
21 adjustments. To the best of my knowledge, based upon a review of

Commission decisions, the relevant Commission decisions dealing with this issue were:

Company	Docket No.	Date	Adjustment
MECO	7000	Aug. 5, 1994	115 basis points
HECO	7700	Dec. 28,1994	115 basis points
HELCO	7764	Feb. 10, 1995	110 basis points
HECO	7766	Dec. 11, 1995	90 basis points
HELCO	94-0140	Apr. 2, 1997	50 basis points
MECO	97-0346	Apr. 6, 1999	50 basis points
HELCO	99-0207	Feb. 8, 2001	50 basis points

As this indicates, the impetus for the adjustments occurred during the 1993-1994 period, as reflected in Commission orders in 1994-1995. Not coincidentally, this was also the time period during which HECO, MECO and HELCO were experiencing downgrades of their securities.

As stated elsewhere in my testimony, MECO's common equity ratio is higher relative to prior years. The Hawaii Commission is one of a few U.S. Commissions to have an "above average" rating by Value Line. In addition, Hawaii's economic strength has improved. I note that even MECO's own perceptions of its relative risks have reflected a decline as the request of 0.25 percent upward adjustment in this case is lower than any previous Commission award.

Q. DOES THIS CONCLUDE YOUR PRE-FILED TESTIMONY?

A. Yes, it does.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member
Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies. Advised financial institutions on

interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy,

and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts
Board of Directors 1992-2000
Secretary/Treasurer 1994-1998
President 1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association, Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

ECONOMIC INDICATORS

YEAR	REAL GDP GROWTH	IND PROD GROWTH	UNEMP RATE	CPI	PPI
		1975 - 1982 Cycle			
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
		1983 - 1991 Cycle			
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
		1992 - 2001 Cycle			
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	6.1%	4.5%	1.6%	0.0%
1999	4.5%	4.7%	4.2%	2.7%	2.9%
2000	3.7%	4.5%	4.0%	3.4%	3.6%
2001	0.8%	-3.5%	4.7%	1.6%	-1.6%
		Current Cycle			
2002	1.6%	0.0%	5.8%	2.4%	1.2%
2003	2.5%	1.1%	6.0%	1.9%	4.0%
2004	3.6%	2.5%	5.5%	3.3%	4.2%
2005	3.1%	3.2%	5.1%	3.4%	5.4%
2006	2.9%	3.9%	4.6%	2.5%	1.1%

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

YEAR	REAL GDP GROWTH	IND PROD GROWTH	UNEMP RATE	CPI	PPI
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.7%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.7%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.2%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	3.6%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	4.3%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	4.0%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	3.3%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.4%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	3.3%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	4.2%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	1.8%	2.9%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	5.6%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	2.6%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	2.0%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	2.5%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	0.6%	2.5%	4.5%	4.8%	0.6%
2nd Qtr.	4.0%	1.6%	4.5%	5.2%	7.2%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%		7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
2003							
Jan	4.25%	1.17%	4.05%		6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%		6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%		6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%		6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%		6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%		6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%		6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%		6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%		6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%		6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%		6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%		6.18%	6.27%	6.61%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%		5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%		5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%		5.55%	5.80%	6.14%
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%		6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%		5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%		5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%		5.80%	5.98%	6.24%
Nov	8.25%	4.95%	4.60%		5.61%	5.80%	6.04%
Dec	8.25%	4.85%	4.56%		5.62%	5.81%	6.05%
2007							
Jan	8.25%	4.96%	4.76%		5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%		5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%		5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%		5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%		5.86%	5.99%	6.23%
June	8.25%	4.63%	5.10%		6.18%	6.30%	6.54%
July	8.25%	4.84%	5.00%		6.11%	6.25%	6.49%
Aug	8.25%	4.34%	4.67%		6.11%	6.24%	6.51%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	Nasdaq Composite	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988			2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		Current Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	Nasdaq Composite	DJIA	S&P D/P	S&P E/P
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	

Source: Council of Economic Advisors, Economic Indicators, various issues.

HAWAIIAN ELECTRIC INDUSTRIES, INC.
SEGMENT FINANCIAL INFORMATION
2003 - 2005
($000)

Segment	Revenues	Income From Continuing Operations	Capital Expenditures	Assets
		2003		
Electric Utility	$1,396,685 78.4%	$78,911 66.8%	$146,964 90.2%	$2,687,798 28.9%
Bank	$371,320 20.8%	$56,261 47.7%	$15,798 9.7%	$6,515,208 70.0%
Other	$13,311 0.7%	-$17,124 -14.5%	$129 0.1%	$104,694 1.1%
Hawaiian Electric Industries, Inc. (Consolidated)	$1,781,316	$118,048	$162,891	$9,307,700
		2004		
Electric Utility	$1,550,671 80.6%	$81,177 75.3%	$201,236 93.7%	$2,879,615 29.6%
Bank	$364,284 18.9%	$41,062 38.1%	$13,085 6.1%	$6,766,505 69.6%
Other	$9,102 0.5%	-$14,500 -13.5%	$333 0.2%	$73,137 0.8%
Hawaiian Electric Industries, Inc. (Consolidated)	$1,924,057	$107,739	$214,654	$9,719,257
		2005		
Electric Utility	$1,806,384 81.5%	$72,802 57.1%	$217,609 97.3%	$3,081,460 31.0%
Bank	$387,910 17.5%	$64,883 50.9%	$5,731 2.6%	$6,835,335 68.7%
Other	$21,270 1.0%	-$10,241 -8.0%	$335 0.1%	$34,782 0.3%
Hawaiian Electric Industries, Inc. (Consolidated)	$2,215,564	$127,444	$223,675	$9,951,577
		2006		
Electric Utility	$2,054,890 83.5%	$74,947 69.4%	$195,072 92.7%	$3,063,134.0 31.0%
Bank	$408,365 16.6%	$55,782 51.6%	$14,927 7.1%	$6,808,499.0 68.8%
Other	-$2,351 -0.1%	-$22,728 -21.0%	$530 0.3%	$19,576.0 0.2%
(Consolidated) (Consolidated)	$2,460,904	$108,001	$210,529	$9,891,209.0

Source: Respose to CA-IR-9.

BOND RATINGS

	HECO		MECO		HELCO		HEI	
Date	Moody's	S&P	Moody's	S&P	Moody's	S&P	Moody's	S&P
Corporate Credit Rating	Baa1	BBB				BBB		BBB
Revenue Bonds (uninsured)	Baa1	BBB	Baa1	BBB	Baa1	BBB		
Medium Term Notes	Baa1	BBB	Baa1	BBB	Baa1	BBB	Baa2	BBB

Source: Response to CA-IR-10.

HISTORY OF SECURITY RATINGS
HAWAIIAN ELECTRIC COMPANY

	First Mortgage Bonds		Revenue Bonds		Preferred Stock		Commercial Paper	
Year	Moody's	S&P	Moody's	S&P	Moody's	S&P	Moody's	S&P
1974	A	A	A		a	A	P-1	
1975	A	A	A		a	A	P-1	
1976	A	A	A		a	A	P-1	
1977	A	A	A		a	A	P-1	A-1
1978	A	A	A		a	A	P-1	A-1
1979	A	A	A		a	A	P-1	A-1
1980	A	A	A		a	A	P-1	A-1
1981	A	A	A		a	A	P-1	A-1
1982	A1	A+	A2	A	a1	A+	P-1	A-1
1983	A1	A+	A2	A	a1	A+	P-1	A-1
1984	A1	A+	A2	A	a1	A+	P-1	A-1+
1985	A1	A+	A2	A	a1	A+	P-1	A-1+
1986	Aa3	A+	A1	A	aa3	A+	P-1	A-1+
1987	Aa3	A	A1	A-	aa3	A-	P-1	A-1
1988	Aa3	A	A1	A-	aa3	A-	P-1	A-1
1989	A1	A	A2	A-	a1	A-	P-1	A-1
1990	A2	A-	A3	BBB+	a2	BBB+	P-1	A-2
1991	A3	A-	Baa1	BBB+	baa1	BBB+	P-2	A-2
1992	A3	A-	Baa1	BBB+	baa1	BBB+	P-2	A-2
1993	A3	BBB+	Baa1	BBB+	baa1	BBB+	P-2	A-2
1994	A3	BBB+	Baa1	BBB+	baa1	BBB+	P-2	A-2
1995	A3	BBB+	Baa1	BBB+	baa1	BBB+	P-2	A-2
1996	A3	BBB+	Baa1	BBB+	baa1	BBB+	P-2	A-2
1997	A3	A-	Baa1	BBB+	baa1	BBB+	P-2	A-2
1998	A3	A-	Baa1	BBB+	baa1	BBB-	P-2	A-2
1999	All first mortgage bonds		Baa1	BBB+	baa1	BBB-	P-2	A-2
2000	redeemed in 1999.		Baa1	BBB+	baa1	BBB-	P-2	A-2
2001			Baa1	BBB+	baa2	BBB-	P-2	A-2
2002			Baa1	BBB+	baa2	BBB-	P-2	A-2
2003			Baa1	BBB+	baa2	BBB-	P-2	A-2
2004			Baa1	BBB+	baa2	BBB-	P-2	A-2
2005			Baa1	BBB+	baa2	BBB-	P-2	A-2
2006			Baa1	BBB+	baa2	BBB-	P-2	A-2
2007			Baa1	BBB	baa2	BB+	P-2	A-2

Sources: Response to CA-IR-11 in Docket No. 2006-0386 and responses to data requests in prior proceedings.

MAUI ELECTRIC COMPANY
CAPITAL STRUCTURE RATIOS
2002 - 2006
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2002	$181,372	$25,000	$151,680	$0
	50.7%	7.0%	42.4%	0.0%
	50.7%	7.0%	42.4%	
2003	$187,194	$25,000	$143,729	
	52.6%	7.0%	40.4%	0.0%
	52.6%	7.0%	40.4%	
2004	$189,413	$15,000	$143,778	$0
	54.4%	4.3%	41.3%	0.0%
	54.4%	4.3%	41.3%	
2005	$194,190	$15,000	$143,852	
	55.0%	4.2%	40.7%	0.0%
	55.0%	4.2%	40.7%	
2006	$192,231	$15,000	$143,899	$5,000
	54.0%	4.2%	40.4%	1.4%
	54.7%	4.3%	41.0%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to CA-IR-7.

HAWAIIAN ELECTRIC COMPANY (CONSOLIDATED)
CAPITAL STRUCTURE RATIOS
2002 - 2006
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2002	$923,256	$134,293	$705,270	$5,600
	52.2%	7.6%	39.9%	0.3%
	52.4%	7.6%	40.0%	
2003	$944,443	$134,293	$699,420	$6,000
	52.9%	7.5%	39.2%	0.3%
	53.1%	7.6%	39.3%	
2004	$1,017,104	$34,293	$752,735	$88,568
	53.7%	1.8%	39.8%	4.7%
	56.4%	1.9%	41.7%	
2005	$1,039,259	$24,293	$765,993	$136,165
	52.9%	1.2%	39.0%	6.9%
	56.8%	1.3%	41.9%	
2006	$958,203	$34,293	$766,185	$113,107
	51.2%	1.8%	40.9%	6.0%
	54.5%	1.9%	43.6%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to CA-IR-7.

HAWAIIAN ELECTRIC INDUSTRIES, INC.
CAPITAL STRUCTURE RATIOS
2002 - 2006
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2002	$1,046,300	$234,406	$1,106,270	
	43.8%	9.8%	46.3%	0.0%
	43.8%	9.8%	46.3%	
2003	$1,089,031	$234,406	$1,064,420	$0
	45.6%	9.8%	44.6%	0.0%
	45.6%	9.8%	44.6%	
2004	$1,210,945	$34,405	$1,166,735	$76,611
	48.7%	1.4%	46.9%	3.1%
	50.2%	1.4%	48.4%	
2005	$1,216,630	$34,293	$1,142,993	$141,758
	48.0%	1.4%	45.1%	5.6%
	50.8%	1.4%	47.7%	
2006	$1,095,240	$34,293	$1,133,185	$176,272
	44.9%	1.4%	46.5%	7.2%
	48.4%	1.5%	50.1%	

Note: Percentages may not total 100.0% due to rounding.

Long-term and short-term debt figures do not include borrowings of bank.

Source: Hawaiian Electric Industries, Inc. Form 10-K.

AUS UTILITY REPORTS
ELECTRIC UTILITY GROUPS
AVERAGE COMMON EQUITY RATIOS

Year	Electric	Combination Electric and Gas
2002	38%	36%
2003	42%	38%
2004	47%	43%
2005	44%	47%
2006	45%	44%

Note: Averages include short-term debt.

Source: AUS Utility Reports.

COMPARISON COMPANIES
BASIS FOR SELECTION
USING COMMISSION CRITERIA

Company	Market Cap (000)	Percent Revenues Electric	Common Equity Ratio	Value Line Safety	Moody's/ Bond Rating
Hawaiian Electric Industries	$2,200,000	84%	49%	2	Baa2
Comparison Group*					
Avista	$1,200,000	50%	46%	3	Baa3
Empire District Electric	$700,000	91%	50%	3	Baa1
IDACORP	$1,500,000	99%	55%	3	A3
OGE Energy	$3,200,000	43%	54%	2	Baa2
Pinnacle West Capital	$4,800,000	77%	52%	1	Baa2
PNM Resources	$2,500,000	79%	49%	2	Baa2
Puget Energy	$3,000,000	61%	44%	3	Baa2
UIL Holdings	$825,000	90%	53%	3	Baa2
Westar Energy	$2,300,000	72%	49%	2	Baa3

* Selected using following criteria:
Market cap of $500 million to $5 billion.
Electric Revenues of 40% or greater.
Common Equity Ratio of 35% to 55%.
Value Line Safety of 1, 2 or 3.
Moody's bond ratings of Baa or A.

Sources: C.A. Turner Utility Reports, Standard & Poor's Stock Guide, Value Line Investment Survey.

COMPARISON COMPANIES
BASIS FOR SELECTION
USING PARCELL CRITERIA

Company	Net Utility Plant (000)	Percent Revenues Electric	Common Equity Ratio	Standard & Poor's Stock Ranking	Moody's/ Bond Rating
Hawaiian Electric Industries	$2,647,500	84%	49%	B+	Baa2
Comparison Group*					
Avista	$2,215,000	50%	46%	B+	Baa3
Empire District Electric	$1,031,000	91%	50%	B+	Baa1
IDACORP	$2,419,100	99%	54%	B+	A3
NSTAR	$3,945,300	81%	40%	A-	A1
PNM Resources	$3,761,900	79%	49%	B+	Baa2
Puget Energy	$5,181,100	61%	44%	B+	Baa2

* Selected using following criteria:
Net Utility Plant of $1 billion to $5 billion.
Electric Revenues of 50% or greater.
Common Equity Ratio of 40% to 55%.
Standard & Poor's Stock Ranking of B or B+.or A-
Moody's bond ratings of BBB or A.
No nuclear generation.

Sources: C.A. Turner Utility Reports, Standard & Poor's Stock Guide, Value Line Investment Survey.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	DPS	July - September, 2007 HIGH	LOW	AVERAGE	YIELD
Comparison Group - PUC Criteria					
Avista	$0.60	$22.38	$18.19	$20.29	3.0%
Empire District Electric	$1.28	$24.29	$21.09	$22.69	5.6%
IDACORP	$1.20	$36.57	$30.07	$33.32	3.6%
OGE Energy	$1.36	$37.59	$29.12	$33.36	4.1%
Pinnacle West Capital	$2.10	$41.76	$36.79	$39.28	5.3%
PNM Resources	$0.92	$28.71	$21.05	$24.88	3.7%
Puget Energy	$1.00	$25.38	$22.47	$23.93	4.2%
UIL Holdings	$1.73	$33.89	$27.02	$30.46	5.7%
Westar Energy	$1.08	$25.43	$22.84	$24.14	4.5%
Average					**4.4%**
Comparison Group - Parcell Criteria					
Avista	$0.60	$22.38	$18.19	$20.29	3.0%
Empire District Electric	$1.28	$24.29	$21.09	$22.69	5.6%
Hawaiian Electric Industries	$1.24	$23.91	$20.25	$33.32	3.7%
IDACORP	$1.20	$36.57	$30.07	$33.32	3.6%
NSTAR	$1.30	$35.05	$30.75	$32.90	4.0%
PNM Resources	$0.92	$28.71	$21.05	$24.88	3.7%
Puget Energy	$1.00	$25.38	$22.47	$23.93	4.2%
Average					**4.0%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2002	2003	2004	2005	2006	Average	2007	2008	2010-2012	Average
Comparison Group - PUC Criteria										
Avista	1.2%	3.4%	1.4%	2.4%	4.9%	2.7%	2.5%	4.0%	3.0%	3.2%
Empire District Electric	0.0%	0.1%	0.0%	0.0%	0.8%	0.2%	1.0%	2.0%	3.0%	2.0%
IDACORP	0.0%	0.0%	2.7%	1.3%	4.3%	1.7%	3.0%	3.5%	3.5%	3.3%
OGE Energy	1.2%	3.6%	3.4%	3.4%	6.6%	3.6%	5.5%	5.5%	5.5%	5.5%
Pinnacle West Capital	2.9%	2.6%	2.3%	1.0%	3.4%	2.4%	1.0%	1.5%	1.5%	1.3%
PNM Resources	3.1%	3.0%	4.5%	4.3%	3.7%	3.7%	4.5%	4.0%	3.5%	4.0%
Puget Energy	1.3%	2.1%	2.8%	2.9%	3.0%	2.4%	3.0%	3.5%	4.0%	3.5%
UIL Holdings	0.6%	0.0%	0.0%	0.0%	0.0%	0.1%	0.5%	1.0%	2.0%	1.2%
Westar Energy	0.0%	4.9%	3.2%	4.3%	5.5%	3.6%	3.5%	3.5%	3.5%	3.5%
Average						**2.3%**				**3.1%**
Comparison Group - Parcell Criteria										
Avista	1.2%	3.4%	1.4%	2.4%	4.9%	2.7%	2.5%	4.0%	3.0%	3.2%
Empire District Electric	0.0%	0.1%	0.0%	0.0%	0.8%	0.2%	1.0%	2.0%	3.0%	2.0%
Hawaiian Electric Industries	4.3%	3.9%	1.1%	1.5%	0.7%	2.3%	0.0%	0.0%	2.5%	0.8%
IDACORP	0.0%	0.0%	2.7%	1.3%	4.3%	1.7%	3.0%	3.5%	3.5%	3.3%
NSTAR	5.2%	5.1%	4.8%	4.6%	4.9%	4.9%	5.0%	5.0%	6.0%	5.3%
PNM Resources	3.1%	3.0%	4.5%	4.3%	3.7%	3.7%	4.5%	4.0%	3.5%	4.0%
Puget Energy	1.3%	2.1%	2.8%	2.9%	3.0%	2.4%	3.0%	3.5%	4.0%	3.5%
Average						**2.6%**				**3.2%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '04-'06 to '10-'12 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Comparison Group - PUC Criteria								
Avista	0.5%	2.5%	3.5%	2.2%	9.0%	12.5%	4.0%	8.5%
Empire District Electric	1.0%	0.0%	2.0%	1.0%	11.0%	1.5%	3.0%	5.2%
IDACORP	-8.5%	-8.5%	2.5%	-4.8%	2.0%	0.0%	4.0%	2.0%
OGE Energy	3.5%	0.0%	3.5%	2.3%	5.5%	2.5%	6.5%	4.8%
Pinnacle West Capital	-5.0%	6.0%	4.0%	1.7%	1.5%	3.0%	1.5%	2.0%
PNM Resources	-2.5%	7.5%	4.5%	3.2%	4.5%	6.0%	5.5%	5.3%
Puget Energy	-4.5%	-11.5%	1.5%	-4.8%	6.0%	3.0%	4.0%	4.3%
UIL Holdings	-8.5%	0.0%	1.0%	-2.5%	5.5%	0.0%	-1.0%	1.5%
Westar Energy	21.0%	-11.0%	-9.0%	0.3%	4.5%	6.0%	4.5%	5.0%
Average				**-0.2%**				**4.3%**
Comparison Group - Parcell Criteria								
Avista	0.5%	2.5%	3.5%	2.2%	9.0%	12.5%	4.0%	8.5%
Empire District Electric	1.0%	0.0%	2.0%	1.0%	11.0%	1.5%	3.0%	5.2%
Hawaiian Electric Industries	-1.0%	0.0%	2.0%	0.3%	1.5%	0.0%	-0.5%	0.3%
IDACORP	-8.5%	-8.5%	2.5%	-4.8%	2.0%	0.0%	4.0%	2.0%
NSTAR	3.5%	3.0%	2.5%	3.0%	8.5%	7.0%	5.5%	7.0%
PNM Resources	-2.5%	7.5%	4.5%	3.2%	4.5%	6.0%	5.5%	5.3%
Puget Energy	-4.5%	-11.5%	1.5%	-4.8%	6.0%	3.0%	4.0%	4.3%
Average				**0.0%**				**4.7%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Comparison Group - PUC Criteria								
Avista	3.0%	2.7%	3.2%	2.2%	8.5%	4.5%	4.2%	7.2%
Empire District Electric	5.7%	0.2%	2.0%	1.0%	5.2%	1/	2.1%	7.8%
IDACORP	3.7%	1.7%	3.3%		2.0%	5.0%	3.0%	6.7%
OGE Energy	4.2%	3.6%	5.5%	2.3%	4.8%	4.0%	4.1%	8.2%
Pinnacle West Capital	5.4%	2.4%	1.3%	1.7%	2.0%	5.7%	2.6%	8.1%
PNM Resources	3.8%	3.7%	4.0%	3.2%	5.3%	10.5%	5.3%	9.1%
Puget Energy	4.3%	2.4%	3.5%		4.3%	5.3%	3.9%	8.1%
UIL Holdings	5.8%	0.1%	1.2%		1.5%	10.0%	3.2%	9.0%
Westar Energy	4.6%	3.6%	3.5%	0.3%	5.0%	5.3%	3.5%	8.1%
Average	4.5%	2.3%	3.1%	1.8%	4.3%	6.3%	3.5%	**8.0%**
Median								**8.1%**
Composite		6.7%	7.5%	6.3%	8.8%	**10.8%**	8.0%	
Comparison Group - Parcell Criteria								
Avista	3.0%	2.7%	3.2%	2.2%	8.5%	4.5%	4.2%	7.2%
Empire District Electric	5.7%	0.2%	2.0%	1.0%	5.2%	1/	2.1%	7.8%
Hawaiian Electric Industries	3.7%	2.3%	0.8%	0.3%	0.3%	2.3%	1.2%	5.0%
IDACORP	3.7%	1.7%	3.3%		2.0%	5.0%	3.0%	6.7%
NSTAR	4.1%	4.9%	5.3%	3.0%	7.0%	6.7%	5.4%	9.4%
PNM Resources	3.8%	3.7%	4.0%	3.2%	5.3%	10.5%	5.3%	9.1%
Puget Energy	4.3%	2.4%	3.5%		4.3%	5.3%	3.9%	8.1%
Average	4.0%	2.6%	3.2%	1.9%	4.7%	5.7%	3.6%	**7.6%**
Median								**7.8%**
Composite		6.6%	7.2%	6.0%	8.7%	**9.7%**	7.6%	

1/ The First Call EPS projection for Empire District Electric of 34 percent is not considered since this is not deemed to be sustainable.

Note: Negative average values not considered.

Sources: Prior pages of this schedule.

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.07	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$18.86	$149.74	12.22%	7.26%	4.96%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$216.51	16.58%	7.60%	8.98%
1996	$38.73	$237.08	17.08%	6.18%	10.90%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.70	$337.37	7.45%	5.53%	1.92%
2002	$27.59	$321.72	8.37%	5.59%	2.78%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
Average					**6.18%**

Sources: Standard & Poor's Analysts' Handbook and Ibbotson Associates 2006 Yearbook.

COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	MARKET PREMIUM	CAPM RATES
Comparison Group - PUC Criteria				
Avista	5.01%	0.90	5.90%	10.3%
Empire District Electric	5.01%	0.85	5.90%	10.0%
IDACORP	5.01%	1.05	5.90%	11.2%
OGE Energy	5.01%	0.75	5.90%	9.4%
Pinnacle West Capital	5.01%	1.00	5.90%	10.9%
PNM Resources	5.01%	0.95	5.90%	10.6%
Puget Energy	5.01%	0.85	5.90%	10.0%
UIL Holdings	5.01%	0.90	5.90%	10.3%
Westar Energy	5.01%	0.90	5.90%	10.3%
Average				**10.4%**
Median				**10.3%**
Comparison Group - Parcell Criteria				
Avista	5.01%	0.90	5.90%	10.3%
Empire District Electric	5.01%	0.85	5.90%	10.0%
Hawaiian Electric Industries	5.01%	0.75	5.90%	9.4%
IDACORP	5.01%	1.05	5.90%	11.2%
NSTAR	5.01%	0.75	5.90%	9.4%
PNM Resources	5.01%	0.95	5.90%	10.6%
Puget Energy	5.01%	0.85	5.90%	10.0%
Average				**10.2%**
Median				**10.0%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES
CAPM COST RATES
USING IBBOTSON RISK PREMIUM

COMPANY	RISK-FREE RATE	BETA	MARKET PREMIUM	CAPM RATES
Comparison Group - PUC Criteria				
Avista	5.01%	0.90	6.50%	10.9%
Empire District Electric	5.01%	0.85	6.50%	10.5%
IDACORP	5.01%	1.05	6.50%	11.8%
OGE Energy	5.01%	0.75	6.50%	9.9%
Pinnacle West Capital	5.01%	1.00	6.50%	11.5%
PNM Resources	5.01%	0.95	6.50%	11.2%
Puget Energy	5.01%	0.85	6.50%	10.5%
UIL Holdings	5.01%	0.90	6.50%	10.9%
Westar Energy	5.01%	0.90	6.50%	10.9%
Average				**10.9%**
Median				**10.9%**
Comparison Group - Parcell Criteria				
Avista	5.01%	0.90	6.50%	10.9%
Empire District Electric	5.01%	0.85	6.50%	10.5%
Hawaiian Electric Industries	5.01%	0.75	6.50%	9.9%
IDACORP	5.01%	1.05	6.50%	11.8%
NSTAR	5.01%	0.75	6.50%	9.9%
PNM Resources	5.01%	0.95	6.50%	11.2%
Puget Energy	5.01%	0.85	6.50%	10.5%
Average				**10.7%**
Median				**10.5%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

Company	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	1992-2001 Average	2001-2005 Average	2006	2007	2009-2011
Comparison Group - PUC Criteria																				
Avista	11.7%	12.2%	10.5%	11.2%	10.6%	15.0%	10.2%	1.1%	13.4%	7.9%	4.5%	6.7%	4.6%	5.8%	8.8%	10.4%	6.1%	5.5%	7.5%	8.0%
Empire District Electric	10.3%	9.4%	10.6%	9.4%	9.4%	9.9%	11.6%	8.4%	10.0%	4.3%	8.4%	8.7%	5.7%	6.2%	9.2%	9.3%	7.6%	9.0%	9.5%	11.0%
IDACORP	9.0%	11.2%	10.1%	11.6%	12.1%	12.4%	12.4%	12.3%	16.7%	14.9%	7.1%	4.2%	8.2%	7.3%	9.4%	12.3%	7.2%	7.5%	7.5%	7.0%
OGE Energy	10.8%	12.4%	13.3%	13.2%	13.8%	13.4%	16.3%	14.9%	14.1%	9.6%	11.1%	13.2%	12.7%	12.4%	14.9%	13.2%	12.9%	13.0%	12.5%	12.5%
Pinnacle West Capital	10.7%	10.9%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.2%	6.7%	9.2%	11.5%	8.2%	7.5%	7.5%	8.0%
PNM Resources	4.6%	8.6%	11.7%	8.5%	9.9%	10.0%	11.3%	9.1%	10.2%	15.8%	6.3%	6.7%	7.9%	8.6%	8.4%	10.0%	7.6%	8.0%	8.0%	7.5%
Puget Energy	12.4%	11.0%	8.8%	10.2%	10.2%	7.4%	11.5%	11.8%	13.2%	7.6%	7.8%	7.4%	8.0%	8.4%	8.1%	10.4%	7.9%	8.5%	8.5%	9.0%
Util. Holdings	8.2%	8.0%	8.1%	9.3%	8.1%	8.4%	7.7%	9.5%	10.9%	10.8%	7.8%	5.2%	6.4%	5.4%	7.6%	8.9%	6.5%	9.5%	10.0%	10.5%
Westar Energy	11.0%	12.4%	10.7%	11.1%	10.4%	-1.6%	7.1%	5.2%	3.2%	-2.2%	5.0%	10.6%	7.7%	9.6%	11.1%	6.7%	8.8%	9.0%	9.5%	9.0%
Average	9.9%	10.7%	10.4%	10.6%	10.6%	9.6%	11.1%	9.4%	11.6%	9.1%	7.4%	7.9%	7.7%	7.8%	9.6%	**10.3%**	**8.1%**	**8.6%**	**8.9%**	**9.2%**
Composite																**10.3%**	**8.1%**			
Comparison Group - Parcell Criteria																				
Avista	11.7%	12.2%	10.5%	11.2%	10.6%	15.0%	10.2%	1.1%	13.4%	7.9%	4.5%	6.7%	4.6%	5.8%	8.8%	10.4%	6.1%	5.5%	7.5%	8.0%
Empire Distnct Electric	10.3%	9.4%	10.6%	9.4%	9.4%	9.9%	11.6%	8.4%	10.0%	4.3%	8.4%	8.7%	5.7%	6.2%	9.2%	9.3%	7.6%	9.0%	9.5%	11.0%
Hawaiian Electric Industries	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	11.0%	10.3%	7.5%	9.0%	11.0%
IDACORP	9.0%	11.2%	10.1%	11.6%	12.1%	12.4%	12.4%	12.3%	16.7%	14.9%	7.1%	4.2%	8.2%	7.3%	9.4%	12.3%	7.2%	7.5%	7.5%	7.0%
NSTAR	11.4%	11.9%	12.2%	10.2%	12.6%	12.6%	12.5%	11.4%	12.3%	13.4%	14.0%	13.9%	13.4%	13.1%	13.2%	12.1%	13.5%	13.5%	14.0%	15.0%
PNM Resources	4.6%	8.6%	11.7%	8.5%	9.9%	10.0%	11.3%	9.1%	10.2%	15.8%	6.3%	6.7%	7.9%	8.6%	8.4%	10.0%	7.6%	8.0%	8.0%	7.5%
Puget Energy	12.4%	11.0%	8.8%	10.2%	10.2%	7.4%	11.5%	11.8%	13.2%	7.6%	7.8%	7.4%	8.0%	8.4%	8.1%	10.4%	7.9%	8.5%	8.5%	9.0%
Average	10.0%	10.7%	10.7%	10.3%	10.8%	11.2%	11.6%	9.3%	12.2%	10.9%	8.6%	8.4%	8.2%	8.4%	9.5%	**10.8%**	**8.6%**	**8.5%**	**9.1%**	**9.8%**
Composite																**10.8%**	**8.6%**			

Source: Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

Company	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	1992-2001 Average	2001-2005 Average
Comparison Group - PUC Criteria																	
Avista	151%	163%	133%	125%	145%	162%	163%	152%	317%	114%	85%	94%	111%	115%	135%	163%	108%
Empire District Electric	184%	178%	143%	142%	143%	138%	168%	177%	183%	162%	132%	133%	144%	148%	149%	162%	141%
IDACORP	155%	172%	146%	148%	168%	177%	177%	158%	189%	185%	134%	112%	125%	122%	139%	168%	126%
OGE Energy	165%	159%	147%	166%	171%	196%	222%	183%	154%	168%	147%	153%	178%	189%	204%	173%	174%
Pinnacle West Capital	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	129%	136%	124%
PNM Resources	72%	84%	87%	95%	108%	106%	106%	85%	94%	123%	95%	93%	124%	147%	134%	96%	119%
Puget Energy	149%	146%	112%	119%	130%	155%	170%	146%	143%	143%	126%	129%	137%	133%	129%	141%	131%
UIL Holdings	109%	121%	98%	97%	91%	90%	123%	119%	120%	124%	110%	97%	120%	126%	145%	109%	120%
Westar Energy	144%	152%	130%	129%	126%	131%	128%	89%	74%	78%	67%	109%	132%	142%	139%	118%	118%
Average	138%	144%	122%	126%	135%	145%	160%	139%	158%	139%	112%	115%	133%	139%	145%	141%	129%
Composite																141%	129%
Comparison Group - Parcell Criteria																	
Avista	151%	163%	133%	125%	145%	162%	163%	152%	317%	114%	85%	94%	111%	115%	135%	163%	108%
Empire District Electric	184%	178%	143%	142%	143%	138%	168%	177%	183%	162%	132%	133%	144%	148%	149%	162%	141%
Hawaiian Electric Industries	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	155%	171%
IDACORP	155%	172%	146%	148%	168%	177%	177%	158%	189%	185%	134%	112%	125%	122%	139%	168%	126%
NSTAR	138%	154%	130%	130%	125%	146%	181%	166%	161%	161%	170%	175%	189%	202%	214%	149%	190%
PNM Resources	72%	84%	87%	95%	108%	106%	106%	85%	94%	123%	95%	93%	124%	147%	134%	96%	119%
Puget Energy	149%	146%	112%	119%	130%	155%	170%	146%	143%	143%	126%	129%	137%	133%	129%	141%	131%
Average	146%	150%	127%	130%	138%	147%	160%	145%	173%	148%	128%	127%	144%	150%	156%	148%	141%
Composite																146%	141%

Source: Calculations made from data contained in Value Line Investment Survey.

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2005

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
Averages:		
1992-2001	14.7%	341%
2001-2005	12.2%	299%

Source: Standard & Poor's Analyst's Handbook, 2006 edition, page 1.

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Comparison Group - PUC Criteria	2.4	0.91	B++	B+
Comparison Group - Parcell Criteria	2.4	0.87	B+	B+
Hawaiian Electric Industries	2.0	0.75	A	B+

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the latter representing the highest level.

MAUI ELECTRIC COMPANY
TOTAL COST OF CAPITAL

ITEM	PERCENT		COST RATE		WEIGHTED COST	
Short-Term Debt	1.27%		5.00%		0.06%	
Long-Term Debt	40.15%		6.11%		2.45%	
Hybrid Securities	2.45%		7.47%		0.18%	
Preferred Stock	1.25%		8.34%		0.10%	
Common Equity	54.89%	9.50%		10.50%	5.21%	5.76%
Total	100.01%				**8.02%**	**8.57%**
						8.29% Mid-point

MAUI ELECTRIC COMPANY
PRE-TAX COVERAGE

ITEM	AMOUNT ($000)	PERCENT	COST RATE	WEIGHTED COST	PRE-TAX COST
Short-Term Debt	$4,750	1.26%	5.00%	0.06%	0.06%
Long-Term Debt	$150,585	39.92%	6.11%	2.44%	2.44%
Purchased Power (1)	$2,122	0.56%	10.00%	0.06%	0.06%
Hybrid Securities	$9,192	2.44%	7.47%	0.18%	0.18%
Preferred Stock	$4,693	1.24%	8.34%	0.10%	0.17%
Common Equity	$205,882	54.58%	10.00%	5.46%	9.10%
TOTAL CAPITAL	$377,224	100.00%		8.30%	12.01%

(1) Average 2007 Purchased Power 'debt equivalent" from MECO-WP-1718, page 3.

Pre-tax coverage = 12.01%/(0.06%+2.42%+0.06%)
4.69 X

Standard & Poor's Utility Benchmark Ratios:

	A	BBB
Pre-tax coverage (X) Business Position:		
5	3.5 - 4.3x	2.4 - 3.5x
Total Debt to Total Capital (%) Business Position		
5	42 - 50%	50 - 60%

Note: *Since 2004, S&P no longer uses the ratio "Pre-tax Coverage" as one* of its benchmark ratios. The benchmark levels shown above reflect the 1999 levels cited by S&P.

RISK PREMIUM BY DECADE AS DERIVED BY MECO WITNESS MORIN

Year	Risk Premium	Risk Premium By Decade
1932	-21.32%	
1933	-22.79%	
1934	-31.59%	
1935	72.01%	
1936	14.27%	
1937	-37.48%	
1938	13.62%	
1939	3.51%	-1.22%
1940	-25.08%	
1941	-34.06%	
1942	20.33%	
1943	55.10%	
1944	4.01%	
1945	43.97%	
1946	9.91%	
1947	-14.14%	
1948	5.33%	
1949	16.16%	8.15%
1950	7.15%	
1951	20.72%	
1952	16.32%	
1953	6.62%	
1954	22.43%	
1955	9.27%	
1956	8.24%	
1957	1.09%	
1958	42.03%	
1959	7.79%	14.17%
1960	7.17%	
1961	33.94%	
1962	-6.66%	
1963	8.50%	
1964	13.16%	
1965	2.20%	
1966	-7.93%	
1967	4.38%	
1968	9.92%	
1969	-10.60%	5.41%
1970	-0.93%	
1971	-10.38%	
1972	-2.27%	
1973	-13.87%	
1974	-28.22%	
1975	44.15%	
1976	11.66%	
1977	12.32%	
1978	-2.88%	
1979	5.74%	1.53%
1980	12.25%	
1981	15.63%	
1982	3.61%	
1983	10.64%	
1984	8.87%	
1985	-1.27%	
1986	2.89%	
1987	-5.07%	
1988	6.97%	
1989	10.99%	6.55%
1990	-2.20%	
1991	9.61%	
1992	-3.65%	
1993	-4.82%	
1994	-7.31%	
1995	0.98%	
1996	3.11%	
1997	6.25%	
1998	8.62%	
1999	-10.32%	0.03%
2000	50.09%	
2001	-11.34%	
2002	-28.38%	
2003	21.30%	
2004	16.64%	
2005	9.00%	

Source: MECO-1602.

COMPANY		CAP ($000)	PLANT ($000)	REVENUES ($000)	ELECTRIC REVENUES (%)	EQUITY RATIO	VALUE LINE SAFETY	VALUE LINE BETA	FIN STR	S&P STOCK RANKING	S&P BOND RATING	MOODY'S BOND RATING	COAL	OIL	GAS	NUCLEAR	HYDRO	PURCH
ALLETE	Minnesota Power	$1,400,000	$921,600	$767,100	83%	64.9%	2	0.90	A	B+	A	Baa1	66%				2%	32%
Alliant Energy	WPL, IES & ISP	$4,500,000	$4,944,900	$3,359,400	73%	62.9%	3	0.95	A	B	A-	A2	57%		•	1%		42%
Allegheny Energy		$9,000,000	$6,512,900	$3,121,500	81%	37.7%	4	2.10	C++	B	BBB-	Baa3	79%	1%	9%		11%	
Ameren Corp.	Un El & CIPSCO	$10,300,000	$14,286,000	$6,880,000	81%	54.6%	2	0.75	A	A-	BBB	Baa1	85%			13%		
American Electric Power Company	AEP & C&SW	$18,000,000	$26,781,000	$12,622,000	94%	43.0%	3	1.35	B++	B	BBB	Baa1						
Aquila, Inc.	UtiliCorp	$1,600,000	$1,955,300	$1,369,600	56%	48.5%	5	1.55	C	C	B	B2	49%	4%	4%			43%
Avista Corp.	Wash Water Pwr	$1,200,000	$2,215,000	$1,506,300	50%	46.3%	3	0.95	B+	B	BBB-	Baa3	15%		13%		36%	34%
Black Hills Corp.	Black Hills Power	$1,300,000	$1,646,400	$656,900	29%	55.7%	3	1.10	B+	B	BBB	Baa1	52%		2%			46%
CMS Energy Corp.	Consumers Energy	$3,900,000	$7,976,000	$6,810,000	48%	24.9%	3	1.65	B	C	BBB-	Baa2	44%			15%		41%
CH Energy Group, Inc.	Cen Hud G & E	$775,000	$827,100	$993,400	51%	58.8%	1	0.85	A	A-	A	A2					3%	97%
CenterPoint Energy, Inc.	Houston Electric	$5,700,000	$9,204,000	$9,319,000	19%	16.6%	3	0.65	B	B	BBB	Baa2	Sold generation assets					
Central Vermont Public Service Corp		$375,000	$208,800	$325,700	100%	57.3%	3	0.70	B	B+	BBB	NR				54%	38%	
Cleco Corp.	Cen La Elec	$1,500,000	$1,304,900	$1,000,700	96%	57.8%	3	1.30	B+	B+	BBB	Baa1	31%	7%	6%			56%
Consolidated Edison, Inc.		$13,100,000	$18,445,000	$12,137,000	63%	48.5%	1	0.75	A++	B+	A	A1						100%
Constellation Energy Group	Baltimore Gas & Elec	$17,000,000	$9,222,100	$19,285,000	11%	51.1%	2	0.95	A	B+	BBB+	Baa2	30%		15%	52%		
DPL, Inc.	Dayton P&L	$3,300,000	$2,559,300	$1,393,500	100%	31.1%	3	0.95	B	B+	BBB		65%					
Duquesne Light Holdings, Inc.	Duquesne Light	$1,800,000	$1,853,800	$902,200	78%	36.8%	4	0.95	B	B	BBB+	Baa1	Sold generation assets in 2000					
Dominion Resources	VA Power	$32,000,000	$29,382,000	$16,482,000	33%	46.2%	2	1.05	B++	B+	BBB+	Baa1	38%	1%	4%	31%		26%
DTE Energy Company	Detroit Edison	$9,000,000	$11,451,000	$9,022,000	53%	43.9%	3	0.75	B+	B	BBB+	A3	67%	2%	1%	13%		17%
Duke Energy Corp.	Duke Pwr, CG&E, PSI	$37,000,000	$29,200,000	$16,746,000	50%	53.1%	2	1.20	A	B	BBB+	A2	51%			44%		4%
Edison International	So. Cal Edison	$17,000,000	$15,913,000	$12,622,000	82%	43.5%	3	1.10	B++	B	BBB+	Baa1	13%			45%	23%	
El Paso Electric Co.		$1,300,000	$1,332,200	$816,500	97%	48.5%	2	0.70	B++	B	BB-	Ba1	9%		25%	42%		24%
Empire District Electric Company		$700,000	$1,031,000	$413,500	91%	50.3%	3	0.85	B+	B	BBB+	Baa1	46%	9%	8%		1%	37%
Energy East Corp	NYSEG, RG&E, CMP	$3,600,000	$5,948,000	$5,230,700	58%	43.3%	2	0.95	B++	B+	BBB+	A3						near 100%
Entergy Corp.		$21,500,000	$19,438,000	$10,932,000	83%	47.2%	2	0.90	A	A-	BBB-	Baa2	11%	8%	7%	33%		41%
Exelon Corp.	PECO & Comm Ed	$52,000,000	$22,775,000	$15,655,000	67%	45.4%	1	0.90	A+	B+	BBB	Baa1				73%		20%
FPL Group, Inc.	Florida P & L	$26,900,000	$24,499,000	$15,710,000	76%	50.9%	1	0.85	A+	A-	A	Aa3	5%	26%	26%	20%		17%
FirstEnergy Corp.	OhEd,CIE,Tol,MeEd,JC	$23,000,000	$14,667,000	$11,501,000	85%	51.4%	2	0.85	A	B+	BBB	Baa1	44%			26%		30%
Great Plains Energy Inc.	KCP&L	$2,600,000	$3,066,200	$2,675,300	43%	67.5%	2	0.95	A	B	BBB	A3	72%	1%		21%		3%
Green Mountain Power Corp.		$185,000	$245,000	$240,500	100%	52.5%	3	0.60	B++		BBB	Baa1	1%	1%	1%	41%	44%	10%
Hawaiian Electric Industries, Inc	Hawaiian Elec. Co.	$2,200,000	$2,647,500	$2,460,900	84%	48.6%	2	0.75	A	B+	BBB	Baa2		62%				38%
IDACORP	Idaho Power	$1,500,000	$2,419,100	$926,300	99%	54.8%	3	1.05	B+	B	A-	A3	33%				43%	24%
Integrys Energy Group	Wisconsin Pub Ser	$4,000,000	$2,534,800	$6,890,700	16%	53.4%	2	0.85	B++	A-	A+	Aa2	62%				2%	36%
MDU Resources Group	Montana Dak Util	$5,500,000	$2,993,400	$4,070,700	5%	64.5%	1	1.00	A+	A	A-	A2	86%	1%				13%
MGE Energy Inc.	Madison Gas & Elec	$700,000	$728,400	$507,500	63%	61.3%	1	0.80	A	B+	AA-	Aa3	49%					44%
NiSource Inc.	NIPSCO	$5,800,000	$9,694,500	$7,490,000	17%	49.3%	3	0.95	B+	B	BBB	Baa2	81%					19%
Northeast Utilities		$5,000,000	$6,242,200	$6,884,400	77%	39.7%	3	0.90	B+	B	BBB	Baa1		•		•	•	•
NSTAR	Boston Edison	$3,900,000	$3,945,300	$3,577,700	81%	39.7%	1	0.80	A	A-	A+	A1	Sold generation assets in 1998 & 1999					
OGE Energy Corp.	Okla Gas & Elec	$3,200,000	$3,867,500	$4,005,600	43%	54.4%	2	0.80	A	A-	BBB+	Baa2	58%		28%			14%
Otter Tail Corp	Otter Tail Power	$950,000	$718,600	$1,105,000	27%	64.5%	2	0.65	A	A-	BBB+	A3	49%					50%
PG&E Corp.	Pacific G & E	$19,000,000	$21,785,000	$12,539,000	70%	52.9%	2	1.20	B++	B	BBB	Baa1				36%	62%	
PPL Corp	Penn P & L	$17,000,000	$12,069,000	$6,899,000	66%	42.2%	2	0.95	B++	B+	A-	A3						
Pinnacle West Capital Corp.	Ariz Pub Ser	$4,800,000	$7,881,900	$3,401,800	77%	51.6%	1	1.00	A	A-	BBB-	Baa2	31%		7%	17%		35%
Pepco Holdings, Inc.	Pepco & Conectiv	$5,900,000	$7,576,600	$8,362,900	58%	45.1%	3	0.90	B	B	BBB+	Baa1						100%
Progress Energy	CP&L & Fl Prog	$13,400,000	$15,245,000	$9,570,000	86%	48.1%	2	0.95	B++	B	BBB	A3	16%	16%	16%	43%	1%	6%
Public Service Enterprise Group, Inc.	PSE&G	$24,300,000	$13,002,000	$12,164,000	61%	39.2%	3	1.00	B++	B+	A-	A3						
PNM Resources	P S of New Mexico	$2,500,000	$3,761,900	$2,471,700	79%	48.8%	2	0.95	B++	B+	BBB	Baa2	71%	1%	2%	26%		
Puget Energy, Inc.	Puget Sound Energy	$3,000,000	$5,181,000	$2,905,700	61%	44.4%	3	0.85	B+	B	BBB	Baa2	20%	2%	1%		4%	72%
SCANA Corp.	SCE&G	$5,100,000	$7,007,000	$4,563,000	41%	47.2%	2	0.85	A	B	A-	A1	66%	5%	4%	19%	4%	2%
Sempra Energy	San Diego G & E	$17,000,000	$13,175,000	$11,761,000	40%	61.4%	2	1.10	A	B+	A+	A1	Purchases most of power					
Sierra Pacific Resources	Nev Pwr & SP Pwr	$4,000,000	$6,087,000	$3,356,000	94%	39.6%	3	1.25	B	B	BB+	Ba1	19%	16%	16%			49%
Southern Company	GA Pwr, Ala Pwr, M Pw	$28,000,000	$31,092,000	$14,356,000	98%	46.2%	1	0.70	A	A-	A	A2	67%	6%	6%	14%	2%	5%
TECO Energy, Inc.	Tampa Elec	$3,800,000	$4,766,900	$3,448,100	60%	35.0%	3	1.05	B	B	BBB-	Baa2	54%	1%	32%			13%
TXU Corp	Texas Utilities	$30,900,000	$18,756,000	$10,856,000	23%	16.8%	3	1.10	B	B	BBB-	Baa2						
UniSource Energy Corp.	Tucson Electric Power	$1,400,000	$2,259,600	$1,316,900	85%	27.1%	3	0.75	C++	B	BBB-	Baa2	81%		6%			13%
UIL Holdings	United Illum	$825,000	$647,000	$846,000	90%	53.0%	3	0.95	B+	B	NR	Baa2						
Vectren	Ind Ener & SIGCORP	$2,100,000	$2,385,500	$2,041,600	21%	49.3%	2	0.95	A	B+	A	A3						
Westar Energy, Inc.	KP&L	$2,300,000	$4,071,600	$1,605,700	72%	49.3%	2	0.95	B++	B	BB+	Baa3	79%		7%	14%		
Wisconsin Energy Corp.	We Energies	$5,300,000	$7,052,500	$3,996,400	63%	48.2%	2	0.80	B++	B	A-	A1	55%		4%	26%	1%	14%
Xcel Energy Inc.	N S Pwr, PSC, SWPS	$9,900,000	$15,549,000	$9,840,300	77%	47.0%	2	0.90	B++	B	BBB+	A3	48%	5%	5%	11%		30%

CA-WP-406
Docket No. 2006-0387

AVISTA

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		10.43				
1976	1.51	11.09	13.2	9.8	14.0%	107%
1977	1.19	11.36	12.8	10.3	10.6%	103%
1978	1.60	11.94	12.2	10.2	13.7%	96%
1979	1.39	12.23	11.8	9.5	11.5%	88%
1980	1.17	11.78	10.3	7.6	9.7%	75%
1981	1.65	11.45	9.2	7.8	14.2%	73%
1982	1.59	11.27	10.8	8.5	14.0%	85%
1983	1.51	11.34	11.4	9.3	13.4%	92%
1984	1.35	11.22	10.3	8.0	12.0%	81%
1985	1.52	11.49	12.6	9.3	13.4%	96%
1986	1.03	10.44	15.8	12.1	9.4%	127%
1987	1.16	10.43	15.1	11.1	11.1%	126%
1988	1.27	10.49	14.2	11.7	12.1%	124%
1989	1.35	10.61	15.7	13.0	12.8%	136%
1990	1.40	10.84	15.5	13.4	13.1%	135%
1991	1.31	11.11	16.9	14.2	11.9%	142%
1992	1.32	11.54	18.4	15.9	11.7%	151%
1993	1.44	12.02	21.0	17.4	12.2%	163%
1994	1.28	12.45	18.9	13.6	10.5%	133%
1995	1.41	12.82	18.1	13.5	11.2%	125%
1996	1.35	12.70	19.9	17.1	10.6%	145%
1997	1.96	13.38	24.8	17.4	15.0%	162%
1998	1.28	11.76	24.9	16.1	10.2%	163%
1999	0.12	10.69	19.6	14.6	1.1%	152%
2000	1.74	15.34	68.0	14.6	13.4%	317%
2001	1.20	15.12	24.0	10.6	7.9%	114%
2002	0.67	14.84	16.6	8.8	4.5%	85%
2003	1.02	15.54	18.7	9.8	6.7%	94%
2004	0.73	15.87	19.4	15.4	4.6%	111%
2005	0.92	15.87	20.2	16.3	5.8%	115%
2006	1.47	17.46	27.5	17.6	8.8%	135%

EMPIRE DISTRICT

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		6.93				
1976	0.79	7.03	8.2	6.8	11.3%	107%
1977	0.92	7.28	8.7	7.5	12.9%	113%
1978	0.85	7.39	7.9	6.6	11.6%	99%
1979	0.86	7.49	7.3	5.6	11.6%	87%
1980	0.79	7.50	6.5	5.0	10.5%	77%
1981	0.67	7.35	5.8	4.9	9.0%	72%
1982	1.06	7.59	7.2	5.1	14.2%	82%
1983	1.26	8.01	8.7	6.8	16.2%	99%
1984	1.48	8.63	9.9	7.4	17.8%	104%
1985	1.38	9.14	12.3	9.3	15.5%	122%
1986	1.43	9.67	18.0	11.6	15.2%	157%
1987	1.48	10.22	17.0	13.7	14.9%	154%
1988	1.53	10.75	15.9	13.8	14.6%	142%
1989	1.47	11.17	16.1	13.3	13.4%	134%
1990	1.28	11.75	15.8	13.6	11.2%	128%
1991	1.43	12.08	24.1	14.8	12.0%	163%
1992	1.26	12.29	24.8	20.1	10.3%	184%
1993	1.16	12.37	24.8	19.1	9.4%	178%
1994	1.32	12.47	20.5	15.0	10.6%	143%
1995	1.18	12.69	19.8	16.0	9.4%	142%
1996	1.21	12.96	19.5	17.1	9.4%	143%
1997	1.29	13.06	20.0	15.8	9.9%	138%
1998	1.53	13.43	26.1	18.4	11.6%	168%
1999	1.13	13.48	26.8	20.7	8.4%	177%
2000	1.35	13.65	30.8	18.9	10.0%	183%
2001	0.59	13.58	26.6	17.5	4.3%	162%
2002	1.19	14.59	22.0	15.1	8.4%	132%
2003	1.29	15.17	22.5	17.0	8.7%	133%
2004	0.86	14.76	23.5	19.5	5.7%	144%
2005	0.92	15.08	25.0	19.3	6.2%	148%
2006	1.41	15.49	25.1	20.3	9.2%	149%

IDACORP

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		13.71				
1976	1.54	14.19	14.5	11.8	11.0%	94%
1977	1.10	14.20	15.1	13.0	7.7%	99%
1978	1.48	14.44	15.6	13.0	10.3%	100%
1979	1.21	14.26	13.8	12.0	8.4%	90%
1980	1.52	14.07	13.2	10.1	10.7%	82%
1981	1.53	14.26	11.9	9.1	10.8%	74%
1982	2.36	15.01	14.6	10.3	16.1%	85%
1983	2.25	15.77	17.4	14.3	14.6%	103%
1984	2.81	16.74	19.3	15.4	17.3%	107%
1985	2.16	17.29	24.5	18.8	12.7%	127%
1986	2.00	17.46	30.9	22.8	11.5%	155%
1987	1.30	17.29	30.3	19.0	7.5%	142%
1988	1.32	16.81	25.4	19.5	7.7%	132%
1989	2.37	17.35	30.0	22.0	13.9%	152%
1990	1.91	17.40	29.4	22.8	11.0%	150%
1991	1.56	17.06	28.8	24.3	9.1%	154%
1992	1.55	17.28	28.8	24.4	9.0%	155%
1993	1.97	17.86	33.0	27.3	11.2%	172%
1994	1.80	17.91	30.6	21.8	10.1%	146%
1995	2.10	18.15	30.0	23.4	11.6%	148%
1996	2.21	18.47	34.3	27.3	12.1%	168%
1997	2.32	18.93	37.8	28.5	12.4%	177%
1998	2.37	19.42	38.1	29.9	12.4%	177%
1999	2.43	20.02	36.5	26.0	12.3%	158%
2000	3.50	21.82	53.0	25.9	16.7%	189%
2001	3.35	23.15	49.4	33.6	14.9%	185%
2002	1.63	23.01	41.0	20.9	7.1%	134%
2003	0.96	22.54	30.2	20.6	4.2%	112%
2004	1.90	23.88	32.9	25.3	8.2%	125%
2005	1.75	24.04	32.1	26.2	7.3%	122%
2006	2.35	25.76	40.2	29.0	9.4%	139%

OGE ENERGY

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		7.58				
1976	0.93	7.83	11.8	8.7	12.1%	133%
1977	1.00	8.20	10.0	8.5	12.5%	115%
1978	0.99	8.43	9.5	8.1	11.9%	106%
1979	0.68	8.25	9.0	6.5	8.2%	93%
1980	0.87	8.23	7.5	5.8	10.6%	81%
1981	1.03	8.20	7.3	6.0	12.5%	81%
1982	1.31	9.04	9.8	6.7	15.2%	96%
1983	1.31	8.97	11.0	8.8	14.5%	110%
1984	1.24	9.26	11.8	9.6	13.6%	117%
1985	1.15	9.44	13.8	10.8	12.3%	132%
1986	1.38	10.22	19.4	13.1	14.0%	165%
1987	1.30	10.05	18.3	14.0	12.8%	159%
1988	1.60	10.50	16.7	14.3	15.6%	151%
1989	1.53	10.64	19.5	16.0	14.5%	168%
1990	1.69	10.96	19.9	16.4	15.6%	168%
1991	1.64	11.30	22.0	18.3	14.7%	181%
1992	1.21	11.18	22.0	15.1	10.8%	165%
1993	1.39	11.24	19.3	16.4	12.4%	159%
1994	1.51	11.41	18.6	14.7	13.3%	147%
1995	1.52	11.61	21.8	16.3	13.2%	166%
1996	1.62	11.91	21.8	18.4	13.8%	171%
1997	1.61	12.19	27.4	20.3	13.4%	198%
1998	2.04	12.91	30.0	25.6	16.3%	222%
1999	1.94	13.09	29.1	18.4	14.9%	183%
2000	1.89	13.66	24.8	16.5	14.1%	154%
2001	1.29	13.34	24.7	20.0	9.6%	166%
2002	1.43	12.53	24.2	13.7	11.1%	147%
2003	1.73	13.75	24.3	16.0	13.2%	153%
2004	1.78	14.28	27.0	22.8	12.7%	178%
2005	1.83	15.19	30.6	25.2	12.4%	189%
2006	2.45	17.59	40.6	26.3	14.9%	204%

PINNACLE WEST

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		19.98				
1976	2.47	20.64	19.9	15.0	12.2%	86%
1977	3.02	21.83	21.4	18.1	14.2%	93%
1978	3.15	22.56	21.6	18.8	14.2%	91%
1979	2.90	22.75	21.4	16.9	12.8%	85%
1980	2.75	21.97	19.6	14.6	12.3%	76%
1981	3.26	22.13	19.6	15.1	14.8%	79%
1982	3.30	22.94	25.1	18.0	14.6%	96%
1983	3.46	23.78	26.5	17.8	14.8%	95%
1984	3.65	24.18	22.6	14.5	15.2%	77%
1985	3.88	25.36	28.1	20.6	15.7%	98%
1986	3.04	25.84	32.0	26.0	11.9%	113%
1987	3.21	26.62	32.8	26.4	12.2%	113%
1988	2.15	23.46	29.8	15.0	8.6%	89%
1989	1.44	16.31	16.4	5.0	7.2%	54%
1990	0.81	17.40	18.6	9.4	4.8%	83%
1991	-3.90	15.23	17.9	9.6	-23.9%	84%
1992	1.73	17.00	20.5	16.8	10.7%	116%
1993	1.95	18.87	25.3	19.6	10.9%	125%
1994	1.99	20.32	22.8	16	10.2%	99%
1995	2.22	21.49	28.9	19.6	10.6%	116%
1996	2.47	22.51	32.3	26.3	11.2%	133%
1997	2.76	23.90	42.8	27.6	11.9%	152%
1998	2.85	25.50	49.3	39.4	11.5%	180%
1999	3.18	26.00	43.4	30.2	12.3%	143%
2000	3.35	28.09	52.7	25.7	12.4%	145%
2001	3.68	29.46	50.7	37.7	12.8%	154%
2002	2.53	29.44	46.7	21.7	8.6%	116%
2003	2.52	31.0	40.5	28.3	8.3%	114%
2004	2.58	32.14	45.8	36.3	8.2%	130%
2005	2.24	34.57	46.7	39.8	6.7%	130%
2006	3.17	34.47	51	38.3	9.2%	129%

PNM RESOURCES

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		13.86				
1976	1.44	14.04	16.3	11.7	10.3%	100%
1977	1.64	14.40	16.0	13.3	11.5%	103%
1978	1.89	14.57	14.9	12.3	13.0%	94%
1979	1.98	14.84	14.3	11.6	13.5%	88%
1980	2.24	15.57	14.5	10.2	14.7%	81%
1981	2.22	15.93	16.6	12.9	14.1%	94%
1982	2.15	16.24	18.7	14.4	13.4%	103%
1983	1.86	16.80	19.7	15.2	11.3%	106%
1984	2.07	16.85	17.7	13.0	12.3%	91%
1985	2.20	17.15	20.5	15.9	12.9%	107%
1986	2.19	17.67	25.3	18.7	12.6%	126%
1987	1.33	17.12	26.2	11.6	7.6%	109%
1988	1.31	12.02	14.9	7.3	9.0%	76%
1989	1.15	12.01	10.6	7.2	9.6%	74%
1990	0.21	11.57	10.3	5.3	1.8%	66%
1991	0.21	11.79	7.7	5.1	1.8%	55%
1992	0.50	10.00	9.4	6.3	4.6%	72%
1993	0.81	8.86	9.3	6.5	8.6%	84%
1994	1.11	10.08	9.1	7.3	11.7%	87%
1995	0.91	11.22	12.2	8.1	8.5%	95%
1996	1.15	12.04	13.7	11.5	9.9%	108%
1997	1.25	12.84	15.8	10.5	10.0%	106%
1998	1.50	13.75	16.5	11.6	11.3%	106%
1999	1.29	14.74	14.3	9.9	9.1%	85%
2000	1.55	15.76	18.9	9.8	10.2%	94%
2001	2.61	17.25	25.2	15.3	15.8%	123%
2002	1.07	16.60	20.5	11.5	6.3%	95%
2003	1.15	17.84	19.6	12.6	6.7%	93%
2004	1.43	18.19	26.1	18.7	7.9%	124%
2005	1.59	18.70	30.5	23.8	8.6%	147%
2006	1.72	22.09	32.1	22.5	8.4%	134%

PUGET ENERGY

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		16.99				
1976	1.92	17.99	16.8	12.7	11.0%	84%
1977	1.88	18.36	18.4	15.5	10.3%	93%
1978	2.17	18.63	18.3	15.6	11.7%	92%
1979	1.67	17.93	17.5	13.6	9.1%	85%
1980	1.60	17.15	15.1	11.0	9.1%	74%
1981	2.86	17.44	14.3	11.5	16.5%	75%
1982	2.29	17.42	16.9	12.4	13.1%	84%
1983	1.93	17.04	16.5	13.1	11.2%	86%
1984	1.52	15.42	15.0	9.3	9.4%	75%
1985	2.07	15.70	18.4	12.6	13.3%	100%
1986	1.74	15.29	25.3	17.6	11.2%	138%
1987	2.13	15.50	22.5	17.8	13.8%	131%
1988	2.14	15.98	20.3	18.0	13.6%	122%
1989	2.13	16.12	22.5	18.0	13.3%	126%
1990	2.16	16.52	22.5	18.6	13.2%	126%
1991	2.21	16.96	26.9	19.1	13.2%	137%
1992	2.16	17.76	27.9	23.9	12.4%	149%
1993	2.00	18.65	29.8	23.5	11.0%	146%
1994	1.64	18.43	24.9	16.5	8.8%	112%
1995	1.89	18.48	24.0	20.1	10.2%	119%
1996	1.89	18.53	26.0	22.1	10.2%	130%
1997	1.28	16.06	30.2	23.5	7.4%	155%
1998	1.85	16.00	30.3	24.1	11.5%	170%
1999	1.91	16.24	28.4	18.6	11.8%	146%
2000	2.16	16.61	28.0	19.1	13.2%	143%
2001	1.22	15.66	27.8	18.5	7.6%	143%
2002	1.24	16.27	23.6	16.6	7.8%	126%
2003	1.22	16.71	24.4	18.1	7.4%	129%
2004	1.32	16.24	24.8	20.5	8.0%	137%
2005	1.42	17.52	24.6	20.2	8.4%	133%
2006	1.44	18.15	25.9	20.1	8.1%	129%

UIL HOLDINGS

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		18.73				
1976	1.99	19.04	18.2	15.1	10.5%	88%
1977	2.53	19.90	20.0	17.2	13.0%	96%
1978	2.05	19.67	19.4	15.1	10.4%	87%
1979	2.64	20.50	17.3	13.6	13.1%	77%
1980	2.39	19.49	15.6	11.4	12.0%	68%
1981	2.84	19.19	13.9	11.9	14.7%	67%
1982	3.61	20.03	17.7	12.5	18.4%	77%
1983	3.80	20.89	19.4	12.8	18.6%	79%
1984	3.62	22.65	16.0	6.0	16.6%	51%
1985	3.90	24.90	18.2	9.3	16.4%	58%
1986	4.00	27.14	24.3	18.0	15.4%	81%
1987	4.01	29.49	22.8	14.3	14.2%	66%
1988	5.05	22.85	18.4	12.8	19.3%	60%
1989	3.56	17.49	23.0	16.5	17.6%	98%
1990	2.38	18.32	22.8	18.0	13.3%	114%
1991	1.93	23.22	26.2	20.0	9.3%	111%
1992	1.90	23.39	28.1	22.8	8.2%	109%
1993	1.88	23.47	30.8	25.8	8.0%	121%
1994	1.91	23.48	26.8	19.3	8.1%	98%
1995	2.18	23.50	25.9	19.7	9.3%	97%
1996	1.90	23.50	24.0	18.7	8.1%	91%
1997	1.96	23.18	27.6	14.2	8.4%	90%
1998	1.80	23.39	32.5	25.0	7.7%	123%
1999	2.23	23.44	32.2	23.3	9.5%	119%
2000	2.56	23.46	33.6	22.7	10.9%	120%
2001	2.53	23.53	31.8	26.3	10.8%	124%
2002	1.85	23.79	35.3	16.9	7.8%	110%
2003	1.24	23.86	27.6	18.5	5.2%	97%
2004	1.54	24.01	32.8	24.9	6.4%	120%
2005	1.30	24.32	33.7	27.4	5.4%	126%
2006	1.86	24.86	43.8	27.4	7.6%	145%

Westar Energy

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		10.42				
1976	1.37	10.80	10.3	9.0	12.9%	91%
1977	1.51	11.41	11.8	9.9	13.6%	98%
1978	1.37	11.56	11.3	9.5	11.9%	91%
1979	1.40	11.53	10.4	7.6	12.1%	78%
1980	1.61	12.04	9.7	7.3	13.7%	72%
1981	1.65	12.00	10.0	8.1	13.7%	75%
1982	1.80	12.55	12.4	8.8	14.7%	86%
1983	2.33	13.59	15.3	12.0	17.8%	104%
1984	2.40	14.62	17.6	13.8	17.0%	111%
1985	2.47	15.51	20.7	16.2	16.4%	122%
1986	2.43	16.35	32.5	19.8	15.3%	164%
1987	2.46	16.98	30.8	20.0	14.8%	152%
1988	2.25	17.51	27.0	22.3	13.0%	143%
1989	2.05	17.80	25.4	21.6	11.6%	133%
1990	2.25	18.25	25.1	19.8	12.5%	125%
1991	2.41	18.59	28.5	20.8	13.1%	134%
1992	2.20	21.51	32.6	25.1	11.0%	144%
1993	2.76	23.08	37.3	30.4	12.4%	152%
1994	2.51	23.93	34.9	26.1	10.7%	130%
1995	2.71	24.71	34.0	28.6	11.1%	129%
1996	2.60	25.14	34.9	28.0	10.4%	126%
1997	-0.46	30.79	43.4	29.8	-1.6%	131%
1998	2.13	29.40	44.2	32.6	7.1%	128%
1999	1.48	27.83	33.9	16.8	5.2%	89%
2000	0.89	27.20	25.9	14.7	3.2%	74%
2001	-0.58	25.97	25.9	15.6	-2.2%	78%
2002	1.00	13.68	18.0	8.5	5.0%	67%
2003	1.48	14.23	20.5	9.8	10.6%	109%
2004	1.17	16.13	22.9	17.1	7.7%	132%
2005	1.55	16.31	25.0	21.1	9.6%	142%
2006	1.88	17.62	27.2	20.1	11.1%	139%

HAWAIIAN ELECTRIC

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		6.18				
1976	0.74	6.47	6.1	5.0	11.6%	87%
1977	0.79	6.73	6.7	5.8	12.0%	95%
1978	0.85	7.05	7.1	6.0	12.3%	95%
1979	0.92	7.39	6.9	5.9	12.7%	89%
1980	0.95	7.51	6.2	4.6	12.7%	72%
1981	0.98	7.66	6.7	5.2	12.9%	78%
1982	0.59	7.92	7.7	5.9	7.6%	87%
1983	1.03	8.16	8.5	6.8	12.8%	95%
1984	1.13	8.50	10.7	7.8	13.5%	111%
1985	1.20	8.92	12.7	9.8	13.8%	129%
1986	1.29	9.48	17.8	12.3	14.0%	163%
1987	1.43	9.80	17.2	11.2	14.8%	147%
1988	1.45	10.98	16.8	13.0	14.0%	143%
1989	1.53	11.59	20.2	14.7	13.6%	154%
1990	1.01	11.65	20.0	13.7	8.7%	145%
1991	1.20	12.18	19.0	14.7	10.1%	141%
1992	1.27	11.06	22.3	17.4	10.9%	171%
1993	1.19	11.62	19.4	15.5	10.5%	154%
1994	1.30	11.90	18.3	14.9	11.1%	141%
1995	1.33	12.25	19.9	16.1	11.0%	149%
1996	1.30	12.52	19.8	16.6	10.5%	147%
1997	1.38	12.77	20.8	16.4	10.9%	147%
1998	1.48	12.87	21.3	18.2	11.5%	154%
1999	1.45	13.16	20.3	14.0	11.1%	132%
2000	1.27	12.72	19.0	13.8	9.8%	127%
2001	1.60	13.06	20.6	16.8	12.4%	145%
2002	1.62	14.21	24.5	17.3	11.9%	153%
2003	1.58	14.36	24.0	19.1	11.1%	151%
2004	1.36	15.01	29.5	23.0	9.3%	179%
2005	1.46	15.02	29.8	24.6	9.7%	181%
2006	1.33	13.44	28.9	25.7	9.3%	192%

NSTAR

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		7.95				
1976	0.68	8.04	6.9	5.6	8.5%	78%
1977	0.52	7.64	7.1	6.2	6.6%	85%
1978	0.74	7.75	6.6	5.6	9.6%	79%
1979	0.88	7.60	6.2	5.0	11.5%	73%
1980	0.94	7.76	6.2	4.7	12.2%	71%
1981	1.04	8.01	6.2	4.9	13.2%	70%
1982	0.80	7.93	6.6	5.0	10.0%	73%
1983	0.90	8.05	7.4	6.3	11.3%	86%
1984	1.22	8.43	8.9	6.2	14.8%	92%
1985	1.26	8.86	11.6	8.4	14.6%	116%
1986	1.29	9.69	14.0	10.6	13.9%	133%
1987	0.99	9.69	14.0	8.4	10.2%	116%
1988	0.93	9.69	9.4	9.3	9.6%	96%
1989	0.95	8.37	11.1	7.7	10.5%	104%
1990	0.80	8.61	10.2	8.2	9.4%	108%
1991	0.98	8.96	12.5	9.2	11.2%	124%
1992	1.05	9.39	14.2	11.2	11.4%	138%
1993	1.14	9.71	16.3	13.1	11.9%	154%
1994	1.21	10.06	14.9	10.8	12.2%	130%
1995	1.04	10.31	14.8	11.6	10.2%	130%
1996	1.31	10.54	15.1	10.9	12.6%	125%
1997	1.36	10.98	19.2	12.3	12.6%	146%
1998	1.38	11.14	22.5	17.5	12.5%	181%
1999	1.39	13.29	22.3	18.2	11.4%	166%
2000	1.60	12.65	23.5	18.2	12.3%	161%
2001	1.64	11.90	22.6	17.0	13.4%	161%
2002	1.69	12.25	24.1	17.0	14.0%	170%
2003	1.74	12.84	24.5	19.3	13.9%	175%
2004	1.76	13.52	27.2	22.7	13.4%	189%
2005	1.83	14.37	31.5	24.9	13.1%	202%
2006	1.93	14.82	35.9	26.5	13.2%	214%

Company	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FINANCIAL STRENGTH		S& P STOCK RANKING	
Comparison Group - PUC Criteria						
Avista	3	0.90	B+	3.33	B	3.00
Empire District Electric	3	0.85	B+	3.33	B	3.00
IDACORP	3	1.05	B+	3.33	B	3.00
OGE Energy	2	0.75	A	4.00	A-	3.67
Pinnacle West Capital	1	1.00	A	4.00	A-	3.67
PNM Resources	2	0.95	B++	3.67	B+	3.33
Puget Energy	3	0.85	B+	3.33	B	3.00
UIL Holdings	3	0.90	B+	3.33	B	3.00
Westar Energy	2	0.90	B++	3.67	B	3.00
Average	2.4	0.91	B++	3.55	B+	3.19
Comparison Group - Parcell Criteria						
Avista	3	0.90	B+	3.33	B	3.00
Empire District Electric	3	0.85	B+	3.33	B	3.00
Hawaiian Electric Industries	2	0.75	A	4.00	B+	3.33
IDACORP	3	1.05	B+	3.33	B	3.00
NSTAR	1	0.75	A	4.00	A+	3.67
PNM Resources	2	0.95	B++	3.67	B+	3.33
Puget Energy	3	0.85	B+	3.33	B	3.00
Average	2.4	0.87	B+	3.57	B+	3.19

CA-T-5
DOCKET NO. 2006-0387

DIRECT TESTIMONY AND EXHIBITS

OF

MICHAEL L. BROSCH

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: Cost of Service Studies, Rate Increase Distribution, Rate Design & Tariffs.

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Q. PLEASE STATE YOUR NAME.

A. My name is Michael L. Brosch.

Q HAVE YOU SUBMITTED TESTIMONY IN THE INSTANT PROCEEDING ON BEHALF OF THE DIVISION OF CONSUMER ADVOCACY, HEREINAFTER REFERRED TO AS CONSUMER ADVOCATE OR CA?

A. I am sponsoring testimony as CA-T-3 in the instant proceeding.

Q, WHAT IS THE PURPOSE OF THE TESTIMONY THAT YOU ARE NOW SPONSORING?

A. As previously stated in CA-T-3, I am also responsible for reviewing and responding to the Company's Cost of Service Study ("COSS"), revenue increase distribution and proposed rates for Maui, Lanai and Molokai in the instant proceeding. As a result, this testimony will address the results of my review, including recommendations regarding the allocation of the costs among customer classes, the distribution of revenue increases among customer classes and the design of rates that are intended to generate the Consumer Advocate's recommended revenue requirement for the 2007 test year.

1 I. **CLASS COST OF SERVICE.**

2 Q. WHAT COST OF SERVICE STUDIES HAS MECO PREPARED IN THIS
3 DOCKET?

4 A. Mr. Young (MECO T-18) has prepared embedded and marginal COSS that
5 are summarized in Exhibits MECO-1802 through MECO-1811. The
6 embedded class cost of service study assigns responsibility among each
7 customer class for each island system based upon the test period overall cost
8 of service using actual "embedded" accounting costs, so as to estimate the
9 relative rates of return being earned by serving each class at present and
10 proposed rates. MECO's embedded COSS is prepared on the same basis
11 that revenue requirement is determined, including all of the estimated rate
12 base components and operating expenses that are the subject of Consumer
13 Advocate ratemaking adjustments.

14

15 Q. HOW IS A COST OF SERVICE STUDY USEFUL IN A RATE CASE
16 DOCKET?

17 A. COSS information can be useful as a guide in the Commission's decision
18 regarding how much of the overall revenue change in this Docket should be
19 attributed to specific customer classes and rates. Exhibits MECO-1802
20 through MECO-1804 summarize class revenue requirement and class rate of
21 return data in different formats for this purpose, showing class returns at
22 present and proposed rate levels. Exhibit MECO-1805 illustrates the class

1 revenue increases that would be required to move fully to calculated cost of
2 service (equal class rates of return), based upon the Company's asserted
3 revenue requirement and cost of service allocation methodologies. An
4 additional purpose for conducting embedded COSS is to evaluate "unit costs,"
5 which divide allocated costs per unit of demand, energy or by customer as a
6 guide to rate design analysis after revenue distribution decisions have been
7 made (see MECO-1808 and MECO-1810). Mr. Young lists and describes the
8 various Exhibits he sponsors to present COSS results at pages 2 and 3 of
9 MECO T-18.

10 The other type of cost study presented by Mr. Young is an evaluation of
11 "marginal costs," which considers the cost associated with serving an
12 additional or "marginal" unit of energy at differentiated points in time. This type
13 of study does not rely upon actual recorded or projected accounting costs and
14 cannot be reconciled to the costs used to determine the revenue requirement,
15 but instead is based upon more theoretical analyses of the rates of change in
16 energy costs on a time differentiated basis. The results of MECO's marginal
17 energy cost studies are presented at MECO-1813 and can be useful in
18 considering how to design specific rates and tariffs that are economically
19 efficient, with an awareness of how costs and pricing revenues may interact to
20 influence customer behavior and utility profitability. However, the Company's
21 embedded COSS is used as the main basis of analysis in support of MECO's

present and proposed rates, while the marginal energy cost study is one of the Company's considerations in the rate design.[1]

Q. WHAT DOES THE MECO EMBEDDED COSS INDICATE REGARDING HOW ANY REVENUE INCREASE IN THIS PROCEEDING SHOULD BE DISTRIBUTED AMONG CUSTOMER CLASSES?

A. The Company's embedded COSS results showing class return levels at present rates and at proposed rates are summarized in Exhibit MECO-1802, pages 1 through 3, for the islands of Maui, Lanai and Molokai, respectively. At present rate levels and with all of MECO's ratemaking adjustments, the Maui Division is calculated to be earning an overall Rate of Return ("ROR") of 6.52 percent. Relative to this overall ROR, all classes are shown to be earning a positive ROR, with the Residential Class on rate "Schedule R" estimated to be contributing an ROR of 3.36 percent, or about 52 percent of the overall average ROR of 6.52 percent. Thus, the Company's study would suggest that Maui Schedule R residential revenues might be increased more than the system average percentage increase in order to move closer to the system average "cost of service" for Schedule R.

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1 According to MECO T-18 at page 13, MECO has estimated marginal energy costs for a five year period 2007 through 2011. See MECO's response to CA-IR-197.

Similarly, MECO's COSS for Maui shows that the rates for commercial customers on Schedule H and lighting customers on Schedule F produce a positive, but somewhat below average ROR, indicating that a higher than average percentage revenue increase may also be needed to move pricing toward indicated cost of service. Conversely, the Company's study shows that two principal commercial rates (Schedules G and P) are contributing somewhat above-average RORs, such that the customers on these rate schedules may require a below average percentage revenue increase to move closer to the system average ROR (closer to cost of service). For Lanai and Molokai, different patterns of return disparity can be observed, as shown on pages 2 and 3 of MECO-1802, but for all three islands the Company's COSS indicates relatively lower rates of return being produced by the residential class under present rates. Of course, with the Consumer Advocate's significantly lower revenue requirement and underlying accounting adjustments, the embedded cost of service results are different in the Consumer Advocate's filing, as discussed more fully herein. In the Revenue Distribution portion of this testimony, I will further discuss COSS results after describing how two Consumer Advocate corrections to the Company's embedded COSS methodologies impact the study results.

Q. HOW DOES THE EXISTENCE OF A SEPARATELY CALCULATED REVENUE REQUIREMENT AND COSS FOR EACH OF THE THREE

ISLANDS SERVED BY MECO IMPACT THE DEVELOPMENT AND UTILIZATION OF STUDY RESULTS?

A. MECO has developed COSS results separately for each rate class on each island, but the results of these studies are largely ignored by the Company in determining the revenue increases proposed for each island and rate class. At page 5 of MECO T-18, Mr. Young states, "The proposed allocation of revenue increase among the MECO divisions and rate classes is based on assigning an across the board increase of 5.27% to all the rate classes in each of the divisions." With regard to cost of service by Division (island), MECO-1801 at page 1 shows that a revenue increase of $1.9 million for Lanai and $1.2 million for Molokai could be justified using the Company's cost support, but the proposed equal percentage increase among islands translates into revenue increases for Lanai and Molokai of only $0.5 and $0.7 million, respectively (see "Proposed Increase" for Lanai and Molokai at MECO-1801, page 2). The rate of return disparities among customer classes on each island are also largely ignored by the Company in proposing equal percentage increases to all classes, although the "ROR Index" for most rate schedules under "Proposed Rates" illustrated at MECO-1802 move generally toward unity with the proposed equal percentage rate increases.

Q. WHAT DOES THE COMPANY'S EMBEDDED COSS REVEAL WITH RESPECT TO RATE DESIGN?

A. MECO-1808 and MECO-1810 summarize the Unit Cost Components using MECO's revenue requirement assumptions and embedded cost allocation methods at proposed rates and at equalized class return levels, respectively. These calculations can be useful to compare rate elements within individual tariffs, such as customer charges, demand charges and energy rates, to the underlying calculated per unit cost to provide service. However, MECO's calculations seriously overstate unit costs because of the overstated revenue requirement proposed by the Company and because of questionable cost classification methods that are being used. The Company's asserted "Unit Customer Costs" (see MECO-1808 and MECO-1810) are particularly overstated because MECO has classified large amounts of distribution network poles, lines and transformers costs as Customer Costs, even though the existence of customers does not really drive such costs.[2] Thus, MECO's "Unit Customer Cost" calculations must be discounted in any evaluation of rate design parameters. In a later "Rate Design" portion of this testimony, I will discuss the Consumer Advocate's COSS Unit Cost results in connection with specific rate design proposals.

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2 CA-501 presents comparable unit cost information, with significantly lower Unit Customer Costs because of the Consumer Advocate's classification of distribution network costs.

1 Q. ASIDE FROM DIFFERENCES IN OVERALL REVENUE REQUIREMENT
2 AND THE TWO ISSUES YOU MENTIONED, IS THE COMPANY'S
3 EMBEDDED COSS BASED UPON REASONABLE METHODS AND
4 PROCEDURES?
5 A. In general, yes it is. The Company's study employs a traditional approach in
6 which costs are first functionalized into production, transmission, distribution
7 and customer-related categories. Once functionalized, the costs are classified
8 as demand, energy, or customer driven, and then are allocated among
9 customer classes by applying allocation factors to the functionalized costs.[3]
10 The general procedures employed by Mr. Young are widely accepted and,
11 with only a few exceptions, reasonable for a utility with MECO's service
12 characteristics. However, I take exception to two specific procedures
13 employed by MECO in the conduct of its cost of service study.
14
15 Q. WHAT ARE YOUR TWO CONCERNS REGARDING MECO'S COSS
16 METHODOLOGY?
17 A. As will be discussed in further detail in the following sections of my testimony,
18 the Consumer Advocate has two significant concerns with the Company's
19 COSS approach:

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[3] These sequential steps are described by Mr. Young at HECO T-18, pages 5 through 12.

- Distribution poles, lines and transformers are improperly classified partially as "customer" costs, and
- *Production O&M expenses other than fuel are classified entirely* as fixed or "demand" costs, when a portion of such expenses vary with the level of "energy" generated.

These issues were presented by the Consumer Advocate in the recent HECO and HELCO rate cases (Docket Nos. 04-0113, 2006-0387 and 05-0315) and again merit consideration by the Commission in evaluating revenue distribution and rate design issues in this Docket.

Q. IS JUDGMENT NECESSARILY INVOLVED IN THE CONDUCT OF ANY EMBEDDED COSS?

A. Yes. Financial and operational data must be analyzed and interpreted by the cost analyst to determine reasonable approaches to the many decisions involved in defining cost classification and allocation methods that will produce meaningful results. Thus, there is no single "correct" embedded cost of service study because of the many judgmental decisions that must be made. The adjustments I propose are intended to improve upon the judgments and estimates employed in the Company's COSS, and are presented as reasonable alternative approaches that should be considered by the Commission.

Q. HAVE YOU PREPARED COSS INFORMATION BASED UPON THE CONSUMER ADVOCATE'S REVENUE REQUIREMENT POSITION, AS SET FORTH IN EXHIBITS CA-101 THROUGH CA-104?

A. Yes. Exhibit CA-500 contains the summary output pages using the Company's COSS model, modified to reflect the Consumer Advocate's position on revenue requirement, as well as restatements for the two COSS methodology issues described herein. Page 1 of Exhibit CA-500 shows class rates of return and "ROR As % of System ROR" under currently effective rates for the Maui Division with the impact of the Consumer Advocate's proposed rate increases shown on page 2, while pages 3 through 6 show the same information for the Lanai and Molokai Divisions, respectively. Exhibit CA-501 displays the "Unit Functionalized Class Revenue Requirements at Equal ROR" associated with each of the Divisions on pages 1 (Maui), 2 (Lanai) and 3 (Molokai).

Q. IS THERE A PRIMARY DECISION FOR WHICH JUDGMENT IS REQUIRED IN THE CONDUCT OF AN ELECTRIC UTILITY'S EMBEDDED COSS?

A. Yes. The single most important judgment in conducting such a study is the selection of the most appropriate production and transmission demand-related cost allocation factor. For this allocation factor, MECO has employed an Average and Excess Demand ("AED") allocation that weights together peak demand data and average demand data, so as to recognize that production

and transmission costs are incurred by MECO to meet customer demands during peak periods, as well as throughout the balance of the year (average demands). The AED allocation approach is particularly well suited to MECO, given the Company's relatively high system load factor and non-seasonal demand characteristics. Load factor is the ratio of average demand divided by the product of peak demand times all hours in the period and for the Maui system exceeds 76 percent,[4] which is an indication of how much of the time demand levels are relatively high in relation to peak demands. I concur in the use of the Company's utilization of the AED allocation approach for production and transmission demand cost allocations.

Q. HAVING AGREED WITH MECO'S AED ALLOCATION OF PRODUCTION AND TRANSMISSION PLANT, PLEASE ELABORATE REGARDING THE TWO METHODOLOGY PROBLEMS WITH MECO'S EMBEDDED COSS THAT SHOULD BE ADJUSTED.

A. First, MECO's embedded COSS classifies a large portion of the costs associated with the network of electric distribution poles, lines and transformers as "customer" driven costs. In addition, the costs of customer service lines and customer meters are classified entirely as "customer" costs. The Consumer Advocate agrees with the classification of service lines and

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4 MECO-WP-1802, page 20, Note 5 shows the "System Load Factor" on Maui of 76.7 percent.

meters as "customer" costs, since these facilities and the related expenses incurred to maintain the facilities are required to connect and serve discrete customers. *However, the distribution network of poles, lines and transformers* do not vary directly with the number of customers served and should be classified entirely as "demand," rather than partially as "customer" costs, which MECO proposes to do. The MECO studies conducted to determine an estimated fraction of poles, lines and transformers to be classified as *"customer" driven are inherently unreliable and the theoretical support for such* a "customer" classification is weak, at best.

Second, MECO's COSS improperly treats all non-fuel production operations and maintenance expenses as "demand" driven. This classification is appropriate for many of the types of costs incurred to operate and maintain generating units, because many costs associated with staffing and maintaining unit availability are fixed and do not vary with KWH output. Some production O&M costs do, however, vary with KWH output and should therefore be treated as "energy" costs. Ideally, a study would be conducted to determine the mix of demand/energy cost drivers for each O&M account. MECO should conduct such an analysis in support of its next rate case filing and embedded

COSS.[5] I have conducted a limited scope study to isolate known production O&M expense elements that clearly require an energy classification, because such expenses very obviously vary with energy output levels.[6]

These two issues are described in detail within the following sections of this testimony.

II. DISTRIBUTION SYSTEM - CUSTOMER CLASSIFICATION ISSUE.

Q. IN MECO'S EMBEDDED COSS, WHAT PORTION OF ELECTRIC DISTRIBUTION POLES, LINES AND TRANSFORMERS ARE DEEMED TO BE DRIVEN BY THE NUMBER OF CUSTOMERS AND THUS CLASSIFIED AS CUSTOMER COSTS?

A. The MECO embedded COSS for the Maui system assumes that 53 percent of the costs of distribution poles and distribution conductors (lines) and 36 percent of distribution transformer costs are caused or influenced by the

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5 According to the Stipulated Settlement Letter dated September 5, 2007 resolving cost of service allocation issues in HECO Docket No. 2006-0386, at Exhibit 1, paragraph 26, "HECO agrees in its next rate case to present a cost of service study utilizing the same distribution classification methodology as it used in this case, as well as a cost of service scenario that classifies all distribution network costs (poles, conduits, lines, and transformers investment and expenses) as demand related. HECO can present other cost of service scenarios, if desired, and make whatever recommendations it chooses regarding interpretation and utilization of cost of service evidence, and 3) HECO agrees to conduct studies designed to isolated the demand (fixed) versus energy (variable) elements of its non-fuel production O&M expenses for use in the next HECO rate case, to be included in all of HECO's cost of service scenarios."

6 These calculations are set forth in CA-WP-501

number of customers being served, with the reciprocal of these percentage values being classified as demand-related.[7]

Q. PLEASE EXPLAIN WHY THE CLASSIFICATION OF ANY PORTION OF ELECTRIC DISTRIBUTION POLES, LINES AND TRANSFORMERS AS "CUSTOMER" RELATED COSTS IS CONTROVERSIAL.

A. The addition of a new customer simply does not cause these costs to be incurred, because these costs are "network" costs for facilities that are designed and constructed to serve the demands of <u>all</u> customers in a given geographical area. MECO has not shown any positive correlation between the number of customers served and the amount invested in distribution network facilities. The costs that can be clearly shown to vary directly with the connection of a new customer are only those costs that must be added each time a new customer is established – specifically, the costs associated with the service line to the customer and his meter, as well as the related O&M costs to read meters, conduct billing and provide customer contact services.

MECO has improperly attributed distribution network costs, including poles, lines and transformers, to the customer-related classification. While this

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7 See MECO-WP-1802 at page 7 (sum of 42.8% for Primary Voltage plus 10.2% for Secondary Voltage) and at page 27 showing classification of "Transformers" as $11,591 "Transformers Customer" relative to $32,468 "Subtotal Transformers", indicating a 35.7% customer classification ($11,591/$32,468 = 35.7%).

1 treatment is consistent with one of several alternatives documented within the
2 National Association of Regulatory Utility Commissioner ("NARUC") Cost
3 Allocation Manual that is relied upon by MECO, if supported by appropriate
4 cost analyses, this practice has proven to be controversial and has been
5 abandoned by electric utilities in other jurisdictions.[8]
6
7 Q. ACCORDING TO MR. YOUNG AT MECO T-18, PAGE 9, "FOLLOWING THE
8 NARUC COST ALLOCATION MANUAL, MECO HAS USED THE MINIMUM
9 SIZE METHOD TO ALLOCATE THESE COSTS TO CUSTOMER-RELATED
10 AND DEMAND-RELATED COMPONENTS." DOES THE NARUC COST
11 ALLOCATION MANUAL SPECIFY USE OF THE MINIMUM SIZE METHOD?
12 A. No. The NARUC Cost Allocation Manual that is referenced by Mr. Young
13 actually describes two different methods that can be used to estimate a
14 demand and customer components of distribution facilities: (a) the minimum
15 size method, and (b) the minimum intercept method. These two analytical
16 methods are theoretical studies intended to segregate a customer versus
17 demand breakdown of distribution network facilities and related costs. The
18 "Minimum Size" method is based upon trended cost analysis and estimation of
19 the costs that might theoretically be incurred to re-build the entire distribution

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8 For example, Public Service Company of Oklahoma, Arizona Public Service Company and PSI Energy (in Indiana) include only distribution services and meters as "customer" costs, with the balance of distribution network facilities classified as "demand" (See footnotes 16 and 17.)

network using only the smallest sized poles, conductors and line transformers that may be employed by the utility. Then, having estimated costs for this theoretical minimum-sized system, it is assumed that all additional costs in the actual distribution network must have been incurred to "up-size" this minimum-sized system to meet actual demand levels.

Q. HAS THE NARUC COST ALLOCATION MANUAL AND ITS PROPOSED CLASSIFICATION APPROACH FOR DISTRIBUTION SYSTEM POLES, LINES AND TRANSFORMERS BEEN UNIFORMLY ADOPTED BY REGULATORS?

A. No. The NARUC manual was last published in 1992 and its treatment of distribution network cost classifications is not uniformly employed. There is really no consensus among regulators regarding how to approach this issue and I have observed several states in which electric distribution system poles, lines and transformers are treated entirely as demand-related costs because of the theoretical problems and controversy surrounding isolation of a customer-related component of such costs.

The Consumer Advocate's COSS presentation avoids the need for unreliable and highly theoretical minimum system studies by treating all distribution network facilities (poles, lines, conduit, line transformers) with a demand classification, recognizing that such facilities are sized and built to meet localized customer demand levels on an economical basis. The only

1 distribution costs that are directly caused by adding a new customer are the
2 costs closest to the customer -- the meters and service line drops required to
3 physically connect the customer to the network.
4
5 Q. WHY IS COST CAUSATION IMPORTANT TO THE ISSUE OF CLASSIFYING
6 DISTRIBUTION NETWORK COSTS?
7 A. Cost causation is the underlying principle behind cost of service study
8 allocations. The principle states that a customer class should bear
9 responsibility for utility costs in proportion to the levels at which that class
10 "causes" the utility to incur costs. For example, fuel costs are widely
11 recognized as being caused by the production of energy, so such costs are
12 allocated among customer classes based upon an "energy" allocator
13 calculated from the relative amounts of loss-adjustment KWH sales to each
14 class. The same principle requires that the Commission not attribute utility
15 costs to customer classes based upon the relative number of customers in
16 each class unless it has been shown that the existence of a customer or
17 changes in the number of customers served causes such costs to be incurred.
18

Q. IF A SINGLE CUSTOMER IS ADDED TO OR REMOVED FROM MECO'S DISTRIBUTION SYSTEM, WHAT COSTS ARE CAUSED BY THAT CUSTOMER'S ADDITION/REMOVAL?

A. Each customer is generally served by a discrete meter and service line. These are the distribution facilities that are unique to individual customers and that are caused by the connection or disconnection of specific customers. Thus, meters and services investment and customer accounting/service expenses are properly classified by MECO as "customer-related" costs and are allocated based upon weighted customer counts within each class. I believe that the Commission should limit the customer classified costs to those costs that vary directly with the number of customers. Unfortunately, MECO has reached beyond the costs that actually vary directly with customers that are added or lost, by adopting abstract fictional theories about distribution poles, lines and transformers that assume some fraction of these costs also vary directly with the number of customers being served. There has been no showing by MECO that it adds poles, distribution lines or transformers in direct proportion to changes in the numbers of customers being served.

Q. IS THE MINIMUM-SIZED SYSTEM THEORY THAT MECO RELIED UPON A REASONABLE BASIS TO ESTIMATE A CUSTOMER COMPONENT OF DISTRIBUTION NETWORK COSTS?

A. No. This theoretical approach is flawed in the way it double counts cost responsibility. The minimum-sized distribution system that is assumed to be constructed and required to connect customers is actually capable of serving a large percentage of customer demand, particularly for residential customers. However, no credit is given for this demand serving capability when allocation factors are devised and applied to the "demand" component of distribution network costs. Under MECO's proposed COSS, the residential customer class pays for the majority of the deemed customer component of the distribution network which is capable of meeting much of the residential KW demand. Then, residential customers pay again for the demand component based upon their full measured demands. This problem is explained in the NARUC Electric Utility Cost Allocation Manual at page 95:

> The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment; "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.
>
> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When

> using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.
>
> When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum size method was used to classify those costs.

This double counting problem has not been resolved in MECO's COSS.

Q. DOES MECO DISPUTE THAT ITS MINIMUM SIZED SYSTEM IS CAPABLE OF SERVING SIGNIFICANT AMOUNTS OF CUSTOMER DEMAND?

A. No. In its response to CA-IR-196, MECO confirmed that the minimum sized primary overhead conductor it installs can serve 245 amps, which is sufficient capacity to completely serve the peak demands of 299 average Maui Division individual residential customers. Allocating over 40 percent of the primary conductor costs mostly to residential customers after deeming them "customer related" without also recognizing a demand serving "credit" for the peak serving capacity of this facility when calculating the demand allocation factor is blatant double counting.

The theoretical minimum sized padmount transformers that MECO installs are 25 kva, which is also sufficient capacity to serve multiple Maui Division individual residential customers. However, MECO's COSS

recognizes no demand serving credit for the load serving ability of such a minimum sized transformer, which credit would be needed to avoid the double counting problem.[9]

Q. IS IT ALWAYS NECESSARY FOR MECO TO CONSTRUCT NEW DISTRIBUTION LINES IN ORDER TO CONNECT AND SERVE CUSTOMERS, AS ASSUMED IN MECO'S CLASSIFICATION OF SUCH COSTS AS A "CUSTOMER" COST?

A. No. Some customers are connected to existing network facilities by merely adding service lines and meters. Adding other customers may require an extension of network facilities, but such extensions are not directly related to the number of customers being served. For example, adding an apartment building or other high-density residential developments may entail minimal new investment in distribution facilities, although dozens or hundreds of new metered customers are added. The challenges associated with correlating distribution network investment levels for poles, conductors and transformers to the number of customers being served is evident when consideration is given to variables such as customer density, the amount of existing electrical infrastructure, the proximity of existing facilities and the estimated demand

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9 See MECO's response to CA-IR-196.

levels of specific customers that all influence distribution network investment levels.

Q. HAS MECO PREPARED ANY STUDIES, WORKPAPERS OR ANALYSES TO SUPPORT THE STATEMENT AT PAGE 9 OF MR. YOUNG'S TESTIMONY THAT "THE CUSTOMER COMPONENT OF THE DISTRIBUTION LINES AND TRANSFORMERS IS THAT PORTION OF COSTS WHICH VARIES WITH THE NUMBER AND LOCATION OF CUSTOMERS?"

A. No.[10] There has been no study or showing by MECO of any correlation between the number of customers and distribution network costs. Moreover, the Company's COSS minimum system approach completely fails to account in any way for the "location of customers," even though the location of customers could very directly affect the amount of distribution network costs that are incurred.[11]

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10 See MECO's response to CA-IR-262, part a.

11 See MECO's response to CA-IR-262, part b.

Q. ARE THE MINIMUM SYSTEM STUDIES THAT WERE PERFORMED BY MECO AND RELIED UPON TO DEVELOP THE PERCENTAGES OF DISTRIBUTION LINES AND TRANSFORMERS DEEMED TO BE A "CUSTOMER COMPONENT" BASED UPON RECENT COST STUDY DATA?

A. No. Aside from the theoretical and practical infirmities in the Company's approach, the underlying cost data used to calculate minimum system percentages was from the period 1982 through 1994, causing such data to potentially be unreliable simply due to its age.[12]

Q. DO ANY RECENT ACTUAL CUSTOMER CHANGES INVOLVING HECO, AS REVEALED IN THE PENDING HECO RATE CASE, HELP TO ILLUSTRATE THE PROBLEM CAUSED BY CLASSIFYING DISTRIBUTION NETWORK COSTS AS CUSTOMER-RELATED?

A. Yes. Two recent changes serve as useful illustrations of this problem. First, the Kukui Gardens apartments were converted from master metering to individual metering pursuant to Commission approval in Docket No. 03-0107. Upon conversion, an existing 32 year-old customer-owned distribution system was replaced with a utility-owned system under an arrangement through which the Developer, Kukui Gardens Corporation would "essentially finance the

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12 See MECO-WP-1802, page 7 at NOTE 2, which states, "DEMAND VS. CUSTOMER BREAKDOWN FROM MINIMUM SYSTEM STUDY BASED ON REPLACEMENT COSTS AS OF 12/31/1995 OF INSTALLED FACILITIES FROM 1982-1994." See also MECO's response to CA-IR-269, pages 2-4 at Note #2.

1 entire project cost with a cash contribution-in-aid-of construction ("CIAC") of
2 $516,384; and an in-kind contribution of $250,000 for the duct,
3 handholes/manholes, and pullboxes."[13] As part of this project, the number of
4 customers being served increased from one master-metered account to
5 approximately 800 separately metered accounts, which would directly increase
6 the allocation of customer-classified distribution poles, lines and conductors to
7 the residential class.[14] However, the incremental investment required to serve
8 these 800 new customers was essentially zero, given the CIAC provided by
9 the developer. More importantly, the construction that was done at Kukui
10 Gardens was not to extend the distribution network, as implied by HECO's
11 classification of distribution network plant as customer-related, but rather to
12 replace existing old distribution plant that was "in urgent need of
13 replacement."[15]

14 The second example also involves HECO and was for the conversion of
15 another master-metered location into new individually metered condos at
16 215 N. King Street. In its Docket No. 2006-0386 response to CA-IR-98, part f,
17 HECO acknowledged that, "Since all of the proposed loads at 215 N. King

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13 See HECO application filed in Docket No. 03-0107 and HECO's response in Docket No. 2006-0386 to CA-IR-398 at 6.

14 See HECO's response in Docket No. 2006-0386 to CA-IR-398, part b.

15 See HECO application filed in Docket No. 03-0107and HECO's response in Docket No. 2006-0386 to CA-IR-398 at 6.

1 Street are contained within a single building structure, the distribution system
2 necessary to serve either a master-metered account, or individually metered
3 accounts, would be the same." However, when the Company's proposed
4 customer-classification of distribution system costs is employed, more costs
5 are allocated to the residential class simply because of conversion to
6 individual metering – even though the distribution system costs caused by the
7 customers "would be the same."
8
9 Q. ARE YOU AWARE OF ANY ELECTRIC UTILITIES THAT, UNLIKE MECO,
10 DO NOT CLASSIFY DISTRIBUTION POLES, LINES OR TRANSFORMERS
11 AS "CUSTOMER" COSTS IN THE CONDUCT OF EMBEDDED COST OF
12 SERVICE ANALYSES?
13 A. Yes. In their most recent rate case proceedings, Public Service Company of
14 Oklahoma and PSI Energy, Inc. classified all distribution poles, lines and line
15 transformers as demand-related costs in the COSS studies filed with the
16 Oklahoma and Indiana regulatory commissions.[16] Similarly, Arizona Public
17 Service Company classified all of its distribution poles, lines and transformers
18 as entirely demand-related costs in the COSS presented by that utility in its

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16 Public Service Company of Oklahoma, Oklahoma Corporation Commission Cause No. PUD 200300076 filed January 23, 2004, Workpaper L-5, page 2, "Classification of Rate Base," PSI Energy Inc., Indiana Utility Regulatory Commission Cause No. 42359 filed March 28, 2003, Petitioner's Exhibit Z, Testimony of Kent K. Freeman at 24.

1 most recent rate case.[17] This treatment of all distribution network poles, lines
2 and transformers as demand-related avoids the controversy and allocation
3 distortions associated with the MECO "customer" classification approach.
4
5 Q. HAVE OTHER RECOGNIZED REGULATORY AUTHORITIES, BEYOND THE
6 REGULATORY JURISDICTIONS YOU HAVE JUST MENTIONED,
7 CONCLUDED THAT CUSTOMER CLASSIFICATION OF DISTRIBUTION
8 NETWORK COSTS, USING A MINIMUM SYSTEM APPROACH, IS
9 INAPPROPRIATE?
10 A. Yes. Dr. James C. Bonbright in his widely recognized book, "Principles of
11 Public Utility Rates" addresses this issue, acknowledging that utilities may
12 attempt to estimate the costs of the hypothetical minimum system, which he
13 characterized as "indefensible" because such costs are not "caused" by the
14 addition of customers to the utility system; nor are they strictly related to the
15 customers' demand:

16 The FERC Handbook (1983, p.52) recognizes that while
17 there are no hard-and-fast rules for allocating customers costs,
18 as they depend on the type of costs involved, the issue is not
19 usually litigated as the dollars involved are usually not
20 substantial. The really controversial aspect of customer-cost
21 imputation arises because of the cost analyst's frequent practice
22 of including, not just those costs that can be definitely
23 earmarked as incurred for the benefit of specific customers, but

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[17] Arizona Public Service Company, Docket No. E-01345A-05-0816, Testimony of David J. Rumolo, Workpaper DJR_WP1 at 11-13 show that utility's classification and allocation of overhead and underground distribution facility costs on a demand basis, with only services, meters and lighting accounts classified and allocated on a customer basis.

also a substantial fraction of the annual maintenance and capital costs of the secondary (low-voltage) distribution system – a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage while keeping them from falling of their own weight. In any case, the annual costs of this phantom, minimum-sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary directly with the number of customers. Alternatively they are calculated by the "zero-intercept" method whereby regression equations are run relating cost to various sizes of equipment and eventually solving for the cost of a zero-sized system (Sterzinger, 1981).

What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution system costs and numbers of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system. While, for the reasons just suggested, the inclusion of a minimum-sized distribution system among the customer-related costs seems to us clearly indefensible, its exclusion from the demand-related costs stands on much firmer ground.

For this exclusion of minimum-sized distribution system costs makes more plausible the assumption that the remaining cost of the secondary distribution system is a cost which varies continuously (and perhaps, even more or less directly) with the maximum demand imposed on this system as measured by

> peak load. But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reasons stated previously, to which cost function does it then belong? The only defensible answer, *in our opinion, is that it belongs to none of them.* Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully distributed cost analysts dare not avail themselves of this solution, since they are prisoners of their own assumption that "the sum of the parts equals the whole". They are therefore under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories.[18]

This challenge in attribution of cost responsibility for a distribution network that serves a joint purpose of connecting customers and meeting their demands does not justify the adoption of theoretical approaches that are not economically rational.

Q. IN A PREVIOUS MECO RATE CASE, DOCKET NO. 97-0346, THE CONSUMER ADVOCATE ALSO CHALLENGED THE COMPANY'S MINIMUM SYSTEM APPROACH AND PROPOSED TO ALLOCATE DISTRIBUTION COSTS ON THE BASIS OF DEMAND AND ENERGY ALLOCATION FACTORS, RATHER THAN ALLOCATING THE COSTS

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[18] James C. Bonbright (with editions co-authors Albert L. Danielsen and David R. Kamerschen.) "Principles of Public Utility Rates" Public Utility Reports, Inc., 1988 (2nd edition) at 491-492.

PARTIALLY BASED ON THE NUMBER OF CUSTOMERS.[19] HOW DID THE COMMISSION RESPOND?

A. According to Decision and Order No. 16922 at page 55, the Commission stated:

> In past commission decisions, [footnote omitted] we rejected similar arguments made by the Consumer Advocate and concluded that the use of the minimum system method was reasonable and consistent with NARUC guidelines. We are not persuaded to change our position in this proceeding. We further find that MECO properly applied the minimum system method and that there was no double counting of demand, and that the zero intercept method is reasonable and consistent with NARUC cost allocation guidelines. Thus, the commission concludes that MECO's proposed classification of MECO's distribution plant costs as demand-related and customer-related is reasonable. We also find MECO's embedded cost of service study to be reasonable.

Q. SHOULD THE COMMISSION CONTINUE TO DEFER TO MECO'S APPLICATION OF THE NARUC MANUAL MINIMUM SYSTEM APPROACH TO CLASSIFY AND ALLOCATE DISTRIBUTION SYSTEM COSTS?

A. No. The Consumer Advocate respectfully submits that this testimony contains ample justification for abandonment of the long controversial minimum system classification theories and studies. Allocating distribution poles, lines and transformer costs solely on the basis of demand is a reasonable alternative under the circumstances. It is an alternative that is routinely accepted in other

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[19] Decision and Order No. 18365, Docket No. 99-0207 at 78-79.

jurisdictions, as noted above, and solves the intractable problems associated with the Company's minimum system calculations. I recommend that the Commission need not feel bound to force-fit a customer classification onto distribution network facilities using the problematic methods described in the NARUC Cost Allocation Manual, and studies prepared more than a decade ago, when doing so represents little more than what Dr. Bonbright referred to as "impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories." The only distribution system costs that vary directly with the number of customers being served are the service lines, meters and installations on customer premises that are used to connect individual customers to the distribution network.[20]

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20 Notably, these are the only distribution plant accounts that are clearly to be allocated solely on a weighted customer basis according to page 87 of the NARUC Cost Allocation Manual relied upon by Mr. Young.

1 III. **PRODUCTION O&M EXPENSE CLASSIFICATION.**

2 Q. THE OTHER PROBLEM YOU IDENTIFIED WITH REGARD TO THE MECO
3 EMBEDDED COSS IS THAT IT IMPROPERLY CLASSIFIES ALL NON-FUEL
4 PRODUCTION OPERATIONS AND MAINTENANCE EXPENSES AS
5 "DEMAND" DRIVEN. PLEASE EXPLAIN THIS ISSUE.

6 A. Production O&M expenses include many types of costs that are relatively
7 "fixed" in nature, meaning the costs do not vary directly with the amount of
8 energy that is generated. For example, the workforce consisting of power
9 plant operators draw the same salary and benefits on a given day without
10 regard to how much customer demand is served by the generators at the
11 station. For these relatively "fixed" costs, MECO's demand classification is
12 reasonable.

13 On the other hand, certain other non-fuel production O&M costs are
14 influenced by the level of plant output, where higher output causes additional
15 wear and required maintenance on moving parts, increases environmental
16 fees assessed to the utility or contributes to the amount of consumable
17 materials used for plant operations. The MECO embedded COSS ignores this
18 distinction and simply deems all of the more than $21 million of non-fuel
19 Production O&M expenses as demand related.[21]

20

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[21] See MECO-502.

Q. HOW SIGNIFICANT IS THIS PROBLEM IN TERMS OF COSS RESULTS?

A. It is impossible to precisely quantify the required adjustment because a special study is required to determine the fixed versus variable nature of costs recorded in the Production O&M Accounts and MECO has apparently not performed such a study. However, the impact is clearly very substantial, because the Consumer Advocate has isolated only four components of Production O&M expenses that MECO has calculated for the test year based upon a variable/energy basis and these four expense elements alone make up 29.9 percent of total test year Production O&M expenses.[22]

For example, MECO has normalized its generating unit overhaul expenses based run time hours in relation to a maintenance frequency interval based upon operating hours, resulting in a reduction of such expenses from test year projected levels exceeding $7.1 million to a more representative normal level of $4.1 million for the Maui Division.[23] These overhaul expenses are not fixed as implied by Mr. Young's 100 percent demand classification, but instead quite clearly vary with the hours the units are operated to produce energy output. Similarly, MECO's test year projections of Nox water purification expenses, lubrication oil consumption expenses and emission fees

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22 See CA-WP-501 for a listing and calculation of the variable Production O&M expense elements as a percentage of total Production O&M.

23 See MECO-WP-505, columns A and B. Calculations for Maui are on pages 1 and 2, with Lanai on page 3 and Molokai on page 4.

1 are all driven by generation unit fuel consumption or run hour input
2 assumptions.
3
4 Q. YOU NOTED IN PRIOR TESTIMONY THAT MR. YOUNG (MECO T-18,
5 PAGE 9) RELIES UPON THE NARUC ELECTRIC UTILITY COST
6 ALLOCATION MANUAL AS SUPPORT FOR HIS MINIMUM SYSTEM
7 APPROACH. HAS MR. YOUNG CONSISTENTLY APPLIED THIS NARUC
8 MANUAL WITH REGARD TO THE APPROPRIATE CLASSIFICATION OF
9 PRODUCTION O&M EXPENSES?
10 A. No. Mr. Young has only selectively applied the guidance provided by the
11 NARUC Electric Cost Allocation Manual. The NARUC Manual also specifies
12 classification of certain Production O&M expense accounts as energy-related,
13 rather than supporting MECO's 100 percent demand classification of such
14 O&M expenses. Specifically, the NARUC Manual sets forth, at Exhibit 4-1, a
15 "Classification of Expenses" table for Production O&M expenses that classifies
16 certain of the O&M Accounts as "Energy Related." I have included as Exhibit
17 CA-502 copies of these pages of the NARUC Manual.
18

Q. HAVE YOU ESTIMATED THE PORTION OF NON-FUEL PRODUCTION O&M EXPENSES THAT SHOULD BE CLASSIFIED AS ENERGY RELATED, BASED UPON THE FERC PREDOMINANCE METHODOLOGY?

A. Yes. I summarized those known elements of MECO's projected test year Production O&M expenses that were calculated on a variable (rather than fixed) basis, as shown in CA-WP-501, and the result suggests that a 29.9 percent energy, 70.1 percent demand classification may be appropriate for the Company in the absence of more detailed analysis. This estimated re-classification is applied within the Consumer Advocate's presentation of cost of service in Exhibits CA-500 and CA-501. I recommend that MECO be directed by the Commission to refine this element of its COSS in future rate filings, by conducting studies of causation of production O&M to more precisely quantify which elements of these expenses vary with the output of MECO generating units.[24]

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[24] As noted in footnote 5, HECO has Stipulated to conduct such a study in support of future HECO Cost of Service studies in resolution of this issue in Docket No. 2006-0386.

Q. HAS THE CONSUMER ADVOCATE RE-CALCULATED THE EMBEDDED COSS BASED UPON THE CONSUMER ADVOCATE ACCOUNTING ADJUSTMENTS AND RECOMMENDED REVENUE REQUIREMENT, EMPLOYING REVISIONS FOR THE CONCERNS YOU RAISE?

A. Yes, restatements and corrections have been made for all of the noted issues. The Consumer Advocate has re-calculated MECO's embedded cost of service studies for each island based upon the Consumer Advocate's pro-forma adjusted rate base and expense amounts. The results of this recalculation are set forth in Exhibits CA-500 and CA-501, which was prepared in the same format as the Company's COSS studies for the sake of comparability, with separate pages for the Maui, Lanai and Molokai Divisions. As a matter of efficiency and to aid in comparing the study results, I linked Mr. Young's spreadsheet model logic into the Consumer Advocate's accounting schedules to prepare my cost of service Exhibits CA-500 and CA-501. Aside from changed test period input amounts for revenues, expense and rate base, the other changes made to the Company's embedded COSS model are:

- Classification of all distribution network poles, lines and transformers as demand-related costs.
- Classification of 29.9 percent of non-fuel production O&M expenses as energy-related, based upon the FERC predominance methodology.

Q. HOW DO THE CHANGES YOU HAVE MADE TO THE MECO COSS METHODOLOGIES IMPACT THE RESULTING CLASS RATE OF RETURN COMPARISONS UNDER MECO'S PRESENT RATES?

A. After making the COSS methodology changes that are needed, the indicated class rates of return at current effective rate levels are somewhat closer to equality (i.e., each customer class is earning closer to the same rate of return on rate base). For example, the indicated Residential Rate of Return for the Maui system with these revisions is 4.75 percent, which is only modestly below the Total System Rate of Return ("ROR") of 7.26 percent, as shown at the bottom of Exhibit CA-500, page 1. Only the Maui Schedule G and J General Service customers have an ROR noticeably above average, designated as "ROR As % of System ROR."

Q. SHOULD THE COMMISSION RELY SOLELY UPON CLASS COST OF SERVICE ALLOCATIONS TO DETERMINE THE RATE CHANGES IN THIS CASE?

A. No. Cost of service results are estimates based upon methods and judgments of analysts that may vary significantly. In addition, cost of service results can change significantly from one test period to another, due to shifts in load conditions, expense levels or methodology changes. Therefore, cost of service results should be used only as a "guide" in the direction rate changes should occur, while other factors must also be considered by the Commission.

1 IV. **REVENUE INCREASE DISTRIBUTION.**

2 Q. DOES MECO ADVOCATE DISTRIBUTING ITS PROPOSED RATE
3 INCREASE OR "RATE SPREAD" AMONG CUSTOMER CLASSES BASED
4 UPON ITS COST OF SERVICE ALLOCATIONS?

5 A. No. The Company's embedded COSS for Maui suggests that Residential
6 Schedule R, Commercial Schedule H and Lighting Schedule F customers
7 should receive an above-average rate increase, while all other commercial
8 rate classes should receive a below-average increase. However, MECO has
9 advocated an "across the board" rate increase distribution, which would
10 increase revenues from each rate class on an equal percentage basis.
11 MECO-1802, pages 1 through 3 illustrates the proposed 5.27% revenue
12 increase above present rates that the Company seeks for each rate schedule
13 on each island.

14 The rationale for MECO's proposed equal percentage increase across
15 rate classes is explained at page 21of Mr. Reinhardt's testimony (MECO T-1),
16 where he stated, "The Company is allocating the requested revenue increase
17 as an equal percentage increase to each rate schedule to share the burden
18 among all ratepayers."

19

Q. DO YOU AGREE WITH THE RATIONALE ADVANCED BY MR. REINHARDT IN FAVOR OF EQUAL PERCENTAGE RATE INCREASES ACROSS CUSTOMER CLASSES?

A. Yes. While the revenue requirement recommended by the Consumer Advocate is lower than the $19 million MECO requested, the rationale for MECO's proposed across the board revenue increase distribution may continue to apply given the large increases in ECAC that have impacted residential customers recently. For most Maui customer classes, such an equal percentage rate increase will produce some gradual movement toward indicated cost of service under either the MECO or Consumer Advocate's recommended cost allocation methodologies.

At the Consumer Advocate's lower revenue requirement in this Docket, and given cost of service results shown in Exhibit CA-500, the equal percentage increase revenue increase distribution advocated by MECO is reasonable and should be approved by the Commission.

Q. IS IT APPROPRIATE, AS A MATTER OF REGULATORY POLICY, TO CONDITION THE APPLICATION OF COST OF SERVICE RESULTS UPON POLICY CONSIDERATIONS SUCH AS CUSTOMER IMPACT?

A. Yes. MECO was quite correct in conditioning its use of cost allocation study results upon customer impacts and acceptance in Mr. Reinhardt's testimony. Cost of service allocations are inherently imprecise and dependent upon a

1 multitude of judgments regarding cost causation, as well as imperfect data
2 regarding customer demands and cost classifications. Therefore, the COSS
3 results must serve only as a guide and not dictate the distribution of revenue
4 changes among customer classes. It is essential to consider many factors,
5 other than the indicated class cost of service results, in determining an
6 appropriate distribution of revenue increases. These other factors include:

7 • Revenue stability for the utility - rates should not be abruptly changed,
8 creating a risk that customers may modify their demand levels or
9 migrate between rates, producing unexpected revenue impacts.

10 • Gradualism in customer impacts - customer understanding and
11 acceptance of rate changes is dependent upon avoidance of abrupt
12 monthly bill impacts.

13 • Administrative practicality – rate structures and the relationship
14 between rates must be rational and simple to apply and understand.

15 • Public policy priorities such as conservation or low-income
16 assistance - purely cost based rates may fail to meet other desirable
17 public policy objectives.

18

Q. DOES THE COMPANY'S PROPOSED EQUAL PERCENTAGE RATE INCREASE APPROACH MAKE THE EXISTING DISPARITY IN THE CONTRIBUTION TOWARDS AN EQUAL RATE OF RETURN AMONG RATE CLASSES ANY WORSE?

A. No. Exhibit MECO-1802 at page 1 indicates that MECO's proposed equal percentage increase actually has the effect of gradually improving the "ROR Index" for most of the various rate schedules, moving each Maui system rate class except Large Power (Schedule P) somewhat closer to a 100 percent Index. For Schedule P, the MECO-proposed equal percentage rate distribution does not meaningfully impact the ROR index. For the Lanai and Molokai systems, the impact of an equal percentage revenue increase upon class returns is generally in the direction of cost of service, but the rates for these smaller systems were clearly not cost-based to start with and no acceptable levels of rate change will move prices quickly toward indicated cost to serve. These results are also evident in Exhibit CA-500, which shows at present and proposed rate levels the resulting "RATE OF RETURN ON RATE BASE (%)" and "RATE OF RETURN INDEX" values at pages 2, 4 and 6 for Maui, Lanai and Molokai, respectively.

Q. MECO'S REVENUE DISTRIBUTION PROPOSAL WAS BASED UPON AN INCREASE ABOVE PRESENT RATE LEVELS OF NEARLY $19 MILLION. WHAT IS THE CONSUMER ADVOCATE'S RECOMMENDATION

REGARDING THE DISTRIBUTION AMONG CUSTOMER CLASSES OF THE SMALLER RECOMMENDED OVERALL RATE INCREASE AMOUNT SET FORTH IN CONSUMER ADVOCATE SCHEDULE A?

A. As noted above, the rate increase proposed by the Consumer Advocate should also be implemented as an equal percentage revenue increase among customer classes, in consideration of customer impacts, as well as the COSS results. In the event the Commission desires a more aggressive movement toward indicated COSS results, Maui Schedule J might receive a somewhat below average revenue increase, while Maui lighting Schedule F might receive a somewhat above average revenue increase. Broader class return disparities exist for Lanai and Molokai, but these results are driven in part by longstanding policies that have subsidized pricing on these islands with revenues from the Maui Division.

V. RESIDENTIAL RATE DESIGN ISSUES.

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING RESIDENTIAL RATE DESIGN FOR SCHEDULE R?

A. Mr. Young has proposed that Schedule R customer charges for all three Divisions remain at the existing $7.50 monthly level ($12.00 for 3-phase service) and that the energy rates in Schedule R be modified to an inclining block design, comparable to what was proposed and agreed upon in HECO Docket No. 2006-0386 and HELCO Docket No. 05-0315. The Consumer

Advocate supports continuation of existing Residential customer charge rates in light of a need to promote conservation by placing utility cost recovery within the energy rates where consumption can impact customers' bills and in recognition of lower unit customer costs that result from the Consumer Advocate's cost of service approach.[25]

Regarding energy charges, MECO's proposed Schedule R inclining block residential rates would have three tiers, with the Maui rates breaking at 350kWH, 850kWh and usage over 1,200 kWh per month and the Lanai and Molokai tiers somewhat smaller at 250/500/750 kwh levels. Pricing within the tiers is designed so that lower than average percentage rate increases occur for usage in the first tier, approximately average percentage increases in the middle tier and above average increases are experienced for usage in the last tier.[26]

Q. IN THE RECENT HECO and HELCO PROCEEDINGS, DOCKET NOS. 2006-0386 and 05-0315, THE CONSUMER ADVOCATE SUPPORTED THE COMPANIES' PROPOSED INCLINING BLOCK RATES BASED UPON COST OF SERVICE, CUSTOMER IMPACT AND CONSERVATION

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25 CA-501, page 1, reflects Schedule R unit customer costs per month of only $19.26, which is much lower than the value quantified at MECO-WP-1802, page 89 where such costs are estimated to be $30.42 per month. This difference is largely driven by the distribution network cost classification issue described herein.

26 See MECO T-18 at page 17 and MECO-1819 at pages 1 and 2.

1 CONSIDERATIONS. DO THESE SAME CONSIDERATIONS CAUSE YOU
2 TO SUPPORT THE MECO PROPOSAL FOR INCLINING BLOCK
3 RESIDENTIAL RATES?
4 A. Yes. In the HECO and HELCO cases, I explained how inclining block rate
5 structures can strengthen the incentive for residential customers to invest in
6 conservation and can improve affordability of electric service for customers
7 with smaller homes and lower monthly usage levels. Inclining block rates can
8 also be effective in mitigating rate increase impacts upon lower income
9 consumers who elect to limit their usage to the lower tiers of the rate.[27]
10 Additionally, inclining block rates for MECO are supported by cost of service
11 differentials because the Company's marginal cost of energy in 2007
12 (MECO-1813) is estimated to be higher than its embedded cost of energy
13 (MECO-1810, page 1).
14
15 Q. AT THE COMPANY'S PROPOSED LEVEL OF RATE INCREASE, WILL THE
16 PROPOSED RESIDENTIAL INCLINING BLOCK RATES PRODUCE
17 ACCEPTABLE CUSTOMER IMPACTS?
18 A. Yes. MECO-1819, pages 1 and 2 illustrate Schedule R customer impacts at
19 proposed rate levels and show how the inclining block structure would produce
20 gradually higher percentage bill increases as usage grows. The pricing

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[27] See Docket No. 05-0315, CA-T-5 at 46-47.

spread between tiers that is proposed by MECO is gradual, such that impact upon the largest residential customers is about six percent. Of course, at the Consumer Advocate's lower recommended revenue requirement, these customer impacts would be further moderated.

Q. HAS THE COMPANY MADE ADDITIONAL PROVISION FOR LOW INCOME RATE RELIEF AS PART OF ITS RESIDENTIAL INCLINING BLOCK RATE PROPOSAL?

A. Yes. As was proposed by HELCO and HECO upon implementation of inclining block rates for residential customers, MECO has committed to offer its customers who receive bill credits under the Low Income Home Energy Assistance Program ("LIHEAP") a tariff concession to be charged for non-fuel energy at only the lowest, initial block within Schedule R.[28] The Consumer Advocate believes this is an important element of the inclining block rate proposal that should be approved by the Commission.

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[28] MECO response to CA-IR-193, part c.

1 VI. **COMMERCIAL AND LIGHTING RATE DESIGN ISSUES.**

2 Q. WHAT IS MECO'S PROPOSAL WITH RESPECT TO CUSTOMER
3 CHARGES IN COMMERCIAL SERVICE SCHEDULES G, J, H, AND P?

4 A. The Company has proposed modest increases in Schedule G customer
5 charge rates, ranging from $1.00 (Molokai) to $8.00 (Lanai) per month.[29]
6 These proposals are generally consistent with the indicated unit cost of service
7 per customer per month, as shown in CA-501 in the column "Schedule G Gen
8 Service Non-Dmd." In addition, the proposed rates do not exceed the
9 customer charges found acceptable in settlement with HECO in Docket
10 No. 04-0113 and should therefore be approved by the Commission.

11 Somewhat larger Schedule J customer charge increases are proposed
12 by MECO, ranging from only $2.00 per month on Molokai to $15.00 per month
13 on Maui. When relatively large customer charge increases are combined with
14 the excessive increases in demand charges (discussed below), unacceptably
15 large percentage rate increases can be imposed upon the smallest,
16 low-load-factor Schedule J customers, as shown at MECO-1819, pages 5
17 and 6, where revenue increases of approximately 17 percent can be
18 experienced by such customers. The Consumer Advocate recommends that
19 Schedule J customer charge increases be limited to $10.00 per month, which
20 would have an impact only on proposed Maui Division rates to limit the

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29 MECO T-18, pages 18, 49 and 80.

customer charge to $45.00 (single phase) and $60.00 (three phase) per month.

For Schedule H service, MECO has proposed no change to customer charges on Molokai, but proposes larger increases of $12.00 to $13.00 per month for Maui and Lanai customers. The same small customer percentage monthly bill impact concern would exist here, as illustrated at MECO-1819, page 7. However, considering the apparently higher unit customer costs to serve Schedule H,[30] the Company's proposal to close Schedule H to new customers, and the limitations recommended for demand charge increases discussed below, the Consumer Advocate does not object to these larger customer charge increases for Schedule H.

Finally, with regard to Schedule P, the MECO-proposed customer charges are unchanged for Lanai and Molokai, but are proposed to be increased from $225 per month to $375 per month for Maui.[31] The Consumer Advocate recommends limiting this increase to $300 per month at this time, so as to moderate the impact of rate changes upon the smallest Schedule P customers which impact appears to be excessive at MECO-1819, page 9, particularly when applied to lower load factor Schedule P customers for which large increases in demand charges are also proposed by MECO.

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30 MECO-1810, page 1 shows Maui Unit Customer Costs for Schedule H are more than double Schedule J customer costs. Similar results appear at CA-501, page 1.

31 See MECO T-18, page 25, line 13.

Q. WHAT IS PROPOSED BY MECO WITH RESPECT TO CHANGES IN DEMAND CHARGES IN SCHEDULES J, H, AND P?

A. For Schedules J and P, MECO has proposed to approximately double demand charges for all three Divisions, but for Schedule H the Company is proposing somewhat lower demand charge increases. For example, the Schedule J demand charge is proposed to be increased from $5.75 per kW to $12.00 per kW for Maui and Lanai[32] and for the Maui Schedule P demand charges are proposed to increase in the blocked rates from $8.50 and $8.00 per kw to $18.00 and $17.00, respectively representing an approximate doubling of the existing demand charges for these rate schedules.[33]

Q. ARE LARGE INCREASES IN DEMAND CHARGES SUPPORTED BY UNIT COST OF SERVICE EVIDENCE?

A. Yes. Mr. Young's testimony on this matter simply notes that the much higher proposed demand charges represent only a fraction of full unit demand cost under the Company's COSS approach and such unit demand costs would be even higher under the Consumer Advocate's demand classification of all distribution network facilities and expenses. However, MECO's existing rate structure has relatively low demand charges that should gradually be adjusted

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32 See MECO T-18 page 20, line 8.

33 Id. at page 25, line 15.

1 upward, so as to mitigate rate impacts upon the Company's lower load factor
2 commercial customers.
3
4 Q. CAN THE UNDESIRABLY ABRUPT RATE IMPACTS UPON LOWER LOAD
5 FACTOR COMMERCIAL CUSTOMERS BE OBSERVED IN MECO'S
6 PREFILED EVIDENCE?
7 A. Yes. For example, at MECO-1819 pages 5 through 9, for each level of "KW"
8 demand that is shown, the lower load factor customers on Schedules J, H and
9 P that use energy less intensively have the lower "KWH/KW" values in each
10 block of data. Primarily as a result of the Company's proposed large
11 increases in demand charges, MECO's proposed "Increase %" is
12 unacceptably large for customers using fewer KWH per KW. Aside from the
13 rate shock potential for such customers, the resulting very small percentage
14 increases for the heaviest users of energy with high "KWH/KW" values is
15 apparently at odds with the Company's proposed desire to encourage
16 conservation of energy use by suggesting the implementation of the proposed
17 inclining block rates for residential customers.
18
19 Q. WHAT SHOULD BE DONE WITH THE COMMERCIAL RATE SCHEDULE
20 DEMAND CHARGES IN THIS DOCKET?
21 A. Gradual increases in such charges would be desirable, so as to move toward
22 cost of service indicators without adverse customer impacts. I recommend

that demand charge increases be limited to no more than 30% above the demand charges presently in effect, so as to more gradually increase rates toward the indicated demand cost of service.

Q. DO YOU AGREE WITH THE ENERGY CHARGE ELEMENTS OF MR. YOUNG'S PROPOSED COMMERCIAL SCHEDULE RATE DESIGN?

A. Yes. The Company has proposed recovery of the remaining class revenue requirement through the energy rates that are developed in this proceeding, after consideration is given to the revenues that are expected to be derived from the customer charges and the demand rates discussed above. This is a reasonable approach, subject to the constraints mentioned above regarding the need to gradually increase customer and demand charges.

Q. WITHIN THE TESTIMONY FILED BY MR. YOUNG, MECO HAS PROPOSED CHANGES TO THE COMMERCIAL RATE AVAILABILITY PROVISIONS AND THE SCHEDULE J DEMAND RATCHET, WHICH ARE COMPARABLE TO TARIFF CHANGES PROPOSED BY HECO IN DOCKET NO. 04-0113. DO YOU OBJECT TO THESE CHANGES?

A. No. These changes generally conform to proposals that were made by HECO in Docket No. 04-0113 and found to be acceptable by the Consumer Advocate.[34]

Q. MECO HAS PROPOSED REDUCTIONS TO THE PERCENTAGE SUPPLY VOLTAGE ADJUSTMENTS FOR SCHEDULES G, J, P, N AND U IN EACH OF THE THREE DIVISIONS.[35] WHAT IS THE BASIS FOR THESE REVISIONS?

A. According to Mr. Young, these changes are based on the system loss analysis prepared for this rate case by MECO's Transmission Planning Division.[36] A summary of this analysis was provided in response to CA-IR-383 and the data provided supports approval of these proposed changes.

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34 See Docket No. 04-0113, CA T-5 at 38-39.

35 MECO T-18, pages 18, 20, 25, 28, 49, 51, 56, 59, 80, 82, 87, 88 and 91.

36 Id. pages 19, 23, etc.

Q. WHAT IS PROPOSED BY MECO WITH RESPECT TO SCHEDULE F LIGHTING SERVICE RATES?

A. At page 27 of his testimony, Mr. Young explains that Schedule F energy block charges are increased by "approximately the same cents per kWh increase over current Schedule F energy block rates." This approach was followed for Lanai and Molokai[37] and has the effect of producing relatively equal percentage increases across all customer usage levels,[38] and is appropriate for implementation of the rate increase that is ultimately assigned to the *lighting customer class.*

VII. TIME OF USE RATES.

Q. HAS MECO PROPOSED RESIDENTIAL AND COMMERCIAL TIME OF USE ("TOU") RATES IN THIS DOCKET?

A. Yes. The Company has proposed four new optional Residential and Commercial time of use rates that are designated TOU-R, TOU-G, TOU-J and TOU-P. Mr. Young describes these proposals at MECO T-18, pages 34 to 44 (Maui Division) with the discussion repeated with slightly different rate levels for Lanai and Molokai at pages 6-75 and pages 97-107, respectively.

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37 *Id. pages 58 and 90.*

38 See MECO-1819, MECO-1820 and MECO-1821 at pages 10, and 11, respectively.

Q. ARE THE NEW TIME OF USE RATES SIMILAR IN STRUCTURE TO THE TOU PROPOSALS MADE BY HECO IN DOCKET NO. 04-0113?

A. Yes. In Docket No. 04-0113, the Consumer Advocate indicated its support for implementation of optional TOU rates on a gradual basis and indicated an interest in monitoring and evaluating the results of these initiatives as more information about customer participation becomes available. MECO's proposed new TOU service would be made available on a "phased-in basis," limited to 300 meters across all three divisions. The information obtained during the interim period regarding any customer and revenue impacts from the adoption of time differentiated pricing, as set forth in the proposed tariffs, will only be determinable after some experience is gained with the new rates.

Q. WHEN DOES MECO INTEND TO REMOVE THE LIMIT ON THE NUMBER OF PARTICIPANTS RECEIVING SERVICE UNDER THE NEW TOU RATES?

A. MECO has imposed the 300 meter limitation at this time because billing for TOU service currently requires a significant amount of resources to manually bill and process service to the TOU customer accounts. When MECO completes the installation of its new Customer Information System ("CIS"), the Company plans to remove the customer number limitation because the new CIS will be able to automatically generate a bill based on TOU rates.[39]

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[39] MECO response to CA-IR-266.

1 Q. WHAT IS THE CONSUMER ADVOCATE'S RESPONSE TO THE
2 COMPANY'S TIME OF USE RATE PROPOSAL?
3 A. The Consumer Advocate again supports the Company's TOU rate proposal,
4 subject to MECO adjusting the final rate levels within the proposed TOU rates
5 to maintain parity with the final sales rate levels ultimately approved by the
6 Commission for the related basic sales rate schedules.
7
8 **VIII. <u>OTHER MECO RATE DESIGN PROPOSALS</u>.**
9 Q. IN DOCKET NO. 04-0113, THE CONSUMER ADVOCATE RAISED
10 CONCERNS ABOUT THE CONTINUED NEED FOR HECO'S RATE
11 SCHEDULE H, THE COMPANY'S ONLY RATE SCHEDULE BASED UPON
12 CUSTOMER END-USE CHARACTERISTICS AND HECO AGREED TO
13 CLOSE SCHEDULE H IN ITS MOST RECENT RATE FILING IN DOCKET
14 NO. 2006-0386. WHAT HAS MECO PROPOSED IN THIS DOCKET WITH
15 RESPECT TO SCHEDULE H?
16 A. MECO has proposed closing Schedule H to new customers. This will enable
17 the Company to gradually migrate the existing Schedule H customers to other
18 effective rate schedules.[40] If all of the existing Schedule H customers have
19 not been migrated to other rate schedules at the time of MECO's next rate
20 case, MECO should be required to submit evidence of the continuing need for

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40 MECO T-18, page 24.

Schedule H or a plan for an orderly migration of remaining Schedule H customers onto the Company's general sales rates. There is no apparent need to continue retaining Schedule H service pricing based upon customer end uses that may be promotional in nature, when the Company is attempting to implement demand constraint and conservation measures as regulatory goals.

Q. IN SETTLEMENT OF THE COST OF SERVICE ISSUES IN DOCKET NO. 04-0113, HECO AGREED TO PERFORM CERTAIN COST STUDIES IN SUPPORT OF COST-BASED POWER FACTOR RATE CREDITS. HAS MECO PERFORMED ANY OF THOSE STUDIES?

A. No. According to the response to CA-IR-191, "There has been no work done with regard to this issue for MECO. There is presently no work planned for any MECO study of power factor cost of service issues. For the purposes of settlement in their respective current rate cases, HELCO (Docket No. 05-0315) and HECO (Docket No. 2006-0386) have each agreed to conduct a power factor study for their next general rate case."

This settlement provision with HELCO and with HECO was in response to concerns raised by the Consumer Advocate about whether the power factor

rate credits that exist in the utilities' tariffs were cost-based.[41] In the most recent HECO rate case, Mr. Young (HECO T-20) testified at page 16 that HECO had not completed the study and its preliminary analysis is that the work required is "complex and subject to variation depending on the needs of the HECO system to meet customer var-hr ("vars") requirements." He also indicated at page 17 that HECO was willing to complete the study, but asked that the power factor adjustment tariff terms remain unchanged pending completion of this work.

Q. SHOULD THE POWER FACTOR TARIFF CREDITS FOR MECO ALSO BE REVIEWED, BASED UPON AVAILABLE COST STUDY SUPPORT, AFTER THIS WORK IS COMPLETED FOR HECO AND HELCO?

A. Yes. I recommend that MECO provide, in its next rate filing, either Company-specific studies in support of proposed power factor rate credits or, in the alternative, explain how results of analysis work done in the area for HELCO and HECO can be applied to MECO's costs and power factor rate elements.

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[41] See HECO Stipulated Settlement Letter dated September 16, 2005 at Exhibit II at 13, item #19 and CA T-3, Docket No. 04-0113, at 62.

Q. SHOULD ANY CHANGES TO MECO'S POWER FACTOR RATE PROVISIONS BE DEFERRED UNTIL COST STUDY SUPPORT IS AVAILABLE IN MECO'S NEXT RATE CASE?

A. Yes. In its rebuttal, MECO should provide an estimated time when the work for HELCO and HECO will be completed, and a plan for recommending the appropriate cost-based power factor tariff revisions within the next MECO rate case proceeding.

Q. AT PAGES 107 AND 110 OF HIS TESTIMONY, MR. YOUNG DISCUSSES STANDBY SERVICE RATES AND RULE NO. 14 INTERCONNECTION PROVISIONS THAT ARE UNDER CONSIDERATION FOR ALL OF THE HECO COMPANIES IN DOCKET NO. 2006-0497. DO ANY OF YOUR COMMENTS OR RECOMMENDATIONS IN THIS TESTIMONY APPLY TO THE STANDBY SERVICE OR INTERCONNECTION ISSUES THAT ARE THE SUBJECT OF DOCKET 2006-0497?

A. No. All issues associated with Standby Service and Rule 14 Interconnection are being analyzed and discussed in the separate docketed proceeding and the Consumer Advocate's position will be presented in that proceeding.

Q. MR. YOUNG ADDRESSES INCREASES FOR SERVICE RELATED CHARGES ASSOCIATED WITH FIELD COLLECTIONS, SERVICE CONNECTIONS AND RETURNED CHECKS AT PAGES 108 TO 111 OF

MECO T-18. ARE THESE PROPOSED RATE CHANGES ACCEPTABLE TO THE CONSUMER ADVOCATE?

A. Yes. These proposed service price changes are set forth in MECO-WP-712 and are supported by detailed time and expense cost studies prepared by MECO to quantify the average cost incurred by the Company to process each type of transaction.[42] The proposed price changes being proposed by MECO, based upon MECO's cost studies, compare reasonably to price changes recently agreed upon by the Consumer Advocate for implementation by HELCO and HECO in Docket Nos. 05-0315 and 2006-0386, respectively.[43]

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42 See Confidential Attachment A to CA-IR-357.

43 The MECO-proposed prices are generally within $3.00 to $5.00 of prices agreed upon between the Consumer Advocate and HECO in the Stipulated Settlement Letter dated September 16, 2005 in Docket No. 04-0113 at Exhibit II, paragraph 189(c). These prices were again submitted by HECO in Docket No. 2006-0386 and agreed upon by the Consumer Advocate, except for an additional increase in the returned payment charge to $22.00 in the most recent rate application (i.e., Docket No. 2006-0386).

1 Q. TO THE EXTENT YOU HAVE NOT SPECIFICALLY ADDRESSED ANY
2 PROPOSED MECO TARIFF REVISIONS THAT ARE SET FORTH IN
3 MECO-108 THROUGH MECO-110 OR IN MR. YOUNG'S (MECO T-18)
4 TESTIMONY, SHOULD THE COMMISSION ASSUME THAT THE
5 CONSUMER ADVOCATE SUPPORTS ALL OF THE COMPANY'S
6 PROPOSED TARIFF REVISIONS?
7 A. No. For example, there are numerous pricing and term revisions proposed
8 within the Company's proposed tariffs that are associated with load
9 management rates Schedules/Riders U, T, M, I, and sales to Qualifying
10 Facilities on Schedule Q. These proposals are based upon the Company's
11 asserted revenue requirement and cost of service allocation results. As a
12 result, the Company's proposed new rates are clearly excessive when
13 considering the Consumer Advocate's revenue requirement recommendation.
14 While not specifically addressed in my rate design testimony, the proposed
15 rates for these Schedules and Riders should be developed to retain the
16 existing rate structure relationships and conform to the implementation of an
17 equal percentage increase among customer classes and other rate design
18 recommendations described herein.
19
20 Q. DOES THIS CONCLUDE YOUR TESTIMONY ON COST OF SERVICE AND
21 RATE DESIGN MATTERS?
22 A. Yes, it does.

MAUI ELECTRIC COMPANY - Maui Division
DOCKET NO. 2006-0387 TEST-YEAR 2007
CLASS RATES OF RETURN ON RATE BASE AT PRESENT RATES

REVENUES	RESIDENTIAL SERVICE R	GEN SERV NON-DMD G	GEN SERV DEMAND J	COMMERCIAL SERVICE H	LARGE POWER P	STREET LIGHTING F	TOTAL SYSTEM
SALES REVENUE	121,860.3	29,799.4	74,994.3	5,906.9	98,934.9	1,420.5	332,916.2
OTHER OPERATING REVENUE	423.9	58.6	83.3	7.6	33.1	782.5	1,389.0
TOTAL OPERATING REVENUE	122,284.2	29,858.1	75,077.6	5,914.4	98,967.9	2,203.0	334,305.2
EXPENSES							
FUEL AND PURCHASED POWER	73,236.5	16,377.0	45,652.1	3,588.0	65,983.3	909.1	205,746.0
OTHER PRODUCTION COSTS	5,006.9	1,105.9	2,627.8	236.6	3,551.5	71.9	12,600.6
TRANSMISSION	804.1	177.6	422.0	38.0	570.4	11.6	2,023.7
DISTRIBUTION	2,731.0	511.9	778.7	78.1	797.1	241.5	5,138.2
CUSTOMER ACCOUNTS	2,107.6	411.5	151.0	14.2	16.4	6.9	2,707.7
UNCOLLECTIBLES	131.2	23.3	32.7	3.1	9.4	0.1	199.8
CUSTOMER SERVICE	365.4	105.8	415.2	274.3	545.1	0.9	1,706.7
ADMIN AND GENERAL	5,499.9	1,162.5	2,311.5	341.9	2,916.1	166.6	12,398.5
WAGE ROLLBACK	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL OPERATING & MAINT EXPENSE	89,882.5	19,875.4	52,391.1	4,574.3	74,389.3	1,408.6	242,521.2
DEPRECIATION EXPENSE	11,636.8	2,383.1	4,719.3	462.0	5,843.9	573.8	25,618.9
TAXES OTHER THAN INCOME TAXES	11,398.2	2,765.3	6,883.5	553.2	9,064.4	191.3	30,855.9
INCOME TAXES	2,021.7	1,518.3	3,559.3	61.9	2,846.0	-38.2	9,969.0
AMORTIZED INVESTMENT TAX CREDIT	-213.6	-44.0	-88.5	-8.5	-110.4	-10.0	-475.0
GAIN ON SALE OF PROPERTY	0.0	0.0	0.0	0.0	0.0	0.0	0.0
INTEREST ON CUSTOMER DEPOSITS	91.5	18.9	38.7	3.7	49.2	2.9	205.0
TOTAL OPERATING EXPENSES	114,817.2	26,517.0	67,503.5	5,646.5	92,082.4	2,128.3	308,694.9
PRESENT RETURN	7,466.9	3,341.0	7,574.2	267.9	6,885.6	74.7	25,610.3
RATE BASE							
GROSS PLANT IN SERVICE	324,576.1	66,848.6	134,730.7	12,984.3	168,215.0	15,256.4	722,611.0
DEPRECIATION BALANCE	-142,529.4	-29,656.2	-61,098.7	-5,912.2	-76,731.8	-7,846.2	-323,774.5
NET PLANT IN SERVICE	182,046.7	37,192.4	73,631.9	7,072.1	91,483.2	7,410.1	398,836.5
PROPERTY HELD FOR FUTURE USE	1,046.2	231.1	549.1	49.4	742.1	15.0	2,633.0
FUEL INVENTORY	3,925.1	877.7	2,446.7	192.3	3,536.4	48.7	11,027.0
MATERIALS AND SUPPLIES	4,441.8	943.0	2,050.3	191.3	2,662.6	146.9	10,436.0
WORKING CASH	2,526.7	559.4	1,483.5	123.2	2,117.4	37.1	6,847.3
CONTRIBUTIONS & ADVANCES	-27,303.6	-5,384.9	-9,829.9	-948.6	-11,164.9	-2,112.9	-56,744.8
DEFERRED INCOME TAXES	-7,282.7	-1,497.5	-3,014.9	-290.1	-3,741.9	-370.6	-16,197.7
UNAMORT INVEST TAX CREDITS	-4,800.0	-988.1	-1,988.3	-191.7	-2,482.3	-225.6	-10,676.0
OTHER RATE BASE DEDUCTIONS	1,559.7	322.0	664.2	59.8	831.1	80.0	3,516.8
TOTAL RATE BASE	156,160.0	32,255.1	65,992.7	6,257.8	83,983.7	5,028.9	349,678.1
RATE OF RETURN (%)	4.78%	10.36%	11.48%	4.28%	8.20%	1.49%	7.32%
ROR AS % OF SYSTEM ROR	65.29%	141.43%	156.71%	58.46%	111.94%	20.29%	100.00%

MAUI ELECTRIC COMPANY - Maui Division
DOCKET NO. 2006-0387 TEST-YEAR 2007
SUMMARY OF PRESENT AND PROPOSED CLASS REVENUES AND RATES OF RETURN

	RESIDENTIAL SERVICE R	GEN SERV NON-DMD G	GEN SERV DEMAND J	COMMERCIAL SERVICE H	LARGE POWER P	STREET LIGHTING F	TOTAL SYSTEM
PRESENT REVENUES ($000s)							
SALES REVENUE	121,860.3	29,799.4	74,994.3	5,906.9	98,934.9	1,420.5	332,916.2
OTHER OPERATING REVENUE	423.9	58.6	83.3	7.6	33.1	782.5	1,389.0
TOTAL OPERATING REVENUE	122,284.2	29,858.1	75,077.6	5,914.4	98,967.9	2,203.0	334,305.2
PROPOSED REVENUES ($000s)							
SALES REVENUE	124,867.3	30,534.8	76,844.8	6,052.6	101,376.2	1,455.6	341,131.2
OTHER OPERATING REVENUE	610.2	70.7	84.8	7.8	33.1	782.6	1,589.0
TOTAL OPERATING REVENUE	125,477.4	30,605.4	76,929.6	6,060.4	101,409.2	2,238.1	342,720.2
PROPOSED INCREASE ($000s)							
SALES REVENUE	3,007.0	735.3	1,850.5	145.8	2,441.3	35.1	8,214.9
OTHER OPERATING REVENUE	186.3	12.0	1.4	0.2	0.0	0.0	200.0
TOTAL OPERATING REVENUE	3,193.3	747.3	1,852.0	146.0	2,441.3	35.1	8,414.9
PROPOSED INCREASE (%)							
SALES REVENUE	2.47%	2.47%	2.47%	2.47%	2.47%	2.47%	2.47%
OTHER OPERATING REVENUE	43.95%	20.47%	1.72%	3.28%	0.00%	0.00%	14.40%
TOTAL OPERATING REVENUE	2.61%	2.50%	2.47%	2.47%	2.47%	1.59%	2.52%
REVENUE INCREASE INDEX (SYSTEM = 100)							
SALES REVENUE INDEX	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
OTHER OPERATING REVENUE INDEX	305.23%	142.15%	11.97%	22.77%	0.00%	0.02%	100.00%
TOTAL OPERATING REVENUE INDEX	103.74%	99.44%	98.00%	98.07%	98.00%	63.25%	100.00%
RATE OF RETURN ON RATE BASE (%)							
PRESENT RATE OF RETURN	4.78%	10.36%	11.48%	4.28%	8.20%	1.49%	7.32%
PROPOSED RATE OF RETURN	5.92%	11.65%	13.04%	5.58%	9.81%	1.87%	8.66%
RATE OF RETURN INDEX (SYSTEM = 100)							
PRESENT RATE OF RETURN INDEX	65.29%	141.43%	156.71%	58.46%	111.94%	20.29%	100.00%
PROPOSED RATE OF RETURN INDEX	68.35%	134.44%	150.49%	64.41%	113.29%	21.63%	100.00%
AVERAGE SALES REVENUE (¢ / KWH)							
PRESENT	28.329	30.979	27.963	28.028	25.241	26.601	27.447
PROPOSED	29.028	31.743	28.653	28.719	25.864	27.258	28.125
INCREASE	0.699	0.764	0.690	0.692	0.623	0.656	0.677
ENERGY SALES (MWH)	430,167.0	96,192.9	268,192.9	21,075.0	391,961.0	5,340.0	1,212,928.8

MAUI ELECTRIC COMPANY - Lanai Division
DOCKET NO. 2006-0387 TEST-YEAR 2007
CLASS RATES OF RETURN ON RATE BASE AT PRESENT RATES

REVENUES	RESIDENTIAL SERVICE R	GEN SERV NON-DMD G	GEN SERV DEMAND J	COMMERCIAL SERVICE H	LARGE POWER P	STREET LIGHTING F	TOTAL SYSTEM
SALES REVENUE	2,731.6	725.2	2,253.8	180.5	4,138.7	36.9	10,066.7
OTHER OPERATING REVENUE	13.8	1.0	1.8	0.3	2.0	19.0	37.9
TOTAL OPERATING REVENUE	2,745.4	726.2	2,255.6	180.8	4,140.7	55.9	10,104.6
EXPENSES							
FUEL AND PURCHASED POWER	1,795.1	427.7	1,363.4	119.6	2,757.7	24.9	6,488.4
OTHER PRODUCTION COSTS	254.8	46.4	160.3	10.9	255.6	4.5	732.4
TRANSMISSION	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DISTRIBUTION	94.3	16.0	48.7	3.2	67.6	7.1	236.9
CUSTOMER ACCOUNTS	110.8	19.4	7.3	0.4	0.8	0.3	139.0
UNCOLLECTIBLES	5.3	0.7	0.0	0.0	0.0	0.0	6.0
CUSTOMER SERVICE	0.1	0.1	0.3	0.2	0.4	0.0	1.0
ADMIN AND GENERAL	144.4	25.7	65.6	4.5	97.5	3.6	341.3
WAGE ROLLBACK	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL OPERATING & MAINT EXPENSE	2,404.8	535.9	1,645.5	138.8	3,179.6	40.5	7,945.0
DEPRECIATION EXPENSE	466.0	82.8	269.1	18.1	410.5	17.7	1,264.1
TAXES OTHER THAN INCOME TAXES	263.2	68.2	210.8	16.8	384.8	5.0	948.6
INCOME TAXES	-129.3	-4.1	-12.6	-1.2	-26.3	-2.6	-176.1
AMORTIZED INVESTMENT TAX CREDIT	-7.4	-1.3	-4.3	-0.3	-6.5	-0.3	-20.0
GAIN ON SALE OF PROPERTY	0.0	0.0	0.0	0.0	0.0	0.0	0.0
INTEREST ON CUSTOMER DEPOSITS	2.2	0.4	1.3	0.1	2.0	0.0	6.0
TOTAL OPERATING EXPENSES	2,999.5	681.8	2,109.7	172.3	3,944.0	60.3	9,967.7
PRESENT RETURN	-254.1	44.4	145.9	8.5	196.7	-4.4	136.9
RATE BASE							
GROSS PLANT IN SERVICE	11,073.6	1,962.3	6,381.5	427.8	9,692.5	447.8	29,985.4
DEPRECIATION BALANCE	-5,289.4	-940.6	-3,107.0	-208.3	-4,732.4	-256.3	-14,534.0
NET PLANT IN SERVICE	5,784.2	1,021.7	3,274.5	219.5	4,960.1	191.5	15,451.4
PROPERTY HELD FOR FUTURE USE	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FUEL INVENTORY	152.2	36.3	115.6	10.1	233.8	2.1	550.0
MATERIALS AND SUPPLIES	52.0	9.2	30.0	2.0	45.7	2.1	141.0
WORKING CASH	92.8	21.3	67.1	5.8	132.5	1.5	320.9
CONTRIBUTIONS & ADVANCES	-852.0	-146.4	-460.1	-29.9	-647.4	-77.0	-2,212.7
DEFERRED INCOME TAXES	-247.7	-43.9	-143.4	-9.6	-217.8	-10.0	-672.5
UNAMORT INVEST TAX CREDITS	-163.9	-29.1	-94.5	-6.3	-143.6	-6.6	-444.0
OTHER RATE BASE DEDUCTIONS	105.1	18.6	61.8	4.1	94.3	4.2	288.2
TOTAL RATE BASE	4,922.6	887.8	2,851.1	195.7	4,457.4	107.8	13,422.4
RATE OF RETURN (%)	-5.16%	5.00%	5.12%	4.34%	4.41%	-4.04%	1.02%
ROR AS % OF SYSTEM ROR	-505.87%	489.81%	501.41%	425.05%	432.43%	-395.97%	100.00%

MAUI ELECTRIC COMPANY - Lanai Division
DOCKET NO. 2006-0387 TEST-YEAR 2007
SUMMARY OF PRESENT AND PROPOSED CLASS REVENUES AND RATES OF RETURN

	RESIDENTIAL SERVICE R	GEN SERV NON-DMD G	GEN SERV DEMAND J	COMMERCIAL SERVICE H	LARGE POWER P	STREET LIGHTING F	TOTAL SYSTEM
PRESENT REVENUES ($000s)							
SALES REVENUE	2,731.6	725.2	2,253.8	180.5	4,138.7	36.9	10,066.7
OTHER OPERATING REVENUE	13.8	1.0	1.8	0.3	2.0	19.0	37.9
TOTAL OPERATING REVENUE	2,745.4	726.2	2,255.6	180.8	4,140.7	55.9	10,104.6
PROPOSED REVENUES ($000s)							
SALES REVENUE	2,799.0	743.1	2,309.4	185.0	4,240.8	37.8	10,315.1
OTHER OPERATING REVENUE	22.5	1.3	1.8	0.3	2.0	19.0	46.9
TOTAL OPERATING REVENUE	2,821.5	744.4	2,311.2	185.3	4,242.8	56.8	10,362.0
PROPOSED INCREASE ($000s)							
SALES REVENUE	67.4	17.9	55.6	4.5	102.1	0.9	248.4
OTHER OPERATING REVENUE	8.7	0.3	0.0	0.0	0.0	0.0	9.0
TOTAL OPERATING REVENUE	76.1	18.2	55.6	4.5	102.1	0.9	257.4
PROPOSED INCREASE (%)							
SALES REVENUE	2.47%	2.47%	2.47%	2.47%	2.47%	2.47%	2.47%
OTHER OPERATING REVENUE	62.94%	29.64%	0.61%	2.43%	0.00%	0.00%	23.75%
TOTAL OPERATING REVENUE	2.77%	2.50%	2.47%	2.47%	2.47%	1.63%	2.55%
REVENUE INCREASE INDEX (SYSTEM = 100)							
SALES REVENUE INDEX	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
OTHER OPERATING REVENUE INDEX	265.04%	124.80%	2.57%	10.23%	0.00%	0.00%	100.00%
TOTAL OPERATING REVENUE INDEX	108.80%	98.34%	96.81%	96.86%	96.82%	63.94%	100.00%
RATE OF RETURN ON RATE BASE (%)							
PRESENT RATE OF RETURN	-5.16%	5.00%	5.12%	4.34%	4.41%	-4.04%	1.02%
PROPOSED RATE OF RETURN	-4.30%	6.14%	6.20%	5.60%	5.69%	-3.57%	2.09%
RATE OF RETURN INDEX (SYSTEM = 100)							
PRESENT RATE OF RETURN INDEX	-505.87%	489.81%	501.41%	425.05%	432.43%	-395.97%	100.00%
PROPOSED RATE OF RETURN INDEX	-205.79%	293.88%	296.91%	268.35%	272.27%	-170.92%	100.00%
AVERAGE SALES REVENUE (¢ / KWH)							
PRESENT	33.383	37.201	36.266	33.119	32.400	32.454	33.804
PROPOSED	34.206	38.119	37.161	33.937	33.199	33.255	34.638
INCREASE	0.824	0.918	0.895	0.817	0.799	0.801	0.834
ENERGY SALES (MWH)	8,182.7	1,949.4	6,214.6	545.0	12,773.9	113.7	29,779.3

MAUI ELECTRIC COMPANY - Molokai Division
DOCKET NO. 2006-0387 TEST-YEAR 2007
CLASS RATES OF RETURN ON RATE BASE AT PRESENT RATES

REVENUES	RESIDENTIAL SERVICE R	GEN SERV NON-DMD G	GEN SERV DEMAND J	COMMERCIAL SERVICE H	LARGE POWER P	STREET LIGHTING F	TOTAL SYSTEM
SALES REVENUE	4,556.7	1,703.7	2,831.8	643.4	2,734.9	160.9	12,631.4
OTHER OPERATING REVENUE	25.5	3.8	2.8	1.0	3.0	71.0	107.1
TOTAL OPERATING REVENUE	4,582.2	1,707.5	2,834.6	644.4	2,737.9	231.9	12,738.5
EXPENSES							
FUEL AND PURCHASED POWER	2,724.6	823.8	1,672.0	415.5	1,865.4	99.7	7,601.0
OTHER PRODUCTION COSTS	304.1	100.4	161.0	46.4	191.2	12.8	815.8
TRANSMISSION	11.5	3.8	6.1	1.8	7.3	0.5	30.9
DISTRIBUTION	190.5	55.5	65.4	20.2	77.2	17.9	426.7
CUSTOMER ACCOUNTS	118.9	35.3	10.0	2.5	1.8	0.4	169.0
UNCOLLECTIBLES	5.6	1.1	0.9	0.2	0.2	0.0	8.0
CUSTOMER SERVICE	0.1	0.1	0.6	0.4	0.8	0.0	2.0
ADMIN AND GENERAL	279.8	87.3	113.6	33.5	131.7	15.5	661.5
WAGE ROLLBACK	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL OPERATING & MAINT EXPENSE	3,635.3	1,107.2	2,029.7	520.4	2,275.6	146.7	9,714.9
DEPRECIATION EXPENSE	442.7	141.2	209.7	61.3	248.4	24.7	1,128.0
TAXES OTHER THAN INCOME TAXES	436.1	160.8	263.7	60.6	256.6	20.1	1,197.8
INCOME TAXES	71.4	-26.7	-18.5	11.4	55.9	-3.7	89.7
AMORTIZED INVESTMENT TAX CREDIT	-9.2	-2.9	-4.2	-1.2	-4.9	-0.6	-23.0
GAIN ON SALE OF PROPERTY	0.0	0.0	0.0	0.0	0.0	0.0	0.0
INTEREST ON CUSTOMER DEPOSITS	4.3	1.4	2.1	0.6	2.5	0.2	11.0
TOTAL OPERATING EXPENSES	4,580.5	1,381.0	2,482.6	653.1	2,833.9	187.4	12,118.4
PRESENT RETURN	1.7	326.5	352.0	-8.7	-96.0	44.5	620.1
RATE BASE							
GROSS PLANT IN SERVICE	13,828.2	4,351.5	6,251.9	1,839.1	7,394.9	846.9	34,512.5
DEPRECIATION BALANCE	-6,568.9	-2,065.3	-2,946.2	-867.4	-3,483.2	-458.0	-16,389.0
NET PLANT IN SERVICE	7,259.3	2,286.2	3,305.8	971.7	3,911.7	388.9	18,123.5
PROPERTY HELD FOR FUTURE USE	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FUEL INVENTORY	226.5	68.5	139.0	34.5	155.1	8.3	632.0
MATERIALS AND SUPPLIES	74.5	22.8	30.4	9.1	35.9	5.4	178.0
WORKING CASH	102.2	31.1	57.8	14.6	64.4	3.8	273.8
CONTRIBUTIONS & ADVANCES	-1,524.2	-448.5	-545.1	-167.3	-642.9	-139.6	-3,467.6
DEFERRED INCOME TAXES	-313.3	-98.8	-143.2	-42.1	-169.5	-19.1	-786.0
UNAMORT INVEST TAX CREDITS	-207.3	-65.3	-94.0	-27.6	-111.2	-12.6	-518.0
OTHER RATE BASE DEDUCTIONS	104.4	33.1	49.0	14.4	58.2	6.3	265.3
TOTAL RATE BASE	5,722.1	1,829.0	2,799.8	807.3	3,301.7	241.2	14,701.0
RATE OF RETURN (%)	0.03%	17.85%	12.57%	-1.07%	-2.91%	18.46%	4.22%
ROR AS % OF SYSTEM ROR	0.70%	423.21%	298.09%	-25.46%	-68.92%	437.68%	100.00%

MAUI ELECTRIC COMPANY - Molokai Division
DOCKET NO. 2006-0387 TEST-YEAR 2007
SUMMARY OF PRESENT AND PROPOSED CLASS REVENUES AND RATES OF RETURN

	RESIDENTIAL SERVICE R	GEN SERV NON-DMD G	GEN SERV DEMAND J	COMMERCIAL SERVICE H	LARGE POWER P	STREET LIGHTING F	TOTAL SYSTEM
PRESENT REVENUES ($000s)							
SALES REVENUE	4,556.7	1,703.7	2,831.8	643.4	2,734.9	160.9	12,631.4
OTHER OPERATING REVENUE	25.5	3.8	2.8	1.0	3.0	71.0	107.1
TOTAL OPERATING REVENUE	4,582.2	1,707.5	2,834.6	644.4	2,737.9	231.9	12,738.5
PROPOSED REVENUES ($000s)							
SALES REVENUE	4,669.1	1,745.7	2,901.7	659.3	2,802.4	164.9	12,943.1
OTHER OPERATING REVENUE	38.9	5.1	2.9	1.1	3.1	71.0	122.1
TOTAL OPERATING REVENUE	4,708.1	1,750.9	2,904.6	660.4	2,805.5	235.9	13,065.2
PROPOSED INCREASE ($000s)							
SALES REVENUE	112.4	42.0	69.9	15.9	67.5	4.0	311.7
OTHER OPERATING REVENUE	13.4	1.3	0.1	0.1	0.1	0.0	15.0
TOTAL OPERATING REVENUE	125.9	43.4	70.0	16.0	67.6	4.0	326.7
PROPOSED INCREASE (%)							
SALES REVENUE	2.47%	2.47%	2.47%	2.47%	2.47%	2.47%	2.47%
OTHER OPERATING REVENUE	52.66%	35.23%	2.97%	8.31%	2.23%	0.00%	14.01%
TOTAL OPERATING REVENUE	2.75%	2.54%	2.47%	2.48%	2.47%	1.71%	2.56%
REVENUE INCREASE INDEX (SYSTEM = 100)							
SALES REVENUE INDEX	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
OTHER OPERATING REVENUE INDEX	375.99%	251.54%	21.19%	59.33%	15.89%	0.00%	100.00%
TOTAL OPERATING REVENUE INDEX	107.11%	99.06%	96.24%	96.57%	96.21%	66.76%	100.00%
RATE OF RETURN ON RATE BASE (%)							
PRESENT RATE OF RETURN	0.03%	17.85%	12.57%	-1.07%	-2.91%	18.46%	4.22%
PROPOSED RATE OF RETURN	1.26%	19.17%	13.96%	0.03%	-1.77%	19.37%	5.46%
RATE OF RETURN INDEX (SYSTEM = 100)							
PRESENT RATE OF RETURN INDEX	0.70%	423.21%	298.09%	-25.46%	-68.92%	437.68%	100.00%
PROPOSED RATE OF RETURN INDEX	23.04%	351.36%	255.91%	0.49%	-32.40%	355.15%	100.00%
AVERAGE SALES REVENUE (¢ / KWH)							
PRESENT	34.845	43.089	35.287	32.264	30.322	33.626	34.561
PROPOSED	35.705	44.152	36.158	33.060	31.071	34.456	35.414
INCREASE	0.860	1.063	0.871	0.796	0.748	0.830	0.853
ENERGY SALES (MWH)	13,077.0	3,953.9	8,025.1	1,994.2	9,019.4	478.5	36,548.1

MAUI ELECTRIC COMPANY - Maui Division
DOCKET NO. 2006-0387 TEST-YEAR 2007
Unit Functionalized Class Revenue Requirements At Equal ROR

	Units	Schedule R/E Residential Service	Schedule G Gen Service Non-Dmd	Schedule J Gen Service Demand	Schedule H Comm Service	Schedule P Large Power Trans	Schedule F Street Lighting
Energy:							
Production	¢/kWh	18.901	18.901	18.898	18.905	18.692	18.678
Demand:							
Production	$/kW/Month	$7.72	$12.51	$14.95	$16.96	$21.48	$11.57
Transmission	$/kW/Month	$1.66	$2.69	$3.22	$3.66	$4.63	$2.10
Distribution Primary							
Substations	$/kW/Month	$0.80	$1.29	$1.37	$1.72	$1.83	$1.64
Primary Lines	$/kW/Month	$1.30	$2.10	$2.23	$2.80	$2.99	$2.30
Primary Demand	$/kW/Month	$2.10	$3.39	$3.60	$4.52	$4.82	$3.94
Distribution Secondary							
Secondary Lines	$/kW/Month	$0.65	$0.82	$0.84	$0.98	$0.54	$0.72
Line Transformer	$/kW/Month	$0.86	$1.08	$1.10	$1.28	$0.71	$0.77
Secondary Demand	$/kW/Month	$1.51	$1.90	$1.94	$2.26	$1.25	$1.49
Distribution Demand	$/kW/Month	$3.61	$5.29	$5.54	$6.78	$6.07	$5.43
Total Demand	$/kW/Month	$12.99	$20.49	$23.71	$27.40	$32.18	$19.10
Total Demand & Energy	¢/kWh	28.274	27.905	26.339	27.653	25.234	24.286
Customer:							
Primary Lines	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Secondary Lines	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Line Transformers	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Services	$/Cust/Month	$10.21	$11.42	$13.59	$13.20	$60.80	$4.67
Meters	$/Cust/Month	$1.46	$1.73	$1.95	$1.87	$6.95	$0.67
Street Lighting	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$384.30
Customer Accounts	$/Cust/Month	$6.20	$8.44	$16.38	$9.26	$20.49	$5.75
Uncollectibles	$/Cust/Month	$0.23	$0.29	$2.14	$1.23	$7.09	$0.06
Customer Service	$/Cust/Month	$1.16	$2.34	$48.51	$192.05	$734.94	$0.77
Total Customer		$19.26	$24.22	$82.57	$217.61	$830.27	$396.22
Total	¢/kWh	31.035	30.134	26.854	30.54	25.542	39.333
Unitizing Factors:							
Energy Sales	MWH	430,167.0	96,192.9	268,192.9	21,075.0	391,961.0	5,340.0
Sum of Customer Demands	MW (NCD)	3,103.0	422.7	841.5	67.3	796.6	15.7
Average Annual Customers	Number	51,398.0	7,378.0	1,395.0	233.0	121.0	169.0

MAUI ELECTRIC COMPANY - Lanai Division
DOCKET NO. 2006-0387 TEST-YEAR 2007
Unit Functionalized Class Revenue Requirements At Equal ROR

	Units	Schedule R/E Residential Service	Schedule G Gen Service Non-Dmd	Schedule J Gen Service Demand	Schedule H Comm Service	Schedule P Large Power Trans	Schedule F Street Lighting
Energy:							
Production	¢/kWh	24.587	24.464	24.461	24.471	24.081	24.109
Demand:							
Production	$/kW/Month	$19.13	$26.97	$15.33	$47.20	$46.92	$31.87
Transmission	$/kW/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Distribution Primary							
Substations	$/kW/Month	$1.89	$2.70	$1.54	$4.67	$4.63	$3.86
Primary Lines	$/kW/Month	$3.91	$5.50	$3.14	$9.59	$9.46	$6.97
Primary Demand	$/kW/Month	$5.80	$8.20	$4.68	$14.26	$14.09	$10.83
Distribution Secondary							
Secondary Lines	$/kW/Month	$0.20	$0.22	$0.17	$0.25	$0.05	($0.01)
Line Transformer	$/kW/Month	$0.62	$0.70	$0.52	$0.96	$0.16	$0.74
Secondary Demand	$/kW/Month	$0.82	$0.92	$0.69	$1.21	$0.21	$0.73
Distribution Demand	$/kW/Month	$6.62	$9.12	$5.37	$15.47	$14.30	$11.56
Total Demand	$/kW/Month	$25.75	$36.09	$20.70	$62.67	$61.22	$43.43
Total Demand & Energy	¢/kWh	44.633	37.904	39.186	35.821	35.236	37.379
Customer:							
Primary Lines	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Secondary Lines	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Line Transformers	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Services	$/Cust/Month	$6.00	$5.42	$6.81	$4.21	$29.86	$3.66
Meters	$/Cust/Month	$1.33	$1.34	$1.43	$1.07	$5.59	($0.17)
Street Lighting	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$527.73
Customer Accounts	$/Cust/Month	$11.86	$14.84	$29.25	$15.47	$36.20	$10.44
Uncollectibles	$/Cust/Month	$0.35	$0.34	$0.00	$0.00	$0.00	$0.00
Customer Service	$/Cust/Month	$0.01	$0.04	$1.32	$7.87	$21.02	$0.00
Total Customer		$19.55	$21.98	$38.81	$28.62	$92.67	$541.66
Total	¢/kWh	48.566	40.448	39.455	36.073	35.263	54.529

MAUI ELECTRIC COMPANY - Molokai Division
DOCKET NO. 2006-0387 TEST-YEAR 2007
Unit Functionalized Class Revenue Requirements At Equal ROR

	Units	Schedule R/E Residential Service	Schedule G Gen Service Non-Dmd	Schedule J Gen Service Demand	Schedule H Comm Service	Schedule P Large Power Trans	Schedule F Street Lighting
Energy:							
Production	¢/kWh	23.308	22.951	23.063	23.341	23.21	22.214
Demand:							
Production	$/kW/Month	$16.28	$13.87	$23.94	$38.23	$33.62	($9.56)
Transmission	$/kW/Month	$0.60	$0.51	$0.88	$1.43	$1.25	($0.42)
Distribution Primary							
Substations	$/kW/Month	$1.85	$2.01	$2.79	$4.29	$3.54	$1.02
Primary Lines	$/kW/Month	$1.38	$1.53	$2.12	$3.19	$2.63	$0.98
Primary Demand	$/kW/Month	$3.23	$3.54	$4.91	$7.48	$6.17	$2.00
Distribution Secondary							
Secondary Lines	$/kW/Month	$1.31	$1.18	$1.48	$2.04	$1.63	$0.61
Line Transformer	$/kW/Month	$0.82	$0.71	$0.90	$1.31	$1.03	$0.26
Secondary Demand	$/kW/Month	$2.13	$1.89	$2.38	$3.35	$2.66	$0.87
Distribution Demand	$/kW/Month	$5.36	$5.43	$7.29	$10.83	$8.83	$2.87
Total Demand	$/kW/Month	$22.24	$19.81	$32.11	$50.49	$43.70	($7.11)
Total Demand & Energy	¢/kWh	39.085	33.714	32.744	39.202	38.035	20.100
Customer:							
Primary Lines	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Secondary Lines	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Line Transformers	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Services	$/Cust/Month	$4.27	$3.14	$4.21	$5.52	$27.42	($0.17)
Meters	$/Cust/Month	$0.72	$0.78	$0.91	$0.84	$4.72	$0.62
Street Lighting	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$214.37
Customer Accounts	$/Cust/Month	$6.38	$9.90	$16.80	$10.37	$17.97	$5.74
Uncollectibles	$/Cust/Month	$0.20	$0.21	$1.03	$0.58	$1.41	$0.02
Customer Service	$/Cust/Month	$0.01	$0.04	$1.28	$2.04	$9.29	$0.00
Total Customer		$11.58	$14.07	$24.23	$19.35	$60.81	$220.58
Total	¢/kWh	41.789	35.681	33.03	39.575	38.148	25.078
Unitizing Factors:							
Energy Sales	MWH	13,077.0	3,953.9	8,025.1	1,994.2	9,019.4	478.5
Sum of Customer Demands	MW (NCD)	92.8	21.5	24.2	6.3	30.6	1.4
Average Annual Customers	Number	2,546.0	461.0	79.0	32.0	14.0	9.0

ELECTRIC UTILITY COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS
1102 Interstate Commerce Commission Building
Constitution Avenue and Twelfth Street, NW
Post Office Box 684
Washington, DC 20044-0684
Telephone No. (202) 898-2200
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Price: $25.00

CHAPTER 4

EMBEDDED COST METHODS FOR ALLOCATING PRODUCTION COSTS

Of all utility costs, the cost of production plant -- i.e., hydroelectric, oil and gas-fired, nuclear, geothermal, solar, wind, and other electric production plant -- is the major component of most electric utility bills. Cost analysts must devise methods to equitably allocate these costs among all customer classes such that the share of cost responsibility borne by each class approximates the costs imposed on the utility by that class.

The first three sections of this chapter discusses functionalization, classification and the classification of production function costs that are demand-related and energy-related. Section four contains a variety of methods that can be used to allocate production plant costs. The final three sections include observations regarding fuel expense data, operation and maintenance expenses for production and a summary and conclusion.

I. THE FIRST STEP: FUNCTIONALIZATION

Functionalization is the process of assigning company revenue requirements to specified utility functions: Production, Transmission, Distribution, Customer and General. Distinguishing each of the functions in more detail -- subfunctionalization -- is an optional, but potentially valuable, step in cost of service analysis. For example, production revenue requirements may be subfunctionalized by generation type -- fossil, steam, nuclear, hydroelectric, combustion turbines, diesels, geothermal, cogeneration, and other. Distribution may be subfunctionalized to lines (underground and overhead) substations, transformers, etc. Such subfunctional categories may enable the analyst to classify and allocate costs more directly; they may be of particular value where the costs of specific units or types of units are assigned to time periods. But, since this is a manual of cost allocation, and this is a chapter on production costs, we won't linger over functionalization or consider costs in other functions. The interested reader will consult generalized texts on the subject. It will suffice to say here that all utility costs are allocated after they are functionalized.

II. CLASSIFICATION IN GENERAL

Classification is a refinement of functionalized revenue requirements. Cost classification identifies the utility operation -- demand, energy, customer -- for which functionalized dollars are spent. Revenue requirements in the production and transmission functions are classified as demand-related or energy-related. Distribution revenue requirements are classified as either demand-, energy- or customer-related.

Cost classification is often integrated with functionalization; some analysts do not distinguish it as an independent step in the assignment of revenue requirements. Functionalization is to some extent reflected in the way the company keeps its books; plant accounts follow functional lines as do operation and maintenance (O&M) accounts. But to classify costs accurately the analyst more often refers to conventional rules and his own best judgment. Section IV of this chapter discusses three major methods for classifying and allocating production plant costs. We will see that the peak demand allocation methods rely on conventional classification while the energy weighting methods and the time-differentiated methods of allocation require much attention to classification and, indeed, are sophisticated classification methods with fairly simple allocation methods tacked on.

The chart below is a basic example of an integrated functionalization/classification scheme.

FUNCTIONALIZED CLASSIFICATION OF ELECTRIC UTILITY COSTS

	Cost Classes			
Functions	**Demand**	**Energy**	**Customer**	**Revenue**
Production				
Thermal	X	X	N/A	N/A
Hydro	X	X	N/A	N/A
Other	X	X	N/A	N/A
Transmission	X	X	X	N/A
Distribution	X	X	X	N/A
OH/UG Lines	X	X	X	N/A
Substations	X	X	X	N/A
Services	N/A	N/A	X	N/A
Meters	N/A	N/A	X	N/A
Customer	N/A	N/A	X	X

III. CLASSIFICATION OF PRODUCTION FUNCTION COSTS

Production plant costs can be classified in two ways between costs that are demand-related and those that are energy-related.

A. Cost Accounting Approach

Production plant costs are either fixed or variable. Fixed production costs are those revenue requirements associated with generating plant owned by the utility, including cost of capital, depreciation, taxes and fixed O&M. Variable costs are fuel costs, purchased power costs and some O&M expenses. Fixed production costs vary with capacity additions, not with energy produced from given plant capacity, and are classified as demand-related. Variable production costs change with the amount of energy produced, delivered or purchased and are classified as energy- related. Exhibit 4-1 summarizes typical classification of FERC Accounts 500-557.

EXHIBIT 4-1

CLASSIFICATION OF PRODUCTION PLANT

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	CLASSIFICATION OF RATE BASE[1]		
	Production Plant		
301-303	Intangible Plant	x	-
310-316	Steam Production	x	x
320-325	Nuclear Production	x	-
330-336	Hydraulic Production	x	x[2]
340-346	Other Production	x	-

Exhibit 4-1
(Continued)
CLASSIFICATION OF PRODUCTION PLANT

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related
	CLASSIFICATION OF EXPENSES[1]		
	Production Plant		
	Steam Power Generation Operations		
500	Operating Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
501	Fuel	-	x
502	Steam Expenses	x[4]	x[4]
503-504	Steam From Other Sources & Transfer. Cr.	-	x
505	Electric Expenses	x[4]	x[4]
506	Miscellaneous Steam Pwr Expenses	x	-
507	Rents	x	-
	Maintenance		
510	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
511	Structures	x	-
512	Boiler Plant	-	x
513	Electric Plant	-	x
514	Miscellaneous Steam Plant	-	x
	Nuclear Power Generation Operation		
517	Operation Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
518	Fuel	-	x
519	Coolants and Water	x[4]	x[4]
520	Steam Expense	x[4]	x[4]
521-522	Steam From Other Sources & Transfe. Cr.	-	x
523	Electric Expenses	x[4]	x[4]
524	Miscellaneous Nuclear Power Expenses	x	-
525	Rents	x	-

EXHIBIT 4-1

(Continued)

CLASSIFICATION OF EXPENSES [1]

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related
	Maintenance		
528	Supervision & Engineering	Prorated on Labor[3]	Prorated on Labor[3]
529	Structures	x	-
530	Reactor Plant Equipment	-	x
531	Electric Plant	-	x
532	Miscellaneous Nuclear Plant	-	x
	Hydraulic Power Generation Operation		
535	Operation Supervision and Engineering	Prorated on Labor[3]	Prorated on Labor[3]
536	Water for Power	x	-
537	Hydraulic Expenses	x	-
538	Electric Expense	x[4]	x[4]
539	Misc Hydraulic Power Expenses	x	-
540	Rents	x	-
	Maintenance		
541	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
542	Structures	x	-
543	Reservoirs, Dams, and Waterways	x	x
544	Electric Plant	x	x
545	Miscellaneous Hydraulic Plant	x	x

Exhibit 4-1
(Continued)

FERC Uniform System of Account	Description	Demand Related	Energy Related
	CLASSIFICATION OF EXPENSES[1]		
	Other Power Generation Operation		
546, 548-554	All Accounts	x	-
547	Fuel	-	x
	Other Power Supply Expenses		
555	Purchased Power	x[5]	x[5]
556	System Control & Load Dispatch	x	-
557	Other Expenses	x	-

[1] Direct assignment or "exclusive use" costs are assigned directly to the customer class or group that exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] In some instances, a portion of hydro rate base may be classified as energy related.

[3] The classification between demand-related and energy-related costs is carried out on the basis of the relative proportions of labor cost contained in the other accounts in the account grouping.

[4] Classified between demand and energy on the basis of labor expenses and material expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related.

[5] As-billed basis.

The cost accounting approach to classification is based on the argument that plant capacity is fixed to meet demand and that the costs of plant capacity should be assigned to customers on the basis of their demands. Since plant output in KWH varies with system energy requirements, the argument continues, variable production costs should be allocated to customers on a KWH basis.

B. Cost Causation

Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability (LOLP), loss of load hours (LOLH),

MAUI ELECTRIC COMPANY, INC.
2007 TEST YEAR
OTHER PRODUCTION MAINTENANCE EXPENSE - DEMAND / ENERGY CLASSIFICATION

Line No.	Description	Labor	Non-labor	Total O&M	Reference
1	Total Production Operations Expense per MECO	5,423.5	4,250.6	9,674.1	MECO-506, p.2
2	Total Production Maintenance Expense per MECO	3,902.4	7,438.3	11,340.7	MECO-506, p.3
3	Total Other Production O&M Proposed by MECO	9,325.9	11,688.9	21,014.8	MECO-502
4	Less: Identified Variable (Energy) Costs				
5	Normalized Overhaul Costs - based on run hours		4,547.9	4,547.9	MECO-505
6	MPP Nox Water Costs - based on fuel burn		293.3	293.3	MECO-WP-504d
7	MPP and Molokai Lube Oil - based on run hours		1,036.9	1,036.9	MECO-WP-509a
8	Emission Fees - based on fuel burn		405.0	405.0	CA-IR-104, p.2
9	Identified Variable - Energy Related Production O&M Exp	-	6,283.1	6,283.1	
10	**Estimated Energy Classification of Production O&M Expense**			**29.9%**	Line 9 / Line 3

DIVISION OF CONSUMER ADVOCACY'S

JOINT ACCOUNTING EXHIBITS

AND

SUPPORTING SCHEDULES

PREPARED
BY
UTILITECH, INC.

CONSOLIDATED Exhibit CA-101

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
INDEX TO JOINT ACCOUNTING EXHIBITS
AND SUPPORTING SCHEDULES

SCHEDULE NO.	DESCRIPTION	WITNESS
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B	**SUMMARY OF JURISDICTIONAL RATE BASE**	Carver
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C-11	HECO MARKETING SUPPORT INTERCOMPANY CHARGES	Brosch
C-12	RESERVED	Brosch
C-13	PAYROLL EXPENSE - AVERAGE EMPLOYEES	Carver
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C-15	PAYROLL TAXES - AVERAGE EMPLOYEES	Carver
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C-19	T&D OUTSIDE SERVICES	Carver
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D	**CAPITAL STRUCTURE & COSTS**	Carver/Parcell
E	**RECONCILIATION OF POSITIONS**	Carver

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
CHANGE IN GROSS REVENUE REQUIREMENT
FOR THE FORECAST 2007 TEST YEAR
(000's)

Exhibit CA-101
Schedule A
Page 1 of 1

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	MECO PROPOSED	CA PROPOSED
	(A)	(B)	(C)	(D)
1	Rate Base at Present Rates	(a)	$ 386,261	$ 377,800
2	Change in Rate Base - Working Cash	(a)	(221)	(105)
3	Rate Base at Proposed Rates		$ 386,040	$ 377,696
4	Rate of Return	(b)	8.98%	8.29%
5	Operating Income Required	Line 3 * Line 4	$ 34,651	$ 31,311
6	Net Operating Income Available	(c)	24,107	26,368
7	Operating Income Deficiency	Line 5 - Line 6	$ 10,544	$ 4,943
8	Revenue Conversion Factor	(d)	1.795059	1.795985
9	Gross Revenue Deficiency (Excess)	Line 7 * Line 8	$ 18,927	$ 8,877
10	**Inter-Island Subsidy**	(e)	50	-
11	Net Revenue Deficiency (Excess)	Line 9 + Line 10	**$ 18,977**	**$ 8,877**

Footnotes:

(a) CA Schedule B.
(b) CA Schedule D.
(c) CA Schedule C.
(d) CA Schedule A-1.
(e) Sum of Division amounts does not net to "zero."

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
REVENUE CONVERSION FACTOR
FOR THE FORECAST 2007 TEST YEAR

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	RATES	COMPANY PROPOSED	CA PROPOSED
	(A)	(B)	(C)	(D)	(E)
1	Gross Electric Sales Revenue			100.0000%	100.0000%
2	Add: Other Operating Revenue	(e)	1.15067%	1.1507%	1.1507%
3	Total Operating Revenue	Line 1 + 2		101.1507%	101.1507%
4	Less: Franchise Royalty Tax	(a) (b)	2.500%	-2.46975%	-2.5000%
5	Less: Public Service Company Tax	(a) (c)	5.885%	-5.8815%	-5.9527%
6	Less: Public Utility Commission Fees	(a) (c)	0.500%	-0.4997%	-0.5058%
7	Less: Uncollectibles	(a) (d)	0.060%	-0.0600%	0.0000%
8	Net Revenue (before income taxes)	Lines 3..7		92.23975%	92.19220%
9	Less: Effective State Income Tax		6.0150%	-5.54822%	-5.54536%
10	Less: Effective Federal Income Tax		35.0000%	-30.34204%	-30.32639%
11	Net Operating Earnings	Lines 8..10		56.34949%	56.32045%
12	Income to Revenue Multiplier	Line 3 / 11		1.795059	1.795985

Footnotes:

(a) Sources: MECO-WP-2001, pp.15, 27 & 39.

(b) In determining the "increase in operating revenues" for purposes of annualizing franchise tax, MECO-WP-2001 reduces the pro forma rate increase by related uncollectibles before applying the applicable tax rates.

(c) In determining the "increase in operating revenues" subject to PSC Tax and PUC Fees, MECO-WP-2001 adjusts pro forma rate increase to include other operating revenue and exclude uncollectibles before applying the applicable tax rates.

(d) Consumer Advocate does not treat uncollectibles as directly variable with revenues, per CA T-3.

(e) Sources: MECO-WP-2001, pp.14 & 26.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF JURISDICTIONAL RATE BASE
FOR THE FORECAST 2007 TEST YEAR
(000's)

CONSOLIDATED

LINE NO.	DESCRIPTION	MECO PRO FORMA TEST YEAR	CA ADJUSTMENTS	CA PROPOSED
	(A)	(B)	(C)	(D)
1	**Additions**			
2	Net Cost of Plant in Service	$ 431,362	$ 1,048	$ 432,410
3	Property Held for Future Use	2,633	-	2,633
4	Fuel Inventory	15,811	(3,602)	12,209
5	Materials & Supplies Inventories	11,651	(896)	10,755
6	Unamort Net SFAS 109 Reg Asset	8,919	(1,166)	7,753
7	Pension Asset	3,322	(3,322)	-
8	OPEB Amount	-	-	-
9	Unamort Sys Dev Costs	234	(234)	-
10	**Total Additions**	473,932	(8,172)	465,760
				-
11	**Deductions**			-
12	Unamortized CIAC	(55,366)	(1,765)	(57,131)
13	Customer Advances	(4,674)	(622)	(5,296)
14	Customer Deposits	(3,883)	202	(3,681)
15	Accumulated Def Income Taxes	(20,518)	2,862	(17,656)
16	Unamortized ITC	(11,206)	(432)	(11,638)
17	**Total Deductions**	(95,647)	245	(95,402)
18	Difference	378,285	(7,927)	370,358
19	Working Cash at Present Rates	7,976	(534)	7,442
20	Rate Base at Present Rates	386,261	(8,461)	377,800
21	Change in Rate Base - Working Cash	(221)	116	(105)
22	**Rate Base at Proposed Rates**	$ 386,040	$ (8,344)	377,696
			(a)	

Footnotes:

(a) Source: Schedule B, pg. 2

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF RATE BASE ADJUSTMENTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

CONSOLIDATED

LINE NO.	DESCRIPTION	ADJUSTMENT NUMBER / SCHEDULE REFERENCE B-1	B-2	B-3	B-4	B-5	B-6	B-7	B-8	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	**Additions**									
2	Net Cost of Plant in Service	$ 1,048	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,048
3	Property Held for Future Use	-	-	-	-	-	-	-	-	-
4	Fuel Inventory	-	-	(3,602)	-	-	-	-	-	(3,602)
5	Materials & Supplies Inventories	(896)	-	-	-	-	-	-	-	(896)
6	Unamort Net SFAS 109 Reg Asset	(1,166)	-	-	-	-	-	-	-	(1,166)
7	Pension Asset	(106)	(3,216)	-	-	-	-	-	-	(3,322)
8	OPEB Amount	-	-	-	-	-	-	-	-	-
9	Unamort Sys Dev Costs	(234)	-	-	-	-	-	-	-	(234)
10	**Total Additions**	(1,354)	(3,216)	(3,602)	-	-	-	-	-	(8,172)
11	**Deductions**									
12	Unamortized CIAC	(1,765)	-	-	-	-	-	-	-	(1,765)
13	Customer Advances	(622)	-	-	-	-	-	-	-	(622)
14	Customer Deposits	202	-	-	-	-	-	-	-	202
15	Accumulated Def Income Taxes	3,717	1,251	-	(2,106)	-	-	-	-	2,862
16	Unamortized ITC	(432)	-	-	-	-	-	-	-	(432)
17	**Total Deductions**	1,100	1,251	-	(2,106)	-	-	-	-	245
18	Difference	(254)	(1,965)	(3,602)	(2,106)	-	-	-	-	(7,927)
19	Working Cash at Present Rates	(244)	-	-	-	(290)	-	-	-	(534)
20	Rate Base at Present Rates	(498)	(1,965)	(3,602)	(2,106)	(290)	-	-	-	(8,461)
21	Change in Rate Base - Working Cash	8	-	-	-	108	-	-	-	116
22	**Rate Base at Proposed Rates**	$ (490)	$ (1,965)	$ (3,602)	$ (2,106)	$ (182)	$ -	$ -	$ -	$ (8,344)

ADJUSTMENTS:

B-1 MECO PROPOSED JUNE UPDATES
B-2 PENSION ASSET
B-3 FUEL INVENTORY
B-4 ACCUMULATED DEFERRED TAX BALANCES
B-5 CASH WORKING CAPITAL
B-6
B-7
B-8

CONSOLIDATED

LINE NO.	DESCRIPTION	REVISED AMOUNT	MECO DIRECT AMOUNT	ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)
1	**Additions**			
2	Net Plant in Service	$ 432,410,000	$ 431,362,000	$ 1,048,000
3	Property Held for Future Use	2,633,000	2,633,000	-
4	Fuel Inventory	15,811,000	15,811,000	-
5	Materials & Supplies Inventories	10,755,000	11,651,000	(896,000)
6	Unamort Net SFAS 109 Reg Asset	7,753,000	8,919,000	(1,166,000)
7	Pension Asset	3,216,000	3,322,000	(106,000)
8	OPEB Amount	-	-	-
9	Unamort Sys Dev Costs	-	234,000	(234,000)
10	**Total Additions**	472,578,000	473,932,000	(1,354,000)
11	**Deductions**			
12	Unamortized CIAC	(57,131,000)	(55,366,000)	(1,765,000)
13	Customer Advances	(5,296,000)	(4,674,000)	(622,000)
14	Customer Deposits	(3,681,000)	(3,883,000)	202,000
15	Accumulated Def Income Taxes	(16,801,000)	(20,518,000)	3,717,000
16	Unamortized ITC	(11,638,000)	(11,206,000)	(432,000)
17	**Total Deductions**	(94,547,000)	(95,647,000)	1,100,000
18	Rate Base (before Working Cash)	378,031,000	378,285,000	(254,000)
19	Working Cash at Present Rates	7,732,000	7,976,000	(244,000)
20	Rate Base at Present Rates	385,763,000	386,261,000	(498,000)
21	Change in Rate Base - Working Cash	(213,000)	(221,000)	8,000
22	**Rate Base at Proposed Rates**	$ 385,550,000	$ 386,040,000	$ (490,000)
		(a)	(b)	

Footnotes:

(a) MECO's response to CA-IR-304, p. 3.

(b) Sources: MECO-2001, p.1, & MECO-WP-2001, p. 2 (per original filing).

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	TEST YEAR AMOUNT	ADJUSTMENT
	(A)	(B)	(C)	(D)
1	MECO Updated Pension Asset	(a)	$ 3,216,000	$ (3,216,000)
2	Less: Accumulated Deferred Income Tax Reserve	(b)	(1,251,397)	1,251,397
3	Net Pension Asset in MECO's Updated Rate Base		$ 1,964,603	
4	**CA ADJUSTMENT TO ELIMINATE NET PENSION**			**$ (1,964,603)**
5	**ASSET FROM RATE BASE**			

Footnotes:

(a)

Prepaid Pension Asset:	12/31/06 Actual	12/31/07 FCST	Average
Ending Balance	$ 5,223,000	$ 1,209,000	$ 3,216,000

Source: MECO-928 & MECO T-9 June 2007 Update, Attachment 5.

(b)

ADIT Reserve:	12/31/06 Actual	12/31/07 FCST	Average
State ADIT	$ (314,158)	$ (72,748)	
Federal ADIT	(1,718,049)	(397,839)	
Total	$ (2,032,207)	$ (470,587)	$ (1,251,397)

Source: MECO-WP-1305 & MECO-1305, June 2007 Update (Att. 1, pp.9-12).

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Fuel Inventory per MECO - Maui Division	MECO-408, p.1	$ 14,628,834
2	Fuel Inventory per Consumer Advocate	CA-208	11,026,849
3	**CONSUMER ADVOCATE ADJUSTMENT TO RESTATE FUEL**	Line 2 - Line 1	**$ (3,601,985)**
4	**INVENTORY**		

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	**Restore Deferred Taxes related to AFUDC and TCI Improperly Removed by MECO:**		
2	AFUDC in CWIP - 12/31/2006 Federal	CA-IR-182, p.15	$ 1,015,303
3	AFUDC in CWIP - 12/31/2006 State	CA-IR-182, p.16	185,655
4	Reg-Asset-AFUDC Eq Grossup 12/31/2006 Federal	CA-IR-182, p.15	444,618
5	Reg-Asset-AFUDC Eq Grossup 12/31/2006 State	CA-IR-182, p.16	81,301
6	**Total Adjustments to 12/31/2006 Beginning of Test Year**		1,726,877
7	AFUDC in CWIP - 12/31/2007 Federal	CA-IR-182, p.15	$ 801,688
8	AFUDC in CWIP - 12/31/2007 State	CA-IR-182, p.16	146,594
9	Reg-Asset-AFUDC Eq Grossup 12/31/2007 Federal	CA-IR-182, p.15	349,356
10	Reg-Asset-AFUDC Eq Grossup 12/31/2007 State	CA-IR-182, p.16	63,882
11	**Total Adjustments to 12/31/2007 End of Test Year**		1,361,520
12	Average Test Year Adjustment for AFUDC/TCI Restoration	Average Lines 6, 11	**$1,544,199**
13	**Correct Deferred Taxes Related to Emission Fees:**		
14	Emission Fee Federal Deferred Taxes at 12/31/2007 per MECO	CA-IR-182, p.15	$331,478
15	Emission Fee State Deferred Taxes at 12/31/2007 per MECO	CA-IR-182, p.16	60,612
16	Test Year End Emission Fee Deferred Taxes per MECO		392,090
17	Revised emission Fee Federal Deferred Taxes -12/31/2007	CA-IR-379	$127,351
18	Revised emission Fee State Deferred Taxes -12/31/2007	"	23,286
19	Corrected Test Year End Emission Fee Deferred Taxes		150,637
20	Difference in Year-end Deferred Tax Balance (Negative DR value)	Line 16-Line 19	$241,453
21	One-half Adjustment for Average Rate Base	Line 20 * 1/2	**$120,727**
22	**Include Deferred Taxes on IRP/DSM Program Costs:**		
23	IRP/DSM Federal Deferred Taxes at 12/31/2006 per MECO	CA-IR-182, p.15	$373,233
24	IRP/DSM State Deferred Taxes at 12/31/2006 per MECO	CA-IR-182, p.16	68,249
25	Test Year Beginning IRP/DSM Related Deferred Taxes per MECO		441,482
26	IRP/DSM Federal Deferred Taxes at 12/31/2007 per MECO	CA-IR-182, p.15	$373,233
27	IRP/DSM State Deferred Taxes at 12/31/2007 per MECO	CA-IR-182, p.16	68,429
28	Test Year End IRP/DSM Related Deferred Taxes per MECO		441,662
29	Average Test Year Adjustment for IRP/DSM Deferred Tax Restoration	Average Lines 25, 28	**$441,572**
30	**CONSUMER ADVOCATE ADJUSTMENT INCREASING ACCUMULATED**	Line 12+21+29	**$ 2,106,497**
31	**DEFERRED INCOME TAXES**		
32	Allocation: Maui Division Portion of Line 30 Total Adjustment - 91.75%	CA-IR-373 Att.1	1,932,711
33	Lanai Division Portion of Line 30 Total Adjustment - 3.80%%		80,047
34	Molokai Division Portion of Line 30 Total Adjustment - 4.45%		93,739

Note: All amounts increase credit deferred taxes, thereby reducing rate base.

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
CASH WORKING CAPITAL
FOR THE FORECAST 2007 TEST YEAR

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	Revenue Lag (Days)	Payment Lag (Days)	Net Lag (Days)	Annual Amount	Average Daily Amount Present Rates (F) / 365	Average Daily Amount Proposed Rates (F) / 365	CWC Present Rates (E) x (G)	CWC Proposed Rates (E) x (H)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	Fuel Purchases	(a)							$ 9,789,490	$ 9,789,490
2	O&M Labor	(a)							1,154,781	1,154,781
3	O&M Nonlabor	(a)(c)							(109,913)	(109,913)
4	Non-Cash Items:									
5	Pension Asset Amortization	(a)(b)							-	-
6	Pension Accrual	(b)(c)							-	-
7	Purchased Power	(a)							(465,597)	(465,597)
8	Revenue Taxes - Present Rates	(a)							(2,777,074)	
9	Revenue Taxes - Proposed Rates	(a)								(2,846,795)
10	Income Taxes - Present Rates	(a)							(149,693)	
11	Income Taxes - Proposed Rates	(a)								(184,591)
12	Total Cash Working Capital								7,441,994	7,337,375
13	Less: MECO Revised Cash Working Capital								(7,732,000)	(7,519,000)
14	**CONSUMER ADVOCATE ADJUSTMENT TO EXCLUDE NON-CASH ITEMS**								**$ (290,006)**	**$ (181,625)**
15	Change in Cash Working Capital									$ 108,381

Values represent sum of Schedule B-5 from Exhibits CA-102 through CA-104

Footnotes:

(a) *Source: MECO T-15 nor June 2007 Update provide a detailed calculation of consolidated cash working capital.*

(b) Both pension items are non-cash, absent a specific funding commitment -- regardless of the existence of a tracking mechanism.
The Consumer Advocate proposes to excluded non-cash excluded from CWC calculation, by assigning "zero" for both revenue lag and expense lag.

(c) O&M Nonlabor:

		TY Expense $	% Distribution	Payment Lag	Wtd. Lag Days
Pension Accrual	(1)	$ 3,063,816			
		-			
Subtotal		$ 3,063,816			
OPEB	(2)(3)	786,888	3.05%	83.71	2.6
Emission Fees		388,816	1.51%	305.50	4.6
EPRI Dues		222,200	0.86%	22.38	0.2
Other Non-Labor O &M		24,369,424	94.57%	31.93	30.2
Subtotal		$ 25,767,328	100.00%		**37.6** Days
Total O&M Non-Labor		$ 28,831,144	100.00%		

Source: MECO-WP-1507, p. 23 per MECO T-15 June 2007 Update (p. 27) & CA Posting Detail.

(1) Accrual & amortization amounts removed from Other Non-Labor O&M and listed separately in CWC calculation.
(2) MECO has historically funded FAS106 accruals. Regardless of OPEB tracker, funding expected to continue.
(3) Source: Expense lags from MECO T-15 June 2007 Update, p. 27.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF OPERATING INCOME
FOR THE FORECAST 2007 TEST YEAR
(000's)

CONSOLIDATED

LINE NO.	DESCRIPTION	MECO PRO FORMA	CA ADJUSTMENTS	CA PROPOSED
	(A)	(B)	(C)	(D)
1	Electric Sales Revenue	$ 355,773	$ (159)	$ 355,614
2	Other Operating Revenue	1,535	-	1,535
3	**Total Operating Revenues**	$ 357,308	$ (159)	$ 357,149
4	Fuel	$ 180,465	$ (653)	$ 179,812
5	Purchased Power	33,982	7	33,989
6	Production	21,015	(286)	20,729
7	Transmission	2,277	(222)	2,054
8	Distribution	6,337	(533)	5,804
9	Customer Accounts	3,086	(70)	3,016
10	Allowance for Uncoll Accounts	214	-	214
11	Customer Service	1,541	(377)	1,164
12	Administrative & General	13,560	(159)	13,401
13	**Operation and Maintenace**	262,476	(2,294)	260,182
14	Depreciation and Amortization	28,871	(860)	28,011
15	Amortization of State ITC	(518)	-	(518)
16	Taxes Other Than Income	33,068	(66)	33,002
17	*Interest on Customer Deposits*	233	(12)	221
18	Income Taxes	9,071	812	9,883
19	**Total Operating Expenses**	$ 333,201	$ (2,420)	$ 330,781
20	**Operating Income**	$ 24,107	$ 2,261	$ 26,368
		(a)	(b)	

Footnotes:

(a) Source: MECO-2001 pg. 1 of 4
(b) Source: CA Schedule C, page 4

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF NOI ADJUSTMENTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

CONSOLIDATED

LINE NO.	DESCRIPTION	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-1	C-2	C-3	C-4	C-5	C-6	C-7	C-8	C-9	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Sales Revenue	$ -	$ (1)	$ (158)	$ -	$ -	$ -	$ -	$ -	$ -	$ (159)
2	Other Operating Revenue	-	-	-	-	-	-	-	-	-	-
3	**Total Operating Revenues**	$ -	$ (1)	$ (158)	$ -	$ -	$ -	$ -	$ -	$ -	$ (159)
4	Fuel	$ -	$ -	$ (653)	$ -	$ -	$ -	$ -	$ -	$ -	$ (653)
5	Purchased Power	-	-	7	-	-	-	-	-	-	7
6	Production	472	-	-	(276)	(146)	(78)	(45)	(16)	-	(89)
7	Transmission	-	-	-	-	-	-	-	-	-	-
8	Distribution	-	-	-	-	-	-	-	-	-	-
9	Customer Accounts	-	-	-	-	-	-	-	-	-	-
10	Allowance for Uncoll Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	202	-	-	-	-	-	-	-	(319)	(117)
12	Administrative & General	322	-	-	-	-	-	-	-	-	322
13	**Operation and Maintenance**	996	-	(646)	(276)	(146)	(78)	(45)	(16)	(319)	(531)
14	Depreciation and Amortization	(860)	-	-	-	-	-	-	-	-	(860)
15	Amortization of State ITC	-	-	-	-	-	-	-	-	-	-
16	Taxes Other than Income	(16)	-	(14)	-	-	-	-	-	-	(30)
17	Interest on Customer Deposits	(12)	-	-	-	-	-	-	-	-	(12)
18	Income Taxes	(426)	(1)	196	107	57	30	17	6	124	111
19	**Total Operating Expenses**	$ (318)	$ (1)	$ (465)	$ (168)	$ (89)	$ (48)	$ (27)	$ (10)	$ (195)	$ (1,321)
20	**Operating Income**	$ 318	$ (1)	$ 307	$ 168	$ 89	$ 48	$ 27	$ 10	$ 195	$ 1,162

ADJUSTMENTS:

- **C-1** MECO PROPOSED JUNE 2007 UPDATES
- **C-2** UPDATE SALES FOR RIDER PARTICIPATION
- **C-3** FUEL AND PURCHASED POWER EXPENSE & ECAC REVENUES
- **C-4** COMPETITIVE BIDDING EXPENSES
- **C-5** LUBE OIL EXPENSE CORRECTION
- **C-6** KAHULUI PLANT STRUCTURE MAINTENANCE NORMALIZATION
- **C-7** NOX WATER EXPENSES
- **C-8** EMISSION FEE EXPENSES
- **C-9** DSM PROGRAM COST RECLASSIFICATION

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF NOI ADJUSTMENTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

CONSOLIDATED

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-10	C-11	C-12	C-13	C-14	C-15	C-16	C-17	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Sales Revenue	$ (159)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (159)
2	Other Operating Revenue	-	-	-	-	-	-	-	-	-	-
3	**Total Operating Revenues**	$ (159)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (159)
4	Fuel	$ (653)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (653)
5	Purchased Power	7	-	-	-	-	-	-	-	-	7
6	Production	(89)	-	-	-	(196)	-	-	-	-	(286)
7	Transmission	-	-	-	-	(42)	-	-	-	-	(42)
8	Distribution	-	-	-	-	(143)	-	-	-	-	(143)
9	Customer Accounts	-	-	-	-	(70)	-	-	-	-	(70)
10	Allowance for Uncoll Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	(117)	(198)	(28)	-	(33)	-	-	-	-	(377)
12	Administrative & General	322	-	-	-	(5)	(56)	-	(242)	(130)	(111)
13	**Operation and Maintenance**	(531)	(198)	(28)	-	(490)	(56)	-	(242)	(130)	(1,676)
14	Depreciation and Amortization	(860)	-	-	-	-	-	-	-	-	(860)
15	Amortization of State ITC	-	-	-	-	-	-	-	-	-	-
16	Taxes Other than Income	(30)	-	-	-	-	-	(36)	-	-	(66)
17	Interest on Customer Deposits	(12)	-	-	-	-	-	-	-	-	(12)
18	Income Taxes	111	77	11	-	191	22	14	94	51	571
19	**Total Operating Expenses**	$ (1,321)	$ (121)	$ (17)	$ -	$ (299)	$ (34)	$ (22)	$ (148)	$ (80)	$ (2,043)
20	**Operating Income**	$ 1,162	$ 121	$ 17	$ -	$ 299	$ 34	$ 22	$ 148	$ 80	$ 1,884

ADJUSTMENTS:
- **C-10** INCREMENTAL IRP EXPENSES IN BASE RATES
- **C-11** HECO MARKETING SUPPORT INTERCOMPANY
- **C-12** RESERVED
- **C-13** PAYROLL EXPENSE - AVERAGE EMPLOYEES
- **C-14** EMPLOYEE BENEFITS - AVERAGE EMPLOYEES
- **C-15** PAYROLL TAXES - AVERAGE EMPLOYEES
- **C-16** PENSION ASSET
- **C-17** RESEARCH & DEVELOPMENT

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF NOI ADJUSTMENTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

CONSOLIDATED

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-18	C-19	C-20	C-21	C-22	C-23	C-24	C-25	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Sales Revenue	$ (159)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (159)
2	Other Operating Revenue	-	-	-	-	-	-	-	-	-	-
3	**Total Operating Revenues**	$ (159)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (159)
4	Fuel	$ (653)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (653)
5	Purchased Power	7	-	-	-	-	-	-	-	-	7
6	Production	(286)	-	-	-	-	-	-	-	-	(286)
7	Transmission	(42)	-	(180)	-	-	-	-	-	-	(222)
8	Distribution	(143)	-	(390)	-	-	-	-	-	-	(533)
9	Customer Accounts	(70)	-	-	-	-	-	-	-	-	(70)
10	Allowance for Uncoll Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	(377)	-	-	-	-	-	-	-	-	(377)
12	Administrative & General	(111)	(23)	-	(24)	-	-	-	-	-	(159)
13	**Operation and Maintenance**	(1,676)	(23)	(570)	(24)	-	-	-	-	-	(2,294)
14	Depreciation and Amortization	(860)	-	-	-	-	-	-	-	-	(860)
15	Amortization of State ITC	-	-	-	-	-	-	-	-	-	-
16	Taxes Other than Income	(66)	-	-	-	-	-	-	-	-	(66)
17	Interest on Customer Deposits	(12)	-	-	-	-	-	-	-	-	(12)
18	Income Taxes	571	9	222	10	-	-	-	-	-	812
19	**Total Operating Expenses**	$ (2,043)	$ (14)	$ (348)	$ (15)	$ -	$ -	$ -	$ -	$ -	$ (2,420)
20	**Operating Income**	$ 1,884	$ 14	$ 348	$ 15	$ -	$ -	$ -	$ -	$ -	$ 2,261

C-18	EXPIRING SOFTWARE AMORTIZATION	**C-22**
C-19	T&D OUTSIDE SERVICES	**C-23**
C-20	HO'OMAIKA'I COSTS	**C-24**
C-21		**C-25**

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	REVISED AMOUNT	MECO DIRECT AMOUNT	ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)	(E)
1	**MECO Update Adjustments to Revenues:**				
2	Electric Sales Revenue	Update CA-IR-304, p.1 & MECO-2001, p.1	$ 355,773,300	$ 355,773,300	$ -
3	Other Operating Revenue	MECO-2001, p.1	1,535,000	1,535,000	-
4	Total Operating Revenue		$ 357,308,300	$ 357,308,300	$ -
5	**MECO Update Adjustments to Expenses:**				
6	Fuel Expense	Update CA-IR-304, p.1 MECO-2001, p.1	$ 180,465,400	$ 180,465,400	$ -
7	Purchased Power Expense	Update CA-IR-304, p.1 MECO-2001, p.1	33,982,000	33,982,000	-
8	Production O&M Expenses:	Update T-5, Att.1			
9	Labor	MECO-503	9,383,724	9,326,000	57,724
10	Non-Labor	MECO-503	12,102,734	11,688,900	413,834
11	Transmission Expenses:	Update CA-IR-304			
12	Labor		774,690	774,690	-
13	Non-Labor		1,502,048	1,502,048	-
14	Distribution Expenses:	Update CA-IR-304			
15	Labor		2,873,771	2,873,771	-
16	Non-Labor		3,462,832	3,462,832	-
17	Customer Accounts Expenses:	Update CA-IR-304, p.1			
18	Labor	MECO-701	2,103,000	2,103,000	-
19	Non-Labor	MECO-701	983,000	983,000	-
20	Uncollectibles	MECO-701	214,000	214,000	-
21	Customer Service Expenses:	Update CA-IR-304, p.1			
22	Labor	MECO-801	739,000	537,000	202,000
23	Non-Labor	MECO-801	1,004,000	1,004,000	-
24	Administrative & General Expenses:	Update T-9, Att.1, p.20			
25	Labor	MECO-901, p. 20	2,476,100	2,476,100	-
26	Non-Labor	MECO-901, p. 20	11,405,800	11,083,600	322,200
27	Total O&M Expenses				
28	Labor	Lines 9+12+15+18+22+25	18,564,285	18,304,561	259,724
29	Non-Labor	Lines 6+7+10+13+16+19+20+23+26	244,907,814	244,171,780	736,034
30	**Total O&M Expenses**		263,472,099	262,476,341	995,758
31	**Depreciation & Amortization**	Update T-12, p.4	28,010,971	28,870,970	(859,999)
32	**Amortization of State ITC**	Update CA-IR-304, p.1	(518,000)	(518,000)	-
33	**Taxes Other than Income**	Update CA-IR-304, p.1	33,052,000	33,068,000	(16,000)
34	**Interest on Customer Deposits**	Update CA-IR-304, p.1	221,000	233,000	(12,000)
35	**Income Taxes**	Update CA-IR-304, p.1	8,645,000	9,071,000	(426,000)
36	Total Operating Expenses		$ 332,883,070	$ 333,201,311	$ (318,241)
37	Net Operating Income		$ 24,425,230	$ 24,106,989	$ 318,241

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Adjustment to Update Tariff Rider Participation:		
2	Maui Customer T32	CA-IR-206, page 2	$ (1,300)
3	Maui Customer T33	CA-IR-206, page 3	(100)
4	**TOTAL ADJUSTMENT TO SALES REVENUE - MAUI SCHEDULE J**		**$ (1,400)**

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
FUEL AND PURCHASED POWER EXPENSE & ECAC REVENUES
FOR THE FORECAST 2007 TEST YEAR

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	MECO PROPOSED AMOUNT	CONSUMER ADVOCATE AMOUNT	DIFFERENCE ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)	(E)
1	Fuel Oil Expense - Production Simulation	MECO-401 /CA-204	$ 179,945,100	$ 179,291,900	$ (653,200)
2	Fuel Related Expense	MECO-401 / CA-205	519,600	519,800	200
3	**CA ADJUSTMENT TO FUEL EXPENSE**	Line 1 + 2	$ 180,464,700	$ 179,811,700	**$ (653,000)**
4	Purchased Power - Energy Payments	MECO-507 / CA-210	$ 32,142,600	$ 32,149,000	$ 6,400
5	Purchased Power - Capacity Payments	MECO-507 / CA-210	1,839,100	1,839,300	200
6	**CA ADJUSTMENT TO PURCHASED POWER EXPENSE**	Line 4 + 5	$ 33,981,700	$ 33,988,300	**$ 6,600**
7	**Energy Cost Adjustment Rate / Present Rates (cents/kwh)**	See Schedule C-3 Calculation by Island			
					ECAC Revenue Change
8	Test Year Proposed Sales - Gigawatthours				
9	Residential R				$ (55,922)
10	Commercial G/J				(47,370)
11	Commercial J (included with Schedule G)				-
12	Commercial H				(2,740)
13	Large Commercial P				(50,825)
14	Lighting F				(694)
15	Total Sales Volume				
16	**CA ADJUSTMENT TO ECAC GROSS REVENUES AT CA FUEL/ENERGY COSTS**				**$ (157,551)**
17	Additional Revenue Taxes on Incremental ECAC Revenues	See Schedule C-3 Calculation by Island			
18	Franchise Royalty Tax				$ (3,939)
19	Public Service Company Tax				(9,272)
20	Public Utility Commission Fees				(788)
21	**CA ADJUSTMENT TO TAXES OTHER - REVENUE TAX ON ECAC REVENUES**				**$ (13,998)**

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	MECO Estimated Competitive Bidding Support Costs to be Incurred in 2007	CA-IR-317, Att. A, page 3	$ 276,300
2	One-half of MECO Estimated 2007 Spending Allowed by Consumer Advocate	CA-T-3	138,150
3	MECO Proposed Test Year Allowance for Competitive Bidding Non-labor	CA-IR-317, Att. A, page 3	413,834
4	**CONSUMER ADVOCATE ADJUSTMENT TO RESTATE COMPETITIVE BIDDING**	Line 2 - Line 3	**$ (275,684)**
5	**NON-LABOR EXPENSES**		

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	ANNUAL EXPENSE AMOUNT
	(A)	(B)	(C)
1	Consumer Advocate Adjustment to Correct Lube Oil Expenses - Maui Division	See Maui C-5	$ (133,708)
2	Consumer Advocate Adjustment to Correct Lube Oil Expenses - Lanai Division	See Lanai C-5	(4,135)
3	*Consumer Advocate Adjustment to Correct Lube Oil Expenses - Molokai Division*	*See Molokai C-5*	*(8,205)*
4	**CONSUMER ADVOCATE ADJUSTMENT TO CORRECT LUBE OIL EXPENSES -**	Sum of Lines 1-3	**$ (146,048)**
5	**CONSOLIDATED MECO**		

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Adjustment required to normalize structure maintenance work at Kahului Station	CA-IR-226, Att.1, page 2	$ (78,146)
2	**CONSUMER ADVOCATE ADJUSTMENT TO NORMALIZE KPP MAINTENANCE**		**$ (78,146)**

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	MECO Ratemaking Adjustment to Increase NOX Water Treatment Costs - Maui Division		
2	Adjustment to NARUC Account 546	MECO-WP-504	$ 21,331
3	Adjustment to NARUC Account 554	and MECO -WP-504d	23,508
4	Total MECO Ratemaking Adjustment for Nox Water Treatment Costs	Line 1 + Line 2	44,839
5	**CONSUMER ADVOCATE ADJUSTMENT TO REVERSE MECO's ADJUSTMENT**		**$ (44,839)**
6	**FOR NOX WATER TREATMENT**		

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(D)
1	Consumer Advocate Adjustment to Restate Emission Fees - Maui Division	See Maui C-8	$ (7,389)
2	*Consumer Advocate Adjustment to Restate Emission Fees - Lanai Division*	*See Lanai C-8*	*(3,800)*
3	Consumer Advocate Adjustment to Restate Emission Fees - Molokai Division	See Molokai C-8	(4,993)
4	**CONSUMER ADVOCATE ADJUSTMENT TO RESTATE**	Sum of Lines 1...3	**$ (16,182)**
5	**EMISSION FEES - CONSOLIDATED**		

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	MECO June 2007 Update Adjustment - DSM Employee Reclassification into Base Rates:		
2	Direct Labor Expense Amount	Update T-8, Attachment A, p.3	$ 201,850
3	Benefits and Overheads (EE 406, 422)	Att. A, p.4	101,967
4	Payroll Taxes on Direct Labor (EE 423)	Att. A, p.4	15,183
5	Total Expense Impact of MECO's Proposed Reclassification of DSM Employees	Sum Lines 2..4	$ 319,000
6	**CONSUMER ADVOCATE ADJUSTMENT TO REVERSE MECO EMPLOYEE**		**$ (319,000)**
7	**RECLASSIFICATION**		

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Actual Non-labor Incremental IRP Expenses Incurred by MECO:		
2	Actual 2005 Amount (Total amount less Labor and Labor Overhead)	MECO-WP-812, p.1	$ 590,813
3	Actual 2006 Amount (Total amount less Labor and Labor Overhead)	CA-IR-411, Att.C, p.2	604,191
4	Actual 2007 Year-to-date August (Total amount less Labor and Labor Overhead)	CA-IR-411, Att.C, p.2	198,585
5	Adjust 2007 YTD August to Full Year (multiply by 12/8 months)	Line 4 * 12/8	297,878
6	Consumer Advocate Proposed Three-year Average Non-labor IRP spending	Average Lines 2, 3, 5	$ 497,627
7	Less: Non-labor IRP Expense Proposed by MECO	MECO-WP-812, p.2	695,844
8	**CONSUMER ADVOCATE ADJUSTMENT TO REVISE MECO IRP**	Line 6 - Line 7	**$ (198,217)**
9	**NORMALIZATION ADJUSTMENT**		

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
HECO MARKETING SUPPORT INTERCOMPANY CHARGES
FOR THE FORECAST 2007 TEST YEAR

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	HECO Intercompany Charges to MECO for RA=PNG Marketing Support		
2	Actual Charges - 2004	CA-IR-154, Att.A, p.1	$ 6,864
3	Actual Charges - 2005	"	32,073
4	Actual Charges - 2006	"	18,227
5	Average of Actual HECO Marketing Support Charges to MECO - Last 3 Years	Average Lines 1..4	19,055
6	Less: MECO Estimated Test Year HECO Marketing Support Charges	CA-IR-154, Att.A, p.1	47,531
7	**CONSUMER ADVOCATE ADJUSTMENT TO REVISE ESTIMATED TEST YEAR**	Line 5 - Line 6	**$ (28,476)**
8	**HECO MARKETING SUPPORT**		

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	This schedule has been reserved for future use.		

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
PAYROLL EXPENSE - AVERAGE EMPLOYEES
FOR THE FORECAST 2007 TEST YEAR
(000's)

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	MAUI	LANAI	MOLOKAI	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)
1	Average Headcount Adjustment:					
2	Production O&M	(a)	$ (153,076)	$ (42,274)	$ (1,018)	$ (196,368)
3	Transmission & Distribution O&M	(b)	(179,355)	(3,715)	(1,935)	(185,006)
4	Customer Accounts O&M	(c)	(70,341)	-	-	(70,341)
5	Customer Service O&M	(d)	(33,272)	-	-	(33,272)
6	Administrative & General O&M	(e)	(5,041)	-	-	(5,041)
7	**CONSUMER ADVOCATE AVERAGE STAFFING**		**$ (441,086)**	**$ (45,990)**	**$ (2,953)**	**$ (490,029)**
8	**ADJUSTMENT**					

Footnotes:

(a) Source: CA-WP-101-C13, p. 1.
(b) Source: CA-WP-101-C13, p. 2.
(c) Source: CA-WP-101-C13, p. 3.
(d) Source: CA-WP-101-C13, p. 4.
(e) Source: CA-WP-101-C13, p. 6.

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	MECO REVISED 2007 FORECAST	CA EMPLOYEE BENEFITS ADJUSTMENT	CA ADJUSTED FORECAST
	(A)	(B)	(C)	(D)	(E)
1	A/C 926000: Employee Pensions and Benefits				
2	Qualified Pension Plan		$ 4,255,300		$ 4,255,300
3	Non-Qualified Pension Plans		-		-
4	Other Postretirement Benefits		1,092,900		1,092,900
5	Long-Term Disability Benefits		126,300		126,300
6	Flex Credits Less Prices		(285,100)	9,067	(276,033)
7	Group Medical Plan		1,906,800	(65,616)	1,841,184
8	Group Dental Plan		279,900	(9,552)	270,348
9	Group Vision Plan		44,300	(1,512)	42,788
10	Group Life Insurance Plan		238,400	(7,621)	230,779
11	Other Benefits/Administration		414,500		414,500
12	Subtotals: Non-Labor		8,073,300	(75,234)	7,998,066
13	Labor		80,100		80,100
14	Total 926000		$ 8,153,400	$ (75,234)	$ 8,078,166
15	926020 Employee Benefits Transfer	-25.04%	$ (2,042,000)	$ 18,842	$ (2,023,158)
16	Total Charged to O&M	Line 15 + 16	$ 6,111,400	$ (56,392)	$ 6,055,008
			(a)	(b)	
17	**CA ADJUSTMENT TO REDUCE EMPLOYEE BENEFIT**		(c) (d)	**$ (56,392)**	
18	**COSTS RELATED TO AVERAGE STAFFING ADJUSTMENT**				

Footnotes:

(a) Source: MECO T-10 June 2007 Update, Exhibit 1 & MECO T-10, Attachment 1, pp.1-2.

(b) Source for CA Average Employee Benefits Adjustment Calculations:

Flex Credits Less Prices	CA-WP-101-C14, p. 1
Group Medical Plan	CA-WP-101-C14, p. 2
Group Dental Plan	CA-WP-101-C14, p. 2
Group Vision Plan	CA-WP-101-C14, p. 2
Group Life Insurance Plan	CA-WP-101-C14, p. 3

(c) Net Headcount Reduction:

	# Employees	
Production	(2.5)	
Trans. & Distr.	(8.5)	
Customer Accts.	(0.5)	Excludes counts removed via other Dpmts.
Customer Service	-	Excludes counts removed via other Dpmts.
A&G Accts.	-	Excludes counts removed via other Dpmts.
Average Employee Count Reduction	(11.5)	

Source: Counts determined from CA-WP-101-C13.

(d) Allocation:

Maui Division	93.181%	$ (52,547)
Lanai Division	2.669%	(1,505)
Molokai Division	4.150%	(2,340)
Total	100.00%	$ (56,392)

Source: MECO T-10 June 2007 Update, Exhibit 1 & MECO T-10, Attachment 1, p.2.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
PAYROLL TAXES - AVERAGE EMPLOYEES
FOR THE FORECAST 2007 TEST YEAR

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	MAUI	LANAI	MOLOKAI	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)
1	Average Headcount Adjustment:					
2	Production O&M	(a)	$ (153,076)	$ (42,274)	$ (1,018)	$ (196,368)
3	Transmission & Distribution O&M	(a)	(179,355)	(3,715)	(1,935)	(185,006)
4	Customer Accounts O&M	(a)	(70,341)	-	-	(70,341)
5	Customer Service O&M	(a)	(33,272)	-	-	(33,272)
6	Administrative & General O&M	(a)	(5,041)	-	-	(5,041)
7	Consumer Advocate Average Staffing Adjustment	(a)	(441,086)	(45,990)	(2,953)	(490,029)
8	Composite Payroll Tax Rate	(b)	7.29%	7.29%	7.29%	7.29%
9	**CA ADJUSTMENT TO REDUCE PAYROLL TAX EXPENSE**		**$ (32,143)**	**$ (3,351)**	**$ (215)**	**$ (35,710)**
10	***RELATED TO AVERAGE STAFFING ADJUSTMENT***					

Footnotes:

(a) Source: CA Adjustment C-13.

(b) Payroll Tax Rate:

Total FICA	$ 1,932,671
Estimated Gross Pay	26,520,940
Composite FICA Rate	7.29%

Source: MECO-WP-1301, p. 3.

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
	MECO Proposed Pension Asset Amortization		
1	Pension Asset Balance at 12/31/2007	(a)(b)	$ 1,209,000
2	Amortization Period	(a)	5
3	Annual Amortization	(a)	$ 241,800
4	**CA ADJUSTMENT TO ELIMINATE MECO's PROPOSED**		**$ (241,800)**
5	**PENSION ASSET AMORTIZATION**		

Footnotes:

(a) *Source: MECO-928 (revised) & MECO T-9 June 2007 Update (Attachment 5, p.3).*

(b) Source: CA Schedule B-2.

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	**Research & Development (non-EPRI)**		
2	2005 Actual	(a)	$ 137,621
3	2006 Actual	(a)	(9,985)
4	2007 Forecast	(b)	247,379
5	Total		375,015
6	Number of Periods		3
7	Three-Year Average R&D		125,005
8	MECO Test Year Forecast (non-EPRI)	(a) (c)	(255,379)
9	**CA ADJUSTMENT TO NORMALIZE A&G-RELATED**		**$ (130,374)**
10	**R&D EXPENSE (NON-EPRI) TO THREE-YEAR AVERAGE**		

Footnotes:

(a) Source: CA-IR-156 MECO T-9 June 2007 Update, Att. 1, p. 44.

(b) Source: MECO response to CA-IR-435.

(c) The amounts on lines 4 and 8 are difference, because MECO's June 2007 update does recognize an $8,000 correction identified in response to CA-IR-265 and included in the response to CA-IR-435.

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Ellipse/MINCOM Monthly Amortization	(a) (b)	$ 17,187
2	Number of Amortization Months in 2007	(a)	9
3	2007 MINCOM Fee Buy-Down Amortization		154,683
4	MECO's % Share	(a)	15%
5	MECO's 2007 MINCOM Buy-Down Amortization		$ 23,202
6	**CA ADJUSTMENT TO ELIMINATE MECO'S**	A/C 923	$ (23,202)
7	**AMORTIZATION EXPIRING IN SEPTEMBER 2007**		

Footnotes:

(a) Source: MECO T-9 response to CA-IR-2, Attachment B.

(b) Relicensing Fee Amortization.

(c) Allocation:

Maui Division	92.75%	$	15,941
Lanai Division	2.45%		421
Molokai Division	4.80%		825
Total	100.00%	$	17,187

Source: Allocations per CA-IR-373.

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	2005 Actual	(a)	$ 1,174,109
2	2006 Actual	(a)	1,257,482
3	2007 Forecast	(a)	2,071,455
4	Total		$ 4,503,046
5	Number of Periods		3
6	Three-Year Average		$ 1,501,015
7	MECO Test Year Forecast		(2,071,455)
8	**CONSUMER ADVOCATE ADJUSTMENT TO NORMALIZE T&D**		**$ (570,440)**
9	**OUTSIDE SERVICES COSTS TO A THREE-YEAR AVERAGE**		

Footnotes:

(a) T&D Outside Contract Services:	2005	2006	2007 FCST
Vegetation Management	$ 682,777	$ 597,701	$ 898,023
Contract Services Other	491,332	659,781	1,173,432
Total	$ 1,174,109	$ 1,257,482	$ 2,071,455

Source: CA-IR-114, CA-IR-135 (revised 9/11/07) & CA-IR-338.

CONSOLIDATED

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	2004 Actual	(a)	$ 5,381
2	2005 Actual	(a)	52,063
3	2006 Actual	(a)	-
4	2007 Forecast	(b)	51,800
5	Total		$ 109,244
6	Number of Periods		4
7	Four-Year Average		$ 27,311
8	MECO Test Year Forecast	(b)	(51,800)
9	**CONSUMER ADVOCATE ADJUSTMENT TO NORMALIZE**	A/C 920	**$ (24,489)**
10	**HO'OMAIKA'I AWARD COSTS TO A FOUR-YEAR AVERAGE**		(c)

Footnotes:

(a) Source: MECO response to CA-IR-372.

(b) Source: MECO T-9 response to CA-IR-2, Attachment C.

(c) Allocation:

Maui Division	92.75%	$ (22,714)
Lanai Division	2.45%	(600)
Molokai Division	4.80%	(1,175)
Total	100.00%	$ (24,489)

Source: Allocations per CA-IR-373.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
CAPITAL STRUCTURE & COSTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

CONSOLIDATED

LINE NO.	DESCRIPTION	AMOUNTS IN THOUSANDS	PERCENT OF TOTAL	EARNINGS REQMTS	WEIGHTED EARNINGS REQMTS
	(A)	(B)	(C)	(D)	(E)
	MECO Proposed (a)				
1	Short-Term Debt	$ 4,750	1.27%	5.00%	0.06%
2	Long-Term Debt	150,585	40.15%	6.11%	2.45%
3	Hybrid Securities	9,192	2.45%	7.47%	0.18%
4	Preferred Stock	4,693	1.25%	8.34%	0.10%
5	Common Equity	205,882	54.89%	11.25%	6.18%
6	Total Capitalization	$ 375,102	100.00%		**8.98%**
	CA Proposed (b)				
7	Short-Term Debt	$ 4,750	1.27%	5.00%	0.06%
8	Long-Term Debt	150,585	40.15%	6.11%	2.45%
9	Hybrid Securities	9,192	2.45%	7.47%	0.18%
10	Preferred Stock	4,693	1.25%	8.34%	0.10%
11	Common Equity (midpoint)	205,882	54.89%	10.00%	5.49%
12	Total Capitalization	$ 375,102	100.00%		**8.29%**

Footnotes :

(a) Source: MECO-2001

(b) Source: Consumer Advocate witness David Parcell (CA-T-4) Exhibit CA-413.

CONSOLIDATED

LINE NO.	SCH./ ADJ. NO.	DESCRIPTION	AMOUNT	DIFFERENCE IN PRETAX RETURN	REVENUE REQUIREMENT VALUE
		(A)	(B)	(C)	(D)
1	SCH. A	**Asserted Revenue Requirement** (excluding inter-island subsidy)			$ 18,927
2	SCH. B	**Return Difference At MECO Rate Base** (before pro forma working cash)	$ 386,261	-1.230%	(4,751)
3		Subtotal Revenue Requirement			$ 14,176
				PRE-TAX RETURN	
4		**RATE BASE ADJUSTMENTS**			
5	B-1	MECO PROPOSED JUNE UPDATES	(498)	14.87%	$ (74)
6	B-2	PENSION ASSET	(1,965)	14.87%	(292)
7	B-3	FUEL INVENTORY	(3,602)	14.87%	(536)
8	B-4	ACCUMULATED DEFERRED TAX BALANCES	(2,106)	14.87%	(313)
9	B-5	CASH WORKING CAPITAL	(290)	14.87%	(43)
10		Total Value of Rate Base Adustments	(8,461)		(1,258)
11		Rate Base Recommendation (before pro forma working cash)	377,800	377,696	
12		Change in Working Cash at Proposed Rates (MECO vs CA)	(105)	16.10%	(17)
13		Rate Base With Working Cash Difference	$ 377,696		$ (1,275)
				REVENUE CONVERSION MULTIPLIER	
14	SCH. A	**Adjusted Net Operating Income**	$ 24,107		
15		**NET OPERATING INCOME ADJUSTMENTS**			
16	C-1	MECO PROPOSED JUNE 2007 UPDATES	318	1.7960	$ (572)
17	C-2	UPDATE SALES FOR RIDER PARTICIPATION	(1)	1.7960	2
18	C-3	FUEL AND PURCHASED POWER EXPENSE & ECAC REVENUES	307	1.7960	(552)
19	C-4	COMPETITIVE BIDDING EXPENSES	168	1.7960	(302)
20	C-5	LUBE OIL EXPENSE CORRECTION	89	1.7960	(160)
21	C-6	KAHULUI PLANT STRUCTURE MAINTENANCE NORMALIZATION	48	1.7960	(86)
22	C-7	NOX WATER EXPENSES	27	1.7960	(49)
23	C-8	EMISSION FEE EXPENSES	10	1.7960	(18)
24	C-9	DSM PROGRAM COST RECLASSIFICATION	195	1.7960	(350)
25	C-10	INCREMENTAL IRP EXPENSES IN BASE RATES	121	1.7960	(217)
26	C-11	HECO MARKETING SUPPORT INTERCOMPANY CHARGES	17	1.7960	(31)
27	C-12	RESERVED	0	1.7960	-
28	C-13	PAYROLL EXPENSE - AVERAGE EMPLOYEES	299	1.7960	(538)
29	C-14	EMPLOYEE BENEFITS - AVERAGE EMPLOYEES	34	1.7960	(62)
30	C-15	PAYROLL TAXES - AVERAGE EMPLOYEES	22	1.7960	(39)
31	C-16	PENSION ASSET	148	1.7960	(265)
32	C-17	RESEARCH & DEVELOPMENT	80	1.7960	(143)
33	C-18	EXPIRING SOFTWARE AMORTIZATION	14	1.7960	(25)
34	C-19	T&D OUTSIDE SERVICES	348	1.7960	(626)
35	C-20	HO'OMAIKA'I COSTS	15	1.7960	(27)
36		Total Value of Net Operating Income Adj.	2,261		$ (4,061)
37	SCH. A	Net Operating Income Recommendation	$ 26,368		
38		RECONCILED REVENUE REQUIREMENT			$ 8,840
39		UNRECONCILED DIFFERENCE			37
40	SCH. A	**REVENUE REQUIREMENT RECOMMENDATION** (excluding Inter-Island subsidy)			$ 8,877

CONSOLIDATED

LINE NO.	DESCRIPTION	WEIGHTED COST (SCH. D)	REVENUE CONVERSION MULTIPLIER (a) (b)	PRETAX RETURN
	(A)	(B)	(C)	(D)
	RETURN PER MECO			
1	Short-Term Debt	0.06%	1.7951	0.108%
2	Long-Term Debt	2.45%	1.7951	4.398%
3	Hybrid Securities	0.18%	1.7951	0.323%
4	Preferred Stock	0.10%	1.7951	0.180%
5	Common Equity	6.18%	1.7951	11.093%
6	Total Capitalization	8.97%		16.102%
	RETURN PER CA			
7	Short-Term Debt	0.06%	1.7960	0.108%
8	Long-Term Debt	2.45%	1.7960	4.400%
9	Hybrid Securities	0.18%	1.7960	0.323%
10	Preferred Stock	0.10%	1.7960	0.180%
11	Common Equity (midpoint)	5.49%	1.7960	9.860%
12	Total Capitalization	8.28%		14.871%
13	DIFFERENCE IN PRE-TAX RETURNS			-1.230%

Source: CA Schedules D & A-1.

MAUI DIVISION Exhibit CA-102

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
INDEX TO JOINT ACCOUNTING EXHIBITS
AND SUPPORTING SCHEDULES

SCHEDULE NO.	DESCRIPTION	WITNESS
A	**CHANGE IN GROSS REVENUE REQUIREMENT**	Carver
A-1	REVENUE CONVERSION FACTOR	Carver
B	**SUMMARY OF JURISDICTIONAL RATE BASE**	Carver
B-1	MECO PROPOSED JUNE UPDATES	Carver
B-2	PENSION ASSET	Carver
B-3	FUEL INVENTORY	Brosch
B-4	ACCUMULATED DEFERRED TAX BALANCES	Brosch
B-5	CASH WORKING CAPITAL	Carver
C	**SUMMARY OF OPERATING INCOME**	Carver
C-1	MECO PROPOSED JUNE 2007 UPDATES	Carver
C-2	UPDATE SALES FOR RIDER PARTICIPATION	Brosch
C-3	FUEL AND PURCHASED POWER EXPENSE & ECAC REVENUES	Brosch
C-4	COMPETITIVE BIDDING EXPENSES	Brosch
C-5	LUBE OIL EXPENSE CORRECTION	Brosch
C-6	KAHULUI PLANT STRUCTURE MAINTENANCE NORMALIZATION	Brosch
C-7	NOX WATER EXPENSES	Brosch
C-8	EMISSION FEE EXPENSES	Brosch
C-9	DSM PROGRAM COST RECLASSIFICATION	Brosch
C-10	INCREMENTAL IRP EXPENSES IN BASE RATES	Brosch
C-11	HECO MARKETING SUPPORT INTERCOMPANY CHARGES	Brosch
C-12	RESERVED	Brosch
C-13	PAYROLL EXPENSE - AVERAGE EMPLOYEES	Carver
C-14	EMPLOYEE BENEFITS - AVERAGE EMPLOYEES	Carver
C-15	PAYROLL TAXES - AVERAGE EMPLOYEES	Carver
C-16	PENSION ASSET	Carver
C-17	RESEARCH & DEVELOPMENT	Carver
C-18	EXPIRING SOFTWARE AMORTIZATION	Carver
C-19	T&D OUTSIDE SERVICES	Carver
C-20	HO'OMAIKA'I COSTS	Carver
D	**CAPITAL STRUCTURE & COSTS**	Carver/Parcell
E	**RECONCILIATION OF POSITIONS**	Carver

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
CHANGE IN GROSS REVENUE REQUIREMENT
FOR THE FORECAST 2007 TEST YEAR
(000's)

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	MECO PROPOSED	CA PROPOSED
	(A)	(B)	(C)	(D)
1	Rate Base at Present Rates	(a)	$ 358,230	$ 349,679
2	Change in Rate Base - Working Cash	(a)	(207)	(98)
3	Rate Base at Proposed Rates		$ 358,023	$ 349,581
4	Rate of Return	(b)	8.98%	8.29%
5	Operating Income Required	Line 3 * Line 4	$ 32,136	$ 28,980
6	Net Operating Income Available	(c)	23,373	25,610
7	Operating Income Deficiency	Line 5 - Line 6	$ 8,763	$ 3,370
8	Revenue Conversion Factor	(d)	1.795059	1.795985
9	Gross Revenue Deficiency (Excess)	Line 7 * Line 8	$ 15,731	$ 6,052
10	**Inter-Island Subsidy**	(e)	2,026	2,258
11	*Net Revenue Deficiency (Excess)*	*Line 9 + Line 10*	**$ 17,757**	**$ 8,311**

Footnotes:

(a) CA Schedule B.
(b) CA Schedule D.
(c) CA Schedule C.
(d) CA Schedule A-1.
(e) Source: MECO-2001, p. 2 (direct filing). Based on 9.29% return on investment.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
REVENUE CONVERSION FACTOR
FOR THE FORECAST 2007 TEST YEAR

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	RATES	COMPANY PROPOSED	CA PROPOSED
	(A)	(B)	(C)	(D)	(E)
1	Gross Electric Sales Revenue			100.0000%	100.0000%
2	Add: Other Operating Revenue	(e)	1.15067%	1.1507%	1.1507%
3	Total Operating Revenue	Line 1 + 2		101.1507%	101.1507%
4	Less: Franchise Royalty Tax	(a) (b)	2.500%	-2.46975%	-2.46975%
5	Less: Public Service Company Tax	(a) (c)	5.885%	-5.8815%	-5.8850%
6	Less: Public Utility Commission Fees	(a) (c)	0.500%	-0.4997%	-0.5000%
7	Less: Uncollectibles	(a) (d)	0.060%	-0.0600%	0.0000%
8	Net Revenue (before income taxes)	Lines 3..7		92.23975%	92.29592%
9	Less: Effective State Income Tax		6.0150%	-5.54822%	-5.55160%
10	Less: Effective Federal Income Tax		35.0000%	-30.34204%	-30.36051%
11	Net Operating Earnings	Lines 8..10		56.34949%	56.38381%
12	Income to Revenue Multiplier	Line 3 / 11		1.795059	1.793967

Footnotes:

(a) Sources: MECO-WP-2001, pp.15, 27 & 39.

(b) In determining the "increase in operating revenues" for purposes of annualizing franchise tax, MECO-WP-2001 reduces the pro forma rate increase by related uncollectibles before applying the applicable tax rates.

(c) In determining the "increase in operating revenues" subject to PSC Tax and PUC Fees, MECO-WP-2001 adjusts pro forma rate increase to include other operating revenue and exclude uncollectibles before applying the applicable tax rates.

(d) Consumer Advocate does not treat uncollectibles as directly variable with revenues, per CA T-3.

(e) Sources: MECO-WP-2001, pp.14 & 26.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF JURISDICTIONAL RATE BASE
FOR THE FORECAST 2007 TEST YEAR
(000's)

MAUI DIVISION

LINE NO.	DESCRIPTION	MECO PRO FORMA TEST YEAR	CA ADJUSTMENTS	CA PROPOSED
	(A)	(B)	(C)	(D)
1	**Additions**			
2	Net Cost of Plant in Service	$ 398,136	$ 701	$ 398,837
3	Property Held for Future Use	2,633	-	2,633
4	Fuel Inventory	14,629	(3,602)	11,027
5	Materials & Supplies Inventories	11,263	(827)	10,436
6	Unamort Net SFAS 109 Reg Asset	7,972	(1,042)	6,930
7	Pension Asset	3,093	(3,093)	-
8	OPEB Amount	-	-	-
9	Unamort Sys Dev Costs	217	(217)	-
10	**Total Additions**	437,943	(8,080)	429,863
				-
11	**Deductions**			-
12	Unamortized CIAC	(50,082)	(1,700)	(51,782)
13	Customer Advances	(4,271)	(692)	(4,963)
14	Customer Deposits	(3,601)	188	(3,413)
15	Accumulated Def Income Taxes	(18,823)	2,625	(16,198)
16	Unamortized ITC	(10,279)	(397)	(10,676)
17	**Total Deductions**	(87,056)	24	(87,032)
18	Difference	350,887	(8,056)	342,831
19	Working Cash at Present Rates	7,343	(496)	6,847
20	Rate Base at Present Rates	358,230	(8,551)	349,679
21	Change in Rate Base - Working Cash	(207)	109	(98)
22	**Rate Base at Proposed Rates**	$ 358,023	$ (8,442)	349,581
			(a)	

Footnotes:

(a) Source: Schedule B, pg. 2

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF RATE BASE ADJUSTMENTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

MAUI DIVISION

LINE NO.	DESCRIPTION	ADJUSTMENT NUMBER / SCHEDULE REFERENCE B-1	B-2	B-3	B-4	B-5	B-6	B-7	B-8	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	**Additions**									
2	Net Cost of Plant in Service	$ 701	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 701
3	Property Held for Future Use	-	-	-	-	-	-	-	-	-
4	Fuel Inventory	-	-	(3,602)	-	-	-	-	-	(3,602)
5	Materials & Supplies Inventories	(827)	-	-	-	-	-	-	-	(827)
6	Unamort Net SFAS 109 Reg Asset	(1,042)								(1,042)
7	Pension Asset	(104)	(2,989)							(3,093)
8	OPEB Amount	-								-
9	Unamort Sys Dev Costs	(217)								(217)
10	**Total Additions**	(1,489)	(2,989)	(3,602)	-	-	-	-	-	(8,080)
11	**Deductions**									
12	Unamortized CIAC	(1,700)	-	-	-	-	-	-	-	(1,700)
13	Customer Advances	(692)	-	-	-	-	-	-	-	(692)
14	Customer Deposits	188	-	-	-	-	-	-	-	188
15	Accumulated Def Income Taxes	3,410	1,148	-	(1,933)	-	-	-	-	2,625
16	Unamortized ITC	(397)	-	-	-	-	-	-	-	(397)
17	**Total Deductions**	809	1,148	-	(1,933)	-	-	-	-	24
18	Difference	(680)	(1,841)	(3,602)	(1,933)	-	-	-	-	(8,056)
19	Working Cash at Present Rates	(222)	-	-	-	(274)	-	-	-	(496)
20	Rate Base at Present Rates	(902)	(1,841)	(3,602)	(1,933)	(274)	-	-	-	(8,551)
21	Change in Rate Base - Working Cash	33	-	-	-	76	-	-	-	109
22	**Rate Base at Proposed Rates**	$ (869)	$ (1,841)	$ (3,602)	$ (1,933)	$ (198)	$ -	$ -	$ -	$ (8,442)

ADJUSTMENTS:

B-1 MECO PROPOSED JUNE UPDATES
B-2 PENSION ASSET
B-3 FUEL INVENTORY
B-4 ACCUMULATED DEFERRED TAX BALANCES
B-5 CASH WORKING CAPITAL
B-6
B-7
B-8

MAUI DIVISION

LINE NO.	DESCRIPTION	REVISED AMOUNT	MECO DIRECT AMOUNT	ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)
1	**Additions**			
2	Net Plant in Service	$ 398,837,000	$ 398,136,000	$ 701,000
3	Property Held for Future Use	2,633,000	2,633,000	-
4	Fuel Inventory	14,629,000	14,629,000	-
5	Materials & Supplies Inventories	10,436,000	11,263,000	(827,000)
6	Unamort Net SFAS 109 Reg Asset	6,930,000	7,972,000	(1,042,000)
7	Pension Asset	2,989,000	3,093,000	(104,000)
8	OPEB Amount	-	-	-
9	Unamort Sys Dev Costs	-	217,000	(217,000)
10	**Total Additions**	436,454,000	437,943,000	(1,489,000)
11	**Deductions**			
12	Unamortized CIAC	(51,782,000)	(50,082,000)	(1,700,000)
13	Customer Advances	(4,963,000)	(4,271,000)	(692,000)
14	Customer Deposits	(3,413,000)	(3,601,000)	188,000
15	Accumulated Def Income Taxes	(15,413,000)	(18,823,000)	3,410,000
16	Unamortized ITC	(10,676,000)	(10,279,000)	(397,000)
17	***Total Deductions***	(86,247,000)	(87,056,000)	809,000
18	Rate Base (before Working Cash)	350,207,000	350,887,000	(680,000)
19	Working Cash at Present Rates	7,121,000	7,343,000	(222,000)
20	Rate Base at Present Rates	357,328,000	358,230,000	(902,000)
21	Change in Rate Base - Working Cash	(174,000)	(207,000)	33,000
22	**Rate Base at Proposed Rates**	$ 357,154,000	$ 358,023,000	$ (869,000)
		(a)	(b)	

Footnotes:

(a) MECO's response to CA-IR-304, p. 12.

(b) Sources: MECO-2001, p. 2, & MECO-WP-2001, p. 10 (per original filing).

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	TEST YEAR AMOUNT	ADJUSTMENT
	(A)	(B)	(C)	(D)
1	MECO UpdateD Pension Asset	(a)	$ 2,989,000	$ (2,989,000)
2	Less: Accumulated Deferred Income Tax Reserve	(b)	(1,148,032)	1,148,032
3	Net Pension Asset in MECO's Updated Rate Base		$ 1,840,968	
4	**CA ADJUSTMENT TO ELIMINATE NET PENSION**			**$ (1,840,968)**
5	**ASSET FROM RATE BASE**			

Footnotes:

(a)

Prepaid Pension Asset:	12/31/06 Actual	12/31/07 FCST
Ending Balance	$ 4,852,000	$ 1,126,000

Source: MECO-928 & MECO T-9 June 2007 Update, Attachment 5.

(b)

ADIT Reserve:	12/31/06 Actual	12/31/07 FCST
State ADIT	$ (288,209)	$ (66,739)
Federal ADIT	(1,576,138)	(364,977)
Total	$ (1,864,347)	$ (431,717)

Source: MECO-WP-1305 & MECO-1305, June 2007 Update (Att. 1, pp.9-12).

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Fuel Inventory per MECO - Maui Division	MECO-408, p.1	$ 14,628,834
2	Fuel Inventory per Consumer Advocate	CA-208	11,026,849
3	**CONSUMER ADVOCATE ADJUSTMENT TO RESTATE FUEL**	Line 2 - Line 1	**$ (3,601,985)**
4	**INVENTORY**		

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	**Restore Deferred Taxes related to AFUDC and TCI Improperly Removed by MECO:**		
2	AFUDC in CWIP - 12/31/2006 Federal	CA-IR-182, p.15	$ 1,015,303
3	AFUDC in CWIP - 12/31/2006 State	CA-IR-182, p.16	185,655
4	Reg-Asset-AFUDC Eq Grossup 12/31/2006 Federal	CA-IR-182, p.15	444,618
5	Reg-Asset-AFUDC Eq Grossup 12/31/2006 State	CA-IR-182, p.16	81,301
6	**Total Adjustments to 12/31/2006 Beginning of Test Year**		1,726,877
7	AFUDC in CWIP - 12/31/2007 Federal	CA-IR-182, p.15	$ 801,688
8	AFUDC in CWIP - 12/31/2007 State	CA-IR-182, p.16	146,594
9	Reg-Asset-AFUDC Eq Grossup 12/31/2007 Federal	CA-IR-182, p.15	349,356
10	Reg-Asset-AFUDC Eq Grossup 12/31/2007 State	CA-IR-182, p.16	63,882
11	**Total Adjustments to 12/31/2007 End of Test Year**		1,361,520
12	Average Test Year Adjustment for AFUDC/TCI Restoration	Average Lines 6, 11	**$1,544,199**
13	**Correct Deferred Taxes Related to Emission Fees:**		
14	Emission Fee Federal Deferred Taxes at 12/31/2007 per MECO	CA-IR-182, p.15	$331,478
15	Emission Fee State Deferred Taxes at 12/31/2007 per MECO	CA-IR-182, p.16	60,612
16	Test Year End Emission Fee Deferred Taxes per MECO		392,090
17	Revised emission Fee Federal Deferred Taxes -12/31/2007	CA-IR-379	$127,351
18	Revised emission Fee State Deferred Taxes -12/31/2007	"	23,286
19	Corrected Test Year End Emission Fee Deferred Taxes		150,637
20	Difference in Year-end Deferred Tax Balance (Negative DR value)	Line 16-Line 19	$241,453
21	One-half Adjustment for Average Rate Base	Line 20 * 1/2	**$120,727**
22	**Include Deferred Taxes on IRP/DSM Program Costs:**		
23	IRP/DSM Federal Deferred Taxes at 12/31/2006 per MECO	CA-IR-182, p.15	$373,233
24	IRP/DSM State Deferred Taxes at 12/31/2006 per MECO	CA-IR-182, p.16	68,249
25	Test Year Beginning IRP/DSM Related Deferred Taxes per MECO		441,482
26	IRP/DSM Federal Deferred Taxes at 12/31/2007 per MECO	CA-IR-182, p.15	$373,233
27	IRP/DSM State Deferred Taxes at 12/31/2007 per MECO	CA-IR-182, p.16	68,429
28	Test Year End IRP/DSM Related Deferred Taxes per MECO		441,662
29	Average Test Year Adjustment for IRP/DSM Deferred Tax Restoration	Average Lines 25, 28	**$441,572**
30	**CONSUMER ADVOCATE ADJUSTMENT INCREASING ACCUMULATED**	Line 12+21+29	**$ 2,106,497**
31	**DEFERRED INCOME TAXES**		
32	Allocation: Maui Division Portion of Line 30 Total Adjustment - 91.75%	CA-IR-373 Att.1	**1,932,711**
33	Lanai Division Portion of Line 30 Total Adjustment - 3.80%%		80,047
34	Molokai Division Portion of Line 30 Total Adjustment - 4.45%		93,739

Note: All amounts increase credit deferred taxes, thereby reducing rate base.

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
CASH WORKING CAPITAL
FOR THE FORECAST 2007 TEST YEAR

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	Revenue Lag (Days)	Payment Lag (Days)	Net Lag (Days)	Annual Amount	Average Daily Amount Present Rates (F) / 365	Average Daily Amount Proposed Rates (F) / 365	CWC Present Rates (E) x (G)	CWC Proposed Rates (E) x (H)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	Fuel Purchases	(a)	36.0	16.0	20.0	$ 166,371,000	$ 455,811	$ 455,811	$ 9,116,219	$ 9,116,219
2	O&M Labor	(a)	36.0	12.0	24.0	15,950,638	43,700	43,700	1,048,809	1,048,809
3	O&M Nonlabor	(a)(c)	36.0	37.6	(1.6)	23,357,708	63,994	63,994	(105,387)	(105,387)
4	Non-Cash Items:									
5	Pension Asset Amortization	(a)(b)	0.0	0.0	0.0	-	-	-	-	-
6	*Pension Accrual*	*(b)(c)*	*0.0*	*0.0*	*0.0*	*2,853,332*				
7	Purchased Power	(a)	36.0	41.0	(5.0)	33,988,600	93,119	93,119	(465,597)	(465,597)
8	Revenue Taxes - Present Rates	(a)	36.0	68.0	(32.0)	29,651,002	81,236		(2,599,540)	
9	Revenue Taxes - Proposed Rates	(a)	36.0	68.0	(32.0)	30,395,500		83,275		(2,664,811)
10	Income Taxes - Present Rates	(a)	36.0	40.0	(4.0)	13,434,966	36,808		(147,232)	
11	Income Taxes - Proposed Rates	(a)	36.0	40.0	(4.0)	16,416,107		44,976		(179,903)
12	Total Cash Working Capital								6,847,272	6,749,331
13	Less: MECO Revised Cash Working Capital	(a)							(7,121,000)	(6,947,000)
14	**CONSUMER ADVOCATE ADJUSTMENT TO EXCLUDE NON-CASH ITEMS**								**$ (273,728)**	**$ (197,669)**
15	Change in Cash Working Capital									$ 76,059

Footnotes:

(a) Source: MECO-1507, as revised by MECO T-15 June 2007 Update, p. 11.

(b) Both pension items are non-cash, absent a specific funding commitment – regardless of the existence of a tracking mechanism.
The Consumer Advocate proposes to excluded non-cash excluded from CWC calculation, by assigning "zero" for both revenue lag and expense lag.

(c) O&M Nonlabor:

		TY Expense $	% Distribution	Payment Lag	Wtd. Lag Days
Pension Accrual	(1)(4)	$ 2,853,332			
Subtotal - Non Cash		$ 2,853,332			
OPEB	(2)(3)(4)	732,829	3.14%	83.71	2.6
Emission Fees	(4)	356,598	1.53%	305.50	4.7
EPRI Dues	(4)	206,091	0.88%	22.38	0.2
Other Non-Labor O &M	(4)	22,062,191	94.45%	31.93	30.2
Subtotal		$ 23,357,708	100.00%		**37.6** Days
Total O&M Non-Labor		$ 26,211,040	100.00%		

Source: MECO-WP-1507, p. 23 per MECO T-15 June 2007 Update (p. 27) & CA Maui Posting detail.

(1) Accrual & amortization amounts removed from Other Non-Labor O&M and listed separately in CWC calculation.
(2) MECO has historically funded FAS106 accruals. Regardless of OPEB tracker, funding expected to continue.
(3) Source: Expense lags from MECO T-15 June 2007 Update, p. 27.
(4) Amounts allocated between divisions.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF OPERATING INCOME
FOR THE FORECAST 2007 TEST YEAR
(000's)

MAUI DIVISION

LINE NO.	DESCRIPTION	MECO PRO FORMA	CA ADJUSTMENTS	CA PROPOSED
	(A)	(B)	(C)	(D)
1	Electric Sales Revenue	$ 333,075	$ (159)	$ 332,916
2	Other Operating Revenue	1,390	-	1,390
3	**Total Operating Revenues**	$ 334,465	$ (159)	$ 334,306
4	Fuel	$ 167,036	$ (653)	$ 166,383
5	Purchased Power	33,982	7	33,989
6	Production	18,742	(221)	18,521
7	Transmission	2,244	(220)	2,023
8	Distribution	5,645	(505)	5,140
9	Customer Accounts	2,778	(70)	2,708
10	Allowance for Uncoll Accounts	200	-	200
11	Customer Service	1,538	(377)	1,161
12	Administrative & General	12,550	(152)	12,398
13	**Operation and Maintenace**	244,714	(2,192)	242,522
14	Depreciation and Amortization	26,598	(979)	25,619
15	Amortization of State ITC	(475)	-	(475)
16	Taxes Other Than Income	30,918	(62)	30,856
17	*Interest on Customer Deposits*	216	(11)	205
18	Income Taxes	9,122	847	9,969
19	**Total Operating Expenses**	$ 311,093	$ (2,397)	$ 308,696
20	**Operating Income**	$ 23,373	$ 2,238	$ 25,610
		(a)	(b)	

Footnotes:

(a) Source: MECO-2001 pg. 2 of 4
(b) Source: CA Schedule C, page 4

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF NOI ADJUSTMENTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

MAUI DIVISION

LINE NO.	DESCRIPTION	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-1	C-2	C-3	C-4	C-5	C-6	C-7	C-8	C-9	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Sales Revenue	$ -	$ (1)	$ (158)	$ -	$ -	$ -	$ -	$ -	$ -	$ (159)
2	Other Operating Revenue	-	-	-	-	-	-	-	-	-	-
3	**Total Operating Revenues**	$ -	$ (1)	$ (158)	$ -	$ -	$ -	$ -	$ -	$ -	$ (159)
4	Fuel	$ -	$ -	$ (653)	$ -	$ -	$ -	$ -	$ -	$ -	$ (653)
5	Purchased Power	-	-	7	-	-	-	-	-	-	7
6	Production	472	-	-	(276)	(134)	(78)	(45)	(7)	-	(68)
7	Transmission	-	-	-	-	-	-	-	-	-	-
8	Distribution	-	-	-	-	-	-	-	-	-	-
9	Customer Accounts	-	-	-	-	-	-	-	-	-	-
10	Allowance for Uncoll Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	202	-	-	-	-	-	-	-	(319)	(117)
12	Administrative & General	306	-	-	-	-	-	-	-	-	306
13	**Operation and Maintenance**	979	-	(646)	(276)	(134)	(78)	(45)	(7)	(319)	(526)
14	Depreciation and Amortization	(979)	-	-	-	-	-	-	-	-	(979)
15	Amortization of State ITC	-									-
16	Taxes Other than Income	(16)	-	(14)	-	-	-	-	-	-	(30)
17	Interest on Customer Deposits	(11)	-	-	-	-	-	-	-	-	(11)
18	Income Taxes	(343)	(1)	196	107	52	30	17	3	124	186
19	**Total Operating Expenses**	$ (369)	$ (1)	$ (465)	$ (168)	$ (82)	$ (48)	$ (27)	$ (5)	$ (195)	$ (1,359)
20	**Operating Income**	$ 369	$ (1)	$ 307	$ 168	$ 82	$ 48	$ 27	$ 5	$ 195	$ 1,200

ADJUSTMENTS:

- **C-1** MECO PROPOSED JUNE 2007 UPDATES
- **C-2** UPDATE SALES FOR RIDER PARTICIPATION
- **C-3** FUEL AND PURCHASED POWER EXPENSE & ECAC REVENUES
- **C-4** COMPETITIVE BIDDING EXPENSES
- **C-5** LUBE OIL EXPENSE CORRECTION
- **C-6** KAHULUI PLANT STRUCTURE MAINTENANCE NORMALIZATION
- **C-7** NOX WATER EXPENSES
- **C-8** EMISSION FEE EXPENSES
- **C-9** DSM PROGRAM COST RECLASSIFICATION

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF NOI ADJUSTMENTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

MAUI DIVISION

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-10	C-11	C-12	C-13	C-14	C-15	C-16	C-17	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Sales Revenue	$ (159)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (159)
2	Other Operating Revenue	-	-	-	-	-	-	-	-	-	-
3	**Total Operating Revenues**	$ (159)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (159)
4	Fuel	$ (653)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (653)
5	Purchased Power	7	-	-	-	-	-	-	-	-	7
6	Production	(68)	-	-	-	(153)	-	-	-	-	(221)
7	Transmission	-	-	-	-	(42)	-	-	-	-	(42)
8	Distribution	-	-	-	-	(137)	-	-	-	-	(137)
9	Customer Accounts	-	-	-	-	(70)	-	-	-	-	(70)
10	Allowance for Uncoll Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	(117)	(198)	(28)	-	(33)	-	-	-	-	(377)
12	Administrative & General	306	-	-	-	(5)	(53)	-	(225)	(130)	(108)
13	**Operation and Maintenance**	(526)	(198)	(28)	-	(441)	(53)	-	(225)	(130)	(1,602)
14	Depreciation and Amortization	(979)	-	-	-	-	-	-	-	-	(979)
15	Amortization of State ITC	-									-
16	*Taxes Other than Income*	(30)	-	-	-	-	-	(32)	-	-	(62)
17	Interest on Customer Deposits	(11)	-	-	-	-	-	-	-	-	(11)
18	Income Taxes	186	77	11	-	172	20	13	88	51	617
19	**Total Operating Expenses**	$ (1,359)	$ (121)	$ (17)	$ -	$ (269)	$ (32)	$ (20)	$ (138)	$ (80)	$ (2,036)
20	**Operating Income**	$ 1,200	$ 121	$ 17	$ -	$ 269	$ 32	$ 20	$ 138	$ 80	$ 1,877

ADJUSTMENTS:
- **C-10** INCREMENTAL IRP EXPENSES IN BASE RATES
- **C-11** HECO MARKETING SUPPORT INTERCOMPANY
- **C-12** RESERVED
- **C-13** PAYROLL EXPENSE - AVERAGE EMPLOYEES
- **C-14** EMPLOYEE BENEFITS - AVERAGE EMPLOYEES
- **C-15** PAYROLL TAXES - AVERAGE EMPLOYEES
- **C-16** PENSION ASSET
- **C-17** RESEARCH & DEVELOPMENT

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF NOI ADJUSTMENTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

MAUI DIVISION

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-18	C-19	C-20	C-21	C-22	C-23	C-24	C-25	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Sales Revenue	$ (159)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (159)
2	Other Operating Revenue	-	-	-	-	-	-	-	-	-	-
3	**Total Operating Revenues**	$ (159)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (159)
4	Fuel	$ (653)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (653)
5	Purchased Power	7	-	-	-	-	-	-	-	-	7
6	Production	(221)	-	-	-	-	-	-	-	-	(221)
7	Transmission	(42)	-	(178)	-	-	-	-	-	-	(220)
8	Distribution	(137)	-	(367)	-	-	-	-	-	-	(505)
9	Customer Accounts	(70)	-	-	-	-	-	-	-	-	(70)
10	Allowance for Uncoll Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	(377)	-	-	-	-	-	-	-	-	(377)
12	Administrative & General	(108)	(22)	-	(23)	-	-	-	-	-	(152)
13	**Operation and Maintenance**	(1,602)	(22)	(546)	(23)	-	-	-	-	-	(2,192)
14	Depreciation and Amortization	(979)	-	-	-	-	-	-	-	-	(979)
15	Amortization of State ITC	-									-
16	Taxes Other than Income	(62)	-	-	-	-	-	-	-	-	(62)
17	Interest on Customer Deposits	(11)	-	-	-	-	-	-	-	-	(11)
18	Income Taxes	617	8	212	9	-	-	-	-	-	847
19	**Total Operating Expenses**	$ (2,036)	$ (13)	$ (333)	$ (14)	$ -	$ -	$ -	$ -	$ -	$ (2,397)
20	**Operating Income**	$ 1,877	$ 13	$ 333	$ 14	$ -	$ -	$ -	$ -	$ -	$ 2,238

C-18	EXPIRING SOFTWARE AMORTIZATION	**C-22**
C-19	T&D OUTSIDE SERVICES	**C-23**
C-20	HO'OMAIKA'I COSTS	**C-24**
C-21		**C-25**

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	REVISED AMOUNT	MECO DIRECT AMOUNT	ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)	(E)
1	***MECO Update Adjustments to Revenues:***				
		Update CA-IR-304, p.10			
2	Electric Sales Revenue	MECO-2001, p.2	$ 333,075,200	$ 333,075,200	$ -
3	Other Operating Revenue	MECO-2001, p.2	1,390,000	1,390,000	-
4	Total Operating Revenue		$ 334,465,200	$ 334,465,200	$ -
5	**MECO Update Adjustments to Expenses:**				
		Update CA-IR-304, p.10			
6	Fuel Expense	MECO-2001, p.2	$ 167,036,400	$ 167,036,400	$ -
		Update CA-IR-304, p.10			
7	Purchased Power Expense	MECO-2001, p.2	33,982,000	33,982,000	-
8	Production O&M Expenses:	Update T-5, Att.1			
9	Labor	MECO-503	8,261,524	8,203,800	57,724
10	Non-Labor	MECO-503	10,951,934	10,538,100	413,834
11	Transmission Expenses:	Update CA-IR-304, p.10			
12	Labor	MECO-604, p. 1	764,909	764,909	-
13	Non-Labor	MECO-604, p. 1	1,478,685	1,478,685	-
14	Distribution Expenses:	Update CA-IR-304, p.10			
15	Labor	MECO-606, p. 1	2,617,995	2,617,995	-
16	Non-Labor	MECO-606, p. 1	3,026,528	3,026,528	-
17	Customer Accounts Expenses:	Update CA-IR-304, p.10			
18	Labor	MECO-703	1,881,000	1,881,000	-
19	Non-Labor	MECO-703	897,000	897,000	-
20	Uncollectibles	MECO-703	200,000	200,000	-
21	Customer Service Expenses:	Update T-8, Att. A			
22	Labor	MECO-803	739,000	537,000	202,000
23	Non-Labor	MECO-803	1,001,000	1,001,000	-
24	Administrative & General Expenses:	Update T-9, Att.1, p.5			
25	Labor	MECO-901, p. 5	2,445,600	2,445,600	-
26	Non-Labor	MECO-901, p. 5	10,409,500	10,104,000	305,500
27	Total O&M Expenses				
28	Labor	Lines 9+12+15+18+22+25	16,710,028	16,450,304	259,724
29	Non-Labor	Lines 6+7+10+13+16+19+20+23+26	228,983,047	228,263,713	719,334
30	**Total O&M Expenses**		245,693,075	244,714,017	979,058
31	**Depreciation & Amortization**	Update T-12, p.4	25,619,000	26,597,500	(978,500)
32	**Amortization of State ITC**	Update CA-IR-304, p.10	(475,000)	(475,000)	-
33	**Taxes Other than Income**	Update CA-IR-304, p.10	30,902,000	30,918,000	(16,000)
34	**Interest on Customer Deposits**	Update CA-IR-304, p.10	205,000	216,000	(11,000)
35	**Income Taxes**	Update CA-IR-304, p.10	8,779,000	9,122,000	(343,000)
36	Total Operating Expenses		$ 310,723,075	$ 311,092,517	$ (369,442)
37	Net Operating Income		$ 23,742,125	$ 23,372,683	$ 369,442

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
UPDATE SALES FOR RIDER PARTICIPATION
FOR THE FORECAST 2007 TEST YEAR

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Adjustment to Update Tariff Rider Participation:		
2	Maui Customer T32	CA-IR-206, page 2	$ (1,300)
3	Maui Customer T33	CA-IR-206, page 3	(100)
4	**TOTAL ADJUSTMENT TO SALES REVENUE - MAUI SCHEDULE J**		**$ (1,400)**

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
FUEL AND PURCHASED POWER EXPENSE & ECAC REVENUES
FOR THE FORECAST 2007 TEST YEAR

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	MECO PROPOSED AMOUNT	CONSUMER ADVOCATE AMOUNT	DIFFERENCE ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)	(E)
1	Fuel Oil Expense - Production Simulation	MECO-401 /CA-204	$ 166,525,300	$ 165,872,100	$ (653,200)
2	Fuel Related Expense	MECO-401 / CA-205	$ 511,400	$ 511,600	$ 200
3	**CA ADJUSTMENT TO FUEL EXPENSE**	Line 1 + 2	$ 167,036,700	$ 166,383,700	**$ (653,000)**
4	Purchased Power - Energy Payments	MECO-507 / CA-210	$ 32,142,600	$ 32,149,000	$ 6,400
5	Purchased Power - Capacity Payments	MECO-507 / CA-210	$ 1,839,100	$ 1,839,300	$ 200
6	**CA ADJUSTMENT TO PURCHASED POWER EXPENSE**	Line 4 + 5	$ 33,981,700	$ 33,988,300	**$ 6,600**
7	**Energy Cost Adjustment Rate / Present Rates (cents/kwh)**	CA-201	13.95400	13.94100	(0.0130)
8	Test Year Proposed Sales - Gigawatthours		MECO MWH HECO-201	Times ECAC Difference	ECAC Revenue Change
9	Residential R		430,167.0	(0.013)	$ (55,922)
10	Commercial G/J		364,386.0	(0.013)	(47,370)
11	Commercial J (included with Schedule G)			(0.013)	-
12	Commercial H		21,075 0	(0.013)	(2,740)
13	Large Commercial P		390,961.0	(0.013)	(50,825)
14	Lighting F		5,340.0	(0.013)	(694)
15	*Total Sales Volume*		1,211,929.0		
16	**CA ADJUSTMENT TO ECAC GROSS REVENUES AT CA FUEL/ENERGY COSTS**				**$ (157,551)**
17	Additional Revenue Taxes on Incremental ECAC Revenues		Tax Rate	Times ECAC Revenue Change	
18	Franchise Royalty Tax		2.500%	($157,551)	$ (3,939)
19	Public Service Company Tax		5.885%	(157,551)	(9,272)
20	Public Utility Commission Fees		0.500%	(157,551)	(788)
21	**CA ADJUSTMENT TO TAXES OTHER - REVENUE TAX ON ECAC REVENUES**				**$ (13,998)**

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
COMPETITIVE BIDDING EXPENSES
FOR THE FORECAST 2007 TEST YEAR

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	MECO Estimated Competitive Bidding Support Costs to be Incurred in 2007	CA-IR-317, Att. A, page 3	$ 276,300
2	One-half of MECO Estimated 2007 Spending Allowed by Consumer Advocate	CA-T-3	138,150
3	MECO Proposed Test Year Allowance for Competitive Bidding Non-labor	CA-IR-317, Att. A, page 3	413,834
4	**CONSUMER ADVOCATE ADJUSTMENT TO RESTATE COMPETITIVE BIDDING**	Line 2 - Line 3	**$ (275,684)**
5	**NON-LABOR EXPENSES**		

EXHIBIT CA-102

SCHEDULE C-5

contains confidential information

and is being submitted under separate cover

pursuant to Protective Order No. 23379

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Adjustment required to normalize structure maintenance work at Kahului Station	CA-IR-226, Att.1, page 2	$ (78,146)
2	**CONSUMER ADVOCATE ADJUSTMENT TO NORMALIZE KPP MAINTENANCE**		**$ (78,146)**

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
NOX WATER EXPENSES
FOR THE FORECAST 2007 TEST YEAR

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	MECO Ratemaking Adjustment to Increase NOX Water Treatment Costs - Maui Division		
2	Adjustment to NARUC Account 546	MECO-WP-504	$ 21,331
3	Adjustment to NARUC Account 554	and MECO -WP-504d	23,508
4	Total MECO Ratemaking Adjustment for Nox Water Treatment Costs	Line 1 + Line 2	44,839
5	**CONSUMER ADVOCATE ADJUSTMENT TO REVERSE MECO's ADJUSTMENT**		**$ (44,839)**
6	**FOR NOX WATER TREATMENT**		

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	MECO Updated Emission Fee Calculation - Maui Division		
2	Kahului Power Plant Tons Emission - Production Simulation	CA-IR-327, Att. A	3,629
3	Maalaea Power Plant Tons Emission - Production Simulation	"	4,484
4	Total Emission Tons Subject to DOH Emission Fees	Line 2 + Line 3	8,113
5	Times: Updated Estimated Fee per Ton for 2007	CA-IR-327	$57.14
6	Estimated Annual Emission Fees - Assuming no Waivers	Line 4 * Line 5	$463,577
7	Times Factor to Assume Waivers in 3 of 13 years (10/13)	Factor 10/13 years	76.9231%
8	Normalized Emission Fees at Updated Rate/Ton per Consumer Advocate	Line 6 * Line 7	$356,598
9	Less: Test Year Emission Fees Estimated by MECO		
10	KPP Plant	CA-IR-2, MECO T-5, Att.30a	$150,247
11	MPP Plant	"	$213,740
12	Total All Plants	Line 10+ Line 11	$363,987
13	**CONSUMER ADVOCATE ADJUSTMENT TO UPDATE AND**	Line 8 - Line 12	**$ (7,389)**
14	**NORMALIZE EMISSION FEES**		

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
DSM PROGRAM COST RECLASSIFICATION
FOR THE FORECAST 2007 TEST YEAR

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	MECO June 2007 Update Adjustment - DSM Employee Reclassification into Base Rates:		
2	Direct Labor Expense Amount	Update T-8, Attachment A, p.3	$ 201,850
3	Benefits and Overheads (EE 406, 422)	Att. A, p.4	101,967
4	Payroll Taxes on Direct Labor (EE 423)	Att. A, p.4	15,183
5	Total Expense Impact of MECO's Proposed Reclassification of DSM Employees	Sum Lines 2..4	$ 319,000
6	**CONSUMER ADVOCATE ADJUSTMENT TO REVERSE MECO EMPLOYEE**		**$ (319,000)**
7	***RECLASSIFICATION***		

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
INCREMENTAL IRP EXPENSES IN BASE RATES
FOR THE FORECAST 2007 TEST YEAR

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Actual Non-labor Incremental IRP Expenses Incurred by MECO:		
2	Actual 2005 Amount (Total amount less Labor and Labor Overhead)	MECO-WP-812, p.1	$ 590,813
3	Actual 2006 Amount (Total amount less Labor and Labor Overhead)	CA-IR-411, Att.C, p.2	604,191
4	Actual 2007 Year-to-date August (Total amount less Labor and Labor Overhead)	CA-IR-411, Att.C, p.2	198,585
5	Adjust 2007 YTD August to Full Year (multiply by 12/8 months)	Line 4 * 12/8	297,878
6	Consumer Advocate Proposed Three-year Average Non-labor IRP spending	Average Lines 2, 3, 5	$ 497,627
7	Less: Non-labor IRP Expense Proposed by MECO	MECO-WP-812, p.2	695,844
8	**CONSUMER ADVOCATE ADJUSTMENT TO REVISE MECO IRP**	Line 6 - Line 7	**$ (198,217)**
9	**NORMALIZATION ADJUSTMENT**		

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
HECO MARKETING SUPPORT INTERCOMPANY CHARGES
FOR THE FORECAST 2007 TEST YEAR

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	HECO Intercompany Charges to MECO for RA=PNG Marketing Support		
2	Actual Charges - 2004	CA-IR-154, Att.A, p.1	$ 6,864
3	*Actual Charges - 2005*	"	32,073
4	Actual Charges - 2006	"	18,227
5	Average of Actual HECO Marketing Support Charges to MECO - Last 3 Years	Average Lines 1..4	19,055
6	Less: MECO Estimated Test Year HECO Marketing Support Charges	CA-IR-154, Att.A, p.1	47,531
7	**CONSUMER ADVOCATE ADJUSTMENT TO REVISE ESTIMATED TEST YEAR**	Line 5 - Line 6	**$ (28,476)**
8	**HECO MARKETING SUPPORT**		

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	This schedule has been reserved for future use.		

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
PAYROLL EXPENSE - AVERAGE EMPLOYEES
FOR THE FORECAST 2007 TEST YEAR

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	MAUI	LANAI	MOLOKAI	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)
1	Average Headcount Adjustment:					
2	*Production O&M*	*(a)*	**$ (153,076)**	$ (42,274)	$ (1,018)	$ (196,368)
3	Transmission & Distribution O&M	(b)	**(179,355)**	(3,715)	(1,935)	(185,006)
4	Customer Accounts O&M	(c)	**(70,341)**	-	-	(70,341)
5	Customer Service O&M	(d)	**(33,272)**	-	-	(33,272)
6	Administrative & General O&M	(e)	**(5,041)**	-	-	(5,041)
7	**CONSUMER ADVOCATE AVERAGE STAFFING**		**$ (441,086)**	$ (45,990)	$ (2,953)	$ (490,029)
8	**ADJUSTMENT**					

Footnotes:

(a) Source: CA-WP-101-C13, p. 1.
(b) Source: CA-WP-101-C13, p. 2.
(c) Source: CA-WP-101-C13, p. 3.
(d) Source: CA-WP-101-C13, p. 4.
(e) Source: CA-WP-101-C13, p. 6.

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	MECO REVISED 2007 FORECAST	CA EMPLOYEE BENEFITS ADJUSTMENT	CA ADJUSTED FORECAST
	(A)	(B)	(C)	(D)	(E)
1	A/C 926000: Employee Pensions and Benefits				
2	Qualified Pension Plan		$ 4,255,300		$ 4,255,300
3	Non-Qualified Pension Plans		-		-
4	Other Postretirement Benefits		1,092,900		1,092,900
5	Long-Term Disability Benefits		126,300		126,300
6	Flex Credits Less Prices		(285,100)	9,067	(276,033)
7	Group Medical Plan		1,906,800	(65,616)	1,841,184
8	Group Dental Plan		279,900	(9,552)	270,348
9	Group Vision Plan		44,300	(1,512)	42,788
10	Group Life Insurance Plan		238,400	(7,621)	230,779
11	Other Benefits/Administration		414,500		414,500
12	Subtotals: Non-Labor		8,073,300	(75,234)	7,998,066
13	Labor		80,100		80,100
14	Total 926000		$ 8,153,400	$ (75,234)	$ 8,078,166
15	926020 Employee Benefits Transfer	-25.04%	(2,042,000)	$ 18,842	$ (2,023,158)
16	Total Charged to O&M	Line 15 + 16	$ 6,111,400	$ (56,392)	$ 6,055,008
			(a)	(b)	
17	**CA ADJUSTMENT TO REDUCE EMPLOYEE BENEFIT**		(c) (d)	**$ (56,392)**	
18	**COSTS RELATED TO AVERAGE STAFFING ADJUSTMENT**				

Footnotes:

(a) Source: MECO T-10 June 2007 Update, Exhibit 1 & MECO T-10, Attachment 1, pp.1-2.

(b) Source for CA Average Employee Benefits Adjustment Calculations:

Flex Credits Less Prices	CA-WP-101-C14, p. 1
Group Medical Plan	CA-WP-101-C14, p. 2
Group Dental Plan	CA-WP-101-C14, p. 2
Group Vision Plan	CA-WP-101-C14, p. 2
Group Life Insurance Plan	CA-WP-101-C14, p. 3

(c) Net Headcount Reduction:

	# Employees	
Production	(2.5)	
Trans. & Distr.	(8.5)	
Customer Accts.	(0.5)	Excludes counts removed via other Dpmts.
Customer Service	-	Excludes counts removed via other Dpmts.
A&G Accts.	-	Excludes counts removed via other Dpmts.
Average Employee Count Reduction	(11.5)	

Source: Counts determined from CA-WP-101-C13.

(d) Allocation:

Maui Division	**93.181%**	**$ (52,547)**
Lanai Division	2.669%	(1,505)
Molokai Division	4.150%	(2,340)
Total	100.00%	$ (56,392)

Source: MECO T-10 June 2007 Update, Exhibit 1 & MECO T-10, Attachment 1, p.2.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
PAYROLL TAXES - AVERAGE EMPLOYEES
FOR THE FORECAST 2007 TEST YEAR

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	MAUI	LANAI	MOLOKAI	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)
1	Average Headcount Adjustment:					
2	Production O&M	(a)	$ (153,076)	$ (42,274)	$ (1,018)	$ (196,368)
3	Transmission & Distribution O&M	(a)	(179,355)	(3,715)	(1,935)	(185,006)
4	Customer Accounts O&M	(a)	(70,341)	-	-	(70,341)
5	Customer Service O&M	(a)	(33,272)	-	-	(33,272)
6	Administrative & General O&M	(a)	(5,041)	-	-	(5,041)
7	Consumer Advocate Average Staffing Adjustment	(a)	(441,086)	(45,990)	(2,953)	(490,029)
8	Composite Payroll Tax Rate	(b)	7.29%	7.29%	7.29%	7.29%
9	**CA ADJUSTMENT TO REDUCE PAYROLL TAX EXPENSE**		$ (32,143)	$ (3,351)	$ (215)	$ (35,710)
10	**RELATED TO AVERAGE STAFFING ADJUSTMENT**					

Footnotes:

(a) Source: CA Adjustment C-13.

(b) Payroll Tax Rate:

Total FICA	$ 1,932,671
Estimated Gross Pay	26,520,940
Composite FICA Rate	7.29%

Source: MECO-WP-1301, p. 3.

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
	MECO Proposed Pension Asset Amortization		
1	Pension Asset Balance at 12/31/2007	(a)(b)	$ 1,126,000
2	Amortization Period	(a)	5
3	Annual Amortization	(a)	$ 225,200
4	**CA ADJUSTMENT TO ELIMINATE MECO's PROPOSED**		**$ (225,200)**
5	**PENSION ASSET AMORTIZATION**		

Footnotes:

(a) Source: MECO-928 (revised) & MECO T-9 June 2007 Update (Attachment 5, p.3).

(b) Source: CA Schedule B-2.

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	**Research & Development (non-EPRI)**		
2	2005 Actual	(a)	$ 137,621
3	2006 Actual	(a)	(9,985)
4	2007 Forecast	(b)	247,379
5	Total		375,015
6	Number of Periods		3
7	Three-Year Average R&D		125,005
8	MECO Test Year Forecast (non-EPRI)	(a) (c)	(255,379)
9	**CA ADJUSTMENT TO NORMALIZE A&G-RELATED**		**$ (130,374)**
10	**R&D EXPENSE (NON-EPRI) TO THREE-YEAR AVERAGE**		

Footnotes:

(a) *Source: CA-IR-156 MECO T-9 June 2007 Update, Att. 1, p. 44.*

(b) Source: MECO response to CA-IR-435.

(c) The amounts on lines 4 and 8 are different, because MECO's June 2007 update does not recognize an $8,000 correction identified in response to CA-IR-265 and included in the response to CA-IR-435.

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Ellipse/MINCOM Monthly Amortization	(a) (b)	$ 15,941
2	Number of Amortization Months in 2007	(a)	9
3	2007 MINCOM Fee Buy-Down Amortization		143,468
4	MECO's % Share	(a)	15%
5	MECO's 2007 MINCOM Buy-Down Amortization		$ 21,520
6	**CA ADJUSTMENT TO ELIMINATE MECO'S**	A/C 923	**$ (21,520)**
7	**AMORTIZATION EXPIRING IN SEPTEMBER 2007**		

Footnotes:

(a) Source: MECO T-9 response to CA-IR-2, Attachment B.
(b) Relicensing Fee Amortization.
(c) Allocation:

Maui Division	92.75%	$	15,941
Lanai Division	2.45%		421
Molokai Division	4.80%		825
Total	100.00%	$	17,187

Source: Allocations per CA-IR-373.

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	2005 Actual	(a)	$ 927,875
2	2006 Actual	(a)	1,130,266
3	2007 Forecast	(a)	1,847,740
4	Total		$ 3,905,881
5	Number of Periods		3
6	Three-Year Average		$ 1,301,960
7	MECO Test Year Forecast		(1,847,740)
8	**CONSUMER ADVOCATE ADJUSTMENT TO NORMALIZE T&D**		**$ (545,780)**
9	**OUTSIDE SERVICES COSTS TO A THREE-YEAR AVERAGE**		

Footnotes:

(a)

T&D Outside Contract Services:	2005	2006	2007 FCST
Vegetation Management	$ 536,762	$ 519,026	$ 743,583
Contract Services Other	391,113	611,240	1,104,157
	$ 927,875	$ 1,130,266	$ 1,847,740

Source: CA-IR-114, CA-IR-135 (revised 9/11/07) & CA-IR-338.

MAUI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	2004 Actual	(a)	$ 4,991
2	2005 Actual	(a)	48,288
3	2006 Actual	(a)	-
4	2007 Forecast	(b)	48,045
5	Total		101,324
6	Number of Periods		4
7	Four-Year Average		25,331
8	MECO Test Year Forecast	(b)	(48,045)
9	**CONSUMER ADVOCATE ADJUSTMENT TO NORMALIZE**	A/C 920	**$ (22,714)**
10	**HO'OMAIKA'I AWARD COSTS TO A FOUR-YEAR AVERAGE**		(c)

Footnotes:

(a) Source: MECO response to CA-IR-372.

(b) Source: MECO T-9 response to CA-IR-2, Attachment C.

(c) Allocation:

Maui Division	92.75%	$ (22,714)
Lanai Division	2.45%	(600)
Molokai Division	4.80%	(1,175)
Total	100.00%	$ (24,489)

Source: Allocations per CA-IR-373.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
CAPITAL STRUCTURE & COSTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

MAUI DIVISION

LINE NO.	DESCRIPTION	AMOUNTS IN THOUSANDS	PERCENT OF TOTAL	EARNINGS REQMTS	WEIGHTED EARNINGS REQMTS
	(A)	(B)	(C)	(D)	(E)
	MECO Proposed (a)				
1	Short-Term Debt	$ 4,750	1.27%	5.00%	0.06%
2	Long-Term Debt	150,585	40.15%	6.11%	2.45%
3	Hybrid Securities	9,192	2.45%	7.47%	0.18%
4	Preferred Stock	4,693	1.25%	8.34%	0.10%
5	Common Equity	205,882	54.89%	11.25%	6.18%
6	Total Capitalization	$ 375,102	100.00%		**8.98%**
	CA Proposed (b)				
7	Short-Term Debt	$ 4,750	1.27%	5.00%	0.06%
8	Long-Term Debt	150,585	40.15%	6.11%	2.45%
9	Hybrid Securities	9,192	2.45%	7.47%	0.18%
10	Preferred Stock	4,693	1.25%	8.34%	0.10%
11	Common Equity (midpoint)	205,882	54.89%	10.00%	5.49%
12	Total Capitalization	$ 375,102	100.00%		**8.29%**

Footnotes :

(a) Source: MECO-2001

(b) Source: Consumer Advocate witness David Parcell (CA-T-4) Exhibit CA-413.

MAUI DIVISION

LINE NO.	SCH./ ADJ. NO.	DESCRIPTION	AMOUNT	DIFFERENCE IN PRETAX RETURN	REVENUE REQUIREMENT VALUE
		(A)	(B)	(C)	(D)
1	SCH. A	**Asserted Revenue Requirement** (excluding inter-island subsidy)			$ 15,731
2	SCH. B	**Return Difference At MECO Rate Base** (before pro forma working cash)	$ 358,230	-1.230%	(4,406)
3		Subtotal Revenue Requirement			$ 11,325
				PRE-TAX RETURN	
4		**RATE BASE ADJUSTMENTS**			
5	B-1	MECO PROPOSED JUNE UPDATES	(902)	14.87%	$ (134)
6	B-2	PENSION ASSET	(1,841)	14.87%	(274)
7	B-3	FUEL INVENTORY	(3,602)	14.87%	(536)
8	B-4	ACCUMULATED DEFERRED TAX BALANCES	(1,933)	14.87%	(287)
9	B-5	CASH WORKING CAPITAL	(274)	14.87%	(41)
10		Total Value of Rate Base Adustments	(8,551)		(1,272)
11		Rate Base Recommendation (before pro forma working cash)	349,679	377,696	
12		Change in Working Cash at Proposed Rates (MECO vs CA)	(105)	16.10%	(17)
13		Rate Base With Working Cash Difference	$ 349,574		$ (1,289)
				REVENUE CONVERSION MULTIPLIER	
14	SCH. A	**Adjusted Net Operating Income**	$ 23,373		
15		**NET OPERATING INCOME ADJUSTMENTS**			
16	C-1	MECO PROPOSED JUNE 2007 UPDATES	369	1.7960	$ (664)
17	C-2	UPDATE SALES FOR RIDER PARTICIPATION	(1)	1.7960	2
18	C-3	FUEL AND PURCHASED POWER EXPENSE & ECAC REVENUES	307	1.7960	(552)
19	C-4	COMPETITIVE BIDDING EXPENSES	168	1.7960	(302)
20	C-5	LUBE OIL EXPENSE CORRECTION	82	1.7960	(147)
21	C-6	KAHULUI PLANT STRUCTURE MAINTENANCE NORMALIZATION	48	1.7960	(86)
22	C-7	NOX WATER EXPENSES	27	1.7960	(49)
23	C-8	EMISSION FEE EXPENSES	5	1.7960	(8)
24	C-9	DSM PROGRAM COST RECLASSIFICATION	195	1.7960	(350)
25	C-10	INCREMENTAL IRP EXPENSES IN BASE RATES	121	1.7960	(217)
26	C-11	HECO MARKETING SUPPORT INTERCOMPANY CHARGES	17	1.7960	(31)
27	C-12	RESERVED	0	1.7960	-
28	C-13	PAYROLL EXPENSE - AVERAGE EMPLOYEES	269	1.7960	(484)
29	C-14	EMPLOYEE BENEFITS - AVERAGE EMPLOYEES	32	1.7960	(58)
30	C-15	PAYROLL TAXES - AVERAGE EMPLOYEES	20	1.7960	(35)
31	C-16	PENSION ASSET	138	1.7960	(247)
32	C-17	RESEARCH & DEVELOPMENT	80	1.7960	(143)
33	C-18	EXPIRING SOFTWARE AMORTIZATION	13	1.7960	(24)
34	C-19	T&D OUTSIDE SERVICES	333	1.7960	(599)
35	C-20	HO'OMAIKA'I COSTS	14	1.7960	(25)
36		Total Value of Net Operating Income Adj.	2,238		$ (4,019)
37	SCH. A	Net Operating Income Recommendation	$ 25,610		
38		RECONCILED REVENUE REQUIREMENT			$ 6,017
39		UNRECONCILED DIFFERENCE			35
40	SCH. A	**REVENUE REQUIREMENT RECOMMENDATION** (excluding Inter-Island subsidy)			$ 6,052

MAUI DIVISION

LINE NO.	DESCRIPTION	WEIGHTED COST (SCH. D)	REVENUE CONVERSION MULTIPLIER (a) (b)	PRETAX RETURN
	(A)	(B)	(C)	(D)
	RETURN PER MECO			
1	Short-Term Debt	0.06%	1.7951	0.108%
2	Long-Term Debt	2.45%	1.7951	4.398%
3	Hybrid Securities	0.18%	1.7951	0.323%
4	Preferred Stock	0.10%	1.7951	0.180%
5	Common Equity	6.18%	1.7951	11.093%
6	Total Capitalization	8.97%		16.102%
	RETURN PER CA			
7	Short-Term Debt	0.06%	1.7960	0.108%
8	Long-Term Debt	2.45%	1.7960	4.400%
9	Hybrid Securities	0.18%	1.7960	0.323%
10	Preferred Stock	0.10%	1.7960	0.180%
11	Common Equity (midpoint)	5.49%	1.7960	9.860%
12	Total Capitalization	8.28%		14.871%
13	DIFFERENCE IN PRE-TAX RETURNS			-1.230%

Source: CA Schedules D & A-1.

LANAI DIVISION Exhibit CA-103

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
INDEX TO JOINT ACCOUNTING EXHIBITS
AND SUPPORTING SCHEDULES

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Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
CHANGE IN GROSS REVENUE REQUIREMENT
FOR THE FORECAST 2007 TEST YEAR
(000's)

LANAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	MECO PROPOSED	CA PROPOSED
	(A)	(B)	(C)	(D)
1	Rate Base at Present Rates	(a)	$ 13,257	$ 13,421
2	Change in Rate Base - Working Cash	(a)	(6)	(3)
3	Rate Base at Proposed Rates		$ 13,251	$ 13,418
4	Rate of Return	(b)	8.98%	8.29%
5	Operating Income Required	Line 3 * Line 4	$ 1,189	$ 1,112
6	Net Operating Income Available	(c)	100	139
7	Operating Income Deficiency	Line 5 - Line 6	$ 1,089	$ 974
8	Revenue Conversion Factor	(d)	1.795059	1.795985
9	Gross Revenue Deficiency (Excess)	Line 7 * Line 8	$ 1,955	$ 1,749
10	**Inter-Island Subsidy**	(e)	(1,416)	(1,497)
11	Net Revenue Deficiency (Excess)	Line 9 + Line 10	**$ 539**	**$ 251**

Footnotes:

(a) CA Schedule B.
(b) CA Schedule D.
(c) CA Schedule C.
(d) CA Schedule A-1.
(e) Source: MECO-2001, p. 3 (direct filing). Based on 3.02% return on investment.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
REVENUE CONVERSION FACTOR
FOR THE FORECAST 2007 TEST YEAR

LANAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	RATES	COMPANY PROPOSED	CA PROPOSED
	(A)	(B)	(C)	(D)	(E)
1	Gross Electric Sales Revenue			100.0000%	100.0000%
2	Add: Other Operating Revenue	(e)	1.15067%	1.1507%	1.1507%
3	Total Operating Revenue	Line 1 + 2		101.1507%	101.1507%
4	Less: Franchise Royalty Tax	(a) (b)	2.500%	-2.46975%	-2.46975%
5	Less: Public Service Company Tax	(a) (c)	5.885%	-5.8815%	-5.8850%
6	Less: Public Utility Commission Fees	(a) (c)	0.500%	-0.4997%	-0.5000%
7	Less: Uncollectibles	(a) (d)	0.060%	-0.0600%	0.0000%
8	Net Revenue (before income taxes)	Lines 3..7		92.23975%	92.29592%
9	Less: Effective State Income Tax		6.0150%	-5.54822%	-5.55160%
10	Less: Effective Federal Income Tax		35.0000%	-30.34204%	-30.36051%
11	Net Operating Earnings	Lines 8..10		56.34949%	56.38381%
12	Income to Revenue Multiplier	Line 3 / 11		1.795059	1.793967

Footnotes:

(a) Sources: MECO-WP-2001, pp.15, 27 & 39.

(b) In determining the "increase in operating revenues" for purposes of annualizing franchise tax, MECO-WP-2001 reduces the pro forma rate increase by related uncollectibles before applying the applicable tax rates.

(c) In determining the "increase in operating revenues" subject to PSC Tax and PUC Fees, MECO-WP-2001 adjusts pro forma rate increase to include other operating revenue and exclude uncollectibles before applying the applicable tax rates.

(d) Consumer Advocate does not treat uncollectibles as directly variable with revenues, per CA T-3.

(e) Sources: MECO-WP-2001, pp.14 & 26.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF JURISDICTIONAL RATE BASE
FOR THE FORECAST 2007 TEST YEAR
(000's)

LANAI DIVISION

LINE NO.	DESCRIPTION	MECO PRO FORMA TEST YEAR	CA ADJUSTMENTS	CA PROPOSED
	(A)	(B)	(C)	(D)
1	**Additions**			
2	Net Cost of Plant in Service	$ 15,187	$ 263	$ 15,450
3	Property Held for Future Use	-	-	-
4	Fuel Inventory	550	-	550
5	Materials & Supplies Inventories	193	(52)	141
6	Unamort Net SFAS 109 Reg Asset	429	(50)	379
7	Pension Asset	90	(90)	-
8	OPEB Amount	-	-	-
9	Unamort Sys Dev Costs	7	(7)	-
10	**Total Additions**	16,456	64	16,520
				-
11	**Deductions**			-
12	Unamortized CIAC	(1,983)	(23)	(2,006)
13	Customer Advances	(249)	42	(207)
14	Customer Deposits	(95)	4	(91)
15	Accumulated Def Income Taxes	(782)	110	(672)
16	Unamortized ITC	(428)	(16)	(444)
17	**Total Deductions**	(3,537)	117	(3,420)
18	Difference	12,919	181	13,100
19	Working Cash at Present Rates	338	(17)	321
20	Rate Base at Present Rates	13,257	164	13,421
21	Change in Rate Base - Working Cash	(6)	3	(3)
22	**Rate Base at Proposed Rates**	$ 13,251	$ 167	13,418
			(a)	

Footnotes:

(a) Source: Schedule B, pg. 2

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF RATE BASE ADJUSTMENTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

LANAI DIVISION

LINE NO.	DESCRIPTION	ADJUSTMENT NUMBER / SCHEDULE REFERENCE B-1	B-2	B-3	B-4	B-5	B-6	B-7	B-8	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	**Additions**									
2	Net Cost of Plant in Service	$ 263	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 263
3	Property Held for Future Use	-	-	-	-	-	-	-	-	-
4	Fuel Inventory	-	-	-	-	-	-	-	-	-
5	Materials & Supplies Inventories	(52)	-	-	-	-	-	-	-	(52)
6	Unamort Net SFAS 109 Reg Asset	(50)								(50)
7	Pension Asset	(6)	(84)							(90)
8	OPEB Amount	-								-
9	Unamort Sys Dev Costs	(7)								(7)
10	**Total Additions**	148	(84)	-	-	-	-	-	-	64
11	**Deductions**									
12	Unamortized CIAC	(23)	-	-	-	-	-	-	-	(23)
13	Customer Advances	42	-	-	-	-	-	-	-	42
14	Customer Deposits	4	-	-	-	-	-	-	-	4
15	Accumulated Def Income Taxes	142	48	-	(80)	-	-	-	-	110
16	Unamortized ITC	(16)	-	-	-	-	-	-	-	(16)
17	**Total Deductions**	149	48	-	(80)	-	-	-	-	117
18	Difference	297	(36)	-	(80)	-	-	-	-	181
19	Working Cash at Present Rates	(9)	-	-	-	(8)	-	-	-	(17)
20	Rate Base at Present Rates	288	(36)	-	(80)	(8)	-	-	-	164
21	Change in Rate Base - Working Cash	(18)	-	-	-	21	-	-	-	3
22	**Rate Base at Proposed Rates**	$ 270	$ (36)	$ -	$ (80)	$ 13	$ -	$ -	$ -	$ 167

ADJUSTMENTS:

B-1 MECO PROPOSED JUNE UPDATES
B-2 PENSION ASSET
B-3
B-4 ACCUMULATED DEFERRED TAX BALANCES
B-5 CASH WORKING CAPITAL
B-6
B-7
B-8

LANAI DIVISION

LINE NO.	DESCRIPTION	REVISED AMOUNT	MECO DIRECT AMOUNT	ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)
1	**Additions**			
2	Net Plant in Service	$ 15,450,000	$ 15,187,000	$ 263,000
3	Property Held for Future Use	-	-	-
4	Fuel Inventory	550,000	550,000	-
5	Materials & Supplies Inventories	141,000	193,000	(52,000)
6	Unamort Net SFAS 109 Reg Asset	379,000	429,000	(50,000)
7	Pension Asset	84,000	90,000	(6,000)
8	OPEB Amount	-	-	-
9	Unamort Sys Dev Costs	-	7,000	(7,000)
10	**Total Additions**	16,604,000	16,456,000	148,000
11	**Deductions**			
12	Unamortized CIAC	(2,006,000)	(1,983,000)	(23,000)
13	Customer Advances	(207,000)	(249,000)	42,000
14	*Customer Deposits*	*(91,000)*	*(95,000)*	*4,000*
15	Accumulated Def Income Taxes	(640,000)	(782,000)	142,000
16	Unamortized ITC	(444,000)	(428,000)	(16,000)
17	**Total Deductions**	(3,388,000)	(3,537,000)	149,000
18	Rate Base (before Working Cash)	13,216,000	12,919,000	297,000
19	Working Cash at Present Rates	329,000	338,000	(9,000)
20	Rate Base at Present Rates	13,545,000	13,257,000	288,000
21	Change in Rate Base - Working Cash	(24,000)	(6,000)	(18,000)
22	**Rate Base at Proposed Rates**	$ 13,521,000	$ 13,251,000	$ 270,000
		(a)	(b)	

Footnotes:

(a) MECO's response to CA-IR-304, p. 25.

(b) Sources: MECO-2001, p. 3, & MECO-WP-2001, p. 22 (per original filing).

LANAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	TEST YEAR AMOUNT	ADJUSTMENT
	(A)	(B)	(C)	(D)
1	MECO UpdateD Pension Asset	(a)	$ 84,000	$ (84,000)
2	Less: Accumulated Deferred Income Tax Reserve	(b)	(47,678)	47,678
3	Net Pension Asset in MECO's Updated Rate Base		$ 36,322	
4	**CA ADJUSTMENT TO ELIMINATE NET PENSION**			**$ (36,322)**
5	**ASSET FROM RATE BASE**			

Footnotes:

(a) Prepaid Pension Asset:

	12/31/06 Actual	12/31/07 FCST
Ending Balance	$ 135,000	$ 33,000

Source: MECO-928 & MECO T-9 June 2007 Update, Attachment 5.

(b) ADIT Reserve:

	12/31/06 Actual	12/31/07 FCST
State ADIT	$ (11,969)	$ (2,772)
Federal ADIT	(65,458)	(15,158)
Total	$ (77,427)	$ (17,929)

Source: MECO-WP-1305 & MECO-1305, June 2007 Update (Att. 1, pp.9-12).

LANAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	**Restore Deferred Taxes related to AFUDC and TCI Improperly Removed by MECO:**		
2	AFUDC in CWIP - 12/31/2006 Federal	CA-IR-182, p.15	$ 1,015,303
3	AFUDC in CWIP - 12/31/2006 State	CA-IR-182, p.16	185,655
4	Reg-Asset-AFUDC Eq Grossup 12/31/2006 Federal	CA-IR-182, p.15	444,618
5	Reg-Asset-AFUDC Eq Grossup 12/31/2006 State	CA-IR-182, p.16	81,301
6	**Total Adjustments to 12/31/2006 Beginning of Test Year**		1,726,877
7	AFUDC in CWIP - 12/31/2007 Federal	CA-IR-182, p.15	$ 801,688
8	AFUDC in CWIP - 12/31/2007 State	CA-IR-182, p.16	146,594
9	Reg-Asset-AFUDC Eq Grossup 12/31/2007 Federal	CA-IR-182, p.15	349,356
10	Reg-Asset-AFUDC Eq Grossup 12/31/2007 State	CA-IR-182, p.16	63,882
11	**Total Adjustments to 12/31/2007 End of Test Year**		1,361,520
12	Average Test Year Adjustment for AFUDC/TCI Restoration	Average Lines 6, 11	**$1,544,199**
13	**Correct Deferred Taxes Related to Emission Fees:**		
14	Emission Fee Federal Deferred Taxes at 12/31/2007 per MECO	CA-IR-182, p.15	$331,478
15	Emission Fee State Deferred Taxes at 12/31/2007 per MECO	CA-IR-182, p.16	60,612
16	Test Year End Emission Fee Deferred Taxes per MECO		392,090
17	Revised emission Fee Federal Deferred Taxes -12/31/2007	CA-IR-379	$127,351
18	Revised emission Fee State Deferred Taxes -12/31/2007	"	23,286
19	Corrected Test Year End Emission Fee Deferred Taxes		150,637
20	Difference in Year-end Deferred Tax Balance (Negative DR value)	Line 16-Line 19	$241,453
21	One-half Adjustment for Average Rate Base	Line 20 * 1/2	**$120,727**
22	**Include Deferred Taxes on IRP/DSM Program Costs:**		
23	IRP/DSM Federal Deferred Taxes at 12/31/2006 per MECO	CA-IR-182, p.15	$373,233
24	IRP/DSM State Deferred Taxes at 12/31/2006 per MECO	CA-IR-182, p.16	68,249
25	Test Year Beginning IRP/DSM Related Deferred Taxes per MECO		441,482
26	IRP/DSM Federal Deferred Taxes at 12/31/2007 per MECO	CA-IR-182, p.15	$373,233
27	IRP/DSM State Deferred Taxes at 12/31/2007 per MECO	CA-IR-182, p.16	68,429
28	Test Year End IRP/DSM Related Deferred Taxes per MECO		441,662
29	Average Test Year Adjustment for IRP/DSM Deferred Tax Restoration	Average Lines 25, 28	**$441,572**
30	**CONSUMER ADVOCATE ADJUSTMENT INCREASING ACCUMULATED**	Line 12+21+29	**$ 2,106,497**
31	**DEFERRED INCOME TAXES**		
32	Allocation: Maui Division Portion of Line 30 Total Adjustment - 91.75%	CA-IR-373 Att.1	1,932,711
33	Lanai Division Portion of Line 30 Total Adjustment - 3.80%%		**80,047**
34	Molokai Division Portion of Line 30 Total Adjustment - 4.45%		93,739

Note: All amounts increase credit deferred taxes, thereby reducing rate base.

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
CASH WORKING CAPITAL
FOR THE FORECAST 2007 TEST YEAR

LANAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	Revenue Lag (Days)	Payment Lag (Days)	Net Lag (Days)	Annual Amount	Average Daily Amount Present Rates (F) / 365	Average Daily Amount Proposed Rates (F) / 365	CWC Present Rates (E) x (G)	CWC Proposed Rates (E) x (H)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	Fuel Purchases	(a)	36.0	15.0	21.0	$ 6,176,000	$ 16,921	$ 16,921	$ 355,332	$ 355,332
2	O&M Labor	(a)	36.0	12.0	24.0	701,010	1,921	1,921	46,094	46,094
3	O&M Nonlabor	(a)(c)	36.0	36.9	(0.9)	985,517	2,700	2,700	(2,314)	(2,314)
4	Non-Cash Items:									
5	Pension Asset Amortization	(a)(b)	0.0	0.0	0.0	0	-	-	-	-
6	Pension Accrual	(b)(c)	0.0	0.0	0.0	82,417	226	226	-	-
7	Purchased Power	(a)			0.0	0	-	-	-	-
8	Revenue Taxes - Present Rates	(a)	36.0	68.0	(32.0)	896,000	2,455		(78,553)	
9	Revenue Taxes - Proposed Rates	(a)	36.0	68.0	(32.0)	918,512		2,516		(80,527)
10	Income Taxes - Present Rates	(a)	36.0	40.0	(4.0)	(33,134)	(91)		363	
11	Income Taxes - Proposed Rates	(a)	36.0	40.0	(4.0)	57,010		156		(625)
12	Total Cash Working Capital								320,921	317,959
13	Less: MECO Revised Cash Working Capital	(a)							(329,000)	(305,000)
14	**CONSUMER ADVOCATE ADJUSTMENT TO EXCLUDE NON-CASH ITEMS**								**$ (8,079)**	**$ 12,959**
15	Change in Cash Working Capital									$ 21,038

Footnotes:

(a) Source: MECO-1513, as revised by MECO T-15 June 2007 Update, p. 17.

(b) Both pension items are non-cash, absent a specific funding commitment -- regardless of the existence of a tracking mechanism.
The Consumer Advocate proposes to excluded non-cash excluded from CWC calculation, by assigning "zero" for both revenue lag and expense lag.

(c) O&M Nonlabor:

		TY Expense $	% Distribution	Payment Lag	Wtd. Lag Days
Pension Accrual	(1)	$ 82,417			
Subtotal		$ 82,417			
OPEB	(2)(3)(4)	21,167	2.15%	83.71	1.8
Emission Fees	(4)	13,933	1.41%	305.50	4.3
EPRI Dues	(4)	5,444	0.55%	22.38	0.1
Other Non-Labor O &M	(4)	944,973	95.89%	31.93	30.6
Subtotal		$ 985,517	100.00%		**36.9** Days
Total O&M Non-Labor		$ 1,067,934	100.00%		

Source: MECO-WP-1507, p. 23 per MECO T-15 June 2007 Update (p. 27) & CA Lanai Posting detail.

(1) Accrual & amortization amounts removed from Other Non-Labor O&M and listed separately in CWC calculation.

(2) MECO has historically funded FAS106 accruals. Regardless of OPEB tracker, funding expected to continue.

(3) Source: Expense lags from MECO T-15 June 2007 Update, p. 27.

(4) Amounts allocated between divisions.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF OPERATING INCOME
FOR THE FORECAST 2007 TEST YEAR
(000's)

LANAI DIVISION

LINE NO.	DESCRIPTION (A)	MECO PRO FORMA (B)	CA ADJUSTMENTS (C)	CA PROPOSED (D)
1	Electric Sales Revenue	$ 10,067	$ -	$ 10,067
2	Other Operating Revenue	38	-	38
3	**Total Operating Revenues**	$ 10,105	$ -	$ 10,105
4	Fuel	$ 6,176	$ -	$ 6,176
5	Purchased Power	-	-	-
6	Production	1,094	(50)	1,044
7	Transmission	-	-	-
8	Distribution	238	(1)	237
9	Customer Accounts	139	-	139
10	Allowance for Uncoll Accounts	6	-	6
11	Customer Service	1	-	1
12	Administrative & General	344	(3)	341
13	**Operation and Maintenace**	7,999	(54)	7,945
14	Depreciation and Amortization	1,243	21	1,264
15	Amortization of State ITC	(20)	-	(20)
16	Taxes Other Than Income	952	(3)	949
17	Interest on Customer Deposits	6	(1)	5
18	Income Taxes	(175)	(1)	(176)
19	**Total Operating Expenses**	$ 10,005	$ (38)	$ 9,966
20	**Operating Income**	$ 100	$ 38	$ 139
		(a)	(b)	

Footnotes:

(a) Source: MECO-2001 pg. 3 of 4.
(b) Source: CA Schedule C, page 4

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF NOI ADJUSTMENTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

LANAI DIVISION

LINE NO.	DESCRIPTION	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-1	C-2	C-3	C-4	C-5	C-6	C-7	C-8	C-9	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Sales Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Operating Revenue	-	-	-	-	-	-	-	-	-	$ -
3	**Total Operating Revenues**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Fuel	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Purchased Power	-	-	-	-	-	-	-	-	-	-
6	Production	-	-	-	-	(4)	-	-	(4)	-	(8)
7	Transmission	-	-	-	-	-	-	-	-	-	-
8	Distribution	-	-	-	-	-	-	-	-	-	-
9	Customer Accounts	-	-	-	-	-	-	-	-	-	-
10	Allowance for Uncoll Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	-	-	-	-	-	-	-	-	-	-
12	Administrative & General	7	-	-	-	-	-	-	-	-	7
13	**Operation and Maintenance**	7	-	-	-	(4)	-	-	(4)	-	(1)
14	Depreciation and Amortization	21	-	-	-	-	-	-	-	-	21
15	Amortization of State ITC										-
16	Taxes Other than Income	-	-	-	-	-	-	-	-	-	-
17	Interest on Customer Deposits	(1)	-	-	-	-	-	-	-	-	(1)
18	Income Taxes	(26)	-	-	-	2	-	-	1	-	(23)
19	**Total Operating Expenses**	$ 1	$ -	$ -	$ -	$ (3)	$ -	$ -	$ (2)	$ -	$ (4)
20	**Operating Income**	$ (1)	$ -	$ -	$ -	$ 3	$ -	$ -	$ 2	$ -	$ 4

ADJUSTMENTS:

C-1	MECO PROPOSED JUNE 2007 UPDATES	**C-6**	
C-2		**C-7**	
C-3	FUEL AND PURCHASED POWER EXPENSE & ECAC REVENUES	**C-8**	EMISSION FEE EXPENSES
C-4		**C-9**	
C-5	LUBE OIL EXPENSE CORRECTION		

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF NOI ADJUSTMENTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

LANAI DIVISION

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-10	C-11	C-12	C-13	C-14	C-15	C-16	C-17	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Sales Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Operating Revenue	-	-	-	-	-	-	-	-	-	-
3	**Total Operating Revenues**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Fuel	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Purchased Power	-	-	-	-	-	-	-	-	-	-
6	Production	(8)	-	-	-	(42)	-	-	-	-	(50)
7	Transmission	-	-	-	-	-	-	-	-	-	-
8	Distribution	-	-	-	-	(4)	-	-	-	-	(4)
9	Customer Accounts	-	-	-	-	-	-	-	-	-	-
10	Allowance for Uncoll Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	-	-	-	-	-	-	-	-	-	-
12	Administrative & General	7	-	-	-	-	(2)	-	(7)	-	(2)
13	**Operation and Maintenance**	(1)	-	-	-	(46)	(2)	-	(7)	-	(55)
14	Depreciation and Amortization	21	-	-	-	-	-	-	-	-	21
15	Amortization of State ITC	-									-
16	Taxes Other than Income	-	-	-	-	-	-	(3)	-	-	(3)
17	Interest on Customer Deposits	(1)	-	-	-	-	-	-	-	-	(1)
18	Income Taxes	(23)	-	-	-	18	1	1	3	-	(1)
19	**Total Operating Expenses**	$ (4)	$ -	$ -	$ -	$ (28)	$ (1)	$ (2)	$ (4)	$ -	$ (39)
20	**Operating Income**	$ 4	$ -	$ -	$ -	$ 28	$ 1	$ 2	$ 4	$ -	$ 39

ADJUSTMENTS:
- **C-10**
- **C-11**
- **C-12** RESERVED
- **C-13** PAYROLL EXPENSE - AVERAGE EMPLOYEES
- **C-14** EMPLOYEE BENEFITS - AVERAGE EMPLOYEES
- **C-15** PAYROLL TAXES - AVERAGE EMPLOYEES
- **C-16** PENSION ASSET
- **C-17**

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF NOI ADJUSTMENTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

LANAI DIVISION

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-18	C-19	C-20	C-21	C-22	C-23	C-24	C-25	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Sales Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Operating Revenue	-	-	-	-	-	-	-	-	-	-
3	**Total Operating Revenues**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Fuel	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Purchased Power	-	-	-	-	-	-	-	-	-	-
6	Production	(50)	-	-	-	-	-	-	-	-	(50)
7	Transmission	-	-	-	-	-	-	-	-	-	-
8	Distribution	(4)	-	3	-	-	-	-	-	-	(1)
9	*Customer Accounts*	-	-	-	-	-	-	-	-	-	-
10	Allowance for Uncoll Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	-	-	-	-	-	-	-	-	-	-
12	Administrative & General	(2)	(1)	-	(1)	-	-	-	-	-	(3)
13	**Operation and Maintenance**	(55)	(1)	3	(1)	-	-	-	-	-	(54)
14	Depreciation and Amortization	21	-	-	-	-	-	-	-	-	21
15	Amortization of State ITC	-									-
16	Taxes Other than Income	(3)	-	-	-	-	-	-	-	-	(3)
17	Interest on Customer Deposits	(1)	-	-	-	-	-	-	-	-	(1)
18	Income Taxes	(1)	0	(1)	0	-	-	-	-	-	(1)
19	**Total Operating Expenses**	$ (39)	$ (0)	$ 2	$ (0)	$ -	$ -	$ -	$ -	$ -	$ (38)
20	**Operating Income**	$ 39	$ 0	$ (2)	$ 0	$ -	$ -	$ -	$ -	$ -	$ 38

C-18	EXPIRING SOFTWARE AMORTIZATION	**C-22**	
C-19	T&D OUTSIDE SERVICES	**C-23**	
C-20	HO'OMAIKA'I COSTS	**C-24**	
C-21		**C-25**	

LANAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	REVISED AMOUNT	MECO DIRECT AMOUNT	ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)	(E)
1	**MECO Update Adjustments to Revenues:**				
		Update CA-IR-304, p.23			
2	Electric Sales Revenue	MECO-2001, p.3	$ 10,066,700	$ 10,066,700	$ -
3	Other Operating Revenue	MECO-2001, p.3	38,000	38,000	-
4	Total Operating Revenue		$ 10,104,700	$ 10,104,700	$ -
5	**MECO Update Adjustments to Expenses:**				
		Update CA-IR-304, p.23			
6	Fuel Expense	MECO-2001, p.3	$ 6,176,000	$ 6,176,000	$ -
		Update CA-IR-304, p.23			
7	Purchased Power Expense	MECO-2001, p.3	-	-	-
8	Production O&M Expenses:	Update T-5, Att.1			
9	Labor	MECO-503	570,500	570,500	-
10	Non-Labor	MECO-503	523,900	523,900	-
11	Transmission Expenses:	Update CA-IR-304, p.23			
12	Labor		-	-	-
13	Non-Labor		-	-	-
14	Distribution Expenses:	Update CA-IR-304, p.23			
15	Labor	MECO-606, p. 3	94,941	94,941	-
16	Non-Labor	MECO-606, p. 3	143,466	143,466	-
17	Customer Accounts Expenses:	Update CA-IR-304, p.23			
18	Labor	MECO-706	57,000	57,000	-
19	Non-Labor	MECO-706	82,000	82,000	-
20	Uncollectibles	MECO-706	6,000	6,000	-
21	Customer Service Expenses:	Update CA-IR-304, p.23			
22	Labor	MECO-805	-	-	-
23	Non-Labor	MECO-805	1,000	1,000	-
24	Administrative & General Expenses:	Update T-9, Att.1, p.10			
25	Labor	MECO-901. p. 10	2,200	2,200	-
26	Non-Labor	MECO-901. p. 10	348,100	341,500	6,600
27	Total O&M Expenses				
28	Labor	Lines 9+12+15+18+22+25	724,641	724,641	-
29	Non-Labor	Lines 6+7+10+13+16+19+20+23+26	7,280,466	7,273,866	6,600
30	**Total O&M Expenses**		8,005,107	7,998,507	6,600
31	**Depreciation & Amortization**	Update T-12, p.4	1,264,000	1,243,000	21,000
32	**Amortization of State ITC**	Update CA-IR-304, p.23	(20,000)	(20,000)	-
33	**Taxes Other than Income**	Update CA-IR-304, p.23	952,000	952,000	-
34	**Interest on Customer Deposits**	Update CA-IR-304, p.23	5,000	6,000	(1,000)
35	**Income Taxes**	Update CA-IR-304, p.23	(201,000)	(175,000)	(26,000)
36	Total Operating Expenses		$ 10,005,107	$ 10,004,507	$ 600
37	Net Operating Income		$ 99,593	$ 100,193	$ (600)

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
FUEL AND PURCHASED POWER EXPENSE & ECAC REVENUES
FOR THE FORECAST 2007 TEST YEAR

LANAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	MECO PROPOSED AMOUNT	CONSUMER ADVOCATE AMOUNT	DIFFERENCE ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)	(E)
1	Fuel Oil Expense - Production Simulation	MECO-401 /CA-204	$ 6,172,600	$ 6,172,600	$ -
2	Fuel Related Expense	MECO-401 / CA-205	$ 2,700	$ 2,700	$ -
3	**CA ADJUSTMENT TO FUEL EXPENSE**	Line 1 + 2	6,175,300	6,175,300	$ -
4	Purchased Power - Energy Payments	MECO-507 / CA-210			-
5	Purchased Power - Capacity Payments	MECO-507 / CA-210			-
6	**CA ADJUSTMENT TO PURCHASED POWER EXPENSE**	Line 4 + 5	-	-	$ -
7	**Energy Cost Adjustment Rate / Present Rates (cents/kwh)**	CA-201	13.91300	13.91300	-
8	Test Year Proposed Sales - Gigawatthours		MECO MWH HECO-201	Times ECAC Difference	ECAC Revenue Change
9	Residential R		8,182.7	-	$ -
10	Commercial G/J		8,164.0	-	-
11	Commercial J (included with Schedule G)			-	-
12	Commercial H		545.0	-	-
13	Large Commercial P		12,773.9	-	-
14	Lighting F		113.7	-	-
15	Total Sales Volume		29,779.3		
16	**CA ADJUSTMENT TO ECAC GROSS REVENUES AT CA FUEL/ENERGY COSTS**				$ -
17	Additional Revenue Taxes on Incremental ECAC Revenues		Tax Rate	Times ECAC Revenue Change	
18	Franchise Royalty Tax		2.500%	$0	$ -
19	Public Service Company Tax		5.885%	$0	-
20	Public Utility Commission Fees		0.500%	$0	-
21	**CA ADJUSTMENT TO TAXES OTHER - REVENUE TAX ON ECAC REVENUES**				$ -

EXHIBIT CA-103

SCHEDULE C-5

contains confidential information

and is being submitted under separate cover

pursuant to Protective Order No. 23379

LANAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	MECO Updated Emission Fee Calculation - Lanai Division		
2	*Miki Power Plant Tons Emissions - Tons*	*CA-IR-104, page 2*	317
3	Times: Updated Estimated Fee per Ton for 2007	CA-IR-327	$57.14
4	Estimated Annual Emission Fees - Assuming no Waivers	Line 4 * Line 5	$18,113
5	Times Factor to Assume Waivers in 3 of 13 years (10/13)	Factor 10/13 years	76.9231%
6	Normalized Emission Fees at Updated Rate/Ton per Consumer Advocate	Line 6 * Line 7	$13,933
7	Less: Test Year Emission Fees Estimated by MECO	CA-IR-2, MECO T-5, Att.30a	$17,733
8	**CONSUMER ADVOCATE ADJUSTMENT TO UPDATE AND**	Line 6 - Line 7	**$ (3,800)**
9	**NORMALIZE EMISSION FEES**		

LANAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	This schedule has been reserved for future use.		

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
PAYROLL EXPENSE - AVERAGE EMPLOYEES
FOR THE FORECAST 2007 TEST YEAR

LANAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	MAUI	**LANAI**	MOLOKAI	TOTAL
	(A)	(B)	(C)	**(D)**	(E)	(F)
1	Average Headcount Adjustment:					
2	Production O&M	(a)	$ (153,076)	**$ (42,274)**	$ (1,018)	$ (196,368)
3	Transmission & Distribution O&M	(b)	(179,355)	**(3,715)**	(1,935)	(185,006)
4	Customer Accounts O&M	(c)	(70,341)	**-**	-	(70,341)
5	Customer Service O&M	(d)	(33,272)	**-**	-	(33,272)
6	Administrative & General O&M	(e)	(5,041)	**-**	-	(5,041)
7	**CONSUMER ADVOCATE AVERAGE STAFFING**		$ (441,086)	**$ (45,990)**	$ (2,953)	$ (490,029)
8	**ADJUSTMENT**					

Footnotes:

(a) Source: CA-WP-101-C13, p. 1.
(b) Source: CA-WP-101-C13, p. 2.
(c) Source: CA-WP-101-C13, p. 3.
(d) Source: CA-WP-101-C13, p. 4.
(e) Source: CA-WP-101-C13, p. 6.

LANAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	MECO REVISED 2007 FORECAST	CA EMPLOYEE BENEFITS ADJUSTMENT	CA ADJUSTED FORECAST
	(A)	(B)	(C)	(D)	(E)
1	A/C 926000: Employee Pensions and Benefits				
2	Qualified Pension Plan		$ 4,255,300		$ 4,255,300
3	Non-Qualified Pension Plans		-		-
4	Other Postretirement Benefits		1,092,900		1,092,900
5	Long-Term Disability Benefits		126,300		126,300
6	Flex Credits Less Prices		(285,100)	9,067	(276,033)
7	Group Medical Plan		1,906,800	(65,616)	1,841,184
8	Group Dental Plan		279,900	(9,552)	270,348
9	Group Vision Plan		44,300	(1,512)	42,788
10	Group Life Insurance Plan		238,400	(7,621)	230,779
11	Other Benefits/Administration		414,500		414,500
12	Subtotals: Non-Labor		8,073,300	(75,234)	7,998,066
13	Labor		80,100		80,100
14	Total 926000		$ 8,153,400	$ (75,234)	$ 8,078,166
15	926020 Employee Benefits Transfer	-25.04%	(2,042,000)	$ 18,842	$ (2,023,158)
16	Total Charged to O&M	Line 15 + 16	$ 6,111,400	$ (56,392)	$ 6,055,008
			(a)	(b)	
17	**CA ADJUSTMENT TO REDUCE EMPLOYEE BENEFIT**		(c) (d)	**$ (56,392)**	
18	**COSTS RELATED TO AVERAGE STAFFING ADJUSTMENT**				

Footnotes:

(a) Source: MECO T-10 June 2007 Update, Exhibit 1 & MECO T-10, Attachment 1, pp.1-2.

(b) Source for CA Average Employee Benefits Adjustment Calculations:

Flex Credits Less Prices	CA-WP-101-C14, p. 1
Group Medical Plan	CA-WP-101-C14, p. 2
Group Dental Plan	CA-WP-101-C14, p. 2
Group Vision Plan	CA-WP-101-C14, p. 2
Group Life Insurance Plan	CA-WP-101-C14, p. 3

(c) Net Headcount Reduction:

	# Employees	
Production	(2.5)	
Trans. & Distr.	(8.5)	
Customer Accts.	(0.5)	Excludes counts removed via other Dpmts.
Customer Service	-	Excludes counts removed via other Dpmts.
A&G Accts.	-	Excludes counts removed via other Dpmts.
Average Employee Count Reduction	(11.5)	

Source: Counts determined from CA-WP-101-C13.

(d) Allocation:

Maui Division	93.181%	$ (52,547)
Lanai Division	**2.669%**	**(1,505)**
Molokai Division	4.150%	(2,340)
Total	100.00%	$ (56,392)

Source: MECO T-10 June 2007 Update, Exhibit 1 & MECO T-10, Attachment 1, p.2.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
PAYROLL TAXES - AVERAGE EMPLOYEES
FOR THE FORECAST 2007 TEST YEAR

LANAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	MAUI	LANAI	MOLOKAI	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)
1	Average Headcount Adjustment:					
2	Production O&M	(a)	$ (153,076)	$ (42,274)	$ (1,018)	$ (196,368)
3	Transmission & Distribution O&M	(a)	(179,355)	(3,715)	(1,935)	(185,006)
4	Customer Accounts O&M	(a)	(70,341)	-	-	(70,341)
5	Customer Service O&M	(a)	(33,272)	-	-	(33,272)
6	Administrative & General O&M	(a)	(5,041)	-	-	(5,041)
7	Consumer Advocate Average Staffing Adjustment	(a)	(441,086)	(45,990)	(2,953)	(490,029)
8	Composite Payroll Tax Rate	(b)	7.29%	7.29%	7.29%	7.29%
9	**CA ADJUSTMENT TO REDUCE PAYROLL TAX EXPENSE**		$ (32,143)	$ (3,351)	$ (215)	$ (35,710)
10	**RELATED TO AVERAGE STAFFING ADJUSTMENT**					

Footnotes:

(a) Source: CA Adjustment C-13.

(b) Payroll Tax Rate:

Total FICA	$ 1,932,671
Estimated Gross Pay	26,520,940
Composite FICA Rate	7.29%

Source: MECO-WP-1301, p. 3.

LANAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
	MECO Proposed Pension Asset Amortization		
1	Pension Asset Balance at 12/31/2007	(a)(b)	$ 33,000
2	Amortization Period	(a)	5
3	Annual Amortization	(a)	$ 6,600
4	**CA ADJUSTMENT TO ELIMINATE MECO's PROPOSED**		**$ (6,600)**
5	**PENSION ASSET AMORTIZATION**		

Footnotes:

(a) Source: MECO-928 (revised) & MECO T-9 June 2007 Update (Attachment 5, p.3).

(b) Source: CA Schedule B-2.

LANAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Ellipse/MINCOM Monthly Amortization	(a) (b)	$ 421
2	Number of Amortization Months in 2007	(a)	9
3	2007 MINCOM Fee Buy-Down Amortization		3,790
4	MECO's % Share	(a)	15%
5	MECO's 2007 MINCOM Buy-Down Amortization		$ 568
6	**CA ADJUSTMENT TO ELIMINATE MECO'S**	A/C 923	**$ (568)**
7	**AMORTIZATION EXPIRING IN SEPTEMBER 2007**		

Footnotes:

(a) Source: MECO T-9 response to CA-IR-2, Attachment B.

(b) Relicensing Fee Amortization.

(c) Allocation:

Maui Division	92.75%	$ 15,941
Lanai Division	2.45%	421
Molokai Division	4.80%	825
Total	100.00%	$ 17,187

Source: Allocations per CA-IR-373.

LANAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	2005 Actual	(a)	$ 76,472
2	2006 Actual	(a)	24,085
3	2007 Forecast	(a)	46,315
4	Total		$ 146,872
5	Number of Periods		3
6	Three-Year Average		$ 48,957
7	MECO Test Year Forecast		(46,315)
8	**CONSUMER ADVOCATE ADJUSTMENT TO NORMALIZE T&D**		**$ 2,642**
9	**OUTSIDE SERVICES COSTS TO A THREE-YEAR AVERAGE**		

Footnotes:

(a)

T&D Outside Contract Services:	2005	2006	2007 FCST
Vegetation Management	$ 15,245	$ 17,598	$ 28,600
Contract Services Other	61,227	6,487	17,715
	$ 76,472	$ 24,085	$ 46,315

Source: CA-IR-114, CA-IR-135 (revised 9/11/07) & CA-IR-338.

LANAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	2004 Actual	(a)	$ 132
2	2005 Actual	(a)	1,276
3	2006 Actual	(a)	-
4	2007 Forecast	(b)	1,269
5	Total		2,676
6	Number of Periods		4
7	Four-Year Average		669
8	MECO Test Year Forecast	(b)	(1,269)
9	**CONSUMER ADVOCATE ADJUSTMENT TO NORMALIZE**	A/C 920	**$ (600)**
10	**HO'OMAIKA'I AWARD COSTS TO A FOUR-YEAR AVERAGE**		(c)

Footnotes:

(a) Source: MECO response to CA-IR-372.

(b) Source: MECO T-9 response to CA-IR-2, Attachment C.

(c) Allocation:

Maui Division	92.75%	$ (22,714)
Lanai Division	2.45%	(600)
Molokai Division	4.80%	(1,175)
Total	100.00%	$ (24,489)

Source: Allocations per CA-IR-373.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
CAPITAL STRUCTURE & COSTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

LANAI DIVISION

LINE NO.	DESCRIPTION	AMOUNTS IN THOUSANDS	PERCENT OF TOTAL	EARNINGS REQMTS	WEIGHTED EARNINGS REQMTS
	(A)	(B)	(C)	(D)	(E)
	MECO Proposed (a)				
1	Short-Term Debt	$ 4,750	1.27%	5.00%	0.06%
2	Long-Term Debt	150,585	40.15%	6.11%	2.45%
3	Hybrid Securities	9,192	2.45%	7.47%	0.18%
4	Preferred Stock	4,693	1.25%	8.34%	0.10%
5	Common Equity	205,882	54.89%	11.25%	6.18%
6	Total Capitalization	$ 375,102	100.00%		**8.98%**
	CA Proposed (b)				
7	Short-Term Debt	$ 4,750	1.27%	5.00%	0.06%
8	Long-Term Debt	150,585	40.15%	6.11%	2.45%
9	Hybrid Securities	9,192	2.45%	7.47%	0.18%
10	Preferred Stock	4,693	1.25%	8.34%	0.10%
11	Common Equity (midpoint)	205,882	54.89%	10.00%	5.49%
12	Total Capitalization	$ 375,102	100.00%		**8.29%**

Footnotes :

(a) Source: MECO-2001

(b) Source: Consumer Advocate witness David Parcell (CA-T-4) Exhibit CA-413.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
RECONCILIATION OF POSITIONS
FOR THE FORECAST 2007 TEST YEAR

LANAI DIVISION

LINE NO.	SCH./ ADJ. NO.	DESCRIPTION	AMOUNT	DIFFERENCE IN PRETAX RETURN	REVENUE REQUIREMENT VALUE
		(A)	(B)	(C)	(D)
1	SCH. A	**Asserted Revenue Requirement** (excluding inter-island subsidy)			$ 1,955
2	SCH. B	**Return Difference At MECO Rate Base** (before pro forma working cash)	$ 13,257	-1.230%	(163)
3		Subtotal Revenue Requirement			$ 1,792
				PRE-TAX RETURN	
4		**RATE BASE ADJUSTMENTS**			
5	B-1	MECO PROPOSED JUNE UPDATES	288	14.87%	$ 43
6	B-2	PENSION ASSET	(36)	14.87%	(5)
7	B-3		-	14.87%	-
8	B-4	ACCUMULATED DEFERRED TAX BALANCES	(80)	14.87%	(12)
9	B-5	CASH WORKING CAPITAL	(8)	14.87%	(1)
10		Total Value of Rate Base Adustments	164		24
11		Rate Base Recommendation (before pro forma working cash)	13,421	377,696	
12		Change in Working Cash at Proposed Rates (MECO vs CA)	(3)	16.10%	(0)
13		Rate Base With Working Cash Difference	$ 13,418		$ 24
				REVENUE CONVERSION MULTIPLIER	
14	SCH. A	**Adjusted Net Operating Income**	$ 100		
15		**NET OPERATING INCOME ADJUSTMENTS**			
16	C-1	MECO PROPOSED JUNE 2007 UPDATES	(1)	1.7960	$ 1
17	C-2		0	1.7960	-
18	C-3	FUEL AND PURCHASED POWER EXPENSE & ECAC REVENUES	0	1.7960	-
19	C-4		0	1.7960	-
20	C-5	LUBE OIL EXPENSE CORRECTION	3	1.7960	(5)
21	C-6		0	1.7960	-
22	C-7		0	1.7960	-
23	C-8	EMISSION FEE EXPENSES	2	1.7960	(4)
24	C-9		0	1.7960	-
25	C-10		0	1.7960	-
26	C-11		0	1.7960	-
27	C-12	RESERVED	0	1.7960	-
28	C-13	PAYROLL EXPENSE - AVERAGE EMPLOYEES	28	1.7960	(50)
29	C-14	EMPLOYEE BENEFITS - AVERAGE EMPLOYEES	1	1.7960	(2)
30	C-15	PAYROLL TAXES - AVERAGE EMPLOYEES	2	1.7960	(4)
31	C-16	PENSION ASSET	4	1.7960	(7)
32	C-17		0	1.7960	-
33	C-18	EXPIRING SOFTWARE AMORTIZATION	0	1.7960	(1)
34	C-19	T&D OUTSIDE SERVICES	(2)	1.7960	3
35	C-20	HO'OMAIKA'I COSTS	0	1.7960	(1)
36		Total Value of Net Operating Income Adj.	38		$ (69)
37	SCH. A	Net Operating Income Recommendation	$ 139		
38		RECONCILED REVENUE REQUIREMENT			$ 1,747
39		UNRECONCILED DIFFERENCE			2
40	SCH. A	**REVENUE REQUIREMENT RECOMMENDATION** (excluding Inter-Island subsidy)			$ 1,749

LANAI DIVISION

LINE NO.	DESCRIPTION	WEIGHTED COST (SCH. D)	REVENUE CONVERSION MULTIPLIER (a) (b)	PRETAX RETURN
	(A)	(B)	(C)	(D)
	RETURN PER MECO			
1	Short-Term Debt	0.06%	1.7951	0.108%
2	Long-Term Debt	2.45%	1.7951	4.398%
3	Hybrid Securities	0.18%	1.7951	0.323%
4	Preferred Stock	0.10%	1.7951	0.180%
5	Common Equity	6.18%	1.7951	11.093%
6	Total Capitalization	8.97%		16.102%
	RETURN PER CA			
7	Short-Term Debt	0.06%	1.7960	0.108%
8	Long-Term Debt	2.45%	1.7960	4.400%
9	Hybrid Securities	0.18%	1.7960	0.323%
10	Preferred Stock	0.10%	1.7960	0.180%
11	Common Equity (midpoint)	5.49%	1.7960	9.860%
12	Total Capitalization	8.28%		14.871%
13	DIFFERENCE IN PRE-TAX RETURNS			-1.230%

Source: CA Schedules D & A-1.

MOLOKAI DIVISION Exhibit CA-104

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
INDEX TO JOINT ACCOUNTING EXHIBITS
AND SUPPORTING SCHEDULES

SCHEDULE NO.	DESCRIPTION	WITNESS
A	**CHANGE IN GROSS REVENUE REQUIREMENT**	Carver
A-1	REVENUE CONVERSION FACTOR	Carver
B	**SUMMARY OF JURISDICTIONAL RATE BASE**	Carver
B-1	MECO PROPOSED JUNE UPDATES	Carver
B-2	PENSION ASSET	Carver
B-3		Brosch
B-4	ACCUMULATED DEFERRED TAX BALANCES	Brosch
B-5	CASH WORKING CAPITAL	Carver
C	**SUMMARY OF OPERATING INCOME**	Carver
C-1	MECO PROPOSED JUNE 2007 UPDATES	Carver
C-2		Brosch
C-3	FUEL AND PURCHASED POWER EXPENSE & ECAC REVENUES	Brosch
C-4		Brosch
C-5	LUBE OIL EXPENSE CORRECTION	Brosch
C-6		Brosch
C-7		Brosch
C-8	EMISSION FEE EXPENSES	Brosch
C-9		Brosch
C-10		Brosch
C-11		Brosch
C-12	RESERVED	Brosch
C-13	PAYROLL EXPENSE - AVERAGE EMPLOYEES	Carver
C-14	EMPLOYEE BENEFITS - AVERAGE EMPLOYEES	Carver
C-15	PAYROLL TAXES - AVERAGE EMPLOYEES	Carver
C-16	PENSION ASSET	Carver
C-17		Carver
C-18	EXPIRING SOFTWARE AMORTIZATION	Carver
C-19	T&D OUTSIDE SERVICES	Carver
C-20	HO'OMAIKA'I COSTS	Carver
D	**CAPITAL STRUCTURE & COSTS**	Carver/Parcell
E	**RECONCILIATION OF POSITIONS**	Carver

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
CHANGE IN GROSS REVENUE REQUIREMENT
FOR THE FORECAST 2007 TEST YEAR
(000's)

Exhibit CA-104
Schedule A
Page 1 of 1

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	MECO PROPOSED	CA PROPOSED
	(A)	(B)	(C)	(D)
1	Rate Base at Present Rates	(a)	$ 14,774	$ 14,701
2	Change in Rate Base - Working Cash	(a)	(8)	(4)
3	Rate Base at Proposed Rates		$ 14,766	$ 14,697
4	Rate of Return	(b)	8.98%	8.29%
5	Operating Income Required	Line 3 * Line 4	$ 1,325	$ 1,218
6	Net Operating Income Available	(c)	634	619
7	Operating Income Deficiency	Line 5 - Line 6	$ 691	$ 599
8	Revenue Conversion Factor	(d)	1.795059	1.795985
9	Gross Revenue Deficiency (Excess)	Line 7 * Line 8	$ 1,241	$ 1,076
10	**Inter-Island Subsidy**	(e)	(560)	(761)
11	Net Revenue Deficiency (Excess)	Line 9 + Line 10	**$ 681**	**$ 315**

Footnotes:

(a) CA Schedule B.
(b) CA Schedule D.
(c) CA Schedule C.
(d) CA Schedule A-1.
(e) Source: MECO-2001, p. 4 (direct filing). Based on 6.86% return on investment.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
REVENUE CONVERSION FACTOR
FOR THE FORECAST 2007 TEST YEAR

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	RATES	COMPANY PROPOSED	CA PROPOSED
	(A)	(B)	(C)	(D)	(E)
1	Gross Electric Sales Revenue			100.0000%	100.0000%
2	Add: Other Operating Revenue	(e)	1.15067%	1.1507%	1.1507%
3	Total Operating Revenue	Line 1 + 2		101.1507%	101.1507%
4	Less: Franchise Royalty Tax	(a) (b)	2.500%	-2.46975%	-2.46975%
5	Less: Public Service Company Tax	(a) (c)	5.885%	-5.8815%	-5.8850%
6	Less: Public Utility Commission Fees	(a) (c)	0.500%	-0.4997%	-0.5000%
7	Less: Uncollectibles	(a) (d)	0.060%	-0.0600%	0.0000%
8	Net Revenue (before income taxes)	Lines 3..7		92.23975%	92.29592%
9	Less: Effective State Income Tax		6.0150%	-5.54822%	-5.55160%
10	Less: Effective Federal Income Tax		35.0000%	-30.34204%	-30.36051%
11	Net Operating Earnings	Lines 8..10		56.34949%	56.38381%
12	Income to Revenue Multiplier	Line 3 / 11		1.795059	1.793967

Footnotes:

(a) Sources: MECO-WP-2001, pp.15, 27 & 39.

(b) In determining the "increase in operating revenues" for purposes of annualizing franchise tax, MECO-WP-2001 reduces the pro forma rate increase by related uncollectibles before applying the applicable tax rates.

(c) In determining the "increase in operating revenues" subject to PSC Tax and PUC Fees, MECO-WP-2001 adjusts pro forma rate increase to include other operating revenue and exclude uncollectibles before applying the applicable tax rates.

(d) Consumer Advocate does not treat uncollectibles as directly variable with revenues, per CA T-3.

(e) Sources: MECO-WP-2001, pp.14 & 26.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF JURISDICTIONAL RATE BASE
FOR THE FORECAST 2007 TEST YEAR
(000's)

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	MECO PRO FORMA TEST YEAR	CA ADJUSTMENTS	CA PROPOSED
	(A)	(B)	(C)	(D)
1	**Additions**			
2	Net Cost of Plant in Service	$ 18,039	$ 84	$ 18,123
3	*Property Held for Future Use*	-	-	-
4	Fuel Inventory	632	-	632
5	Materials & Supplies Inventories	195	(17)	178
6	Unamort Net SFAS 109 Reg Asset	518	(74)	444
7	Pension Asset	139	(139)	-
8	OPEB Amount	-	-	-
9	Unamort Sys Dev Costs	10	(10)	-
10	**Total Additions**	19,533	(156)	19,377
				-
11	**Deductions**			-
12	Unamortized CIAC	(3,301)	(42)	(3,343)
13	Customer Advances	(154)	28	(126)
14	Customer Deposits	(187)	10	(177)
15	Accumulated Def Income Taxes	(913)	127	(786)
16	*Unamortized ITC*	(499)	(19)	(518)
17	**Total Deductions**	(5,054)	104	(4,950)
18	Difference	14,479	(52)	14,427
19	*Working Cash at Present Rates*	295	(21)	274
20	Rate Base at Present Rates	14,774	(73)	14,701
21	Change in Rate Base - Working Cash	(8)	4	(4)
22	**Rate Base at Proposed Rates**	$ 14,766	$ (69)	14,697
			(a)	

Footnotes:

(a) Source: Schedule B, pg. 2

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF RATE BASE ADJUSTMENTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	ADJUSTMENT NUMBER / SCHEDULE REFERENCE B-1	B-2	B-3	B-4	B-5	B-6	B-7	B-8	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	**Additions**									
2	Net Cost of Plant in Service	$ 84	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 84
3	Property Held for Future Use	-	-	-	-	-	-	-	-	-
4	Fuel Inventory	-	-	-	-	-	-	-	-	-
5	Materials & Supplies Inventories	(17)	-	-	-	-	-	-	-	(17)
6	Unamort Net SFAS 109 Reg Asset	(74)								(74)
7	Pension Asset	4	(143)							(139)
8	OPEB Amount	-								-
9	Unamort Sys Dev Costs	(10)								(10)
10	**Total Additions**	(13)	(143)	-	-	-	-	-	-	(156)
11	**Deductions**									
12	Unamortized CIAC	(42)	-	-	-	-	-	-	-	(42)
13	Customer Advances	28	-	-	-	-	-	-	-	28
14	Customer Deposits	10	-	-	-	-	-	-	-	10
15	Accumulated Def Income Taxes	165	56	-	(94)	-	-	-	-	127
16	Unamortized ITC	(19)	-	-	-	-	-	-	-	(19)
17	**Total Deductions**	142	56	-	(94)	-	-	-	-	104
18	Difference	129	(87)	-	(94)	-	-	-	-	(52)
19	Working Cash at Present Rates	(13)	-	-	-	(8)	-	-	-	(21)
20	Rate Base at Present Rates	116	(87)	-	(94)	(8)	-	-	-	(73)
21	Change in Rate Base - Working Cash	(7)	-	-	-	11	-	-	-	4
22	**Rate Base at Proposed Rates**	$ 109	$ (87)	$ -	$ (94)	$ 3	$ -	$ -	$ -	$ (69)

ADJUSTMENTS:

B-1 MECO PROPOSED JUNE UPDATES
B-2 PENSION ASSET
B-3
B-4 ACCUMULATED DEFERRED TAX BALANCES
B-5 CASH WORKING CAPITAL
B-6
B-7
B-8

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REVISED AMOUNT	MECO DIRECT AMOUNT	ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)
1	**Additions**			
2	Net Plant in Service	$ 18,123,000	$ 18,039,000	$ 84,000
3	Property Held for Future Use	-	-	-
4	Fuel Inventory	632,000	632,000	-
5	Materials & Supplies Inventories	178,000	195,000	(17,000)
6	Unamort Net SFAS 109 Reg Asset	444,000	518,000	(74,000)
7	Pension Asset	143,000	139,000	4,000
8	OPEB Amount	-	-	-
9	Unamort Sys Dev Costs	-	10,000	(10,000)
10	**Total Additions**	19,520,000	19,533,000	(13,000)
11	**Deductions**			
12	Unamortized CIAC	(3,343,000)	(3,301,000)	(42,000)
13	Customer Advances	(126,000)	(154,000)	28,000
14	Customer Deposits	(177,000)	(187,000)	10,000
15	Accumulated Def Income Taxes	(748,000)	(913,000)	165,000
16	Unamortized ITC	(518,000)	(499,000)	(19,000)
17	**Total Deductions**	(4,912,000)	(5,054,000)	142,000
18	Rate Base (before Working Cash)	14,608,000	14,479,000	129,000
19	Working Cash at Present Rates	282,000	295,000	(13,000)
20	Rate Base at Present Rates	14,890,000	14,774,000	116,000
21	Change in Rate Base - Working Cash	(15,000)	(8,000)	(7,000)
22	**Rate Base at Proposed Rates**	$ 14,875,000	$ 14,766,000	$ 109,000
		(a)	(b)	

Footnotes:

(a) MECO's response to CA-IR-304, p. 38.

(b) Sources: MECO-2001, p. 4, & MECO-WP-2001, p. 34 (per original filing).

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
PENSION ASSET
FOR THE FORECAST 2007 TEST YEAR

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	TEST YEAR AMOUNT	ADJUSTMENT
	(A)	(B)	(C)	(D)
1	MECO UpdateD Pension Asset	(a)	$ 143,000	$ (143,000)
2	Less: Accumulated Deferred Income Tax Reserve	(b)	(55,687)	55,687
3	Net Pension Asset in MECO's Updated Rate Base		$ 87,313	
4	**CA ADJUSTMENT TO ELIMINATE NET PENSION**			**$ (87,313)**
5	**ASSET FROM RATE BASE**			

Footnotes:

(a) Prepaid Pension Asset:

	12/31/06 Actual	12/31/07 FCST
Ending Balance	$ 236,000	$ 50,000

Source: MECO-928 & MECO T-9 June 2007 Update, Attachment 5.

(b) ADIT Reserve:

	12/31/06 Actual	12/31/07 FCST
State ADIT	$ (13,980)	$ (3,237)
Federal ADIT	(76,453)	(17,704)
Total	$ (90,433)	$ (20,941)

Source: MECO-WP-1305 & MECO-1305, June 2007 Update (Att. 1, pp.9-12).

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	**Restore Deferred Taxes related to AFUDC and TCI Improperly Removed by MECO:**		
2	AFUDC in CWIP - 12/31/2006 Federal	CA-IR-182, p.15	$ 1,015,303
3	AFUDC in CWIP - 12/31/2006 State	CA-IR-182, p.16	185,655
4	Reg-Asset-AFUDC Eq Grossup 12/31/2006 Federal	CA-IR-182, p.15	444,618
5	Reg-Asset-AFUDC Eq Grossup 12/31/2006 State	CA-IR-182, p.16	81,301
6	**Total Adjustments to 12/31/2006 Beginning of Test Year**		1,726,877
7	AFUDC in CWIP - 12/31/2007 Federal	CA-IR-182, p.15	$ 801,688
8	AFUDC in CWIP - 12/31/2007 State	CA-IR-182, p.16	146,594
9	Reg-Asset-AFUDC Eq Grossup 12/31/2007 Federal	CA-IR-182, p.15	349,356
10	Reg-Asset-AFUDC Eq Grossup 12/31/2007 State	CA-IR-182, p.16	63,882
11	**Total Adjustments to 12/31/2007 End of Test Year**		1,361,520
12	Average Test Year Adjustment for AFUDC/TCI Restoration	Average Lines 6, 11	**$1,544,199**
13	**Correct Deferred Taxes Related to Emission Fees:**		
14	Emission Fee Federal Deferred Taxes at 12/31/2007 per MECO	CA-IR-182, p.15	$331,478
15	Emission Fee State Deferred Taxes at 12/31/2007 per MECO	CA-IR-182, p.16	60,612
16	Test Year End Emission Fee Deferred Taxes per MECO		392,090
17	Revised emission Fee Federal Deferred Taxes -12/31/2007	CA-IR-379	$127,351
18	Revised emission Fee State Deferred Taxes -12/31/2007	"	23,286
19	Corrected Test Year End Emission Fee Deferred Taxes		150,637
20	Difference in Year-end Deferred Tax Balance (Negative DR value)	Line 16-Line 19	$241,453
21	One-half Adjustment for Average Rate Base	Line 20 * 1/2	**$120,727**
22	**Include Deferred Taxes on IRP/DSM Program Costs:**		
23	IRP/DSM Federal Deferred Taxes at 12/31/2006 per MECO	CA-IR-182, p.15	$373,233
24	IRP/DSM State Deferred Taxes at 12/31/2006 per MECO	CA-IR-182, p.16	68,249
25	Test Year Beginning IRP/DSM Related Deferred Taxes per MECO		441,482
26	IRP/DSM Federal Deferred Taxes at 12/31/2007 per MECO	CA-IR-182, p.15	$373,233
27	IRP/DSM State Deferred Taxes at 12/31/2007 per MECO	CA-IR-182, p.16	68,429
28	Test Year End IRP/DSM Related Deferred Taxes per MECO		441,662
29	Average Test Year Adjustment for IRP/DSM Deferred Tax Restoration	Average Lines 25, 28	**$441,572**
30	**CONSUMER ADVOCATE ADJUSTMENT INCREASING ACCUMULATED**	Line 12+21+29	**$ 2,106,497**
31	**DEFERRED INCOME TAXES**		
32	Allocation: Maui Division Portion of Line 30 Total Adjustment - 91.75%	CA-IR-373 Att.1	1,932,711
33	Lanai Division Portion of Line 30 Total Adjustment - 3.80%%		80,047
34	Molokai Division Portion of Line 30 Total Adjustment - 4.45%		**93,739**

Note: All amounts increase credit deferred taxes, thereby reducing rate base.

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
CASH WORKING CAPITAL
FOR THE FORECAST 2007 TEST YEAR

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	Revenue Lag (Days)	Payment Lag (Days)	Net Lag (Days)	Annual Amount	Average Daily Amount Present Rates (F) / 365	Average Daily Amount Proposed Rates (F) / 365	CWC Present Rates (E) x (G)	CWC Proposed Rates (E) x (H)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	Fuel Purchases	(a)	36.0	20.0	16.0	$ 7,253,000	$ 19,871	$ 19,871	$ 317,940	$ 317,940
2	O&M Labor	(a)	36.0	12.0	24.0	910,647	2,495	2,495	59,878	59,878
3	O&M Nonlabor	(a)(c)	36.0	36.6	(0.6)	1,424,102	3,902	3,902	(2,212)	(2,212)
4	Non-Cash Items:									
5	Pension Asset Amortization	(a)(b)	0.0	0.0	0.0	-	-	-	-	-
6	Pension Accrual	(b)(c)	0.0	0.0	0.0	128,068	351	351	-	-
7	Purchased Power	(a)			0.0	-	-	-	-	-
8	Revenue Taxes - Present Rates	(a)	36.0	68.0	(32.0)	1,129,000	3,093		(98,981)	
9	Revenue Taxes - Proposed Rates	(a)	36.0	68.0	(32.0)	1,157,248		3,171		(101,457)
10	Income Taxes - Present Rates	(a)	36.0	40.0	(4.0)	257,684	706		(2,824)	
11	Income Taxes - Proposed Rates	(a)	36.0	40.0	(4.0)	370,793		1,016		(4,063)
12	Total Cash Working Capital								273,801	270,085
13	Less: MECO Revised Cash Working Capital	(a)							(282,000)	(267,000)
14	**CONSUMER ADVOCATE ADJUSTMENT TO EXCLUDE NON-CASH ITEMS**								**$ (8,199)**	**$ 3,085**
15	Change in Cash Working Capital									$ 11,284

Footnotes:

(a) Source: MECO-1519, as revised by MECO T-15 June 2007 Update, p. 23.

(b) Both pension items are non-cash, absent a specific funding commitment – regardless of the existence of a tracking mechanism.
The Consumer Advocate proposes to excluded non-cash excluded from CWC calculation, by assigning "zero" for both revenue lag and expense lag.

(c) O&M Nonlabor:

		TY Expense $	% Distribution	Payment Lag	Wtd. Lag Days
Pension Accrual	(1)	$ 128,068			
Subtotal		$ 128,068			
OPEB	(2)(3)(4)	32,892	2.31%	83.71	1.9
Emission Fees	(4)	18,285	1.28%	305.50	3.9
EPRI Dues	(4)	10,666	0.75%	22.38	0.2
Other Non-Labor O &M	(4)	1,362,260	95.66%	31.93	30.5
Subtotal		$ 1,424,102	100.00%		**36.6** Days
Total O&M Non-Labor		$ 1,552,170	100.00%		

Source: MECO-WP-1507, p. 23 per MECO T-15 June 2007 Update (p. 27) & CA Molokai Posting detail.

(1) Accrual & amortization amounts removed from Other Non-Labor O&M and listed separately in CWC calculation.

(2) MECO has historically funded FAS106 accruals. Regardless of OPEB tracker, funding expected to continue.

(3) Source: Expense lags from MECO T-15 June 2007 Update, p. 27.

(4) Amounts allocated between divisions.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF OPERATING INCOME
FOR THE FORECAST 2007 TEST YEAR
(000's)

MOLOKAI DIVISION

LINE NO.	DESCRIPTION (A)	MECO PRO FORMA (B)	CA ADJUSTMENTS (C)	CA PROPOSED (D)
1	Electric Sales Revenue	$ 12,631	$ -	$ 12,631
2	Other Operating Revenue	107	-	107
3	**Total Operating Revenues**	$ 12,738	$ -	$ 12,738
4	Fuel	$ 7,253	$ -	$ 7,253
5	Purchased Power	-	-	-
6	Production	1,179	(14)	1,164
7	Transmission	33	(2)	31
8	Distribution	454	(27)	426
9	Customer Accounts	169	-	169
10	Allowance for Uncoll Accounts	8	-	8
11	Customer Service	2	-	2
12	Administrative & General	666	(5)	662
13	**Operation and Maintenace**	9,764	(48)	9,716
14	Depreciation and Amortization	1,030	98	1,128
15	Amortization of State ITC	(23)	-	(23)
16	Taxes Other Than Income	1,198	(0)	1,198
17	Interest on Customer Deposits	11	-	11
18	Income Taxes	124	(34)	90
19	**Total Operating Expenses**	$ 12,104	$ 15	$ 12,119
20	**Operating Income**	$ 634	$ (15)	$ 619
		(a)	(b)	

Footnotes:

(a) Source: MECO-2001 pg. 4 of 4.

(b) Source: CA Schedule C, page 4

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF NOI ADJUSTMENTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-1	C-2	C-3	C-4	C-5	C-6	C-7	C-8	C-9	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Sales Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Operating Revenue	-	-	-	-	-	-	-	-	-	$ -
3	**Total Operating Revenues**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Fuel	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Purchased Power	-	-	-	-	-	-	-	-	-	-
6	Production	-	-	-	-	(8)	-	-	(5)	-	(13)
7	Transmission	-	-	-	-	-	-	-	-	-	-
8	Distribution	-	-	-	-	-	-	-	-	-	-
9	Customer Accounts	-	-	-	-	-	-	-	-	-	-
10	Allowance for Uncoll Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	-	-	-	-	-	-	-	-	-	-
12	Administrative & General	10	-	-	-	-	-	-	-	-	10
13	**Operation and Maintenance**	10	-	-	-	(8)	-	-	(5)	-	(3)
14	Depreciation and Amortization	98	-	-	-	-	-	-	-	-	98
15	Amortization of State ITC										-
16	Taxes Other than Income	-	-	-	-	-	-	-	-	-	-
17	Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-
18	*Income Taxes*	(57)	-	-	-	3	-	-	2	-	(52)
19	**Total Operating Expenses**	$ 51	$ -	$ -	$ -	$ (5)	$ -	$ -	$ (3)	$ -	$ 43
20	**Operating Income**	$ (51)	$ -	$ -	$ -	$ 5	$ -	$ -	$ 3	$ -	$ (43)

ADJUSTMENTS:

C-1	MECO PROPOSED JUNE 2007 UPDATES	**C-6**	
C-2		**C-7**	
C-3	FUEL AND PURCHASED POWER EXPENSE & ECAC REVENUES	**C-8**	EMISSION FEE EXPENSES
C-4		**C-9**	
C-5	LUBE OIL EXPENSE CORRECTION		

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF NOI ADJUSTMENTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-10	C-11	C-12	C-13	C-14	C-15	C-16	C-17	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Sales Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Operating Revenue	-	-	-	-	-	-	-	-	-	-
3	**Total Operating Revenues**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Fuel	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Purchased Power	-	-	-	-	-	-	-	-	-	-
6	Production	(13)	-	-	-	(1)	-	-	-	-	(14)
7	Transmission	-	-	-	-	(0)	-	-	-	-	(0)
8	Distribution	-	-	-	-	(2)	-	-	-	-	(2)
9	Customer Accounts	-	-	-	-	-	-	-	-	-	-
10	Allowance for Uncoll Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	-	-	-	-	-	-	-	-	-	-
12	Administrative & General	10	-	-	-	-	(2)	-	(10)	-	(2)
13	**Operation and Maintenance**	(3)	-	-	-	(3)	(2)	-	(10)	-	(18)
14	Depreciation and Amortization	98	-	-	-	-	-	-	-	-	98
15	Amortization of State ITC	-									-
16	Taxes Other than Income	-	-	-	-	-	-	(0)	-	-	(0)
17	Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-
18	*Income Taxes*	*(52)*	-	-	-	*1*	*1*	*0*	*4*	-	*(46)*
19	**Total Operating Expenses**	$ 43	$ -	$ -	$ -	$ (2)	$ (1)	$ (0)	$ (6)	$ -	$ 33
20	**Operating Income**	$ (43)	$ -	$ -	$ -	$ 2	$ 1	$ 0	$ 6	$ -	$ (33)

ADJUSTMENTS:

C-10
C-11
C-12 RESERVED
C-13 PAYROLL EXPENSE - AVERAGE EMPLOYEES
C-14 EMPLOYEE BENEFITS - AVERAGE EMPLOYEES
C-15 PAYROLL TAXES - AVERAGE EMPLOYEES
C-16 PENSION ASSET
C-17

Witness: S. Carver

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
SUMMARY OF NOI ADJUSTMENTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-18	C-19	C-20	C-21	C-22	C-23	C-24	C-25	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Sales Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Operating Revenue	-	-	-	-	-	-	-	-	-	-
3	**Total Operating Revenues**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Fuel	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Purchased Power	-	-	-	-	-	-	-	-	-	-
6	Production	(14)	-	-	-	-	-	-	-	-	(14)
7	Transmission	(0)	-	(2)	-	-	-	-	-	-	(2)
8	Distribution	(2)	-	(25)	-	-	-	-	-	-	(27)
9	Customer Accounts	-	-	-	-	-	-	-	-	-	-
10	Allowance for Uncoll Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	-	-	-	-	-	-	-	-	-	-
12	Administrative & General	(2)	(1)	-	(1)	-	-	-	-	-	(5)
13	**Operation and Maintenance**	(18)	(1)	(27)	(1)	-	-	-	-	-	(48)
14	Depreciation and Amortization	98	-	-	-	-	-	-	-	-	98
15	Amortization of State ITC	-									-
16	Taxes Other than Income	(0)	-	-	-	-	-	-	-	-	(0)
17	Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-
18	Income Taxes	(46)	0	11	0	-	-	-	-	-	(34)
19	**Total Operating Expenses**	$ 33	$ (1)	$ (17)	$ (1)	$ -	$ -	$ -	$ -	$ -	$ 15
20	**Operating Income**	$ (33)	$ 1	$ 17	$ 1	$ -	$ -	$ -	$ -	$ -	$ (15)

C-18	EXPIRING SOFTWARE AMORTIZATION	**C-22**
C-19	T&D OUTSIDE SERVICES	**C-23**
C-20	HO'OMAIKA'I COSTS	**C-24**
C-21		**C-25**

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	REVISED AMOUNT	MECO DIRECT AMOUNT	ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)	(E)
1	**MECO Update Adjustments to Revenues:**				
		Update CA-IR-304, p.36			
2	Electric Sales Revenue	MECO-2001, p.4	$ 12,631,400	$ 12,631,400	$ -
3	Other Operating Revenue	MECO-2001, p.4	107,000	107,000	-
4	Total Operating Revenue		$ 12,738,400	$ 12,738,400	$ -
5	**MECO Update Adjustments to Expenses:**				
		Update CA-IR-304, p.36			
6	Fuel Expense	MECO-2001, p.4	$ 7,253,000	$ 7,253,000	$ -
		Update CA-IR-304, p.36			
7	Purchased Power Expense	MECO-2001, p.4	-	-	-
8	Production O&M Expenses:	Update T-5, Att.1			
9	Labor	MECO-503	551,700	551,700	-
10	Non-Labor	MECO-503	626,900	626,900	-
11	Transmission Expenses:	Update CA-IR-304, p.36			
12	Labor	MECO-604, p. 2	9,781	9,781	-
13	Non-Labor	MECO-604, p. 2	23,363	23,363	-
14	Distribution Expenses:	Update CA-IR-304, p.36			
15	Labor	MECO-606, p. 2	160,835	160,835	-
16	Non-Labor	MECO-606, p. 2	292,838	292,838	-
17	Customer Accounts Expenses:	Update CA-IR-304, p.36			
18	Labor	MECO-709	165,000	165,000	-
19	Non-Labor	MECO-709	4,000	4,000	-
20	Uncollectibles	MECO-709	8,000	8,000	-
21	Customer Service Expenses:	Update CA-IR-304, p.36			
22	Labor	MECO-809	-	-	-
23	Non-Labor	MECO-809	2,000	2,000	-
24	Administrative & General Expenses:	Update T-9, Att.1, p.15			
25	Labor	MECO-901, p. 15	28,300	28,300	-
26	Non-Labor	MECO-901, p. 15	648,200	638,100	10,100
27	Total O&M Expenses				
28	Labor	Lines 9+12+15+18+22+25	915,616	915,616	-
29	Non-Labor	Lines 6+7+10+13+16+19+20+23+26	8,858,301	8,848,201	10,100
30	**Total O&M Expenses**		$ 9,773,917	$ 9,763,817	$ 10,100
31	**Depreciation & Amortization**	Update T-12, p.4	$ 1,127,971	$ 1,030,470	$ 97,501
32	**Amortization of State ITC**	Update CA-IR-304, p.36	(23,000)	(23,000)	-
33	**Taxes Other than Income**	Update CA-IR-304, p.36	1,198,000	1,198,000	-
34	**Interest on Customer Deposits**	Update CA-IR-304, p.36	11,000	11,000	-
35	**Income Taxes**	Update CA-IR-304, p.36	67,000	124,000	(57,000)
36	Total Operating Expenses		$ 12,154,888	$ 12,104,287	$ 50,601
37	Net Operating Income		$ 583,512	$ 634,113	$ (50,601)

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
FUEL AND PURCHASED POWER EXPENSE & ECAC REVENUES
FOR THE FORECAST 2007 TEST YEAR

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	MECO PROPOSED AMOUNT	CONSUMER ADVOCATE AMOUNT	DIFFERENCE ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)	(E)
1	Fuel Oil Expense - Production Simulation	MECO-401 /CA-204	$ 7,247,200	$ 7,247,200	$ -
2	Fuel Related Expense	MECO-401 / CA-205	$ 5,500	$ 5,500	$ -
3	**CA ADJUSTMENT TO FUEL EXPENSE**	Line 1 + 2	$ 7,252,700	$ 7,252,700	$ -
4	Purchased Power - Energy Payments	MECO-507 / CA-210	$ -		$ -
5	Purchased Power - Capacity Payments	MECO-507 / CA-210	$ -		$ -
6	**CA ADJUSTMENT TO PURCHASED POWER EXPENSE**	Line 4 + 5	$ -	$ -	$ -
7	**Energy Cost Adjustment Rate / Present Rates (cents/kwh)**	CA-201	15.774	15.774	-
8	Test Year Proposed Sales - Gigawatthours		MECO MWH HECO-201	Times ECAC Difference	ECAC Revenue Change
9	Residential R		13,077.0	-	$ -
10	Commercial G/J		11,979.0	-	-
11	Commercial J (included with Schedule G)			-	
12	Commercial H		1,994.2	-	-
13	Large Commercial P		9,019.4	-	-
14	Lighting F		478.5	-	-
15	Total Sales Volume		36,548.1		
16	**CA ADJUSTMENT TO ECAC GROSS REVENUES AT CA FUEL/ENERGY COSTS**				$ -
17	Additional Revenue Taxes on Incremental ECAC Revenues		Tax Rate	Times ECAC Revenue Change	
18	Franchise Royalty Tax		2.500%	$0	$ -
19	Public Service Company Tax		5.885%	$0	-
20	Public Utility Commission Fees		0.500%	$0	-
21	**CA ADJUSTMENT TO TAXES OTHER - REVENUE TAX ON ECAC REVENUES**				$ -

EXHIBIT CA-104

SCHEDULE C-5

contains confidential information

and is being submitted under separate cover

pursuant to Protective Order No. 23379

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
EMISSION FEE EXPENSES
FOR THE FORECAST 2007 TEST YEAR

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	MECO Updated Emission Fee Calculation - Molokai Division		
2	Palaau Power Plant Tons Emissions - Tons	CA-IR-104, page 2	416
3	Times: Updated Estimated Fee per Ton for 2007	CA-IR-327	$57.14
4	Estimated Annual Emission Fees - Assuming no Waivers	Line 4 * Line 5	$23,770
5	Times Factor to Assume Waivers in 3 of 13 years (10/13)	Factor 10/13 years	76.9231%
6	Normalized Emission Fees at Updated Rate/Ton per Consumer Advocate	Line 6 * Line 7	$18,285
7	Less: Test Year Emission Fees Estimated by MECO	CA-IR-2, MECO T-5, Att.30a	$23,278
8	**CONSUMER ADVOCATE ADJUSTMENT TO UPDATE AND**	Line 6 - Line 7	**$ (4,993)**
9	**NORMALIZE EMISSION FEES**		

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	This schedule has been reserved for future use.		

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
PAYROLL EXPENSE - AVERAGE EMPLOYEES
FOR THE FORECAST 2007 TEST YEAR

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	MAUI	LANAI	**MOLOKAI**	TOTAL
	(A)	(B)	(C)	(D)	**(E)**	(F)
1	Average Headcount Adjustment:					
2	Production O&M	(a)	$ (153,076)	$ (42,274)	**$ (1,018)**	$ (196,368)
3	Transmission & Distribution O&M	(b)	(179,355)	(3,715)	**(1,935)**	(185,006)
4	Customer Accounts O&M	(c)	(70,341)	-	**-**	(70,341)
5	Customer Service O&M	(d)	(33,272)	-	**-**	(33,272)
6	Administrative & General O&M	(e)	(5,041)	-	**-**	(5,041)
7	**CONSUMER ADVOCATE AVERAGE STAFFING**		$ (441,086)	$ (45,990)	**$ (2,953)**	$ (490,029)
8	**ADJUSTMENT**					

Footnotes:

(a) Source: CA-WP-101-C13, p. 1.
(b) Source: CA-WP-101-C13, p. 2.
(c) Source: CA-WP-101-C13, p. 3.
(d) Source: CA-WP-101-C13, p. 4.
(e) Source: CA-WP-101-C13, p. 6.

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	MECO REVISED 2007 FORECAST	CA EMPLOYEE BENEFITS ADJUSTMENT	CA ADJUSTED FORECAST
	(A)	(B)	(C)	(D)	(E)
1	A/C 926000: Employee Pensions and Benefits				
2	Qualified Pension Plan		$ 4,255,300		$ 4,255,300
3	Non-Qualified Pension Plans		-		-
4	Other Postretirement Benefits		1,092,900		1,092,900
5	Long-Term Disability Benefits		126,300		126,300
6	Flex Credits Less Prices		(285,100)	9,067	(276,033)
7	Group Medical Plan		1,906,800	(65,616)	1,841,184
8	Group Dental Plan		279,900	(9,552)	270,348
9	Group Vision Plan		44,300	(1,512)	42,788
10	Group Life Insurance Plan		238,400	(7,621)	230,779
11	Other Benefits/Administration		414,500		414,500
12	Subtotals: Non-Labor		8,073,300	(75,234)	7,998,066
13	Labor		80,100		80,100
14	Total 926000		$ 8,153,400	$ (75,234)	$ 8,078,166
15	926020 Employee Benefits Transfer	-25.04%	(2,042,000)	$ 18,842	$ (2,023,158)
16	Total Charged to O&M	Line 15 + 16	$ 6,111,400	$ (56,392)	$ 6,055,008
			(a)	(b)	
17	**CA ADJUSTMENT TO REDUCE EMPLOYEE BENEFIT**		(c) (d)	**$ (56,392)**	
18	**COSTS RELATED TO AVERAGE STAFFING ADJUSTMENT**				

Footnotes:

(a) Source: MECO T-10 June 2007 Update, Exhibit 1 & MECO T-10, Attachment 1, pp.1-2.

(b) Source for CA Average Employee Benefits Adjustment Calculations:

Flex Credits Less Prices	CA-WP-101-C14, p. 1
Group Medical Plan	CA-WP-101-C14, p. 2
Group Dental Plan	CA-WP-101-C14, p. 2
Group Vision Plan	CA-WP-101-C14, p. 2
Group Life Insurance Plan	CA-WP-101-C14, p. 3

(c) Net Headcount Reduction:

	# Employees	
Production	(2.5)	
Trans. & Distr.	(8.5)	
Customer Accts.	(0.5)	Excludes counts removed via other Dpmts.
Customer Service	-	Excludes counts removed via other Dpmts.
A&G Accts.	-	Excludes counts removed via other Dpmts.
Average Employee Count Reduction	(11.5)	

Source: Counts determined from CA-WP-101-C13.

(d) Allocation:

Maui Division	93.181%	$ (52,547)
Lanai Division	2.669%	(1,505)
Molokai Division	**4.150%**	**(2,340)**
Total	100.00%	$ (56,392)

Source: MECO T-10 June 2007 Update, Exhibit 1 & MECO T-10, Attachment 1, p.2.

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	MAUI	LANAI	**MOLOKAI**	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)
1	Average Headcount Adjustment:					
2	Production O&M	(a)	$ (153,076)	$ (42,274)	**$ (1,018)**	$ (196,368)
3	Transmission & Distribution O&M	(a)	(179,355)	(3,715)	**(1,935)**	(185,006)
4	Customer Accounts O&M	(a)	(70,341)	-	**-**	(70,341)
5	Customer Service O&M	(a)	(33,272)	-	**-**	(33,272)
6	Administrative & General O&M	(a)	(5,041)	-	**-**	(5,041)
7	Consumer Advocate Average Staffing Adjustment	(a)	(441,086)	(45,990)	**(2,953)**	(490,029)
8	Composite Payroll Tax Rate	(b)	7.29%	7.29%	**7.29%**	7.29%
9	**CA ADJUSTMENT TO REDUCE PAYROLL TAX EXPENSE**		$ (32,143)	$ (3,351)	**$ (215)**	$ (35,710)
10	**RELATED TO AVERAGE STAFFING ADJUSTMENT**					

Footnotes:

(a) Source: CA Adjustment C-13.

(b) Payroll Tax Rate:

Total FICA	$ 1,932,671
Estimated Gross Pay	26,520,940
Composite FICA Rate	7.29%

Source: MECO-WP-1301, p. 3.

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
	MECO Proposed Pension Asset Amortization		
1	Pension Asset Balance at 12/31/2007	(a)(b)	$ 50,000
2	Amortization Period	(a)	5
3	Annual Amortization	(a)	$ 10,000
4	**CA ADJUSTMENT TO ELIMINATE MECO's PROPOSED**		**$ (10,000)**
5	**PENSION ASSET AMORTIZATION**		

Footnotes:

(a) Source: MECO-928 (revised) & MECO T-9 June 2007 Update (Attachment 5, p.3).

(b) Source: CA Schedule B-2.

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Ellipse/MINCOM Monthly Amortization	(a) (b)	$ 825
2	Number of Amortization Months in 2007	(a)	9
3	2007 MINCOM Fee Buy-Down Amortization		7,425
4	MECO's % Share	(a)	15%
5	MECO's 2007 MINCOM Buy-Down Amortization		$ 1,114
6	**CA ADJUSTMENT TO ELIMINATE MECO'S**	A/C 923	**$ (1,114)**
7	**AMORTIZATION EXPIRING IN SEPTEMBER 2007**		

Footnotes:

(a) Source: MECO T-9 response to CA-IR-2, Attachment B.

(b) Relicensing Fee Amortization.

(c) Allocation:

Maui Division	92.75%	$ 15,941
Lanai Division	2.45%	421
Molokai Division	4.80%	825
Total	100.00%	$ 17,187

Source: Allocations per CA-IR-373.

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	2005 Actual	(a)	$ 169,762
2	2006 Actual	(a)	103,131
3	2007 Forecast	(a)	177,400
4	Total		$ 450,293
5	Number of Periods		3
6	Three-Year Average		$ 150,098
7	MECO Test Year Forecast		(177,400)
8	**CONSUMER ADVOCATE ADJUSTMENT TO NORMALIZE T&D**		**$ (27,302)**
9	**OUTSIDE SERVICES COSTS TO A THREE-YEAR AVERAGE**		

Footnotes:

(a)

T&D Outside Contract Services:	2005	2006	2007 FCST
Vegetation Management	$ 130,770	$ 61,077	$ 125,840
Contract Services Other	38,992	42,054	51,560
	$ 169,762	$ 103,131	$ 177,400

Source: CA-IR-114, CA-IR-135 (revised 9/11/07) & CA-IR-338.

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	2004 Actual	(a)	$ 258
2	2005 Actual	(a)	2,499
3	2006 Actual	(a)	-
4	2007 Forecast	(b)	2,486
5	Total		5,244
6	Number of Periods		4
7	Four-Year Average		1,311
8	MECO Test Year Forecast	(b)	(2,486)
9	**CONSUMER ADVOCATE ADJUSTMENT TO NORMALIZE**	A/C 920	**$ (1,175)**
10	**HO'OMAIKA'I AWARD COSTS TO A FOUR-YEAR AVERAGE**		(c)

Footnotes:

(a) Source: MECO response to CA-IR-372.

(b) Source: MECO T-9 response to CA-IR-2, Attachment C.

(c) Allocation:

Maui Division	92.75%	$ (22,714)
Lanai Division	2.45%	(600)
Molokai Division	4.80%	(1,175)
Total	100.00%	$ (24,489)

Source: Allocations per CA-IR-373.

MAUI ELECTRIC COMPANY
DOCKET NO. 2006-0387
CAPITAL STRUCTURE & COSTS
FOR THE FORECAST 2007 TEST YEAR
(000's)

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	AMOUNTS IN THOUSANDS	PERCENT OF TOTAL	EARNINGS REQMTS	WEIGHTED EARNINGS REQMTS
	(A)	(B)	(C)	(D)	(E)
	MECO Proposed (a)				
1	Short-Term Debt	$ 4,750	1.27%	5.00%	0.06%
2	Long-Term Debt	150,585	40.15%	6.11%	2.45%
3	Hybrid Securities	9,192	2.45%	7.47%	0.18%
4	Preferred Stock	4,693	1.25%	8.34%	0.10%
5	Common Equity	205,882	54.89%	11.25%	6.18%
6	Total Capitalization	$ 375,102	100.00%		**8.98%**
	CA Proposed (b)				
7	Short-Term Debt	$ 4,750	1.27%	5.00%	0.06%
8	Long-Term Debt	150,585	40.15%	6.11%	2.45%
9	Hybrid Securities	9,192	2.45%	7.47%	0.18%
10	Preferred Stock	4,693	1.25%	8.34%	0.10%
11	Common Equity (midpoint)	205,882	54.89%	10.00%	5.49%
12	Total Capitalization	$ 375,102	100.00%		**8.29%**

Footnotes :

(a) Source: MECO-2001

(b) Source: Consumer Advocate witness David Parcell (CA-T-4) Exhibit CA-413.

MOLOKAI DIVISION

LINE NO.	SCH./ ADJ. NO.	DESCRIPTION	AMOUNT	DIFFERENCE IN PRETAX RETURN	REVENUE REQUIREMENT VALUE
		(A)	(B)	(C)	(D)
1	SCH. A	**Asserted Revenue Requirement** (excluding inter-island subsidy)			$ 1,241
2	SCH. B	**Return Difference At MECO Rate Base** (before pro forma working cash)	$ 14,774	-1.230%	(182)
3		Subtotal Revenue Requirement			$ 1,059
				PRE-TAX RETURN	
4		**RATE BASE ADJUSTMENTS**			
5	B-1	MECO PROPOSED JUNE UPDATES	116	14.87%	$ 17
6	B-2	PENSION ASSET	(87)	14.87%	(13)
7	B-3		-	14.87%	-
8	B-4	ACCUMULATED DEFERRED TAX BALANCES	(94)	14.87%	(14)
9	B-5	CASH WORKING CAPITAL	(8)	14.87%	(1)
10		Total Value of Rate Base Adustments	(73)		(11)
11		Rate Base Recommendation (before pro forma working cash)	14,701	377,696	
12		Change in Working Cash at Proposed Rates (MECO vs CA)	(4)	16.10%	(1)
13		Rate Base With Working Cash Difference	$ 14,697		$ (11)
				REVENUE CONVERSION MULTIPLIER	
14	SCH. A	**Adjusted Net Operating Income**	$ 634		
15		**NET OPERATING INCOME ADJUSTMENTS**			
16	C-1	MECO PROPOSED JUNE 2007 UPDATES	(51)	1.7960	$ 91
17	C-2		0	1.7960	-
18	C-3	FUEL AND PURCHASED POWER EXPENSE & ECAC REVENUES	0	1.7960	-
19	C-4		0	1.7960	-
20	C-5	LUBE OIL EXPENSE CORRECTION	5	1.7960	(9)
21	C-6		0	1.7960	-
22	C-7		0	1.7960	-
23	C-8	EMISSION FEE EXPENSES	3	1.7960	(5)
24	C-9		0	1.7960	-
25	C-10		0	1.7960	-
26	C-11		0	1.7960	-
27	C-12	RESERVED	0	1.7960	-
28	C-13	PAYROLL EXPENSE - AVERAGE EMPLOYEES	2	1.7960	(3)
29	C-14	EMPLOYEE BENEFITS - AVERAGE EMPLOYEES	1	1.7960	(3)
30	C-15	PAYROLL TAXES - AVERAGE EMPLOYEES	0	1.7960	(0)
31	C-16	PENSION ASSET	6	1.7960	(11)
32	C-17		0	1.7960	-
33	C-18	EXPIRING SOFTWARE AMORTIZATION	1	1.7960	(1)
34	C-19	T&D OUTSIDE SERVICES	17	1.7960	(30)
35	C-20	HO'OMAIKA'I COSTS	1	1.7960	(1)
36		Total Value of Net Operating Income Adj.	(15)		$ 27
37	SCH. A	Net Operating Income Recommendation	$ 619		
38		RECONCILED REVENUE REQUIREMENT			$ 1,075
39		UNRECONCILED DIFFERENCE			2
40	SCH. A	**REVENUE REQUIREMENT RECOMMENDATION** (excluding Inter-Island subsidy)			$ 1,076

MOLOKAI DIVISION

LINE NO.	DESCRIPTION	WEIGHTED COST (SCH. D)	REVENUE CONVERSION MULTIPLIER (a) (b)	PRETAX RETURN
	(A)	(B)	(C)	(D)
	RETURN PER MECO			
1	Short-Term Debt	0.06%	1.7951	0.108%
2	Long-Term Debt	2.45%	1.7951	4.398%
3	Hybrid Securities	0.18%	1.7951	0.323%
4	Preferred Stock	0.10%	1.7951	0.180%
5	Common Equity	6.18%	1.7951	11.093%
6	Total Capitalization	8.97%		16.102%
	RETURN PER CA			
7	Short-Term Debt	0.06%	1.7960	0.108%
8	Long-Term Debt	2.45%	1.7960	4.400%
9	Hybrid Securities	0.18%	1.7960	0.323%
10	Preferred Stock	0.10%	1.7960	0.180%
11	Common Equity (midpoint)	5.49%	1.7960	9.860%
12	Total Capitalization	8.28%		14.871%
13	DIFFERENCE IN PRE-TAX RETURNS			-1.230%

Source: CA Schedules D & A-1.